NEXTera ENERGY
POINT BEACH

October 4, 2022

L-2022-158
10 CFR 50.71(e)
10 CFR 54.37(b)

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

Point Beach Nuclear Plant, Units 1 and 2
Dockets 50-266 and 50-301
Renewed License Nos. DPR-24 and DPR-27

Periodic Update of the Final Safety Analysis Report

In accordance with the requirements of 10 CFR 50.71(e) and 10 CFR 54.37(b), this letter submits a periodic update of the Point Beach Nuclear Plant Final Safety Analysis Report (FSAR).

Enclosure 1 to this letter includes the non-public version of the Point Beach FSAR, including the description of changes. The FSAR is being submitted in its entirety, constituting a total replacement copy. Enclosure 1 contains security related information as defined by 10 CFR 2.390(d) and should be withheld from public disclosure. The enclosure reflects changes since the last periodic update of April 2, 2021.

Enclosure 2 to this letter includes the public version of the Point Beach FSAR.

Enclosure 3 to this letter includes a report describing how the effects of aging of newly-identified structures, systems or components (SSCs) will be managed, as required by 10 CFR 54.37(b).

This letter contains no new Regulatory Commitments and no revisions to existing Regulatory Commitments.

~~Security Related Information - Withhold Under 10 CFR 2.390.~~
Enclosure 1 Contains ~~Security Related Information~~,
Upon Separation of Enclosure 1 this letter is Non-Security Related.

I declare under penalty of perjury that this submittal accurately presents changes made since the previous submittal that reflect information and analyses submitted to the NRC or prepared pursuant to NRC requirements, and changes made under the provisions of 10 CFR 50.59.

Executed on the 4th day of October 2022.

Sincerely,

Dianne Strand
General Manager Regulatory Affairs
NextEra Energy

Enclosures (3)

cc: Administrator, Region III, USNRC
Project Manager, Point Beach Nuclear Plant, USNRC
Resident Inspector, Point Beach Nuclear Plant, USNRC
PSCW (less enclosures)

ENCLOSURE 2

NEXTERA ENERGY POINT BEACH, LLC
POINT BEACH NUCLEAR PLANT, UNITS 1 AND 2

2021 UPDATE OF THE FINAL SAFETY ANALYSIS REPORT
REDACTED - PUBLIC VERSION

POINT BEACH NUCLEAR PLANT UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

LIST OF EFFECTIVE PAGES

The following is a List of Effective Pages for the Point Beach Nuclear Plant Final Safety Analysis Report (FSAR). This List of Effective Pages should be filed at the front of the FSAR manual.

All holders of this FSAR should check their manuals against this List of Effective Pages to ensure that the FSAR is accurate and complete.

Some figures are identified as for information only because they are updated on a periodic frequency commensurate with the docketed submittal of this FSAR.

The last update submitted to the NRC is identified on the lower-left hand side of each page, followed by the update year, (e.g., UFSAR 2007).

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DESCRIPTION OF CHANGES

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Throughout	Editorial Changes: Editorial changes were made to correct grammar, punctuation, spelling, and to ensure consistency between text headings, table titles, figure titles, table of contents, etc. These changes may not be identified by a revision bar.
Chapter 1	
FSAR 1.2-4	Licensing Basis Change: Added reference to the new Holtec HI-STORM FW cask system to the discussion. (EC295671)
FSAR 1.2-4	Licensing Basis Change: Replaced “Reference 3” with “Reference 6.” (EC295671, Rev. 1)
FSAR 1.2-5	Licensing Basis Change: Added Reference 6. (EC295671)
FSAR 1.2-11	Updated Figure to reflect approved drawing of record.
FSAR 1.2-13	Updated Figure to reflect approved drawing of record.
FSAR 1.4-1	Licensing Basis Change: Replaced paragraph to describe the objective of QATR plus outline QATR revision control requirements per 10 CFR 50.54(a), and added information to restore a definition of "safety-related." (EC297149)
FSAR 1.4-1	Licensing Basis Change: Replaced Reference 1 and added Reference 3. (EC297149)
Chapter 2	
FSAR 2.2-6	Updated Figure to reflect approved drawing of record.
FSAR 2.9-1	Editorial Change: Replaced the word “Coast” with “U.S. Coast.” (EC 295799)
Chapter 4	
FSAR 4.2-22	Updated Figure to reflect approved drawing of record.
FSAR 4.2-25	Updated Figure to reflect approved drawing of record.
Chapter 5	
FSAR 5.5-1	Editorial Change: Replaced last full sentence in 5.5.2. (EC 295799)
FSAR 5.6-16	Editorial Change: Deleted revision numbers for References 18, 19, and 20. (EC 295799)

Chapter 6	
FSAR 6.2-43 through FSAR 6.2-44	Updated Figures to reflect approved drawings of record.
FSAR 6.4-8	Licensing Basis Change: Removed references of the nitrogen blanket being maintained over the sodium hydroxide in the Spray Additive Tanks and allowing either air or nitrogen. (EC297391)
FSAR 6.4-18	Licensing Basis Change: Removed references of the nitrogen blanket being maintained over the sodium hydroxide in the Spray Additive Tanks and allowing either air or nitrogen. (EC297391)
Chapter 7	
FSAR 7.6-17	Licensing Basis Change: Updated category value “2D” with “3D” for Accumulator Tank Level and Accumulator Tank Pressure variables. (EC297270)
FSAR 7.7-6	Editorial Change: Updated verbiage to account for replacement of Rod Position Indication meters and rod bottom lights on the control room panels 1C04 and 2C04 with digital Rod Position Indication Recorders. (EC 295284)
Chapter 8	
FSAR 8.0-7 through FSAR 8.0-9	Updated Figure to reflect approved drawing of record.
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FSAR 9.1-9 through FSAR 9.1-10	Licensing Basis Change: Revised Component Cooling Pump value as a result of new Flowserve pump maximum allowable working temperature and pressure. (EC 295304)
FSAR 9.3-34	Updated Figure to reflect approved drawing of record.
FSAR 9.6-13	Updated Figure to reflect approved drawing of record.

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FSAR 10.1-38	Updated Figure to reflect approved drawing of record.
FSAR 10.1-47	Updated Figure to reflect approved drawing of record.
FSAR 10.2-12	Updated Figure to reflect approved drawing of record.
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Chapter 14	
FSAR 14.0-12	Licensing Basis Change: Updated table as a result of the installation of Unit 2 Loop A Narrow Range RTDs with Ultra Electronics RTDs. (EC 293565)
FSAR 14.1.4-3	Licensing Basis Change: Deleted RCS active volume of 5035 ft^3 and added discussion regarding the reactivity insertion to be based on a revised pre-trip reactivity insertion rate for the Mode 1 manual rod control case. (EC 296204)
FSAR 14.2.6-4	Licensing Basis Change: Updated based on conditional elimination of control rod worth testing from the startup physics testing program. (EC 296204)
FSAR 14.2.6-5 through FSAR 14.2.6-6	Licensing Basis Change: Updated results to reflect the revised Rod Ejection Analysis. (EC 296811)
FSAR 14.2.6-9	Licensing Basis Change: Added Reference 9. (EC 296204)
FSAR 14.2.6-10	Licensing Basis Change: Updated results to reflect the revised Rod Ejection Analysis. (EC 296811)
FSAR 14.2.6-13 through FSAR 14.2.6-16	Updated Figures to reflect the revised Rod Ejection Analysis. (EC 296811)
FSAR 14.3.5-3 through FSAR 14.3.5-4	Editorial Change: Clarified the actual limits on the measured leakage rate to the PAB and measured total ECCS leakage rates in the UFSAR. (EC 296912)
FSAR 14.3.5-16	Editorial Change: Added footnote clarifying PAB and RWST leakage rates. (EC 296912)

<u>Chapter 15</u>	
FSAR 15.2-6	Licensing Basis Change: Added a paragraph changing Commitment 29 of the Reactor Vessel Internals Program to use the latest NRC accepted revision of MRP-227. (EC 295829)
FSAR 15.2-8	Licensing Basis Change: Added Reference 7. (EC 295829)
<u>Appendix A</u>	
FSAR A.3-4	Licensing Basis Change: Removed specific mention of the cask designs/ vendors, generically referencing the cask FSAR and the 72.212 and Certificate of Compliance reports. (EC295671)
FSAR A.3-5	Editorial Change: Added references in text to sources of justification for use of acoustic emission technology. (EC 296234)
FSAR A.3-11	Editorial Change: Added Reference 26. (EC 296234)
FSAR A.5-8 through FSAR A.5-9	Editorial Change: Replaced the word "combination(s)" with the word "condition(s)" as noted. (EC 295799)
FSAR A.5-14	Editorial Change: Replaced "Figure A.5-1 and Figure A.5-2" with "Figure A.5-10." (EC 295799)
FSAR A.5-21	Licensing Basis Change: Deleted first paragraph of Section A.5.10 to document the updates to the license basis associated with the containment dome truss as approved by Amendments 263 (Unit 1) and 266 (Unit 2). (EC 297528)
FSAR A.5-24	Licensing Basis Change: Modified and deleted text to document the updates to the license basis associated with the containment dome truss as approved by Amendments 263 (Unit 1) and 266 (Unit 2). (EC 297528)
FSAR A.5-27	Licensing Basis Change: Added Reference 37, related to the updates to the license basis associated with the containment dome truss as approved by Amendments 263 (Unit 1) and 266 (Unit 2). (EC 297528)
FSAR A.6-3	Editorial Change: Updated to show the word "Stripper" on one line. (EC 295799)
FSAR A.6-7	Editorial Change: Deleted duplicate word "water." Additionally, replaced "will have" with "has." (EC 295799)
FSAR A.6-8	Editorial Change: Deleted "to be." (EC 295799)
FSAR A.7-2	Editorial Change: Replaced "Wave Runup Event" with "elevated lake level." (EC 295799)

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CHAPTER 1 TABLE OF CONTENTS

1.0 INTRODUCTION AND SUMMARY

The Safety Analysis Report (FSAR) is submitted as required by 10 CFR 50.71(e) "Periodic Updating of Final Safety Analysis Report." The FSAR is based on the original Final Facility Description and Safety Analysis Report (FFDSAR) and a compilation of docketed material that affected the original FFDSAR content. The FFDSAR was submitted in support of the application by Wisconsin Electric Power Company to operate a nuclear power plant designated as Point Beach Nuclear Plant, Units 1 and 2. The FSAR and other docketed material remain as the licensing basis for the Point Beach Nuclear Plant. Unit 2 is located adjacent to Unit 1 on a site situated on Lake Michigan. Certain components of Units 1 and 2 are shared and described herein.

The Point Beach Units 1 and 2 reactors are pressurized light water moderated and cooled systems. Each unit was intitially designed to produce a reactor thermal output of 1518.5 MWt. All steam and power conversion equipment, including each turbine generator, was originally designed to permit generation of 523.8 MW of gross electrical power. Unit 1 achieved commercial operation in December 1970. Unit 2 achieved commercial operation in October 1972. Since being placed into commercial operation, each unit has undergone a LP Turbine retrofit modification that increases the unit design output to 537,960 kWe. In addition, a measurement uncertainty recapture (MUR) power uprate has been implemented for both units. The MUR uprate increased license reactor thermal power to 1540 MWt and turbine generator output to approximately 545MWe.

For Extended Power Uprate (EPU) operation, the reactor thermal power was increased to 1800 MWt, and the turbine generator output to approximately 640 MWe. For EPU, modifications were made to both unit's high pressure turbines, instrumentation and controls, and the associated steam, condensate, and feedwater paths.

The nuclear power plant incorporates two Westinghouse closed-cycle pressurized water nuclear steam supply systems and turbine-generator systems utilizing dry and saturated steam. Equipment includes systems for the processing of radioactive wastes, handling of fuel, electrical distribution, cooling, power generation structures, and all other on-site facilities required to provide a complete and operable nuclear power plant.

All plant safety systems, including containment and engineered safety features are designed and evaluated for operation at 1800 MWt power rating of the reactor. This power rating is used in the analysis of postulated accidents reported herein.

The remainder of Chapter 1 of this report summarizes the principal design features and safety criteria of the nuclear units. Also provided is a description of the Quality Assurance program which ensures compliance with standards. Chapter 2 contains a description and evaluation of the Point Beach Site and environs, supporting the suitability of that site for a nuclear plant of the size and type described.

Chapter 3 and Chapter 4 describe the reactors and the reactor coolant systems, Chapter 5 the containment and related systems, and Chapter 6 through Chapter 10 the emergency and other auxiliary systems. Chapter 11 describes the Radiological Protection aspects of the station. Chapter 12 describes the Company's program for organization and training of plant personnel. Chapter 13 contains an outline and description of the initial tests and operations associated with plant startup and the on-site Quality Assurance program. Chapter 14 is a safety evaluation summarizing the analyses that demonstrate the adequacy of the reactor protection system and the engineered safety features systems. The consequences of various postulated accidents are within the guidelines set forth in the Nuclear Regulatory Commission regulation 10 CFR 50.67.

Chapter 15 is a description of the Aging Management Program and Time Limited Aging Analysis.

Appendix T incorporates by reference the Technical Requirements Manual; a compilation of specifications relocated from the previous Technical Specifications in conjunction with the Improved Standard Technical Specification conversion. The appendices contain the additional analyses and initial licensing information.

The Technical Specifications for Point Beach designate safety limits, maximum safety system settings, minimum conditions for operation, and surveillance standards for the safe operation of the plant. Included with these specifications is a summary of the material presented in the Final Safety Analysis Report used as the bases for each specification. The Technical Specifications are provided in a separate volume.

Within the context of the FSAR, the following definitions apply:

1) Hot Shutdown – The reactor is in the hot shutdown condition when the reactor is subcritical, by an amount greater than or equal to Technical Requirements Manual (TRM) 2.1, Figure 2 and T_{avg} is at or greater than 540°F.

2) Refueling Shutdown – The reactor is in the refueling shutdown condition when the reactor is subcritical by at least 5 percent $\Delta k/k$, and T_{avg} is less than or equal to 140°F. A refueling shutdown refers to a shutdown to move fuel to and from the reactor core.

1.1 SITE AND ENVIRONMENT

The plant site is in east central Wisconsin on the west shore of Lake Michigan about 30 miles SE of Green Bay and about 90 miles NNE of Milwaukee. Cooling water is drawn from Lake Michigan. Farming is the predominant activity in this sparsely populated area of the state. The plant is situated in a productive dairy farming and vegetable canning region; however, it is industrialized to the south in Two Rivers and Manitowoc and to the west in the Fox River Valley.

Soil and subsurface layers contain high clay content which inhibit percolation and drainage to Lake Michigan. The site is well ventilated and not subject to severe persistent inversions. While tornadoes occur in the region, none has been reported to affect the lakeshore site directly. High winds (on the order of 108 mph) can be expected once in 100 years from storms.

Upper glacial till or underlying lake deposits on the site provide a suitable foundation for plant structures. A horizontal ground acceleration of 0.06 gravity and a vertical acceleration of 0.04 gravity are used for the earthquake design criteria, based on a report by John A. Blume and Associates. These accelerations are considered as acting simultaneously. Site soil and geological investigations were performed by Dames and Moore. Additional consultants in the site evaluation were Harza Engineering Company for hydrologic and hydraulic studies.

1.2 SUMMARY PLANT DESCRIPTION

Inherent to the design of closed-cycle reactors is the ability to significantly reduce the release of fission products to the environment. Four barriers exist between the fission product accumulation and the environment. These are the uranium dioxide fuel matrix, the fuel cladding, the reactor vessel and coolant loops, and the reactor containment. The consequences of a breach of the fuel cladding are greatly reduced by the ability of the uranium dioxide lattice to retain fission products. Escape of fission products through fuel cladding defect would be contained within the pressure vessel, loops, and auxiliary systems. Breach of these systems or equipment would release the fission products to the reactor containment where they would be retained. The reactor containment is designed to adequately retain these fission products under the most severe accident conditions, as analyzed in Section 14.

Several engineered safety features have been incorporated into the plant design to reduce the consequences of a loss-of-coolant accident. These safety features include a safety injection system. This system automatically delivers borated water to the reactor vessel for cooling the core under high and low reactor coolant pressure conditions. The safety injection system also serves to insert negative reactivity into the core in the form of borated water during an uncontrolled plant cooldown following a steam line break or an accidental steam release. Other safety features which have been included in the reactor containment design are a containment air recirculation cooling system which acts to effect a depressurization of the containment following a loss of coolant, and a containment spray system which acts to depressurize the containment and remove elemental iodine and particulates from the atmosphere by washing action. The containment spray system provides redundant backup by an alternate principle for the containment air recirculation cooling system.

1.2.1 STRUCTURES

The major structures on the site are the two reactor containments, one for each unit, and the following which are shared: Auxiliary building, pumphouse, turbine building (including the control room), emergency diesel generator building, and service buildings. The relationship of the Unit 2 containment to the Unit 1 containment is shown in Figure 1.2-1. General equipment and plant layout appear in Figure 1.2-2 through Figure 1.2-14.

The reactor containment is a steel-lined concrete cylinder with prestressed tendons in the walls and dome, anchored to a reinforced concrete foundation slab which is supported by steel H-piles driven to refusal in the underlying bedrock. The containment is designed to withstand the internal pressure accompanying a loss-of-coolant accident, is virtually leak-tight, and provides adequate radiation shielding for both normal operation and accident conditions.

<u>Seismic Classification of Particular Structures and Equipment</u>

Particular structures and equipment are classified according to seismic design. The definition of the three seismic classifications is given in Appendix A.5.

1.2.2 NUCLEAR STEAM SUPPLY SYSTEM

For each unit the nuclear steam supply system consists of a pressurized water reactor, reactor coolant system, and associated auxiliary fluid systems. The reactor coolant system is arranged as two closed reactor coolant loops connected in parallel to the reactor vessel, each containing a reactor coolant pump and a steam generator. An electrically heated pressurizer is connected to one of the loops.

The reactor core is composed of uranium dioxide pellets enclosed in ZIRLO® or Optimized ZIRLOTM High Performance Fuel Cladding Material with welded end plugs. The use of Optimized ZIRLO material was approved by NRC Safety Evaluation dated May 9, 2014 (Reference 5). The tubes are supported in assemblies by a spring clip grid structure. The mechanical control rods consist of clusters of stainless steel clad absorber rods which are inserted into ZIRLO guide tubes located within the fuel assembly. The core fuel is loaded during each refueling in accordance with a loading pattern designed and analyzed to achieve the desired thermal and nuclear characteristics. The steam generators are vertical U-tube units utilizing inconel tubes. Integral separating equipment reduces the moisture content of the steam at the steam generator outlet to 1/4% or less.

The reactor coolant pumps are vertical, single stage, centrifugal pumps equipped with controlled leakage shaft seals.

Auxiliary systems are provided to charge the reactor coolant system and to add makeup water, purify and degas reactor coolant water, provide chemicals for corrosion inhibition and reactor control, cool system components, remove residual heat when the reactor is shut down, cool the spent fuel storage pool, sample reactor coolant water, provide for emergency safety injection, and vent and drain the reactor coolant system.

1.2.3 REACTOR AND PLANT CONTROL

The reactor is controlled by a coordinated combination of chemical shim and mechanical control rods. The control system allows the plant to accept step load changes of 10% and ramp load changes of 5% per minute over the load range of 15 to 100% power under nominal operating conditions. It is also designed to sustain reactor operation following a rapid load decrease of 50% power at a rate up to 200%/minute with the steam and atmospheric dumps available.

Complete supervision of both the reactor and turbine generator is accomplished from the control room. Units 1 and 2 share the control room located as an integral part of the turbine hall. The control room layout, including location of control boards for each unit, is shown in Figure 7.5-1.

The control room for the combined plant is approximately 50'× 80'. Annunciators for alarms for the two units are on different control boards with the exception that safeguards and electrical system alarms are on common control boards. The Auxiliary Safety Instrumentation Panels (ASIPs) described in Chapter 7 are common panels with unit specific and common alarms.

The waste disposal control board is located in the auxiliary building. This board permits the auxiliary operator to control and monitor the processing of wastes from a central location in the same general area where equipment is located.

1.2.4 WASTE DISPOSAL SYSTEM

The waste disposal system, common to both units, provides all equipment necessary to collect, process, and prepare for disposal all potentially radioactive liquid, gaseous, and solid wastes produced as a result of reactor operation.

Liquid wastes are processed through a filtration and demineralization system. The processed liquid is sampled to determine residual activity and monitored during discharge to the lake via the condenser circulating water discharge to assure concentrations below 10 CFR 20 limits. Exhausted filtration and demineralization media is dewatered and packaged for shipping from the site for ultimate disposal in an authorized location.

Gaseous wastes are collected and stored until their radioactivity level is low enough so that discharge to the environment does not create radioactivity concentrations above 10 CFR 20 limits. Measures provided for the purpose of keeping releases of radioactive materials to unrestricted areas during normal reactor operations, including expected operational occurrences, as low as reasonably achievable are presented in Chapter 11 to this document.

1.2.5 FUEL HANDLING SYSTEM

Each reactor is refueled with equipment designed to handle spent fuel under water from the time it leaves either reactor vessel until it is placed in a cask for shipment from the site. Underwater transfer of spent fuel provides an optically transparent radiation shield, as well as a reliable source of coolant for removal of decay heat. This system also provides capability for receiving, handling, and storage of new fuel. Both the new fuel storage facility and the spent fuel storage facility are shared by the two units.

1.2.6 TURBINE AND AUXILIARIES

Each turbine is a tandem-compound, 3-element, 1,800 rpm unit. Four moisture separator reheater units are employed to dry and superheat the steam between the high and low pressure turbine cylinders.

Single-pass de-aerating, radial flow surface condensers, steam-jet air ejector, two 50% capacity condensate pumps, two 50% capacity motor-driven feedwater pumps, and five stages of feedwater heaters are provided. One steam-driven and one motor-driven auxiliary feedwater pump per unit are available to remove residual heat in case of a complete loss of auxiliary power.

1.2.7 ELECTRICAL SYSTEM

Each main generator is an 1,800 rpm, 3-phase, 60 cycle, hydrogen inner-cooled unit. Three single phase main step-up transformers on each unit deliver power to the 345 kV switchyard.

The Station Service System consists of auxiliary transformers, 4.16 kV switchgear, 480V motor control centers, and 125V DC and 120V AC equipment.

Emergency power is supplied by four emergency diesel generators. Each emergency diesel generator (DG) is capable of operating one train of post-accident containment cooling equipment as well as high head and low head safety injection pumps to ensure an acceptable post-loss-of-coolant containment pressure transient. Sufficient power capacity is provided to safely shut down the unaffected unit at the same time adequate power is provided to the engineered safety features of the affected unit.

1.2.8 ENGINEERED SAFETY FEATURES SYSTEMS

The engineered safety features (ESF) systems provided for this plant have redundant components and power sources such that under the conditions of a hypothetical loss-of-coolant accident, the systems can, even when operating with partial effectiveness, maintain the integrity of the containment and keep the exposure of the public below the limits of 10 CFR 50.67.

The ESF systems provided are summarized below:

1. Each containment system provides a highly reliable, essentially leak-tight barrier against the escape of fission products. These provisions minimize leakage to the environment.

2. Each safety injection system (SI) provides borated water to cool the core by redundant injection into the cold legs of the reactor coolant loops and by discharging coolant over the top of the core via injection through the core deluge nozzles.

3. Each containment air recirculation cooling system (VNCC) provides a dynamic heat sink to cool the containment atmosphere under the conditions of a loss-of-coolant accident. The system utilizes the normal containment ventilation and cooling equipment.

4. Each containment spray system (SI) provides a spray of cool, chemically treated borated water to the containment atmosphere to provide removal of elemental iodine and particulates and works independent of the containment air recirculation cooling system to remove heat.

1.2.9 SHARED FACILITIES AND EQUIPMENT

Per GDC 4, Reactor Facilities may share systems or components if it can be shown that such sharing will not result in undue risk to the health and safety of the public.

Separate and similar systems and equipment are provided for each unit and are described in Appendix A.6. In these instances where some components of a system are shared by both units, only those components which are shared are shown. A functional evaluation of the components of the systems which are shared by the two units is provided in Appendix A.6 together with a short discussion on the operation of those items of shared equipment which are components of the engineered safety features system.

1.2.10 INDEPENDENT SPENT FUEL STORAGE INSTALLATION

The Point Beach Nuclear Plant site has an Independent Spent Fuel Storage Installation (ISFSI) that was built to accommodate dry storage containers of spent nuclear fuel from the spent fuel pool. The ISFSI was constructed because the national spent nuclear fuel disposal facility was not ready to accept spent fuel. Without removal of fuel from the spent fuel pool fuel storage racks, the racks would have been full before the end of license life, resulting in premature shutdown of the plant. The ISFSI is shown on Figure 2.2-4.

Complete information on the licensing of the ISFSI may be found in Reference 1, Reference 2, and Reference 6.

REFERENCES:

1. Point Beach 10 CFR 72.212 and Certificate of Compliance Evaluation Report for VSC-24 System.

2. Point Beach 10 CFR 72.212 and Certificate of Compliance Evaluation Report for NUHOMS®-32PT System.

3. NRC Safety Evaluation 2011-0004, "Issuance of License Amendments Regarding Extended Power Uprate," dated May 3, 2011.

4. NRC Safety Evaluation 2011-0003, "Issuance of License Amendments Regarding Use of Alternate Source Term," dated April 14, 2011.

5. NRC Safety Evaluation, "Issuance of Amendment Regarding the Use of Optimized ZIRLOTM Fuel Rod Cladding Material," dated May 9, 2014.

6. Point Beach 10 CFR 72.212 and Certificate of Compliance Evaluation Report for HOLTEC HI-STORM FW Storage Module.

Figure 1.2-1 CONTAINMENT LAYOUT PLAN EQUIPMENT ARRANGEMENT

[redacted]

Figure 1.2-2 EQUIPMENT LOCATION PLAN UNIT 1

[redacted]

Figure 1.2-3 EQUIPMENT LOCATION PLAN UNIT 1

[redacted]

Figure 1.2-4 UNIT-1 EQUIPMENT LOCATION PLAN

[redacted]

Figure 1.2-5 UNIT-1 EQUIPMENT LOCATION PLAN

[redacted]

Figure 1.2-6 EQUIPMENT LOCATION PLAN

[redacted]

Figure 1.2-7 UNIT 1 EQUIPMENT LOCATION - SECTIONS

[redacted]

Figure 1.2-8 MISCELLANEOUS SECTIONS UNIT 1

[redacted]

Figure 1.2-9 UNIT-2 EQUIPMENT LOCATION - PLAN

[redacted]

Figure 1.2-10 EQUIPMENT LOCATION PLAN UNIT 2

[redacted]

Figure 1.2-11 EQUIPMENT LOCATION PLAN UNIT 2

[redacted]

Figure 1.2-12 UNIT 2 EQUIPMENT LOCATION - PLAN

[redacted]

Figure 1.2-13 UNIT-2 EQUIPMENT LOCATION - PLAN

[redacted]

Figure 1.2-14 MISCELLANEOUS SECTIONS UNIT 2

[redacted]

Figure 1.2-15 GENERAL ARRANGEMENT - WASTE DISPOSAL SYSTEM MODIFICATIONS

[redacted]

1.3 GENERAL DESIGN CRITERIA

The general design criteria define the principal criteria and safety objectives for the design of this plant. A complete set of these GDCs are stated explicitly in Table 1.3-1. Table 1.3-1 also identifies other locations in this report that repeat specific GDCs.

Regarding the origin of these criteria, the Atomic Energy Commission (AEC) published proposed GDCs for public comment in 1967. The Atomic Industrial Forum (AIF) reviewed these proposed criteria and recommended changes. The Point Beach GDCs documented in this FSAR are similar in content to the AIF version of the Proposed 1967 GDCs.

Appendix A of 10 CFR 50 contains a different set of GDCs which were published in 1971 (After Point Beach construction permits were issued). Note that the GDCs found in 10 CFR 50 Appendix A differ both in numbering and content from the GDCs adopted herein for PBNP.

The parenthetical numbers following the section headings indicate the numbers of the proposed General Design Criterion (GDC).

1.3.1 OVERALL PLANT REQUIREMENTS (GDC 1- GDC 5)

All systems and components of the facility are classified according to their importance. The original classification system at PBNP used designators called Class I, Class II and Class III. Those items vital to safe shutdown and isolation of the reactor, or whose failure might cause or increase the severity of an accident or result in an uncontrolled release of excessive amounts of radioactivity were designated Class I. Class I systems and components were considered essential to the protection of the health and safety of the public. Those items important to reactor operation, but not essential to safe shutdown and isolation of the reactor or control of the release of substantial amounts of radioactivity were designated Class II. Those items not related to reactor operation or safety were designated Class III.

Subsequent evaluation of the equipment classification system pursuant to NRC Generic Letter 83-28 resulted in the definition of safety-related functions and the related classification criteria described in more detail in the Quality Assurance Program section of the FSAR (1.4).

These safety classifications are: Safety-Related, Augmented Quality, and Non-Safety-Related. After the adoption of these classifications pursuant to Generic Letter 83-28, PBNP systems and components were reclassified accordingly. Although there may be some commonality between the original Class I category and the Safety-Related category, it is important to note that these classifications are defined differently and represent different time periods of plant operation. Quality standards of material selection, design, fabrication, and inspection conform to the applicable provisions of recognized codes and good nuclear practice.

All systems and components designated Seismic Class I are designed so that there is no loss of function in the event of the maximum hypothetical ground acceleration acting in the horizontal and vertical directions simultaneously. The working stress for both Seismic Class I and Seismic Class II items is kept within code allowable values for the design earthquake. Similarly, measures are taken in the plant design to protect against high winds, flooding, and other natural phenomena.

The containments and Seismic Class I portions of the Auxiliary Building, the turbine hall, the pumphouse, and the diesel generator building are designed to withstand the effects of a tornado. The design criteria of the containment and the Class I portions of the auxiliary and turbine buildings to withstand the effects of a tornado, including wind force, pressure differential, and missile impingement are described in Bechtel Topical Report B-TOP-3, "Design Criteria for Nuclear Power Plants Against Tornadoes." Design criteria for the diesel generator building are described in FSAR Appendix D. The design of the pumphouse to withstand tornados and tornado missiles is described in Section 9.6. Seismic design criteria are described in FSAR Appendix A.5.

The design basis for tornado missile protection of systems and components is that it is possible to shut down the plant and maintain the plant in safe shutdown during and after the passage of a tornado. The equipment needed for this event remains operable provided (Reference 1):

a. Critical items are housed in structures capable of withstanding tornado winds, depressurization and missiles, or

b. the separation provided between redundant systems or components is such that reasonable assurance exists that a single missile cannot cause a loss of function of both systems or components, and

c. large structures, such as facade, auxiliary building superstructure, turbine buildings, etc., are so designed that they will not collapse and fall on redundant components or systems.

Reference Sections:

Section Title	Chapter/ Section
SITE AND ENVIRONMENT; METEOROLOGY, SEISMOLOGY	2.0
REACTOR COOLANT SYSTEM; DESIGN BASIS (RCS)	4.1
CONTAINMENT SYSTEM STRUCTURE; DESIGN BASIS (CONT)	5.1
ELECTRICAL SYSTEM; DESIGN BASES	8.0
FUEL HANDLING SYSTEM (FH)	9.4
SERVICE WATER SYSTEM (SW)	9.6
CLASS I DESIGN CRITERIA FOR VESSELS, AND STRUCTURES	Appendix A.5
DIESEL GENERATOR PROJECT	Appendix D
FIRE PROTECTION SYSTEM (FP)	Reference 9.10

A complete set of as-built facility plant and system diagrams, including arrangement plans and structural plans, and records of initial tests and operation are maintained throughout the life of the plant. A set of all the quality assurance data generated during fabrication and erection of the essential components of the plant, as defined by the quality assurance program, is retained.

Reference Sections:

Section Title	Chapter
RECORDS	12.5
SITE SURVEILLANCE AND TESTING PROGRAMS	13

1.3.2 PROTECTION BY MULTIPLE FISSION PRODUCT BARRIERS (GDC 6-GDC 10)

Each reactor core, with its related control and protection system, is designed to function throughout its design lifetime without exceeding acceptable fuel damage limits. The core design, together with reliable process and decay heat removal systems, provides for this capability under all expected conditions of normal operation with appropriate margins for uncertainties and anticipated transient situations.

Each reactor control and protection system is designed to actuate a reactor trip for any anticipated combination of plant conditions, when necessary, to ensure a minimum Departure from Nucleate Boiling (DNB) ratio equal to or greater than the limit value.

Reference Sections:

Section Title	Chapter
REACTOR, DESIGN BASIS	3.1
INSTRUMENTATION AND CONTROL, Protective Systems (RP)	7.2
SAFETY ANALYSIS	14.0

The design of the reactor core and related protection systems ensures that power oscillations which could cause fuel damage in excess of acceptable limits are not possible or can be readily suppressed. The potential for possible spatial oscillations of power distribution for these cores has been reviewed. It is concluded that low frequency xenon oscillations may occur in the axial dimension, and part length control rods were initially provided to suppress these oscillations. Experience has demonstrated that full length rods are effective in controlling these oscillations and the part length control rods have been removed. The core has been stable with respect to xenon oscillations in the X-Y dimension.

Out-of-core instrumentation is provided to obtain necessary information concerning power distribution. This instrumentation is adequate to enable the operator to monitor and control xenon induced oscillations.

In the power operating range, overall power coefficient is maintained negative and the moderator temperature coefficient is maintained within acceptable limits by the inclusion of burnable poison shims as necessary, dependent on a particular core reload.

Reference Sections:

Section Title	Chapter
REACTOR DESIGN, NUCLEAR DESIGN AND EVALUATION	3.0
PRIMARY SYSTEM PIPE RUPTURE	14.3

Each reactor coolant system, in conjunction with its control and protective provisions, is designed to accommodate the system pressures and temperatures attained under all expected modes of plant operation or anticipated system interactions, and maintain the stresses within applicable code stress limits.

The materials of construction of the pressure boundary of the reactor coolant system are protected, by control of coolant chemistry, from corrosion phenomena which might otherwise reduce the system structural integrity during its service lifetime.

System conditions resulting from anticipated transients or malfunctions are monitored, and appropriate action is automatically initiated to maintain the required cooling capability and to limit system conditions to a safe level.

The system is protected from overpressure by means of pressure relieving devices, as required by Section III of the ASME Boiler and Pressure Vessel Code.

Sections of the system that can be isolated are provided with overpressure relieving devices discharging to closed systems, such that the system allowable pressure within the protected section is not exceeded

Reference Section:

Section Title	Chapter
DESIGN BASIS, REACTOR COOLANT SYSTEM (RCS)	4.1

The containment design pressure and temperature exceeds the peak pressure and temperature occurring as the result of the complete blowdown of the reactor coolant through any pipe rupture of the reactor coolant system up to and including the hypothetical severance of a reactor coolant pipe.

The penetration for the main steam, feedwater, blowdown, and sample lines are designed so that the penetration is stronger than the piping system and the vapor barrier will not be breached due to a hypothesized pipe rupture. All lines connected to the reactor coolant system that penetrate the vapor barrier are also anchored in the loop compartment shield walls and are each provided with at least one valve between the anchor and the coolant system. These anchors are designed to withstand the thrust moment and torque resulting from a hypothesized rupture of the attached pipe or the loads induced by the maximum hypothetical earthquake.

All isolation valves are supported to withstand, without impairment of valve operability, the loading of the design basis accident or maximum hypothetical seismic conditions

Reference Section:

Section Title	Chapter
CONTAINMENT SYSTEM STRUCTURE (CONT)	5.1

1.3.3 NUCLEAR AND RADIATION CONTROLS (GDC 11 - GDC 18)

The plant is equipped with a control room which contains the controls and instrumentation necessary for operation of both reactors and turbine generators under normal and accident conditions.

Sufficient shielding, distance, ventilation-purification, and containment integrity are provided to assure that control room personnel shall not be subjected to doses under postulated accident conditions during occupancy of, ingress to, and egress from the control room which, in the aggregate, would exceed 5 rem total effective dose equivalent (TEDE), or its equivalent to any part of the body, for the duration of the accident.

For each unit, instrumentation and controls essential to avoid undue risk to the health and safety of the public are provided to monitor and maintain neutron flux, primary coolant pressure, flow rate, temperature, and control rod positions within prescribed operating ranges.

Other instrumentation and control systems are provided to monitor and maintain within prescribed operating ranges the temperatures, pressures, flows, and levels in the reactor coolant systems, steam systems, containments, and other auxiliary systems. The quantity and types of instrumentation provided are adequate for safe and orderly operation of all systems and processes over the full operating range of the plant.

The operational status of each reactor is monitored from the control room. When the reactor is subcritical, the neutron source multiplication is continuously monitored and indicated by proportional counters located in instrument wells in the primary shield adjacent to the reactor vessel. Neutron sources can be installed in the core, if necessary, during startup to provide a minimum count rate for verifying operation of the source detector channels. Any appreciable increase in the neutron source multiplication, including that caused by the maximum physical boron dilution rate, is slow enough to give ample time to start corrective action (boron dilution stop and/or emergency boron injection) to prevent the core from becoming critical inadvertently.

Means for showing the relative reactivity status of each reactor is provided by control bank positions displayed in the control room. Periodic samples of coolant boron concentration are taken. The variation in concentration during core life provides a further check on the reactivity status of the reactor, including core depletion.

Instrumentation and controls provided for the protective systems are designed to trip the reactors when necessary to prevent or limit fission product release from the cores and to limit energy release; to signal containment isolation; and to control the operation of engineered safety features equipment.

During reactor operation in the startup and power modes, redundant safety limit signals will automatically actuate two reactor trip breakers which are in series with the rod drive mechanism coils. The action would interrupt rod drive power and initiate reactor trip

Reference Section:

Section Title	Chapter
INSTRUMENTATION AND CONTROL	7.0

If the reactor protection system receives signals which are indicative of an approach to an unsafe operating condition, the system actuates alarms, prevents control rod out motion, initiates load cutback, and/or opens the reactor trip breakers.

The basic reactor tripping philosophy is to define an allowable region of power and coolant temperature conditions. This allowable range is defined by the primary tripping functions, the overpower high ΔT trip, overtemperature high ΔT trip, and the nuclear overpower trip. The operating region below these trip settings is designed so that no combination of power, temperatures, and pressure could result in a Departure from Nucleate Boiling Ratio (DNBR) less than the limit value. Additional tripping functions such as a high pressurizer water level trip, loss of flow trip, steam and feedwater flow mismatch trip, steam generator low-low level trip, turbine trip, safety injection trip, nuclear source and intermediate range trips, and manual trip are provided to back up the primary tripping functions for specific accident conditions and mechanical failures.

Rod stops from nuclear overpower, overpower ΔT and overtemperature ΔT deviation are provided to prevent abnormal power conditions which could result from excessive control rod withdrawal initiated by a malfunction of the reactor control system or by operator violation of administrative procedures.

Reference Sections:

Section Title	Chapter
ENGINEERED SAFETY FEATURES (ESF)	6.0
REACTOR PROTECTION SYSTEM (RPS)	7.2

Positive indication in the control room of leakage of coolant from the reactor coolant systems to the containments is provided by equipment which permits continuous monitoring of the containment air activity and humidity, and is provided by the runoff from the condensate collecting pans under the cooling coils of the containment air recirculation units. The basic design criterion is the detection of deviations from normal containment environmental conditions including air particulate activity, radiogas activity, humidity, condensate and floor drain runoff, and in addition, in the case of gross leakage, the liquid inventory in the process systems and containment sump.

The containment atmosphere, the plant vents, the containment service water discharges, the condenser air ejectors, the steam generator blowdown effluents, and the Waste Disposal System liquid effluent are monitored for radioactivity concentration during all normal operations, anticipated transients, and accident conditions.

For the case of leakage from the reactor containment under accident conditions, the plant area radiation monitoring system supplemented by portable survey equipment provides adequate monitoring of releases during an accident.

Monitoring and alarm instrumentation are provided for fuel and waste storage and handling areas to detect inadequate cooling and to detect excessive radiation levels. Radiation monitors are provided to maintain surveillance over the release of radioactive gases and liquids.

Controlled ventilation systems remove gaseous radioactivity from the atmosphere of the fuel storage and waste treating areas of the auxiliary building and discharge it to the atmosphere via the vents. Radiation monitors are in continuous service in these areas to actuate high-activity alarms on the control board annunciator, as described in Chapter 11.0.

Reference Sections:

Section Title	Chapter
ENGINEERED SAFETY FEATURES (ESF)	6.0
AUXILIARY COOLANT SYSTEM (CC, SF, SW)	9.0
RADIATION PROTECTION (RM)	11.0

1.3.4 RELIABILITY AND TESTABILITY OF PROTECTION SYSTEMS (GDC 19 - GDC 26)

Upon a loss of power to the gripper coils, the rod cluster control (RCC) assemblies are released and fall by gravity into the core. The reactor internals, fuel assemblies, RCC assemblies, and drive system components are designed as Safety-Related equipment. The RCC assemblies are fully guided through the fuel assembly and for the maximum travel of the control rod into the guide tube. Furthermore, the RCC assemblies are never fully withdrawn from their guide tube thimbles in the fuel assembly while in the core. As a result of these design safeguards and the flexibility designed into the RCC assemblies, abnormal loading and misalignments can be sustained without impairing operation of the RCC assemblies.

Protection channels are designed with sufficient redundancy for individual channel calibration and test to be made during operation without degrading the reactor protection system. Bypass removal of one trip circuit is accomplished by placing that channel in a partial-tripped mode, i.e., a two-out-of-three trip matrix becomes a one-out-of-two trip matrix. Testing does not cause a trip unless a trip condition exists in a channel not being tested. The trip signal furnished by the remaining channels is unimpaired by testing.

In the reactor protection system (RP) of each unit, two reactor trip breakers are provided to interrupt power to the RCCA drive mechanisms.

The breaker main contacts are connected in series (with the power supply) so that opening either breaker interrupts power to all RCC assemblies permitting them to fall by gravity into the core. Each trip breaker is opened through an undervoltage or shunt trip coil. Each protection channel actuates two separate trip logic trains, one for each reactor trip breaker. The protection system is thus inherently safe in the event of a loss of rod control power.

Channel independence is carried throughout the system extending from the sensor to the relay actuating the protective function. The protective and control functions are combined only through isolation devices. A failure in the control circuit does not affect the protection channel.

The power supplied to the channels is fed from four 120 volt instrument buses for each unit. Each instrument bus is supplied from an inverter. The inverters are supplied from the common 125 volt DC buses. Each of the four DC buses are connected to a plant battery.

The initiation of the engineered safety features provided for loss-of-coolant accidents; e.g., high head safety injection and residual heat removal pumps, and containment spray systems, is accomplished from redundant signals derived from reactor coolant system and containment instrumentation. The initiation signal for containment spray comes from coincidence of two sets of two-out-of-three high containment pressure signals. On loss of voltage of a safety features equipment bus, the diesel generator aligned to that bus will be automatically started and connected to the bus. Automatic safety injection actuation actuates containment isolation.

The components of the protection system are designed and laid out so that the mechanical and thermal environment accompanying any emergency situation in which the components are required to function does not interfere with that function.

Each protection channel in service at power is capable of being calibrated and tripped independently by simulated signals to verify its operation without tripping the plant.

Each reactor trip circuit is designed so that trip occurs when the circuit is de-energized.

Therefore, an open circuit or loss of channel power causes the system to go into its trip mode. In a two-out-of-three circuit, the three channels are equipped with separate primary sensors and each channel is energized from independent electrical buses.

Redundancy in emergency power is provided in that there are four diesel generator sets capable of supplying separate 4.16 kV buses. One complete set of safety features equipment for both units is, therefore, capable of being independently supplied from either one of the two diesels associated with a train, or both diesels each supplying safety features equipment for one unit.

Diesel engine cranking is accomplished by a Diesel Air Starting System (DA) supplied solely for the associated diesel generator. The undervoltage relay scheme is designed so that loss of power does not prevent the relay scheme from functioning properly.

The ability of the diesel generator sets to start within the prescribed time and to carry load can periodically be checked. The diesel generator breaker is not closed automatically after starting during this testing. The generator may be manually synchronized to 4.16 kV bus for loading.

Reference Section:

Section Title	Chapter
INSTRUMENTATION AND CONTROL; PROTECTION SYSTEMS (RPS)	7.2

1.3.5 REACTIVITY CONTROL (GDC 27 - GDC 32)

In addition to the reactivity control achieved by the RCC assemblies as detailed in Chapter 7.0, reactivity control is provided by the chemical and volume control system which regulates the concentration of boric acid solution neutron absorber in the reactor coolant system. The system is designed to prevent uncontrolled or inadvertent reactivity changes which might cause system parameters to exceed design limits. The reactivity control systems provided are capable of making and holding the core subcritical from any cold shutdown, hot shutdown, or hot operating condition, including those resulting from power changes.

The RCC assemblies are divided into categories comprising control and shutdown groups. One control group of RCC assemblies is used to compensate for short term reactivity changes at power such as those produced due to variations in reactor power requirements or in coolant temperature. The chemical shim control is used to compensate for the more slowly occurring changes in reactivity throughout core life such as those due to fuel depletion, fission product buildup and decay, and load follow.

The shutdown groups are provided to supplement the control groups of RCC assemblies to make the reactor at least 1% subcritical (K_{eff}= 0.99) following trip from any credible operating condition to the hot, zero power condition assuming the most reactive RCC assembly remains in the fully withdrawn position.

Any time that the plant is at power, the quantity of boric acid retained in the boric acid storage tanks or the refueling water storage tank (RWST) and ready for injection will always exceed that quantity required for normal cold shutdown of both units.

For each unit, boric acid may be pumped from the boric acid storage tanks by one of two boric acid transfer pumps (or via gravity feed from the RWST) to the suction of one of three charging pumps which inject boric acid into the reactor coolant. Any charging pump and any boric acid transfer pump can be operated from diesel generator power on loss of offsite power. Boric acid can be injected by one charging pump supplied by one boric acid transfer pump to take the reactor to hot shutdown, with no rods inserted, in less than 150 minutes. In 150 additional minutes, enough boric acid can be injected to compensate for xenon decay. If two charging pumps are available, the time is reduced. Additional boric acid injection is employed if it is desired to bring the reactor to cold shutdown conditions.

The reactor protection systems are designed to limit reactivity transients to DNBR ≥ the limit value due to any single malfunction in the deboration controls.

Limits, which include considerable margin, are placed on the maximum reactivity worth of control rods or elements and on rates at which reactivity can be increased to ensure that the potential effects of a sudden or large change of reactivity cannot (a) rupture the reactor coolant pressure boundary or (b) disrupt the core, its support structures, or other vessel internals so as to lose capability to cool the core.

The rod cluster drive mechanisms are wired into preselected groups, and are normally prevented from being withdrawn in other than their respective groups. The control and shutdown rod drive mechanisms are of the magnetic latch type and the coil actuation is programmed to provide variable speed rod travel. The maximum insertion rate is analyzed in the detailed plant analysis assuming two of the highest worth groups to be accidentally withdrawn at maximum speed, yielding reactivity insertion rates of the order of 6 x 10^{-4} Δk/sec, which is well within the capability of the reactor protection circuits to prevent core damage.

Reference Sections:

Section Title	Chapter
REACTOR DESIGN BASIS	3.1
PROTECTION SYSTEMS (RPS)	7.2
REGULATING SYSTEMS (RDC)	7
CHEMICAL AND VOLUME CONTROL SYSTEM (CV)	9.3

1.3.6 REACTOR COOLANT PRESSURE BOUNDARY (GDC 33 - GDC 36)

The reactor coolant boundary is shown to be capable of accommodating, without rupture, the static and dynamic loads imposed as a result of a sudden reactivity insertion such as a rod ejection. The operation of the reactor is such that the severity of an ejection accident is inherently limited. Since RCC assemblies are used to control load variations only and boron dilution is used to compensate for core depletion, only the RCC assemblies in the controlling groups are inserted in the core at power, and at full power these rods are only partially inserted. Rod insertion alarms are provided as an aid to the operator to ensure that this condition is met.

By using the flexibility in the selection of control rod groupings, radial locations, and position as a function of load, the design limits the maximum fuel temperature for the highest worth ejected rod to a value which precludes any resultant damage to the primary system pressure boundary from possible excessive pressure surges.

The failure of a rod mechanism housing causing a rod cluster to be rapidly ejected from the core is evaluated as a theoretical, though not a credible accident. While limited fuel damage could result from this hypothetical event, the fission products are confined to the reactor coolant system and the reactor containment.

The reactor coolant pressure boundary is designed to reduce, to an acceptable level, the probability of a rapidly propagating type failure.

The fracture toughness of the materials in the beltline region of the reactor vessel will decrease as a result of fast neutron irradiation induced embrittlement. Fracture toughness will decrease with increasing the reference nil ductility temperature (RT_{NDT}) which increases as a function of several factors, including accumulated fast neutron fluence. This change in material properties is factored into the operating procedures such that the reactor coolant system pressure is limited with respect to RCS temperature during plant heatup, cooldown, and normal operation. These limits are determined in accordance with the methods of analysis and the margins of safety of Appendix G of ASME Code Section XI and are included in the Point Beach Pressure Temperature Limits Report (PTLR).

The design of the reactor vessel and its arrangement in the system permits accessibility during the service life to the entire internal surfaces of the vessel and to the following external zones of the vessel: the flange seal surface, the flange O.D. down to the cavity seal ring, the closure head and the nozzle to reactor coolant piping welds. The reactor arrangement within the containment provides sufficient space for inspection of the external surfaces of the reactor coolant piping, except for the length of pipe within the primary shielding concrete.

To define permissible operating conditions, a pressure range is established which is bounded by a lower limit for pump operation and an upper limit that satisfies the criteria of ASME Code Section XI, Appendix G, "Protection Against Nonductile Failure." The criteria of Appendix G of the ASME Code also ensures that the reactor vessel temperature for normal operation is maintained such that brittle fracture is not considered to be credible.

Monitoring of the RT_{NDT} of the beltline region plates, forgings, weldments and associated heat affected zone materials is performed in accordance with ASTM E 185-82 (Standard Practice for Conducting Surveillance Tests for Light-Water Cooled Nuclear Power Reactor Vessels). In addition to the required tension and Charpy impact specimens, the Point Beach material surveillance program also includes fracture toughness specimens. Additional samples of reactor vessel plate and forging materials have been retained and catalogued and are available for future testing, as needed.

The measured shift in RT_{NDT} of the beltline region materials with irradiation are used to establish plant specific values of shift in accordance with the regulatory guidance of NRC Regulatory Guide 1.99, Rev. 2, "Radiation Embrittlement of Reactor Vessel Materials." Where credible data is not available for specific weld or base metals, Regulatory Guide 1.99 provides trend curves for the shift in RT_{NDT} based on fast neutron fluence, material form (base or weld metal), and the weight-percent of copper and nickel of the reactor vessel steel. A margin term is also added to the shift to obtain conservative, upper-bound values of the adjusted RT_{NDT} for use in the evaluations required by Appendix G to 10 CFR 50. See Section 15.4.1 for the discussion of the fracture toughness methodology evaluation reviewed and approved by the NRC for License Renewal for Unit 2. (NRC SE dated 12/2005, NUREG-1839)

As a supplement to the plant specific material surveillance program for Point Beach, additional surveillance data is available through participation in the Babcock & Wilcox Owners Group Master Integrated Reactor Vessel Surveillance Program. This integrated program includes weld metals used in the construction of the Point Beach reactor vessels that are not included in the plant specific surveillance program for Point Beach.

Reference Sections:

Section Title	Chapter
REACTOR COOLANT SYSTEM (RCS)	4.1
RCS SYSTEM DESIGN AND OPERATION	4.0
SYSTEM DESIGN EVALUATION	4.3
VESSEL RT_{NDT}	4.0

1.3.7 ENGINEERED SAFETY FEATURES (GDC 37 - GDC 65)

The design, fabrication, testing, and inspection of the core, reactor coolant pressure boundary, and their protection systems give assurance of safe and reliable operation under all anticipated normal, transient, and accident conditions.

However, engineered safety features are provided in the facility to back up the safety provided by these components. These engineered safety features have been designed to cope with any size reactor coolant pipe break up to and including the circumferential rupture of any pipe assuming unobstructed discharge from both ends, and to cope with any steam or feedwater line break up to and including the main steam or feedwater headers. The concurrent, total loss of all offsite power is assumed with these accidents.

The release of fission products from the reactor fuel is limited by the Safety Injection System which, by cooling the core and limiting the fuel cladding temperature, keeps the fuel in place and substantially intact with its heat transfer geometry preserved and limits the metal-water reaction to an insignificant amount.

The basic criteria for loss-of-coolant accident evaluations (discussed in Chapter 6.0) are: no cladding melting, Zircaloy-water reactions will be limited to an insignificant amount and the core geometry is to remain essentially in place and intact so that effective cooling of the core will not be impaired. The Zircaloy-water reactions will be limited to an insignificant amount so that the accident:

1. Does not interfere with the emergency core cooling function to limit cladding temperatures.

2. Does not produce H_2 in an amount that when burned would cause the containment pressure to exceed the design value.

For any rupture of a steam pipe and the associated uncontrolled heat removal from the core, the emergency core cooling system adds shutdown reactivity so that with a stuck rod, loss of off-site power, and minimum engineered safety features, there is no consequential damage to the primary system and the core remains in place and intact. With no stuck rod, no off-site power, and all equipment operating at design capacity, there is insignificant cladding rupture.

The safety injection system (SI) consists of high and low head centrifugal pumps driven by electric motors, and passive accumulator tanks which are self energized and which act independently of any actuation signal or power source.

The release of fission products from the containment is limited in three ways:

1. Blocking the potential leakage paths from the containment. This is accomplished by:

   a. A steel-lined, concrete reactor containment with testable penetrations and liner weld channels.

   b. Isolation of process lines by the containment isolation system which imposes double barriers for each line which penetrates the containment.

2. Reducing the fission product concentration in the containment atmosphere. This is accomplished by spraying chemically treated borated water which removes airborne elemental iodine and particulates by washing action.

3. Reducing the containment pressure and thereby limiting the driving potential for fission product leakage by cooling the containment atmosphere using the following independent systems:

    a. Containment Spray System (SI)

    b. Containment Air Recirculation Cooling System (VNCC)

A comprehensive program of plant testing is formulated for all equipment systems and system control vital to the functioning of engineered safety features. The program consists of performance tests of individual pieces of equipment in the manufacturer's shop, integrated tests of the system as a whole, and periodic tests of the actuation circuitry and mechanical components to assure reliable performance upon demand throughout the plant lifetime. In the event that one of the components should require maintenance as a result of failure to perform during the test according to prescribed limits, the necessary corrections or minor maintenance will be made and the unit retested.

The plant is supplied with normal, standby, and emergency power sources as follows:

1. The normal source of auxiliary power for safeguards equipment is the off-site power source. Power is supplied via the high- and low-voltage unit station auxiliary transformers.

2. Four diesel generator sets are connected to the emergency buses to supply power in the event of loss of all other AC auxiliary power. Each of the diesel engine electric generator sets is capable of supplying automatically the engineered safety features load required for an acceptable post-blowdown containment pressure transient for any loss-of-coolant accident, and shutdown of the other unit.

3. Emergency power supply for vital instruments, for control, and for emergency lighting is supplied from the 125V DC station batteries.

The emergency bus electrical power arrangement and logic network provides the capability to manually transfer component loads to another diesel following the failure of one diesel generator unit to start.

For such engineered safety features as are required to ensure safety in the event of such an accident or equipment failure, protection from these dynamic effects or missiles is considered in the layout of plant equipment and missile barriers.[1]

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1. The licensing requirement for protection of plant equipment against the dynamic effects associated with Loss of Coolant Accidents from postulated pipe ruptures is no longer applicable. This was an original design and licensing basis requirement, and the description has been retained because some missiles resulting from other postulated events (RCP flywheel failure, CRDM ejection, etc.) remain. See the discussion of GDC 40 in Section 4.1 for further details.

Layout and structural design specifically protect injection paths leading to unbroken reactor coolant loops against damage as a result of the maximum reactor coolant pipe rupture. Injection lines penetrate the main compartment walls which act as missile barriers. The injection headers are located in the missile-protected area between the compartment walls and the containment outside wall. Individual injection lines are connected to the injection header, pass through the compartment walls, and then connect to the loops. Movement of the injection line, associated with rupture of a reactor coolant loop, is accommodated by line flexibility and by the design of the pipe supports such that no damage outside the missile barrier is possible.[1]

Each engineered safety feature provides sufficient performance capability to accommodate any single failure of an active component and still function in a manner to avoid undue risk to the health and safety of the public.

Under the hypothetical accident conditions, the containment air recirculation cooling system and the containment spray system are designed and sized to rapidly reduce the containment pressure following blowdown. Either of the two spray pumps is capable of providing the necessary iodine and particulate removal.

All active components of the safety injection system (with the exception of injection line isolation valves) and the containment spray system are located outside the containment and not subjected to containment accident conditions.

Instrumentation, motors, cables, and penetrations located inside the containment are selected to meet the most adverse accident conditions to which they may be subjected. These items are either protected from containment accident conditions or are designed to withstand, without failure, exposure to the worst combination of temperature, pressure, and humidity expected during the required operational period.

The reactor is maintained subcritical following a primary system pipe rupture accident. Introduction of borated cooling water into the core results in a net negative reactivity addition. The control rods insert and remain inserted.

The delivery of cold safety injection water to the reactor vessel following accidental expulsion of reactor coolant does not cause further loss of integrity of the reactor coolant system boundary.

Design provisions are made to facilitate access to the critical parts of the reactor vessel internals, injection nozzles, pipes, valves, and safety injection pumps for visual or boroscopic inspection for erosion, corrosion, and vibration wear evidence; and for non-destructive inspection where such techniques are desirable and appropriate.

The design provides for periodic testing of active components of the Safety Injection System for operability and functional performance. If required, the Safety Injection System flow path can be tested during plant operation up to the valves inside the containment using the minimum flow test line. The safety injection (SI) pumps and the residual heat removal (RH) pumps can also be tested during plant operation using the full flow test lines provided. The residual heat removal pumps are also used every time the residual heat removal loop is put into operation.

An integrated system test can be performed when the residual heat removal loop is in service. This test does not introduce flow into the reactor coolant system, but does demonstrate the operation of the valves, pump circuit breakers, and automatic circuitry upon initiation of safety injection.

The accumulators and the safety injection piping up to the final isolation valve is maintained full of borated water at refueling water concentration while the plant is in operation. Flow in each of the high head injection header lines and in the main flow line for the residual heat removal pumps is monitored by a flow indicator.

The design provides for capability to test initially, to the extent practical, the full operational sequence up to the design conditions for the safety injection system to demonstrate the state of readiness and capability of the system. These functional tests provide information to confirm valve operating times, pump motor starting times, the proper automatic sequencing of load addition to the diesel generators, and delivery rates of injection water to the reactor coolant system.

The following general criteria are followed to assure conservatism in computing the required containment structural load capacity:

1. In calculating the containment pressure, rupture sizes up to and including a double-ended severance of reactor coolant pipe are considered.

2. In considering post-accident pressure effects, various malfunctions of the emergency systems are evaluated. Contingent mechanical or electrical failures are assumed to disable one of the diesel generators, such that only two of the four fan-cooler units and one of the two containment spray units operate.

3. The pressure and temperature loadings obtained by analyzing various loss-of-coolant accidents, when combined with operating load and maximum wind or seismic forces, do not exceed the load-carrying capacity of the structure, its access opening, or penetrations.

Discharge of reactor coolant through a double-ended rupture of the main loop piping, followed by operation of only those engineered safety features which can run simultaneously with power from an emergency on-site diesel generator results in a sufficiently low radioactive materials leakage from the containment structure such that there is no undue risk to the health and safety of the public.

The reinforced concrete containment is not susceptible to a low temperature brittle fracture. The containment liner is enclosed within the containment and thus is not exposed to the temperature extremes of the environs. The containment ambient temperature during operation is expected to be well above the NDT temperature +30 °F for the liner material. Containment penetrations which can be exposed to the environment are also designed to the NDT +30 °F criterion.

Isolation valves are provided as necessary for all fluid system lines penetrating the containment to assure at least two barriers for redundance against leakage of radioactive fluids to the environment in the event of a loss-of-coolant accident. These barriers, in the form of isolation valves or closed systems, are defined on an individual line basis. In addition to satisfying containment isolation criteria, the valving is designed to facilitate normal operation and maintenance of the systems and to ensure reliable operation of other engineered safety features.

After completion of the containment structure and installation of all penetration and weld channels, an initial integrated leakage rate test was conducted at the peak calculated accident pressure and maintained for a minimum of 24 hours to verify that the leakage rate was not greater than 0.4% by weight of the containment volume per day. The Absolute Method was used, and the test continued at a reduced pressure to provide a leak rate versus pressure characteristic curve. Weld channels and double penetrations were not pressurized during this test. A leak rate test at the peak calculated accident pressure using the same method as the initial leak rate test can be performed during the unit shutdown. The allowable leakage rate has since been reduced to 0.2% per day.

Most penetrations are designed with double seals to permit test pressurization of the interior of the penetration. To accomplish this, a supply of clean, dry, compressed air is connected to the penetrations raising the internal pressure to the peak calculated accident pressure. Leakage from the system is checked by either direct flow measurement of the input air, or measurement of the pressure loss. In the event excessive leakage is discovered, penetration groups can then be checked separately.

Capability is provided to the extent practical for testing the functional operability of valves and associated apparatus during periods of reactor shutdown.

Initiation of containment isolation employs coincidence circuits which allow checking of the operability and calibration of one channel at a time.

The main steam and feedwater barriers and isolation valves in systems which connect to the Reactor Coolant System are hydrostatically tested to measure leakage. The main steam isolation valves (MSIVs) can be tested periodically for operability during the life of the plant.

Design provisions are made to the extent practical to facilitate access for periodic visual inspection of important components of the containment air recirculation cooling and containment spray systems. The containment pressure reducing systems are designed to the extent practical so that the spray pumps, spray injection valves, spray nozzles, and additive injection valves can be tested periodically and after any component maintenance for operability and functional performance. Permanent test lines for all the containment spray loops are located so that all components up to the isolation valves at the containment may be tested. These isolation valves are checked separately.

The air test lines, for checking that spray nozzles are not obstructed, connect downstream of the isolation valves. Air flow through the nozzles is monitored by use of a smoke generator or tell-tale devices.

Capability is provided to test initially, to the extent practical, the operational startup sequence beginning with transfer to alternate power sources and ending with near design conditions for the containment spray, including the transfer to the alternate emergency diesel generator power source.

Reference Sections:

Section Title	Chapter
CONTAINMENT SYSTEMS (CONT)	5.0
ENGINEERED SAFETY FEATURES (ESF)	6.0
ELECTRICAL SYSTEM	8.0

1.3.8 FUEL AND WASTE STORAGE SYSTEMS (GDC 66 - GDC 69)

The new fuel storage area is designed so it is impossible to insert assemblies in locations other than those in the new fuel racks. However, the spent fuel storage rack design does not prevent placing assemblies in areas outside the spent fuel storage racks. The minimum spent fuel pool boron concentration specified in Technical Specifications 3.7.11 ensures the K_{eff} storage limit of 0.95 is maintained under postulated accident conditions. Administrative controls ensure fuel is stored in accordance with requirements of criticality analyses discussed in FSAR Section 9.4, Fuel Handling System.

During reactor vessel head removal, and while loading and unloading fuel from the reactor, the boron concentration is maintained at not less than that required to shut down the core to a $K_{eff} = 0.95$. This shutdown margin maintains the core at $K_{eff} < 0.99$ even if all control rods are withdrawn from the core. Periodic checks of refueling water boron concentration ensure the proper shutdown margin.

The design of the fuel handling equipment incorporated built-in interlocks and safety features, the use of detailed refueling instructions, and observance of minimum operating conditions provide assurance that no incident could occur during the refueling operations that would result in a hazard to public health and safety.

The refueling water provides a reliable and adequate cooling medium for spent fuel transfer. Heat removal is accomplished with an auxiliary cooling system.

Adequate shielding for radiation protection is provided during reactor refueling by conducting all spent fuel transfer and storage operations under water. This permits visual control of the operation at all times while maintaining the ability to alert personnel should radiation levels increase during fuel movement. Low and high spent fuel pool water level are alarmed in the control room and corrective action is initiated as necessary. Shielding is provided for waste handling and storage facilities to permit operation within requirements of 10 CFR 20.

The reactor cavity, refueling canal, and spent fuel storage pool are reinforced concrete structures with a seam-welded stainless steel plate liner. These structures are designed to withstand the anticipated earthquake loadings as Seismic Class I structures so the liner will prevent leakage.

Gamma radiation is monitored continuously at various locations in the auxiliary building. A high level signal is alarmed locally and is annunciated in the control room.

Auxiliary shielding for the waste disposal system and its storage components is designed to limit the dose rate levels.

All waste handling and storage facilities are contained and equipment designed so accidental releases directly to the atmosphere are monitored and will not exceed the guidelines of 10 CFR 20, Subpart D. Refer also to Chapter 11.0.

Reference Sections:

Section Title	Chapter
FUEL HANDLING SYSTEM (FH)	9.4
WASTE DISPOSAL SYSTEM (WG, WL, WS)	11.0
RADIATION PROTECTION (RM)	11.0
SPENT FUEL COOLING & FILTRATION (SF)	9.9

1.3.9 PLANT EFFLUENTS (GDC 70)

Liquid, gaseous, and solid waste disposal facilities are designed so discharge of effluents and off-site shipments are in accordance with applicable governmental regulations.

Radioactive fluids entering the waste disposal system are collected in sumps and tanks until determination of subsequent treatment can be made. They are sampled and analyzed to determine the quantity of radioactivity, with an isotopic identification, if necessary. Before discharge, radioactive fluids are processed as required and then released under controlled conditions. The system design and operation are characteristically directed toward minimizing releases to unrestricted areas. Discharge streams are appropriately monitored and safety features are incorporated to preclude releases in excess of the limits of 10 CFR 20.

Radioactive gases are pumped by compressors through a manifold to one of the gas decay tanks where they are held for a suitable period of time for decay. Cover gases in the nitrogen blanketing system are re-used to minimize gaseous wastes. During normal operation, gases are discharged intermittently at a controlled rate from these tanks through the monitored plant vent.

Liquid wastes are processed to remove radioactive materials. Filter cartridges, the spent resins from the demineralizers, and the concentrates from the evaporators are packaged and stored on-site until shipped off-site for disposal.

Since Alternate Source Term was implemented, the basis for reactor accident dosage level guidelines is 10 CFR 50.67.

Reference Sections:

Section Title	Chapter
WASTE DISPOSAL SYSTEM (WG, WL, WS)	11.0

1.3.10 RESOLUTION OF SYSTEMATIC EVALUATION PROGRAM ISSUES

In 1977, the NRC initiated the Systematic Evaluation Program (SEP) to review the designs of 51 older operating nuclear power plants. Point Beach Units 1 and 2 were listed among the 51 plants. In Phase I of the SEP, the NRC staff defined 137 issues for which the regulatory requirements had changed enough over time to warrant an evaluation of those plants licensed before the issuance of the Standard Review Plan. In Phase II of the SEP, the NRC staff compared the design of 10 of the 51 older plants to the Standard Review Plan issued in 1975. Based on these reviews, the NRC staff identified 27 issues of the original 137 that required some corrective action at one or more of the 10 plants which were reviewed. The staff referred to the issues on this smaller list as the SEP "lessons learned" issues, and concluded that these issues would generally apply to operating plants that received operating licenses before the Standard Review Plan was issued in 1975.

The NRC staff placed each SEP issue into one of the following categories: (1) issues that have been completely resolved (i.e. necessary corrective actions had been identified by the NRC staff, transmitted to licensees and implemented by licensees); (2) issues which are of such low safety significance so as to require no further regulatory action; (3) issues which are unresolved, but for which the NRC staff had identified existing regulatory programs that cover the scope of the technical concerns and whose implementation would resolve the specific SEP issues; and (4) issues which were unresolved, and regulatory actions to resolve the issues had not been identified (Reference 2).

The NRC staff concluded that there were six category 1 or 2 issues that were considered resolved, twenty category 3 issues that would be adequately addressed by ongoing programs, and one category 4 issues that would be resolved using the established generic issues resolution process (Reference 3).

Table 1.3-2lists the SEP Category 3 and 4 issues that have been resolved on the Point Beach docket using information submitted in support of the Individual Plant Examination of External Events (IPEEE; Reference 4). SEP issues not listed in the table were either dropped by the NRC (e.g. Item 1.6, Turbine Missiles), were resolved by other means (e.g. Item 3.2, Service and Cooling Water under Generic Letters 89-13 and 91-13), or else no specific docketed resolution was identified (e.g. Item 3.4, Isolation of High and Low Pressure Systems).

1.3.11 RESOLUTION OF OTHER ISSUES ADDRESSED BY THE INDIVIDUAL PLANT EXAMINATION OF EXTERNAL EVENTS

In addition to several SEP issues, the IPEEE addressed several other Generic Safety Issues (GSIs) identified by the NRC in Generic Letter 88-20 Supplement 4. The NRC subsequently reviewed and accepted the information contained in the IPEEE submittal, and closed the associated open GSIs based on that information (Reference 5). In addition, during the NRC review of the Extended Power Uprate (EPU) License Amendment Request, the NRC revisited the IPEEE information (Reference 6), thereby incorporating it by reference into the EPU license bases.

Table 1.3-3 lists the Generic Safety Issues that were resolved for Point Beach by the IPEEE submittals and review.

1.3.12 REFERENCES

1. Westinghouse Letter E-R-206, "Point Beach Criteria", from R. Salvatori, Westinghouse PWR Systems Division Reliability Group, to F. Konchar, Point Beach Project, October 2, 1969.

2. SECY-90-343, "Status of the Staff Program to Determine How the Lessons Learned from the Systematic Evaluation Program Have Been Factored Into the Licensing Bases of Operating Plants," October 4, 1990.

3. NRC Generic Letter 95-04, "Final Disposition of the Systematic Evaluation Program Lessons-Learned Issues," April 28, 1995.

4. Point Beach Letter VPNPD-95-056, “Generic Letter 88-20, Supplement 4 Summary Report on Individual Plant Examination of External Events for Severe Accident Vulnerabilities,” June 30, 1995.

5. NRC Staff Evaluation Report on Individual Plant Examination of External Events Submittal for Point Beach Units 1 and 2, dated Sept 15, 1999 (ML112030452, SER 1999-0003).

6. NRC Safety Evaluation Report, “Point Beach Nuclear Plant Units 1 and 2 - Issuance of License Amendments Regarding Extended Power Uprate,” May 3, 2011 (ML11045159, SER 2011-0004).

Table 1.3-1 POINT BEACH GENERAL DESIGN CRITERIA

CRITERION	DESCRIPTION	FSAR LOCATION(S)
1	Quality Standards Those systems and components of reactor facilities which are essential to the prevention, or the mitigation of the consequences, of nuclear accidents which could cause undue risk to the health and safety of the public shall be identified and then designed, fabricated, and erected to quality standards that reflect the importance of the safety function to be performed. Where generally recognized codes and standards pertaining to design, materials, fabrication, and inspection are used, they shall be identified. Where adherence to such codes or standards does not suffice to assure a quality product in keeping with the safety function, they shall be supplemented or modified as necessary. Quality assurance programs, test procedures, and inspection acceptance criteria to be used shall be identified. An indication of the applicability of codes, standards, quality assurance programs, test procedures, and inspection acceptance criteria used is required. Where such items are not covered by applicable codes and standards, a showing of adequacy is required.	4.1, 5.1
2	Performance Standards Those systems and components of reactor facilities which are essential to the prevention or to the mitigation of the consequences of nuclear accidents which could cause undue risk to the health and safety of the public shall be designed, fabricated, and erected to performance standards that enable such systems and components to withstand, without undue risk to the health and safety of the public, the forces that might reasonably be imposed by the occurrence of an extraordinary natural phenomenon such as earthquake, tornado, flooding condition, high wind, or heavy ice. The design bases so established shall reflect: (a) appropriate consideration of the most severe of these natural phenomena that have been officially recorded for the site and the surrounding area and (b) an appropriate margin for withstanding forces greater than those recorded to reflect uncertainties about the historical data and their suitability as a basis for design.	4.1, 5.1, 8.0
3	Fire Protection A reactor facility shall be designed to ensure that the probability of events such as fires and explosions and the potential consequences of such events will not result in undue risk to the health and safety of the public. Noncombustible and fire resistant materials shall be used throughout the facility wherever necessary to preclude such risk, particularly in area containing critical portions of the facility such as containment, control room, and components of engineered safety features.	5.1, 9.10
4	Sharing of Systems Reactor facilities may share systems or components if it can be shown that such sharing will not result in undue risk to the health and safety of the public.	6.1
5	Records Requirement The reactor licensee shall be responsible for assuring the maintenance throughout the life of the reactor of records of the design, fabrication, and construction of major components of the plant essential to avoid undue risk to the health and safety of the public.	4.1, 5.1

Table 1.3-1 POINT BEACH GENERAL DESIGN CRITERIA

CRITERION	DESCRIPTION	FSAR LOCATION(S)
6	Reactor Core Design The reactor core with its related controls and protection systems shall be designed to function throughout its design lifetime without exceeding acceptable fuel damage limits which have been stipulated and justified. The core and related auxiliary system designs shall provide this integrity under all expected conditions of normal operation with appropriate margins for uncertainties and for specified transient situations which can be anticipated.	3.1, 7.1
7	Suppression of Power Oscillations The design of the reactor core with its related controls and protection systems shall ensure that power oscillations, the magnitude of which could cause damage in excess of acceptable fuel damage limits, are not possible or can be readily suppressed.	3.1, 7.1
8	THIS GDC DOES NOT APPEAR IN THE FSAR	N/A
9	Reactor Coolant Pressure Boundary The reactor coolant pressure boundary shall be designed, fabricated, and constructed so as to have an exceedingly low probability of gross rupture or significant uncontrolled leakage throughout its design lifetime.	4.1
10	Reactor Containment The containment structure shall be designed (a) to sustain, without undue risk to the health and safety of the public, the initial effects of gross equipment failures, such as a large reactor coolant pipe break, without loss of required integrity, and (b) together with other engineered safety features as may be necessary, to retain for as long as the situation requires, the functional capability of the containment to the extent necessary to avoid undue risk to the health and safety of the public.	5.1
11	Control Room The facility shall be provided with a control room from which actions to maintain safe operational status of the plant can be controlled. Adequate radiation protection shall be provided to permit continuous occupancy of the control room under any credible post-accident condition or as an alternative, access to other areas of the facility as necessary to shut down and maintain safe control of the facility without excessive radiation exposures of personnel.	7.1
12	Instrumentation and Control Systems Instrumentation and controls shall be provided as required to monitor and maintain within prescribed operating ranges essential reactor facility operating variables.	7.1
13	Fission Process Monitors and Controls Means shall be provided for monitoring or otherwise measuring and maintaining control over the fission process throughout core life under all conditions that can reasonable be anticipated to cause variations in reactivity of the core.	7.1
14	Core Protection Systems Core protection systems, together with associated equipment, shall be designed to prevent or to suppress conditions that could result in exceeding acceptable fuel damage limits.	7.1
15	Engineered Safety Features Protection Systems Protection systems shall be provided for sensing accident situations and initiating the operation of necessary engineered safety features.	7.1

Table 1.3-1 POINT BEACH GENERAL DESIGN CRITERIA

CRITERION	DESCRIPTION	FSAR LOCATION(S)
16	Monitoring Reactor Coolant Leakage Means shall be provided to detect significant uncontrolled leakage from the reactor coolant pressure boundary.	4.1, 6.5
17	Monitoring Radioactivity Releases Means shall be provided for monitoring the containment atmosphere and the facility effluent discharge paths for radioactivity released from normal operations, from anticipated transients, and from accident conditions. An environmental monitoring program shall be maintained to confirm that radioactivity releases to the environs of the plant have not been excessive.	6.5, 11.5
18	Monitoring Fuel and Waste Storage Areas Monitoring and alarm instrumentation shall be provided for fuel and waste storage and associated handling areas for conditions that might result in loss of capability to remove decay heat and to detect excessive radiation levels.	11.5
19	Protection Systems Reliability Protection systems shall be designed for high functional reliability and inservice testability necessary to avoid undue risk to the health and safety of the public.	7.1
20	Protection Systems Redundancy and Independence Redundancy and independence designed into protection systems shall be sufficient to assure that no single failure or removal from service of any component or channel of such a system will result in loss of the protection function. The redundancy provided shall include, as a minimum, two channels of protection for each protection function to be served.	7.1
21	THIS GDC DOES NOT APPEAR IN THE FSAR	N/A
22	THIS GDC DOES NOT APPEAR IN THE FSAR	N/A
23	Protection Against Multiple Disability for Protection Systems The effects of adverse conditions to which redundant channels or protection systems might be exposed in common, either under normal conditions or those of an accident, shall not result in loss of the protection function or shall be tolerable on some other basis.	7.1
24	THIS GDC DOES NOT APPEAR IN THE FSAR	N/A
25	Demonstration of Functional Operability of Protection Systems Means shall be included for suitable testing of the active components of protection systems while the reactor is in operation to determine if failure or loss of redundancy has occurred.	7.1
26	Protection Systems Failure Analysis Design The protection systems shall be designed to fail into a safe state or into a state established as tolerable on a defined basis if conditions such as disconnection of the system, loss of energy (e.g., electrical power, instrument air), or adverse environments (e.g., extreme heat or cold, fire, steam, or water) are experienced.	7.1
27	Redundancy of Reactivity Control Two independent [reactivity] control systems, preferably of different principles, shall be provided.	3.1, 6.2, 9.3

Table 1.3-1 POINT BEACH GENERAL DESIGN CRITERIA

CRITERION	DESCRIPTION	FSAR LOCATION(S)
28	Reactivity Hot Shutdown Capability The reactivity control system provided shall be capable of making and holding the core subcritical from any hot standby or hot operating condition.	3.1, 9.3
29	Reactivity Shutdown Capability One of the reactivity control systems shall be capable of making the core subcritical under any anticipated operating condition (including anticipated operational transients) sufficiently fast to prevent exceeding acceptable fuel damage limits. Shutdown margin should assure subcriticality with the most reactive control rod fully withdrawn.	3.1, 9.3, 7.1
30	Reactivity Hold-down Capability The reactivity control systems provided shall be capable of making the core subcritical under credible accident conditions with appropriate margins for contingencies and limiting any subsequent return to power such that there will be no undue risk to the health and safety of the public.	3.1, 9.3
31	Reactivity Control Systems Malfunction The reactor protection system shall be capable of protecting against any single malfunction of the reactivity control system, such as unplanned continuous withdrawal (not ejection or dropout) of a control rod, by limiting reactivity transients to avoid exceeding fuel damage limits.	3.1, 7.1, 9.0
32	Maximum Reactivity Worth of Control Rods Limits, which include reasonable margin, shall be placed on the maximum reactivity worth of control rods or elements and on rates at which reactivity can be increased to ensure that the potential effects of a sudden or large change of reactivity cannot (a) rupture the reactor coolant pressure boundary or (b) disrupt the core, its support structures, or other vessel internals sufficiently to lose capability of cooling the core.	3.1
33	Reactor Coolant Pressure Boundary Capability The reactor coolant pressure boundary shall be capable of accommodating without rupture the static and dynamic loads imposed on any boundary component as a result of an inadvertent and sudden release of energy to the coolant. As a design reference, this sudden release shall be taken as that which would result from a sudden reactivity insertion such as rod ejection (unless prevented by positive mechanical means), rod dropout, or cold water addition.	4.1
34	Reactor Coolant Pressure Boundary Rapid Propagation Failure Prevention The reactor coolant pressure boundary shall be designed and operated to reduce to an acceptable level the probability of rapidly propagating type failures. Consideration is given (a) to the provisions for control over service temperature and irradiation effects which may require operational restrictions, (b) to the design and construction of the reactor pressure vessel in accordance with applicable codes, including those which establish requirements for absorption of energy within the elastic strain energy range and for absorption of energy by plastic deformation and (c) to the design and construction of reactor coolant pressure boundary piping and equipment in accordance with applicable codes.	4.1
35	THIS GDC DOES NOT APPEAR IN THE FSAR	N/A

Table 1.3-1 POINT BEACH GENERAL DESIGN CRITERIA

CRITERION	DESCRIPTION	FSAR LOCATION(S)
36	Reactor Coolant Pressure Boundary Surveillance Reactor coolant pressure boundary components shall have provisions for inspection, testing, and surveillance of critical areas by appropriate means to assess the structural and leaktight integrity of the boundary components during their service lifetime. For the reactor vessel, a material surveillance program conforming with current applicable codes shall be provided.	4.1
37	Engineered Safety Features Basis for Design Engineered safety features shall be provided in the facility to back up the safety provided by the core design, the reactor coolant pressure boundary, and their protection systems. Such engineered safety features shall be designed to cope with any size reactor coolant piping break up to and including the equivalent of a circumferential rupture of any pipe in that boundary, assuming unobstructed discharge from both ends.	6.1
38	Reliability and Testability of Engineered Safety Features All engineered safety features shall be designed to provide such functional reliability and ready testability as is necessary to avoid undue risk to the health and safety of the public.	6.1
39	Emergency Power An emergency power source shall be provided and designed with adequate independency, redundancy, capacity, and testability to permit the functioning of the engineered safety features and protection systems required to avoid undue risk to the health and safety of the public. This power source shall provide this capacity assuming a failure of a single active component.	8.0
40	Missile Protection Adequate protection for those engineered safety features, the failures of which could cause an undue risk to the health and safety of the public, shall be provided against dynamic effects and missiles that might result from plant equipment failures other than a rupture of the Reactor Coolant System piping. An original design basis for protection of equipment against the dynamic effects of a rupture of the Reactor Coolant System piping is no longer applicable.	4.1, 6.1
41	Engineered Safety Features Performance Capability Engineered safety features, such as the emergency core cooling system and the containment heat removal system, shall provide sufficient performance capability to accommodate the failure of any single active component without resulting in undue risk to the health and safety of the public.	6.1, 9.0
42	Engineered Safety Features Components Capability Engineered safety features shall be designed so that the capability of these features to perform their required function is not impaired by the effects of a loss-of-coolant accident to the extent of causing undue risk to the health and safety of the public.	6.1
43	Accident Aggravation Prevention Protection against any action of the engineered safety features which would accentuate significantly the adverse after- effects of a loss of normal cooling shall be provided.	6.1

Table 1.3-1 POINT BEACH GENERAL DESIGN CRITERIA

CRITERION	DESCRIPTION	FSAR LOCATION(S)
44	Emergency Core Cooling System Capability An emergency core cooling system with the capability for accomplishing adequate emergency core cooling shall be provided. This core cooling system and the core shall be designed to prevent fuel and clad damage that would interface with the emergency core cooling function and to limit the clad metal-water reaction to acceptable amounts for all sizes of breaks in the reactor coolant piping up to the equivalent of a double-ended rupture of the largest pipe. The performance of such emergency core cooling system shall be evaluated conservatively in each area of uncertainty.	6.2
45	Inspection of Emergency Core Cooling System Design provisions shall, where practical, be made to facilitate inspection of physical parts of the emergency core cooling system, including reactor vessel internals and water injection nozzles.	6.2
46	Testing of Emergency Core Cooling System Components Design provisions shall be made so that components of the emergency core cooling system can be tested periodically for operability and functional performance.	6.2
47	Testing of Emergency Core Cooling System Capability shall be provided to test periodically the operability of the emergency core cooling system up to a location as close to the core as is practical.	6.2
48	Testing of Operational Sequence of Emergency Core Cooling System Capability shall be provided to test initially, under conditions as close as practical to design, the full operational sequence that would bring the emergency core cooling system into action, including the transfer to alternate power sources.	6.2
49	Reactor Containment Design Basis The reactor containment structure, including openings and penetrations, and any necessary containment heat removal systems, shall be designed so that the leakage of radioactive materials from the containment structure under conditions of pressure and temperature resulting from the largest credible energy release following a loss-of-coolant accident, including the calculated energy from metal-water or other chemical reactions that could occur as a consequence of failure of any single active component in the emergency core cooling system, will not result in undue risk to the health and safety of the public.	5.1
50	NDT Requirement for Containment Material The selection and use of containment materials shall be in accordance with applicable engineering codes.	5.1
51	THIS GDC DOES NOT APPEAR IN THE FSAR	N/A
52	Containment Heat Removal Systems Where an active heat removal system is needed under accident conditions to prevent exceeding containment design pressure, this system shall perform its required function, assuming failure of any single active component.	6.3, 9.0
53	Containment Isolation Valves Penetrations that require closure for the containment function shall be protected by redundant valving and associated apparatus.	5.2

Table 1.3-1 POINT BEACH GENERAL DESIGN CRITERIA

CRITERION	DESCRIPTION	FSAR LOCATION(S)
54	Initial Containment Leakage Rate Testing Containment shall be designed so that integrated leakage rate testing can be conducted at the peak pressure calculated to result from the design basis accident after completion and installation of all penetrations and the leakage rate shall be measured over a sufficient period of time to verify its conformance with required performance.	5.7
55	Periodic Containment Leakage Rate Testing The containment shall be designed so that an integrated leakage rate can be periodically determined by test during plant lifetime.	5.7
56	Provisions for Testing of Penetrations Provisions shall be made to the extent practical for periodically testing penetrations which have resilient seals or expansion bellows to permit leak tightness to be demonstrated at the peak pressure calculated to result from occurrence of the design basis accident.	5.7
57	Provisions for Testing of Isolation Valves Capability shall be provided to the extent practical for testing functional operability of valves and associated apparatus essential to the containment function for establishing that no failure has occurred and for determining that valve leakage does not exceed acceptable limits.	5.7
58	Inspection of Containment Pressure Reducing Systems Design provisions shall be made to the extent practical to facilitate the periodic physical inspection of all important components of the containment pressure reducing systems, such as pumps, valves, spray nozzles and sumps.	6.3, 6.4
59	Testing of Containment Pressure Reducing Systems Components The containment pressure reducing systems shall be designed, to the extent practical, so that active components, such as pumps and valves, can be tested periodically for operability and required function performance.	6.3, 6.4
60	Testing of Containment Spray Systems A capability shall be provided to the extent practical to test periodically the delivery capability of the containment spray system at a position as close to the spray nozzles as is practical.	6.4
61	Testing of Operational Sequence of Containment Pressure-Reducing Systems A capability shall be provided to test initially under conditions as close as practical to the design and the full operational sequence that would bring the containment pressure reducing systems into action, including the transfer to alternate power sources.	6.3, 6.4
62	Inspection of Air Cleanup Systems Design provisions shall be made to the extent practical to facilitate physical inspection of all critical parts of containment air cleanup systems, such as ducts, filters, fans, and damper.	6.4
63	Testing of Air Cleanup Systems Components Design provisions shall be made to the extent practical so that active components of the air cleanup systems, such as fans and dampers, can be tested periodically for operability and required functional performance.	6.4

Table 1.3-1 POINT BEACH GENERAL DESIGN CRITERIA

CRITERION	DESCRIPTION	FSAR LOCATION(S)
64	Testing Air Cleanup Systems A capability shall be provided, to the extent practical, for on-site periodic testing and surveillance of the air cleanup systems to ensure (a) filter bypass paths have not developed, and (b) filter and trapping materials have not deteriorated beyond acceptable limits.	6.4
65	Testing of Operational Sequence of Air Cleanup Systems A capability shall be provided to test initially under conditions, as close to design as practical, the full operational sequence that would bring the air cleanup systems into action, including the transfer to alternate power sources and the design air flow delivery capability.	6.4
66	Prevention of Fuel Storage Criticality Criticality in the new and spent fuel storage pits shall be prevented by physical systems or processes. Such means as geometrically safe configurations shall be emphasized over procedural controls.	9.4
67	Fuel and Waste Storage Decay Heat Reliable decay heat removal systems shall be designed to prevent damage to the fuel in storage facilities and to waste storage tanks that could result in radioactivity release which would result in undue risk to the health and safety of the public.	9.4, 9.9
68	Fuel and Waste Storage Radiation Shielding Adequate shielding for radiation protection shall be provided in the design of spent fuel and waste storage facilities.	9.4, 11.6
69	Protection Against Radioactivity Release from Spent Fuel and Waste Storage Provisions shall be made in the design of fuel and waste storage facilities such that no undue risk to the health and safety of the public could result from an accidental release of radioactivity.	9.4, 11.5
70	Control of Releases of Radioactivity to the Environment The facility design shall include those means necessary to maintain control over the plant radioactive effluents, whether gaseous, liquid, or solid. Appropriate holdup capacity shall be provided for retention of gaseous, liquid, or solid effluents, particularly where unfavorable environmental conditions can be expected to require operational limitations upon the release of radioactive effluents to the environment. In all cases, the design for radioactivity control shall be justified (a) on the basis of 10 CFR 20 requirements, for both normal operations and for any transient situation that might reasonably be anticipated to occur and (b) on the basis of 10 CFR 50.67 dosage level requirements for potential reactor accidents.	11.1, 11.2, 11.3,

Table 1.3-2 SEP CATEGORY 3 AND 4 ISSUES RESOLVED BY IPEEE

Page 1 of 1

Issue	SEP Issue #	References
Settlement of Foundations & Buried Equipment	1.1	Reference 2, Reference 3, Reference 4, and Reference 5
Dam Integrity & Site Flooding	1.2	Reference 2, Reference 3, Reference 4, and Reference 5
Site Hydrologic Characteristics & Capability to Withstand Flooding	1.3	Reference 2, Reference 3, Reference 4, and Reference 5
Industrial Hazards	1.4	Reference 2, Reference 3, Reference 4, and Reference 5
Tornado Missiles	1.5	Reference 2, Reference 3, Reference 4, and Reference 5
Severe Weather Effects on Structures	2.1	Reference 2, Reference 3, and Reference 5
Design Codes, Criteria, and Load Combinations for Structures	2.2	Reference 2, Reference 3, and Reference 5
Seismic Design of Structures, Systems and Components	2.4	Reference 2, Reference 3, and Reference 5

Table 1.3-3 ADDITIONAL GENERIC SAFETY ISSUES RESOLVED BY IPEEE

Page 1 of 1

Issue	GSI Designation	References
Shutdown Decay Heat Removal Requirements	USI A-45	Reference 4 and Reference 5
Potential Seismic Interaction Involving the Movable In-Core Flux Mapping System Used in Westinghouse Plants	GSI-131	Reference 4 and Reference 5
Design for Probable Maximum Precipitation	GSI-103	Reference 4 and Reference 5
Fire Risk Scoping Study Issues	[no designation]	Reference 4 and Reference 5
Effects of Fire Protection System Actuation on Safety-Related Equipment	GSI-57	Reference 4 and Reference 5
Fire-Induced Alternate Shutdown/Control Room Panel Interactions	GSI-147	Reference 4 and Reference 5
Smoke Control and Manual Fire-Fighting Effectiveness	GSI-148	Reference 4 and Reference 5
Systematic Evaluation Program (SEP)	GSI-156	Reference 4 and Reference 5
Multiple System Responses Program (MSRP)	GSI-172	Reference 4 and Reference 5

1.4 QUALITY ASSURANCE PROGRAM

NextEra Energy Point Beach, LLC nuclear plant operational and support activities are conducted under NextEra Energy Quality Assurance Topical Report (QATR), FPL-1. FPL-1 is the top-level policy document that establishes how quality is to be assured. The QATR responds to and satisfies the requirements of Appendix B of Part 50.

Revision 0 of the QATR was previously accepted by the NRC (Reference 1). The QATR was subsequently revised, and applied to Point Beach Nuclear Plant, as allowed by 10 CFR 50.54(a)(3) (Reference 3).

Subsequent revisions of the QATR are subject to the restrictions of 10 CFR 50.54(a) – reviewing the proposed change from the QATR previously accepted by the NRC.

The requirements of the QATR are applied to SSCs affecting quality (i.e., safety-related structures systems and components).

Safety-related structures, systems, and components are those that are relied upon to remain functional during and following design basis events to ensure:

1. The integrity of the reactor coolant pressure boundary;
2. The capability to shut down the reactor and maintain it in a safe shutdown condition, or
3. The capability to prevent or mitigate the consequences of accidents that could result in potential offsite exposures comparable to the guideline exposures of 10 CFR Part 100 or as referred to in 10 CFR 50.34 or 10 CFR 50.67 as applicable.

In addition to the commitments identified in the QATR, Point Beach also has the following commitment to Regulatory Guide (RG) 1.54 dated June 1973:

PBNP is committed to follow the position of RG 1.54 (1973), Quality Assurance Requirements for Protective Coatings Applied to Water-Cooled Nuclear Power Plants, which endorses and supplements ANSI N101.4-1972, Quality Assurance for Protective Coatings Applied to Nuclear Facilities, for activities that affect quality and occur during the operational phase, and that are comparable in nature and extent to related activities occurring during construction.

Procedures and programmatic controls ensure that the applicable requirements for the procurement, application, inspection, and maintenance of Service Level I coatings in containment are implemented. The surface preparation, application and surveillance during installation of Service Level I coatings used for new applications or repair/replacement activities inside containment meet the applicable portions of RG 1.54 and ANSI N101.4-1972.

Point Beach was built and licensed prior to RG 1.54 being issued, and, as such, does not conform fully to all aspects of ANSI N101.4-1972 and RG 1.54. The original coatings inside containment were applied without the documentation and/or testing necessary to be considered Service Level I coatings. These original coatings are considered acceptable based on WCAP-7198-L and the evaluation in Section 5.6.2.4.

Relatively small amount of coatings applied by vendors on supplied equipment, miscellaneous structural supports, and small areas of touch-up on qualified Service Level I coatings may not be Service Level I coatings. With the exception of isolated minor touch-up repairs (i.e., less than 1 ft^2), all coating repairs, maintenance, and applications inside containment are required to be performed with Service Level I coatings.

For details of the Quality Assurance requirements for the Aging Management Programs implemented in accordance with 10 CFR 54, see Chapter 15. Records necessary to document compliance with the provisions of 10 CFR 54 will be retained for the term of the renewed operating license (Reference 2).

1.4.1 REFERENCES

1. "Florida Power and Light Company, FPL Energy Seabrook, LLC, and FPL Energy Duane Arnold, LLC - Approval of Common Quality Assurance Topical Report," Moroney, NRC to Stall, FPL, dated December 29, 2006.
2. NUREG-1839, Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, Docket Nos. 50-266 and 50-301, dated December 2005.
3. FPL letter to the NRC; "Quality Assurance Topical Report (QATR FPL-1), Revisions 1 and 2," dated June 27, 2008.

1.5 FACILITY SAFETY CONCLUSIONS

The safety of the public and plant operating personnel and reliability of plant equipment and systems have been the primary considerations in the plant design. The approach taken in fulfilling the safety consideration is three-fold. First, careful attention has been given to the design to prevent the release of radioactivity to the environment under conditions which could be hazardous to the health and safety of the public. Second, the plant has been designed so as to provide adequate protection for plant personnel wherever a potential radiation hazard exists. Third, reactor systems and controls have been designed with a great degree of redundancy and fail-safe characteristics.

Based on the over-all design of the plant including its safety features, the analyses of the possible incidents and of hypothetical accidents, and the operational history of the Point Beach Nuclear Plant, it is concluded that Point Beach Nuclear Plant Units 1 and 2 can be operated without undue hazard to the health and safety of the public.

On April 16, 1970, by letter to the Chairman of the U. S. Atomic Energy Commission, the Advisory Committee on Reactor Safeguards (ACRS) reported its completed review of the operating license application for Point Beach Nuclear Plant Units 1 and 2 (Reference 1). The ACRS concluded that subject to satisfactory completion of construction and pre-operational testing, and given due regard for those items mentioned in the letter, Point Beach Nuclear Plant Units 1 and 2 can be operated at power levels up to 1518.5 MWt for each unit without undue risk to the health and safety of the public. Similarly, the U.S. Atomic Energy Commission, in its Safety Evaluation Report for the Point Beach Nuclear Plant Units 1 and 2 dated July 15, 1970 (Reference 2), concluded that, “There is reasonable assurance (i) that the activities authorized by the operating license can be conducted without endangering the health and safety of the public, and (ii) that such activities will be conducted in compliance with the regulations of the Commission set forth in 10 CFR Chapter 1.” On 11/29/2002 a License Amendment Request, increasing Thermal Power to 1540 MWt, was approved by the NRC (Reference 3). The basis of the change was the implementation of a 10 CFR 50, Appendix K uprate based on a reduction in power measurement uncertainty.

In December, 2005, the NRC issued NUREG-1839, “Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2.” Based on the license renewal application, the NRC staff concluded that the requirements of 10 CFR 54.29(a) had been met and that all open items and confirmatory items have been resolved. The renewed licenses are applicable for 20 years beyond the expiration date of midnight, October 5, 2010 for Unit 1 and midnight, March 8, 2013 for Unit 2.

On May 3, 2011, the NRC approved a License Amendment Request increasing core thermal power to 1800 MWt (Reference 4). This power increase and associated changes to the operating license, Technical Specifications, and licensing basis is defined as an Extended Power Uprate (EPU).

1.5.1 REFERENCES

1. Advisory Committee on Reactor Safeguards letter to the U. S. Atomic Energy Commission, dated April 16, 1970.

2. U. S. Atomic Energy Commission letter to Wisconsin Electric Power Company, dated July 15, 1970

3. NRC letter to NMC, “Point Beach Nuclear Plant, Units 1 and 2 - Issuance of Amendments Re: Measurement of Uncertainty Recapture Power Uprate (TAC NOS. MB4956 and MB4957),” dated November 29, 2002.

4. NRC Safety Evaluation 2011-0004, “Issuance of License Amendments Regarding Extended Power Uprate,” dated May 3, 2011

CHAPTER 2 TABLE OF CONTENTS

2.0 SITE AND ENVIRONMENT

Information presented in this section was used to develop criteria for storm, flood, and earthquake protection and to evaluate site characteristics affecting routine and accidental releases of radioactive liquids and gases to the environment. Field programs to investigate geology and seismology have been completed. A meteorological program on site commenced in April 1967 and continued until April 1969. Environmental radiological monitoring programs and ecological monitoring and research programs have been continued from prior to Unit 1 criticality until the present.

The site is in east central Wisconsin on the west shore of Lake Michigan approximately 30 miles SE of Green Bay and about 90 miles NNE of Milwaukee. Cooling water is drawn from an intake crib located 1750 feet offshore in Lake Michigan. Farming is the predominant activity in this sparsely populated area of the state. The plant is situated in a productive dairy farming and vegetable canning region; however, the area is heavily industrialized to the south in Two Rivers and Manitowoc, and to the west in the Fox River Valley.

Soil and subsurface layers have a high clay content which inhibits percolation and drainage to Lake Michigan. The site is well ventilated and not subject to severe persistent inversions. While tornadoes occur in the region, none have been reported to affect the lakeshore directly. High winds (on the order of 108 mph) can be expected once in 100 years from storms.

Upper glacial till or underlying lake deposits on the site provide a suitable foundation for plant structures other than reactor containment. To minimize differential settlement between adjacent structures, the reactor containments and spent fuel pool are supported on steel H piles driven to refusal in the underlying bedrock. A horizontal ground acceleration of 0.06 gravity combined with a vertical acceleration of 0.04 gravity is used for the earthquake design criteria at the site based on a report by John A. Blume and Associates. Site geological investigations were performed by Dames and Moore. Harza Engineering Company and Sargent and Lundy Engineers were consultants for hydrologic and hydraulic studies. Analysis of the environmental data was performed by NUS Corporation, Sargent and Lundy Engineers, and Murray and Trettel Inc.

2.1 SITE LOCATION AND BOUNDARIES

The site is in the Town of Two Creeks in the northeast corner of Manitowoc County, Wisconsin, on the west shore of Lake Michigan about 30 miles southeast of the center of the city of Green Bay, and 90 miles NNE of Milwaukee. It is located at longitude 87° 32.5′W and latitude 44° 17.0′N. Its location is shown in Figure 2.2-1. The international boundary between Canada and the United States is approximately 200 miles NE of the site.

The site comprises approximately 1260 acres, all of which is owned by NextEra Energy Point Beach.

Figure 2.2-2 shows the general topography of the region out to 50 miles. A site topographic map covering details out to a 5 mile radius is shown in Figure 2.2-2A. Figure 2.2-3 is a site plot depicting the site details, boundaries, and structures.

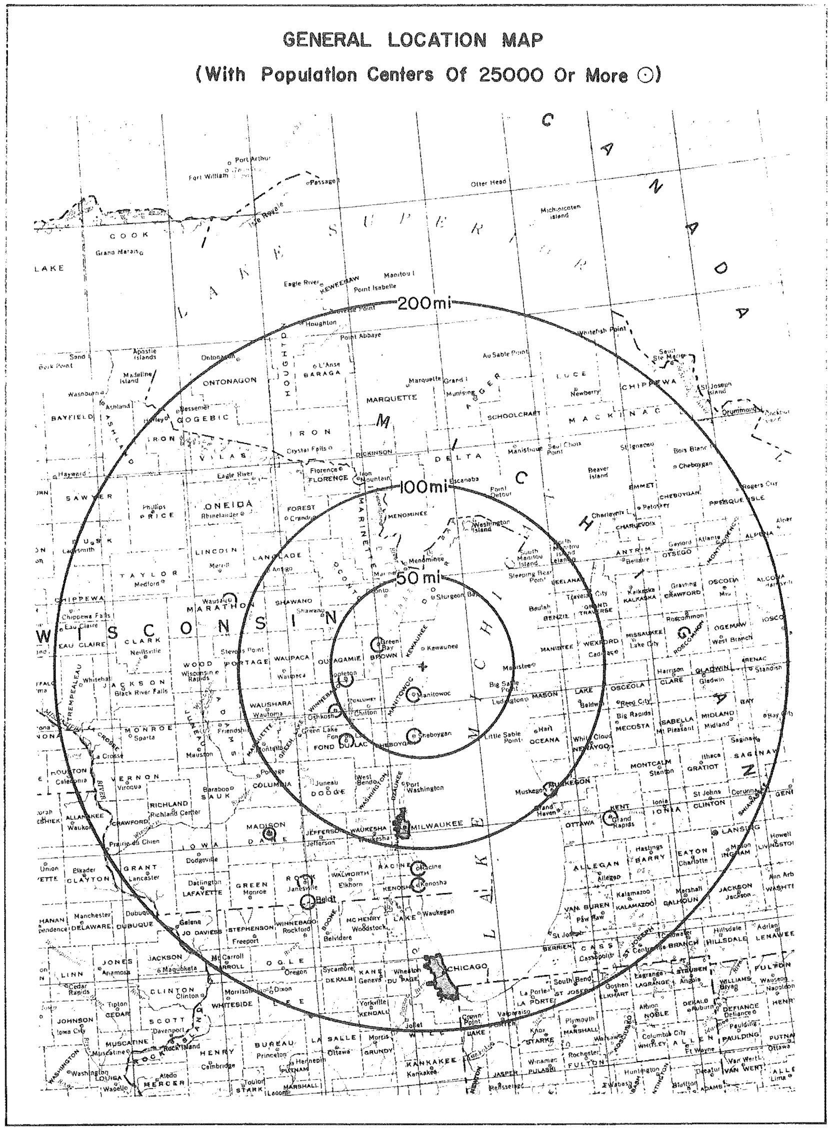
2.2 TOPOGRAPHY

Overall ground surface at the site of the Point Beach Nuclear Plant is gently rolling to flat with elevations varying from 3 to 58 feet above Plant Datum. Subdued knob and kettle topography is visible from aerial photographs. The land surface slopes gradually toward the lake from the higher glacial moraine areas west of the site. Higher ground adjacent to the lake, however, diverts the drainage to the north and south.

The major surface drainage features are two small creeks which drain to the north and south. One creek discharges into the lake about 1500 feet north of the northern corner of the site and the other near the center of the site. During the spring, ponds of water occupy many shallow depressions. Site drainage is poor due to the high clay content of the soil combined with the pock-marked surface.

Low bluffs face the Lake Michigan shore with evidence of marked erosion near the center of the site. At this point the beach is narrow (ranging in width from 20 to 50 feet) with bare mud slopes showing active erosion due to lake storms. In this area, shoreline recession ranges from 2 ½ (Reference 1) to 5 feet per year. Special protection is provided to control further recession of the shoreline at the site.

Figure 2.2-1 GENERAL LOCATION MAP



GENERAL LOCATION MAP
FIG. 2.2-1

Figure 2.2-2 GENERAL TOPOGRAPHY MAP

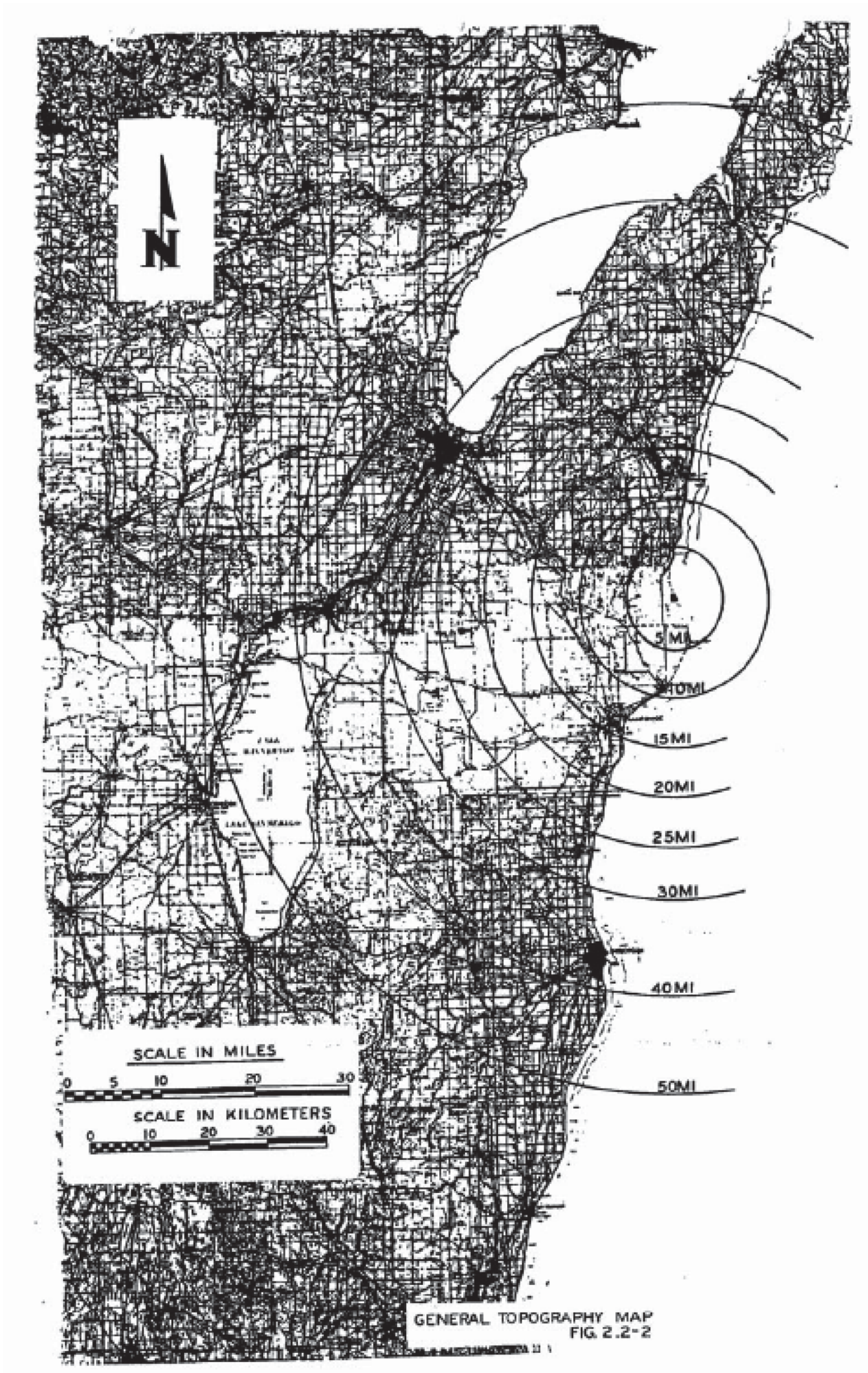


Figure 2.2-2A GENERAL TOPOGRAPHY MAP

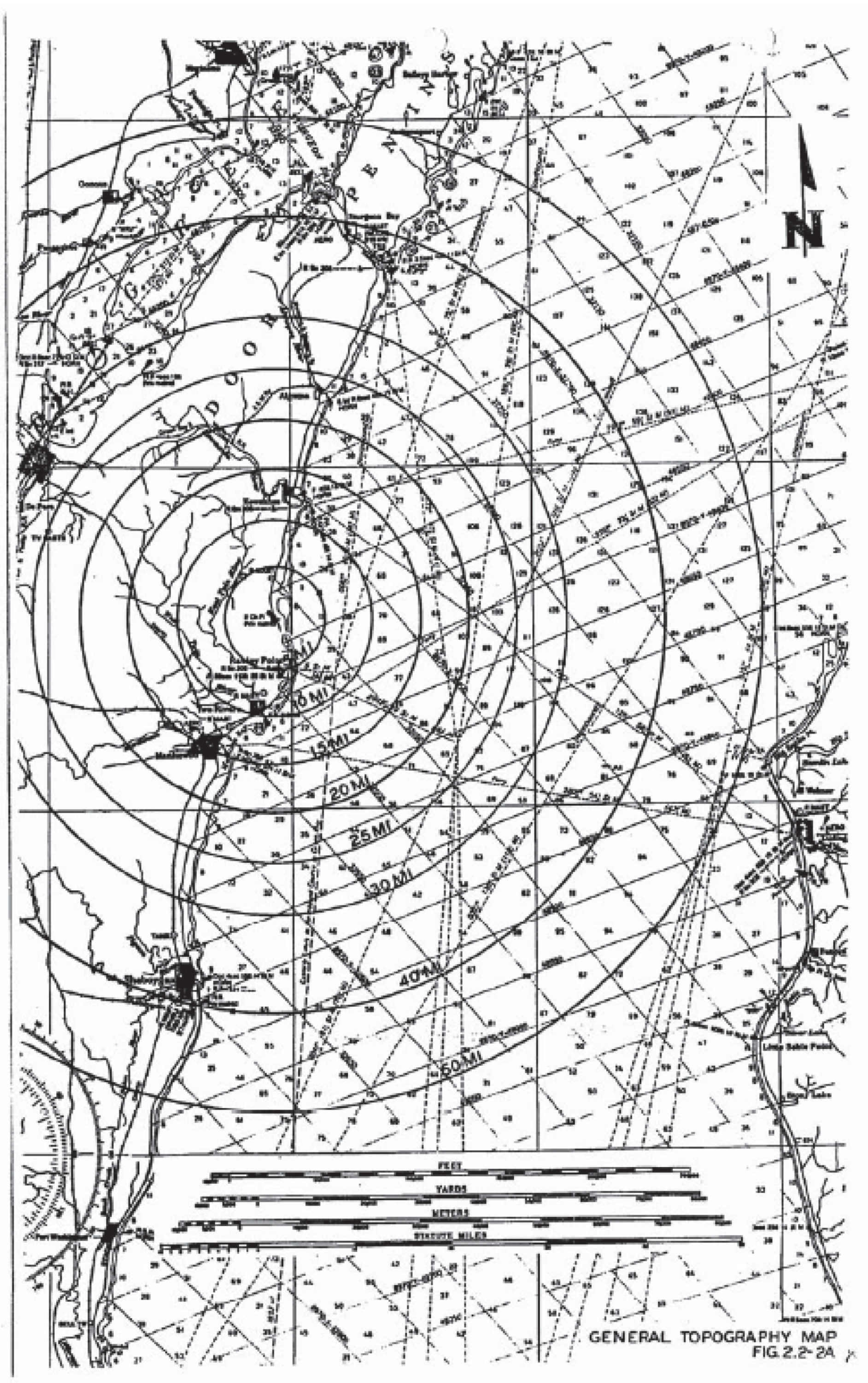


Figure 2.2-3 SITE TOPOGRAPHY MAP

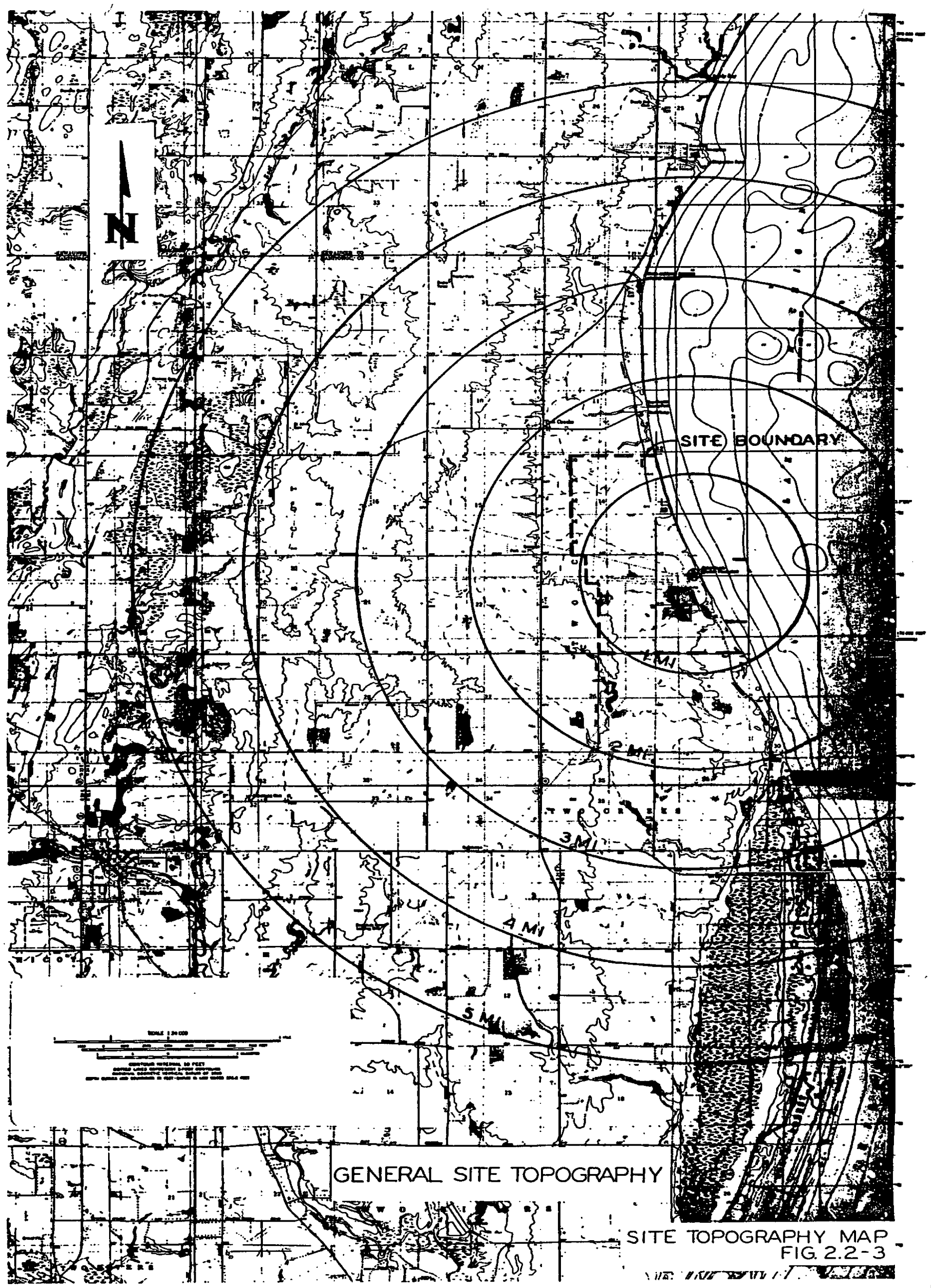
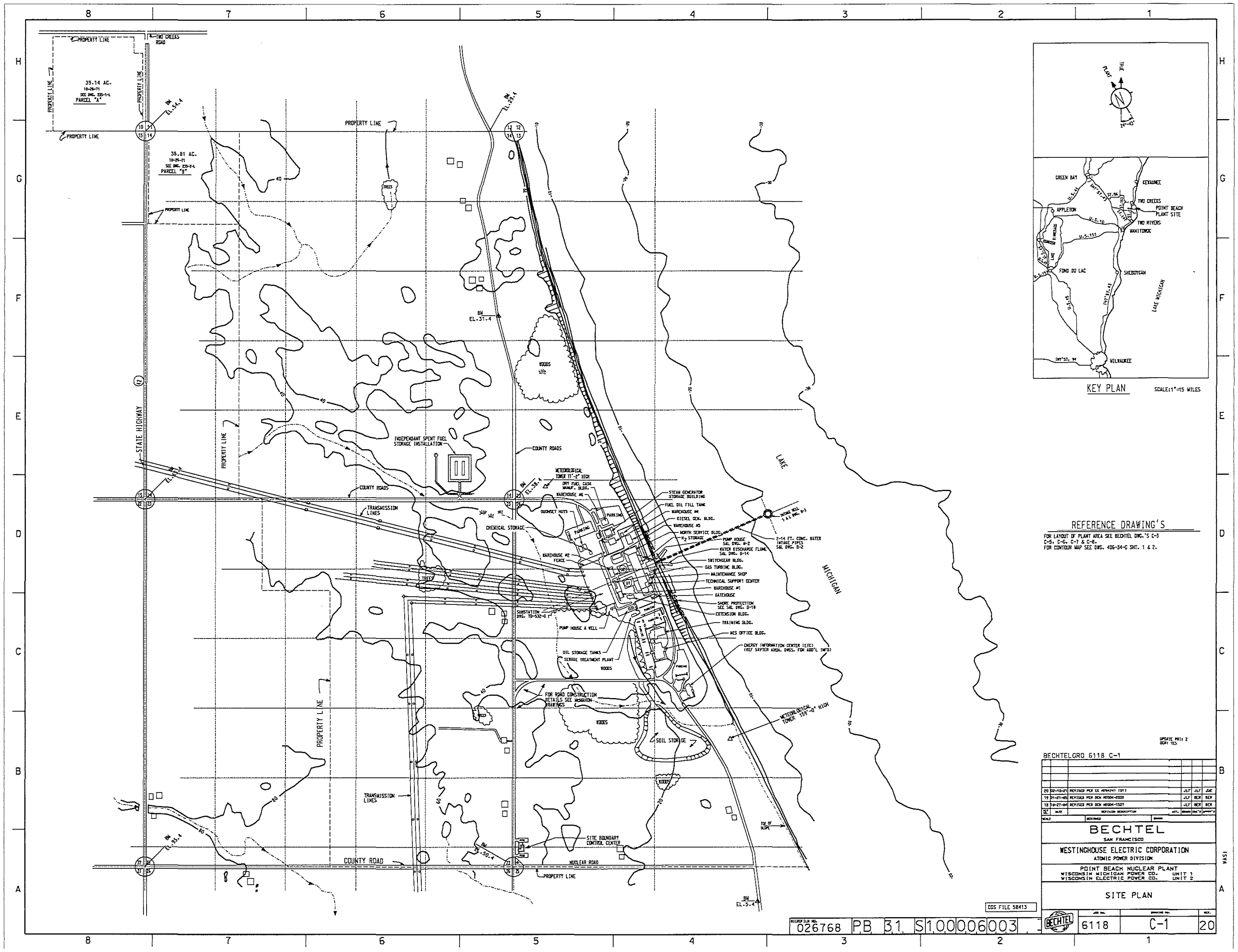


Figure 2.2-4 UNITS 1 & 2 SITE PLAN



2.3 POPULATION

Figure 2.2-1 depicts population centers of over 25,000 people within a radius of 100 miles of the site. The nearest population centers of 25,000 or more are Manitowoc (13 miles SSW of the site) with 32,547 people, Green Bay (27 miles NW of the site) with 87,899 people, Appleton (43 miles West of the site) with 53,531 people, and Sheboygan (36 miles SSW of the site) with 48,085 people. There are no other population centers greater than 25,000 people that lie within 50 miles of the site. Milwaukee, with a population of 636,210 lies 90 miles SSW of the site. All population figures are according to the 1980 Census.

Figure 2.3-1 shows the 1980 and projected (1990, 2000, 2010, 2020) population distribution in 16 directional sectors centered on the site and within 1, 2, 3, 4, and 5 mile radii. Figure 2.3-2 shows similar information for 5, 10, 20, 30, and 40 miles.

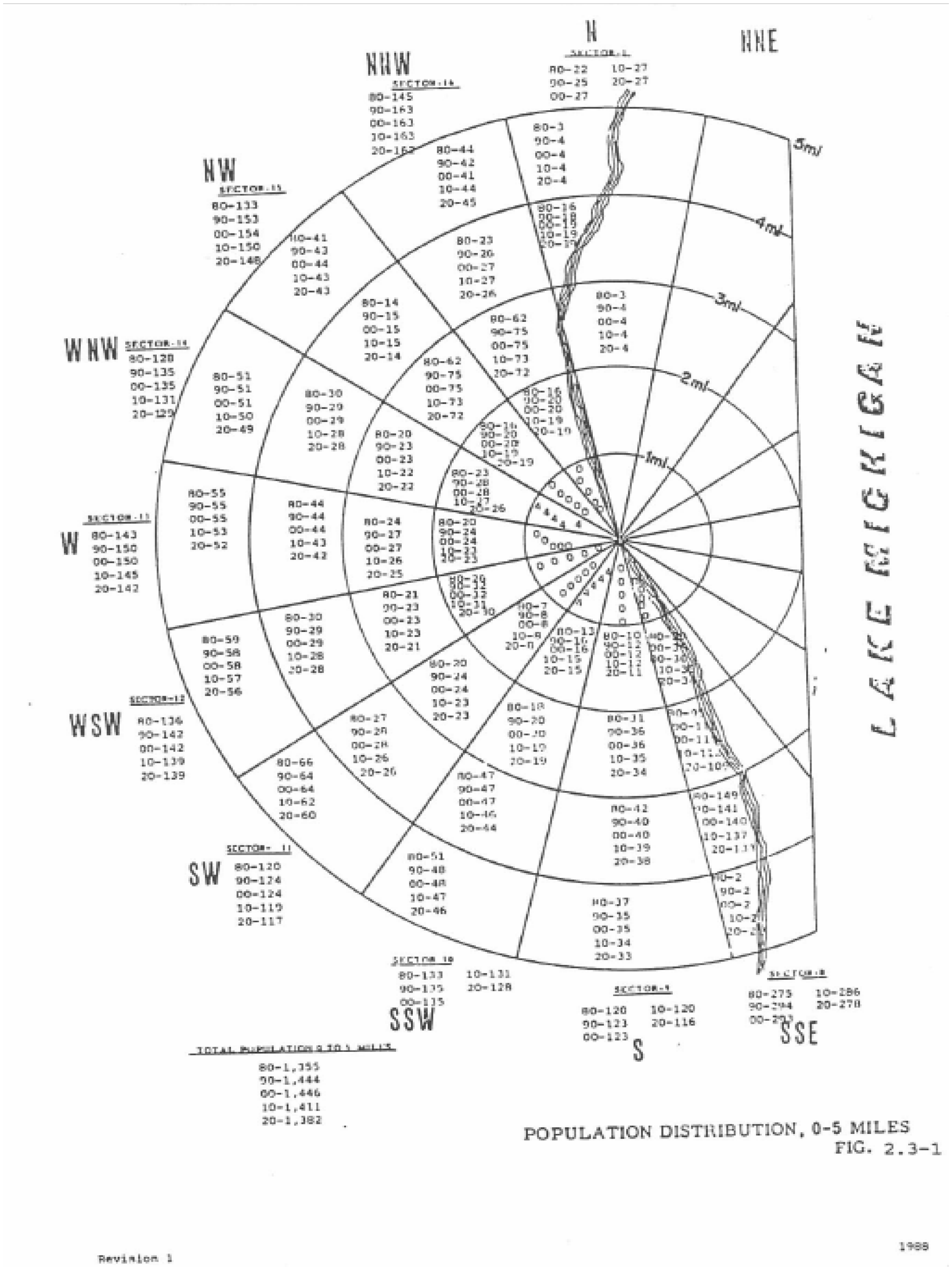
The population estimates in Figure 2.3-1 are based on population figures obtained in the 1980 U.S. Census. This information was applied to a series of 7.5 minute topographic maps of the area. These maps were developed by the United States Geological Survey in cooperation with the Wisconsin Division of Highways and Wisconsin Geological and Natural History Survey, and are based on aerial photographs.

Population projections for the years 1990, 2000, 2010, and 2020 were derived from the document "Wisconsin Population Projections 1980-2020," Fifth Edition, June 1988. This document was prepared by the Demographic Services Center of the Wisconsin Department of Administration in cooperation with the Applied Population Laboratory of the University of Wisconsin - Madison.

Population increase due to summertime cottage occupants in the vicinity of the site is minimal. These cottages are limited to the SSE and N sectors along the lake shore. There are 24 cottages between 1 to 4 miles SSE of the site and one cottage 4 to 5 miles north of the site. Projection of these summertime residents to 2020 is difficult, but a conservative increase by 100% would result in a total of 200 people. Additionally, in Point Beach State Forest, 127 individual campsites and two group campsites are located 3 to 7 miles S and SSE from the site.

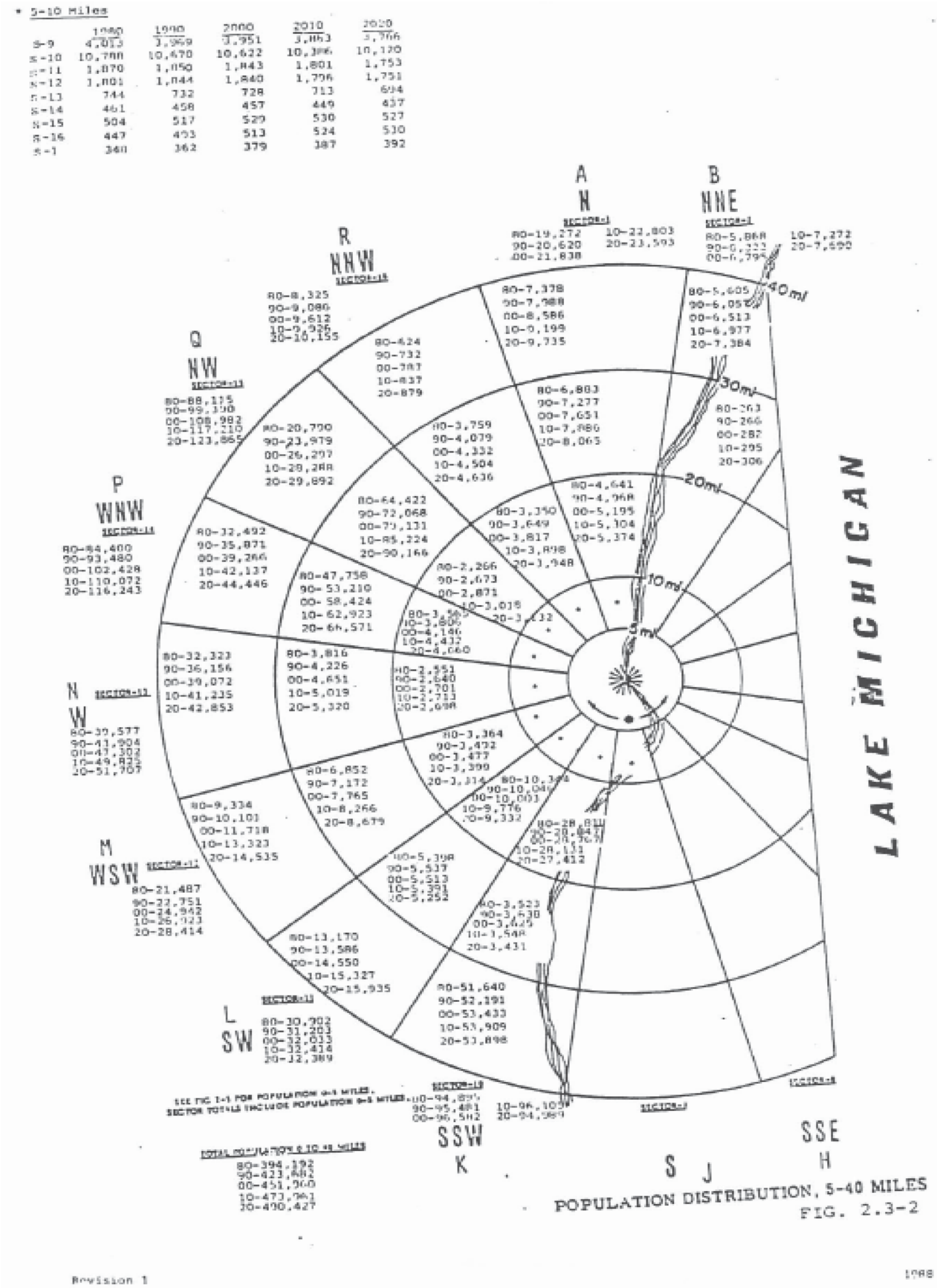
The closest approach of the plant site boundary is about 1200 meters (3900 feet) from either reactor. This is defined as the exclusion radius for this site. The nearest population center having a population in excess of 25,000 is the Two Rivers-Manitowoc area which has an outer boundary approximately 12,000 meters (7 1/2 miles) from the plant. As defined in 10 CFR 100, the population center distance shall be not closer than 1 1/3 times the low population zone distance. Because of the relatively small number of people between the site boundary and the population center of Two Rivers-Manitowoc, the outer boundary of the low population zone for this site is defined as 9000 meters (5.6 miles). Analysis of predicted population and existing roads shows that the total number and density of the residents within the low population zone is such that there is a reasonable probability that appropriate protective measures could be taken in their behalf in the event of a serious accident.

Figure 2.3-1 POPULATION DISTRIBUTION 0-5 MILES



POPULATION DISTRIBUTION, 0-5 MILES
FIG. 2.3-1

Figure 2.3-2 POPULATION DISTRIBUTION 5-40 MILES



2.4 LAND USE

Regional Land Use

Manitowoc County, in which the site is located, and adjacent counties of Kewaunee, Brown, Calumet, and Sheboygan are predominantly rural. Agricultural pursuits account for approximately 90% of the total county acreage with individual farms ranging in average size from 110-124 acres. Dairy products and livestock account for 85% of the counties farm production with field crops and vegetables accounting for most of the remainder. The principal crops are grain corn, silage corn, oats, barley, hay, potatoes, green peas, lima beans, snap beans, beets, cabbage, sweet corn, cucumbers, sunflowers, and cranberries. Agricultural receipts in the five county area amounted to about $77,000,000 in 1963 according to the Wisconsin Department of Natural Resources and the Wisconsin Department of Agriculture. Within a 20 mile radius of the site there are approximately 11 dairy plants in Manitowoc County and approximately 4 in Kewaunee County.

More than one-third of the workers residing in the five county area were engaged in manufacturing operation; one-eighth were occupied in agriculture; about two-fifths in service industries. The remainder are in all other occupations according to 1960 statistics of the Wisconsin Department of Natural Resources.

Brown County, northwest of Manitowoc County and Outagamie County farther west are the centers of a large paper making industry on the Fox River. Heavy manufacturing is found in Manitowoc, Two Rivers, and Sheboygan. Representative industries at the time of license application in a 20 mile radius of the site are listed in Table 2.4-1.

Local Land Use

The region within a radius of 5 miles of the site is presently devoted exclusively to agriculture. During 1965, approximately 1390 acres of cash crops (peas and snap beans) were produced and sold to Lakeside Cannery in Manitowoc. Within the township of Two Creeks surrounding the site (15 sq. miles) there are about 800 producing cows on about 40 dairy farms. Some beef cattle are raised 2.5 miles north of the site. Cows are on pasture from the first of June to late September or early October. During the winter, cows are fed on locally produced hay and silage. Of the milk produced in this area, about 25% is consumed as fluid milk and 50% is converted to cheese, with the remainder being used in butter making and other by-products. In accordance with the Environmental Manual (EM), a visual verification of grazing animal population in the vicinity of the site boundary is conducted annually. This verification provides assurance that the selection of sampling locations remain as conservative as practicable.

The Kewaunee Nuclear Power Plant is located 4.5 miles N of the Point Beach site.

At the time of plant construction, the buildings within the exclusion area were farm complexes consisting of a residence, a major barn or barns for livestock, and miscellaneous out-buildings. Buildings in poor condition and not worthy of continued maintenance were razed. Existing residences in one or two cases were repurchased by the original owner and removed from the exclusion area. The remaining residences in good condition were to have been offered for rent to employees of the Licensee. Those employees who take up residence within the exclusion area will do so under an immediate evacuation agreement.

Existing buildings may be offered for rent to local area farmers for use only for crop and machinery storage. Livestock will not be housed in the buildings.

The above policy is compatible with the Licensee’s plans for continued crop land and pasture and use of all areas within the exclusion boundary except the inner operating area inside the chain link fence.

As indicated earlier, the closest occupied residence off-site is at least 3/4 miles from the plant.

Table 2.4-1 TYPICAL INDUSTRIES IN REGION AT THE TIME OF LICENSE APPLICATION

Sheet 1 of 2

Company	Product	City and Location Manitowoc County
Aluminum Specialty Co.	Aluminum Cookware	Manitowoc, 15 miles SW
Anheuser-Busch, Inc.	Barley Malt	Manitowoc, 15 miles SW
Burger Boat Co., Inc.	Aluminum and Steel Boats	Manitowoc, 15 miles SW
Canada Dry Bottling Co.	Carbonated Beverages	Manitowoc, 15 miles SW
Cher-make Sausage Co.	Sausages	Manitowoc, 15 miles SW
Consumers Steel and Dock Co.	Alum. and Steel Fabrication	Manitowoc, 15 miles SW
Dick Bros. Bakery Co.	Bakery Products	Manitowoc, 15 miles SW
Fischl Ice Cream and Dairy Co.	Ice Cream and Dairy Products	Manitowoc, 15 miles SW
Great Atlantic and Pacific Tea Co.	Evaporated Milk, Ice Cream (White House Milk Division)	Manitowoc, 15 miles SW
Heresite and Chemical Co.	Phenolic Resins	Manitowoc, 15 miles SW
Imperial-Eastman Corp. (Eastman Division)	Brass and Steel Fittings	Manitowoc, 15 miles SW
Invincible Metal Furniture Co.	Steel Office Furniture	Manitowoc, 15 miles SW
Kornely Guernsey Farm Dairy	Milk	Manitowoc, 15 miles SW
Lake to Lake Dairy	Dairy Products	Manitowoc, 15 miles SW
Lakeside Packing Co.	Vegetable Canning	Manitowoc, 15 miles SW
Manitowoc Bottling Works	Soda Water	Manitowoc, 15 miles SW
Manitowoc Engineering Co.	Lift Cranes and Shovels	Manitowoc, 15 miles SW
Manitowoc Shipbuilding, Inc.	Ship Construction	Manitowoc, 15 miles SW
Manitowoc Portland Cement	Cement	Manitowoc, 15 miles SW
Mirro Aluminum Co.	Cooking Utensils, Giftware	Manitowoc, 15 miles SW
Northern Laboratories	Toiletries	Manitowoc, 15 miles SW
A. M. Richter Sons, Co.	Vinegars	Manitowoc, 15 miles SW

Table 2.4-1 TYPICAL INDUSTRIES IN REGION AT THE TIME OF LICENSE APPLICATION

Sheet 2 of 2

Company	Product	City and Location
		Manitowoc County
Sorge Ice Cream and Dairy Co.	Cottage Cheese, Ice Cream, Grade A Milk	Manitowoc, 15 miles SW
Weyerhauser Co.	Fiber Shipping Containers	Manitowoc, 15 miles SW
Yindra's Home Bakery	Bakery Products	Manitowoc, 15 miles SW
Eggers Plywood Co.	Plywood Manufacturing	Two Rivers, 9 miles SW
Formrite Tube Co.	Formed Tube Assemblies	Two Rivers, 9 miles SW
Hamilton Mfg. Co.	Automatic Washers and Driers	Two Rivers, 9 miles SW
Kahlenberg Bros. Co.	Marine Engines and Parts	Two Rivers, 9 miles SW
Paragon Electric Co., Inc.	Electric Timers	Two Rivers, 9 miles SW
Schwartz Mfg. Co.	Food Filter Bags	Two Rivers, 9 miles SW
Two Rivers Beverage Co.,	Inc. Beer and Soda Water	Two Rivers, 9 miles SW
Foremost Dairies, Inc.	Concentrated Whey	Mishicot, 7 miles WSW
Mishicot Modern	Dairy American Cheese	Mishicot, 6 miles WSW
Two Creeks Dairy	American Cheese	Two Creeks, 2 miles NW
		Kewaunee County
Frank Hamachek Machine Co.	Special Machinery and Castings	Kewaunee, 11 miles N
Kewaunee Engineering Corp.	Steel Fabrications	Kewaunee, 11 miles N
Kewaunee Orange Crush Bottling	Soft Drinks	Kewaunee, 11 miles N
Leyse Aluminum Co.	Aluminum Products	Kewaunee, 11 miles N
		Brown County
Lake to Lake Dairy Corp.	Milk Receiving Station, Butter, Powdered Milk	Denmark, 15 miles WNW

2.5 HYDROLOGY

Lake Michigan is the source of cooling water to the Point Beach Nuclear Plant. All radioactive liquid wastes generated at the plant are collected and monitored before discharge from the site in accordance with 10 CFR 20. Radioactivity levels do not exceed permissible concentrations at the cooling water outlets. Additional dilution is available due to the large volume of water in Lake Michigan and a minimum distance of 12 miles to the nearest potable water intake. Protection of the plant is provided against flooding, waves, and storms as well as ice build-up along the shore.

2.5.1 GENERAL LAKE HYDROLOGY

Lake Michigan is the third largest of the Great Lakes. It is 307 miles long from north to south and has an average width of 70 miles. It has a maximum depth of 923 feet, an average depth of 325 feet, and covers an area of 22,400 square miles. The total volume of water in Lake Michigan is approximately 1,400 cubic miles. The water level in Lake Michigan depends primarily on the runoff from the drainage basin.

In the general vicinity of the site, the 30-foot depth contour of the lake is between 1.0 and 1.5 miles, and the 60-foot depth contour is 3.0 to 3.5 miles from the shore.

Plant Datum

Plant Datum (plant elevation zero) is defined as 580.2 feet above the International Great Lakes Datum of 1955 (IGLD 1955), and is equal to 580.9 feet IGLD 1985, the datum currently used by the U.S. Army Corps of Engineers to report Lake Michigan water level. IGLD 1985 replaced IGLD 1955 in January 1992; the IGLD year refers to the central year of the data set used to determine the datum, not the year in which it was adopted. Elevations in the FSAR are relative to the Plant Datum unless otherwise noted. (Reference 19)

Thermal Stratification

The temperature stratification and circulation patterns of water in Lake Michigan have very distinct characteristics, as follows:

At the beginning of March, a warming trend starts in the lake water and at the end of May all of the water in the lake has reached approximately 40°F, which is the temperature of maximum water density. Until the temperature reaches this point, the surface water is colder than the deeper water in the lake; the colder surface water, which remains at approximately 34°F, is lighter than the 40°F deeper water. This layer of colder water circulates on the surface of the warmer deep water, reaching depths of 25 to 30 feet from the surface.

When all the water in the lake reaches approximately 40°F, the thermocline layer disappears and complete mixing of all the water in the lake takes place. However, when the ambient air temperature warms up the surface water, a thermocline layer is formed again at depths of 30 to 50 feet from the surface. This occurs from May to July and at this time parts of the water in the lake reach 65°F to 70°F. Consequently, the warmer and lighter surface water circulates above the denser and relatively stagnant 40°F water at the bottom of the lake. This condition continues until a cooling trend starts in September, reaching a peak about the last part of January, at which time the water in the lake again reaches an overall temperature of 40°F. At this time, complete mixing of the waters in the lake takes place until a colder and lighter layer of surface water starts to build up.

Currents (Reference 2)

Surface currents in Lake Michigan are generated primarily by wind stress on the water surface. The lake surface wind-driven currents have speeds averaging 1 to 2% of the wind speeds. Thus, an average wind speed of 15 mph over the lake would generate an average surface current of about 0.15 to 0.3 mph. Such currents may persist for several days after the wind has died down. On large water surfaces, the wind-driven current is theoretically 45° to the right of the wind vector, due to the rotation of the earth. On the west side of Lake Michigan, the current is largely parallel to the shore and more nearly 22° to the right of the prevailing wind. The predominant current direction near the western shore during the period of greatest stratification is in the northerly direction. However, temporary reversals of the general trend may take place. (Reference 3)

Current velocity was measured (Reference 4) at 20-minute intervals from August to October, 2 miles off the coast of Sheboygan. The measurements were taken from the surface of the lake down to the 30-foot depth. The following persistence patterns for different current velocities were observed:.

Current Velocity (ft/sec)	Persistence (% of the time)
0 - 0.5	68
0.6 - 0.7	10
0.8 - 0.9	12
1.0 or higher	10

It is fairly certain that this pattern does not differ greatly during the other months of the year.

Littoral Drift

Waves are responsible for most of the littoral drift on Lake Michigan. In this specific area, the predominant drift appears to be to the north. Under unfavorable conditions, littoral drift may have a pronounced effect on the advance or retreat of certain shore lines.

Ground Water

The subsurface water table at the site has a definite slope eastward toward the lake. The gradient indicated by test drilling on the site is approximately 30 feet per mile. It is, therefore, extremely unlikely that any accidental release of radioactivity on the site could spread inland. Furthermore, the rate of subsurface flow is small due to the relative impervious nature of the soil and will not promote the spread of accidental releases (Reference 24).

In addition to the ground water table, an upper aquifer composed of glacial drifts and recent deposits exists at depths ranging from +31 to -33 feet in respect to the plant elevation zero. A lower (bedrock) aquifer can be found at -81 to -38 feet. The bedrock aquifer in the general site region is known to produce saline water, hence that aquifer is usually not used for potable water supplies. Such supplies are taken from the upper aquifer or from the lake.

Potable Water Sources

Lake Michigan is used as the source of potable water supplies in the vicinity of the site for the cities of Two Rivers (12 miles south), Manitowoc (13 miles SSW), Sheboygan (40 miles south), Green Bay (intake at Rostok 1 mile north of Kewaunee, 13 miles north) and the Central Brown County Water Authority (supplied from Manitowoc). No other potable water uses are recorded within 50 miles of the site along the lake shore. All public water supplies drawn from Lake Michigan are treated in purification plants. The nearest surface waters used for drinking other than Lake Michigan are the Fox River 30 miles NW and Lake Winnebago 40 miles W of the site.

Ground water provides the remaining population with potable supplies. Public ground water supplies within a 20-mile radius of the site are listed in Table 2.5-3. Additional wells for private use are in existence throughout the region. The potable water for use at the Point Beach Nuclear Plant is drawn from a 257 feet deep well located at the southwest corner of the plant yard. The well pump has a capacity of 65 gpm. Water from this well is sampled as part of the environmental studies described in Section 2.7.

Fishing (Reference 5) (Reference 6)

Commercial fishing in Lake Michigan decreased in the fifteen years prior to license application due to the proliferation of the sea lamprey, causing a reduction in lake trout and an increase in less desirable rougher species of fish. A secondary cause for the decline was the botulism scare in 1963 which focused nationwide attention on the potential contamination of smoked whitefish and chubs. Alewives, chubs, and yellow perch accounted for 84% of the 1963 production from Lake Michigan. Total landings in Wisconsin from Lake Michigan accounted for 14.4 million pounds valued at $1.1 million in 1963. Manufactured fishery products accounted for nearly $3 million in Wisconsin in 1963.

Fishing is practiced generally throughout the lake with fishermen tending to operate within easy reach of their home ports. These ports are generally far enough apart to minimize any overlap in fishermen's routes. Fishing depths are in excess of 12 fathoms (72 feet) by law for trawlers and generally greater than 20 fathoms (120 feet). These depth restrictions place the fishing grounds at least 5 miles offshore. Inshore fishing is licensed occasionally when alewives (a shad-like food fish) are schooling in along the shore. This fish is used mostly for fertilizer and fish meal manufacture.

At the time of license application, active fish boats on the Wisconsin shore of Lake Michigan were as follows: Milwaukee (6 full-time and 12 part-time), Sheboygan (2), Manitowoc (1), Two Rivers (2), Kewaunee (2), and Algoma (5). Fishing in Lake Winnebago (40 miles to the west of the site) is confined primarily to rough species, most of which go to mink ranchers in the area for use as animal food.

Sport fishing is one of Wisconsin's prime tourist attractions. It may be considered as existing throughout the state and along all shoreline areas of the lake.

2.5.2 LAKE LEVELS AND FLOODING

This section provides the hydrological review of the potential external flooding sources at the Point Beach site. A detailed discussion of plant flooding protection methods and design is provided in Appendix A.7 “Plant Flooding.”

Lake Level

The nominal water level in Lake Michigan at the time of the original license submittal was -2 feet relative to the Plant Datum. A maximum water level was recorded in 1886 at +1.7 feet and minimum recorded to date occurred in 1964 at -4.8 feet. The site is, on average, about 20 or more feet above plant elevation zero and there is no record that it has been flooded by the lake.

The maximum analyzed value for high lake level is +3.7 feet (Reference 33). Operators will take actions to commence the orderly shutdown of any operating reactor per Abnormal Operating Procedure direction prior to reaching the analyzed limit.

Flood Level

The license basis level for protection of critical equipment from lake flooding is +9.0 feet (Reference 25). This is an acceptable and bounding value as each lake flooding source when evaluated individually, or in the combined effects review, provides resultant flood levels conservatively below this threshold thereby satisfying the General Design Criteria 2 requirement to include "an appropriate margin for withstanding forces greater than recorded to reflect uncertainties about the historical data and their suitability as a basis for design."

Tides

Tides on Lake Michigan created by the attraction of the moon and sun are insignificant. The total range of oscillation does not exceed 2 inches.

Surges

Using the method delineated in "The Prediction of Surges in the Southern Basin of Lake Michigan, Part I, The Dynamical Basis for Prediction" by G. W. Paltzman (Reference 31), the storm surge that could occur at the site will be 4.14 feet due to the passage of a squall line with a pressure jump of 8 millibars and a simultaneous speed of movement of 65 knots with a shoaling factor of 3.5. Adding this surge of 4.14 feet to the maximum analyzed water level in Lake Michigan of +3.7 feet results in a maximum elevation of 7.84 feet, which is bounded by the license basis flood level.

The value of 4.14 feet was developed using Platzman's contours of amplitude for pressure. There are no contours for the lake in the area of the site so a conservative approach was taken using the reflected surge values for Waukegan at 90° with a speed of movement of 65 knots, giving a pressure rise of 0.05 feet. Using 8 millibars or 0.236", the maximum surge due to pressure with a 3.5 shoaling factor will, therefore, be

$$0.05 \times \frac{0.236}{0.01} \times 3.5 = \ 4.14 feet$$

Using the above method, the computed amplitudes were adjusted using Reference 32 for wind velocities equal to or greater than 70 knots. The resultant amplitude for wind velocities equal to or greater than 70 knots is one foot over the computed value. If this 1'0" increase is added to the maximum surge elevation of 7.84 feet, the maximum elevation will be 8.84 feet, still bounded by the license basis flood level.

Seiches

Seiches are caused by a frontal line defining an abrupt change in atmospheric pressure in the range of 0.1 inch, moving across the lake at a high velocity. An average of 20 seiches per year occur in the vicinity of Chicago, but the rise in the lake level due to most of these is insignificant.

Conditions at Point Beach with its open shoreline will not be subject to reflection and should not produce any amplification of the seiche height. It appears logical to consider that the rise in water level due to a seiche would be a maximum of 1 to 2 feet.

Historical records show that the peak rise in water level associated with a seiche can be achieved very quickly. The record seiche in Chicago on June 26, 1954 lasted about ½ hour. The historical records do not support a coincident occurrence of a major seiche with a major high wave condition. Winds of high velocity have been recorded before or after seiches for relatively short periods of time, but there is no basis to superimpose the conditions of maximum wave upon the maximum seiche. Thus, a maximum seiche is not combined with the maximum lake level, maximum wind setup and maximum wave run-up in the combined effects analysis (Reference 28).

Deep Water Wave Height

The predicted magnitude of deep water wave heights is shown in Table 2.5-1.

The calculation of deep water wave heights is based upon the data given in Technical Memorandum No. 36 of the Beach Erosion Board, Office of the Chief of Engineers, Department of the Army. The data for Baileys Harbor, Wisconsin, and Milwaukee, Wisconsin, were extrapolated to include the period up to 500 years. The height at Point Beach was calculated by applying the results on the basis of an interpolation recognizing the relationship of Point Beach to these two sites.

The calculated wave height shown in Table 2.5-1 refers entirely to deep water waves. In the vicinity of Point Beach, the extremely flat slopes of the beach extend so far out into the water (approximately 1 on 100 for the first 1000 feet into the lake and 1 on 200 for the next 4000 feet) that the deep water waves break offshore. In this case, only waves of lesser height actually need to be considered in the run-up of the beach.

The shore is protected by riprap as shown in Figure 2.5-1. Note that Reference 33 does not credit the security barriers for reducing wave run-up. An incoming wave will, therefore, encounter either the protected shore or the vertical forebay walls.

Off-shore Veritcal Surface

In the calculation of wave run-up, three methods of analysis were followed. In one case, the wave was treated as impinging upon a breakwater with very flat slopes, with the toe of the slope located in 12 foot deep water (the depth 1000 feet offshore). The computed vertical height of the run-up above the normal water level which exists at that time for this case was 1.4 feet.

Shore-line Vertical Surface

In the second case, an estimate of the probable maximum secondary wave run-up was calculated based on the average depth conditions prevailing after the deeper water wave has broken and reformed and the run-up on the beach above the water level was computed for a period equal to 8 seconds to be 6.55 ft. The effect of a wind tide will increase this level by 0.17 feet. The wind tide is conservatively calculated based upon a sustained easterly wind velocity of 40 mph over a fetch length of 70 miles and average depth of 465 feet (Reference 27). Combining these values with a maximum still lake level of +3.7 ft results in a vertical surface total wave run-up height of 10.42 ft. plant elevation.

The forebay as shown in Figure 2.5-1 extends 65 feet from the pumphouse towards the shoreline. The top of the walls parallel to the shoreline (front) reach +15.4 feet elevation. The top of the walls perpendicular to the shoreline reach +12.0 feet elevation. These walls protect the pumphouse since they are higher than the total wave run-up on a vertical surface.

Rip-rap Surface

In the third case, the hydrodynamics programs Delft3D-FLOW and Delft3D-WAVE were used to determine wind and wave setup. Wave run-up on rip-rap slopes was computed in accordance with JLD-ISG-2012-06 using empirical relationships as presented in the 2011 USACE Coastal Engineering Manual (Reference 34). Parameters such as wave height, wave period, and wave length were obtained from the time series of Delft3D output, and the wave run-up and maximum water surface elevation were computed.

The bank adjacent to the intake structure has rip-rap placed on a 1 to 3.0 (vertical to horizontal) slope on the north side and 1 to 4.5 (vertical to horizontal) on the south side of the CWPH. A shoreline rip-rap analysis using these slopes demonstrates that the vertical wave run-up height is 6.8 ft., based on a maximum still lake level of +3.7 ft. (Reference 33) This value is bounded by the license basis flood level of +9.0 feet which is used for determining protection requirements for essential plant equipment (see Appendix A.7 "Plant Flooding").

With the exception of the tabulated combinations above, the Point Beach License Basis does not require consideration of the simultaneous combined effects of more than one extraordinary natural phenomenon (Reference 25).

Summary of High Lake Level Scenarios

Cause of High Water	Maximum Water Elevation	Allowable Water Elevation
Storm Surge	8.84 ft	9 ft
Wave Run-up on Vertical Structure	10.42 ft	12 ft
Wave Run-up on Riprap	6.8 ft	9 ft

Precipitation

Lakes Michigan and Huron are considered as a unity from the standpoint of drainage and water level since these two lakes are connected. The drainage basin for these two lakes comprises 115,700 square miles and has an average annual rainfall of about 31 inches. The average and maximum precipitations recorded at various locations on the Wisconsin shore of Lake Michigan are listed in Table 2.5-2.

The maximum amount of precipitation at Point Beach is calculated from a combination of snowmelt and sustained heavy rains. The license basis precipitation values are developed from the once in 50 year water content value for snow in the latter half of March combined with the once in 50 year six hour rainfall (Reference 4) (Reference 22) (Reference 23) (Reference 29).

Drainage

There are no rivers or large streams on or near the site. The surface water on the site flows directly to Lake Michigan either through the storm sewer system or through two small creeks which drain the site. Natural drainage and site topography have proven adequate to remove water from precipitation flooding sources.

The bank at Point Beach is graded so that it slopes down on a 6% slope from elevation +23.5 feet at points approximately 300 feet north and south of the intake structure to elevation +7.0 feet (the lowest elevation) at the intake structure.

The topography of the site results in adequate natural drainage to remove the maximum amount of precipitation and snowmelt and limit ponding depth to prevent adversely affecting safety related equipment (Reference 22) and (Reference 23).

Ice Formation

The U. S. Coast Guard reported pile up of ice in the form of frozen spray and ice floes to a height of 30 to 40 feet at the shore and extending about 100 feet into the lake. These observations were made at Rawley Point Lighthouse 5 miles south of the site. Similar conditions have been experienced at many power stations along the lake.

The primary reason for build-up seems to be the formation of ice which is driven out to deep water by offshore winds and collected until a change in wind drives these ice floes toward the shore. As they approach shallow water, they ground and the offshore floes are driven up and over the grounded floes. The peak point in height of this buildup does not occur at the shoreline on extremely flat beaches, but some distance offshore. This action has given rise to reports of “ice shoves” which have damaged fish shanties on a beach or light wharf structures projecting out into the water.

Beach structures for power stations represent a massive installation and the history of such structures has shown no major damage from ice shoves even where these have been located next to the shoreline on shallow beaches. The outer wall of the intake forebay, the only structure on the beach, is designed with a 3 ft. minimum thickness of reinforced concrete. It is considered that this is adequate to withstand any pressure from the ice. The water intake is located 1750 feet offshore in a water depth of 18 feet (measured from the lowest recorded level of -4.8 feet plant elevation). Water is drawn from the intake crib through two 14 ft. diameter pipes buried below the lake bed and will not be affected by the ice. The cooling water is discharged through two flumes consisting of well braced steel sheet piling driven 40 feet into the lake bed and protected by riprap. It is considered that this also is adequate to withstand any pressure from the ice. Other structures are located approximately 190 feet from the beach line and are further protected by the low bluff along the shoreline.

There are no rivers or large streams on or near the site. Thus, ice dam induced flooding is not a potential source of external flooding at Point Beach.

2.5.3 DILUTION AND DIFFUSION IN LAKE MICHIGAN

Water from Lake Michigan is extensively used for municipal and domestic water supplies. Radioactive contamination of the lake can only occur in two modes. The first is by a continuous release of small amounts of activated corrosion products and fission products into the cooling water stream. The second mode of radioactivity release into the cooling water is conceivable only as a result of an operating error and equipment failure. This type of contamination may be regarded as a batch release (a release over a relatively short period of time) before the waste release is shut off.

As described in Chapter 11, all radioactive liquid wastes generated at the plant will be collected and monitored before discharge from the site. Release rates are manually controlled so that all liquid waste discharged will be much less than $(MPC)_w$ in the outfalling cooling water. Also, automatic radiation monitoring equipment prohibits releases that exceed permissible values. Thus, any radioactive release from the site into the lake will be diluted well below $(MPC)_w$ before it reaches the nearest water supply intake. It has already been indicated that the nearest municipal and domestic water intakes are located at Two Rivers and Rostok (1 mile N of Kewaunee), approximately 12 miles south and 13 miles north of the site, respectively.

Thermal stratification has insignificant effect on the dilution of released fission products by lake water currents. Discharge velocity of the circulating water is less than 4 ft/sec. It is expected that this jet action will promote mixing with colder water in the immediate vicinity of the discharge flume and a rapid reduction in pronounced differential temperatures. In addition to this, observations at power station discharges in Lake Michigan at Gary, Indiana, and Waukegan, Illinois, have shown that the wave action and shore currents are very effective in breaking up any tendency to pronounced stratification and isolation of the warm water. It is expected that this action, together with the jet momentum entrainment of colder water, will cause all temperature effects to be indiscernible within less than one mile from the point of discharge. The same conditions will prevent the establishment of a distinct pronounced plume of heated water which would transport released fission products directly to any potable water intake structure.

For completeness, computational models for evaluating the dilution of both types of radioactive release are discussed below.

Continuous Release

For continuing releases at a uniform discharge rate, the maximum concentration as a function of distance along the direction of the mean flow can be predicted by several methods. One of the more frequently used relationships for instantaneous releases is that derived by Okubo and Pritchard (Reference 7):

$$S(x, y, t) = \frac{nM}{2\sqrt{\pi}PDx}\exp-\left[\frac{y^2}{(Pt)^2}\right]$$

where:

$S(x,y,t)$ = Concentration as a function of time and distance, µCi/cm^3

M = Rate of release, µCi/sec

D = Depth of mixing layer, cm

P = Diffusion velocity, cm/sec

y = Cross plume point at which S is determined, cm

t = Time after start of release, sec

n = Degree of constraint for diffusing material (2 for 180° release)

x = The distance downstream from release point at which S is determined, cm

At a given distance, x, the concentration, S, equals zero initially (t = 0), but eventually a saturation condition is reached, corresponding to a maximum condition S_{max}, which will exist as long as the radioactive material is released at a constant rate. Under these conditions, S_{max} is a function of distance only and:

$$S_{max} = \frac{nM}{2\sqrt{\pi}PDx}$$

It has been indicated previously that the mixing depth during stratification of the lake is 25 to 50 feet, depending on the time of the year. It is conservatively assumed here that D = 10 m; P = 10^{-2} m/sec; and n = 2 to compensate for the effect of the shore. Thus, the peak concentration in µCi/cm^3 per µCi/sec released is given by:

$$S_{max}/M = \frac{5.64\times10^{-6}}{x}$$

Assuming various distances for x (in meters), the maximum concentration per unit release rate as a function of distance (in miles) is as follows:

Distance from Site (Miles)	Maximum Concentration per-unit Release S_{max}/M, μCi/cm³ Per μCi/sec
1	3.5×10^{-9}
5	7×10^{-10}
10	3.5×10^{-10}
12	2.9×10^{-10}
15	2.3×10^{-10}
20	1.75×10^{-10}
25	1.4×10^{-10}

For a mixture of unidentified fission products with an $(MPC)_w$ 3×10^{-8} μCi/ml, approximately 8 curies per day may be released at the site without exceeding $(MPC)_w$ at the nearest potable water intake.

Batch Releases

The Okubo and Pritchard (Reference 7) diffusion model for a release over a relatively short period of time (batch release) is:

$$S(r, t) = \frac{nM}{\pi D(Pt)^2} \exp - \left[\frac{r^2}{(Pt)^2} \right]$$

where now:

M = Total radioactivity released, μCi

r = Distance, cm

If a volume of radioactive material is released into the offshore current, the radioactive volume will be carried along by the current. Although the overall concentration of radioactivity in this volume will decrease with passing time due to the mixing and outward diffusion from this volume, the peak concentration at any given time can be assumed to exist at the center (origin) of the drifting volume. Since r is the distance from the origin, r = 0 at the center of the radioactive volume and the peak concentration is a function of time only:

$$S_{peak} = \frac{nM}{\pi D(Pt)^2}$$

Assuming D = 10 m, P = 10^{-2} m/sec, and n = 2 the expression for peak concentration in µCi/cm³ per µCi released at time t (in seconds) is:

$$s_{peak}/M = \frac{6.37\times10^{-4}}{t^2}$$

The velocity of the current and its persistence at various speeds has been discussed previously. An average velocity calculated from these values is approximately 0.35 ft/sec. The peak concentration as a function of distance from the site, assuming this average current velocity, is indicated below:

Distance, Miles	Peak Concentration per Unit Release S_{peak}/M, µCi/cc per µCi
1 (4.2 hours)	2.8×10^{-12}
5 (21 hours)	1.1×10^{-13}
10 (42 hours)	2.8×10^{-14}
12 (50 hours)	2.0×10^{-14}
15 (63 hours)	1.25×10^{-14}
20 (84 hours)	7.0×10^{-15}
25 (105 hours)	4.5×10^{-15}

According to 10 CFR 20, the annual average concentration of an unknown mixture of fission products in unrestricted areas should not exceed 3 x 10^{-8} µCi/ml. Thus, it may be seen that a batch release of 1.5 curies at the site will be diluted to 3 x 10^{-8} µCi/ml at the nearest municipal water intake (12 miles). With one circulating water pump in operation at 214,000 gallons per minute flow, a release of 1.5 curies over a period of one hour results in a discharge flume concentration of approximately 3 x 10^{-5} µCi/ml or approximately 1 x 10^{3} MPC. Maximum short term releases for Point Beach Nuclear Plant are limited to less than 100 times MPC over a period not greater than one hour. Furthermore, it should be noted that the above concentration will be an instantaneous peak concentration and not the average concentration which could enter the water intake.

Table 2.5-1 FREQUENCY AND WAVE HEIGHT FOR DEEP WATER CONDITIONS

	Wave Height in Feet	
Frequency	Full Year	Ice-Free Period
Once each month	6	6
Once each 6 months	9.5	7
Once each year	11	8
Once each 2 years	12.5	9
Once each 5 years	15	11
Once each 10 years	17	12
Once each 25 years	17.7	13.6
Once each 500 years	23.5	18.0

Table 2.5-2 AVERAGE AND MAXIMUM PRECIPITATION

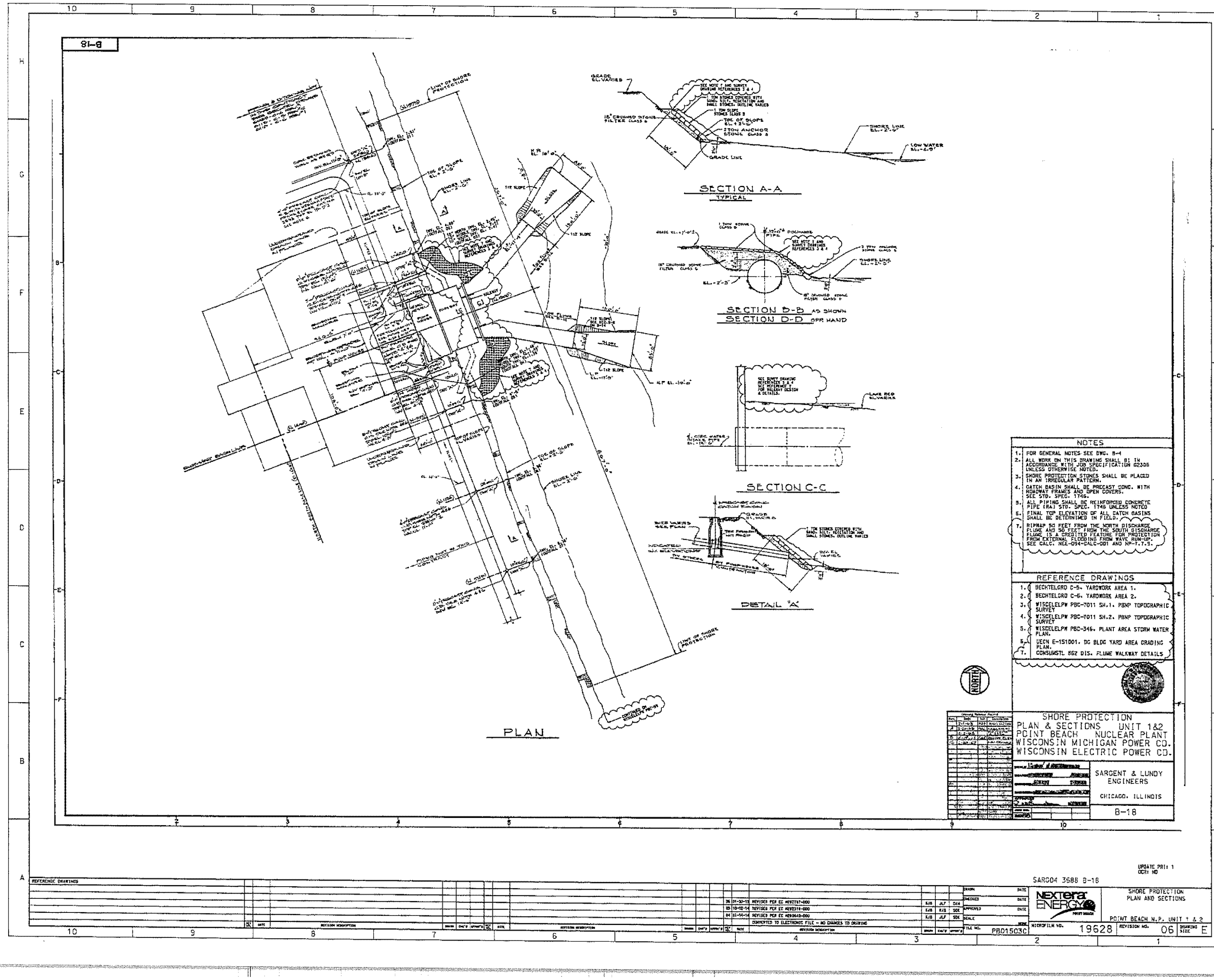
Location	Average Annual Precip., Inches	Maximum Annual Precip., Inches	Maximum 24-hr. Rainfall, Inches
Kenosha	29.86	41.84	3.55
Racine	31.90	48.33	4.00
Milwaukee	27.62	41.86	5.28
Shorewood	31.64	42.46	--
Port Washington	27.96	38.39	--
Sheboygan	29.27	40.14	4.55
Manitowoc	28.39	46.43	6.39
Two Rivers	28.65	41.17	--
Kewaunee	26.53	34.99	4.92
Sturgeon Bay	27.20	39.65	4.57
Green Bay	26.56	38.03	3.68
Washington Island	28.11	37.25	--

Table 2.5-3 MUNICIPAL GROUND WATER SUPPLIES AT THE TIME OF LICENSE APPLICATION

Place	1960 Population	Well Depth, ft.	Treatment[a]
Denmark, Brown County	1106	309-456	a, b, d, f
Kewaunee, Kewaunee County	2772	187-700	a, b, d, f
Luxemburg, Kewaunee County	730	431-495	d, h, z
Mishicot, Manitowoc County	762	80	d
Whitelaw, Manitowoc County	420	495	--

a. Type of treatment:
a. aeration
b. iron or manganese removal
d. disinfection
f. filtration
h. hardness removal
z. zeolite softening

Figure 2.5-1 SHORE PROTECTION



2.6 METEOROLOGY

Historical climatology in the region of the site and data collected at the site over the period April 1967 through April 1968 has been evaluated to provide a basis for determination of annual average waste gas release limits, estimates of exposure from potential accidents, and design criteria for storm protection. Information is provided in this section to show the adequacy of the design criteria and the estimates of site capabilities for diluting routine and accidental releases of radioactive gases.

The climate of the region is primarily continental in character, greatly influenced by the easterly flow of storms along the northern portion of the country and from the southwest to the Great Lakes. Lake Michigan acts as a moderating influence in spring, summer, and fall. The site is well ventilated with infrequent calms. Prevailing winds during spring and summer are lake breezes from the NNE. Beginning in the summer, a flow from the SSW appears which is reinforced in the fall by overland flows from WSW and WNW. During winter the flow is from the sector NW through SSW. During the first year of site data collection, maximum persistence of extremely stable conditions occurred for 41 hours under an average wind speed of 6.7 meters/sec.

Extreme winds are not expected to exceed 108 mph more than once in 100 years. Tornadoes occur in the state but only one has been reported causing major property damage and injury to people in this region. This one occurred in Green Bay in 1959, 30 miles NW of the site.

Measurement of on-site meteorological parameters of wind speed and direction began in April 1967 and continued for a period of two years. A wind speed and direction recorder was placed on a 150-foot tower erected for this purpose on the site. These data are used to establish routine release limits of radioactive gases and to assess consequences of potential accidental releases of radioactive materials.

Data and analyses in this section are based on one year of hourly 15-minute average observations at the site supplemented by 5 years of hourly surface observations at Milwaukee, Wisconsin; summaries of data from Green Bay, Wisconsin and Escanaba, Michigan; plus 3 years of observations at Coast Guard Stations at Two Rivers and Kewaunee, Wisconsin; and Weather Bureau records of a more specialized nature referred to in the text.

METEOROLOGICAL PROGRAM

Site data collection began in April 1967 and continued for 2 years. A set of Belfort Type M wind transmitters was installed on top of a 150-foot tower approximately 2000 feet south of the nearest reactor containment structure.

Wind data were collected on the strip-chart recorder and reduced for computer input by Murray and Trettel, Inc. by manual (visual) methods. These data were extracted from the analog charts, keypunched on cards, and processed by a CDC-3600 computer using a computer code, WINDVANE, developed by NUS Corporation for this purpose. The code operates on the input data to provide seasonal and annual distributions of wind speed, wind direction, wind direction variance, and wind direction persistence. The variance of wind direction is a direct measure of the ability of the atmosphere to accept and disperse injected materials. Variance is computed (in the WINDVANE code) by measuring the range of wind fluctuations during the sampling period and dividing by six, according to methods used by Holland (Reference 8) and Slade (Reference 9), etc.

Currently three meteorological monitoring towers with instrumentation are provided for collecting weather data. This data may be used as input to an atmospheric diffusion model to provide radiation dose estimates from routine or emergency radioactive releases from the plant site. Refer to Emergency Plan Appendix L for detailed description of Meteorological System (Reference 17).

DESCRIPTIVE METEOROLOGY

Climate (Reference 10)

Climatic characteristics are illustrated in Figure 2.6-1 which shows average and extreme temperatures, precipitation, and extreme winds for 30 years of record at Kewaunee and Manitowoc, Wisconsin.

The climate of the site region is influenced by the general storms which move eastward along the northern tier of the United States and by those which move northeastward from the southwestern part of the country to the Great Lakes. This continental type of climate is modified by Lake Michigan. During spring, summer, and fall months the lake temperature differs greatly from the air temperature. Wind shifts from westerly to easterly directions produce marked cooling of daytime temperatures in spring and summer. In autumn the relatively warm water of the lake prevents nighttime temperatures from falling as low as they do a few miles inland from the shoreline. Summer time temperatures exceed 90°F for 6 days on the average. Freezing temperatures occur 147 days and below zero on 14 days of the winter on the average. Rainfall averages about 28 inches per year with 55% falling in the months of May through September. Maximum rainfall during 24 hours was 6.17 inches in September,1931. Snowfall averages about 45 inches per year with maximum of 15 inches in 24 hours in January, 1947.

Extreme winds for design purposes are also plotted in Figure 2.6-1. Results are from a special study by the Weather Bureau in conjunction with the Bureau of Public Roads for winds at 30 feet elevation (Reference 11). Extreme-mile winds are: 54 mph with a probability of 0.50 and a recurrence interval of once in 2 years; a 50-year recurrence interval is associated with a 100-mph wind with a probability of 0.02; and a 100-year recurrence interval is associated with a 108mph with a probability of 0.01. (The extreme-mile wind speed is defined as the 1-mile passage of wind with the highest speed for a day.)

Tornadoes (Reference 12)

Wisconsin lies to the northeast of the principal tornado belt in the United States. During the period 1916 through 1967, 359 tornadoes were experienced in the state. Of these, only six occurred in Manitowoc County, one in Kewaunee County, and nine in Brown County. Only one tornado of this latter group caused injury to people or major property damage. This one occurred in Green Bay, 30 miles WNW of the site with three people injured and property damage in the range of $500,000 to $5,000,000 on May 10,1959 at 8:50p.m. The tornado path was 6 miles long and 600 yards wide. The region north of Sheboygan along the Lake Michigan coast appears to be relatively free of tornadoes. Tornadoes appear to advance from the west with most of the tracks from the southwest. Maximum occurrence during the year is in June with 90% reported in May through September.

Tornado frequency was analyzed using the recorded tornadoes within increasing radii of the site for the period 1953 through 1967. The cumulative number of tornadoes within radii out to 75 miles are listed in Table 2.6-1.

These values were used in the statistical method proposed by Thom (Reference 13) by which the probability of a tornado striking a point within a given area may be estimated. This probability is given as:

$$P = \frac{\bar{z}t}{A}$$

where P is the mean probability, $\bar{z}$ is the mean tornado path area, $\bar{t}$ is the mean number of tornadoes per year, and A is the area of concern.

At a 95% confidence level, Thom's formula becomes:

$$P' = P\left[1 \pm \frac{1.96}{(N)^{1/2}}\right]$$

where N is the total number of tornadoes in the area of concern in the years of record, 1953 to 1967.

In order to maximize the point probability of striking the site, the probability and the confidence limits were calculated at increasing radii from the site. The maximum point probability occurs at 30miles:

$$P' = 1.6 \times 10^{-3} \text{ per year}$$

and the 95% confidence limits are 7.65×10^{-4} to 2.50×10^{-3} per year. The mean recurrence interval, R=1/P′, is 625 years and at the 95% confidence limit the recurrence interval range becomes 400 to 1310 years.

Ice Storms

Ice storms are infrequent in this region of Wisconsin. Wisconsin Public Service Corporation, which has transmission lines in this area, reports only a single line extending from Green Bay to Kewaunee to Sturgeon Bay has experienced outages due to ice storms since 1940. Six such outages occurred ranging in duration from 22 minutes to 2.5 hours. Since rebuilding the lines with improved conductors in 1956, only one outage has occurred.

Wind Speed and Direction

Average annual and seasonal wind rose patterns are shown in Figure 2.6-2 based on one year of records on-site from April 1967 through April 1968. On an annual basis, the winds blow onshore (from Lake Michigan toward the land) an average of 33.8% of the time. Onshore winds are defined as those which blow from the north through the south-southeast. Annually, winds blow from the shore towards the lake 63.5% of the time. Seasonal distributions of onshore and offshore flows are shown below in Table 2.6-2.

During the spring season, the predominant wind directions during the period of record were northeasterly and south-southwesterly. Wind speeds tended to be above 10 mph from all directions but east. Calm conditions were recorded 3.5% of the spring time.

A very predominating south-southwest wind was noted over the summer. Again, wind speeds tended to average near 10 mph, with the exception of southeasterly quadrant winds. The lowest average wind speed was 4.4 mph from the east. Calm conditions occurred 2.2% of the summer time.

During autumn, average wind speeds from the western semicircle of the compass ranged from 10 to over 14 mph. There were relatively frequent occurrences of winds approximately parallel to the shoreline in both the northerly and southerly directions. The lowest wind speeds were again from the east, the calm winds were observed 2.3% of the season. The onset of cold weather is evidenced by the increased frequencies of winds from the northwesterly quadrant.

The winter season is characterized by a preponderance of winds from the northwest quadrant. Winds from this quadrant were observed to occur over 60% of the time. During the winter months, no average wind speed from any direction was below 10 mph, but calm conditions occurred 3.1% of the winter time. It is noteworthy that the average wind speed from the north-northeast was over 20 mph.

On an annual basis, the winds at the Point Beach site show predominating spikes of higher frequency winds from the west-northwest and the south-southwest. Average wind speeds are generally quite high from all directions from south-southeast clockwise through northeast. These average values are all in excess of 10 mph. Significantly lower frequencies and lower wind speeds are observed with easterly winds, partially reflecting the Lake Michigan influence on winds which travel against the normal gradient flow.

Wind Directional Persistence

Wind persistence is defined as the duration of time that winds blow without interruption from any given direction. The annual summary of one-sector wind persistences is shown in Figure 2.6-3.

The distribution of long period persistences agrees well with the predominating directions, as may be expected, since higher percentage occurrences of direction produce a greater possibility of persistent winds from that direction. The most surprising feature of the persistence evaluation is the episode (on April 14-16, 1968) of 41 hours of Pasquill Type “G,” or highly non-turbulent conditions. The ameliorating circumstance is an average wind speed of 13.1 mph for the duration of the persistence. This effect of an air trajectory over a long fetch of open water has been investigated and discussed by several researchers (Reference 14, Reference 15). Briefly, when air passes over long fetches of relatively frictionless open water, there is a net loss of turbulent energy and a corresponding increase in wind speed.

The longest persistence of calm winds was for 25 hours, during which 9 hours were unstable and 16 hours were stable.

Atmospheric Stability

An assessment of atmospheric stability at the site was made based on one year of data. These data were analyzed according to methods described by Holland and Slade, and formulated into a computer code, WINDVANE, by NUS Corporation. Hourly observations from both stations were analyzed for seasonal stability, dispersion (χ/Q) calculations, and persistence.

A portion of the output of the WINDVANE run made from site data, is shown in Table 2.6-3 and Table 2.6-4 with the results of the annual average calculations excluding the building wake effect correction.

On annual and seasonal bases, atmospheric stabilities at the Point Beach site occurred during the period of record as shown in Table 2.6-5 according to the WINDVANE breakdown of the site data.

ATMOSPHERIC DISPERSION

The directional variability of atmospheric stability on an annual basis may be best illustrated by Figure 2.6-4, which shows plots of stability by wind direction in percent of direction total. Figure 2.6-4 (the annual average) shows two peaks of unstable and neutral conditions with winds blowing roughly parallel to the shoreline or in a slightly offshore direction. This pattern is repeated in the seasonal plots with a great deal of uniformity, although with some slight seasonal variations. It is evident that atmospheric stability at the Point Beach site is, to a large degree, a function of seasonal variation. That is, atmospheric stability shows good correlation with direction and a fair correlation with season.

As described in Section 11, routine releases of radioactive gases will be made intermittently from the vent discharge pipe near the top of the containment structure.

Atmospheric dispersion of these gases may be described by various analytical expressions such as the Gaussian Formulation described by Gifford (Reference 16). This is modified for the building wake effect by using a virtual source distance correction. The basic expression for diffusion is as follows.

$$\chi/Q = \frac{1}{\pi\sigma_y\sigma_z\bar{\mu}}\exp(-1/2)\left[\left(\frac{h^2}{\sigma_z{}^2}+\frac{y^2}{\sigma_y{}^2}\right)\right]$$

where:

χ	=	Concentration (units/m^3)
Q	=	Release rate (units/sec)
$\bar{\mu}$	=	Mean wind speed (m/sec)
σ_y and σ_z	=	Respectively, the lateral and vertical dispersion coefficients (m)
y	=	Lateral distance from plume centerline (m)
h	=	Height of release point (m)

Virtual source corrections may be made by setting half the area of the containment equal to an ellipse with semi-diameters of σ_y and σ_z and solving for source distance based on neutral stability conditions (the predominant case). For distances out to the exclusion boundary, the predominant dispersion mechanism is that due to aerodynamic turbulence in the wake of the containment structure as contrasted with release from a tall stack with no local interferences. The above expression integrated with respect to y from $+\infty$ to $-\infty$ can yield a long term average based on wind speed, direction, and atmospheric stability frequency. This technique is particularly appropriate to an evaluation of annual average stack release rates. Similarly, short term releases may be evaluated with the appropriate short period averages and information on wind and stability persistence.

Average Atmospheric Dilution

In making initial estimates of site annual average dilution factors in order to establish maximum permissible waste gas release rates for use in the PSAR document, meteorological data from General Mitchell Field in Milwaukee, Wisconsin, were reduced by a computer code, WINDIF, the output of which is exactly the same as the WINDVANE program previously described. The data used in that analysis encompassed December 1958 through November 1963. Based on the Milwaukee data, an overlay of annual average dilution factors, (χ/Q), in units of seconds per cubic meter, was superimposed on an aerial photograph of the Point Beach site. These data were corrected for building wake using a virtual source distance of 225 m. The results indicated that the nearest residence to the site, over 3900 feet (1200 meters) to the southwest, would have an annual average dilution factor of approximately 5×10^{-7} seconds per cubic meter, and the highest value at the site boundary would also be 5×10^{-7} seconds per cubic meter. The overlay of χ/Q isopleths from the Milwaukee data is shown in Figure 2.6-5.

The results of the WINDVANE output based on site data and using a 300 meter virtual source distance are shown in Figure 2.6-5. In most respects, there is good agreement between both sets of χ/Q values, with good correspondence of the isopleths. The exception is the southerly direction where, because of a higher incidence of north winds at the site than was recorded at Milwaukee, the highest annual average value of χ/Q at the site boundary is about 1.5×10^{-6} seconds per cubic meter, a factor of three higher than originally estimated. However, at the nearest residence 3900 feet southwest of the reactor, the revised value of χ/Q based on site data indicates only a 50% increase to about 7.5×10^{-7} seconds per cubic meter.

Using an unrestricted MPCa of 3×10^{-7} curies per cubic meter (χ), and the maximum annual average χ/Q value of 1.5×10^{-6} seconds per cubic meter, the resulting permissible release rate for a decayed noble gas mixture is 0.2 curies per second averaged over a year.

HYPOTHETICAL ACCIDENT METEOROLOGY

One year of continuous on-site meteorological data has provided some information to permit re-evaluation of the conditions which could realistically be expected to persist during a hypothetical accident situation.

Since offshore winds would blow any released waste gases away from nearby populations and would have no effect on people for a distance in excess of 50 miles across Lake Michigan (more for northwesterly or southwesterly winds), conditions under these winds were omitted from consideration although they were examined in detail for other facets of site meteorology. Based on one year of on-site data, a close examination of onshore winds which would blow released gases toward nearby segments of the local population indicates that the season of poorest diffusion is summer. This season has the highest percentage of stable conditions and the concomitant lowest wind speeds, which yields the poorest downwind dispersion of effluents. Accordingly, a revised meteorological model for application to hypothetical accident has been derived from site data and is presented in Table 2.6-6.

Model Comparison

In the original meteorological model as presented in the PSAR document, the calculations of χ/Q were made using the virtual source method. For the invariant wind condition, the basic form:

$$\frac{\chi}{Q} = \frac{1}{\pi \bar{u} \sigma_y \sigma_z}$$

was used for centerline values at various downwind distances. Where the average concentration over a 22 1/2 degree sector was indicated, the form:

$$\frac{\chi}{Q} = \left[\frac{2}{\pi}\right]^{1/2} \Sigma \frac{8 F_i f_i}{\pi \bar{u} \sigma_z \sigma_y x}$$

was used, where:

χ	=	Concentration, units per cubic meter
Q	=	Source term, units per second
$\bar{u}$	=	Mean wind speed, meters per second
σ_y and σ_z	=	Lateral and vertical dispersion parameters, meters
F_i	=	Fraction of time condition “i” exists
f_i	=	Fraction of time winds associated with condition “i” are in the sector of interest

Under a virtual source configuration, values of χ/Q at distance x are corrected for initial dilution in the turbulent wake of the containment by adding the virtual source distance x which, in this case, was 680 meters associated with Pasquill “F.”

In the revised model, downwind values of χ/Q were obtained by use of the building wake model which is of the form:

$$\frac{\chi}{Q} = \frac{1}{(\pi \sigma_y \sigma_z + cA)\bar{u}}$$

for centerline values, and of the form:

$$\frac{\chi}{Q_{ave}} = \left[\frac{2}{\pi}\right]^{1/2} \frac{8}{\pi} \Sigma_i \frac{F_i f_i}{(\sigma_{zi} + (cA)/(\pi\sigma_{yi}))\bar{u}x}$$

for 22 1/2 degree sector average values, where:

c = Building shape factor, dimensionless

A = Smallest cross sectional area of the containment structure, square meters

For the rectangular oblong containment at Point Beach, c was taken to be 1 and A is 1640 square meters.

The major differences in the resulting values is in the second time period, where an invariant wind was assumed for the original calculations and a sector-averaged condition was assumed for the revised model. All other calculated values are in close agreement, with minor differences in the 0 to 2 hour period entirely attributed to the difference between virtual source and building wake calculational methods. The calculated results from the two sets of model conditions are shown in Figure 2.6-7 and Figure 2.6-8.

Alternate Source Term

On April 14, 2011, the NRC approved a License Amendment Request (LAR) regarding the use of Alternate Source Term (AST). To support this LAR five years of hourly onsite meteorological data collected between September 2000 and September 2005 were used to generate new control room air intake atmospheric dispersion factors (χ/Q values) (Reference 18).

Table 2.6-1 CUMULATIVE NUMBER OF TORNADOES WITHIN VARYING RADII OF POINT BEACH

(Site: 1953 - 1967)

Radius From Site Miles	Cumulative Number Of Tornadoes
10	0
25	3
30	12
35	14
50	22
60	28
75	42

Table 2.6-2 WIND DISTRIBUTION (%)

	Onshore (N-SSE)	Offshore (S-NNW)	Calm
Spring	44.5	52.0	3.5
Summer	36.4	61.4	2.2
Autumn	30.8	67.0	2.3
Winter	22.9	74.0	3.1
Annual	33.8	63.5	2.7

Table 2.6-3 SITE ATMOSPHERIC STABILITY ANALYSIS ANNUAL AVERAGE - POINT BEACH, WISCONSIN THIRTEEN MONTH DATA - 4/67-4/68

(Sheet 1 of 3)

Hourly Stability Index Distribution - Total No. of Obs. - 7999

	Percent Total Obs.							In Percent of Hourly Obs						
Hour Index	1	2	3	4	5	6	7	1	2	3	4	5	6	7
1	0.09	0.03	0.28	1.19	1.49	0.84	0.26	2.10	0.60	6.61	28.53	35.74	20.12	6.31
2	0.09	0.03	0.21	1.30	1.53	0.84	0.15	2.11	0.60	5.14	31.42	36.86	20.24	3.63
3	0.10	0.04	0.19	1.26	1.55	0.89	0.13	2.41	0.90	4.52	30.42	37.35	21.39	3.01
4	0.04	0.01	0.15	1.33	1.54	0.91	0.16	0.91	0.30	3.63	32.02	37.16	22.05	3.93
5	0.08	0.04	0.16	1.39	1.55	0.74	0.18	1.82	0.91	3.94	33.64	37.58	17.88	4.24
6	0.08	0.03	0.25	1.26	1.83	0.51	0.15	1.83	0.61	6.10	30.79	44.51	12.50	3.66
7	0.06	0.03	0.44	1.54	1.55	0.46	0.06	1.51	0.60	10.57	37.16	37.46	11.18	1.51
8	0.09	0.01	0.50	1.76	1.39	0.35	0.03	2.12	0.30	12.12	42.73	33.64	8.48	0.61
9	0.11	0.25	0.63	1.74	1.10	0.30	0.04	2.70	6.01	15.02	41.74	26.43	7.21	0.90
10	0.10	0.21	0.64	1.75	1.11	0.31	0.04	2.40	5.11	15.32	42.04	26.73	7.51	0.90
11	0.06	0.31	0.63	1.78	0.96	0.43	0.04	1.49	7.44	14.88	42.26	22.92	10.12	0.89
12	0.11	0.25	0.61	1.69	1.09	0.40	0.04	2.69	5.97	14.63	40.30	25.97	9.55	0.90
13	0.11	0.15	0.59	1.85	0.99	0.41	0.08	2.69	3.59	14.07	44.31	23.65	9.88	1.80
14	0.14	0.11	0.68	1.85	0.90	0.38	0.11	3.30	2.70	16.22	44.44	21.62	9.01	2.70
15	0.10	0.18	0.53	1.73	1.19	0.40	0.05	2.40	4.20	12.61	41.44	28.53	9.61	1.20
16	0.15	0.16	0.43	1.79	1.21	0.35	0.06	3.61	3.92	10.24	43.07	29.22	8.43	1.51
17	0.08	0.15	0.33	1.64	1.39	0.48	0.09	1.81	3.63	7.85	39.58	33.53	11.48	2.11
18	0.06	0.03	0.31	1.36	1.76	0.54	0.13	1.49	0.60	7.46	32.54	42.09	12.84	2.99
19	0.08	0.03	0.18	1.33	1.73	0.73	0.15	1.79	0.60	4.17	31.55	41.07	17.26	3.57
20	0.04	0.01	0.28	1.20	1.68	0.78	0.23	0.89	0.30	6.55	28.57	39.88	18.45	5.36
21	0.10	0.00	0.24	1.16	1.59	0.88	0.25	2.37	0.00	5.64	27.60	37.69	20.77	5.93
22	0.10	0.01	0.25	1.25	1.44	0.95	0.21	2.37	0.30	5.93	29.67	34.12	22.55	5.04
23	0.06	0.03	0.25	1.20	1.41	0.99	0.28	1.48	0.59	5.93	28.49	33.53	23.44	6.53
24	0.06	0.00	0.25	1.26	1.60	0.85	0.16	1.49	0.00	5.97	30.15	38.21	20.30	3.88

Table 2.6-3 (Sheet 2 of 3)

Average Wind Speed For Each Stability Index and Direction (In MPH), Average Inverse Speed

Index	NNE	NE	ENE	E	ESE	SE	SSE	S	SSW	SW	WSW	W	WNW	NW	NNW	N
1	0.16	0.35	0.28	0.70	0.33	0.29	0.25	0.16	0.15	0.31	0.30	0.23	0.31	0.17	0.17	0.43
2	0.00	0.38	0.44	0.33	0.33	0.44	0.34	0.13	0.30	0.20	0.17	0.22	0.14	0.12	0.22	0.80
3	0.31	0.42	0.53	0.42	0.35	0.32	0.15	0.16	0.12	0.15	0.15	0.15	0.10	0.11	0.15	0.32
4	0.16	0.18	0.25	0.26	0.27	0.25	0.13	0.10	0.09	0.14	0.12	0.12	0.11	0.12	0.11	0.13
5	0.09	0.12	0.15	0.26	0.19	0.15	0.15	0.18	0.11	0.13	0.13	0.12	0.14	0.17	0.15	0.11
6	0.09	0.13	0.17	0.23	0.25	0.19	0.19	0.24	0.21	0.14	0.13	0.15	0.16	0.17	0.22	0.12
7	0.07	0.07	0.00	0.13	0.18	0.19	0.12	0.21	0.17	0.15	0.12	0.10	0.11	0.12	0.11	0.13

Stability Index Distribution In Percent of Total Obs.

Index	NNE	NE	ENE	E	ESE	SE	SSE	S	SSW	SW	WSW	W	WNW	NW	NNW	N	CALM
1	0.15	0.19	0.10	0.09	0.04	0.10	0.11	0.19	0.31	0.16	0.14	0.09	0.10	0.15	0.06	0.10	0.00
2	0.00	0.03	0.04	0.01	0.01	0.04	0.13	0.04	0.08	0.04	0.04	0.08	0.16	0.24	0.08	0.05	1.04
3	0.05	0.16	0.08	0.19	0.13	0.11	0.14	0.59	0.33	0.24	0.16	0.50	2.80	2.95	0.41	0.14	0.00
4	0.93	1.05	0.51	0.55	0.48	0.78	1.43	6.00	4.65	1.60	1.66	3.31	4.71	2.94	3.78	1.23	0.00
5	4.23	3.06	0.96	0.68	0.76	1.06	1.06	1.23	4.71	3.06	1.69	2.46	0.83	0.54	0.93	4.60	1.70
6	1.33	0.75	0.43	0.39	0.35	0.76	0.53	0.48	1.36	2.84	0.78	1.00	0.64	0.44	0.14	2.50	0.00
7	0.13	0.09	0.00	0.01	0.03	0.13	0.10	0.06	0.39	0.54	0.20	0.40	0.18	0.06	0.01	0.74	0.00

Average Wind Speed For Each Stability Index and Direction (In MPH)

Index	NNE	NE	ENE	E	ESE	SE	SSE	S	SSW	SW	WSW	W	WNW	NW	NNW	N
1	8.7	5.1	6.1	2.3	3.3	4.1	6.7	10.3	9.3	10.2	6.1	6.1	10.6	10.4	7.4	5.5
2	0.0	3.0	2.3	3.0	3.0	2.3	4.1	7.7	6.3	6.7	6.7	5.3	8.2	9.3	6.8	2.0
3	6.5	4.8	3.2	3.7	4.2	7.1	7.9	9.2	9.8	9.1	9.7	11.4	14.1	12.3	10.6	7.5
4	11.8	8.9	7.5	5.7	5.8	9.0	12.3	14.8	14.4	11.8	12.2	15.5	13.2	11.3	12.0	12.7
5	15.3	12.2	11.3	6.3	10.9	11.6	9.8	8.2	13.6	11.3	10.8	11.9	9.6	8.2	9.4	14.2
6	14.1	11.8	10.3	8.5	6.5	6.7	8.4	6.3	8.2	9.6	10.0	10.2	8.7	9.1	7.4	12.6
7	14.6	15.6	0.0	8.0	5.5	6.9	9.1	5.0	7.9	8.6	10.1	11.3	10.6	9.8	9.0	11.2

Table 2.6-3 (Sheet 3 of 3)

Wind Rose For Each Stability Index (In Percent of Each Index Total)

Index	NNE	NE	ENE	E	ESE	SE	SSE	S	SSW	SW	WSW	W	WNW	NW	NNW	M	CALM
1	7.23	9.04	4.82	4.22	1.81	4.82	5.42	9.04	15.06	7.83	6.63	4.22	4.82	7.23	3.01	4.82	0.00
2	0.00	1.20	1.81	0.60	0.60	1.81	6.02	1.81	3.61	1.81	1.81	3.61	7.83	11.45	3.61	2.41	50.00
3	0.56	1.81	0.84	2.09	1.39	1.26	1.53	6.56	3.63	2.65	1.81	5.58	31.24	32.91	4.60	1.53	0.00
4	2.60	2.95	1.44	1.55	1.33	2.18	4.00	16.86	13.07	4.50	4.67	9.31	13.24	8.25	10.61	3.44	0.00
5	12.59	9.13	2.87	2.01	2.27	3.17	3.17	3.65	14.05	9.13	5.03	7.34	2.46	1.60	2.76	13.71	5.07
6	9.02	5.11	2.89	2.64	2.38	5.19	3.57	3.23	9.28	19.32	5.28	6.81	4.34	2.98	0.94	17.02	0.00
7	4.10	2.87	0.00	0.41	0.82	4.10	3.28	2.05	12.70	17.62	6.56	13.11	5.74	2.05	0.41	24.18	0.00

Gross Wind Rose (In Percent of Total Obs.)

	NNE	NE	ENE	E	ESE	SE	SSE	S	SSW	SW	WSW	W	WNW	NW	NNW	N	CALM
	6.80	5.33	2.11	1.91	1.79	2.98	3.49	8.58	11.83	8.48	4.66	7.84	9.41	7.31	5.40	9.35	2.74
Speed	14.4	11.1	9.5	6.1	7.9	8.9	10.2	12.8	12.8	10.5	10.9	13.0	12.7	11.3	11.2	13.1	0.0

Stability Index Distribution For Each Wind Direction (In Percent of Direction Total)

Index	NNE	NE	ENE	E	ESE	SE	SSE	S	SSW	SW	WSW	W	WNW	NW	NNW	N	CALM
1	2.21	3.52	4.73	4.58	2.10	3.36	3.23	2.19	2.64	1.92	2.95	1.12	1.06	2.05	1.16	1.07	0.00
2	0.00	0.47	1.78	0.65	0.70	1.26	3.58	0.44	0.63	0.44	0.80	0.96	1.73	3.25	1.39	0.53	37.90
3	0.74	3.05	3.55	9.80	6.99	3.78	3.94	6.85	2.75	2.80	3.49	6.38	29.75	40.34	7.64	1.47	0.00
4	13.60	19.72	24.26	28.76	26.57	26.05	40.86	69.97	39.32	18.88	35.66	42.26	50.07	40.17	69.91	13.10	0.00
5	62.13	57.51	45.56	35.29	42.66	35.71	30.47	14.29	39.85	36.14	36.19	31.42	8.76	7.35	17.13	49.20	62.10
6	19.49	14.08	20.12	20.26	19.58	25.63	15.05	5.54	11.52	33.48	16.62	12.76	6.77	5.98	2.55	26.74	0.00
7	1.84	1.64	0.00	0.65	1.40	4.20	2.87	0.73	3.28	6.34	4.29	5.10	1.86	0.85	0.23	7.89	0.00

Stability Index Distribution (In Percent of Total Obs.)

Index	1	2	3	4	5	6	7
	2.08	2.08	8.96	35.59	33.55	14.69	3.05

Average Wind Speed For Each Stability Index (In MPH)

	1	2	3	4	5	6	7
Average Speed	7.6	3.2	11.6	12.8	11.6	10.1	10.0
Inverse Speed	0.26	0.13	0.14	0.12	0.12	0.15	0.13

Table 2.6-4 SITE ATMOSPHERIC STABILITY ANALYSIS ANNUAL AVERAGE - POINT BEACH, WISCONSIN, THIRTEEN MONTH DATA - 4/67-4/68

(Sheet 1 of 2)

CHI/Q For Release Height of 0.000+000 Meters (In Sec. Per CU Meter)

Dist, M	NNE	NE	ENE	E	ESE	SE	SSE	S
2.0000+002	2.7258-005	2.6373-005	1.3928-005	1.7493-005	1.5479-005	2.2919-005	1.8666-005	3.3966-005
4.0000+002	7.3458-006	7.0720-006	3.7420-006	4.6845-006	4.1776-006	6.1963-006	5.0298-006	9.1893-006
6.0000+002	3.5278-006	3.3798-006	1.7923-006	2.2384-006	2.0097-006	2.9897-006	2.4172-006	4.4214-006
8.0000+002	2.1472-006	2.0482-006	1.0886-006	1.3574-006	1.2255-006	1.8296-006	1.4732-006	2.6939-006
1.2000+003	1.1111-006	1.0521-006	5.6038-007	6.9743-007	6.3460-007	9.5317-007	7.6230-007	1.3877-006
1.6000+003	7.0122-007	6.6081-007	3.5179-007	4.3752-007	3.9978-007	6.0245-007	4.7984-007	8.6942-007
2.4000+003	3.6739-007	3.4418-007	1.8307-007	2.2761-007	2.0895-007	3.1643-007	2.5064-007	4.5083-007
3.2000+003	2.3271-007	2.1718-007	1.1545-007	1.4354-007	1.3214-007	2.0085-007	2.5849-007	2.8347-007
4.0000+003	1.6353-007	1.5219-007	8.0861-008	1.0055-007	9.2747-008	1.4139-007	1.1125-007	1.9805-007
4.8000+003	1.2272-007	1.1395-007	6.0521-008	7.5260-008	6.9532-008	1.0626-007	8.3428-008	1.4791-007
5.6000+003	9.6354-008	8.9307-008	4.7416-008	5.8966-008	5.4551-008	8.3549-008	6.5475-008	1.1566-007
6.4000+003	7.8204-008	7.2370-008	3.8413-008	4.7770-008	4.4245-008	6.7895-008	5.3126-008	9.3533-008
7.2000+003	6.5100-008	6.0159-008	3.1924-008	3.9701-008	3.6809-008	5.6583-008	4.4215-008	7.7607-008
8.0000+003	5.5285-008	5.1025-008	2.7071-008	3.3665-008	3.1242-008	4.8102-008	3.7543-008	6.5710-008
8.8000+003	4.7713-008	4.3988-008	2.3332-008	2.9015-008	2.6950-008	4.1555-008	3.2398-008	5.6556-008
9.6000+003	4.1732-008	3.8434-008	2.0382-008	2.5346-008	2.3560-008	3.6378-008	2.8335-008	4.9340-008
1.0400+004	3.6911-008	3.3962-008	1.8006-008	2.2392-008	2.0829-008	3.2203-008	2.5061-008	4.3536-008
1.1200+004	3.2959-008	3.0300-008	1.6062-008	1.9973-008	1.8591-008	2.8779-008	2.2378-008	3.8788-008
1.2000+004	2.9674-008	2.7257-008	1.4446-008	1.7964-008	1.6731-008	2.5930-008	2.0147-008	3.4847-008
1.2800+004	2.6908-008	2.4698-008	1.3086-008	1.6273-008	1.5166-008	2.3530-008	1.8269-008	3.1535-008
1.4400+004	2.2530-008	2.0650-008	1.0937-008	1.3601-008	1.2689-008	1.9728-008	1.5297-008	2.6304-008
1.5200+004	2.0777-008	1.9031-008	1.0077-008	1.2531-008	1.1697-008	1.8204-008	1.4106-008	2.4212-008
1.6000+004	1.9245-008	1.7617-008	9.3265-009	1.1598-008	1.0831-008	1.6872-008	1.3067-008	2.2389-008
1.6800+004	1.7898-008	1.6374-008	8.6667-009	1.0778-008	1.0070-008	1.5700-008	1.2152-008	2.0787-008
1.7600+004	1.6706-008	1.5275-008	8.0832-009	1.0052-008	9.3958-009	1.4663-008	1.1343-008	1.9371-008
1.8400+004	1.5646-008	1.4297-008	7.5641-009	9.4067-009	8.7965-009	1.3739-008	1.0639-008	1.8112-008
1.9200+004	1.4697-008	1.3423-008	7.1001-009	8.8297-009	8.2605-009	1.2913-008	9.9786-009	1.6988-008
2.0000+004	1.3844-008	1.2638-008	6.6832-009	8.3115-009	7.7788-009	1.2170-008	9.3997-009	1.5978-008
2.0800+004	1.3075-008	1.1930-008	6.3171-009	7.8440-009	7.3441-009	1.1499-008	8.8771-009	1.5068-008
2.1600+004	1.2377-008	1.1288-008	5.9664-009	7.4205-009	6.9502-009	1.0891-008	8.4036-009	1.4244-008
2.2400+004	1.1743-008	1.0705-008	5.6567-009	7.0354-009	6.5920-009	1.0338-008	7.9728-009	1.3495-008
2.3200+004	1.1164-008	1.0172-008	5.3740-009	6.6841-009	6.2651-009	9.8323-009	7.5797-009	1.2812-008
2.4000+004	2.0634-008	9.6850-009	5.1153-009	6.3626-009	5.9658-009	9.3696-009	7.2196-009	1.2187-008
5.0000+004	3.9511-009	3.5604-009	1.8638-009	2.3221-009	2.1967-009	3.5197-009	2.6798-009	4.3709-009
1.0000+005	1.8701-009	1.6632-009	8.5352-010	1.0683-009	1.0237-009	1.6948-009	1.2671-009	1.9710-009

Table 2.6-4 CHI/Q For Release Height of 0.000+000 Meters (InSec.PerCUMeter)

(Sheet 2 of 2)

Dist, M	SSW	SW	WSW	W	WNW	NW	NNW	N
2.0000+002	5.5353-005	5.2632-005	2.2391-005	3.5416-005	2.9993-005	2.2692-005	1.9474-005	5.1034-005
4.0000+002	1.4973-005	1.4258-005	6.0414-006	9.5820-006	8.0820-006	6.0870-006	5.2637-006	1.3799-005
6.0000+002	7.2223-006	6.9014-006	2.9066-006	4.6191-006	3.8743-006	2.9043-006	2.5257-006	6.6625-006
8.0000+002	4.4165-006	4.2383-006	1.7733-006	2.8214-006	2.3526-006	1.7554-006	1.5334-006	4.0808-006
1.2000+003	2.2991-006	2.2242-006	9.1973-007	1.4637-006	1.2042-006	8.9145-007	7.8408-007	2.1341-006
1.6000+003	1.4540-006	1.4135-006	5.8036-007	9.2277-007	7.5047-007	5.5269-007	4.8862-007	1.3548-006
2.4000+003	7.6409-007	7.4805-007	3.0416-007	4.8283-007	3.8656-007	2.8268-007	2.5141-007	7.1596-007
3.2000+003	4.8509-007	4.7728-007	1.9276-007	3.0559-007	2.4202-007	1.7613-007	1.5718-007	4.5643-007
4.0000+003	3.4153-007	3.3734-007	1.3553-007	2.1464-007	1.6858-007	1.2224-007	1.0932-007	3.2242-007
4.8000+003	2.5671-007	2.5436-007	1.0176-007	1.6102-007	1.2561-007	9.0819-008	8.1339-008	2.4303-007
5.6000+003	2.0185-007	2.0054-007	7.9939-008	1.2640-007	9.8044-008	7.0716-008	6.3400-008	1.9157-007
6.4000+003	1.6404-007	1.6336-007	6.4912-008	1.0258-007	7.9170-008	5.6985-008	5.1127-008	1.5603-007
7.2000+003	1.3672-007	1.3643-007	5.4059-008	8.5387-008	6.5609-008	4.7139-008	4.2315-008	1.3030-007
8.0000+003	1.1623-007	1.1621-007	4.5928-008	7.2511-008	5.5493-008	3.9807-008	3.5747-008	1.1098-007
8.8000+003	1.0042-007	1.0056-007	3.9654-008	6.2580-008	4.7719-008	3.4181-008	3.0703-008	9.6048-008
9.6000+003	8.7915-008	8.8180-008	3.4696-008	5.4736-008	4.1597-008	2.9758-008	2.6733-008	8.4223-008
1.0400+004	7.7830-008	7.8177-008	3.0700-008	4.8414-008	3.6678-008	2.6207-008	2.3546-008	7.4675-008
1.1200+004	6.9559-008	6.9963-008	2.7423-008	4.3234-008	3.2658-008	2.3309-008	2.0942-008	6.6835-008
1.2000+004	6.2677-008	6.3121-008	2.4698-008	3.8927-008	2.9323-008	2.0907-008	1.8784-008	6.0305-008
1.2800+004	5.6880-008	5.7351-008	2.2404-008	3.5300-008	2.6523-008	1.8892-008	1.6972-008	5.4799-008
1.4400+004	4.7698-008	4.8199-008	1.8771-008	2.9562-008	2.2104-008	1.5716-008	1.4116-008	4.6066-008
1.5200+004	4.4016-008	4.4524-008	1.7316-008	2.7263-008	2.0339-008	1.4449-008	1.2976-008	4.2560-008
1.6000+004	4.0799-008	4.1311-008	1.6044-008	2.5256-008	1.8800-008	1.3345-008	1.1983-008	3.9494-008
1.6800+004	3.7969-008	3.8481-008	1.4926-008	2.3490-008	1.7449-008	1.2377-008	1.1111-008	3.6794-008
1.7600+004	3.5464-008	3.5974-008	1.3936-008	2.1928-008	1.6256-008	1.1522-008	1.0342-008	3.4403-008
1.8400+004	3.3233-008	3.3741-008	1.3055-008	2.0538-008	1.5195-008	1.0763-008	9.6582-009	3.2273-008
1.9200+004	3.1238-008	3.1742-008	1.2267-008	1.9295-008	1.4248-008	1.0085-008	9.0481-009	3.0365-008
2.0000+004	2.9443-008	2.9943-008	1.1559-008	1.8177-008	1.3398-008	9.4774-009	8.5007-009	2.8649-008
2.0800+004	2.7823-008	2.8317-008	1.0919-008	1.7169-008	1.2632-008	8.9298-009	8.0075-009	2.7098-008
2.1600+004	2.6354-008	2.6843-008	1.0340-008	1.6255-008	1.1939-008	8.4344-009	7.5614-009	2.5692-008
2.2400+004	2.5018-008	2.5501-008	9.8127-009	1.5424-008	1.1309-008	7.9845-009	7.1562-009	2.4411-008
2.3200+004	2.3798-008	2.4274-008	9.3315-009	1.4665-008	1.0734-008	7.5746-009	6.7870-009	2.3242-008
2.4000+004	2.2680-008	2.3151-008	8.8908-009	1.3970-008	1.0209-008	7.1998-009	6.4495-009	2.2170-008
5.0000+004	8.5562-009	8.8830-009	3.3310-009	5.2156-009	3.6537-009	2.5396-009	2.2513-009	8.5620-009
1.0000+005	4.1604-009	4.4097-009	1.6052-009	2.5050-009	1.6535-009	1.1243-009	9.7402-010	4.3089-009

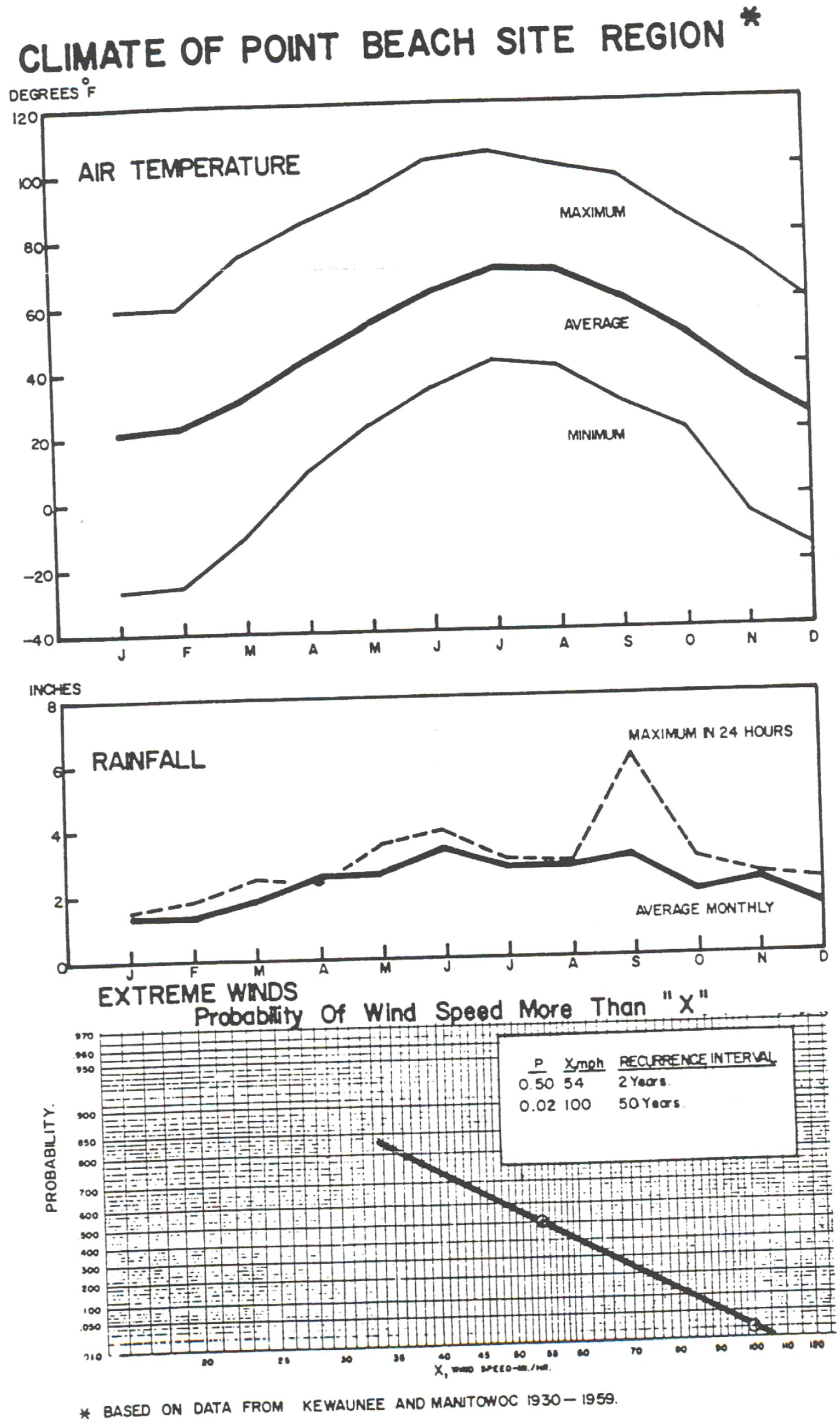
Table 2.6-5 ATMOSPHERIC STABILITY (%)

	Unstable	**Neutral**	**Stable**
Spring	11.21	31.90	56.89
Summer	14.16	25.97	59.87
Autumn	12.23	40.68	47.10
Winter	14.91	44.81	40.27
Annual	13.12	35.59	51.29

Table 2.6-6 HYPOTHETICAL ACCIDENT METEOROLOGICAL MODEL BASIC ON SITE DATA, 1967 - 1968

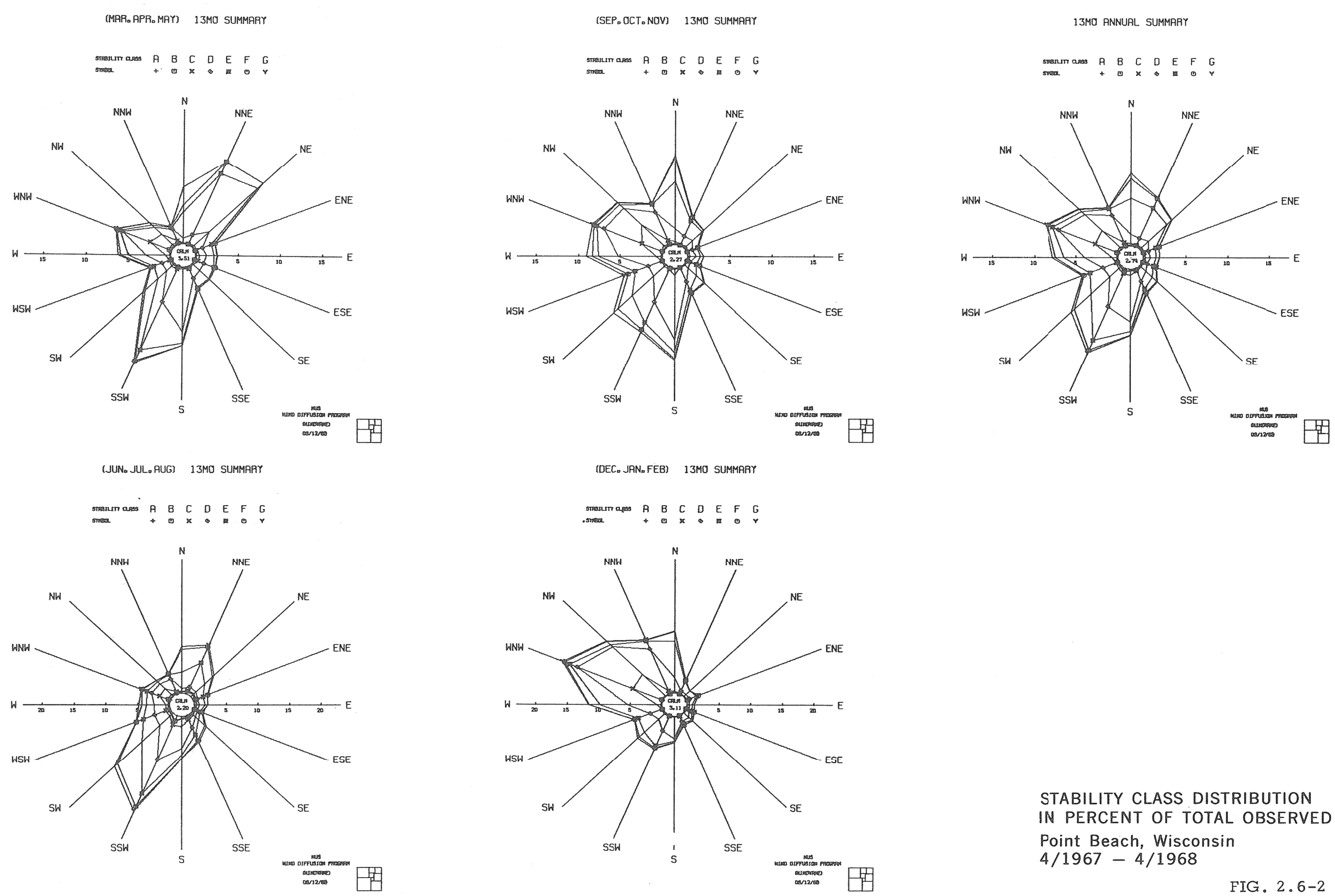
Time Period	Pasquill Stability	Wind Speed (Meters/Sec)	Fi	fi	Wind Condition
0 - 2 Hours	F	1.0	1.00	1.00	Invariant
2 - 48 Hours	F	2.5	1.00	1.00	Sector Avg.
2 - 30 Days	B	3.5	0.75	0.75	Sector Avg.
	D	4.0	0.15	0.20	Sector Avg.
	F	2.0	0.10	0.15	Sector Avg.

Figure 2.6-1 CLIMATE OF POINT BEACH SITE REGION



CLIMATE OF POINT BEACH SITE REGION
FIGURE 2.6-1

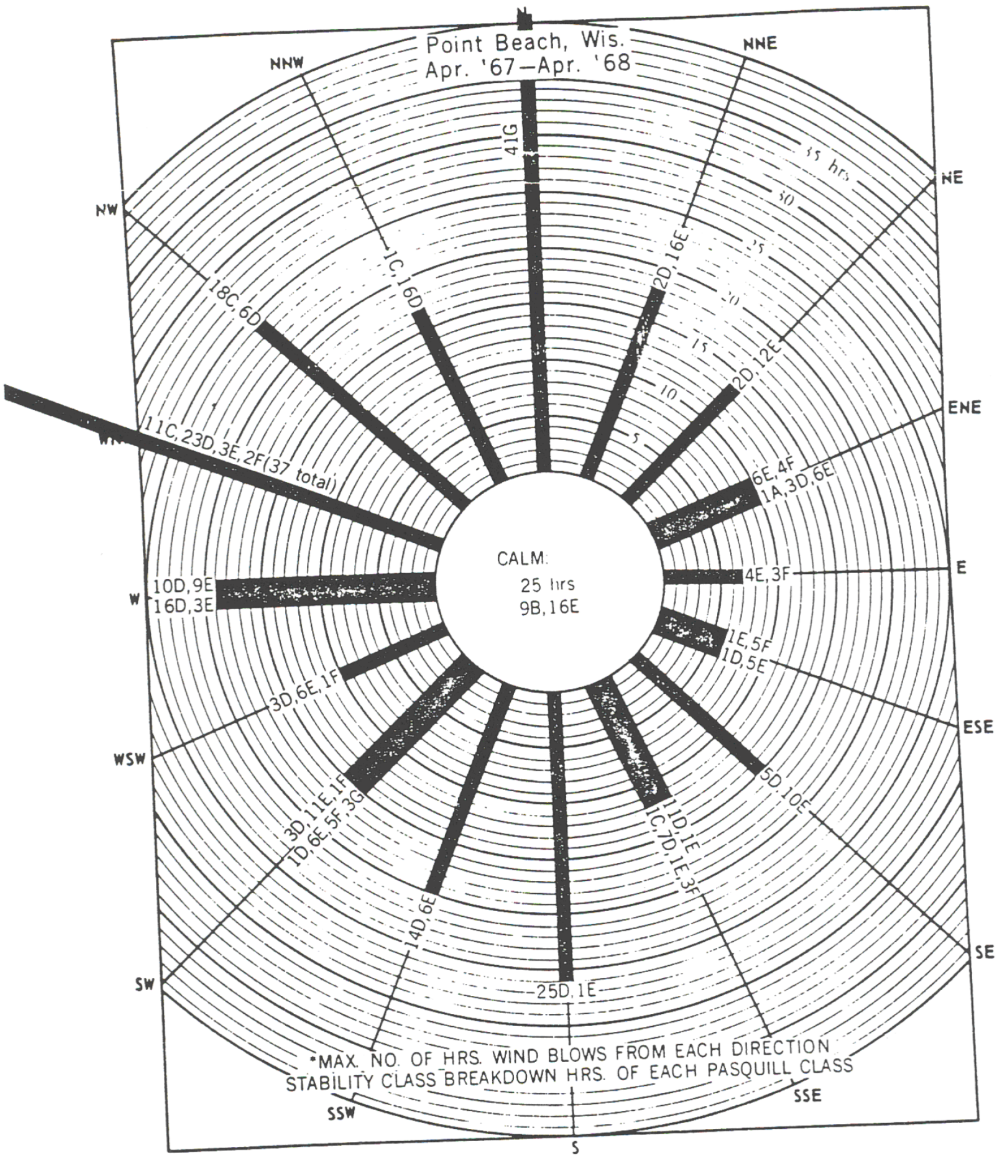
Figure 2.6-2 STABILITY CLASS DISTRIBUTION IN PERCENT OF TOTAL OBSERVED



STABILITY CLASS DISTRIBUTION
IN PERCENT OF TOTAL OBSERVED
Point Beach, Wisconsin
4/1967 – 4/1968

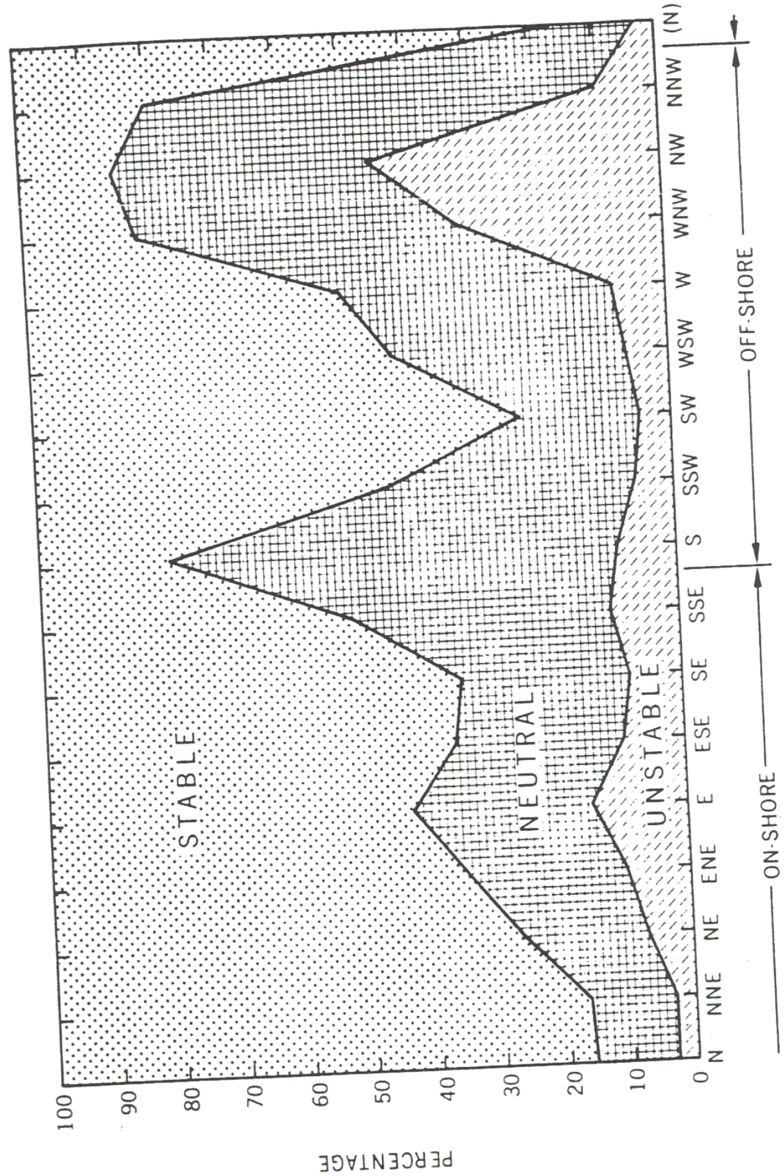
FIG. 2.6-2

Figure 2.6-3 PERSISTENCE WIND ROSE



PERSISTENCE WIND ROSE*
FIGURE 2.6-3

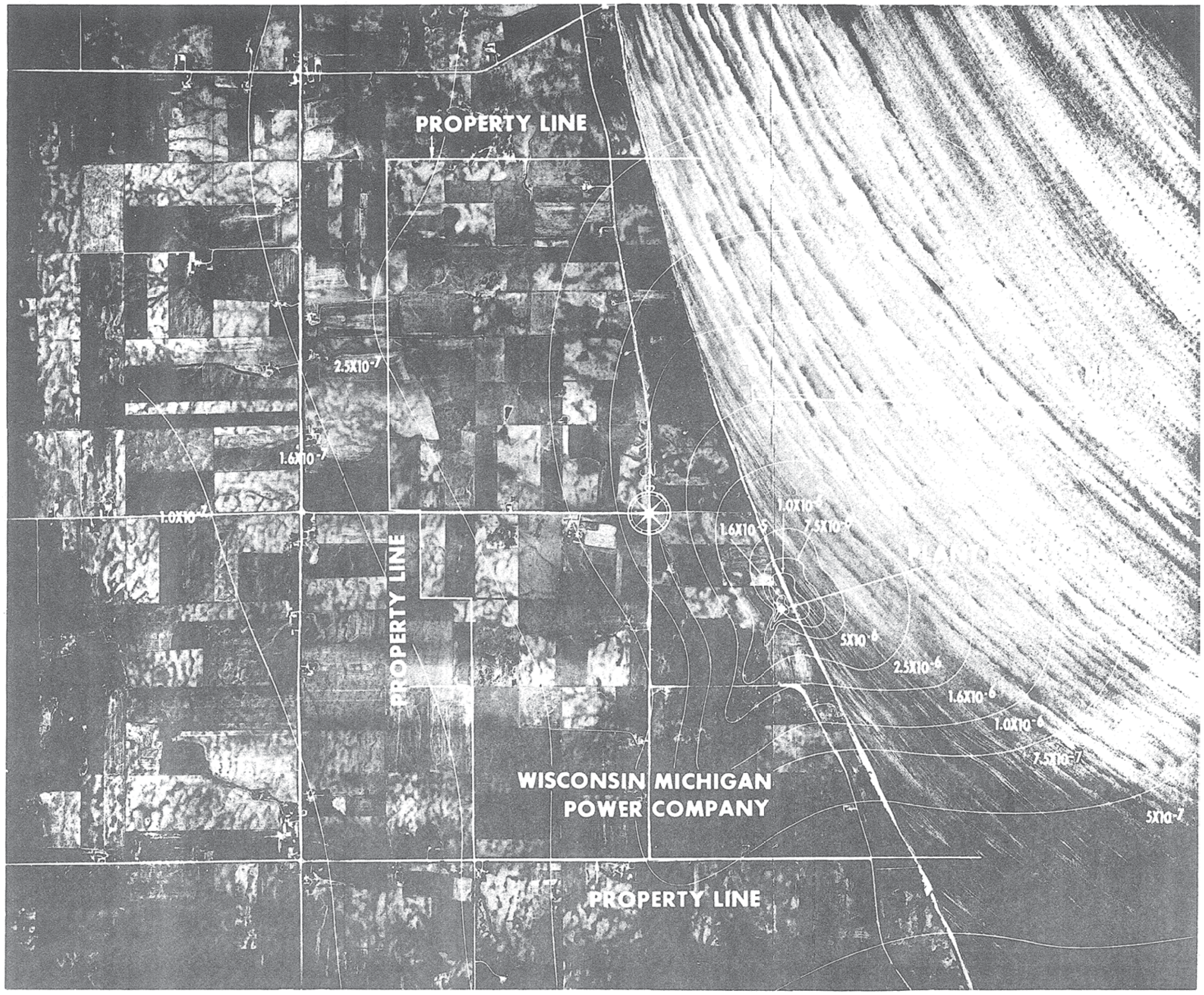
Figure 2.6-4 DISTRIBUTION OF STABILTY BY DIRECTION - POINT BEACH ANNUAL AVERAGE - 4/67-4/68



DISTRIBUTION OF STABILITY BY DIRECTION - POINT BEACH ANNUAL AVERAGE - 4/67-4/68

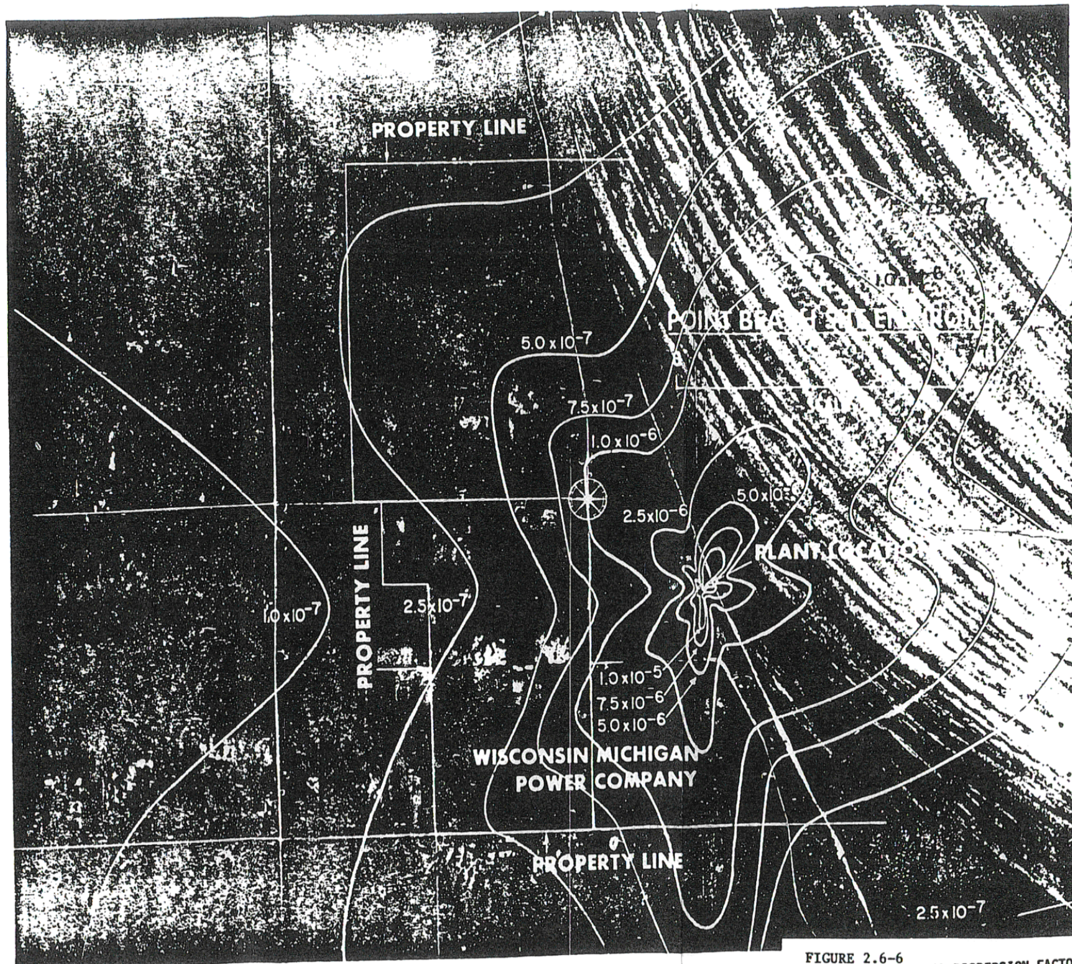
FIGURE 2.6-4

Figure 2.6-5 ANNUAL χ/Q DISPERSION FACTOR MILWAUKEE DATA



ANNUAL AVERAGE χ/Q DISPERSION FACTOR
MILWAUKEE DATA FIGURE 2.6-5

Figure 2.6-6 ANNUAL AVERAGE χ/Q DISPERSION FACTOR SITE DATA (4/67-4/68)



ANNUAL AVERAGE χ/Q DISPERSION FACTOR
SITE DATA (4/67—4/68)

FIGURE 2.6-6
ANNUAL AVERAGE x/Q DISPERSION FACTOR
Site Data (4/67-4/68)
Point Beach Nuclear Plant

Figure 2.6-7 FSAR ACCIDENT MODEL

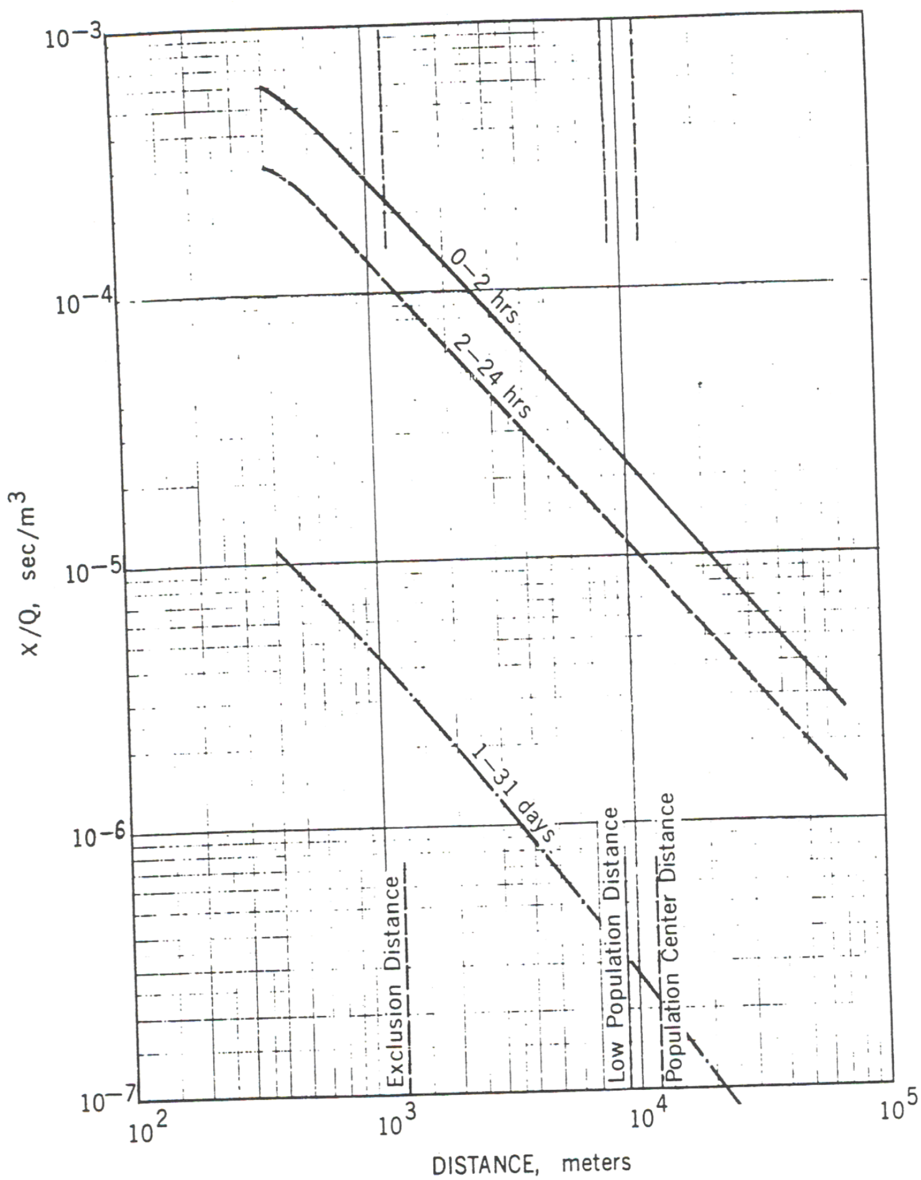


FIGURE 2.6-7
PSAR ACCIDENT MODEL
Virtual Source Distance = 680 meters
Point Beach Nuclear Plant

Figure 2.6-8 REVISED ACCIDENT MODEL

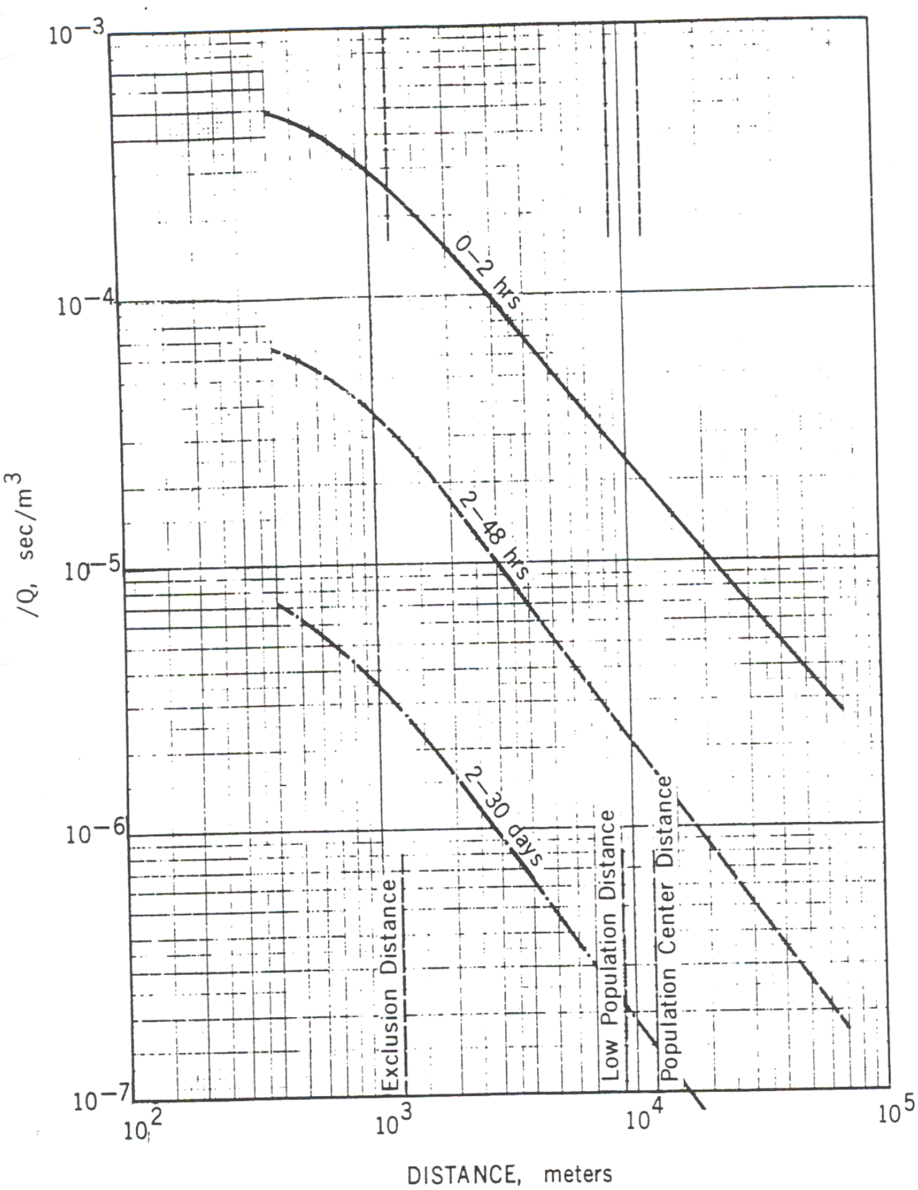


FIG. 2.6-8
REVISED ACCIDENT MODEL
Building Wake Factor = (1×1640)m^2
Point Beach Nuclear Plant

2.7 ENVIRONMENTAL RADIOACTIVITY STUDIES

PRE-OPERATIONAL

A pre-operational environmental radiological monitoring program was started in November, 1967. Monitored variables included air, water, shoreline sediment, soil vegetation, milk and algae samples as listed in Table 2.7-1. Figure 2.7-1 shows the locations of the sampling stations used.

The purpose of the pre-operational environmental program was to test equipment, sampling and analytical procedures, to investigate the suitability of the selected sampling points, and to provide a radiological background base line from which possible changes in radiation levels during and following plant operations could be detected and evaluated.

The milk samples were collected monthly from a local dairy and processed by the Radiation Protection Section of the Wisconsin Department of Health and Social Services. The Radiation Protection Section also agreed to gamma scan lake water samples and perform confirmatory checks on selected Point Beach Nuclear Plant environmental samples.

Soil and vegetation samples were taken at the sample stations listed in Table 2.7-1. All the exclusion area stations were under control of the Licensee, and the off-site stations were chosen with consideration of minimum disturbance by the public and continuing availability for the lifetime of the plant. Soil, air, and vegetation analyses were performed by an outside environmental analysis contractor.

Lake water, shoreline sediment, and algae samples were taken at points along the Lake Michigan shoreline as shown in Table 2.7-1. These samples were also analyzed by an outside environmental contractor.

Since the subsurface water table at the site has a definite lakeward slope, only the plant well was sampled. Pre-operational samples of the plant well were taken and analysis was handled by an outside environmental contractor. Air particulate samples, film badges, and stray radiation chambers were employed for pre-operational studies. These were also analyzed by an outside environmental contractor.

Lake Michigan fish life is undergoing a rapid state of evolution caused by the various programs to introduce salmon and trout species and control the alewife and sea lamprey populations. For this reason and because of the migratory habits of lake fish, an environmental monitoring program concerning lake fish would have had questionable value and was not performed directly by the Licensee. Others in the vicinity of Point Beach Nuclear Plant included fish in their environmental monitoring programs. These included samples taken by the Wisconsin Department of Natural Resources for the Radiation Protection Section of the Wisconsin Department of Health and Social Services and samples from monitoring activities at the Kewaunee Nuclear Plant site approximately 4.5 miles north of the Point Beach site. These studies were considered to provide an adequate baseline for sampling fish in the vicinity of the Point Beach Nuclear Plant.

The lake bottom in the vicinity of Point Beach Nuclear Plant is primarily either solid clay and rock or hard-packed sand. There is very little solid organic material in the bottom sediments due, in part, to the grinding action of suspended sediments. Because of these conditions, there are very few benthic (bottom dwelling) organisms present in the area. Snails were not found in any samples at this time. A few crustaceans, e.g., Pontopareia, had been found, but their populations were not large enough to be practical as an indicator organism.

OPERATIONAL

The operational radiological environmental monitoring program is based on the pre-operational program, and is carried out in accordance with the schedule presented in the Offsite Dose Calculation Manual (ODCM). The program provides sufficient sample types and locations to detect and evaluate changes (if any) in environmental radioactivity due to releases from the plant.

Since plant radioactivity releases are continuously monitored and recorded, the need for environmental monitoring is limited.

Because land in the area is primarily used for farming and dairy operations, sampling of environmental components such as soil or vegetation is implemented to detect changes in radiological conditions at the base of the terrestrial food chain for animals. Since dairy farming is a major industry in the area, area-produced milk is also sampled.

Air particulate samples and thermoluminescent dosimeters at various locations provide means of detecting significant changes in environmental radioactivity as a result of plant releases to the atmosphere.

Locations for terrestrial radiological sampling emphasize monitoring around the site boundary and at various other points out to a distance of 5 miles. A single sampling location well beyond a distance of 10 miles in a low χ/Q sector is provided for many sample types to provide an estimate of background levels. The locations are listed and depicted in the ODCM.

In the aquatic environment, sample types such as lakewater and shoreline sediment are selected both north and south of the discharge point.

NONRADIOLOGICAL ENVIRONMENTAL STUDIES

A non-radiological environmental program is also implemented at Point Beach Nuclear Plant. Ambient, intake, and condenser cooling water discharge temperatures are monitored. Chemicals and dissolved and suspended solids in liquid plant effluents are also monitored.

In addition to the routine thermal and chemical monitoring of plant effluent, an intensive non-radiological monitoring program was conducted during the first several years of plant operation as required by Technical Specifications. This program includes measurements of physical, chemical, and biological characteristics with a sufficient frequency and at a sufficient number of locations to establish the need and bases for longer term monitoring activities. Additionally, the experimental field was selected such that the short and long term plume effects could be isolated and the relative strength of variables could be established. Measurement of the vertical profiles of the lake water physical and chemical characteristics provide a determination of the physical and chemical spatial effects resulting from natural occurrences and from plant operations. Each biological measurement was associated, as far as practicable, with a simultaneous set of chemical and physical measurements to enable the observation of potential correlations with plume characteristics, meteorology, or plant operation.

In the early 1990s, zebra mussels were discovered in the vicinity of Point Beach Nuclear Plant. These mussels have been known to cause macroscopic biological fouling in fresh water cooling systems. In response to the potential infestation, routine inspections for zebra mussels are conducted in the cooling water discharge flumes, the outside of the intake crib, the forebay, and service water pump house. In addition, a chlorination / dechlorination system has been installed to control microscopic fouling if zebra mussels or mussel viligers (larvae) are found.

Table 2.7-1 PRE-OPERATIONAL ENVIRONMENTAL RADIOLOGICAL SURVEY FOR THE POINT BEACH NUCLEAR PLANT

Sheet 1 of 2

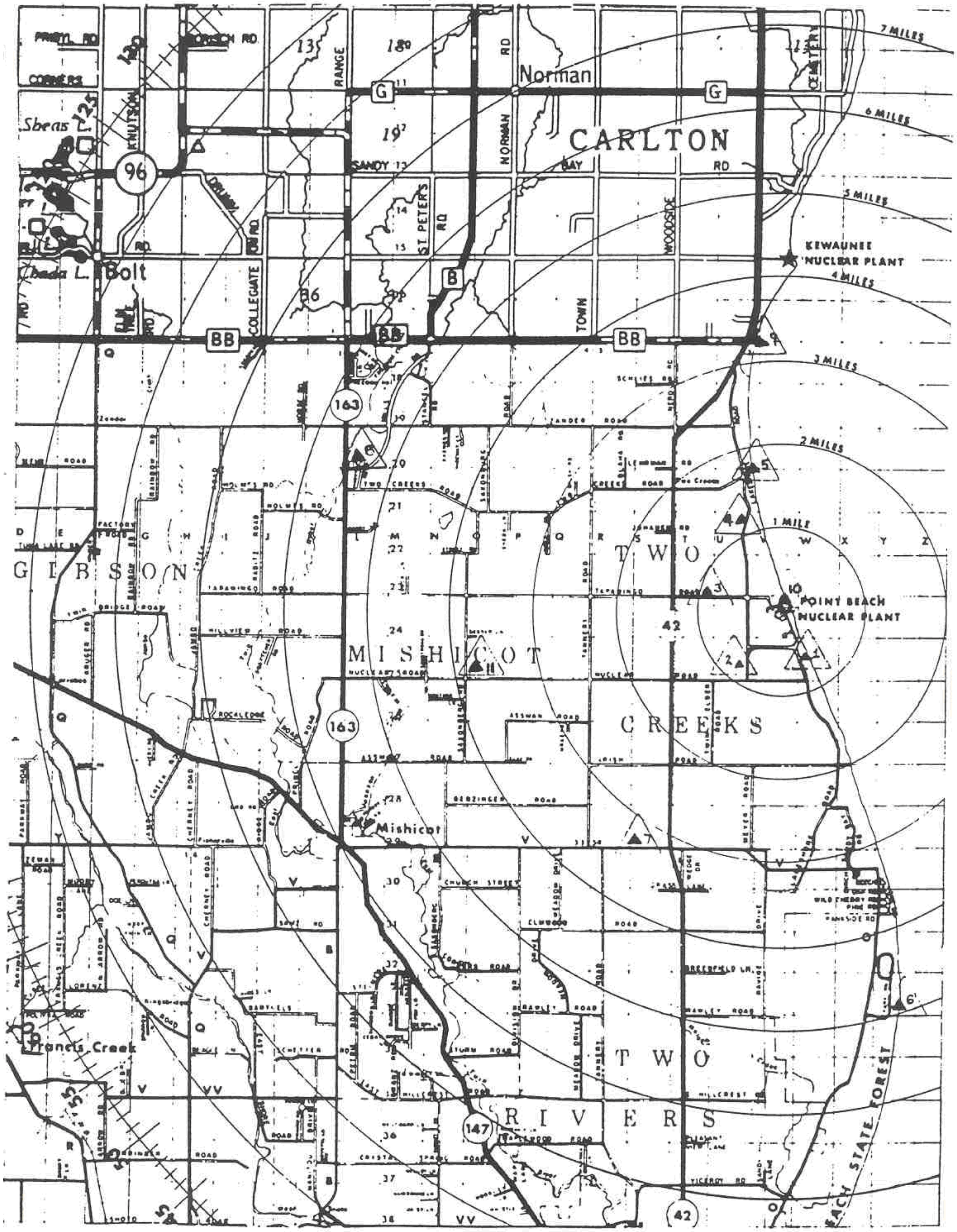
Station Number	Location	Type of Sample	Analysis	Frequency
1	Meteorological tower, south of the plant	Soil Vegetation Film badge Shoreline sediment Lake water Suspended solids Dissolved solids	Gross Beta Gross Beta Integrated Dose Gross Beta Gamma Scan Gross Beta Gross Beta	Annual Biannual Monthly Biannual Biannual Biannual Biannual
2	Southwest boundary of exclusion area	Soil Vegetation	Gross Beta Gross Beta	Annual Biannual
3	West boundary of exclusion area	Soil Vegetation	Gross Beta Gross Beta	Annual Biannual
4	Northern boundary of exclusion area	Soil Vegetation Air particulate Film badge	Gross Beta Gross Beta Gross Beta Integrated Dose	Annual Biannual Weekly Monthly
5	Two Creeks County Park	Shoreline sediment Lake water Suspended solids Dissolved solids Aquatic biota algae	Gross Beta Gamma Scan Gross Beta Gross Beta Gross Beta	Annual Biannual Biannual Biannual Biannual
6	Point Beach State Park	Soil Vegetation Shoreline sediment Lake water Suspended solids Dissolved solids	Gross Beta Gross Beta Gross Beta Gamma Scan Gross Beta Gross Beta	Annual Biannual Biannual Biannual Biannual Biannual
7	Wisconsin Public Service Corporation Substation on County Highway V SW of site	Soil Vegetation	Gross Beta Gross Beta	Annual Biannual
8	Farm just off State Highway 163 NW of site	Soil Vegetation	Gross Beta Gross Beta	Annual Biannual

Table 2.7-1 PRE-OPERATIONAL ENVIRONMENTAL RADIOLOGICAL SURVEY FOR THE POINT BEACH NUCLEAR PLANT

Sheet 2 of 2

Station Number	Location	Type of Sample	Analysis	Frequency
9	Nature Conservancy Buried Forest Site at Manitowoc-Kewaunee County line on the shore of Lake Michigan	Soil Vegetation Shoreline sediment Lake water Suspended solids Dissolved solids	Gross Beta Gross Beta Gross Beta Gamma Scan Gross Beta Gross Beta	Annual Biannual Biannual Biannual Biannual Biannual
10	Well at plant site	Water	Gross Alpha and Beta	Biannual
11	Local milk pool Kornely Dairy, Mishicot	Milk	Gamma Scan Strontium-90	Monthly

Figure 2.7-1 PRE-OPERATIONAL ENVIRONMENTAL RADIOACTIVITY SAMPLING SITES



2.8 GEOLOGY

A geological program involving a regional geological survey, borings, and other tests at the site was completed to provide preliminary information needed to assess foundation conditions, seismic activity, and ground water conditions. A comprehensive foundation investigation was performed (Final Dames and Moore Soils Report), the results of which were filed with the Atomic Energy Commission on January 5, 1967 as a part of the APPLICATION FOR EXEMPTION UNDER SECTION 50.12 OF THE REGULATIONS OF THE AEC (Docket No. 50-266). This investigation disclosed that a pile foundation would be required under the reactor containment and spent fuel pool to minimize differential settlements. The soil is adequate to support other structures at bearing pressures of three to five tons per square foot. Findings concerning ground water and seismology are described in Subsections 2.5 and 2.9, respectively.

GEOLOGICAL PROGRAM

An evaluation of the geological characteristics of the Point Beach site was made as follows:

1. A description of geological structure in the site region was developed, including estimates of the character and thickness of underlying strata. This was based on existing geological data and discussions with geologists working in the area.

2. On-site subsurface conditions were explored with 4-inch diameter test holes up to 132 feet deep and a seismic refraction survey to develop bedrock profiles.

3. Samples of the soils and rock underlying the site were subjected to a variety of laboratory tests to evaluate the physical and chemical properties of the soil and rock.

DESCRIPTIVE GEOLOGY

Regional Geology

The geologic structure of the region is essentially very simple. Gently dipping sedimentary rock strata of Paleozoic age outcrop in a horseshoe pattern around a shield of Precambrian crystalline rock which occupies the western part of the region. The site is located on the western flank of the Michigan Basin, which is a broad downwarp ringed by discontinuous outcrops of more resistant formations. The bedrock formations are principally limestones, dolomites, and sandstones with subordinate shale layers. The Maquoketa shale is the only formation in which shale predominates. The rocks form a succession of extensive layers that are relatively uniform in thickness. The bedrock strata dip very gently towards Lake Michigan at from 15 to 35 feet per mile. A geologic column listing the bedrock units encountered in the area is presented in Table 2.8-1.

Local Geology

The uppermost bedrock under the site is Niagara Dolomite. Bedrock does not outcrop on the site, but is covered by glacial till and lake deposits.

The thickness, texture, and type of deposits are extremely variable from place to place. The soils contain expansive clay minerals and have moderately high base exchange capacity.

In the area of the site, the overburden soils are approximately 70 to 100 feet in thickness. Although the character of the glacial deposits may vary greatly within relatively short distances, a generalized section through the overburden soils adjacent to Lake Michigan at the site consists of the following sequence which is depicted in Figure 2.8-1 and Figure 2.8-2.

1. An upper layer of brown clay silt topsoil underlain with several feet of brown silty clay with layers of silty sand.
2. A layer of 20 feet of reddish-brown silty clay with some sand and gravel and occasional lenses of silt.
3. A layer of 25 feet of reddish-brown silty clay with layers of silty sand and lenses of silt.
4. A layer of 50 feet of reddish-brown silty clay with some sand and gravel, the lower portion of which contains gravels, cobbles, and boulders resting on a glacial eroded surface of Niagara dolomite bedrock.

Elevations shown in Figure 2.8-1 refer to the Plant Datum. Detailed geological data are given in the Dames and Moore Final Foundation Report included in Appendix B to the APPLICATION FOR EXEMPTION UNDER SECTION 50.12 OF REGULATIONS OF THE AEC, Wisconsin Michigan Power Company, Point Beach Unit No.1, (Docket No.50-266).

Table 2.8-1 BEDROCK FORMATIONS IN EASTERN WISCONSIN

Geologic Age	Geologic Name	Description
Quaternary	Recent deposits	Sand, silt, peat, and gravel.
	Pleistocene deposits	Glacial drift, mostly till, clay silt, sand, gravel, and boulders.
Silurian	Niagara Dolomite	Dominate, thin-bedded to massive, some coral reefs. Some chert.
Ordovician	Maquoketa Shale	Shale and dolomitic shale.
	Galena Dolomite Decorah formation Plattevillte formation	Dolomite. Some shale. Sandy at base.
	St. Peter Sandstone	Sandstone, fine to medium grained dolomitic in places.
	Prairie du Chien Group	Dolomite. Sandy and shaly zones in places.
Cambrian	Trempealean Formation Franconia Sandstone Dresbach Group	Sandstone, fine to coarse grained, dolomitic. Some shale and dolomite beds.
Precambrian	Undifferentiated	Granite and quarzite.

Figure 2.8-1 POINT BEACH BORING LOCATIONS

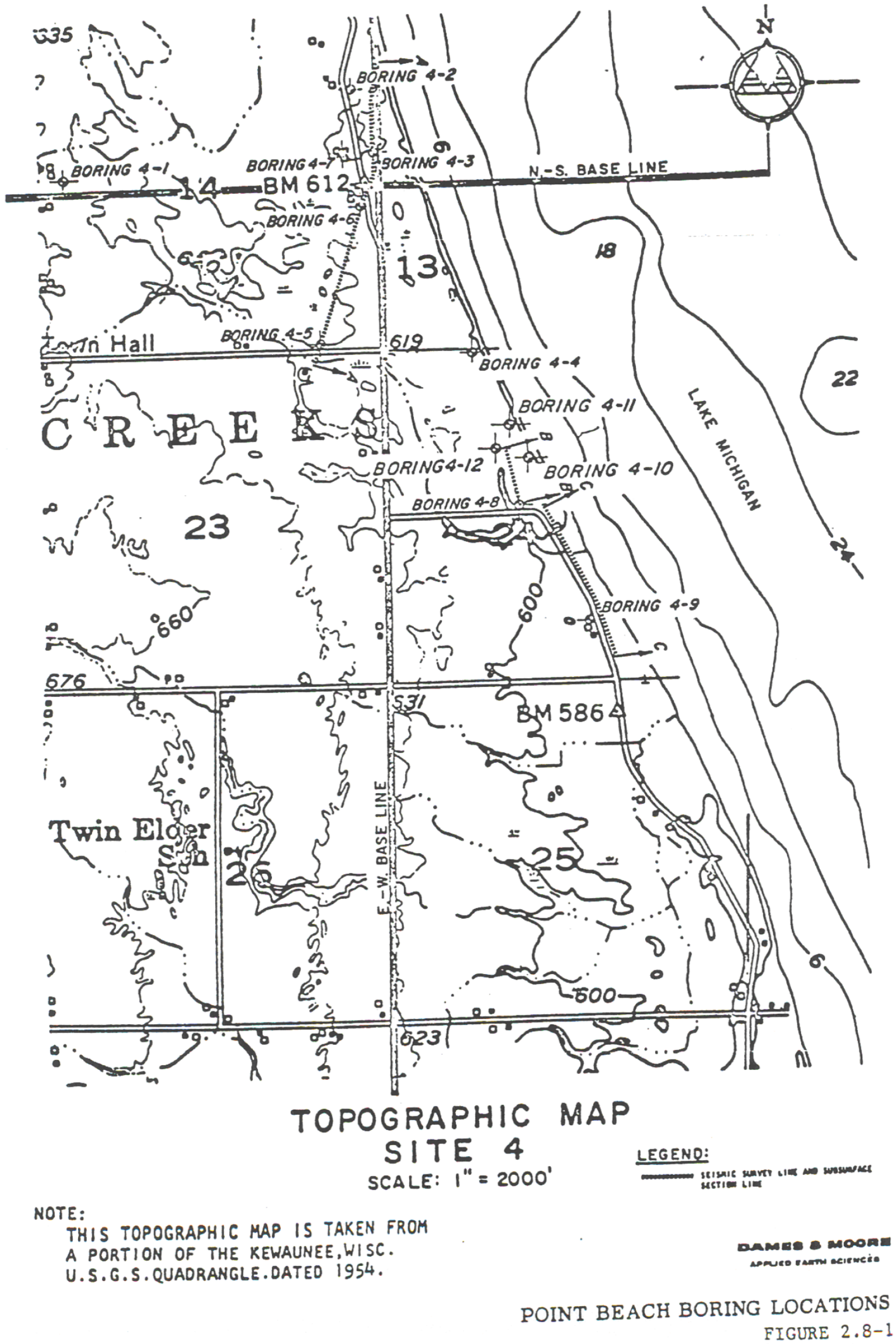


Figure 2.8-2 POINT BEACH BORING LOG

(Sheet 1 of 2)

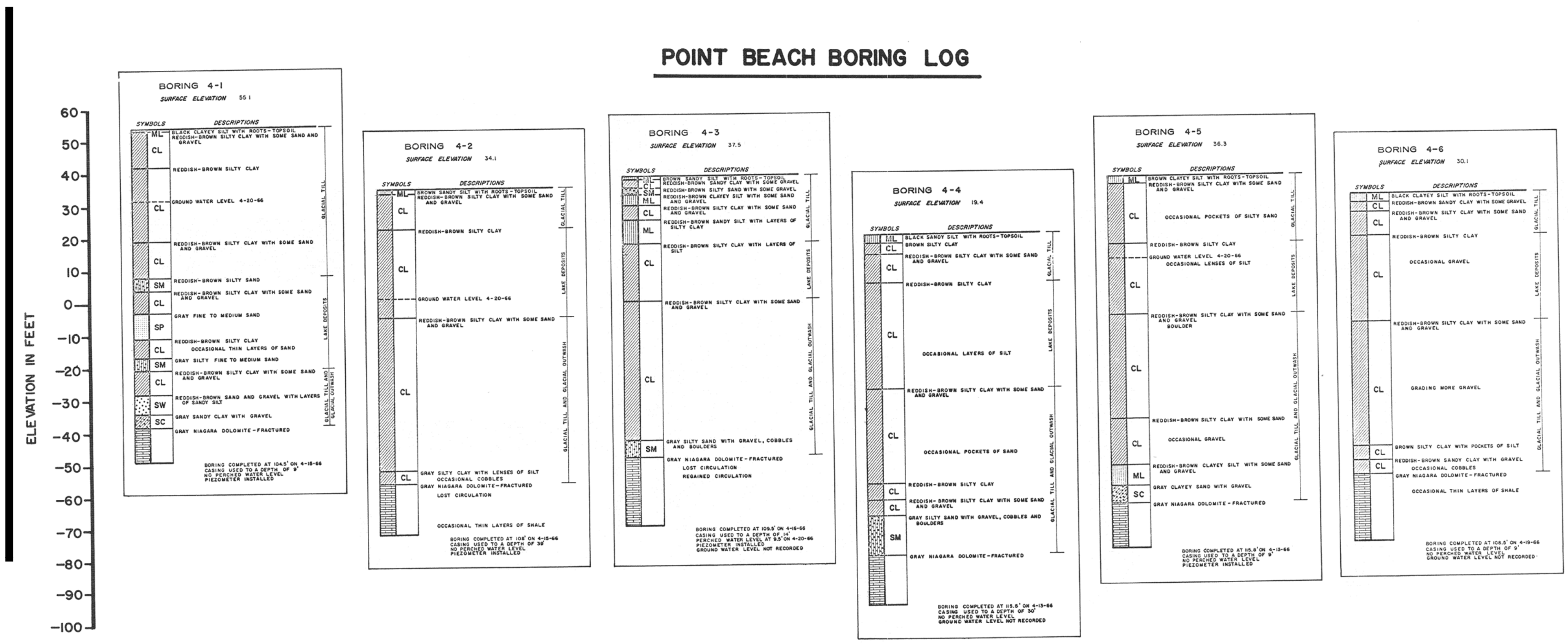
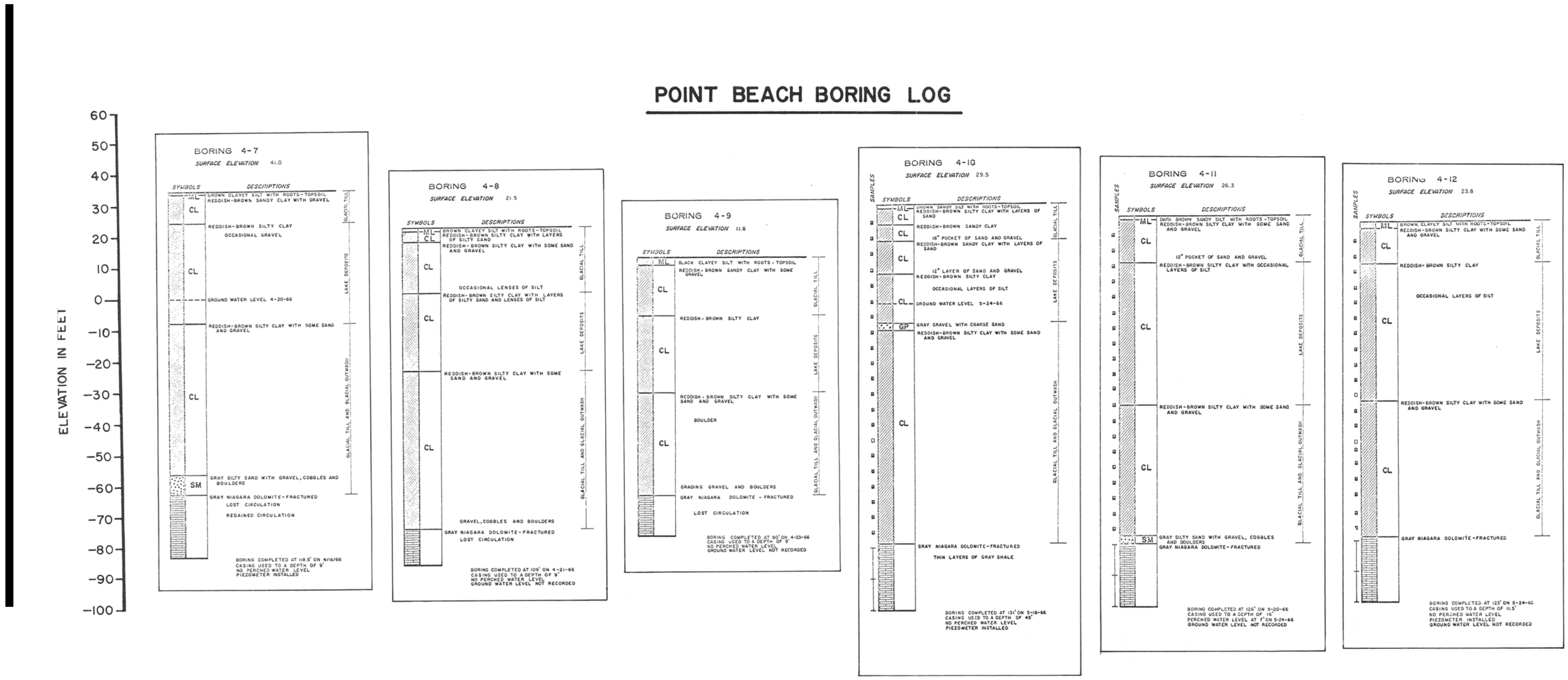


Figure 2.8-2 POINT BEACH BORING LOG

(Sheet 2 of 2)



2.9 SEISMOLOGY

A seismological program has been carried out to provide information for predicting possible seismic effects at the site. Estimates of such effects are described in this section as a basis for judging the seismic design criteria set forth in Chapter 5 and Appendix A. Field investigations have been made by Dames and Moore and are described in Appendix A of the Preliminary Safety Analysis Report for Point Beach Nuclear Plant, Unit 1, Docket No.50-266. Assessments of seismicity by John A. Blume and Associates are set forth in Appendix D of that report.

The seismic history of the region and of this area in particular is young, but a review of these data and the field investigations of Dames and Moore by John A. Blume and Associates permits the opinion that the possibility of damaging earthquakes is relatively minor. It is estimated that the maximum earthshock would produce a horizontal acceleration at the site of less than 0.06 gravity.

SEISMOLOGY PROGRAM

The following explorations were made to evaluate the seismological characteristics of the Point Beach site.

1. An investigation of the earthquake history of northcentral United States was used to develop estimates of the maximum earthquake which could affect the site. All recorded earthquakes in this region with Modified Mercalli (MM) intensity of V or greater were plotted and considered.

   Two local quakes of MM intensity IV and one of MM intensity III are also plotted. They are shown on Figure 2.9-1.

2. Investigations were made of the local and regional geology. This involved examination of drilling logs and the development of a bedrock surface profile from on-site borings, probings, and refraction survey.

DESCRIPTIVE SEISMOLOGY

The northcentral United States is a relatively inactive earthquake area. The U.S. Coast and Geodetic Survey, Seismic Probability Map of the United States assigns the area to Zone 0 - no damage. There is no instrumental or verifiable record of large intensity shocks (above MM VII) within
200 miles of the site, and there is no record of damaging earthquakes with epicenters within 100 miles of the site. Appendix D of the Unit 1 Preliminary Safety Analysis Report, Docket No. 50-266 contains a listing of the seismic history of the regions.

None of the maps presently available, including the Tectonic Map of the United States, shows the presence of faults on which the earthquakes of eastern Wisconsin may have originated. It seems highly unlikely that a regional zone of fracture of any magnitude is present but as yet unmapped. There is a strong possibility that local earthquakes are manifestations of the release of residual stresses remaining in the rock since the glacial periods. The Wisconsin drift sheet is the youngest of these, having occurred only a few thousands of years ago.

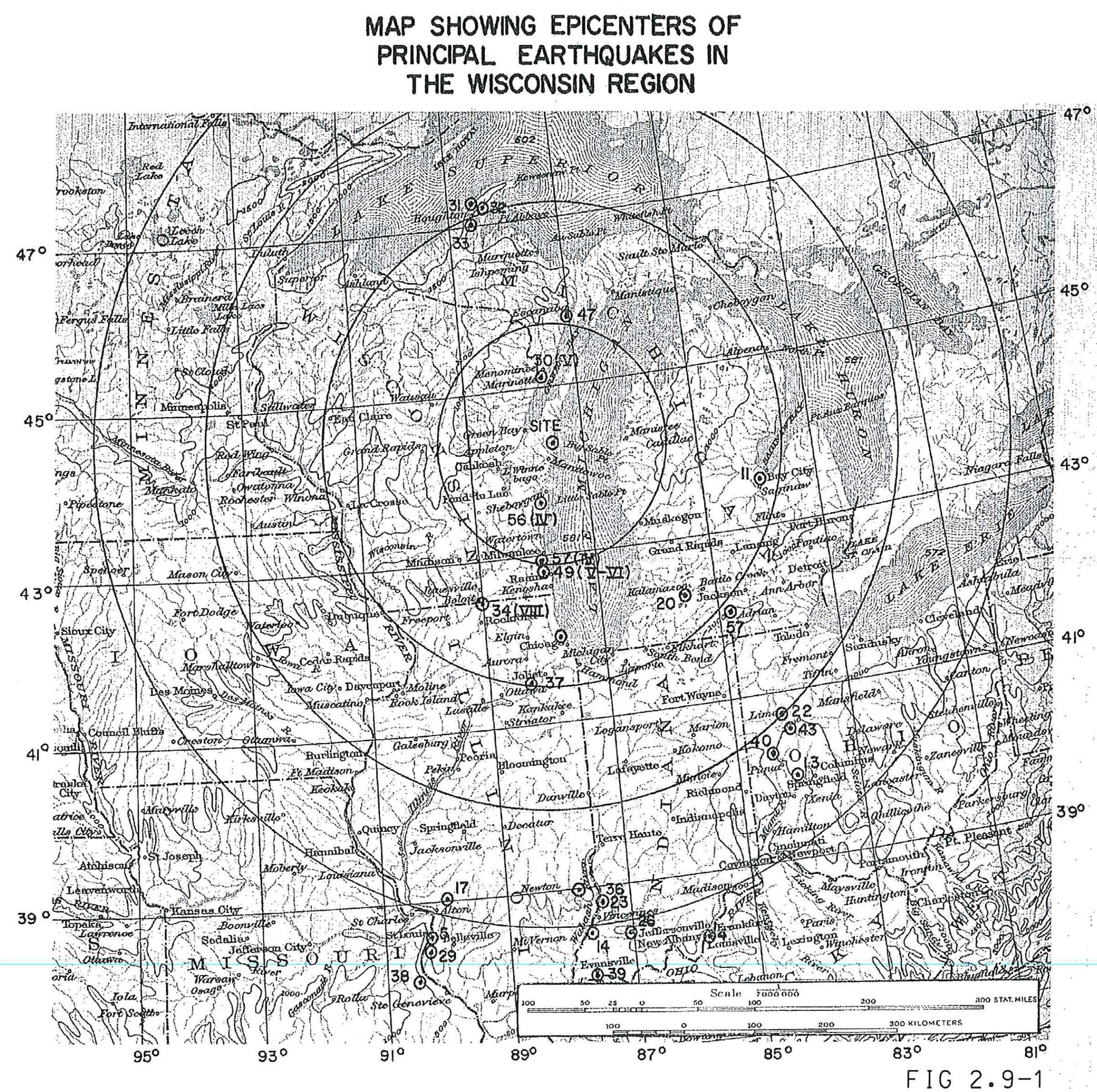
Neither the seismic history of the site nor the regional tectonics indicates that a large intensity earthquake is to be expected near the proposed site, and the large earthquakes which have occurred at great distances have had but little effect at the site.

Because the constantly operating stress-relieving mechanism suggested above may produce a small shock anywhere in the affected region, a small intensity earthquake very close to the proposed site is postulated.

A horizontal ground acceleration at the site of 0.06g combined with a vertical acceleration of 0.04g are used for the design earthquake (Operating Basis Earthquake, OBE) criteria. These accelerations are considered as acting simultaneously.

The hypothetical earthquake (Safe Shutdown Earthquake, SSE) is twice the magnitude of the design earthquake; the horizontal and vertical accelerations are considered as acting simultaneously. Components that are essential to safety are designed such that there is no loss of function due to seismic effects.

Figure 2.9-1 MAP SHOWING EPICENTERS OF PRINCIPAL EARTHQUAKES IN THE WISCONSIN REGION



2.10 ENVIRONMENTAL CONCLUSIONS

POPULATION

One factor influencing the selection of the Point Beach site was the relatively low population density around the site. Analysis of predicted population and existing roads shows that the total number and density of the residents within 5.6 miles of the site (the low population zone as defined in Section 2) is such that there is a reasonable probability that appropriate protective measures could be taken in their behalf in the event of a serious accident. The accident analysis described in Section 14 demonstrates that the offsite dose due to the maximum hypothetical accident for this low population zone is well below the 10 CFR 50.67 limit for the low population zone.

LAND USE

The land use information shows that the surrounding area is devoted to agriculture, the main products being milk or vegetables. Since these products are for human consumption, the environmental monitoring program includes milk and vegetation samples (see Section 2.7). The disposition of the residences with respect to the site at the time of application is indicated in Section 2.

HYDROLOGY

Lake Michigan is the source of plant service and cooling water. Low level liquid wastes is discharged to the lake through the condenser circulating water discharge under carefully controlled and monitored conditions. The maximum allowable concentration at the circulating water outlet does not exceed the limits of 10 CFR 20. Based on operating experience, discharges are less than about 0.03 MPC of 10 CFR 20 per year for all isotopes (Section 11). Additional dilution of any releases from the plant occurs before the water reaches the nearest public water supply intake 12 miles away. This dilution factor is 2.9×10^{-10} $\mu Ci/cm^3$ per mCi/sec for continuous release and 2.0×10^{-14} for $\mu Ci/cm^3$ per μCi for batch releases. Since it is estimated that the peak concentration at the nearest intake will occur 50 hours after a batch release, there is ample time after an accidental release to take appropriate action for the public water supplies. Sources of other nearby public water supplies are wells which lie north, south, or west of the site. Since the ground water table has a definite eastward slope (towards the lake) and the soils are relatively impervious, the possibility of contaminating any water supply by an accidental release of radioactivity on the site or nearby is remote. Furthermore, the surface waters on the site flows directly to Lake Michigan either through the storm sewer system or through the two small creeks which drain the site. The plant potable water well is periodically sampled for radioactivity as a check.

The water level in Lake Michigan is dependent on rainfall and does not vary greatly. Other than the Circulating Water Pump House (CWPH), the lowest plant elevation having drain connections to the lake is at Elevation +8.0' which is 6.3 feet above the highest level recorded to date. The CWPH has floor relief dampers at Elevation +7.0’. The existing natural drainage system now draining the site is adequate to prevent flooding of the site due to rainfall and snowmelt. Thus, there is no danger of inundating equipment due to rainfall, snow melting, or longtime variation in lake levels. Possible inundation of plant equipment due to waves or seiches is discussed in Section 2.5. Protection of the plant from ice in Lake Michigan is discussed in Section 2.5. No safety problem is expected to occur from fishing. Radioactivity in Lake Michigan is monitored as described in Section 2.7.

GEOLOGY

The Final Dames and Moore Soils Report filed with the Atomic Energy Commission on January 5,1967 as Appendix B to the APPLICATION FOR EXEMPTION UNDER SECTION 50.12 OF THE REGULATIONS OF THE AEC, indicated that the containment structure would undergo settlements of up to 2 inches relative to adjacent structures if it were placed on a mat foundation. In addition, the report indicates an ultimate soil bearing value of 15,000 lb/sq ft and recommends a safety factor of 3 for dead and permanent live loads, and a factor of safety of 2 1/ 2 for dead, live, and seismic loads in combination; the recommended design values are, therefore, 5000 and 6000 lb/sq ft, respectively.

The soil bearing loads under a containment mat and the fuel pool would have exceeded the above recommendations with no opportunity to spread the foundation to reduce bearing loads to tolerable values. Therefore, the decision was made to put the containment structure and fuel pool on piles. The differential settlements are in the order of 1/4 inch with the fuel pool and containment structure on piles. The soil bearing loads of all other structures in the plant are held to approximately 4000 lb/sq ft for dead and live loads and 5300 lb/sq ft for dead and live loads in combination with seismic or wind loads.

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CHAPTER 3 TABLE OF CONTENTS

3.0 REACTOR

NOTE: Fuel assembly design information in Section 3.1 through Section 3.4 is partially historical because cores are currently designed using only 422 VANTAGE + fuel.

The reactor utilizes a multi-region cycled core design, with fuel assemblies containing slightly enriched uranium dioxide (UO_2) fuel clad with ZIRLO® or Optimized ZIRLO™ tubing. Nuclear design data is summarized in Table 3.2-1. Thermal-hydraulic design parameters are provided in Table 3.2-4. Reactor mechanical design information is presented in Table 3.2-5.

3.1 DESIGN BASIS

3.1.1 PERFORMANCE OBJECTIVES

The construction permit for each Point Beach Unit was issued for an initial reactor power of 1396 MWt with an ultimate rating of 1518.5 MWt. In 2002, a measurement uncertainty recapture (MUR) power uprate was approved by the NRC resulting in an increased rated thermal power of 1540 MWt (Reference 3). Subsequently an extended power uprate (EPU) was approved (Reference 4) for 1800 MWt. This power operation is the basis, except where specifically noted, for all the safety evaluations in this report. Most of the Chapter 14 safety analyses bound operation at 1800 MWt, except where specifically noted. The reactor core fuel loading and programming is designed to yield an equilibrium cycle nominal burnup of approximately 19000 MWD/MTU.

In November 1984, Unit 2 began operating in its eleventh reload cycle with its first region of optimized fuel assemblies (OFA) and in June 1985, Unit 1 began operating in its thirteenth reload cycle with its first region of OFA fuel. Point Beach Unit 1 operated in Cycle 17 with its first region of upgraded OFA fuel. Point Beach Unit 2 operated Cycle 16 with its first region of upgraded OFA fuel. Natural enrichment axial blankets and Integrated Fuel Burnable Absorbers (IFBAs) began implementation with Unit 1 Cycle 19 in May 1991 and Unit 2 Cycle 18 in November 1991. Starting with Unit 1 Cycle 27 and Unit 2 Cycle 25, 14x14 0.422" VANTAGE+ assemblies, referred to as 422V+ fuel, were loaded as feed assemblies. Designs were no longer based on annual reload cycles operating with OFA fuel, but were based on 18 month cycles with OFA and 422V+ fuel. Since Unit 1 Cycle 30 and Unit 2 Cycle 28, cores have been designed using only 422V+ fuel. The reactor core can still utilize either OFA fuel, upgraded OFA fuel, or any combination of previously burned OFA, previously burned upgraded OFA, and 422V+ fuel assemblies. The original Low-Parasitic (LOPAR) fuel, also known as STD fuel, can no longer be used.

Based on the analyzed departure from nucleate boiling ratio (DNBR) limits and associated reactor control and protection system settings, the RCS must be operated at a nominal pressure of 2235 psig while 422V+ fuel assemblies are in the core.

The control rods provide sufficient control rod worth to shut the reactor down ($k_{eff} \leq 0.99$) from the hot condition at any time during cycle life with the most reactive control rod stuck in the fully withdrawn position. Redundant equipment is provided to add a soluble neutron absorber to the reactor coolant to ensure a similar shutdown capability when the reactor coolant is cooled to ambient temperatures.

Experimental measurements from critical experiments or operating reactors, or both, are used to validate the methods employed in the design. During design, nuclear parameters are calculated for every phase of operation of the respective core cycle and, where applicable, are compared with design limits to show that an adequate margin of safety exists.

In the thermal hydraulic design of the core, the maximum fuel and cladding temperatures during normal reactor operation and at design thermal overpower are evaluated conservatively and found to be consistent with safe operating limitations.

3.1.2 PRINCIPAL DESIGN CRITERIA

3.1.2.1 Reactor Core Design

Criterion: The reactor core with its related controls and protection systems shall be designed to function throughout its design lifetime without exceeding acceptable fuel damage limits which have been stipulated and justified. The core and related auxiliary system designs shall provide this integrity under all expected conditions of normal operation with appropriate margins for uncertainties and for specified transient situations which can be anticipated. (GDC 6)

The reactor core, with its related control and protection system, is designed to function throughout its design lifetime without exceeding acceptable fuel damage limits. The core design, together with reliable process and decay heat removal systems, provides for this capability under all expected conditions of normal operation with appropriate margins for uncertainties and anticipated transient situations, including the effects of the loss of reactor coolant flow (Section 14.1.8), likelihood of turbine generator unit overspeed (Section 14.1.12), loss of normal feedwater (Section 14.1.10), and loss of external electric load (Section 14.1.9).

The reactor control and protection system is designed to actuate a reactor trip for any anticipated combination of plant conditions, when necessary, to ensure a departure from nucleate boiling ratio (DNBR) equal to or greater than the limits specified for STD, OFA, upgraded OFA, or 422V+ fuel, as applicable.

The integrity of the fuel cladding is ensured by preventing excessive cladding overheating and excessive cladding stress and strain. This is achieved by designing the core so that the following conservative limits are not exceeded during normal operation or any anticipated transient condition:

1. The minimum DNBR is equal to, or greater than, the safety limit DNBR values specified for STD fuel, OFA fuel, upgraded OFA fuel, or 422V+ fuel, as applicable.

2. Fuel center temperature below melting point of UO_2.

3. The internal pressure of the lead rod in the reactor is limited to a value below that which could cause:

   a) The diametral gap to increase due to outward cladding creep during steady state operations, and

   b) Extensive departure from nucleate boiling (DNB) propagation to occur.

4. Cladding stresses less than the Zircaloy, ZIRLO® or Optimized ZIRLO™ yield strength

5. Cladding strain less than 1%.

6. Cumulative strain fatigue cycles less than 100% of design strain fatigue life.

The ability of fuel designed and operated to these criteria to withstand postulated normal and abnormal service conditions is shown by the analyses described in Chapter 14 to satisfy the demands of plant operation well within applicable regulatory limits.

The reactor coolant pumps provided for the plant are supplied with sufficient rotational inertia to maintain an adequate flow coastdown in the event of a simultaneous loss of power to all pumps. The flow coastdown inertia is sufficient such that the reduction in heat flux obtained with a low flow reactor trip prevents core damage.

In the unlikely event of a turbine trip from full power without an immediate reactor trip, the subsequent reactor coolant temperature increase and volume insurge to the pressurizer results in a high pressurizer pressure trip and thereby prevents fuel damage for this transient. A loss of external electrical load of 50% of full power or less is normally controlled by rod cluster insertion together with a controlled steam dump to the condenser to prevent a large temperature and pressure increase in the reactor coolant system and thus prevent a reactor trip. In this case, the overpower-overtemperature protection would guard against any combination of pressure, temperature, and power which during the transient could result in a DNBR less than the safety limit DNBR values specified.

In neither the turbine trip nor the loss-of-flow events do the changes in coolant conditions provoke a nuclear power excursion because of the large system thermal inertia and relatively small void fraction. Protection circuits actuated directly by the coolant conditions identified with core limits are, therefore, effective in preventing core damage.

3.1.2.2 Suppression of Power Oscillations

Criterion: The design of the reactor core with its related controls and protection systems shall ensure that power oscillations, the magnitude of which could cause damage in excess of acceptable fuel damage limits, are not possible or can be readily suppressed. (GDC 7)

The potential for possible spatial oscillations of power distribution for this core has been reviewed. In summary, the review concludes that the only potential spatial instability is the xenon-induced axial instability which may be a nearly free-running oscillation with little or no inherent damping. Initially, part-length control rods were provided to suppress these oscillations; however, experience demonstrated that full-length control rods were effective in controlling these oscillations and the part-length rods were removed and replaced with thimble plugging devices. These thimble plugs were used on STD fuel only. Out-of-core instrumentation is provided to obtain necessary information concerning axial distributions. This instrumentation is adequate to enable the operator to monitor and control xenon induced oscillations. In-core instrumentation is used to periodically calibrate and verify the axial flux information provided by the out-of-core instrumentation. The analysis, detection, and control of these oscillations is discussed in Reference 1.

The moderator temperature coefficient in the power operating range is maintained less than or equal to +5 pcm/°F below 70% power, and below zero or negative above 70% power by inclusion of IFBAs and burnable absorber rods, as needed, in the core loadings.

3.1.2.3 Redundancy of Reactivity Control

Criterion: Two independent reactivity control systems, preferably of different principles, shall be provided. (GDC 27)

Two independent reactivity control systems are provided, one involving rod cluster control assemblies (RCCAs) and the other involving the injection of a soluble poison.

3.1.2.4 Reactivity Hot Shutdown Capability

Criterion: The reactivity control systems provided shall be capable of making and holding the core subcritical from any hot standby or hot operating condition. (GDC 28)

The reactivity control systems provided are capable of making and holding the core subcritical from any hot standby or hot operating condition, including those resulting from power changes. This includes the maximum excess reactivity expected for the core, which occurs for the cold, clean condition at the beginning of life (BOL) of the initial core.

The RCCAs are divided into two categories comprising control and shutdown rod groups. The control group, used in combination with soluble poison, provides reactivity control throughout the life of the core at power conditions. This group of RCCAs is used to compensate for short term reactivity changes at power from variations in reactor power requirements or coolant temperature. The soluble poison control is used to compensate for the more slowly occurring changes in reactivity throughout core life such as those due to fuel depletion and fission product buildup and for load-follow.

Upon demand for the hot shutdown condition, insertion of both the control and shutdown groups of RCCAs will immediately make the reactor subcritical from any hot standby or hot operating condition. Subsequent injection of soluble poison can be used to assure continuation of the hot shutdown condition under all circumstances.

3.1.2.5 Reactivity Shutdown Capability

Criterion: One of the reactivity control systems provided shall be capable of making the core subcritical under any anticipated operating condition (including anticipated operational transients) sufficiently fast to prevent exceeding acceptable fuel damage limits. Shutdown margin should assure subcriticality with the most reactive control rod fully withdrawn. (GDC 29)

The reactor core, together with the reactor control and protection system, is designed so that the minimum allowable DNBR is at least equal to the limits specified for STD, OFA, upgraded OFA, or 422V+ fuel, as applicable, and there is no fuel melting during normal operation, including anticipated transients.

The shutdown groups are provided to supplement the control group of RCCAs to make the reactor at least 1% subcritical (k_{eff}= 0.99) following a trip from any credible operating condition to the hot, zero power condition assuming the most reactive RCCA remains in the fully withdrawn position.

Sufficient shutdown capability is also provided to maintain the core subcritical for the most severe anticipated cooldown transient associated with a single active failure, e.g., accidental opening of a steam bypass or safety valve stuck fully open.

The criteria of GDC 28 and 29 are met fast enough to prevent exceeding acceptable fuel damage limits, even with the most reactive control rod fully withdrawn.

3.1.2.6 Reactivity Holddown Capability

Criterion: The reactivity control systems provided shall be capable of making the core subcritical under credible accident conditions with appropriate margins for contingencies and limiting any subsequent return to power such that there will be no undue risk to the health and safety of the public. (GDC 30)

The reactivity control systems provided are capable of making and holding the core subcritical, under accident conditions, in a timely fashion with appropriate margins for contingencies. Normal reactivity shutdown capability is provided within 2.2 seconds following a trip signal by control rods with soluble neutron absorber (boric acid) injection used to compensate for the long term xenon decay transient and for plant cooldown. Any time that the reactor is at power, the quantity of boric acid retained in the boric acid storage tanks and/or the refueling water storage tank (RWST) and ready for injection always exceeds that required for the normal cold shutdown. This quantity also exceeds that required to bring the reactor to hot shutdown and to compensate for subsequent xenon decay.

Boric acid may be pumped from the boric acid tanks by one of two boric acid transfer pumps (or via gravity feed from the RWST) to the suction of one of three charging pumps which inject boric acid into the reactor coolant. Any charging pump and either boric acid transfer pump can be operated from diesel generator power on loss of outside power. Boric acid can be injected by one charging pump supplied by one boric acid transfer pump at a rate which shuts the reactor down hot with no rods inserted in less than 150 minutes. In 150 additional minutes, enough boric acid can be injected to compensate for xenon decay, although xenon decay below the equilibrium operating level does not begin until approximately fifteen hours after shutdown. If two boric acid transfer pumps are available, these time periods are reduced. Additional boric acid injection is employed if it is desired to bring the reactor to cold shutdown conditions.

On the basis of the above, the injection of boric acid is shown to afford backup reactivity shutdown capability independent of RCCAs which normally serve this function in the short term situation. Shutdown for long term and reduced temperature conditions can be accomplished with boric acid injection using redundant components, thus achieving the measure of reliability implied by the criterion.

Alternatively, boric acid solution at lower concentration can be supplied from the RWST. This solution can be transferred directly by the charging pumps. The reduced boric acid concentration lengthens the time required to achieve equivalent shutdown. For added flexibility, the safety injection pumps can also be supplied with boric acid solution from either the boric acid storage tanks or the RWST.

3.1.2.7 Reactivity Control Systems Malfunction

Criterion: The reactor protection systems shall be capable of protecting against any single malfunction of the reactivity control system, such as unplanned continuous withdrawal (not ejection or dropout) of a control rod, by limiting reactivity transients to avoid exceeding acceptable fuel damage limits. (GDC 31)

The reactor protection systems are capable of protecting against any single anticipated malfunction of the reactivity control system by limiting reactivity transients so as to avoid exceeding acceptable fuel damage limits.

Reactor shutdown with rods is completely independent of the normal rod control functions since the trip breakers completely interrupt the power to the latch type rod mechanisms regardless of existing control signals.

Details of the effects of continuous withdrawal of a control rod are described in Section 14.1.1 and Section 14.1.2. Details of the effects of continuous boron dilution are described in Section 14.1.4.

3.1.2.8 Maximum Reactivity Worth of Control Rods

Criterion: Limits, which include reasonable margin, shall be placed on the maximum reactivity worth of control rods or elements and on rates at which reactivity can be increased to ensure that the potential effects of a sudden or large change of reactivity cannot (a) rupture the reactor coolant pressure boundary or (b) disrupt the core, its support structures, or other vessel internals sufficiently to lose capability of cooling the core. (GDC 32)

Limits, which include considerable margin, are placed on the maximum reactivity worth of control rods or elements and on rates at which reactivity can be increased to ensure that the potential effects of a sudden or large reactivity change cannot (a) rupture the reactor coolant pressure boundary or (b) disrupt the core, its support structures, or other vessel internals so as to lose capability to cool the core.

The reactor control system employs control rod clusters, approximately half of which are fully withdrawn during power operation, serving as shutdown rods. The remaining rods comprise the controlling group which are used to control load and reactor coolant temperature. The rod cluster drive mechanisms are wired into preselected groups and are, therefore, prevented from being withdrawn in other than their respective groups. The rod drive mechanism is of the magnetic latch type and the coil actuation is sequenced to provide variable speed rod travel.

The maximum positive reactivity insertion rate assumed in the detailed plant analysis is greater than that for the simultaneous withdrawal of the combination of the two sequential control banks having the greatest combined worth at maximum speed. The resultant reactivity insertion rates are well within the capability of the overpower-overtemperature protection circuits to prevent core damage.

No credible mechanical or electrical control system malfunction can cause a rod cluster to be withdrawn at a speed greater than 72 steps per minute (45 inches per minute).

3.1.3 SAFETY LIMITS

The reactor is capable of meeting the performance objectives throughout core life under both steady state and transient conditions without violating the integrity of the fuel cladding. Thus, the release of unacceptable amounts of fission products to the coolant is prevented.

The limiting conditions for operation specify the highest functional capability or performance levels permitted to assure safe operation of the facility.

Design parameters which are established by safety limits are specified below for the nuclear, reactivity control, thermal and hydraulic, and mechanical aspects of the design.

3.1.3.1 Nuclear Limits

At a full power level of 1800 MWt, the nuclear heat flux hot channel factor, $F^N{}_q$, specified in Table 3.2-4 is not exceeded.

The nuclear axial peaking factor, $F^N{}_Z$, and the nuclear enthalpy rise hot channel factor, $F^N{}_{\Delta H}$, are limited in their combined relationship so as not to exceed the $F^N{}_q$ or DNBR limits. The effects of fuel densification and rod bow are taken into account.

The limiting nuclear hot channel factors are higher than those calculated at full power for the range from all control rods fully withdrawn to maximum allowable control rod insertion. Control rod insertion limits as a function of power are delineated in the Technical Specifications to ensure that despite differences in control rod insertion the DNBR is always greater at part power than at full power.

Axial xenon oscillations are monitored and controlled with the control rods to preclude adverse core conditions. The protection system ensures that the nuclear core limits are not exceeded.

3.1.3.2 Reactivity Control Limits

The control system and the operational procedures provide adequate control of the core reactivity and power distribution. The following control limits are met:

1. Sufficient control is available to produce a hot shutdown margin of at least that required in the Core Operating Limits Report (COLR), (Reference 2).
2. The shutdown margin is maintained with the most reactive RCCA stuck in the fully withdrawn position.
3. The shutdown margin is maintained at ambient temperature by the use of soluble neutron absorber.

3.1.3.3 Thermal and Hydraulic Limits

The reactor core is designed to meet the following limiting thermal and hydraulic criteria:

1. The minimum allowable DNBR during normal operation, including anticipated transients, is the DNBR for which DNB will not occur with a 95% probability at a 95% confidence level.

2. No fuel melting during any anticipated normal operating condition.

To maintain fuel rod integrity and prevent fission product release, it is necessary to prevent cladding overheating under all operating conditions. This is accomplished by preventing a DNB which causes a large decrease in the heat transfer coefficient between the fuel rods and the reactor coolant, resulting in high cladding temperatures.

Considering plant parameter uncertainties, there must be at least a 95 percent probability that the minimum DNBR of the limiting power rod during Condition I and II events is greater than or equal to the DNBR limit of the DNB correlation being used. The DNBR limit for the correlation is established based on the variance of the correlation such that there is a 95 percent probability with 95 percent confidence that DNB will not occur when the calculated DNBR is at the DNBR limit.

DNB is not, however, an observable parameter during reactor operation. Therefore, the observable parameters, reactor power, reactor coolant temperature, and pressure have been related to DNB through the W3 DNB correlation for STD fuel and the WRB-1 DNB correlation for OFA fuel, upgraded OFA fuel, and 422V+. Curves presented in Reference 2 represent the loci of points of reactor power, reactor coolant pressure, and average temperature for which the DNBR is less than the limit specified for STD, OFA, or 422V+ fuel, as applicable. The area of safe operation is the lower average temperatures and higher reactor coolant pressures limited by one specified curve of the reactor power parameter family of curves shown. The parameters used in the development of the curves were checked in the course of initial startup tests and are modified as necessary.

3.1.3.4 Mechanical Limits-Reactor Internals

The reactor internal components are designed to withstand the stresses resulting from startup, steady state operation with any number of pumps running, and shutdown conditions. No damage to the reactor internals occurs as a result of loss of pumping power.

Lateral deflection and torsional rotation of the lower end of the core barrel are limited to prevent excessive movements resulting from seismic disturbances and thus prevent interference with RCCAs. Core drop in the event of failure of the normal supports is limited so that the RCCAs do not disengage from the fuel assembly guide thimbles.

The structural internals are designed to maintain their functional integrity in the event of a major loss-of-coolant accident. The dynamic loading resulting from the pressure oscillations because of a loss-of-coolant accident does not prevent RCCA insertion even during an earthquake.

3.1.3.5 Fuel Assemblies

The fuel assemblies are designed to perform satisfactorily throughout their lifetime. The loads, stresses, and strains resulting from the combined effects of flow induced vibrations, earthquakes, reactor pressure, fission gas pressure, fuel growth, thermal strain, and differential expansion during both steady state and transient reactor operating conditions have been considered in the design of the fuel rods and fuel assembly. The assembly is also structurally designed to withstand handling and shipping loads prior to irradiation and to maintain sufficient integrity at the completion of design burnup to permit safe removal from the core and subsequent handling during cooldown, shipment, and fuel reprocessing or storage.

The fuel rods are supported at several locations along their length within the fuel assemblies by grid assemblies which are designed to maintain control of the lateral spacing between the rods throughout the design life of the assemblies. The magnitude of the support loads provided by the grids are established to minimize possible fretting without overstressing the cladding at the points of contact between the grids and fuel rods. The grid assemblies also allow axial thermal expansion of the fuel rods without imposing restraint of sufficient magnitude to result in buckling or distortion of the rods.

The fuel rod cladding is designed to withstand operating pressure loads without collapse or rupture and to maintain encapsulation of the fuel throughout the design life.

3.1.3.6 Rod Cluster Control Assemblies (RCCAs)

The criteria used for the design of the cladding on the individual absorber rods in the RCCAs are similar to those used for the fuel rod cladding. The stainless steel cladding is designed to be free standing under all operating conditions and will maintain encapsulation of the absorber material throughout the absorber rod design life. Allowance for wear during operation is included in the RCCA cladding thickness. The EP-RCCA (Enhanced Performance RCCA) has all the features described and also has full length chrome plating to reduce guide card wear and reduced tip absorber diameter to alleviate tip swelling and cracking.

Adequate clearance is provided between the absorber rods and the guide thimbles, which position the rods within the fuel assemblies so that coolant flow along the length of the absorber rods is sufficient to remove the heat generated, thereby preventing overheating of the absorber cladding. The clearance is also sufficient to compensate for any misalignment between the absorber rods and guide thimbles and to prevent mechanical interference between the rods and guide thimbles under any operating conditions.

3.1.3.7 Control Rod Drive Assembly

Each control rod drive assembly is designed as a hermetically sealed unit to prevent leakage of reactor coolant water. All pressure containing components are designed to meet the requirements of the ASME Code, Section III, Class 1, 1998 Edition through 2000 Addenda.

The control rod drive assemblies provide RCCA insertion and withdrawal rates consistent with the required reactivity changes for reactor operational load changes. This rate is based on the worths of the various rod groups which are established to limit power peaking flux patterns to design values. The maximum reactivity addition rate is specified to limit the magnitude of a possible nuclear excursion resulting from a control system or operator malfunction.

Also, the control rod drive assemblies provide a fast insertion rate during a "trip" of the RCCAs which results in a rapid shutdown of the reactor for conditions that cannot be handled by the reactor control system. This rate is based on the results of various reactor emergency analyses, including instrument and control delay times and the amount of reactivity that must be inserted before deceleration of the RCCA occurs.

REFERENCES

1. "Nuclear Design of Westinghouse Pressurized Water Reactor with Burnable Poison Rods," WCAP-9000 (Proprietary), 1968.

2. Point Beach Nuclear Plant Technical Requirements Manual (TRM) 2.1, Core Operating Limits Reports (COLRs) for Unit 1 and Unit 2."

3. NRC Safety Evaluation dated November 29, 2002, "Issuance of Amendments Re: Measurement Uncertainty Recapture Power Uprate (TAC Nos. MB4956 and MB4957)."

4. NRC Safety Evaluation dated May 3, 2011, "Issuance of License Amendments Regarding Extended Power Uprate (TAC Nos. ME1044 and ME1045)."

3.2 REACTOR DESIGN

3.2.1 NUCLEAR DESIGN AND EVALUATION

This section presents the nuclear characteristics of the core and an evaluation of the characteristics and design parameters which are significant to design objectives. The capability of the reactor to achieve these objectives while performing safely under operational modes, including both transient and steady state, is demonstrated.

Four fuel designs are considered in this section: the standard (STD) 14x14 fuel assembly; the 14x14 optimized fuel assembly (OFA); the upgraded OFA 14x14 assembly; and the 14x14 422 VANTAGE+ fuel assembly (422V+). The reload core may contain part-length hafnium absorber rods in peripheral assemblies to reduce the fast neutron flux at the reactor vessel walls. The upgraded OFA assembly includes a removable top nozzle (RTN) with high burnup enhancements and a debris filter bottom nozzle (DFBN), and may include the addition of Integral Fuel Burnable Absorber (IFBA) fuel rods and six-inch axial blankets, utilizing natural UO_2 at the top and bottom of the fuel stack. The 422V+ assembly includes the same features as the upgraded OFA assembly. Key differences between the upgraded OFA and 422V+ assemblies are the increased fuel rod and instrumentation tube OD (0.422") and a slight reduction (0.75") in the enriched (non-blanketed) portion of the fuel pellet stack. Additionally, the 422V+ assemblies include ZIRLO® or Optimized ZIRLO™ cladding and structural material, mid-enriched annular pellets in axial blankets of between 6 and 8 inches in length, and an increased B-10 loading for the IFBA fuel rods. These upgrade features, along with a low-low leakage loading pattern, maintain radial and axial neutron leakage and improve fuel economy. Since Unit 1 Cycle 30 and Unit 2 Cycle 28 cores have been designed using only 422V+ fuel.

Burnable absorber rods in RCC guide thimble tubes are no longer used and description of their design and use is retained for historical purposes.

3.2.1.1 Reactivity Control

Reactivity control is provided by:

1. A soluble chemical neutron absorber, boric acid, in the reactor coolant (chemical shim).
2. Movable neutron absorbing control rods, or rod cluster control assemblies (RCCAs).
3. Fixed burnable or non-burnable absorber rods, as specified in the respective cycle core design.

For the upgraded OFA assemblies, introduced into the Unit 1 Cycle 17 core and Unit 2 Cycle 16 core, and 422V+ assemblies, introduced into the Unit 1 Cycle 27 core and Unit 2 Cycle 25 core, the nuclear design analyses and evaluations allow the use of IFBA rods and axial blankets.

The concentration of boric acid is varied as necessary during the life of the core to compensate for:

1. Changes in reactivity which occur with the change in temperature of the reactor coolant from cold shutdown to the hot operating, zero power conditions.

2. Changes in reactivity associated with changes in concentration of the fission product absorbers xenon and samarium.

3. Reactivity losses associated with the depletion of fissile inventory and buildup of long-lived fission product absorbers other than xenon and samarium.

4. Changes in reactivity due to burnable absorber depletion.

5. Load-follow operation.

The control rods provide reactivity control for:

1. Fast shutdown.

2. Reactivity changes associated with changes in the average coolant temperature above hot zero power (core average coolant temperature is increased with power level).

3. Reactivity associated with any void formation.

4. Reactivity changes associated with the power coefficient of reactivity.

The rods are divided into two categories according to their function. The rods which compensate for changes in reactivity due to variations in operating conditions of the reactor, such as power or temperature, comprise the control group of rods. The other rods provide additional shutdown reactivity and are termed shutdown rods. The total shutdown worth of all the rods is specified to provide adequate shutdown with the most reactive rod stuck out of the core.

The burnable absorber rods provide control of part of the excess reactivity available. By using specific placement, fresh and depleted burnable absorber rods serve to reduce peaking factors and maintain the moderator temperature coefficient within limits. IFBA rods contain a stack of fuel pellets coated with a thin boron absorber compound. The IFBA is described and evaluated in Sections 2.4 and 2.5 of Reference 7.

3.2.1.2 Nuclear Design Data - Core Reactivity Characteristics

A summary of nuclear design data including core reactivity characteristics for full STD cores, reload OFA and upgraded OFA cores, and reload 422V+ cores is presented in Table 3.2-1. Discussion of the table is facilitated by numbering the lines. In addition, a summary of reactivity requirements and control rod worths is given in Table 3.2-2 and Table 3.2-3 which may be used in conjunction with Table 3.2-1.

A tabulation of general structural characteristics for 422V+, OFA and STD fuel is given in lines 1 through 10 of Table 3.2-1, while performance characteristics are listed in lines 11 through 19. Values of effective neutron multiplication constants and critical boron concentrations for the first core, equilibrium cycle OFA cores, and equilibrium cycle 422V+ cores are listed for specified conditions in lines 20 through 37. Several of these items, such as shim control, are discussed in greater detail below. The values provided are typical. Values for key parameters are determined for each reload design.

Control to render the reactor subcritical at temperatures below the operating range is provided by chemical shim. The boron concentration during refueling, reported in line 28 of Table 3.2-1, together with the control rods, provides approximately a 5% shutdown margin for these operations. The concentration is also sufficient to maintain the core subcritical (k = 0.99) without any RCCAs during refueling. For cold shutdown at the beginning of core life, Table 3.2-1 line 36 shows a concentration sufficient for a 1% shutdown margin with all but one stuck rod inserted. The boron concentration for refueling is equivalent to less than 2% by weight boric acid (H_3BO_3) and is well within solubility limits at ambient temperature. This concentration is comparable to the range of boron concentration maintained in the spent fuel pool. The effects of different concentrations are acceptable even when the reactor coolant is directly connected with the refueling canal during refueling operations (Reference 12).

The initial and equilibrium core full power boron concentration without equilibrium xenon and samarium is shown in Table 3.2-1 line 33. As these fission product poisons are built up, the boron concentration is reduced. The initial boron concentration is that which permits the positioning of the control banks at their operational limits. The xenon-free, zero power shutdown (k = 0.99) with all but one stuck rod inserted, must be maintained with the boron concentrations shown in lines 36 and 37 for the cold and hot conditions, respectively.

The chemical shim concentrations discussed above are those used when burnable absorber rods are present in the initial core, as listed in Table 3.2-1 lines 38, 39 and 40. Likewise, kinetic characteristics are dependent upon boron concentrations, presence of burnable absorbers, and control rods. Equivalent values are calculated for each reload core design.

3.2.1.3 Kinetic Characteristics

The response of the reactor core to plant conditions or operator adjustments during normal operation, as well as the response during abnormal or accidental transients, is evaluated by means of a detailed plant simulation. In these calculations, reactivity coefficients are required to couple the response of the core neutron multiplication to the variables which are set by conditions external to the core. Since the reactivity coefficients change during the life of the core, a range of coefficients is established to determine the response of the plant throughout life and to establish the design of the reactor control and protection system.

3.2.1.4 Moderator Temperature Coefficient of Reactivity

The moderator temperature coefficient in a core controlled by chemical shim is less negative than the coefficient in an equivalent rodded core. One reason is that control rods contribute a negative increment to the coefficient and, in a chemical shim core, the rods are only partially inserted. Also, the chemical absorber density is decreased with the water density upon an increase in temperature. This gives rise to a positive component of the moderator temperature coefficient due to the boron being removed from the core. This component is directly proportional to the amount of reactivity controlled by the soluble absorber.

To reduce the dissolved absorber requirement for control of excess reactivity, burnable absorber rods can be incorporated in the core design. The result is that changes in the coolant density will have less effect on the density of absorber and the moderator temperature coefficient will be more negative.

The fixed discrete burnable absorber is in the form of borated pyrex glass rods clad in stainless steel. Clusters of these rods are distributed throughout the core in vacant rod cluster control guide thimbles. As an example, the initial core pattern is shown in Figure 3.2-5 and Figure 3.2-6 on a gross core and assembly-wise basis, respectively. Information regarding research, development, and nuclear evaluation of the discrete burnable absorber rods can be found in Reference 1 and Reference 2. The number of rods and the corresponding reactivity worths for the initial core are indicated in lines 38, 39, and 40 of Table 3.2-1.

The IFBA fuel rods are distributed in selective upgraded OFAs and 422V+ assemblies to control peaking factors and to reduce the moderator temperature coefficient. The length of the boron burnable absorber coating in the enriched fuel stack may vary from assembly to assembly and cycle to cycle. As a part of the contraints to ensure sub-criticality in the spent fuel pool, as discussed in Section 9.4.1, there are some restrictions in the IFBA patterns used for reactivity control during the core design process. Allowable IFBA patterns of 52 or less IFBA pins are identified in Reference 51, Figure 3-5. IFBA patterns of 52 or less IFBA pins other than those shown in Reference 51 require a 10 CFR 50.59 evaluation to validate that the conclusions from the criticality analysis remain unchanged. Such an evaluation was performed in Reference 52 and Reference 53 to document the acceptability of additional IFBA patterns, less than 52 pins, which can be credited for storage in the Point Beach spent fuel pool. Any IFBA loadings with more than 52 pins per assembly up to 120 are allowed with no IFBA pattern restrictions (Reference 54). In addition, allowable IFBA length must be 120 inches or greater and poison loading must be equal to or greater than 1.0X IFBA (e.g., 1.5X, 2.0X, etc), as identified in Reference 51.

The moderator temperature coefficient becomes more negative with increasing burnup, resulting from buildup of plutonium and fission products and dilution of the boric acid concentration. The reactivity loss due to equilibrium xenon is also controlled by soluble boron. As xenon builds up, boron is taken out. The range of the calculated net unrodded moderator temperature coefficient is shown in Table 3.2-1 line 41.

The control rods provide a negative contribution to the moderator coefficient as illustrated in Figure 3.2-17.

3.2.1.5 Moderator Pressure Coefficient of Reactivity

The moderator pressure coefficient is positive at plant operating conditions. Its effect on core reactivity and stability is small because of the small magnitude of the pressure coefficient.

3.2.1.6 Moderator Density Coefficient of Reactivity

A uniform moderator density coefficient is defined as a change in the neutron multiplication per unit change in moderator density. The range of the moderator density coefficient from BOL to EOL is specified in Table 3.2-1, line 43.

3.2.1.7 Fuel Temperature (Doppler) Coefficient

The fuel temperature (Doppler) coefficient is defined as the change in reactivity per degree change in effective fuel temperature and is primarily a measure of the Doppler broadening of

U-238 and Pu-240 resonance absorption peaks. Doppler broadening of other isotopes such as U-236, Np-237 etc. are also considered but their contributions to the overall Doppler effect is negligible. An increase in fuel temperature increases the effective resonance absorption cross sections of the fuel and produces a corresponding reduction in reactivity.

The fuel temperature coefficient is calculated by performing two-group three dimensional calculations using the ANC code (Reference 11). Moderator temperature is held constant and the power level is varied. Spatial variation of fuel temperature is taken into account by calculating the effective fuel temperature as a function of power density.

The Doppler temperature coefficient is shown in Figure 3.2-18 as a function of the effective fuel temperature (at beginning-of-life (BOL) conditions). The effective fuel temperature is lower than the volume averaged fuel temperature since the neutron flux distribution is non-uniform through the pellet and gives preferential weight to the surface temperature. The Doppler-only contribution to the power coefficient, defined later, is shown in Figure 3.2-19 as a function of relative core power.

3.2.1.8 Power Coefficient

The combined effect of moderator temperature and fuel temperature change as the core power level changes is called the total power coefficient and is expressed in terms of reactivity change per percent power change. The typical power coefficient at BOL conditions is given in Figure 3.2-20.

It becomes more negative with core life reflecting the combined effect of moderator and fuel temperature coefficients with fuel depletion.

3.2.1.9 Summary of Control Rod Requirements

Control rod reactivity requirements at BOL and EOL are summarized in Table 3.2-2. The installed worth of the control rods is shown in Table 3.2-3. The difference is available for excess shutdown upon reactor trip.

The control rods are required to provide sufficient reactivity to account for the power defect from full power to zero power and to provide the required shutdown margin. The reactivity addition resulting from power reduction consists of contributions from Doppler, variable average moderator temperature, flux redistribution, and reduction in void content as discussed below.

3.2.1.10 Doppler

The Doppler effect arises from the broadening of U-238 and Pu-240 resonance peaks with an increase in effective pellet temperature. This effect is most noticeable over the range of zero power to full power due to the large pellet temperature increase with power generation.

3.2.1.11 Variable Average Moderator Temperature

When the core is shutdown to the hot, zero power condition, the average moderator temperature changes from the equilibrium full load value determined by the steam generator and turbine characteristics (steam pressure, heat transfer, tube fouling, etc.) to the equilibrium no load value, which is based on the steam generator shell side design pressure. The design change in temperature is conservatively increased by 4°F to account for the control dead band and measurement errors.

Since the moderator coefficient is usually negative (may be positive up to 70% power at or near BOL), there is a reactivity addition with power reduction. The moderator coefficient becomes more negative as the fuel depletes because the boron concentration is reduced. This effect is the major contributor to the increased requirement for control rod reactivity at EOL.

3.2.1.12 Redistribution

During full power operation the coolant density decreases with core height, and this, together with partial insertion of control rods, results in less fuel depletion near the top of the core. Under steady state conditions, the relative power distribution will be slightly asymmetric towards the bottom of the core. On the other hand, at hot zero power conditions, the coolant density is uniform up the core, and there is no flattening due to Doppler. The result will be a flux distribution which at zero power can be skewed toward the top of the core. The reactivity insertion due to the skewed distribution is calculated with an allowance for the most adverse effects of xenon distribution.

3.2.1.13 Void Content

A small void content in the core is due to nucleate boiling at full power. The void collapse coincident with power reduction makes a small reactivity contribution.

3.2.1.14 Rod Insertion Allowance

At full power, the control bank is operated within a prescribed band of travel to compensate for small periodic changes in boron concentration, changes in temperature and very small changes in the xenon concentration not compensated for by a change in boron concentration. When the control bank reaches either limit of this band, a change in boron concentration is required to compensate for additional reactivity changes. Since the insertion limit is set by a rod travel limit, a conservatively high calculation of the inserted worth is made which exceeds the normally inserted reactivity.

3.2.1.15 Xenon Stability Control

This 121-assembly core is too small to experience azimuthal, radial, or diametral xenon oscillations. Although minimal xenon oscillations may be experienced in the axial direction, experience has demonstrated these oscillations can be controlled with the normal control rods. Consequently, no extra rods are needed or provided to mitigate such spatial transients.

3.2.1.16 Excess Reactivity Insertion Upon Reactor Trip

The control requirements are nominally based on providing an amount of excess reactivity insertion upon a reactor trip sufficient to obtain the shutdown margin required by the COLR.

3.2.1.17 Calculated Rod Worths

The compliment of 33 control rods is arranged as shown in Figure 3.2-1. Table 3.2-3 lists the calculated worths of this rod configuration for BOL and EOL. In order to be sure of maintaining a conservative margin between calculated and required rod worths, the calculated reactivity worths listed are decreased in the design by 7 to 10% (as defined by the reload specific design) to account for any errors or uncertainties in the calculation. This worth is established for the condition that the highest worth rod is stuck in the fully withdrawn position. A comparison between calculated and measured rod worths in operating reactors has shown the calculations to be well within the allowed uncertainty of 7%.

3.2.1.18 Reactor Core Power Distribution

In order to meet the performance objectives without violating safety limits, the peak to average power density must be within the limits set by the nuclear hot channel factors. For the peak power point in the core at rated power, the nuclear heat flux hot channel factor, F^N_q, was established as specified in Table 3.2-1, line 18. For the hottest channel at rated power, the nuclear enthalpy rise hot channel factor, $F^N_{\Delta H}$, was established as specified in Table 3.2-1, line 19.

Power capability of a PWR core is determined largely by consideration of the power distribution and its interrelationship to limiting conditions involving:

1. The linear power density.

2. The fuel cladding integrity.

3. The enthalpy rise of the coolant.

To determine the core power capability, local as well as gross core neutron flux distributions have been determined for various operating conditions at different times in core life. Allowance for the effect of fuel densification has been made in the design (Reference 2, Reference 3, and Reference 32). The effects of rod bow on DNB have been taken into account and appropriate design penalties have been imposed.

The presence of control rods, burnable absorber rods, and chemical shim concentration all play significant roles in establishing the fission power distribution, in addition to the influence of thermal-hydraulic and temperature feedback considerations. The computer programs used to determine neutron flux distributions include a model to simulate nonuniform water and chemical shim density distributions.

Thermal-hydraulic feedback considerations are especially important late in cycle life where the magnitude of the flux redistribution and reactivity change with change in core power or rod movement are strongly influenced by enthalpy rise up the core and by the fuel burnup distribution. Consequently, extensive X, Y and Z power distribution analyses have been performed to evaluate fission power distributions. In-core instrumentation is employed to evaluate the core power distributions throughout core lifetime to assure that the thermal design criteria are met.

The control system for axial power distribution control is based on manual operation and the use of Constant Axial Offset Control (CAOC) analysis methodology (Reference 8, Reference 9 and Reference 10). Administrative procedures, alarms, and automatic rod stops guide the operator in performing these tasks.

The out-of-core nuclear instrumentation system supplies the necessary information for the operator to control the core power distribution within the limits established for the protection system design. This information consists of recorders for the long ion chambers which display the upper and lower ion chamber currents and indicators which give the difference in these two currents for each long ion chamber. The ion chamber currents to the recorders and indicators are calibrated against the in-core power distribution generated in the adjacent section of the core as obtained from the movable detector system. This essentially divides the core into eight sections, four in the upper half and four in the lower half, and the operator manually positions the rods to maintain a prescribed relationship between the power generated in the upper and lower sections of the core.

The relationship between core power distribution and out-of-core nuclear instrumentation readings was established during the startup testing program. In-core flux measurements were made over the range of relative positions between control banks for reactor power in the range of 25% to 100%. These measurements, together with long ion chamber currents, were processed to yield the relationships between core average axial power generation, the axial peak factor, and axial offset as indicated by the out-of-core nuclear instrumentation. These relationships were then checked during operation to assess the effect of core burnup on the sensitivity between in-core power distribution and out-of-core readings.

The reactor core is subject to axial xenon oscillations at the end of a fuel cycle life. The axial instability is due principally to the negative moderator temperature coefficient of reactivity which exists at EOL. Since the moderator coefficient at BOL is small, the core is stable with respect to axial oscillations at BOL.

Figure 3.2-2 through Figure 3.2-4 show the radial power distributions in various planes of one quarter of the initial core at BOL. Figure 3.2-7 illustrates a typical reload pattern (OFA or STD assemblies) with four fuel regions. Figure 3.2-8 shows a typical BOL assembly burnup distribution for a low-low leakage loading pattern with an upgraded OFA reload. The location and number of IFBA rods is shown. Figure 3.2-9 through Figure 3.2-12 show the radial power distributions in various planes of one quarter of a typical reload core with a full OFA loading at BOL and EOL conditions. For the full upgraded OFA Core, Figure 3.2-13 through Figure 3.2-14a show typical radial power distributions at BOL and EOL conditions. For a full 422V+ core, Figure 3.2-15 and Figure 3.2-16 illustrate a typical core loading power distribution. The upgraded OFA and 422V+ cores may contain IFBAs, axial blankets, and part-length hafnium rods in peripheral assemblies.

A more detailed discussion of the background, and both the analytical and experimental data which forms the basis for this approach is given in Reference 4.

3.2.1.19 Analytical Methods

Calculations required in nuclear design consist of three distinct types which are performed in sequence:

1. determination of effective fuel temperatures for Doppler cross section calculation
2. generation of macroscopic few-group parameters
3. space-dependent, few-group diffusion calculations

These calculations have been performed using the PHOENIX-P and ANC computer codes (Reference 11 and Reference 33). Beginning with Unit 1 Cycle 37 and Unit 2 Cycle 36, PARAGON (Reference 55) computer code was implemented in the reload design analysis. PARAGON is a two-dimensional transport theory based code that calculates lattice physics constants. These are the same methods and models that have been used in several Westinghouse reload cycle designs. PARAGON can be used as a standalone or as a direct replacement for the previously licensed Westinghouse PWR PHOENIX-P lattice codes as approved by the NRC in Reference 55.

3.2.1.20 Fuel Temperature (Doppler) Calculations

Temperatures vary radially within the fuel rod, depending on the heat generation rate in the pellet, the conductivity of the materials in the pellet, gap, and cladding, and the temperature of the coolant.

Calculation of fuel pellet temperatures for Doppler cross section calculations is performed by the FIGHT-H computer code. PHOENIX-P and PARAGON incorporates, in their depletion, the same FIGHT-H fuel temperature calculational model used in the present Westinghouse design methodology. The FIGHT-H model includes radial variations of heat generation rate, thermal conductivity, and thermal expansion in the fuel pellet, elastic deflection of the cladding, and a pellet-clad gap conductance which depends on the kind of initial fill gas, the hot open gap dimension, and the fraction of the pellet circumference over which the gap is effectively closed due to pellet cracking. The steady-state radial temperature distribution in the fuel rod is calculated at a specified burnup, given the local value of the linear heat generation rate in the pellet and the moderator temperature and flow rate. The effective resonance temperatures of U-238 and Pu-240 are obtained by appropriate radial weighting of the temperature distribution, and used by PHOENIX-P and PARAGON in their depletion calculations.

3.2.1.21 Macroscopic Group Constants

Macroscopic few-group constants and analogous microscopic cross sections (needed for feedback and microscopic depletion analysis) are generated by PHOENIX-P or PARAGON (Reference 33 and Reference 55). PHOENIX-P is a two dimensional, multi-group transport theory code which has been approved by the USNRC. The nuclear cross section library used by PHOENIX-P contains cross section data based on multiple energy-group structure. The solution of the flux distribution is divided into two major steps in PHOENIX-P:

1. Solve for two-dimensional, multiple energy-group nodal fluxes which couple individual subcell regions (pellet, clad, moderator) as well as surrounding pins using a method based on collision probabilities and heterogeneous response flux.

2. Solve for a coarse energy-group flux distribution using a standard S4 discrete ordinates calculation and use these fluxes to normalize the detailed multiple energy group nodal fluxes from step 1.

PARAGON is a two dimensional, multi-group neutron (and Gamma) transport theory code which has been approved by the NRC. PARAGON contains cross-section data based on multiple energy-group structure. The PARAGON flux solver is based on Collision Probability theory and interface current coupling methods. The code uses the cross-section library group structure in all calculation steps (resonance self-shielding, flux solution, homogenization, and burnup calculation) to generate the multi-group data which will be used by a core simulator code. In the flux solution and depletion steps, the exact heterogeneity of the assembly is preserved in the calculation schemes.

PHOENIX-P or PARAGON is capable of modeling all cell types necessary for PWR design applications. Nodal group constants (two group) are obtained by flux-volume homogenization of the fuel cell (including IFBA pins), guide thimbles, instrumentation thimbles, and inter-assembly gaps using the PHOENIX-P or PARAGON multi-group flux distribution. Group constants for control rods are calculated in a similar manner. Validation of the cross section method is based on analysis of critical experiments, isotopic data, and plant critical boron values at HZP and at HFP conditions as a function of burnup as discussed in detail in Reference 33 and Reference 55. Control rod worth measurements are also discussed in the reference.

Confirmatory critical experiments on burnable absorbers are described in Reference 6.

3.2.1.22 Spatial Few-Group Diffusion Calculations

The ANC code (Reference 11) is used in two-dimensional and three dimensional core calculations. ANC can be used in safety analysis calculations, and to determine critical boron concentrations, control rod worths, and reactivity coefficients.

Axial calculations are used to determine differential control rod worth curves (reactivity versus rod insertion) and axial power shapes during steady state and transient xenon conditions (flyspeck curve). Group constants and the radial buckling used in the axial calculation are obtained from the ANC radial calculation, in which group constants in annular rings representing the various material regions in the X-Y plane are homogenized by flux-volume weighting. Two-group axial calculations utilize APOLLO, an updated version of the PANDA code (Reference 35).

Validation of the spatial codes for calculating power distributions involves the use of incore and excore detectors and is discussed in Reference 5, Reference 33 and Reference 55.

Based on comparison with measured data it is estimated that the accuracy of current analytical methods is:

$\pm 0.2\%$ $\Delta\rho$ for Doppler defect

$\pm 2 \times 10^5$ $\Delta k/k/°F$ for moderator coefficient

±50 ppm for critical boron concentration with depletion

±3% for power distributions

$\pm 0.2\%$ $\Delta\rho$ for rod bank worth

±4 pcm/step for differential rod worth

±0.5 pcm/ppm for boron worth

$\pm 0.1\%$ $\Delta\rho$ for moderator defect

3.2.2 THERMAL AND HYDRAULIC DESIGN AND EVALUATION

This section presents an evaluation of the characteristics and design parameters which are significant to the thermal-hydraulic design objectives. The capability of the reactor to achieve these objectives while performing safely under operational modes, including both transient and steady-state, is demonstrated in this section.

The thermal and hydraulic design parameters are given in Table 3.2-4

3.2.2.1 Thermal Hydraulic Design Basis

The reactor core is designed to meet the following thermal and hydraulic criteria:

A. There is at least a 95% probability that DNB will not occur on the most limiting fuel rods during MODES 1 and 2, operational transients, or any conditions of moderate frequency at a 95% confidence level.

B. No fuel melting during any anticipated normal operating condition, operational transients, or any conditions of moderate frequency.

3.2.2.1.1 Departure from Nucleate Boiling Design Basis

There shall be at least a 95% probability (at a 95% confidence level) that departure from nucleate boiling (DNB) will not occur on the most limiting fuel rod during normal operation, operational transients, and any transient conditions arising from faults of moderate frequency (Condition I and II events).

By preventing DNB, adequate heat transfer is assured between the fuel cladding and the reactor coolant, thereby preventing cladding damage as a result of inadequate cooling. Maximum fuel rod surface temperature is not a design basis as it is within a few degrees of coolant temperature during operation in the nucleate boiling region. Limits provided by the nuclear control and protection systems are such that this design basis will be met for transients associated with Condition I1 events, including overpower transients.

3.2.2.1.2 Fuel Temperature Design Basis

For Condition I and II events, the fuel design and overpower protection system setpoints are designed to assure that a calculated centerline fuel temperature does not exceed the fuel melting temperature. The melting temperature of U02 is taken to be 5080°F (un-irradiated) and decreases by 58°F per 10,000 MWD/MTU of fuel burnup (Reference 45). The fuel temperatures have been evaluated by the same methods used for all Westinghouse fuel designs. Rod geometries, thermal properties, heat fluxes, and temperature differences are modeled to calculate the temperature at the surface and centerline of the fuel pellet. To preclude fuel melting, the peak local power experienced during Condition I and II events can be limited to a maximum value which is sufficient to ensure that the fuel centerline temperatures remain below the melting temperature at all burnups.

3.2.2.2 Thermal Hydraulic Design Analysis

3.2.2.2.1 Departure from Nucleate Boiling

3.2.2.2.1.1 DNBR Correlations

Departure from nucleate boiling (DNB) is predicated upon a combination of hydrodynamic and heat transfer phenomena and is affected by the local and upstream conditions including the heat flux distribution.

W-3

The W-3 DNB correlation (Reference 14) incorporates both local and system parameters in predicting the local DNB heat flux. The W-3 correlation was developed from tests with flow in tubes and rectangular channels. Good agreement is obtained when the correlation is applied to test data for rod bundles. This correlation includes the nonuniform axial heat flux effect. The W-3 correlation has been extensively validated against test data and shown to be conservative for the prediction of DNB in fuel rod bundles with and without mixing vane grids.

The W-3 DNBR correlation is used where the WRB-1 correlation is not applicable. The WRB-1 correlation was developed based on mixing vane data and therefore is only applicable in the heated rod spans above the first mixing vane grid. In addition, the W-3 correlation is applied in the analysis of accident conditions where the system pressure is below the range of the WRB-1 correlation. For system pressures in the range of 500 psia to 1000 psia, the W-3 correlation limit is 1.45 (Reference 42). For system pressures greater than 1000 psia, the W-3 correlation limit is 1.30.

WRB-1

The WRB-1 DNB correlation is based entirely on rod bundle data and takes credit for improvements in the accuracy of the critical heat flux predictions over previous DNB correlations. This correlation, based on local fluid conditions, represents the rod bundle data with better accuracy over a wide range of variables than the previous correlation used in design. This correlation accounts directly for both typical and thimble cold wall cell effects, uniform and non-uniform heat flux profiles, and variations in rod heated length and in grid spacing (Reference 18, Reference 19). A DNB evaluation based upon criteria presented in Reference 36, the Westinghouse Fuel Criteria Evaluation Process (FCEP), for the 422V+ fuel design concludes that the WRB-1 DNB correlation with a limit of 1.17 can be conservatively applied to this design.

3.2.2.2.1.2 DNBR Analysis

In conjunction with the WRB-1 correlation, the design method employed to meet the DNB design basis is “Revised Thermal Design Procedure” (RTDP) (Reference 22). With RTDP methodology, uncertainties in plant operating parameters, nuclear and thermal parameters, fuel fabrication parameters, computer codes, and DNB correlation predictions are considered statistically to obtain DNB uncertainty factors. Based on the DNB uncertainty factors, RTDP design limit DNBR values are determined such that there is at least 95-percent probability at a 95-percent confidence level that DNB will not occur on the most limiting fuel rod during normal operation and operational transients and during transient conditions arising from faults of moderate frequency. Only the random portion of the plant operating parameter uncertainties is included in the statistical combination. Instrumentation bias is treated as a direct DNBR penalty. Since the parameter uncertainties are considered in determining the RTDP design limit DNBR values, the safety analyses are performed using input parameters at their nominal values.

The RTDP design limit DNBR values are 1.24 and 1.23 for typical and thimble cells, respectively. To maintain DNBR margin to offset DNB penalties such as those due to fuel rod bow, transition cores, and instrumentation biases, the safety analyses are performed to DNBR limits higher than the design limit DNBR values. The difference between the design limit DNBRs and the safety analysis limit DNBRs results in available DNBR margin. The net DNBR margin, after consideration of all penalties, is available for operating and design flexibility.

The Standard Thermal Design Procedure (STDP) is used for those analyses where RTDP is not appropriate. In STDP, the parameters used in analysis are treated in a conservative way from a DNBR standpoint. The parameter uncertainties are applied directly to the plant safety analysis input values to give the lowest minimum DNBR. The DNBR limit for STDP is the appropriate DNB correlation limit increased by sufficient margin to offset the applicable DNBR penalties.

Prior to the power uprate to 1800 MWt, the THINC-IV code (Reference 20 and Reference 21) was used for the core thermal design. Commencing with the power uprate, the VIPRE-01 code is used for the core thermal design. VIPRE-01 is a three-dimensional subchannel code that has been developed to account for hydraulic and nuclear effects on the enthalpy rise in the core and hot channels (Reference 43 and Reference 44). VIPRE-01 modeling of a PWR core is based on one-pass modeling approach. In the one-pass modeling, hot channels and their adjacent channels are modeled in detail, while the rest of the core is modeled simultaneously on a relatively coarse mesh. The behavior of the hot assembly is determined by superimposing the power distribution upon inlet flow distribution while allowing for flow mixing and flow distribution between flow channels. Local variations in fuel rod power, fuel rod and pellet fabrication, and turbulent mixing are also considered in determining conditions in the hot channels. Conservation equations of mass, axial and lateral momentum, and energy are solved for the fluid enthalpy, axial flow rate, lateral flow, and pressure drop. The VIPRE-01 model has been demonstrated in Reference 44 to be equivalent to the THINC-IV code.

3.2.2.2.2 Hot Channel Factors

The total hot channel factors for heat flux and enthalpy rise are defined as the maximum to-core average ratios of these quantities. The heat flux factors consider the local maximum at a point (the “hot spot”), and the enthalpy rise factors involve the maximum integrated value along a channel (the “hot channel”).

Each of the total hot channel factors is a function of a nuclear hot channel factor describing the neutron flux distribution and an engineering hot channel factor to allow for variations in flow conditions and fabrication tolerances. The engineering hot channel factors are made up of subfactors accounting for the influence of the variations of fuel pellet diameter, density, enrichment and eccentricity; fuel rod diameter; pitch and bowing; inlet flow distribution; flow redistribution; and flow mixing. These engineering hot channel factors are described below.

Heat Flux Engineering Hot Channel Factor, F^EQ

The heat flux engineering hot channel factor is used to evaluate the maximum heat flux. This subfactor is determined by statistically combining the tolerances for the fuel pellet diameter, density, enrichment, eccentricity and the fuel rod diameter, and has a value of 1.03. Measured manufacturing data on recent Westinghouse fuel were used to verify that this value was not exceeded for 95 percent of the limiting fuel rods at a 95 percent confidence level. Thus, it is expected that a statistical sampling of the fuel assemblies of the reference plant will yield a value no larger than 1.03. This factor is used in kW/ft analyses. An additional factor of 0.003 is added for DNB analysis to account for a nonuniform azimuthal heat flux distribution.

Enthalpy Rise Engineering Hot Channel Factor, $F^E DH$

The effect of variations in flow conditions and fabrication tolerances on the hot-channel enthalpy rise is directly considered in the core thermal subchannel analysis under any reactor operating condition. The items considered contributing to the enthalpy rise engineering hot channel factor are discussed below:

1. Pellet Diameter, Density and Enrichment and Fuel Rod Diameter, Pitch and Bowing Design values employed in the VIPRE analysis related to the above fabrication variations are based on applicable limiting tolerances such that these design values are met for 95 percent of the limiting channels at a 95 percent confidence level. Measured manufacturing data cited above show the tolerances used in this evaluation are conservative. These fabrication variations are considered statistically in establishing the DNBR limit.

2. Inlet Flow Maldistribution

   Studies performed on 1/7 scale hydraulic reactor models indicate that a conservative design basis is to consider a 5% reduction in the flow to the hot fuel assembly under isothermal conditions.

3. Flow Redistribution

   The flow redistribution accounts for the reduction in flow in the hot channel resulting from the high flow resistance in the channel due to the local or bulk boiling. The effect of the non-uniform power distribution is inherently considered in the VIPRE analysis for every operating condition which is evaluated.

4. Flow Mixing

   Mixing vanes have been incorporated into the spacer grid design. These vanes induce flow mixing between the various flow channels in a fuel assembly and also between adjacent assemblies. This mixing reduces the enthalpy rise in the hot channel resulting from local power peaking or unfavorable mechanical tolerances.

3.2.2.2.3 Hydraulic Analysis

Pressure Drop and Hydraulic Forces

The total pressure drop across the reactor vessel, including the inlet and outlet nozzles, and the pressure drop across the core are listed in Table 3.2-4. These values include a 10% uncertainty factor. The hydraulic forces are not sufficient to lift a control rod cluster during normal operation even if the rod is not attached to its coupling.

Hydrodynamic and Flow Power Coupled Instability

Boiling flows may be susceptible to thermohydrodynamic instabilities (Reference 46). These instabilities are undesirable in reactors since they may cause a change in thermohydraulic conditions that may lead to a reduction in the DNB heat flux relative to that observed during a steady flow condition or to undesired forced vibrations of core components.

Two (2) specific types of flow instabilities are considered for Westinghouse PWR operation. These are the Ledinegg of flow excursion type of static instability and the density wave type of dynamic instability.

Ledinegg instability involves a sudden change in flow rate from one steady-state to another. This instability occurs when the slope of the reactor coolant system pressure drop-flow rate curve ($\delta\Delta P/\delta G$ internal) becomes algebraically smaller than the loop supply (pump head) pressure drop-flow rate curve ($\delta\Delta P/\delta G$ external). The Westinghouse pump head pressure drop-flow rate curve has negative slope ($\delta\Delta P/\delta G$ external <0) whereas the reactor coolant system pressure drop-flow rate curve has a positive slope ($\delta\Delta P/\delta G$ internal > 0) over the Condition I and II operational ranges. Thus, the Ledinegg instability will not occur.

The mechanism of density wave oscillations in a heated channel has been described by Lahey and Moody (Reference 47). However, since the total pressure drop across the core is maintained by the characteristics of the fluid system external to the core, then the two-phase pressure drop perturbation feeds back to the single phase region. These resulting perturbations can be either attenuated or self-sustained.

A simple method has been developed by Ishii (Reference 48) for parallel closed channel systems to evaluate whether a given condition is stable with respect to the density wave type of dynamic instability.

The application of the method of Ishii to Westinghouse reactor designs is conservative due to the parallel open channel feature of Westinghouse PWR Cores. For such cores, there is little resistance to lateral flow leaving the flow channels of high power density. This coupling with cooler channels has led to the opinion that an open channel configuration is more stable than the above closed channel analysis under the same boundary conditions.

Flow instabilities which have been observed have occurred almost exclusively in closed channel systems operating at low pressures relative to the Westinghouse PWR operating pressures. Kao, Morgan, and Parker (Reference 49) analyzed parallel closed channel stability experiments simulating a reactor core flow. These experiments were conducted at pressures up to 2200 psia. The results showed that for flow and power levels typical of power reactor conditions, no flow oscillations could be induced above 1200 psia.

Additional evidence that flow instabilities do not adversely affect thermal margin is provided by the data from the rod bundle DNB tests.

In summary, it is concluded that thermohydrodynamic instabilities will not occur under Condition I and II modes of operation for Westinghouse PWR reactor designs. A large power margin, greater than doubling rated power, exists to predicted inception of such instabilities. Analysis has been performed which shows that minor plant to plant differences in Westinghouse reactor designs such as fuel assembly arrays, core power to flow ratios, fuel assembly length, etc. will not result in gross deterioration of the above power margins.

3.2.2.2.4 Fuel Temperature Analysis

Fuel rod thermal evaluations (fuel centerline, average and surface temperatures) are performed at several times in the fuel rod lifetime (with consideration of time dependent densification) to determine the maximum fuel temperatures using the PAD 4.0 code (Reference 50). The fuel rod behavior is evaluated utilizing a semi-empirical thermal model which considers, in addition to the thermal aspects, such items as cladding creep, fuel swelling, fission gas release, release of absorbed gases, cladding corrosion and elastic deflection, and helium solubility. To preclude fuel melting, the peak local power experienced during Condition I and II events can be limited to a maximum value which is sufficient to ensure that the fuel centerline temperatures remain below the melting temperature at burnups less than 62,000 MWD/MTU.

3.2.2.2.5 Effects of DNB on Neighboring Rods

DNB has never been observed to occur in a group of neighboring rods in a rod bundle as a result of DNB in one rod in the bundle.

3.2.2.2.6 DNB with Physical Burnout

Westinghouse has conducted DNB tests in a 25-rod bundle where physical burnout occurred with one rod (Reference 15). After this occurrence, the 25-rod test section was used for several days to obtain more DNB data from the other rods in the bundle. The burnout and deformation of the rod did not affect the performance of neighboring rods in the test section during the burnout or the validity of the subsequent data points. No occurrences of flow instability or other abnormal operation were observed.

3.2.2.2.7 DNB with Return to Nucleate Boiling

Additional DNB tests have been conducted by Westinghouse (Reference 16) on 19 and 21 rod bundles. In these tests, DNB without physical burnout was experienced more than once on single rods in the bundles for short periods of time. Each time, a reduction to power of approximately 10% was sufficient to re-establish nucleate boiling on the surface of the rod. During these and subsequent tests, no adverse effects were observed on this rod or any other rod in the bundle as consequences of operating in DNB.

3.2.2.2.8 Rod Bow As Applied to DNBR Analysis

DNBR reduction as a result of rod bow is calculated by:

$$MDNBR_B = MDNBR_{NB}\,(1-\delta_B)$$

where:

MDNBR = minimum DNBR
$MDNBR_{NB}$ = MDNBR for non-bowed fuel
$MDNBR_B$ = MDNBR for bowed fuel
δ_B = rod bow penalty, fractional reduction in MDNBR due to bowing

Westinghouse's detailed methodology for calculating fuel rod bowing and its MDNBR effect is given in Reference 23.

δ_B is given as a function of assembly average burnup. The value of δ_B is less than 3.5% for low flow. This value bounds the full flow value of the rod bow penalty and is used for the full and reduced flow calculations. This rod bow penalty is representative for an average assembly burnup of 24,000 MWD/MTU (Reference 24).

While the amount of rod bowing increases beyond this exposure, the fuel is not capable of achieving limiting peaking factors due to the decrease in fissionable isotopes and buildup of fission product inventory. The physical burndown effect is greater than the rod bowing effects which would be calculated based on the amount of bow predicted at those burnups.

Therefore, for the purpose of evaluating effects of rod bow on Westinghouse fuel, 24,000 MWD/MTU represents the maximum burnup of concern.

The reduction in MDNBR is accounted for by taking a DNBR penalty for all conditions at which the rod bow penalty applies.

3.2.3 MECHANICAL DESIGN AND EVALUATION

The reactor core and reactor vessel internals are shown in cross-section in Figure 3.2-34 and in elevation in Figure 3.2-35. The core, consisting of the fuel assemblies and control rods, provides and controls the heat source for the reactor operation. Source rods, thimble plugging devices and burnable absorber rods in RCC guide thimbles are no longer being used. The internals, consisting of the lower core support structure, upper core support assembly, in-core instrumentation support structures, core barrel and thermal shield, are designed to support, align, and guide the core components, direct the coolant flow to and from the core components, and to support and guide the in-core instrumentation. The laws of the State of Wisconsin require American Society of Mechanical Engineers (ASME) Code construction on the reactor vessel. A listing of the core mechanical design parameters for the initial core as well as reload fuel, is given in Table 3.2-5.

The fuel assemblies are arranged in a roughly circular cross-sectional pattern. The assemblies are all mechanically compatible and similar in design, but contain fuel of different enrichments depending on the location of the assembly within the core. Each reload core is designed to utilize fresh and previously burned fuel in a low leakage loading pattern.

The fuel is in the form of slightly enriched uranium dioxide (UO_2) ceramic pellets. In STD and OFA fuel assemblies, the pellets are stacked to an active height of 144 inches within Zircaloy-4 tubular cladding which is plugged and seal welded at the ends to encapsulate the fuel. In the 422V+ fuel, the active height of the pellet stack has been reduced to 143.25 inches within the ZIRLO® or Optimized ZIRLO™ tubular cladding which is plugged and seal welded at the ends to encapsulate the fuel. Heat generated by the fuel is removed by demineralized borated light water which flows upward through the fuel assemblies and acts as both moderator and coolant.

The control rods, designated as rod cluster control (RCC) assemblies, consist of groups of individual absorber rods which are held together by a spider at the top end and actuated as a group. In the inserted positions, the absorber rods fit within hollow guide thimbles in the fuel assemblies. The guide thimbles are an integral part of the fuel assemblies and occupy locations within the regular fuel rod pattern where fuel rods have been deleted. In the withdrawn position, the absorber rods are guided and supported laterally by guide tubes which form an integral part of the upper core support structure. Figure 3.4-1 shows a typical RCCA, and Section 3.4 describes the functional operation of the RCCAs.

As shown in Figure 3.2-35, the fuel assemblies are positioned and supported vertically in the core between the upper and lower core plates. The core plates are provided with pins which index into closely fitting mating holes in the fuel assembly top and bottom nozzles. The pins maintain the fuel assembly alignment, which permits free movement of the control rods from the fuel assembly into the guide tubes in the upper support structure without binding or restriction between the rods and their guide surfaces.

Operational or seismic loads imposed on the fuel assemblies are transmitted through the core plates to the upper and lower support structures and ultimately to the internals support ledge at the pressure vessel flange in the case of vertical loads, or to the lower radial support and internals support ledge in the case of horizontal loads. The internals also provide a form fitting baffle surrounding the fuel assemblies which confines the upward flow of coolant in the core area to the fuel bearing region.

3.2.3.1 Reactor Internals Design Description

The reactor internals are designed to support and orient the reactor core fuel assemblies and control rod assemblies, absorb the control rod dynamic loads and transmit these and other loads to the reactor vessel flange, provide a passageway for the reactor coolant, and support in-core instrumentation. The reactor internals are shown in Figure 3.2-35.

The internals are designed to withstand the forces due to weight, preload of fuel assemblies, control rod dynamic loading, vibration, possible blowdown forces, and earthquake acceleration. These internals are analyzed in a manner similar to Connecticut Yankee, San Onofre, Zorita, Saxton, and Yankee. Under the loading conditions, including conservative effects of design earthquake loading, the structure satisfies stress values prescribed in Section III, ASME Nuclear Vessel Code. The dynamic criteria for design and stress levels of the internals in this plant are similar to those in Connecticut Yankee.

The reactor internals are equipped with bottom-mounted in-core instrumentation supports. These supports are designed to sustain the applicable loads outlined above.

In the event of downward vertical displacement of the internals, energy absorbing devices limit the displacement by contacting the vessel bottom head. The load is transferred through the energy absorbing devices to the vessel. The energy absorbers, cylindrical in shape, are contoured on their bottom surface to the reactor vessel bottom head geometry. Their number and design are determined so as to limit the forces imposed to a safe fraction of yield strength. Assuming a downward vertical displacement, the potential energy of the system is absorbed mostly by the strain energy of the energy absorbing devices (see Figure 3.2-37).

The free fall in the hot condition is on the order of 1/2 inch, and there is an additional strain displacement in the energy absorbing devices of approximately 3/4 inch. Alignment features in the internals prevent cocking of the internals structure during this postulated drop. The control system, as designed, provides assurance of control rod insertion capabilities under these assumed drop conditions. The drop distance of about 1-1/4 inch is not enough to cause the tips of the shutdown group of RCCAs to come out of the guide tubes in the fuel assemblies.

The components of the reactor internals are divided into three parts consisting of the lower core support structure (including the entire core barrel and thermal shield), the upper core support structure, and the in-core instrumentation support structure.

Lower Core Support Structure

The major containment and support member of the reactor internals is the lower core support structure shown in Figure 3.2-37. This support structure assembly consists of the core barrel, the core baffle, the lower core plate and support columns, the thermal shield, the intermediate diffuser plate, and the bottom support plate which is welded to the core barrel. All the major material for this structure is Type 304 stainless steel. The core support structure is supported at its upper flange from a ledge in the reactor vessel head flange and its lower end is restrained in its transverse movement by a radial support system attached to the vessel wall. Within the core barrel are axial baffle and former plates which are attached to the core barrel wall and form the enclosure periphery of the assembled core. The lower core plate is positioned at the bottom level of the core below the baffle plates and provides support and orientation for the fuel assemblies.

The lower core plate provides the necessary flow distributor holes for each fuel assembly. Fuel assembly locating pins (two for each assembly) are also inserted into this plate. Columns are placed between this plate and the bottom support plate of the core barrel in order to provide stiffness to this plate and transmit the core load to the bottom support plate. Intermediate between the support plate and lower core support plate is positioned a perforated plate to uniformly diffuse the coolant flowing into the core.

Irradiation baskets, into which material samples can be inserted and irradiated during reactor operation, are attached to the thermal shield. The irradiation capsule basket supports are welded to the thermal shield. There is no extension of this support above the thermal shield as was done in the older designs. Thus, the basket has been removed from the high flow disturbance zone. The welded attachment to the shield extends the full length of the support except for small interruptions about one inch long. This type of attachment has an extremely high natural frequency. The specimens are held in position within the baskets by a stop on the bottom and a slotted cylindrical spring at the top which fits against a relief in the basket. The specimen does not extend through the top of the basket and thus is protected by the basket from the flow.

The lower core support structure, and principally the core barrel, serve to provide passageways and control for the coolant flow. Inlet coolant flow from the vessel inlet nozzles proceeds down the annulus between the core barrel and the vessel wall, flows on both sides of the thermal shield, and then into a plenum at the bottom of the vessel. It then turns and flows up through the lower support plate, passes through the intermediate diffuser plate, and then through the lower core plate. The flow holes in the diffuser plate and the lower core plate are arranged to give a very uniform entrance flow distribution to the core. After passing through the core, the coolant enters the area of the upper support structure and then flows generally radially to the core barrel outlet nozzles and directly through the vessel outlet nozzles.

A small amount of water flows between the baffle plates and core barrel to provide additional cooling of the barrel. Similarly, a small amount of the entering flow is directed into the vessel head plenum and exits through the vessel outlet nozzles.

Vertically downward loads from weight, fuel assembly preload, control rod dynamic loading, and earthquake acceleration are carried by the lower core plate partially through the lower core plate support flange on the core barrel shell and partially through the lower support columns to the bottom support plate and thence through the core barrel shell to the core barrel flange supported by the vessel head flange. Transverse loads from earthquake acceleration, coolant cross flow, and vibration are transmitted to the core barrel shell to be shared between the lower radial support and the vessel head flange. Transverse acceleration of the fuel assemblies is transmitted to the core barrel shell by direct connection of the lower core support plate to the barrel wall and by a radial support type connection of the upper core plate to slab sided pins pressed into the core barrel.

The main radial support system of the core barrel is accomplished by “key” and “keyway” joints to the reactor vessel wall. At equally spaced points around the circumference, an Inconel block is welded to the vessel inner face. Another Inconel block is bolted to each of these blocks, and has a “keyway” geometry. Opposite each of these is a “key” which is attached to the internals. At assembly, as the internals are lowered into the vessel, the keys engage the keyways in the axial direction. With this design, the internals are provided with a support at the farthest extremity and may be viewed as a beam fixed at the top and simply supported at the bottom.

Radial and axial expansions of the core barrel are accommodated, but transverse movement of the core barrel is restricted by this design. With this system, cycle stresses in the internal structures are within the ASME Section III limits.

<u>Upper Core Support Assembly</u>

The upper core support assembly shown in Figure 3.2-38 consists of the upper support plate, deep beam sections, and upper core plate between which are contained support columns and guide tube assemblies. The support columns which establish the spacing between the upper support plate, deep beam sections, and the upper core plate are fastened at top and bottom to these plates and beams. The support columns transmit the mechanical loadings between the two plates and serve the supplementary function of supporting thermocouple guide tubes. The guide tube assemblies shown on Figure 3.2-39 sheath and guide the control rod drive shafts and control rods and provide no other mechanical functions. They are fastened to the upper support plate and are guided by pins in the upper core plate for proper orientation and support. Additional guidance for the control rod drive shafts is provided by the control rod shroud tube which is attached to the upper support plate and guide tube.

The upper core support assembly, which is removed as a unit during refueling operation, is positioned in its proper orientation with respect to the lower support structure by flat-sided pins pressed into the core barrel which in turn engage in slots in the upper core plate. At an elevation in the core barrel where the upper core plate is positioned, the flat-sided pins are located at equal angular positions. Slots are milled into the upper core plate at the same positions. As the upper support structure is lowered into the main internals, the slots in the plate engage the flat-sided pins in the axial direction. Lateral displacement of the plate and of the upper support assembly is restricted by this design. Fuel assembly locating pins protrude from the bottom of the upper core plate and engage the fuel assemblies as the upper assembly is lowered into place. Proper alignment of the lower core support structure, the upper core support assembly, the fuel assemblies, and control rods is thereby assured by this system of locating pins and guidance arrangement. The upper core support assembly is restrained from any axial movements by a large circumferential spring which rests between the upper barrel flange and the upper core support assembly, and is compressed by the reactor vessel head flange.

Vertical loads from fuel assembly preload are transmitted through the upper core plate via the support columns to the deep beams and upper support plate and then through the circumferential spring to the reactor vessel head. Transverse loads from coolant cross flow, earthquake acceleration, and possible vibrations are distributed by the support columns to the upper support plate and upper core plate. The upper support plate is particularly stiff to minimize deflection.

In-Core Instrumentation Support Structures

The in-core instrumentation support structures consist of an upper system to convey and support thermocouples penetrating the vessel through the head and a lower system to convey and support flux thimbles penetrating the vessel through the bottom.

The upper system utilizes the reactor vessel head penetrations. Instrumentation port columns are slip-connected to in-line columns that are in turn fastened to the upper support plate. These port columns protrude through the head penetrations. The thermocouples are routed through these port columns and across the upper support plate to positions above their readout locations. The thermocouple conduits are supported from the columns of the upper core support system. The thermocouple conduits are sealed stainless steel tubes.

In addition to the upper in-core instrumentation, there are reactor vessel bottom port columns which carry the retractable, cold worked stainless steel flux thimbles that are pushed upward into the reactor core. Conduits extend from the bottom of the reactor vessel down through the concrete shield area and up to a thimble seal table. The minimum bend radius is about 90 inches and the trailing ends of the thimbles (at the seal table) are extracted approximately 13 feet during refueling of the reactor in order to avoid interference within the core. The thimbles are closed at the leading ends and serve as the pressure barrier between the reactor pressurized water and the nuclear detector.

Mechanical seals between the retractable thimbles and the surrounding conduits are provided to seal the reactor coolant from the containment atmosphere. Thus, primary system pressure exists up to the seal table. During normal operation, the retractable thimbles are stationary in the core and are moved only during refueling or for maintenance. Section 7.6 contains more information on the arrangement of the in-core instrumentation system.

The in-core instrumentation support structure is designed for adequate support of instrumentation during reactor operation and is rugged enough to resist damage or distortion under the conditions imposed by handling during the refueling sequence.

Evaluation of Core Barrel and Thermal Shield

The internals design is based on analysis, test, and operational information. Problems in previous Westinghouse PWRs have been evaluated and information derived has been considered in this design. For example, the Point Beach design uses a one-piece thermal shield which is attached rigidly to the core barrel at one end and flexured at the other. The earlier designs that malfunctioned were multi-piece thermal shields that rested on vessel lugs and were not rigidly attached at the top.

Early core barrel designs that have malfunctioned in service, now abandoned, employed threaded connections such as tie rods joining the bottom support to the bottom of the core barrel, and a bolted connection that tied the core barrel to the upper barrel. The malfunctioning of the core barrel designs in earlier service was believed to have been caused by the thermal shield which was oscillating, thus creating forces on the core barrel. Other forces were induced by unbalanced flow in the lower plenum of the reactor. In the Point Beach RCCA design there are no fuel followers to necessitate a large bottom plenum in the reactor. The elimination of these fuel followers enabled Westinghouse to build a shorter core barrel.

The Connecticut Yankee reactor and the Zorita reactor core barrels are of the same construction as the Point Beach reactor core barrel. Deflection measuring devices employed in the Connecticut Yankee reactor during the hot-functional test, and deflection and strain gauges employed in the Zorita reactor during the hot-functional test have provided important information that has been used in the design of the later internals, including that for Point Beach. When the Connecticut Yankee thermal shield was modified to the same design as for Southern California Edison, it, too, operated satisfactorily as was evidenced by the examination after the hot-functional test. After these hot-functional tests on all of these reactors, a careful inspection of the internals was provided. All the main structural welds were examined, nozzle interfaces were examined for any differential movement, upper core plate inside supports were examined, the thermal shield attachments to the core barrel, including all lock welds on the devices used to lock the bolt were checked; no malfunctions were found.

Substantial scale model testing was performed at Westinghouse Atomic Power Division. This included tests which involved a complete full-scale fuel assembly which was operated at reactor flow, temperature, and pressure conditions. Tests were run on a 1/7 scale model of the Indian Point 1 reactor. Measurements taken from these tests indicate very little shield movement, on the order of a few mils when scaled up to Point Beach. Strain gauge measurements taken on the core barrel also indicate very low stresses. Testing to determine thermal shield excitation due to inlet flow disturbances have been included. Information gathered from these tests was used in the design of the thermal shield and core barrel. It can be concluded from the testing program and the analyses and with the experience gained that the design as employed on the Point Beach Nuclear Plant is adequate.

Point Beach Nuclear Plant Units 1 and 2 achieved initial criticality in November 1970 and in May 1972, respectively. The reactor vessels were constructed prior to the existence of many of the present materials requirements. Accordingly, analyses have been performed to evaluate the fracture toughness of the reactor vessels and vessel internals and tests have been conducted on the materials surveillance capsules to verify the adequacy of the original design.

The core barrel support pads thermal, mechanical, and pressure stresses are calculated at various locations on the pad and at the vessel wall. Mechanical stresses are calculated by the flexure formula for bending stress in a beam; pressure stresses are taken from the analysis of the vessel to bottom head juncture; and thermal stresses are determined by the conservative method of skin stresses. The stresses due to the cyclic loads are multiplied by a stress concentration factor where applicable and used in the fatigue evaluation.

In the event of a loss-of-coolant accident and subsequent operation of the emergency core cooling system, cold water is injected from the accumulators, through the nozzles and downcomer, to the core. Thermal gradients through the core support components will originate transient thermal stresses. Analysis shows that the worst thermal stress case occurs to the core barrel. The barrel is affected by the cold water in the downcomer and the somewhat hotter water in the compartments between barrel and baffle, producing a thermal gradient across barrel wall. The lower support structure is cooled more uniformly because of the large and numerous flow holes, and consequently, thermal stresses are lower.

The method used to obtain the maximum barrel stresses is as follows:

1. Temperature distribution across the barrel wall is computed as a function of time taking into consideration water temperatures and film coefficients.

2. Assuming that the obtained thermal gradients are axisymmetrically distributed, which is conservative for stresses, maximum thermal stresses are computed in the barrel considered as an infinite cylinder.

3. Thermal stresses are added to primary stresses, including seismic, in order to obtain the maximum stress state of the barrel.

Results of studies performed for different conditions show that maximum thermal stresses in the barrel wall are well below the allowable criteria given for design by Section III of the ASME Code.

Interaction Analyses

The following discussion is applicable to the original reactor vessel components and has been retained without revision.

Areas of discontinuity or stress concentration of the following components of the reactor pressure vessel have been analyzed in detail through systematic analytical procedures. The reactor vessel areas and discontinuity geometries are presented in Figure 3.2-43. A summary description of the stress analysis is provided.

An interaction analysis is performed on the CRDM housing. The flange is assumed to be a ring and the tube is assumed to be a long cylinder. The different values of Young's Modulus and coefficients of thermal expansion of the tubes are taken into account in the analysis. The local flexibility is considered at appropriate locations. The closure head is treated as a perforated spherical shell with modified elastic constants. The effects of redundants on the closure head are assumed to be local only. Using the mechanical and thermal stresses from this analysis, a fatigue evaluation is made for the J weld.

The closure head, closure head flange, vessel flange, vessel shell, and closure studs are all evaluated in the same analysis. An analytical model is developed by dividing the actual structure into different elements such as sphere, ring, long cylinder, and cantilever beam, etc. An interaction analysis is performed to determine the stresses due to mechanical and thermal loads. These stresses are evaluated in light of the strength and fatigue requirements of the ASME Boiler and Pressure Vessel Code Section III. A similar analysis is performed for the vessel flange to vessel shell juncture and main closure studs.

For the analysis of nozzle and nozzle to shell juncture, the loads considered are internal pressure, operating transients, thermally induced and seismic pipe reactions, static weight of vessel, earthquake loading, and expansion and contraction, etc. A combination of methods is used to evaluate the stresses due to mechanical and thermal loads and external loads resulting from seismic pipe reactions, earthquake, and pipe break, etc.

For fatigue evaluation, peak stresses resulting from external loads and thermal transients are determined by concentrating the stresses as calculated by the above described methods. Combining these stresses enables the fatigue evaluation to be performed. Method of analysis for outlet nozzle and vessel supports is the same as described above.

Vessel wall transition is analyzed by means of a standard interaction analysis. The thermal stresses are determined by the skin stress method where it is assumed that the inside surface of the vessel is at the same temperature as the reactor coolant and the mean temperature of the shell remains at the steady state temperature. This method is considered conservative.

For the bottom head to shell juncture, the standard interaction analysis and skin stress methods are employed to evaluate the stresses due to mechanical and thermal stresses, respectively. The fatigue evaluation is made on a cumulative basis where superposition of all transients is taken into consideration.

For the bottom head instrument penetrations, an interaction analysis is performed by dividing the actual structure into an analytical model composed of different structural elements. The effects of the redundants on the bottom head are assumed to be local only. It is also assumed that for any condition where there is interference between the tube and the head no bending at the weld can exist. Using the mechanical and thermal stresses from this analysis, a fatigue evaluation is made for the J weld.

The location and geometry of the areas of discontinuity and/or stress concentration are shown in Figure 3.2-43.

For reactor vessels, the maximum thermal stress due to gamma ray heating occurs in the cylindrical portion of the vessel adjacent to the core and its value is about 2200 psi. This additional thermal stress does not augment the stress intensity values considerably. The maximum stress intensity values under steady state and transient operating conditions are still far below the allowable limits of N-414 of ASME Boiler and Pressure Vessel Code Section III. The effect of gamma ray heating on the cumulative usage factor is negligible.

The following pressure or strength bearing stainless steel component parts in the reactor vessel became furnace sensitized during the fabrication sequence:

1. Four primary nozzle safe ends - weld metal buttering
2. Two safety injection nozzle safe ends - forgings
3. Bottom instrumentation safe ends - forgings

Follow-up nondestructive examinations show no loss of integrity of the materials in the furnace sensitized areas.

<u>Interaction Analyses for Replacement Reactor Vessel Closure Heads and CRDMs</u>

The original reactor vessel closure heads, along with their respective CRDMs, have been replaced. The following discussion applies to the replacement components.

The pressure-retaining portions of the replacement CRDMs are evaluated to the requirements of Section III of the ASME Boiler and Pressure Vessel Code. The analysis is performed using two-dimensional axisymmetric finite element models of critical portions of the pressure housings, including models of the lower portion of the latch housing, the upper portion of the latch housing and the lower portion of the rod travel housing including the full penetration weld, and the upper portion of the rod travel housing. Stresses and fatigue usages are calculated for critical locations in the lower and upper portions of the latch housing, as well as the weld to the rod travel housing. The rod travel housing region is qualified by comparison with the upper latch housing region, which is concluded to bound the critical locations of the rod travel housing for stress and fatigue considerations.

The replacement vessel closure head and closure head flange have been evaluated in a separate analysis to the stress and fatigue requirements of Section III of the ASME Boiler and Pressure Vessel Code. Stresses are calculated using a finite element analysis approach. Several analysis models are used to envelope all locations of the replacement closure head. These models include the reactor vessel closure head, closure head flange, CRDM head adapter (including a portion of the head) for the centermost and outermost penetrations, the bimetallic weld joint between the head adapters and CRDM adapter flange tubes, the vent pipe to shell junction, and the instrument port head adapter flange for the core exit thermocouple nozzle assembly. Lift lugs on the closure head were also analyzed, but this analysis used empirical (not finite element) analysis techniques.

3.2.3.2 Core Components Design Description

Fuel Assembly

All of the fuel assemblies in the core are of similar design. The overall configuration of the fuel assemblies is shown in Figure 3.2-41 Sheets 1 to 7. The assemblies are square in cross section, nominally 7.761 inches on a side, and have an overall height (excluding hold down springs) of 159.975 inches for STD and OFA and 159.775 inches for upgraded OFA and 422V+.

The Westinghouse 14x14 422V+ fuel assembly design is a 14x14 array with a 0.422 inch fuel rod design. The 14x14 422V+ fuel assembly incorporates and adapts many of the current Westinghouse advanced fuel features.

The 14x14 422V+ fuel assembly features include: reconstitutable top nozzles (RTNs), reduced rod bow (RRB) inconel top grid, ZIRLO OFA-type mid-grids, high burnup inconel bottom grid, skirted debris filter bottom nozzle (DFBN), ZIRLO guide thimble and instrumentation tubes and fuel rods with zirconium dioxide coated cladding.

Although the 14x14 422V+ fuel assembly design incorporates and adapts many new Westinghouse fuel features, the parameters and dimensions are designed to be identical or compatible with STD or OFA Point Beach Unit 1 and 2 fuel. Figure 3.2-41 Sheet 6 illustrates the overall height and grid elevation dimensions of the Westinghouse 14x14 422V+ fuel assembly. The principle differences between the 14x14 422V+ fuel assembly and the 14x14 OFA fuel designs are:

1. 0.422 inch fuel rod outer diameter versus 0.400 inches for the 14x14 OFA
2. Thin strap ZIRLO OFA-type mid-grids versus thick-strap Zircaloy-4 OFA mid-grid
3. 0.200 inch lower top nozzle adapter plate and top grid elevation

The fuel rods in a fuel assembly are arranged in a square array with 14 rod locations per side and a nominal centerline-to-centerline pitch of 0.556 inch between rods. Of the total possible 196 rod locations per assembly, 16 are occupied by guide thimbles for the RCC rods or burnable absorber rods and one for in-core instrumentation. The remaining 179 locations contain fuel rods. However, limited substitutions of Zircaloy-4, ZIRLO® or Optimized ZIRLO™, or stainless steel filler rods for fuel rods, in accordance with NRC approved applications of fuel rod configurations, may be used when fuel assembly reconstitution is required due to leaking fuel rods. This methodology is addressed in detail in Reference 37. In addition to fuel rods, a fuel assembly is composed of a top nozzle, a bottom nozzle, 7 grid assemblies, 16 absorber rod guide thimbles, and one instrumentation thimble. Figure 3.2-40 shows a typical fuel assembly and control cluster cross section.

The guide thimbles, in conjunction with the grid assemblies and the top and bottom nozzles, comprise the basic structural fuel assembly skeleton. The top and bottom ends of the guide thimbles are fastened to the top and bottom nozzles, respectively. The grid assemblies, in turn, are fastened to the guide thimbles at each location along the height of the fuel assembly at which lateral support for the fuel rods is required. Within this skeletal frame-work, the fuel rods are contained and supported and the rod-to-rod centerline spacing is maintained along the assembly. Figure 3.2-41 shows a typical fuel assembly outline and detail.

<u>Bottom Nozzle</u>

The bottom nozzle is a square pedestal structure which controls the coolant flow distribution to the fuel assembly and functions as the bottom structural element of the fuel assembly. The nozzle, which is square in cross section, is fabricated from 304 stainless steel parts consisting of a perforated plate and 4 pads or feet. The legs are welded to the plate to form a plenum space for the inlet coolant to the fuel assembly. The perforated plate serves as the bottom end support for the fuel rods. The bottom support surface for the fuel assembly is formed under the plenum space by the four pads which are welded to the corner angles.

Coolant flow to the fuel assembly is directed from the plenum in the bottom nozzle, upward to the interior of the fuel assembly and to the channel between assemblies.

A stainless steel debris filter bottom nozzle (DFBN) has been introduced into the Point Beach Unit 1 Region 19 (Cycle 17 feed) upgraded OFAs and into the Unit 2 Region 18 (Cycle 16 feed) upgraded OFAs to reduce the possibility of fuel damage due to debris-induced fretting. The 14 x 14 DFBN design is based upon the VANTAGE 5 bottom nozzle design (Reference 7). The re-designed top plate of the nozzle includes a revised pattern of smaller flow holes that are sized to minimize passage of flow-entrained debris particles large enough to cause damage while providing sufficient flow area, comparable pressure drop, and continued structural integrity of the nozzle. A typical revised bottom nozzle flow hole pattern is illustrated in Figure 3.2-36. The DFBN design also incorporates the “extended burnup,” or low profile, geometry of the VANTAGE 5 bottom nozzle. This low profile nozzle, which has a reduced nozzle height and a thinner top plate, is designed to accommodate longer fuel rods and provide greater fuel rod growth room within the 14 x 14 upgraded OFA and 422V+ assemblies. Increased fuel rod plenum volumes and rod growth gaps accommodate the increased fission gas releases and fuel rod growths associated with extended discharge fuel burnups.

The RCC guide thimbles, which carry axial loads imposed on the assembly, are fastened to the bottom nozzle end plate. These loads, as well as the weight of the assembly, are distributed through the nozzle to the lower core support plate. Indexing and positioning of the fuel assembly in the core is controlled through two holes in diagonally opposite pads which mate with locating pins in the lower core plate. Lateral loads imposed on the fuel assembly are also transferred to the core support structures through the locating pins.

Top Nozzle

The top nozzle is a box-like structure which functions as the fuel assembly upper structural element and forms a plenum space where the heated coolant leaves the fuel assembly and is directed toward the flow holes in the upper core plate. The nozzle is comprised of an adapter plate, enclosure, top plate, two clamps, four double leaf springs, and assorted hardware. All parts with the exception of the springs and their hold-down bolts are constructed of Type 304 stainless steel. The springs are made from age hardened Inconel 718. The spring screws are made from peened Inconel 718 or Inconel 600.

The adapter plate is square in cross section and is perforated by machined slots to provide for coolant flow through the plate. At assembly, the top ends of the control guide thimbles are fastened to the adapter. Thus, the adapter plate acts as the fuel assembly top end plate and provides a means of distributing evenly among the guide thimbles any axial loads imposed on the fuel assemblies.

The nozzle enclosure is a square thin walled shell which forms the plenum section of the top nozzle. The bottom end of the enclosure is pinned and welded to the periphery of the adapter plate and the top end is welded to the periphery of the top plate.

The top plate is square in cross section with a central hole. The hole allows clearance for the RCC absorber rods to pass through the nozzle into the guide thimbles in the fuel assembly and for coolant exit from the fuel assembly to the upper internals area. Two pads containing axial through-holes which are located on diametrically opposite corners of the top plate provide a means of positioning and aligning the top of the fuel assembly. As with the bottom nozzle, alignment pins in the upper core plate mate with the holes in the top nozzle plate.

Hold-down forces of sufficient magnitude to oppose the hydraulic lifting forces on the fuel assembly are obtained by means of the double leaf springs which are mounted on the top plate. The springs are fastened in pairs to the top plate at the two corners where alignment holes are not used and radiate out from the corners parallel to the sides of the plate. Fastening and locking of springs is accomplished with a clamp which fits over the ends of the springs and two bolts (one per spring) which pass through the clamp and spring and thread into the top plate. At assembly, the spring bolts are torqued sufficiently to preload against the maximum spring load and then lockwelded to the clamp. The clamp is locally welded to the top plate to retain its position, prior to the spring bolt being lockwelded to the clamp.

The spring load is obtained through deflection of the spring set by the upper core plate. The spring form is such that it projects above the fuel assembly and is depressed by the core plate when the internals are loaded into the reactor. The free end of the spring is bent downward and captured in a key slot in the top plate. The free end of the lower spring is captured by the bent down leg of the upper spring. This is done to guard against loose parts in the reactor in the event (however remote) of spring fracture. In addition, the fit between the upper spring and key slot and between the spring set and the mating slot in the clamp are sized to prevent rotation of either end of the spring set into the control rod path in the event of spring fracture.

In addition to its plenum and structural functions, the nozzle provides a protective housing for components which mate with the fuel assembly. In handling a fuel assembly with a control rod inserted, the control rod spider is contained within the nozzle. During operation in the reactor, the nozzle protects the absorber rods from coolant cross flows in the unsupported span between the fuel assembly adapter plate and the end of the guide tube in the upper internals package. Plugging devices which can be used to fill the ends of the fuel assembly thimble tubes at unrodded core locations and the spiders which support the source rods and burnable absorber rods are all contained within the fuel top nozzle.

Reconstitutable top nozzles (RTN) have been introduced into the Point Beach upgraded OFA reloads beginning with Unit 1 Region 19 (Cycle 17 feed) and Unit 2 Region 18 (Cycle 16 feed). The reconstitutable top nozzle for this upgraded fuel assembly differs from the OFA/STD design in that a groove is provided in each thimble through-hole in the nozzle plate to facilitate removal. To remove the top nozzle, a tool is first inserted through a lock tube and expanded radially to engage the bottom edge of the tube. An axial force is then exerted on the tool which overrides local lock tube deformations and withdraws the lock tube from the insert. After the lock tubes have been withdrawn, the nozzle is removed by raising it off the upper slotted ends of the nozzle inserts which deflect inwardly under the axial lift load.

With the top nozzle removed, direct access is provided for fuel rod examinations or replacement. Reconstitution is completed by the remounting of the nozzle and the re-insertion of the lock tubes. Additional details of this design feature, the design bases and evaluation of the reconstitutable top nozzle are given in Section 2.3.2 in Reference 7.

<u>Guide Thimbles</u>

The control rod guide thimbles in the fuel assembly provide guided channels for the absorber rods during insertion and withdrawal of the control rods. They are fabricated from a single piece of Zircaloy-4 or ZIRLO tubing which is drawn to two different diameters. The larger inside diameter at the top provides a relatively large annular area for rapid insertion of a withdrawn control rod during a reactor trip and to accommodate a small amount of upward cooling flow during normal operations. The bottom portion of the guide thimble is of reduced diameter to produce a dashpot action when the absorber rods are near the end of travel in the guide thimbles during a reactor trip. The transition zone at the dashpot section is conical in shape so that there are no rapid changes in diameter in the tube.

Flow holes are provided just above the transition of the two diameters to permit the entrance of cooling water during normal operation and to accommodate the outflow of water from the dashpot during reactor trip.

The dashpot is closed at the bottom by means of a welded end plug. The end plug is fastened to the bottom nozzle during fuel assembly fabrication.

Grids

The spring clip grid assemblies consist of individual slotted straps which are assembled and interlocked in an "egg crate" type arrangement and then furnace brazed or welded to permanently join the straps at their points of intersection. Details such as spring fingers, support dimples, mixing vanes, and tabs are punched and formed in the individual straps prior to assembly.

Two types of grid assemblies are used in the fuel assembly. One type of grid, having mixing vanes which project from the edges of the straps into the coolant stream, is used in the high heat region of the fuel assemblies to promote mixing of the coolant. A grid of this type is shown in Figure 3.2-42. The other type of grid, located at the bottom and top ends of the assembly, are of the nonmixing type. They are similar to the mixing type with the exception that they contain no mixing vanes on the internal straps.

The outside straps on all grids contain mixing vanes which, in addition to their mixing function, aid in guiding the grids and fuel assemblies past projecting surfaces during handling or loading and unloading the core. Additional small tabs on the outside straps and the irregular contour of the straps are also for this purpose.

Inconel 718 is chosen for the grid material on STD fuel assembly design and top and bottom grids of the OFA and 422V+ designs, because of its corrosion resistance and high strength properties. After the combined brazing and solution annealing temperature cycle, the grid material is age hardened to obtain the material strength necessary to develop the required grid spring forces. The OFA mixing vane grids are made from Zircaloy-4 and the 422V+ mixing vane grids are made from ZIRLO.

Fuel Rods

The fuel rods consist of UO_2 ceramic pellets in a slightly cold worked and partially annealed Zircaloy-4 or ZIRLO® or Optimized ZIRLO™ tubing which is plugged and seal welded at the ends to encapsulate the fuel. Sufficient void volume and clearances are provided within the rod to accommodate fission gases released from the fuel, differential thermal expansion between the cladding and the fuel, and fuel swelling due to accumulated fission products without overstressing of the cladding or seal welds. Shifting of the fuel within the cladding is prevented during handling or shipping prior to core loading by a stainless steel helical compression spring which bears on the top of the fuel.

At assembly, the pellets are stacked in the cladding to the required fuel height. The compression spring is then inserted into the top end of the fuel and the end plugs pressed into the ends of the tube and welded. All fuel rods are internally pressurized with helium at a pressure in the range of one to three hundred pounds during the welding process. A hold-down force in excess of the weight of the fuel is obtained by compression of the spring between the top end plug and the top of the fuel pellet stack.

The fuel pellets are right circular cylinders consisting of slightly enriched UO_2 powder which has been compacted by cold pressing and then sintered to the required density. The ends of each pellet are dished slightly to allow the greater axial expansion at the center of the pellets to be taken up within the pellets themselves and not in the overall fuel length. Reload fuel contains pellets with a small chamfer around the outer cylindrical surface on the pellet ends. This reduces the potential for pellet chipping during the fabrication process.

To prevent the possibility of mixing enrichments during fuel manufacture and assembly, meticulous process control is exercised. The UF_6 gas is received from the supplier in sealed containers, the contents of which are fully identified both by descriptive tagging and preselected color coding. A single enrichment only is received per shipment. Upon receipt, an additional Westinghouse identification tag completely describing the contents is affixed to the containers before transfer to segregated storage, where containers of different enrichment are never mixed.

The UF_6 is then converted to UO_2 powder by a series of highly controlled processes. The UO_2 powder is also placed in segregated storage according to enrichment. Powder withdrawal from storage can be made by one authorized group only who directs the powder to the correct pellet production line. All pellet production lines are physically separated from each other and pellets of only a single enrichment and density are produced in a given production line.

Finished pellets are placed on trays having the same color code as the powder containers and transferred to segregated storage racks. Physical barriers prevent mixing of pellets of different densities and enrichments in this storage area. Unused powder and substandard pellets to be reprocessed are returned to storage in the original color coded containers.

Loading of the pellets into the cladding is again accomplished in isolated production lines and again only one density and enrichment is loaded on a line at a time.

At the time of loading, the top fuel tube end plug identification character is checked with the density and enrichment identification of the color code of the pellet storage tray. After each fuel tube is seal welded, it is given the same color coding as has been carried throughout the previous processes. The fuel tube remains color coded until just prior to installation in the fuel assembly. The color coding, therefore, provides a cross reference of the fuel contained in the fuel rods.

At the time of installation into an assembly, the color coding is removed. After the fuel rods are installed, an inspector verifies that the top nozzle to be used on the assembly carries the correct identification character describing the fuel enrichment and density for the core region being fabricated. The top nozzle identification then becomes the permanent description of the fuel contained in the assembly.

The identification numbers on the fuel assembly top nozzles will then maintain the enrichment identity and ensure that the assemblies with the correct enrichment are loaded into the proper core region.

Each assembly will be assigned a core loading position prior to insertion. A record will then be made of the core loading position, serial number, and enrichment. Prior to core loading, independent checks will be made to ensure that this assignment is correct.

During initial core loading and subsequent refueling operations, detailed written handling and checkoff procedures will be utilized throughout the sequence. Current reload cores utilize loading patterns which are consistent with low-low leakage fuel management.

<u>Neutron Source Assemblies</u>

Neutron sources can be used to provide at least a required minimum count rate during startup operations. Four neutron source assemblies were initially utilized in the core; two secondary source assemblies with four secondary source rods each and two primary source assemblies comprised of one combination primary and secondary rod, three secondary rods, and twelve burnable absorber rods. Currently, source assemblies are not utilized in Unit 1 and Unit 2. When sources are used, source rods are fastened to a spider at the top end similar to the RCC spiders.

In the core, the neutron source assemblies are inserted into the RCC guide thimbles in fuel assemblies at unrodded locations.

The primary and secondary source rods utilize the same type of cladding material as the absorber rods (cold-worked Type 304 stainless steel tubing, 0.432 in. OD, 0.019 in. thick walls). All secondary source rods contain Sb-Be pellets stacked to a height of 121.754 inches. The primary source for Unit 1 contained capsules of Po-Be source material 6 inches long and Sb-Be pellet material to fill the remainder of the rod height. The primary source rods for Unit 2 contained Pu-Be source. The active material was encased in a length of 24 inches maximum and was enclosed in a custom fabricated capsule. The remainder of the rod length was void. Design criteria similar to those for the fuel rods are used for the design of the source rods; i.e., the cladding is free standing, internal pressures are always less than reactor operating pressure, and internal gaps and clearances are provided to allow for differential expansion between the source material and cladding.

Plugging Devices

When necessary to limit bypass flow through the RCC guide thimbles in fuel assemblies which do not contain either control rods, source assemblies, or burnable absorbers, the fuel assemblies at those locations can be fitted with plugging devices. When utilized, the plugging devices would consist of a flat spider plate with short rods suspended from the bottom surface and a spring pack assembly attached to the top surface. At installation in the core, the plugging devices fit within the fuel assembly top nozzles and rest on the adapter plate. The short rods project into the upper ends of the thimble tubes to reduce the bypass flow area. The spring pack is compressed by the upper core plate when the upper internals package is lowered into place. Similar short rods are also used on any insert assembly which does not have sixteen rods. The plugging rods can be used to fill the upper ends of any vacant guide thimbles in a fuel assembly.

All components in the plugging device, except for the springs, are constructed from Type 304 stainless steel. The springs (one per plugging device) are wound from an age hardenable nickel base alloy to obtain higher strength.

Although the core bypass flow through the thimble tubes increases with the removal of thimble plugging devices, all thermal hydraulic criteria and safety limits are satisfied.

3.2.3.3 Evaluation of Core Components

Fuel Rod Evaluation

The fission gas release and the associated buildup of internal gas pressure in the fuel rods are calculated by the PAD code based on experimentally determined rates. The increase of internal pressure in the fuel rod due to these phenomena is included in the determination of the maximum cladding stresses at the end of core life when the fission product gap inventory is a maximum.

The maximum allowable strain in the cladding, considering the combined effects of internal fission gas pressure, external coolant pressure, fuel pellet swelling, and cladding creep is limited to less than 1% throughout core life. The associated stresses are below the yield strength of the material under all normal operating conditions.

To assure that manufactured fuel rods meet a high standard of excellence from the standpoint of functional requirements, many inspections and tests are performed both on the raw material and the finished product. These tests and inspections include chemical analysis, elevated temperature tensile testing of fuel tubes, dimensional inspection, x-ray of both end plug welds, ultrasonic testing, and helium leak tests.

In the event of cladding defects, the high resistance of UO_2 fuel pellets to attack by hot water protects against fuel deterioration or decrease in fuel integrity. Thermal stress in the pellets, while causing some fracture of the bulk material during temperature cycling, does not result in pulverization or gross void formation in the fuel matrix. As shown by operating experience and experimental work in the industry, the thermal design parameters conservatively account for any changes in the thermal performance of the fuel element due to pellet fracture.

The consequences of a breach of cladding are greatly reduced by the ability of uranium dioxide to retain fission products including those which are gaseous or highly volatile. This retentiveness decreases with increasing temperature or fuel burnup, but remains a significant factor even at full power operating temperature in the maximum burnup element.

A survey of high burnup UO_2 fuel element behavior indicates that for an initial UO_2 void volume, which is a function of the fuel density, it is possible to conservatively define the fuel swelling as a function of burnup (Reference 25). The fuel swelling model considers the effect of burnup, temperature distribution, and internal voids. It is an empirical model which has been checked with data from Bettis, Yankee, CVTR, Saxton, and others. Region 3 was retained through three initial cycles of reactor operation and Region 2 through two initial cycles. The initial pellet density was 92% in Region 2 and 91% in Region 3 for Unit 1 to accommodate the effects of increased burnup. For Unit 2, pellet densities were 94% in Region 1, 93% in Region 2, and 92% in Region 3.

Experience with the earlier fuel regions mentioned above provided information which was later used to improve fuel rod designs so as to reduce the effects of fuel pellet densification and eliminate clad collapse during the useful life of the fuel assemblies (Reference 29, and Reference 30). The integrity of fuel rod cladding so as to retain fission products or fuel material is directly related to cladding stress and strain under normal operating and overpower conditions. Design limits (cladding perforation) in terms of stress and strain are as follows:

	Damage Limit	Design Limit
Stress	Ultimate Strength 65,000 psi minimum	Yield Strength 52,000 psi minimum
Strain	1.7%	1.0%

The stress damage and design limits given above are minimum values. Actual damage and design limits depend upon cladding temperature, neutron exposure and normal variation of material properties and are greater than these minimum limits.

For most of the fuel rod life the actual stresses and strains are considerably below the design limits. Thus, significant margin exists between actual operating conditions and the damage limits. The other parameters having influence on cladding stress and strain and the relationship of these parameters to the damage limits are as follows:

1. <u>Internal Gas Pressure</u>

The internal pressure of the lead fuel rod in the reactor will be limited to a value below that which cause (1) the diametral gap to increase due to outward clad creep during steady state operation, and (2) extensive DNB propagation to occur.

The rod internal pressure for the Point Beach Unit 1 and Unit 2 fuel rods has been evaluated by modeling the gas inventories, gas temperature, and rod internal volumes through the rods' life. The resulting rod internal pressure is compared to the design limit on a case-by-case basis of current operating conditions to EOL. Reload evaluations show that the rod internal pressure satisfies the design limit.

The second part of the rod internal pressure design basis precludes extensive DNB propagation and associated fuel failure. The basis for this criterion is that no significant additional fuel failures, due the DNB propagation, will occur in cores which have fuel rods operating with rod internal pressure in excess of system pressure. The design limit for Condition II events is that DNB propagation is not extensive, i.e., the process is shown to be self limiting and the number of additional rods in DNB due to propagation is relatively small. For Condition III/IV events, it is shown that the total number of rods in DNB, including propagation effects, is consistent with the assumptions used in radiological dose calculations for the event under consideration.

2. <u>Cladding Temperature</u>

The strength of the fuel cladding is temperature dependent. The minimum ultimate strength reduces to the design yield strength at an average cladding temperature of approximately 850°F.

For Condition I and II events, the fuel and reactor protection systems are designed to assure that a calculated centerline fuel temperature does not exceed the fuel melting temperature criterion. The intent of this criterion is to avoid a condition of gross fuel melting which can result in severe duty on the clad. The concern here is based on the large volume increase associated with the phase change in the fuel and the potential for loss of clad integrity as a result of molten fuel/clad interaction.

The temperature of the fuel pellets was evaluated by modeling the fuel rod geometry, thermal properties, heat fluxes, and temperature differences in order to calculate fuel surface, average, and centerline temperatures of the fuel pellets.

3. <u>Swelling and Cladding Strain</u>

Fuel burnup results in fuel swelling which produces cladding strain. The strain damage limit is conservatively set at a 1.0% strain limit from the unirradiated condition for all Westinghouse fuel during steady-state operation. An evaluation performed for the 14x14 422V+ design has demonstrated that the cladding strain criterion has been met for this design.

4. Fuel Temperature and kW/ft

At zero burnup, cladding damage for fuel rods is calculated to occur at 31 kW/ft based upon cladding strain reaching the damage limit.

At this power rating, 17% of the pellet central region is expected to be in the molten condition. The maximum thermal output at rated power is 16.0 kW/ft.

Effects of Vibration and Thermal Cycling on Fuel Assemblies

Analyses of the effect of cyclic deflection of the fuel rods, grid spring fingers, RCC control rods, and burnable absorber rods due to hydraulically induced vibrations and thermal cycling show that the design of the components is good for an infinite number of cycles.

In the case of the fuel grid spring support, the amplitude of a hydraulically induced motion of the fuel rod is extremely small (~0.001) and the stress associated with the motion is significantly small (<100 psi).

Likewise, the reactions at the grid spring due to the motion is much less than the preload spring force and contact is maintained between the fuel cladding and the grid spring and dimples. Fatigue of the cladding and fretting between the cladding and the grid support have not normally been experienced and are not anticipated.

The effect of thermal cycling on the grid-cladding support is merely a slight relative movement between the grid contact surfaces and the cladding, which is gradual in nature during heatup and cooldown. Since the number of cycles of the occurrence is small over the life of a fuel assembly (up to 4 years), negligible wear of the mating parts is expected.

In-core operation of assemblies in the Yankee Rowe and Saxton reactors using similar cladding support have verified the calculated conclusions. Additional test results under a simulated reactor environment in the Westinghouse Reactor Evaluation Center also support these conclusions.

The dynamic deflection of the full length control rods, source rods, and the burnable absorber rods is limited by their fit with the inside diameter of either the upper portion of the guide thimble or the dashpot (0.074 inch diametral clearance at guide thimble for the STD fuel and 0.061 for the OFA and 422V+ fuel; 0.0155 inch diametral clearance at the dashpot). With this limitation, the occurrence of truly cyclic motion is questionable. However, an assumed cyclic deflection through the available clearance gap results in an insignificantly low stress in either the cladding tubing in the joint at the spider or retainer plate. The above consideration assumes the rods are supported as cantilevers from the spider or the retainer plate in the case of the burnable absorber rods.

A calculation assuming the rods are supported by the surface of the dashpots and the upper end by the spider or retainer results in a similar conclusion.

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Table 3.2-1 NUCLEAR DESIGN DATA

(Sheet 1 of 4)

		Cores With All Standard Assemblies (STD)*	Reloads of OFA and Upgraded OFA*	Reloads of 422V+** W/O EPU	Reloads of 422V+ W/EPU***
STRUCTURAL CHARACTERISTICS					
1.	Fuel Weight (UO_2), lbs.	118,729	107,430	120,047	120,047
2.	Zircaloy (STD & OFA) or ZIRLO® (422V+) or Optimized ZIRLO™ (422V+) Weight, lbs.	24,260	26,380	27,429	27,429
3.	Core Diameter, inches	96.5	96.85	96.5	96.5
4.	Core Height, inches	144	144	143.25	143.25
	Reflector Thickness and Composition				
5.	Top Reflector - (Water Plus Steel), inches	~10	~10	~10	~10
6.	Bottom Reflector - (Water Plus Steel), inches	~10	~10	~10	~10
7.	Side Reflector - (Water Plus Steel), inches	~15	~15	~15	~15
	Fuel				
8.	H_2O/U Volume Ratio (cold)	1.9	2.27	2.0	2.0
9.	Number of Fuel Assemblies	121	121	121	121
10.	UO_2 Rods per Assembly	179	179	179	179
PERFORMANCE CHARACTERISTICS					
11.	Total Core Heat Output, MW_t (initial rating)	1518.5	1518.5	1540	1800
12.	Total Primary Heat Output, MW_t (maximum calculated turbine rating)	1524	1524	1546	1806
13.	Fuel Burnup, First Cycle MWD/MTU	15,100			
	Equilibrium Cycles (Nominal Cycle)	9,500	10,800 10,500 (1)	17,200	19,000
	Region Average Discharge	33,000	40,000 45,000 (1)	52,000	52,000
	Lead Rod Average Burnup			62,000 (3)	62,000(3)

* These parameter values are typical for a nominal 12 month fuel cycle length. Reload designs for a nominal 18 month fuel cycle length may be different.
** These parameter values are typical for a nominal 18 month fuel cycle length.
*** These parameter values are typical for a nominal 18 month fuel cycle at uprated conditions.

Table 3.2-1 NUCLEAR DESIGN DATA

(Sheet 2 of 4)

		Cores With All Standard Assemblies (STD)*	Reloads of OFA and Upgraded OFA*	Reloads of 422V+** W/O EPU	Reloads of 422V+ W/EPU***
PERFORMANCE CHARACTERISTICS					
14.	Region 1 Enrichment, w/o	2.27			
15.	Region 2 Enrichment, w/o	3.03			
16.	Region 3 Enrichment, w/o	3.40			
17.	Equilibrium Enrichment, w/o	3.2 - 3.6	3.2 - 3.6 3.8 - 4.0 (1)	4.4 - 4.95	4.4 - 4.95
18.	Nuclear Heat Flux Hot Channel Factor, F^N_q	2.32	2.50	2.60 (V+) 2.50 (OFA)	2.60
19.	Nuclear Enthalpy Rise Hot Channel Factor, $F^N_{\Delta H}$	1.58	1.70	1.77 (V+) 1.70 (OFA)	1.68
CONTROL CHARACTERISTICS					
	Effective Multiplication (Beginning-of-Life)				
	Boron Free, Rods Out				
20.	Cold, No Power, Xenon Free	1.211	1.232	1.200	1.200
21.	Hot, No Power, Xenon Free	1.167	1.171	1.156	1.156
22.	Hot, Full Power, Xenon Free	1.151	1.146	1.131	1.131
23.	Hot, Full Power, Xe and Sm Equilibrium	1.113	1.109	1.097	1.097
	Rod Cluster Control Assemblies				
24.	Material	5% Cd; 15% In; 80% Ag			
25.	Number of Full Length RCC Assemblies	33	33	33	33
26.	Number of Absorber Rods per RCC Assembly	16	16	16	16
27.	Rod Worth		See Table 3.2-3		

* These parameter values are typical for a nominal 12 month fuel cycle length. Reload designs for a nominal 18 month fuel cycle length may be different.
** These parameter values are typical for a nominal 18 month fuel cycle length.
*** These parameter values are typical for a nominal 18 month fuel cycle at uprated conditions.

Table 3.2-1 NUCLEAR DESIGN DATA

(Sheet 3 of 4)

		Cores With All Standard Assemblies (STD)*	Reloads of OFA and Upgraded OFA*	Reloads of 422V+** W/O EPU	Reloads of 422V+ W/EPU***
	BOL Boron Concentrations				
28.	Refueling Shutdown; Rods in (k =0.95)	<1800 ppm	1800 ppm	2100 ppm	2502
29.	Cold Shutdown (k =0.99) with All Rods Inserted, Xenon Free	1015 ppm	928 ppm	1450 ppm	1777
30.	Hot Shutdown (k=0.99) with all Rods Inserted, Xenon Free	667 ppm	677 ppm	1575 ppm	1405
31.	Cold Shutdown (k=0.99) with No Rods Inserted, Xenon Free	1581 ppm	1426 ppm	2200 ppm	2480
32.	Hot Shutdown (k=0.99) with No Rods Inserted, Xenon Free	1613 ppm	1419 ppm	2300 ppm	2576
	Boron Concentrations To Control at Hot Full Power, Rods Inserted, k= 1.0 (With Burnable Absorber Rods)				
33.	Xenon Free	1348 ppm	1184 ppm	1817 ppm	2101
34.	Xenon	1023 ppm	931 ppm	1435 ppm	1673
35.	Xenon and Samarium	970 ppm	880 ppm	1383 ppm	1621
36.	Cold Shutdown (k=0.99) All But Most Reactive Rod Inserted, Xenon Free	1117 ppm	1034 ppm	1550 ppm	1796
37.	Hot Shutdown (k=0.99), All but Most Reactive Rod Inserted, Xenon Free	771 ppm	773 ppm	1650 ppm	1496
BURNABLE ABSORBER RODS					
38.	Number/Material	Discrete 704/ Borated Pyrex Glass	ZrB_2 IFBA	ZrB_2 IFBA	ZrB_2 IFBA
39.	Worth Hot, Δk/k	7.4%	N/A	N/A	N/A
40.	Worth Cold, Δk/k	5.8%	N/A	N/A	N/A

* These parameter values are typical for a nominal 12 month fuel cycle length. Reload designs for a nominal 18 month fuel cycle length may be different.

** These parameter values are typical for a nominal 18 month fuel cycle length.

*** These parameter values are typical for a nominal 18 month fuel cycle at uprated conditions.

Table 3.2-1 NUCLEAR DESIGN DATA

(Sheet 4 of 4)

	Cores With All Standard Assemblies (STD)*	Reloads of OFA and Upgraded OFA*	Reloads of 422V+** W/O EPU	Reloads of 422V+ W/EPU***
KINETIC CHARACTERISTICS				
(Equilibrium Cycle Design)				
41. Moderator Temperature Coefficient, (% Δk/k/°F)		$+3.0\text{x}10^{-3}$ to $-25.0\text{x}10^{-3(2)}$	$+1.0\text{x}10^{-3}$ to $-36.0\text{x}10^{-3}$	$+2.0\text{x}10^{-3}$ to $-37.0\text{x}10^{-3}$
42. Moderator Pressure Coefficient, (% Δk/k/psi)		$-0.3\text{x}10^{-4}$ to $+2.8\text{x}10^{-4(2)}$	$-0.1\text{x}10^{-4}$ to $+4.5\text{x}10^{-4}$	$-0.2\text{x}10^{-4}$ to $+4.5\text{x}10^{-4}$
43. Moderator Density Coefficient, (% Δk/k/gm/cm^3)		-3.0 to +22$^{(2)}$	-1.0 to +36.0	-2.0 to +36.0
44. Doppler Coefficient (% Δk/k/°F)		$-2.9\text{x}10^{-3}$ to $-1.4\text{x}10^{-3(2)}$	$-2.5\text{x}10^{-3}$ to $-1.0\text{x}10^{-3}$	$-2.90\text{x}10^{-3}$ to $-0.91\text{x}10^{-3}$
45. Delayed Neutron Fraction, (%)		0.58 to 0.51$^{(2)}$	0.45 to 0.70	0.43 to 0.72
46. Prompt Neutron Lifetime, (sec.)		$1.9\text{x}10^{-5}$ to $2.1\text{x}10^{-5(2)}$	$1.0\text{x}10^{-5}$ to $1.7\text{x}10^{-5}$	$1.0\text{x}10^{-5}$ to $1.7\text{x}10^{-5}$

(1) Upgraded OFA Value

(2) Typical Values for a Full OFA/Upgraded OFA Core

(3) Per NRC letter to Westinghouse (Reference 41), the lead rod average burnup limit for WCAP-12610-P-A, "Vantage + Fuel Assembly Reference Core Report," (Reference 38) can be increased to a maximum of 62,000 MWD/MTU provided the evaluation of the fuel design performance is performed with PAD 4.0 (Reference 30). The NRC letter also concludes that the use of the FCEP (Reference 36) is also valid up to a burnup limit of 62,000 MWD/MTU provided the change process uses PAD 4.0 to evaluate the effect of any proposed design change on the fuel.

* These parameter values are typical for a nominal 12 month fuel cycle length. Reload designs for a nominal 18 month fuel cycle length may be different.

** These parameter values are typical for a nominal 18 month fuel cycle length.

*** These parameter values are typical for a nominal 18 month fuel cycle at uprated conditions.

Table 3.2-2 REACTIVITY REQUIREMENTS FOR CONTROL RODS ΔK/K (%)

	BOL (Cycle 1)	EOL (Cycle 1)	EOL Typical STD Fuel Core*	EOL Typical OFA Fuel Core (1) *	EOL Typical 422V+ Fuel Core **	EOL Typical 422V+ Fuel Core w/ EPU ***
Reactivity Defects (Combined Doppler, T_{avg}, Void and Redistribution Effects)	2.09	3.22	2.80	2.57	2.50	3.10
Rod Insertion Allowance	0.50	0.50	0.50	0.50	0.40	0.40
Total Control			3.30	3.07	2.90	3.50
Worth of 32 Rods Less 10%	2.59	3.72	6.88	6.78	6.02	5.91
Shutdown Margin	7.12	6.49	3.58	3.71	3.12	2.41
Shutdown Margin Requirement	2.59	3.72	2.77	2.77	2.77	2.00
Excess Shutdown Margin	4.53	2.77	0.81	0.94	0.35	0.41

(1) Includes OFA Upgrade

* These parameter values are typical for a nominal 12 month fuel cycle length. Reload designs for a nominal 18 month fuel cycle length may be different.
** These parameter values are typical for a nominal 18 month fuel cycle length.
*** These parameter values are typical for a nominal 18 month fuel cycle at uprated conditions.

Table 3.2-3 CALCULATED [1] ROD WORTHS, ΔK/K(%)

Core Condition	Rod Configuration	Worth	Less 10%[1]	Design Reactivity Requirements	Shutdown Margin
BOL, HFP Cycle 1	33 Rods In	9.42			
BOL, HZP Cycle 1	32 Rods In Highest Worth Rod Stuck Out	7.91	7.12	2.59	4.53
EOL, HFP Cycle 1	33 Rods In	9.41			
EOL, HZP Cycle 1	32 Rods In Highest Worth Rod Stuck Out	7.21	6.49	3.72	2.77
EOL, HFP Equilibrium Cycle	33 Rods In	8.38[2]* 7.44[3]***			
EOL, HZP Equilibrium Cycle	32 Rods In Highest Worth Rod Stuck Out	7.54 6.57***	6.78 5.91***	3.07 3.50***	3.71[2]* 2.41[3]***

BOL = Beginning-of-Life HFP = Hot Full Power

EOL = End-of-Life HZP = Hot Zero Power

[1] Calculated rod worth is reduced by 10% to allow for uncertainties.
[2] Typical Full OFA/Upgraded OFA Core.
[3] Typical Full 422V+ Core.

* These parameter values are typical for a nominal 12 month fuel cycle length. Reload designs for a nominal 18 month fuel cycle length may be different.
**These parameter values are typical for a nominal 18 month fuel cycle length.
*** These parameter values are typical for a nominal 18 month fuel cycle at uprated conditions.

Table 3.2-4 THERMAL AND HYDRAULIC DESIGN PARAMETERS

(Sheet 1 of 2)

	Pre-EPU Reloads of 422V+ Fuel	EPU Reloads with 422V+ Fuel
Total Primary Heat Output, MW_t	1546	1806
Total Reactor Coolant Pump Heat Output, MW_t	6.0	6.0
Total Core Heat Output, MW_t	1540	1800
Total Heat Output, Btu/hr	5.181×10^9	6.142×10^9
Heat Generated in Fuel, % of Total Core Heat Output	97.4	97.4
Maximum Thermal Overpower, %	21.1	20.0
Nominal System Pressure, psia	2250	2250
Nuclear Heat Flux Hot Channel Factor, F^N_Q (1)	2.60	2.60
Nuclear Enthalpy Rise Hot Channel Factor, $F^N_{\Delta H}$	1.77	1.68
Coolant Flow (2)		
Total Flow Rate (Thermal Design Flow), gpm	178,000	178,000
Total Flow Rate (Thermal Design Flow), lbm/hr	6.76×10^7	6.76×10^7
Design Bypass Flow	6.5%	6.5%
Average Velocity Along Fuel Rods, ft/sec	14.6	13.7
Average Mass Velocity, lbm/hr-ft^2	2.34×10^6	2.34×10^6
Coolant Temperature, °F (2)		
Nominal Inlet	542.5	542.9
Average Rise in Vessel	63.0	68.2
Average Rise in Core	67.0	72.4
Average in Core	577.5	581.0
Average In Vessel	574.0	577.0
Heat Transfer (2)		
Active Heat Transfer Surface Area, ft^2	28,507	28,507
Average Heat Flux, Btu/hr-ft^2	177,075	209,584
Maximum Heat Flux, Btu/hr-ft^2	460,395	545,620
Maximum Thermal Output, kw/ft	14.9	17.7
Peak Fuel Centerline Temperature for Prevention of Centerline Melt, °F	4700	4700

Table 3.2-4 THERMAL AND HYDRAULIC DESIGN PARAMETERS

(Sheet 2 of 2)

	Pre-EPU Reloads of 422V+ Fuel	EPU Reloads with 422V+ Fuel
DNB Ratio		
Minimum DNB Ratio at Nominal Operation Conditions	2.15 [(3)]	1.95[(3)]
Pressure Drop, psi		
Across Core	20.9 [(4)]	25.0[(4)]
Across Vessel, Including Nozzles	44	47.3

(1) Includes a nuclear uncertainty of 1.05 and an engineering uncertainty of 1.03

(2) Based on thermal design flow and 2250 psia system pressure.

(3) Minimum DNBR reflects RTDP Methodology.

(4) Reflects elimination of thimble plugs. Based on RCS flow rate of 201,200 gpm.

Table 3.2-5 CORE MECHANICAL DESIGN PARAMETERS [1]

(Sheet 1 of 2)

	STD Fuel	OFA Fuel	422V+ Fuel
Active Portion of the Core			
Equivalent Diameter, in.	96.5	96.5	96.5
Active Fuel Height, in.	144.0	144.0	143.25
Length-to-Diameter Ratio	1.495	1.495	1.495
Total Cross Section Area, ft^2	50.8	50.8	50.8
Fuel Assemblies			
Number	121	121	121
Rod Array	14 x 14	14 x 14	14 x 14
Rods per Assembly	179 [2]	179 [2]	179 [2]
Rod Pitch, in.	0.556	0.556	0.556
Nominal Assembly Envelope at Bottom Nozzle	7.761 x 7.761	7.761 x 7.761	7.761 x 7.761
Fuel Weight (as UO_2), pounds	118,729	108,078	120,047
Total Weight, pounds	154,519	137,335	151,250
Number of Grids per Assembly	7 (Inconel)	2 (Inconel) Ends 5 (Zircaloy) Middle	2 (Inconel) Ends 5 (ZIRLO) Middle
Guide Thimble Diameters			
(in. above dashpot) I D	0.505	0.492	0.492
OD	0.539	0.526	0.526
(in. below dashpot) I D	0.4465	0.4465	0.4465
OD	0.4805	0.4805	0.4805
Fuel Rods			
Number	21,659	21,659	21,659
Outside Diameter, in.	0.422	0.400	0.422
Diametrical Gap, in.	0.0075	0.0070	0.0075
Clad Thickness, in.	0.0243	0.0243	0.0243
Clad Material	Zircaloy-4	Zircaloy-4	ZIRLO® or Optimized ZIRLO™
Overall Length, in.	151.850	151.850 [3]	152.563
Fuel Pellets			
Material	UO_2 sintered	UO_2 sintered	UO_2 sintered
Density (% of Theoretical Initial Cores)	95	95	96
Diameter, in.	0.3659	0.3444	0.3659
Length, in.	0.600	0.565 [4] 0.413 [5]	0.4390

Table 3.2-5 CORE MECHANICAL DESIGN PARAMETERS [1]

(Sheet 2 of 2)

<u>Rod Cluster Control Assemblies</u>	
Neutron Absorber	5% Cd, 15% In, 80% Ag
Cladding Material	Type 304 SS - Cold worked
Clad Thickness, in.	0.019
Number of Full-Length Clusters	33
Number of Control Rods per Cluster	16
Weight in 60°F Water	
Full-Length, pounds	114
Length of Control Rod, in.	158.454 (Overall)
	150.954 (Insertion Length)
Length of Absorber Section, in.	142.00 (Full-Length)
<u>Core Structure</u>	
Core Barrel, in.	
ID	109.0
OD	112.5
Thermal Shield, in.	
ID	115.3
OD	122.5
<u>Burnable Absorber Rods</u>	
Material	Borosilicate Glass
Outside Diameter, in.	0.431
Inner Tube, OD, in.	0.2365
Clad Material	SS
Inner Tube Material	SS
Boron Loading (Natural)	
gm/cm of glass rod	0.0429

(1) All dimensions for cold conditions
(2) Seventeen rods are omitted; sixteen to provide passage for control rods and one to contain in-core instrumentation
(3) 152.285 for upgraded OFA
(4) Up to Region 17 of Point Beach Unit 1 and Region 16 of Point Beach Unit 2.
(5) Standardized fuel pellet-used in Region 18 and 19 of Point Beach Unit 1 and Region 17 and 18 of Point Beach Unit 2.

Figure 3.2-1 CONTROL ROD CLUSTER GROUPS

[redacted]

Figure 3.2-2 STANDARD FUEL NORMALIZED POWER DENSITY DISTRIBUTION (BOL) MAXIMUM POWER DENSITY = 1.364

[redacted]

Figure 3.2-3 NORMALIZED POWER DENSITY DISTRIBUTION (BOL) MAXIMUM POWER DENSITY = 1.505

[redacted]

Figure 3.2-4 STANDARD FUEL NORMALIZED POWER DENSITY DISTRIBUTION (BOL) IN A PLANE HAVING NO CONTROL RODS
MAXIMUM POWER DENSITY = 1.384

[redacted]

Figure 3.2-5 INITIAL BURNABLE ABSORBER ROD LOCATION

[redacted]

Figure 3.2-6 ARRANGEMENT OF BURNABLE ABSORBER RODS WITHIN AN ASSEMBLY

[redacted]

Figure 3.2-7 TYPICAL EQUILIBRIUM RELOAD LOADING PATTERN

[redacted]

Figure 3.2-8 UPGRADED CORE ASSEMBLY EQUILIBRIUM LOADING PATTERN AND IFBA PLACEMENT

[redacted]

Figure 3.2-9 OFA NORMALIZED POWER DENSITY DISTRIBUTION NEAR BEGINNING OF LIFE, UNRODDED CORE, HOT FULL POWER, EQUILIBRIUM XENON

[redacted]

Figure 3.2-10 OFA NORMALIZED POWER DENSITY DISTRIBUTION NEAR BEGINNING OF LIFE, GROUP D AT INSERTION LIMIT HOT FULL POWER, EQUILIBRIUM XENON

[redacted]

Figure 3.2-11 OFA NORMALIZED POWER DENSITY DISTRIBUTION NEAR END OF LIFE, UNRODDED CORE HOT FULL POWER, EQUILIBRIUM XENON

[redacted]

Figure 3.2-12 OFA NORMALIZED POWER DENSITY DISTRIBUTION NEAR END OF LIFE, GROUP D AT INSERTION LIMIT HOT FULL POWER, EQUILIBRIUM XENON

[redacted]

Figure 3.2-13 UPGRADED CORE NORMALIZED POWER DISTRIBUTION AT 150 MWD/MTU UNRODDED, HOT FULL POWER, EQUILIBRIUM XENON

PEAK $F_{\Delta H}$ = 1.555

[redacted]

Figure 3.2-13a UPGRADED CORE NORMALIZED POWER DISTRIBUTION AT 150 MWD/MTU D-BANK AT ROD INSERTION LIMIT, HOT FULL POWER, EQUILIBRIUM XENON PEAK $F_{\Delta H}$ = 1.574

[redacted]

Figure 3.2-14 UPGRADED CORE NORMALIZED POWER DISTRIBUTION AT 10600 MWD/MTU UNRODDED, HOT FULL POWER, EQUILIBRIUM XENON PEAK $F_{\Delta H}$ = 1.50

[redacted]

Figure 3.2-14a UPGRADED CORE NORMALIZED POWER DISTRIBUTION AT 10600 MWD/MTU D-BANK AT ROD INSERTION LIMIT, HOT FULL POWER, EQUILIBRIUM XENON PEAK $F_{\Delta H}$ = 1.515

[redacted]

Figure 3.2-15 EQUILIBRIUM CYCLE BOC, MOC AND EOC ASSEMBLY POWER DISTRIBUTIONS FOR 422V+ FUEL

[redacted]

Figure 3.2-16 EQUILIBRIUM CYCLE LOADING PATTERN WITH BOC AND EOC ASSEMBLY BURNUPS FOR 422V+ FUEL

[redacted]

Figure 3.2-17 MODERATOR TEMPERATURE COEFFICIENT vs. MODERATOR TEMPERATURE

[redacted]

Figure 3.2-18 DOPPLER COEFFICIENT vs. EFFECTIVE FUEL TEMPERATURE (BOL)

[redacted]

Figure 3.2-19 POWER COEFFICIENT

[redacted]

Figure 3.2-20 POWER COEFFICIENT

[redacted]

Figure 3.2-21 CALCULATED AND MEASURED DOPPLER DEFECT AND COEFFICIENTS AT BEGINNING OF LIFE, TWO-LOOP PLANT, 121 ASSEMBLIES, 12-FOOT CORE

[redacted]

Figure 3.2-22 COMPARISON OF CALCULATED AND MEASURED BORON CONCENTRATION FOR 2-LOOP PLANT, 121 ASSEMBLIES, 12-FOOT CORE

[redacted]

Figure 3.2-23 THERMAL CONDUCTIVITY OF UO_2 (DATA CORRECTED TO 95% THEORETICAL DENSITY)

[redacted]

Figure 3.2-24 HIGH POWER FUEL ROD EXPERIMENTAL PROGRAM

[redacted]

Figure 3.2-25 COMPARISON OF W-3 PREDICTION AND UNIFORM FLUX DATA

[redacted]

Figure 3.2-26 W-3 CORRELATION PROBABILITY DISTRIBUTION CURVE

[redacted]

Figure 3.2-27 COMPARISON OF W-3 CORRELATION WITH ROD BUNDLE DNB DATA (SIMPLE GRID WITHOUT MIXING VANE)

[redacted]

Figure 3.2-28 COMPARISON OF W-3 CORRELATION WITH ROD BUNDLE DNB DATA (SIMPLE GRID WITH MIXING VANE)

[redacted]

Figure 3.2-29 STABLE FILM BOILING HEAT TRANSFER DATA AND CORRELATION

[redacted]

Figure 3.2-30 COMPARISON OF W-3 PREDICTION AND NON UNIFORM FLUX DATA
($-0.15 \leq X_{DNB} \leq +0.15$)

[redacted]

Figure 3.2-31 COMPARISON OF W-3 PREDICTION WITH MEASURED DNB LOCATION

[redacted]

Figure 3.2-32 RADIAL POWER DISTRIBUTION

[redacted]

Figure 3.2-33 MEASURED vs. PREDICTED CRITICAL HEAT FLUX WRB-1 CORRELATION

[redacted]

Figure 3.2-34 REACTOR CORE CROSS SECTION

[redacted]

Figure 3.2-35 REACTOR VESSEL INTERNALS

[redacted]

Figure 3.2-36 BOTTOM NOZZLE FLOW HOLE COMPARISON

[redacted]

Figure 3.2-37 LOWER CORE SUPPORT STRUCTURE

[redacted]

Figure 3.2-38 UPPER CORE SUPPORT ASSEMBLY

[redacted]

Figure 3.2-39 GUIDE TUBE ASSEMBLY

[redacted]

Figure 3.2-40 FUEL ASSEMBLY AND CONTROL CLUSTER CROSS SECTION

[redacted]

Figure 3.2-41 FUEL ASSEMBLY OUTLINE

Sheet 1 of 7

[redacted]

Figure 3.2-41 FUEL ASSEMBLY OUTLINE

(Sheet 2 of 7)

[redacted]

Figure 3.2-41 FUEL ASSEMBLY OUTLINE

Sheet 3 of 7

[redacted]

Figure 3.2-41 FUEL ASSEMBLY OUTLINE

Sheet 4 of 7

[redacted]

Figure 3.2-41 FUEL ASSEMBLY OUTLINE

Sheet 5 of 7

[redacted]

Figure 3.2-41 14 X 14 422VANTAGE + (422V+) FUEL ASSEMBLY OUTLINE

Sheet 6 of 7

[redacted]

Figure 3.2-41 COMPARISON OF 14 X 14 OFA AND 422V + FUEL ROD DESIGNS

Sheet 7 of 7

[redacted]

Figure 3.2-42 SPRING CLIP GRID ASSEMBLY WITH SPLIT MIXING VANES

[redacted]

Figure 3.2-42a SPRING CLIP GRID ASSEMBLY WITH SPLIT MIXING VANES

[redacted]

Figure 3.2-43 REACTOR VESSEL STRESS CONCENTRATIONS

Sheet 1 of 3

[redacted]

Figure 3.2-43 REACTOR VESSEL STRESS CONCENTRATIONS

Sheet 2 of 3

[redacted]

Figure 3.2-43 REACTOR VESSEL STRESS CONCENTRATIONS

Sheet 3 of 3

[redacted]

3.3 RELOAD CORE DESIGN AND SAFETY ANALYSIS

At the reactivity end of life (end of cycle), the reactor is shut down for refueling. A portion of the fuel assemblies comprising the core are discharged, fresh fuel assemblies are added and, based on design calculations, a new core loading pattern is implemented. The core configuration following refueling operations comprises the reload core which will be operated until its respective end of reactivity life.

Nuclear design calculations are performed for each reload core to determine a proper core loading pattern which satisfies the cycle energy and safety analysis requirements. Particular attention is paid to peaking factors and core kinetics characteristics. If core characteristics fall outside of the range of values covered by the previous nuclear design or safety analysis, those core conditions or accidents so affected are reanalyzed (Reference 1).

As part of the reload safety evaluation, the mechanical, nuclear, and thermal-hydraulic characteristics of the reload core are assessed. Special conditions such as off-nominal operating conditions, LOCA limits, or special operational limitations are also addressed. Thus, each reload core is designed and provided with the same or better safety margins than the initial core analysis presented in this FSAR (Reference 2, Reference 3).

Fuel assemblies which comprise the reload region originally utilized Low-Parasitic (LOPAR) fuel also known as STD fuel assemblies. Starting with Unit 1, Region 15, Cycle 13, and Unit 2, Region 13, Cycle 11, the fuel assemblies are of the OFA design, described in Section 3.2. Upgraded OFAs have been inserted starting with the Point Beach Unit 1, Region 19, Cycle 17 core and the Unit 2, Region 18, Cycle 16 core. The upgraded OFA has a Reconstitutable Top Nozzle (RTN), a slightly longer fuel rod for a higher burnup capability, and a Debris Filter Bottom Nozzle (DFBN). The OFA design assemblies and the upgraded assemblies are fully compatible with previously irradiated OFA and STD assemblies in a reload core. Fuel enrichment and/or fuel rod internal pressurization may change to accommodate energy requirements of the respective duty cycles.

Commencing with Unit 1, Region 29, Cycle 27, and Unit 2, Region 27, Cycle 25, the Point Beach units were upgraded to the 14x14, 422VANTAGE+ (422V+) fuel design. This design uses the larger, 0.422" OD, fuel rod. Other major design features include the use of ZIRLO® or Optimized ZIRLO™ cladding, ZIRLO fabricated guide thimbles, instrumentation tubes, and mid-grids; mid-enriched annular pellets in axial blankets; and a pre-oxidized coating on the lower portion of the fuel rod. These reload cycles are based on an eighteen month operating cycle design.

The reactor core can consist of either OFA, and upgraded OFA assemblies, or any combination of previously burned OFA, previously burned upgraded OFA, and 422V+ assemblies. The use of previously-depleted STD fuel assemblies is no longer allowed (Reference 7).

In addition to incorporating upgraded OFA and 422V+ assemblies, the Point Beach core designs have deleted fuel assembly thimble plugs and deleted burnable absorber rods in RCC guide thimbles, and had previously used part length hafnium neutron absorber rods in core Peripheral Power Suppression Assemblies (PPSAs) to further reduce the fast neutron flux at the reactor pressure vessel welds.

A reduced neutron leakage fuel management scheme is presently used in the Point Beach cores. This scheme, defined as a low-low leakage loading pattern uses highly burned fuel in all assembly locations on the periphery. Use of highly burned fuel and absorber rods in core peripheral locations results in a reduced power in peripheral assemblies which is offset by power increases in the remaining fuel assemblies. This increased power has been accommodated by increasing the core peaking factor limits for $F_{\Delta H}$ and F_Q. The benefits of these loading patterns are:

1. Improved fuel utilization, and

2. Reduced fast neutron exposure of the reactor pressure vessel, with the corresponding reduction in the irradiation-induced embrittlement rate of the vessel material (Reference 4)

Peripheral Power Suppression Assemblies (PPSAs) were previously utilized to suppress fuel assembly powers at the flats of the core to shield key areas of the vessel from fast neutron flux. PPSAs are neutron-absorbing core component assemblies which locally suppress the power at the periphery of the fuel core near critical reactor vessel welds. The twelve assemblies on the core flats each contained a PPSA, with absorber in the lower six feet of the guide tubes. Each PPSA consisted of sixteen part-length hafnium absorber rods which were attached to a low profile spider. The mechanical design of the PPSAs was similar to the Westinghouse hafnium RCC assembly design, and would fit into the thimble tubes of the fuel assemblies. Two different assemblies exist, which were identical in design other than the length of hafnium contained within the rods. One assembly design utilized six foot long hafnium absorbers, which would protect both radial and vertical reactor vessel welds. The other assembly design utilized three foot long hafnium absorbers, which would protect only radial reactor vessel welds (Reference 3, Reference 4).

The PPSAs were removed from the Point Beach Unit 1 core beginning with Cycle 32 and were removed from the Point each Unit 2 core beginning with Cycle 35.

NOTE: Test fuel assemblies were used in some cores early in plant life. The following paragraph is retained for historical purposes.

When used, test assemblies may have removable fuel rods which can be examined to determine specialized fuel characteristics. If RTNs are not used for these assemblies, a special thimble plug device provides equivalent top nozzle flow characteristics while also providing the fuel rod holddown constraints of the top nozzle plate. Otherwise the test assemblies normally have the same mechanical and thermal-hydraulic characteristics as production fuel assemblies.

Reload fuel may also utilize axial blankets and Integral Fuel Burnable Absorbers (IFBA), as described below.

Axial blankets are sections of natural or mid-enriched uranium pellets at the top and bottom of the fuel stack of each fuel rod. Axial blankets may be annular to increase fuel rod plenum volume. Blanket length may also be increased to increase plenum volume.

The IFBA is a section of fuel pellets coated by a thin film of zirconium diboride (ZrB_2) burnable absorber material. The coated IFBA rod fuel stack was originally 96 inches in length and axially centered at the core midplane to obtain reasonable normal-operation, elevation dependent F_Q

values. The coating length may be reduced or increased, depending upon the number of IFBA rods and the core loading arrangement. Since Unit 1 Cycle 25 and Unit 2 Cycle 25 a nominal IFBA coating length of 120 inches has been used. In cycles in which full-length discrete burnable absorber rods are used, the fuel assemblies containing these absorbers will not have axial blankets. This will result in lower F_Q values and, therefore, the ΔI envelope will be conservative (Reference 5).

Where safety limits are not violated, limited substitutions of fuel rods by filler rods consisting of ZIRLO, Zircaloy-4 or stainless steel, or by vacancies, may be made to replace damaged fuel rods if justified by cycle-specific reload analysis. Replacement of leaking fuel rods will permit better utilization of the energy in the remaining non-leaking rods of fuel assemblies. In general, substitution of a limited number of fuel rods with filler rods or water holes has negligible effect on core physics parameters and consequently on the safety analysis. For each fuel cycle an analysis is conducted to ensure that, with each reload of fuel, all core design safety criteria are met (Reference 6).

REFERENCES

1. Bordelon, F. M., et. al., "Westinghouse Reload Safety Evaluation Methodology," WCAP-9272-P-A (Proprietary), dated July 1985

2. WE letter to NRC, "Additional Information, Technical Specification Change Request No. 87, Safety Evaluation for Optimized Fuel, Point Beach Nuclear Plant, Units 1 And 2," dated September 6, 1983.

3. NRC letter to WE, "Approval to Allow Use of Westinghouse Optimized Fuel Assemblies At Point Beach Nuclear Plant For Units 1 And 2 Reloads," dated October 5, 1984.

4. NRC letter to WE, "Amendment Nos. 120 and 123 to Facility Operating License Nos. DPR-24 and DPR-27 (TACs 69349/69350)," dated May 8, 1989.

5. WE letter to NRC, "Additional Information for Technical Specification Change Request 127 - Increased Allowable Core Power Peaking Factors," dated October 28, 1988.

6. NRC letter to WE, "Point Beach Technical Specification Amendments No. 108 and 111," dated May 27, 1987.

7. NRC letter to WE, "Issuance of Amendments 193 and 198, Design and Operation of Fuel Cycles with Upgraded Westinghouse Fuel," dated February 8, 2000.

3.4 FUNCTIONAL DESIGN OF REACTIVITY CONTROL SYSTEMS

Rod Cluster Control Assemblies

The control rods or rod cluster control assemblies (RCCAs) each consist of a group of individual absorber rods fastened at the top end to a common hub or spider assembly. These assemblies, one of which is shown in Figure 3.4-1, are provided to control the reactivity of the core under operating conditions.

The absorber material used in the control rods is silver indium cadmium alloy which is essentially "black" to thermal neutrons and has sufficient additional resonance absorption to significantly increase its worth. The alloy is in the form of extruded single length rods which are sealed in chrome plated (EP-RCCA) stainless steel tubes to prevent the rods from coming in direct contact with the coolant.

The overall control rod length is such that when the assembly has been withdrawn through its full travel, the tip of the absorber rods remains engaged in the guide thimbles so that alignment between rods and thimbles is always maintained. Since the rods are long and slender, they are relatively free to conform to any small misalignments with the guide thimble. Prototype tests have shown that the RCCAs are very easily inserted and not subject to binding even under conditions of severe misalignment.

The spider assembly is in the form of a center hub with radial vanes containing cylindrical fingers from which the absorber rods are suspended. Handling detents and detents for connection to the drive shaft are machined into the upper end of the hub. A spring pack is assembled into a skirt integral to the bottom of the hub to stop the RCCA and absorb the impact energy at the end of a trip insertion. The radial vanes are joined to the hub and the fingers are joined to the vanes by furnace brazing. A center post which holds the spring pack and its retainer is threaded into the hub within the skirt and welded to prevent loosening in service. All components of the spider assembly are made from Type 304 stainless steel except for the springs which are Inconel X-750 alloy and the retainer which is of 17-4 PH material.

The absorber rods are secured to the spider so as to assure trouble free service. The rods are first threaded into the spider fingers and then pinned to maintain joint tightness, after which the pins are welded in place. The end plug below the pin position is designed with a reduced section to permit flexing of the rods to correct for small operating or assembly misalignments.

In construction, the silver indium cadmium rods are inserted into cold-worked stainless steel tubing which is then sealed at the bottom and the top by welded end plugs. The EP-RCCA tubes are then chrome plated. Sufficient diametral and end clearances are provided to accommodate relative thermal expansions and to limit the internal pressure to acceptable levels.

The bottom plugs are made bullet nosed to reduce the hydraulic drag during a reactor trip and to guide smoothly into the dashpot section of the fuel assembly guide thimbles. The upper plug is threaded for assembly to the spider and has a reduced end section to make the joint more flexible.

Stainless steel clad silver indium cadmium alloy absorber rods are resistant to radiation and thermal damage, thereby ensuring their effectiveness under all operating conditions. Rods of similar design have been successfully used in the Saxton, Trino, Yankee Rowe, Indian Point 1, San Onofre, and Connecticut Yankee reactors.

Control Rod Drive Mechanism

Design Description

The magnetic latch control rod drive mechanisms (CRDMs) are used for withdrawal and insertion of the rod cluster control assemblies (RCCAs) into the reactor core and to provide sufficient holding power for stationary support.

Fast total insertion (reactor trip) is obtained by simply removing the electrical power, allowing the rods to fall by gravity.

The complete drive mechanism shown in Figure 3.4-2 consists of the internal latch assembly, the pressure vessel, the operating coil stack, the drive shaft assembly, and the position indicator coil stack.

Each assembly is an independent unit which can be dismantled or assembled separately. A full penetration weld attaches each drive to an adapter on top of the reactor pressure vessel and is connected to the control rod directly below by means of a grooved drive shaft. The upper section of the drive shaft is suspended from the working components of the drive mechanism. The drive shaft and control rod remain connected during reactor operation, including tripping of the rods.

Reactor coolant fills the pressure containing parts of the drive mechanism. All working components and the shaft are immersed in the coolant.

Three magnetic coils which form a removable electrical unit and surround the rod drive pressure housing induce magnetic flux through the housing wall to operate the working components. They move two sets of latches which lift or lower the grooved drive shaft. The three magnets are turned on and off in a fixed sequence by solid-state switches.

The sequencing of the magnets produces step motion over the 228 steps (144 inches) of normal control rod travel. The mechanism develops a lifting force approximately two times the static lifting load. Therefore, extra lift capacity is available for overcoming mechanical friction between the moving and the stationary parts. Gravity provides the drive force for rod insertion and the weight of the whole rod assembly is available to overcome any resistance.

The unit of steps is the preferred reference for control rod movement, as it corresponds to indications used in the Technical Specifications and by plant operators. One control rod step equals 5/8 inch of rod motion.

The mechanisms are designed to operate in water at 650°F and 2485 psig. The temperature at the mechanism head adapter will be much less than 650°F because it is located in a region where there is limited flow of water from the reactor core, while the pressure is the same as in the reactor pressure vessel.

A multi-conductor cable connects the mechanism operating coils to the 125 volt DC power supply. The power supply is described in Section 7.0.

Latch Assembly

The latch assembly contains the working components which withdraw and insert the drive shaft and attached control rod. It is located within the pressure housing and consists of the pole pieces for three electromagnets. They actuate two sets of latches which engage the grooved section of the drive shaft.

The upper set of latches moves up or down to raise or lower the drive rod by one step (5/8 inch). The lower set of latches has 1/16 inch axial movement to shift the weight of the control rod from the upper to the lower latches. In the de-energized condition, the latch assembly does not engage the drive shaft.

Pressure Vessel

The pressure vessel consists of the pressure housing and rod travel housing. The pressure housing is the lower portion of the vessel and contains the latch assembly. The rod travel housing is the upper portion of the vessel. It provides space for the drive shaft during its upward movement as the control rod is withdrawn from the core. The housings are designed in accordance with the requirements of the ASME Code, Section III, Class 1, 1998 Edition through 2000 Addenda.

Operating Coil Stack

The operating coil stack is an independent unit which is installed on the drive mechanism by sliding it over the outside of the pressure housing.

It rests on a pressure housing flange without any mechanical attachment and can be removed or installed while the reactor coolant system is pressurized.

The operator coils (A, B, and C) are made of round copper wire which is insulated with a double layer of filament type glass yarn. The design temperature limit of the coils is 200°C (392°F). Coil temperature can be determined by resistance measurement. Forced air cooling along the outside of the coil stack maintains the coil temperatures below 200°C (392°F).

Drive Shaft Assembly

The main function of the drive shaft is to connect the control rod to the mechanism latches. Grooves for engagement and lifting by the latches are located throughout the 228 steps of control rod travel. The grooves are spaced 5/8 inch apart to coincide with the mechanism step length and have 45° angle sides.

The drive shaft is attached to the control rod by the coupling. The coupling has two flexible arms which engage the grooves in the spider assembly hub.

A 1/4 inch diameter disconnect rod runs down the inside of the drive shaft. It utilizes a locking button at its lower end to lock the coupling and control rod. At its upper end, there is a disconnect assembly for remote disconnection of the drive shaft assembly from the control rod. During plant operation the drive shaft assembly remains connected to the control rod at all times.

Position Indicator Coil Stack

The position indicator coil stack slides over the rod travel housing section of the pressure vessel. It detects drive rod position by means of cylindrically wound differential transformers which span the normal 228 step length of the rod travel.

Drive Mechanism Materials

All parts exposed to reactor coolant, such as the pressure vessel, latch assembly, and drive rod, are made of metals which resist the corrosive action of the water.

Three types of metals are used exclusively: stainless steels, Inconel X-750, and cobalt based alloys. Wherever magnetic flux is carried by parts exposed to the reactor coolant, stainless steel is used. Cobalt based alloys are used for the pins and latch tips.

Inconel X-750 is used for the springs of both latch assemblies and 316 stainless steel is used for all pressure containment. Hard chrome plating provides wear surfaces on the sliding parts and prevents galling between mating parts during assembly.

Outside of the pressure vessel where the metals are exposed only to the reactor plant containment environment and cannot contaminate the main coolant, carbon and stainless steels are used. Carbon steel, because of its high permeability, is used for flux return paths around the operating coils. It is zinc plated 0.001 inch thick to prevent corrosion.

Principles of Operation

The drive mechanisms shown schematically in Figure 3.4-3 withdraw and insert their respective control rods as electrical pulses are received by the operator coils.

ON and OFF sequence, repeated by solid-state switches in the power programmer causes either withdrawal or insertion of the control rod. Position of the control rod is indicated by the differential transformer action of the position indicator coil stack surrounding the rod travel housing. The differential transformer output changes as the top of the ferromagnetic drive shaft assembly moves up the rod travel housing.

Generally, during plant operation, the drive mechanisms hold the control rods withdrawn from the core in a static position, and only the stationary gripper coil is energized on each mechanism.

Control Rod Withdrawal

The control rod is withdrawn by repeating the following sequence:

1. Movable Gripper Coil - ON

   The movable gripper armature rises and swings the movable gripper latches into the drive shaft groove.

2. Stationary Gripper Coil - OFF

   Gravity causes the stationary gripper latches and armature to move downward until the load of the drive shaft is transferred to the movable gripper latches. Simultaneously, the stationary gripper latches swing out of the shaft groove.

3. Lift Coil - ON

   The gap between the lift armature and the lift magnet pole closes and the drive rod rises one step length.

4. Stationary Gripper Coil - ON

   The stationary gripper armature rises and closes the gap below the stationary gripper armature and swings the stationary gripper latches into a drive shaft groove. The latches contact the shaft and lift it 1/32 inch. The load is so transferred from the movable to the stationary gripper latches.

5. Movable Gripper Coil - OFF

   The movable gripper armature separates from the lift armature under the force of three springs and gravity. Three links, pinned to the movable gripper armature, swing the three movable gripper latches out of the groove.

6. Lift Coil - OFF

   The gap between the lift armature and the lift magnet pole opens. The movable gripper latches drop one step length to a position adjacent to the next groove.

Control Rod Insertion

The sequence for control rod insertion is similar to that for control rod withdrawal:

1. Lift Coil - ON

   The movable gripper latches are raised to a position adjacent to a shaft groove.

2. Movable Gripper Coil - ON

   The movable gripper armature rises and swings the movable gripper latches into a groove.

3. Stationary Gripper Coil - OFF

   The stationary gripper armature moves downward and swings the stationary gripper latches out of the groove.

4. Lift Coil -OFF

   Gravity separates the lift armature from the lift magnet pole and the control rod drops down one step length.

5. Stationary Gripper Coil - ON

6. Movable Gripper Coil -OFF

The sequences described above are termed as one step and the control rod moves 5/8 inch for each step. Each sequence can be repeated at a rate of up to 72 steps per minute and the control rods can, therefore, be withdrawn or inserted at a rate of up to 45 inches per minute.

Control Rod Position Definitions

During any approach to criticality, except for physics tests, the control rod position resulting in reactor criticality shall not be lower than the insertion limit for zero power. That is, if the control rods were withdrawn in normal sequence with no other reactivity change, the reactor would not be critical until the control banks were above the insertion limit (Reference 1).

During power operation, the shutdown banks are fully withdrawn. Fully withdrawn is defined as a bank demand position equal to or greater than 225 steps. Evaluation has shown that positioning control rods at 225 steps, or greater, has a negligible effect on core power distributions and peaking factors. Due to the low reactivity worth in this region of the core and the fact that, at 225 steps, control rods are only inserted one step into the active fuel region of the core, positioning rods at this position or higher has minimal effect. This position is varied, based on a predetermined schedule, in order to minimize wear of the guide cards in the guide tubes of the RCCAs (Reference 2).

Control Rod Tripping

If power to the stationary gripper coil is cut off, as for tripping, the combined weight of the drive shaft and the RCCA is sufficient to move the latches out of the shaft groove. The control rod falls by gravity into the core. The tripping occurs as the magnetic field, holding the gripper armature against the lift magnet, collapses and the gripper armature is forced down by the weight acting upon the latches.

Part-Length Rod Drive Mechanisms

The part-length RCCAs have been removed as reactor operating experience has shown them to be unnecessary.

Fuel Assembly and RCC Mechanical Evaluation

To confirm the mechanical adequacy of the fuel assembly and RCCA, functional test programs have been conducted on a full scale San Onofre mock-up version of the fuel assembly and control rods. Additional tests were run on two full scale prototype assemblies for a 12 foot active core.

One of the 12 foot assemblies incorporated stainless steel guide tubes and the other incorporated Zircaloy 4 tubes.

Reactor Evaluation Center (REC) Tests

The prototype assemblies were tested under simulated reactor operating conditions (1875 psig, 575°F, and 17.8 fps flow velocity) in the Westinghouse Reactor Evaluation Center for a total of more than 6400 hours.

Each prototype assembly was subjected to scram cycling equivalent to one or more plant lifetimes. The test history for each prototype is summarized in Table 3.4-1.

Each of the three prototype fuel assemblies described in Table 3.4-1 remained in excellent mechanical condition. No measurable signs of wear on the fuel tubes or control rod guide tubes were found. The control rod was also found to be in excellent condition, having maximum wear measured on absorber cladding of approximately 0.001 inch.

Loading and Handling Tests

Tests simulating the loading of the prototype fuel assembly into a core location were also successfully conducted to determine that proper provisions had been made for guidance of the fuel assembly during refueling operation.

Axial and Lateral Bending Tests

In addition, axial and lateral bending tests were performed in order to simulate mechanical loading of the assembly during refueling operation.

Although the maximum column load expected to be experienced in service is approximately 1000 pounds, the fuel assembly can successfully be loaded to 2200 pounds axially with no damage resulting. This information is also used in the design of fuel handling equipment to establish the limits for inadvertent axial loads during refueling.

CRDM Housing Mechanical Failure Evaluation

An evaluation of the possibility of damage to adjacent CRDM housings in the event of a circumferential or longitudinal failure of a rod housing located on the vessel head is presented.

A CRDM schematic is shown in Figure 3.4-3. The operating coil stack assembly of this mechanism has a 10.8 inch by 10.8 inch cross section and a 39.875 inch length. The position indicator coil stack assembly (not shown in this figure) is located above the operating coil stack assembly. It surrounds the rod travel housing over nearly its entire length. The rod travel housing outside diameter is 3.8 inches and the position indicator coil stack assembly consists of a 1/8 inch thick stainless steel tube surrounded by a continuous stack of copper wire coils. This assembly is held together by two end plates (the top end plate is square), an outer sleeve, and four axial tie rods.

Effect of Rod Travel Housing Longitudinal Failures

Should a longitudinal failure of the rod travel housing occur, the region of the stainless steel tube opposite the break would be stressed by the reactor coolant pressure of 2250 psia. The most probable leakage path would be provided by the radial deformation of the position indicator coil assembly, resulting in the growth of axial flow passages between the rod travel housing and the stainless steel tube. A radial free water jet is not expected to occur because of the small clearance between the stainless steel tube and the rod travel housing and the considerable resistance of the combination of the stainless steel tube and the position indicator coils to internal pressure. Calculations based on the mechanical properties of stainless steel and copper at reactor operating temperature show that an internal pressure of at least 4000 psia would be necessary for the combination of the stainless steel tube and the coils to rupture.

Therefore, the combination of stainless steel tube and copper coils stack is more than adequate to prevent formation of a radial jet following a control rod housing split, which assures the integrity of the adjacent rod housings.

Effect of Rod Travel Housing Circumferential Failures

If circumferential failure of a rod travel housing should occur, the broken off section of the housing would be ejected vertically because the driving force is vertical and the position indicator coil stack assembly and the drive shaft would tend to guide the broken off piece upwards during its travel. Travel is limited to three feet by the missile shield, thereby limiting the projectile acceleration. When the projectile reaches the missile shield, it would partially penetrate the shield and dissipate its kinetic energy. The water jet from the break would push the broken off piece against the missile shield.

If the broken off piece were short enough to clear the break when fully ejected, it could rebound after impact with the missile shield. The top end plates of the position indicator coil stack assemblies would prevent the broken piece from directly hitting the rod travel housing of a second drive mechanism. Even if a direct hit by the rebounding piece were to occur, the low kinetic energy of the rebounding projectile would not be expected to cause significant damage. (Reference 5)

Based on the above, failure of a control rod housing due to either longitudinal or circumferential cracking would not cause damage to adjacent housings that would increase the severity of the initial accident.

Burnable Absorber Rods (No longer used)

The burnable absorber rods are statically suspended and positioned in RCC thimble tubes within the fuel assemblies at some nonrodded core locations. The absorber rods at each core location are grouped and attached together at the top end of the rods by a flat spider plate which fits within the fuel assembly top nozzle and rests on the top adapter plate. The plate (and the absorber rods) are held down and restrained against vertical motion through a spring pack which is attached to the plate and is compressed by the upper core plate when the reactor upper internals package is lowered into the reactor. This ensures that the absorber rods cannot be lifted out of the core by flow forces.

The absorber rods consist of pyrex glass tubes contained within Type 304 stainless steel tubular cladding which is plugged and seal welded at the ends to encapsulate the glass. The glass is also supported along the length of its inside diameter by a thin wall Type 304 stainless steel tubular inner liner. A typical burnable absorber rod is shown in longitudinal and transverse cross sections in Figure 3.4-4.

The rods are designed in accordance with the standard fuel rod design criteria; i.e., the cladding is free standing at reactor operating pressures and temperatures and sufficient cold void volume is provided within the rods to limit internal pressures to less than the reactor operating pressure assuming total release of all helium generated in the glass as a result of the B_{10} (n,α) reaction. The large void volume required for the helium is obtained through the use of glass in tubular form which provides a central void along the length of the rods. The resulting cladding stresses at temperature and pressure are given in Reference 3.

Based on available data on properties of pyrex glass and on nuclear and thermal calculations for the rods, gross swelling or cracking of the glass tubing is not expected during operation. Some minor creep of the glass at the hot spot on the inner surface of the tube is expected to occur but continues only until the glass comes into contact with the inner liner. The inner liner is provided to maintain the central void along the length of the glass and to prevent the glass from slumping or creeping into the void as a result of softening at the hot spot. The wall thickness of the inner liner is sized to provide adequate support in the event of slumping but to collapse locally before rupture of the exterior cladding if large volume changes due to swelling or cracking should possibly occur. The top end of the inner liner is open to receive the helium which diffuses out of the glass.

To ensure the integrity of the burnable absorber rods, the tubular cladding and end plugs are procured to the same specifications and standard of quality as are used for stainless steel fuel rod cladding and end plugs in other Westinghouse plants. In addition, the end plug seal welds are checked for integrity by visual inspection and x-ray. The finished rods are helium leak checked.

Water displacer rods may also be used for power distribution control. These rods consist of outer burnable absorber stainless steel tubes without any borosilicate glass or inner stainless tubes inserted in them. The rods are plugged and seal welded at each end and pressurized with helium.

Evaluations of Burnable Absorber Rods

The burnable absorber rods are positively positioned in the core inside RCCA guide thimbles and held down in place by attachment to a plate assembly compressed beneath the upper core plate and hence cannot be the source of any reactivity transient. Due to the low heat generation rate and the conservative design of the absorber rods, there is no possibility for release of the absorber as a result of helium pressure or cladding temperature during accident transients including loss-of-coolant.

In-pile testing of two of the rods in the Saxton reactor has been conducted to verify mechanical performance of the burnable absorber material and rod configuration in a power reactor environment.

A visual examination of the rods was made in early June 1968, and a visual and profilometer examination was made July 30, 1968 after an exposure of 1900 effective full power hours (~25%

B_{10} depletion). The rods were found to be in excellent condition and profilometry results showed no dimensional variation from the original new condition.

An experimental verification of the reactivity worth calculations for pyrex glass tubing is presented in Reference 4.

REFERENCES

1. WE letter to NRC, "Technical Specification Change Request 153 - Modification of Technical Specification 15.3.10.A.5, Zero Power Rod Insertion Limit," dated November 24, 1992.

2. WE letter to NRC, "Technical Specification Change Request 151 - Documentation of Rod Position in Steps Vice Inches," dated October 6, 1992.

3. WCAP-7113, "Use of Burnable Poison Rods in Westinghouse Pressurized Water Reactors," (Proprietary), October 1967.

4. WCAP-9000, "Nuclear Design of Westinghouse Pressurized Water Reactor with Burnable Poison Rods," (Proprietary), 1968.

5. Westinghouse Calculation CN-RVHP-04-10, "Point Beach Units 1 and 2 HAUP-Missile Impact Analysis," (Westinghouse Proprietary), Revision 5, dated May 18, 2006.

TABLE 3.4-1 PROTOTYPE FUEL ASSEMBLY AND RCC ASSEMBLY TESTS

Prototype	Test Time (Hours)	Number of SCRAMs	Total Rod Travel (Feet)	Total Driven Travel (Feet)	Total SCRAM Travel (Feet)
San Onofre, 10 foot assembly, stainless steel guide thimbles	4132	1461	38,927	27,217	11,710
12 foot assembly, stainless steel guide thimbles	1000	600	45,000	38,500	6,500
12 foot assembly, Zircaloy-4 guide thimbles	1277	600	124,200	117,700	6,500

Figure 3.4-1 TYPICAL ROD CLUSTER CONTROL ASSEMBLY

[redacted]

Figure 3.4-2 CONTROL ROD DRIVE MECHANISM ASSEMBLY

[redacted]

Figure 3.4-3 CONTROL ROD DRIVE MECHANISM SCHEMATIC

[redacted]

Figure 3.4-4 DETAIL OF BURNABLE POISON ROD

[redacted]

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4.0 REACTOR COOLANT SYSTEM

The Reactor Coolant System shown in the Flow Diagram, Figure 4.2-1 and Figure 4.2-1A, consists of two essentially identical heat transfer loops connected in parallel to the reactor vessel. Each loop contains a circulating pump and a steam generator. The system also includes a pressurizer, pressurizer relief tank, connecting piping, and instrumentation necessary for operational control.

FOREIGN OBLIGATIONS

The reactor vessel closure heads and control rod drive mechanisms for Point Beach Nuclear Plant Units 1 and 2 were manufactured in Japan. Consequently, as stated in letters from the NRC dated December 16 and 17, 2004, use of this equipment ("foreign obligated equipment") obligates Point Beach Nuclear Plant to comply with certain peaceful use commitments and material tracking obligations specified in the U.S.-Japan Agreement for Peaceful Nuclear Cooperation. This equipment will not be used for any purpose that would result in any nuclear explosive device (e.g., producing tritium for the weapons program). Additionally, export of this equipment will require similar peaceful use assurances from the proposed recipient country. Finally, all nuclear material used in or produced through the use of the reactors with this equipment will also become obligated to Japan so long as that equipment is in use. All nuclear material transaction and status reports must be adjusted accordingly.

4.1 DESIGN BASIS

PERFORMANCE OBJECTIVES

The Reactor Coolant System transfers the heat generated in the core to the steam generators where steam is generated to drive the turbine generator. Borated light water, meeting exacting chemical standards, is circulated at the flow rate and temperature consistent with achieving the reactor core thermal hydraulic performance presented in Section 3.2. The water also acts as a neutron moderator and reflector and as a solvent and transport medium for the neutron absorber, boron, used in chemical shim control.

The Reactor Coolant System provides a boundary for containing the coolant under operating temperature and pressure conditions. It serves to confine radioactive material and limits to acceptable values any release to the secondary system and to other parts of the plant under conditions of either normal or abnormal reactor operation. During transient operation the system's heat capacity attenuates coolant volume changes within the protection system criteria.

By appropriate selection of the inertia of the reactor coolant pumps, the thermal hydraulic effects which result from a loss-of-flow situation are reduced to a safe level during the pump coastdown. The layout of the system assures the natural circulation capability following a loss-of-flow to permit plant cooldown without overheating the core. The system provides connections for the Safety Injection System to assure cooling water delivery to the core during a loss-of-coolant accident.

GENERAL DESIGN CRITERIA

General design criteria which apply to the Reactor Coolant System are given below.

Quality Standards

CRITERION: Those systems and components of reactor facilities which are essential to the prevention or the mitigation of the consequences of nuclear accidents which could cause undue risk to the health and safety of the public shall be identified and then designed, fabricated, and erected to quality standards that reflect the importance of the safety function to be performed. Where generally recognized codes and standards pertaining to design, materials, fabrication, and inspection are used, they shall be identified. Where adherence to such codes or standards does not suffice to assure a quality product in keeping with the safety function, they shall be supplemented or modified as necessary. Quality assurance programs, test procedures, and inspection acceptance criteria to be used shall be identified. An indication of the applicability of codes, standards, quality assurance programs, test procedures, and inspection acceptance criteria used is required. Where such items are not covered by applicable codes and standards, a showing of adequacy is required. (GDC 1)

The Reactor Coolant System is of primary importance with respect to its safety function in protecting the health and safety of the public. Quality standards of material selection, design, fabrication, and inspection conform to the applicable provisions of recognized codes and good nuclear practice. Details of the quality assurance programs, test procedures, and inspection acceptance levels are given in Section 4.4. Particular emphasis is placed on the assurance of quality of the reactor vessel to obtain material whose properties are uniformly within code specifications.

Performance Standards

CRITERION: Those systems and components of reactor facilities which are essential to the prevention or to the mitigation of the consequences of nuclear accidents which could cause undue risk to the health and safety of the public shall be designed, fabricated, and erected to performance standards that will enable such systems and components to withstand, without undue risk to the health and safety of the public, the forces that might reasonably be imposed by the occurrence of an extraordinary natural phenomenon such as earthquake, tornado, flooding condition, high wind, or heavy ice. The design bases so established shall reflect: (a) appropriate consideration of the most severe of these natural phenomena that have been officially recorded for the site and the surrounding area and (b) an appropriate margin for withstanding forces greater than those recorded to reflect uncertainties about the historical data and their suitability as a basis for design. (GDC 2)

All piping, components, and supporting structures of the Reactor Coolant System are designed as seismic Class I equipment.

Seismic Design Classification details are given in Appendix A.5.

The Reactor Coolant System is located in the containment building whose design, in addition to being a seismic Class I structure, also considers accidents or other applicable natural phenomena. Details of the containment design are given in Section 5.0.

Records Requirements

CRITERION: The reactor licensee shall be responsible for assuring the maintenance throughout the life of the reactor of records of the design, fabrication, and construction of major components of the plant essential to avoid undue risk to the health and safety of the public. (GDC 5)

Records of the design, of the major Reactor Coolant System components, and the related engineered safety feature components are maintained at Point Beach and will be retained throughout the life of the plant.

Note: The portion of the following paragraph pertaining to fabrication records is historical. Per the Asset Sale Agreement between WE Energy and FPL Energy Point Beach, FPL Energy Point Beach acquired rights to documents owned by third parties. (Reference 9).

Records of fabrication are maintained in the manufacturer's plants as required by the appropriate code or other requirements pending submittal to Westinghouse or Wisconsin Electric Power Company. They are available at any time to Wisconsin Electric Power Company throughout the life of the plant. Construction records are available at the Point Beach Nuclear Plant where they will be retained for the life of the plant.

Missile Protection

CRITERION: Adequate protection for those engineered safety features, the failures of which could cause an undue risk to the health and safety of the public, shall be provided against dynamic effects and missiles that might result from plant equipment failures. (GDC 40)

This plant-specific General Design Criterion is very similar to 10 CFR 50 Appendix A GDC 4. Under the provisions of that criterion, the dynamic effects associated with postulated pipe ruptures of the RCS may be excluded from the design basis when appropriate analyses approved by the NRC demonstrate that the probability of such ruptures is extremely low (Reference 1). Analyses have been completed for PBNP for the Reactor Coolant Loop piping and the Pressurizer Surge Line (Reference 2 and Reference 6). The NRC has approved the analyses (Reference 3, Reference 7, and Reference 8). As such, the original design features of the facility to accommodate the dynamic effects of a Reactor Coolant pipe or Pressurizer Surge line pipe rupture are no longer applicable. In the balance of this chapter, discussions of these features have been retained for historical information, and to provide continuity in the discussion of related features.

The steam generators are supported, guided, and restrained in a manner which prevents rupture of the steam side of a generator, the steam pipelines, and the feedwater piping as a result of forces created by a Reactor Coolant System pipe rupture. These supports, guides, and restraints also prevent rupture of the primary side of a steam generator as a result of forces created by a steam or feedwater pipeline rupture. The mechanical consequences of a pipe rupture are restricted by design such that the functional capability of the engineered safety features is not impaired.

PRINCIPAL DESIGN CRITERIA

The criteria which apply solely to the Reactor Coolant System are given below.

Reactor Coolant Pressure Boundary

CRITERION: The reactor coolant pressure boundary shall be designed, fabricated, and constructed so as to have an exceedingly low probability of gross rupture or significant uncontrolled leakage throughout its design lifetime. (GDC 9)

The Reactor Coolant System, in conjunction with its control and protective provisions, is designed to accommodate the system pressures and temperatures attained under all expected modes of plant operation or anticipated system interactions, and maintain the stresses within applicable code stress limits. Fabrication of the components which constitute the pressure boundary of the Reactor Coolant System is carried out in accordance with the applicable codes at the time of fabrication. In addition, there are areas where specifications for Reactor Coolant System components go beyond the applicable codes. Details are given in Section 4.4.

The materials of construction of the pressure boundary of the Reactor Coolant System are protected from corrosion phenomena which might otherwise significantly reduce the system structural integrity during its service lifetime by the use of noncorrosive materials (such as stainless steel) and by the maintenance of proper chemistry control.

System conditions resulting from anticipated transients or malfunctions are monitored and appropriate action is automatically initiated to maintain the required cooling capability and to limit system conditions to a safe level.

The system is protected from overpressure by means of pressure relieving devices, as required by Section III of the ASME Boiler and Pressure Vessel Code. The system is also protected from overpressure at low temperatures by the Low Temperature Overpressure Protection System.

Isolable sections of the system are provided with overpressure relieving devices discharging to closed systems such that the system code allowable relief pressure within the protected section is not exceeded.

Monitoring Reactor Coolant Leakage

CRITERION: Means shall be provided to detect significant uncontrolled leakage from the reactor coolant pressure boundary. (GDC 16)

Positive indications in the control room of leakage of coolant from the Reactor Coolant System to the containment are provided by equipment which permits continuous monitoring of containment air activity and humidity, as well as collection of runoff from the condensate collecting pans under the cooling coils of the containment air recirculation units, and from the containment floor drains. This equipment provides indication of normal background which is indicative of a basic level of leakage from primary systems and components. Any increase in the observed parameters is an indication of change within the containment, and the equipment provided is capable of monitoring this change. The basic design criterion is the detection of deviations from normal containment environmental conditions including air particulate activity, radiogas activity, humidity, volume of condensate and floor drain runoff, and in addition, in the case of gross leakage, the liquid inventory in the process systems and containment sump.

Further details are supplied in Section 6.0.

Reactor Coolant Pressure Boundary Capability

CRITERION: The reactor coolant pressure boundary shall be capable of accommodating without rupture the static and dynamic loads imposed on any boundary component as a result of an inadvertent and sudden release of energy to the coolant. As a design reference, this sudden release shall be taken as that which would result from a sudden reactivity insertion such as rod ejection (unless prevented by positive mechanical means), rod dropout, or cold water addition. (GDC 33)

The reactor coolant boundary is shown to be capable of accommodating, without rupture, the static and dynamic loads imposed as a result of a sudden reactivity insertion such as a rod ejection. Details of this analysis are provided in Section 14.2.6. The operation of the reactor is such that the severity of an ejection accident is inherently limited. Since control rod clusters are primarily used to control load variations and boron dilution is used primarily to compensate for core depletion, only the rod cluster control assemblies in the controlling groups are inserted in the core at power, and at full power these rods are only partially inserted. A rod insertion limit monitor is provided as an administrative aid to the operator to insure that this condition is met.

By defining control rod groupings, radial locations, and allowed axial position as a function of load, the design limits the maximum fuel temperature for the highest worth ejected control rod accident to a value which precludes excessive pressure surges and any resultant damage to the primary system pressure boundary. The failure of a rod mechanism housing causing a rod cluster to be rapidly ejected from the core is evaluated as a theoretical, though not a credible accident. While limited fuel damage could result from the hypothetical event, any released fission products are confined to the Reactor Coolant System and the reactor containment. The environmental consequences of rod ejection are less severe than from the hypothetical loss-of-coolant for which public health and safety is shown to be adequately protected in Section 14.3.5.

Reactor Coolant Pressure Boundary Rapid Propagation Failure Prevention

CRITERION: The reactor coolant pressure boundary shall be designed and operated to reduce to an acceptable level the probability of rapidly propagating type failures. Consideration is given (a) to the provisions for control over service temperature and irradiation effects which may require operational restrictions, (b) to the design and construction of the reactor pressure vessel in accordance with applicable codes, including those which establish requirements for absorption of energy within the elastic strain energy range and for absorption of energy by plastic deformation and (c) to the design and construction of reactor coolant pressure boundary piping and equipment in accordance with applicable codes. (GDC 34)

The reactor coolant pressure boundary is designed to reduce to an acceptable level the probability of a rapidly propagating type failure. The fracture toughness of the materials in the beltline region of the reactor vessel will decrease as a result of fast neutron irradiation induced embrittlement. Fracture toughness will decrease with increasing the reference nil ductility temperature (RT_{NDT}), which increases as a function of several factors, including accumulated fast neutron fluence. This change in material properties is factored into the operating procedures such that the reactor coolant system pressure is limited with respect to RCS temperature during plant heatup, cooldown, and normal operation. These limits are determined in accordance with the methods of analysis and the margins of safety of Appendix G of ASME Code Section XI and are included in the Point Beach Pressure Temperature Limits Report (PTLR). The Low Temperature Overpressure Protection System provides protection during low-temperature operations.

All pressure containing components of the Reactor Coolant System are designed, fabricated, inspected, and tested in conformance with the applicable codes at the time of order placement. Further details are given in Table 4.1-9.

Reactor Coolant Pressure Boundary Surveillance

CRITERION: Reactor coolant pressure boundary components shall have provisions for inspection, testing, and surveillance of critical areas by appropriate means to assess the structural and leaktight integrity of the boundary components during their service lifetime. For the reactor vessel, a material surveillance program conforming with current applicable codes shall be provided. (GDC 36)

The design of the reactor vessel and its arrangement in the system permits access during the service life to the entire internal surfaces of the vessel and to the following external zones of the vessel: the flange seal surface, the flange OD down to the cavity seal ring, the closure head and the nozzle to reactor coolant piping welds. The reactor arrangement within the containment provides sufficient space for inspection of the external surfaces of the reactor coolant piping, except for the area of pipe within the primary shielding concrete.

Monitoring of the RT_{NDT} properties of the core region base material, weldments, and associated heat affected zones are performed in accordance with a surveillance program meeting the requirements of 10 CFR 50, Appendix H. Samples of reactor vessel plate and forging materials are retained and catalogued and are available for future testing, as needed.

To define permissible operating conditions heatup and cooldown limit curves are established in accordance with the methods of analysis and the margins of safety of the ASME Boiler and Pressure Vessel Code, Section XI, Appendix G. In addition, the Low Temperature Overpressure Protection System using the power-operated relief valves is activated whenever the reactor coolant system is not open to the atmosphere and the coolant temperature is less than criteria established by ASME Section XI.

DESIGN CHARACTERISTICS

Design Pressure and Temperature

The Reactor Coolant System design and operating pressure, together with the safety, power operated relief, and pressurizer spray valves set points, and the protection system set point pressures, are listed in Table 4.1-1. The design pressure allows for operating transient pressure changes. The selected design margin considers core thermal lag, coolant transport times and pressure drops, instrumentation and control response characteristics, and assumed system relief valve characteristics. The design pressures and data for the respective system components are listed in Table 4.1-2 through Table 4.1-6. Table 4.1-7 gives the design pressure drop of the system components. The design temperature for each component is selected to be above the maximum coolant temperature in that component under all normal and anticipated transient load conditions. The design and operating temperatures of the respective system components are listed in Table 4.1-2 through Table 4.1-6.

Seismic Loads

The seismic loading conditions are established by the "Operating Basis Earthquake" (OBE) and "Safe Shutdown Earthquake" (SSE). The former is selected to be typical of the largest probable ground motion based on the site seismic history. The latter is selected to be the largest potential ground motion at the site based on seismic and geological factors and their uncertainties. For the "Operating Basis Earthquake" loading condition, the systems necessary for continued operation without undue risk to the health and safety of the public are designed to remain functional.

The seismic design for the "Safe Shutdown Earthquake" is intended to provide a margin in design that assures:

1. The integrity of the reactor coolant pressure boundary.

2. The capability to shutdown the reactor and maintain it in a safe shutdown condition, or

3. The capability to prevent or mitigate the consequences of accidents which could result in potential offsite exposures comparable to the exposures of 10 CFR 50.67 (Reference 11).

For the combination of normal plus design earthquake loadings, the stresses in the support structures are kept within the limits of the applicable codes. For the combination of normal plus no-loss-of-function earthquake loadings, the stresses in the support structures are limited to values necessary to ensure their integrity and to keep the stresses in the Reactor Coolant System components within the allowable limits as given in Appendix A.5.

Cyclic Loads

All components in the Reactor Coolant System are designed to withstand the effects of cyclic loads due to reactor system temperature and pressure changes. These cyclic loads are introduced by normal power changes, reactor trip, and startup and shutdown operation. The number of thermal and loading cycles used for design purposes and their bases are given in Table 4.1-8. During unit heatup and cooldown, pressure and the rates of temperature change are limited. The cycles are estimated to be an accurate representation of actual transients or actual operating experience.

The Reactor Coolant System and its components are designed to accommodate 10% of full power step changes in plant load and 5% of full power per minute ramp changes over the range from 15% full power, up to and including but not exceeding 100% of full power, without reactor trip. The Reactor Coolant System will accept a complete loss of load from full power with reactor trip. In addition, the turbine bypass and steam dump system make it possible to accept a rapid load decrease of 50% of full power at a rate up to 200%/minute without reactor trip, or a turbine trip from below 50% power without a reactor trip.

To provide the necessary high degree of integrity for the equipment in the Reactor Coolant System, the transient conditions selected for equipment fatigue evaluation are based on a conservative estimate of the magnitude and frequency of the temperature and pressure transients resulting from normal operation, and normal and abnormal load transients. To a large extent, the specific transient operating condition considered for equipment fatigue analyses are based upon engineering judgment and experience. Those transients are chosen which are representative of transients to be expected during plant operation and which are sufficiently severe or frequent to be of possible significance to component cyclic behavior.

Clearly, it is difficult to discuss in absolute terms, the transients that the plant will actually experience during the 60 years operating life. (NRC SE dated 12/2005, NUREG -1839) For clarity, however, each transient condition is discussed in order to make clear the nature and basis for the various transients.

Heatup and Cooldown

The heatup or cooldown cases are conservatively represented by a continuous operation performed at a uniform temperature rate of 100°F per hour. For these cases, the heatup occurs from ambient to the no-load temperature and pressure condition and the cooldown represents the reverse situation. In actual practice, the rate of temperature change of 100°F per hour will not be attained because of other limitations such as:

1. Material NDT considerations which may establish maximum permissible temperature rate of change, as a function of plant pressure and temperature, which are below the design rate of 100°F per hour.

2. Slower initial heatup rates attainable from pump energy and pressurizer heaters only.

3. Interruptions in the heatup and cooldown cycles due to such factors as drawing a pressurizer steam bubble, required testing, rod withdrawal, sampling, water chemistry, and gas adjustments.

4. Design and operating restrictions associated with reactor critical conditions.

The number of complete heatup and cooldown operations is specified at 200 times for the 60-year plant design life. For the ideal plant, only one heatup and one cooldown would occur per fuel cycle, i.e., the period between refuelings. (NRC SE dated 12/2005, NUREG -1839) In practice, experience to date indicates that, during the first year or so of operation, additional unscheduled plant cooldowns may be necessary for plant maintenance.

Unit Loading and Unloading

The unit loading and unloading cases are conservatively represented by a continuous and uniform ramp power change of 5% per minute between no load and full load. The reactor coolant temperature will vary with load as prescribed by the temperature control system. The number of each operation is specified in Table 4.1-8 for the 60-year plant life. (NRC SE dated 12/2005, NUREG-1839) In practice, the plant is generally operated at base load conditions with changes in power at a rate much less than 5% per minute.

Step Increase and Decrease of 10%

The ±10% step change in load demand is a control transient which is assumed to be a change in turbine control valve opening which might be occasioned by disturbances in the electrical network into which the plant output is tied. The reactor control system is designed to restore plant equilibrium without reactor trip following a ±10% step change in turbine load demand in the range between 15% and 100% full load, the power range for automatic reactor control. In effect, during load change conditions, the reactor control system attempts to match turbine and reactor outputs in such a manner that peak reactor coolant temperature is minimized and reactor coolant temperature is restored to its programmed set point at a sufficiently slow rate to prevent excessive pressurizer pressure change.

Following a step load decrease in turbine load, the secondary side steam pressure and temperature initially increase since the decrease in nuclear power lags behind the step decrease in turbine load. During the same increment of time, the Reactor Coolant System average temperature and pressurizer pressure also initially increase. Because of the power mismatch between the turbine and reactor, the increase in reactor coolant temperature will be ultimately reduced from its peak value to a value below its initial equilibrium value at the inception of the transient. The reactor coolant average temperature set point change is made as a function of turbine generator load as determined by first stage turbine pressure measurement. The pressurizer pressure will also decrease from its peak pressure value and follow the reactor coolant decreasing temperature trend. At some point during the decreasing pressure transient, the saturated water in the pressurizer begins to flash, which reduces the rate of pressure decrease. Subsequently, the pressurizer heaters come on to restore the plant pressure to its normal value.

Following a step load increase in turbine load, the reverse situation occurs, i.e., the secondary side steam pressure and temperature initially decrease and the reactor coolant average temperature and pressure initially decrease. The control system automatically withdraws the control rods to increase core power. The decreasing pressure transient is reversed by actuation of the pressurizer heaters and eventually the system pressure is restored to its normal value. The reactor coolant average temperature will be raised to a value above its initial equilibrium value at the beginning of the transient. The number of each operation is specified at 2000 times for the 60-year plant life. (NRC SE dated 12/2005, NUREG -1839)

Large Step Decreases in Load

This transient applies to a step decrease in turbine load of such magnitude that the resultant rapid increase in reactor coolant average temperature and secondary side steam pressure and temperature will automatically initiate a condenser steam dump system to avert a reactor shutdown or lifting of steam generator safety valves. The number of occurrences of this transient is specified at 200 times for the 60-year plant life. (NRC SE dated 12/2005, NUREG -1839) The operating experience of Point Beach Nuclear Plant Units 1 and 2 also indicates that this basis is adequately conservative.

Loss-of-Load Transient

The loss-of-load transient is the most severe transient on the Reactor Coolant System. The transient applies to a step decrease in turbine load from full power occasioned by the loss-of-turbine-load without immediately initiating a reactor trip. The reactor and turbine eventually trip as a consequence of a high pressurizer pressure trip initiated by the reactor protection system. See Section 14.1.9 for loss-of-load transient analysis.

Loss-of-Flow

The loss-of-flow transient applies to a partial loss of flow accident from full power in which a reactor coolant pump is tripped out of service as a result of a loss of power to that pump. The consequences of such an accident are a reactor and turbine trip followed by automatic opening of the steam dump system and flow reversal in the affected loop. The net result of the flow reversal is a sizable reduction in the hot leg coolant temperature of the affected loop. See Section 14.1.8 for loss-of-flow transient analysis.

The number of occurrences of the above transients is generally specified at two per year of plant design life. All components in the Reactor Coolant System are designed to withstand the effects of these and other transients that result in system temperature and pressure changes.

Reactor Trip From Full Power

A reactor trip from full power may occur for a variety of causes resulting in temperature and pressure transients in the Reactor Coolant System and in the secondary side of the steam generator. This is the result of continued heat transfer from the reactor coolant in the steam generator. The transient continues until the reactor coolant and steam generator secondary side temperatures are in equilibrium at zero power conditions. A continued supply of feedwater and controlled dumping of secondary steam remove the core residual heat and prevent the steam generator safety valves from lifting. The reactor coolant temperature and pressure undergo a rapid decrease from full power values as the reactor protection system causes the control rods to move into the core.

The number of occurrences of this transient is specified at 400 times for the 60 year plant life. (NRC SE dated 12/2005, NUREG -1839) The tripping history of Point Beach Nuclear Plant Units 1 and 2 indicate that this basis is indeed conservative.

Feedwater Cycling at Hot Standby

Feedwater cycling can occur when the plant is being maintained at hot standby or no-load conditions. This transient assumes the intermittent addition of 32°F feedwater into the steam generator secondary side while it is in a no-load condition at 547°F. For design purposes, it is assumed that the steam generators will experience 25,000 cycles of cold feedwater introduction. Feedwater additions required during plant heatup and cooldown are assumed to by bounded by the feedwater cycling transient, with no increase in the total number of cycles.

Boron Concentration Equalization

Following a large change in boron concentration in the RCS, spray is initiated in order to equalize concentration between the loops and the pressurizer. For design purposes, it is assumed that this operation is performed once after each unit loading or unloading. The number of loading and unloading operations is defined as 11,680 occurrences during the 60-year life of the plant. On this basis, the total number of boron concentration equalization cycles is 23,360.

Loss of Power

This transient applies to a blackout situation involving the loss of outside electrical power to the station with a reactor and turbine trip. Under these circumstances, the reactor coolant pumps are de-energized and following the coastdown of the reactor coolant pumps, natural circulation builds up in the system to some equilibrium value. This condition permits removal of core residual heat through the steam generators, which are assumed to receive feedwater from the Auxiliary Feed System (operating from diesel generator power). Steam is removed for reactor cooldown through atmospheric relief valves. The number of occurrences of this transient is assumed to be a total of 40 times in a 60-year plant life.

Inadvertent Actuation of Auxiliary Spray

Inadvertent actuation of auxiliary spray will occur if the auxiliary spray valve is opened inadvertently during normal operation of the plant. This will introduce cold water into the pressurizer with a very sharp pressure decrease within the pressurizer, as a result. The pressure decreases rapidly to the low pressure reactor trip point, at which point it is assumed the trip is actuated. This accentuates the pressure decrease until the pressure is finally limited to the hot leg saturation pressure. At five minutes, spray is stopped and all the pressurizer heaters return the pressure to 2250 psia. For design purposes, it is assumed that there are no temperature changes in the RCS, with the exception of the pressurizer. A total of 10 occurrences of this transient are specified for a 60-year plant life.

It should be noted that the design transient pressurizer pressure and temperature variations are considered only to occur in the pressurizer during Inadvertent Actuation of Auxiliary Spray. The design transient is not applicable to the other RCS components.

Reactor Coolant Pipe Break

This transient involves the postulated rupture of a Reactor Coolant System pipe resulting in a loss of coolant. It is conservatively assumed that the system pressure is reduced rapidly and the emergency core cooling system (ECCS) is initiated to introduce water into the reactor coolant system. Because of the rapid blowdown of coolant from the system and the conservatively large heat capacity of the metal sections of the components, it is likely that the metal will remain at or near the no-load temperature conditions when the ECCS water is introduced into the system.

This hypothetical transient is not expected to occur. The postulated one-time event was included in the transient sets used to evaluate thermal and loading cycles over the 60-year plant life.

Steam Line Break

For component evaluation, the following conservative conditions are considered:

1. The reactor is initially in a hot, zero-power subcritical condition assuming all rods in except the most reactive rod which is assumed to be stuck in its fully withdrawn position.
2. A major steam line rupture occurs and the result is a reactor and turbine trip.
3. Subsequent to the break the reactor coolant temperature cools down to 212°F.
4. The ECCS pumps restore the reactor coolant pressure to 2500 psia.

This hypothetical transient is not expected to occur. The postulated one-time event was included in the transient sets used to evaluate thermal and loading cycles over the 60-year plant life.

Turbine Roll Test

The turbine roll test transient is imposed upon the plant during the hot functional test period for turbine cycle checkout. Reactor coolant pump power is used to heat the reactor coolant to operating temperature (no-load conditions), and the steam generated is used to perform a turbine roll test. The number of test cycles is specified as 10 occurrences, to be performed at the beginning of plant operating life prior to irradiation.

Steady-State Fluctuations

The reactor coolant pressure and temperature can vary around the steady state values during operation. For purposes of design, two cases are considered. Initial fluctuations due to control rod cycling during the first 20 months of operation are assumed to result in reactor coolant temperature and pressure variations of +/-3°F and +/-25 psi once during each 2-minute period. The total number of these occurrences is limited to 150,000 cycles. In addition, random fluctuations of reactor coolant temperature (varying by 0.5°F) and pressure (varying up to +/-6 psi) are assumed to occur once during each 6-minute period. The total number of these random occurrences during the plant life is specified at 5,000,000 cycles.

Hydrostatic Test Conditions

The pressure tests outlined below apply to field hydrostatic tests conducted on the erected reactor coolant system. The number of tests given below does not include any allowance for pressure tests conducted on a specific component in the manufacturer's shop in accordance with vessel code requirements.

1. Primary Side Hydrostatic Test Before Initial Startup at 3110 psig

   This hydrostatic pressure test was performed at a minimum water temperature of 100°F imposed by reactor vessel material Crack Arrest Temperature (CAT) of 100°F at beginning of life, and a maximum test pressure of 3110 psig. In this test, the primary side of the steam generator was pressurized to 3110 psig coincident with the secondary side pressure of 0 psig. The Reactor Coolant System was evaluated for up to 5 cycles of this hydrostatic pressure test.

2. Primary Side Post Operation Leak Test at 2485 psig

   The Reactor Coolant System is designed to permit periodic pressure testing to assure the structural and leaktight integrity of its components. All components in the Reactor Coolant System are designed to withstand the effects of transients that result in system temperature and pressure changes.

Stress intensity values at all critical points in the reactor vessel due to these excursions of pressure and temperature are determined for each of these transients through systematic analytical procedures. These stress intensity values S_{ij} (i,j = 1, 2, 3) are plotted against a time interval for each cycle. This plot may represent one or more stress cycles. For each cycle, extreme values of S_{max} and S_{min} are determined. From these values, the largest S_{alt} (alternating stress intensity) is found.

For this value of $S_{alt,}$ an allowable number of cycles (N) is determined through design fatigue curves established for specific materials. The ratio of design cycles (n) to allowable cycles (N) gives the usage factor u_i (i = 1, 2, 3, etc.). Usage factor is determined in this manner for all transients. The cumulative usage factor is determined by summing the individual usage factors. The cumulative usage factor ($U = u_1 + u_2 + u_3 ...$) is never allowed to exceed a value of 1.0. This means that the allowable number of cycles always exceeds the design cycles. This certainty assures safety of the components against fatigue failure.

Service Life

The service life of Reactor Coolant System pressure components depends upon the end of life material radiation damage, unit operational thermal cycles, quality manufacturing standards, environmental protection, and adherence to established operating procedures.

The reactor vessel is the only component of the Reactor Coolant System which is exposed to a significant level of neutron irradiation and it is therefore the only component which is subject to any appreciable material radiation damage effects. The RT_{NDT} shift of the vessel material and welds during service due to radiation damage effects is monitored by a material surveillance program which conforms with ASTM E185-82 (Standard Practice for Conducting Surveillance Tests for Light Water Cooled Nuclear Power Reactor Vessels).

Reactor coolant system pressure and temperature limits, including those for plant heatup and cooldown, are obtained in accordance with 10 CFR 50, Appendix G by following the methods of analysis and the required margins of safety of Appendix G of ASME Code Section XI. Additional discussion of these limits is provided in Section 4.3.

To establish the service life of the Reactor Coolant System components as required by the ASME (Part III) Boiler and Pressure Vessel Code for Class A Vessels, the unit operating conditions have been established for the 60-year life. (NRC SE dated 12/2005, NUREG-1839) These operating conditions include the cyclic application of pressure loadings and thermal transients. The number of thermal and loading cycles used for design purposes is listed in Table 4.1-8 (Reference 10).

CODES AND CLASSIFICATIONS

All pressure containing components of the Reactor Coolant System are designed, fabricated, inspected, and tested in conformance with the applicable codes listed in Table 4.1-9. Unless stated otherwise, the version of the code which was in effect at the time the original component was ordered is applicable. The Reactor Coolant System is classified as Class I for seismic design, requiring that there will be no loss of function of such equipment in the event of the assumed maximum potential ground acceleration acting in the horizontal and vertical directions simultaneously, when combined with the primary steady state stresses.

REFERENCES

1. G.E. Lear, "Exemption from the requirements of 10 CFR 50 Appendix A, General Design Criterion 4," dated May 6, 1986.

2. Westinghouse WCAP 14439 P Revision 2, "Technical Justification for Eliminating Large Primary Loop Pipe Units 1 and 2 for the Power Uprate and License Renewal Program." (Proprietary)

3. H.K. Chernoff, “Point Beach Nuclear Plant, Units 1 and 2, Issuance of Amendments re: Leak Before Break Evaluation for Primary Loop Piping (TAC Nos. MC1279 and MC1280),” dated June 6, 2005.

4. NRC Letter, V. L. Ordaz (NRC) to J. McCarthy (NMC), dated December 16, 2004.

5. NRC Letter, V. L. Ordaz (NRC) to J. McCarthy (NMC), dated December 17, 2004.

6. WCAP-15065-P-A, Rev. 1 “Technical Justification for Eliminating Pressurizer Surge Line Rupture as the Structural Design Basis for Point Beach Units 1 and 2 Nuclear Plants,” (Proprietary) dated June 1, 2001.

7. NRC SE “Safety Evaluation of the Request to Apply Leak-Before-Break Status to the Pressurizer Surge Line Piping,” dated December 15, 2000.

8. NRC SE “PBNP, Units 1 and 2 - Supplement to Safety Evaluation on Leak-Before-Break Regarding Correction of Leak Detection Capability,” dated February 7, 2005.

9. NMC Letter, WE Energies and FPL Energy Point Beach to NRC, “Application for Order and Conforming License Amendments to Transfer Facility Operating Licenses,” dated January 26, 2007.

10. WCAP-16983-P, Rev. 0, “Point Beach Units 1 and 2 Extended Power Uprate (EPU) Engineering Report,” (Proprietary) dated September 2009.

11. NRC Safety Evaluation dated May 3, 2011, “Issuance of License Amendment Regarding Extended Power Uprate (TAC Nos. ME1044 and ME1045).”

12. FPL Energy letter to NRC, NRC 2009-0030, “License Amendment Request 261 Extended Power Uprate,” dated April 7, 2009.

Table 4.1-1 REACTOR COOLANT SYSTEM DESIGN PARAMETERS AND PRESSURE SETTINGS

Total Primary Heat Output, MWt (w/RCPs)	1806
Total Primary Heat Output, Btu/hr	6162×10^6
Number of Loops	2
Coolant Volume (liquid), including original pressurizer volume, at full power (60% full), ft^3	6148 (Unit 2) 6000 (Unit 1)
Total Reactor Coolant Flow, lb/hr	$67.6\text{-}69.3 \times 10^6$
	<u>Pressure (psig)</u>
Design Pressure	2485
Operating Pressure (at pressurizer)	2235 ± 100
Safety Valves	2485
Power Operated Relief Valves	2335(1)
Pressurizer Spray Valves (open)	2260
High Pressure Trip	≤2385
Low Pressure Trip	≥ 1855
Hydrostatic Test Pressure (Cold)	3110

(1) ≤ PORV lift setting limits for RCS low temperature operation as defined in TRM 2.2; Pressure Temperature Limits Report.

Table 4.1-2 REACTOR VESSEL DESIGN DATA

Design/Operating Pressure, psig	2485/2235
Hydrostatic Test Pressure, psig	3110
Design Temperature, °F	650
Overall Height of Vessel and Closure Head, feet-inches (Bottom Head O.D. to top of CRDM Housing)	39-0
Water Volume, ft^3 (with core and internals in place),	2473
Thickness of Insulation, min., in.	3
Number of Reactor Closure Head Studs	48
Diameter of Reactor Closure Head Studs, in.	6
Flange, ID, in.	123.8
Flange, OD, in.	157.3
ID at Shell, in.	132
Inlet Nozzle ID, in.	27.47
Outlet Nozzle ID, in.	28.97
Clad Thickness, min., in. (not including closure head)	0.156
Clad Thickness, min., in. (closure head)	0.125
Lower Head Thickness, min., in.	4.125
Vessel Belt Line Thickness, min., in.	6.5
Closure Head Thickness, in.	5.375
Reactor Coolant Inlet Temperature, °F	523.1 (552.5)[(1)]
Reactor Coolant Outlet Temperature, °F	611.1 (610.1)[(1)]
Reactor Coolant Flow, lb/hr	67.6×10^6
Safety Injection Nozzle, number/size, in.	2/4

(1) Original reactor coolant inlet and outlet temperatures. Reactor coolant temperature operating band was changed subsequent to initial plant operation.

Table 4.1-3 PRESSURIZER AND PRESSURIZER RELIEF TANK DESIGN DATA

<u>Pressurizer</u>	
Design/Operating Pressure, psig	2485/2235
Hydrostatic Test Pressure (cold), psig	3110
Design/Operating Temperature, °F	680/653
Water Volume, Full Power, ft^3	472
Steam Volume, Full Power, ft^3	528
Surge Line Nozzle Diameter, in./Pipe Schedule	14/Sch 140
Shell ID, in./Minimum Shell Thickness, in.	84/4.1
Minimum Clad Thickness, in.	0.188
Electric Heaters Capacity, kw (total)	1000(2)
Maximum Heatup rate of Reactor Coolant System using Heaters only, °F/hr	55 (approximately)
<u>Power Relief Valves</u>	
Number	2
Set Pressure (open), psig	2335(1)
Capacity, lb/hr saturated steam/valve	179,000
<u>Safety Valves</u>	
Number	2
Set Pressure, psig	2485
Capacity, lb/hr saturated steam / valve	288,000
<u>Pressurizer Relief Tank</u>	
Design pressure, psig	100
Rupture Disc Release Pressure, psig	100
Design temperature, °F	340
Normal water temperature, °F	Containment Ambient
Total volume, ft^3	800
Rupture Disc Relief Capacity, lb/hr	7.2×10^5

(1) ≤ PORV lift setting limits as defined in TRM 2.2; Pressure Temperature Limits Report.
(2) Design value. Control system analysis supports a minimum value of 670 KW (total).

Table 4.1-4 STEAM GENERATOR DESIGN DATA

Sheet 1 of 2

	Unit 2	Unit 1
Model	Δ47	44F
Number of Steam Generators	2	2
Design Pressure, Reactor Coolant/ Steam, psig	2485/1085	2485/1085
Tube Design Primary-to-Secondary Differential Pressure, psig	1700	1700
Reactor Coolant Hydrostatic Test pressure (tube side-cold), psig	3107	3106
Design Temperature, Reactor Coolant/Steam, °F	650/556	650/556
Reactor Coolant Flow, gpm	89,000	89,000
Total Heat Transfer Surface Area, ft^2	47,500	43,467
Heat Transferred, Btu/hr	3081×10^6	3081×10^6
Steam Conditions at Full Load, Outlet Nozzle:		
Steam Flow, 10^6 lbm/hr	3.68 - 4.06	3.68 - 4.06
Steam Temperature, °F	486.3 - 511.6	486.3 - 511.6
Steam Pressure, psia	601 - 755	601 - 755
Feedwater Temp., at 100% Load, °F	390.0 - 458.0	390.0 - 458.0
Overall Height, ft-in.	62-11	63-1.6
Shell OD, upper/lower, in.	166.4/127.8	166/127
Shell Thickness, upper/lower, in.	3.47/2.61	3.5/2.62
Number of U-Tubes	3499	3214
U-Tube OD, in.	0.875	0.875
Tube Wall Thickness, (nominal), in.	0.050	0.050
Number of Manways/ID, in.	4/16	3/16
Number of Handholes/ID, in.	6/6	6/6
Inspection Ports/ID, in.	2/4	1/3

Table 4.1-4 (cont'd) STEAM GENERATOR DESIGN DATA

Sheet 2 of 2

	---- Unit 2 ----		----Unit 1----	
	1806 MWt	Zero Power	1806 MWt	Zero Power
Reactor Side Coolant Water Volume, ft^3	991	991	925	925
Primary Side Fluid Heat Content, 10^6 Btu	23.6 - 25.8	25.3	22.2 - 24.2	24.42
Secondary Side Water Volume, ft^3	1353-1577	2704	1443 - 1672	2877
Secondary Side Steam Volume, ft^3	3084 - 3309	1970	3026 - 3256	1804
Secondary Side Fluid Heat Content, 10^6 Btu	36.9 - 43.5	73.5	39.7 - 45.6	75.5

Table 4.1-5 REACTOR COOLANT PUMPS DESIGN DATA

Number of Pumps	2
Design Pressure/Operating Pressure, psig	2485/2235
Hydrostatic Test Pressure (cold), psig	3110
Design Temperature (casing), °F	650
RPM at Nameplate Rating	1189
Suction, Temperature, °F	551.8
Net Positive Suction Head, ft.	172
Developed Head, ft.	252
Capacity, gpm	89,000
Seal Water Injection, gpm	8
Seal Water Return, gpm	3
Pump Discharge Nozzle ID, in.	27.5
Pump Suction Nozzle ID, in.	31
Overall Unit Height, ft.	28.4
Water Volume, ft^3	192
Pump Motor Moment of Inertia, lb ft^2	80,000
Motor Data:	
Type	AC Induction Single Speed, Air Cooled
Voltage	4000
Insulation Class	B Thermalastic Epoxy
Phase	3
Frequency, cps	60
Current, maximum, amp	4800
Input (hot reactor coolant), kw	4000
Input (cold reactor coolant), kw	5300
Power, HP (nameplate)	6000

Table 4.1-6 REACTOR COOLANT PIPING DESIGN DATA

Parameter	Value
Design/Operating Pressure, psig	2485/2235
Hydrostatic Test Pressure, (cold) psig	3110
Design Temperature, °F	650
Design Temperature, (pressurizer surge line), °F	680
Reactor Inlet Piping, ID, inches	27 1/2
Reactor Inlet Piping, nominal thickness, inches	2.375
Reactor Outlet Piping, ID, inches	29
Reactor Outlet Piping, nominal thickness, inches	2.50
Coolant Pump Suction Piping, ID, inches	31
Coolant Pump Suction Piping, nominal thickness, inches	2.625
Pressurizer Surge Line Piping, ID, inches/Pipe Schedule	10/Sch 140*
Pressurizer Surge Line Piping, nominal thickness, inches	1*
Water Volume, (2 loops) ft^3	552

* Surge line fitted with a 14"/10" adapter at the pressurizer

Table 4.1-7 REACTOR COOLANT SYSTEM DESIGN PRESSURE DROP(1)

	Pressure Drop, psi
Across Pump Discharge Leg	1.3
Across Vessel, including nozzles	44.0
Across Hot Leg	1.5
Across Steam Generator	32.2
Across Pump Suction Leg	3.0
Total Pressure Drop	82.0

(1) These are nominal full power design values provided in the FFDSAR. Subsequent changes, such as the replacement of both units' steam generators, the core barrel upflow modification, and fuel design changes, have changed these values. This information is historical.

Table 4.1-8 THERMAL AND LOADING CYCLES

Transient Condition	Design Cycles*
1. Plant heatup at 100°F per hour	200
2. Plant cooldown at 100°F per hour	200
3. Plant loading at 5% of full power per minute	18,300 (for all components except pressurizer and reactor vessel internal baffle bolts which are 11,600 and 2,485 respectively)
4. Plant unloading at 5% of full power per minute	18,300 (for all components except pressurizer and reactor vessel internal baffle bolts which are 11,600 and 2,485 respectively)
5. Step load increase of 10% of full power (but not to exceed full power)	2,000 (1)
6. Step load decrease of 10% of full power	2,000 (1)
7. Step load decrease of 50% of full power	200 (1)
8. Steady State Fluctuations	
Initial Fluctuations (+3°F and + 25 psi)	1.5×10^5
Random Fluctuations (+0.5°F and + 6 psi)	5×10^6
9. Feedwater cycling at hot standby	2000 Reactor Vessel 25,000 (Unit 1 - other components) 10,000 (Unit 2 - other components)
10. Boron concentration equilibrium	23,360
11. Loss of Load	80 (1)
12. Loss of Power	40 (1)
13. Loss of flow in one loop	80 (1)
14. Reactor trip and attendant temperature transients	400 (1)
15. Inadvertent auxiliary spray	10
16. Reactor Coolant Pipe Break	1
17. Steam Line Break	1
18. Turbine roll test	10
19. Hydrostatic test, pressure 3110 psig temperature-cold	5 (preoperational)
20. Hydrostatic test, pressure 2485 psig temperature 400°F	94 (post-operational)
21. Primary to secondary leak test (2250) psig	27
22. Secondary to primary leak test	128

* Estimated for equipment design purposes (60-year life) and not intended to be an accurate representation of actual transients or to reflect actual operating experience. These cycles also assume a power uprate. (NRC SE dated 12/2005, NUREG 1839)

(1) For Reactor Vessel Internal baffle bolts, the total of these 7 transients is 750.

Table 4.1-9 REACTOR COOLANT SYSTEM - CODE REQUIREMENTS

Component	Codes
Reactor Vessel (excluding reactor vessel closure head)	ASME III* Class A
Reactor Vessel Closure Head	ASME III* Class 1; 1998 Edition through 2000 Addenda
Control Rod Drive Mechanism Housing	ASME III* Class 1; 1998 Edition through 2000 Addenda
Steam Generators	
Tube Side	Unit 1: ASME III* Class 1; 1977 Edition through Winter 1978 Addenda. Unit 2: ASME III* Division 1, Subsection NB; 1986 Edition, No Addenda.
Shell Side	Unit 1, Upper Shell above Transition Cone: ASME III* Class C; 1965 through 1966 Summer Addenda. NOTE: The shell side of the original Steam Generators conformed to the requirements for Class A vessels and were so stamped. Unit 1, Lower Shell and Transition Cone: ASME III* Class 2; 1977 Edition through Winter 1978 Addenda. NOTE: The lower shell and Transition Cone of the replacement Steam Generators were designed to Class 1 requirements. Unit 2: ASME III* Division 1, Subsection NB; 1986 Edition, No Addenda.
Reactor Coolant Pump Casing	No Code (Design per ASME III Article H)
Pressurizer	ASME III* Class A
Pressurizer Relief Tank	ASME III* Class C
Pressurizer Safety Valves	ASME III*
Reactor Coolant Piping	USAS B31.1**
System Valves, Fittings, and Piping	USAS B31.1**

Note: The version of the code which was in effect at the time the original component was ordered is applicable.

* ASME Boiler and Pressure Vessel Code, Section III, Nuclear Vessels
** USAS B31.1 Code for Pressure Piping

4.2 RCS SYSTEM DESIGN AND OPERATION

General Description

The Reactor Coolant Systems of the two nuclear power plant units are essentially identical and do not share any components. The following description applies to either unit.

Each Reactor Coolant System consists of two similar heat transfer loops connected in parallel to the reactor vessel. Each loop contains a steam generator, a pump, loop piping, and instrumentation. The pressurizer is connected to one of the loops by the pressurizer surge line. Auxiliary system piping connections into the reactor coolant piping are provided as necessary. A flow diagram of the system is shown in Figure 4.2-1 (Unit 1) and Figure 4.2-1A (Unit 2).

The containment boundary shown on the flow diagram indicates those major components which are to be located inside the containment. The intersection of a process line with this boundary indicates a containment penetration. Reactor Coolant System and components design data are listed in Table 4.1-1 through Table 4.1-7.

Pressure in the system is controlled by the pressurizer, where water and steam pressure are maintained through use of electrical heaters and sprays. Steam can either be formed by the heaters or condensed by a pressurizer spray to minimize pressure variations due to contraction and expansion of the coolant. Instrumentation used in the pressure control system is described in Section 7.0. Spring loaded steam safety valves and power-operated relief valves are connected to the pressurizer and discharge to the pressurizer relief tank where the discharged steam is condensed and cooled by mixing with water.

COMPONENTS

Reactor Vessel

The reactor vessel is cylindrical in shape with a hemispherical bottom head and a flanged and gasketed removable hemispherical upper head. Figure 4.2-2 is a schematic of the reactor vessel. The materials of construction of the reactor vessel are given in Table 4.2-1.

Coolant enters the reactor vessel through inlet nozzles in a plane just below the vessel flange and above the core. The coolant flows downward through the annular space between the vessel wall and the core barrel into a plenum at the bottom of the vessel where it reverses direction. Approximately 95% of the total coolant flow is effective for heat removal from the core. The core bypass flow provides cooling to parts of the vessel and internal components, including upward flow between the core baffle plates and core barrel to provide cooling of the barrel, the flow deflected into the head of the vessel for cooling and also includes the flow through the RCC guide-tubes and, the leakage across the fuel assembly outlet nozzles. All the coolant is united and mixed in the upper plenum, and the mixed coolant stream then flows out of the vessel through exit nozzles located on the same plane as the inlet nozzles.

A one-piece thermal shield, concentric with the reactor core, is located between the core barrel and the reactor vessel. The shield is bolted and welded to the top of the core barrel. The shield, which is cooled by the coolant on its downward pass, protects the reactor vessel by attenuating much of the gamma radiation and some of the fast neutrons which escape from the core. This shield minimizes thermal stresses in the reactor vessel which result from heat generated by the absorption of gamma energy. It is illustrated in Figure 3.2-35 and is further described in Section 3.2.3. Thirty-six core instrumentation nozzles penetrate the lower head.

The reactor closure head and the reactor vessel flange are joined by 48 six inch diameter studs. Two metallic O-rings seal the reactor vessel when the reactor closure head is bolted in place. A leakoff connection is provided between the two O-rings to monitor leakage across the inner O-ring. In addition, a leak-off connection is also provided beyond the outer O-ring seal.

The reactor vessel insulation is primarily a reflective type, supported from the nozzles and consisting of inner and outer sheets of stainless steel with multi layer stainless steel foil as the reflective (insulating) agent. Metal reflective insulation is also installed on the reactor closure head.

The reactor vessel contains the core support assembly, upper plenum assembly, fuel assemblies, control rod cluster assemblies, surveillance specimens, and in-core instrumentation access thimbles. The reactor vessel internals are designed to direct the coolant flow, support the reactor core, and guide the control rods in the withdrawn position.

Surveillance specimens made from representative reactor vessel steel are located between the reactor vessel wall and the thermal shield. Periodically removed specimens are examined to evaluate reactor vessel material property changes as described in Section 4.4.

The reactor internals are described in detail in Section 3.2.3 and the general arrangement of the reactor vessel and internals is shown in Figure 3.2-35. Reactor vessel design data are listed in Table 4.1-2.

Reactor Vessel - Support Structure

The Reactor Support Structure consists of a six sided structural steel ring supported at each apex by steel columns extending downward to a point below the reactor vessel and, at the center of each segment of the ring, by structural members imbedded in the surrounding concrete.

The reactor vessel has six supports, one at each of four reactor vessel nozzles with pads, and one at each of two reactor vessel support brackets. Each support bears on a support shoe, which is fastened to the support structure. The support shoe is a structural member that transmits the support loads to the supporting structure. The support shoe is designed to restrain vertical, lateral, and rotational movement of the reactor vessel, but allows for thermal growth by permitting radial sliding at each support on bearing plates.

Pressurizer

The general arrangement of the pressurizer is shown in Figure 4.2-3, and the design data are listed in Table 4.1-3. The pressurizer maintains the required reactor coolant pressure during steady-state operation, limits the pressure changes caused by coolant thermal expansion and contraction during normal load transients, and prevents the pressure in the Reactor Coolant System from exceeding the design pressure.

The pressurizer vessel contains replaceable direct immersion heaters, multiple safety and relief valves, a spray nozzle, and interconnecting piping, valves, and instrumentation. The electric heaters, located in the lower spherical head of the vessel, maintain the pressure of the Reactor Coolant System by keeping the water and steam in the pressurizer at system saturation temperature. The heaters are capable of raising the temperature of the pressurizer and contents at approximately 55°F/hr during RCS heatup.

The pressurizer is designed to accommodate positive and negative surges caused by load transients. The surge line which is attached to the bottom of the pressurizer, connects the pressurizer to the hot leg of a reactor coolant loop. During a positive surge caused by an increase in RCS temperature, the spray system, which is fed from the cold leg of each coolant loop, operates to condense steam in the pressurizer vessel to prevent the pressure from reaching the setpoint of the power-operated relief valves. Though normally automatically controlled, the gas operated spray valves can be operated manually from the control room. A small continuous spray flow is provided to assure that the pressurizer surge line and spray piping do not cool excessively during steady-state conditions.

During a negative pressure surge caused by decreasing RCS temperature, water in the pressurizer flashes to steam to mitigate the pressure drop, and heaters automatically actuate to restore RCS pressure to normal. Heaters are also energized on high water level during positive surges to heat the subcooled surge water entering the pressurizer from the reactor coolant loop.

The pressurizer is constructed of carbon steel with internal surfaces clad with austenitic stainless steel. The heaters are sheathed in austenitic stainless steel. All nozzle safe ends (forgings) in the top and bottom heads, and the nozzles of the pressurizer safety valves which could have been furnace sensitized during the fabrication sequence, have received non-destructive examination, which showed no degradation in integrity of the materials.

The pressurizer vessel surge nozzle is protected from thermal shock by a thermal sleeve. A thermal sleeve also protects the pressurizer spray nozzle connection.

PRESSURIZER SAFETY VALVE LIFT INDICATING SWITCH ASSEMBLIES (LISA)

See Section 7.5.1.3 for a description of the LISAs.

Pressurizer - Support Structure

The pressurizer is supported on a heavy concrete slab spanning the concrete shield walls of its compartment. The pressurizer is a bottom-skirt supported vessel.

Steam Generators

Each loop contains a vertical shell and U-tube steam generator. A steam generator of this type is shown in Figure 4.2-4. Principal design parameters are listed in Table 4.1-4. Reactor coolant enters the inlet side of the channel head at the bottom of the steam generator through the inlet nozzle, flows through the U-tubes to an outlet channel, and leaves the generator through another bottom nozzle.

The inlet and outlet channels are separated by a partition. Primary side manways are provided to permit access to the U-tubes. This permits steam generator tubes to be periodically inspected and allows defective tubes to be repaired or plugged in accordance with approved procedures.

Feedwater to the steam generator enters just above the top of the U-tubes through a feedwater ring. The water flows downward through an annulus formed by the tube wrapper and the shell and then upward through the tube bundle where part of it is converted to steam.

The steam-water mixture from the tube bundle passes through a steam swirl vane assembly which imparts a centrifugal motion to the mixture, separating the water droplets from the steam. Operation under EPU conditions required modifications to the moisture separation and steam drying components to limit steam moisture content to 0.25%. The mid-deck inlet vent area was reduced, the open top pipe vent design was changed to a flow diverter vent pipe design with vent caps, the formed single pocket vanes in the double tier secondary separators were replaced with double pocket vanes, the mid-deck plate was extended to the S/G shell wall and an inspection hatch was also added. Evaluations identified no predicted vibrational issues for the PBNP Units 1 and 2 SG steam dryer bank assemblies operating at EPU conditions.

The steam generator is constructed primarily of carbon steel. The heat transfer tubes are Inconel. The interior surfaces of the channel heads and nozzles are clad with austenitic stainless steel, and the side of the tubesheet in contact with the reactor coolant is clad with a NiCrFe Alloy. The tube-to-tubesheet joint is welded.

The following discussion of tubesheet stress analysis is retained in the FSAR for historical perspective. (Reference 10)

The evaluation of both units' Westinghouse steam generator tubesheets is performed according to rules of the ASME Boiler and Pressure Vessel Code for Nuclear Vessels, Section III, 1965 through Summer 1966 Addenda Edition Article 4 - Design. The design criteria encompasses steady-state, transient, and emergency operations as specified in the Equipment Specification. Due to the complex nature of the tube-tubesheet shell head structure, the analysis of the tubesheet required the application of results of related research programs (such as the design data on perforated plates resulting from PVRC programs) and the utilization of current techniques in computer analysis, the application of which is verified by comparison of analytical and experimental results for related equipment.

The Westinghouse analysis of the steam generator tubesheets is included as part of the Stress Report requirements for Class A Nuclear Pressure Vessels. The evaluation is based on the stress and fatigue limitations outlined in Article 4 Design of Section III. The stress analysis techniques utilized include all factors considered appropriate to conservative determination of the stress levels utilized in evaluation of the tubesheet complex. The analysis of the tubesheet complex includes the effect of all appurtenances attached to the perforated region of the tubesheet considered appropriate to conservative analysis of stress for evaluation on the basis of Section III stress limitations. The evaluation involves the heat conduction and stress analysis of the tubesheet, channel head, secondary shell structure for particular steady design conditions for which Code stress limitations are to be satisfied, and for discrete points during transient operation for which the temperature/pressure conditions must be known to evaluate stress maxima and minima for fatigue life usage. In addition, limit analyses are performed to determine tubesheet capability to sustain emergency operating conditions for which elastic analysis does not suffice. The analytic techniques utilized are computerized and significant stress problems are verified experimentally to justify the techniques where possible.

Generally, the analytic treatment of the tube-tubesheet complex includes determination of elastic equivalent plate stress within the perforated region from an interaction analysis utilizing effective elastic constants appropriate to the nature of the perforation array. For the perforated region of the tubesheet, the flexural rigidity is based on studies of behavior of plates with square hole arrays utilizing techniques such as those reported by O'Donnell (Reference 1), Mahoney (Reference 2), Lemcoe (Reference 3), and others. Similarly, stress intensity factors are determined for square hole arrays using the combined equivalent plate interaction forces and moments applied to results of photoelastic tests of model coupons of such arrays as well as verification using computer analysis techniques such as “Point Matching” or “Collocation.” The stress analysis considers stress due to symmetric temperature and pressure drop across the tubesheet divider lane.

The fatigue analysis of the complex is performed at potentially critical regions in the complex such as the junction between tubesheet and channel head or secondary shell as well as at many locations throughout the perforated region of the tubesheet. For the holes for which fatigue evaluation is done, several points around the hole periphery are considered to assure that the maximum stress excursion has been considered. The fatigue evaluation is computerized to include stress maxima-minima excursions considered on the intra-transient basis.

The evaluation of the tube-to-tubesheet juncture of Westinghouse PWR System steam generators is based on a stress analysis of the interaction between tube and tubesheet hole for the significant thermal and pressure transients that are applied to the steam generator in its predicted histogram of cyclic operation. The evaluation is based on the numerical limits specified in the 1968 Edition of the ASME Boiler and Pressure Vessel Code, Section III, Nuclear Vessels.

Of importance in the analysis of the interaction system is the behavior of the tube hole, where it is recognized that the hole behavior is a function of the behavior of the entire tubesheet complex with attached head and shell. Hence, the output of the tubesheet analysis giving equivalent plate stresses in the perforated region is utilized in determining the free boundary displacements of the perforation to which the tube is attached.

Analysis of the juncture for the tube-to-tubesheet fillet-type weld utilized in the Westinghouse steam generator design has been made with consideration of the effect of the rolled-in joint in the weld region as well as with the conservative assumption that the tube flexure relative to the perforation is not inhibited with the rolled-in effect.

The major concern in fatigue evaluation of the tube weld is the fatigue strength reduction factor to be assigned to the weld root notch. For this reason, Westinghouse has conducted low-cycle fatigue tests of tube material samples to determine the fatigue strength reduction factor and applied them to the analytic interaction analysis results in accordance with the accepted techniques in the Nuclear Pressure Vessel Code for Experimental Stress Analysis. The fatigue strength reduction factor determined therefrom is not different from that reported in the well known paper on the subject by O'Donnell and Purdy (Reference 4). An actual tubesheet joint contained in a tubesheet has been successfully tested experimentally under thermal transient conditions much more severe than that achieved in anticipated power plant operation. A wide range of computational tools are utilized in these solutions including finite element, heat conduction, and thin shell computer solutions. In addition, analysis techniques have been verified by photoelastic model tests and strain gaging of prototype models of an actual steam generator tubesheet.

Finally, in order to evaluate the ultimate safety of the structural complex, a computer program for determining a lower-bound pressure limit for the complex based on elastic-plastic analysis has been developed and applied to the structure. This was verified by a strain gage steel model of the complex tested to failure.

In all cases evaluated, the Westinghouse steam generator tubesheet complex meets the stress limitations and fatigue criteria specified in Article 4 of the Code as well as emergency condition limitations specified in the Equipment Specifications or anticipated otherwise. In this way, the tube-tubesheet integrity of a Westinghouse steam generator is demonstrated under the most adverse conceivable conditions resulting from a major breach in either the primary or secondary system piping.

Steam Generator - Support Structure

Each steam generator is supported on a structural system consisting of four vertical support columns and two (upper and lower) support rings. The vertical columns, which are pin connected to the steam generator support feet, serve as vertical restraint for operating weights, pipe rupture, and seismic considerations while permitting movement in the horizontal plane. The support rings, by using a combination of pins, stops, guides, and snubbers, prevent rotation and excessive movement of the steam generator in any plane. Thermal expansion is permitted in the support rings by a key arrangement.

Unit 1 - Steam Generator Replacement

Both Unit 1 steam generators lower assemblies were replaced during 1984. The performance of the replacement lower assemblies matches the performance of the original lower assemblies. However, several design features that do not alter the performance parameters are included in the design. Design data of the replacement Westinghouse Model 44F steam generators is provided in Table 4.1-4. The design features of the Model 44F steam generator lower assemblies and modifications made to the moisture separator equipment of the upper assemblies provide improved thermal hydraulic performance, provide improved access to the tube bundle, and reduce the potential for secondary side corrosion.

Unit 2 - Steam Generator Replacement

Both Unit 2 steam generators have been replaced. Whereas the Unit 1 replacement project changed out only the lower assemblies, the Unit 2 replacement steam generators (RSGs) consisted of the complete vessel, i.e., both the lower and upper assemblies. The RSGs are Westinghouse Model 47 and are similar in design and functionally the same as the original Westinghouse Model 44 steam generators. Design data of the replacement generators for Unit 2 are provided in Table 4.1-4. The RSGs have design features which provide additional resistance to known degradation mechanisms and which support their reliability and maintainability.

Reactor Coolant Pumps

Each reactor coolant loop contains a vertical single stage centrifugal pump which employs a controlled leakage seal assembly. A view of a controlled leakage pump is shown in Figure 4.2-6 and the principal design parameters for the pumps are listed in Table 4.1-5. The reactor coolant pump estimated performance and NPSH characteristic are shown in Figure 4.2-7. The performance characteristic is common to all of the higher specific speed centrifugal pumps and the "knee" at about 45% design flow introduces no operational restrictions since the pumps operate at full flow.

The motor-impeller can be removed from the casing for maintenance or inspection without removing the casing from the piping. All parts of the pumps in contact with the reactor coolant are austenitic stainless steel or equivalent corrosion resistant materials.

The pump employs a controlled leakage seal assembly to restrict leakage along the pump shaft, as well as a secondary seal which directs the controlled leakage out of the pump, and a third seal which minimizes the leakage of water and vapor from the pump into the containment atmosphere.

The shaft seal section consists of the No. 1 controlled leakage, film riding face seal, a shut down seal (SDS) assembly, and the No. 2 and No. 3 rubbing face seals. The seals are contained within the main flange and seal housing. The SDS is housed within the No. 1 seal area and is a passive device actuated by high temperature resulting from a loss of seal injection and CCW cooling to the thermal barrier heat exchanger. The SDS is designed to function only when exposed to an elevated fluid temperature downstream of the RCP number 1 seal. SDS deployment limits leakage from the RCS through the RCP seal package. Leakage is limited when the SDS thermal actuator retracts due to intrusion of hot reactor coolant water into the seal area, which causes the SDS seal ring to constrict around the pump shaft.

Testing of pumps with the number 1 seal entirely bypassed (full system pressure on the number 2 seal) shows that small (approximately 4 to 12 gpm) leakage rates would be maintained for a period of time sufficient to secure the pump. Even if the number 1 seal were to fail entirely during normal operation, the number 2 seal would maintain these small leakage rates if the proper action is taken by the operator. An increase in number 1 seal leakoff rate will warn the plant operator of number 1 seal damage. Following warning of excessive seal leakage conditions, the plant operator will take corrective actions. Gross leakage from the pump does not occur if these procedures are followed.

A portion of the high pressure water flow from the charging pumps is injected into the reactor coolant pump between the impeller and the controlled leakage seal. Part of the flow enters the Reactor Coolant System through a labyrinth seal surrounding the lower pump shaft. The labyrinth seal serves as a buffering interface, to limit the exchange of reactor coolant from the seal portion of the pump. The remainder of the injection water flows along the drive shaft, through the controlled leakage seal, and finally out of the pump. A very small amount which leaks through the secondary seal is also collected and removed from the pump. Component cooling water is supplied to the motor bearing cooler and the thermal barrier cooling coil.

The squirrel cage induction motor driving the pump is air cooled and has oil lubricated thrust and radial bearings. A water lubricated bearing provides radial support for the pump shaft.

Precautionary measures, taken to preclude missile formation from primary coolant pump components, assure that the pumps will not produce missiles under any anticipated accident condition. The primary coolant pumps run at 1189 rpm and the motors are designed in accordance with NEMA standards for operation at a maximum speed of 125% of rated speed. Each component of the primary pumps has been analyzed for missile generation. Any fragments would be contained by the heavy stator. The same conclusion applies to the impeller because the small fragments that might be ejected would be contained by the heavy casing.

The primary coolant pump flywheels are shown in Figure 4.2-8. As for the pump motors, the most adverse operating condition of the flywheels is the loss-of-load situation. The following conservative design-operation conditions preclude missile production by the pump flywheels. The wheels are fabricated from rolled, vacuum-degassed, steel plates. The material is ASTM A533 Grade B Class 1. (Reference 11) Flywheel blanks are flame-cut from the plate, with allowance for exclusion of flame affected metal. A minimum of three Charpy tests are made from each plate parallel and normal to the rolling direction to determine that each blank satisfies design requirements. An NDTT less than +10°F is specified. The finished flywheels are subjected to 100% volumetric ultrasonic inspection. The finished machined bores are also subjected to magnetic particle or liquid penetrant examination.

These design fabrication techniques yield flywheels with primary stress at operating speed (shown in Figure 4.2-9) less than 50% of the minimum specified material yield strength at room temperature (100 to 150°F). Bursting speed of the flywheels has been calculated on the basis of Griffith-Irwin's results (Reference 6), to be 3900 rpm, more than three times the operating speed. A fracture mechanics evaluation was made on the reactor coolant pump flywheel. This evaluation considered the following assumptions:

1. Maximum tangential stress at an assumed overspeed of 125%.
2. A crack through the thickness of the flywheel at the bore.
3. 400 cycles of startup operation in 40 years.

Using critical stress intensity factors and crack growth data attained on flywheel material, the critical crack size for failure was greater than 17 inches radially and the crack growth data was 0.030 in. to 0.060 in. per 1000 cycles. Ultrasonic examination techniques which are capable of detecting and sizing flaws smaller than the critical flaw size of the flywheel fracture analysis are utilized for the inspection of the flywheel. Based on the above information and the inspections outlined in the ISI Long-Term Plan, the intent of Regulatory Guide 1.14 is satisfied.

An additional stress and fracture evaluation was completed in November 1996 (WCAP-14535-A). The evaluation assumed a leak before break limitation on the maximum pump speed and 6000 cycles of reactor coolant pump starts and stops for a 60-year service life. The estimated radial crack extension was shown to be negligible even when assuming a large initial crack length. See Section 15.4.3 for further License Renewal information. (NRC SE dated 12/2005, NUREG-1839)

WCAP-15666-A, Revision 1, “Extension of Reactor Coolant Pump Motor Flywheel Examination,” October 2003, builds on the arguments in WCAP-14535-A and provides additional rationale, including a risk assessment of all credible flywheel speeds. The risk assessment followed the risk-informed methodology and guidelines of Regulatory Guide 1.174 to justify the RCP motor flywheel examination interval extension for all domestic Westinghouse plants from 10 years to 20 years. WCAP-15666-A concludes that the change in risk is below the Regulatory Guide CDF and LERF acceptable guidelines.

The NRC approved the use of the Topical Report in NRC SER "Safety Evaluation of Topical Report WCAP-15666, Extension of Reactor Coolant Pump Motor Flywheel Examination," May 5, 2003. The NRC SER has been incorporated into the "A" revision of the WCAP.

All pressure bearing parts of the reactor coolant pump are analyzed in accordance with Article 4 of the ASME Boiler and Pressure Vessel Code, Section III, 1965 Edition. This includes the casing, the main flange, and the main flange bolts. The analysis includes pressure, thermal, and cyclic stresses, and these are compared with the allowable stresses in the Code. Mathematical models of the parts are prepared and used in the analysis which proceeds in two phases.

1. In the first phase, the design is checked against the design criteria of the ASME Code, with stress calculations using the allowable stress at design temperature. By this procedure, the shells are profiled to attain optimum metal distribution with stress levels adequate to meet the more exacting requirements of the second phase.

2. In the second phase, the interacting forces needed to maintain geometric capability between the various components are determined and applied to the components, along with the external load, to determine the final stress state of the components. This stress will also be used in the fatigue analyses. These results are finally compared with the Code allowable values.

There are no other sections of the Code which are specified as areas of compliance, but where Code methods, allowable stresses, fabrication methods, etc., are applicable to a particular component, these are used to give a rigorous analysis and conservative design.

Stress Analysis Reports are prepared on these components as described in Section 4.3. These reports include the calculation of stress intensities and a summary of fatigue usage factors. These reports are a part of the plant documentation on file with the applicant.

Reactor Coolant Pump Missile Protection

The construction of the loop compartment concrete walls is such that they enclose two sides of the reactor coolant pump area and protect the containment liner from loss-of-coolant accident generated missiles. The third side of the pump area is enclosed by the refueling canal wall. On the fourth side, a partition wall containing reinforcing steel and tension members divides the upper pump area from the steam generator compartment. The minimum compartment wall thickness is 30 inches.

Since there is no assumed mode of failure of the flywheel, no further design calculations were performed on this item as a missile. However, if a missile weight (W) 2500 lbs. (greater than 1/4 of flywheel) and a velocity (V) of 300 ft. per second were to strike the pump cavity walls, the penetration would be less than 20 inches, in accordance with the formula:

$$Penetration = \frac{222 \frac{W}{A} D^{0.215} V^{1.5}}{Y} + \frac{D}{2}$$

where:

Y = A function of the compressive strength of the concrete
A = Impact Area of 2.8 sq. ft.
D = Diameter of 22.7 inches

Pump Support Structure

The reactor coolant pump is supported by a structural system consisting of three vertical columns and a system of stops. The vertical columns are bolted to the pump support feet and permit movement in the horizontal plane to accommodate reactor coolant pipe expansion. Horizontal restraint is accomplished by a combination of tie rods and stops which limit horizontal movement for pipe rupture and seismic effects.

Pressurizer Relief Tank

Principal design parameters of the pressurizer relief tank are given in Table 4.1-3. Steam discharged from the power relief and safety valves passes to the pressurizer relief tank which is partially filled with water at or near ambient containment conditions. The tank normally contains water in a predominantly nitrogen atmosphere. Steam is discharged under the water level to condense and cool by mixing with the water. The tank is equipped with a spray and drain which are operated to cool the tank following a discharge.

The tank size is based on the requirement to condense and cool a discharge equivalent to 110% of the pressurizer steam volume above 60% (original full power) pressurizer level.

The tank is protected against a discharge exceeding the design value by a rupture disc which discharges into the reactor containment. The rupture disc on the relief tank has a relief capacity equal to the combined capacity of the pressurizer safety valves. The tank design pressure (and the rupture disc setting) is twice the calculated pressure resulting from the maximum safety valve discharge described above. This margin is to prevent deformation of the disc. The tank and rupture disc holder are also designed for full vacuum to prevent tank collapse if the tank contents cool without nitrogen being added.

The discharge piping from the safety and relief valves to the relief tank is sufficiently large to prevent backpressure at the safety valves from exceeding 20% of the setpoint pressure at full flow. The pressurizer relief tank, by means of its connection to the Waste Disposal System, provides a means for removing any noncondensable gases from the Reactor Coolant System which might collect in the pressurizer vessel. The tank is constructed of stainless steel.

Piping

The general arrangement of the Reactor Coolant System piping is shown on the plant layout drawings in Section 1. Piping design data are presented in Table 4.1-6. The reactor coolant piping layout is designed on the basis of providing "floating" supports for the steam generator and reactor coolant pump in order to absorb the thermal expansion from the fixed or anchored reactor vessel.

The austenitic stainless steel reactor coolant piping and fittings which make up the loops are 29 in. I.D. in the hot legs, 27.5 in. I.D. in the cold legs, and 31 in. I.D. between each loop's steam generator outlet and its reactor coolant pump suction. Smaller piping, including the pressurizer surge spray and relief lines, drains, and connections to other systems are austenitic stainless steel. All joints and connections are welded except for stainless steel flange connections to the pressurizer relief tank and the connections at the safety valves.

Thermal sleeves are installed at the following locations where high thermal stresses could otherwise develop due to rapid changes in fluid temperature during normal operational transients:

1. Return line from the residual heat removal loop
2. Both ends of the pressurizer surge line
3. Pressurizer spray line connection to the pressurizer
4. Charging line and auxiliary charging line connections

Valves

Normally operating, outgoing lines connected to the Reactor Coolant System are provided with remote isolation capability. Each line is isolated near its connection to the Reactor Coolant System.

All valve surfaces in contact with reactor coolant are austenitic stainless steel or equivalent corrosion resistant materials. Connections to stainless steel piping are welded. Valves that perform a modulating function are equipped with sufficient packing to minimize leakage to the atmosphere.

Applicable Codes

Steel	American Institute of Steel Construction (AISC), "Code of Standard Practice for Steel Buildings and Bridges"
Welding	American Welding Society (AWS) D1.0-66 and (AWS) D12.1, "Standard Specification for Welding Highway and Railway Bridges"
Connections	Bolt Connections Conforming to "Specification for Structural Joints Using ASTM A325 or A490 Bolts" as approved by the Research Council on Riveted and Bolted Structural Joints of the Engineering Foundation, 1964
Concrete	American Concrete Institute (ACI) 318-63

PRESSURE-RELIEVING DEVICES

The Reactor Coolant System is protected against overpressure by control and protective circuits such as the high pressure trip and by code relief valves connected to the top head of the pressurizer. Those relief valves discharge into the pressurizer relief tank which condenses and collects the valve effluent. The schematic arrangement of the relief devices is shown in Figure 4.2-1, and the valve design parameters are given in Table 4.1-3. Valve sizes are determined as indicated in Section 4.3.

Power-operated relief valves and code safety valves are provided to protect against pressure surges which are beyond the pressure limiting capacity of the pressurizer spray. Additionally a keyswitch enabled bistable on each of two reactor coolant pressure channels allows the power-operated relief valves to perform as a low temperature overpressure protection system when the RCS temperature is below its minimum pressurization temperature. (Reference 7) The residual heat removal (RH) system relief valves also provide a diverse relief system for the reactor coolant system when the RH system is aligned for decay heat removal operation. (Chapter 9)

The pressurizer relief tank is protected against a steam discharge exceeding the design pressure value by a rupture disc which discharges into the reactor containment. The rupture disc relief conditions are given in Table 4.1-3.

PROTECTION AGAINST PROLIFERATION OF DYNAMIC EFFECTS

Protection against the proliferation of the dynamic effects of a Reactor Coolant System Main Loop or Pressurizer Surge Line pipe rupture is no longer a design or license basis requirement. See the discussion in Section 4.1 under "Missile Protection" for further information and historical context. The following is retained as historical information.

Engineered Safety Features and associated systems are protected from loss of function due to dynamic effects and missiles which might result from a loss-of-coolant accident. Protection is provided by missile shielding and/or segregation of redundant components. This is discussed in detail in Section 6.0.

The Reactor Coolant System is surrounded by concrete shield walls. These walls provide shielding to permit access into the containment during full power operation for inspection and maintenance of miscellaneous equipment. These shielding walls also provide missile protection for the containment liner plate. A missile shield is integrated into the design of the reactor vessel head assembly and provides protection from missiles generated by postulated CRDM housing failures.

Steam generator lateral bracing is provided near the tubesheet and feedring elevations to resist lateral loads, including those resulting from seismic forces and pipe rupture forces. Missile protection afforded by the arrangement of the Reactor Coolant System is illustrated in the containment structure drawings which are given in Section 5.0.

MATERIALS OF CONSTRUCTION

Each of the materials used in the Reactor Coolant System is selected for the expected environment and service conditions. The major component materials are listed in Table 4.2-1. All of the Reactor Coolant System materials which are exposed to the coolant are corrosion resistant. They consist of several types of stainless steels and Inconel, and they are chosen for specific purposes at various locations within the system for their superior compatibility with the reactor coolant. The chemical composition of the reactor coolant is maintained within the specification given in the EPRI PWR Primary Water Chemistry Guidelines (Reference 15). Reactor coolant chemistry is further discussed in Section 4.2.

The phenomena of stress corrosion cracking and corrosion fatigue are not encountered unless a specific combination of conditions is present. The necessary conditions are a susceptible alloy, a specific chemical environment, a tensile stress, and time. It is characteristic of stress corrosion that combinations of alloy and environment which result in cracking are usually quite specific. Environments which have been shown to cause stress corrosion cracking of stainless steels are free alkalinity in the presence of a concentrating mechanism and the presence of chlorides and free oxygen. With regard to the former, experience has shown that deposition of chemicals on the surface of tubes can occur in a steam blanketed area within a steam generator. In the presence of this environment, stress corrosion cracking can occur in stainless steels having the nominal residual stresses resulting from normal manufacturing procedures. However, the steam generators contain Inconel tubes. Testing to investigate the susceptibility of heat exchanger construction materials to stress corrosion in caustic and chloride aqueous solutions has indicated that Inconel alloy has excellent resistance to general and pitting type corrosion in severe operating water conditions.

All external insulation of Reactor Coolant System components is compatible with the component materials. The cylindrical shell exterior, closure head, and closure flanges to the reactor vessel are insulated with metallic reflective insulation. All other external corrosion resistant surfaces in the Reactor Coolant System are insulated with low or halide-free insulating material as required.

Prior to the initial plant operation, the Nil-Ductility Transition Temperature (NDTT) of the reactor vessel plate or forging material opposite the core was established at a Charpy V-notch test value of 30 ft-lb or greater. The material was tested to verify conformity to specified requirements and to determine the actual NDTT value. In addition, this plate was 100% volumetrically inspected by ultrasonic testing using both longitudinal and shear wave methods.

Subsequently, the NRC issued 10 CFR 50.60, “Acceptance Criteria for Fracture Prevention Measures for Lightwater Nuclear Power Reactors for Normal Operation,” and Appendix G to Part 50, “Fracture Toughness Requirements.” These regulations imposed an additional requirement applicable to Point Beach that the Charpy upper-shelf energy of reactor vessel beltline materials must be maintained no less than 50 ft-lb throughout the life of the vessel, unless it is demonstrated in a manner approved by the Director, Office of Nuclear Reactor Regulation, that lower values of upper-shelf energy will provide margins of safety against fracture equivalent to those required by Appendix G of the ASME Code. Topical reports BAW-2178PA (Reference 8) and BAW-2192PA (Reference 9) were issued by the B&W Owners Group Reactor Vessel Working Group in April, 1994 and were applicable to PBNP Units 1 and 2. These reports demonstrated that the Point Beach Units 1 and 2 reactor vessel beltline welds fabricated by Babcock & Wilcox provided margins of safety against fracture equivalent to those required by Appendix G of the ASME Code through the end of their respective original Operating Licenses.

Additional reactor vessel fracture mechanics analyses for PBNP Units 1 and 2 were performed to satisfy the reactor pressure vessel (RPV) Charpy upper-shelf energy (USE) requirements of 10 CFR 50, Appendix G, Section IV.A.1.c through the end of the unit’s extended operating licenses. See Section 15.4.1 for a description of theses analyses.

The remaining material in the reactor vessel and other Reactor Coolant System components meets the appropriate design code requirements and specific component function.

The reactor vessel material was heat treated specifically to obtain good notch ductility, which ensures a low NDTT and thereby gives assurance that the finished vessel can be initially hydrostatically tested and operated as near to room temperature as possible without restrictions. A reactor cavity neutron measurement program has been instituted at Point Beach to provide a continuous monitoring of the reactor pressure vessel and reactor vessel support structure. The use of the cavity measurement program coupled with available surveillance capsule measurements provides a plant specific data base that enables the evaluation of the vessel neutron exposure and the uncertainty associated with that exposure over the service life of the units.

The cavity neutron measurement program also establishes three-dimensional fluence profiles and enables the true effects of three-dimensional and potentially non-symmetric flux reduction measures to be accurately accounted for in a manner that would be difficult using analysis alone. All calculations and dosimetry evaluations are performed based on nuclear cross-section data derived from ENDF/B-VI. The calculational method used to obtain the maximum neutron exposure of the reactor vessel is identical to that for the Point Beach surveillance capsules.

To evaluate the RT_{NDT} shift of welds, heat affected zones, and base material for the vessel, test coupons of these material types have been included in the reactor vessel material surveillance program, which is described in Section 4.4.

MATERIALS OF CONSTRUCTION - COMPARISON TO USAS B31.7

In response to an Atomic Energy Commission question regarding the degree to which the reactor coolant system valves, fittings and piping met the requirements of the USAS B31.7 code, the following response was provided.

The valves, fittings, and piping are designed to the ASA B31.1 (1955) Code for Power Piping using the allowable stresses found in the Nuclear Code, Cases N-7 and N-10 for pipe and fittings, respectively. Nuclear piping, Class I, is defined as the Reactor Coolant System out to the second normally closed isolation valve. For those valves which are normally open, the system extends to the first valve outside containment capable of external actuation.

The quality assurance requirements of Westinghouse WAPD in the purchase and examination of the reactor coolant piping assured that the quality level of the Westinghouse plant is comparable to that delineated for USAS B31.7 1967 Edition nuclear piping, Class I, to the extent described below.

1. All materials for fabrication conform to ASTM specifications listed for Class I nuclear piping. In addition, all materials are certified and identified for conformance to governing ASTM requirements.

2. Piping base materials are examined by methods to quality acceptance criteria and to the extent that meets requirements described in USAS B31.7 for Class I nuclear piping.

3. All welding procedures, welders, and welding operators are qualified to the requirements of ASME IX, Welding Qualifications.

4. All welds are examined by NDE methods and to the extent prescribed in USAS B31.7 for Class I nuclear piping.

5. All branch connection nozzle welds of nominal sizes 3 in. and larger are 100% radiographed. This exceeds USAS B31.7 requirements which requires radiographing nozzle welds of nominal sizes 6 in. and larger.

6. All finished welds are liquid penetrant examined on both the outside and inside (if accessible) surfaces as required by USAS B31.7, Class I.

7. Hydrostatic testing is performed on the erected and installed piping. This requirement is the same as in USAS B31.7, Class I.

A thermal expansion flexibility stress analysis is performed in accordance with the criteria set forth in USAS B31.1 to assure that the stress range and number of thermal cycles are safely within the limits prescribed in B31.1. In addition, seismic analyses are performed on the composite piping, including the combined stress effects of all steady-state (pressure and weight) loadings plus seismic vertical/horizontal loading components. The resultant reactions of the piping due to the separate and combined effects of thermal, sustained, and seismic loadings are factored into the checking of the final design of the equipment nozzles to which the piping is interconnected. In turn, the equipment supporting structures are checked for adequate design, including the added effects of these same loadings. Thus, the total design, including pipe, equipment, and structures include the effects of thermal expansion and sustained and seismic loadings.

Thermally induced stresses arising from temperature gradients are limited to a safe and low order of magnitude in assigning a maximum permissible time rate of temperature change on plant heatup, cooldown, and incremental loadings. Thermal sleeves are utilized at nozzles wherein a cold fluid is introduced into a pipe conveying a significantly hotter fluid or vice-versa. Typical examples are the charging line, pressurizer surge, and residual heat return nozzle connections to the primary coolant loop piping.

Shop and field fabrication requirements, documentation, and quality assurance examinations all comply with those found in USAS B31.7 for Class I nuclear piping except that chemical and physical certifications are documented by pipe lot. The above criteria for Reactor Coolant System valves, fittings, and piping apply to the pressurizer surge line and the remainder of the piping between the 27.5 in., 29 in., and 31 in. pipe to the second isolation stop valve, with the following exceptions:

1. Pipe/fittings of nominal sizes 2 in. and smaller will not be subject to volumetric inspection of the base material.

2. A complete flexibility/seismic stress analysis is not necessarily performed on all of the branch piping to the extent performed on the 27.5 in. and larger primary loop piping.

Piping Code Class I pipe and fittings in the balance of plant conform to USAS B31.1 Code - 1967 Edition.

MAXIMUM HEATING AND COOLING RATES

The reactor system operating cycles used for design purposes are given in Table 4.1-8 and described in Section 4.1. The maximum allowable normal system heatup and cooldown rate is 100°F/hr. Sufficient electrical heaters are installed in the pressurizer to permit a heatup rate, starting with a minimum water level, of 55°F/hr. This rate takes into account the small continuous spray flow provided to maintain the pressurizer liquid homogeneous with the coolant. The fastest cooldown rates which result from the hypothetical case of a break of a main steam line are discussed in Section 14.2.5.

WATER CHEMISTRY

The water chemistry is selected to provide the necessary boron content for reactivity control and to minimize corrosion of reactor coolant system surfaces. All of the materials exposed to reactor coolant are corrosion resistant. Periodic analyses of the coolant chemical composition are performed to monitor the adherence of the system to the reactor coolant water quality as stated in EPRI PWR Primary Water Chemistry Guidelines (Reference 15). Maintenance of the water quality to minimize corrosion is accomplished using the Chemical and Volume Control System and Sampling System which are described in Section 9.0.

REACTOR COOLANT FLOW MEASUREMENTS

Elbow taps are used in the primary coolant system as an instrument device that indicates the status of the reactor coolant flow. The basic function of this device is to provide information as to whether or not a reduction in the flow rate has occurred. The correlation between flow reduction and elbow tap read-out has been well established by the following equation:

$$\frac{WP}{WP_0} = \left(\frac{1}{1_0}\right)^2$$

where:

WP_0 = the referenced pressure differential with the corresponding referenced flow rate 1_0

WP = the pressure differential with the corresponding referenced flow rate l

The full flow reference point is established during initial plant startup. The low flow trip point is then established by extrapolating along the correlation curve. The technique has been well established in providing core protection against low coolant flow in Westinghouse PWR plants. The expected absolute accuracy of the channel is within ± 10% and field results have shown the repeatability of the trip point to be within ± 1%. The analysis of the loss-of-flow transient presented in Section 14.1.8 assumes instrumentation error of ± 3%.

RCS GAS VENT SYSTEM

The RCS Gas Vent System is designed to permit the operator to vent non-condensable gases from the reactor vessel head and/or pressurizer steam space remotely from the control room during post-accident situations when large quantities of non-condensable gases may collect. The purpose of venting is to prevent possible interference from accumulated gases with core cooling. Small amounts of gas can be vented to the pressurizer relief tank (PRT) and thus not enter the containment atmosphere. Use of the PRT provides a discharge location which can be used to store small quantities of gas without influencing containment hydrogen concentration levels. Larger volumes will require venting directly to the containment.

The vent path from either the pressurizer or reactor vessel head is single active failure proof with regards to either establishing or isolating a flow path. Parallel valves powered from independent 125 V DC emergency power supplies are provided at both vent sources to ensure a vent path exists to a common header in the event of a single failure of either a valve or a power source. Vent paths from the common header to the PRT and from the common header to the containment atmosphere are provided by separate solenoid valves powered from independent 125 V DC emergency power supplies. All solenoid valves close upon de-energization. The venting rate from either source is controlled by an in-line flow-restricting orifice which limits the flow so that, in the event of a pipe break or isolation valve failure, makeup water for the leakage can be provided by a single charging pump. Covers are installed over the solenoid valve switches to minimize the possibility of inadvertent operation. Open and Closed valve position indication lights are provided in the control room. Pressure instrumentation is used to monitor the system for leakage during normal plant operation. A flow diagram of the system is shown in Figure 4.2-1 (Unit 1) and Figure 4.2-1A (Unit 2). Vent path operability and system testing requirements are discussed in TRM 3.4.4, "Reactor Coolant Gas Vent System."

The design parameters for the Reactor Coolant Gas Vent System are listed below:

Flow	-	> 100 scfm H2, dependent upon RCS pressure and temperature
Temperature	-	700°F
Pressure	-	2500 psia
Line	-	1 inch
Orifice Size	-	7/32 inch

The NRC determined the RCS Gas Vent System design to be acceptable and in conformance to the requirements of 10 CFR 50.44 (c)(3)(iii) and the guidelines of NUREG-0737 Item II.B.1 and NUREG-0800 Section 5.4.12 (Reference 12 and Reference 13). The RCS gas vent requirements of 10 CFR 50.44 (c)(3)(iii) were subsequently revised and relocated to 10 CFR 50.46a.

In addition to its primary, post-accident function, the system may be used to aid in the draining or fill and venting of the reactor coolant system. The system can also be used to reduce primary pressure at hot shutdown allowing boration of the RCS using high head safety injection pumps. Large flow rates can be achieved by opening two normally closed, series connected, one-inch manual valves which bypass the orifice.

The RCS Gas Vent System is also credited in the event of a fire and has been evaluated in the at-power and non-power analyses (Reference 16).

<u>REACTOR VESSEL LEVEL INDICATION SYSTEM (RVLIS)</u>

Four channels of reactor vessel level indication (two wide range, two narrow range) were installed by modification, to provide core level indication for all reactor coolant pump combinations, whether operating or secured. (MR IC-244)

RESISTANCE TEMPERATURE DETECTOR BYPASS LOOPS

See Section 7.2.3.2 for a description of the resistance temperature detector bypass loops.

THERMAL RELIEF PROTECTION

All reactor coolant system piping inside containment which is isolated as a result of normal operating alignment, or which could become isolated as a result of automatic action from a containment isolation signal (including in-series containment isolation valves) are protected from the thermal expansion effect of accident conditions by thermal relief valves. (MR 97-132, MR 97-102).

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1. W. J. O'Donnell, “A Study of Perforated Plates With Square Penetration Patterns”, Welding Research Council Bulletin No. 124, September 1967.

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4. W. J. O'Donnell and C. M. Purdy, “The Fatigue Strength of Members Containing Cracks”, ASME Transactions, Journal of Engineering for Industry, Vol. 86-B, 1964.

5. Ernest L. Robinson, “Bursting Tests of Steam-Turbine Disk Wheels”, Transactions of the ASME, July 1944. (“disk type” LP turbine spindles have been replaced with spindles of a “mono-block” design)

6. Application of the Griffith-Irwin Theory of Crack Propagation to the Bursting Behavior of Disks, Including Analytical and Experimental Studies by D. H. Winne and B. M. Wundy, ASME, December 1, 1957. (“disk type” LP turbine spindles have been replaced with spindles of a “mono-block” design)

7. Safety Evaluation by the Office of Nuclear Reactor Regulation related to Amendment No. 45 to Facility Operating License No. DPR-24 and Amendment No. 50 to Facility Operating License No. DPR-27, Point Beach Nuclear Plant, Unit Nos. 1 and 2, dated May 20, 1980.

8. K. K. Yoon, “Low Upper-Shelf Toughness Fracture Mechanics Analysis of Reactor Vessels of B&W Owners Reactor Vessel Working Group for Level C & D Service Loads,” BAW-2178PA, April 1994.

9. K. K. Yoon, “Low Upper-Shelf Toughness Fracture Mechanics Analysis of Reactor Vessels of B&W Owners Reactor Vessel Working Group for Level A & B Service Loads,” BAW-2192PA, April 1994.

10. Answer to NRC Question Q4.12 to the FFDSAR. dated March 13, 1970.

11. WCAP-14535, “Topical Report on Reactor Coolant Pump Flywheel Inspection Elimination,” January 1996.

12. NUREG-0800, Standard Review Plan Section 5.4.12, “Reactor Coolant System High Point Vents,” dated July 1981.

13. NRC Safety Evaluation, Point Beach Nuclear Plant Units 1 and 2, Wisconsin Electric Power Company, dated September 22. 1983.

14. NRC Safety Evaluation dated May 3, 2011, “Issuance of License Amendment Regarding Extended Power Uprate (TAC Nos. ME1044 and ME 1045).”

15. EPRI 1014986, “Pressurized Water Reactor Primary Water Chemistry Guidelines.”

16. NFPA 805 Fire Protection Program Design Document (FPPDD)

Table 4.2-1 MATERIALS OF CONSTRUCTION OF THE REACTOR COOLANT SYSTEM COMPONENTS

Sheet 1 of 2

Component	Section	Materials
Reactor Vessel	Shell Plate (Unit 1)	SA 302, Gr. B
	Shell Forging (Unit 2)	A 508 Class II
	Nozzle Shell & Nozzle Forgings	A 508 Class II
	Cladding, Stainless Weld Rod	Type 304 Equivalent
	Thermal Shield and Internals	A 240, Type 304
	Insulation	SS SS Foil SS
	Closure Head	SA 508 Grade 3 Class 1
Steam Generators, Unit 1	Upper Shell Barrel	SA 302, Gr. B
	Lower Shell Barrels	SA-533 Gr A, CL. 2
	Channel Head Casting	SA-216 WCC
	Channel Head Cladding Weld Rod	SFA-5.9, CL. ER 308L and 309L
	Tube Sheet Forging	SA-508, CL. 2A
	Cladding for Tubesheet (Primary Side)	NiCrFe Alloy
	Tubes	SB-163, Alloy 600 TT
	Primary Nozzle Safe-Ends	Type 308L Weld Buildup
Steam Generators, Unit 2	Upper and Lower Shell Barrels	SA-533 Type B, CL. 2
	Channel Head Forging	SA-508, CL. 3
	Channel Head Cladding Weld Rod	SFA-5.4 CL. E308L and E309L
	Tube Sheet Forging	SA-508, CL. 3A
	Cladding for Tubesheet (Primary Side)	NiCrFe Alloy
	Tubes	SB-163, Alloy 690 TT
	Primary Nozzle Safe-Ends	SA-336, CL. F316LN
Pressurizer	Shell	SA 302, Gr. B
	Heads	SA 216 WCC
	External Plate	SA 302, Gr. B
	Cladding, Stainless	Type 304 equivalent
	Internal Plate	SA 240 Type 304
	Internal Piping	SA 376 Type 316

Table 4.2-1 MATERIALS OF CONSTRUCTION OF THE REACTOR COOLANT SYSTEM COMPONENTS

Sheet 2 of 2

Component	Section	Material
Pressurizer Relief Tank	Shell	A 285 Gr. C
	Heads	A 285 Gr. C
Piping	Pipes	A 376 Type 316
	Fittings	A 351, CF8M
	Nozzles	A 182 F316
Pump	Shaft	Type 304
	Impeller	A 351, CF8
	Casing	A 351, CF8M
Valves	Pressure Containing Parts	A 351, CF8M and A 182 F316

Figure 4.2-1 UNIT 1 REACTOR COOLANT SYSTEM PROCESS FLOW DIAGRAM (Sheet 1)

[redacted]

Figure 4.2-1 UNIT 1 REACTOR COOLANT SYSTEM PROCESS FLOW DIAGRAM (Sheet 2)

[redacted]

Figure 4.2-1 UNIT 1 REACTOR COOLANT SYSTEM PROCESS FLOW DIAGRAM (Sheet 3)

[redacted]

Figure 4.2-1A UNIT 2 REACTOR COOLANT SYSTEM PROCESS FLOW DIAGRAM (Sheet 1)

[redacted]

Figure 4.2-1A UNIT 2 REACTOR COOLANT SYSTEM PROCESS FLOW DIAGRAM (Sheet 2)

[redacted]

Figure 4.2-1A UNIT 2 REACTOR COOLANT SYSTEM PROCESS FLOW DIAGRAM (Sheet 3)

[redacted]

Figure 4.2-2 REACTOR VESSEL SCHEMATIC

[redacted]

Figure 4.2-3 PRESSURIZER

[redacted]

Figure 4.2-4 UNIT 1 STEAM GENERATOR

[redacted]

Figure 4.2-5 UNIT 2 STEAM GENERATOR

[redacted]

Figure 4.2-6 REACTOR COOLANT PUMP

[redacted]

Figure 4.2-7 REACTOR COOLANT PUMP ESTIMATED PERFORMANCE CHARACTERISTICS

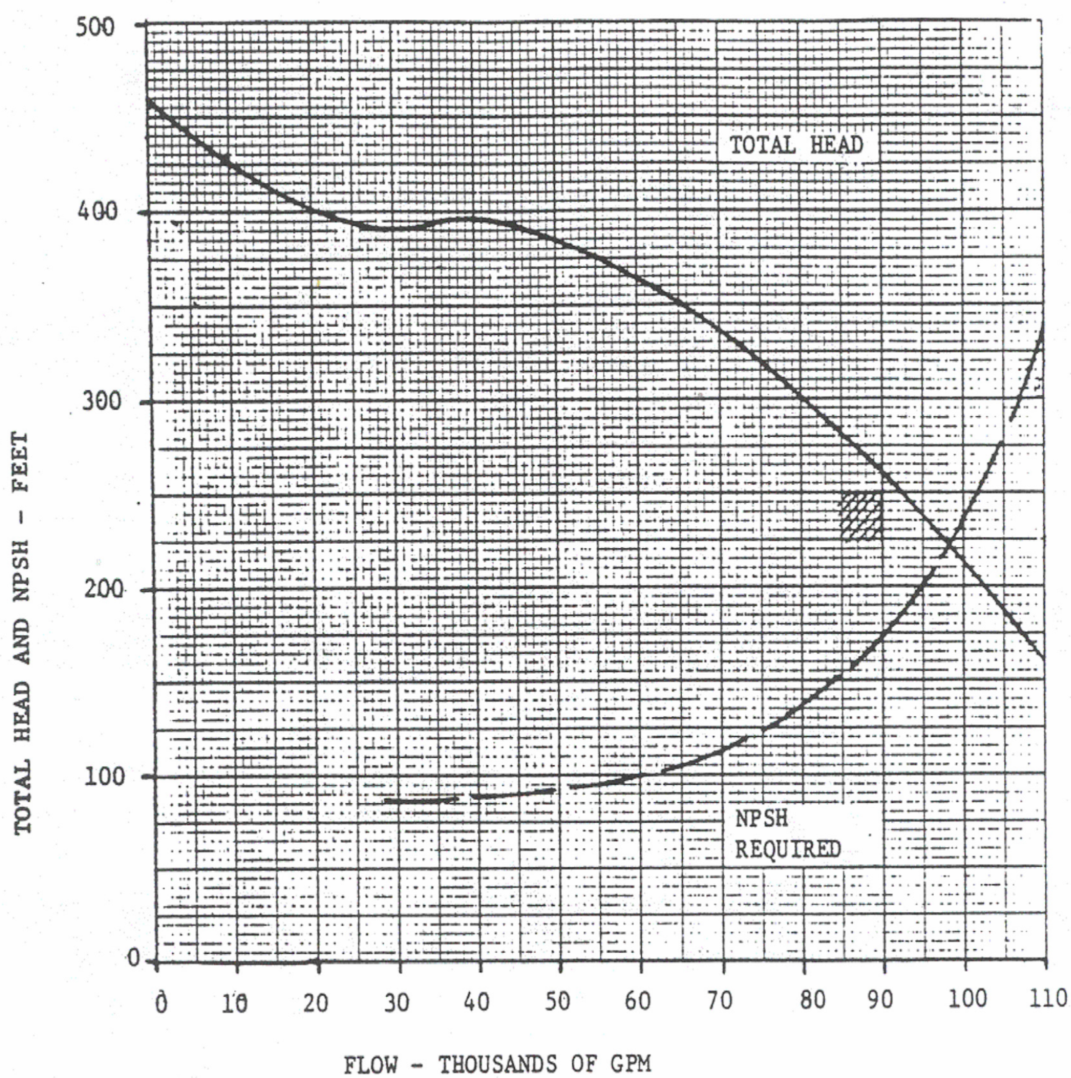
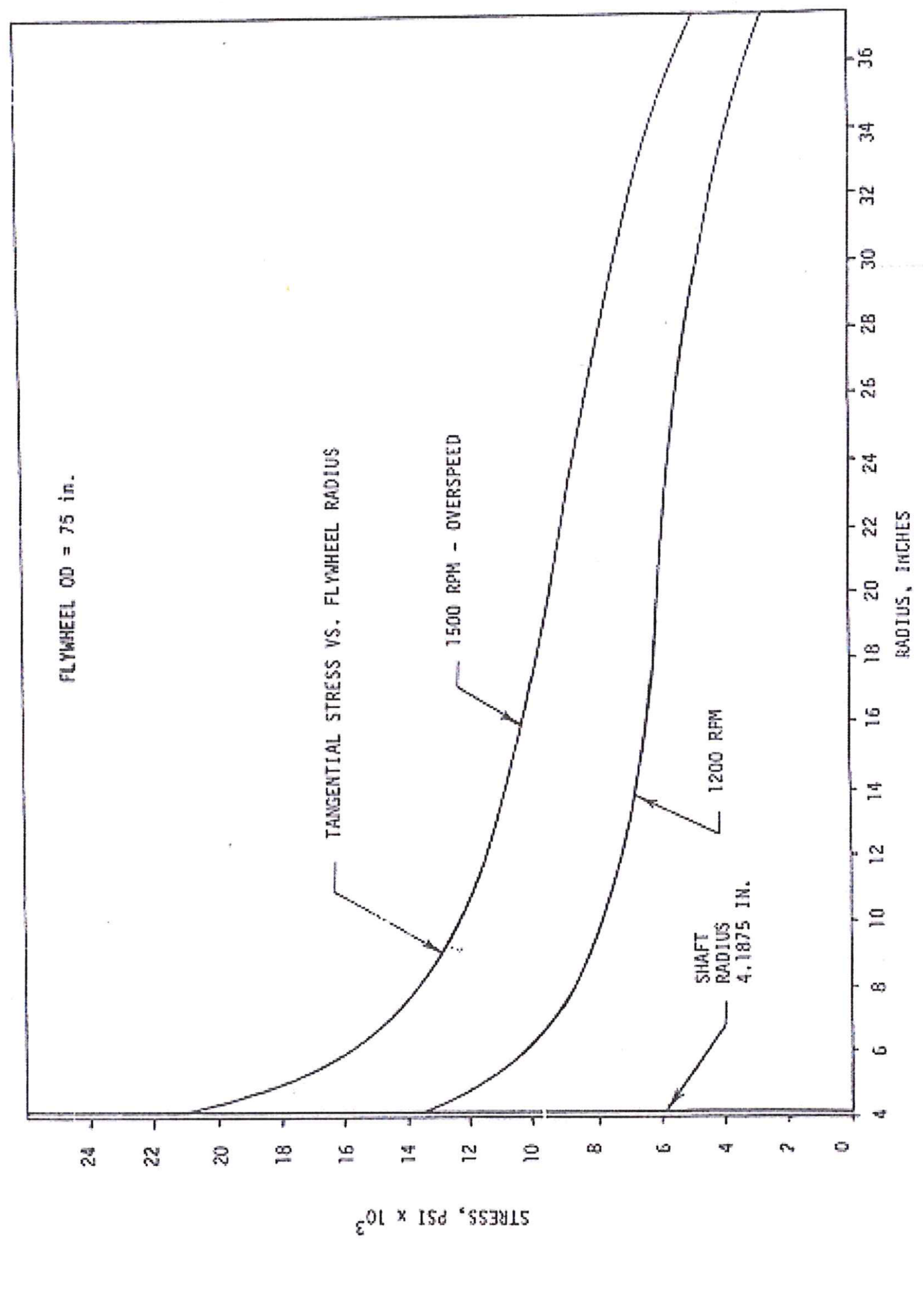


Figure 4.2-8 REACTOR COOLANT PUMP FLYWHEEL

[redacted]

Figure 4.2-9 FLYWHEEL STRESS



4.3 SYSTEM DESIGN EVALUATION

SAFETY FACTORS

The safety of the reactor vessel and all other Reactor Coolant System pressure containing components and piping is dependent on several major factors including design and stress analysis, material selection and fabrication, quality control, and operations control.

Reactor Vessel

The reactor vessel has a 132 in. ID and is within size limits for which good experience exists. A stress evaluation of the reactor vessel has been carried out in accordance with the rules of the applicable Edition of Section III of the ASME Code. The evaluation demonstrates that stress levels are within the stress limits of the Code. Table 4.3-1 presents a summary of the results of the stress evaluation. A summary of fatigue usage factors for components of the reactor vessel is given in Table 4.3-2.

The cycles specified for the fatigue analysis are the results of an evaluation of the expected plant operation coupled with experience from nuclear power plants such as Yankee Rowe. These cycles include five heatup and cooldown cycles per year, a conservative selection when the vessel may not complete more than one cycle per year during normal operation.

The vessel design pressure is 2485 psig, while the normal design operating pressure is 2235 psig. The resulting operating membrane stress is, therefore, amply below the code allowable membrane stress to account for operating pressure transients.

Appendix G to 10 CFR 50 establishes requirements for the fracture toughness of the reactor vessel pressure boundary which provide adequate margins of safety during any condition of normal operation, including anticipated operational occurrences, to which the pressure boundary may be subjected over its service lifetime. Section IV.A.2 of Appendix G requires that the reactor vessel be operated with pressure temperature limits at least as conservative as those obtained by following the methods of analysis and the required margins of safety of Appendix G of ASME Code Section XI.

See Section 15.4 for the discussion of the fracture toughness methodology evaluation reviewed and approved by the NRC for License Renewal for Unit 2. (NRC SE dated 12/2005, NUREG-1839)

Appendix G of ASME Code Section XI requires that pressure temperature limits be calculated: (a) using a safety factor of two on the principal membrane (pressure) stresses; (b) assuming a flaw at the surface with a depth of one quarter of the vessel wall thickness and a length of six times its depth; (c) using a conservative fracture toughness curve that is based on the lower bound of static, dynamic, and crack arrest fracture toughness tests on material similar to the Point Beach reactor vessel material; and (d) applying a 2 sigma margin in the determination the adjusted reference temperature (RT_{NDT}). The irradiation induced shift in RT_{NDT} is determined using the guidance of Regulatory Guide 1.99, Rev. 2 (Radiation Embrittlement of Reactor Vessel Materials) which is a conservative measure of material embrittlement.

Limits on the reactor coolant system pressure with respect to temperature during plant heatup, cooldown, and normal operation are determined in accordance with the methods of analysis and the margins of safety of Appendix G of the ASME Code Section XI and are included in the Point Beach Pressure Temperature Limits Report (PTLR).

The vessel closure contains 48 six inch studs. The stud material is ASTM A 540 and Code Case 1335.2, which has a minimum yield strength of 104,000 psi at design temperature. The membrane stress in the studs when they are at the steady state operational condition is approximately 37,500 psi.

Steam Generators

Calculations confirm that the steam generator tubesheet will withstand the loading (which is a quasi static rather than a shock loading) by loss of reactor coolant. The maximum primary membrane plus primary bending stress in the tubesheet under these conditions is 23,600 psi. This is well below ASME Section III yield strength of 41,400 psi at 650°F. Because the pressure in the primary channel head would drop to zero under the condition postulated, no damage will result to the tubesheet.

The rupture of primary or secondary piping has been assumed to impose a maximum pressure differential of 2250 psi across the tubes and tubesheet from the primary side or a maximum pressure differential of 1100 psi across the tubes and tubesheet from the secondary side, respectively. A criterion is established from these conditions under which there is no rupture of the primary-to-secondary boundary (tubes and tubesheet). This criterion prevents any violation of the containment boundary.

To meet this criterion, it has been established that, under the postulated accident conditions where a primary-to-secondary side differential pressure of 2250 psi exists, the primary membrane stresses in the tubesheet ligaments, averaged across the ligament and through the tubesheet thickness, do not exceed 90% of the material yield stress at the operating temperature. Furthermore, the primary membrane plus primary bending stress in the tubesheet ligaments, averaged across the ligament width at the tubesheet surface location giving maximum stress, do not exceed 135% of the material yield stress at the operating temperature. This criterion is felt to be applicable to abnormal operating circumstances in that it is consistent with the ASME, Nuclear Pressure Vessel Code, Section III rules, Paragraph N 714, 2 for hydrotest limitations. An examination of stresses under these conditions shows that for the case of a 2485 psi maximum tubesheet pressure differential, the stresses are within acceptable limits. These stresses, together with the corresponding stress limits, are given in Table 4.3-3.

The tubes have been designed to the requirements (including stress limitations) of Section III for normal operation, assuming 2485 psi as the normal operating pressure differential. Hence, the secondary pressure loss accident condition imposes no extraordinary stress on the tubes beyond that normally expected and considered in Section III requirements. In the case of a primary pressure loss accident, the secondary-to-primary pressure differential can reach 1100 psi. This pressure differential is less than the primary-to-secondary design pressure differential (1700 psi) for normal operating conditions. Hence, no stresses in excess of those covered in Section III rules for normal operation are experienced on the tubesheet for this accident case.

ASME Section VIII design curves for iron chromium nickel steel cylinders under external pressure indicate a collapse pressure of 2310 psi for tubes having the minimum properties required by the ASTM specification. This indicates a minimum factor of safety of 2.4 against collapse. Collapse tests of 7/8 0.050 wall straight tubes at room temperature indicate actual tube strengths are significantly higher than specification and a collapse pressure of 6,000 psi was recorded for the straight tube. The difference is attributed to the fact that the yield strength of the tube tested was 44,000 psi and the Code charts are based on a yield strength of approximately 29,000 psi at room temperature.

Consideration has been given to the superimposed effects of secondary side pressure loss and the maximum potential earthquake loading. The fluid dynamic forces on the internal components affecting the primary-to-secondary boundary (tubes) has been considered as well. For this condition, the criterion is that no rupture of primary-to-secondary boundary (tubes and tubesheet) occurs.

For the case of the tubesheet, the maximum hypothetical earthquake loading will contribute an equivalent static pressure loading over the tubesheet of less than 10 psi (for vertical shock). Such an increase is small when compared to the pressure differentials (up to 2485 psi) for which the tubesheet is designed. Under horizontal shock loading of the maximum hypothetical earthquake, the stresses are less than those for 1.0 g gravity loading experienced in a horizontal position, which the design can readily accept.

The fluid dynamic forces on the internals under secondary steam break accident conditions indicate, in the more severe case, that the tubes are adequate to constrain the motion of the baffle plates with some plastic deformation, but boundary integrity is maintained. The ratios of the allowable stresses (based on an allowable membrane stress of 0.9 of the nominal yield stress of the material) to the computed stresses, are summarized in Table 4.3-4.

RELIANCE ON INTERCONNECTED SYSTEMS

The principal heat removal systems which are interconnected with the Reactor Coolant System are the steam and feedwater systems and the safety injection and residual heat removal systems. The Reactor Coolant System is dependent upon the steam generators and the steam, feedwater, and condensate systems for decay heat removal from normal operating conditions to a reactor coolant temperature of approximately 350°F. The layout of the system ensures the natural circulation capability to permit plant cooldown following a loss of both reactor coolant pumps.

The flow diagram of the Steam and Power Conversion System is shown in Figure 10.1-1 through Figure 10.1-4A. In the event that the condensers are not available to receive the steam generated by residual heat, the water stored in the feedwater system may be pumped into the steam generators and the resultant steam vented to the atmosphere. The auxiliary feedwater system (AF) will supply water to the steam generators in the event that the main feedwater pumps are inoperative. The system is described in Section 10.0. The Safety Injection System is described in Section 6.0. The Residual Heat Removal System is described in Section 10.0.

SYSTEM INTEGRITY

A complete stress analysis which reflects consideration of all design loadings detailed in the design specification has been prepared by the manufacturer. The analysis shows that the reactor vessel, steam generator, pump casing, and pressurizer comply with the stress limits of Section III of the ASME Code. A similar analysis of the piping shows that it complies with the stress limits of the applicable USAS Code.

As part of the design control on materials, Charpy V notch toughness test curves were run on all ferritic material used in fabricating pressure parts of the reactor vessel, steam generator, and pressurizer to provide assurance for hydrostatic testing and initial operation in the ductile region. In addition, drop weight tests were performed on the reactor vessel plate material. Following initial plant operation, additional testing of reactor vessel materials is performed as part of the reactor vessel surveillance program to obtain information on the effects of neutron irradiation embrittlement of reactor vessel materials under operating conditions. This program is described in Section. 4.4.

As an assurance of system integrity, all components in the system were hydrostatically tested at 3110 psig prior to initial operation. In addition, to assure primary system integrity, the system is leak tested at normal operating pressure following each refueling outage, as required by ASME Section XI.

PRESSURE RELIEF

The Reactor Coolant System is protected against overpressure by safety valves located on the top of the pressurizer. The safety valves on the pressurizer are sized to prevent system pressure from exceeding the design pressure by more than 10%, in accordance with the applicable Edition of Section III of the ASME Boiler and Pressure Vessel Code. The capacity of the pressurizer safety valves is determined from considerations of; (1) the reactor protective system, and (2) accident or transient conditions which may potentially cause overpressure.

The combined capacity of the safety valves is equal to or greater than the maximum surge rate resulting from complete loss of load without a direct reactor trip or any other control, except that the safety valves on the secondary plant are assumed to open when the steam pressure reaches the secondary plant safety valves' setpoints.

SYSTEM INCIDENT POTENTIAL

The potential of the Reactor Coolant System as a cause of accidents is evaluated by investigating the consequences of certain credible types of components and control failures as discussed in Section 14.1.1 and Section. 14.2. Reactor coolant pipe rupture is evaluated in Section. 14.3.

REFERENCES

1. NRC Safety Evaluation dated May 3, 2011, "Issuance of License Amendments Regarding Extended Power Uprate (TAC Nos. ME1044 and ME1045)."

2. Westinghouse Calculation CN-MRCDA-08-43, Revision 1, "Reactor Vessel Evaluation for Point Beach Units 1 and 2 17 Percent Power Extended Power Uprate Program," dated April 2, 2009.

3. WCAP-16983-P, Revision 0, "Point Beach Units 1 and 2 Extended Power Uprate (EPU) Engineering Report," (Proprietary) dated September 2009.

Table 4.3-1 SUMMARY OF PRIMARY PLUS SECONDARY STRESS INTENSITY FOR COMPONENTS OF THE REACTOR VESSEL

Area	Stress Intensity (psi)	Allowable Stress 3 Sm (psi)
CRDM Nozzle	45,300	60,000
Closure Head at Flange	69,200	80,100
Vessel at Flange	71,100	80,100
Closure Studs	117,600	118,800
Primary Nozzles	48,800[a]	80,100
External Support Brackets	41,200	80,100
Core Support Pad	57,500	69,900
Bottom Head to Shell Juncture	28,600	80,100
Bottom Instrumentation	57,800	69,900
Safety Injection Nozzle	46,800	80,100
Vent Nozzle	53,600	60,000
Vessel Wall Transition	32, 200	80,100
Instrumentation Port Head Adapter for Core Exit Thermocouple Nozzle Assembly	25,600	50,100

(NRC SE dated 12/2005, NUREG-1839)

a. Limiting value considering both the inlet and outlet nozzles.

Table 4.3-2 SUMMARY OF CUMULATIVE FATIGUE USAGE FACTORS FOR COMPONENTS OF THE REACTOR VESSEL

Item	Usage Factor*[a]
CRDM Nozzle	0.672
Closure Head at Flange	0.248
Vessel at Flange	0.992
Closure Studs	0.991
Primary Nozzles	0.155[b]
External Support Brackets	0.842
Core Support Pad	0.960
Bottom Head to Shell Juncture	0.004
Bottom Instrumentation	0.384
Safety Injection Nozzle	0.465
Vent Nozzle	0.023
Vessel Wall Transition	0.006
Instrumentation Port Head Adapter for Core Exit Thermocouple Nozzle Assembly	0.029

(NRC SE dated 12/2005, NUREG-1839)

* Covers all transients

a As defined in the applicable Edition of Section III of the ASME Boiler and Pressure Vessel Code, Nuclear Vessels

b Limiting value considering both the inlet and outlet nozzles.

Table 4.3-3 STRESSES DUE TO MAXIMUM STEAM GENERATOR TUBESHEET PRESSURE DIFFERENTIAL (2485 PSI)

Stress	Computed Value	(668° F) Allowable Value
Primary Membrane Stress	23,300 psi	37,000 psi (0.9 Sy)
Primary Membrane plus Primary Bending Stress	53,000 psi	55,600 psi (1.35 Sy)

In addition to the foregoing evaluation, elasto plastic limit analysis of the tubesheet head shell combination indicates a limit pressure of 3400 psi at operating conditions, giving a safety factor of 1.36 for the abnormal condition.

Table 4.3-4 RATIO OF ALLOWABLE STRESSES TO COMPUTED STRESSES FOR A STEAM GENERATOR TUBESHEET PRESSURE DIFFERENTIAL OF 2485 PSI

Component Part	Stress Ratio
Channel Head	1.35
Channel Head Tubesheet Joint	1.63
Tubes	1.20
Tubesheet	
Maximum Average Ligament	1.04
Effective Ligament	1.58

4.4 TESTS AND INSPECTIONS

REACTOR COOLANT SYSTEM INSPECTION

Nondestructive Inspection of Material and Components Prior to Operation

Table 4.4-1 summarizes the nondestructive examination program for all Reactor Coolant System components. In this table, all of the nondestructive examinations which were required by the Westinghouse specifications on Reactor Coolant System components and materials are specified for each component. All examinations required at the time of manufacture and installation by the applicable codes are included in this table. Westinghouse requirements, which were more stringent in some areas than those requirements specified in the applicable codes, are also included.

Westinghouse required, as part of its reactor vessel specification, that certain special tests which are not specified by the applicable codes be performed. These tests are listed below:

1. Ultrasonic Testing - Westinghouse required that a 100% volumetric ultrasonic test of reactor vessel plate by both shear wave and longitudinal wave be performed. Section III Class A vessel plates are required by code to receive only a longitudinal wave ultrasonic test on a 9 in. x 9 in. grid. The 100% volumetric ultrasonic test is a severe requirement, but it assured that the plate used for Westinghouse reactor vessels is of the highest quality.

2. Material Surveillance Program - The beltline region of the reactor pressure vessel is the most critical region because it is subjected to significant neutron irradiation. The overall effects of neutron irradiation on the mechanical properties of low alloy ferritic materials is known as neutron embrittlement and encompasses an increase in hardness and tensile properties and a decrease in ductility and toughness with cumulative neutron irradiation.

A reactor pressure vessel surveillance program in accordance with the requirements of 10 CFR Part 50, Appendix H (Reactor Vessel Material Surveillance Program Requirements) and ASTM E 185-82 (Standard Practice for Conducting Surveillance Tests for Light Water Cooled Nuclear Power Reactor Vessels) has been implemented for the Point Beach Nuclear Plant to obtain information on the effects of irradiation on the reactor pressure vessel material under operating conditions. The program consists of periodically testing irradiated reactor vessel material specimens at intervals defined in E 185-82 and comparing the data with pre-irradiation data to establish the shift in RT_{NDT}. This information may be used in the development of reactor coolant system pressure temperature limits and to demonstrate compliance with 10 CFR 50.60 (Acceptance Criteria for Fracture Prevention Measures for Lightwater Nuclear Power Reactors for Normal Operation) and 50.61 (Fracture Toughness Requirements for Protection Against Pressurized Thermal Shock Events).

See Section 15 for the discussion of the fracture toughness methodology evaluation reviewed and approved by the NRC for License Renewal for Unit 2 (NRC SE dated 12/2005, NUREG 1839).

Six material surveillance capsules were located in the reactor vessel between the thermal shield and the vessel wall prior to initial startup. The capsules contain Charpy V-notch impact specimens, tensile specimens, Wedge Opening Loading (WOL) specimens from the shell plate or ring forgings of the reactor vessel and representative weld metal, and Charpy V-notch impact specimens of heat affected zone (HAZ) metal and the ASTM correlation monitor material. Dosimeters to measure the integrated neutron flux (fluence) and thermal monitors to measure temperature are also included in each of the six material test capsules. The removal schedules for the Unit 1 and 2 reactor vessel surveillance capsules are contained in TRM 2.2, Pressure Temperature Limits Report.

Pre-irradiation tests consisted of Charpy V-notch impact tests on the vessel shell plate or ring forgings, weld materials, HAZ metal, and on the correlation monitor material, and tensile tests performed on the vessel shell plate or ring forging and weld metal. The data established the nil ductility transition temperature, NDTT, for the materials. As a supplement to the plant specific material surveillance program for Point Beach, additional surveillance data is available through participation in the Babcock & Wilcox Owners Group Master Integrated Reactor Vessel Surveillance Program. This integrated program includes weld metal heats used in the construction of the Point Beach reactor vessels that are not included in the plant specific surveillance program for Point Beach.

Following establishment of the pre-irradiation mechanical properties of the subject materials, the ASME Boiler and Pressure Vessel Code adopted new fracture toughness requirements for ferritic components of nuclear reactor systems. The new Code provisions utilize fracture mechanics concepts as a method of analysis to prevent brittle fracture in reactor pressure vessels.

The method of fracture mechanics is based on the RT_{NDT} (reference nil-ductility temperature), which is defined as the greater of the drop weight nil ductility transition temperature (NDTT per ASTM E-208) or the temperature, which is 60 F less than the 50 ft-lb (and 35 mils lateral expansion) temperature as determined from Charpy specimens oriented normal to the rolling direction of the material. The RT_{NDT} of a given material is used to index that material to a reference stress intensity factor curve (K_{IR} curve) as presented in Appendix G of ASME Boiler and Pressure Vessel Code Section XI. When a given material is indexed to the K_{IR} curve, allowable stress intensity factors can be obtained for this material as a function of temperature. Allowable operating limits are then determined utilizing the allowable stress intensity factors and methodology of ASME Appendix G.

RT_{NDT}, and thus the operating limits of Point Beach Nuclear Plant, are adjusted to account for the effects of radiation on the reactor vessel material properties through the information provided by the reactor pressure vessel surveillance program or by utilizing embrittlement trend correlations prepared by the NRC or others. Details of the development and use of the surveillance program are found in WCAP-9513, June 1978;

WCAP-7712, June 1971; WCAP-7924, July 1972; WCAP-8738, and WCAP-8743, January 1977.

Non-Destructive Examination of Materials

Table 4.4-1 summarizes the non destructive examinations performed on primary system components. In addition to the inspections shown in Table 4.4-1, there are those which the equipment supplier performs to confirm the adequacy of material received, and those performed by the material manufacturer in producing the basic material. The examinations of the reactor vessel, pressurizer, and steam generator are governed by ASME Code requirements. The examination procedures and acceptance standards required on pipe materials and piping fabrication are governed by USAS B31.1 and Westinghouse requirements and are equivalent to those performed on ASME Code vessels.

Procedures for performing the examinations are consistent with those established in the ASME Code, Section III and were reviewed by qualified Westinghouse engineers. These procedures have been developed to provide the highest assurance of quality material and fabrication. They consider not only the size of the flaws, but equally as important, how the material is fabricated, the orientation and type of possible flaws, and the areas of most severe service conditions. In addition, the surfaces most subject to damage as a result of the heat treating, rolling, forging, forming, and fabricating processes, received a 100% surface inspection by magnetic particle or liquid penetrant testing after all these operations are completed. All reactor coolant plate materials are also subject to shear as well as longitudinal ultrasonic testing to give maximum assurance of quality. All forgings receive the same inspection. In addition, 100% of the material volume is covered in these tests as an added assurance over the grid basis required in the Code.

Westinghouse quality control engineers and Wisconsin Electric's engineers monitored the supplier's work, witnessing key inspections not only in the supplier's shop but in the shops of subvendors of the major forgings and plate material. Normal surveillance included verification of records of material, physical and chemical properties, review of radiographs, performance of required tests, and qualification of supplier personnel.

Field erection and field welding of the Reactor Coolant System were performed such as to permit exact fit up of the 31 in. ID closure pipe subassemblies between the steam generator and the reactor coolant pump. After installation of the pump casing and the steam generator, measurements were taken of the pipe length required to close the loop. Based on these measurements, the 31 in. ID closure pipe subassembly was properly machined and then erected and field welded to the pump suction nozzle and to the steam generator exit nozzle.

Cleaning of RCS piping and equipment was accomplished before and/or during erection of various equipment. Stainless steel piping was cleaned in sections as specific portions of the systems were erected. Pipe and units large enough to permit entry by personnel were cleaned by locally applying approved solvents (Stoddard solvent, acetone, and alcohol) and demineralized water, and by using a rotary disc sander or 18-8 wire brush to remove all trapped foreign particles. Standards for final physical and chemical cleanliness are defined in Section 13.

Equipment specifications for fabrication required that suppliers submit the manufacturing procedures (welding, heat treating, etc.) to Westinghouse where they were reviewed by qualified Westinghouse engineers. This also was done on the field fabrication procedures to assure that installation welds were of equal quality.

Section III of the ASME Boiler and Pressure Vessel Code required that nozzles carrying significant external loads be attached to the shell by full penetration welds. This requirement has been carried out in the reactor coolant piping, where all auxiliary pipe connections to the reactor coolant loop were made using full penetration welds.

The Reactor Coolant System components were welded under procedures which require the use of both preheat and post heat. Preheat requirements, nonmandatory under Code rules, were performed on all weldments, including P1 and P3 materials, which were the materials of construction in the reactor vessel, pressurizer, and steam generators. Preheat and post heat of weldments both serve a common purpose; the production of tough, ductile metallurgical structures in the completed weldment. Preheating produces tough ductile welds by minimizing the formation of hard zones, post heating achieves this by tempering any hard zones which may have formed due to rapid cooling. Thus, the Reactor Coolant System components were welded under procedures which require the use of both preheat and post-heat.

Inservice Inspection

During the design phase of the Reactor Coolant System, careful consideration was given to provide access for both visual and nondestructive inservice inspection of primary loop components. If necessary, the following components and areas can be made available for 100% visual and 100% nondestructive inspection (except as noted):

1. Reactor Vessel - The entire inside surface
2. Reactor Vessel Nozzles - The entire inside surface
3. Closure Head - The entire inside and outside surface
4. Reactor Vessel Studs, Nuts, and Washers
5. Field Welds between the Reactor Vessel, Steam Generators, and Reactor Coolant Pumps and the Reactor Coolant Piping
6. Reactor Internals
7. Reactor Vessel Flange Seal Surface
8. Fuel Assemblies (External visual only)
9. Rod Cluster Control Assemblies

10. Control Rod Drive Shafts

11. Control Rod Drive Mechanism Assemblies

12. Reactor Coolant Pipe External Surfaces (except for the five foot penetration of the primary shield)

13. Steam Generator   The external surface, the internal surfaces of the Steam Drum, and the Channel Head

14. Pressurizer - The Internal and External Surfaces

15. Reactor Coolant Pump - The External Surfaces, Motor, Impeller, and Flywheel

The design considerations which have been incorporated into the primary system design to permit the above inspections are as follows:

1. All reactor internals are completely removable. The tools and storage space required to permit these inspections are provided.

2. The closure head is stored dry on an operating deck during refueling to facilitate direct visual inspection.

3. All reactor vessel studs, nuts, and washers are removed to dry storage during refueling.

4. Removable plugs are provided in the primary shield just above the coolant nozzles, and the insulation covering the nozzle welds is readily removable.

5. Access holes are provided in the lower internals barrel flange to allow remote access to the reactor vessel internal surfaces between the flange and the nozzles without removal of the internals.

6. A removable plug is provided in the lower core support plate to allow access for inspection of the bottom head without removal of the lower internals.

7. The storage stands provided for storage of the internals allow for inspection access to both the inside and outside of the structures.

8. The station provided for change out of control rod clusters from one fuel assembly to another is specially designed to allow inspection of both fuel assemblies and control rod clusters. The control rod mechanism is specially designed to allow removal of the mechanism assembly from the reactor vessel head.

9. Manways are provided in the steam generator steam drum and channel head to allow access for internal inspection.

10. A manway is provided in the pressurizer top head to allow access for internal inspection.

11. All insulation on primary system components (except the reactor vessel) and piping (except for the penetration in the primary shield) is removable.

The metal reflective insulation on the closure head may be removed as desired to perform inspection.

The use of conventional nondestructive, direct visual, and remote visual examination techniques can be applied to the inspection of all primary loop components except for the reactor vessel. The reactor vessel presents special problems because of the radiation levels and remote underwater accessibility to this component. Because of these limitations on access to the reactor vessel, several steps have been incorporated into the design and manufacturing procedures.

1. Shop ultrasonic examinations were performed on all internally clad surfaces to an acceptance and repair standard to assure an adequate cladding bond to allow later ultrasonic testing of the base metal. Size of cladding bonding defect allowed is 3/4 inch.

2. The design of the reactor vessel shell in the core area is a clean, uncluttered cylindrical surface to permit positioning of test equipment without obstruction.

3. Reactor Vessel Postoperational Ultrasonic Testing - Following hydrostatic testing of the vessel, selected areas of the reactor vessel were ultrasonic tested and mapped to facilitate the inservice inspection program. The area selected for ultrasonic testing mapping included:

   a. Vessel flange radius, including the vessel flange to upper shell weld
   b. Middle shell course
   c. Lower shell course above the radial core supports
   d. Nozzle to upper shell weld
   e. Middle shell to lower shell weld
   f. Upper shell to middle shell weld

Various tests have been conducted to determine the effect of cladding surface finish on ultrasonic inspectability of vessel material.

Detailed procedures for inservice inspection are specified in the PBNP Inservice Inspection Program, including the use of visual inspections, ultrasonic, magnetic particle, and dye penetrant testing of selected parts during refueling periods.

The internal surface of the reactor vessel is inspected periodically using optical devices over the accessible areas. During refueling, the vessel cladding can be inspected in certain areas between the closure flange and the primary coolant inlet nozzles. If deemed necessary by this inspection, the core barrel could be removed, making the entire inside vessel surface accessible. The reactor vessel welds are periodically examined by means of ultrasonic testing. In order to facilitate this test program, critical areas of the reactor vessel were mapped during the fabrication phase to serve as a reference base for subsequent ultrasonic tests.

Externally, the control rod drive mechanism nozzles on the closure head, the instrument nozzles on the bottom of the vessel, and the extension spool pieces on the primary coolant outlet nozzles are accessible for visual, magnetic particle, or dye penetrant inspection during refuelings.

The closure head is examined visually during each refueling. Optical devices permit a selective visual inspection of the cladding, control rod drive mechanism nozzles, and the gasket seating surface. The knuckle transition piece, which is the area of highest stress of the closure head, also is accessible on the outer surface for inspection by visual and dye penetrant means.

The closure studs are inspected periodically using either magnetic particle tests and/or ultrasonic tests. Additionally, it is possible to perform strain tests during the tensioning, which assists in verifying the material properties.

These areas are subjected to periodic inservice inspection. A complete program dealing with the frequency of inspection and the methods for such inspections is defined in the PBNP Inservice Inspection Program.

The preservice inspection of the Reactor Coolant System, which established a base line for later inservice inspection, included all the initial tests necessary to evaluate the inservice inspection program. The preservice and initial inservice inspection programs were based on the October 1968 Draft ASME Code for Inservice Inspection of Nuclear Reactor Coolant Systems (N-45). Several differences exist between the base line inspections and those outlined in the October 1969 Draft ASME Code. N-45 calls for the preparation of specific patches on the cladding surface of the reactor vessel, pressurizer, and steam generator primary head. No specific patches were prepared, but a complete base line visual and surface inspection was performed on all cladding and a general visual inservice inspection was made of all accessible areas of cladding; not limited to specific patches. The inner radii of integrally cast nozzles of the pressurizer were not subjected to baseline volumetric inspection. These areas require extremely high personnel radiation exposure to perform inservice inspection, due to difficulties of access, and the information gained would not justify this high personnel exposure. All primary system pipe welds are included in the quality assurance program outlined in Table 4.4-1 and received preservice volumetric inspection to verify weld integrity, except no volumetric inspection of pressure containing welds in piping 2 in. and smaller were performed. A pipe break 2 in. or smaller in size is well within the capability of the safety injection system and will not cause core damage. All pressure containing welds in piping greater than 2 in. in size were included in the base line volumetric inspection. The integrally welded external support attachments to auxiliary piping are inspected. The geometry of the restraints precludes meaningful volumetric inspection.

The location of the reactor vessel biological shield makes several areas of the Reactor Coolant System pressure boundary inaccessible to inspection. Although the areas are inaccessible for inservice inspection, they have all received preservice volumetric inspection to insure weld integrity.

Examination of the primary pump flywheels may be conducted at approximately 20-year intervals. A qualified in-place UT examination over the volume from the inner bore of the flywheel to the circle one-half of the outer radius or a surface examination (MT and/or PT) of exposed surfaces of the removed flywheels shall be performed. (Reference SER 2005-0008 dated June 6, 2005, and WCAP-15666)

The reactor vessel external supports have limited accessibility for inservice inspection. The bottom portion of the legs are visible from the keyway area, and the top of the support is visible when the sandbox covers around the RPV flange are opened and the plugs are removed.

Technical Specifications require that a program be established and implemented to ensure that steam generator tube integrity is maintained. The Steam Generator Program establishes performance criteria for structural integrity, accident induced leakage, and operational leakage. Meeting these performance criteria provides reasonable assurance of maintaining tube integrity during normal and accident conditions.

Table 4.4-1 REACTOR COOLANT SYSTEM NONDESTRUCTIVE EXAMINATION

(Sheet 1 of 3)

Component	Type of Examination*
1. Steam Generator	
1.1 Tubesheet	
1.1.1 Forging	UT(1), MT
1.1.2 Cladding	UT(1), PT(2)
1.2 Channel Head	
1.2.1 Casting	RT, MT
1.2.2 Cladding	PT
1.3 Secondary Shell and Head Plates	UT
1.4 Tubes	UT, ET
1.5 Nozzles (Forgings)	UT, MT
1.6 Weldments	
1.6.1 Shell, longitudinal	RT, MT
1.6.2 Shell, circumferential	RT, MT
1.6.3 Cladding (Channel Head Tubesheet joint cladding restoration	PT
1.6.4 Steam and Feedwater Nozzle to Shell	RT, MT
1.6.5 Support Brackets	MT
1.6.6 Tube to Tubesheet	PT
1.6.7 Instrument connections (primary and secondary)	MT
1.6.8 Temporary attachments after removal	MT
1.6.9 After hydrostatic test (all welds and complete channel head where accessible)	MT
1.6.10 Nozzle Safe Ends (if forgings)	RT, PT
1.6.11 Nozzle Safe Ends (if weld deposit)	PT
2. Pressurizer	
2.1 Heads	
2.1.1 Casting	RT, MT
2.1.2 Cladding	PT
2.2 Shell	
2.2.1 Plates	UT, MT
2.2.2 Cladding	PT
2.3 Heaters	
2.3.1 Tubing(3)	UT, PT
2.3.2 Centering of element	RT
2.4 Nozzle	UT, PT

Table 4.4-1 REACTOR COOLANT SYSTEM NONDESTRUCTIVE EXAMINATION

(Sheet 2 of 3)

Component	Type of Examination*
2. Pressurizer (continued)	
2.5 Weldments	
2.5.1 Shell, longitudinal	RT, MT
2.5.2 Shell, circumferential	RT, MT
2.5.3 Cladding	PT
2.5.4 Nozzle Safe End (if forging)	RT, PT
2.5.5 Nozzle Safe End (if weld deposit)	PT
2.5.6 Instrument Connections	PT
2.5.7 Support Skirt	PT
2.5.8 Temporary Attachments after removal	MT
2.5.9 All welds and cast heads after hydrostatic test	MT
2.6 Final Assembly	
2.6.1 All accessible surfaces after hydrostatic test	MT
3. Piping	
3.1 Fittings (Castings)	RT, PT
3.2 Fittings (Forgings)	UT, PT
3.3 Pipe	UT, PT
3.4 Weldments	
3.4.1 Circumferential	RT, PT
3.4.2 Nozzle to run pipe (No RT for nozzles less than 3 in.)	RT, PT
3.4.3 Instrument connections	PT
4. Pumps	
4.1 Castings	RT, PT
4.2 Forgings	PT
4.2.1 Main Shaft	UT, PT
4.2.2 Main Studs	UT, PT
4.2.3 Flywheel (Rolled Plate)	UT
4.3 Weldments	
4.3.1 Circumferential	RT, PT
4.3.2 Instrument Connections	PT
5. Reactor Vessel	
5.1 Forgings	
5.1.1 Flanges	UT, MT

Table 4.4-1 REACTOR COOLANT SYSTEM NONDESTRUCTIVE EXAMINATION

(Sheet 3 of 3)

Component	Type of Examination*
5. Reactor Vessel (continued)	
5.1 Forgings (continued)	
5.1.2 Studs	UT, MT
5.1.3 Head Adapters	UT, PT
5.1.4 Head Adapter Tube	UT, PT
5.1.5 Instrumentation Tube	UT, PT
5.1.6 Main Nozzles	UT, MT
5.1.7 Nozzle Safe Ends (If forging is employed)	UT, PT
5.2 Plates	UT, MT
5.3 Weldments	
5.3.1 Main Steam	RT, MT
5.3.2 CRD Head Adapter Connection	PT
5.3.3 Instrumentation Tube Connection	PT
5.3.4 Main Nozzles	RT, MT
5.3.5 Cladding	UT(4), PT
5.3.6 Nozzle Safe Ends (If forging)	RT, PT
5.3.7 Nozzle Safe Ends (If weld deposit)	RT, PT
5.3.8 Head adapter forging to head adapter tube	RT, PT
5.3.9 All welds after hydrotest	PT
6. Valves	
6.1 Castings	RT, PT
6.2 Forgings (No UT for valves 2 in. and smaller)	UT, PT

Notes:

(1) Flat surfaces only
(2) Weld deposit areas only
(3) Or a UT and ET
(4) UT of Clad bond to base metal

* RT - Radiographic
UT - Ultrasonic
PT - Dye Penetrant
MT - Magnetic Particle
ET - Eddy Current

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5.0 CONTAINMENT SYSTEM STRUCTURE

5.1 CONTAINMENT SYSTEM STRUCTURE

5.1.1 DESIGN BASIS

The reactor containment completely encloses the entire reactor and reactor coolant system and ensures that an acceptable upper limit for leakage of radioactive materials to the environment is not exceeded even if gross failure of the reactor coolant system occurs. The structure provides biological shielding for both normal and accident situations. The containment structures of Units 1 and 2 are designed to maintain leakage no greater than 0.2%/24 hours of containment air weight at a design pressure of 60 psig and 286°F.

5.1.1.1 GENERAL DESIGN CRITERIA

General Design Criteria that apply to the Containment System Structure are delineated below.

Quality Standards

Criterion: Those systems and components of reactor facilities which are essential to the prevention, or the mitigation of the consequences, of nuclear accidents which could cause undue risk to the health and safety of the public shall be identified and then designed, fabricated, and erected to quality standards that reflect the importance of the safety function to be performed. Where generally recognized codes and standards pertaining to design, materials, fabrication, and inspection are used, they shall be identified. Where adherence to such codes or standards does not suffice to assure a quality product in keeping with the safety function, they shall be supplemented or modified as necessary. Quality assurance programs, test procedures, and inspection acceptance criteria to be used shall be identified. An indication of the applicability of codes, standards, quality assurance programs, test procedures, and inspection acceptance criteria used is required. Where such items are not covered by applicable codes and standards, a showing of adequacy is required. (GDC 1)

The Containment System structure is of primary importance with respect to its safety function in protecting the health and safety of the public. Quality standards of material selection, design, fabrication, and inspection governing the above features conform to the applicable provisions of recognized codes at the time of construction and good nuclear practice. The concrete structure of the reactor containment conforms to the applicable portions of ACI-318-63. Further elaboration on quality standards of the reactor containment is given in Section 5.1.2.5 and Section 5.6.

Performance Standards

Criterion: Those systems and components of reactor facilities which are essential to the prevention or to the mitigation of the consequences of nuclear accidents which could cause undue risk to the health and safety of the public shall be designed, fabricated, and erected to performance standards that enable such systems and components to withstand, without undue risk to the health and safety of the public, the forces that might reasonably be imposed by the occurrence of an extraordinary natural phenomenon such as earthquake, tornado, flooding condition, high wind, or heavy ice. The design bases so established shall reflect: (a) appropriate consideration of the most severe of these natural phenomena that have been officially recorded for the site and the surrounding area and (b) an appropriate margin for withstanding forces greater than those recorded to reflect uncertainties about the historical data and their suitability as a basis for design. (GDC 2)

All components and supporting structures of the reactor containment are designed so that there is no loss of function of such equipment in the event of maximum potential ground acceleration acting in the horizontal and vertical directions simultaneously, or other extraordinary natural phenomena referred to in the criterion above. The dynamic response of the structure to ground acceleration, based on the site characteristics and on the structural damping, is included in the design analysis.

The reactor containment is defined as a Class I structure for purposes of seismic design (see Section 5.1.2.3). Its structural members have sufficient capacity to accept, without exceeding specified stress limits, a combination of normal operating loads, functional loads due to a loss of coolant accident, and the loadings imposed by the safe shutdown earthquake (SSE).

Fire Protection

Refer to the Fire Protection Program Design Document (FPPDD) (Reference 14) at Point Beach Nuclear Plant.

Records Requirement

Criterion: The reactor licensee shall be responsible for assuring the maintenance throughout the life of the reactor of records of the design, fabrication, and construction of major components of the plant essential to avoid undue risk to the health and safety of the public. (GDC 5)

Records of the design, fabrication, construction, and testing of the reactor containment are maintained throughout the life of the reactor.

Reactor Containment

Criterion: The containment structure shall be designed (a) to sustain, without undue risk to the health and safety of the public, the initial effects of gross equipment failures, such as a large reactor coolant pipe break, without loss of required integrity, and (b) together with other engineered safety features as may be necessary, to retain for as long as the situation requires, the functional capability of the containment to the extent necessary to avoid undue risk to the health and safety of the public. (GDC 10)

The reactor containment structure is a horizontally and vertically prestressed post tensioned concrete cylinder on top of a reinforced concrete slab and covered by a prestressed post tensioned shallow concrete dome.

The design pressure of the containment exceeds the peak pressure occurring as the result of the complete blowdown of the reactor coolant through any rupture of the reactor coolant system up to and including the hypothetical double ended severance of a reactor coolant pipe.

The containment structure and all penetrations are designed to withstand, within design limits, the combined loadings of the design basis accident and safe shutdown earthquake.

All piping systems which penetrate the containment structure are anchored at the penetration. Penetrations for lines containing high pressure or high temperature fluids (steam, feedwater, and blowdown lines) are designed so that the containment is not breached by a hypothesized pipe rupture. All lines connected to the primary coolant system that penetrate the containment are also anchored in the secondary shield walls (i.e., walls surrounding the steam generators and reactor coolant pumps). These anchors are designed to withstand the thrust, moment, and torque resulting from a hypothesized rupture of the attached pipe.

All isolation valves are supported to withstand, without impairment of valve operability, the combined loadings of the design basis accident and safe shutdown earthquake.

The design pressure is not exceeded during any subsequent long term pressure transient determined by the combined effects of heat sources such as residual heat and metal water reaction with minimum operation of the emergency core cooling and the containment air recirculation and spray cooling systems.

Reactor Containment Design Basis

Criterion: The reactor containment structure, including openings and penetrations, and any necessary containment heat removal systems, shall be designed so that the leakage of radioactive materials from the containment structure under conditions of pressure and temperature resulting from the largest credible energy release following a loss-of-coolant-accident, including the calculated energy from metal-water or other chemical reactions that could occur as a consequence of failure of any single active component in the emergency core cooling system, will not result in undue risk to the health and safety of the public. (GDC 49)

The following general criteria are followed to assure conservatism in computing the required structural load capacity:

1. In calculating the containment pressure, rupture sizes up to and including a double ended severance of reactor coolant pipe are considered.

2. In considering post accident pressure effects, various malfunctions of the emergency systems are evaluated. Contingent mechanical or electrical failures are assumed to disable one of the diesel generators, two of the four fan cooler units, and one of the two containment spray units. Equipment which can be run from diesel power is described in Chapter 6, Chapter 8, Chapter 9, and Chapter 10.

3. The pressure and temperature loadings obtained by analyzing various loss-of-coolant accidents, when combined with operating loads and maximum wind or seismic forces, do not exceed the load carrying capacity of the structure, its access opening, or penetrations.

The most stringent case of these analyses is summarized below:

Discharge of reactor coolant through a double ended rupture of the main loop piping, followed by operation of only those engineered safety features which can run simultaneously with power from one emergency on site diesel generator (one high head safety injection pump, one residual heat removal pump, two fan cooler units, one spray pump), results in a sufficiently low radioactive materials leakage from the containment structure that there is no undue risk to the health and safety of the public.

<u>NDT Requirement for Containment Material</u>

Criterion: The selection and use of containment materials shall be in accordance with applicable engineering codes. (GDC 50)

The selection and use of containment materials comply with the applicable codes and standards tabulated in Section 5.1.1.5.

The concrete containment is not susceptible to a low temperature brittle fracture.

The containment liner is enclosed within the containment and thus is not exposed to the temperature extremes of the environs. The containment ambient temperature during operation is between 50 and 120°F.

Containment penetrations which can be exposed to the environment are also designed to the NDT + 30°F criterion in accordance with ASME Section III, Subsection B.

5.1.1.2 SUPPLEMENTARY ACCIDENT CRITERIA

Systems relied upon to operate under post accident conditions, which are located external to the containment and communicate directly with the containment, are considered to be extensions of the leakage limiting boundary.

The pressure retaining components of the containment structure are designed for the maximum potential earthquake ground motion of the site combined with the simultaneous loads of the design basis accident, and the normal operating loads.

5.1.1.3 ENERGY AND MATERIAL RELEASE

The principal design loads on the containment structure are created by the hypothetical large break loss-of-coolant accident and rupture of a steam pipe accident. The large break loss-of-coolant accident (LOCA) postulates three distinct locations for a double-ended break in the reactor coolant system piping: the reactor coolant pump suction (between the steam generator and pump), the hot-leg (between the vessel and steam generator), and the cold-leg (between the pump and reactor vessel). The steam pipe rupture accident assumes a double-ended rupture of a main steam line downstream of the integral flow restrictor in the outlet of the steam generator. The energy released in both accidents cause a rapid rise in containment pressure and temperature. The LOCA analysis is described in Section 14.3.2 and the steam pipe rupture analysis is described in Section 14.2.5.

The capability of the containment to withstand the loss-of-coolant and steam line rupture accidents energy release and other design loads imposed on it is discussed in Section 5.1.2.2.

5.1.1.4 ENGINEERED SAFETY FEATURES CONTRIBUTION

Engineered safety features are included in the design of this facility to assure containment integrity. These systems are discussed in Chapter 6 and their effectiveness analyzed in Chapter 14.

5.1.1.5 CODES AND CLASSIFICATIONS

Electrical penetrations are designed and demonstrated by test to withstand, without loss of leak tightness, the containment post accident pressure and to meet the following guides:

1. IEEE - Guide for Electrical Penetration Assemblies in Containment Structures for Stationary Nuclear Power Reactors (Eighth Revision)

2. Electrical requirements of IEEE 317 - IEEE Standard for Electrical Penetration Assemblies in Containment Structures for Nuclear Fueled Power Generating Stations (1971 or 1976 versions)

Containment design gives consideration to leakage testability, including necessary provisions to enable tests to comply with:

1. ANS 7.60 - Proposed Standard for Leakage Testing of Containment Structures (July 14, 1967)

2. AEC Technical Safety Guide 7.5.1, "Reactor Containment Leakage Testing and Surveillance Requirements", (December 15, 1966)

The design, materials, fabrication, inspection, and proof testing of the containment vessel complies with the applicable parts of the following:

ASHO M-73-49 Cotton Mats for Curing Concrete

ACI 214-57	Recommended Practice for Evaluation of Compression Test Results of Field Concrete
ACI 301-66	Specification for Structural Concrete for Buildings (proposed)
ACI 306-66	Recommended Practice for Cold Weather Concreting
ACI 311-64	Recommended Practice for Concrete Inspection
ACI 315-65	Manual of Standard Practice for Detailing Reinforced Concrete Structures
ACI 318-63	Building Code Requirements for Reinforced Concrete
ACI 347-63	Recommended Practice for Concrete Form Work
ACI 605-59	Recommended Practice for Hot Weather Concreting

ACI 613-54	Recommended Practice for Selecting Proportions for Concrete
ACI 614	Recommended Practice for Measuring, Mixing, and Placing Concrete
ACI SP-2	Manual of Concrete Inspection
AISC	Code of Standard Practice for Steel Buildings and Bridges, (February 1964)
AISC	Specification for the Design, Fabrication, and Erection of Structural Steel for Buildings, (April 1963)
ASA N 6.2	Safety Standard for Design, Fabrication, and Maintenance of Steel Containment Structures for Stationary Nuclear Power Reactors
ASME III	Nuclear Vessels (mostly 1965 Edition; 1968 Edition and all Addenda was used for the design, fabrication, inspection, and testing of the Class B containment penetration head fittings)
ASME III	Division 2, Subsection CC-3440, Concrete Temperatures
AMSE VIII	Unfired Pressure Vessels
ASME IX	Welding Qualifications
ASTM A15-64	Specification for Billet Steel Bars for Concrete Reinforcement
ASTM A36-63T	Specification for Structural Steel
ASTM A148-65	Specification for High Strength Steel Castings for Structural Purposes
ASTM A155-68	Specification for Electric Fusion Welded Steel Pipe for High Temperature Service
ASTM A185-64	Specification for Welded Steel Wire Fabric for Concrete Reinforcement
ASTM A193-66	Specification for Alloy Steel Bolting Materials for High Temperature Service
ASTM A233-64T	Specification for Mild Steel Covered Arc Welding Electrodes
ASTM A300-63T	Specification for Steel Plates for Pressure Vessels for Service at Low Temperatures
ASTM A516-64	Specification for Carbon Steel Plates of Intermediate Tensile Strength for Fusion Welded Pressure Vessels for Atmospheric and Lower Temperature Service
ASTM A559-65T	Specification for Mild Steel Electrodes for Gas Metal Arc Welding
ASTM A572-66	Specification for High Strength Low Alloy Columbian Vanadium Steels of Structural Quality

ASTM C31-66	Making and Curing Concrete Compression and Flexure Test Specimens in the Field
ASTM C33-67	Specification for Concrete Aggregates
ASTM C39-68	Test for Compressive Strength of Molded Concrete Cylinders
ASTM C40-66	Test for Organic Impurities in Sand for Concrete
ASTM C42-68	Methods of Obtaining and Testing Drilled Cones and Sawed Beams of Concrete
ASTM C87-68	Test for Effect of Organic Impurities in Fine Aggregate on Strength of Mortar
ASTM C88-63	Test for Soundness of Aggregates by Use of Sodium Sulfate or Magnesium Sulfate
ASTM C94-68	Specification for Ready Mixed Concrete
ASTM C117-67	Test for Materials Finer Than No. 200 Sieve in Material Aggregates by Washing
ASTM C127-68	Test for Specific Gravity and Absorption of Coarse Aggregate
ASTM C12-68	Test for Specific Gravity and Absorption of Fine Aggregates
ASTM C131-66	Test for Resistance to Abrasion of Small Size Coarse Aggregate by Use of the Los Angeles Abrasion Machine
ASTM C136-67	Test for Sieve or Screen Analysis of Fine and Coarse Aggregates
ASTM C138-63	Test for Weight Per Cubic Foot Yield, and Air Content (Gravimetric) of Concrete
ASTM C142-67	Test for Friable Particles in Aggregates
ASTM C143-58	Test for Slump of Portland Cement Concrete
ASTM C150-65	Specification for Portland Cement
ASTM C171-63	Specification for Waterproof Paper for Curing Concrete
ASTM C172-68	Method of Sampling Fresh Concrete
ASTM C173-68	Test for Air Content of Freshly Mixed Concrete by the Volumetric Method
ASTM C177-63	Test for Thermal Conductivity of Materials by Means of the Guarded Hot Plate
ASTM C192-68	Method of Making and Curing Concrete Compression and Flexure Test Specimens in the Laboratory

ASTM C227-65	Method of Test for Potential Alkali Reactivity of Cement Aggregate Combinations (Mortar Bar Method)
ASTM C231-68	Method of Test for Air Content to Freshly Mixed Concrete by the Pressure Method
ASTM C232-58	Method of Test for Bleeding of Concrete
ASTM C260-66T	Specification for Air Entraining Admixtures for Concrete
ASTM C289-66	Test for Potential Reactivity of Aggregates (Chemical Method)
ASTM C309-58	Specification for Liquid Membrane - Forming Compounds for Curing Concrete
ASTM C350-65T	Specification for Fly Ash for Use as an Admixture in Portland Cement Concrete
ASTM C494-62T	Specification for Chemical Admixtures for Concrete
ASTM D92-66	Test for Flash and Fire Points by Cleveland Open Cup
ASTM D97-66	Test for Pour Points
ASTM D127-63	Test for Drop Melting Point of Petroleum Wax, Including Petrolatum
ASTM D287-64	Method of Test API Gravity of Crude Petroleum and Petroleum Products (Hydrometer Method)
ASTM D512-62T	Tests for Chloride Ion in Industrial Water and Industrial Waste Water
ASTM D937-58	Method of Test for Cone Penetration of Petrolatum
ASTM D992-52	Test for Nitrate Ion in Industrial Water
ASTM D1190-64	Specification for Concrete Joint Sealer, Hot Poured Elastic Type
ASTM D1255-65T	Test for Sulfides in Industrial Water and Industrial Waste Water
ASTM D1751-65	Specification for Performed Expansion Joint Fillers for Concrete Paving and Structural Construction (Nonextruding and Resilient Bituminous Types)

5.1.2 CONTAINMENT SYSTEM STRUCTURE DESIGN

5.1.2.1 GENERAL DESCRIPTION

The general configuration and dimensions of the reactor containment structure for Point Beach Unit 1 are shown in Figure 5.1-1.

The structure is a right cylinder with a flat base slab and a shallow domed roof. A 1/4 in. thick welded ASTM A 442 steel liner is attached to the inside face of the concrete shell to insure a high degree of leak tightness. The base liner is installed on top of the structural slab and is covered with concrete. The structure provides biological shielding for both normal and accident situations.

The nominal 3 ft. 6 in. thick cylindrical wall and 3 ft. thick dome are prestressed and post tensioned. The nominal 9 ft. thick concrete base slab is reinforced with high strength reinforcing steel. The slab is supported on H piles driven to refusal in the underlying bedrock.

The reactor containment structure for Point Beach Unit 2 is essentially identical in design and construction to that of Unit 1 except that it is oriented to conform to the overall site plan as shown in Figure 5.1-1.

Numerous mechanical and electrical systems penetrate the containment wall through welded steel penetrations as shown in Figure 5.1-2 and Figure 5.1-3.

In the concept of post-tensioned containment, the internal pressure load is balanced by the application of an opposing external pressure type load on the structure. Sufficient post-tensioning is used on the cylinder and dome to more than balance the internal pressure so that a margin of external pressure exists beyond that required to resist the design accident pressure. Nominal, bonded reinforcing steel is also provided to distribute strains due to shrinkage and temperature. Additional bonded reinforcing steel is used at penetrations and discontinuities to resist local moments and shears.

The internal pressure loads on the base slab are resisted by both the piles and the strength of the reinforced concrete slab. Thus, post tensioning is not required to exert an external pressure for this portion of the structure.

The post tensioning system design consists of:

1. Three groups of 49 dome tendons oriented at 120° to each other, for a total of 147 tendons anchored at the vertical face of the dome ring girder;

2. 168 vertical tendons anchored at the top surface of the ring girder and at the bottom of the base slab;

3. A total of 367 hoop tendons anchored at the six vertical buttresses.

Each tendon design consists of ninety 1/4 in. diameter wires with button headed BBRV type anchorages, furnished by Inland-Ryerson Construction Products Company. Actual number of tendon wires vary as documented in tendon surveillance reports. The tendons are housed in spiral wrapped corrugated thin wall sheathing and capped at each anchorage by a sheathing filler cap. After fabrication, the tendon is shop dipped in a petrolatum corrosion protection material, bagged, and shipped. After installation, the tendon sheathing and caps are filled with a corrosion preventive grease. In addition to this corrosion protection system, that portion of the tendon system in the base slab and the reinforcing steel are connected into an impressed current cathodic protection system. The cathodic protection system provided utilizes close coupled anodes to protect the interconnected liner, reinforcing bars, and tendon steel casings. The system is conservatively designed for a 40 year life.

Permanent zinc reference electrodes are installed under the containment base slab in order to obtain potential gradient data throughout the foundation and thereby insure that the cathodic protection system is operating satisfactorily.

Ends of all tendons are covered with grease filled pressure tight caps for corrosion protection.

ASTM A-432 reinforcing steel is used throughout the base slab and around the large penetrations. A-15 steel is used for the bonded reinforcing throughout the cylinder and dome as crack control reinforcing. At areas of discontinuities where additional steel is used, such steel is generally A-432 to provide an additional margin of elastic strain capability.

The entire containment structure is housed in an unheated enclosure (facade) that provides protection from the weather.

The 1/4 in. thick liner plate is attached to the concrete by means of an angle grid system stitch welded to the liner plate and embedded in the concrete. The details of the anchoring system are provided in Figure 5.1-1. The frequent anchoring is designed to prevent significant distortion of the liner plate during accident conditions and to insure that the liner maintains its leaktight integrity. The design of the liner anchoring system also considers the various erection tolerances and their effect on its performance. The liner plate is coated on the inside with 1-1/2 mil zinc silicate primer. Top coat is an epoxy finish with thickness as required by location. There is no paint on the side in contact with concrete.

The liner plate is fabricated with a leak chase channel (LCC) system which covers all welded seams in the liner plate. In addition, some penetrations have leak chase channels installed over penetration assembly welds. The LCCs are welded on the inside of the liner plate, except for the dome LCCs, which are welded to the outside of the liner plate. The original purpose of the LCCs was to have the ability to pressure test the liner plate or penetration welds for leaks without pressurizing the full containment structure. They are not presently used, but are considered an integral part of the liner plate and therefore a part of the leak tight containment pressure boundary. See Section 5.1.2.9 for further discussion of the LCC system.

Personnel and equipment access to the structure is provided by a double door lock and by a 15 ft. clear diameter double gasketed single door as shown in Figure 5.1-4 and Figure 5.1-5. A double door emergency personnel escape lock is also provided. These locks and hatches are designed and fabricated of SA-516, Grade 70 firebox quality steel made to SA-300 specification, Charpy V notch impact tested to -45°F.

The structural brackets provided for the containment crane runway and for the dome liner erection trusses are fabricated of A-36 steel. Structural brackets and reinforcing plates were shop fabricated and then shipped to the job site for welding into the 1/4 in. liner plate similar to the penetration assemblies.

The containment structure is designed and constructed in accordance with the design criteria. These criteria are based upon ACI 318-63, ACI 301, and the ASME Pressure Vessel Code, Sections III, VIII, and IX. It is the intent of the criteria to provide a structure of unquestionable integrity that will meet the postulated design conditions with a low strain elastic response. The Point Beach containment structure meets these criteria because:

1. The design criteria are, in general, based on the proven stress, strain, and minimum proportioning requirements of the ACI or ASME Codes. Where departures or additions from these codes are made, they were done in the following manner:

    a. The environmental conditions of severity of load, load cycling, weather, corrosion conditions, maintenance, and inspection for this structure are compared and evaluated with those for code structures to determine the appropriateness of the modifications.

    b. During the design and construction phase, the consultants were retained to assist in the development of the criteria. In addition to assisting with the criteria submitted in the PSAR, they were involved in the updating of the criteria and the review of design methods and drawings to assure that the criteria were implemented as intended.

    c. Consultants were retained during the design and construction phase to assist in developing the proper approach to design criteria for combined shear bending and axially loaded structures.

    d. During the design and construction of the structure, all criteria, specifications, and details relating to liner plate and penetrations, cathodic protection, and corrosion protection were referred to Bechtel's Metallurgy and Quality Control Department. This department maintained a staff to advise and assist in problems of welding, quality control, metallurgy, cathodic protection, and corrosion protection.

    e. The design of the Point Beach containment structure was continuously reviewed as the improved criteria for subsequent license applications became available.

2. The primary membrane integrity of the structure is provided by the unbonded post-tensioning tendons, each one of which is stressed from 75% to 80% of ultimate strength during installation and performs at approximately 60%-65% during the life of the structure. The 75%-80% range is provided in order to recognize practical considerations in measuring the elongation of the tendons and in the accuracy of the jacking gages. Thus, the main strength elements were individually proof tested prior to operation of the plant.

3. Six hundred and eighty two such post-tensioning elements are provided, 147 in the dome, and 168 vertical and 367 hoop tendons in the cylinder. Any three adjacent tendons in any of these groups can be lost without significantly affecting the strength of the structure due to the load redistribution capabilities of the shell structure. The bonded reinforcing steel provided for crack control insures that this redistribution capability exists.

4. The unbonded tendons are continuous from anchorage to anchorage, being deflected around penetrations and isolated from secondary strains of the shell. Thus, the membrane integrity of the shell can be insured regardless of conditions of high local strains.

5. The unbonded tendons exist in the structure at a slightly ever decreasing stress due to relaxation of the tendon and creep of the concrete and, even during pressurization, are subject to a stress change of very small magnitude (2% to 3% of ultimate strength).

6. a. The prestressed concrete portion of the structure was subjected to the highest membrane compressive stresses after the post tensioning sequence was completed. Membrane compressive stress is defined in this case as the resultant normal force acting on the concrete cross sectional area.

   The local high compressive stress concentrations in the concrete are:

   (1) Behind the bearing plates of the tendon anchorages. These stresses reach their highest level at the time of the post tensioning operations, and then decrease because of prestressing losses.

   (2) At discontinuities, such as the inner edge of the penetrations through the containment wall. These stresses reach the highest level for load combination $(D + F + T_A)$.

   b. Membrane tension, the tension force that is a result of the stresses throughout the concrete portion of the wall, is prevented by the post-tensioning forces for working stress design load combinations. The post-tensioning forces also prevent membrane tension for yield stress design load combinations if the self limiting thermal expansion of the liner plate is neglected.

   Tensile stresses are caused by uneven temperatures, discontinuities, and nonaxisymmetric loading, such as earthquake, wind, and pipe penetrations. In places and for load conditions where the tensile stresses exceed the values given, mild steel reinforcement is carrying the tensile forces.

7. The deformations of the structure during plant operation or due to accident conditions are relatively minor. The radial deflections in the shell at the time of initial post-tensioning and shortly thereafter were expected to be between 0.20 and 0.25 in. The design of the piping anchors to the shell takes into account the above mentioned shell deformations, thus eliminating the use of expansion bellow seals for containment barriers inside containment. (See Figure 5.1-2 for typical piping penetrations). The design of the piping restraint system is such as to accommodate shell deformations at all pipe penetration elevations without exceeding pipe and pipe restraint allowable stresses and without jeopardizing containment leak tightness integrity.

8. Virtually all of the exposed protective coatings and paints within the containment consist of (a) Dimetcote Steel Primer with Amercoat 66 epoxy top coat and modified phenolic coatings on carbon steel structures, equipment, and concrete, (b) galvanized steel on duct work, I&C conduit, and miscellaneous structural steel, and (c) polyvinyl chloride used for conduit sheathing and electrical insulation. For more information on committed standards relating to containment coatings, see Section 1.4.

5.1.2.2 MECHANICAL DESIGN BASES

Safety of the structure under extraordinary circumstances and proper performance of the containment structure at various loading stages were the main considerations in establishing the structural design criteria.

The two basic criteria are:

1. The integrity of the liner plate shall be guaranteed under all credible loading conditions.

2. The structure shall have a low strain elastic response such that its behavior will be predictable under all design loadings.

The strength of the containment structure at working stress and overall yielding is compared to various loading combinations to insure safety. The analysis and design of the containment structure is carried out with consideration for strength, the nature and the amount of cracking, the magnitude of deformation, and the extent of corrosion to insure proper performance. The structure is designed to meet the performance and strength requirements under the following conditions:

1. Prior to prestressing

2. At transfer of prestress

3. Under sustained prestress

4. At design loads

5. At yield loads

Deviations in allowable stresses for the design loading conditions in the working stress method are permitted if the yield capacity criteria are fully satisfied. All design is in accordance with the ACI Code 318-63 unless otherwise stated herein.

No special design bases are required for the design and checking of the base slab. It acts primarily in bending rather than membrane stress. This condition is covered by the ACI Code 318-63. The loads and stresses in the cylinder and dome are determined as described below.

<u>Design Method</u>

The structure is analyzed using a finite element computer program for individual and various combinations of loading cases of dead load, live load, prestress, temperature, and pressure. The computer output includes direct stresses, shear stresses, principal stresses, and displacements of each nodal point.

Stress plots which show the total stresses from appropriate combinations of loading cases are made and areas of high stress are identified. The modulus of elasticity is corrected to account for the nonlinear stress-strain relationship at high compression where necessary. Stresses are recomputed where there are sufficient areas which require attention.

In order to consider creep deformation, the modulus of elasticity of concrete under sustained loads such as dead and prestress load is differentiated from the modulus of elasticity of concrete under instantaneous loads such as internal pressure and earthquake loads.

The forces and shears are added over the cross section, and the total moment, axial force, and shear determined. From these values, the straight line elastic stresses are computed and compared to the allowable values. The ACI Code 318-63 design methods and allowable stresses are used for concrete and prestressed and nonprestressed reinforcing steel except as noted in these criteria.

Loads Prior To Prestressing

Under this condition the structure is designed as a conventionally reinforced concrete structure. It is designed for dead load, live loads (including construction loads), and a reduced wind load. Allowable stresses are according to ACI 318-63 Code requirements.

Loads At Transfer Of Prestress

The containment structure is checked for prestress loads and the stresses compared with those allowed by the ACI 318-63 Code with the following exceptions: ACI 318-63, Section 26 allows concrete stress of 0.60 f'_{ci} at initial transfer. In order to limit creep deformations, the membrane compression stress is limited to 0.30 f'_{ci}, whereas, in combination with flexural compression, the maximum allowable stress is limited to 0.60 f'_{ci} per the ACI 318-63 Code.

For local stress concentrations with nonlinear stress distribution as predicted by the finite element analysis, 0.75 f'_{ci} is permitted when local reinforcing is included to distribute and control these localized strains. These high local stresses are present in every structure but they are seldom identified because of simplifications made in design analysis. These high stresses are allowed because they occur in a very small percentage of the cross section, are confined by material at lower stress, and would have to be considerably greater than the values allowed before significant local plastic yielding would result. Nonprestressed reinforcing is added to distribute and control these local strains.

Membrane tension and flexural tension are permitted provided they do not jeopardize the integrity of liner plate. Membrane tension is permitted to occur during post tensioning sequence but is limited to 1.0 f'_{ci}. When there is flexural tension but no membrane tension, the section is designed in accordance with Section 2605(a) of the ACI Code. The stress in the liner plate due to combined membrane tension and flexural tension is limited to 0.5 f_y.

Shear criteria are in accordance with the ACI 318-63 Code, Chapter 26, as modified by the equations shown elsewhere in this section using a load factor of 1.5 for shear loads.

Loads Under Sustained Prestress

The conditions for design and the allowable stresses for this case are the same as above except that the allowable tensile stress in nonpressurized reinforcing are limited to 0.5 f_y. The ACI limits the concrete compression to 0.45 f'_c for sustained prestress load.

Values of 0.30 f'_c and 0.60 f'_c are used as described above, which bracket the ACI allowable value. However, with these same limits for concrete stress at transfer of prestress, the stresses under sustained load will be reduced due to creep.

At Design Loads

This loading case is the basic "working stress" design. The containment structure is designed for the following specific loading cases:

1. D + F + L + To

2. D + F + L + P + T_A + W (or E)

3. D + F + L + P'

D = Dead Load
L = Appropriate Live Load
F = Appropriate Prestressing Load
P = Pressure Load (Varies with Time from Design Pressure to Zero Pressure)
T_o = Thermal Loads Due to Operating Temperature
T_A = Thermal Loads Based on a Temperature Corresponding to a Pressure P
E = Design Earthquake Load
P' = Test Pressure (1.15 P)
W = Wind Load

Sufficient prestressing is provided in the cylindrical and dome portions of the vessel to eliminate membrane tensile stress (tensile stress across the entire wall thickness) under design loads. Flexural tensile cracking of the concrete is permitted but is controlled by bonded unprestressed reinforcing steel.

According to the analysis of the containment, the working stress design limits for the loading condition, D + F + L + P + T_A + E will be reached at values of ground acceleration as shown below:

1. Flexural Stresses

   The predicted critical section for flexural stresses is J-J (Table 5.1-1). The hoop reinforcement stress predicted there is 30,000 psi for a horizontal ground acceleration of 0.061 g. At Section K-K (Table 5.1-1) (taking an average of stresses obtained by using meshes #3 and #4), a 0.075 g ground acceleration is predicted to result in a 30,000 psi stress in the reinforcement.

2. Shear Stresses

   The critical section for shear stresses is L-L (Table 5.1-1). The limiting stresses will be reached there (using average shear stresses from mesh #3 and #4) at a horizontal ground acceleration of 0.094 g.

3. Membrane Stresses

   The design criteria require that the average stress across the concrete cross section should not be tensile. That design criterion is satisfied at section F-F (Table 5.1-1) for horizontal ground accelerations not in excess of 0.069 g. (Combination of membrane forces from axisymmetric loadings and seismic membrane shear.)

Under the design loads the same performance limits stated elsewhere in this section apply with the following exceptions:

1. If the net membrane compression is below 100 psi, it is neglected and a cracked section is assumed in the computation of flexural bonded reinforcing steel. The allowable tensile stresses in bonded reinforcing are 0.5 f_y.

2. When the maximum flexural stress does not exceed $6\sqrt{f'_c}$ and the extent of the tension zone is not more than 1/3 the depth of the section, bonded reinforcing steel is provided to carry the entire tension in the tension block. Otherwise, the bonded reinforcing steel is designed assuming a cracked section. When the bending moment tension is additive to the thermal tension, the allowable tensile stress in the bonded reinforcing steel is 0.5 f_y minus the stress in reinforcing due to the thermal gradient as determined in accordance with the method of ACI 505.

3. The problem of shear and diagonal tension in a prestressed concrete structure is considered in two parts: membrane principal tension and flexural principal tension. Since sufficient prestressing was used to eliminate membrane tensile stress, membrane principal tension is not critical at design load. Membrane principal tension due to combined membrane tension and membrane shear is considered in the next section.

   Flexural principal tension is the tension associated with bending in planes perpendicular to the surface of the shell and shear stress normal to the shell (radial shear stress). The ACI 318-63 provisions of Chapter 26 for shear are adequate for design purposes with proper modifications as discussed using a load factor of 1.5 for shear loads.

Crack control in the concrete is accomplished by adhering to the ACI-ASCE Code Committee standards for the use of reinforcing steel. These criteria are based upon a recommendation of the Prestressed Concrete Institute and are as follows:

   0.25 percent reinforcing is provided at the tension face for small members

   0.20 percent for medium size members

   0.15 percent for large members

A minimum of 0.15 percent mild steel reinforcing is provided in two perpendicular directions on the exterior faces of the wall and dome for proper crack control.

The liner plate is attached on the inside faces of the wall and dome. Since, in general, there are no tensile stresses due to temperature on the inside faces, bonded reinforcing steel is provided at the inside face only where required to carry discontinuity moment tensile stresses.

The prestressing steel helps limit the amount of thermal cracking in concrete by virtue of the fact that it is close to the outside face and will be cooler compared to the inside face and thus causes compression in the elements of the structure. Additionally, any membrane cracking in the structure at factored load is resisted by tendons, mild steel reinforcing, and liner plate without exceeding the tensile yield strength of any of these resisting elements.

The containment structure is designed to withstand the thermal gradient shown in Figure 5.1-6. The increased temperature of the liner plate and concrete during an incident results in greater membrane forces and thus requires more tendons and external face reinforcing steel.

The accident temperature distribution through the wall sections is nonlinear. Since the finite element mesh, which uses the entire containment as a model, consists of 6 concrete element layers through the wall thickness with one additional layer for the liner plate, a nonlinearity in the temperature distribution gives rise to a nonlinear thermal stress distribution through the wall thickness.

This elastic thermal stress distribution is combined with the membrane stresses (uniformly distributed through the wall thickness) obtained from the live loads (D + F, P, and E) by the elastic finite element method for load combinations including (D + F and P) and by hand for (E), respectively. The stress reduction ($\Delta\sigma_c$) resulting from the cracking of the tensile zone of the concrete will reduce the compressive part of the nonlinear combined stress diagram by a constant value Δs_c, and will increase the stress in the reinforcing steel by Δs_c. The stress values obtained thus far are not based on any linearity in the considered stress diagram. Stress from loads, other than the thermal moment effect and seismic loads, are then superimposed on the above stresses. The steel and concrete stresses produced by these moments are assumed to be linear in accordance with the usual reinforced concrete design assumptions. The stresses are computed from moments resulting from the nonlinear stress distribution through the wall thickness.

The total stresses are obtained by adding the nonlinear stresses from the “relieved” thermal state of stress and linear stresses induced by the other moments.

These two computation methods were necessary for increased realism of stress predictions since the Point Beach containment was analyzed by a finite element program which required the idealized assumptions of the theory of elasticity.

Loads Necessary To Cause Structural Yielding

The structure is checked for the factored loads and load combinations given below and compared with the yield strength of the structure.

The load factors are the ratio by which loads are multiplied for design purposes to assure that the load/deformation behavior of the structure is one of elastic, low strain behavior. The load factor approach is used in this design as a means of making a rational evaluation of the isolated factors which are considered in assuring an adequate safety margin for the structure. This approach permits the designer to place the greatest conservatism on those loads most subject to variation and which most directly control the overall safety of the structure. It also places minimum emphasis on the fixed gravity loads and maximum emphasis on accident and earthquake or wind loads.

The final design of the containment structure satisfies the following loading combinations and factors:

1. $Y = 1/\Phi\ (1.05D + 1.5P + 1.0T_A + 1.0F)$

2. $Y = 1/\Phi\ (1.05D + 1.25P + 1.0T_A + 1.25H + 1.25E + 1.0F)$

3. $Y = 1/\Phi\ (1.05D + 1.25H + 1.0R + 1.0F + 1.25E + 1.0T_o)$

4. $Y = 1/\Phi\ (1.05D + 1.0F + 1.25H + 1.0W + 1.0T_o)$

5. $Y = 1/\Phi\ (1.0D + 1.0P + 1.0T_A + 1.0H + 1.0E' + 1.0F)$

6. $Y = 1/\Phi\ (1.0D + 1.0H + 1.0R + 1.0E' + 1.0F + 1.0T_o)$

Note: 0.95D is used instead of 1.05D where dead load subtracts from critical stress.

where

Y = Required yield strength of the structure as defined below

Φ = Yield capacity reduction factor

D = Dead loads of structures and equipment plus any other permanent loadings contributing stress, such as hydrostatic or soil. In addition, a portion of the live load is added when it includes items such as piping, cable, and trays suspended from floors. An allowance is made for future additional permanent loads.

P = Design accident pressure load

F = Effective prestress loads

R = Force or pressure on structure due to rupture of any one pipe

H = Force on structure due to thermal expansion of pipes due to design conditions

T_o = Thermal loads due to the temperature gradient through wall during operating conditions (see Figure 5.1-6)

T_A = Thermal loads due to the temperature gradient through the wall and expansion of the liner. It is based on a temperature corresponding to the factored design accident pressure.

E = Design earthquake or wind load (see Figure 5.1-14)

E′ = Hypothetical earthquake load (see Figure 5.1-14)

W = Tornado load

Equation 1 defines the containment's capacity to withstand pressure loadings at least 50% greater than those calculated for the postulated loss of coolant accident alone.

Equation 2 defines the containment's capacity to withstand loadings at least 25% greater than those calculated for the postulated loss of coolant accident with a coincident design earthquake or wind.

Equation 3 defines the containment's capacity to withstand loadings at least 25% greater than those calculated for the design earthquake coincident with rupture of any attached piping.

Equation 4 defines the containment's capacity to withstand tornado loadings equal to the design tornado.

Equations 5 and 6 assure that the containment has the capacity to withstand either the postulated loss of coolant accident or the rupture of any attached piping coincident with the maximum hypothetical earthquake.

With respect to the dynamic analysis for the containment, the following describes the procedures used to determine stresses at the various sections from the shear and moment envelopes. Figure 5.1-19 serves as a basis for the stress analysis. The following procedure was used to find the stresses at various sections in the containment.

1. Find the overturning M_o at the bottom of the base slab

2. Find the triangular soil stress distribution as $P = \frac{M_0 C}{1}$

3. Assuming base slab fixed at edges and subjected to triangular soil pressure as determined above, find the following moments and forces:

   a. Radial Moment M_r

   b. Hoop Moment M_θ

   c. Radial Shear Force Q_r

   d. Tangential Shear Force Q_θ

   e. Twisting Moment $M_{r\theta}$

   (Reference 2, Chapter 9)

4. Find the percentage of fixity at the edge of the base slab. For this, apply 1 ksf uniform load at the base of the slab and find moment M_1 at a section near the edge of finite element computer analysis. The radial normal force N_1 of this calculation will be used in Step 6.

   Also, the same load is applied while assuming complete fixity around the base slab, obtaining a moment M_2 around the same section.

   The actual fixity is the ratio of M_1 and M_2: $f = \frac{M_1}{M_2}$

5. Make correction for the difference between the actual edge moment (fM_r) and moment (M_r) that would exist in case of complete fixity by applying a moment around the base slab varying as a cosine function (1-f) M_r cosθ. The resulting moments and forces are added to those obtained from Steps 3 and 4.

6. In addition, there are membrane forces N in the base slab due to the interaction with the cylinder. These membrane forces can be determined by the following edge loadings of the base slab.

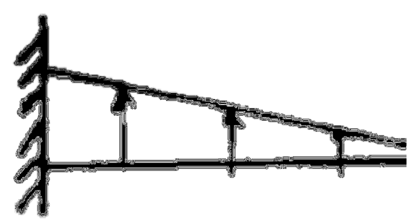
$$N = \frac{fM_1N_1}{M_1}$$

7. In the cylindrical portion of the containment there are membraned forces in general and radial shear and moment at the base resulting from the edge moments around the base slab. These latter ones are obtained as a result of the analysis of the base slab.

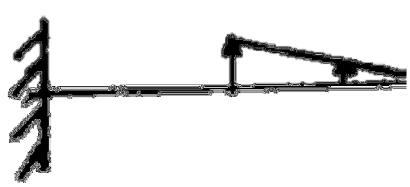
SAMPLE CALCULATIONS FOR THE MOMENTS AND FORCES IN THE BASE SLAB CAUSED BY SEISMIC FORCES (E = 0.06g)

2.8'			24.0'		41.5'		53.0'	
Load Case	Moment kips-ft	Force kips	Moment kips-ft	Force kips	Moment kips-ft	Force kips	Moment kips-ft	Force kips
Radial								
I	+35.0		+188.0		+2.4		-396.0	
II	+20.0		+90.0		-25.6		-80.0	
III	-16.0		-19.0		+7.2		+17.7	
IV	+2.0	+0.8	-8.0	-0.8	-16.8	0.0		
V	+8.0	+1.0	+64.0	+9.0	+110.4	+16.0	+141.0	+20.0
Total	+49.0	+1.8	+315.0	+8.2	+77.6	+16.0	-317.3	+20.0
Hoop								
I	+15.7		+100.0		+57.8		-66.3	
II	+9.6		+53.0		+12.4		-17.7	
III	- 8.0		-13.8		-2.4		+5.7	
IV	+1.0	+0.9	-2.4	-1.4	-11.7	0.0		
V	+3.2	+3.2	+28.4	+27.0	+47.6	+47.0	+67.5	+60.0
Total	+21.5	+4.1	+165.2	+25.6	+103.7	+47.0	-10.8	+60.0

I



II



P-3.36 K, LATERAL EARTHQUAKE

ECCENTRICITY OF INTERNALS

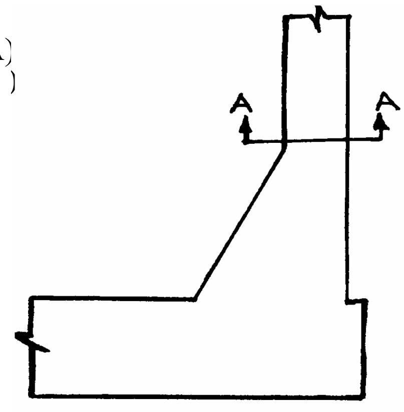
EFFECT OF VERTICAL 'E' ON ECCENTRICITY

VERTICAL EARTHQUAKE

CORRECTION FOR PARTIAL FIXITY

These moments and forces due to earthquake were then combined with the moments and forces due to other loading conditions and for various loading combination stresses were worked out. Table 5.1-1 shows the stress summaries.

Principal Stress Calculations Near Base Of Cylinder (Section A-A)



V = Shear from seismic calculations (at Section A-A) = 5478kips

$$\sigma_v = \frac{VQ}{It} = 127.5 \text{ psi}$$

Meridional Stresses (σ_1):

Vertical Prestress	= +290.0 k/ft (+ denotes compression)
Force Due to Pressure	= -234.5 k/ft
Force Due to Dead Load	= +100.0 k/ft
Force in Liner Plate	= -100.0 k/ft
Net Vertical Force	= +55.5 k/ft

$$\sigma_1 = \frac{55.5 \times 1000}{42 \times 12} = +110.1 \text{ psi}$$

Hoop Stresses (σ_2):

Hoop Prestress	= +662.0 k/ft
Force Due to Pressure	= -469.9 k/ft
Force In Liner Plate	= -100.0 k/ft
Net Hoop Force	= +92.1 k/ft

$$\sigma_2 = \frac{92.1 \times 1000}{42 \times 12} = +182.7 \text{ psi}$$

$$\text{Principal Stresses} = \frac{110.1 + 182.7}{2} \pm \sqrt{\left(\frac{182.7 - 110.1}{2}\right)^2 + (127.5)^2}$$

$$= +13.8 \text{ psi and } +279 \text{ psi}$$

For Class I equipment, sample dynamic analysis calculations are demonstrated by reference to the following typical application. The containment cavity cooling fan units, Items W4A and W4B, are carried, one above the other, on a structural steel frame located in containment on the 21' 0" elevation. The two level steel structure consists of platforms at the 26' 0" and 34' 0" levels fabricated from 8 in. and 10 in. WF beams connected by 8 in. WF columns and double angle bracing on all sides. The combined weight of the fans, motors, cooling coils, and plenum chamber casing is approximately 10,000 lbs. per platform. The configuration of the two fan units yields a two degrees of freedom system. The structure itself is analyzed as a rigid frame. The deflection of this frame, given a unit lateral loading, is used to generate a flexibility matrix. This matrix, when converted to a stiffness matrix, provides the stiffness factors for a simulated mathematical model. The weights of the two fan units and components are treated as lumped masses. The model is analyzed as a cantilever beam with a loading equivalent to the lumped masses to obtain the material frequency and mode shapes.

The acceleration values for these units obtained from the appropriate amplified response curves plus the natural frequencies and mode shapes are entered as input to a computer program (Bechtel CE641). This program generates a response of the structure to the seismic loads. Output is in terms of inertial forces and the shear, moment, acceleration, and displacement envelopes. The inertial forces are applied to the structure in this case by use of the STRESS structural analysis program, as additional stresses added algebraically to the normal dead load stresses. The final evaluation of the frame reflects the combined effects of each loading.

Sample Values

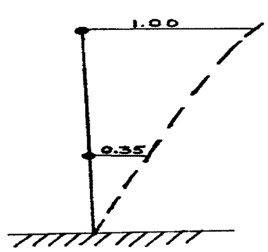
The flexibility matrix is:

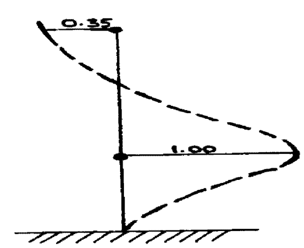
$$\begin{bmatrix} 0.6636 & -0.1919 \\ 0.1919 & 0.1806 \end{bmatrix} \times 10^{-5} \text{ in. - lb.}$$

The first and second frequencies respectively are:

16.4 cps 41.5 cps

The mode shapes are:





The inertia loads, due to accelerations from safe shutdown earthquake curves are:

	Bottom Platform	Top Platform
1st Mode	273 lbs	782 lbs
2nd Mode	377 lbs	-132 lbs
SBS Sum	650 lbs	914 lbs

These loads, which are the absolute sum of the model inertia forces, are applied to the structure combined with dead load forces. By inspection, the most highly stressed member is the double angle cross bracing which, however, is well within allowable stresses.

The load combinations considering load factors given above are less than the yield strength of the structure. The yield strength of the structure is defined as the upper limit of elastic behavior of the effective load carrying structural materials. For steel (both prestress and nonprestress), this limit is taken to be the guaranteed minimum yield given in the appropriate ASTM specification. For concrete, it is the ultimate values of shear (as a measure of diagonal tension) and bond per ACI 318-63 and the 28 day ultimate compressive strength for concrete in flexure (f'_c). The ultimate strength assumptions of the ACI Code for concrete beams in flexure are not allowed; that is, the concrete stress is not allowed to go beyond yield and redistribute at a strain of 3 to 4 times that which causes yielding.

The maximum concrete strain due to secondary moments, membrane loads, and local loads exclusive of thermal loads is limited to that corresponding to the ultimate stress divided by the modulus of elasticity (f'_c/E_c) and a straight line distribution from there to the neutral axis assumed.

For the above loads combined with thermal loads, the peak strain is limited to 0.003 in./in. For concrete membrane compression, the yield strength is assumed to be 0.85 f'_c to allow for local irregularities, in accordance with the ACI approach. The reinforcing steel forming part of the load carrying system is allowed to go to, but not to exceed, yield as is allowed for ACI ultimate strength design.

A further definition of yielding is the deformation of the structure which causes strains in the steel liner plate to exceed 0.005 in./in. The yielding on nonprestress reinforcing steel is allowed, either in tension or compression, if the above restrictions are not violated. Yielding of the prestress tendons is not allowed under any circumstances.

Principal concrete tension due to combined membrane tension and membrane shear, excluding flexural tension due to bending moments or thermal gradients, is limited to $3\sqrt{f'_c}$. Principal concrete tension due to combined membrane tension, membrane shear, and flexural tension due to bending moments or thermal gradients is limited to $6\sqrt{f'_c}$. When the principal concrete tension exceeds the limit of $6\sqrt{f'_c}$, bonded reinforcing steel is provided in the following manner:

1. Thermal Flexural Tension

   Bonded reinforcing steel is provided in accordance with the methods of ACI 505. The minimum area of steel provided is 0.15% in each direction.

2. Bending Moment Tension

Sufficient bonded reinforcing steel is provided to resist the moment on the basis of cracked section theory using the yield stresses stated above with the following exception: When the bending moment tension is additive to the thermal tension, the allowable tensile stress in the reinforcing steel is f_y minus the stress in reinforcing due to thermal gradient as determined in accordance with the methods of ACI 505.

Shear stress limits and shear reinforcing for radial shear are in accordance with Chapter 26 of ACI 318-63 with the following exceptions:

Formula 26-12 of the Code shall be replaced by

$$V_{ci} = Kb'd\sqrt{f'_c} + M_{cr}\left(\frac{V}{M'}\right) + V_i \qquad (1)$$

where

$$K = \left[1.75 - \frac{0.036}{np'} + np'\right]$$

but not less than 0.6 for $p' \geq 0.003$. For $p' < 0.003$, the value of K shall be zero.

$$M_{cr} = \frac{I}{Y}[6\sqrt{f'_c} + f_{pe} + f_n + f_i]$$

where

f_{pe} = Compressive stress in concrete due to prestress applied normal to the cross section after all losses (including the stress due to any secondary moment) at the extreme fiber of the section at which tension stresses are caused by live loads.

f_n = Stress due to axial applied loads (f_n shall be negative for tension stress and positive for compression stress).

f_i = Stress due to initial loads at the extreme fiber of a section at which tension stresses are caused by applied loads (including the stress due to any secondary moment, f_i shall be negative for tension stress and positive for compression stress).

$$n = \frac{505}{\sqrt{f'_c}}$$

$$p' = \frac{A's}{bd}$$

V = Shear at the section under consideration due to the applied loads.

M = Moment at a distance d/2 from the section under consideration, measured in the direction of decreasing moment, due to applied loads.

V_i = Shear due to initial loads (positive when initial shear is in the same direction as the shear due to applied loads).

Lower limit placed by ACI 318-63 on V_{ci} as $1.7b'd\sqrt{f'_c}$ is not applied. Formula 26-13 of the Code shall be replaced by:

$$V_{cw} = 3.5\ b'd\ \sqrt{f'_c}\left(\sqrt{1 + \frac{f_{pc} + f_n}{3.5\sqrt{f'_c}}}\right) \qquad (2)$$

The term f_n is as defined above. All other notations are in accordance with Chapter 26, ACI 318-63.

Formula (1) is based on the tests and work done by Dr. A. H. Mattock of the University of Washington.

Formula (2) is based on the commentary for proposal redraft of Section 2610, ACI 318 by Dr. A. H. Mattock, dated December 1962.

When the above mentioned equations show that allowable shear in concrete is zero, radial horizontal shear ties are provided to resist all the calculated shear.

Yield Capacity Reduction Factors

The yield capacity of all load carrying structural elements is reduced by a yield capacity reduction factor Φ as given below. This factor provides for “the possibility that small adverse variations in material strengths, workmanship, dimensions, control, and degree of supervision while individually within required tolerance and limits of good practice, occasionally may combine to result in undercapacity” (refer to footnote on Page 66 of ACI 318-63 Code).

Yield Capacity Reduction Factors:

1. Φ = 0.90 for concrete in flexure
2. Φ = 0.85 for tension shear bond and anchorage in concrete
3. Φ = 0.75 for spirally reinforced concrete compression members
4. Φ = 0.70 for tied compression members
5. Φ = 0.90 for fabricated structural steel
6. Φ = 0.90 for mild reinforcing steel in direct tension
7. Φ = 0.90 for mild reinforcing steel with welded splices
8. Φ = 0.85 for mild reinforcing steel with lap splices
9. Φ = 0.95 for prestressed tendons in direct tension

The Capacity Reduction Factors 5 through 9 are in addition to those factors presented in ACI 318-63 Code and represent Bechtel's best judgement of how much under strength should be assigned to each material and condition not covered by the ACI Code.

The Φ factor is multiplied into the basic strength equation or into the basic permissible unit stress to obtain the dependable strength. The basic strength equation gives the “ideal” strength assuming materials are as strong as specified, sizes are as shown on the drawings, the workman- ship is excellent, and the strength equation itself is theoretically correct. The practical, dependable strength may be something less since all these factors vary.

Liner Plate Criteria

The design criteria which is applied to the containment liner to meet the specified leak rate under accident conditions are as follows:

1. That the liner is protected against damage by missiles coincident with the loss of coolant accident, excluding missiles generated by a rupture of the Reactor Coolant System piping (see Section 4.1 for additional details).

2. That the liner plate strains are limited to allowable values considerably below those that have been shown to result in leaktight vessels or pressure piping;

3. That the liner plate is prevented from developing significant distortion;

4. That all discontinuities and openings are well anchored to accommodate the forces exerted by the restrained liner plate, and that careful attention is paid to details of corners and connections to minimize the effects of discontinuities.

The leak tight criteria as applied to the liner plate Leak Chase Channels (LCCs) is discussed in Reference 1 and Reference 11.

The following sections of the ASME Boiler and Pressure Vessel Code, Section III, Nuclear Vessels, Article 4, are used as guides in establishing allowable strain limits:

1. Paragraph N-412(m)
2. Paragraph N-414.5
3. Table N-413
4. Figure N-414, N-415(A)
5. Paragraph N-412(n)
6. Paragraph N-415.1

Implementation of the ASME design criteria requires that the liner material be prevented from experiencing significant distortion due to thermal load and that the stresses be considered from a fatigue standpoint. [Paragraph N 412(m)(2)]

The following fatigue loads are considered in the design of the liner plate:

1. Thermal cycling due to annual outdoor temperature variations. The number of cycles for this loading is 60 cycles for the plant life of 60 years. (NRC SE dated 12/2005, NUREG-1839)

2. Thermal cycling due to containment interior temperature varying during the startup and shutdown of the reactor system. The number of cycles for this loading is assumed to be 500 cycles.

3. Thermal cycling due to the design basis accident is assumed to be one cycle. Thermal load cycles in the piping systems are somewhat isolated from the liner plate penetrations by the concentric sleeves between the pipe and the liner plate. The attachment sleeve is designed in accordance with ASME Section III fatigue considerations. All penetrations are reviewed for a conservative number of cycles to be expected during the plant life.

The thermal stresses in the liner plate fall into the categories considered in Article 4, Section III, Nuclear Vessels of the ASME Boiler and Pressure Vessel Code. The allowable stresses in Figure N-415(A) are for alternating stress intensity for carbon steel and temperatures not exceeding 700°F.

In accordance with ASME Code, Paragraph 412(m)(2), the liner plate is restrained against significant distortion by continuous angle anchors and never exceeds the temperature limitation of 700°F and also satisfies the criteria for limiting strains on the basis of fatigue consideration.

Paragraph 412(n), Figure N-415(A) of the ASME Code has been developed as a result of research, industry experience, and the proven performance of code vessels, and it is a part of a recognized design code. Figure N-415(A) and its appropriate limitations are used as a basis for establishing allowable liner plate strains. Since the graph in Figure N-415(A) does not extend below ten cycles, ten cycles are being used for a design basis accident instead of one cycle.

The maximum compressive strains are caused by accident pressure, thermal loading prestress, shrinkage, and creep. The maximum strains do not exceed 0.0025 in./in. and the liner plate always remains in a stable condition.

At all penetrations, the liner plate is thickened to reduce stress concentrations in accordance with the ASME Boiler and Pressure Vessel Code 1965, Section III, Nuclear Vessels.

<u>Penetration Criteria</u>

Penetrations conform to the applicable sections of ASA N6.2-1965, “Safety Standard for the Design, Fabrication, and Maintenance of Steel Containment Structures for Stationary Nuclear Power Reactors.” All personnel locks and any portion of the equipment access door extending beyond the concrete shall conform in all respects to the requirements of ASME Section III, Nuclear Vessels Code.

The basis for limiting strains in the penetration steel is the ASME Boiler and Pressure Vessel Code for Nuclear Vessels, Section III, Article 4, 1965, and, therefore, the penetration structural and leak tightness integrity are maintained. Local heating of the concrete immediately around the penetration will develop compressive stress in the concrete adjacent to the penetration and a negligible amount of tensile stress over a large area. The mild steel reinforcing added around penetrations distributes local compressive stresses for overall structural integrity.

<u>Missile Protection Criteria</u>

High pressure reactor coolant system equipment which could be the source of missiles is suitably screened either by the concrete shield wall enclosing the reactor coolant loops, by the concrete operating floor, or by special missile shields to block any passage of missiles to the containment walls. Potential missile sources are oriented so that the potential missile is intercepted by the shields and structures provided. A structure is provided over the control rod drive mechanisms to block any missiles generated from fracture of the mechanisms.

Missile protection is provided to comply with the following criteria:

1. The containment and liner are protected from loss of function due to damage by such missiles as might be generated in a loss of coolant accident.

2. The engineered safeguards system and components required to maintain containment integrity are protected against loss of function due to damage by the missiles defined below.

During the detailed plant design, the missile protection necessary to meet the above criteria was developed and implemented using the following methods:

1. Components of the reactor coolant system were examined to identify and to classify missiles according to size, shape, and kinetic energy for purposes of analyzing their effects.

2. Missile velocities were calculated considering both fluid and mechanical driving forces which can act during missile generation.

3. The structural design of the missile shielding takes into account both static and impact loads and is based upon the state of the art of missile penetration protection.

The types of missiles for which missile protection is provided are:

1. Valve stems
2. Valve bonnets
3. Instrument thimbles
4. Various types and sizes of nuts and bolts
5. Complete control rod drive mechanisms or parts thereof
6. Reactor coolant pump flywheels

Certain types of postulated accidents resulting in generation of missiles are considered incredible because of the material characteristics, inspections, quality control during fabrication, and conservative design of the particular component. Included in this category are missiles caused by massive, rapid failure of the reactor vessel, steam generator, pressurizer, and main coolant pump casings and drives.

<u>Substructure Criteria</u>

The vertical piling loads include the dead weight of the structure, all the live loads acting upon this piling, the vertical seismic load, and the vertical load in the pile due to overturning forces from the horizontal seismic load. In addition, under seismic or wind lateral loading, the piling is subjected to a bending moment due to a slight deflection of the structures in passive pressure on the soil. A cathodic protection system is provided which utilizes close coupled anodes to protect the piles. The system is conservatively designed for a 40 year life, derating manufacturer's recommendations for inert anodes by approximately 50%.

The final Dames & Moore soils report (Reference 3) indicated that the containment structure could undergo settlements of up to 2 in. relative to adjacent structures if it were placed on a mat foundation. In addition, the report indicated an ultimate soil bearing value of 15,000 lb/sq ft and recommended a safety factor of 3 for dead and permanent live loads, and a factor of safety of 2 1/2 for dead, live, and seismic loads in combination; the recommended design values are, therefore, 5000 and 6000 lb/sq ft, respectively.

The soil bearing loads under a containment mat and the fuel pool could have exceeded the above recommendations with no opportunity to spread the foundation to reduce bearing loads to tolerable values. Therefore, the decision was made to put the containment structure and fuel pool on piles. The differential settlements are anticipated to be in the order of 1/4 in. with the fuel pool and containment structure on piles.

The type of pile chosen is a standard steel H pile (14BP117) having a 150 to 200 ton compression load capability. Pile material conforms to ASTM Standard A-572-66, Grade 55, Type 2. These piles are approximately 65 to 75 feet long under the containment structure and about 100 feet long under the fuel pool. The piling is designed according to the structural criteria for Class I structures.

The piles are driven to refusal in bedrock at approximately elevation 75 ft. with the criteria that there shall be not more than 1/4 in. movement of the piles under the last 8 blows with a hammer of approximately 32,000 ft.-lb. energy.

The H piles are distributed under the mat with added concentration of piles under the outer circumference of the mat where the foundation loadings are greatest due to seismic or wind overturning forces as shown in Table 5.1-1.

The piling is designed using working stress design methods with an allowable axial compressive stress of 12,000 psi for dead load plus live load in combination with wind or seismic loading, and an allowable axial plus bending stress of 33,000 psi from combined vertical and horizontal loads. In addition, the piling is checked using the formula:

$$Y = \frac{1}{\phi}[1.0D + 1.0T + 1.0P + 1.0E']$$

A ϕ of 0.90 is used as for fabricated structural steel.

The lateral loads allowed on the piling are determined from the method proposed by Reese and Matlock of the University of Texas entitled, “Nondimensional Solutions for Laterally Loaded Piles with Soil Modulus Assumed Proportional to Depth.” (See Reference 4) Curves are presented in the referenced article which relate the shearing force at the top of the pile to the maximum moment in the pile and to the maximum deflection at the top of the pile which is necessary to develop that force in the soil.

A model for analysis was used which includes the structures, the piling, the rock below the piling, and, for the lateral resistance, the soil around the piles and the mat (see Figure 5.1-14). A computer analysis was performed which yielded the maximum seismic response and the resulting vertical and horizontal loads and deformations for both the design and the maximum hypothetical earthquake.

The procedure used in the design of the pile foundation was as follows:

1. An initial probable pile foundation design was made using hand calculations and based on vertical loads and approximated (assumed) lateral loads.

2. A model for computer analysis was selected on the basis of lump masses and moments of inertia derived from this design. The lateral stiffness coefficient, K_2, was derived by considering piles bearing on an elastic foundation against lateral loads. Rotational stiffness coefficient, K_1, was derived using the stiffness property of

   the pile $\left(\frac{E\ I}{L}\right)$.

3. A computer model analysis was performed to determine modes and frequencies for the design earthquake and maximum hypothetical earthquake.

4. The maximum seismic response and forces were obtained by hand solution using the results of the computer model analysis.

5. The pile formation design was rechecked based on lateral loads obtained above. The lateral loads allowed on the piling were determined from the method proposed by Reese and Matlock as noted above.

Spacing of piles under the containment vessel varies from approximately 4 feet to 9 feet. With a mat thickness approximately equal to maximum pile spacing, the design of the mat is not significantly different from one with uniform soil bearing under it. Bearing plates are welded to the piles to transfer the pile reaction to the concrete without exceeding the allowable concrete stresses.

The piles are embedded 3 feet into the mat, which is a sufficient distance to ensure that the pile end is fixed so that the maximum horizontal load can be developed in the soil surrounding the pile.

<u>Design Loads</u>

The following loadings are considered:

1. The loadings caused by the pressure and temperature transient of the maximum credible accident.

2. Structure dead load

3. Live loads

4. Internal test pressure loads

5. Earthquake load

6. Wind force and tornado loads

7. Uplift due to buoyant forces

8. External pressure load

The critical loading condition is that caused by the maximum credible accident resulting from severance of a reactor coolant pipe coincident with the maximum hypothetical earthquake.

Loss of Coolant Accident Load

The design pressure and temperature of the containment is in excess of the peak pressure and temperature occurring as the result of the complete blowdown of the reactor coolant through any rupture of the reactor coolant system up to and including the hypothetical severance of a reactor coolant pipe.

The supports for the reactor coolant system are designed to withstand the blowdown forces associated with the severance of the reactor coolant piping so that the coincidental rupture of the steam system is not considered credible. Transients resulting from the loss of coolant accident and other lesser accidents are presented in Chapter 14 and serve as the basis for a containment design pressure of 60 psig.

The design pressure is not exceeded during any subsequent long term pressure transient caused by the combined effects of such heat sources as residual heat and metal-water reactions. These effects are overcome by the combination of emergency powered engineered safeguards and structural heat sinks.

The temperature gradient through the wall during the loss of coolant accident is shown in Figure 5.1-6. The variation of temperature with time and the expansion of the liner plate are considered in designing for the thermal stresses associated with the loss of coolant accident load.

Structure Dead Load

Dead load consists of the weight of the concrete wall, dome, base slab, and any internal concrete. Weights used for dead load calculations are as follows:

1.	Concrete	143 lb/ft^3
2.	Steel Reinforcing & Prestressing Steel	489 lb/ft^3 using nominal cross sectional areas of reinforcing as defined in ASTM for bar sizes and nominal cross sectional areas of prestressing tendons.
3.	Steel Lining	489 lb/ft^3 using nominal cross sectional area of lining.

Live Loads

Live loads include snow loads on the roof of the enclosure over the containment dome, which is partially supported by columns to the dome. The roof load on the enclosure is 30 lbs. per horizontal square foot.

Equipment loads are those specified on the drawings supplied by the manufacturers of the various pieces of equipment.

Uniform live loads for the design of internal slabs are consistent with the intended use of the slabs. Most slabs are designed for 250 psf.

Internal Test Pressure Loads

At the end of construction, the containment was pressurized to prove the structural integrity of the vessel. The maximum test pressure is 69 psig, or 115% of the design pressure. This pressure was applied only as an initial test under controlled conditions.

Earthquake Loads

Earthquake loading is derived from an operating base earthquake (OBE) at the site having a horizontal ground acceleration of 0.06 g. In addition, a safe shutdown earthquake having a ground acceleration of 0.12 g is used to check the design to ensure no loss of function. A vertical component of ground acceleration of 2/3 of the magnitude of the horizontal component is applied in the load equations simultaneously.

Structures and equipment are analyzed and designed in compliance with the following criteria:

Class I

A dynamic analysis is used to determine loadings resulting from a postulated earthquake. Primary steady state stresses, when combined with seismic stresses calculated for the earthquake loading, are maintained within the allowable working stress limits accepted as good practice and set forth in appropriate design standards where applicable.

Values of damping coefficients used in the analysis are:

	OBE	SSE
Ground Surface Acceleration	.06 g	.12 g
Type of Condition and Structure	Percentage of Critical Damping	
Welded Steel Plate Assemblies	1%	2%
Welded Steel Framed Structures	2%	2%
Bolted Steel Framed Structures	2.5%	5%
Interior Concrete Equipment Supports	2%	2%
Reinforced Concrete Structures on Soil	5%	7.5%

Prestressed Concrete Containment Structure on Piles	2%	5%
Vital Piping Systems	0.5%	0.5%

The calculation of modal damping is based on the relative strain energy of the individual materials. The damping is proportional to the displacement and strain energy as determined from the evaluation of the mode shapes.

Class II

A static analysis for a base shear is based on the .06g design earthquake.

Class III

A static analysis for a base shear is determined and distributed in accordance with the Uniform Building Code.

Figure 5.1-7 shows the acceleration response spectra to be used for the design earthquake and is based upon curves presented in TID 7024, "Nuclear Reactors and Earthquakes," August 1963.

Figure 5.1-8 shows the acceleration response spectra for the earthquake and is based upon curves presented in TID 7024.

Wind and Tornado Forces

Wind loading for the containment structure is based on Figure 1(b) of ASCE Paper 3269, "Wind Forces on Structures" (Reference 5), using the fastest wind speed for a 100 year recurrence period. This results in a 108 mph basic wind at 30 feet above grade.

ASCE Paper 3269 is also used to determine shape factors, gust factors, and variation of wind velocity with height.

The structure is analyzed for tornado loading (not coincident with accident or earthquake) on the following basis:

1. Differential pressure between the inside and outside of the containment structure is assumed to be 3 lbs. per sq. in. positive pressure.

2. Lateral forces on the containment structure is assumed as the force caused by a tornado funnel having a peripheral tangential velocity of 300 mph plus a forward progress of 60 mph. The applicable portions of wind design methods described in Reference 5 have been used, particularly for shape factors. The provision for gust factors and variation of wind velocity with height do not apply.

3. Tornado driven missiles equivalent to an airborne 4 in. by 12 in. by 12 ft. plank traveling end on at 300 mph (440 fps) or a 4000 lb. automobile flying through the air at 50 mph (74 fps) and at not more than 25 feet above the ground, are assumed.

There are few reliable measurements of the pressure drop associated with a tornado funnel. The greatest drop recorded was equivalent to a bursting pressure of approximately 3 psi. This measurement, however, is highly questionable and not regarded as authoritative. The greatest reliably measured pressure drops have been in the order of 1.5 psi or less.

Because of the complexity of the airflow in a tornado, it has not been possible to calculate the velocity or trajectory of missiles that would truly represent tornado conditions. For design purposes, it is assumed that objects of low cross sectional density, such as boards, metal siding, and similar items may be picked up and carried at the maximum wind velocity of 300 mph.

The behavior of heavier, oddly shaped objects such as an automobile, is less predictable. The design values of 50 mph for a 4000 lb. automobile lifted 25 feet in the air is felt to be representative of what would happen in a 300 mph wind as the automobile was lifted, tumbled along the ground, and ejected from the tornado funnel by centrifugal force. These missile velocities are consistent with reported behavior of such objects in previous tornadoes.

Uplift Due to Buoyant Forces

Uplift forces which are created by the displacement of ground water by the structure are accounted for in the design of the structure.

External Pressure Load

The containment is designed to withstand an internal design vacuum condition of 2 psi, which is equivalent to an external pressure loading with a differential of 2 lbs. per sq. in. from outside to inside. This condition will accommodate either a barometric pressure rise to 31 in. Hg after the containment is sealed at 29 in. Hg, or an interior containment cooldown from 120°F to 50°F. Therefore, operation of purge valves is not necessary due to barometric changes during normal operation or cooldown conditions, and vacuum breakers are not required.

5.1.2.3 SEISMIC DESIGN CLASSIFICATION

All equipment and structures are classified as Class I, Class II, or Class III as described in Appendix A.5.1.

These classifications are defined as follows:

1. Class I

   Those structures and components including instruments and control whose failure might cause or increase the severity of a loss of coolant accident or result in an uncontrolled release of excessive amounts of radioactivity. Also, those structures and components vital to safe shutdown and isolation of the reactor.

2. Class II

   Those structures and components which are important to reactor operation but not essential to safe shutdown and isolation of the reactor and whose failure could not result in the release of substantial amounts of radioactivity.

3. Class III

   Those structures and components which are not related to reactor operation or containment.

5.1.2.4 DETAILED DESIGN CRITERIA

General

The analysis for the containment structure falls into two general categories, axisymmetric analysis and nonaxisymmetric analysis. The axisymmetric analysis is performed through the use of the finite element computer program for the individual loading cases of dead load, live load, temperature, prestress, and pressure using the usual assumptions of the theory of elasticity as described in Section 5.1.2.2.

The finite element approximation of the containment structure does not consider the buttresses, and the lateral loads due to seismic or wind are considered in the nonaxisymmetric analysis described later in the section.

This section of the FSAR discusses analytical techniques, references, and design philosophy. The design criteria, analysis, and construction drawings were reviewed by Bechtel's consultants, T. Y. Lin, Kulka, Yang & Associate.

Axisymmetric Techniques

The finite element technique is a general method of structural analysis in which the continuous structure is replaced by a system of elements (members) connected at a finite number of nodal points (joints). Conventional analysis of frames and trusses can be considered to be examples of the finite element method. In the application of the method to an axisymmetric solid (e.g., a concrete containment structure), the continuous structure is replaced by a system of rings of triangular cross section which are interconnected along circumferential joints. Based on energy principles, work equilibrium equations are formed in which the radial and axial displacements at the circumferential joints are the unknowns of the system. The results of the solution of this set of equations is the deformation of the structure under the given loading conditions. For the output, the stresses are computed knowing the strain and stiffness of each element.

The finite element mesh used to describe the structure is shown in Figure 5.1-9. The upper portion and lower portion of the structure are analyzed independently to permit a greater number of elements to be used for those areas of the structure of major interest such as the ring girder area and the base of the cylinders. The finite element mesh of the structure base slab is extended down into the foundation material to take into consideration the elastic nature of the foundation material and its effect upon the behavior of the base slab.

The use of the finite element computer program permitted an accurate estimate of the stress pattern at various locations of the structure. The following material properties were used in the program for the various loading conditions:

	Load Conditions D, F, T_o, T_A	Load Condition P
$E_{concrete, foundation (psi)}$	2.7×10^6	5.0×10^6
$E_{concrete, shell (psi)}$	2.5×10^6	5.0×10^6
$\nu_{concrete(Poission's\ ratio)}$	0.17	0.17

$\alpha_{concrete\ (coeff\ of\ expansion)}$	0.5×10^{-5}	
$E_{rock\ (psi)}$	0.13×10^{8}	0.13×10^{8}
$E_{liner\ (psi)}$	30×10^{6}	30×10^{6}
$E_{piles\ (psi)}$	30×10^{6}	30×10^{6}
$fy_{liner\ (psi)}$	34,000	

For definition of Load Conditions, see Section 5.1.2.2.

The structure is analyzed assuming an uncracked homogeneous material.

The major benefit of the program is the capability to predict shears and moments due to internal restraint and the interaction of the foundation slab relative to the soil. The use of an uncracked section is conservative because the decreased relative stiffness of a cracked section would result in smaller secondary shears and moments.

In arriving at the above mentioned values of E_c, the effect of creep is included by using the following equation for long term loads such as thermal load, dead load, and prestress:

$$E_{cs} = E_{ci}\frac{\varepsilon_i}{\varepsilon_s + \varepsilon_i}$$

where

E_{cs} = Sustained modulus of elasticity of concrete
E_{ci} = Instantaneous modulus of elasticity of concrete
ε_i = Instantaneous strain, in./in. per psi
ε_s = Creep strain, in./in. per psi

The thermal gradients used for design are shown in Figure 5.1-6. The gradients for both the design accident condition and the factored load condition are based on the temperature associated with the factored pressure. The design pressure and temperature of 60 psig and 286°F become 90 psig and 310°F at factored conditions. For such a small increase in temperature, it was decided to use a single set of thermal gradients to simplify the analysis.

The thermal loads are a result of the temperature differential within the structure. The design temperature stresses for this finite element analysis were prepared so that when temperatures are given at every nodal point, stresses are calculated at the center of each element.

Thus, the liner plate is handled as an integral part of the structure but having different material properties, and not as a mechanism which would act as an outside source to produce loading on the concrete portion of the structure.

Under the design accident condition or factored load condition, cracking of the concrete at the outside face would be expected. The value of modulus of elasticity of concrete, E_{cs} was used together with the method described in ACI Code 505-54 to find the stresses in concrete, reinforcing steel, and liner plate from the predicted design accident thermal loads and factored accident loads.

The isostress plots shown in Figure 5.1-10 and Figure 5.1-11 do not consider the concrete cracked. The thermal stresses are combined in the isostress output for the cases of D + F + T and D + F + 1.5P + T. The first case was critical for concrete stresses and occurs after depressurization of the containment; the second case is critical for the reinforcing stresses and it occurs when pressure and thermal loads are combined and cause cracking at the outside face.

The stresses shown in Table 5.1-1 consider cracking. The general approach of determining stresses in the concrete and reinforcement required the evaluation of the stress blocks of the cross section being analyzed.

The value of stresses was taken from the computer output in case of axisymmetric loading and from analytical solutions is case of nonaxisymmetric loading. Both computations are based on homogeneous materials, therefore, some adjustment is necessary to evaluate the true stress strain conditions when cracks develop in the tensile zone of the concrete.

The procedures used to determine the area of conventional reinforcing required and the stress in the concrete resulting from the loading condition, considering the effects of cracking where required, are presented.

Basic Assumption: The thermal stresses in the containment are comparable to those developed in a reinforced concrete slab which is restrained from rotation. The temperature varies linearly across the slab. The concrete will crack in tension and the neutral axis will be shifted toward the compressive extreme fiber. The cracking will reduce the compression at the extreme fiber and increase the tensile stress in reinforcing steel.

The following analysis is based on the equilibrium of normal forces, therefore, any normal force acting on the section must be added to the normal forces resulting from the stress diagram. The effects of Poisson's ratio are considered while the reinforcement is considered to be identical in both directions.

Stress-strain relationship in compressed region of concrete:

$$E_c \varepsilon_x = \sigma_x - v_c \sigma_y$$

$$E_c \varepsilon_y = - v_c \sigma_x + \sigma_y$$

$$\sigma_x = E_c \frac{\varepsilon_x + \varepsilon_y v}{1 - v_c^2}$$

$$\sigma_y = E_c \frac{\varepsilon_y + \varepsilon_x v}{1 - v_c^2}$$

assuming

$$\sigma_x = \sigma_y = \sigma_c \qquad \text{and} \qquad \varepsilon_x = \varepsilon_y = \varepsilon_c$$

$$\sigma_c = E_c \varepsilon_c \frac{1}{1 - v_c} = 1.205\ E_c \varepsilon_c [\text{if } v_c = 0.17]$$

The reinforcement is acting in one direction, independently from the reinforcement in the perpendicular direction.

Example:

If $E_c = 3 \times 10^6$ and $E_s = 30 \times 10^6$

$$n_r = \frac{30}{1.205 \times 3} = 8.3$$

The liner plate is acting in two directions, similar to the concrete except for the difference caused by the Poissons ratios:

$$\sigma_L = E_s \varepsilon_s \frac{1}{1 - v_L} = 1.35 E_s \varepsilon_s$$

If $v_L = 0.25$ and $v_c = 0.17$

$$n_L = \frac{1.35 \times 30}{1.205 \times 3} = 11.2$$

The following is an example of the use of the analytical method derived. Thermal stress in base slab:

$E_c = 3 \times 10^6$ psi

$E_s = 30 \times 10^6$ psi

$v_c = 0.17$

$v_L = 0.25$

$n_R = 8.3$

$n_L = 11.2$

Equilibrium of forces considering crack section:

$$4.42[293 + \Delta\sigma_c]8.3 - [65.0 + 105.7 + 24.0]$$
$$1000 + \Delta\sigma_c[12 \times 42 + 3 \times 11.2] = N = -95{,}000 \text{ lbs.}$$

$\Delta\sigma_c = 156.5$ psi

$\sigma_s = [293 + 156.5]8.3 = 3{,}731$ psi

The concrete and reinforcement stresses are calculated by conventional methods from the moment caused by loading other than thermal. The analyses assume homogeneous concrete sections. Those concrete and reinforcing steel stresses are then added to the thermal stresses as obtained by the method described.

Notation:

E_c = Modulus of elasticity of concrete
E_s = Modulus of elasticity of steel
n_L = Modular ratio of liner plate/concrete
n_R = Modular ratio of reinforcement/concrete
$\Delta\sigma_c$ = Reduction of concrete compressive stress considering cracking
ε_c = Concrete strain
ε_s = Steel strain
ε_x = Concrete strain in X direction
ε_y = Concrete strain in Y direction
ν_c = Poisson's ratio of concrete
ν_L = Poisson's ratio of liner plate
σ_c = Stress in concrete
σ_L = Stress in liner plate
σ_R = Stress in reinforcement
σ_x = Stress in concrete in direction X

An equilibrium equation can be written considering the tension force in the reinforcement, the compressive force in the concrete, and the axial force acting on the section. In this manner the neutral axis is shifted from the position defined by the computer analyses into a position which is the function of the amount of reinforcement, the modulus ratio, and the acting axial forces.

Large axial compressive force might prevent the existence of any tension stresses, as in the loading condition, D + F + T, therefore, no self relieving action is existing; the stresses are taken directly from the computer output.

In the case of D + F + 1.5P + T, the development of cracks in the concrete decreases the thermal moment and this effect is considered, but the self relieving properties of other loadings are not taken into account even in places where they do exist, such as at discontinuities, e.g., the cylinder base slab connection. This means that in analyzing the section, a reduced thermal moment is added to the moment caused by other loadings without any reduction.

Nonaxisymmetric Analysis

The nonaxisymmetric aspects of configuration of loading required various methods of analysis. The description of the methods used as applied to different parts of the containment are given in the sections below.

Buttresses

The buttresses are analyzed for two effects, nonaxisymmetry and anchorage zone stresses. Both effects are shown in the results of a two dimensional plane strain finite element analysis with loads acting in the plane of the coordinate system (Figure 5.1-12).

At each buttress, the hoop tendons are alternately either continuous or spliced by being mutually anchored on the opposite faces of the buttress. Between the opposite anchorages, the compressive force exerted by the spliced tendon is twice as much as elsewhere, therefore, this increased value added to the effects of the tendon which is not spliced will be 1.5 times larger than the prestressing force acting outside of the buttresses. The cross sectional area of the buttress is about 1.5 times that of the wall so the hoop stress as well as the hoop strains and radial displacements can be considered as being nearly constant all around the structure. Isostress plots of the plane strain analysis, Figure 5.1-13, confirm this. The vertical stresses and strains caused by the vertical post tensioning become constant at a short distance away from the anchorages because of the large stiffness of the cylindrical shell. Since, as stated above, the stresses and strains remain nearly axisymmetric despite the presence of the buttresses, their effect on the overall analysis is negligible when the structure is loaded with dead load or prestressing loads.

When an increasing internal pressure acts upon the structure, combined with a thermal gradient such as at the design accident condition, the resultant forces being axisymmetric, the stiffness variation caused by the buttresses will be decreased as the concrete develops cracks. The structure will then tend to shape itself to even more closely follow the direction of the acting axisymmetric at yield loads, which include factored pressure, than at design loads including pressure. This fact, combined with the redundancy of the pressure resisting structural elements, indicates that the buttresses will not reduce the margins of safety available in the structure.

Seismic or Wind Loading

Design requirements dictated by seismic loading of the structure are greater than that of tornado or wind loading. The seismic analysis is conducted in the following manner.

The loads on the containment structure caused by earthquake are determined by a dynamic analysis of the structure. The dynamic analysis is made on an idealized structure of lumped masses and weightless elastic columns acting as spring restraints.

The analysis is performed in two stages: the determination of the natural frequencies of the structure and its mode shapes, and the modal response of these modes to the earthquake by the spectrum response method.

The natural frequencies and mode shapes are computed from the equations of motion of the lumped masses established in a virtual displacement method solved by iteration techniques using a fully tested digital computer program. The form of the equation is:

$$(K) \times (\Delta) = \omega^2 \times (M) \times (\Delta)$$

(K)	=	Matrix of stiffness coefficient including the combined effects of shear, flexure, rotation, and horizontal translation
(M)	=	Matrix of concentrated masses
(Δ)	=	Matrix of mode shape
ω	=	Angular frequency of vibration

The results of this computation are the several values of ω_n and mode shapes Δn for n = 1, 2, 3 -- m where m is the number of degrees of freedom (i.e., lumped masses) assumed in the idealized structure.

The response of each mode of vibration to the design earthquake is then computed by the response spectrum technique as follows:

1. The base shear contribution of the n^{th} mode

$$V_n = W_n \times S_{an}(\omega_n;\delta)$$

where

ω_n = Angular frequency of the n^{th} mode

W_n = Effective weight of the structure in the n^{th} mode

$$W_n = \frac{(\Sigma_x \Delta_{xn} W_x)^2}{\Sigma_x (\Delta_{xn})^2 W_x}$$

where the subscript x refers to levels throughout the height of the structure and Wx is the weight of the lumped mass at level x.

$S_{an}(\omega_n;\gamma)$ = Spectral acceleration of a single degree of freedom system with a damping coefficient of obtained from the response spectrum

2. The horizontal load distribution for the nth mode was then computed as:

$$F_x = V_n(\Delta_{xn}W_x)/(\Sigma_x\Delta_{xn}W_x)$$

The several mode contributions are then combined to give the final response of the structure to the design and hypothetical earthquake.

3. The number of modes to be considered in the analysis is determined to adequately represent the structure being analyzed. Since the spectral response technique yields the maximum value of response for each mode and these maxima do not occur at the same time, the response of the modes of vibration is combined by taking the square root of the sum of the squares of the modal values. The analytical model and results are shown in Figure 5.1-14.

<u>Large Openings (Equipment Hatch and Personnel Lock Opening)</u>

As stated in the design criteria, the primary loads considered in the design of the equipment hatch and personnel lock opening, as for any of the structure, are dead load, prestress, pressure, earthquake, and thermal loads. The secondary loads considered, caused by the above primary loads were:

1. The deflection of tendons around the opening

2. The curvature of the shell at the opening

3. The thickening around the opening

The loads described under primary loads are mainly membrane loads with the exception of the thermal loads. In addition to membrane loads, accident pressure also produces punching shear around the edge of the opening. The values of these loads for design purposes are the magnitudes of these loads at the center of the opening. These are fairly simple to establish, knowing the values of hoop and vertical prestress loads, accident pressure loads, and the geometry and location of the opening.

The hoop normal forces caused by either post tensioning or internal pressure have a very low value right at the base slab and gradually increase at higher elevations, accompanied by varying shear forces. The effects of the earthquake loading is also a function of the elevation.

The equipment hatch on the Point Beach containment is close to the base slab so that the forces are not constant in the vertical direction.

The analysis considers these forces and the values are obtained from calculations considering a continuous shell.

The shear stress near the edge of the opening, (E), for various components of loading is predicted to be as follows:

Prestress - 19 psi
Pressure - 36 psi
Earthquake - 3 psi

The contribution from temperature and dead load are very small. Under the D + F + P + TA + E case the shear stress is predicted to be 20 psi.

Secondary loads are predicted by the following methods:

1. The membrane stress concentration factors and effect of the deflection of the tendons around the equipment hatch are analyzed for a flat plate by the finite element method. The stresses predicted by conventional stress concentration factors, when compared with those values from the previously mentioned finite element computer program, demonstrated that the deflection of the tendons does not significantly affect the stress concentrations. This is a plane stress analysis and does not include the effect of the curvature of the shell. However, it gives an assurance of the correctness of the assumed stress pattern caused by the prestressing around the opening.

2. With the help of Reference 6, stress resultants around the large opening are found for various loading cases. Comparison of the results found from this reference with the results of a flat plate of uniform thickness with a circular hole show the effect of the cylindrical curvature on stress concentrations around the opening.

   Normal shear forces (relative to opening) are modified to account for the effect of twisting moments. These modified shear forces are called Kirschoff's shear forces. Horizontal wall ties are provided to resist a portion of these shear forces.

3. The effect of the thickening on the outside face around the large opening is considered using a separate axisymmetric finite element computer analysis for a flat plate with anticipated thickening on the outside face. This particular finite element computer program handles both axisymmetric and nonaxisymmetric loads. This finite element computer program is also used to predict the effect of concentration of hoop tendons (with respect to the containment) at the top and bottom of the opening.

Various conditions checked by the flat plate plane stress finite element analysis were as follows:

1. During prestressing with only the hoop tendons stressed

2. The local effects of hoop tendon curvature under the D + F + 1.5P design load condition

3. After total prestressing D + F

The membrane loads were applied at the flat plate boundary and the tendon loads from curvature in the plane of the model were applied at the tendon locations.

The analysis considered the effects of thickening by assigning increased E values for the elements representing the thickened portion of the shell, but it did not consider the shell curvature effects and the fact that the thickening is not symmetrical about the opening.

Reference 6 was used to determine the effects of shell curvature on the stress concentrations around the opening.

For the analysis of the thermal stresses around the opening, the same method is used as for the other loadings. At the edge of the opening, a uniformly distributed moment equal but opposite to the thermal moment existing on the rest of the shell is applied and evaluated using the methods of Reference 6. The effects are then superimposed on the stresses calculated for the other loads and effects.

In the case of accident temperature, after the accident pressure has already been decreased, very little or no tension develops on the outside, so thermal strains will exist without the relieving effect of the cracks. However, the liner plate will reach a high strain level, and so will the concrete at the inside corner of the penetration, thereby relieving once again the very high stresses, but still carrying a high moment in the state of redistribution stresses.

In the case of 1.5P (prestress fully neutralized) + 1.0T (accident temperature), the cracked concrete with highly strained tension reinforcement constitutes a shell with stiffness decreased but still essentially constant in all directions. In order to control the increased hoop moment around the opening, the hoop reinforcement is about twice that of the radial reinforcement (see Figure 5.1-15).

The equipment hatch opening is thickened for the following reasons:

1. To reduce the larger than acceptable predicted stresses around the opening;
2. To accommodate tendon placement;
3. To accommodate bonded steel reinforcing placement;
4. To compensate for the reduction in the overall shell stiffness due to the opening.

In order to minimize the effect of tensile stresses at the outside face and to distribute the concentration of radial forces exerted by hoop tendons in a more uniform manner, the inside row of vertical tendons is given a reverse curvature (they are deflected outward as they pass the opening) so as to reduce the inward acting radial forces (due to hoop tendons) at the top and bottom of the opening and to produce inward acting forces on the sides of the large opening.

The working stress method (elastic analysis) is applied to both the load combinations for design loads as well as for yield loads for the analytical procedures described above. The only difference is the higher allowable stresses under yield conditions. The various factored load combinations and capacity reduction factors are specified in Section 5.1.2.2 and are used for the yield load combinations using the working stress design method. The design assumption of straight line variation of stresses is maintained under yield conditions.

The governing design condition for the sides of the equipment hatch opening at the outside edge of the opening is the accident condition. Under this condition, approximately 60% of the total bonded reinforcing steel needed at the edge of the opening at the outside face is a result of the thermal load.

A breakdown of total loading follows:

1.	Stress Breakdown From Thermal Gradient	(Plus 60%)
2.	From Membrane Force Including The Thickening Effect	(Minus 14%)
3.	From Moments Caused by Thickening	(Plus 60%)
4.	From Membrane Forces and Moments Caused by the Effect of Cylindrical Curvature	(Minus 6%)
	Total	(100%)

Excluding thermal load, the remaining stress (equivalent to approximately 40% of the total load, including thermal) at the edge of the outside face is the contribution of the following stress resultants:

1. Normal stresses resulting from membrane forces, including the effect of thickening, contribute approximately -35% (-14% of total).
2. Flexural stresses resulting from the moments caused by thickening on the outside face contribute approximately 150% (60% of total).
3. Normal and flexural stresses resulting from membrane forces and moments caused by the effect of cylindrical curvature contribute approximately -15% (-6% of total).

<u>Penetrations</u>

Analysis of the containment penetrations falls into three categories:

1. The concrete shell;
2. The liner plate reinforcement and closure to the pipe or electrical canister;
3. The thermal gradients and protection requirements at the high temperature penetrations.

The three categories will be discussed separately.

The basic computer analyses applied in the design of the containment shell are for axisymmetric solids subjected to axisymmetric loadings; therefore, areas where either the shape or the loading is nonaxisymmetric are analyzed by other methods. The nonaxisymmetric effects are not included in the axisymmetric analyses directly, but the results of two independent calculation methods are combined.

Small penetrations without appreciable accident pressure loads or pipe failure loads were analyzed as holes in a flat plate and the stress concentrations from the membrane loads were the main consideration in specifying the reinforcing steel. For penetrations which could be subjected to external forces and moments, additional reinforcement was added where necessary to resist moments and shear.

1. Concrete Shell

In general, special design consideration is given to all openings in the containment structure. Analysis of the various openings has, however, indicated that the degree of attention required depends upon the penetration size. Small penetrations are considered to be those with a diameter smaller than 1-1/2 times the shell thickness, i.e., approximately 8 ft. in diameter or less. Reference 6 indicates that for openings of 8 ft. diameter or less the curvature effect of the shell is negligible. In general, the existing concrete wall thickness is found to be capable of taking the imposed stresses using bonded reinforcement and the thickness is increased only as required to permit space requirements for tendon deflection. The induced stresses due to normal thermal gradients and postulated rupture conditions distribute rapidly and are of a minor nature compared to the numerous loading conditions for which the shell must be designed. The penetrations are analyzed as holes in a plane sheet. Applied piping restraint loads due to thermal expansion or accident forces are assumed to distribute in the cylinder as stated in Reference 6. Typical details associated with these openings are indicated in Figure 5.1-2 and Figure 5.1-3.

2. Liner Plate Closure

The stress concentrations around openings in the liner plate are calculated using the theory of elasticity. The stress concentrations are then reduced by the use of a reinforcing plate around the opening. In the case of a penetration with no appreciable external load, anchor bolts are used to maintain strain compatibility between the liner plate and the concrete. Inward displacement of the liner plate at the penetration is also controlled by the anchor bolts.

In the case of a pipe penetration in which large external operating loads are imposed upon the penetration, the stress level from the external loads is limited to the design stress intensity values, $S_{m,}$ given in the ASME Boiler and Pressure Vessel Code, Section III, Article 4. The stress level in the anchor bolts from external loads is in accordance with bearing values meeting ACI Code Requirements.

The combining of stresses from all effects is done by the methods outlined in the ASME Boiler and Pressure Vessel Code, Section III, Article 4, Figure 414. The maximum allowable stress intensity, $S_{a,}$ is the value from Figure N 415(A) of this code. Shown in Figure 5.1-16 is a typical penetration and the applied loads.

The stresses from the effects of pipe loads, pressure loads, dead load, and earthquake are calculated and the stress intensity kept below S_m.

The stresses from the remaining effects are combined with the above calculated stresses and the stress intensity kept below S_a.

3. Thermal Gradient

The only large lines penetrating the containment shell normally having high temperatures are the main steam and feedwater. The analytical steady state temperature gradients are determined for the case with no cooling with maximum insulation using the Generalized Heat Transfer Program (see Figure 5.1-17 for analytical results). In addition, temperatures have been measured in the concrete at the main steam penetrations. The results indicate that local heating of containment concrete is below the limit of 200°F (ASME Section III, Division 2, Subsection CC-3440, “Concrete Temperatures”) and active cooling for these penetrations is not required (NUREG-1839“Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2”).

Smaller lines penetrating the containment shell normally having high temperatures and normally in operation include the RCS hot leg sample line, steam generator blowdown sample lines and the steam generator blowdown lines. Temperature readings of the containment concrete in the vicinity of smaller lines have been measured during plant operation and found to be well below 200°F (Reference 10).

Liner Plate

There are no design conditions under which the liner plate is relied upon to assist the concrete in maintaining the integrity of the structure even though the liner will at times provide such assistance.

Loads are transmitted to the liner plate through the anchorage system and direct contact with the concrete and vice versa. Loads may be also transmitted by bond and/or friction with the concrete. These loads cause or are caused by liner strain. The liner is designed to withstand the predicted strains without leaking.

Possible cracking of concrete is considered and reinforcing steel is provided to control the width and spacing of the cracks. In addition, the design is made such that total structural deformation remains small during the loading conditions and that any cracking will be orders of magnitude less than that sustained in the repeated attempts to fail the prestressed concrete from overpressure tests of “Model 2” (both at General Atomic). (See “Prestressed Concrete Reactor Vessel, Model 1, #GA 7097, HTGR and Laboratory Staff” and “Concrete Reactor Vessel, Model 2, #GA 7150, Advance HTGR Staff.”)

Under test condition, the cylinder wall and the dome will be under net membrane compressive stress. Therefore, there is only a slight possibility of cracking at the outside face of the wall and the dome from thermal gradient present during the test across the thickness of the wall and the dome.

The crack width is calculated using Reference 7.

Following is the equation as mentioned in the above reference to calculate the maximum size of the crack:

$$\text{W max.} = 0.115\sqrt[4]{A} \times f_s \times 10^{-6}\ \text{in.}$$

where

W max. = Maximum crack width

A = Area of concrete surrounding each bar, sq. in.

f_s = Stress in the bar, psi

The maximum crack width is predicted to be 0.0055 in. The corresponding spacing of the crack is predicted to be 10 in.

It is expected that the crack pattern will be two dimensional. However, because of the higher circumferential prestressing compared to the vertical prestressing in the cylinder wall, the size of the vertical crack is predicted to be smaller than the horizontal crack. As described, the structural integrity consequences of concrete cracking are limited by the bonded reinforcing and unbonded tendons provided in accordance with the design criteria. The effect of concrete cracking on the liner plate is also considered. The anchor spacing and other design criteria are such that the liner will sustain, for example, orders of magnitude of strain less than did the liner of Model 1 at General Atomic without tensile failure.

<u>Liner Plate Anchors</u>

The liner plate anchors are designed to preclude failure when subjected to the worst possible loading combinations. The anchors are also designed such that, in the event of a missing or failed anchor, the total integrity of the anchorage system would not be jeopardized by the failure of adjacent anchors. The following loading conditions are considered in the design of the anchorage system:

1. Prestress;
2. Internal Pressure;
3. Shrinkage and Creep of Concrete;
4. Thermal Gradient (Normal and Design Basis Accident);
5. Dead Load;
6. Earthquake;
7. Vacuum.

The following factors are considered in the design of the anchorage system:

1. Initial inward curvature of the liner plate between anchors due to fabrication and erection accuracies;
2. Variation of anchor spacing;
3. Misalignment of liner plate seams;

4. Variation of plate thickness;

5. Variation of liner plate material yield stress;

6. Variation of Poisson's ratio for liner material;

7. Cracking of concrete in anchor zone;

8. Variation of the anchor stiffness.

The anchorage system satisfies the following conditions:

1. The anchor has sufficient strength and ductility so that its energy absorbing capability is sufficient to restrain the maximum force and displacement resulting from the condition where a panel with initial outward curvature is adjacent to a panel with initial inward curvature.

2. The anchor has sufficient flexural strength to resist the bending moment which would result from Condition 1.

3. The anchor has sufficient strength to resist radial pull out force.

When the liner plate moves inward radially as shown in Figure 5.1-18, the sections will develop membrane stress due to the fact that the anchors have moved closer together. Due to initial inward curvature, the section between 1 and 4 will deflect inward giving a longer length than adjacent sections and some relaxation of membrane strength will occur. It should be noted here that section 1-4 cannot reach an unstable condition due to the manner in which it is loaded.

The first part of the solution for the liner plate and anchorage system is to calculate the amount of relaxation that occurs in section 1-4, since this value is also the force across Anchor 1 if it is infinitely stiff. This solution is obtained by solving the general differential equation for beams, including the effect of relaxation or the lengthening of section 1-4. Figure 5.1-18, Sheet 1, shows the symbols for the forces that result from the first step in the solution.

Using the model shown in Figure 5.1-18, Sheet 2, and evaluating the necessary spring constants, the anchor is allowed to displace.

The solution yields a force and displacement at Anchor 1, but the force in Section 1-2 is (N)-$K_{R(Plate)}S_1$ and Anchor 2 is no longer in force equilibrium.

The model shown in Figure 5.1-18, Sheet 2, is used to allow Anchor 2 to displace and then to evaluate the effects on Anchor 1.

The displacement of Anchor 1 is $S_1 + S'_1$ and the force an Anchor 1 is $K_c(S_1 + S'_1)$. Then Anchor 3 is not in force equilibrium and the solution is continued to the next anchor.

After the solution is found for displacing Anchor 2 and Anchor 3, the pattern is established with respect to the effect on Anchor 1 and, by inspection, the solution considering an infinite amount of anchors is obtained in the form of a series solution.

The preceding solution yielded all necessary results. The most important results are the displacement and force on Anchor 1.

Various patterns of welds attaching the angle anchors to the liner plate were tested for ductility and strength when subject to a transverse shear load such as ΔN and are shown in Figure 5.1-19. Using the results from these tests together with the tests made for the Fort St. Vrain PSAR, Amendment No. 2, and Oldbury vessels, a range of possible spring constants were evaluated for the Point Beach liner. By using the solution previously obtained together with a chosen spring constant, the amount of energy required to be absorbed by the anchor was evaluated.

By dividing the amount of energy that the system will absorb by the most probable maximum energy, the result then yielded the factor of safety.

By considering the worst possible loading condition which resulted from the listed loading conditions and the conditions stated below, the following results are obtained:

Case I — Simulates a plate with a yield stress of 32 ksi and no variation in any other parameters.

Case II — Simulates a 1.25 increase in yield stress and no variation in any other parameters.

Case III — Simulates a 1.25 increase in yield stress, a 1.16 increase in plate thickness, and a 1.08 increase for all other parameters.

Case IV — Simulates a 1.88 increase in yield stress with no variation of any other parameters.

Case V — Is the same as Case III except the anchor spacing is doubled to simulate what happens if an anchor is missing or has failed.

LINER PLATE CALCULATIONS - RESULTS

Case	Nominal Plate Thickness (In)	Initial Inward Displacement (In)	Anchor Spacing L (In)	Anchor Spacing L_2 (In)	Factor of Safety Against Failure
I	0.25	0.125	15	15	37.0
II	0.25	0.125	15	15	19.4
III	0.25	0.125	15	15	9.9
IV	0.25	0.125	15	15	6.28
V	0.25	0.25	30	15	4.25

FSAR Section 5.1.2.9 provides additional information regarding structural analysis and testing associated with the containment liner plate leak chase channels (LCC).

Supports

In designing for structural bracket loads applied perpendicular to the plane of the liner plate or loads transferred through the thickness of the liner plate, the following criteria and methods are used:

a. The liner plate is thickened to reduce the predicted stress level in the plane of the liner plate. The thickened plate with the corresponding thicker weld attaching the bracket to the plate will also reduce the probability of the occurrence of a leak at this location.

b. Under the application of a real tensile load applied perpendicular to the plane of the liner plate, no yielding is to occur in the perpendicular direction. By limiting the predicted strain to 90% of the minimum guaranteed yield value, this criterion is satisfied.

c. The allowable stress in the perpendicular direction is calculated using the above allowable predicted strain in the perpendicular direction together with the predicted stresses in the plane of the liner plate.

d. In setting the above criteria, the reduced strength and strain ability of the material perpendicular to the direction of rolling (in plane of plate) is also considered if the bracket did not penetrate the liner reinforcing plate. In this case, the major stress is normal to the plane of the liner plate. The allowable stresses are reduced to 75% of the stress permitted in (c) above.

e. The necessary plate characteristics are assured by ultrasonic examination of the reinforcement plates for lamination defects.

Missiles

The containment structural design considered the following external missiles:

Item	Weight (lb)	Velocity (fps)
4 x 12 plank, 12 ft. long	200	440
Automobile	4,000	74

The depth of penetration of these missiles was analyzed in Reference 8. None of the above missiles would penetrate the containment. The 200 lb. plank weight was used in the structural design of PBNP. However, the submittal of Bechtel Topical Report B-TOP-3, "Design Criteria for Nuclear power Plants Against Tornadoes," to the AEC in early 1970 established the weight of the licensing basis plank missile as 108 lbs (Section 1.3.1).

Implementation of Criteria

This section documents the manner in which the design criteria are met by the designer. Various types of documentation are presented.

Figure 5.1-10, Figure 5.1-11, and Figure 5.1-13 illustrate isostress plots and tabulations of predicted stresses for the various materials. The isostress plots of the homogeneous uncracked concrete structure indicate the general stress pattern for the structure as a whole under various loading conditions. More specific documentation is made of the predicted stresses for all materials in the structure. In these tabulations, the predicted stress is compared with the allowable to permit an easy comparison and evaluation of the adequacy of the design.

Results of Analysis

The isostress plots, Figure 5.1-10, Figure 5.1-11, and Figure 5.1-13, show the three principal stresses and the direction of the principal stresses normal to the hoop direction. The principal stresses are the most significant information about the behavior of the structure under the various conditions and are a valuable aid for the final design.

The plots were prepared by a cathode ray tube plotter. The data for plotting were taken from the stress output of the finite element computer program of the following design load cases:

$D + F$

$D + F + 1.15P$

$D + F + 1.5P + T_A$

$D + F + T_A$

The above axisymmetric loading conditions are found to be governing in the design since they result in highest stresses at various locations of the structure.

The table of predicted stresses, Table 5.1-1, for various materials has been prepared for the presentation of the combined stresses of the axisymmetric and nonaxisymmetric loading cases. These stresses are computer analyzed considering cracked concrete sections where applicable, in the manner described previously. No stresses are shown for the tendons due to the almost constant stress level regardless of loading condition. The tabulated stresses may be considered the final results of the analysis and design.

The upper stress limit for a linear stress strain relationship was assumed to be 3000 psi (0.6 f'_c) for use with analyses made by the use of the axisymmetric finite element analytical method. (The analyses referred to considered the concrete as uncracked and the analytical model is the entire containment.) However, the maximum predicted compressive stress was about 2600 psi. The load combination considered was ($D + F + T_A$) and the location for the predicted stress was near the junction of the base slab and cylinder. Therefore, only the linear portion of the stress curve was used in the analyses that used the entire containment structure as a model.

The compressive stress and strain level is the highest (after the LOCA when temperature is still relatively high, 200°F, and pressure is dropping rapidly) at the inside face of the concrete at the edge of openings and also under the liner plate anchors. Neither concentration is a result of what may be considered a real load. In the case of an opening, the real stress is a result of prestress, reduced pressure, and dead load. Applying stress concentration factors to these loads still keeps the concrete in essentially the elastic range. When the strain and resulting stress from the thermal gradient are also multiplied by a stress concentration factor, the total strain and resulting stress will be above the linear stress range as determined by a uniaxial compression test. The relatively high stress level is not of real concern due to the following:

1. The concrete affected is completely surrounded by either other concrete or the penetration nozzle and liner reinforcing plate. This confinement puts the concrete in triaxial compression and gives it the ability to resist forces far in excess of that indicated by a uni-axial compression test.

2. The high state of stress and strain exist at a very local area and really have no effect on the overall containment integrity.

However, to be conservative, reinforcing steel was placed in these areas and, also, the penetration nozzle will function as compressive reinforcement.

The concrete under the liner plate anchors experiences some limited yielding in order to get the necessary stress distribution required to resist the liner plate self relieving loads.

Liner Plate Design Provisions

The liner plate is anchored as shown in Figure 5.1-1 with anchorage in both the longitudinal and hoop direction. The anchor spacing and welds are designed to preclude failure of an individual anchor. The load deformation tests, referred to above, indicate that the alternate stitch fillet weld used to secure the anchor to the liner plate would first fail in the weld and not jeopardize the liner plate leaktight integrity.

Erection and fabrication inaccuracies are controlled by specified tolerances given in Section 5.6.1.5.

Offsets at liner plate seams are controlled in accordance with ASME Section III Code which allows 1/16 in. misalignment for 1/4 in. plate. The flexural strains due to the moment resulting from the misalignment are added to calculate the total strain in the liner plate.

Penetration Details

Typical penetration details are shown in Figure 5.1-2 and Figure 5.1-3.

Horizontal and vertical bonded reinforcement is provided to help resist membrane and flexural loads at the penetrations. This reinforcement is located on both the inside and outside face of the concrete. Stirrups are also used to assist in resisting shear loads. Local crushing of the concrete due to deflection of the reinforcing or tendons is precluded by the following details.

1. The surface reinforcements either have a very large radius, such as the hoop bars, concentric with the penetration or are practically straight, having only standard hooks as anchorages where necessary.

2. The tendons are bent around penetrations at a minimum radius of approximately 20 feet. Maximum tendon force at initial prestress is 850 kips, which results in a bearing stress of about 880 psi on the concrete.

It is also important to note that the deflected tendons are continuous past the openings and are isolated from the local effects of stress concentrations by virtue of being unbonded.

In accordance with ASME Section III, all penetration reinforcing plates and the weldment of the pipe closure to it are shop stress relieved as a unit. This code requirement and the grouping of penetrations into large shop assemblies permits a minimum of field welding at penetrations.

Butt welds are used between the penetration sleeve and process piping. Both flued ends and drilled standard weight pipe caps are used for the closure piece between the sleeves and the pipes. The design, fabrication, inspection, and testing of the containment penetration head fittings are in accordance with ASME Boiler and Pressure Vessel Code, Section III, Class B, 1968 Edition and all addenda. Inspection procedures used for all closure welds consisted of liquid penetrant and local leak pressure testing at the containment design accident pressure. Open butt welds without backing rings were specified prior to June 1970. All of these welds were radiographed. Welds after June 1970 did not have the requirement for backing rings and radiographic inspection. Consequently, most of the Unit 1 penetration closure welds were radiographed and the majority of the Unit 2 closure welds were not.

Prestress Losses

The following categories and values of prestress losses are considered in the design:

Type of Loss	Assumed Value
Seating of Anchorage	None
Elastic Shortening of Concrete	$\frac{f_{cpi}}{5. \times 10^6}$ In/In
Creep of Concrete	0.27×10^{-6} In/In/Psi
Shrinkage of Concrete	100×10^{-6} In/In/Psi
Relaxation of Prestressing Steel	8% of $0.65f_s$ = 12.5 Ksi
Frictional Loss	$K = 0.0003$, $\mu = 0.156$

There is no allowance for the seating of the BBRV anchor since no slippage occurs in the anchor during transfer of the tendon load into the structure. Sample lift off readings will be taken to confirm that any seating loss is negligible.

The loss of tendon stress due to elastic shortening is based on the strain change in the initial tendon relative to the last tendon stressed.

A concrete properties study using Point Beach samples was conducted at the University of California. (Reference 9) A similar study conducted on a nearly identical concrete mix has indicated a creep value of 0.125 x 10^{-6} In/In/Psi. Conversion of this unit creep data to hoop, vertical, and dome stress gives these values of stress loss in tendons:

Hoop - 5.5 Ksi
Vertical - 2.8 Ksi
Dome - 5.5 Ksi

A single creep loss figure of 400 x 10^{-6} in/in at 1500 psi (f_{cpi}) in the concrete is used throughout the structure. This results in a prestress loss of 11.8 ksi in the prestressing steel.

The value used for shrinkage loss represents only that shrinkage that could occur after stressing. Since the concrete is, in general, well aged at the time of stressing, little shrinkage is left to occur and add to prestress loss.

The value of relaxation loss is based on information furnished by the tendon system vendor, Inland-Ryerson Construction Products Company.

Frictional loss parameters for unintentional curvature (K) and intentional curvature (μ) are based on full scale friction test data. This data indicate actual values of K = 0.0003 and μ = 0.125 versus the design values of K = 0.0003 and μ = 0.156.

Assuming that the jacking stress for the tendons is 0.8 f'_s or 192,000 psi and using the assumed prestress loss parameters, the following tabulation shows the magnitude of the design losses and the final effective prestress at end of 60 years for a typical dome, hoop, and vertical tendon. (NRC SE dated 12/2005, NUREG-1839)

	Dome (Ksi)	Hoop (Ksi)	Vertical (Ksi)
Jacking Stress	192	192	192
Friction Loss	18.5	20.8(1)	20.0
Seating Loss	0	0	0
Seating Stress	173.5	171.2	172.0

(1) Average of crossing tendons

	Dome (Ksi)	Hoop (Ksi)	Vertical (Ksi)
Elastic Loss	8.8	9.4	4.1
Creep Loss	11.8	11.8	11.8
Shrinkage Loss	3.0	3.0	3.0
Relaxation Loss	12.5	12.5	12.5
Final Effective Stress(2)	137.4	134.5	140.6

(2) This force does not include the effect of pressurization which increases the prestress force.

To provide assurance of achievement of the desired level of final effective prestress and that ACI 318-63 requirements are met, a written procedure was prepared for guidance of post tensioning work. The procedure provided nominal values for end anchor forces in terms of pressure gage readings for calibrated jack-gage combinations. Force measurements were made at the end anchor, of course, since that is the only practical location for such measurements.

The procedure required the measured temporary jacking force, for a single tendon, to approach but not exceed 850 kips ($0.8f'_s$). Thus, the limits set by ACI 318-63, Paragraph 2606(a)1, and of the prestressing system supplier, were observed. Additionally, benefits were obtained by in place testing of the tendon to provide final assurance that the force capability exceeded that required by design. During the increase in force, measurements were required of elongation changes and force changes in order to allow documentation of compliance with ACI 318-63, Paragraph 2621(e). The jacking force of $0.8f'_s$ further provided for a means of equalizing the force in individual wires of a tendon to establish compliance with ACI 318-63, Paragraph 2621(b). The procedures required compliance with ACI 318-63 such that if broken wires resulted from the post-tensioning sequence, compliance with Paragraph 2621(d) was documented. Each of the above procedures contributed to assurance that the desired level of final effective prestress would be achieved.

The requirements of ACI 318-63, Paragraph 2606(a)2 state that f_s should not exceed $0.7f'_s$ for "post-tensioning tendons immediately after anchoring."

Paragraph 2606(a)2 of ACI 318-63 refers to "tendons" rather than to an individual tendon. Further, the paragraph does not refer to the location to be considered for the determination of fs in the manner, for example, of the "temporary jacking force" referred to in Paragraph 2606(a)1. Two interpretations were therefore required. Both interpretations had to consider the effect of the resultant actions on both the prestressing system and structure.

The first interpretation was that the location for measurement of the seating force used in calculating f_s was at the end anchor and just subsequent to the measurement of the "temporary jacking force" referred to in Paragraph 2606(a)1. The advantages of this location are several. One is that it is a practical one and thus the possibility for achieving valid measurements could be made without the added complexity of additional measuring devices. Another advantage is that measurements at this location provide assurance that the calculated f_s does not anywhere exceed the maximum fs ($0.8f'_s$) to which that tendon has been subjected.

One case considered was that of anchoring each tendon at a measured force of 850 kips ($0.8f'_s$). Although there was no apparent detrimental effect to the prestressing system or structure, insertion of shims would be almost impossible. Further, it was concluded that this case would not establish compliance with ACI 318-63.

The case adopted was to seat each tendon with a measured "pressure" reading for the jack, at "lift-off" of the end anchor, of 775 kips (between 0.72 and 0.73 f'_s). This procedure had several advantages.

One advantage was that the force on the containment and the tendon was within the bounds of those for which it had been tested and resulted in no known detrimental effects. The second advantage was that the stressing procedure was simplified since the stressing crews did not have to accommodate a large number of different anchoring force requirements. The third advantage was that, at the completion of stressing the last tendon, the expected losses were such that the average f_s at the end anchors of the tendons would be less than $0.7f'_s$, thus establishing compliance with ACI 318-63, Paragraph 2606(a)1 and 2. The fourth advantage was that the percentage loss of prestressing force was less than would be the case if the tendons were anchored in such a manner that the calculated value of f_s nowhere exceeded $0.7f'_s$.

The latter advantage deserves special mention since it plays a strong role in assuring that the final effective prestress equaled or exceeded the desired value. For example, if the f_s at anchorage of the tendons were $0.1f'_s$, the final effective prestress, neglecting relaxation for the moment, would be about 86% of the initial prestress. Clearly, the assurance (that the concrete creep and shrinkage losses have been properly accounted for) increases as the f_s for the anchored tendons and tendon increases. However, this design was committed to meeting the ACI 318-63 requirement and the anchorage force for the tendons was kept at or below $0.7f'_s$ in accordance with the interpretation described.

Miscellaneous Considerations

In various cases, it is the designer's decision to provide structural adequacy in excess of design criteria submitted in the PSAR. Those cases are as follows:

1. Section 5.1.2.2 requires a minimum of 0.15% bonded reinforcing steel in two perpendicular directions on the exterior faces of the wall and dome for proper crack control. Due to the cold weather exposure, a minimum of approximately 0.25% is provided.

2. Section 5.1.2.2 requires a minimum of 0.15% at cross section area bonded steel reinforcing (as stated above) for any location. At the base of the cylinder, the controlling design case requires 0.25% vertical reinforcing. As a result of pursuing the recommendation of the NRC Staff to further investigate current research on shear in concrete, several steps were taken:

    a. The work of Dr. Alan H. Mattock was reviewed and he was retained as a consultant on the implementation of the research being conducted under his direction. The criteria was updated in accordance with his recommendation.

    b. In addition to reviewing Dr. Mattock's work, the firm of T. Y. Lin, Kulka, Yang and Associate was consulted to review the detailed design of the cylinder to slab connection. Pursuant to their recommendation, approximately 0.5% reinforcing was used rather than the 0.25% reinforcing indicated by the detailed design analysis for the vertical wall dowels. This increase insures that there was sufficient flexural steel to place the section within the lower limits of Mattock's test data (approximately 0.3%) to prevent flexural cracking from adversely affecting the shear capability of the section.

5.1.2.5 QUALITY CONTROL

Quality Control of materials and construction during the construction phase is considered historical information, and is described in FFDSAR Section 5.1.2.5.

5.1.2.6 PENETRATIONS

Penetrations conform to the applicable sections of ASA N6.2-1965, "Safety Standard for the Design, Fabrication, and Maintenance of Steel Containment Structures for Stationary Nuclear Power Reactors." All personnel locks and the equipment access door conform in all respects to the requirements of ASME Section III Nuclear Vessels Code.

The basis for limiting strains in the penetration steel is the ASME Boiler and Pressure Vessel Code for Nuclear Vessels, Section III, Article 4, 1965, and, therefore, the penetration structural and leak tightness integrity is maintained. Local heating of the concrete immediately around the penetration will develop compressive stress in the concrete adjacent to the penetration and a negligible amount of tensile stress over a large area. The mild steel reinforcing added around penetrations distributes local compressive stresses for overall structural integrity.

Spare penetrations without process piping are not considered penetrations that require double barriers. The containment side weld provides the single ASME Section XI Class MC boundary.

Double barriers may consist of double gasketed or sealed joints as defined in the specific examples in the remainder of this section.

<u>Equipment Hatch</u>

An equipment hatch 15 ft. in diameter is provided as shown in Figure 5.1-5. The hatch is fabricated from steel and furnished with a double gasketed flange and bolted dished door. Equipment up to and including the size of the reactor vessel O ring seal can be transferred into or out of containment through this hatch.

Provision is made to allow test pressurization of the spaces between the double gaskets of the door flanges and the weld seam channels at the liner joint, hatch flanges, and dished door.

<u>Personnel Locks</u>

Two personnel locks are provided as shown on Figure 5.1-4 and Figure 5.1-5. One of these is for convenience access and penetrates the dished door of the equipment hatch. Each personnel lock is a double door, welded steel assembly. The locks are designed to withstand all containment design conditions with either or both doors closed and locked. Doors open toward the center of the containment and are thus sealed under containment pressure. The lock barrel may be pressurized to demonstrate its leak tightness without pressurizing the containment. The personnel lock was pneumatically shop tested for pressure and leakage. Quick acting type equalizing valves connect the personnel lock with the interior and exterior of the containment vessel for the purposes of equalizing pressure in the two systems when entering or leaving the containment. Each air lock door is provided with double gaskets to permit pressurization between the gaskets for leakage testing.

The two doors in each personnel lock are interlocked to prevent both being opened simultaneously and to ensure that one door is completely closed before the opposite door can be opened. Provision is made to permit by-passing the door interlocking system to allow doors to be left open during the plant cold shutdown. Each door lock hinge is designed to be capable of independent, three-dimensional adjustment to assist proper seating.

Operation of the lock is manual, that is, without power assist. Normal procedure requires personnel using the lock to close the door behind them. If a door is inadvertently left open, a person approaching the lock in the same direction may remotely close the open (far) door, thus permitting him to open the near door and travel through the lock in the normal manner.

Containment personnel airlock inner and outer doors are provided with alarms to remotely monitor the position of the containment airlock doors. The door alarms may be used to provide indication of personnel entry or to monitor the status of airlock door position for containment integrity.

Fuel Transfer Penetration

A fuel transfer penetration is provided in each containment structure for fuel movement between the refueling transfer canal and the spent fuel pool. The penetration consists of a 20 in. stainless steel pipe installed inside a 24 in. pipe. The inner pipe acts as the transfer tube and is fitted with a double gasketed Transfer Tube Closure assembly in the refueling canal and a standard gate valve in the spent fuel pool. This arrangement prevents leakage through the transfer tube in the event of an accident. The outer pipe is welded to the containment liner and provision is made by use of continuous leakchase channels for test pressurizing all welds essential to the integrity of the penetration during plant operation. Bellows expansion joints are provided on the pipes to compensate for any differential movement between the two pipes or other structures. Figure 5.1-20 shows a sketch of the fuel transfer tube.

Piping and Ventilation Penetrations

All piping and ventilation penetrations are of the rigid welded type and are solidly anchored to the containment wall, thus eliminating the need to use expansion bellows for containment barriers inside containment. All penetrations and anchorages are designed for the forces and moments resulting from operating condition or postulated pipe rupture. External guides and stops or increased pipe wall thickness are provided as required to limit motions, bending, and torsional moments to prevent rupture of the penetrations and the adjacent liner plate. Each penetration flued head or pipe cap inside containment and its connection to the piping are designed to withstand containment design basis accident pressure and temperature. Most mechanical penetration assemblies include test connections and pipe caps with or without expansion bellows outside containment for leak testing purposes. Penetration bellows and pipe caps outside containment are not considered part of the containment pressure boundary.

For typical details of piping penetrations, see Figure 5.1-2.

Electrical Penetrations

There are two general areas for electrical containment penetrations located approximately 38 ft. apart. Each one of the two areas contains one of the trains for engineered safeguards service and two of the four channels of instrumentation (for reactor protection and safeguards). Within each area, penetrations for safeguards or protection are located below the penetrations for nonessential services. In one of the general areas, the vertical clearance between penetrations for safeguards or protection and penetrations for nonessential services is 5 ft., except for one of the protection channels which has approximately 2 ft. clearance to the nonessential penetrations above. In the other area, vertical clearance is 14 ft. Outside the containment, safeguards or protection service penetrations load into two pipe tunnels where nonessential penetrations are located above the concrete tunnel ceilings.

The 38 ft. separation between the two areas will preclude propagation of fire from one to the other of the two general areas described above. Therefore, fire separation is provided between the penetrations for the two safeguards trains. Likewise, a 38 ft. separation is provided between the two pairs of penetrations serving reactor protection circuits. Separation between the two penetrations for one pair is by 3 ft. vertical clearance and for the other pair by 1 ft.

Electrical penetrations consist of carbon steel pipe canisters with stainless steel header plates welded to each end. Identical hermetically ceramic sealed multipin connectors are welded into both headers for all conductors rated less than 600 volts. High voltage conductors utilize single conductor hermetically sealed ceramic busings welded to both header plates. Thus, each canister affords a double barrier against leakage. A flange on each canister is welded to the penetration sleeve. Thermal conduction and radiation paths are sufficient to prevent damage to seals or conductors during field welding of the canisters to the containment liner.

The canister with two welded headers permits pressure and leakage tests to be performed simply and reliably both at the shop and after installation. A tap, convenient to the exterior of the containment, is provided for pressurizing the canister. The terminations of the conductors to the connectors inside the canisters are potted to protect against moisture.

Typical details are shown in Figure 5.1-3.

5.1.2.7 MISSILE PROTECTION

High pressure equipment, which is a potential source of missiles, is surrounded by barriers to prevent credible missiles from reaching the primary system, the containment liner, the secondary steam and feedwater piping, or the engineered safeguards system. Principal barriers against missiles are the reinforced concrete in biological shield and secondary shield walls surrounding the primary coolant loops. Supplementary barriers are provided to protect the liner plate from missiles which might be projected through openings in the secondary shield walls.

In addition, a missile shield located above the reactor vessel head is designed to block any missiles that could be generated by the control rod drive mechanisms. A reinforced concrete roof is provided above the pressurizer to prevent missiles from the pressurizer piping valves from reaching the containment liner plate or other metal structures and systems.

5.1.2.8 CONTAINMENT ACCESSIBILITY CRITERIA

The normal mode of operation is to have the containment completely closed whenever the reactor is not cold shutdown (at least 1% $\Delta k/k$ subcritical and the reactor coolant system temperature is less than or equal to 200°F) with nuclear fuel in place in accordance with Technical Specifications. Also, a containment carbon filter cleanup system consisting of roughing, high efficiency and carbon filters, and fans is designed to keep the radioactivity levels safe for personnel. During the emergency repair or inspection under hot shutdown or power conditions, radioactivity levels are continuously monitored to assure personnel safety and compartment access is limited accordingly.

For cooldown and shutdown entry, the containment vessel may be purged to reduce the concentration of radioactive gases and airborne particulates. This purge system is designed to reduce the radioactivity level to doses defined by 10 CFR 20 for a 40 hour occupational work week, within 2 to 6 hours after plant shutdown. However, this objective may not be achievable until containment purge is available after inboard blind flanges are removed. Since minimal fuel defects are expected for this particular reactor configuration, much less than the 1% fuel rod defects used for design, purging of the containment is normally accomplished in less than 2 hours. If necessary to ensure removal of particulate matter, the purged air can be passed through a high efficiency filter before being released to the atmosphere through the purge vent. The containment carbon filter system, as described above, is utilized as standby for cleanup purposes.

The primary reactor shield is designed so that access to the primary equipment would be limited by the activity of the primary system equipment and not the reactor. Specific conditions under which the containment equipment hatch or both doors of the personnel locks may be open are outlined in Technical Specifications.

5.1.2.9 Leak Chase Channels (LCC)

The leak chase channels which cover the containment liner welds are welded to the liner plate. These channels were not specifically addressed in the original liner plate analysis, were not intended to be vented to the containment, and were not vented during the early containment integrated leakage rate tests (CILRT). It was subsequently recognized that the requirement of 10 CFR Part 50 Appendix J to test the qualified leakage barrier may not have been strictly met during periodic Type A testing with the LCCs not vented. Additional analyses, tests and comparison to more recent ASME design codes were performed to demonstrate both structural and leaktight integrity of the LCC system. This additional information, as described below, formed the basis for the NRC's approval to continue Type A testing with the LCCs not vented (Reference 11).

Structural Analysis

Structural analyses of typical containment liner plate sections were performed to evaluate the severity of loading on leak chase channels (Reference 12). These analyses included investigation of internal forces, stresses, strains and displacements of the leak chase channels in the liner plate system and the assessment of the effect of the presence of the leak chase channels on the structural behavior of the liner plate system. The results of these analyses indicate that some of the leak chase channel sections in the cylindrical portion of the containment could sustain minor inelastic deformations when subjected to maximum design load conditions. The dome area leak chase channels, which are embedded in concrete, would also sustain some nonlinear deformation with a high factor of safety.

For analytical purposes, each leak chase channel section may be placed in one of two categories. In the first category, which is typical of the dome sections, the leak chase channel projects outward and interacts with the containment structure concrete when relative displacement occurs between the liner plate and the concrete. In the second category, all leak chase channel sections project inward and do not directly interact with the concrete.

The general approach for the first category, i.e., embedded channels, included definition of loads in terms of induced strains, load-deformation characteristics in both linear and nonlinear response ranges, development of a mathematical model and a parametric analysis of the system. Conventional structural analysis techniques are utilized with evaluations based on lower bound physical material properties. Because the loads in the liner plate leak chase channel system are predominantly a direct function of the relative strain between the liner plate and the containment structure concrete, the loads were redefined in terms of relative strain. The load combination includes dead load, differential pressure, accident pressure, seismic prestress, shrinkage, creep, operating thermal, and accident thermal loads.

Analytical results for embedded leak chase channels in concrete show that the lowest calculated safety factor is 11.3. The presence of the leak chase channels increases safety margins for other critical elements of the liner plate system.

In the analyses of the second category, the interior leak chase channel sections receive direct containment internal pressure load in addition to forced displacements due to the strain in the structural elements to which the leak chase channel members are attached. The axial stresses and strains of the leak chase channels are comparable to those of the support element in the axial direction of the channels. The forced lateral displacements induce internal forces and moments into the leak chase channel member cross section which responds to these displacements and to direct pressure loading essentially as a rigid frame with flexural continuity at corners and support points. Conventional structural analysis procedures were utilized in solving the frame models. Most leak chase channels were found to remain elastic. In cases where inelastic response was predicted, ductility ratios based on strain levels and plastic section strengths were calculated. The resulting maximum ductility ratio was found to be 1.94 which is well within acceptable range and is comparable to a safety factor based on displacement of about 22.

Load Deformation and Leak Tests

Testing was conducted to obtain the load-deformation characteristics of leak chase channels interacting with the liner plate and containment concrete and to verify the leak tight integrity of the leak chase channels under the severe load and deformation conditions imposed during testing (Reference 13).

The LCCs were pressurized to 70 psig internal pressure during the load tests. The tests demonstrated that the leak chase channels and the 3/16-inch double pass fillet welds retained their leaktight integrity throughout the test loading which produced lateral deformations in the 2-inch channel sections in excess of 0.149 inch.

For the composite tests (channels embedded in concrete), the shear resistance capacity was controlled by compressive failure of the concrete engaged by the leak chase channels. For the liner plate leak chase channel (steel only) tests, the capacity was limited by the flexural resistance of the 1/4-inch-thick liner plate. Although the sections sustained inelastic displacement in excess of 0.10 inch, no failures were observed in the channels or welds to the liner plate.

Code Comparison

While acknowledging that Point Beach was constructed prior to the implementation of the ASME Section III, Division 1, Subsection MC, the NRC staff required that the LCCs, as built, meet the intent of the Code. A comparison of the ASME code to the original design and construction codes was included in a summary report provided to the NRC (Reference 1). The summary report supports the conclusions that: 1) the channel welds are qualitatively equivalent to those for the primary containment liner welds as demonstrated by construction records, quality control measures, leak tests and inspection reports, and 2) the analyses and tests demonstrate that the leak chase channels, external or internal, are rugged components which will function as integral parts of the liner plate system, are capable of withstanding the loading conditions of both normal operation and design basis accidents, and will maintain their structural integrity at all times.

5.1.3 REFERENCES

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10. CAP01125324, “High Temperature Containment Penetrations,” April 10, 2008.

11. NRC Safety Evaluation, AC Nos. 63152 and 63153, “Containment Liner Leak Chase Channel Venting,” September 18, 1989.

12. “Evaluation of Containment Liner Plate Leak Chase System for Point Beach Nuclear Plant, Units 1 and 2,” by Bechtel Associates Professional Corporation, dated June, 1986.

13. “Test Report on Static Load Tests on Liner Plate Leak Chase Channel Assemblies,” by University of Michigan Department of Civil Engineering, dated December 1985.

14. NFPA 805 Fire Protection Program Design Document (FPPDD)

Table 5.1-1 CONTAINMENT STRUCTURE SUMMARY OF CONCRETE AND REINFORCING STEEL STRESSES

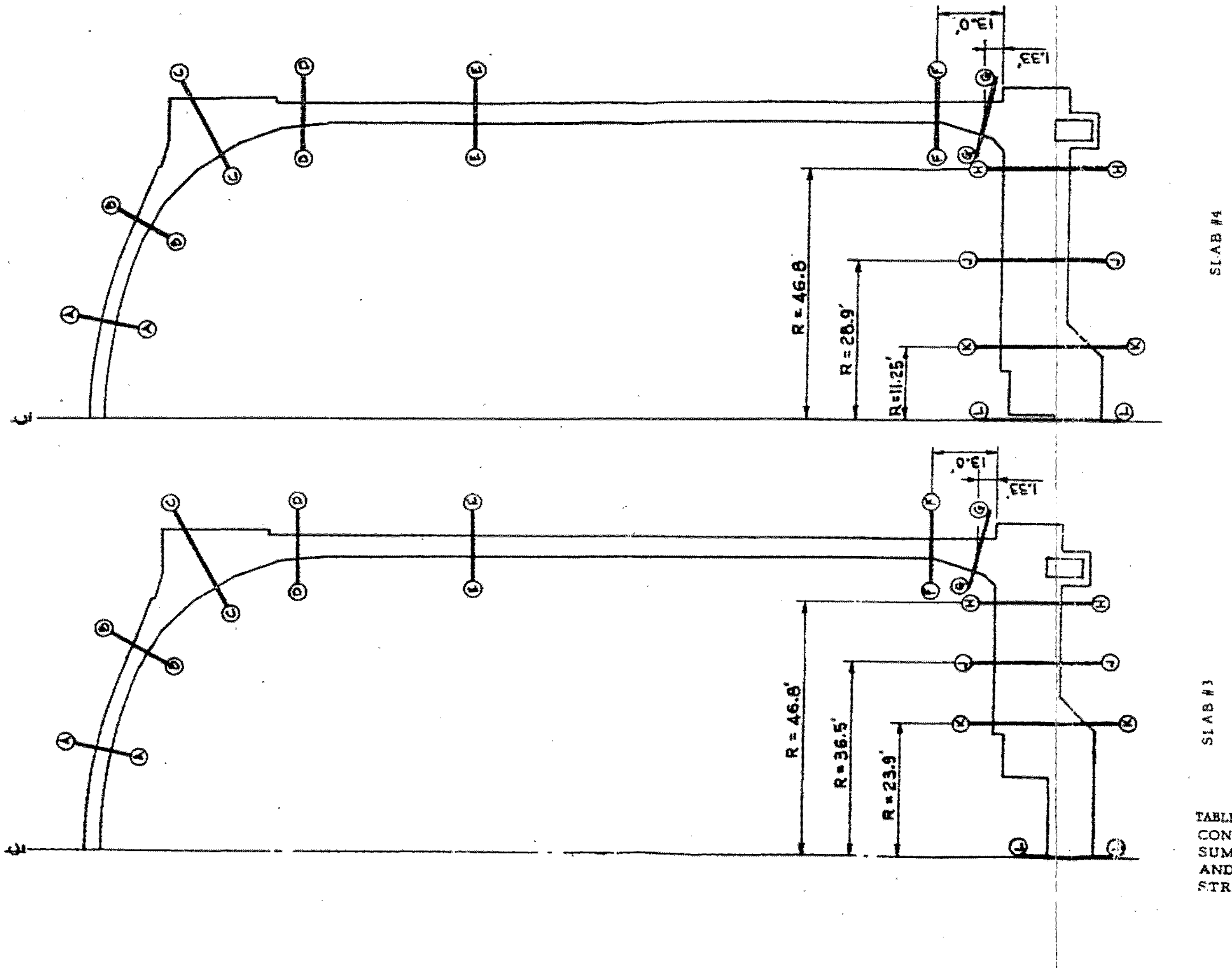


TABLE 5.1-1
CONTAINMENT STRUCTURE
SUMMARY OF CONCRETE
AND REINFORCING STEEL
STRESSES.

SHEET 1

Table 5.1-1(2A) CONTAINMENT STRUCTURE SUMMARY OF CONCRETE AND REINFORCING STEEL STRESSES

Structural Data

Location	p'_c-psi	Concrete t-in.	Type	Reinforcing Steel P_m-%	P_h-%
A-A	5000	36	A-15	0.07	0.07
A-A	5000	36	A-15	0.23	0.23
B-B	5000	60	A-15	0.09	0.09
B-B	5000	60	A-15	0.24	0.22
C-C	5000	148	A-432	-	-
C-C	5000	148	A-432	0.09	0.09
D-D	5000	50	A-432	0.11	-
D-D	5000	50	A-432	0.73	0.28
E-E	5000	42	A-15	-	-
E-E	5000	42	A-15	0.25	0.25
F-F	5000	42	A-15	0.25	0.25
F-F	5000	42	A-15	0.31	-
G-G	4000	78	A-432	0.29	0.20
G-G	4000	78	A-432	0.57	0.25
H-H	4000	110	A-432	0.22	0.12
H-H	4000	110	A-432	0.42	0.32
J-J	4000	138	A-432	0.17	0.10
J-J	4000	138	A-432	0.28	0.25
K-K	4000	150	A-432	0.17	0.09
K-K	4000	150	A-432	0.28	0.19
L-L	4000	84	A-432	0.19	0.19
L-L	4000	84	A-432	0.37	0.37

First line for each section refers to interior face containment structure, second line refers to exterior face.

Table 5.1-1(2B) CONTAINMENT STRUCTURE SUMMARY OF CONCRETE AND REINFORCING STEEL STRESSES

Notes

1. Loading Cases I, II, and IV are for Working Stress Analysis. Case III has been included for additional information. Cases V, VI, and VII are for Yield Stress Analysis.
2. The stresses shown are based on cracked section analysis unless noted by *.
3. Deviation in allowable stresses are in accordance with 5.1.2-2.
4. All concrete extreme fiber stresses ( ) are shown for the inside surface. Outside surface stresses are indicated by ( ). The stresses listed are the controlling stresses for that section.
5. Computed vs. allowable ratios for Cases V, VI, and VII include appropriate factors.
6. Allowable shear stresses include stirrups wherever applicable.

Notation

D	Dead Load
F	Prestress
P	Internal Pressure
E	Earthquake
E′	Earthquake
T_A	Accident Temperature
f_c	Ultimate Concrete Stress
f_y	Steel Rebar Yield Stress
f_a	Allowable Concrete Axial Stress
f_{ce}	Allowable Concrete Axial and Flexure Stress
ν	Allowable Concrete Shear Stress Including Stirrups if Applicable
f_s	Allowable Steel Stress
σ_a	Average Axial Stress, Thermal Effects Excluded
σ_e	Flexural Stress
σ Total	Sum of Membrane and Flexural Stresses
h	Subscript Indicating Hoop Direction
m	Subscript Indicating Meridional Direction
P_h	Hoop Steel Percentage
P_m	Meridional Steel Percentage
+	Tensile Stresses
-	Compressive Stresses
τ	Nominal Shear Stress: $\tau = \frac{V}{bd}$

Table 5.1-1(2C) CONTAINMENT STRUCTURE SUMMARY OF CONCRETE AND REINFORCING STEEL STRESSES

Allowable Stresses

Working Stress Design

Shell Concrete	f_a = 1500 psi
	f_{ce} = 3000 psi
Base Concrete	f_{ce} = 1800 psi
Steel A-15	f_s = 20,000 psi
Steel A-432	f_s = 30,000 psi

Yield Stress Design

Shell Concrete	$f_a = \phi_a f_c = (0.85)(5000) = 4{,}250$ psi
	$f_{cd} = \phi_{ce} f_c = (0.90)(5000) = 4{,}500$ psi
Base Concrete	$f_a = \phi_a f_c = (0.85)(4000) = 3{,}400$ psi
	$f_{ce} = \phi_{ce} f_c = (0.90)(4000) = 3{,}600$ psi
Steel	$f_s = \phi f_y = (0.90)(40{,}000) = 36{,}000$ psi
	$f_s = \phi f_y = (0.90)(60{,}000) = 54{,}000$ psi

Table 5.1-1(3) CONTAINMENT STRUCTURE SUMMARY OF CONCRETE AND REINFORCING STEEL STRESSES D & F INITIAL (STRESSES IN PSI) CASE I MESH #3 AND #4

	Meridional			Inside			Shear		
	σ Outside (psi)	σ Inside (psi)	σ Axial (psi)	σ Outside (psi)	σ Inside (psi)	σ Axial (psi)	τ (psi)	ν_{ci} (psi)	ν_{cw} (psi)
Section									
Shell	-802	-950	-840	-770	-833	-775	-96	1,140	619
F-F	-135	-1,123	-478	-77	-365	-237	-212	424	541
G-G									
Slab #4								ν_c (psi)	
H-H	+206	-440	-111	0	-198	-103	+96	214	
J-J	-60	-80	-71	-67	-56	-62	+21	162	
K-K	-72	-93	-76	-61	-67	-64	-35	169	
L-L	-29	-60	-49	-37	-69	-56	+2	122	
Slab #3									
J-J	-8	-135	-77	-31	-129	-84	23	132	
K-K	-31	-250	-69	-35	-159	-101	38	133	
L-L	+34	-79	-20	+27	-63	-16	5	122	

Allowable Concrete Stresses

Shell: f_a = 1500 psi, f_{ce} = 3000 psi Base: f_a = 1200 psi, f_{ce} = 1800 psi

Table 5.1-1(4A) CONTAINMENT STRUCTURE SUMMARY OF CONCRETE AND REINFORCING STEEL STRESSES MESH #4

	Concrete										Reinforcing Steel					
	Computed							Computed vs Allowable			Computed		Computed vs Allowable		Liner Plate	
Load Case	σ_{em}	σ_{eh}	σ_{am}	σ_{ah}	Total σ_m	Total σ_h	τ	Total $\frac{\sigma}{f_{ce}}$	$\frac{\sigma_a}{f_a}$	$\frac{\tau}{v}$	σ_m	σ_h	$\frac{\sigma_m}{f_s}$	$\frac{\sigma_h}{f_s}$	σ_m	σ_h
Section F-F																
I D+F+1.15P	-88*	-11*	-297	-348	-385	-359	+8	0.128*	0.232	0.039					-2,720	-4,780
II D+F+T_A	-1,721	-1,251	-720	-665	-2,441	-1,916	-120	0.814	0.480	0.219	12,085	10,530	0.403	0.351	-49,910	-43,450
III D+F+P+T_A	-1,064	-883	-334	-332	-1,398	-1,215	-24	0.470	0.223	0.119	9,220	13,450	0.461	0.673	-33,940	-36,150
IV D+F+P+T_A+E	-1,130	-793	-397	-309	-1,527	-1,102	-27	0.509	0.166	0.130	13,285	15,060	0.443	0.502	-35,550	-33,390
V 1.05+F+1.5P+T_A	-303	-282	-138	-186	-441	-468	+20	0.104	0.044	0.086	10,800	17,840	0.300	0.495	-22,950	-27,525
VI 1.05D+F+1.25P+1.25E+T_A	-1,066	-792	-315	-229	-1,381	-1,021	-5	0.308	0.074	0.023	12,060	14,180	0.335	0.393	-33,820	-33,750
VII 1.05D+F+P+E′+T_A	-1,195	-703	-460	-285	-1,655	-988	-30	0.368	0.108	0.140	17,350	6,670	0.482	0.463	-37,160	-30,630
Section G-G																
I D+F+1.15P	+37*	-13*	-183	-155	(-146)	-168	-40	0.093*	0.122	0.1.54	-	-	-	-	-500	-2,850
II D+F+T_A	-1,294	-954	-410	-203	-1,704	-1,157	-216	0.950	0.274	0.532	25,420	26,930	0.847	0.898	-40,730	-36,690
III D+F+P+T_A	-698	-423	-213	-161	-911	-584	-95	0.507	0.142	0.300	8,100	21,400	0.270	0.713	-28,230	-29,820
IV D+F+P+T_A+E	-787	-339	-255	-118	-1,042	-457	-108	0.580	0.106	0.295	9,105	26,675	0.303	0.889	-30,472	-28,595
V 1.05D+F+1.5P+T_A	-65	-328	-115	-140	-180	-468	-34	0.130	0.027	0.103	2,030	17,700	0.037	0.328	-19,280	-28,560
VI 1.05D+F+1.25P+1.25E+T_A	-628	-231	-242	-96	-870	-327	-85	0.242	0.057	0.223	5,600	26,000	0.104	0.480	-25,835	-27,100
VII 1.05D+F+E′+P+T_A	-876	-254	-296	-74	-1,172	-328	-120	0.326	0.070	0.289	10,110	31,950	0.174	0.591	-32,715	-27,370
Section H-H																
I D+F+1.15P	0	-72	+52	-31	+52	-103	-68	0.057	LIMIT	0.326	3,200	3,000	0.107	0.100	+600	-1,460
II D+F+T_A	-799	-424	-95	-88	-894	-512	+77	0.498	fa	0.486	18,050	9,350	0.602	0.312	-14,060	-8,750
III D+F+P+T_A	-372	-397	-60	-68	-432	-465	-53	0.258	DOES	0.337	7,800	11,000	0.260	0.367	-7,560	-7,990
IV D+F+P+T_A+E	-447	-242	-40	-9	-487	-251	-127	0.271	NOT	0.816	11,850	20,900	0.395	0.697	-8,410	-5,950
V 1.05D+F+1.5P+T_A	-120	-368	-12	-43	-132	-411	-118	0.114	APPLY	0.437	3,100	12,000	0.057	0.222	-3,900	-7,490
VI 1.05D+F+1.25P+1.25E+T_A	-295	-380	-11	+24	-306	-356	-178	0.099	HERE	0.690	11,500	25,500	0.213	0.472	-6,320	-7,340
VII 1.05D+F+E′+P+T_A	-521	-87	-20	+51	-541	-36	-201	0.150		0.779	15,900	30,800	0.294	0.570	-9,260	-3,910

Table 5.1-1(4B) CONTAINMENT STRUCTURE SUMMARY OF CONCRETE AND REINFORCING STEEL STRESSES MESH #4

	Concrete										Reinforcing Steel					
	Computed							Computed vs Allowable			Computed		Computed vs Allowable		Liner Plate	
Load Case	σ_{em}	σ_{eh}	σ_{am}	σ_{ah}	Total σ_m	Total σ_h	τ	Total $\frac{\sigma}{f_{ce}}$	$\frac{\sigma_a}{f_a}$	$\frac{\tau}{v}$	σ_m	σ_h	$\frac{\sigma_m}{f_s}$	$\frac{\sigma_h}{f_s}$	σ_m	σ_h
Section J-J																
I D+F+1.15P	-338	-411	-2	-8	-340	-419	-23	0.232		0.212	14,100	20,400	0.470	0.680	-4,500	-5,400
II D+F+T_A	-409	-181	-61	-53	-470	-242	+11	0.261		0.104	3,640	3,326	0.121	0.111	-6,900	-5,370
III D+F+P+T_A	-535	-475	-62	-24	-597	-499	-25	0.332		0.234	11,800	15,000	0.393	0.500	-9,380	-8,870
IV D+F+P+T_A+E	-781	-366	-43	+6	-823	-360	-32	0.457		0.303	20,900	23,650	0.697	0.788	-12,400	-7,585
V 1.05+F+1.5P+T_A	-641	-617	-37	-4	-678	-621	-43	0.189		0.244	19,200	23,800	0.355	0.440	-10,550	-10,510
VI 1.05D+F+1.25P+1.25E+T_A	-917	-427	-40	+6	-957	-421	-43	0.266		0.249	26,300	31,300	0.486	0.580	-14,200	-8,600
VII 1.05D+F+P+E′+T_A	-1,027	-257	-23	+35	-1,050	-222	-39	0.293		0.255	30,000	32,300	0.555	0.598	-15,420	-6,300
Section K-K																
I D+F+1.15P	-397	-242	-18	-3	-415	-245	-25	0.230	LIMIT	0.231	15,400	11,000	0.513	0.367	-5,300	-3,300
II D+F+T_A	-541	-117	-65	-55	-606	-172	-19	0.344	DOES	0.179	2,340	4,658	0.095	0.155	-10,320	-3,140
III D+F+P+T_A	-1,143	-388	-176	+87	-1,319	-301	-15	0.734	NOT	0.141	15,930	22,600	0.531	0.753	-17,890	-5,170
IV D+F+P+T_A+E	-1,318	-449	-170	+100	-1,488	-349	-37	0.926	APPLY	0.350	20,155	25,540	0.672	0.851	-20,245	-6,015
V 1.05D+F+1.5P+T_A	-1,412	-571	-155	+110	-1,567	-461	-13	0.436	HERE	0.075	25,750	29,400	0.477	0.544	-21,430	-7,650
VI 1.05D+F+1.25P+1.25E+T_A	-1,622	-567	-157	+114	-1,779	-453	-42	0.495		0.242	25,130	30,100	0.465	0.557	-24,330	-7,600
VII 1.05D+F+E′+P+T_A	-1,493	-510	-165	+114	-1,658	-396	-59	0.460		0.341	24,380	28,480	0.451	0.527	-22,600	-6,860
Section L-L																
I D+F+1.15P	-179	-172	+99	+82	-80	-90	-18	0.050		0.017	4,900	4,600	0.060	0.053	-1,400	-1,600
II D+F+T_A	-378	-448	-42	-48	-420	-496	-11	0.276		0.104	5,767	5,965	0.192	0.199	-4,770	-12,300
III D+F+P+T_A	-465	-534	+13	-35	-452	-569	-29	0.311		0.270	6,600	6,500	0.220	0.216	-5,150	-12,770
IV D+F+P+T_A+E	-509	-566	+17	-33	-492	-599	-73	0.332		0.69	8,700	7,150	0.290	0.238	-6,085	-13,250
V 1.05D+F+1.5P+T_A	-410	-517	+75	+22	-335	-495	-38	0.138		0.220	9,400	9,200	0.174	0.171	-4,180	12,360
VI 1.05D+F+1.25P+1.25E+T_A	-575	-574	+49	-4	-526	-578	-89	0.161		0.515	10,200	9,000	0.189	0.166	-6,900	13,290
VII 1.05D+F+E′+P+T_A	-553	-597	+21	-30	-532	-627	-117	0.174		0.675	10,800	7,800	0.200	0.144	-7,020	13,730

Table 5.1-1(5) CONTAINMENT STRUCTURE SUMMARY OF CONCRETE AND REINFORCING STEEL STRESSES MESH #3

	Concrete										Reinforcing Steel					
	Computed							Computed vs Allowable			Computed		Computed vs Allowable		Liner Plate	
Load Case	σ_{em}	σ_{eh}	σ_{am}	σ_{ah}	Total σ_m	Total σ_h	τ	Total $\frac{\sigma}{f_{ce}}$	$\frac{\sigma_a}{f_a}$	$\frac{\tau}{\nu}$	σ_m	σ_h	$\frac{\sigma_m}{f_s}$	$\frac{\sigma_h}{f_s}$	σ_m	σ_h
Section J-J																
I D+F+1.15P	-240	-432	+13	-14	-227	-446	-53	0.250	LIMIT	0.500	8,760	22,640	0.292	0.755	-3,000	-5,900
II D+F+T_A	-430	-253	-61	-66	-491	-319	+8	0.273	fa	0.075	5,920	8,510	0.197	0.284	-8,400	-6,500
III D+F+P+T_A	-533	-522	-64	+1	-597	-521	-54	0.332	DOES	0.508	8,700	19,000	0.290	0.633	-9,150	-9,240
IV D+F+P+T_A+E	-749	-648	-39	+38	-788	-610	-61	0.437	NOT	0.577	14,000	29,850	0.467	0.995	-11,680	-9,720
V 1.05+F+1.5P+T_A	-565	-460	-32	+25	-597	-435	-86	0.166	APPLY	0.492	11,300	27,900	0.209	0.516	-9,260	-9,200
VI 1.05D+F+1.25P+1.25E+T_A	-825	-818	-31	+37	-856	-781	-79	0.238	HERE	0.456	17,000	40,400	0.315	0.747	-12,670	-10,500
VII 1.05D+F+P+E′+T_A	-965	-773	-15	+76	-980	-697	-68	0.272		0.393	19,300	40,700	0.357	0.754	-14,210	-10,200
Section K-K																
I D+F+1.15P	-559	-481	+6	-12	-553	-493	-78	0.307		0.74	27,100	18,170	0.903	0.602	-7,300	-6,300
II D+F+T_A	-682	-31	-56	-82	-738	-113	-49	0.410		0.460					-12,770	-4,650
III D+F+P+T_A	-1,276	-731	-112	+75	-1,388	-656	-80	0.770		0.757	26,560	25,700	0.885	0.856	-20,190	-9,250
IV D+F+P+T_A+E	-1,535	-732	-105	+123	-1,640	-609	-102	0.910		0.965	34,665	32,150	1.155	1.071	-23,605	-10,075
V 1.05D+F+1.5P+T_A	-1,568	-973	-85	+106	-1,653	-867	-100	0.460		0.578	36,590	40,300	0.678	0.746	-23,960	-13,000
VI 1.05D+F+1.25P+1.25E+T_A	-1,782	-853	-89	+123	-1,871	-730	-117	0.520		0.675	42,700	40,300	0.791	0.746	-26,900	-11,600
VII 1.05D+F+E′+P+T_A	-1,793	-732	-98	+171	-1,891	-561	-124	0.525		0.715	42,770	38,600	0.792	0.715	-27,020	-10,900
Section L-L																
I D+F+1.15P	-430	-418	+211	+144	-219	-274	-44	0.152		0.414	11,800	11,600	0.393	0.387	-3,300	-3,600
II D+F+T_A	-49	-207	-17	-37	-66	-244	-12	0.136		0.114	8,690	3,710	0.290	0.290	-3,700	-6,800
III D+F+P+T_A	-192	-262	+226	+146	+34	-166	-46	0.065		0.433	29,000	22,000	0.967	0.733	-4,000	-4,900
IV D+F+P+T_A+E	-283	-295	+230	+149	-53	-146	-90	0.081		0.85	31,350	22,750	1.045	0.758	-5,550	-5,450
V 1.05D+F+1.5P+T_A	-219	-322	+325	+225	+106	-97	-63	0.029		0.369	42,600	32,000	0.789	0.592	-5,000	-6,260
VI 1.05D+F+1.25P+1.25E+T_A	-338	-347	+298	+188	-40	-159	-110	0.042		0.635	38,700	29,200	0.716	0.540	-6,800	-6,450
VII 1.05D+F+E′+P+T_A	-347	-327	+234	+151	-140	-176	-134	0.049		0.774	33,700	23,500	0.624	0.435	-7,100	-6,000

Table 5.1-1(5) CONTAINMENT STRUCTURE SUMMARY OF CONCRETE AND REINFORCING STEEL STRESSES

Section	Load Case	Concrete Computed σ_{em}	Concrete Computed σ_{eh}	Concrete Computed σ_{am}	Concrete Computed σ_{ah}	Concrete Computed Total σ_m	Concrete Computed Total σ_h	Concrete Computed τ	Concrete Computed vs Allowable Total σ / f_{ce}	Concrete Computed vs Allowable σ_a / f_a	Concrete Computed vs Allowable τ / ν	Reinforcing Steel Computed σ_m	Reinforcing Steel Computed σ_h	Reinforcing Steel Computed vs Allowable σ_m / f_s	Reinforcing Steel Computed vs Allowable σ_h / f_s	Liner Plate σ_m	Liner Plate σ_h
Section Mesh #4																	
F-F	E	-66	+90	-63	+23	-129	+113	-3	0.043	0.042	n/a	4,065	1,610	0.135	0.053	-1,610	+2,760
G-G	E	-89	+84	-42	+43	-131	+127	-13	0.073	0.023	n/a	1,005	5,275	0.035	0.176	-2,242	+1,225
H-H	E	-75	+155	-20	+59	-95	+214	-74	0.013	n/a	n/a	4,050	9,900	0.135	0.330	-850	+2,040
J-J	E	-246	+109	+19	+30	-227	+139	-7	0.125	n/a	n/a	9,100	8,650	0.303	0.289	-3,020	+1,285
K-K	E	-175	-61	+6	+13	-169	-48	-48	0.092	n/a	n/a	4,225	2,960	0.141	0.099	-2,355	-845
L-L	E	-44	-32	+4	+2	-40	-30	-30	0.022	n/a	n/a	2,100	650	0.070	0.022	-935	-480
Mesh #3																	
J-J	E	-216	-126	+25	+37	-191	-89	-7	0.106	n/a	n/a	5,300	10,850	0.177	0.362	-2,530	-500
K-K	E	-259	-1	+7	+48	-252	+47	-22	0.140	n/a	n/a	8,105	6,450	0.270	0.215	-3,415	-825
L-L	E	-91	-33	+4	+3	-87	-30	-44	0.048	n/a	n/a	2,350	750	0.078	0.003	-1,550	-550

Table 5.1-2 TABLE OF LOADING CONDITIONS

Figure 5.1-11 Sheet 1	D + F initial - Mesh #3
Figure 5.1-11 Sheet 2	D + F + $T_{A\ eq}$ - Mesh #3
Figure 5.1-11 Sheet 3	D + F + T_A + 1.5P - Mesh #3
Figure 5.1-11 Sheet 4	D + F + 1.15P - Mesh #3
Figure 5.1-11 Sheet 5	D + F initial - Mesh #4
Figure 5.1-11 Sheet 6	D + F + T_A - Mesh #4
Figure 5.1-11 Sheet 7	D + F + 1.5P + T_A - Mesh #4
Figure 5.1-11 Sheet 8	D + F + 1.15P - Mesh #4

Figure 5.1-1 CONTAINMENT STRUCTURE - GENERAL ARRANGEMENT
Sheet 1

[redacted]

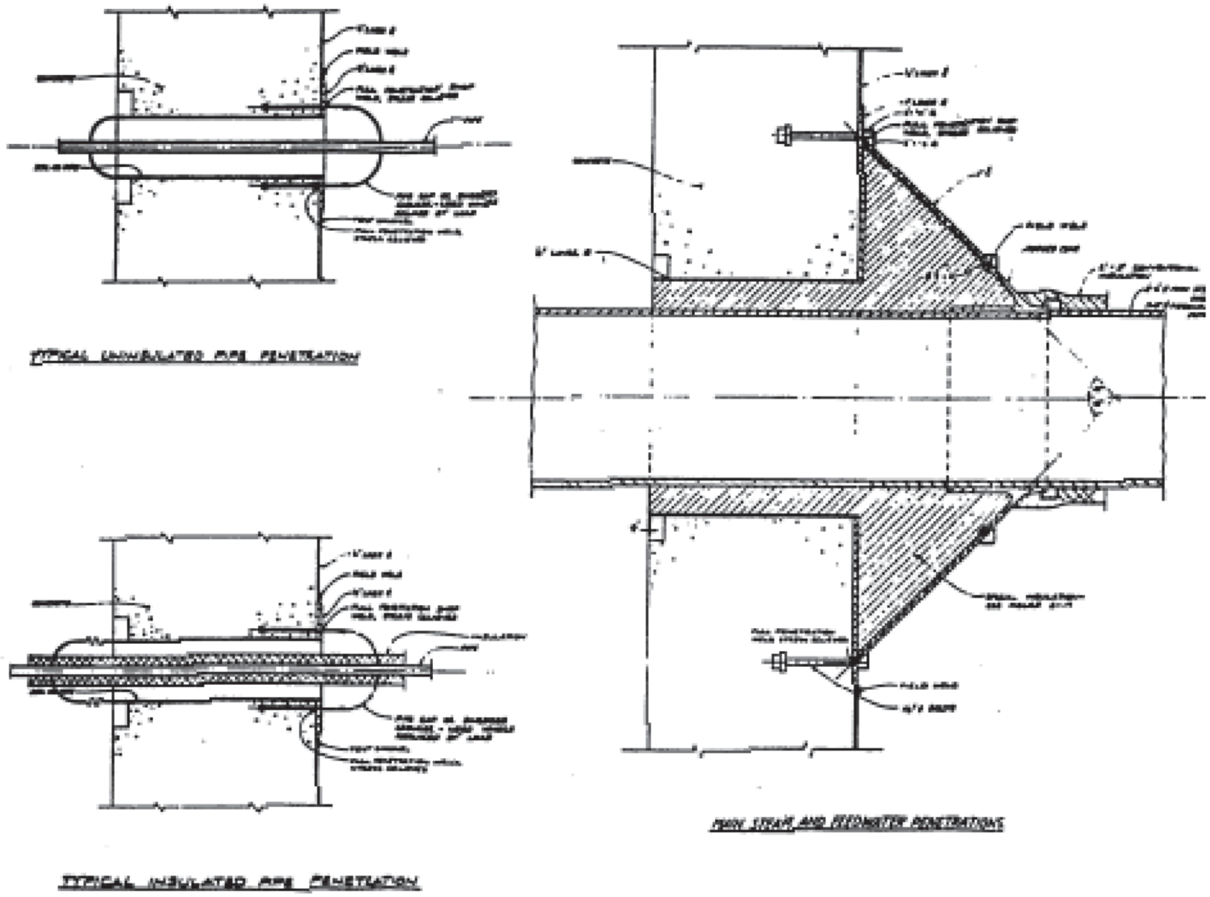
Figure 5.1-1 CONTAINMENT STRUCTURE - GENERAL ARRANGEMENT
Sheet 2

[redacted]

Figure 5.1-1 CONTAINMENT STRUCTURE - GENERAL ARRANGEMENT
Sheet 3

[redacted]

Figure 5.1-2 CONTAINMENT STRUCTURE - TYPICAL PIPING PENETRATIONS



CONTAINMENT STRUCTURE - TYPI

Figure 5.1-3 CONTAINMENT STRUCTURE - TYPICAL ELECTRICAL PENETRATIONS

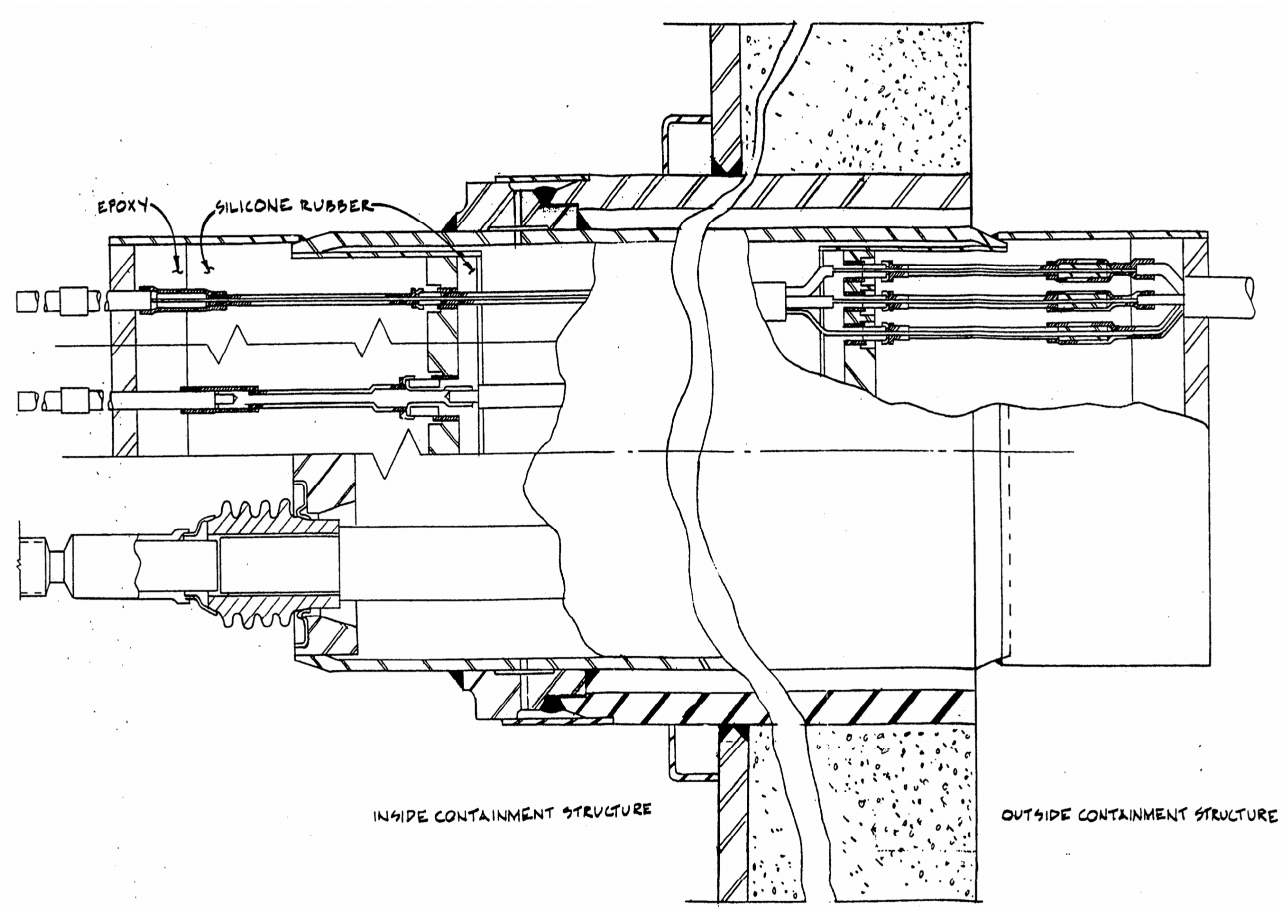


Figure 5.1-4 CONTAINMENT STRUCTURE - PERSONNEL LOCK

[redacted]

Figure 5.1-5 CONTAINMENT STRUCTURE - EQUIPMENT HATCH

[redacted]

Figure 5.1-6 DESIGN THERMAL GRADIENT ACROSS CONTAINMENT WALL
POINT BEACH NUCLEAR PLANT

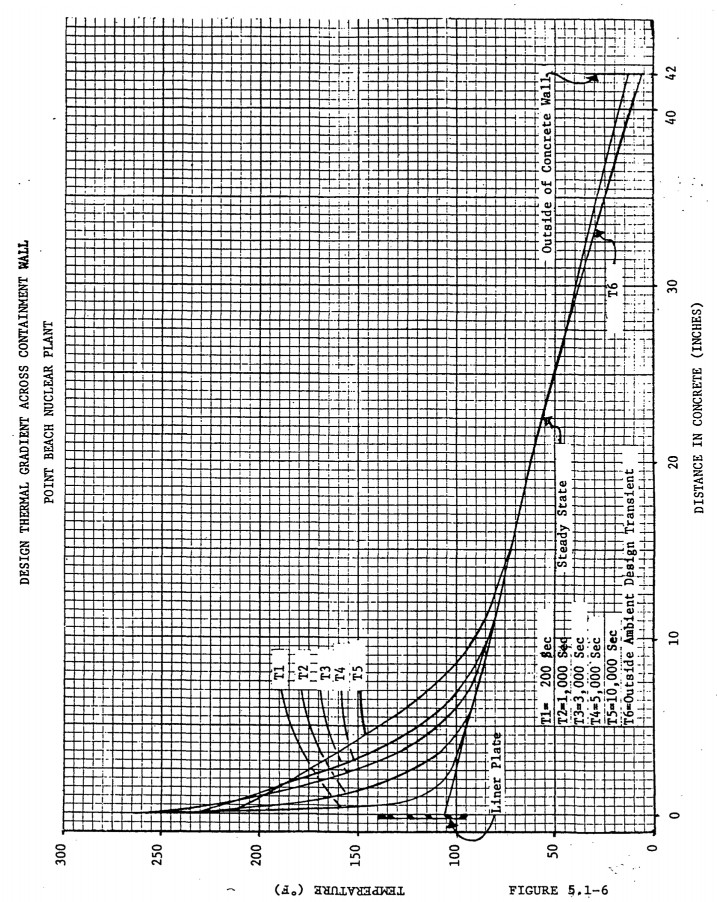


Figure 5.1-7 EARTHQUAKE RESPONSE SPECTRUM - 0.06g

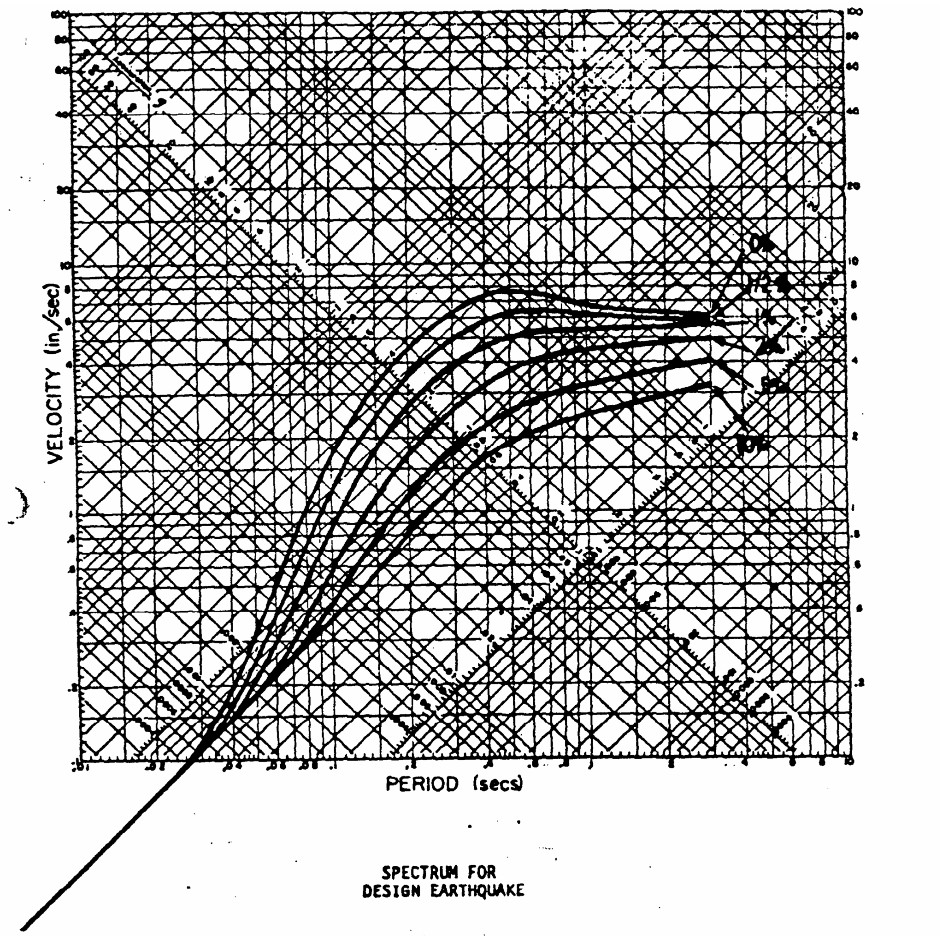
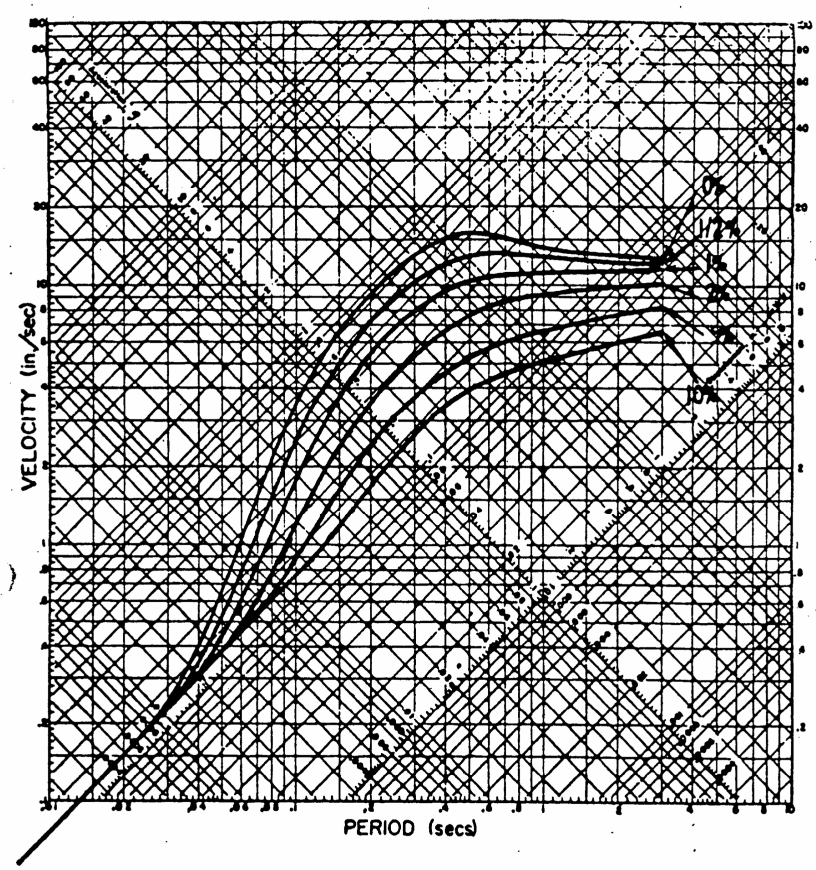
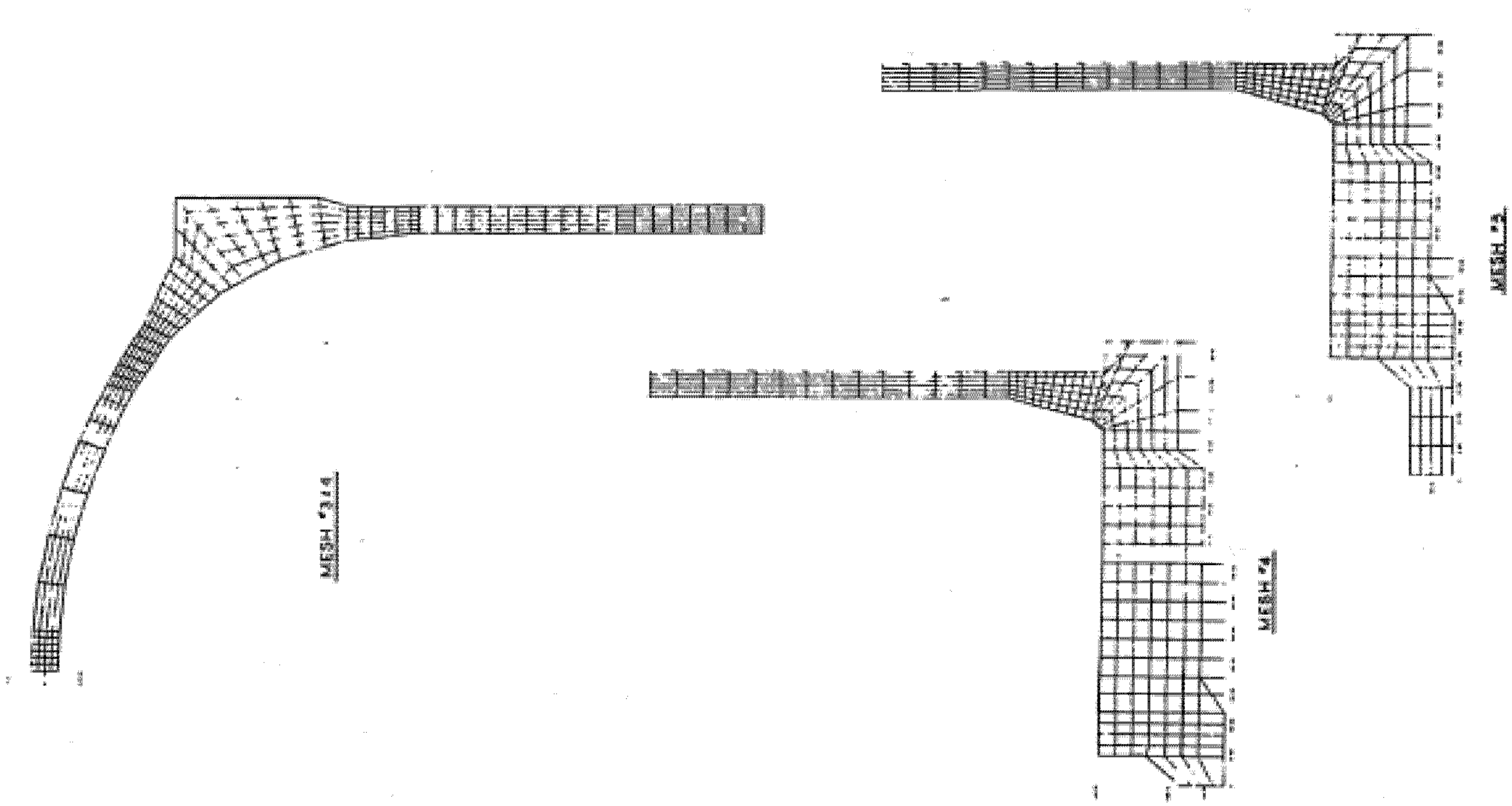


Figure 5.1-8 EARTHQUAKE RESPONSE SPECTRUM - 0.12g



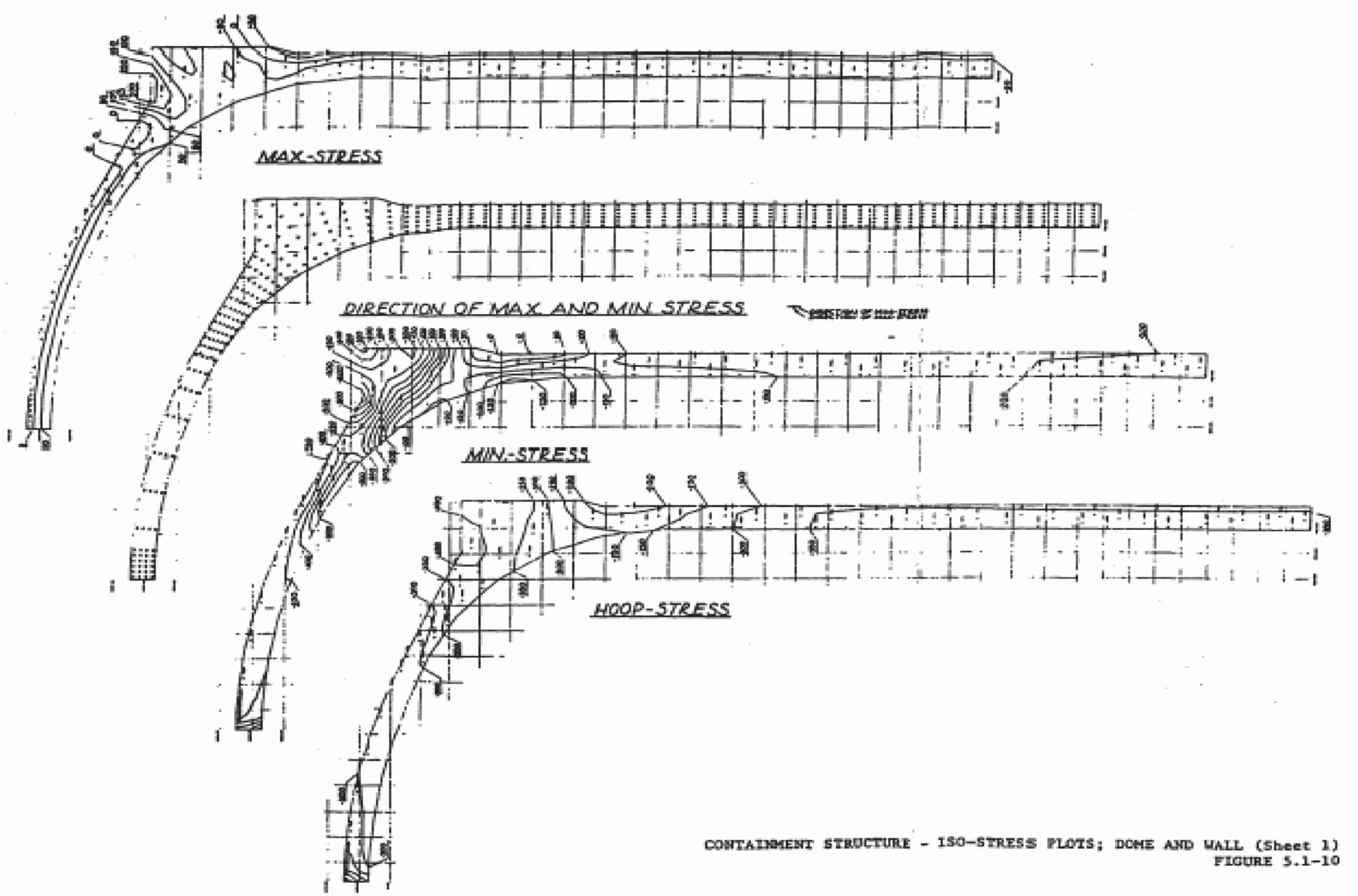
SPECTRUM FOR
HYPOTHETICAL EARTHQUAKE

Figure 5.1-9 CONTAINMENT STRUCTURE - FINITE ELEMENT MESH



CONTAINMENT STRUCTURE - FINITE ELEMENT MESH
FIGURE 5.1-9

Figure 5.1-10 CONTAINMENT STRUCTURE - ISO-STRESS PLOTS: DOME AND WALL
Sheet 1



CONTAINMENT STRUCTURE - ISO-STRESS PLOTS; DOME AND WALL (Sheet 1)
FIGURE 5.1-10

Figure 5.1-10 CONTAINMENT STRUCTURE - ISO-STRESS PLOTS: DOME AND WALL
Sheet 2

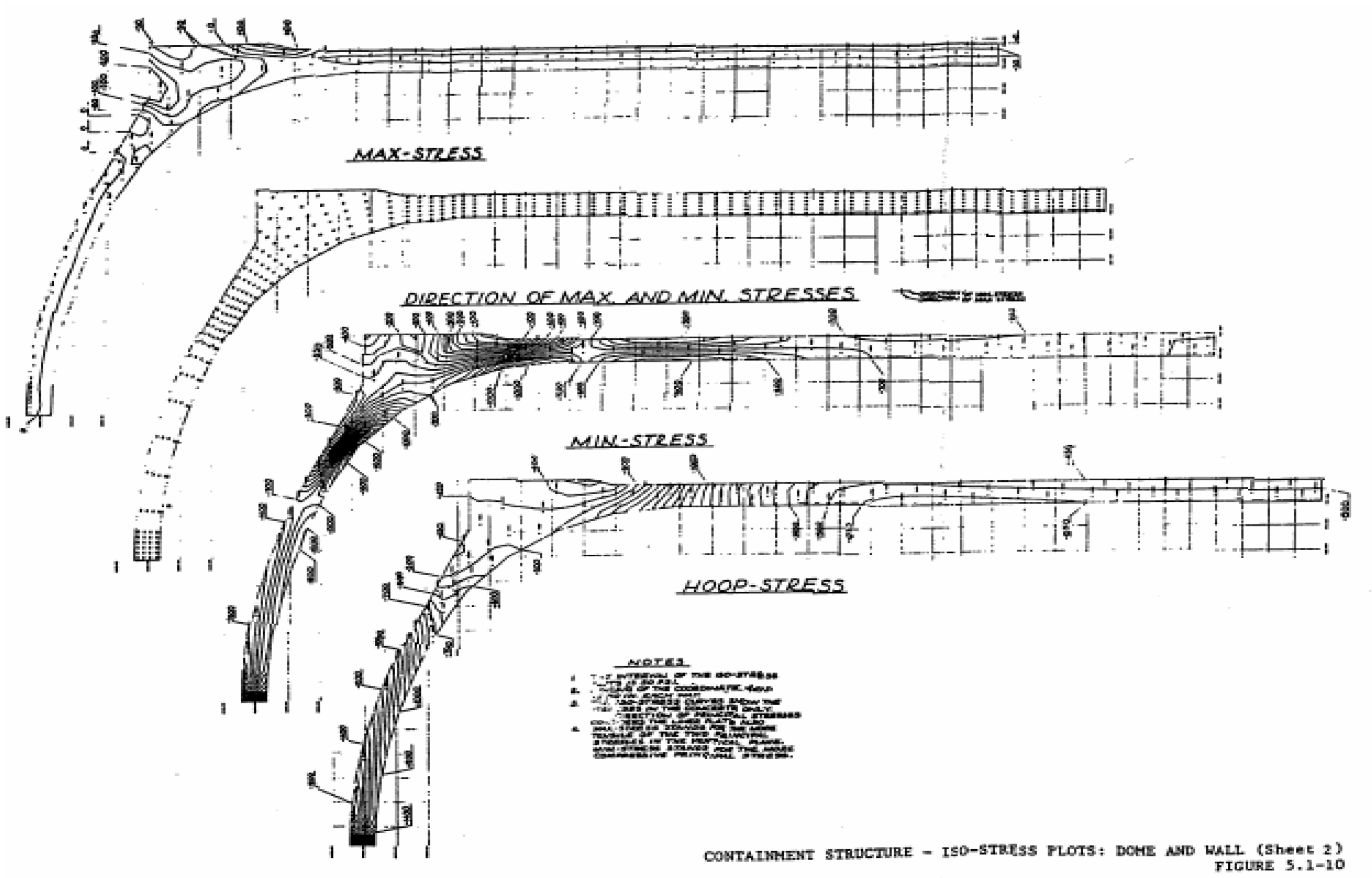
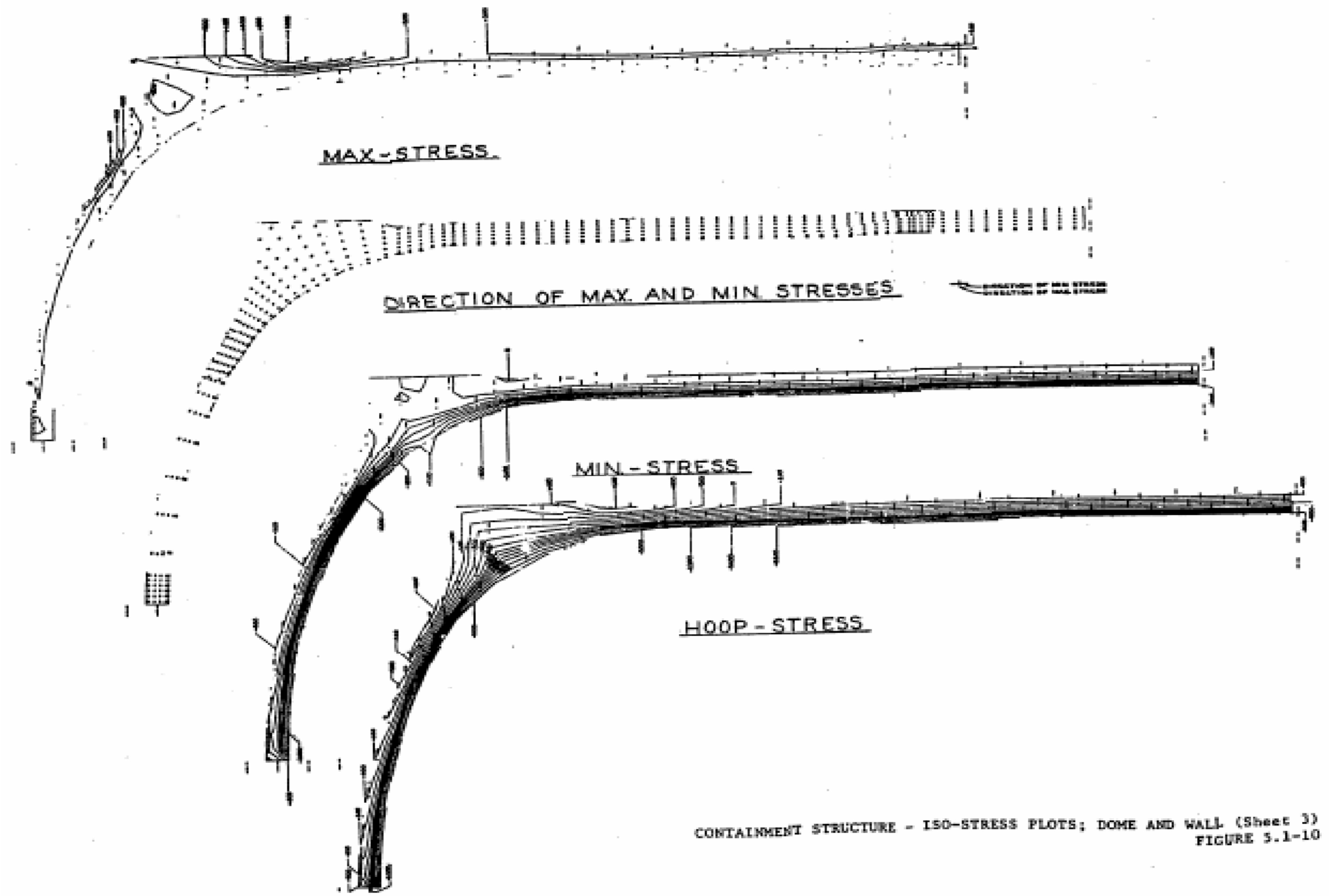


Figure 5.1-10 CONTAINMENT STRUCTURE - ISO-STRESS PLOTS: DOME AND WALL
Sheet 3



CONTAINMENT STRUCTURE - ISO-STRESS PLOTS; DOME AND WALL (Sheet 3)
FIGURE 5.1-10

Figure 5.1-10 CONTAINMENT STRUCTURE - ISO-STRESS PLOTS: DOME AND WALL
Sheet 4

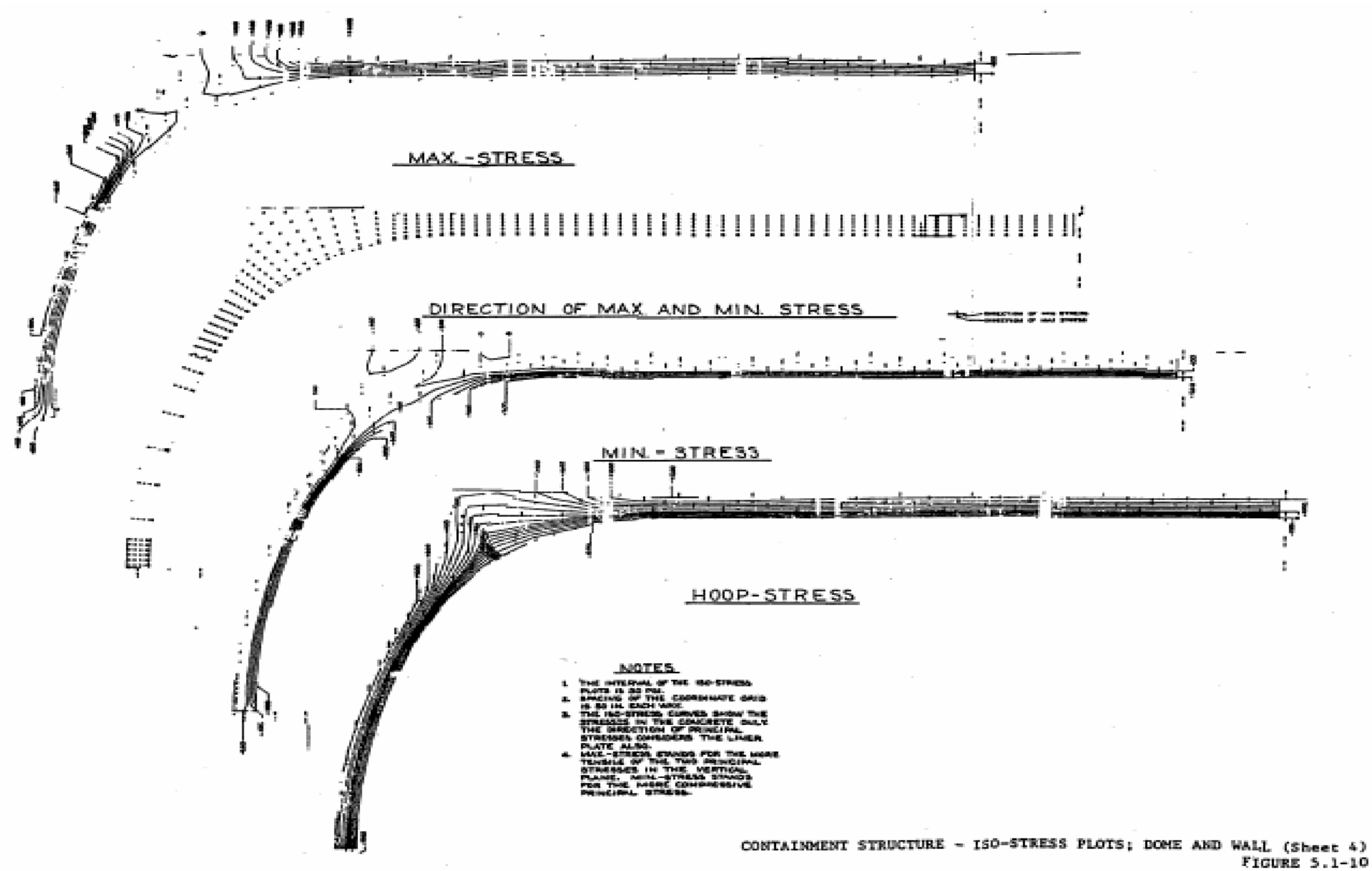


Figure 5.1-10 CONTAINMENT STRUCTURE - ISO-STRESS PLOTS: DOME AND WALL
Sheet 5

Table Of Loading Conditions

Figure	Loading
Figure 5.1-10 Sheet 1	D + F + 1.15P
Figure 5.1-10 Sheet 2	D + F initial
Figure 5.1-10 Sheet 3	D + F+ T_A
Figure 5.1-10 Sheet 4	D + F + T_A + 1.5P

Figure 5.1-11 CONTAINMENT STRUCTURE - ISO-STRESS PLOTS: BASE AND WALL
Sheet 1

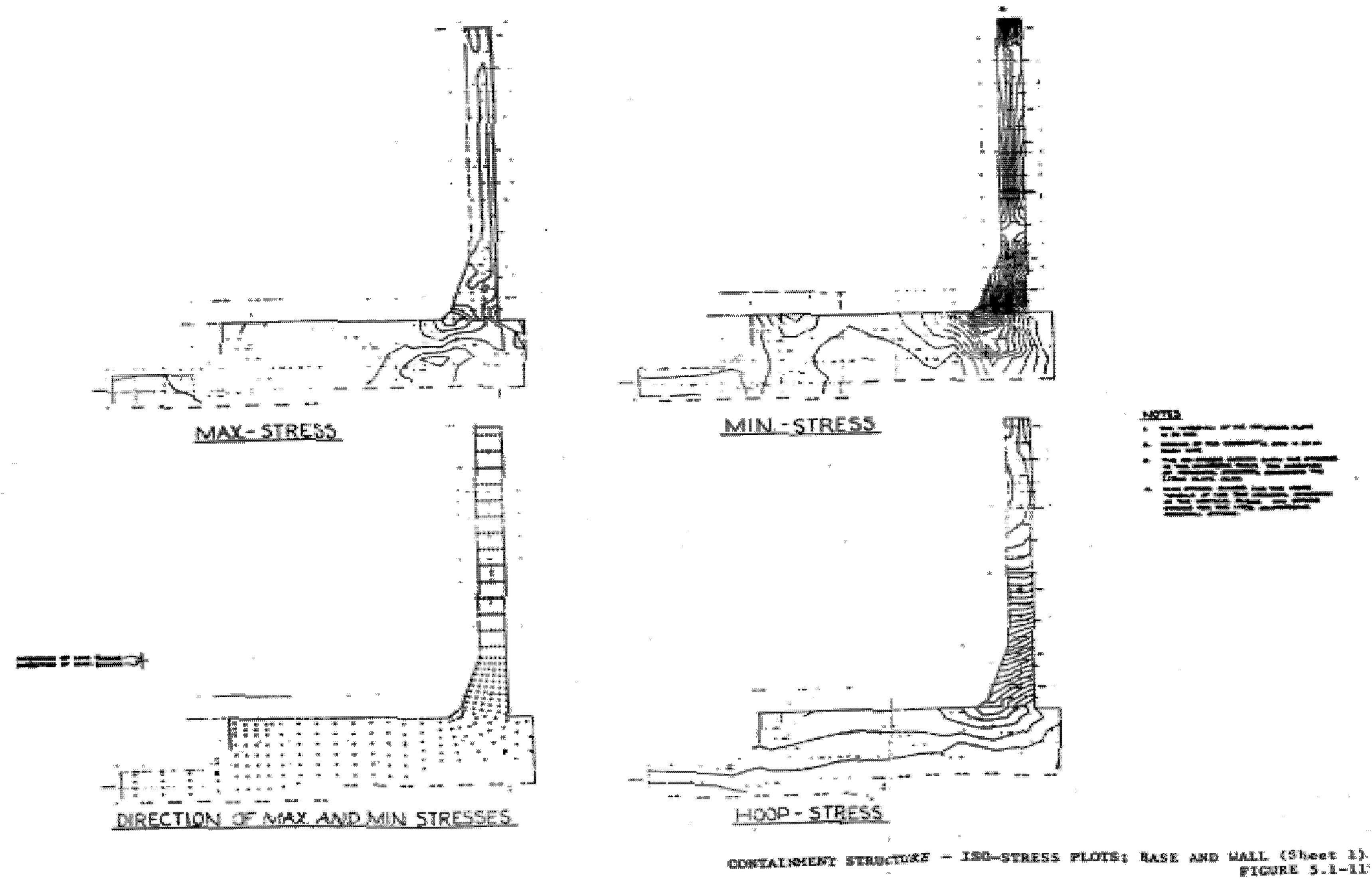


Figure 5.1-11 CONTAINMENT STRUCTURE - ISO-STRESS PLOTS: BASE AND WALL
Sheet 2

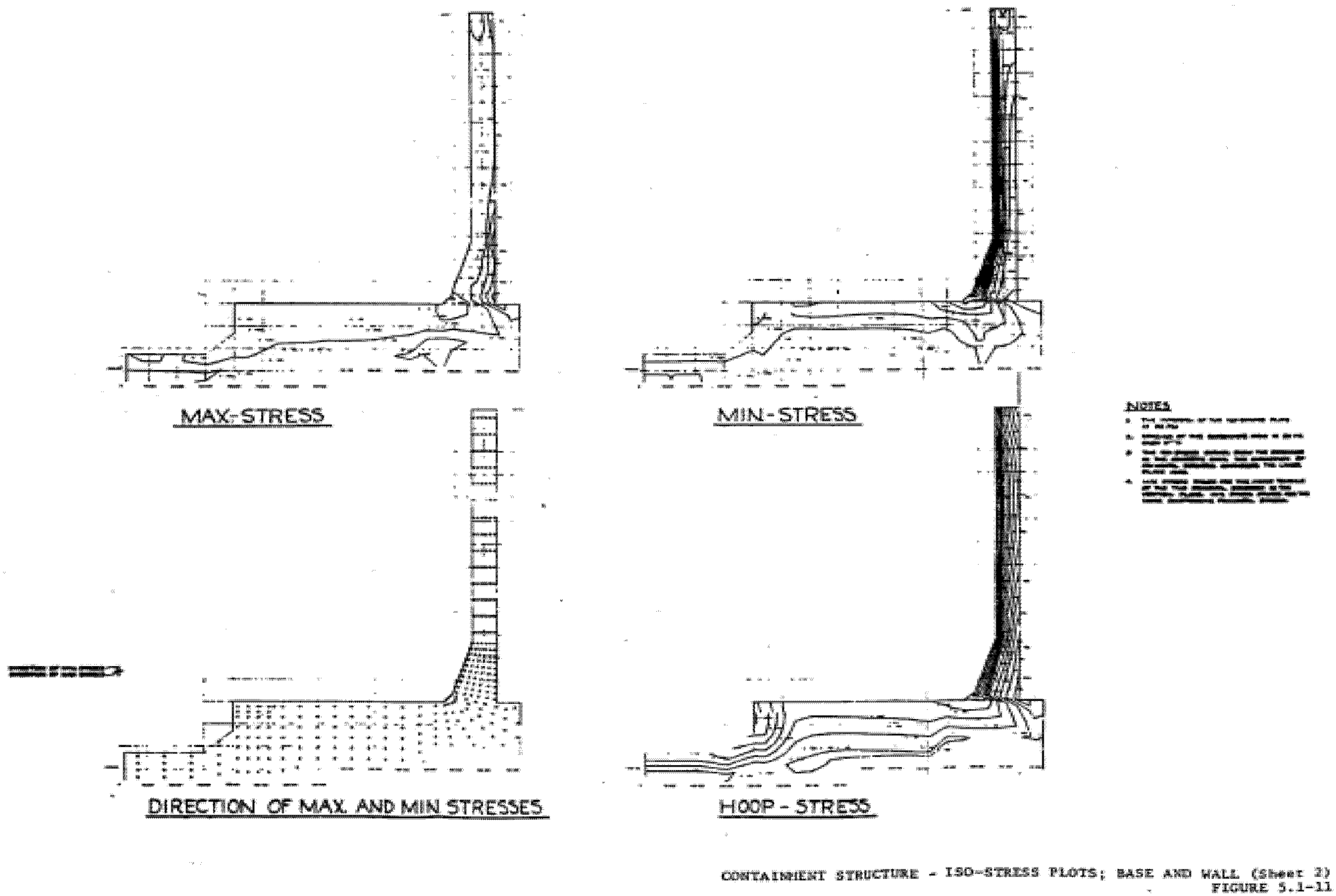


Figure 5.1-11 CONTAINMENT STRUCTURE - ISO-STRESS PLOTS: BASE AND WALL
Sheet 3

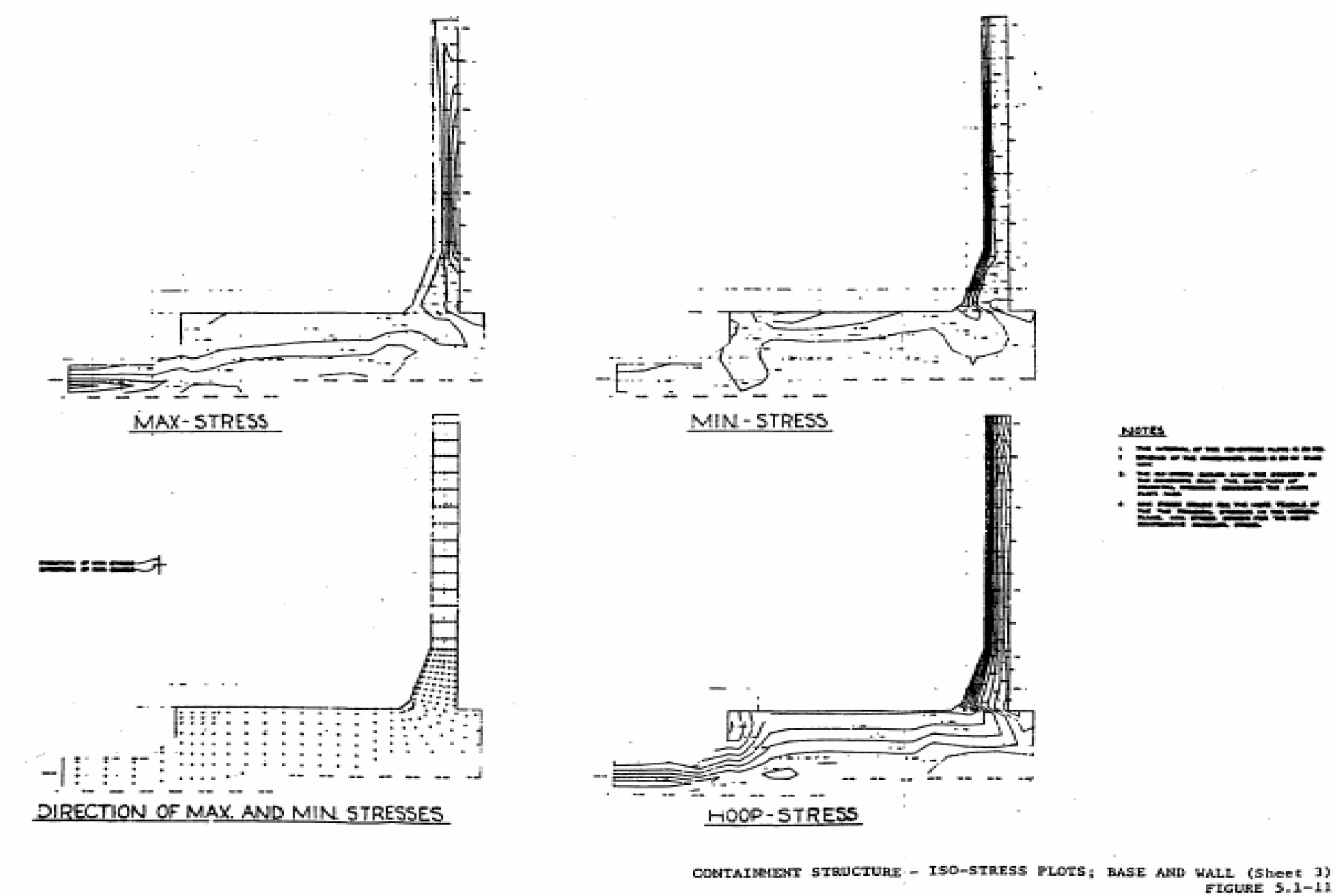
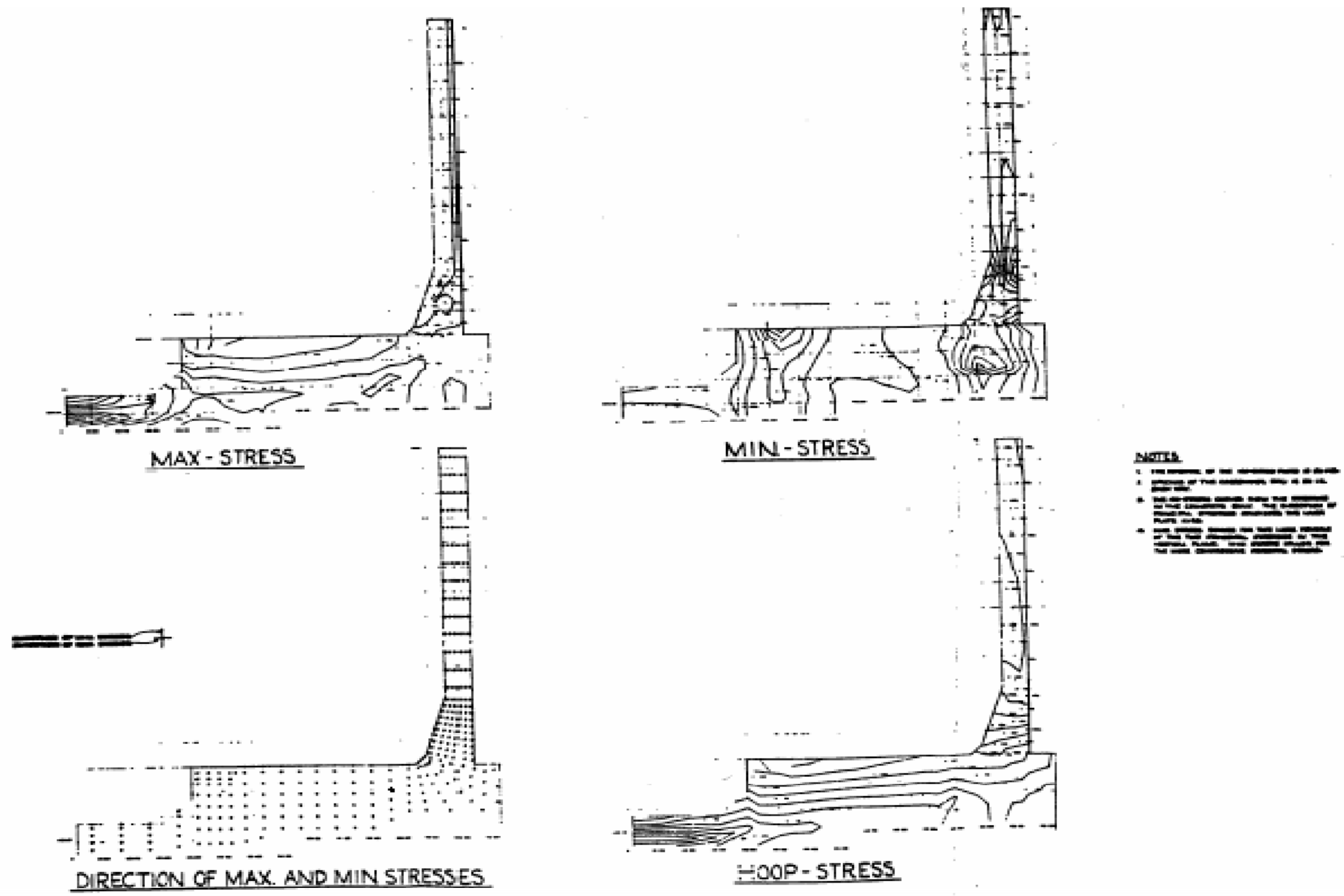
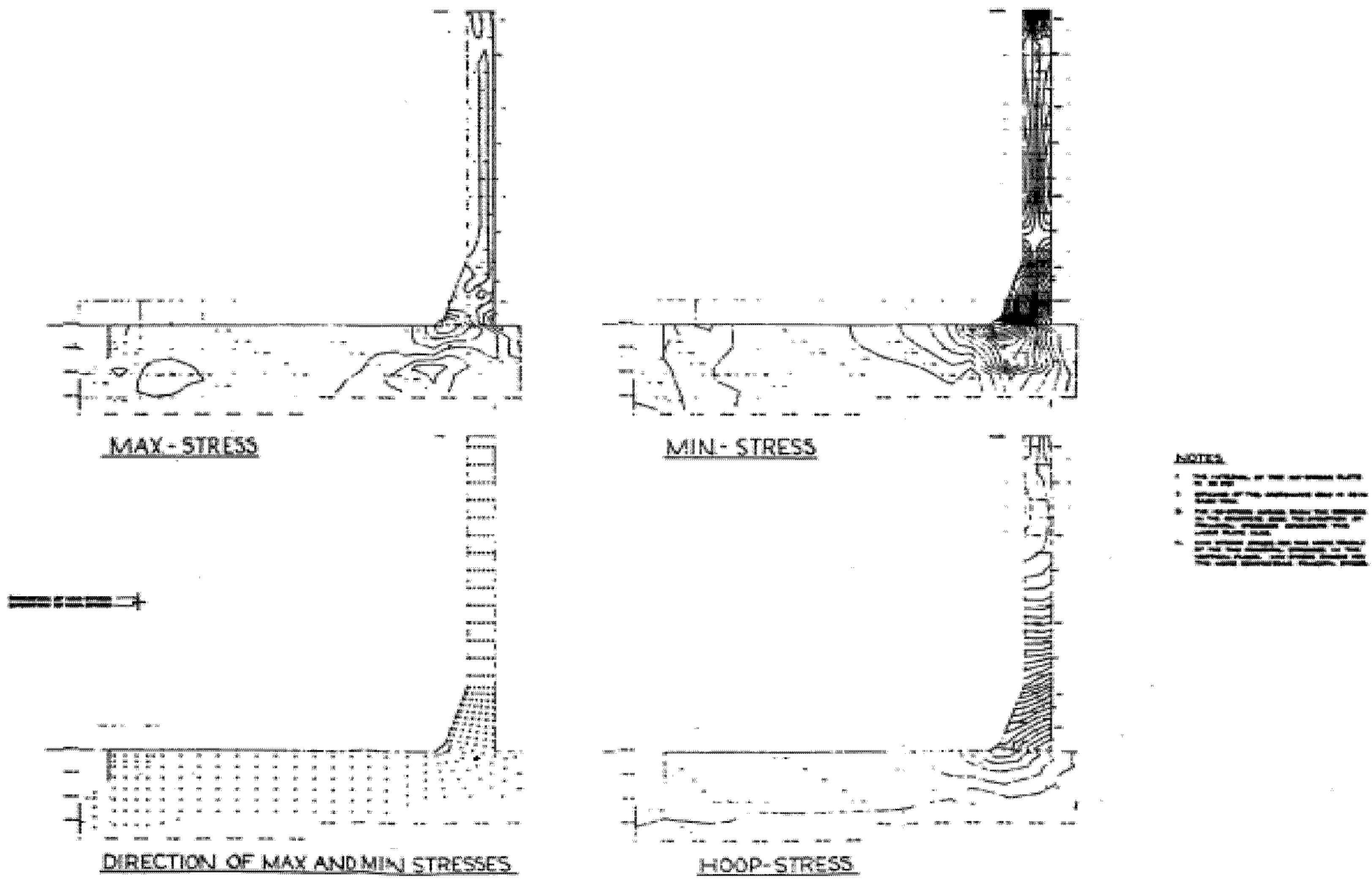


Figure 5.1-11 CONTAINMENT STRUCTURE - ISO-STRESS PLOTS: BASE AND WALL
Sheet 4



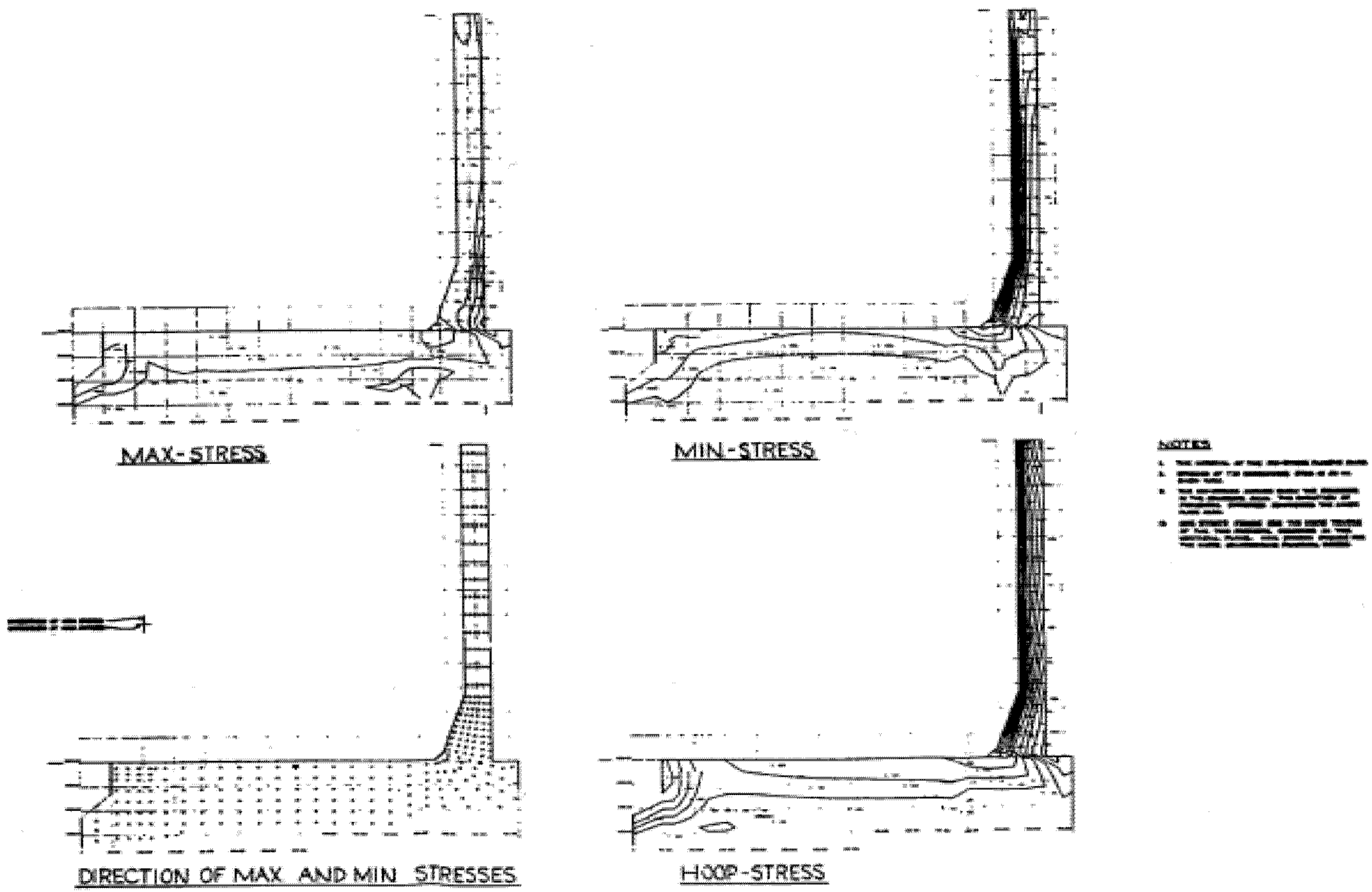
CONTAINMENT STRUCTURE - ISO-STRESS PLOTS; BASE AND WALL (Sheet 4)
FIGURE 5.1-11

Figure 5.1-11 CONTAINMENT STRUCTURE - ISO-STRESS PLOTS: BASE AND WALL
Sheet 5



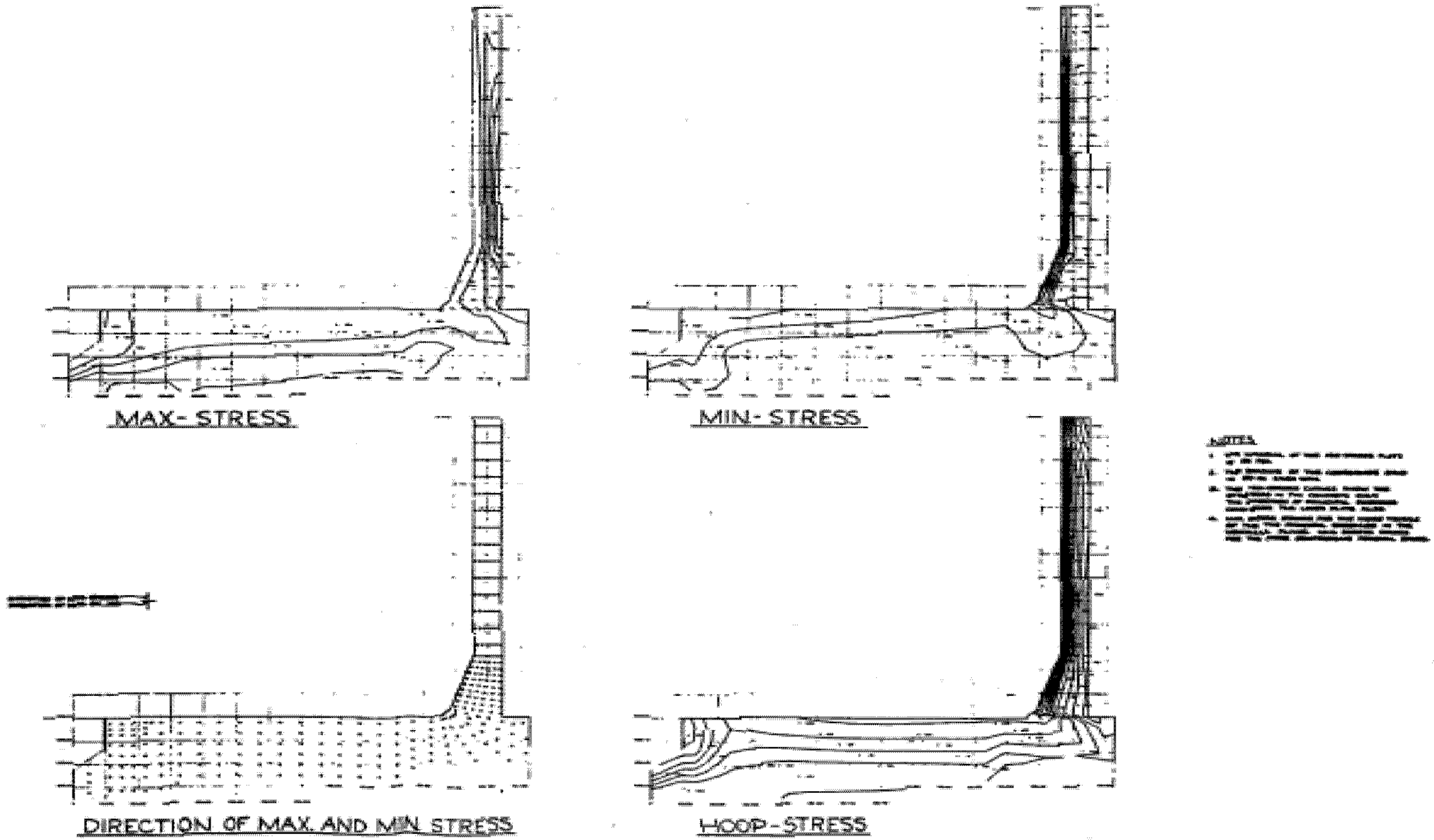
CONTAINMENT STRUCTURE - ISO-STRESS PLOTS; BASE AND WALL (Sheet 5)
FIGURE 5.1-11

Figure 5.1-11 CONTAINMENT STRUCTURE - ISO-STRESS PLOTS: BASE AND WALL
Sheet 6



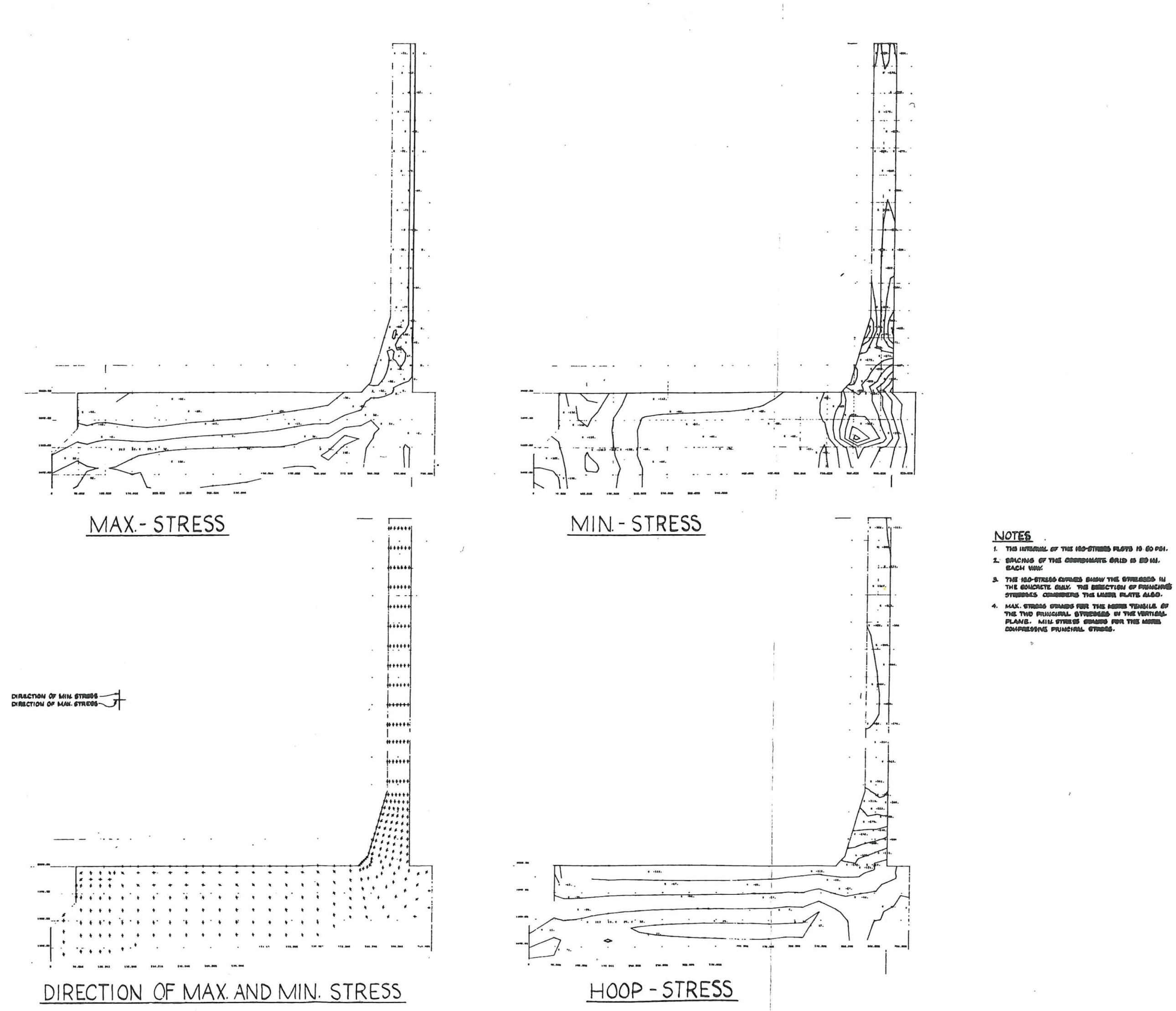
CONTAINMENT STRUCTURE - ISO-STRESS PLOTS; BASE AND WALL (Sheet 6)
FIGURE 5.1-11

Figure 5.1-11 CONTAINMENT STRUCTURE - ISO-STRESS PLOTS: BASE AND WALL
Sheet 7



CONTAINMENT STRUCTURE - ISO-STRESS PLOTS; BASE AND WALL (Sheet 7)
FIGURE 5.1-11

Figure 5.1-11 CONTAINMENT STRUCTURE - ISO-STRESS PLOTS: BASE AND WALL
Sheet 8



CONTAINMENT STRUCTURE - ISO-STRESS PLOTS; BASE AND WALL (Sheet 8)
FIGURE 5.1-11

Figure 5.1-12 CONTAINMENT STRUCTURE - FINITE ELEMENT MESH FOR BUTTRESS

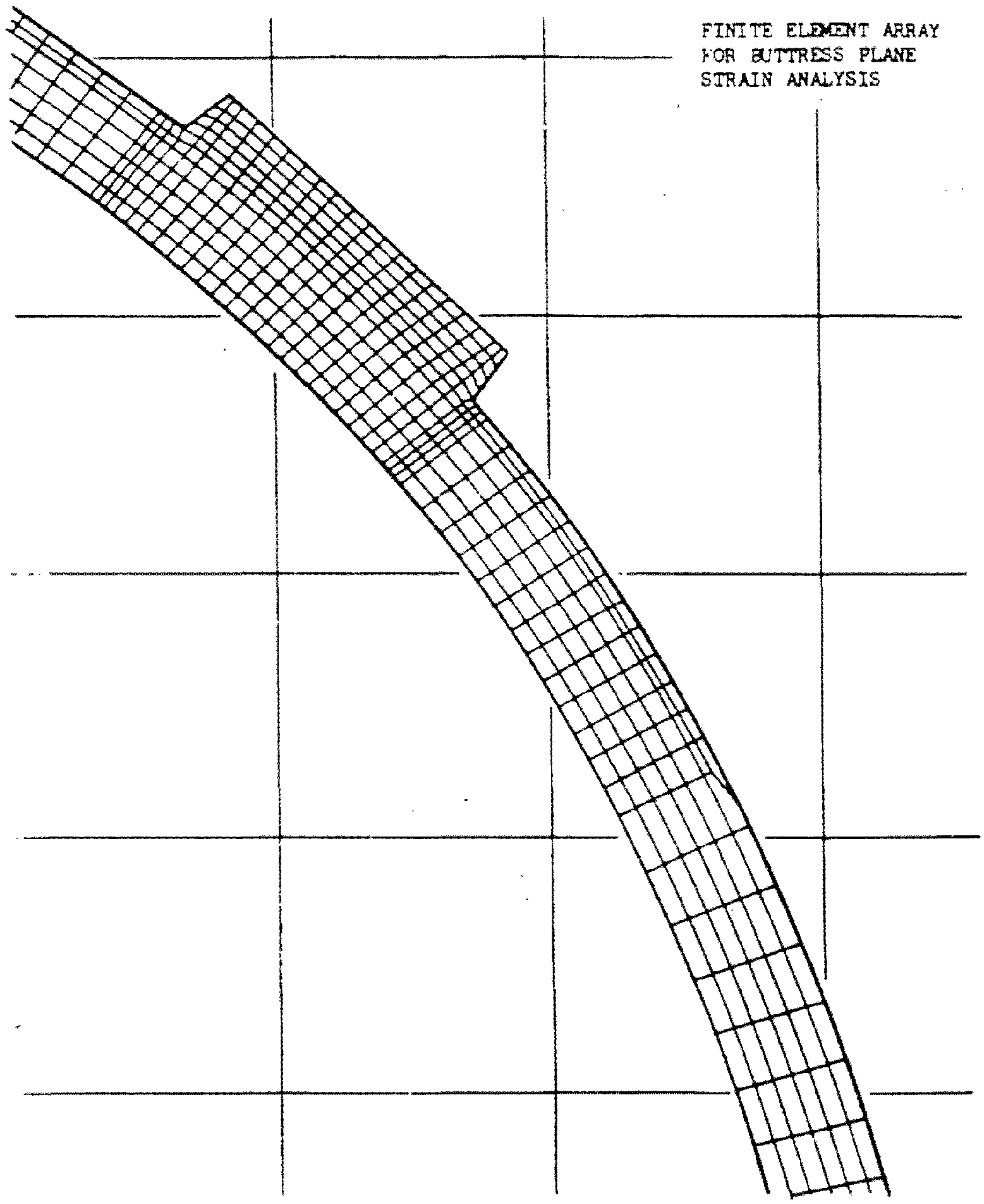


FIGURE 5.1-12
CONTAINMENT STRUCTURE -
FINITE ELEMENT MESH FOR
BUTTRESS

Figure 5.1-13 ISO-STRESS PLOTS - CONTAINMENT STRUCTURE BUTTRESS
Sheet 1

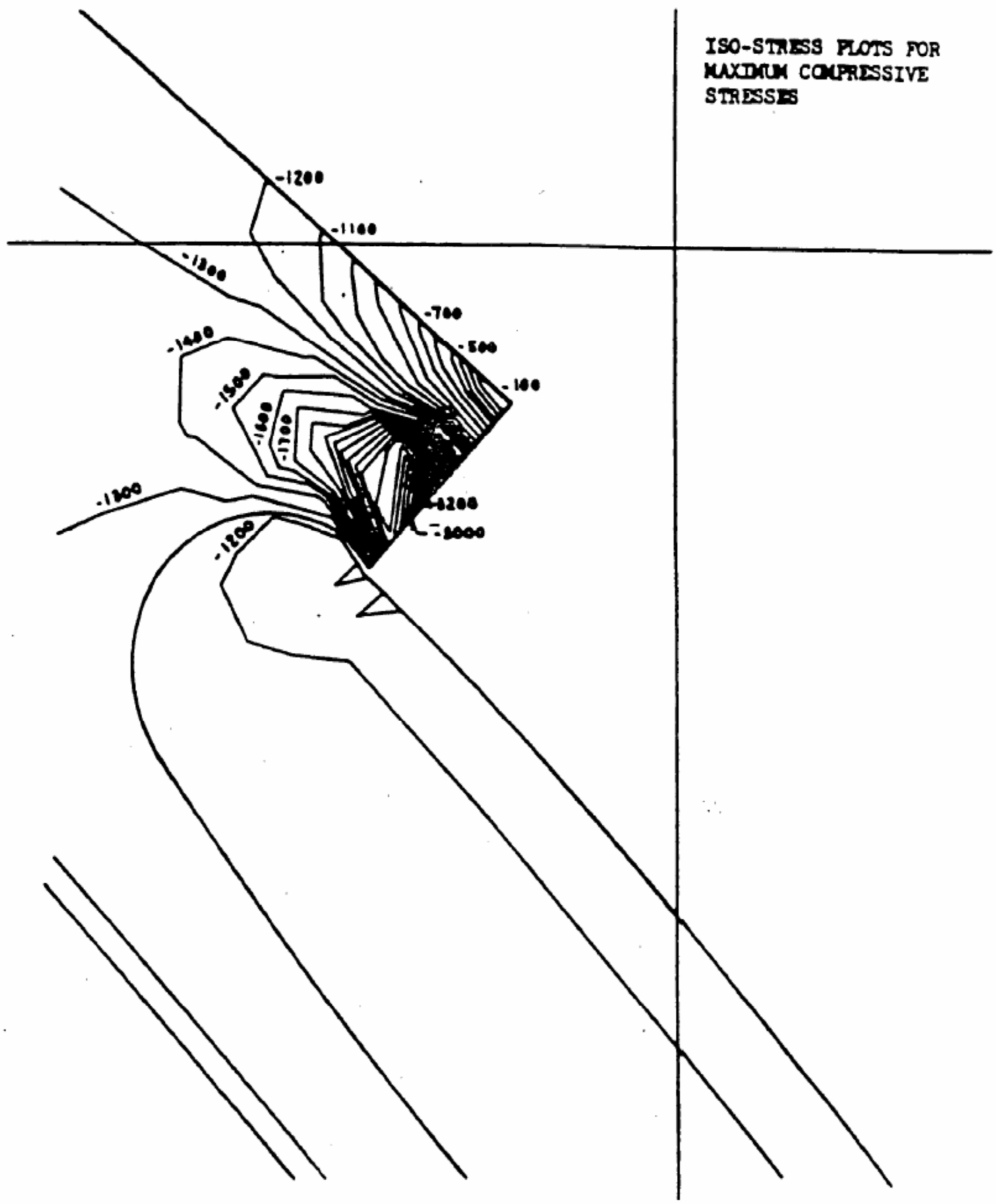


FIGURE 5.1-13 SHEET 1
ISO-STRESS PLOTS -
CONTAINMENT STRUCTURE
BUTTRESS

Figure 5.1-13 ISO-STRESS PLOTS - CONTAINMENT STRUCTURE BUTTRESS
Sheet 2

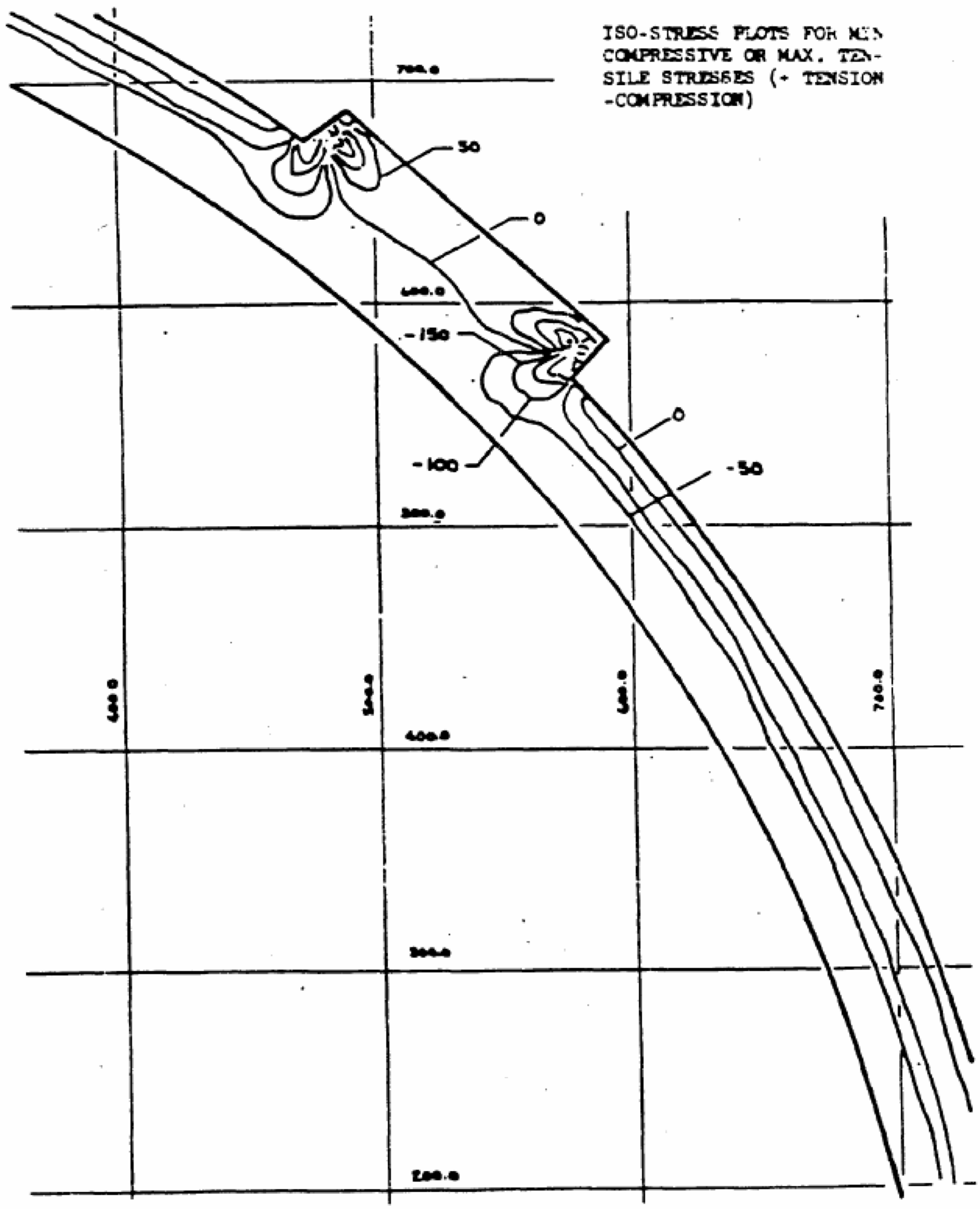
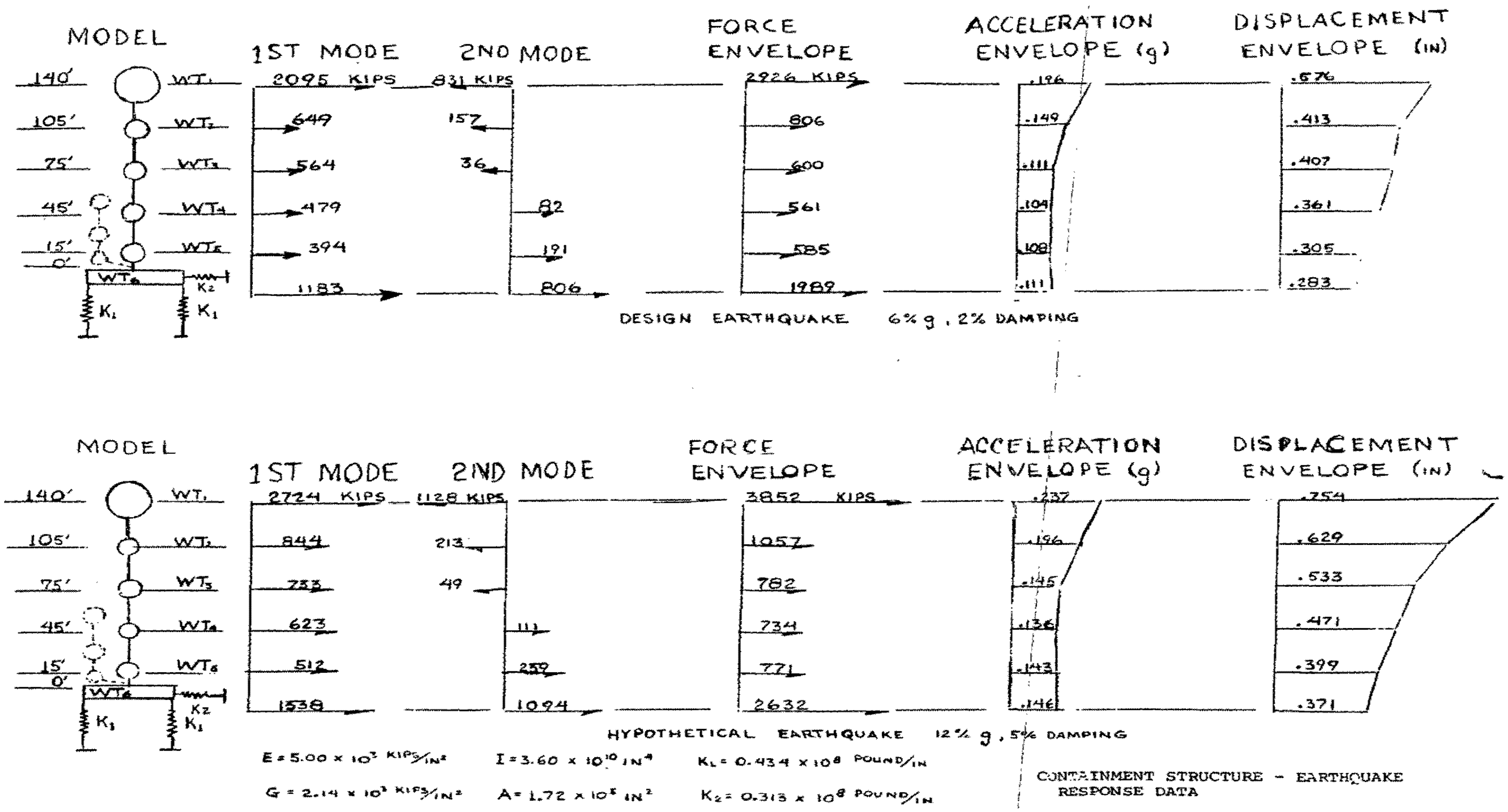


FIGURE 5.1-13 SHEET 2
ISO-STRESS PLOTS -
CONTAINMENT STRUCTURE
BUTTRESS

Figure 5.1-14 CONTAINMENT STRUCTURE - EARTHQUAKE RESPONSE DATA



CONTAINMENT STRUCTURE - EARTHQUAKE RESPONSE DATA

FIGURE 5.1-14

Figure 5.1-15 CONTAINMENT STRUCTURE - CONSTRUCTION DETAILS AT EQUIPMENT OPENING

[redacted]

Figure 5.1-16 CONTAINMENT STRUCTURE - PENETRATION LOADS

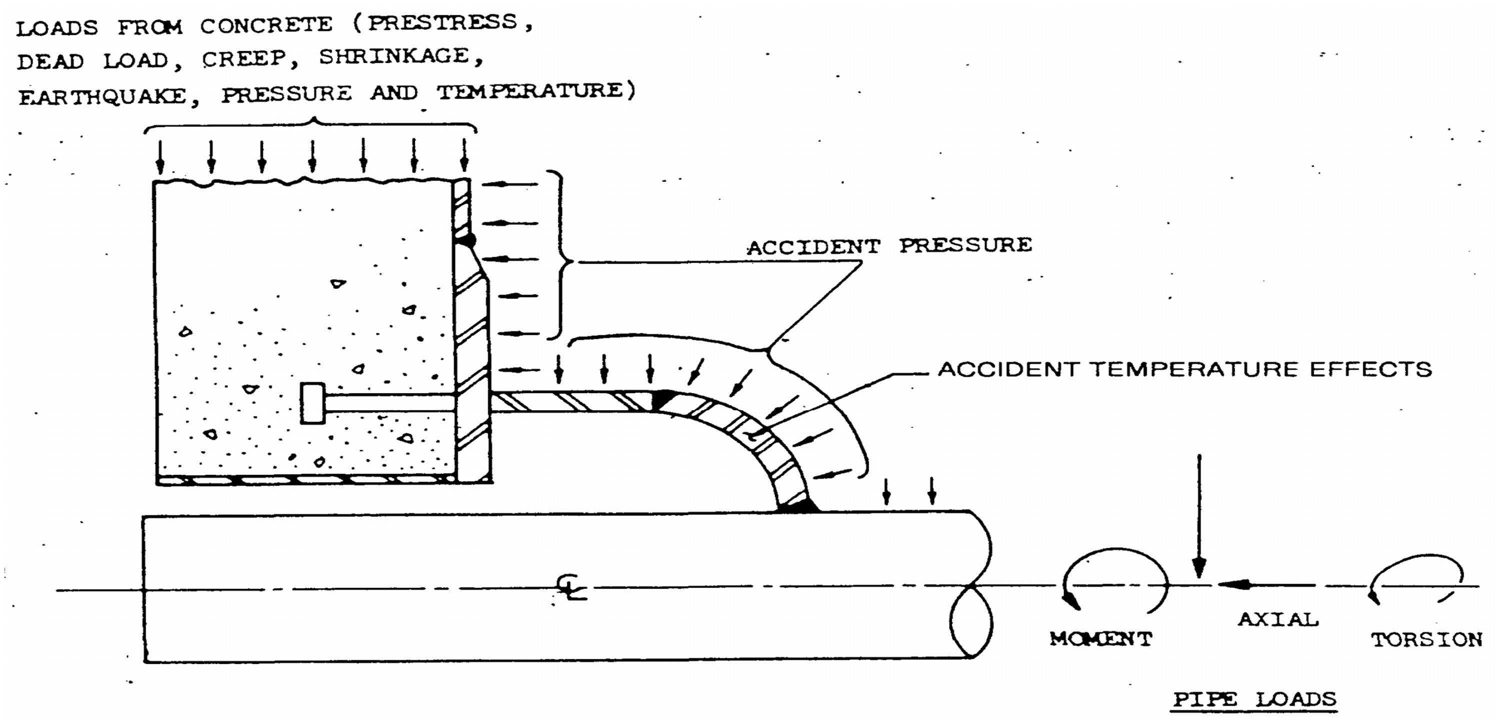
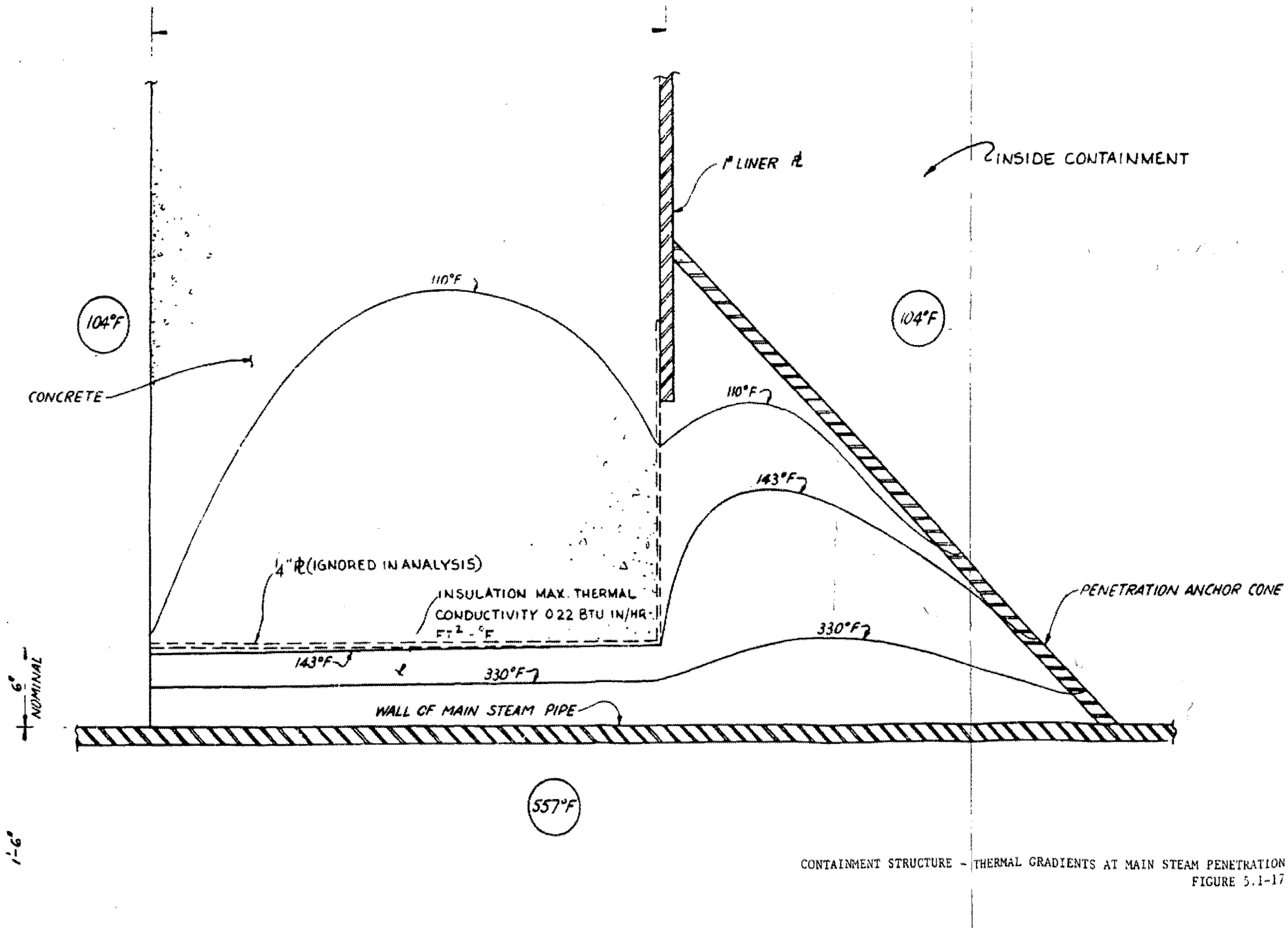
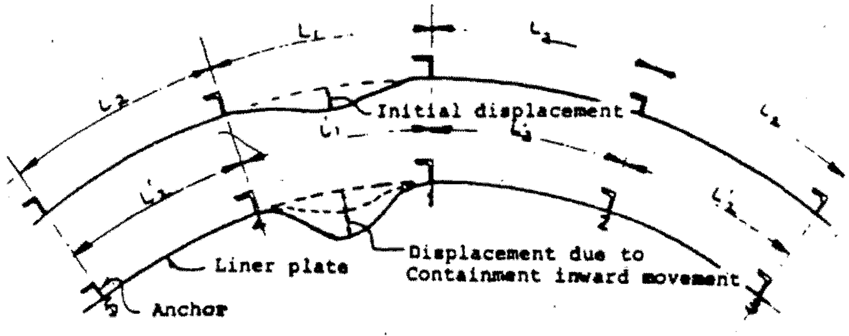


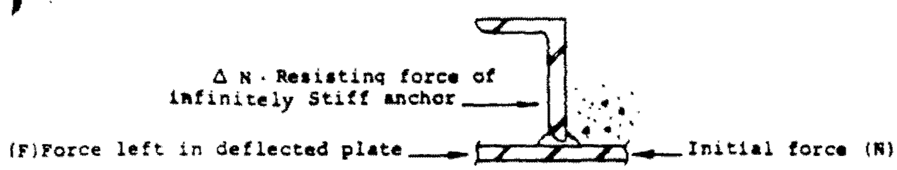
Figure 5.1-17 CONTAINMENT STRUCTURE - THERMAL GRADIENTS AT MAIN STEAM PENETRATION



CONTAINMENT STRUCTURE - THERMAL GRADIENTS AT MAIN STEAM PENETRATION
FIGURE 5.1-17

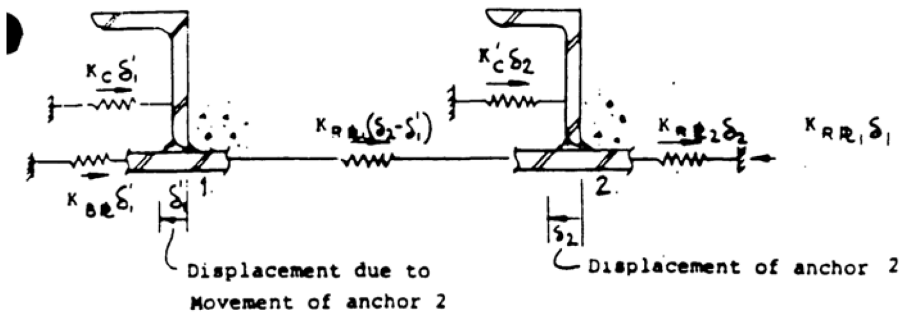
Figure 5.1-18 CONTAINMENT STRUCTURE - MODEL FOR LINER PLATE ANALYSIS
Sheet 1 of 2

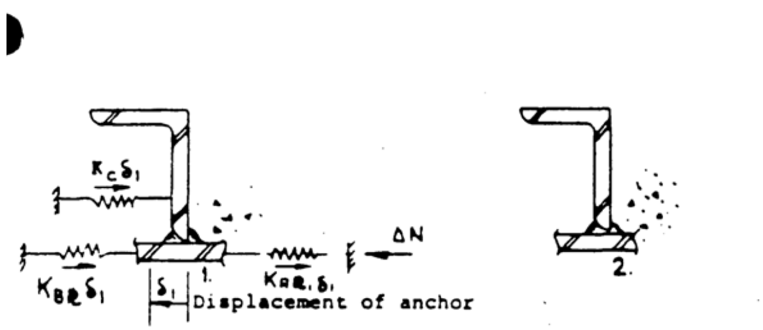




CONTAINMENT STRUCTURE
MODEL FOR LINER
PLATE ANALYSIS

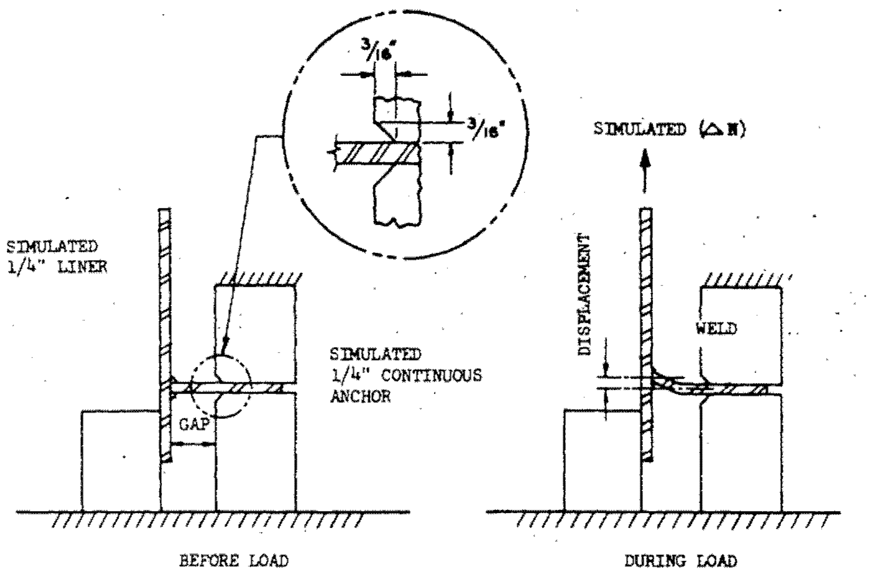
Figure 5.1-18 CONTAINMENT STRUCTURE - MODEL FOR LINER PLATE ANALYSIS
Sheet 2 of 2





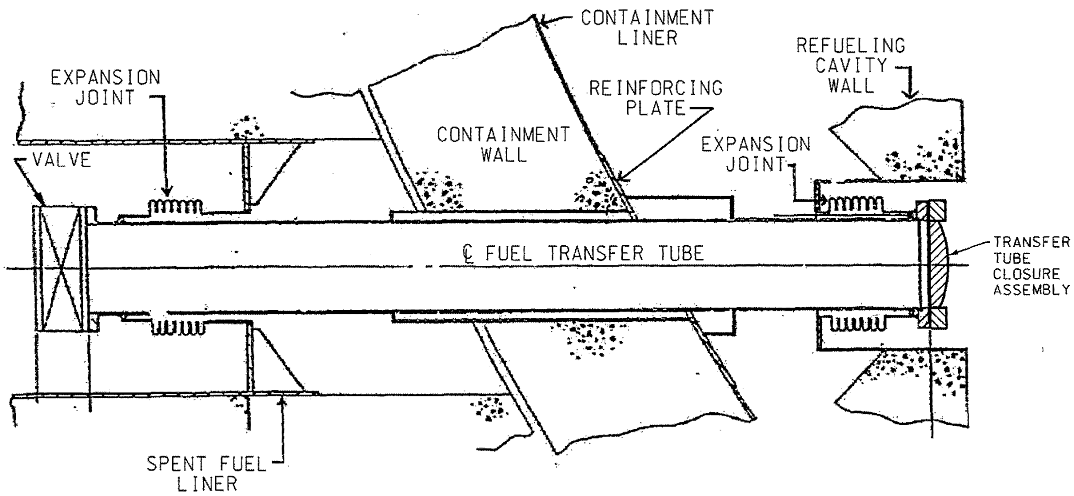
CONTAINMENT STRUCTURE
MODEL FOR LINER PLATE
ANALYSIS

Figure 5.1-19 CONTAINMENT STRUCTURE - RESULTS FROM TESTS ON LINER PLATE ANCHORS



WELD CONFIGURATION	GAP (IN)	ULTIMATE LOAD (K/IN)	ULTIMATE DISPLACEMENT (IN)	LOCATION OF FAILURE
3/16	0	14.95	.14	LINER PLATE
3/16	5/8	5.56	.68	ANCHOR WELD
3/16 6-12	0	7.65	.18	ANCHOR WELD
3/16 6-12	5/8	2.93	.60	ANCHOR WELD
3/16 4-12	0	6.67	.18	ANCHOR WELD
3/16 4-12	5/8	2.46	.30	ANCHOR WELD

Figure 5.1-20 FUEL TRANSFER TUBE PENETRATION



POINTBEACH FSAR FIG 5.1-20

REV NO.	DATE	REVISION DESCRIPTION	DRAWN	CHK'D	APPRV'D
00	03-21-16	INCORP. INTO PDS PER EC #282573-004	KJB	JLF	JJN

UPDATE PRI: 2
SUB TYPE: FSAR
OCR: NO

DRAWN KJB	DATE 03-20-16	
CHECKED BMS	DATE	SCALE NONE
APPROVED	DATE	FILE NO. PB22903C

NEXTera ENERGY POINT BEACH

FUEL TRANSFER TUBE
PENETRATION
POINT BEACH N.P. UNIT 1

MICROFILM NO.	REV. NO.	DWG SIZE
PB22903	00	CUSTOM

5.2 CONTAINMENT ISOLATION SYSTEM

5.2.1 DESIGN BASES

Each system whose piping penetrates the containment leakage limiting boundary is designed to maintain or establish isolation of the containment from the outside environment under the following postulated conditions:

1. Any accident for which isolation is required (severely faulted conditions)
2. A coincident independent single failure or malfunction (expected fault condition) occurring in any active system component within the isolated bounds

Piping penetrating the containment is designed for pressures at least equal to the containment design pressure. Containment isolation valves are provided as necessary in lines penetrating the containment to assure that no unrestricted release of radioactivity can occur. Such releases might be due to rupture of a line within the containment concurrent with a loss-of-coolant accident or due to rupture of a line outside the containment which connects to a source of radioactive fluid within the containment.

In general, isolation of a line outside the containment protects against rupture of the line inside concurrent with a loss-of-coolant accident or closes off a line which communicates with the containment atmosphere in the event of a loss-of-coolant accident.

Isolation of a line inside the containment prevents flow from the reactor coolant system or any other large source of radioactive fluid in the event that a piping rupture outside the containment occurs. A piping rupture outside the containment at the same time as a loss-of-coolant accident is not considered credible, as the penetrating lines are seismic Class I design at least up to and including the second isolation barrier and are assumed to be an extension of the containment. The isolation valve arrangement provides barriers between the reactor coolant system or containment atmosphere and the environment.

System design is such that no manual operation is required for immediate isolation. In addition, containment isolation can be accomplished if one valve fails to close. Closure of automatic isolation valves is initiated by a containment isolation signal, Chapter 7, derived either from any automatic safety injection signal or manually.

The containment isolation valves have been examined to assure that they are capable of withstanding the maximum potential seismic loads. To assure their adequacy in this respect:

1. Valves are located in a manner to reduce the accelerations on the valves. Valves suspended on piping spans are reviewed for adequacy for the loads to which the span would be subjected. Valves are mounted in the position recommended by the manufacturer.
2. Valve yokes have been reviewed for adequacy and strengthened as required for the response of the valve operator to seismic loads.
3. Where valves are required to operate during seismic loading, the operator forces have been reviewed to assure that system function is preserved. Seismic forces on the operating parts of the valve are small compared to the other forces present.

4. Control wires and piping to the valve operators have been designed and installed to assure that the flexure of the line does not endanger the control system. Appendages to the valve, such as position indicators and operators, have been checked for structural adequacy.

Containment Isolation Valves

Criterion: Penetrations that require closure for the containment function shall be protected by redundant valving and associated apparatus. (GDC 53)

Isolation valves are provided as necessary for all fluid system lines penetrating the containment to assure at least two barriers for redundance against leakage of radioactive fluids to the environment in the event of a loss-of-coolant accident. These barriers, in the form of isolation valves or closed systems, are defined on an individual line basis. In addition to satisfying containment isolation criteria, the valving is designed to facilitate normal operation and maintenance of the systems and to ensure reliable operation of other engineered safeguards systems.

With respect to numbers and locations of isolation valves, the criteria applied are generally those outlined by the five classes described below.

5.2.2 SYSTEM DESIGN

The five classes listed below are general categories into which lines penetrating the containment may be classified. The following notes apply to those classifications.

1. The “not missile protected” designation refers to lines that are not protected throughout their length inside containment against missiles generated as the result of a loss-of-coolant accident. These lines, therefore, are not assumed invulnerable to rupture as a result of a loss of coolant accident.[1]

2. In order to qualify for containment isolation, valves inside the containment must be protected against loss of function following an accident. They must, therefore, either be located outside the missile barrier, or be afforded protection against missiles (including jet forces and pipe whip) by physical barriers, restraints, or design configuration.[1]

3. Manual and remotely operated isolation valves that are locked closed or otherwise closed and under administrative control during power operation qualify as automatic trip valves.

4. A check valve qualifies as an automatic trip valve in certain incoming lines.

5. The double disk type of gate valve is used to isolate certain lines.

6. Isolation lines between the containment and the second outside isolation barrier (valve or closed system) are designed to the same seismic criteria as the containment vessel and are assumed to be an extension of containment.

1. Missiles may be generated as the result of various Loss-of-Coolant Accidents (LOCAs), though not from reactor coolant pipe ruptures. See Section 5.1 for further details.

7. The first outside isolation valve is located as close to the containment as possible unless a more remote location is dictated by equipment isolation requirements.

Class 1 (Outgoing Lines, Reactor Coolant System)

Normally operating outgoing lines connected to the reactor coolant system are provided with two automatic trip valves in series, one located inside containment and one located outside containment.

Class 2 (Outgoing Lines)

Normally operating outgoing lines not connected to the reactor coolant system and not protected from missiles throughout their length are provided with either (1) two automatic trip valves in series or (2) a closed system outside containment and either a remotely operated stop valve or an automatic trip valve in series.

Class 3 (Incoming Lines)

Incoming lines connected to open systems outside containment are provided with two automatic trip valves in series, one of which may be located inside containment. Incoming lines connected to closed systems outside containment are provided with one automatic trip valve located inside containment.

Class 4 (Missile Protected)

Normally operating incoming and outgoing lines which penetrate the containment and are connected to closed systems inside the containment and protected from missiles throughout their length are provided with at least one containment isolation valve located outside the containment. See Section 5.1 for details of design missiles.

Class 5 (Normally Closed Lines Open to the Containment)

Lines which penetrate the containment and which can be opened to the containment atmosphere but which are normally closed during reactor operation are provided with two isolation valves in series or one isolation valve and one blank flange. One valve or flange is located inside and the second valve or flange located outside the containment.

Special Classed Penetrations

In the detailed design of the nuclear plant systems, certain lines required minor modification to the arrangements defined by the above classes in order to implement the basic redundant barrier criterion.

The designation “Special” indicates that the line cannot be classified in accordance with the five general classifications. In these lines, special arrangements of isolation features provide the redundant barriers and are described in the note associated with each figure.

The equipment access closure is bolted, gasketed, and sealed during reactor operation. The personnel air lock consists of two doors in series with mechanical interlocks to assure that one door is closed at all times. Each air lock door and the equipment closure are provided with double gaskets to permit pressurization between the gaskets for leakage testing.

Closed Systems Inside Containment

PBNP is committed to NEI 94-01, Revision 3-A, and the conditions and limtations specified in NEI 94-01, Revision 2-A, which set the requriements for and explain performance based leakage testing programs for implementing 10CFR50 Appendix J, including acceptable leakage-rate test methods, procedures, and analysis that may be used to implement these requirements. NEI 94-01 states the following is exempt from leak testing under the Appendix J program: "primary containment boundaries that do not constitute potential primary containment atmospheric pathways during and following a Design Basis Accident (DBA)." PBNP recognizes these boundaries that do not constitute potential primary containment atmospheric pathways as Closed Systems. This applies to the designated CIVs listed in the FSAR Figures 5.2 as Closed Systems.

Some lines which penetrate the containment are not open to the containment atmosphere. When these lines meet the following criteria, they are considered as closed systems, not subject to rupture following a LOCA. The main steam lines, feedwater lines, and service water lines are examples of closed systems within containment.

1. Class 1 seismic,

2. Design pressure greater than containment design pressure,

3. Penetrations conform to the applicable sections of ASA N6.2-1965, "Safety Standard for the Design, Fabrication, and Maintenance of Steel Containment Structures for Stationary Nuclear Power Reactors."

Where closed system lines penetrate the missile shield they also must be protected against the dynamic effects of a break of the RCS pressure boundary, for those parts of the pressure boundary that have not been demonstrated to have an extremely low probably of rupture ("Leak-Before-Break"). This protection includes missiles, jet impingement, and pipe whip.

By meeting these criteria closed systems inside containment are considered missile protected throughout their length.

5.2.2.1 ISOLATION VALVES AND INSTRUMENTATION DIAGRAMS

Figure 5.2-1 through Figure 5.2-X2 show all containment isolation valves in lines leading to the atmosphere or to closed systems on both sides of the containment barrier, valve actuation and preferential failure modes, the application of "trip" (containment isolation) signals, and relative location of the valves with respect to missile barriers. Containment penetrations that previously had process lines through them but were modified so they no longer are in use, do not have isolation valves or other barriers that require periodic testing (other than Type A), are now considered spares, and have been removed from the figures shown in this section. Figure 5.2-72 shows a fuel transfer tube penetration. Figure 5.2-73-1 shows the containment structure and spent fuel pool pile foundation layout.

All trip isolation valves are provided with position indication in the main control room. Air operated valves which are designed as automatic trip isolation valves are designed to fail to the closed position upon loss of control air or electric services. The trip valves will be closed automatically upon receipt of the containment isolation signal. Circuits which control redundant automatic valves shall be redundant in the sense that no single failure shall preclude isolation of the penetration. Table 5.2-1 is an index of figures showing the physical configuration of each penetration and their isolation features. The applicable piping and instrumentation drawing is listed for each figure.

Certain penetrations for engineered safeguards systems lines are exceptions to the above categories. The operation of valves in these systems is governed by the functional requirements of the systems as outlined in this section.

Supplementary criteria noted below, which pertain to certain lines penetrating containment, have also been applied in the selection of isolation features incorporated in these lines. These criteria are identified in the containment penetration drawings.

1. Lines which penetrate containment and are open to the external atmosphere or to systems designed for less than containment design pressure shall be protected by redundant, automatic[1] isolation valves if they fulfill either of the following conditions:

   a. They are connected to the primary system
   b. They are normally open to containment atmosphere

   Exception: Lines which must remain open subsequent to loss-of-coolant accident shall be protected by redundant valves, one or both of which shall be remote-manual.

2. Ventilation lines shall be isolated upon receipt of "Safety Injection" signals.

3. Lines which have a low probability of rupture during Design Basis Accident, DBA (e.g., certain secondary system lines) shall be protected by at least one automatic valve external to containment.

   Exception: Lines which must remain open subsequent to DBA shall be protected by one automatic valve or one remote manual valve external to containment.

1. Check valves are considered to be automatic valves.

EXPLANATORY NOTES
FOR CONTAINMENT PENETRATION FIGURES

General Note: The purpose of these figures is to illustrate the general configuration of the containment isolation provisions for each penetration. It is not the intent of these figures to illustrate piping and instrumentation details, and particularly those details outside a penetration's pressure boundary. Refer to the associated P&ID for piping and instrumentation details.

General Note: Valves are depicted in their normal at-power position, which should coincide with the normal position depicted in the P&ID. Refer to the P&ID for these details.

Note A: Relief valves are not considered as leakage paths if set pressure is such that the relief valve will not lift with 60 psig containment design pressure present.

Note B: The designation "CS" in the figures applies to penetrating lines connected to a closed system either inside or outside containment. These systems are also protected against missiles and are designed in accordance with Class I seismic criteria. Their design pressure is higher than the containment design pressure.

Note C: The term "in use" indicates that the line will be in service following a loss-of-coolant accident.

Table 5.2-1 INDEX OF CONTAINMENT PENETRATION FIGURES
(1 of 4)

PENETRATION	FIGURE	DESCRIPTION	P & I D No. Unit 1	Unit 2
1	5.2-1	MAIN STEAM LOOP A	M-201	M-2201
2	5.2-2	MAIN STEAM LOOP B	M-201	M-2201
3	5.2-3	MAIN FEEDWATER LINE TO STEAM GENERATOR	M-202	M-2202
4	5.2-4	MAIN FEEDWATER LINE TO STEAM GENERATOR	M-202	M-2202
5-1	5.2-5-1	AUXILIARY FEEDWATER LINES (UNIT 1)	M-217	
5-2	5.2-5-2	AUXILIARY FEEDWATER LINES (UNIT 2)		M-217
6-1	5.2-6-1	AUXILIARY FEEDWATER LINES (UNIT 1)	M-217	
6-2	5.2-6-2	AUXILIARY FEEDWATER LINES (UNIT 2)		M-217
7	5.2-7	RESIDUAL HEAT REMOVAL SUCTION	W110E018	W110E029
8	5.2-8	RESIDUAL HEAT REMOVAL LOOP INTO CONTAINMENT	W684J741 W54lF091 W110E017 W110E018	W685J175 W541F445 W110E035 W110E029
9	5.2-9	REACTOR COOLANT DRAIN TANK DISCHARGE	W684J971	W684J971
10	5.2-10	LETDOWN LINE	W684J741 W541F091	W685J175 W541F445
11	5.2-11	EXCESS LETDOWN AND REACTOR COOLANT PUMP SEAL WATER RETURN LINE	W684J741	W685J175
12a	5.2-12a	CONTAINMENT DE-IONIZED WATER SUPPLY	PBM-231	PBM-231
12c	5.2-12c	CONTAINMENT VENT HEADER	W684J971 W541F091 W684J972	
13	5.2-13	SAFETY INJECTION SYSTEM	W110E017	W110E035
14a	5.2-14a	PRESSURIZER RELIEF TANK NITROGEN SUPPLY LINE	W541F091	W541F445
14b	5.2-14b	CONTAINMENT PRESSURE TRANSMITTERS/INDICATORS	M-224	M-224
14c	5.2-14c	ACCUMULATOR NITROGEN SUPPLY	W110E017	W110E035
15	5.2-15	COMPONENT COOLING WATER SUPPLY TO REACTOR COOLANT PUMP	W110E018	W110E029
16	5.2-16	COMPONENT COOLING WATER SUPPLY TO REACTOR COOLANT PUMP	W110E018	W110E029
17	5.2-17	COMPONENT COOLING WATER FROM REACTOR COOLANT PUMP	W110E018	W110E029
18	5.2-18	COMPONENT COOLING WATER FROM REACTOR COOLANT PUMP	W110E018	W110E029
19	5.2-19	COMPONENT COOLING WATER SUPPLY TO EXCESS LETDOWN HEAT EXCHANGER	W110E018	W110E029

Table 5.2-1 INDEX OF CONTAINMENT PENETRATION FIGURES
(2 of 4)

PENETRATION	FIGURE	DESCRIPTION	P & I D No. Unit 1	Unit 2
20	5.2-20	COMPONENT COOLING WATER FROM EXCESS LETDOWN HEAT EXCHANGER	W110E018	W110E029
22	5.2-22	SAFETY INJECTION SYSTEM	W110E017 W110E018	W110E035 W110E029
25c	5.2-25c	POST-ACCIDENT CONTAINMENT VENTILATION SYSTEM (UNIT 1 ONLY)	M-224	
26	5.2-26	CHARGING LINE	W684J741	W685J175
27	5.2-27	SAFETY INJECTION SYSTEM	W110E017	W110E035
28a	5.2-28a	REACTOR COOLANT SYSTEM SAMPLE LINES (HOT LEG SAMPLE)	W541F092	W541F448
28b	5.2-28b	REACTOR COOLANT SYSTEM SAMPLE LINES (PZR LIQUID SAMPLE)	W541F092	W541F448
28c	5.2-28c	REACTOR COOLANT SYSTEM SAMPLE LINES (PZR STEAM SPACE SAMPLE)	W541F092	W541F448
29a	5.2-29a	REACTOR COOLANT PUMP SEAL WATER SUPPLY LINE (PUMP A)	W684J741	W685J175
29b	5.2-29b	REACTOR COOLANT PUMP SEAL WATER SUPPLY LINE (PUMP B)	W684J741	W685J175
30c	5.2-30c	PRESSURIZER RELIEF TANK MAKEUP	W541F091	W541F445
31a	5.2-31a	CONTAINMENT PRESSURE TRANSMITTERS	M-224	M-224
31b	5.2-31b	POST-ACCIDENT CONTAINMENT VENTILATION SYSTEM SAMPLE	M-224	M-224
31c	5.2-31c	POST-ACCIDENT CONTAINMENT VENTILATION SYSTEM	M-224	M-224
32a	5.2-32a	CONTAINMENT PRESSURE TRANSMITTERS	M-224	M-224
32b	5.2-32b	SAFETY INJECTION TEST LINE	W110E017	W110E035
32c	5.2-32c	AUXILIARY CHARGING LINE	W684J741	W685J175
33a-1	5.2-33ab1	INSTRUMENT AIR HEADERS (UNIT 1)	M-209	
33a-2	5.2-33ab2	INSTRUMENT AIR HEADERS (UNIT 2)		M-209
33b-1	5.2-33ab1	INSTRUMENT AIR HEADERS (UNIT 1)	M-209	
33b-2	5.2-33ab2	INSTRUMENT AIR HEADERS (UNIT 2)		M-209
33c	5.2-33c	SERVICE AIR HEADER	M-209	M-209
34a	5.2-34a	PRESSURIZER RELIEF TANK GAS ANALYZER LINE	W541F091	W541F445
34b	5.2-34b	STEAM GENERATOR BLOWDOWN SAMPLE LINE	M-201	M-2201
34c	5.2-34c	STEAM GENERATOR BLOWDOWN SAMPLE LINE	M-201	M-2201

Table 5.2-1 INDEX OF CONTAINMENT PENETRATION FIGURES
(3 of 4)

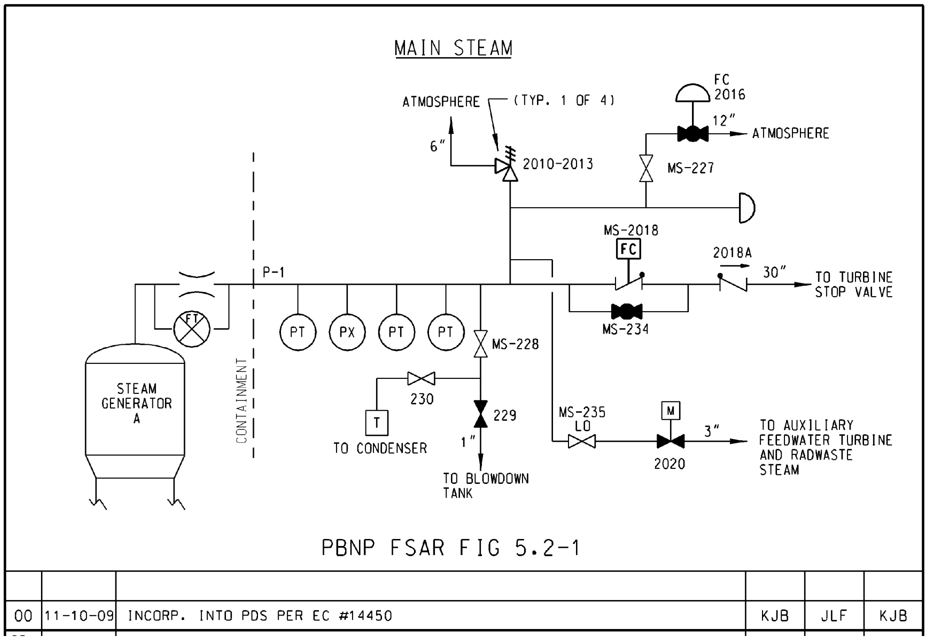
PENETRATION	FIGURE	DESCRIPTION	P & I D No. Unit 1	Unit 2
34d	5.2-34d	REACTOR COOLANT DRAIN TANK SAMPLE TO GAS ANALYZER	W684J971 W684J972	W684J971 W684J972
35-1	5.2-35-1	SERVICE WATER SUPPLY TO CONTAINMENT FAN COOLER UNIT (UNIT 1)	M-207	
35-2	5.2-35-2	SERVICE WATER SUPPLY TO CONTAINMENT FAN COOLER UNIT (UNIT 2)		M-2207
36-1	5.2-36-1	SERVICE WATER SUPPLY TO CONTAINMENT FAN COOLER UNIT (UNIT 1)	M-207	
36-2	5.2-36-2	SERVICE WATER SUPPLY TO CONTAINMENT FAN COOLER UNIT (UNIT 2)		M-2207
37-1	5.2-37-1	SPARE LINE (UNIT 1)	M-207	
37-2	5.2-37-2	SPARE LINE (UNIT 2)		M-2207
38-1	5.2-38-1	SPARE LINE (UNIT 1)	M-207	
38-2	5.2-38-2	SPARE LINE (UNIT 2)		M-2207
39-1	5.2-39-1	SERVICE WATER SUPPLY TO CONTAINMENT FAN COOLER UNIT (UNIT 1)	M-207	
39-2	5.2-39-2	SERVICE WATER SUPPLY TO CONTAINMENT FAN COOLER UNIT (UNIT 2)		M-2207
40-1	5.2-40-1	SERVICE WATER SUPPLY TO CONTAINMENT FAN COOLER UNIT (UNIT 1)	M-207	
40-2	5.2-40-2	SERVICE WATER SUPPLY TO CONTAINMENT FAN COOLER UNIT (UNIT 2)		M-2207
42c-2	5.2-42c-2	POST-ACCIDENT CONTAINMENT VENTILATION SYSTEM (UNIT 2)	M-224	
43-1	5.2-43-1	SERVICE WATER RETURN LINE FROM CONTAINMENT FAN COOLER UNITS (UNIT 1)	M-207	
43-2	5.2-43-2	SERVICE WATER RETURN LINE FROM CONTAINMENT FAN COOLER UNIT (UNIT 2)		M-2207
44-1	5.2-44-1	SERVICE WATER RETURN LINE FROM CONTAINMENT FAN COOLER UNIT (UNIT 1)	M-207	
44-2	5.2-44-2	SERVICE WATER RETURN LINE FROM CONTAINMENT FAN COOLER UNIT (UNIT 2)		M-2207

Table 5.2-1 INDEX OF CONTAINMENT PENETRATION FIGURES
(4 of 4)

PENETRATION	FIGURE	DESCRIPTION	P & I D No. Unit 1	Unit 2
45-1	5.2-45-1	SPARE LINE (UNIT 1)	M-207	
45-2	5.2-45-2	SPARE LINE (UNIT 2)		M-2207
46-1	5.2-46-1	SPARE LINE (UNIT 1)	M-207	
46-2	5.2-46-2	SPARE LINE (UNIT 2)		M-2207
47-1	5.2-47-1	SERVICE WATER RETURN LINE FROM CONTAINMENT FAN COOLER UNIT (UNIT 1)	M-207	
47-2	5.2-47-2	SERVICE WATER RETURN LINE FROM CONTAINMENT FAN COOLER UNIT (UNIT 2)		M-2207
48-1	5.2-48-1	SERVICE WATER RETURN LINE FROM CONTAINMENT FAN COOLER UNIT (UNIT 1)	M-207	
48-2	5.2-48-2	SERVICE WATER RETURN LINE FROM CONTAINMENT FAN COOLER UNIT (UNIT 2)		M-2207
50-1	5.2-50-1	STEAM GENERATOR BLOWDOWN LINE (UNIT 1)	M-201	
50-2	5.2-50-2	STEAM GENERATOR BLOWDOWN LINE (UNIT 2)		M-2201
51-1	5.2-51-1	STEAM GENERATOR BLOWDOWN LINE (UNIT 1)	M-201	
51-2	5.2-51-2	STEAM GENERATOR BLOWDOWN LINE (UNIT 2)		M-2201
54	5.2-54	CONTAINMENT SPRAY HEADERS	W110E017	W110E035
55	5.2-55	CONTAINMENT SPRAY HEADERS	W110E017	W110E035
56	5.2-56	SPARE PENETRATION		
57	5.2-57	MAIN STEAM GENERATOR VENTS	M-201	M-2201
58	5.2-58	MAIN STEAM GENERATOR VENTS	M-201	M-2201
67-2	5.2-67-2	SPARE PENETRATION		
69	5.2-69	CONTAINMENT SUMP RECIRCULATION LINES	W110E017 W110E018	W110E035 W110E029
70	5.2-70	CONTAINMENT SUMP RECIRCULATION LINES	W110E017 W110E018	W110E035 W110E029
71	5.2-71	CONTAINMENT SUMP DISCHARGE	W684J971	W684J971
Vl	5.2-V1	CONTAINMENT PURGE EXHAUST DUCT	M-215	M-2215
V2	5.2-V2	CONTAINMENT PURGE SUPPLY DUCT	M-215	M-2215
X1	5.2-X1	CONTAINMENT AIR SAMPLE OUT	M-215	M-2215
X2	5.2-X2	CONTAINMENT AIR SAMPLE IN	M-215	M-2215

NOTE: Standard equipment data base designations are used for valve numbers. See Bechtel drawing M-200 P&ID “Legend” for symbol descriptions used in the figures.

Figure 5.2-1 MAIN STEAM LOOP A



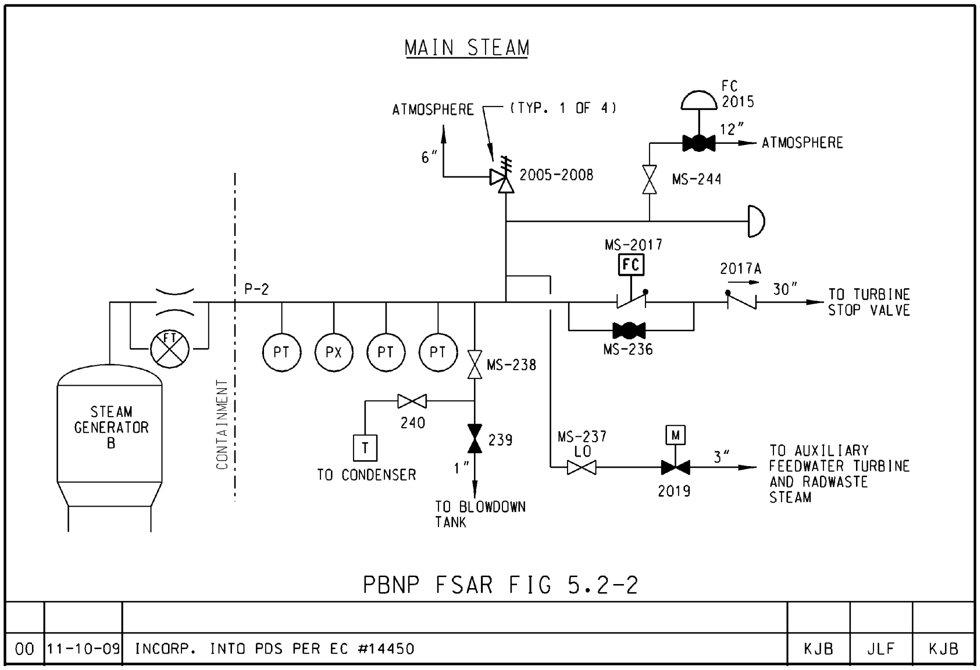
PENETRATION	CONTAINMENT ISOLATION VALVES INSIDE	OUTSIDE	BRANCH/SYSTEM	LINE SIZE	FLUID	TEMP. HOT>200 COLD<200	CLASS
1	CLOSED SYSTEM	MS-227	ATMOSPHERIC STEAM DUMP/MS	6'	G	HOT	4
	CLOSED SYSTEM	MS-2018	STEAM TO TURBINE/ MS	30'	G	HOT	4
	CLOSED SYSTEM	MS-234	MSIV BYPASS/MS	3'	G	HOT	4
	CLOSED SYSTEM	MS-228	STEAM LINE DRAIN TO BLOWDOWN TANK AND CONDENSER/MS	2'	G	HOT	4
	CLOSED SYSTEM	MS-235	AUXILIARY FEED PUMP AND RADWASTE STEAM/ MS	3'	G	HOT	4

FOR FURTHER INFORMATION REFER TO FSAR CHAPTER 10 & FIGURE 10.2-1 SHT. 1

NOTE:

1. ATMOSPHERIC STEAM DUMP - THIS IS AN OUTGOING LINE CONNECTED TO A CLOSED SYSTEM INSIDE CONTAINMENT. THE MANUAL ISOLATION REQUIREMENT IS MET BY MS-227.
2. STEAM TO TURBINE - THIS IS AN OUTGOING LINE CONNECTED TO A CLOSED SYSTEM INSIDE CONTAINMENT. IT THEREFORE SATISFIES CLASS 4 PENETRATION CRITERIA BECAUSE REMOTE STOP VALVE MS-2018 PROVIDES A DEGREE OF ISOLATION WHICH EXCEEDS THAT OF A MANUAL VALVE SINCE IT CAN BE REMOTELY OPERATED.
3. MSIV BYPASS - THIS IS AN OUTGOING LINE CONNECTED TO A CLOSED SYSTEM INSIDE CONTAINMENT. THE MANUAL ISOLATION REQUIREMENT IS SATISFIED BY MS-234.
4. STEAMLINE DRAIN TO STEAM GENERATOR BLOWDOWN TAND AND CONDENSER - THIS IS AN OUTGOING LINE CONNECTED TO A CLOSED SYSTEM INSIDE CONTAINMENT. THE MANUAL ISOLATION REQUIREMENT IS SATISFIED BY MS-228.
5. AUXILIARY FEED PUMP AND RADWASTE STEAM SUPPLY - THIS IS AN OUTGOING LINE CONNECTED TO A CLOSED SYSTEM INSIDE CONTAINMENT. THE MANUAL ISOLATION VALVE IS SATISFIED BY MS-235.

Figure 5.2-2 MAIN STEAM LOOP B



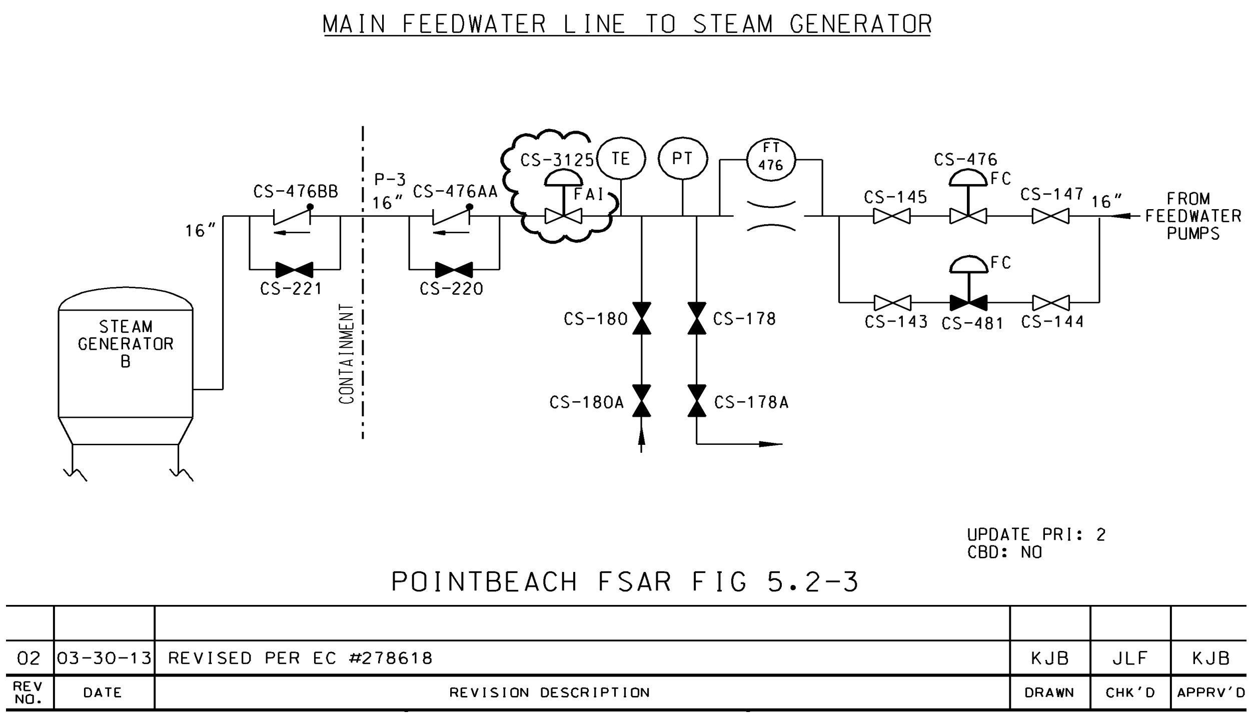
PENETRATION	CONTAINMENT ISOLATION VALVES INSIDE	OUTSIDE	BRANCH/SYSTEM	LINE SIZE	FLUID	TEMP. HOT>200 COLD<200	CLASS
2	CLOSED SYSTEM	MS-244	ATMOSPHERIC STEAM DUMP/MS	6’	G	HOT	4
	CLOSED SYSTEM	MS-2017	STEAM TO TURBINE/ MS	30’	G	HOT	4
	CLOSED SYSTEM	MS-236	MSIV BYPASS/MS	3’	G	HOT	4
	CLOSED SYSTEM	MS-238	STEAM LINE DRAIN TO BLOWDOWN TANK AND CONDENSER/MS	2’	G	HOT	4
	CLOSED SYSTEM	MS-237	AUXILIARY FEED PUMP AND RADWASTE STEAM/ MS	3’	G	HOT	4

FOR FURTHER INFORMATION REFER TO FSAR CHAPTER 10 & FIG 10.2-1 SHT. 1

NOTE:

1. ATMOSPHERIC STEAM DUMP - THIS IS AN OUTGOING LINE CONNECTED TO A CLOSED SYSTEM INSIDE CONTAINMENT. THE MANUAL ISOLATION REQUIREMENTS IS MET BY MS-244.
2. STEAM TO TURBINE - THIS IS AN OUTGOING LINE CONNECTED TO A CLOSED SYSTEM INSIDE CONTAINMENT. IT THEREFORE SATISFIES CLASS 4 PENETRATION CRITERIA BECAUSE REMOTE STOP VALVE MS-2017 PROVIDES A DEGREE OF ISOLATION WHICH EXCEEDS THAT OF A MANUAL VALVE SINCE IT CAN BE REMOTELY OPERATED.
3. MSIV BYPASS - THIS IS AN OUTGOING LINE CONNECTED TO A CLOSED SYSTEM INSIDE CONTAINMENT. THE MANUAL ISOLATION REQUIREMENT IS SATISFIED BY MS-236.
4. STEAMLINE DRAIN TO STEAM GENERATOR BLOWDOWN TAND AND CONDENSER - THIS IS AN OUTGOING LINE CONNECTED TO A CLOSED SYSTEM INSIDE CONTAINMENT. THE MANUAL ISOLATION REQUIREMENT IS SATISFIED BY MS-238.
5. AUXILIARY FEED PUMP AND RADWASTE STEAM SUPPLY - THIS IS AN OUTGOING LINE CONNECTED TO A CLOSED SYSTEM INSIDE CONTAINMENT. THE MANUAL ISOLATION VALVE IS SATISFIED BY MS-237.

Figure 5.2-3 MAIN FEEDWATER LINE TO STEAM GENERATOR



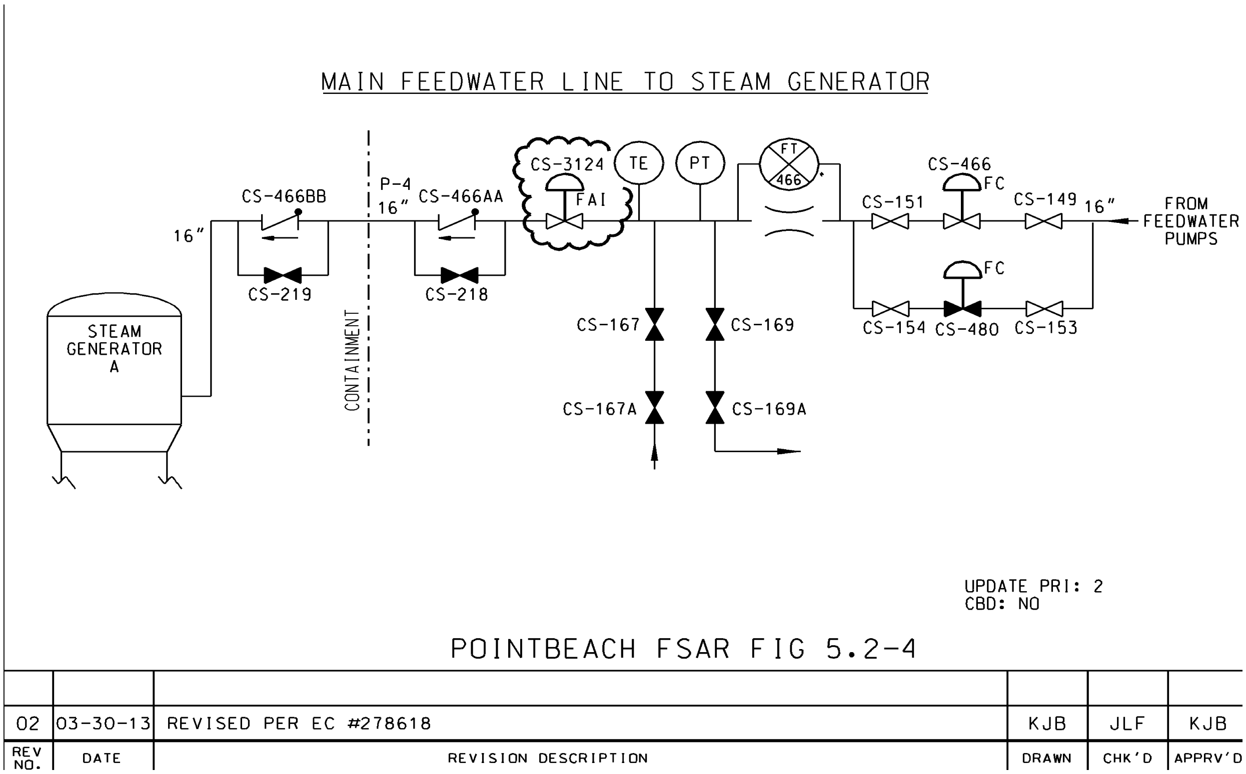
PENETRATION	CONTAINMENT ISOLATION VALVES INSIDE	CONTAINMENT ISOLATION VALVES OUTSIDE	BRANCH/SYSTEM	LINE SIZE	FLUID	TEMP. HOT>200 COLD<200	CLASS
3	CLOSED SYSTEM	CS-476AA	MAIN FEED TO STEAM GENERATOR/CS	16"	W	HOT	4
3	CLOSED SYSTEM	CS-220	MAIN FEED TO STEAM GENERATOR TEST LINE/CS	2"	W	HOT	4

FOR FURTHER INFORMATION REFER TO FSAR CHAPTER 10, FIGURE 10.1.2 SHEET 2, AND FIGURE 10.1-2A Sheet 2

NOTE:

MAIN FEED TO STEAM GENERATOR - THIS IS AN INCOMING LINE CONNECTED TO A CLOSED SYSTEM INSIDE CONTAINMENT. IT DOES NOT PRECISELY SATISFY THE CLASS 4 CRITERIA BECAUSE THERE IS A CHECK VALVE RATHER THAN A MANUAL ISOLATION VALVE OUTSIDE CONTAINMENT. IT ALSO SATISFIES SUPPLEMENTAL CRITERION #3 IN THAT IT IS A LINE WITH LOW PROBABILITY OF RUPTURE AND THEREFORE MAY HAVE AN AUTOMATIC VALVE EXTERNAL TO CONTAINMENT AS EXPLAINED IN FSAR Section 5.2 "A CHECK VALVE QUALIFIES AS AN AUTOMATIC TRIP VALVE..." OUTSIDE OF CONTAINMENT CHECK VALVE CS-476AA FULFILLS THIS REQUIREMENT.

Figure 5.2-4 MAIN FEEDWATER LINE TO STEAM GENERATOR



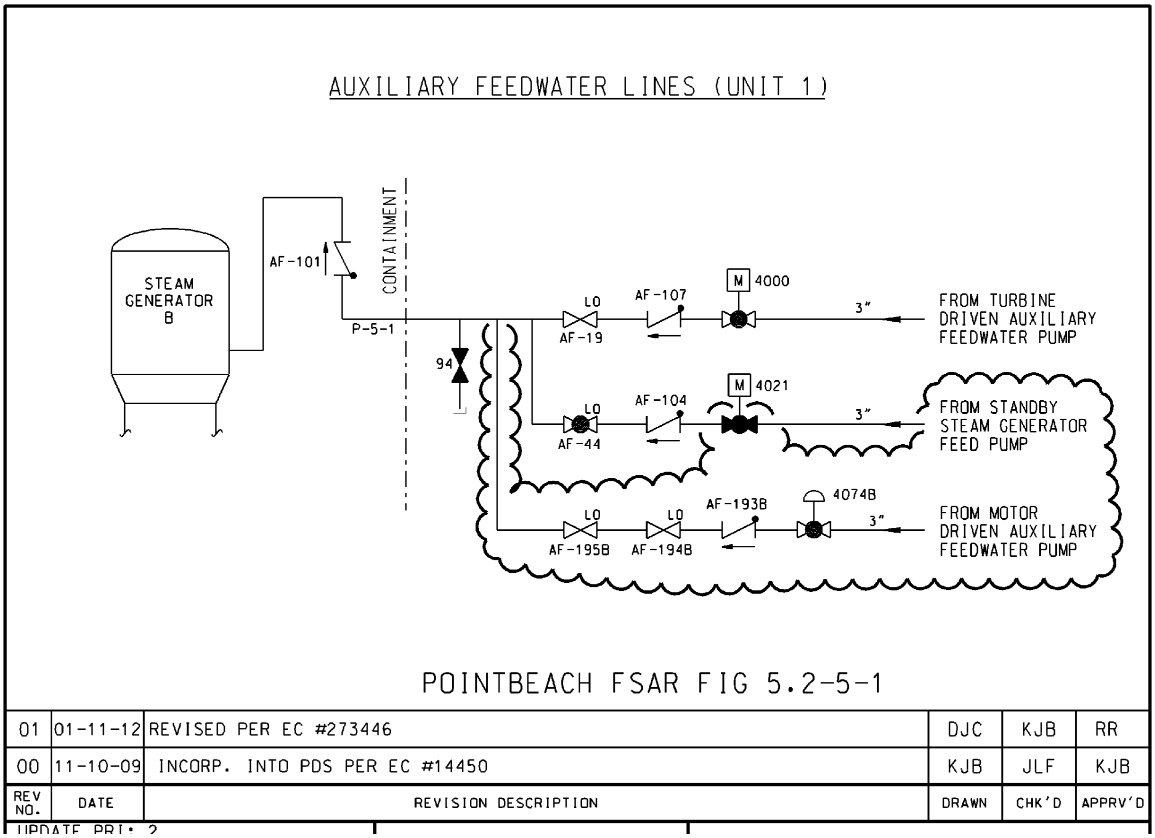
PENETRATION	CONTAINMENT ISOLATION VALVES INSIDE	OUTSIDE	BRANCH/SYSTEM	LINE SIZE	FLUID	TEMP. HOT>200 COLD<200	CLASS
4	CLOSED SYSTEM	CS-466AA	MAIN FEED TO STEAM GENERATOR/CS	16"	W	HOT	4
4	CLOSED SYSTEM	CS-218	MAIN FEED TO STEAM GENERATOR TEST LINE/CS	2"	W	HOT	4

FOR FURTHER INFORMATION REFER TO FSAR CHAPTER 10, FIGURE 10.1.2 SHEET 2, AND FIGURE 10.1-2A SHEET. 2

NOTE:

MAIN FEED TO STEAM GENERATOR - THIS IS AN INCOMING LINE CONNECTED TO A CLOSED SYSTEM INSIDE CONTAINMENT. IT DOES NOT PRECISELY SATISFY THE CLASS 4 CRITERIA BECAUSE THERE IS A CHECK VALVE RATHER THAN A MANUAL ISOLATION VALVE OUTSIDE CONTAINMENT. IT ALSO SATISFIES SUPPLEMENTAL CRITERION #3 IN THAT IT IS A LINE WITH LOW PROBABILITY OF RUPTURE AND THEREFORE MAY HAVE AN AUTOMATIC VALVE EXTERNAL TO CONTAINMENT AS EXPLAINED IN FSAR Section 5.2 "A CHECK VALVE QUALIFIES AS AN AUTOMATIC TRIP VALVE..." OUTSIDE OF CONTAINMENT CHECK VALVE CS-466AA FULFILLS THIS REQUIREMENT.

Figure 5.2-5-1 AUXILIARY FEEDWATER LINES (UNIT 1)



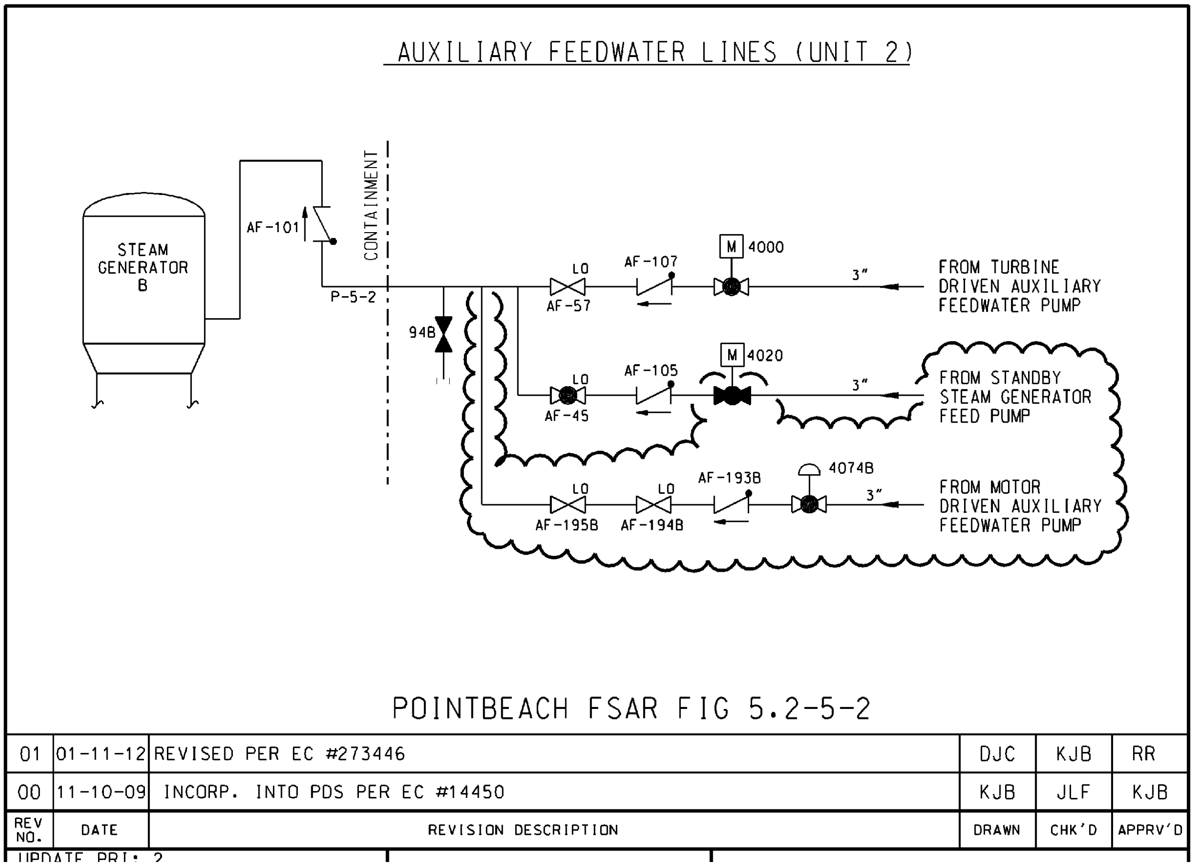
PENETRATION	CONTAINMENT ISOLATION VALVES INSIDE	OUTSIDE	BRANCH/SYSTEM	LINE SIZE	FLUID	TEMP. HOT>200 COLD<200	CLASS
5-1	CLOSED SYSTEM	AF-19	TURBINE DRIVEN AUXILIARY FEED TO STEAM GENERATOR/ AF	3"	W	HOT	4
	CLOSED SYSTEM	AF-44	STANDBY STESM GENERATOR FEED TO STEAM GENERATOR/ AF	3"	W	HOT	4
	CLOSED SYSTEM	AF-195B	MOTOR DRIVEN AUXILIARY FEED TO STEAM GENERATOR/ AF	3"	W	HOT	4

FOR FURTHER INFORMATION REFER TO FSAR CHAPTER 10 & FIG. 10.2-1 SHEETS 1 AND 2

NOTE:

AUXILIARY FEEDWATER LINES - THESE ARE INCOMING LINES NORMALLY OPERATING AFTER A DBA. THE MANUAL ISOLATION VALVE REQUIREMENT FOR A CLASS 4 PENETRATION IS MET BY VALVES AF-19, AF-44, AND AF-195B

Figure 5.2-5-2 AUXILIARY FEEDWATER LINES (UNIT 2)

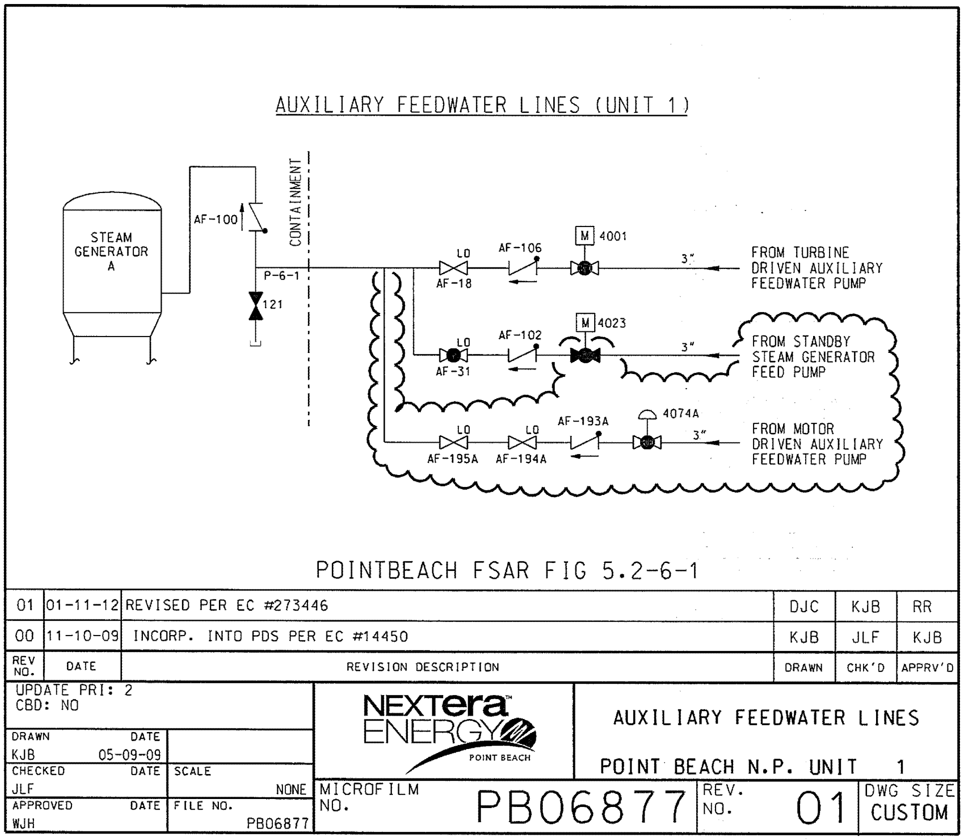


PENETRATION	CONTAINMENT ISOLATION VALVES INSIDE	CONTAINMENT ISOLATION VALVES OUTSIDE	BRANCH/SYSTEM	LINE SIZE	FLUID	TEMP. HOT>200 COLD<200	CLASS
5-2	CLOSED SYSTEM	AF-57	TURBINE DRIVEN AUXILIARY FEED TO STEAM GENERATOR/ AF	3"	W	HOT	4
	CLOSED SYSTEM	AF-45	STANDBY STEAM GENERATOR FEED TO STEAM GENERATOR/ AF	3"	W	HOT	4
	CLOSED SYSTEM	AF-195B	MOTOR DRIVEN AUXILIARY FEED TO STEAM GENERATOR/ AF	3"	W	HOT	4

FOR FURTHER INFORMATION REFER TO FSAR CHAPTER 10 & FIG. 10.2-1 SHEETS 1 AND 2

NOTE: AUXILIARY FEEDWATER LINES - THESE ARE INCOMING LINES NORMALLY OPERATING AFTER A DBA. THE MANUAL ISOLATION VALVE REQUIREMENT FOR A CLASS 4 PENETRATION IS MET BY VALVES AF-57, AF-44, AND AF-195B.

Figure 5.2-6-1 AUXILIARY FEEDWATER LINES (UNIT 1)



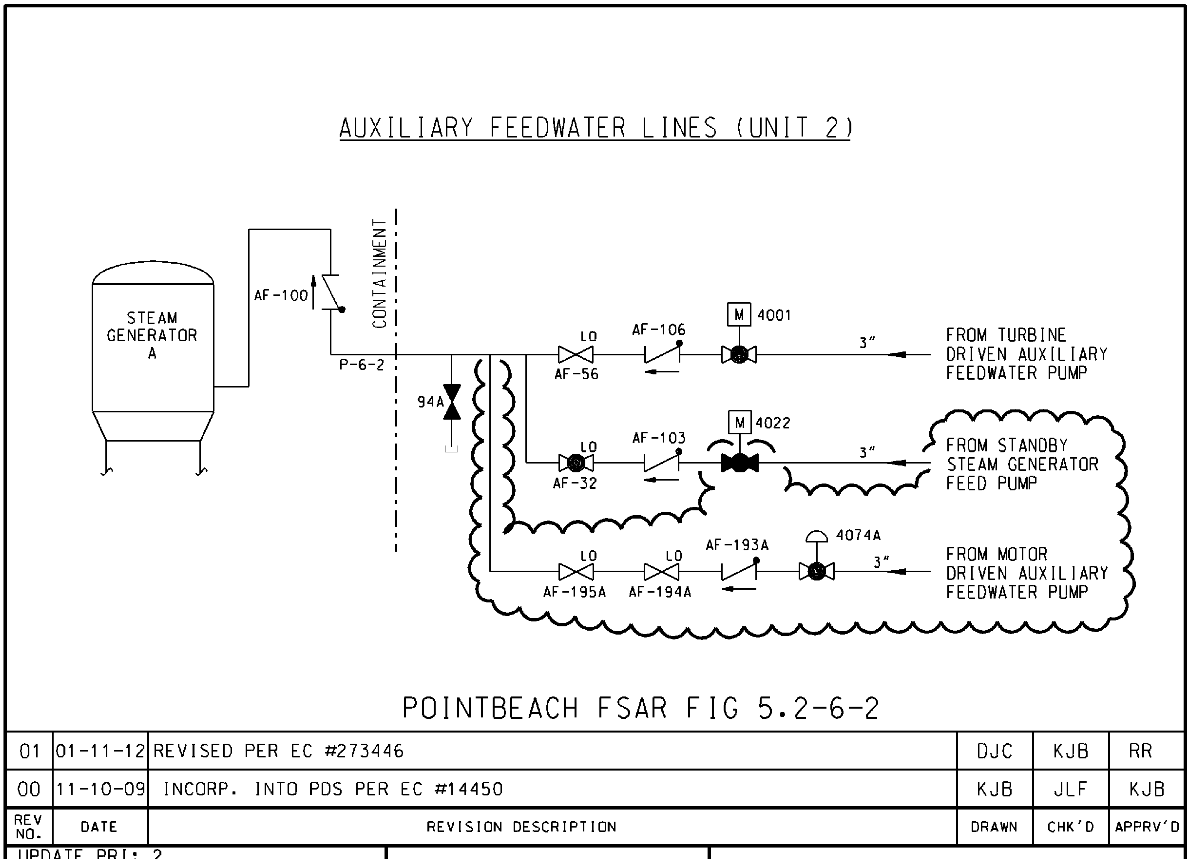
PENETRATION	CONTAINMENT ISOLATION VALVES INSIDE	CONTAINMENT ISOLATION VALVES OUTSIDE	BRANCH/SYSTEM	LINE SIZE	FLUID	TEMP. HOT>200 COLD<200	CLASS
6-1	CLOSED SYSTEM	AF-18	TURBINE DRIVEN AUXILIARY FEED TO STEAM GENERATOR/ AF	3"	W	HOT	4
	CLOSED SYSTEM	AF-31	STANDBY STEAM GENERATOR FEED TO STEAM GENERATOR/ AF	3"	W	HOT	4
	CLOSED SYSTEM	AF-195A	MOTOR DRIVEN AUXILIARY FEED TO STEAM GENERATOR/ AF	3"	W	HOT	4

FOR FURTHER INFORMATION REFER TO FSAR CHAPTER 10 & FIG. 10.2-1 SHEETS 1 AND 2

NOTE:

AUXILIARY FEEDWATER LINES - THESE ARE INCOMING LINES NORMALLY OPERATING AFTER A DBA. THE MANUAL ISOLATION VALVE REQUIREMENT FOR A CLASS 4 PENETRATION IS MET BY VALVES AF-31, AF-18, AND AF-195A.

Figure 5.2-6-2 AUXILIARY FEEDWATER LINES (UNIT 2)

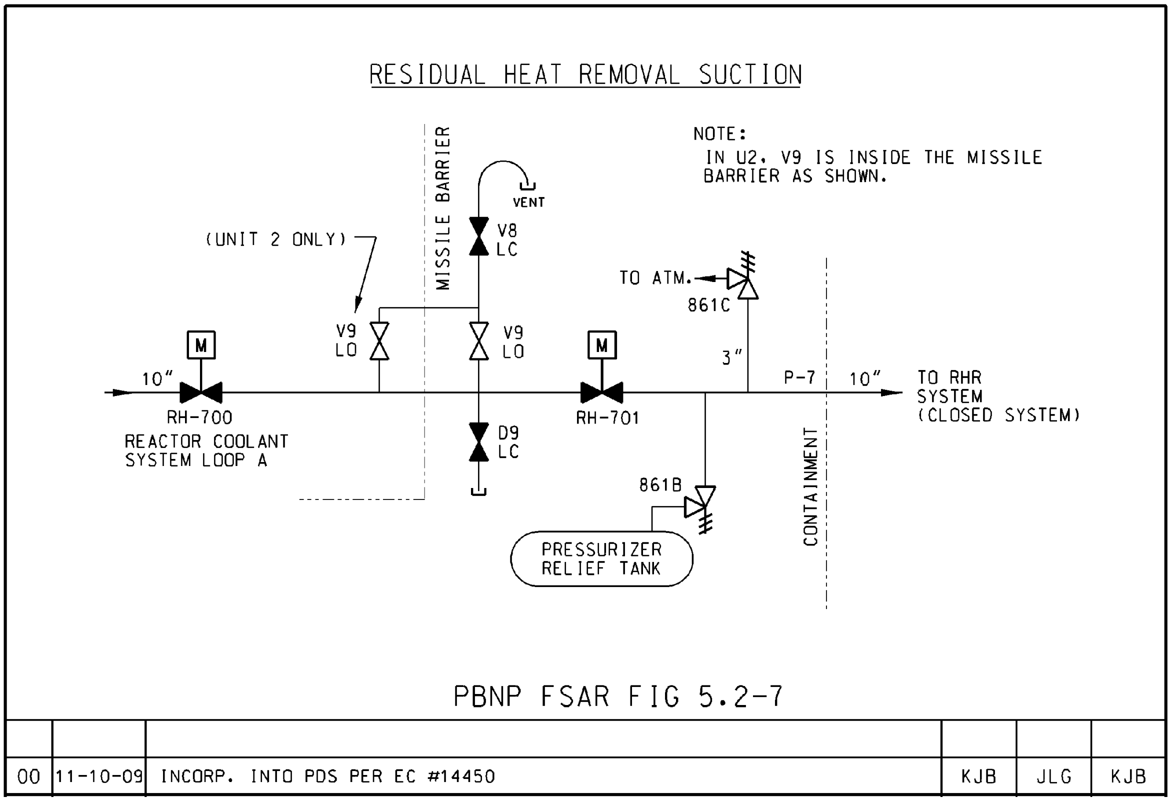


PENETRATION	CONTAINMENT ISOLATION VALVES INSIDE	CONTAINMENT ISOLATION VALVES OUTSIDE	BRANCH/SYSTEM	LINE SIZE	FLUID	TEMP. HOT>200 COLD<200	CLASS
6-2	CLOSED SYSTEM	AF-56	TURBINE DRIVEN AUXILIARY FEED TO STEAM GENERATOR/ AF	3"	W	HOT	4
	CLOSED SYSTEM	AF-32	STANDBY STEAM GENERATOR FEED TO STEAM GENERATOR/ AF	3"	W	HOT	4
	CLOSED SYETEM	AF-195A	MOTOR DRIVEN AUXILIARY FEED TO STEAM GENERATOR/ AF	3"	W	HOT	4

FOR FURTHER INFORMATION REFER TO FSAR CHAPTER 10 & FIG. 10.2-1 SHEETS 1 AND 2

NOTE: AUXILIARY FEEDWATER LINES - THESE ARE INCOMING LINES NORMALLY OPERATING AFTER A DBA. THE MANUAL ISOLATION VALVE REQUIREMENT FOR A CLASS 4 PENETRATION IS MET BY VALVES AF-56, AF-32, AND AF-195A.

Figure 5.2-7 RESIDUAL HEAT REMOVAL SUCTION



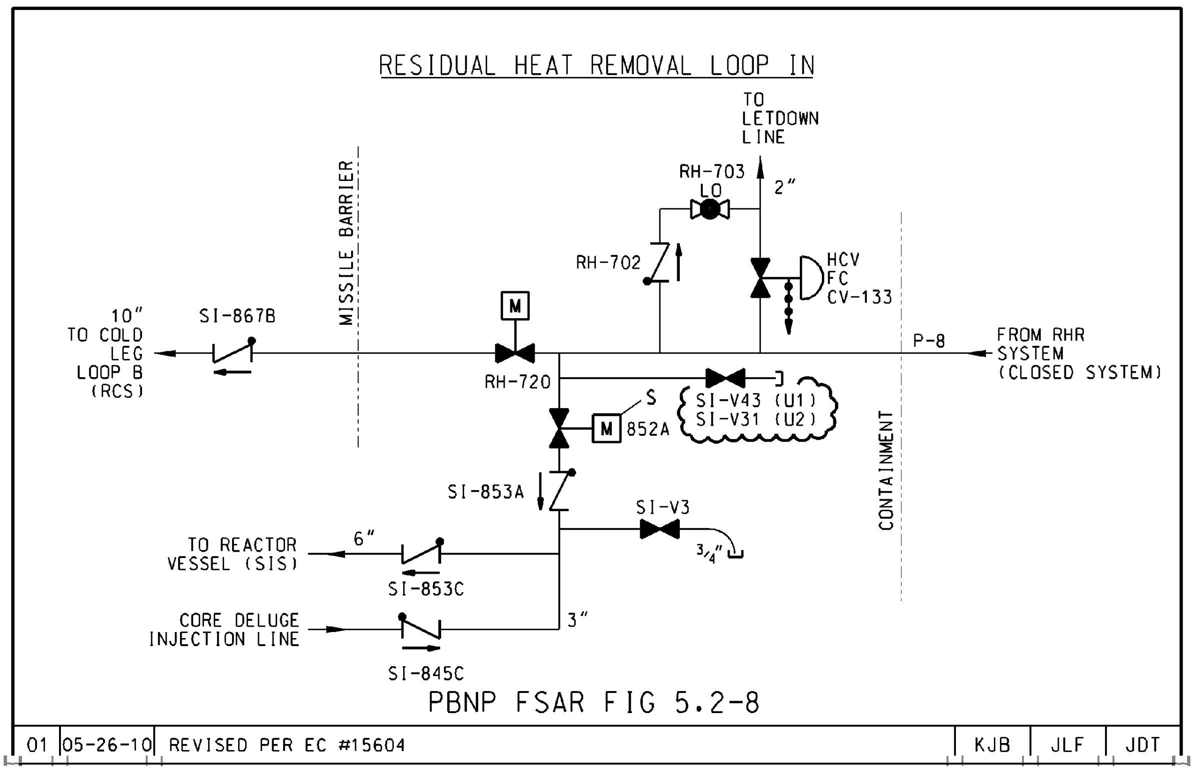
	CONTAINMENT ISOLATION VALVES					TEMP.	
PENETRATION	INSIDE	OUTSIDE	BRANCH/SYSTEM	LINE SIZE	FLUID	HOT>200 COLD<200	CLASS
7	RH-701	CLOSED SYSTEM	RHR	10”	W	HOT	SPECIAL

FOR FURTHER INFORMATION REFER TO FSAR CHAPTER 9 & FIGURE 9.2-1

NOTE:

THIS PENETRATION IS CLASSIFIED SPECIAL AND IS IN USE POST DBA. THE CLOSED SYSTEM OUTSIDE CONTAINMENT PROVIDES THE CONTAINMENT ISLOATION BOUNDARY POST DBA.

Figure 5.2-8 RESIDUAL HEAT REMOVAL LOOP IN



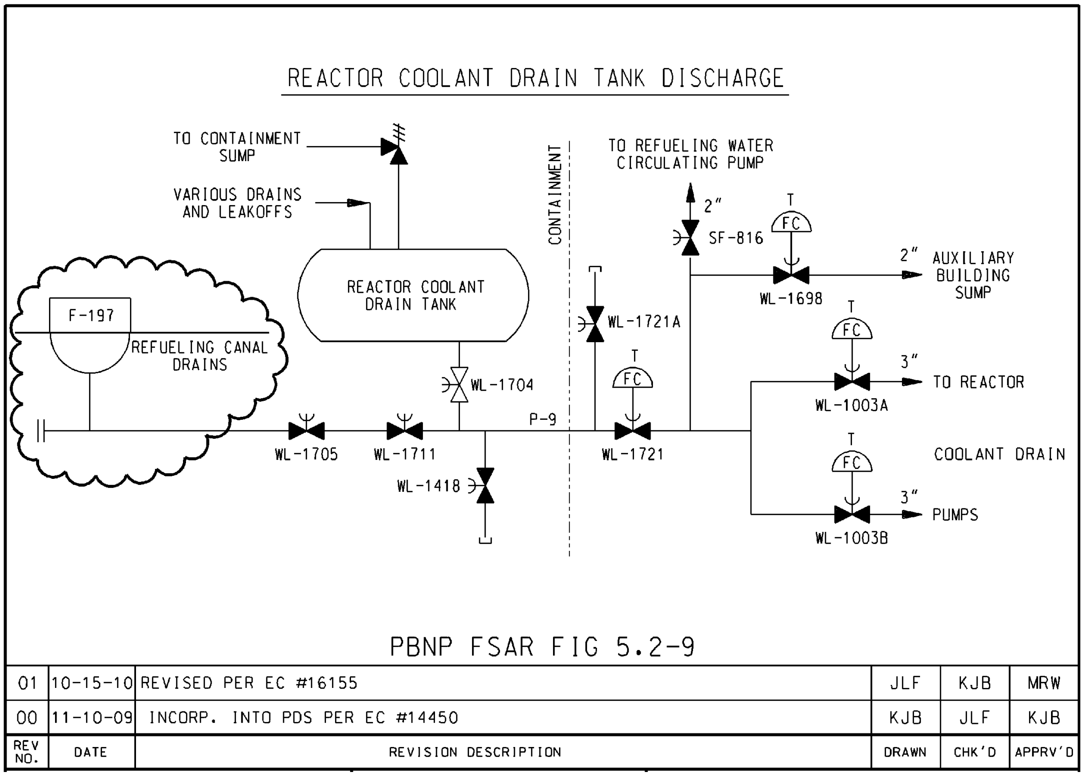
	CONTAINMENT ISOLATION VALVES					TEMP.	
PENETRATION	INSIDE	OUTSIDE	BRANCH/SYSTEM	LINE SIZE	FLUID	HOT>200 COLD<200	CLASS
8	SI-853A RH-720 RH-702 CV-133	CLOSED SYSTEM	RHR INJECTION TO LOOP B COLD LEG/ RHR	10”	W	HOT	SPECIAL

FOR FURTHER INFORMATION REFER TO FSAR CHAPTER 9 & FIGURE 9.3-1, FIGURE 9.4-1

NOTE:

THIS PENETRATION IS CLASSIFIED SPECIAL AND IS IN USE POST DBA. THE CLOSED SYSTEM OUTSIDE CONTAINMENT PROVIDES THE CONTAINMENT ISOLATION BOUNDARY POST DBA.

Figure 5.2-9 REACTOR COOLANT DRAIN TANK DISCHARGE



PENETRATION	CONTAINMENT ISOLATION VALVES INSIDE	CONTAINMENT ISOLATION VALVES OUTSIDE	BRANCH/SYSTEM	LINE SIZE	FLUID	TEMP. HOT>200 COLD<200	CLASS
9		WL-1721 WL-1003A WL-1003B	REACTOR COOLANT DRAIN PUMP SUCTION/WDS	3"	W	COLD	2
		WL-1721 SF-816	REFUELING WATER CIRCULATION PUMP/ WDS	2"	W	COLD	2
		WL--1721 WL-1698	AUXILIARY BUILDING SUMP/WDS	2"	W	COLD	2

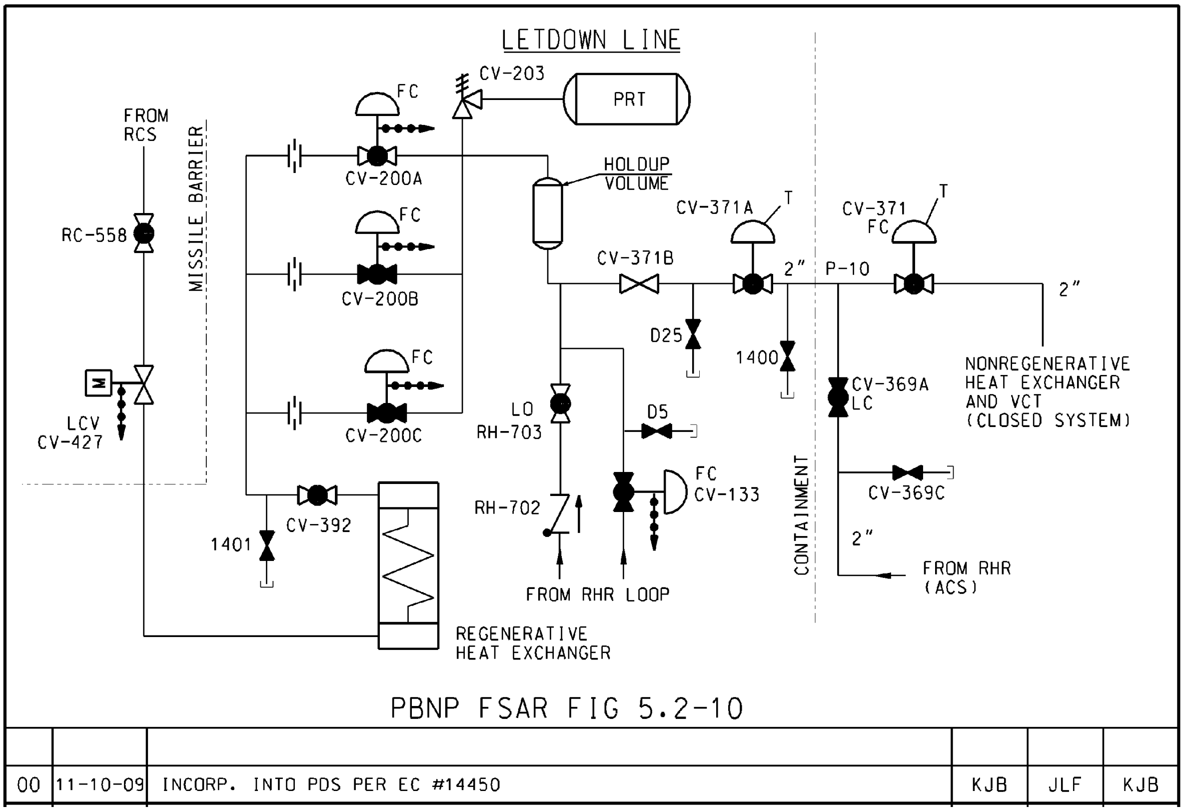
FOR FURTHER INFORMATION REFER TO FSAR CHAPTER 11 & FIGURE 11.1-1

NOTE:

THIS PENETRATION MEETS CLASS 2 CONTAINMENT ISOLATION CRITERIA.

1. REACTOR COOLANT DRAIN PUMP SUCTION BRANCH - AUTOMATIC TRIP VALVE WL-1721 IN SERIES WITH AUTOMATIC TRIP VALVES WL-1003A AND WL-1003B OUTSIDE CONTAINMENT MEET CLASS 2 CRITERIA.
2. REFUELING WATER CIRCULATION PUMP BRANCH - AUTOMATIC TRIP VALVE WL-1721 IN SERIES WITH LOCKED CLOSED MANUAL VALVE SF-816 SERVING THE PURPOSE OF AN AUTOMATIC TRIP VALVE OUTSIDE CONTAINMENT MEET CLASS 2 CRITERIA.
3. AUXILIARY BUILDING SUMP BRANCH - AUTOMATIC TRIP VALVE WL-1721 IN SERIES WITH AUTOMATIC TRIP VALVE WL-1698 OUTSIDE CONTAINMENT MEET CLASS 2 CRITERIA.

Figure 5.2-10 LETDOWN LINE



PENETRATION	CONTAINMENT ISOLATION VALVES INSIDE	OUTSIDE	BRANCH/SYSTEM	LINE SIZE	FLUID	TEMP. HOT>200 COLD<200	CLASS
10	CV-371A	CV-371	LETDOWN LINE/RCS	2"	W	HOT	1
	CV-371A	CV-369A	RHR PUMP DISCHARGE TO LETDOWN LINE/RHR	2"	W	HOT	1

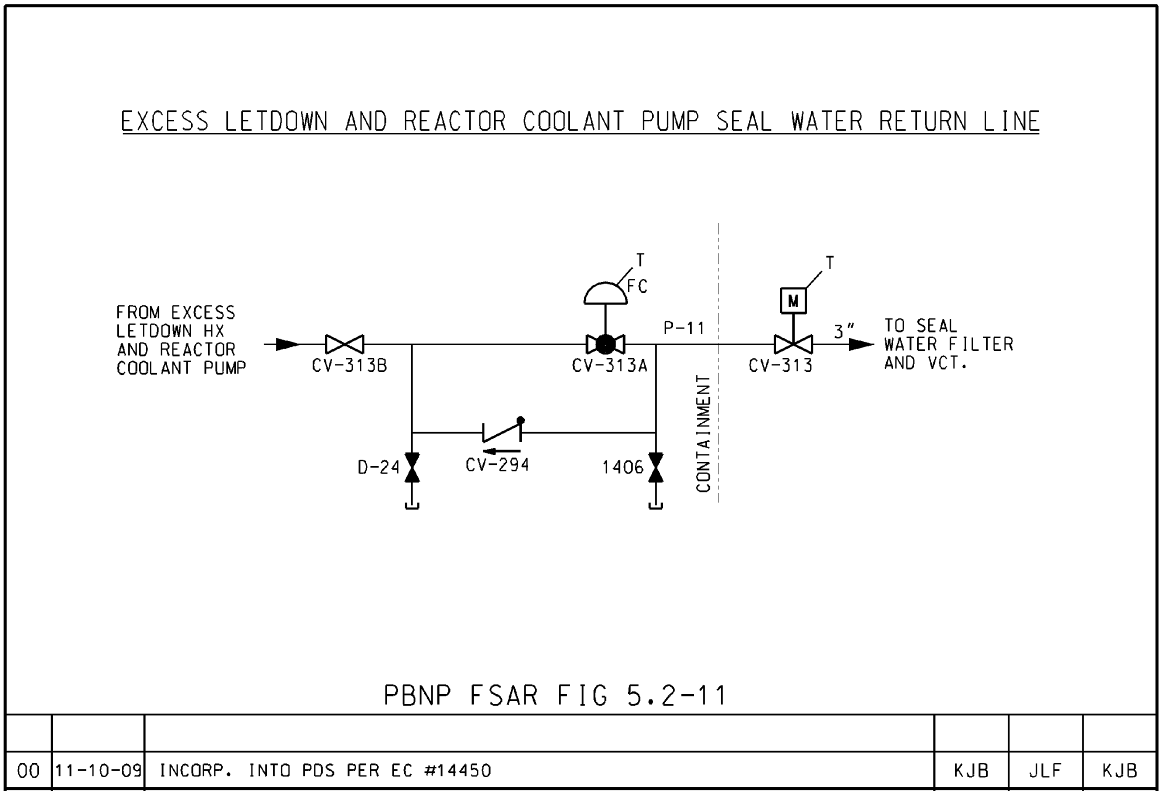
FOR FURTHER INFORMATION REFER TO FSAR CHAPTER 9 & FIGURE 9.2-1, 9.2-2

NOTE:

THIS PENETRATION MEETS CLASS 1 CONTAINMENT ISOLATION CRITERIA.

1. LETDOWN LINE BRANCH - AUTOMATIC TRIP VALVES CV-371A INSIDE CONTAINMENT AND CV-371 OUTSIDE CONTAINMENT MEET CLASS 1 CRITERIA.
2. RHR PUMP DISCHARGE TO LETDOWN LINE BRANCH - AUTOMATIC TRIP VALVE CV-371A INSIDE CONTAINMENT AND LOCKED SHUT MANUAL VALVE CV-369A OUTSIDE CONTAINMENT SERVING THE PURPOSE OF AN AUTOMATIC TRIP VALVE MEET CLASS 1 CRITERIA.

Figure 5.2-11 EXCESS LETDOWN AND REACTOR COOLANT PUMP SEAL WATER RETURN LINE



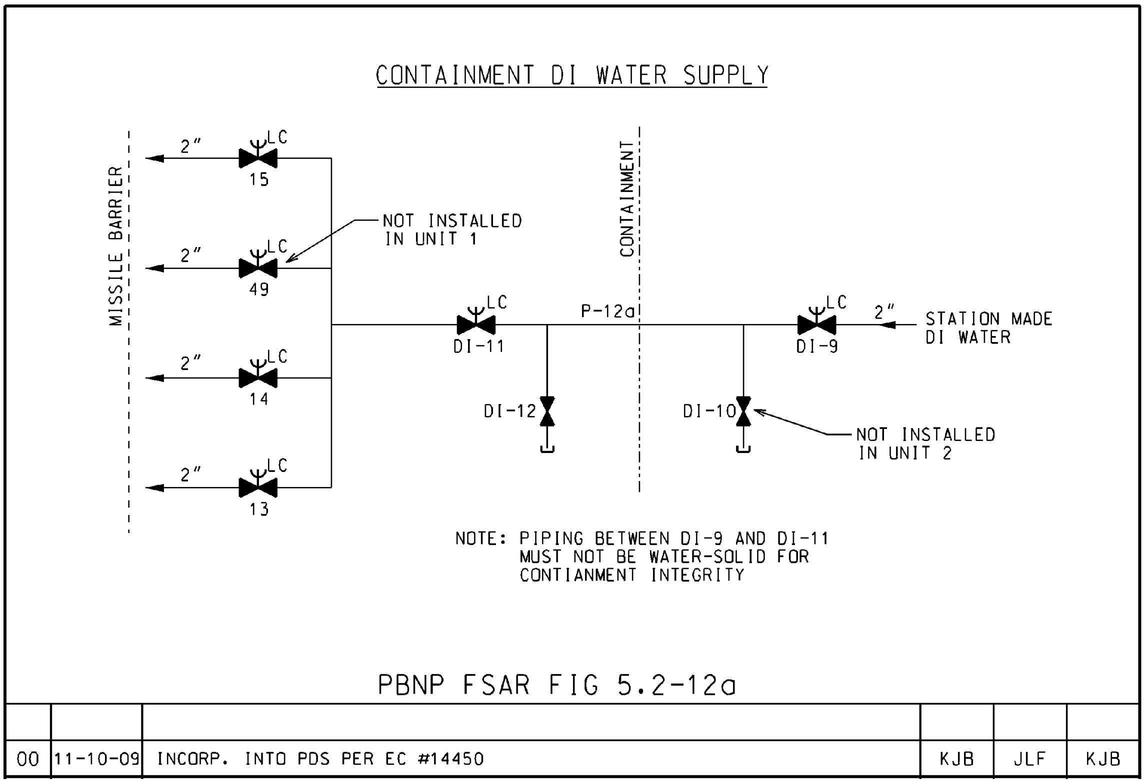
	CONTAINMENT ISOLATION VALVES					TEMP.	
PENETRATION	INSIDE	OUTSIDE	BRANCH/SYSTEM	LINE SIZE	FLUID	HOT>200 COLD<200	CLASS
11	CV-313A CV-294	CV-313	EXCESS LETDOWN AND REACTOR COOLANT PUMP SEAL WATER RETURN/CV	3”	W	HOT	1

FOR FURTHER INFORMATION REFER TO FSAR CHAPTER 9

NOTE:

THIS PENETRATION MEETS CLASS 1 CONTAINMENT ISOLATION CRITERIA WITH AUTOMATIC TRIP VALVES CV-313A INSIDE CONTAINMENT AND CV-313 OUTSIDE CONTAINMENT.

Figure 5.2-12a CONTAINMENT DI WATER SUPPLY

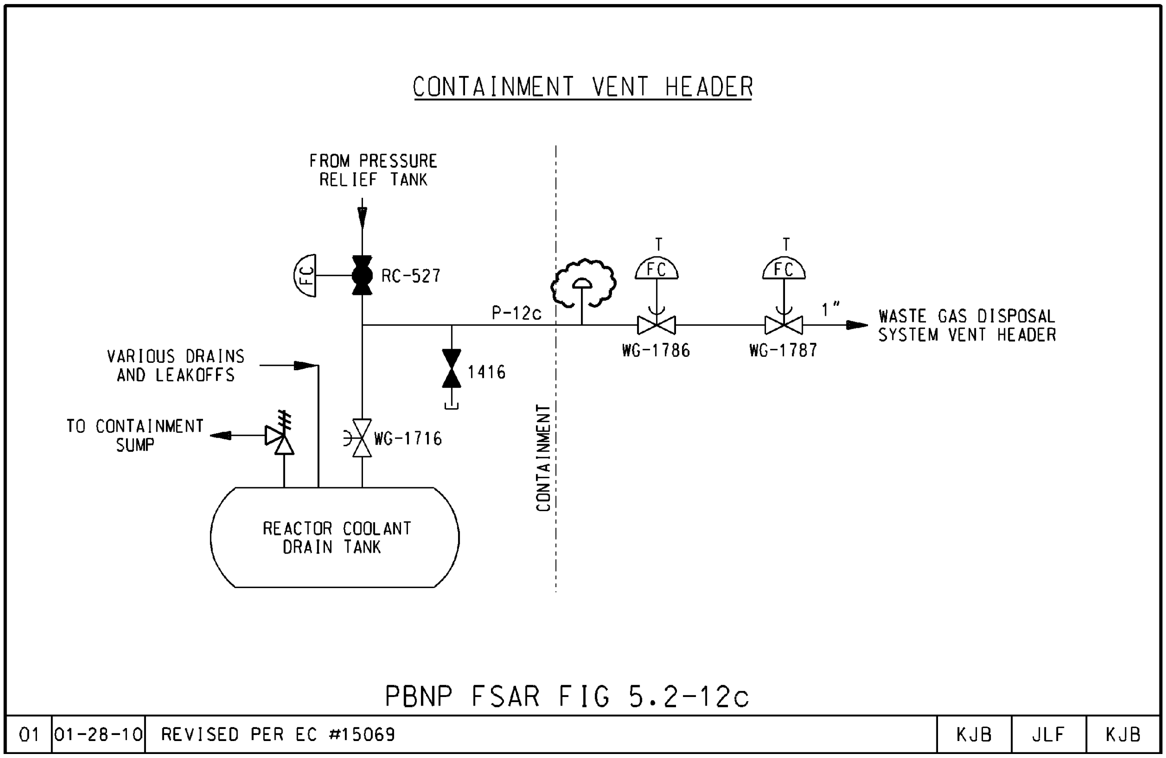


PENETRATION	CONTAINMENT ISOLATION VALVES INSIDE	OUTSIDE	BRANCH/SYSTEM	LINE SIZE	FLUID	TEMP. HOT>200 COLD<200	CLASS
12a	DI-11	DI-9	CONTAINMENT SECTION DI WATER CONNECTIONS	2”	W	COLD	5

NOTE:

THIS PENETRATION MEETS CLASS 5 CONTAINMENT ISOLATION CRITERIA WITH LOCKED CLOSED MANUAL VALVE DI-11 INSIDE CONTAINMENT AND LOCKED CLOSED MANUAL VALVE DI-9 OUTSIDE CONTAINMENT.

Figure 5.2-12c CONTAINMENT VENT HEADER



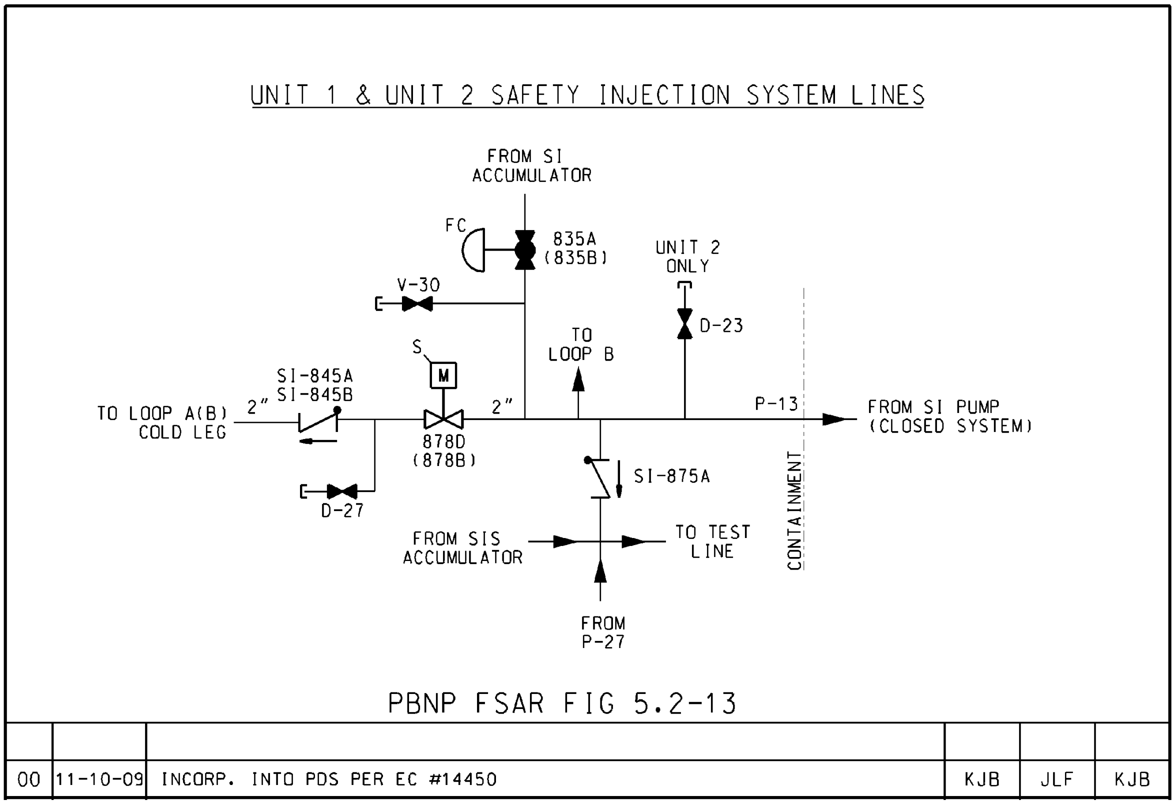
PENETRATION	CONTAINMENT ISOLATION VALVES INSIDE	OUTSIDE	BRANCH/SYSTEM	LINE SIZE	FLUID	TEMP. HOT>200 COLD<200	CLASS
12c		WG-1786 WG-1787	REACTOR COOLANT DRAIN TANK TO VENT HEADER/WDS	1"	G	COLD	2

FOR FURTHER INFORMATION REFER TO FSAR CHAPTER 11 & FIGURE 11.1-1

NOTE:

THIS PENETRATION MEETS CLASS 2 CONTAINMENT ISOLATION CRITERIA WITH AUTOMATIC TRIP VALVES WG-1786 AND WG-1787 IN SERIES OUTSIDE CONTAINMENT.

Figure 5.2-13 UNIT 1 AND UNIT 2 SAFETY INJECTION SYSTEM LINES



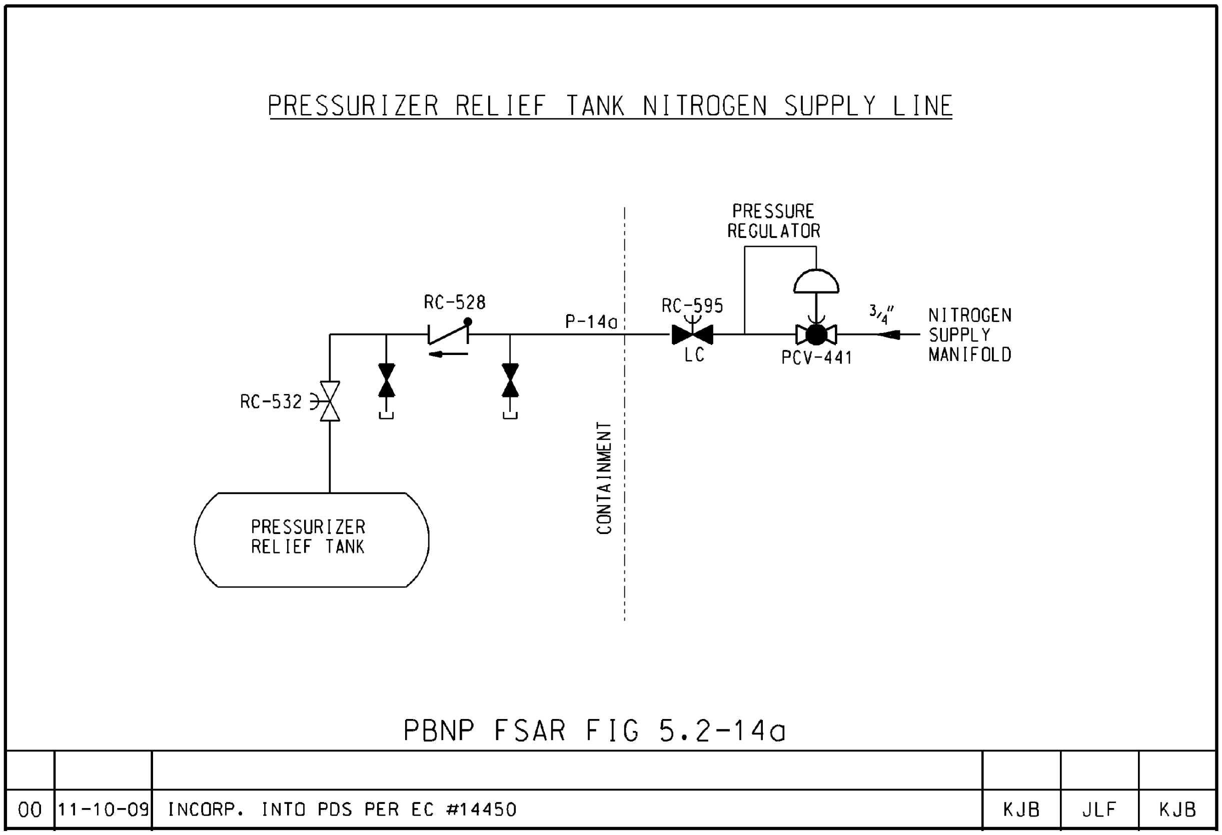
PENETRATION	CONTAINMENT ISOLATION VALVES INSIDE	OUTSIDE	BRANCH/SYSTEM	LINE SIZE	FLUID	TEMP. HOT>200 COLD<200	CLASS
13	SI-845A,B SI-875B SI-835A,B	CLOSED SYS	SAFETY INJECTION SYS COLD LEG/SIS	4"	W	COLD	SPECIAL

FOR FURTHER INFORMATION REFER TO FSAR CHAPTER 6

NOTE:

THIS PENETRATION IS CLASSIFIED SPECIAL AND IS IN USE POST DBA. THE CLOSED SYSTEM OUTSIDE CONTAINMENT PROVIDES THE CONTAINMENT ISOLATION BOUNDARY POST DBA.

Figure 5.2-14a PRESSURIZER RELIEF TANK NITROGEN SUPPLY LINE



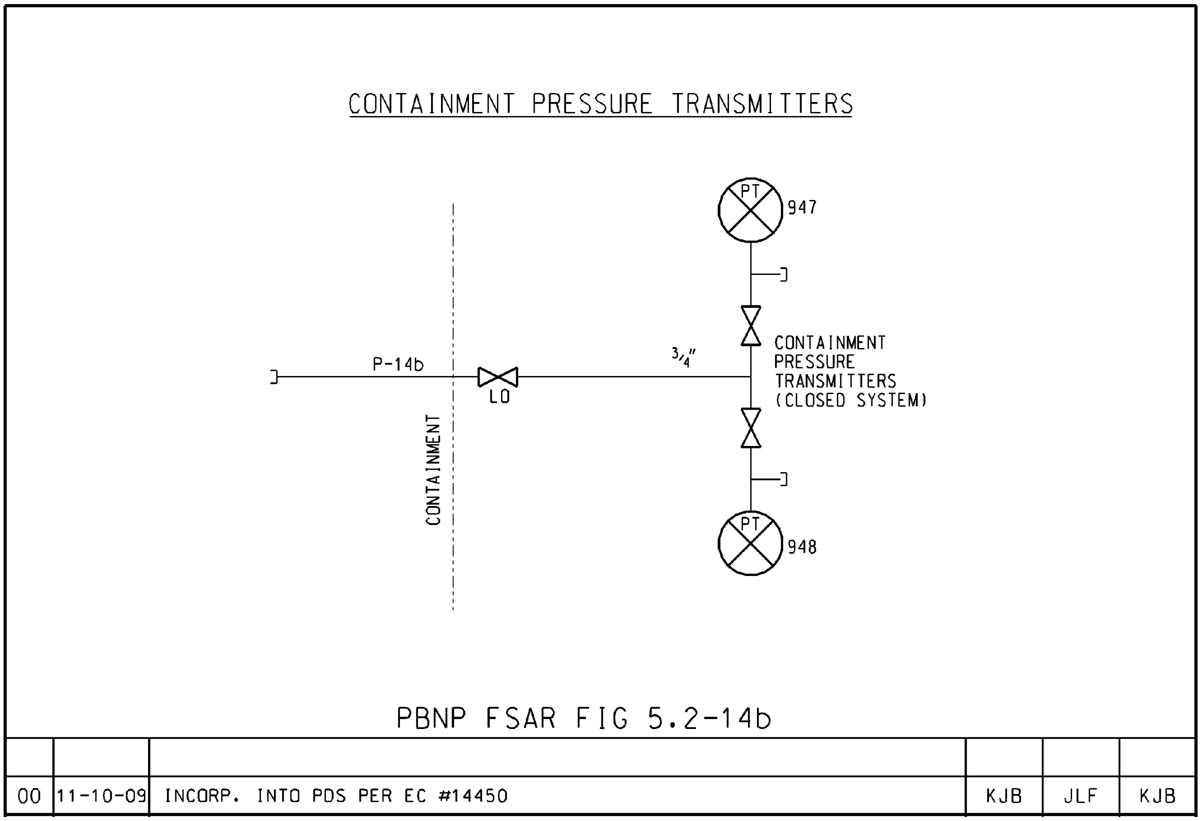
PENETRATION	CONTAINMENT ISOLATION VALVES INSIDE	OUTSIDE	BRANCH/SYSTEM	LINE SIZE	FLUID	TEMP. HOT>200 COLD<200	CLASS
14a	RC-528	RC-595	NITROGEN SUPPLY TO PRESSURE RELIEF TANK /REACTOR COOLANT SYS.	3/4”	G	COLD	3

FOR FURTHER INFORMATION REFER TO FSAR CHAPTER 4 & FIGURE 4.2-1 SHT. 2

NOTE:

THIS PENETRATION MEETS CLASS 3 CONTAINMENT ISOLATION CRITERIA WITH CHECK VALVE RC-528 INSIDE CONTAINMENT SERVING THE PURPOSE OF AN AUTOMATIC TRIP VALVE AND LOCKED CLOSED MANUAL VALVE RC-595 OUTSIDE CONTAINMENT SERVING THE PURPOSE OF AN AUTOMATIC TRIP VALVE.

Figure 5.2-14b CONTAINMENT PRESSURE TRANSMITTERS

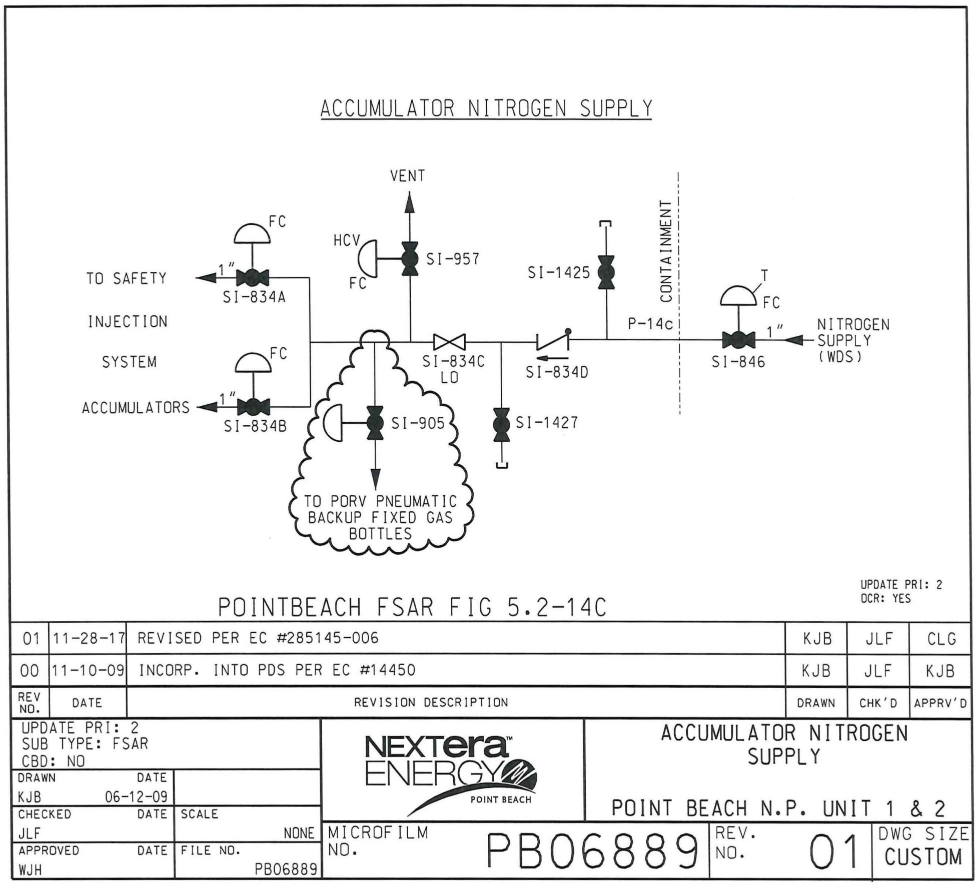


	CONTAINMENT ISOLATION VALVES					TEMP.	
PENETRATION	INSIDE	OUTSIDE	BRANCH/SYSTEM	LINE SIZE	FLUID	HOT>200 COLD<200	CLASS
14b		MANUAL VALVE CLOSED SYS.	CONTAINMENT PRESSURE TRANSMITTER.	3/4"	G	COLD	SPECIAL

NOTE:

THIS PENETRATION IS CLASSIFIED SPECIAL AND IS IN USE POST DBA. THE CLOSED SYSTEM OUTSIDE CONTAINMENT PROVIDES THE CONTAINMENT ISOLATION BOUNDARY POST DBA.

Figure 5.2-14c ACCUMULATOR NITROGEN SUPPLY



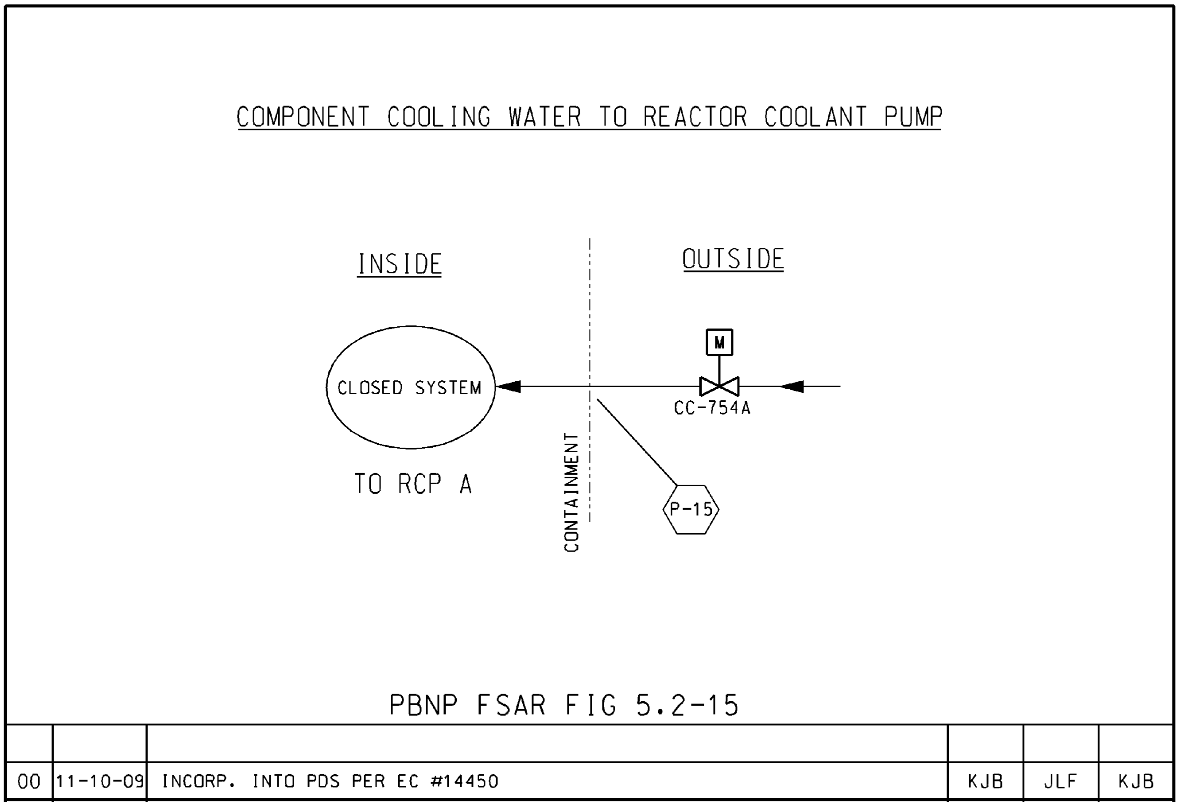
	CONTAINMENT ISOLATION VALVES					TEMP.	
PENETRATION	INSIDE	OUTSIDE	BRANCH/SYSTEM	LINE SIZE	FLUID	HOT>200 COLD<200	CLASS
14c	SI-834D	SI-846	NITROGEN SUPPLY TO ACCUMULATOR/ SAFETY INJECTION SYSTEM.	1"	G	COLD	3

FOR FURTHER INFORMATION REFER TO FSAR CHAPTER 6 & FIGURE 6.2-1 SHEET 1

NOTE:

THIS MEETS CLASS 3 CRITERIA. SI-846 MEETS THE REQUIREMENT TO HAVE AN AUTOMATIC TRIP VALVE OUTSIDE CONTAINMENT. CHECK VALVE SI-834D MEETS THE REQUIREMENT TO HAVE AN AUTOMATIC TRIP VALVE INSIDE CONTAINMENT.

Figure 5.2-15 COMPONENT COOLING WATER TO REACTOR COOLANT PUMP

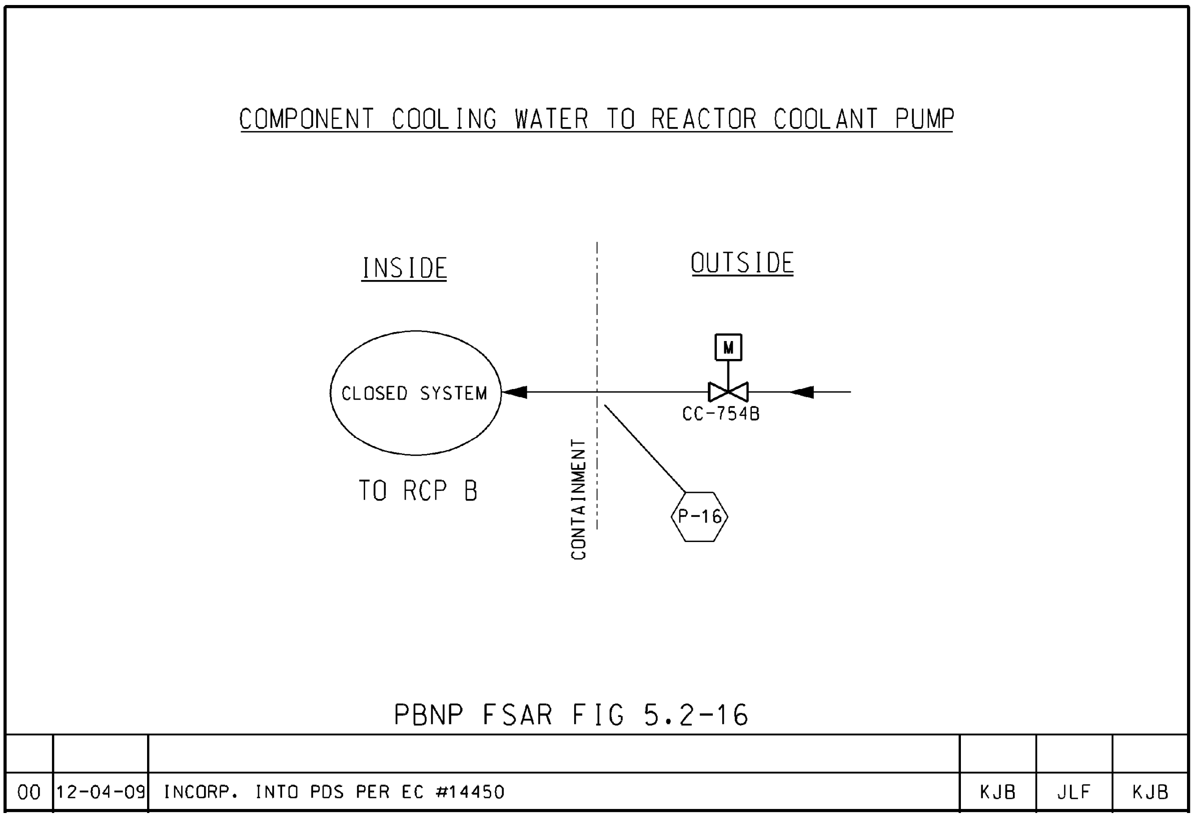


PENETRATION	CONTAINMENT ISOLATION VALVES INSIDE	OUTSIDE	BRANCH/SYSTEM	LINE SIZE	FLUID	TEMP. HOT>200 COLD<200	CLASS
15	CLOSED SYSTEM	CC-754A	CC WATER SUPPLY TO RCP A.	4”	W	COLD	4

NOTE:

THIS PENETRATION MEETS CLASS 4 CONTAINMENT ISOLATION CRITERIA WITH CLOSED SYSTEM INSIDE CONTAINMENT AND REMOTELY OPERATED VALVE CC-754A OUTSIDE CONTAINMENT.

Figure 5.2-16 COMPONENT COOLING WATER TO REACTOR COOLANT PUMP

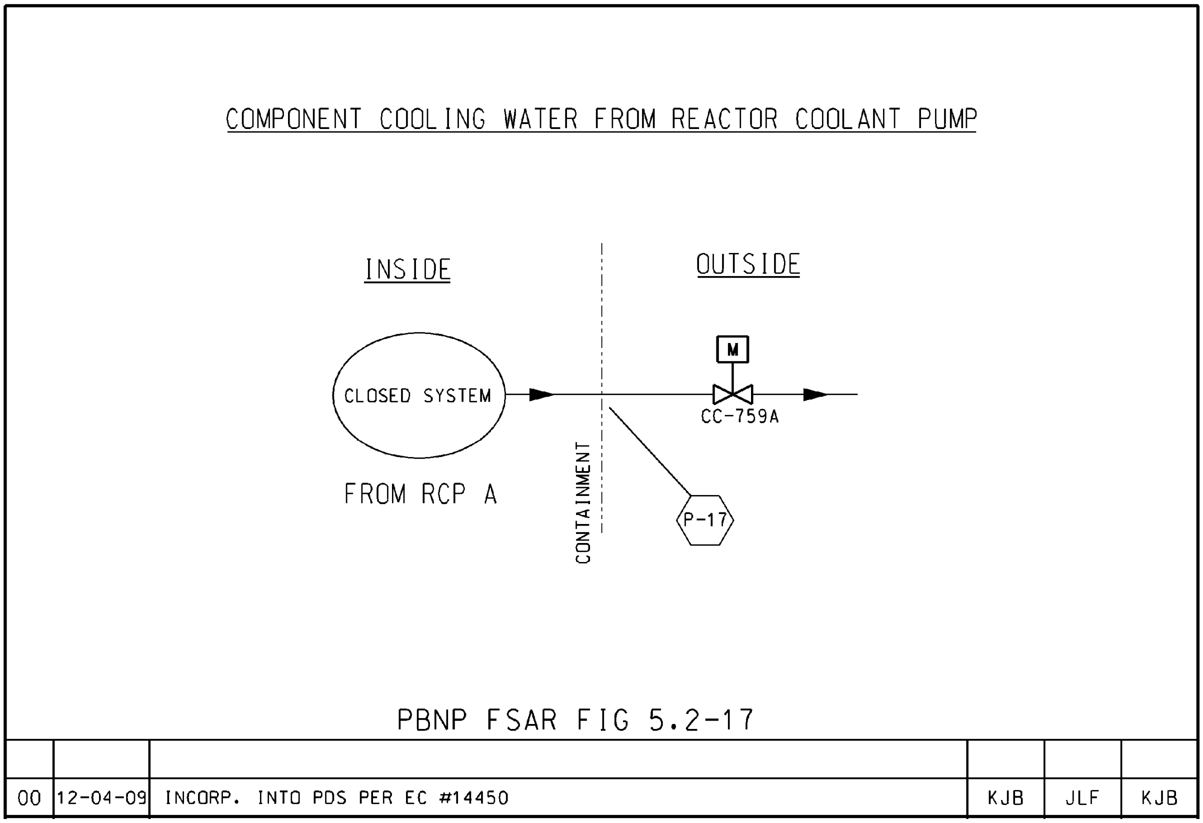


	CONTAINMENT ISOLATION VALVES					TEMP.	
PENETRATION	INSIDE	OUTSIDE	BRANCH/SYSTEM	LINE SIZE	FLUID	HOT>200 COLD<200	CLASS
16	CLOSED SYSTEM	CC-754B	CC WATER SUPPLY TO RCP B.	4”	W	COLD	4

NOTE:

THIS PENETRATION MEETS CLASS 4 CONTAINMENT ISOLATION CRITERIA WITH CLOSED SYSTEM INSIDE CONTAINMENT AND REMOTELY OPERATED VALVE CC-754B OUTSIDE CONTAINMENT.

Figure 5.2-17 COMPONENT COOLING WATER FROM REACTOR COOLANT PUMP

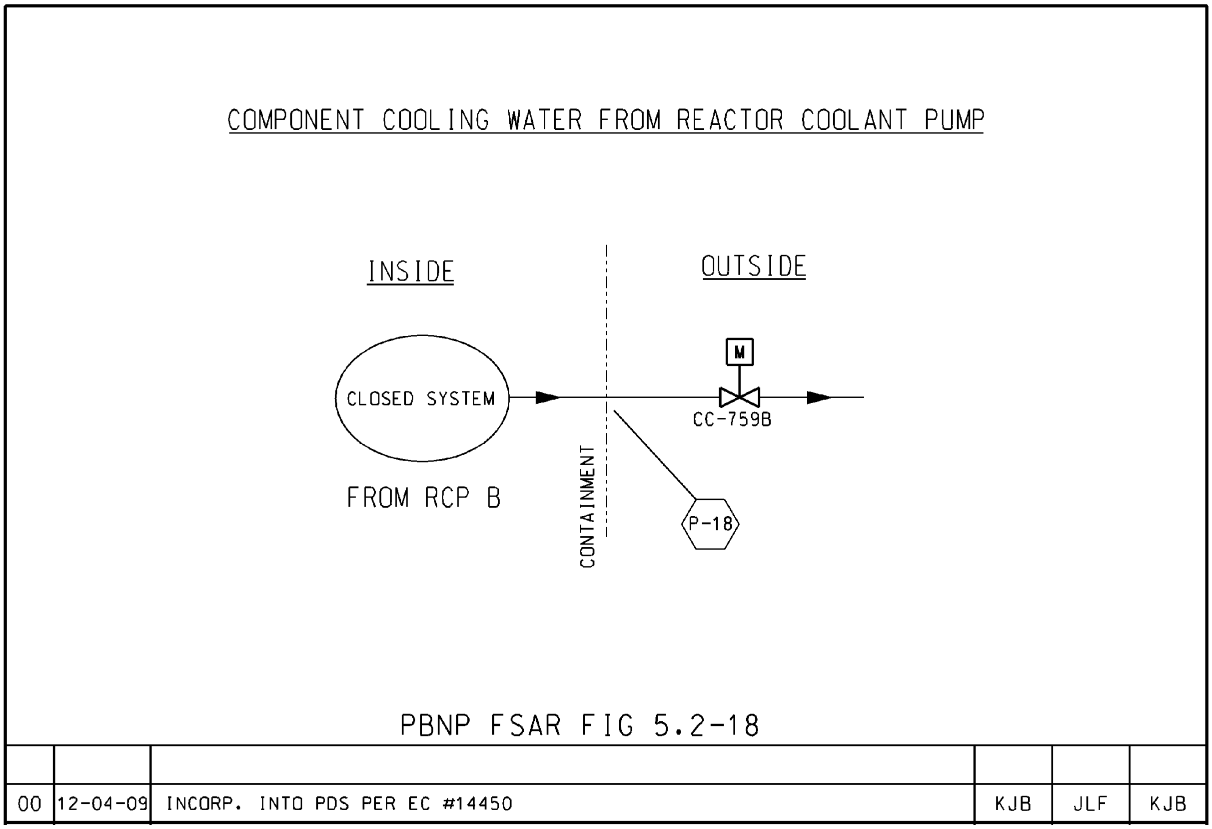


PENETRATION	CONTAINMENT ISOLATION VALVES		BRANCH/SYSTEM	LINE SIZE	FLUID	TEMP.	CLASS
	INSIDE	OUTSIDE				HOT>200 COLD<200	
17	CLOSED SYSTEM	CC-759A	CC WATER RETURN FROM RCP A.	4”	W	COLD	4

NOTE:

THIS PENETRATION MEETS CLASS 4 CONTAINMENT ISOLATION CRITERIA WITH CLOSED SYSTEM INSIDE CONTAINMENT AND REMOTELY OPERATED VALVE CC-759A OUTSIDE CONTAINMENT.

Figure 5.2-18 COMPONENT COOLING WATER FROM REACTOR COOLANT PUMP

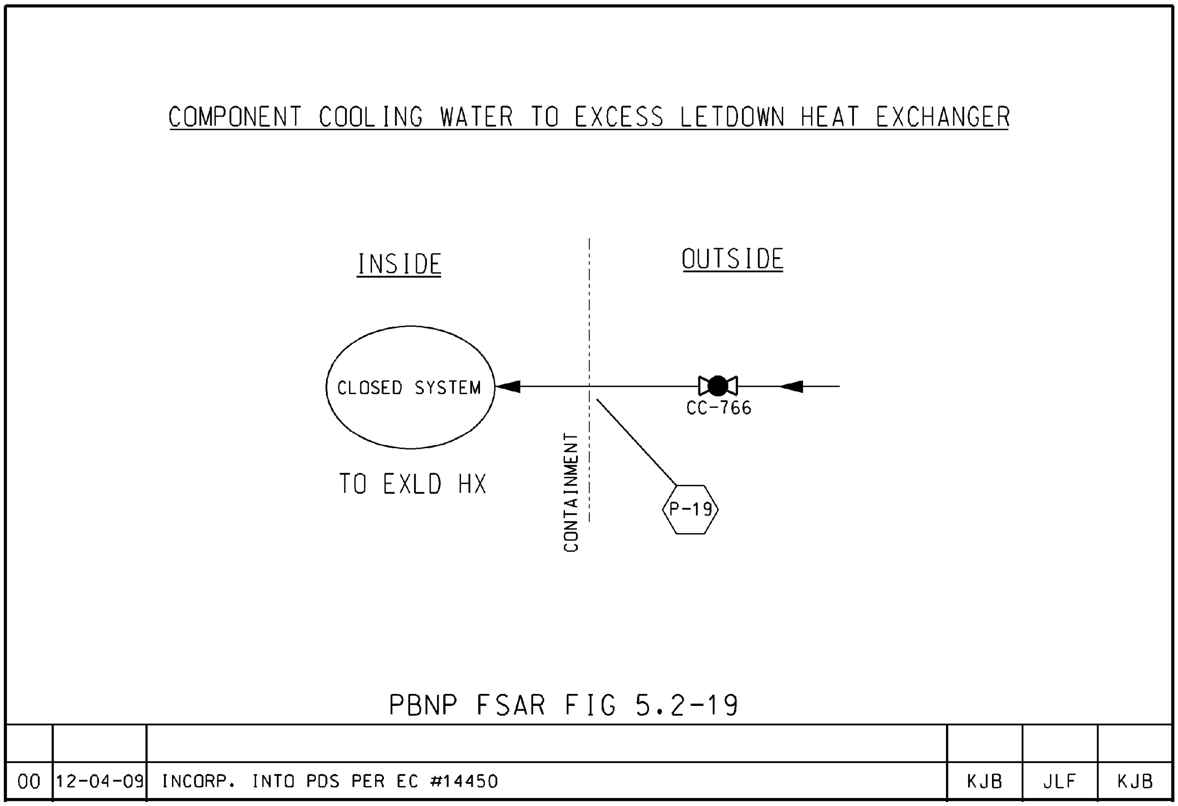


PENETRATION	CONTAINMENT ISOLATION VALVES INSIDE	OUTSIDE	BRANCH/SYSTEM	LINE SIZE	FLUID	TEMP. HOT>200 COLD<200	CLASS
18	CLOSED SYSTEM	CC-759B	CC WATER RETURN FROM RCP B.	4"	W	COLD	4

NOTE:

THIS PENETRATION MEETS CLASS 4 CONTAINMENT ISOLATION CRITERIA WITH CLOSED SYSTEM INSIDE CONTAINMENT AND REMOTELY OPERATED VALVE CC-759B OUTSIDE CONTAINMENT.

Figure 5.2-19 COMPONENT COOLING WATER TO EXCESS LETDOWN HEAT EXCHANGER

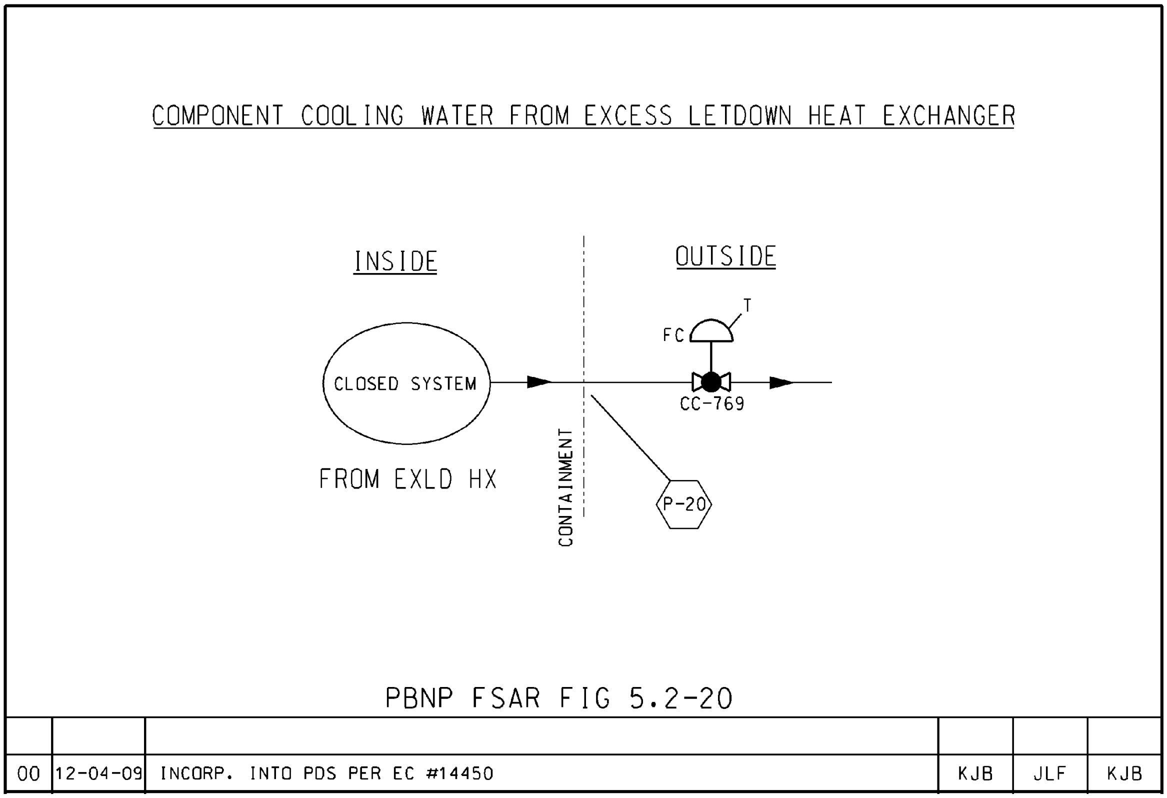


PENETRATION	CONTAINMENT ISOLATION VALVES INSIDE	OUTSIDE	BRANCH/SYSTEM	LINE SIZE	FLUID	TEMP. HOT>200 COLD<200	CLASS
19	CLOSED SYSTEM	CC-766	CC WATER SUPPLY TO EXCESS LETDOWN HEAT EXCHANGER.	2”	W	COLD	4

NOTE:

THIS PENETRATION MEETS CLASS 4 CONTAINMENT ISOLATION CRITERIA WITH CLOSED SYSTEM INSIDE CONTAINMENT AND MANUALLY OPERATED VALVE CC-766 OUTSIDE CONTAINMENT.

Figure 5.2-20 COMPONENT COOLING WATER FROM EXCESS LETDOWN HEAT EXCHANGER

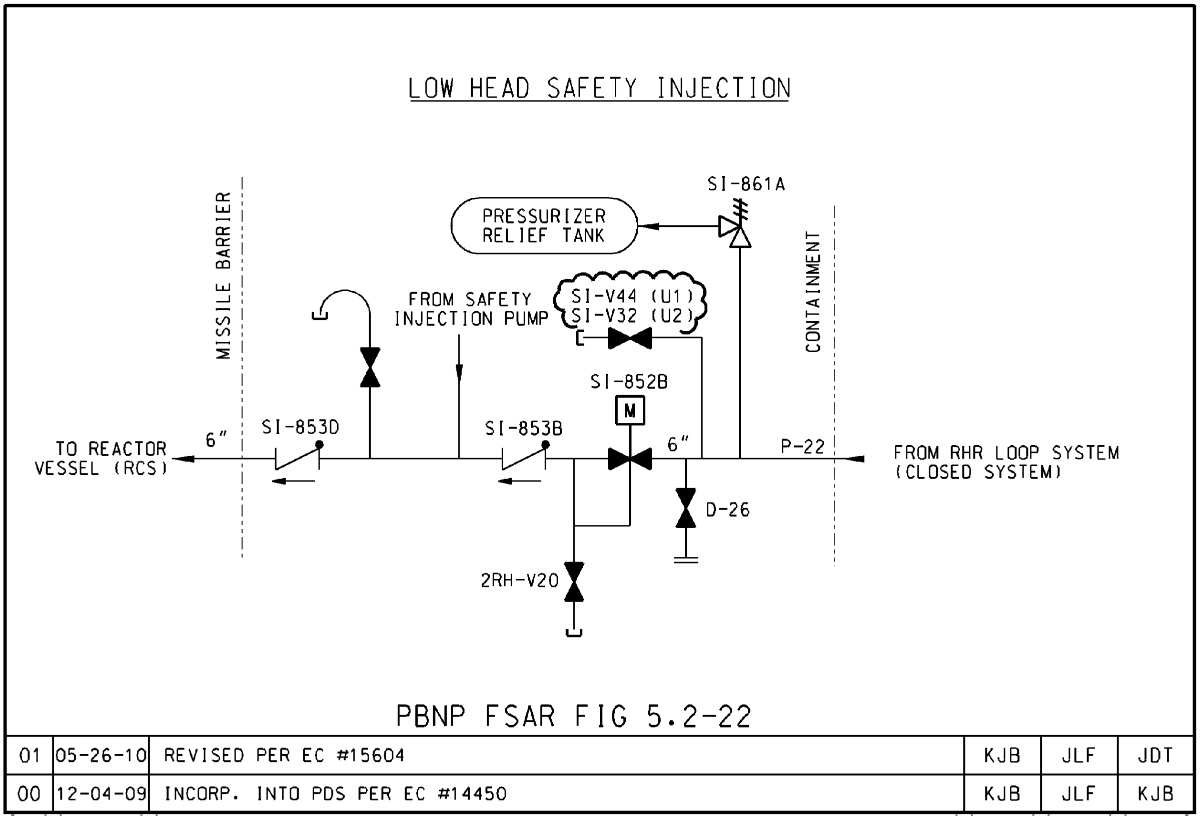


	CONTAINMENT ISOLATION VALVES					TEMP.	
PENETRATION	INSIDE	OUTSIDE	BRANCH/SYSTEM	LINE SIZE	FLUID	HOT>200 COLD<200	CLASS
20	CLOSED SYSTEM	CC-769	CC WATER RETURN FROM EXCESS LETDOWN HEAT EXCHANGER.	2”	W	COLD	4

NOTE:

THIS PENETRATION MEETS CLASS 4 CONTAINMENT ISOLATION CRITERIA WITH CLOSED SYSTEM INSIDE CONTAINMENT AND AUTOMATIC TRIP VALVE CC-769 OUTSIDE CONTAINMENT.

Figure 5.2-22 LOW HEAD SAFETY INJECTION



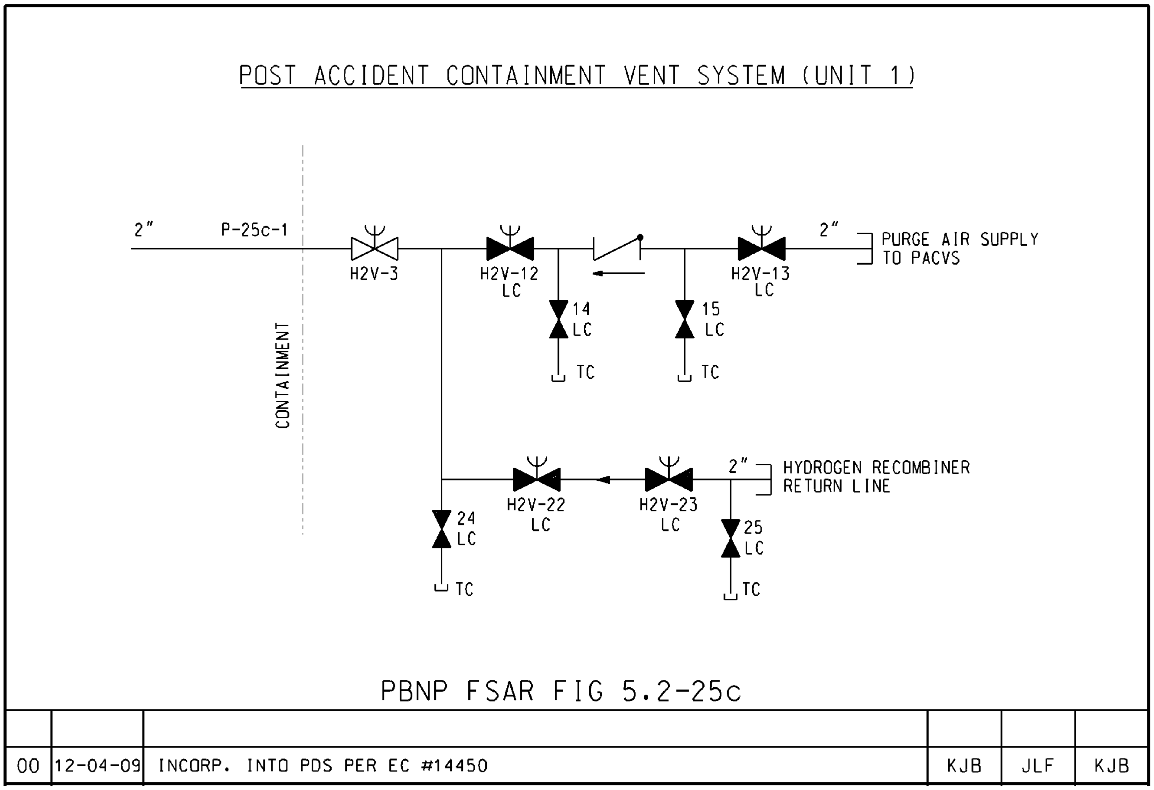
	CONTAINMENT ISOLATION VALVES					TEMP.	
PENETRATION	INSIDE	OUTSIDE	BRANCH/SYSTEM	LINE SIZE	FLUID	HOT>200 COLD<200	CLASS
22	SI-853B	CLOSED SYSTEM.	REACTOR VESSEL INJECTION LINE/ SAFETY INJECTION SYSTEM.	6”	W	HOT	SPECIAL

FOR FURTHER INFORMATION REFER TO FSAR CHAPTER 6 & FIGURE 6.2-1 SHT. 1

NOTE:

THIS PENETRATION IS CLASSIFIED SPECIAL AND IS IN USE POST DBA. THE CLOSED SYSTEM OUTSIDE CONTAINMENT PROVIDES THE CONTAINMENT ISOLATION BOUNDARY POST DBA.

Figure 5.2-25c POST-ACCIDENT CONTAINMENT VENT SYSTEM (UNIT 1)



PENETRATION	CONTAINMENT ISOLATION VALVES INSIDE	OUTSIDE	BRANCH/SYSTEM	LINE SIZE	FLUID	TEMP. HOT>200 COLD<200	CLASS
25c-1		H2V-12 H2V-13	PURGE AIR TO POST ACCIDENT CONTAINMENT VENT SYS./PACVS	2"	G	COLD	SPECIAL
		H2V-22 H2V-23	H_2 RECOMBINER RETURN LINE/PACVS	2"	G	COLD	SPECIAL

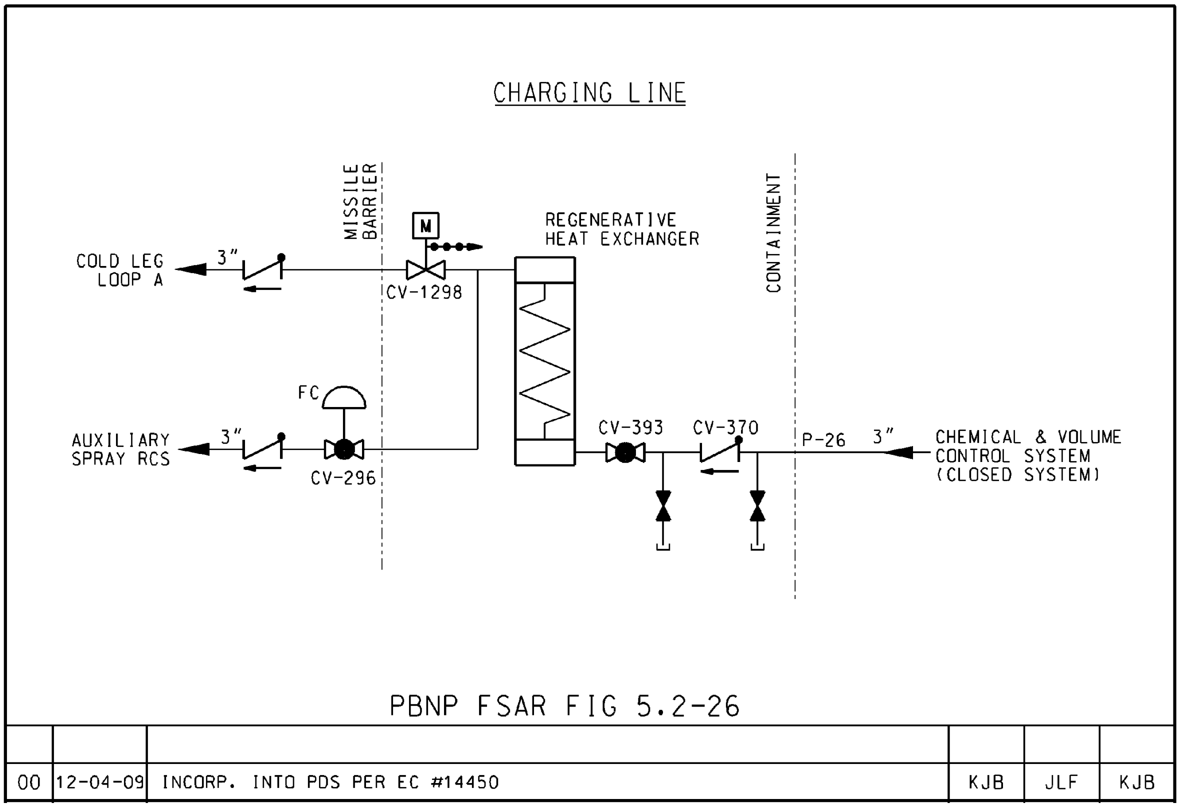
FOR FURTHER INFORMATION REFER TO FSAR CHAPTER 5 & FIGURE 5.3-1 SHEET 2 & FIGURE 5.3-1 SHEET 3

NOTE:

THIS PENETRATION IS CLASSIFIED SPECIAL AND IS IDENTIFIED AS AN INTERMITTENT USE SYSTEM POST DBA.

1. PURGE AIR SUPPLY BRANCH - LOCKED CLOSED MANUAL VALVES H2V-12 AND H2V-13 OUTSIDE CONTAINMENT MEET CONTAINMENT ISOLATION CRITERIA.
2. HYDROGEN RECOMBINER BRANCH - LOCKED CLOSED MANUAL VALVES HSV-22 AND H2V-23 OUTSIDE CONTAINMENT MEET CONTAINMENT ISOLATION CRITERIA.

Figure 5.2-26 CHARGING LINE



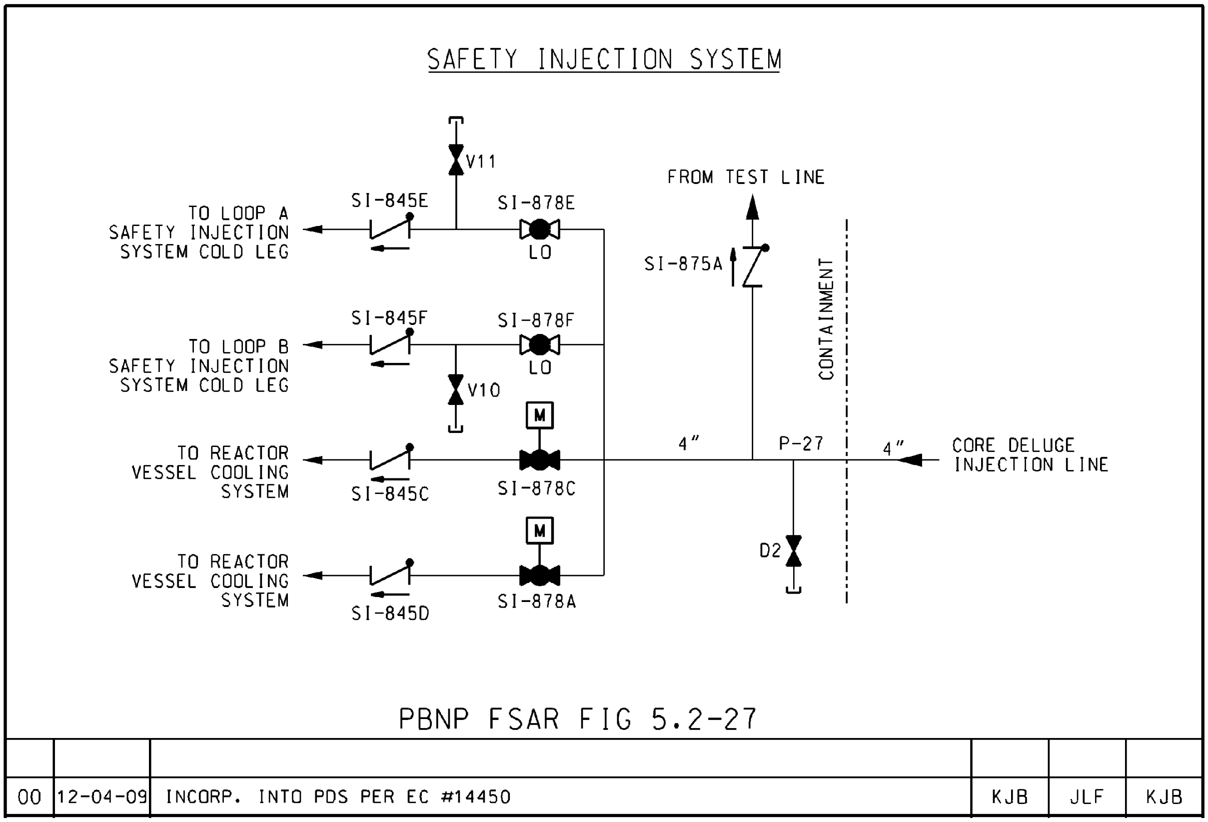
PENETRATION	CONTAINMENT ISOLATION VALVES INSIDE	OUTSIDE	BRANCH/SYSTEM	LINE SIZE	FLUID	TEMP. HOT>200 COLD<200	CLASS
26	CV-370	CLOSED SYSTEM	CHARGING LINE/ CHEMICAL & VOLUME CONTROL SYS.	3”	W	HOT	3

FOR FURTHER INFORMATION REFER TO FSAR CHAPTER 9 & FIGURE 9.2-1, 9.2-2

NOTE:

THIS PENETRATION MEETS CLASS 3 CONTAINMENT ISOLATION CRITERIA WITH CHECK VALVE CV-370 INSIDE CONTAINMENT SERVING THE PURPOSE OF AN AUTOMATIC TRIP VALVE AND CVCS A CLOSED SYSTEM OUTSIDE CONTAINMENT.

Figure 5.2-27 SAFETY INJECTION SYSTEM



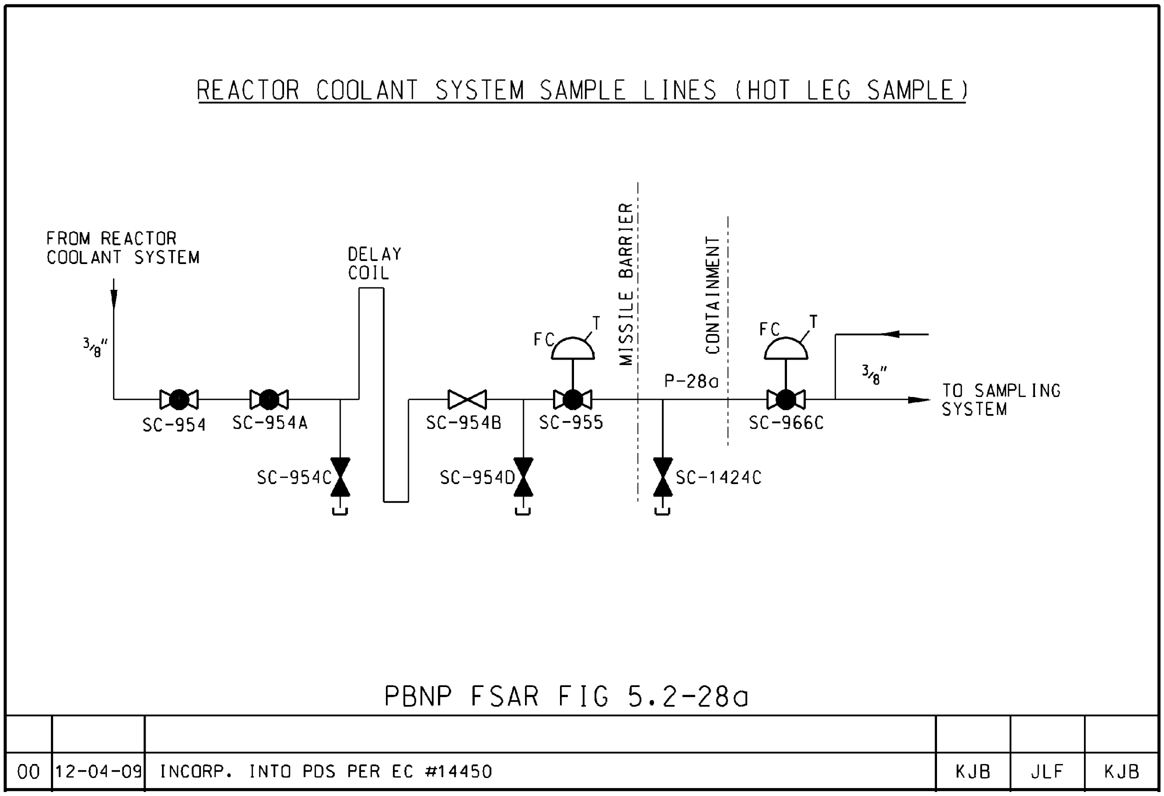
PENETRATION	CONTAINMENT ISOLATION VALVES INSIDE	CONTAINMENT ISOLATION VALVES OUTSIDE	BRANCH/SYSTEM	LINE SIZE	FLUID	TEMP. HOT>200 COLD<200	CLASS
27	SI-845C & D SI-845E & F SI-875A	CLOSED SYSTEM.	SAFETY INJECTION SYSTEM.	4"	W	COLD	SPECIAL

FOR FURTHER INFORMATION REFER TO FSAR CHAPTER 6 & FIGURE 6.2-1 SHEET 1

NOTE:

THIS PENETRATION IS CLASSIFIED SPECIAL AND IS IN USE POST DBA. THE CLOSED SYSTEM OUTSIDE CONTAINMENT PROVIDES THE CONTAINMENT ISOLATION BOUNDARY POST DBA.

Figure 5.2-28a REACTOR COOLANT SYSTEM SAMPLE LINES (HOT LEG SAMPLE)



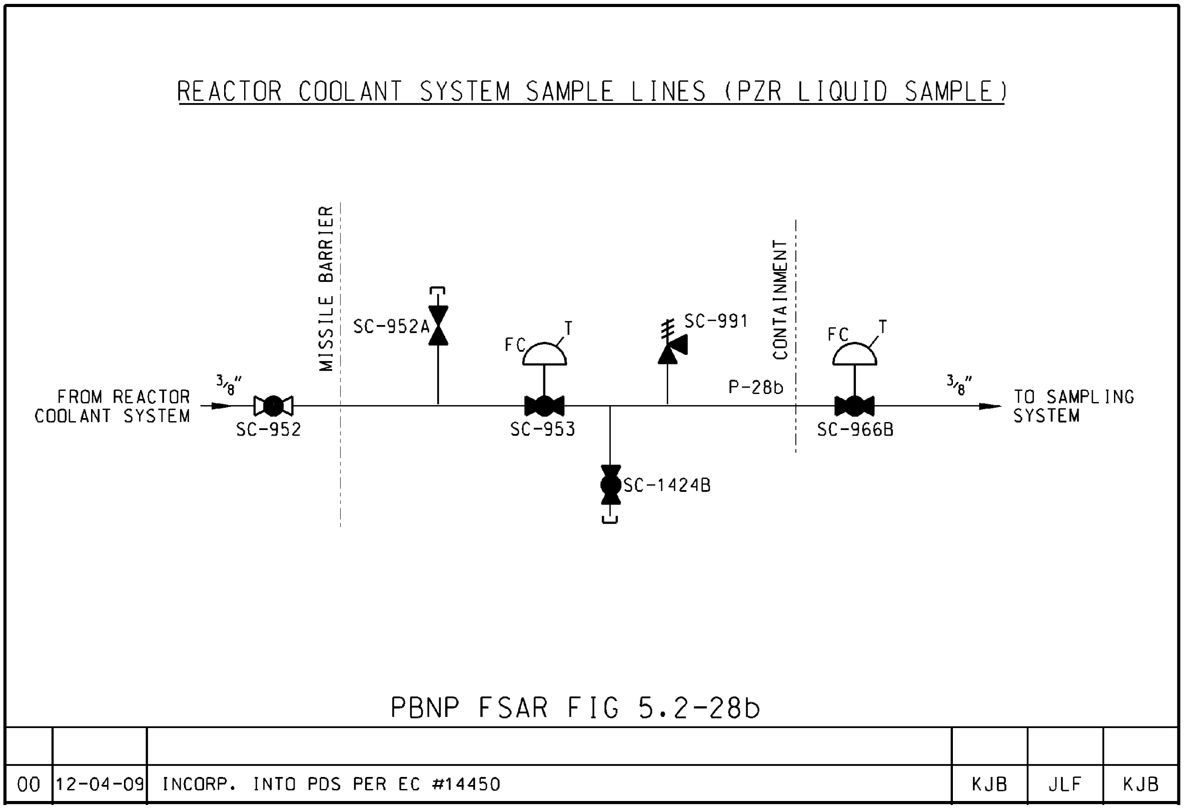
PENETRATION	CONTAINMENT ISOLATION VALVES INSIDE	CONTAINMENT ISOLATION VALVES OUTSIDE	BRANCH/SYSTEM	LINE SIZE	FLUID	TEMP. HOT>200 COLD<200	CLASS
28a	SC-955	SC-966C	HOT LEG SAMPLE /SAMPLING SYSTEM	3/8"	G	HOT	1

FOR FURTHER INFORMATION REFER TO FSAR CHAPTER 9 & FIGURE 9.4-1

NOTE:

1. THIS PENETRATION MEETS CLASS 1 CONTAINMENT ISOLATION CRITERIA WITH AUTOMATIC TRIP VALVES SC-955 INSIDE CONTAINMENT AND SC-966C OUTSIDE CONTAINMENT.
2. ALTHOUGH LOCATED INSIDE THE MISSLE BARRIER, THERE ARE NO CREDIBLE MISSILES THAT COULD IMPACT VALVES 1&2 SC-955 (REFERENCE SCR 2007-0181.)

Figure 5.2-28b REACTOR COOLANT SYSTEM SAMPLE LINES (PZR LIQUID SAMPLE)



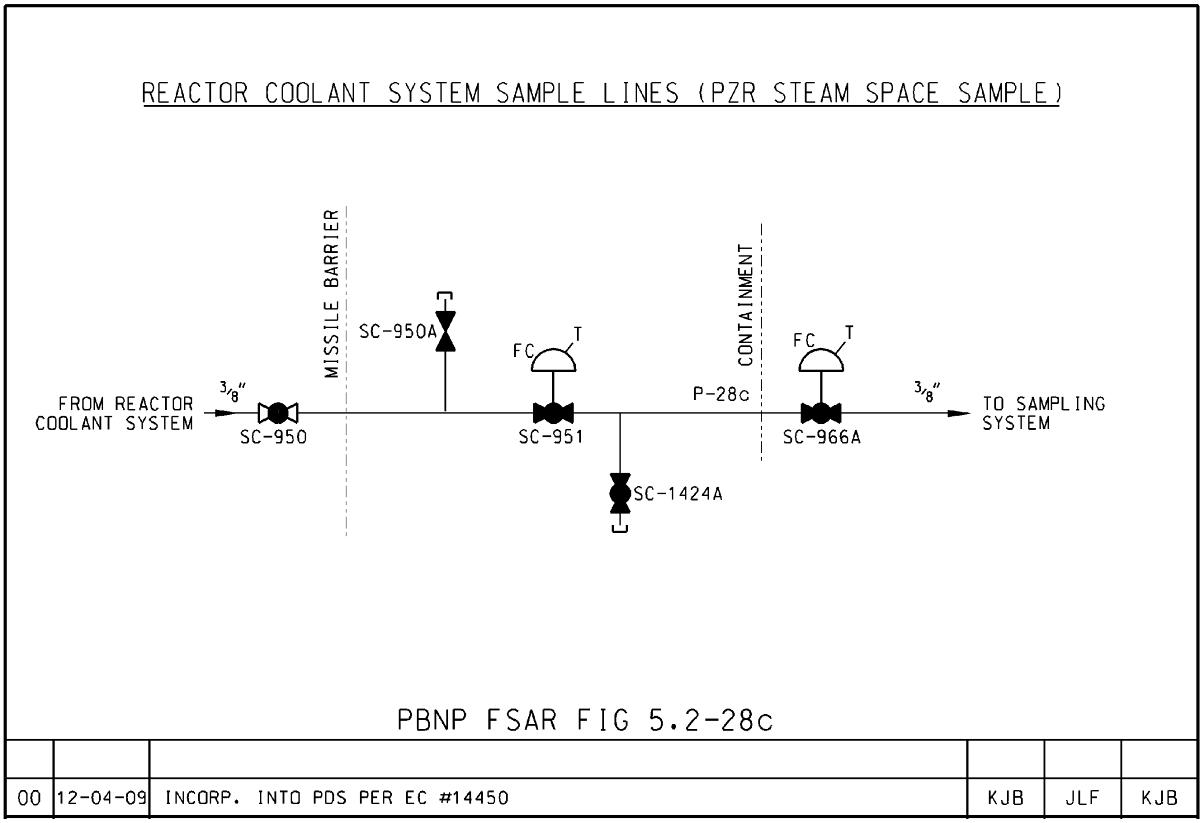
PENETRATION	CONTAINMENT ISOLATION VALVES INSIDE	CONTAINMENT ISOLATION VALVES OUTSIDE	BRANCH/SYSTEM	LINE SIZE	FLUID	TEMP. HOT>200 COLD<200	CLASS
28b	SC-953 SC-991	SC-966B	PRESSURIZER LIQ SAMPLE /SAMPLING SYSTEM	3/8"	W	HOT	1

FOR FURTHER INFORMATION REFER TO FSAR CHAPTER 9

NOTE:

THIS PENETRATION MEETS CLASS 1 CONTAINMENT ISOLATION CRITERIA WITH AUTOMATIC TRIP VALVES SC-953 INSIDE CONTAINMENT AND SC-966B OUTSIDE CONTAINMENT.

Figure 5.2-28c REACTOR COOLANT SYSTEM SAMPLE LINES (PZR STEAM SPACE SAMPLE)



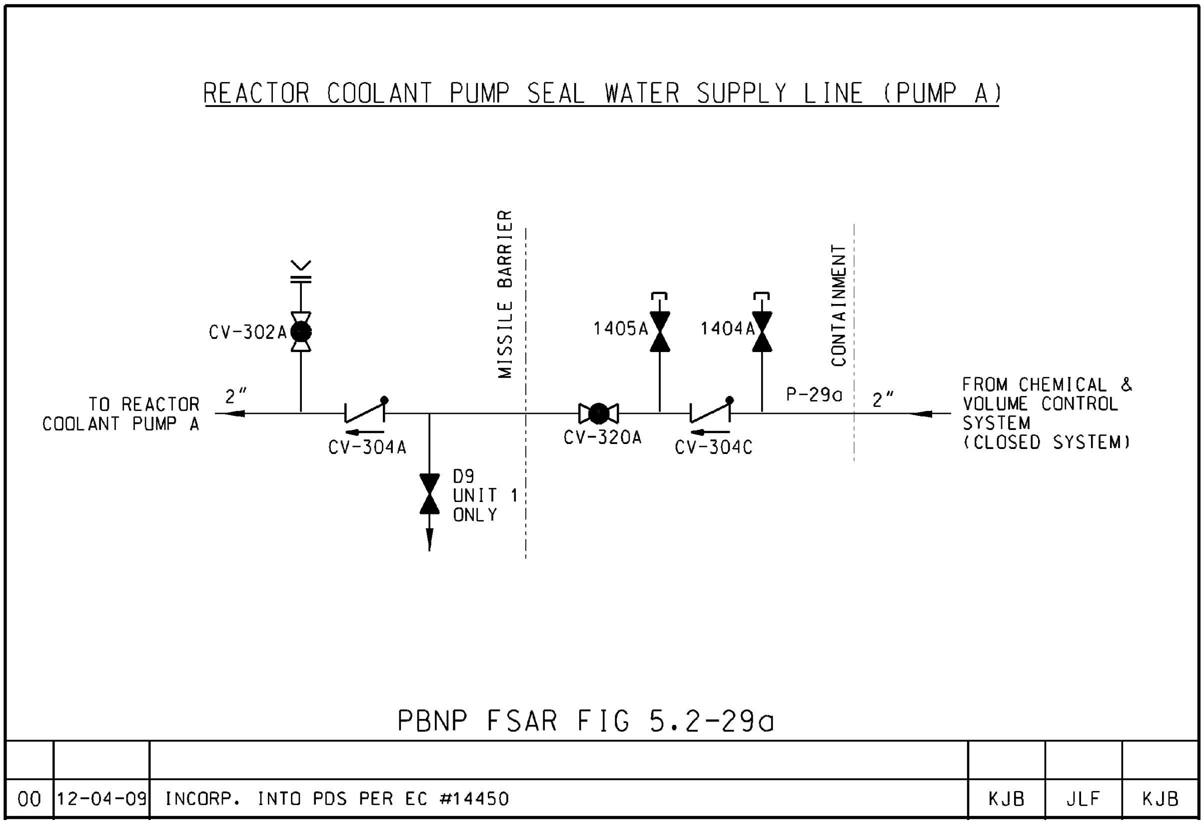
	CONTAINMENT ISOLATION VALVES					TEMP.	
PENETRATION	INSIDE	OUTSIDE	BRANCH/SYSTEM	LINE SIZE	FLUID	HOT>200 COLD<200	CLASS
28c	SC-951	SC-966A	PRESSURIZER STEAM SPACE SAMPLE /SAMPLING SYSTEM	3/8”	G	HOT	1

FOR FURTHER INFORMATION REFER TO FSAR CHAPTER 9 & FIGURE 9.4-1

NOTE:

THIS PENETRATION MEETS CLASS 1 CONTAINMENT ISOLATION CRITERIA WITH AUTOMATIC TRIP VALVES SC-951 INSIDE CONTAINMENT AND SC-966A OUTSIDE CONTAINMENT.

Figure 5.2-29a REACTOR COOLANT PUMP SEAL WATER SUPPLY LINE (PUMP A)



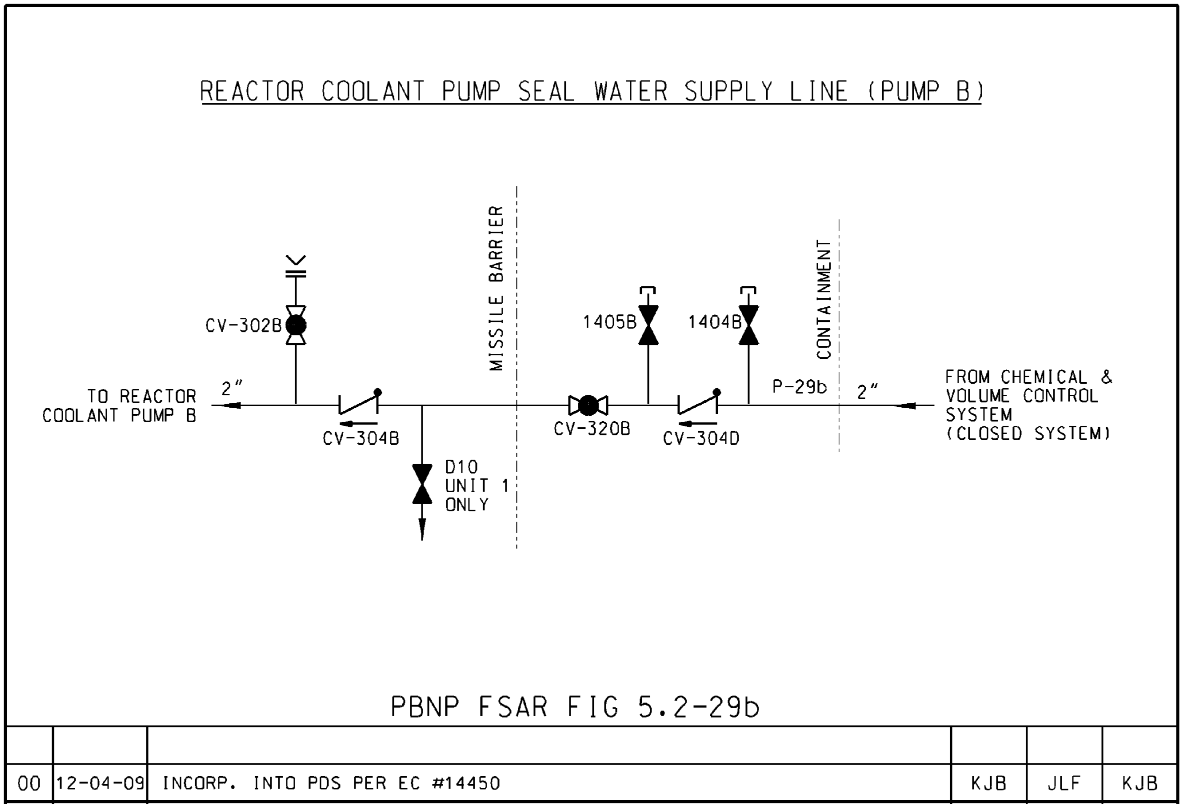
	CONTAINMENT ISOLATION VALVES					TEMP.	
PENETRATION	INSIDE	OUTSIDE	BRANCH/SYSTEM	LINE SIZE	FLUID	HOT>200 COLD<200	CLASS
29a	CV-304C	CLOSED SYSTEM	SEAL WATER INTO PUMP "A"/CHEMICAL & VOLUME CONTROL SYS.	2"	W	COLD	3

FOR FURTHER INFORMATION REFER TO FSAR CHAPTER 9 & FIGURE 9.2-1, 9.2-2

NOTE:

THIS PENETRATION MEETS CLASS 3 CONTAINMENT ISOLATION CRITERIA WITH CHECK VALVE CV-304C INSIDE CONTAIMENT SERVING THE PURPOSE OF AN AUTOMATIC TRIP VALVE AND CVCS A CLOSED SYSTEM OUTSIDE CONTAINMENT.

Figure 5.2-29b REACTOR COOLANT PUMP SEAL WATER SUPPLY LINE (PUMP B)



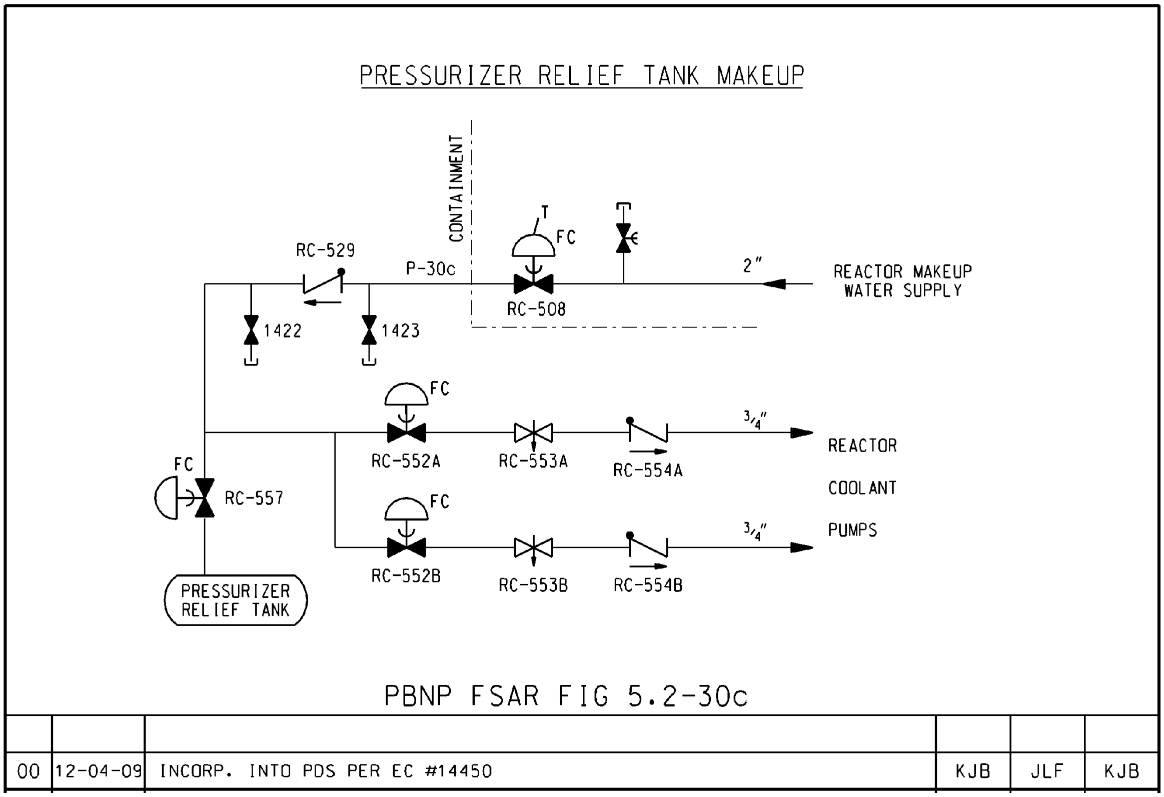
PENETRATION	CONTAINMENT ISOLATION VALVES INSIDE	CONTAINMENT ISOLATION VALVES OUTSIDE	BRANCH/SYSTEM	LINE SIZE	FLUID	TEMP. HOT>200 COLD<200	CLASS
29b	CV-304D	CLOSED SYSTEM	SEAL WATER INTO PUMP "B"/CHEMICAL & VOLUME CONTROL SYS.	2"	W	COLD	3

FOR FURTHER INFORMATION REFER TO FSAR CHAPTER 9 & FIGURE 9.2-1, 9.2-2

NOTE:

THIS PENETRATION MEETS CLASS 3 CONTAINMENT ISOLATION CRITERIA WITH CHECK VALVE CV-304D INSIDE CONTAIMENT SERVING THE PURPOSE OF AN AUTOMATIC TRIP VALVE AND CVCS A CLOSED SYSTEM OUTSIDE CONTAINMENT.

Figure 5.2-30c PRESSURIZER RELIEF TANK MAKEUP



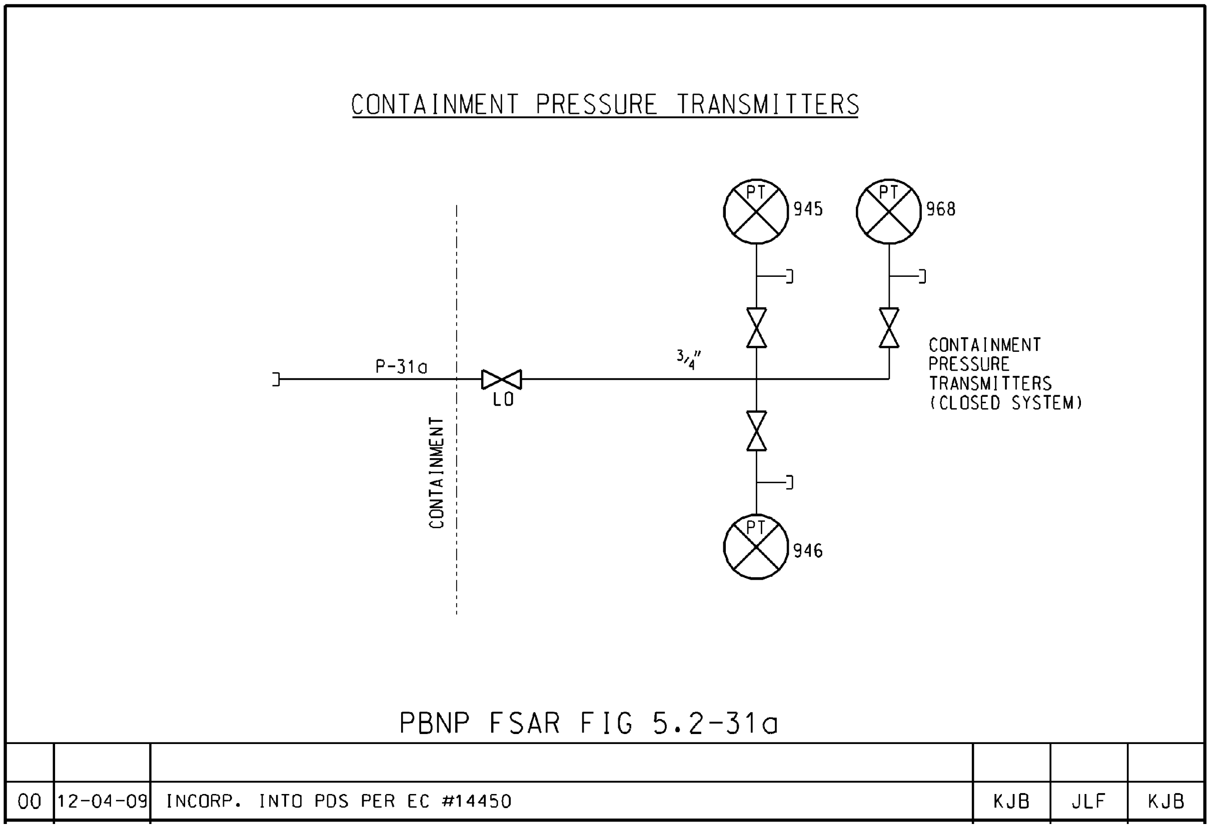
PENETRATION	CONTAINMENT ISOLATION VALVES INSIDE	CONTAINMENT ISOLATION VALVES OUTSIDE	BRANCH/SYSTEM	LINE SIZE	FLUID	TEMP. HOT>200 COLD<200	CLASS
30c	RC-529	RC-508	REACTOR MAKEUP WATER TO PRESSURIZER RELIEF TANK/REACTOR COOLANT SYS.	2”	W	COLD	3

FOR FURTHER INFORMATION REFER TO FSAR CHAPTER 4, FIGURE 4.2-1 SHT. 2, & FIGURE 4.2-1A SHT.2

NOTE:

THIS PENETRATION MEETS CLASS 3 CONTAINMENT ISOLATION CRITERIA WITH CHECK VALVE RC-529 INSIDE CONTAIMENT SERVING THE PURPOSE OF AN AUTOMATIC TRIP VALVE AND AUTOMATIC TRIP VALVE RC-508 OUTSIDE CONTAINMENT.

Figure 5.2-31a CONTAINMENT PRESSURE TRANSMITTERS

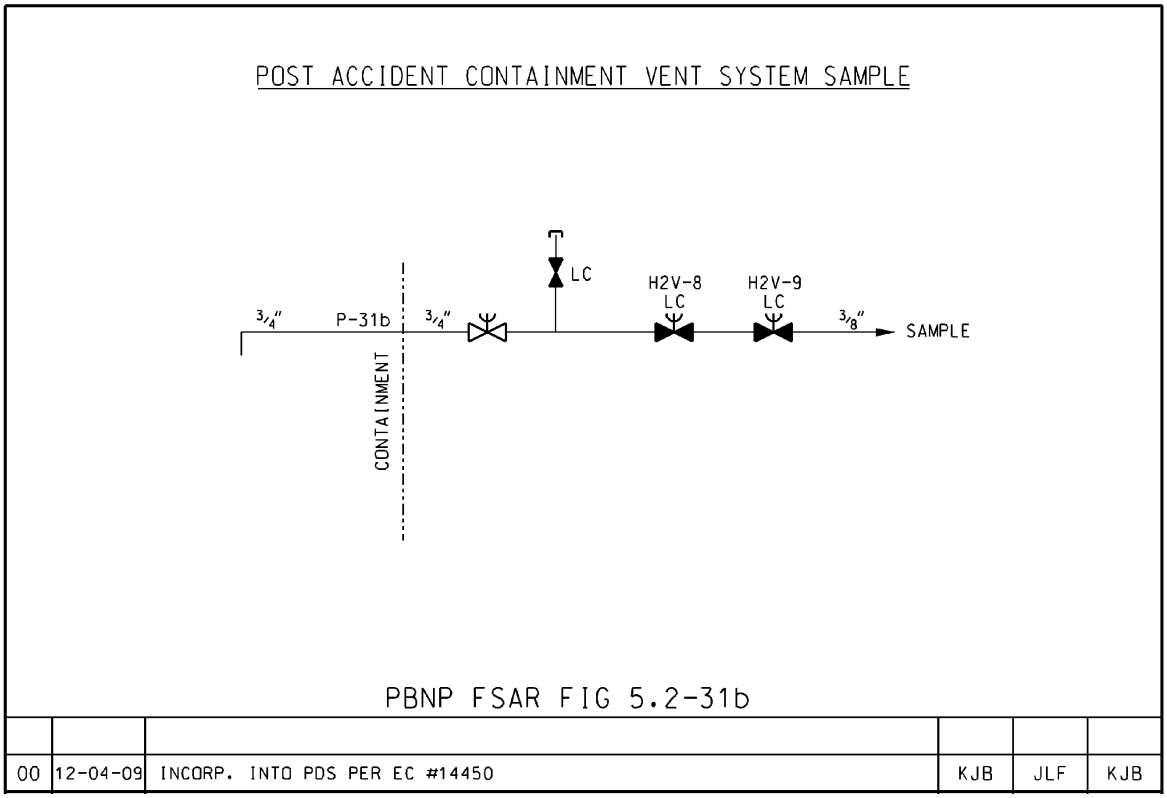


PENETRATION	CONTAINMENT ISOLATION VALVES INSIDE	OUTSIDE	BRANCH/SYSTEM	LINE SIZE	FLUID	TEMP. HOT>200 COLD<200	CLASS
31a		MANUAL VALVE CLOSED SYSTEM	CONTAINMENT PRESSURE TRANSMITTER.	3/4"	G	COLD	SPECIAL

NOTE:

THIS PENETRATION IS CLASSIFIED SPECIAL AND IS IN USE POST DBA. THE CLOSED SYSTEM OUTSIDE CONTAINMENT PROVIDES THE CONTAINMENT ISOLATION BOUNDARY POST DBA.

Figure 5.2-31b POST-ACCIDENT CONTAINMENT VENT SYSTEM SAMPLE



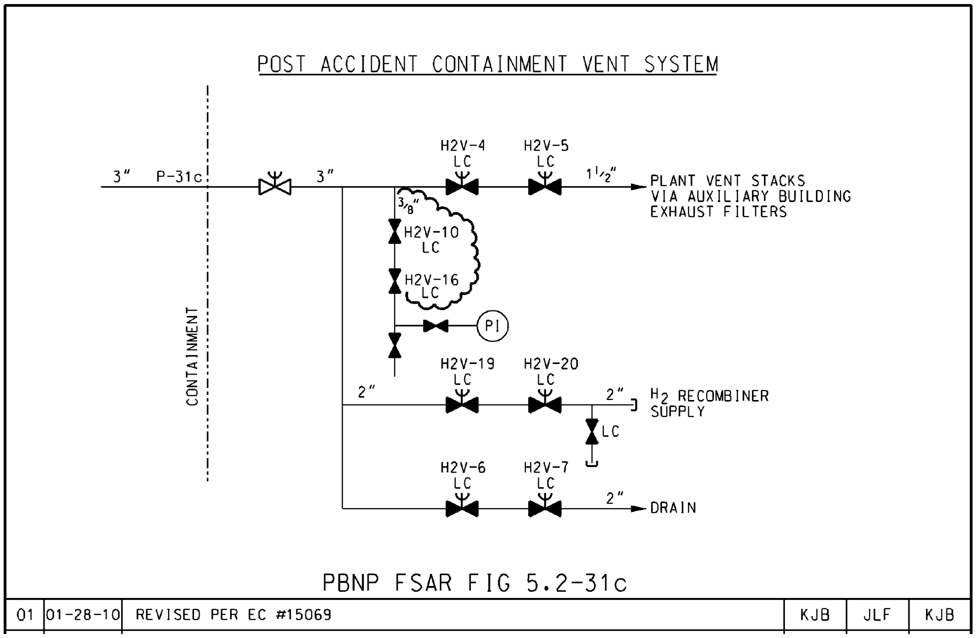
PENETRATION	CONTAINMENT ISOLATION VALVES INSIDE	OUTSIDE	BRANCH/SYSTEM	LINE SIZE	FLUID	TEMP. HOT>200 COLD<200	CLASS
31b		H2V-8 H2V-9	POST ACCIDENT CONTAINMENT VENT SYS. H_2 SAMPLE/ PACVS.	3/4”	G	COLD	SPECIAL

FOR FURTHER INFORMATION REFER TO FSAR CHAPTER 5 & FIGURE 5.3-1 SHT. 2 & FIGURE 5.3-1 SHT. 3

NOTE:

THIS PENETRATION IS CLASSIFIED SPECIAL AND IS IDENTIFIED AS AN INTERMITTENT USE SYSTEM POST DBA. LOCKED CLOSED MANUAL VALVES H2V-8 AND H2V-9 OUTSIDE CONTAINMENT MEET CONTAINMENT ISOLATION CRITERIA.

Figure 5.2-31c POST-ACCIDENT CONTAINMENT VENT SYSTEM



PENETRATION	CONTAINMENT ISOLATION VALVES INSIDE	CONTAINMENT ISOLATION VALVES OUTSIDE	BRANCH/SYSTEM	LINE SIZE	FLUID	TEMP. HOT>200 COLD<200	CLASS
31c		H2V-6 H2V-7	POST ACCIDENT CONTAINMENT VENT SYS. DRAIN/PACVS.	2”	G	COLD	SPECIAL
		H2V-4 H2V-5	POST ACCIDENT CONTAINMENT VENT SYS TO VENT DUCT / PACVS.	1-1/2”	G	COLD	SPECIAL
		H2V-20 H2V-19	POST ACCIDENT CONTAINMENT VENT SYS. H_2 RECOMBINER SUPPLY/PACVS.	2”	G	COLD	SPECIAL

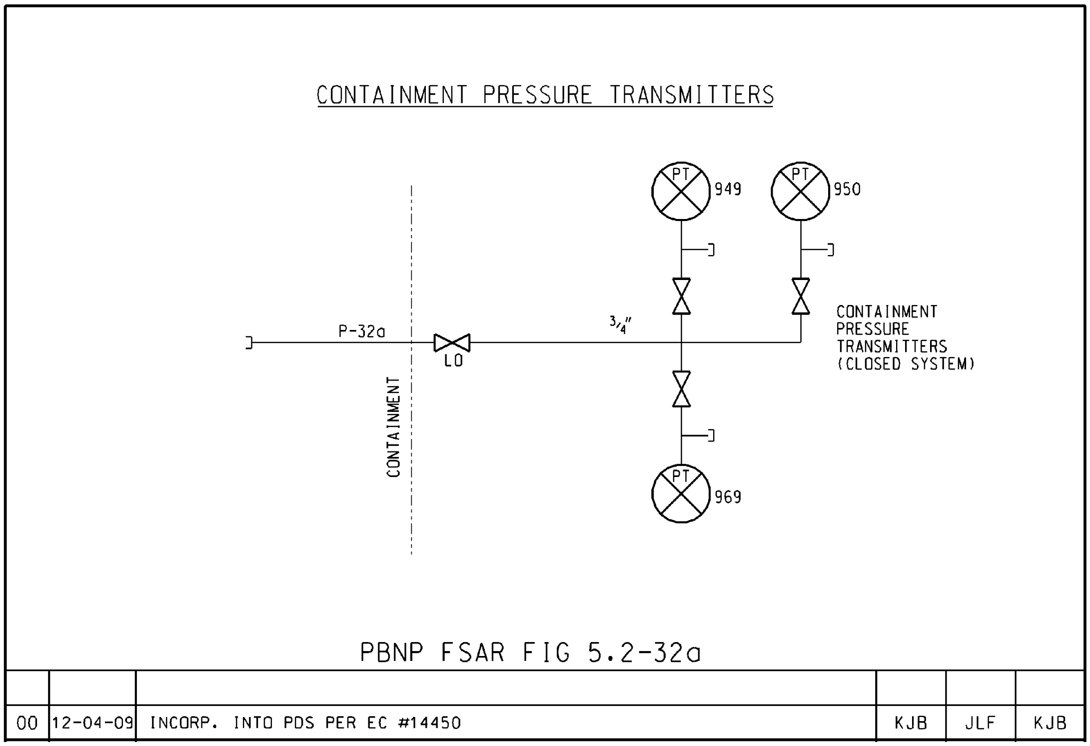
FOR FURTHER INFORMATION REFER TO FSAR CHAPTER 5 & FIGURE 5.3-1 SHT. 2 & FIGURE 5.3-1 SHT. 3

NOTE:

THIS PENETRATION IS CLASSIFIED SPECIAL AND IS IDENTIFIED AS AN INTERMITTENT USE SYSTEM POST DBA.

1. VENT STACK BRANCH - LOCKED CLOSED MANUAL VALVES H2V-4 AND H2V-5 OUTSIDE CONTAINMENT MEET CONTAINMENT ISOLATION CRITERIA.
2. HYDROGEN RECOMBINER BRANCH - LOCKED CLOSED MANUAL VALVES H2V-19 AND H2V-20 OUTSIDE CONTAINMENT MEET CONTAINMENT ISOLATION CRITERIA
3. DRAIN BRANCH - LOCKED CLOSED MANUAL VALVES H2V-6 AND H2V-7 OUTSIDE CONTAINMENT MEET CONTAINMENT ISOLATION CRITERIA.

Figure 5.2-32a CONTAINMENT PRESSURE TRANSMITTERS

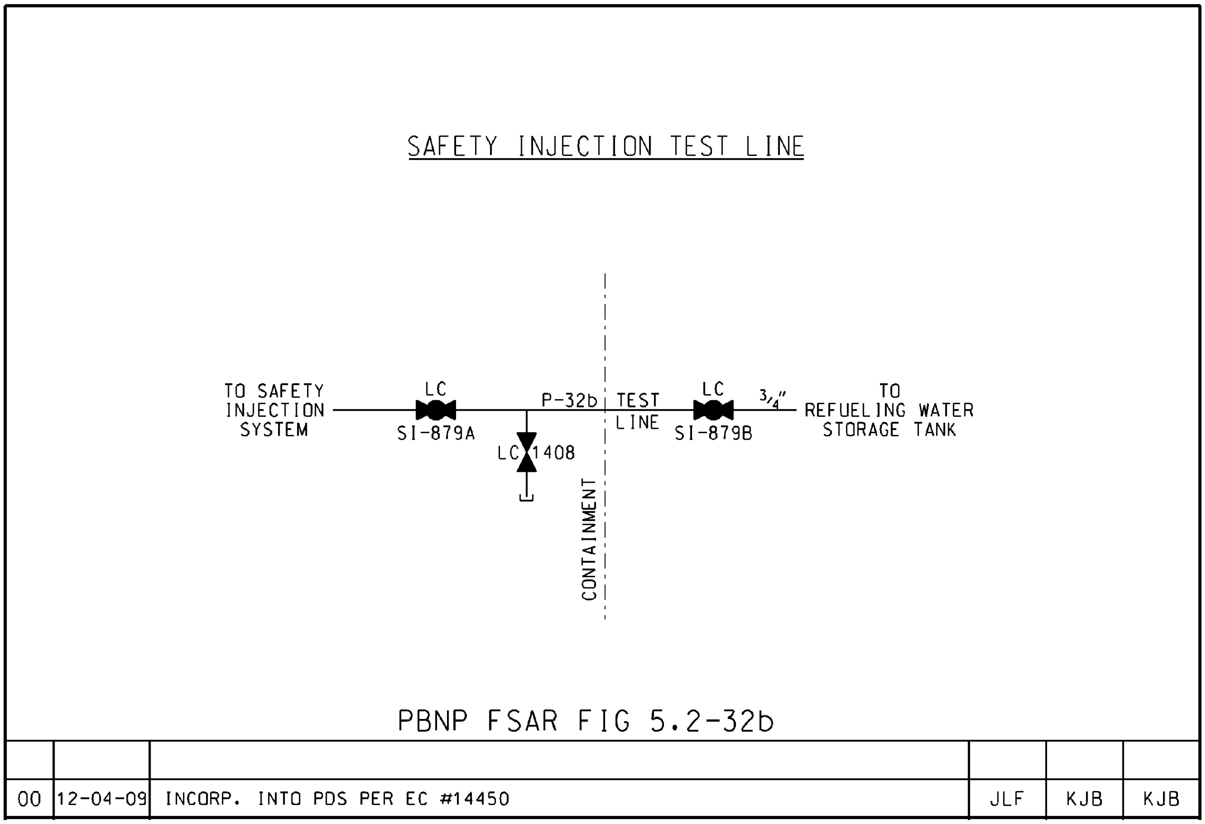


	CONTAINMENT ISOLATION VALVES					TEMP.	
PENETRATION	INSIDE	OUTSIDE	BRANCH/SYSTEM	LINE SIZE	FLUID	HOT>200 COLD<200	CLASS
32a		MANUAL VALVE CLOSED SYSTEM	CONTAINMENT PRESSURE TRANSMITTER.	3/4”	G	COLD	SPECIAL

NOTE:

THIS PENETRATION IS CLASSIFIED SPECIAL AND IS IN USE POST DBA. THE CLOSED SYSTEM OUTSIDE CONTAINMENT PROVIDES THE CONTAINMENT ISOLATION BOUNDARY.

Figure 5.2-32b SAFETY INJECTION TEST LINE



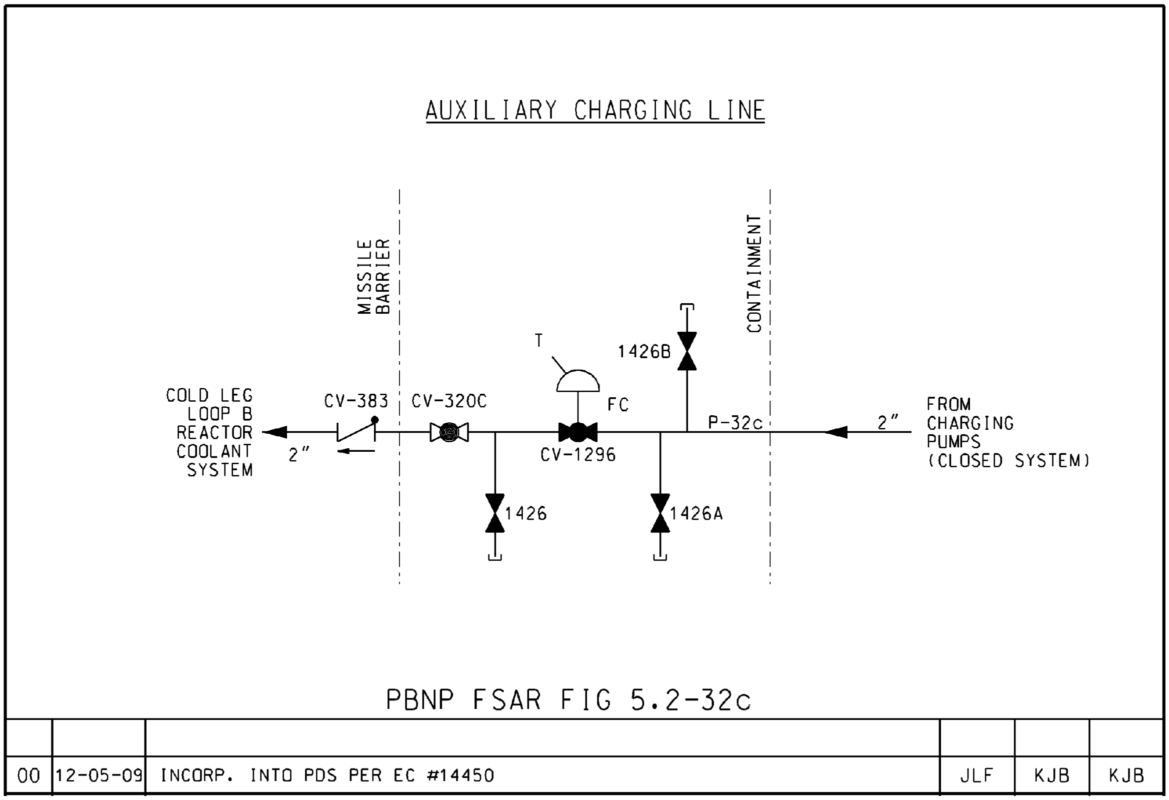
	CONTAINMENT ISOLATION VALVES					TEMP.	
PENETRATION	INSIDE	OUTSIDE	BRANCH/SYSTEM	LINE SIZE	FLUID	HOT>200 COLD<200	CLASS
32b	SI-879A	SI-879B	SAFETY INJECTION SYS. TEST LINE/SAFETY INJECTION SYSTEM	3/4”	W	COLD	SPECIAL

FOR FURTHER INFORMATION REFER TO FSAR CHAPTER 6

NOTE:

THIS PENETRATION IS CLASSIFIED SPECIAL AND MEETS CONTAINMENT ISOLATION CRITERIA WITH LOCKED CLOSED MANUAL VALVES SI-879A AND SI-879B SERVING THE PURPOSE OF AUTOMATIC TRIP VALVES.

Figure 5.2-32c AUXILIARY CHARGING LINE



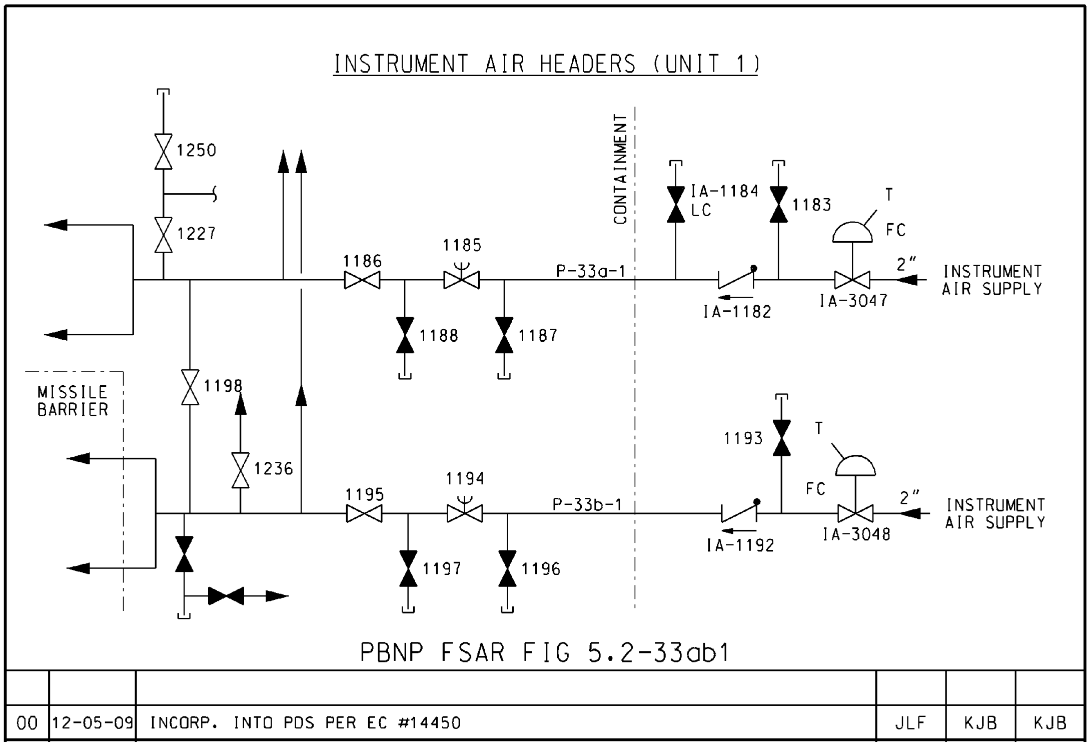
PENETRATION	CONTAINMENT ISOLATION VALVES INSIDE	OUTSIDE	BRANCH/SYSTEM	LINE SIZE	FLUID	TEMP. HOT>200 COLD<200	CLASS
32c	CV-1296	CLOSED SYSTEM	AUXILIARY CHARGING LINE/CVCS	2"	W	COLD	3

FOR FURTHER INFORMATION REFER TO FSAR CHAPTER 9 & FIGURE 9.2-1, 9.2-2

NOTE:

THIS PENETRATION MEETS CLASS 3 CONTAINMENT ISOLATION CRITERIA WITH AUTOMATIC TRIP VALVE CV-1296 INSIDE CONTAIMENT AND CVCS A CLOSED SYSTEM OUTSIDE CONTAINMENT.

Figure 5.2-33ab1 INSTRUMENT AIR HEADERS (UNIT 1)



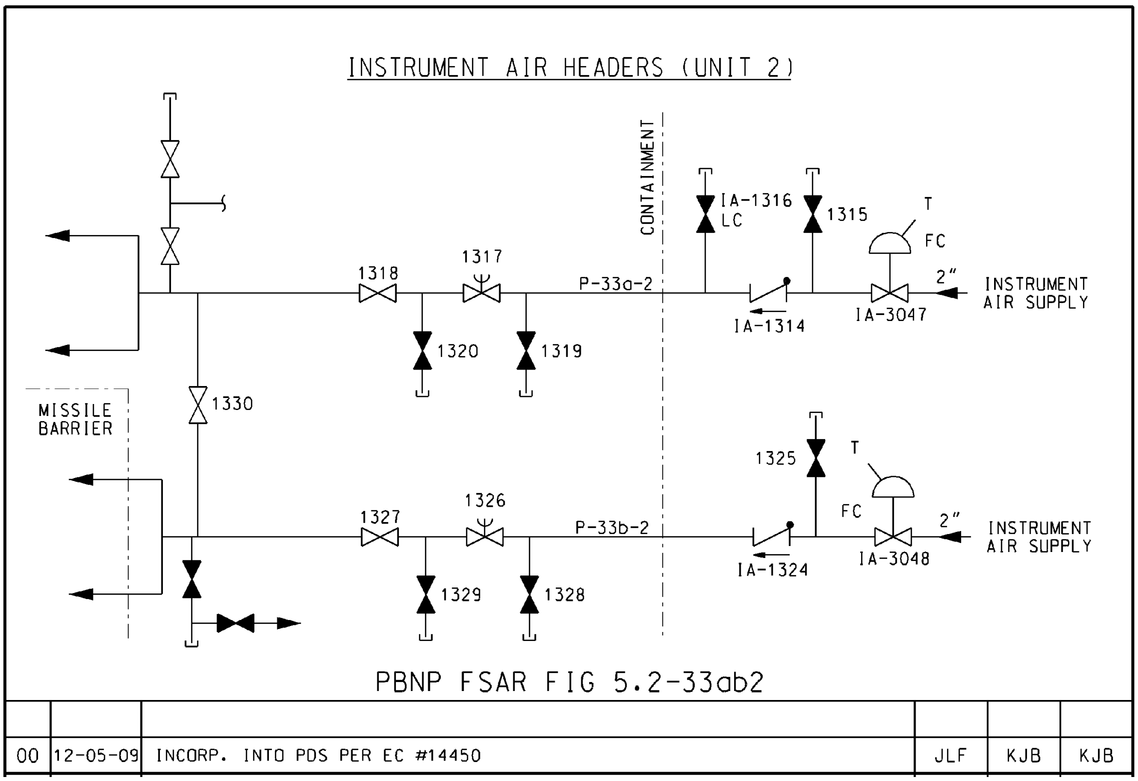
PENETRATION	CONTAINMENT ISOLATION VALVES INSIDE	OUTSIDE	BRANCH/SYSTEM	LINE SIZE	FLUID	TEMP. HOT>200 COLD<200	CLASS
33a-1		IA-3047 IA-1182	INSTRUMENT AIR SUPPLY/SECONDARY SYSTEM.	2”	G	COLD	3
33b-1		IA-3048 IA-1192	INSTRUMENT AIR SUPPLY/SECONDARY SYSTEM.	2”	G	COLD	3

NOTE:

33a-1 THIS PENETRATION MEETS CLASS 3 CONTAINMENT ISOLATION CRITERIA WITH CHECK VALVE IA-1182 SERVING THE PURPOSE OF AN AUTOMATIC TRIP VALVE AND AUTOMATIC TRIP VALVE IA-3047 OUTSIDE CONTAINMENT.

33b-1 THIS PENETRATION MEETS CLASS 3 CONTAINMENT ISOLATION CRITERIA WITH CHECK VALVE IA-1192 SERVING THE PURPOSE OF AN AUTOMATIC TRIP VALVE AND AUTOMATIC TRIP VALVE IA-3048 OUTSIDE CONTAINMENT.

Figure 5.2-33ab2 INSTRUMENT AIR HEADERS (UNIT 2)



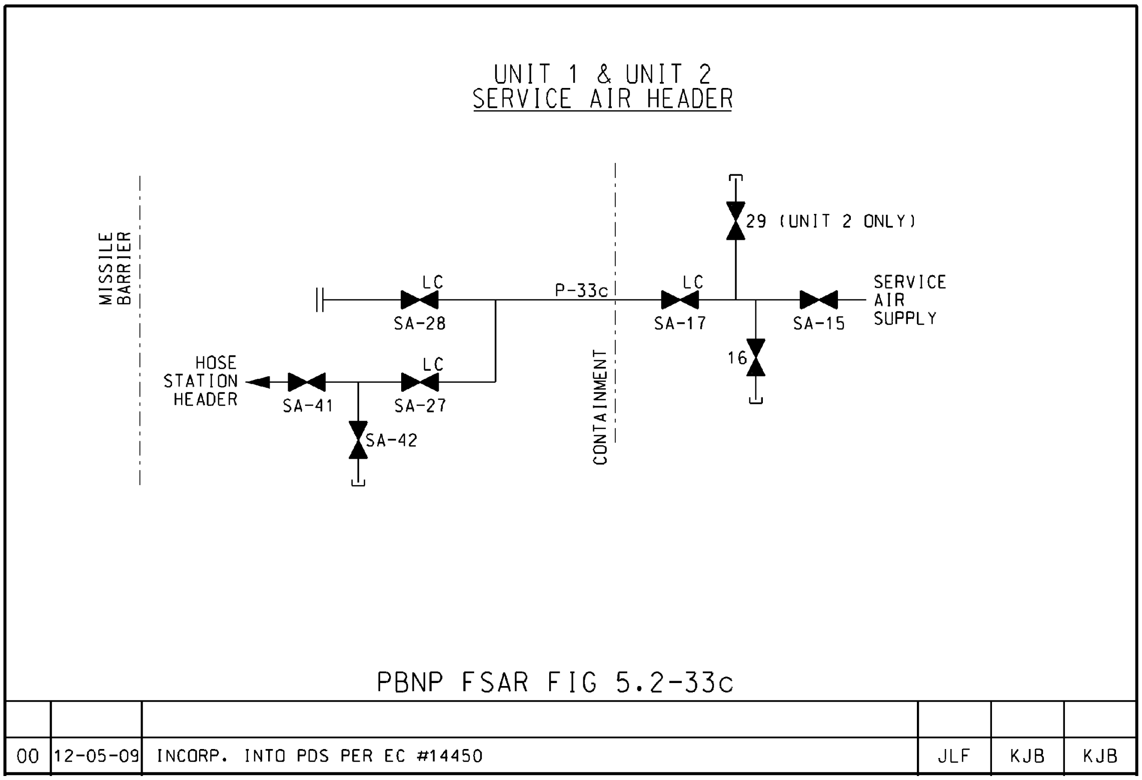
PENETRATION	CONTAINMENT ISOLATION VALVES INSIDE	OUTSIDE	BRANCH/SYSTEM	LINE SIZE	FLUID	TEMP. HOT>200 COLD<200	CLASS
33a-2		IA-3047 IA-1314	INSTRUMENT AIR SUPPLY/SECONDARY SYSTEM.	2”	G	COLD	3
33b-2		IA-3048 IA-1324	INSTRUMENT AIR SUPPLY/SECONDARY SYSTEM.	2”	G	COLD	3

NOTE:

33a-2 THIS PENETRATION MEETS CLASS 3 CONTAINMENT ISOLATION CRITERIA WITH CHECK VALVE IA-1314 SERVING THE PURPOSE OF AN AUTOMATIC TRIP VALVE AND AUTOMATIC TRIP VALVE IA-3047 OUTSIDE CONTAINMENT.

33b-2 THIS PENETRATION MEETS CLASS 3 CONTAINMENT ISOLATION CRITERIA WITH CHECK VALVE IA-1324 SERVING THE PURPOSE OF AN AUTOMATIC TRIP VALVE AND AUTOMATIC TRIP VALVE IA-3048 OUTSIDE CONTAINMENT.

Figure 5.2-33c UNIT 1 AND UNIT 2 SERVICE AIR HEADER

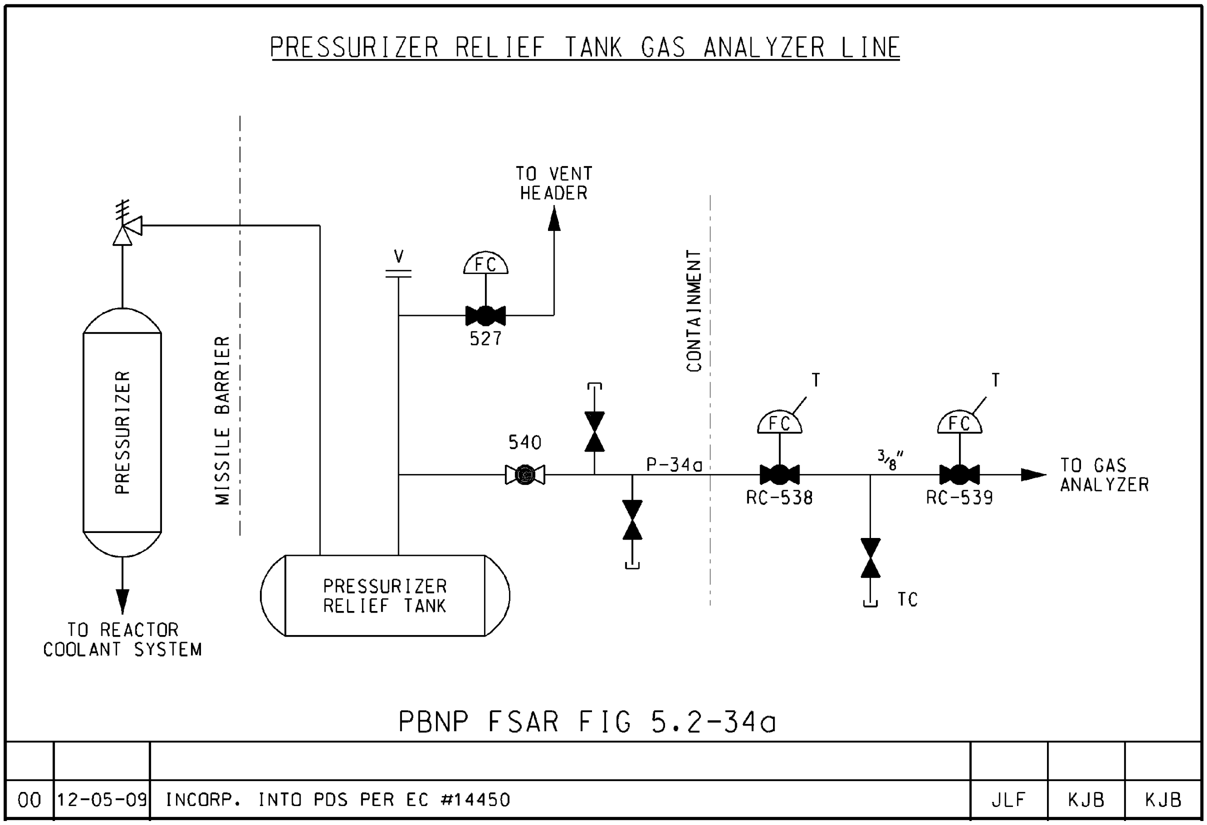


	CONTAINMENT ISOLATION VALVES					TEMP.	
PENETRATION	INSIDE	OUTSIDE	BRANCH/SYSTEM	LINE SIZE	FLUID	HOT>200 COLD<200	CLASS
33c	SA-27 BLANK FLANGE	SA-17	SERVICE AIR SUPPLY/ SECONDARY SYSTEM.	4”	G	COLD	5

NOTE:

THIS PENETRATION MEETS CLASS 5 CONTAINMENT ISOLATION CRITERIA. REQUIREMENTS ARE MET BY A LOCKED CLOSED MANUAL VALVE SA-17 OUTSIDE CONTAINMENT AND A LOCKED CLOSED MANUAL VALVE SA-27 AND THE BLANK FLANG AT SA-28 INSIDE CONTAINMENT.

Figure 5.2-34a PRESSURIZER RELIEF TANK GAS ANALYZER LINE



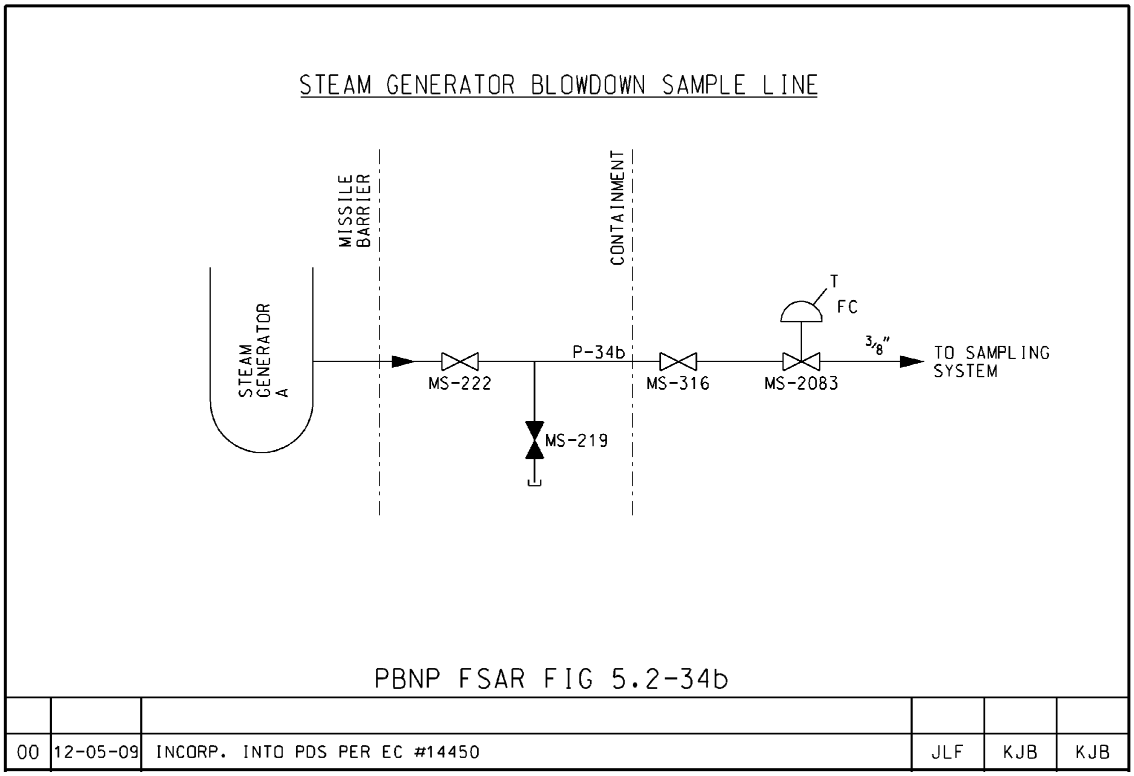
PENETRATION	CONTAINMENT ISOLATION VALVES INSIDE	CONTAINMENT ISOLATION VALVES OUTSIDE	BRANCH/SYSTEM	LINE SIZE	FLUID	TEMP. HOT>200 COLD<200	CLASS
34a		RC-538 RC-539	PRESSURIZER RELIEF TANK SAMPLE TO GAS ANALYZER/REACTOR COOLANT SYSTEM	3/8"	G	COLD	2

FOR FURTHER INFORMATION REFER TO FSAR CHAPTER 4 & FIGURE 4.2-1 SHT. 2

NOTE:

THIS PENETRATION MEETS CLASS 2 CONTAINMENT ISOLATION CRITERIA WITH AUTOMATICALLY OPERATED TRIP VALVES (RC-538 AND RC-539) IN SERIES LOCATED OUTSIDE OF CONTAINMENT.

Figure 5.2-34b STEAM GENERATOR BLOWDOWN SAMPLE LINE



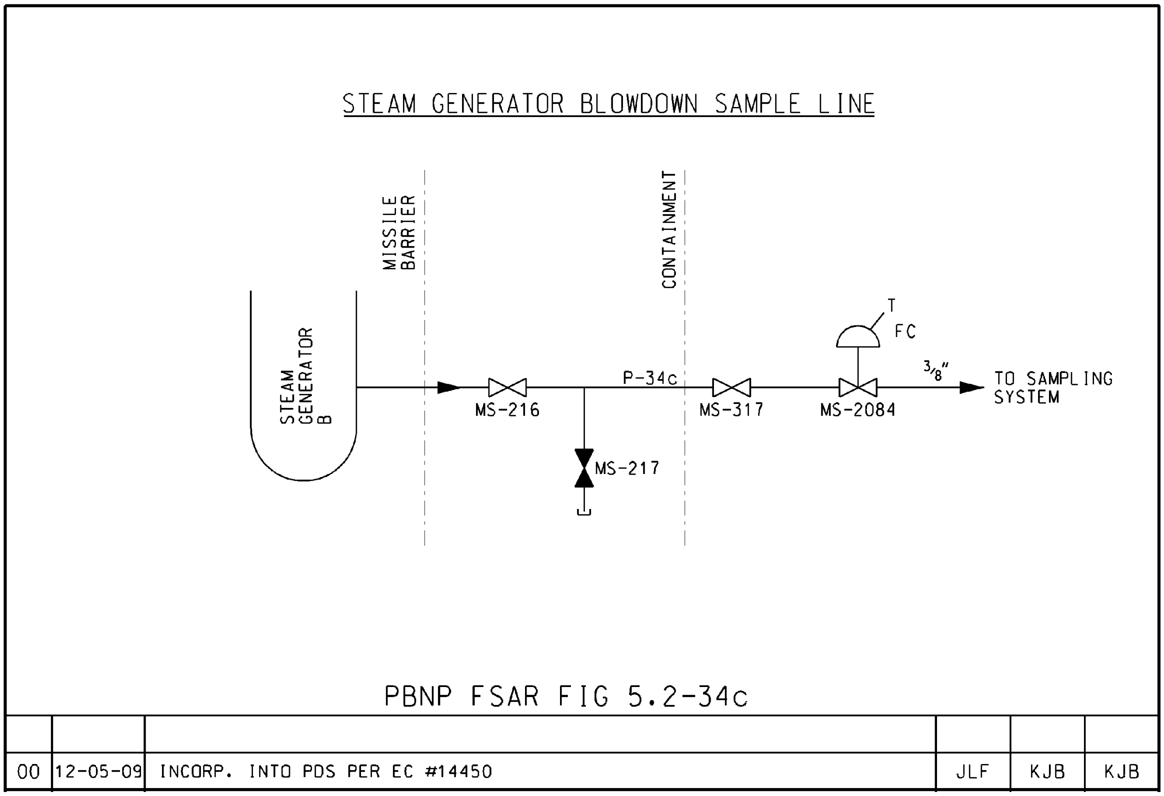
PENETRATION	CONTAINMENT ISOLATION VALVES INSIDE	OUTSIDE	BRANCH/SYSTEM	LINE SIZE	FLUID	TEMP. HOT>200 COLD<200	CLASS
34b	CLOSED SYS.	MS-2083	STEAM GENERATOR BLOWDOWN SAMPLE LINE/SECONDARY SYSTEM	3/8"	W	HOT	4

FOR FURTHER INFORMATION REFER TO FSAR CHAPTER 10 & FIGURE 10.2-1 SHT. 1

NOTE:

THIS PENETRATION MEETS CLASS 4 CONTAINMENT ISOLATION CRITERIA WITH AUTOMATIC TRIP VALVE (MS-2083) LOCATED OUTSIDE OF CONTAINMENT. THE SYSTEM INSIDE CONTAINMENT IS A CLOSED SYSTEM. MS-2083 IS USED AS THE CONTAINMENT ISOLATION VALVE OUTSIDE CONTAINMENT BECAUSE IT WAS ADDED AS AN NRC COMMITMENT.

Figure 5.2-34c STEAM GENERATOR BLOWDOWN SAMPLE LINE



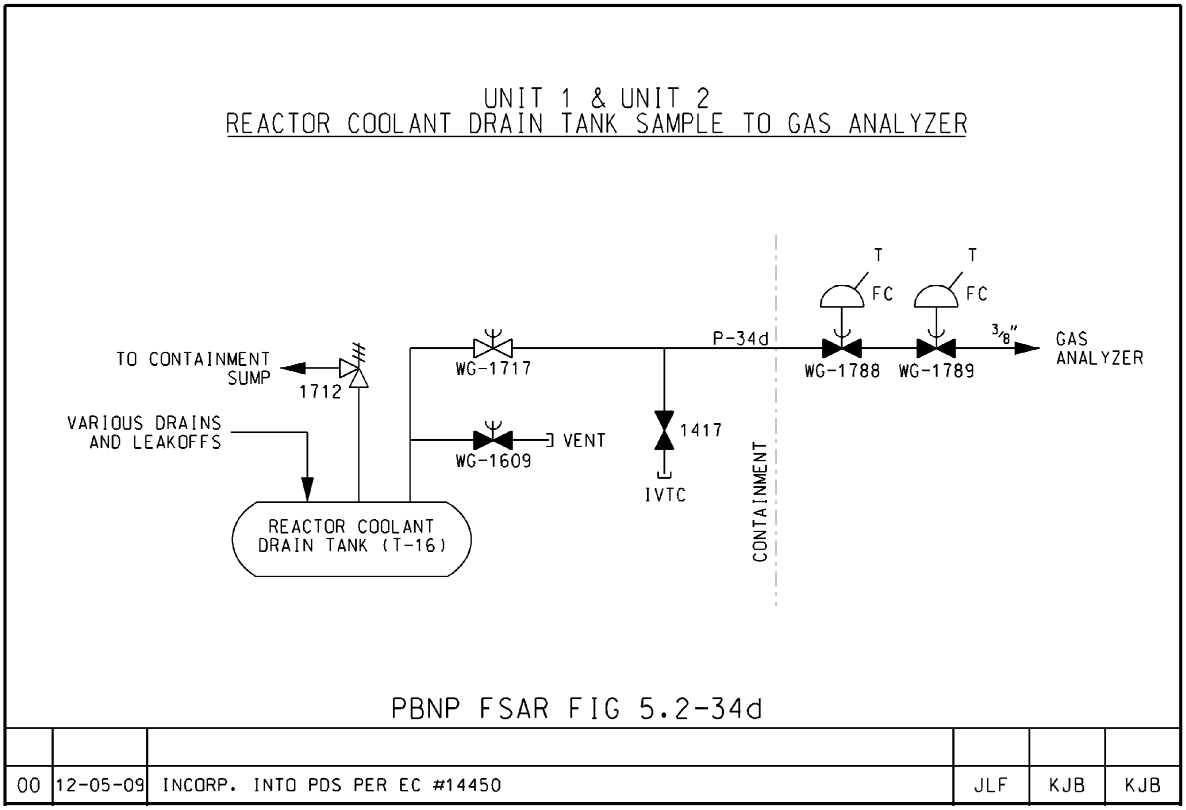
	CONTAINMENT ISOLATION VALVES					TEMP.	
PENETRATION	INSIDE	OUTSIDE	BRANCH/SYSTEM	LINE SIZE	FLUID	HOT>200 COLD<200	CLASS
34c	CLOSED SYS.	MS-2084	STEAM GENERATOR BLOWDOWN SAMPLE LINE/SECONDARY SYSTEM	3/8"	W	HOT	4

FOR FURTHER INFORMATION REFER TO FSAR CHAPTER 10 & FIGURE 10.2-1 SHT. 1

NOTE:

THIS PENETRATION MEETS CLASS 4 CONTAINMENT ISOLATION CRITERIA WITH AUTOMATIC TRIP VALVE (MS-2084) LOCATED OUTSIDE OF CONTAINMENT. THE SYSTEM INSIDE CONTAINMENT IS A CLOSED SYSTEM. MS-2084 IS USED AS THE CONTAINMENT ISOLATION VALVE OUTSIDE CONTAINMENT BECAUSE IT WAS ADDED AS AN NRC COMMITMENT.

Figure 5.2-34d UNIT 1 & UNIT 2 REACTOR COOLANT DRAIN TANK SAMPLE TO GAS ANALYZER



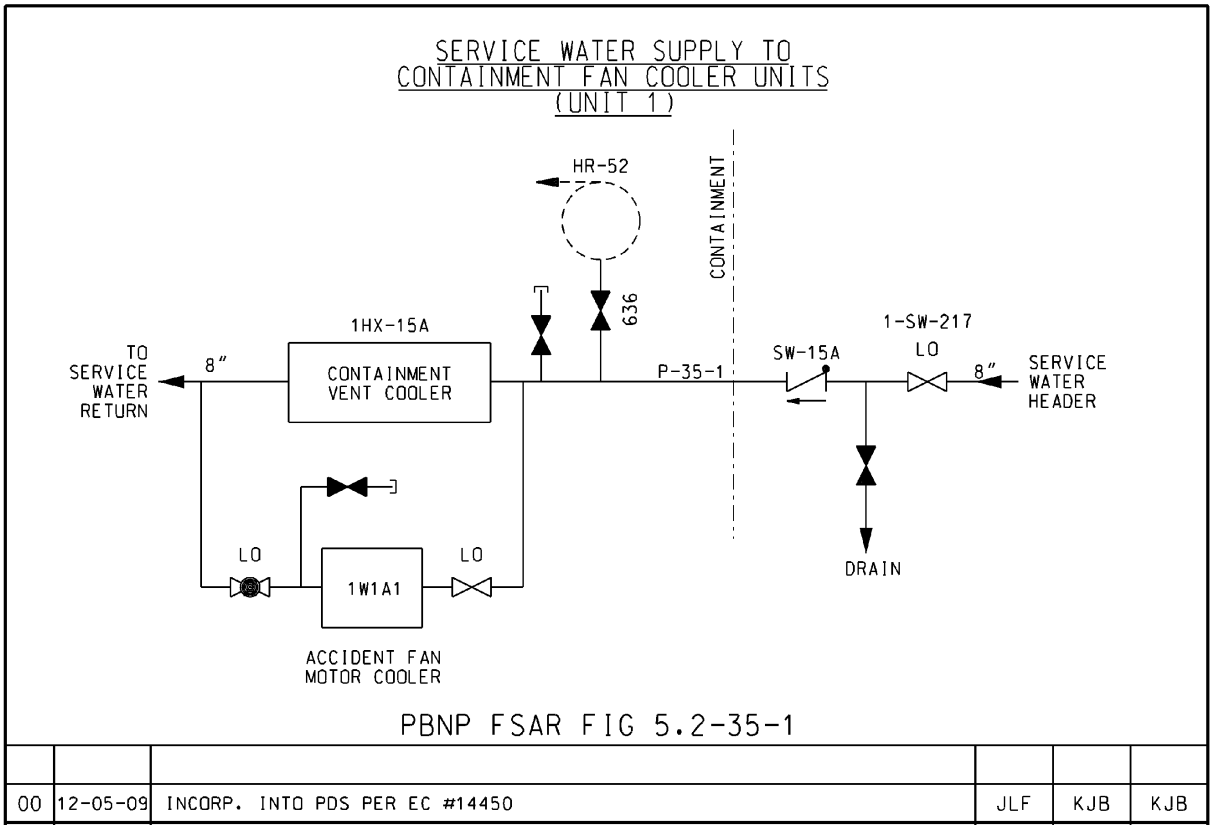
PENETRATION	CONTAINMENT ISOLATION VALVES INSIDE	OUTSIDE	BRANCH/SYSTEM	LINE SIZE	FLUID	TEMP. HOT>200 COLD<200	CLASS
34d		WG-1788 WG-1789	REACTOR COOLANT DRAIN TANK SAMPLE TO GAS ANALYZER/ WASTE DISPOSAL SYSTEM	3/8”	G	COLD	2

FOR FURTHER INFORMATION REFER TO FSAR CHAPTER 11

NOTE:

THIS PENETRATION MEETS CLASS 2 CONTAINMENT ISOLATION CRITERIA WITH AUTOMATICALLY OPERATED TRIP VALVES WG-1788 AND WG-1789 IN SERIES LOCATED OUTSIDE CONTAINMENT.

Figure 5.2-35-1 SERVICE WATER SUPPLY TO CONTAINMENT FAN COOLER UNITS (UNIT 1)



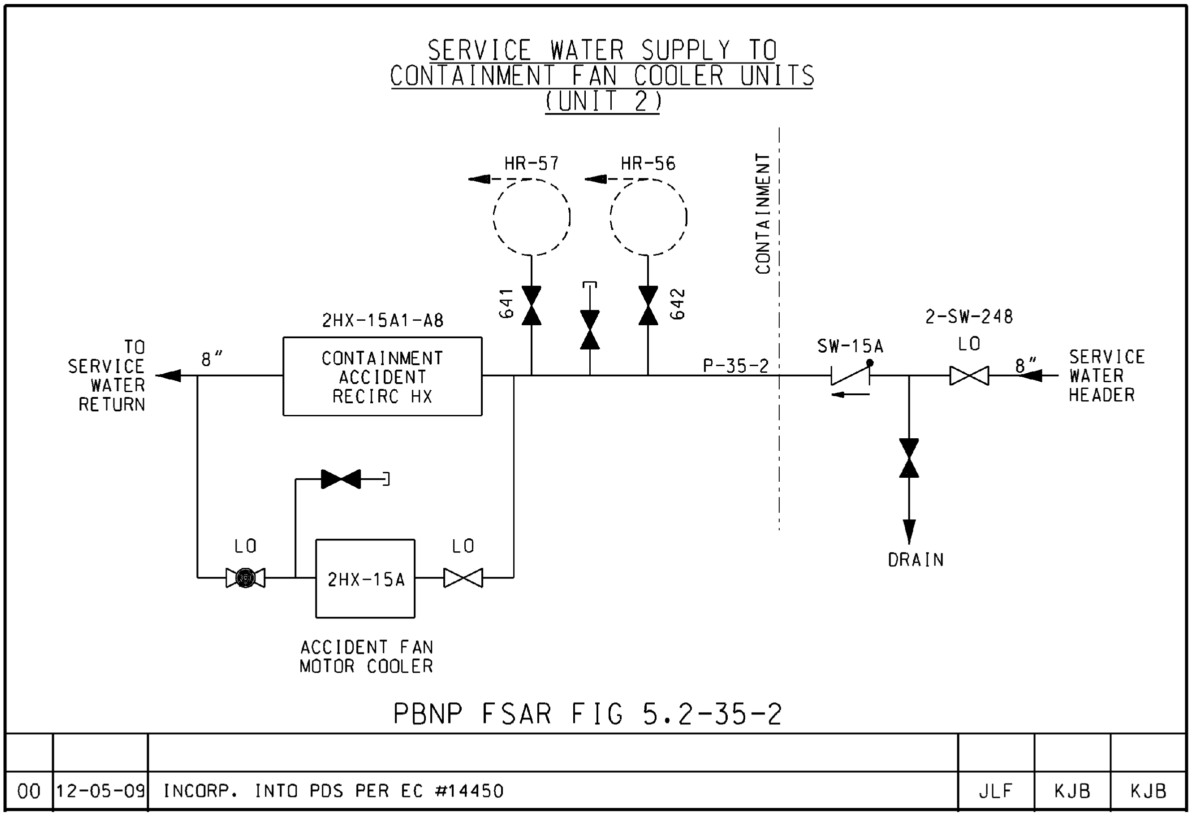
PENETRATION	CONTAINMENT ISOLATION VALVES INSIDE	CONTAINMENT ISOLATION VALVES OUTSIDE	BRANCH/SYSTEM	LINE SIZE	FLUID	TEMP. HOT>200 COLD<200	CLASS
35-1	CLOSED SYS.	SW-217	VENTILATION COOLER WATER IN/SERVICE WATER	8”	W	COLD	4

FOR FURTHER INFORMATION REFER TO FSAR CHAPTER 9 & FIGURE 9.6-5

NOTE:

THIS PENETRATION MEETS CLASS 4 CONTAINMENT ISOLATION CRITERIA. REQUIREMENTS ARE MET BY MANUAL VALVE (SW-217) LOCATED OUTSIDE CONTAINMENT. INSIDE CONTAINMENT THE SERVICE WATER SYSTEM IS A CLOSED SYSTEM.

Figure 5.2-35-2 SERVICE WATER SUPPLY TO CONTAIMENT FAN COOLER UNITS (UNIT 2)



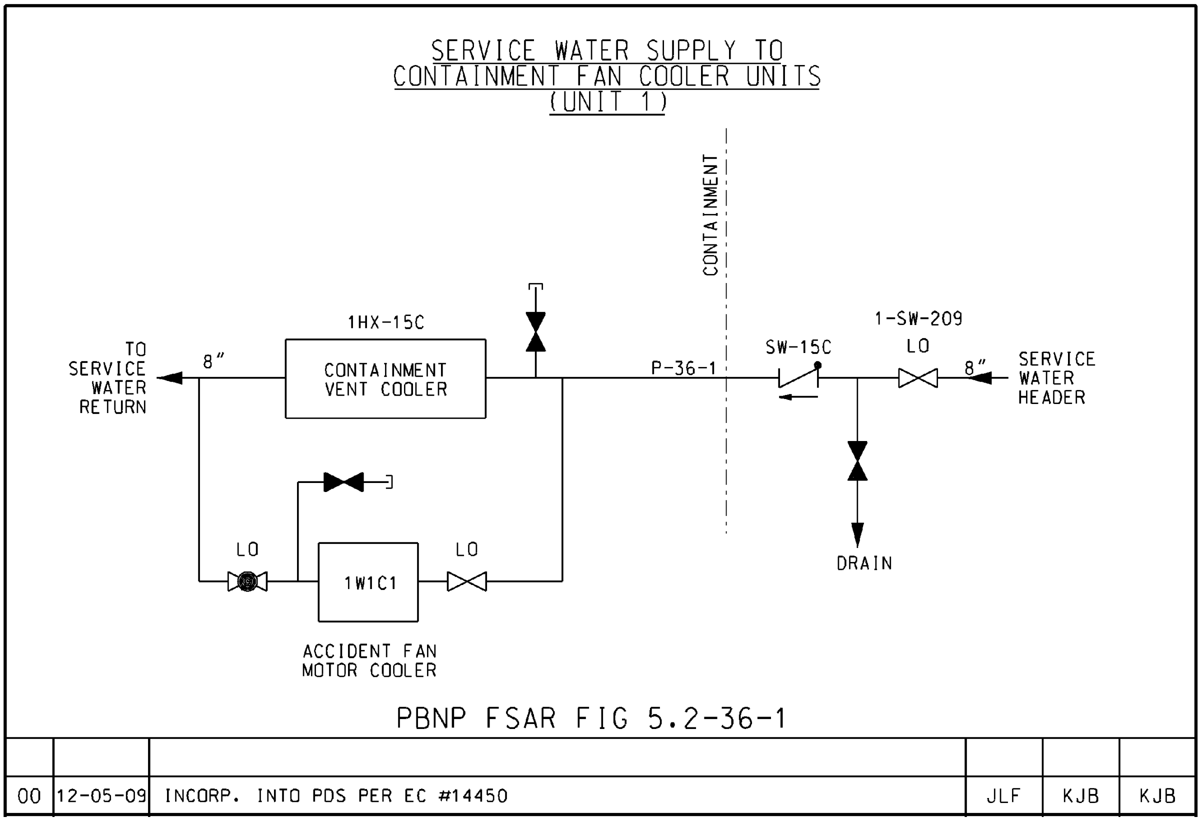
PENETRATION	CONTAINMENT ISOLATION VALVES INSIDE	OUTSIDE	BRANCH/SYSTEM	LINE SIZE	FLUID	TEMP. HOT>200 COLD<200	CLASS
35-2	CLOSED SYS.	SW-248	VENTILATION COOLER WATER IN/SERVICE WATER	8"	W	COLD	4

FOR FURTHER INFORMATION REFER TO FSAR CHAPTER 9 & FIGURE 9.6-5

NOTE:

THIS PENETRATION MEETS CLASS 4 CONTAINMENT ISOLATION CRITERIA. REQUIREMENTS ARE MET BY MANUAL VALVE (SW-248) LOCATED OUTSIDE CONTAINMENT. INSIDE CONTAINMENT THE SERVICE WATER SYSTEM IS A CLOSED SYSTEM.

Figure 5.2-36-1 SERVICE WATER SUPPLY TO CONTAIMENT FAN COOLER UNITS (UNIT 1)



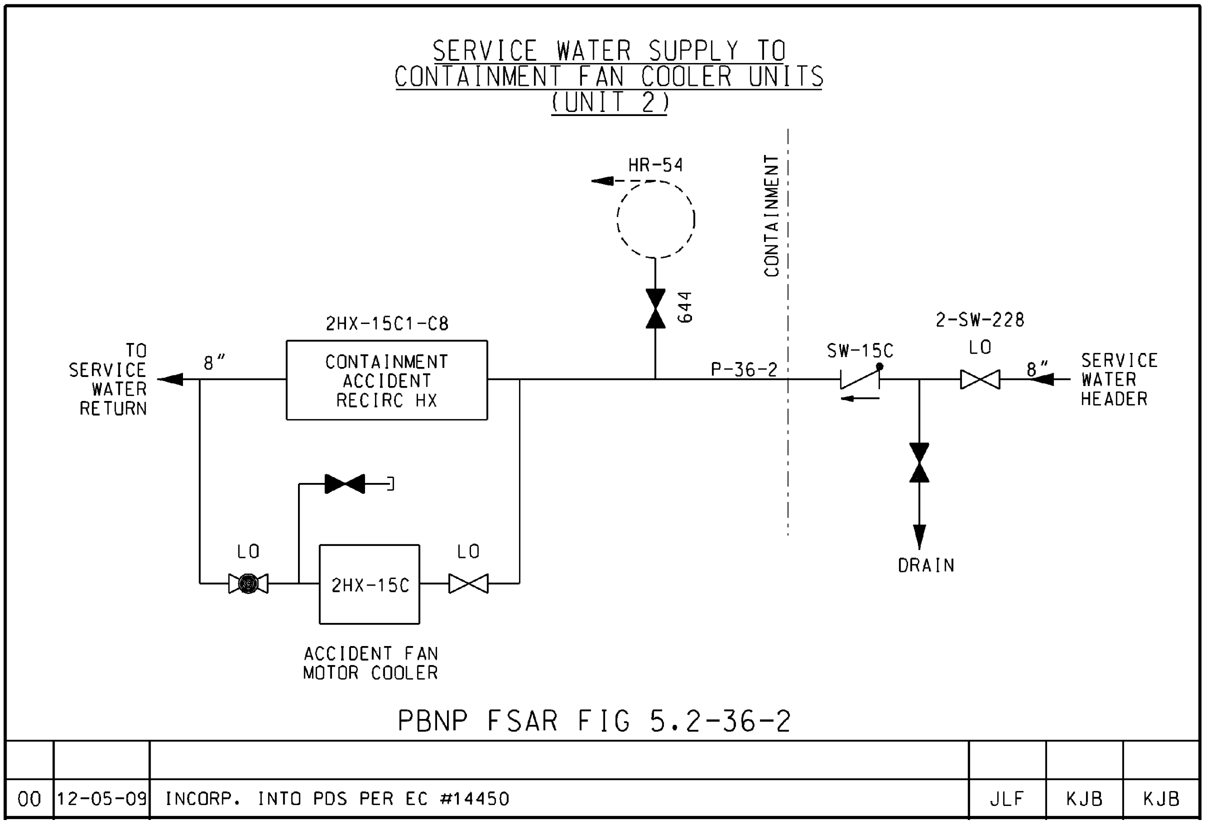
PENETRATION	CONTAINMENT ISOLATION VALVES: INSIDE	CONTAINMENT ISOLATION VALVES: OUTSIDE	BRANCH/SYSTEM	LINE SIZE	FLUID	TEMP. HOT>200 COLD<200	CLASS
36-1	CLOSED SYSTEM	SW-209	VENTILATION COOLER WATER IN/SERVICE WATER	8"	W	COLD	4

FOR FURTHER INFORMATION REFER TO FSAR CHAPTER 9 & FIGURE 9.6-5

NOTE:

THIS PENETRATION MEETS CLASS 4 CONTAINMENT ISOLATION CRITERIA. REQUIREMENTS ARE MET BY MANUAL VALVE (SW-209) LOCATED OUTSIDE CONTAINMENT. INSIDE CONTAINMENT THE SERVICE WATER SYSTEM IS A CLOSED SYSTEM.

Figure 5.2-36-2 SERVICE WATER SUPPLY TO CONTAINMENT FAN COOLER UNITS (UNIT 2)



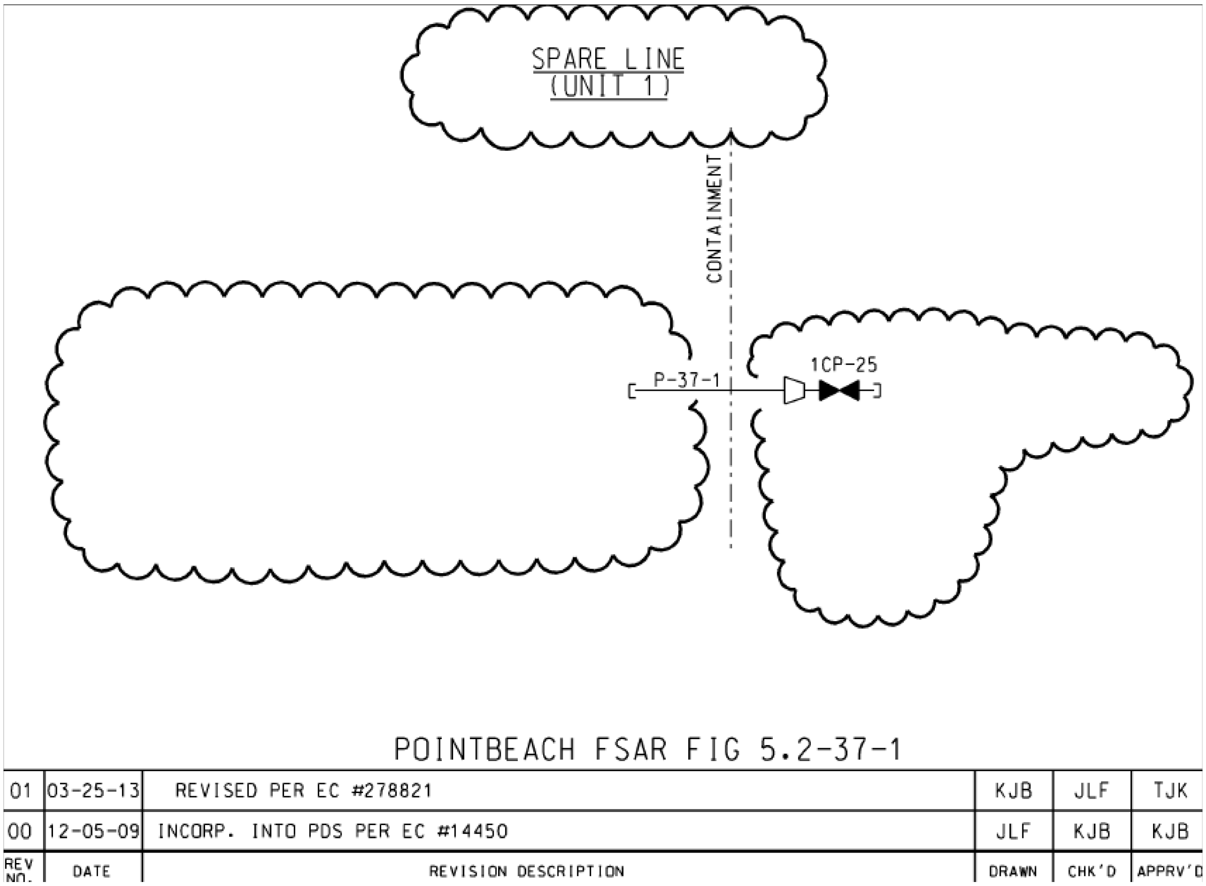
PENETRATION	CONTAINMENT ISOLATION VALVES INSIDE	OUTSIDE	BRANCH/SYSTEM	LINE SIZE	FLUID	TEMP. HOT>200 COLD<200	CLASS
36-2	CLOSED SYS.	SW-228	VENTILATION COOLER WATER IN/SERVICE WATER	8”	W	COLD	4

FOR FURTHER INFORMATION REFER TO FSAR CHAPTER 9 & FIGURE 9.6-5

NOTE:

THIS PENETRATION MEETS CLASS 4 CONTAINMENT ISOLATION CRITERIA. REQUIREMENTS ARE MET BY MANUAL VALVE (SW-228) LOCATED OUTSIDE CONTAINMENT. INSIDE CONTAINMENT THE SERVICE WATER SYSTEM IS A CLOSED SYSTEM.

Figure 5.2-37-1 SPARE LINE (UNIT 1)



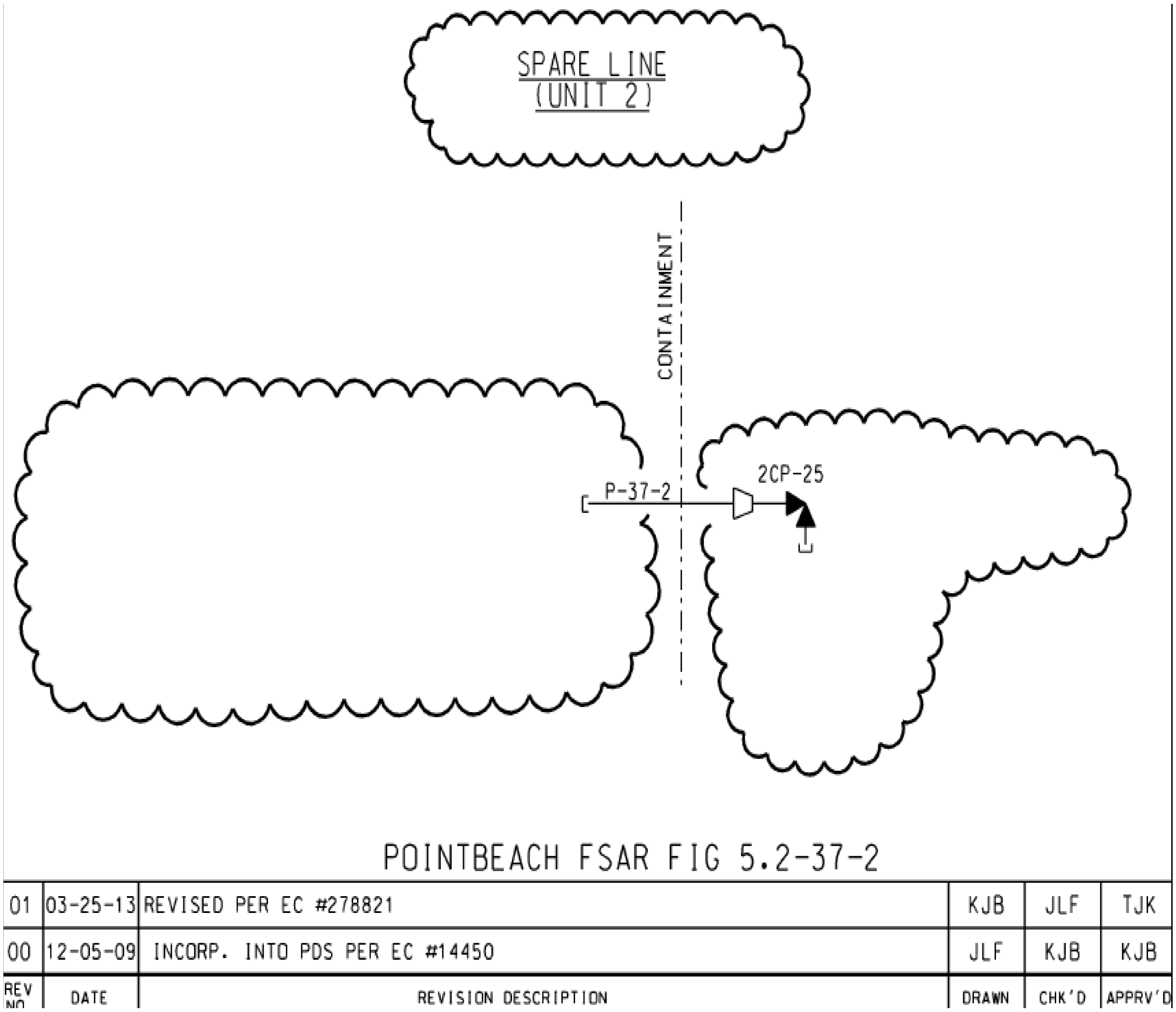
	CONTAINMENT ISOLATION VALVES					TEMP.	
PENETRATION	INSIDE	OUTSIDE	BRANCH/SYSTEM	LINE SIZE	FLUID	HOT>200 COLD<200	CLASS
37-1	CAPPED	1CP-25	SPARE	2"	Air	COLD	5

FOR FURTHER INFORMATION REFER TO FSAR CHAPTER 9 & FIGURE 9.6-5

NOTE:

THIS PENETRATION MEETS CLASS 5 CONTAINMENT ISOLATION CRITERIA. REQUIREMENTS ARE MET BY MANUAL VALVE (1CP-25) LOCATED OUTSIDE CONTAINMENT AND WELDED CAP INSIDE CONTAINMENT.

Figure 5.2-37-2 SPARE LINE (UNIT 2)



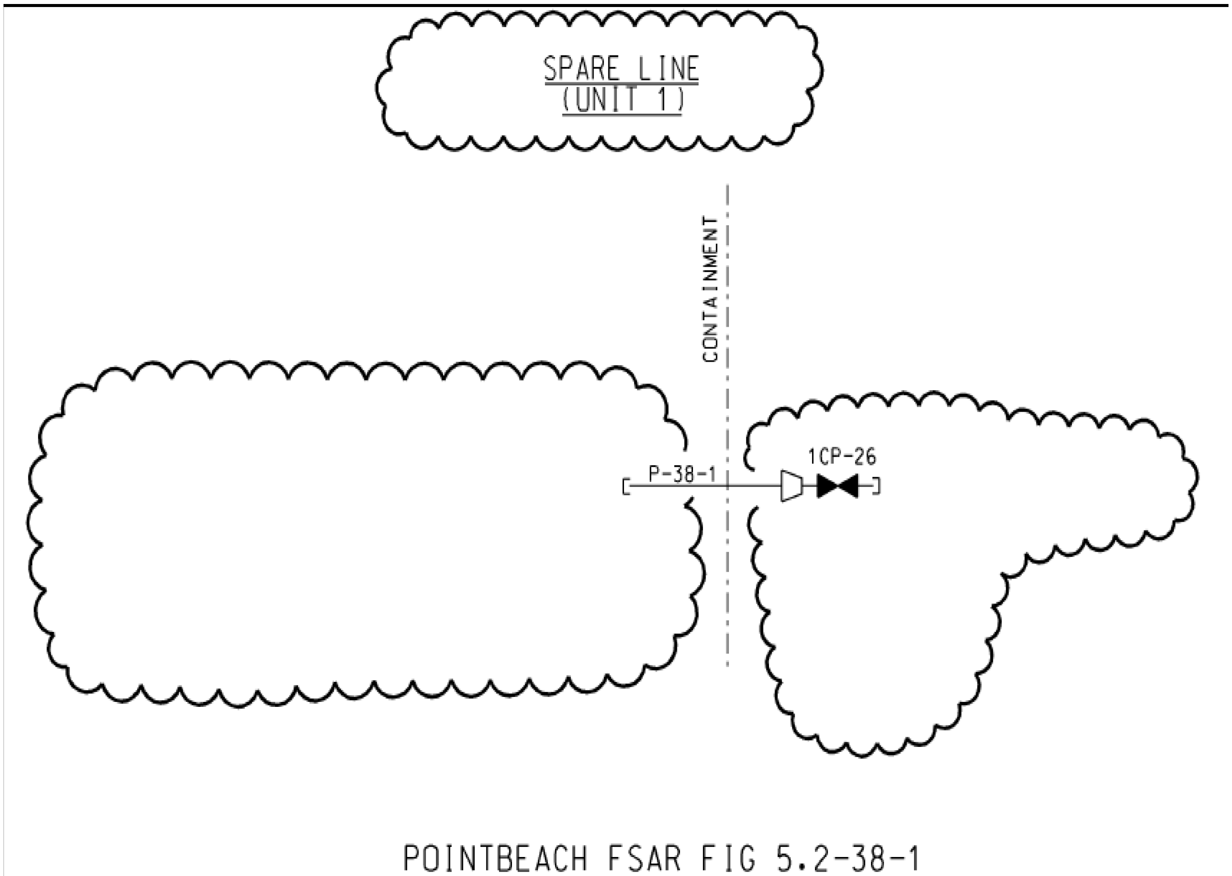
	CONTAINMENT ISOLATION VALVES					TEMP.	
PENETRATION	INSIDE	OUTSIDE	BRANCH/SYSTEM	LINE SIZE	FLUID	HOT>200 COLD<200	CLASS
37-2	CAPPED	2CP-25	SPARE	2"	Air	COLD	5

FOR FURTHER INFORMATION REFER TO FSAR CHAPTER 9 & FIGURE 9.6-5

NOTE:

THIS PENETRATION MEETS CLASS 5 CONTAINMENT ISOLATION CRITERIA. REQUIREMENTS ARE MET BY MANUAL VALVE (2CP-25) LOCATED OUTSIDE CONTAINMENT AND WELDED CAP INSIDE CONTAINMENT.

Figure 5.2-38-1 SPARE LINE (UNIT 1)



REV NO.	DATE	REVISION DESCRIPTION	DRAWN	CHK'D	APPRV'D
01	03-25-13	REVISED PER EC #278821	KJB	JLF	TJK
00	12-05-09	INCORP. INTO PDS PER EC #14450	JLF	KJB	KJB

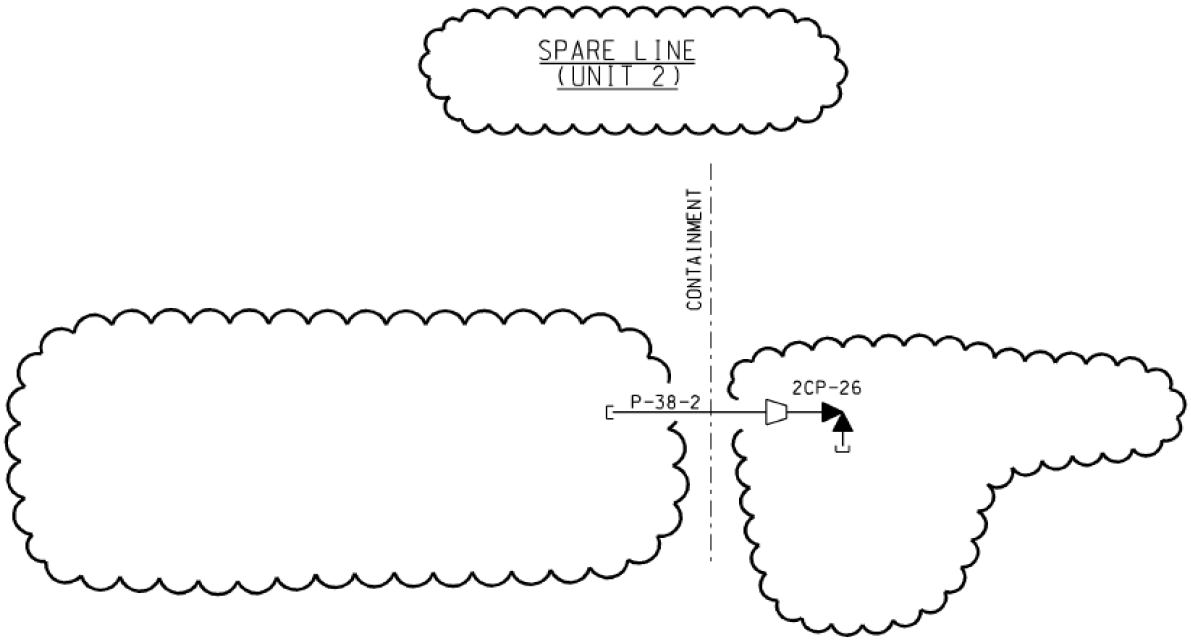
PENETRATION	CONTAINMENT ISOLATION VALVES INSIDE	CONTAINMENT ISOLATION VALVES OUTSIDE	BRANCH/SYSTEM	LINE SIZE	FLUID	TEMP. HOT>200 COLD<200	CLASS
38-1	CAPPED	1CP-26	SPARE	2”	Air	COLD	5

FOR FURTHER INFORMATION REFER TO FSAR CHAPTER 9 & FIGURE 9.6-5

NOTE:

THIS PENETRATION MEETS CLASS 5 CONTAINMENT ISOLATION CRITERIA. REQUIREMENTS ARE MET BY MANUAL VALVE (1CP-26) LOCATED OUTSIDE CONTAINMENT AND WELDED CAP INSIDE CONTAINMENT.

Figure 5.2-38-2 SPARE LINE (UNIT 2)



POINTBEACH FSAR FIG 5.2-38-2

REV NO.	DATE	REVISION DESCRIPTION	DRAWN	CHK'D	APPRV'D
01	03-25-13	REVISED PER EC #278821	KJB	KLF	TJK
00	12-05-09	INCORP. INTO PDS PER EC #14450	JLF	KJB	KJB

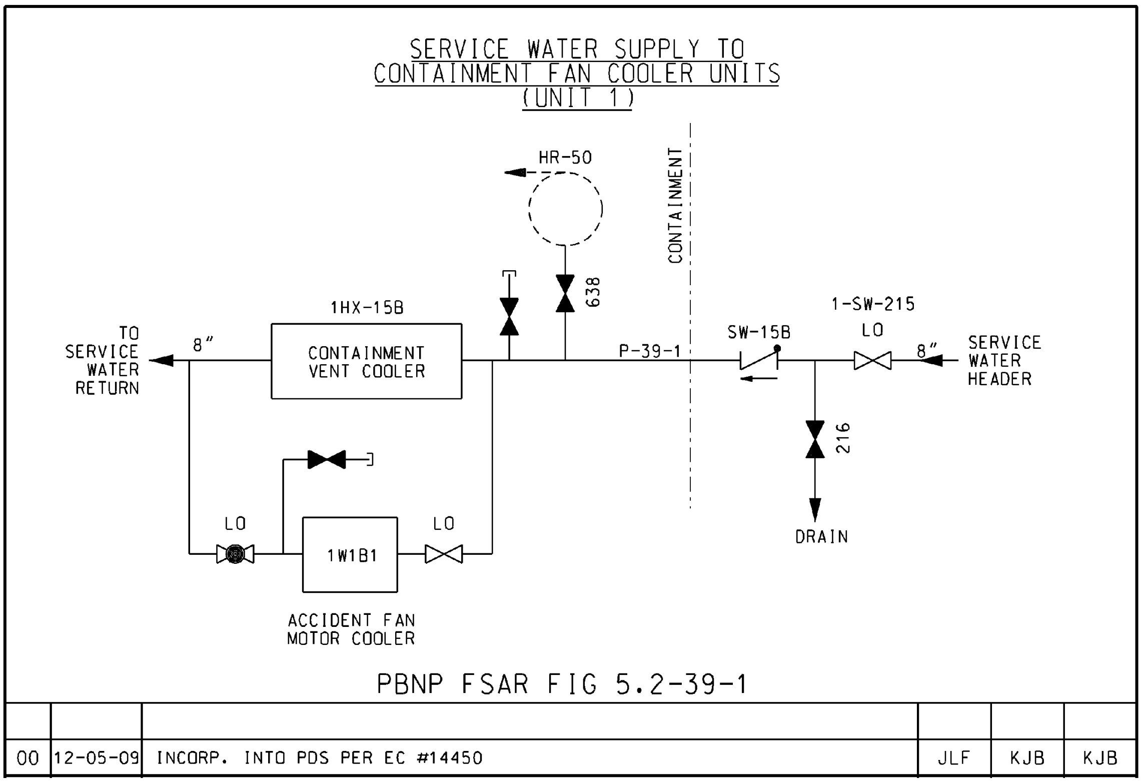
	CONTAINMENT ISOLATION VALVES					TEMP.	
PENETRATION	INSIDE	OUTSIDE	BRANCH/SYSTEM	LINE SIZE	FLUID	HOT>200 COLD<200	CLASS
38-2	CAPPED	2CP-26	SPARE	2”	Air	COLD	5

FOR FURTHER INFORMATION REFER TO FSAR CHAPTER 9 & FIGURE 9.6-5

NOTE:

THIS PENETRATION MEETS CLASS 5 CONTAINMENT ISOLATION CRITERIA. REQUIREMENTS ARE MET BY MANUAL VALVE (2CP-26) LOCATED OUTSIDE CONTAINMENT AND WELDED CAP INSIDE CONTAINMENT.

Figure 5.2-39-1 SERVICE WATER SUPPLY TO CONTAIMENT FAN COOLER UNITS (UNIT 1)



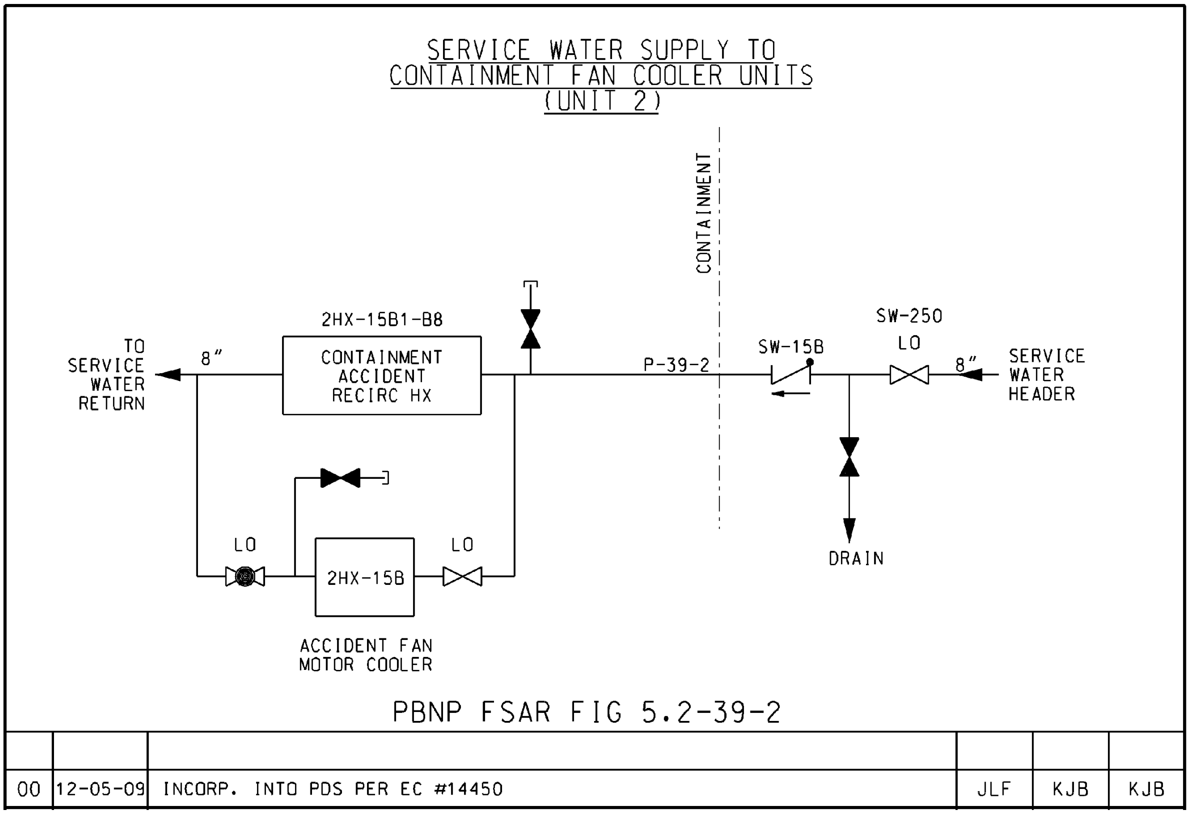
PENETRATION	CONTAINMENT ISOLATION VALVES INSIDE	OUTSIDE	BRANCH/SYSTEM	LINE SIZE	FLUID	TEMP. HOT>200 COLD<200	CLASS
39-1	CLOSED SYSTEM	SW-215	VENTILATION COOLER WATER IN/SERVICE WATER	8"	W	COLD	4

FOR FURTHER INFORMATION REFER TO FSAR CHAPTER 9 & FIGURE 9.6-5

NOTE:

THIS PENETRATION MEETS CLASS 4 CONTAINMENT ISOLATION CRITERIA. REQUIREMENTS ARE MET BY MANUAL VALVE (SW-215) LOCATED OUTSIDE CONTAINMENT. INSIDE CONTAINMENT THE SERVICE WATER SYSTEM IS A CLOSED SYSTEM.

Figure 5.2-39-2 SERVICE WATER SUPPLY TO CONTAIMENT FAN COOLER UNITS (UNIT 2)



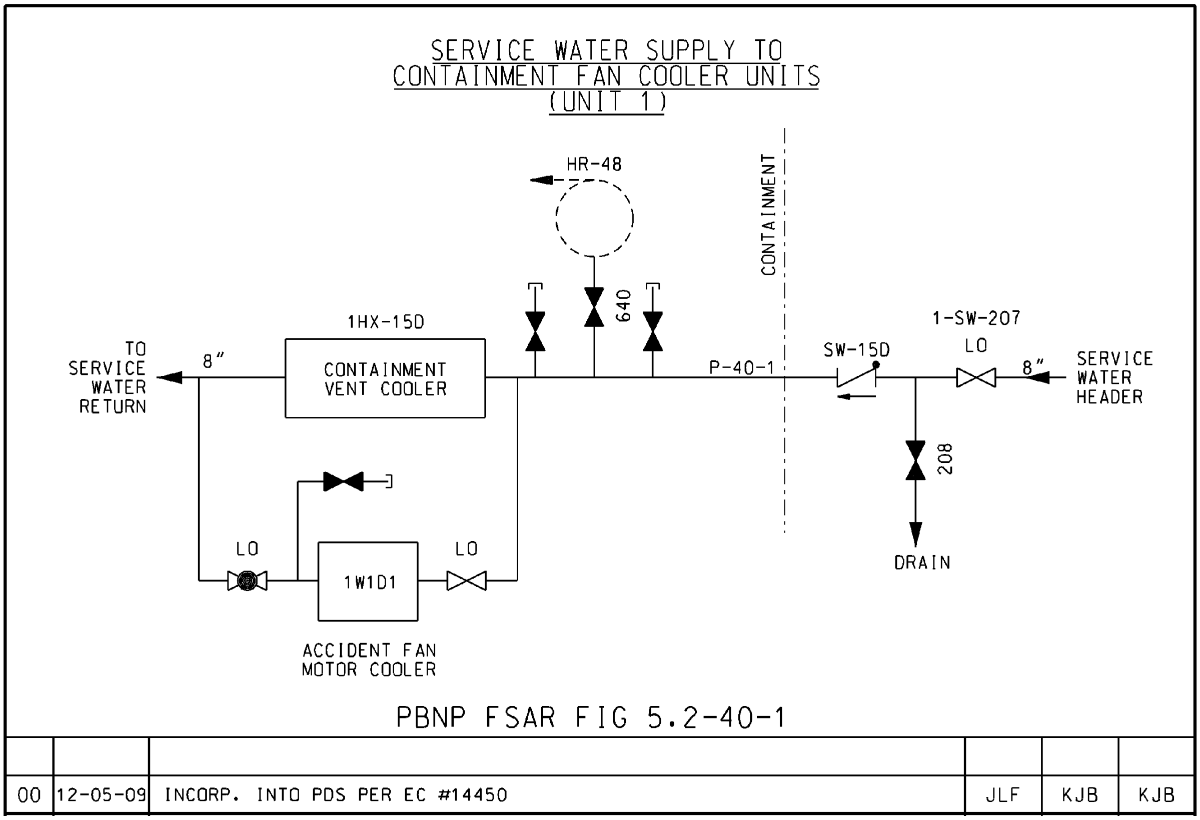
PENETRATION	CONTAINMENT ISOLATION VALVES INSIDE	OUTSIDE	BRANCH/SYSTEM	LINE SIZE	FLUID	TEMP. HOT>200 COLD<200	CLASS
39-2	CLOSED SYS.	SW-250	VENTILATION COOLER WATER IN/SERVICE WATER	8”	W	COLD	4

FOR FURTHER INFORMATION REFER TO FSAR CHAPTER 9 & FIGURE 9.6-5

NOTE:

THIS PENETRATION MEETS CLASS 4 CONTAINMENT ISOLATION CRITERIA. REQUIREMENTS ARE MET BY MANUAL VALVE (SW-250) LOCATED OUTSIDE CONTAINMENT. INSIDE CONTAINMENT THE SERVICE WATER SYSTEM IS A CLOSED SYSTEM.

Figure 5.2-40-1 SERVICE WATER SUPPLY TO CONTAIMENT FAN COOLER UNITS (UNIT 1)



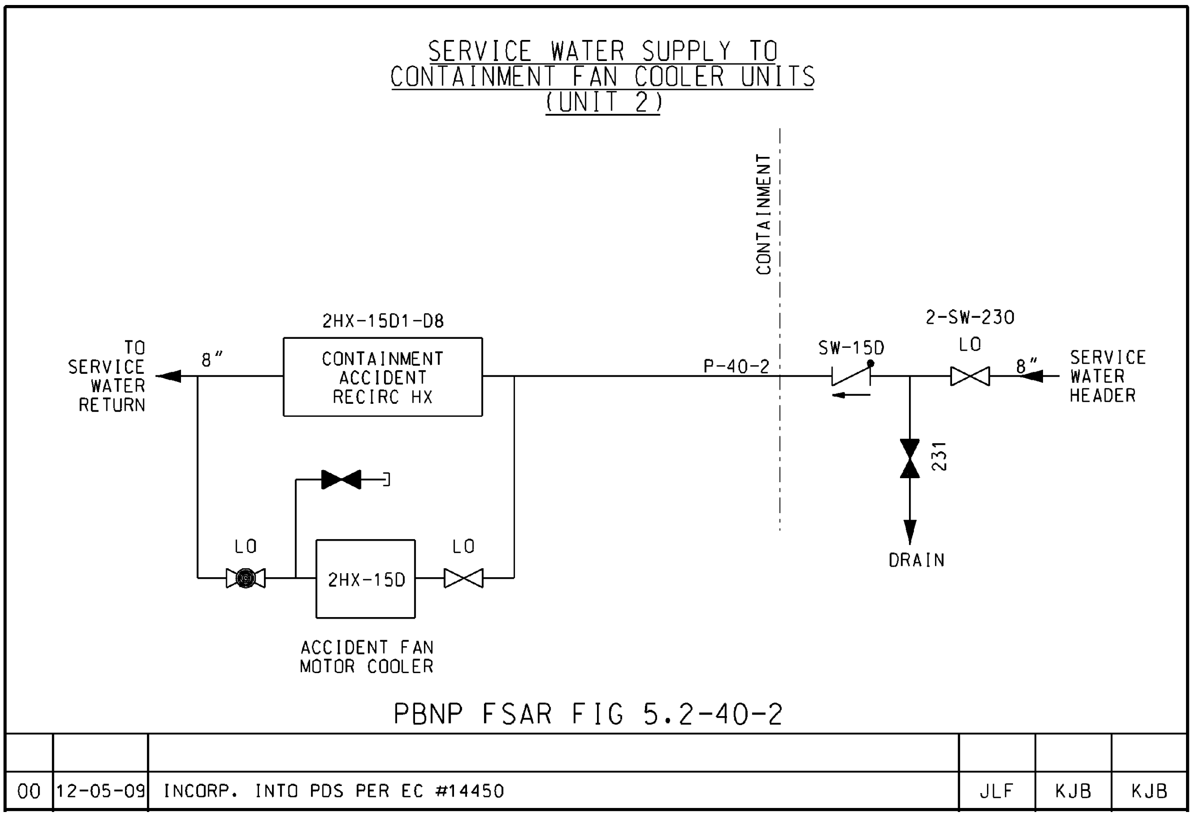
PENETRATION	CONTAINMENT ISOLATION VALVES		BRANCH/SYSTEM	LINE SIZE	FLUID	TEMP.	CLASS
	INSIDE	OUTSIDE				HOT>200 COLD<200	
40-1	CLOSED SYSTEM	SW-207	VENTILATION COOLER WATER IN/SERVICE WATER	8"	W	COLD	4

FOR FURTHER INFORMATION REFER TO FSAR CHAPTER 9 & FIGURE 9.6-5

NOTE:

THIS PENETRATION MEETS CLASS 4 CONTAINMENT ISOLATION CRITERIA. REQUIREMENTS ARE MET BY MANUAL VALVE (SW-207) LOCATED OUTSIDE CONTAINMENT. INSIDE CONTAINMENT THE SERVICE WATER SYSTEM IS A CLOSED SYSTEM.

Figure 5.2-40-2 SERVICE WATER SUPPLY TO CONTAIMENT FAN COOLER UNITS (UNIT 2)



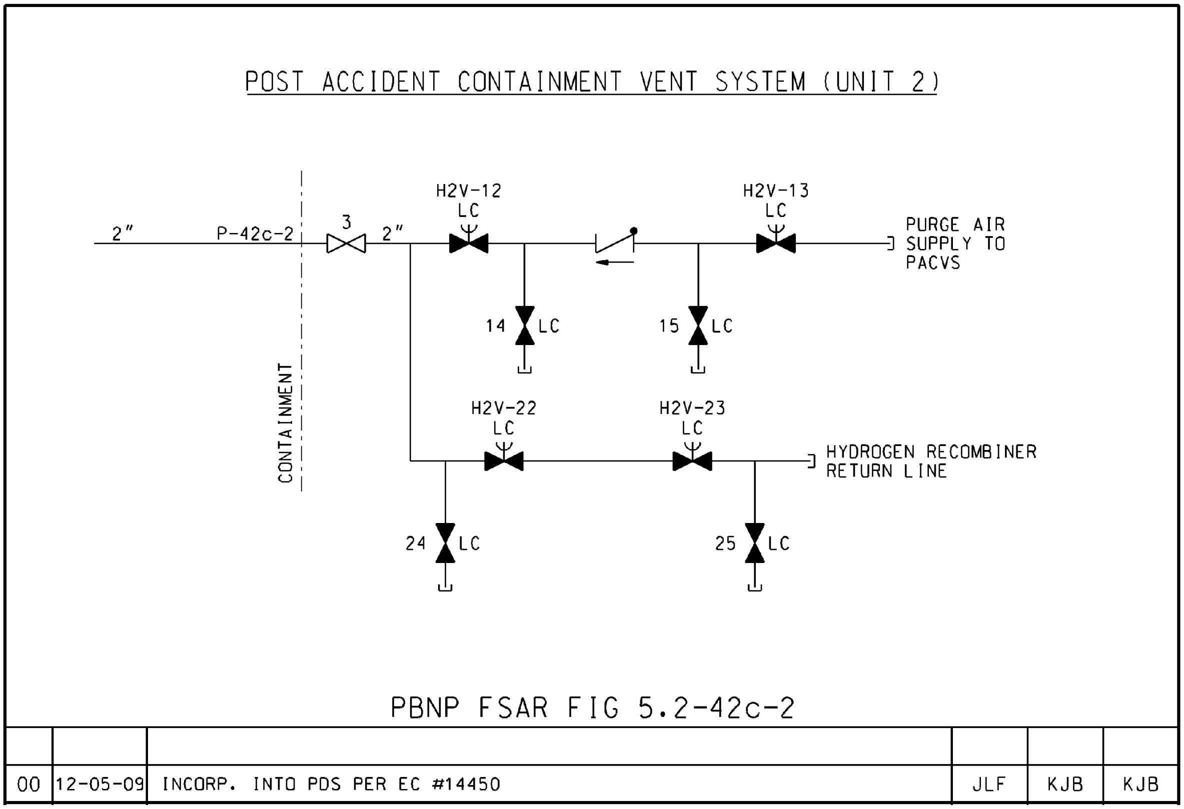
PENETRATION	CONTAINMENT ISOLATION VALVES INSIDE	OUTSIDE	BRANCH/SYSTEM	LINE SIZE	FLUID	TEMP. HOT>200 COLD<200	CLASS
40-2	CLOSED SYS.	SW-230	VENTILATION COOLER WATER IN/SERVICE WATER	8"	W	COLD	4

FOR FURTHER INFORMATION REFER TO FSAR CHAPTER 9 & FIGURE 9.6-5

NOTE:

THIS PENETRATION MEETS CLASS 4 CONTAINMENT ISOLATION CRITERIA. REQUIREMENTS ARE MET BY MANUAL VALVE (SW-230) LOCATED OUTSIDE CONTAINMENT. INSIDE CONTAINMENT THE SERVICE WATER SYSTEM IS A CLOSED SYSTEM.

Figure 5.2-42c-2 POST ACCIDENT CONTAINMENT VENT SYSTEM (UNIT 2)



PENETRATION	CONTAINMENT ISOLATION VALVES INSIDE	OUTSIDE	BRANCH/SYSTEM	LINE SIZE	FLUID	TEMP. HOT>200 COLD<200	CLASS
42c-2		H2V-12 H2V-13	PURGE AIR TO POST ACCIDENT CONTAINMENT VENT SYS./PACVS.	2”	G	COLD	SPECIAL
		H2V-22 H2V-23	POST ACCIDENT CONTAINMENT VENT SYS H_2 RECOMBINER RETURN LINE /PACVS.	2”	G	COLD	SPECIAL

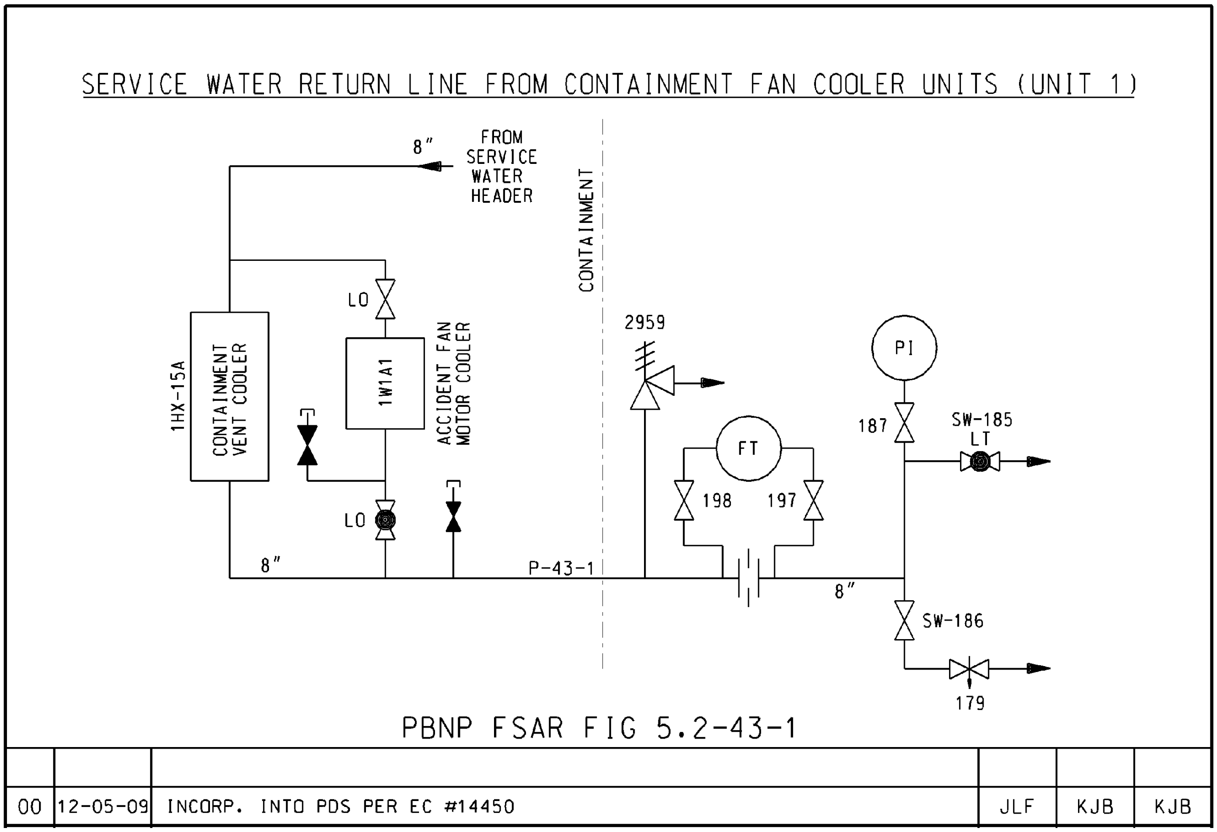
FOR FURTHER INFORMATION REFER TO FSAR CHAPTER 5 & FIGURE 5.3-1 SHT. 2 & FIGURE 5.3-1 SHT. 3

NOTE:

THIS PENETRATION IS CLASSIFIED SPECIAL AND IS IDENTIFIED AS AN INTERMITTENT USE SYSTEM POST DBA.

1. PURGE AIR SUPPLY BRANCH - LOCKED CLOSED MANUAL VALVES H2V-12 AND H2V-13 OUTSIDE CONTAINMENT MEET CONTAINMENT ISOLATION CRITERIA.
2. HYDROGEN RECOMBINER BRANCH - LOCKED CLOSED MANUAL VALVES H2V-22 AND H2V-23 OUTSIDE CONTAINMENT MEET CONTAINMENT ISOLATION CRITERIA.

Figure 5.2-43-1 SERVICE WATER RETURN LINE FROM CONTAIMENT FAN COOLER UNITS (UNIT 1)



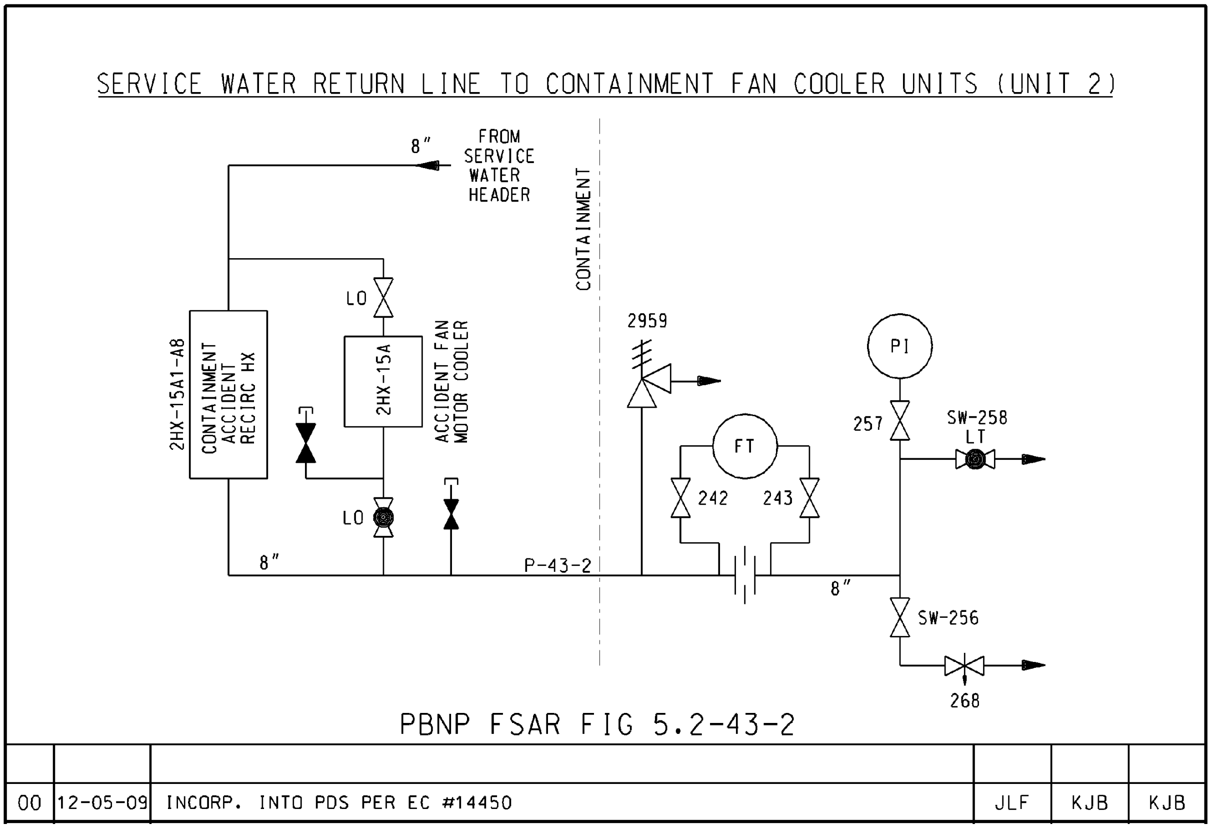
PENETRATION	CONTAINMENT ISOLATION VALVES INSIDE	OUTSIDE	BRANCH/SYSTEM	LINE SIZE	FLUID	TEMP. HOT>200 COLD<200	CLASS
43-1	CLOSED SYSTEM	SW-185 SW-186	VENTILATION COOLER WATER OUT/SERVICE WATER	8"	W	COLD	4

FOR FURTHER INFORMATION REFER TO FSAR CHAPTER 9 & FIGURE 9.6-5

NOTE:

THIS PENETRATION MEETS CLASS 4 CONTAINMENT ISOLATION CRITERIA WITH TWO MANUAL VALVES (SW-185 AND SW-186) LOCATED OUTSIDE CONTAINMENT. IT IS A CLOSED SYSTEM INSIDE CONTAINMENT.

Figure 5.2-43-2 SERVICE WATER RETURN LINE TO CONTAIMENT FAN COOLER UNITS (UNIT 2)



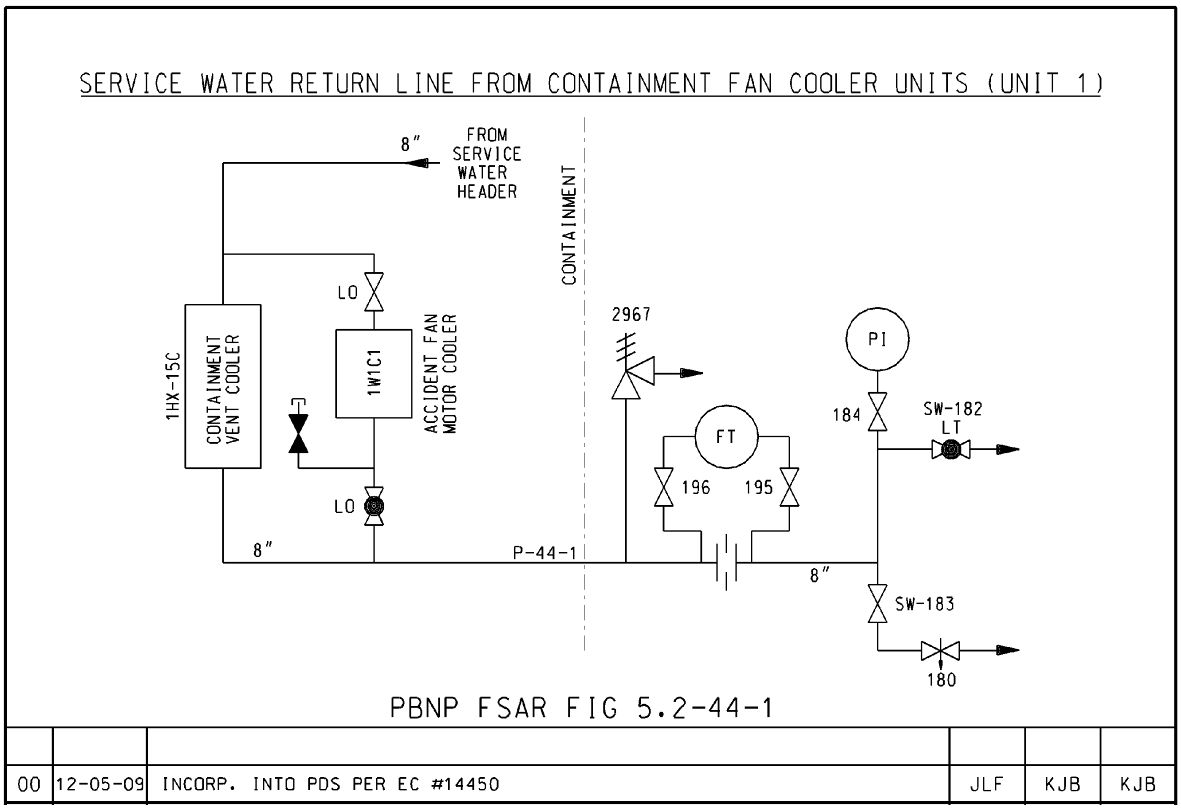
PENETRATION	CONTAINMENT ISOLATION VALVES INSIDE	CONTAINMENT ISOLATION VALVES OUTSIDE	BRANCH/SYSTEM	LINE SIZE	FLUID	TEMP. HOT>200 COLD<200	CLASS
43-2	CLOSED SYS.	SW-256 SW-258	VENTILATION COOLER WATER OUT/SERVICE WATER	8"	W	COLD	4

FOR FURTHER INFORMATION REFER TO FSAR CHAPTER 9 & FIGURE 9.6-5

NOTE:

THIS PENETRATION MEETS CLASS 4 CONTAINMENT ISOLATION CRITERIA WITH TWO MANUAL VALVES (SW-256, SW-258) LOCATED OUTSIDE CONTAINMENT. IT IS A CLOSED SYSTEM INSIDE CONTAINMENT.

Figure 5.2-44-1 SERVICE WATER RETURN LINE FROM CONTAIMENT FAN COOLER UNITS (UNIT 1)



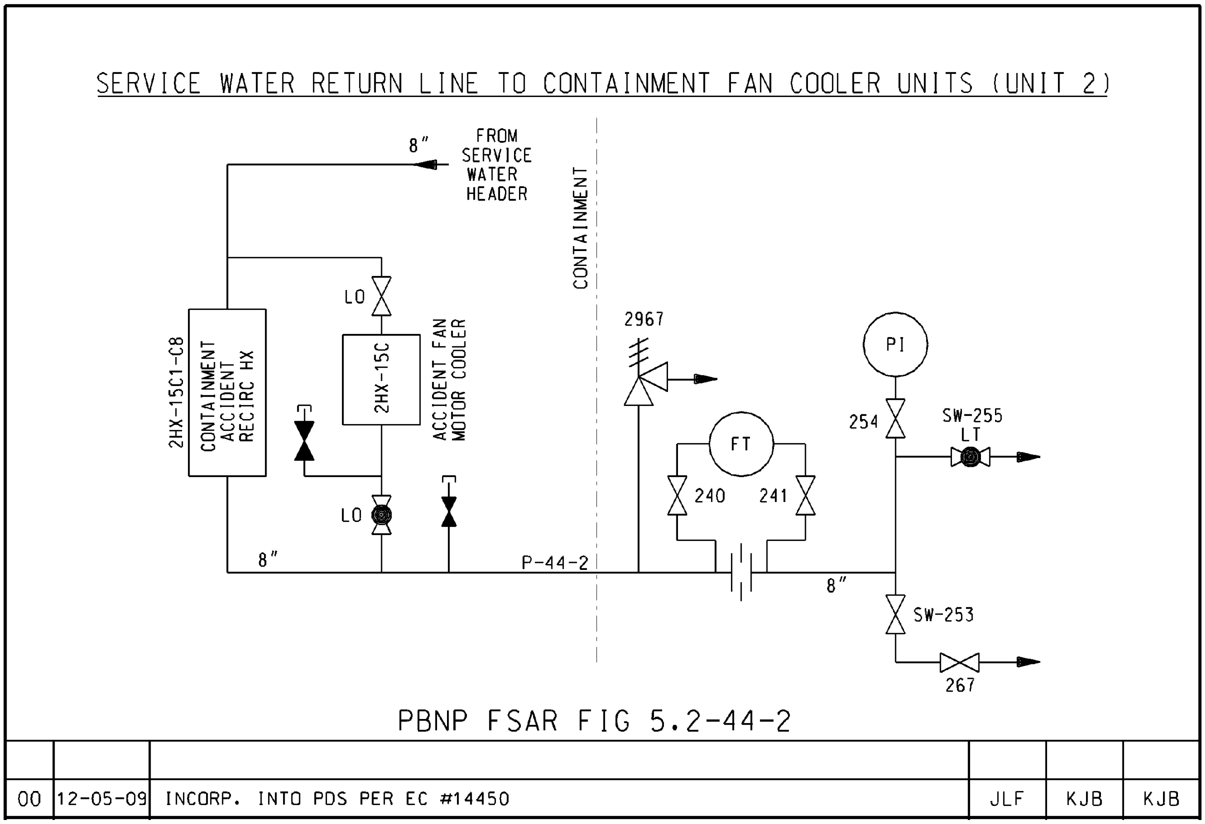
PENETRATION	CONTAINMENT ISOLATION VALVES INSIDE	 OUTSIDE	BRANCH/SYSTEM	LINE SIZE	FLUID	TEMP. HOT>200 COLD<200	CLASS
44-1	CLOSED SYSTEM	SW-182 SW-183	VENTILATION COOLER WATER OUT/SERVICE WATER	8”	W	COLD	4

FOR FURTHER INFORMATION REFER TO FSAR CHAPTER 9 & FIGURE 9.6-5

NOTE:

THIS PENETRATION MEETS CLASS 4 CONTAINMENT ISOLATION CRITERIA WITH TWO MANUAL VALVES (SW-182 AND SW-183) LOCATED OUTSIDE OF CONTAINMENT. IT IS A CLOSED SYSTEM INSIDE CONTAINMENT.

Figure 5.2-44-2 SERVICE WATER RETURN LINE TO CONTAIMENT FAN COOLER UNITS (UNIT 2)



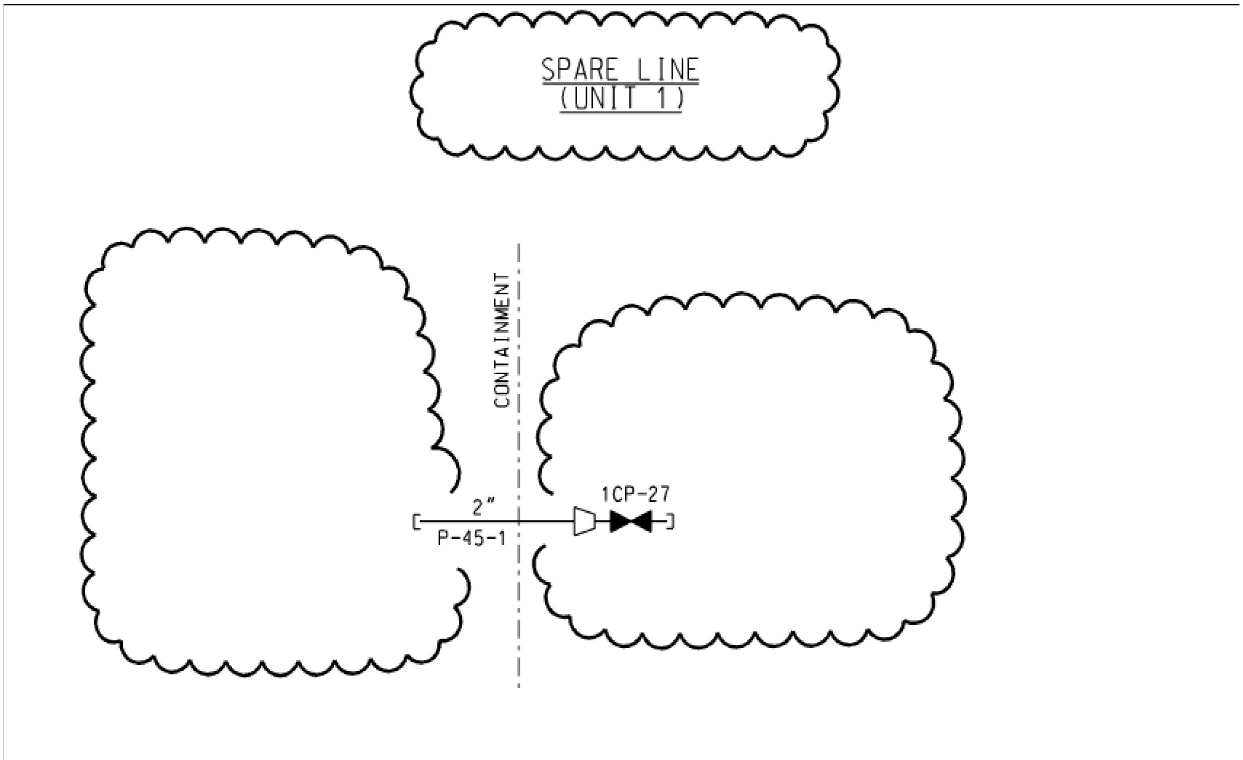
	CONTAINMENT ISOLATION VALVES					TEMP.	
PENETRATION	INSIDE	OUTSIDE	BRANCH/SYSTEM	LINE SIZE	FLUID	HOT>200 COLD<200	CLASS
44-2	CLOSED SYS.	SW-253 SW-255	VENTILATION COOLER WATER OUT/SERVICE WATER	8"	W	COLD	4

FOR FURTHER INFORMATION REFER TO FSAR CHAPTER 9 & FIGURE 9.6-5

NOTE:

THIS PENETRATION MEETS CLASS 4 CONTAINMENT ISOLATION CRITERIA WITH TWO MANUAL VALVES (SW-253, SW-255) LOCATED OUTSIDE CONTAINMENT. IT IS A CLOSED SYSTEM INSIDE CONTAINMENT.

Figure 5.2-45-1 SPARE LINE (UNIT 1)



POINTBEACH FSAR FIG 5.2-45-1

REV NO.	DATE	REVISION DESCRIPTION	DRAWN	CHK'D	APPRV'D
01	03-25-13	REVISED PER EC #278821	KJB	JLF	TJK
00	12-05-09	INCORP. INTO PDS PER EC #14450	JLF	KJB	KJB

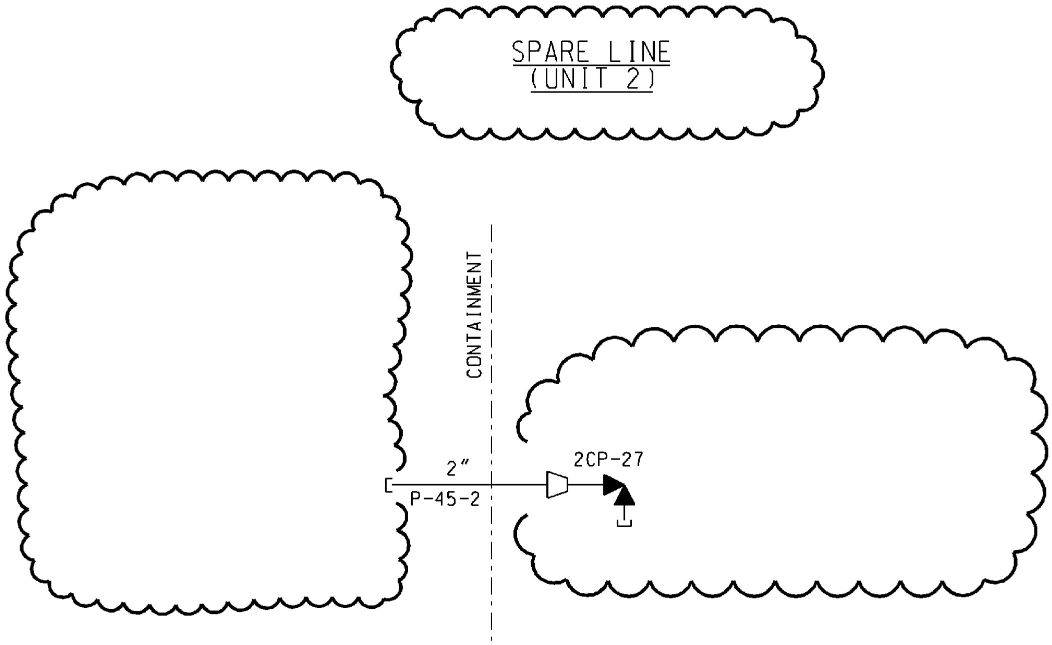
PENETRATION	CONTAINMENT ISOLATION VALVES INSIDE	OUTSIDE	BRANCH/SYSTEM	LINE SIZE	FLUID	TEMP. HOT>200 COLD<200	CLASS
45-1	CAPPED	1CP-27	SPARE	2"	Air	COLD	5

FOR FURTHER INFORMATION REFER TO FSAR CHAPTER 9 & FIGURE 9.6-5

NOTE:

THIS PENETRATION MEETS CLASS 5 CONTAINMENT ISOLATION CRITERIA. REQUIREMENTS ARE MET BY MANUAL VALVE (1CP-27) LOCATED OUTSIDE CONTAINMENT AND WELDED CAP INSIDE CONTAINMENT.

Figure 5.2-45-2 SPARE LINE (UNIT 2)



POINTBEACH FSAR FIG 5.2-45-2

REV NO.	DATE	REVISION DESCRIPTION	DRAWN	CHK'D	APPRV'D
01	03-25-13	REVISED PER EC #278821	KJB	JLF	TJK
00	12-05-09	INCORP. INTO PDS PER EC #14450	JLF	KJB	KJB

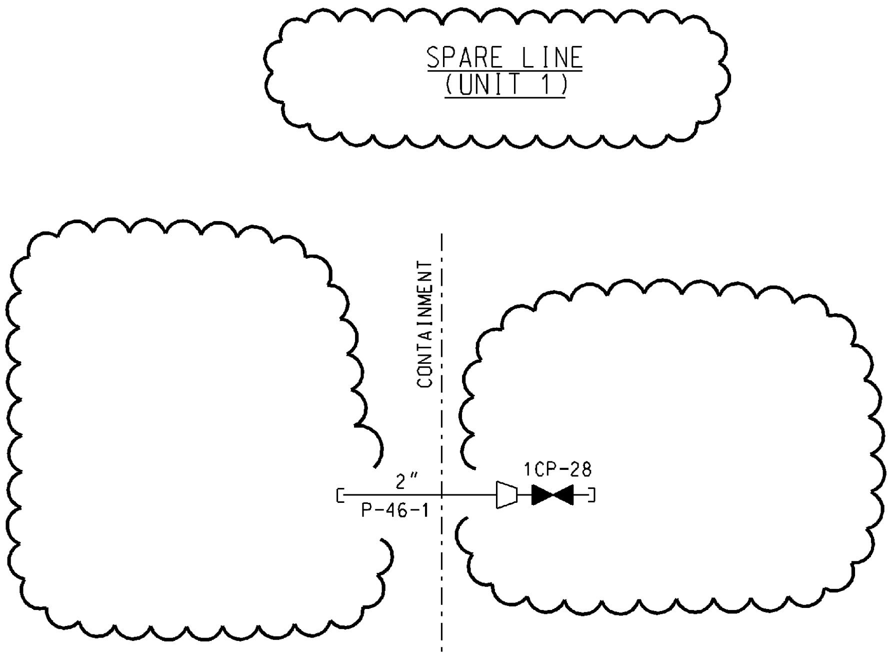
PENETRATION	CONTAINMENT ISOLATION VALVES		BRANCH/SYSTEM	LINE SIZE	FLUID	TEMP.	CLASS
	INSIDE	OUTSIDE				HOT>200 COLD<200	
45-2	CAPPED	2CP-27	SPARE	2"	Air	COLD	5

FOR FURTHER INFORMATION REFER TO FSAR CHAPTER 9 & FIGURE 9.6-5

NOTE:

THIS PENETRATION MEETS CLASS 5 CONTAINMENT ISOLATION CRITERIA. REQUIREMENTS ARE MET BY MANUAL VALVE (1CP-27) LOCATED OUTSIDE CONTAINMENT AND WELDED CAP INSIDE CONTAINMENT.

Figure 5.2-46-1 SPARE LINE (UNIT 1)



POINTBEACH FSAR FIG 5.2-46-1

REV NO.	DATE	REVISION DESCRIPTION	DRAWN	CHK'D	APPRV'D
01	03-25-13	REVISED PER EC #278821	KJB	JLF	TJK
00	12-05-09	INCORP. INTO PDS PER EC #14450	JLF	KJB	KJB

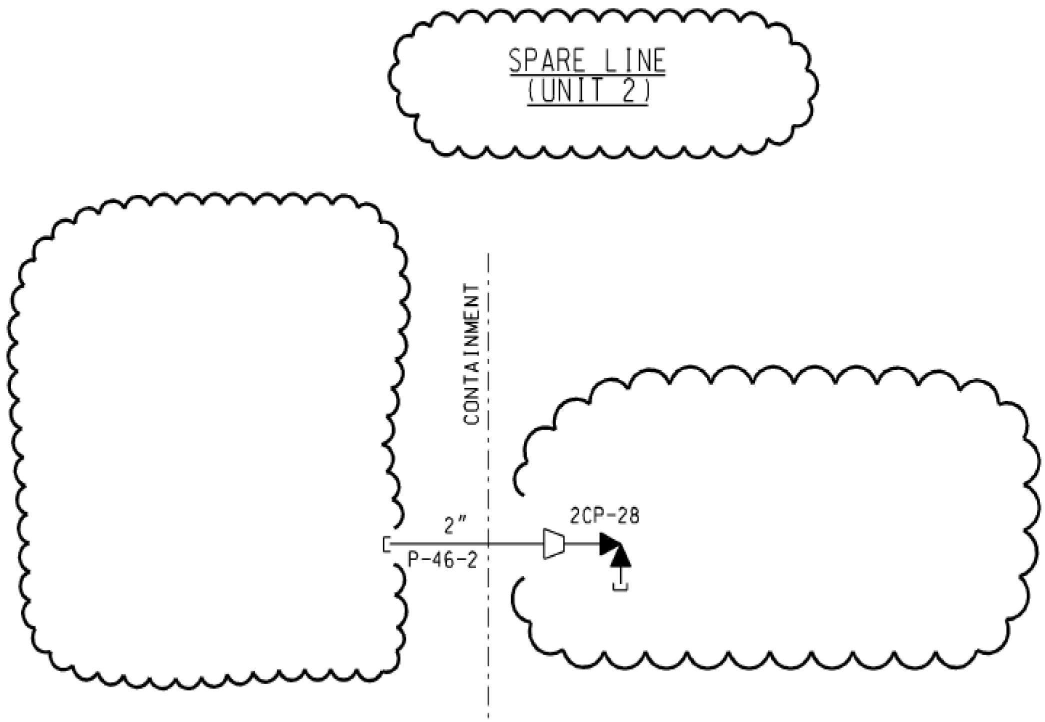
	CONTAINMENT ISOLATION VALVES					TEMP.	
PENETRATION	INSIDE	OUTSIDE	BRANCH/SYSTEM	LINE SIZE	FLUID	HOT>200 COLD<200	CLASS
46-1	CAPPED	1CP-28	SPARE	2”	Air	COLD	5

FOR FURTHER INFORMATION REFER TO FSAR CHAPTER 9 & FIGURE 9.6-3

NOTE:

THIS PENETRATION MEETS CLASS 5 CONTAINMENT ISOLATION CRITERIA. REQUIREMENTS ARE MET BY MANUAL VALVE (1CP-28) LOCATED OUTSIDE CONTAINMENT AND WELDED CAP INSIDE CONTAINMENT.

Figure 5.2-46-2 SPARE LINE (UNIT 2)



POINTBEACH FSAR FIG 5.2-46-2

REV NO.	DATE	REVISION DESCRIPTION	DRAWN	CHK'D	APPRV'D
01	03-25-13	REVISED PER EC #278821	KJB	JLF	TJK
00	12-05-09	INCORP. INTO PDS PER EC #14450	JLF	KJB	KJB

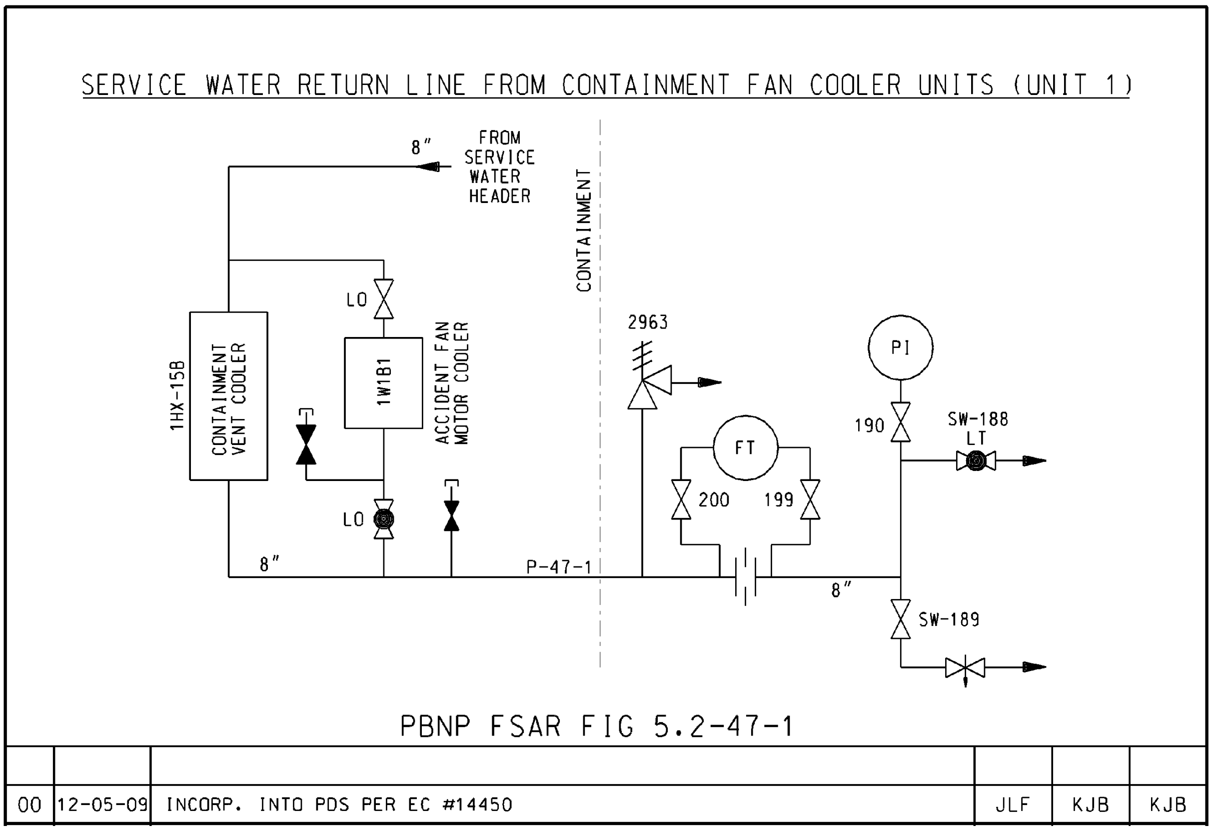
	CONTAINMENT ISOLATION VALVES					TEMP.	
PENETRATION	INSIDE	OUTSIDE	BRANCH/SYSTEM	LINE SIZE	FLUID	HOT>200 COLD<200	CLASS
46-2	CAPPED	2CP-28	SPARE	2"	Air	COLD	5

FOR FURTHER INFORMATION REFER TO FSAR CHAPTER 9 & FIGURE 9.6-5

NOTE:

THIS PENETRATION MEETS CLASS 5 CONTAINMENT ISOLATION CRITERIA. REQUIREMENTS ARE MET BY MANUAL VALVE (2CP-28) LOCATED OUTSIDE CONTAINMENT AND WELDED CAP INSIDE CONTAINMENT.

Figure 5.2-47-1 SERVICE WATER RETURN LINE FROM CONTAINMENT FAN COOLER UNITS (UNIT 1)



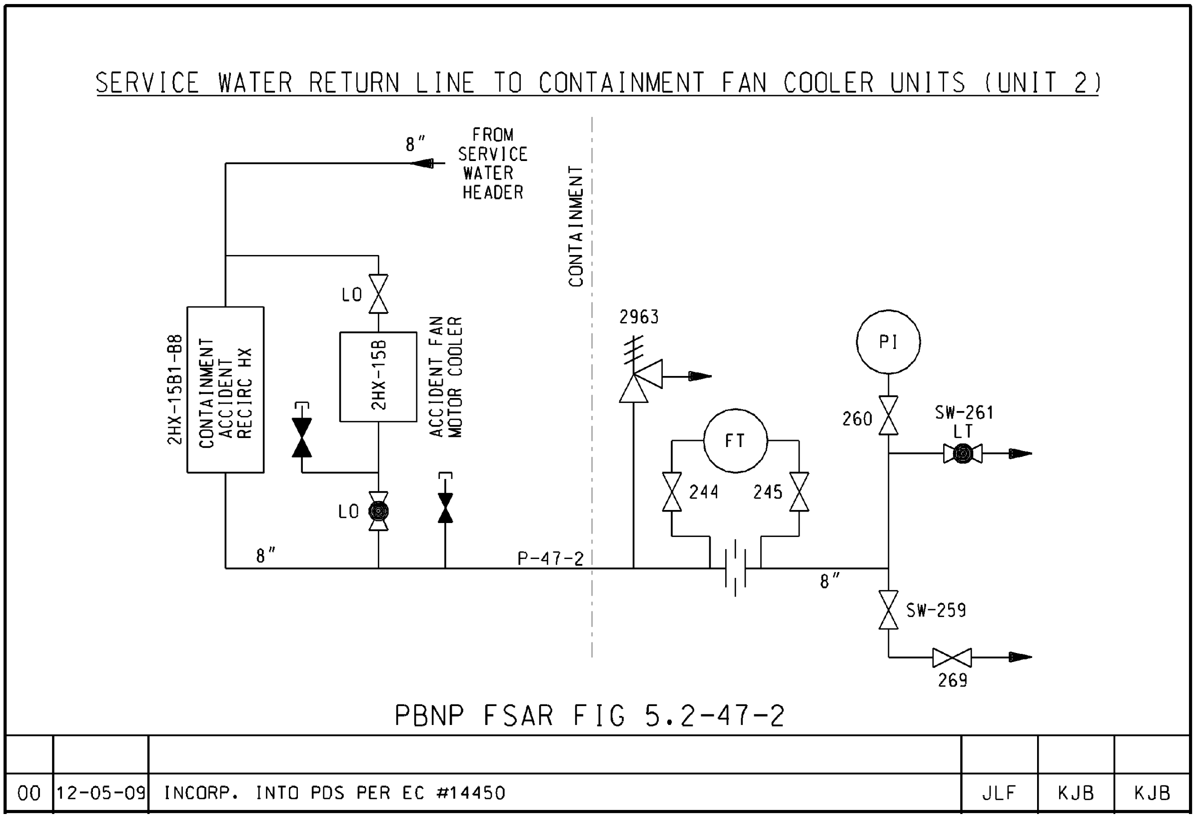
PENETRATION	CONTAINMENT ISOLATION VALVES INSIDE	OUTSIDE	BRANCH/SYSTEM	LINE SIZE	FLUID	TEMP. HOT>200 COLD<200	CLASS
47-1	CLOSED SYSTEM	SW-188 SW-189	VENTILATION COOLER WATER OUT/SERVICE WATER	8”	W	COLD	4

FOR FURTHER INFORMATION REFER TO FSAR CHAPTER 9 & FIGURE 9.6-5

NOTE:

THIS PENETRATION MEETS CLASS 4 CONTAINMENT ISOLATION CRITERIA WITH TWO MANUAL VALVES (SW-188 AND SW-189) LOCATED OUTSIDE CONTAINMENT. IT IS A CLOSED SYSTEM INSIDE CONTAINMENT.

Figure 5.2-47-2 SERVICE WATER RETURN LINE TO CONTAINMENT FAN COOLER UNITS (UNIT 2)



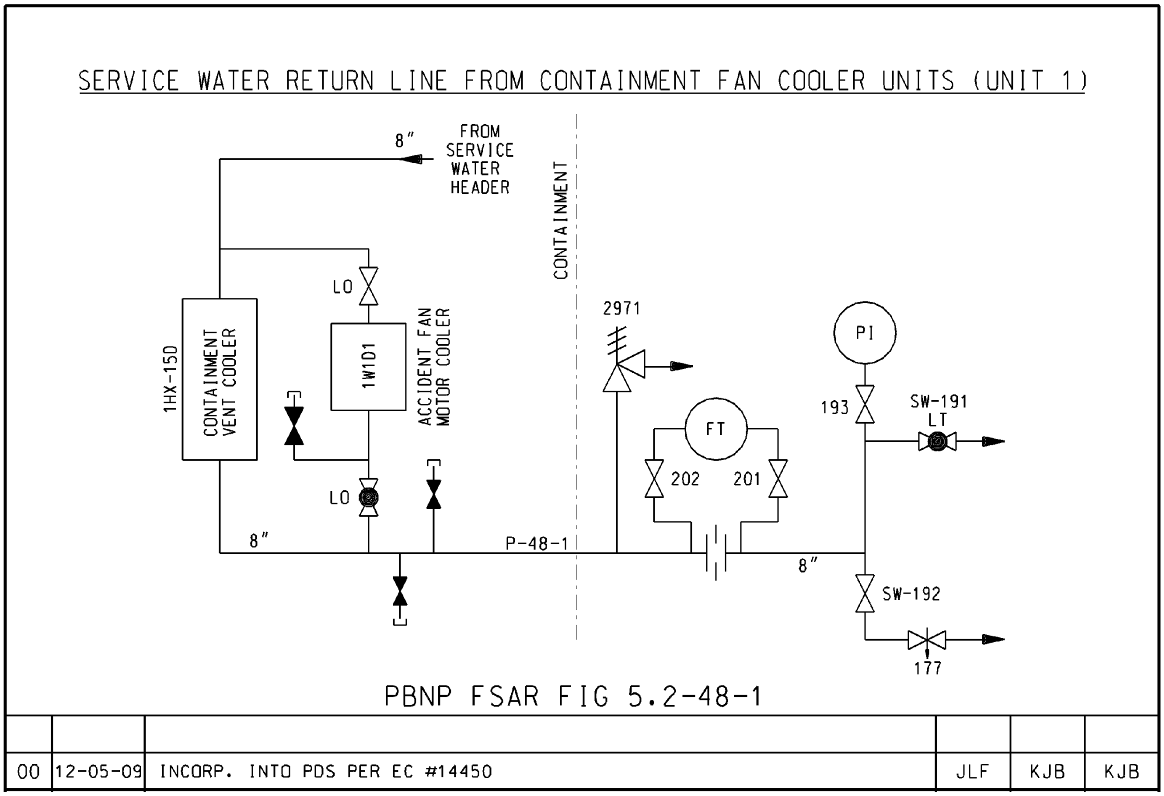
PENETRATION	CONTAINMENT ISOLATION VALVES INSIDE	 OUTSIDE	BRANCH/SYSTEM	LINE SIZE	FLUID	TEMP. HOT>200 COLD<200	CLASS
47-2	CLOSED SYS.	SW-259 SW-261	VENTILATION COOLER WATER OUT/SERVICE WATER	8"	W	COLD	4

FOR FURTHER INFORMATION REFER TO FSAR CHAPTER 9 & FIGURE 9.6-5

NOTE:

THIS PENETRATION MEETS CLASS 4 CONTAINMENT ISOLATION CRITERIA WITH TWO MANUAL VALVES (SW-259, SW-261) LOCATED OUTSIDE CONTAINMENT. IT IS A CLOSED SYSTEM INSIDE CONTAINMENT.

Figure 5.2-48-1 SERVICE WATER RETURN LINE FROM CONTAINMENT FAN COOLER UNITS (UNIT 1)



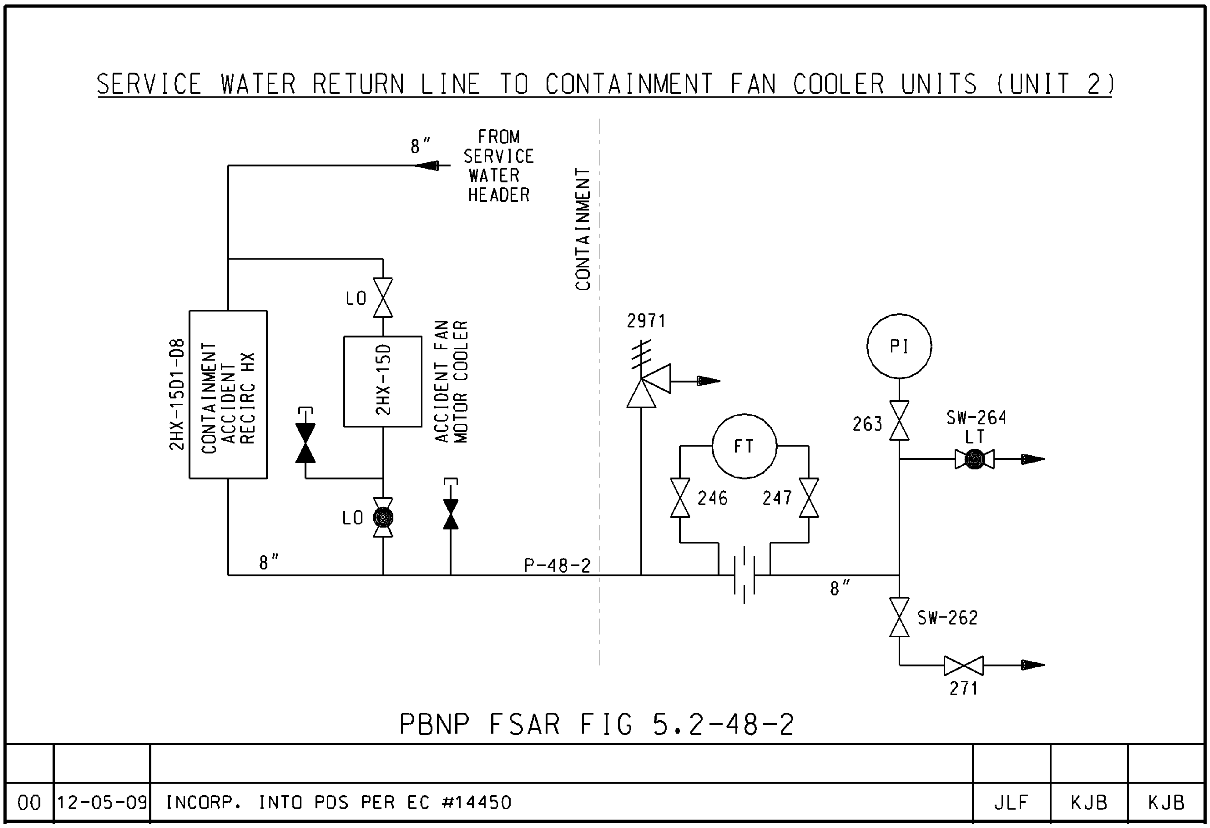
PENETRATION	CONTAINMENT ISOLATION VALVES INSIDE	CONTAINMENT ISOLATION VALVES OUTSIDE	BRANCH/SYSTEM	LINE SIZE	FLUID	TEMP. HOT>200 COLD<200	CLASS
48-1	CLOSED SYSTEM	SW-191 SW-192	VENTILATION COOLER WATER OUT/SERVICE WATER	8”	W	COLD	4

FOR FURTHER INFORMATION REFER TO FSAR CHAPTER 9 & FIGURE 9.6-5

NOTE:

THIS PENETRATION MEETS CLASS 4 CONTAINMENT ISOLATION CRITERIA WITH TWO MANUAL VALVES (SW-191 AND SW-192) LOCATED OUTSIDE CONTAINMENT. IT IS A CLOSED SYSTEM INSIDE CONTAINMENT.

Figure 5.2-48-2 SERVICE WATER RETURN LINE TO CONTAINMENT FAN COOLER UNITS (UNIT 2)



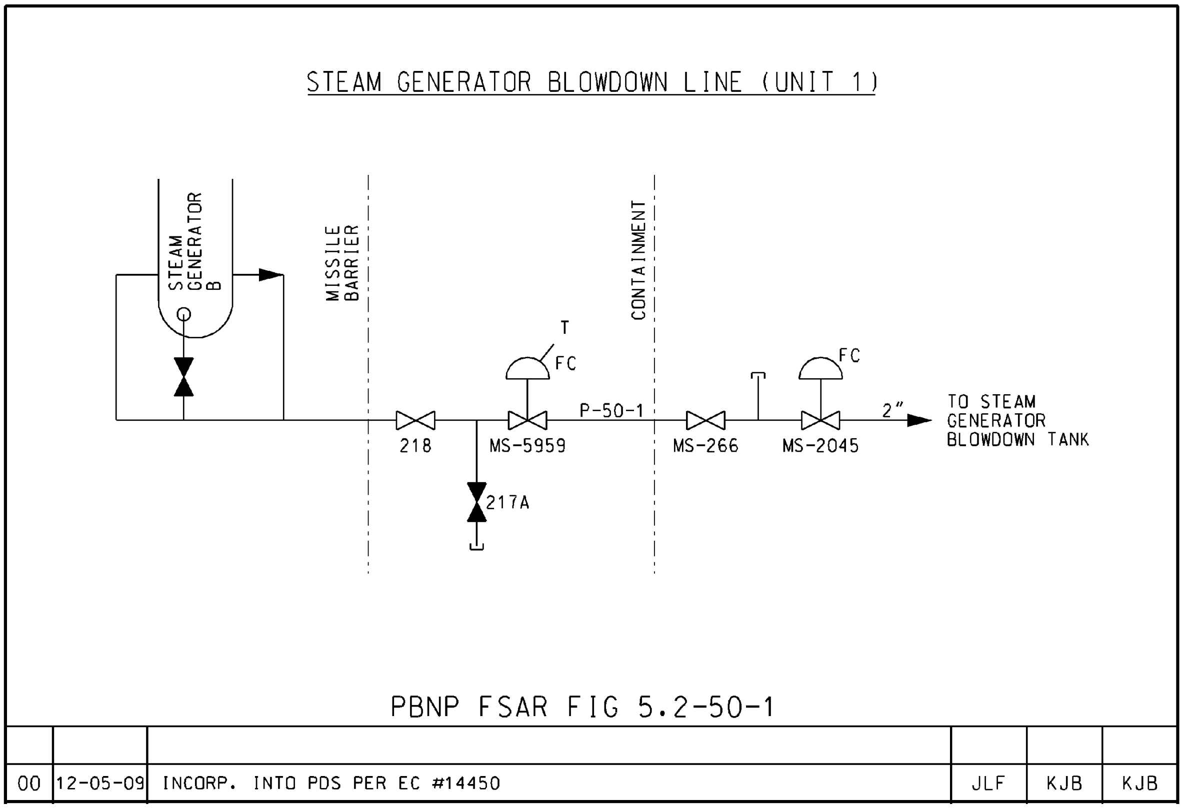
PENETRATION	CONTAINMENT ISOLATION VALVES INSIDE	OUTSIDE	BRANCH/SYSTEM	LINE SIZE	FLUID	TEMP. HOT>200 COLD<200	CLASS
48 -2	CLOSED SYS.	SW-262 SW-264	VENTILATION COOLER WATER OUT/SERVICE WATER	8”	W	COLD	4

FOR FURTHER INFORMATION REFER TO FSAR CHAPTER 9 & FIGURE 9.6-5

NOTE:

THIS PENETRATION MEETS CLASS 4 CONTAINMENT ISOLATION CRITERIA WITH TWO MANUAL VALVES (SW-262, SW-264) LOCATED OUTSIDE CONTAINMENT. IT IS A CLOSED SYSTEM INSIDE CONTAINMENT.

Figure 5.2-50-1 STEAM GENERATOR BLOWDOWN LINE (UNIT 1)



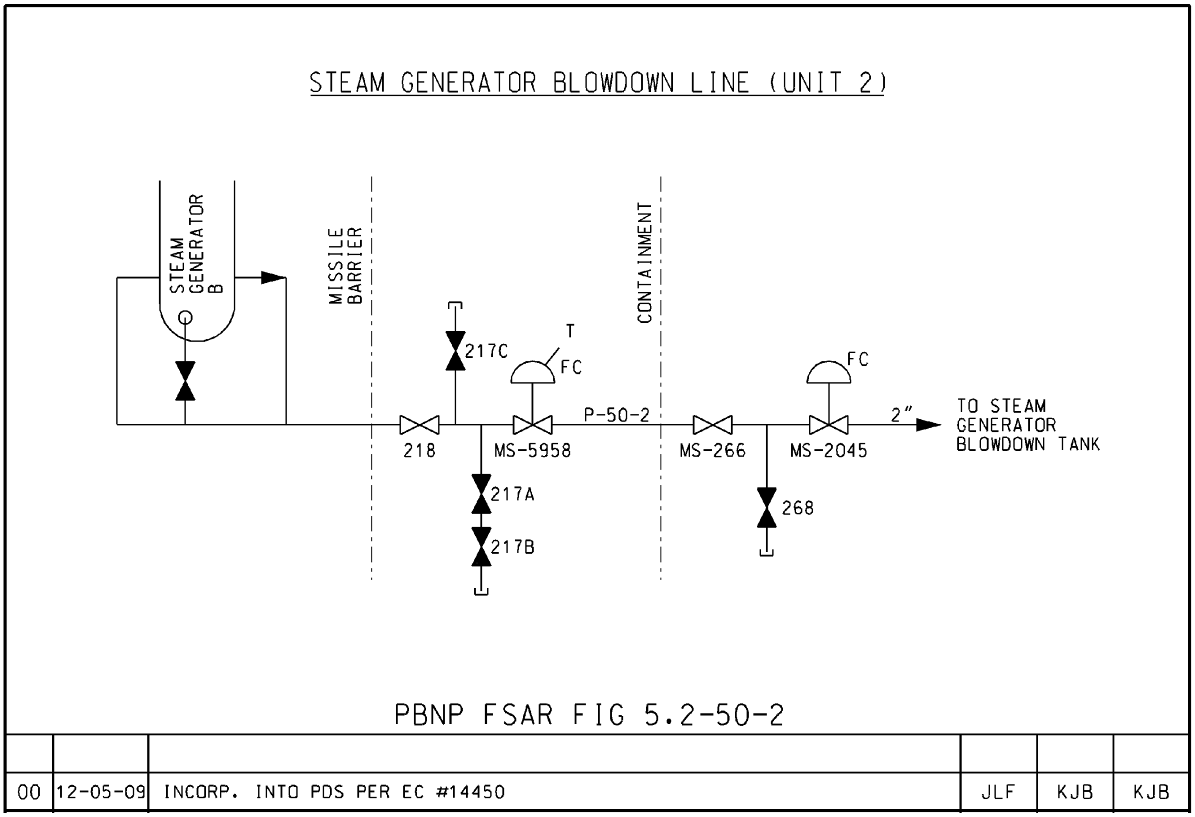
PENETRATION	CONTAINMENT ISOLATION VALVES INSIDE	OUTSIDE	BRANCH/SYSTEM	LINE SIZE	FLUID	TEMP. HOT>200 COLD<200	CLASS
50-1	MS-5959 CLOSED SYS.	MS-266	STEAM GENERATOR BLOWDOWN/ SECONDARY SYSTEM	2"	W	HOT	4

FOR FURTHER INFORMATION REFER TO FSAR CHAPTER 10 & FIGURE 10.2-1 SHT. 1

NOTE:

THIS PENETRATION MEETS CLASS 4 CONTAINMENT ISOLATION CRITERIA WITH A MANUAL VALVE (MS-266) LOCATED OUTSIDE CONTAINMENT. THE SYSTEM INSIDE CONTAINMENT IS A CLOSED SYSTEM. IN ADDITION, AUTOMATIC TRIP VALVE (MS-5959) IS AN ISOLATION VALVE INSIDE CONTAINMENT AND WAS ADDED AS A TMI COMMITMENT.

Figure 5.2-50-2 STEAM GENERATOR BLOWDOWN LINE (UNIT 2)



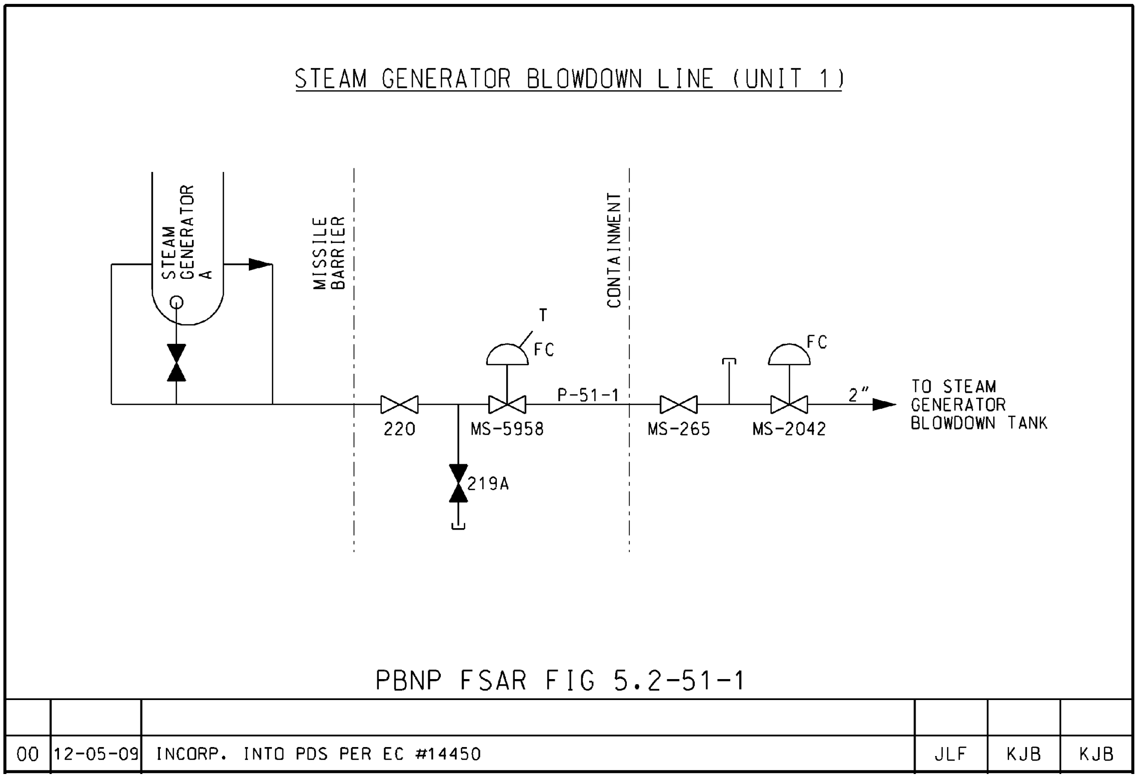
PENETRATION	CONTAINMENT ISOLATION VALVES INSIDE	OUTSIDE	BRANCH/SYSTEM	LINE SIZE	FLUID	TEMP. HOT>200 COLD<200	CLASS
50-2	MS-5958 CLOSED SYS.	MS-266	STEAM GENERATOR BLOWDOWN/ SECONDARY SYSTEM	2"	W	HOT	4

FOR FURTHER INFORMATION REFER TO FSAR CHAPTER 10 & FIGURE 10.2-1 SHT. 1

NOTE:

THIS PENETRATION MEETS CLASS 4 CONTAINMENT ISOLATION CRITERIA WITH A MANUAL VALVE (MS-266) LOCATED OUTSIDE CONTAINMENT. THE SYSTEM INSIDE CONTAINMENT IS A CLOSED SYSTEM. IN ADDITION, AUTOMATIC TRIP VALVE (MS-5958) IS AN ISOLATION VALVE INSIDE CONTAINMENT AND WAS ADDED AS A TMI COMMITMENT.

Figure 5.2-51-1 STEAM GENERATOR BLOWDOWN LINE (UNIT 1)



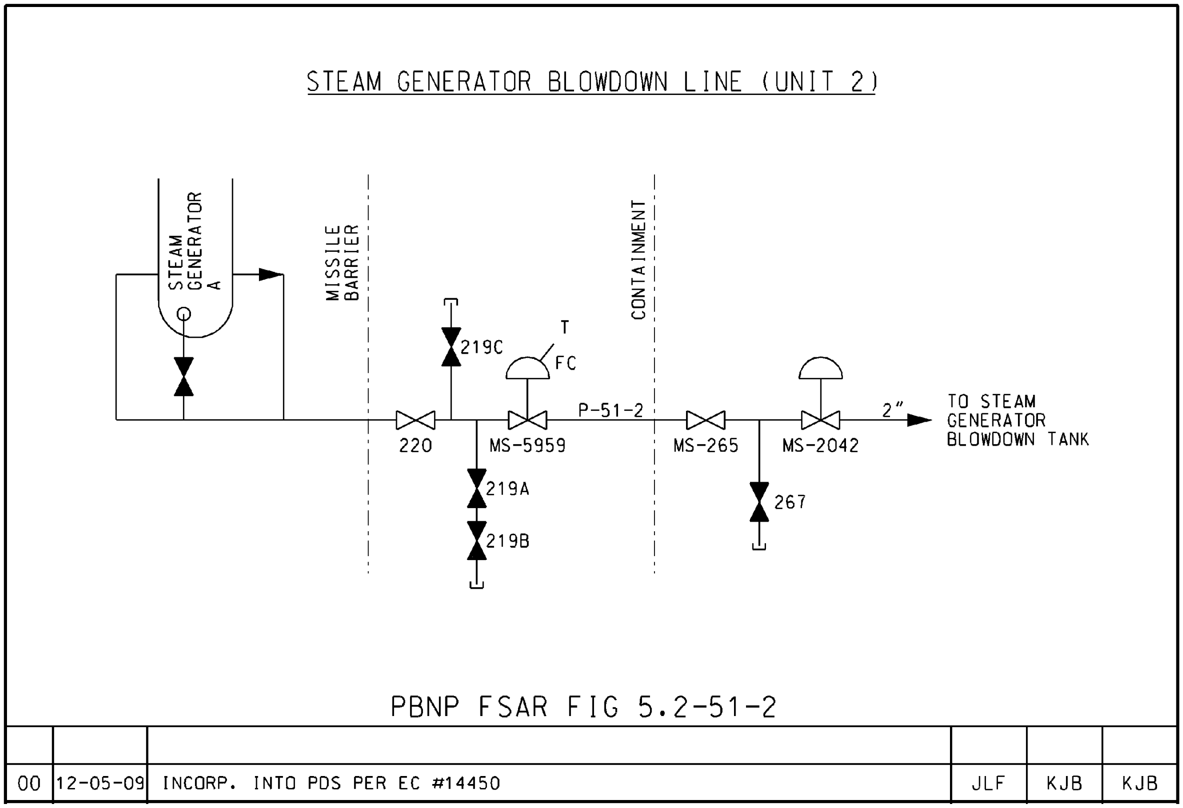
PENETRATION	CONTAINMENT ISOLATION VALVES INSIDE	CONTAINMENT ISOLATION VALVES OUTSIDE	BRANCH/SYSTEM	LINE SIZE	FLUID	TEMP. HOT>200 COLD<200	CLASS
51-1	MS-5958 CLOSED SYS.	MS-265	STEAM GENERATOR BLOWDOWN/ SECONDARY SYSTEM	2"	W	HOT	4

FOR FURTHER INFORMATION REFER TO FSAR CHAPTER 10 & FIGURE 10.2-1 SHT. 1

NOTE:

THIS PENETRATION MEETS CLASS 4 CONTAINMENT ISOLATION CRITERIA WITH A MANUAL VALVE (MS-265) LOCATED OUTSIDE CONTAINMENT. THE SYSTEM INSIDE CONTAINMENT IS A CLOSED SYSTEM. IN ADDITION, AUTOMATIC TRIP VALVE (MS-5958) IS AN ISOLATION VALVE INSIDE CONTAINMENT AND WAS ADDED AS A TMI COMMITMENT.

Figure 5.2-51-2 STEAM GENERATOR BLOWDOWN LINE (UNIT 2)



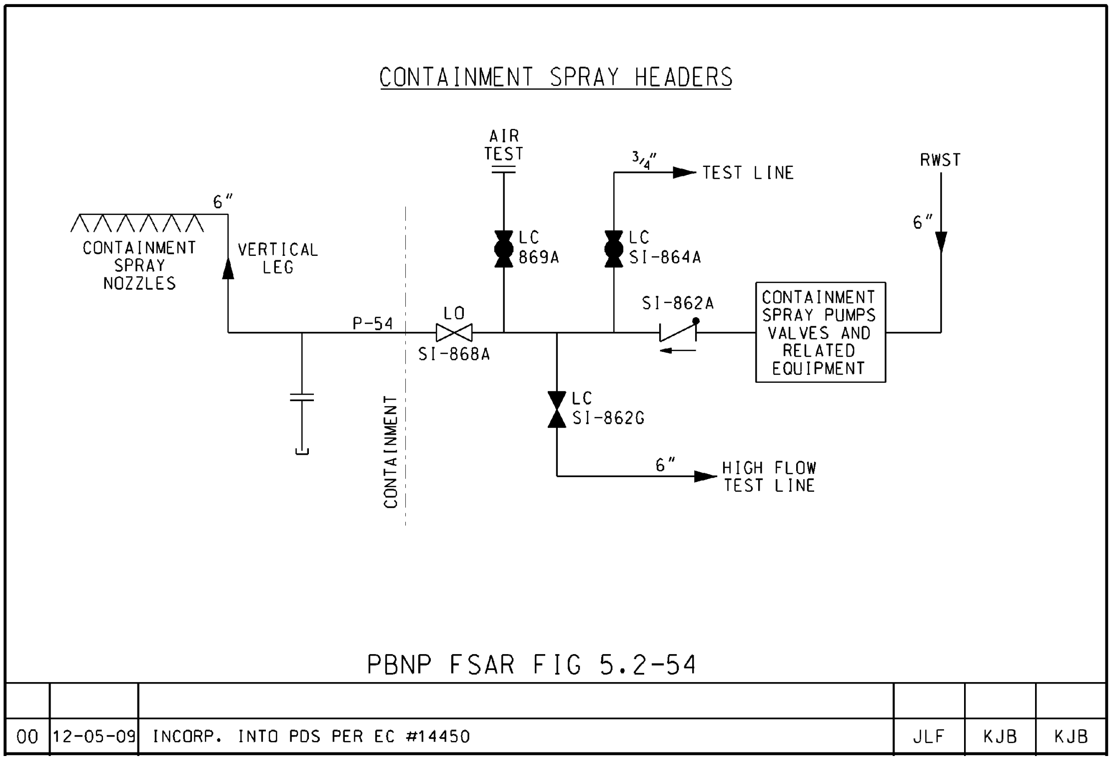
PENETRATION	CONTAINMENT ISOLATION VALVES INSIDE	CONTAINMENT ISOLATION VALVES OUTSIDE	BRANCH/SYSTEM	LINE SIZE	FLUID	TEMP. HOT>200 COLD<200	CLASS
51-2	MS-5959 CLOSED SYS.	MS-265	STEAM GENERATOR BLOWDOWN/ SECONDARY SYSTEM	2"	W	HOT	4

FOR FURTHER INFORMATION REFER TO FSAR CHAPTER 10 & FIGURE 10.2-1 SHT. 1

NOTE:

THIS PENETRATION MEETS CLASS 4 CONTAINMENT ISOLATION CRITERIA WITH A MANUAL VALVE (MS-265) LOCATED OUTSIDE CONTAINMENT. THE SYSTEM INSIDE CONTAINMENT IS A CLOSED SYSTEM. IN ADDITION, AUTOMATIC TRIP VALVE (MS-5959) IS AN ISOLATION VALVE INSIDE CONTAINMENT.

Figure 5.2-54 CONTAINMENT SPRAY HEADERS



PENETRATION	CONTAINMENT ISOLATION VALVES INSIDE	OUTSIDE	BRANCH/SYSTEM	LINE SIZE	FLUID	TEMP. HOT>200 COLD<200	CLASS
54		SI-862A CLOSED SYS	CONTAINMENT SPRAY/SAFETY INJECTION SYS.	6”	W	COLD	SPECIAL
		SI-864A CLOSED SYS	CONTAINMENT SPRAY TEST/SAFETY INJECTION SYSTEM	3/4”	W	COLD	SPECIAL
		SI-862G CLOSED SYS	CS HIGH FLOW TEST / SI SYSTEM.	6”	W	COLD	SPECIAL

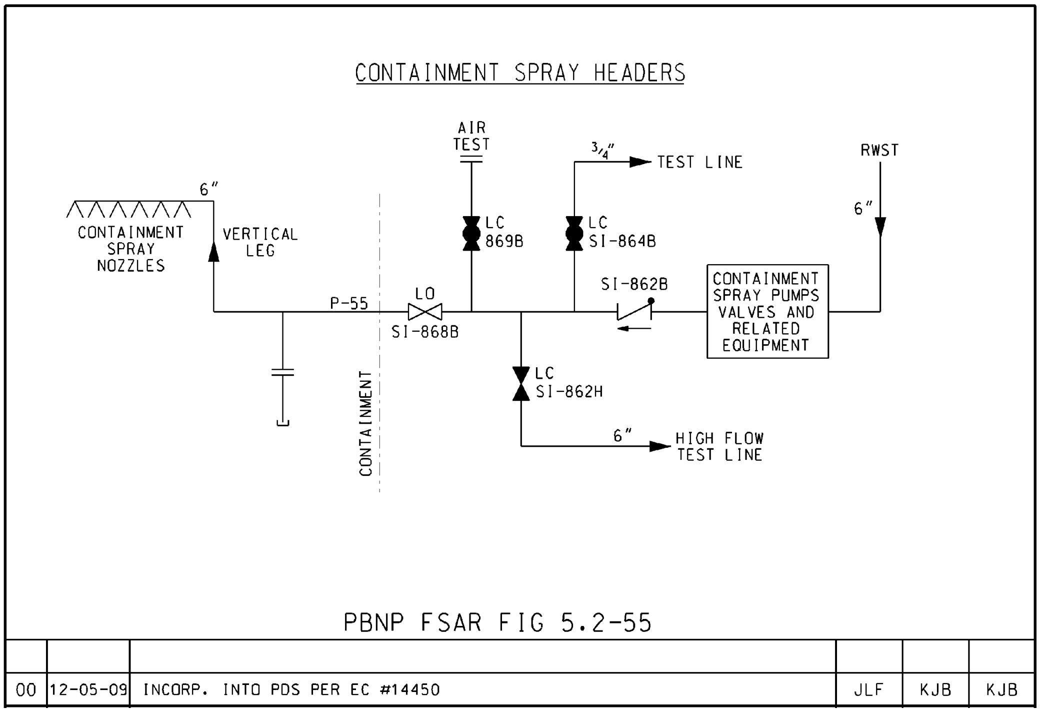
FOR FURTHER INFORMATION REFER TO FSAR CHAPTER 6 & FIGURE 6.2-1 SHEET 1

NOTE:

THIS PENETRATION IS CLASSIFIED SPECIAL AND IS IDENTIFIED AS AN INTERMITTENT USE SYSTEM POST DBA.

1. CONTAINMENT SPRAY BRANCH - THIS BRANCH MEETS CONTAINMENT ISOLATION CRITERIA WITH CHECK VALVE SI-862A WHICH SERVES THE PURPOSE OF AN AUTOMATIC TRIP VALVE AND A CLOSED SYSTEM OUTSIDE CONTAINMENT.
2. HIGH FLOW TEST LINE BRANCH -THIS BRANCH MEETS CONTAINMENT ISOLATION CRITERIA WITH LOCKED CLOSED MANUAL VALVE SI-862G WHICH SERVES THE PURPOSE OF AN AUTOMATIC TRIP VALVE AND A CLOSED SYSTEM OUTSIDE CONTAINMENT.
3. TEST LINE BRANCH - THIS BRANCH MEETS CONTAINMENT ISOLATION CRITERIA WITH LOCKED CLOSED MANUAL VALVE SI-864A WHICH SERVES THE PURPOSE OF AN AUTOMATIC TRIP VALVE AND A CLOSED SYSTEM OUTSIDE CONTAINMENT.

Figure 5.2-55 CONTAIMENT SPRAY HEADERS



PENETRATION	CONTAINMENT ISOLATION VALVES INSIDE	OUTSIDE	BRANCH/SYSTEM	LINE SIZE	FLUID	TEMP. HOT>200 COLD<200	CLASS
55		SI-862B CLOSED SYS.	CONTAINMENT SPRAY/SAFETY INJECTION SYS.	6”	W	COLD	SPECIAL
		SI-864B CLOSED SYS.	CONTAINMENT SPRAY TEST/SAFETY INJECTION SYSTEM	3/4”	W	COLD	SPECIAL
		SI-862H CLOSED SYS.	CS HIGH FLOW TEST / SI SYSTEM.	6”	W	COLD	SPECIAL

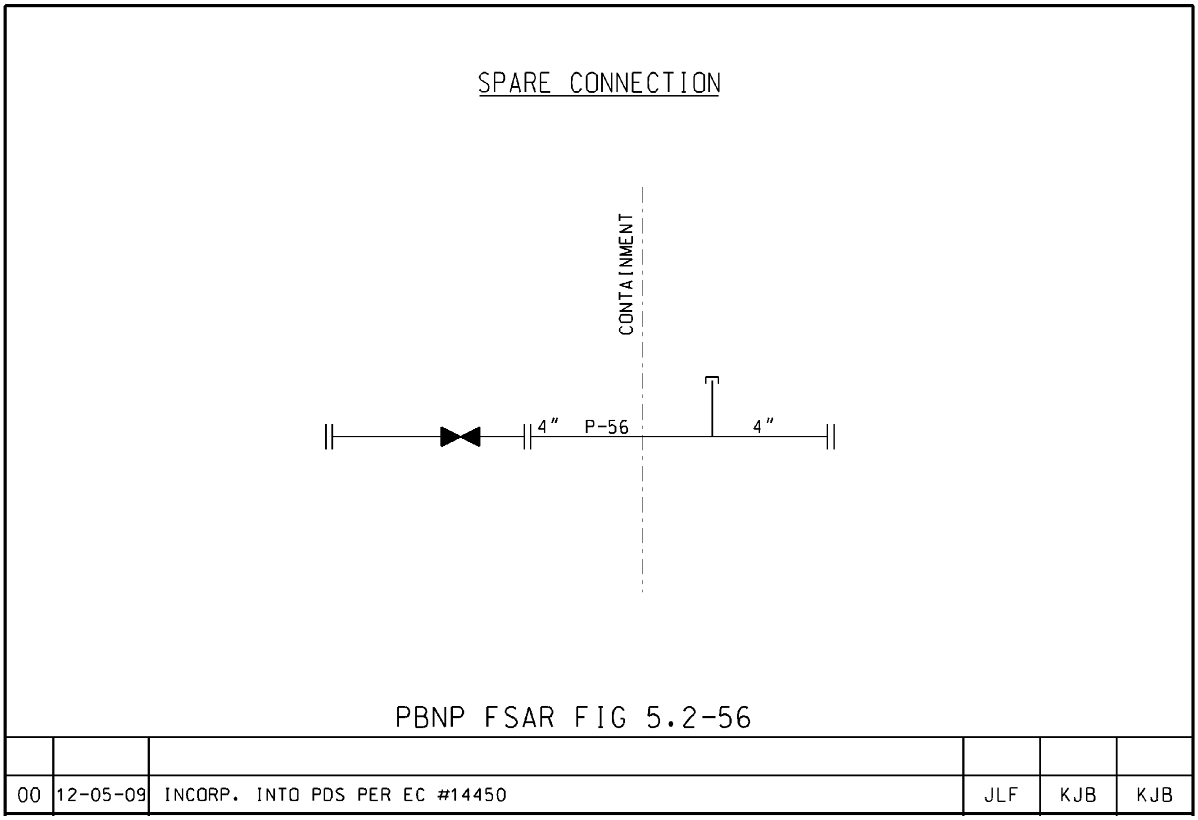
FOR FURTHER INFORMATION REFER TO FSAR CHAPTER 6 & FIGURE 6.2-1 SHEET 1

NOTE:

THIS PENETRATION IS CLASSIFIED SPECIAL AND IS IDENTIFIED AS AN INTERMITTENT USE SYSTEM POST DBA.

1. CONTAINMENT SPRAY BRANCH - THIS BRANCH MEETS CONTAINMENT ISOLATION CRITERIA WITH CHECK VALVE SI-862B WHICH SERVES THE PURPOSE OF AN AUTOMATIC TRIP VALVE AND A CLOSED SYSTEM OUTSIDE CONTAINMENT.
2. HIGH FLOW TEST LINE BRANCH -THIS BRANCH MEETS CONTAINMENT ISOLATION CRITERIA WITH LOCKED CLOSED MANUAL VALVE SI-862H WHICH SERVES THE PURPOSE OF AN AUTOMATIC TRIP VALVE AND A CLOSED SYSTEM OUTSIDE CONTAINMENT.
3. TEST LINE BRANCH - THIS BRANCH MEETS CONTAINMENT ISOLATION CRITERIA WITH LOCKED CLOSED MANUAL VALVE SI-864B WHICH SERVES THE PURPOSE OF AN AUTOMATIC TRIP VALVE AND A CLOSED SYSTEM OUTSIDE CONTAINMENT.

Figure 5.2-56 SPARE CONNECTION



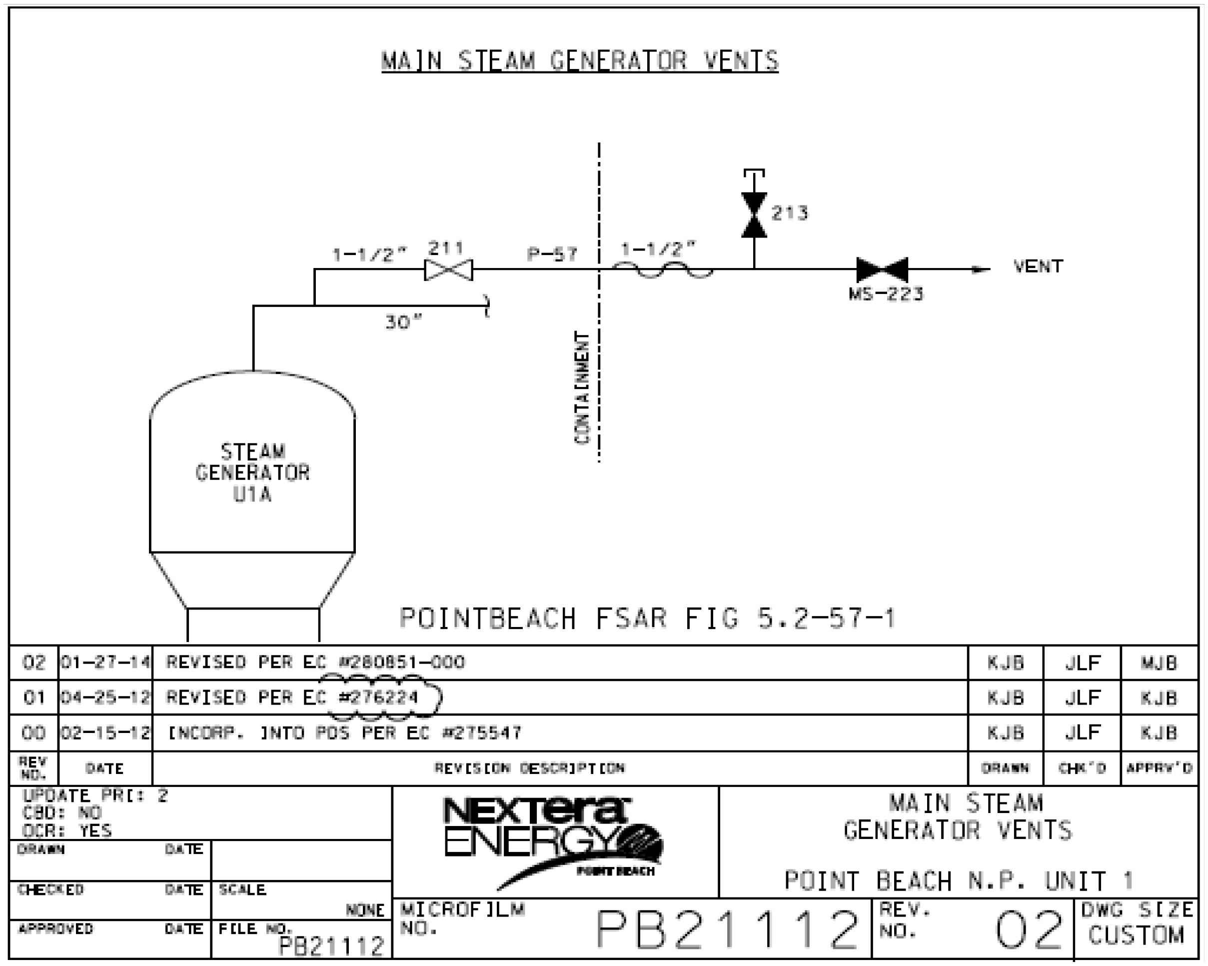
PENETRATION	CONTAINMENT ISOLATION VALVES INSIDE	OUTSIDE	BRANCH/SYSTEM	LINE SIZE	FLUID	TEMP. HOT>200 COLD<200	CLASS
56	BLANK FLG..	BLANK FLG.	SPARE	4"	G	COLD	5

FOR FURTHER INFORMATION REFER TO FSAR CHAPTER 10 & FIGURE 10.2-1 SHT. 1

NOTE:

THIS PENETRATION MEETS CLASS 5 SINCE THE BLANK FLANGES PROVIDE EQUAL OR GREATER PROTECTION THAN THE MANUAL VALVE AND BLANK FLANGE PROVIDED FOR IN THE CRITERIA.

Figure 5.2-57-1 MAIN STEAM GENERATOR VENTS



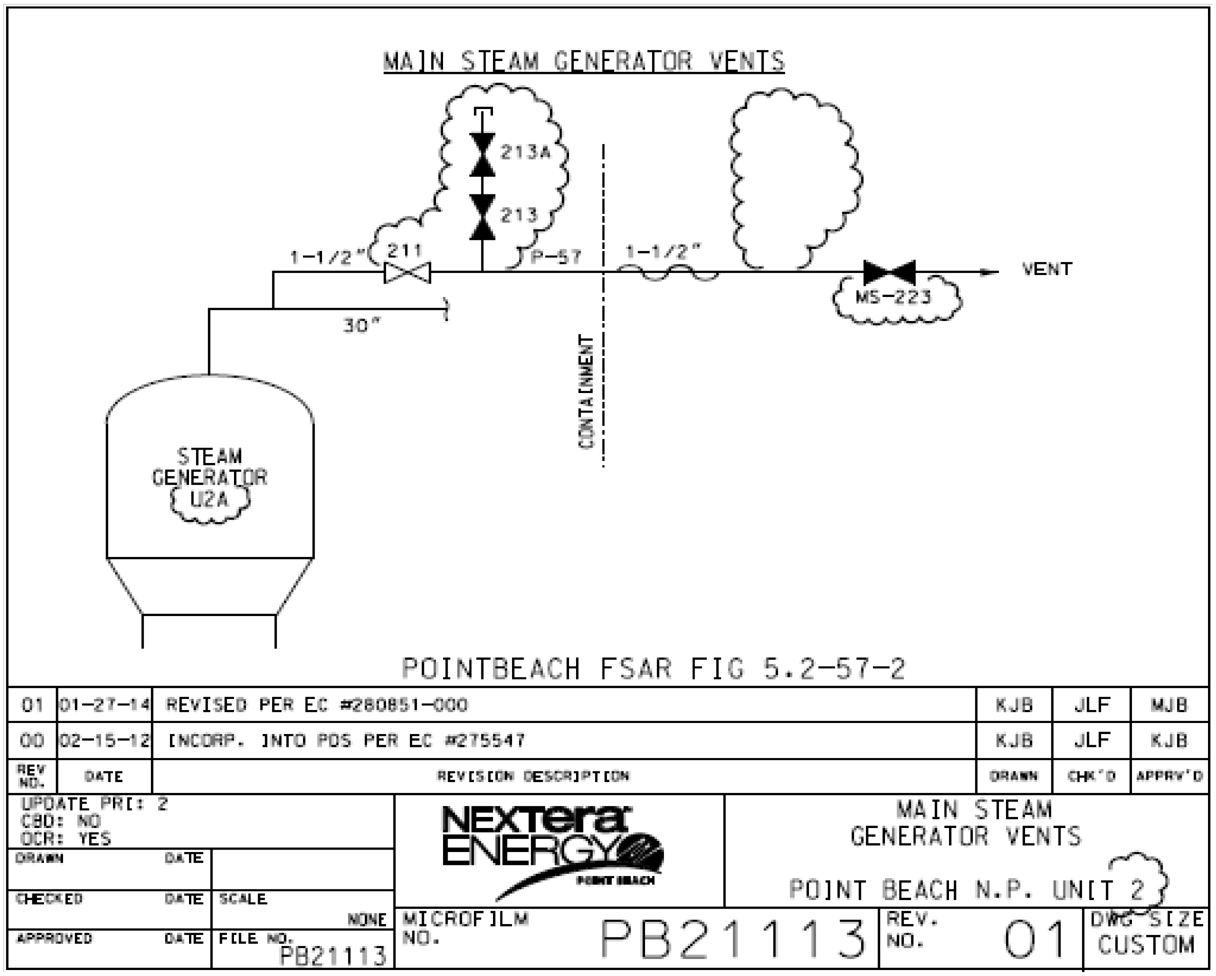
PENETRATION	CONTAINMENT ISOLATION VALVES INSIDE	OUTSIDE	BRANCH/SYSTEM	LINE SIZE	FLUID	TEMP. HOT>200 COLD<200	CLASS
57	CLOSED SYS.	MS-223	STEAM GENERATOR VENTS/MS	1-1/2”	G	COLD	4

FOR FURTHER INFORMATION REFER TO FSAR CHAPTER 10 & FIGURE 10.1-1 SHT. 1

NOTE:

THIS PENETRATION MEETS CLASS 4 CONTAINMENT ISOLATION CRITERIA WITH A MANUAL VALVE MS-223 OUTSIDE CONTAINMENT. THIS IS A CLOSED SYSTEM INSIDE CONTAINMENT.

Figure 5.2-57-2 MAIN STEAM GENERATOR VENTS



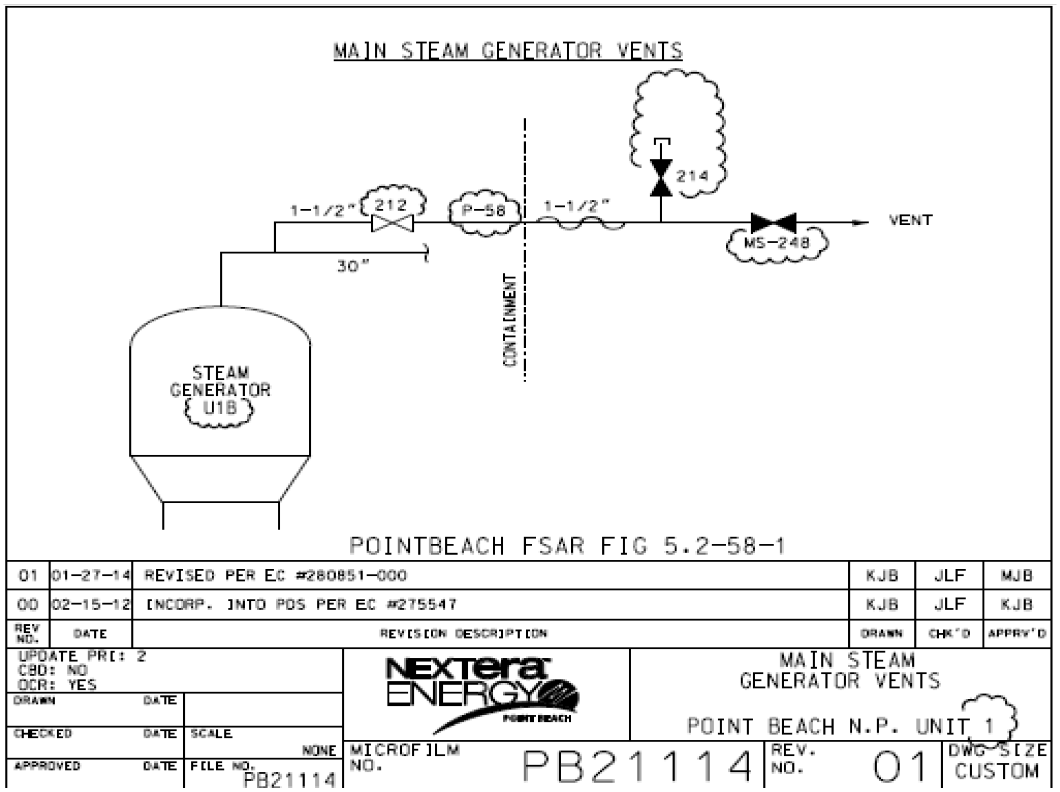
	CONTAINMENT ISOLATION VALVES					TEMP.	
PENETRATION	INSIDE	OUTSIDE	BRANCH/SYSTEM	LINE SIZE	FLUID	HOT>200 COLD<200	CLASS
57	CLOSED SYS.	MS-223	STEAM GENERATOR VENTS/MS	1-1/2”	G	COLD	4

FOR FURTHER INFORMATION REFER TO FSAR CHAPTER 10 & FIGURE 10.1-1 SHT. 1

NOTE:

THIS PENETRATION MEETS CLASS 4 CONTAINMENT ISOLATION CRITERIA WITH A MANUAL VALVE MS-223 OUTSIDE CONTAINMENT. THIS IS A CLOSED SYSTEM INSIDE CONTAINMENT.

Figure 5.2-58-1 MAIN STEAM GENERATOR VENTS



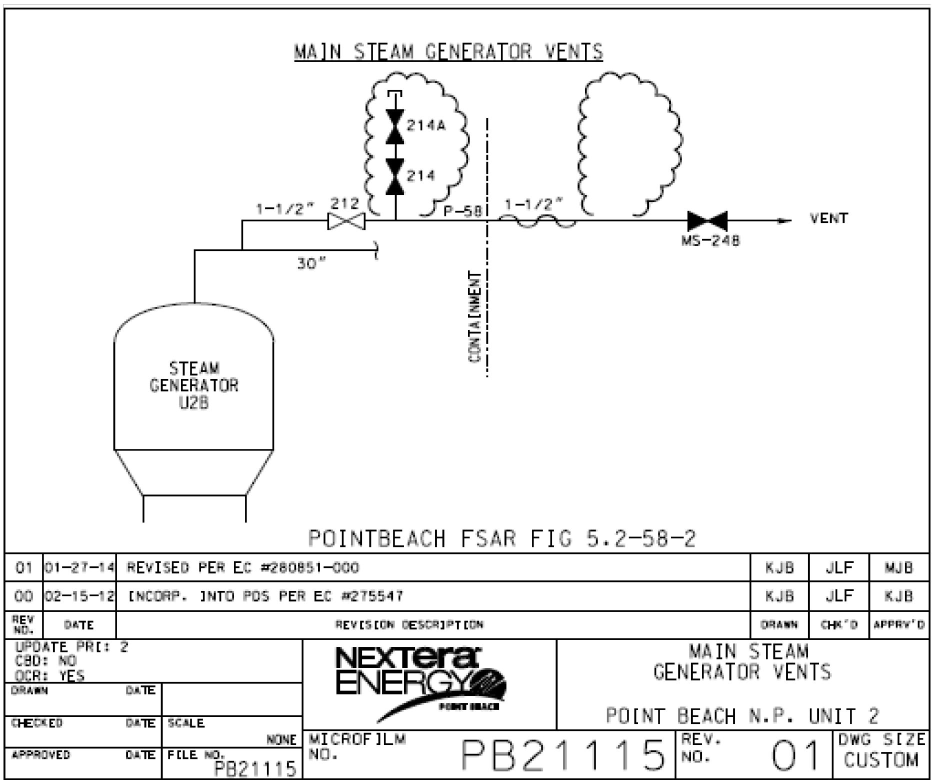
	CONTAINMENT ISOLATION VALVES					TEMP.	
PENETRATION	INSIDE	OUTSIDE	BRANCH/SYSTEM	LINE SIZE	FLUID	HOT>200 COLD<200	CLASS
58	CLOSED SYS.	MS-248	STEAM GENERATOR VENTS/MS	1-1/2"	G	COLD	4

FOR FURTHER INFORMATION REFER TO FSAR CHAPTER 10 & FIGURE 10.1-1A SHEET 1

NOTE:

THIS PENETRATION MEETS CLASS 4 CONTAINMENT ISOLATION CRITERIA WITH A MANUAL VALVE MS-248 OUTSIDE CONTAINMENT. THIS IS A CLOSED SYSTEM INSIDE CONTAINMENT.

Figure 5.2-58-2 MAIN STEAM GENERATOR VENTS



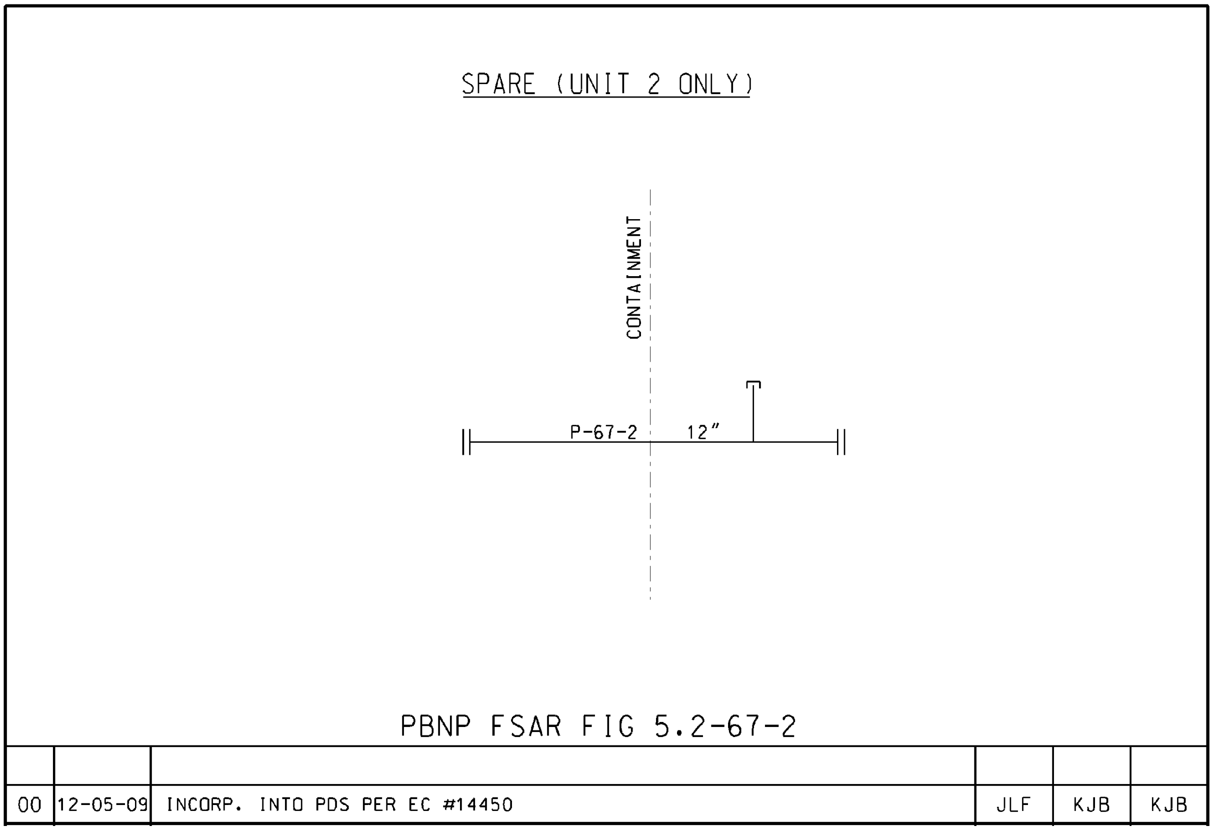
	CONTAINMENT ISOLATION VALVES					TEMP.	
PENETRATION	INSIDE	OUTSIDE	BRANCH/SYSTEM	LINE SIZE	FLUID	HOT>200 COLD<200	CLASS
58	CLOSED SYS.	MS-248	STEAM GENERATOR VENTS/MS	1-1/2”	G	COLD	4

FOR FURTHER INFORMATION REFER TO FSAR CHAPTER 10 & FIGURE 10.1-1A SHEET 1

NOTE:

THIS PENETRATION MEETS CLASS 4 CONTAINMENT ISOLATION CRITERIA WITH A MANUAL VALVE MS-248 OUTSIDE CONTAINMENT. THIS IS A CLOSED SYSTEM INSIDE CONTAINMENT.

Figure 5.2-67-2 SPARE (UNIT 2 ONLY)

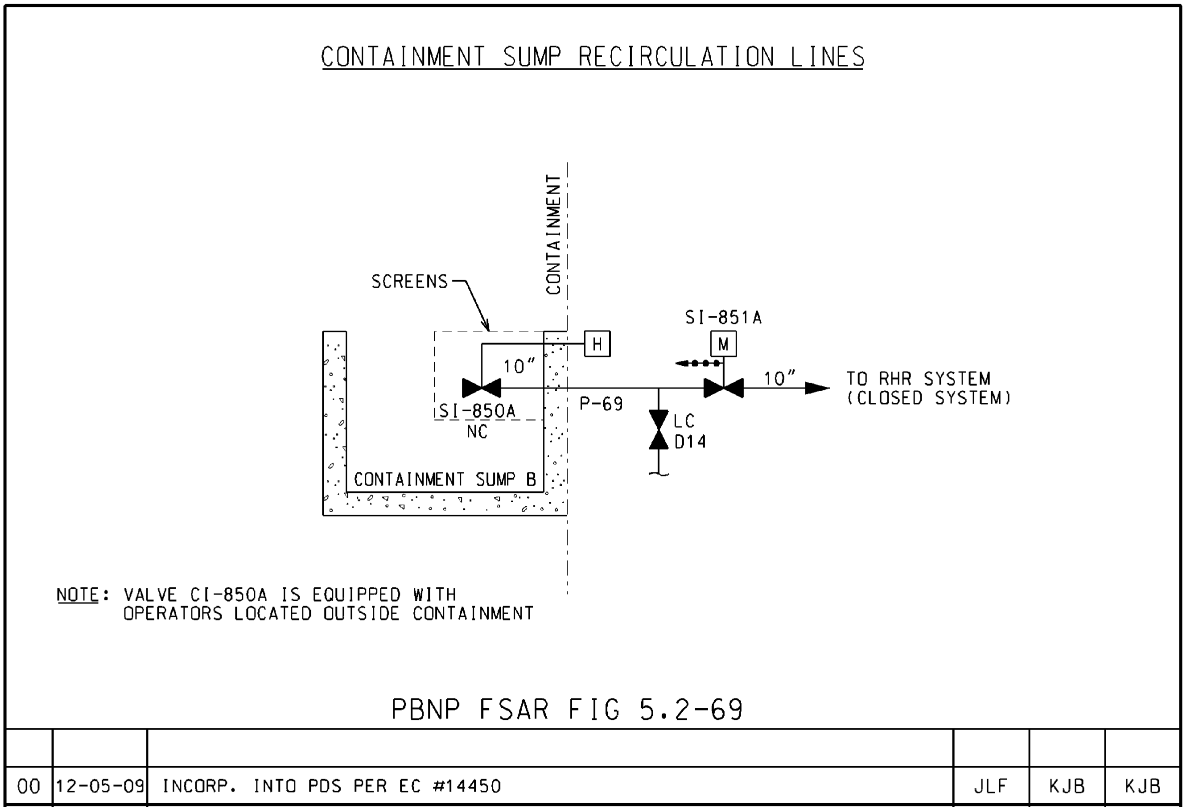


	CONTAINMENT ISOLATION VALVES					TEMP.	
PENETRATION	INSIDE	OUTSIDE	BRANCH/SYSTEM	LINE SIZE	FLUID	HOT>200 COLD<200	CLASS
67	BLANK FLG..	BLANK FLG.	SPARE	12"	G	COLD	5

NOTE:

THIS PENETRATION MEETS CLASS 5 CONTAINMENT ISOLATION CRITERIA WITH TWO BLANK FLANGES. THIS SPARE PENETRATION IS USED ROUTINELY FOR EDDY CURRENT TESTING FOR UNIT 2.

Figure 5.2-69 CONTAINMENT SUMP RECIRCULATION LINES



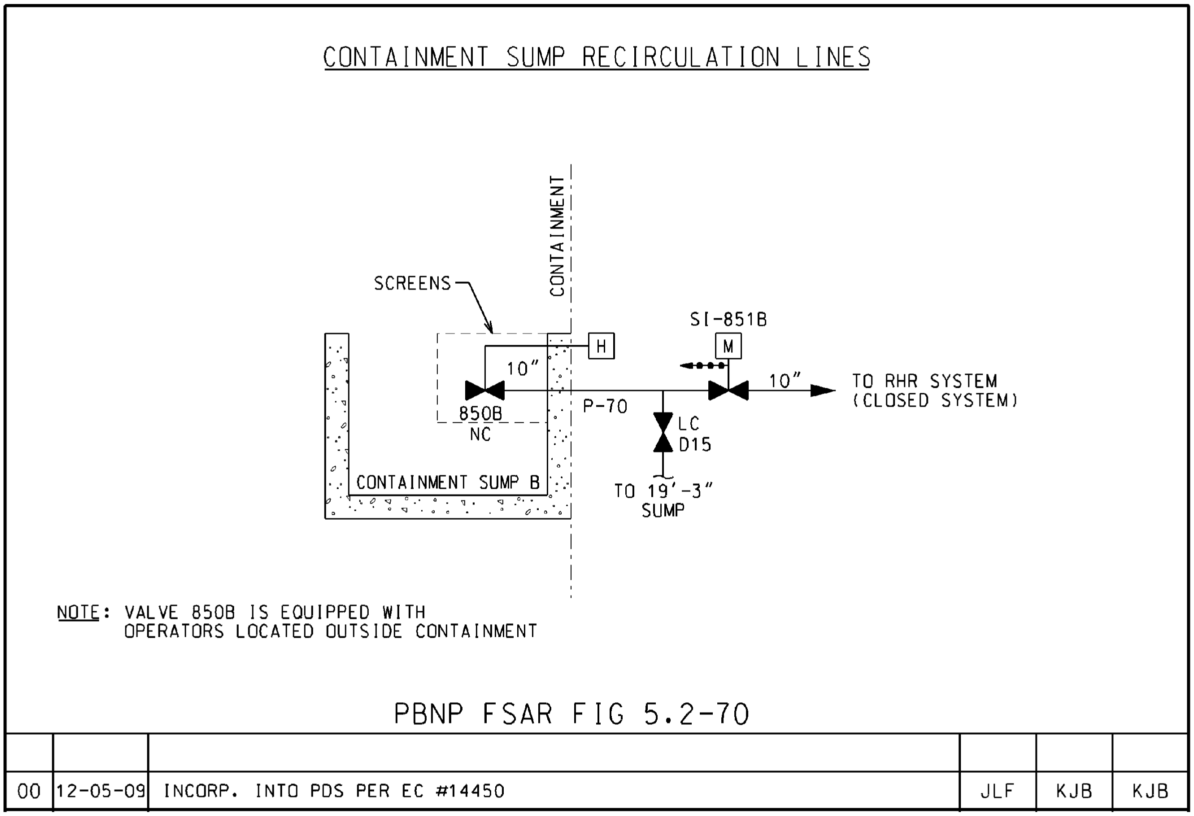
PENETRATION	CONTAINMENT ISOLATION VALVES INSIDE	OUTSIDE	BRANCH/SYSTEM	LINE SIZE	FLUID	TEMP. HOT>200 COLD<200	CLASS
69		SI-851A CLOSED SYS.	SUMP B RECIRCULATION LINES/SAFETY INJECTION SYSTEM.	10"	W	COLD	SPECIAL

FOR FURTHER INFORMATION REFER TO FSAR CHAPTER 6 & FIGURE 6.2-1 SHEET 1

NOTE:

THIS PENETRATION IS CLASSIFIED SPECIAL AND IS IN USE POST DBA. THE CLOSED SYSTEM OUTSIDE CONTAINMENT PROVIDES THE CONTAINMENT ISOLATION BOUNDARY POST DBA.

Figure 5.2-70 CONTAINMENT SUMP RECIRCULATION LINES



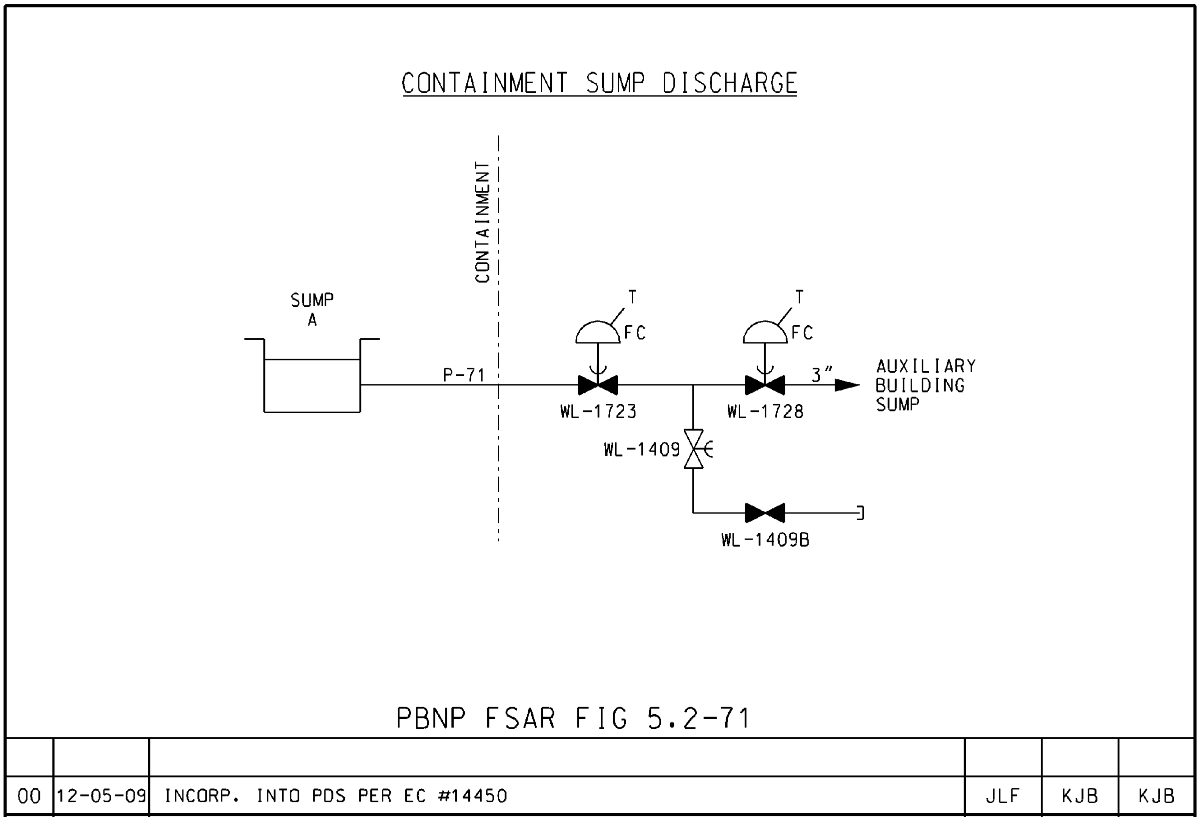
PENETRATION	CONTAINMENT ISOLATION VALVES INSIDE	CONTAINMENT ISOLATION VALVES OUTSIDE	BRANCH/SYSTEM	LINE SIZE	FLUID	TEMP. HOT>200 COLD<200	CLASS
70		SI-851B CLOSED SYS.	SUMP B RECIRCULATION LINES/SAFETY INJECTION SYSTEM.	10"	W	COLD	SPECIAL

FOR FURTHER INFORMATION REFER TO FSAR CHAPTER 6 & FIGURE 6.2-1 SHEET 1

NOTE:

THIS PENETRATION IS CLASSIFIED SPECIAL AND IS IN USE POST DBA. THE CLOSED SYSTEM OUTSIDE CONTAINMENT PROVIDES THE CONTAINMENT ISOLATION BOUNDARY POST DBA.

Figure 5.2-71 CONTAINMENT SUMP DISCHARGE



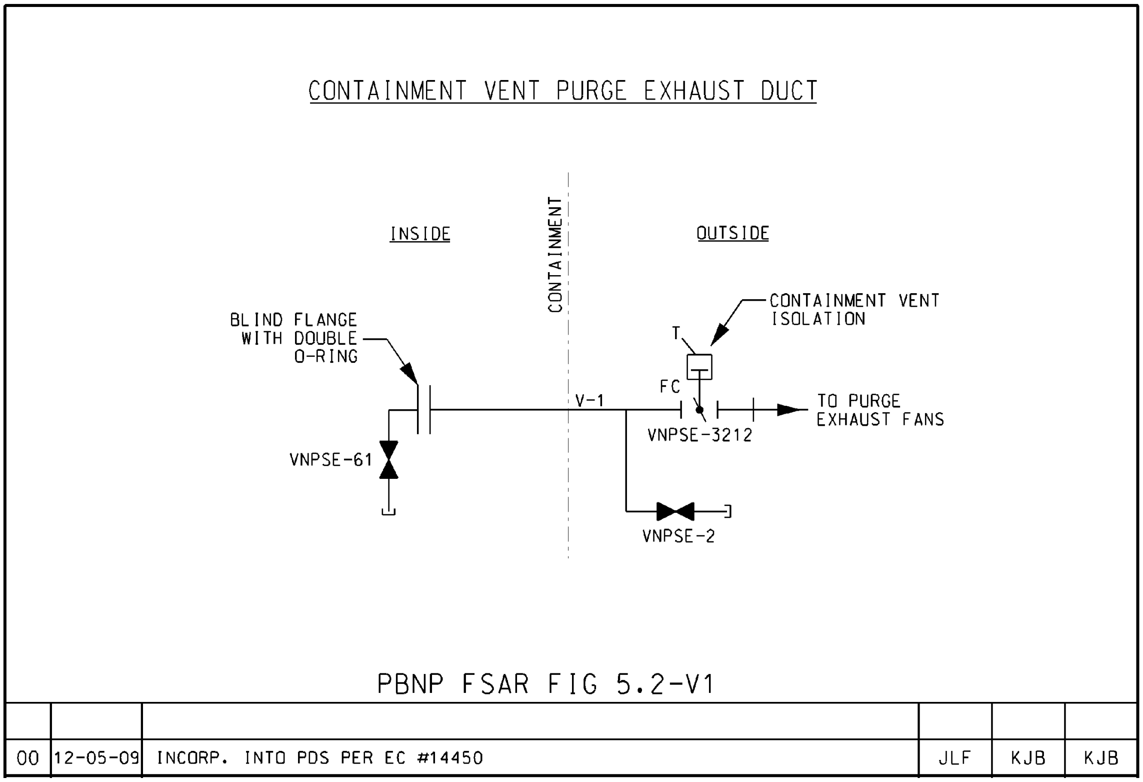
PENETRATION	CONTAINMENT ISOLATION VALVES INSIDE	OUTSIDE	BRANCH/SYSTEM	LINE SIZE	FLUID	TEMP. HOT>200 COLD<200	CLASS
71		WL-1723 WL-1728	SUMP A DRAIN TO AUXILIARY BUILDING SUMP/WASTE DISPOSAL SYSTEM	3”	W	COLD	SPECIAL

FOR FURTHER INFORMATION REFER TO FSAR CHAPTER 11 & FIGURE 11.1-1 SHEET 1

NOTE:

THIS PENETRATION IS CLASSIFIED SPECIAL AND MEETS CONTAINMENT ISOLATION CRITERIA WITH AUTOMATIC TRIP VALVE WL-1723 AND AUTOMATIC TRIP VALVE WL-1728 OUTSIDE CONTAINMENT.

Figure 5.2-V1 CONTAIMENT VENT PURGE EXHAUST DUCT

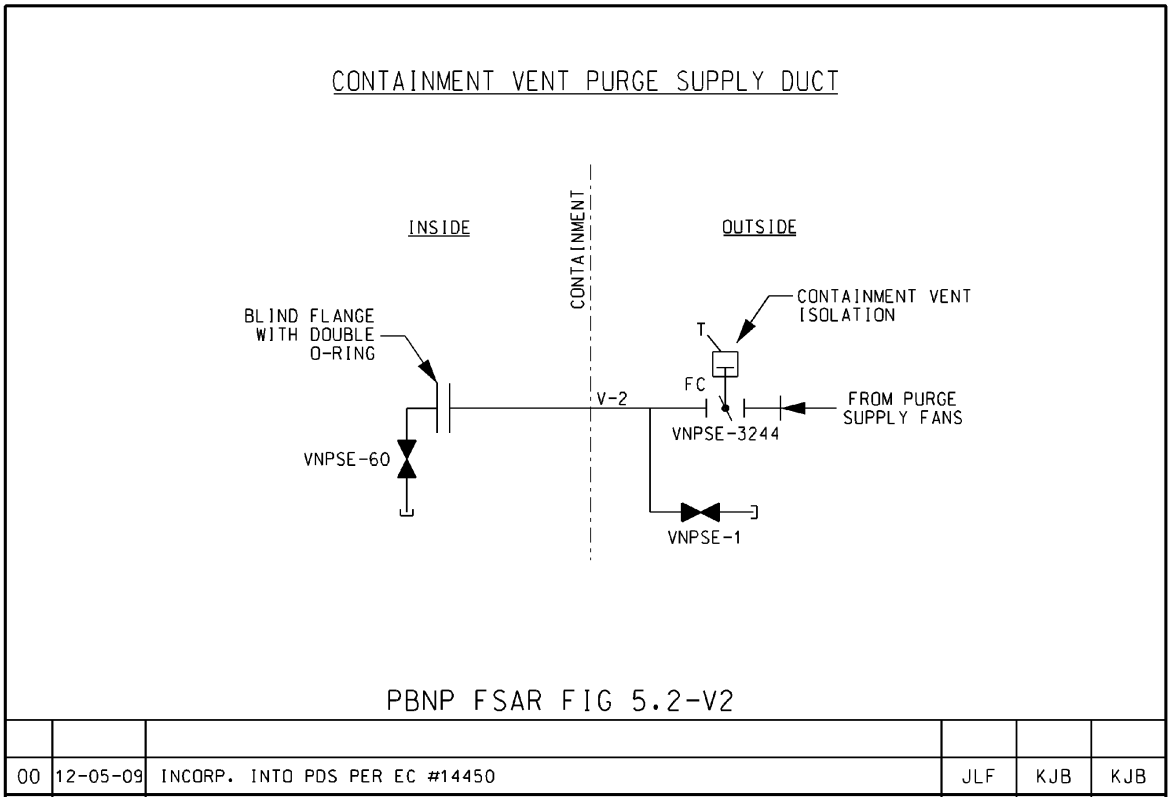


PENETRATION	CONTAINMENT ISOLATION VALVES		BRANCH/ SYSTEM	LINE SIZE	FLUID	TEMP HOT>200 COLD<200	CLASS
	INSIDE	OUTSIDE					
V-1	BLIND FLANGE	NONE	PURGE VENT EXHAUST	36"	G	COLD	SPECIAL

NOTE:

VALVE VNPSE-3212 AND ITS UPSTREAM TEST CONNECTION ARE NOT CONTAINMENT ISOLATION VALVES. THEY PROVIDE CONTAINMENT CLOSURE DURING MODES 5 AND 6.

Figure 5.2-V2 CONTAIMENT VENT PURGE SUPPLY DUCT

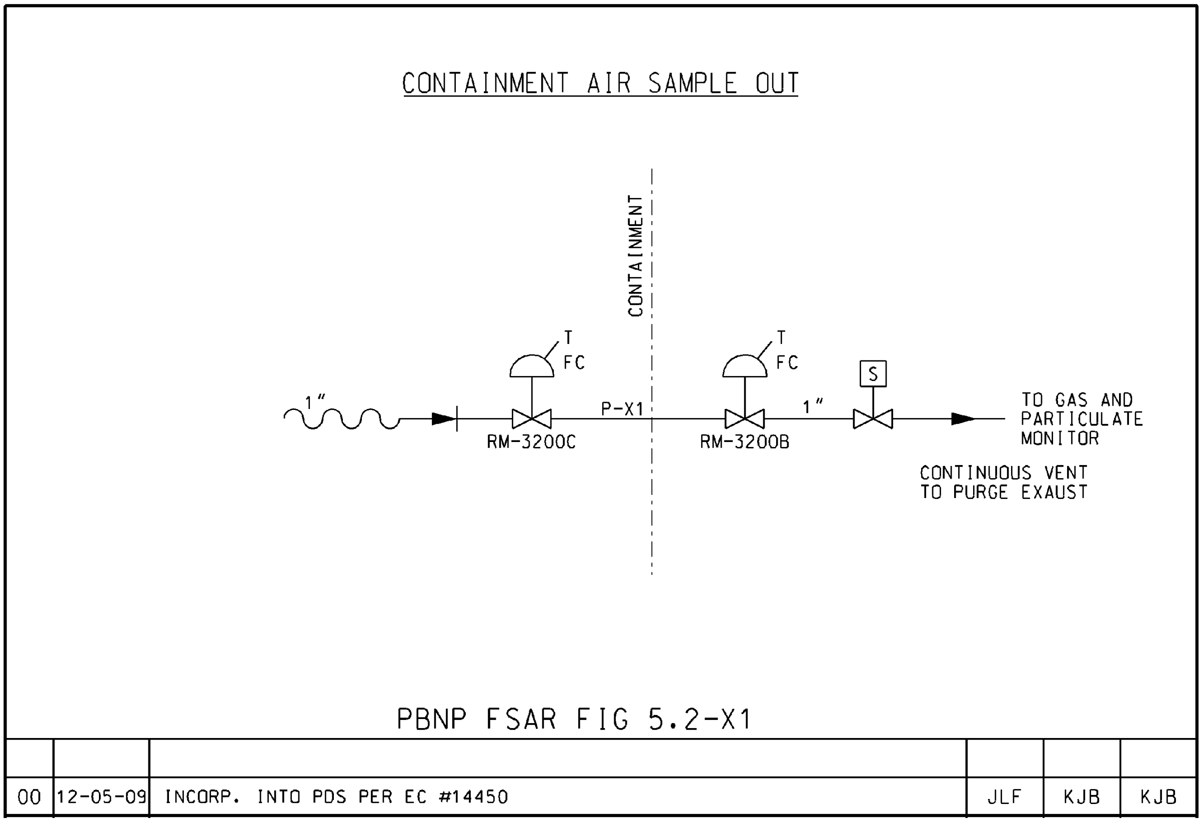


PENETRATION	CONTAINMENT ISOLATION VALVES		BRANCH/ SYSTEM	LINE SIZE	FLUID	TEMP HOT>200 COLD<200	CLASS
	INSIDE	OUTSIDE					
V-2	BLIND FLANGE	NONE	PURGE VENT SUPPLY	36”	G	COLD	SPECIAL

NOTE:

VALVE VNPSE-3244 AND ITS DOWNSTREAM TEST CONNECTION ARE NOT CONTAINMENT ISOLATION VALVES. THEY PROVIDE CONTAINMENT CLOSURE DURING MODES 5 AND 6.

Figure 5.2-X1 CONTAINMENT AIR SAMPLE OUT



NOTE: PENETRATIONS ARE THROUGH THE UPPER PERSONNEL LOCK.

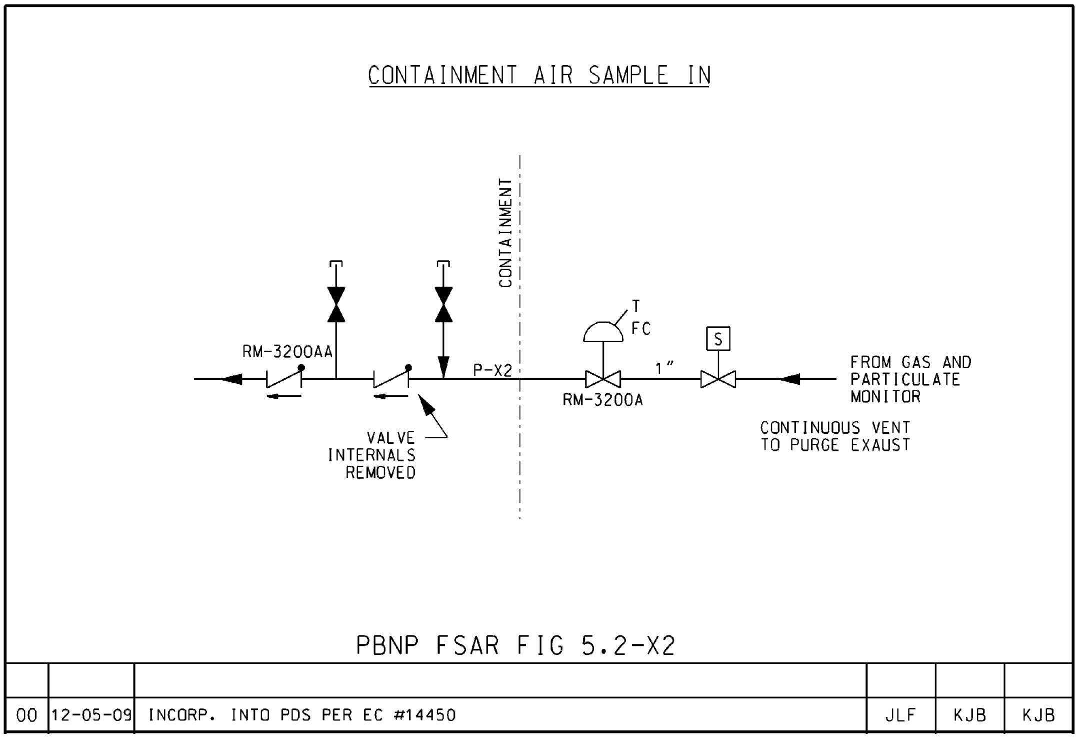
NOTE: CONTAINMENT ISOLATION SIGNAL APPLIED TO THESE VALVES MUST BE OVERRIDDEN IN ORDER TO USE THE MONITOR AFTER AN ACCIDENT.

PENETRATION	CONTAINMENT ISOLATION VALVES		BRANCH/ SYSTEM	LINE SIZE	FLUID	TEMP HOT>200 COLD<200	CLASS
	INSIDE	OUTSIDE					
X-1	RM-3200C	RM-3200B	CONTAINMENT AIR SAMPLE (SUPPLY)/RM	1"	G	COLD	SPECIAL

NOTE:

THIS PENETRATION IS CLASSIFIED SPECIAL AND IS IDENTIFIED AS AN INTERMITTENT USE SYSTEM POST DBA. AUTOMATIC TRIP VALVE (RM-3200C) INSIDE CONTAINMENT AND AUTOMATIC TRIP VALVE (RM-3200B) OUTSIDE CONTAINMENT MEET CONTAINMENT ISOLATION CRITERIA.

Figure 5.2-X2 CONTAINMENT AIR SAMPLE IN



NOTE: PENETRATIONS ARE THROUGH THE UPPER PERSONNEL LOCK.

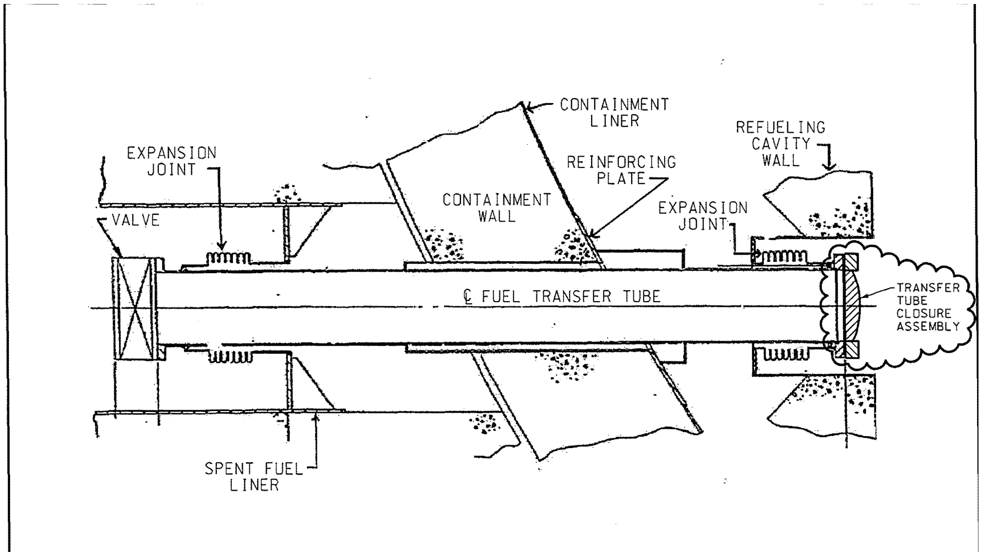
NOTE: CONTAINMENT ISOLATION SIGNAL APPLIED TO THESE VALVES MUST BE OVERRIDDEN IN ORDER TO USE THE MONITOR AFTER AN ACCIDENT.

PENETRATION	CONTAINMENT ISOLATION VALVES		BRANCH/ SYSTEM	LINE SIZE	FLUID	TEMP HOT>200 COLD<200	CLASS
	INSIDE	OUTSIDE					
X-2	RM-3200AA	RM-3200A	CONTAINMENT AIR SAMPLE (RETURN)/RM	1”	G	COLD	3

NOTE:

THIS PENETRATION MEETS CLASS 3 CONTAINMENT ISOLATION CRITERIA WITH CHECK VALVE (RM-3200AA) INSIDE CONTAINMENT SERVING THE PURPOSE OF AN AUTOMATIC TRIP VALVE AND AUTOMATIC TRIP VALVE (RM-3200A) OUTSIDE CONTAINMENT.

Figure 5.2-72 FUEL TRANSFER TUBE PENETRATION



POINTBEACH FSAR FIG 5.2-72

REV NO.	DATE	REVISION DESCRIPTION	DRAWN	CHK'D	APPRV'D
01	03-17-16	REVISED PER EC #282573-004	KJB	JLF	JJN
00	12-05-09	INCORP. INTO PDS PER EC # 14450	KJB	JLF	KJB

UPDATE PRI: 2
SUB TYPE: FSAR
OCR: NO

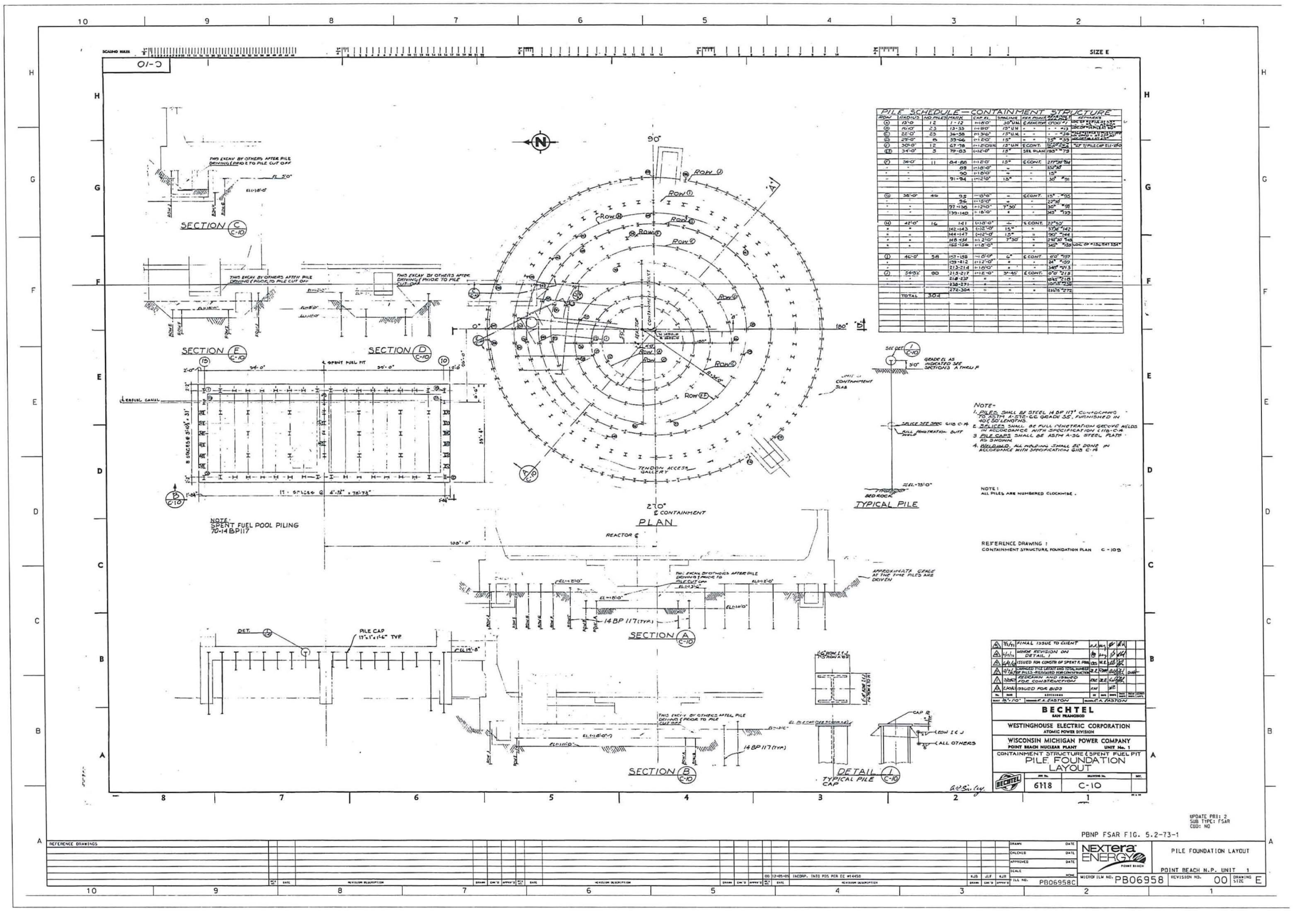
DRAWN	DATE	
KJB	09-18-09	
CHECKED	DATE	SCALE
BMS		NONE
APPROVED	DATE	FILE NO. PB06957C

NEXTera ENERGY POINT BEACH

FUEL TRANSFER TUBE
PENETRATION
POINT BEACH N.P. UNIT 1

MICROFILM NO. PB06957 REV. NO. 01 DWG SIZE CUSTOM

Figure 5.2-73-1 PILE FOUNDATION LAYOUT



5.3 CONTAINMENT VENTILATING SYSTEM

5.3.1 DESIGN BASES

5.3.1.1 PERFORMANCE OBJECTIVES

The containment ventilating systems are designed to accomplish the following:

1. Remove the normal heat loss from all equipment and piping in the containment during plant operation and to maintain a normal ambient temperature less than 105°F.

2. Provide sufficient air circulation and filtering throughout all containment areas to permit safe and continuous access to the reactor containment within two hours after reactor shut-down assuming defects exist in no more than 1% of the fuel rods.

3. Provide for positive circulation of air across the refueling water surface when necessary to minimize personnel inhalation hazards during shutdown.

4. Provide a minimum containment ambient temperature of 50°F during reactor shutdown.

5. Provide for purging of the containment vessel to the plant vent for dispersion to the environment.

6. Provide for depressurization of the containment vessel following an accident. The post-accident design and operating criteria are detailed in Chapter 6.

In order to accomplish these objectives, the following systems are provided:

1. Containment Air Recirculation Cooling System (VNCC)

2. Control Rod Drive Mechanism Cooling System (VNCRD)

3. Reactor Cavity Cooling System (VNRC)

4. Refueling Water Surface Ventilation System (VNRF)

5. Purge Supply and Exhaust System (VNPSE)

6. Containment Cleanup (Charcoal Filter) System (VNCF)

7. Post-Accident Containment Venting System (PACV)

8. Radiation Monitoring System (RM)

5.3.1.2 DESIGN CHARACTERISTICS - SIZING

The design characteristics of the equipment required in the containment for cooling, filtration and heating to handle the normal thermal and air cleaning loads during normal plant operation are presented in Table 5.3-1. In certain cases where engineered safeguards functions are also served by the equipment, component sizing is determined from the heavier duty specifications associated with the design basis accident detailed further in Chapter 6.

5.3.2 SYSTEM DESIGN AND OPERATION

The containment air recirculation, control rod drive mechanism cooling, reactor cavity cooling, refueling water surface ventilation, purge supply and exhaust, containment cleanup (charcoal filter) and post-accident containment ventilation systems are shown in Figure 5.3-1. The containment ventilation ductwork (except the CRDM cooling system ductwork), fans (except the refueling water surface supply and exhaust fans and the CRDM cooling system fans), filters, coils, and housings within the containment are designed as Seismic Class I structures.

The containment clean-up fans, control rod drive mechanism cooling fans, and reactor cavity cooling fans are direct driven units, each with standby units for redundancy. Each of the associated systems, except the refueling water surface ventilation system is provided with flow switches to verify existence of air flow in the associated duct system. The purge system containment isolation valves are provided with limit switches to indicate valve positions.

5.3.2.1 CONTAINMENT AIR RECIRCULATION

Containment air recirculation is summarized in this section, and discussed in more detail in Chapter 6. The air recirculating cooling function, during normal operation, is accomplished using three of the four air cooling units (with 2 fans/unit) discharging to a common duct to assure adequate distribution of filtered and cooled air throughout the containment. However, as service water temperature increases beyond 75° up to 80°, operation of four air cooling units may be required to maintain containment temperature within Technical Specification Limits (Reference 5). Each cooling coil in an air handling unit is designed to transfer up to 1.57×10^6 BTU/hr to the service water system during normal plant operation. Each of the two fan cooler trains, consisting of two fan cooler units, must be capable of transferring heat at a rate of 60×10^6 BTU/hr for a limiting design basis accident condition.

Each air cooling unit consists of the following equipment arranged so that, during normal operation, air flows through the assembly in the following sequence: inlet screen, roughing filter, cooling coil, vaneaxial fans, backdraft damper and a discharge header which is common to all four units. Roughing filters are installed during refueling outages with a significant potential for a dusty containment atmosphere.

In the event of a loss-of-coolant accident, only two of the four units are required to function. These cooling units, in conjunction with one train of containment spray, have sufficient capacity to maintain the containment pressure within design limits after a loss-of-coolant accident. For each of these two units, only one of the two vane-axial fans would continue to operate. Air flow through the idle fan would be prevented by means of backdraft dampers. The air is then distributed through the common discharge header into the containment atmosphere.

The normal air flow rate per air handling unit is 58,000 cfm (both accident and normal fans operating) and the design post-accident flow rate is 33,500 cfm (Reference 6) (accident fan only) at 60 psig containment pressure. Periodic air flow measurements are taken to evaluate accident fan performance.

The air recirculating cooling units are located in the space between the loop compartment wall and the containment wall on three elevations. The shielded location makes inspection of the equipment possible at power under controlled access conditions and immediately after a hot shutdown.

The fans, motors, electrical connections and all other equipment in the containment necessary for operation of the system under accident conditions are capable of operating under the environmental conditions existing following a loss-of-coolant accident.

During power operation, containment integrity is maintained with no release from the containment air recirculation ventilation system to the atmosphere. Prior to purging the containment air, particulate and radiogas monitor indications of the closed containment activity levels are used to determine routine releases from the containment.

During power operation, the containment particulate and radiogas monitor indications help determine the desirability of using the containment cleanup (charcoal filter) system or the purge supply and exhaust systems or both for pre-access cleanup.

When containment purging for access following reactor shutdown is in progress, releases from the plant vent are continuously monitored with a radiogas monitor.

Four additional systems supplement the main containment air recirculation cooling systems. These systems include:

1. Containment cleanup (charcoal filter) system;
2. Control rod drive cooling system;
3. Refueling water surface ventilation system; and
4. Reactor cavity cooling system.

Containment Cleanup (Charcoal Filter) System

The containment cleanup (charcoal filter) system draws contaminated air from the containment. The air is then drawn across a filter assembly which consists of a roughing filter, HEPA filter and a charcoal filter, passes through the system fan and is then discharged into containment.

CRDM Cooling System

The control rod drive cooling system consists of fans and duct work to draw air through the control rod drive mechanism shroud and eject it to the main containment atmosphere. One hundred percent redundancy is provided by a standby fan.

Refueling Water Surface Ventilation System

The refueling water surface ventilation system may be used during refueling operations to remove contaminants emanating from the water pool above the fuel elements. This is accomplished by the supply fan drawing air from the containment atmosphere and supplying it above the water surface. This air then mixes with containment air and is exhausted by the refueling surface exhaust fan to the purge exhaust system where it is filtered and discharged to atmosphere. The system is not required to assist in mitigating a fuel handling accident or operate during refueling operations.

Reactor Cavity Cooling System

The reactor cavity cooling system, consisting of cooling coils, fans, and ductwork is arranged to supply cooled air to the annulus between the reactor vessel and the primary shield and to the nuclear instrumentation external to the reactor. One hundred percent redundancy is provided by a standby fan. The cooling coils are maintained for air flow resistance.

5.3.2.2 CONTAINMENT PURGE SYSTEM

The containment purge system is independent of any other system and includes provisions to both supply and exhaust air from the containment. The supply system includes outside air connection to roughing filters, heating coils, fans, duct system, and supply penetration with one butterfly valve and one blind flange in series. The exhaust system includes an exhaust penetration with one butterfly valve and one blind flange in series, duct system, filter bank with roughing and HEPA filters, and exhaust fans. The blind flanges located inside containment provide containment isolation during normal operation (MODES 1 through 4). The filters in one bank may be temporarily removed, should the air activity levels permit. Both supply and exhaust systems include two fans with isolating dampers so that purging can be performed at half or full flow rate. The full flow rate is 25,000 cfm.

The purge supply and exhaust system includes four pre-heaters and four heaters with a total capacity of 2,028,000 Btu/hr, which may be used to maintain a minimum temperature of 50°F during winter shutdowns.

In accordance with Technical Specifications, containment integrity shall not be violated when a nuclear core is installed unless the reactor is in the cold shutdown condition. Therefore, purging of the containment is prohibited unless the reactor is in the cold shutdown condition.

5.3.2.3 ISOLATION VALVES

The containment purge supply and exhaust butterfly valves are located outside containment (see Figure 5.2-V1 and Figure 5.2-V2 in Section 5.2) and are used during plant shutdowns to provide containment closure. Blind flanges with double O-rings are installed inside containment to provide containment isolation during normal operation (MODES 1 through 4). Penetration leakage can be checked by using the test connection between the blind flange O-rings. The butterfly valves are designed for rapid closing by a Train "A" Containment Ventilation Isolation Signal (see Table 7.3-1) to limit a radioactivity release to the atmosphere. A reset function is provided as described in Section 7.3.3.3.c, Containment Isolation Reset, to allow opening the purge inlet and outlet valves after the actuation signals are no longer present. Instrument air is used to operate the butterfly valves and inflate the boot seal style seats in the valves (Reference 4).

5.3.2.4 POST ACCIDENT CONTAINMENT VENTING SYSTEM

The NRC eliminated the hydrogen release associated with a design basis loss of coolant accident from 10 CFR 50.44 and the associated requirements that necessitated the hydrogen recombiners and the containment post accident hydrogen vent and purge system (Reference 1, Reference 2, and Reference 3). As a result of this regulatory change, the availability of and capability to install hydrogen recombiners has been removed from the licensing and design basis. In addition, the post accident containment purge system has been removed from the licensing basis. However, the capability to facilitate post accident containment purging is being maintained for beyond design basis accident management.

5.3.2.5 CONTAINMENT VENTING DURING NORMAL OPERATION (Radiation Monitoring System)

During normal reactor operation at power, the containment may be continuously vented by use of the containment gaseous and particulate sampling and monitoring penetrations. (See Figure 5.2-X1 and Figure 5.2-X2.) The containment air sample is routed through a calibrated full view rotameter and flow transmitter and then to the RE-211, containment air particulate, and RE-212, containment noble gas monitors. Details of the RE-211 and RE-212 monitors are provided in Section 11.5. The containment air sample flow is normally routed back to the containment atmosphere. When the unit is in cold shutdown and the containment purge exhaust fans are operating, the containment air sample returns are normally routed to the containment purge exhaust stack. The flow transmitter output and signals from the RE-211 and RE-212 are wired to the plant computer to allow continuous computation of radiation releases.

Use of this continuous containment ventilation system precludes the buildup of pressure inside the containment which would normally result from instrument air leakoff to various instrumentation and valve operators and during containment atmosphere heatup due to primary system temperature increase. If containment pressure reaches approximately 1 psig, the RE-211/212 radiation monitoring forced ventilation pump is placed in service which discharges to the purge exhaust filter units. The system is automatically isolated in the event of a containment isolation signal.

5.3.3 REFERENCES

1. NRC Safety Evaluation 2004-0008, dated August 13, 2004, "Point Beach Nuclear Plant Unit 1 and 2 - Issuance of Amendments Re: Relocation of Requirements for Hydrogen Monitors (TAC Nos. MC 1904 and MC1905)."

2. 2003 Federal Register Vol. 68, No. 179, September 16, pages 54123 - 54138.

3. 2003 Federal Register Vol. 68, No. 186, September 25, pages 55416 - 55421.

4. SCR 2008-0066, "Isolation of Purge Valve T-Seal Backup Nitrogen," March 27, 2005.

5. Calculation 129187-M-0022, "Verification of Adequacy of Containment Fan Cooler Units during Normal Operations under Extended Power Uprate (EPU) Conditions", Revision 1, December 16, 2008.

6. NPL 2006-0097 Letter 5/31/06, "Re-analysis of Point Beach Nuclear Plant (PBNP) Design Basis Radiological Accidents Using Alternate Source Term Methodology: Design Input Transmittal of Common and LOCA Input Parameters".

7. SCR 2012-0191-1, "EC 277852 - Abandonment of Unit 2 Cavity Cooler SW Piping," November 24, 2012.

8. SCR 2012-0197, "EC 277917 - Abandonment of Unit 1 Cavity Cooler SW Piping," January 16, 2013.

9. SCR 2013-0188-01, "Reduction of CFC Heat Removal Requirement," dated November 21, 2013.

Table 5.3-1 PRINCIPAL COMPONENT DATA SUMMARY

Page 1 of 2

System	Units Installed	Unit Capacity	Units Required for Normal Operation
Containment Recirculating			
Cooling Coils - Normal	4	1.57×10^6 BTU/hr	3
Cooling Coils - DBA	4 (2 per train)	60×10^6 BTU/hr per train	N/A
Roughing Filters*	4		0
Fans	8 (per unit)		3
Fan Pressure			
Normal Conditions		6.94 in. H_2O	
Accident Conditions		8.05 in. H_2O	
Fan Capacity - Normal op. fan	4		3
Normal Conditions		29,000 cfm	
Accident Conditions			
Fan Capacity - Accident fan	4		3
Normal Conditions		29,000 cfm	
Accident Conditions		33,500 cfm	
Control Rod Drive Cooling			
Fans, Standard Conditions	2	14,000 cfm	1
Fan Pressure		14 in. H_2O	
Fan Motors	2	50 hp	1
Reactor Cavity Cooling			
Plenum	1		1
Fans, Standard Conditions	2	28,000 cfm	1
Fan Pressure		7 in. H_2O	
Fan Motors	2	40 hp	1
Cooling Coils	2	not applicable	1
Purge Supply			
Fans, Standard Conditions	2	12,500 cfm	Optional
Fan Pressure		4 in. H_2O	
Fan Motors	2	15 hp	
Pre-heat Coils	4	372,000 BTU/hr	Optional
Re-heat Coils	4	135,000 BTU/hr	Optional
Air Filters, Roughing		25,000 cfm	1
Purge Exhaust			
Fans, Standard Conditions	2	12,500 cfm	Optional
Fan Pressure		7.5 in. H_2O	
Fan Motors	2	25 hp	Optional
Plenums	2	12,500 cfm	Optional
Filters, 12 HEPA Cells/Unit	2	12,500 cfm	Optional

Table 5.3-1 PRINCIPAL COMPONENT DATA SUMMARY

Page 2 of 2

System	Units Installed	Unit Capacity	Units Required for Normal Operation
Refueling Canal Supply			
Fan, Standard Conditions	1	11,000 cfm	1
Fan Pressure		2.0 in. H_2O	
Fan Motor	1	7.5 hp	1
Refueling Canal Exhaust			
Fan, Standard Conditions	1	22,000 cfm	
Fan Pressure		3.0 in. H_2O	
Fan Motor	1	15 hp	1
Containment Cleanup (Charcoal Filter) System			
Fans, Standard Conditions	2	5,400 cfm	Optional
Fan Pressure		9.0 in H_2O	
Fan Motors	2	15 hp	Optional
Filters, 6 HEPA Cells/Unit	2	5,400 cfm	Optional
Charcoal Filters, 16 Cells/Unit		5,400 cfm	Optional

Figure 5.3-1 UNITS 1 & 2 CONTAINMENT VENTILATION SYSTEM FLOW DIAGRAM (Sheet 1)

[redacted]

Figure 5.3-1 UNIT 1 CONTAINMENT VENTILATION SYSTEM FLOW DIAGRAM (Sheet 2)

[redacted]

Figure 5.3-1 CONTAINMENT VENTILATION SYSTEM FLOW DIAGRAM (Sheet 3)

[redacted]

5.4 SYSTEM DESIGN EVALUATION

5.4.1 RELIANCE ON INTERCONNECTED SYSTEMS

The containment leakage limiting boundary is provided in the form of a single, carbon steel liner on the vessel. Each system whose piping penetrates this boundary is designed to maintain isolation of the containment from the outside environment. Provision is made to periodically monitor leakage by pressurizing penetrations or double barriers at individual potential leak paths.

5.4.2 SYSTEM INTEGRITY AND SAFETY FACTORS

5.4.2.1 PIPE RUPTURE - PENETRATION INTEGRITY

The penetrations for the main steam, feedwater, and steam generator blowdown and sample lines are designed so that the penetration is stronger than the piping system and that the vapor barrier will not be breeched due to a hypothesized pipe rupture. Details of the main steam and feedwater penetrations are shown in Figure 5.1-2.

5.4.2.2 CONTAINMENT STRUCTURE COMPONENTS ANALYSIS

The details of radial, longitudinal and horizontal shear analysis for the containment reinforced concrete are given in Section 5.1.2.4.

5.4.3 PERFORMANCE CAPABILITY MARGIN

The containment structure is designed based upon limiting load factors which are used as the ratio by which accident and earthquake loads are multiplied for design purposes to ensure that the load/deformation behavior of the structure is one of elastic, low strain behavior. This approach places minimum emphasis on fixed gravity loads and maximum emphasis on accident and earthquake loads. Because of the refinement of the analysis and the restrictions on construction procedures, the load factors primarily provide for a safety margin on the load assumptions. Load combinations and load factors utilized in the design which provide an estimate of the margin with respect to all loads are tabulated in Section 5.1.2.2.

5.5 MINIMUM OPERATING CONDITIONS

5.5.1 CONTAINMENT INTEGRITY

Containment integrity will be maintained unless the reactor is in the cold shutdown or refueling conditions (MODES 5 or 6).

The reactor coolant system and cold shutdown condition assure that no steam will be formed and hence there would be no pressure buildup in the containment if a reactor coolant system rupture were to occur. During movement of recently irradiated fuel assemblies inside the containment (MODE 6), the containment is maintained closed or in a condition conducive to rapid closure.

5.5.2 EXTERNAL PRESSURE AND INTERNAL VACUUM

The containment is designed to withstand an internal design vacuum condition of 2 psi which is equivalent to an external pressure loading with a differential of 2 psi from outside to inside. This condition will accommodate either a barometric pressure rise to 31 in. Hg after the containment is sealed at 29 in. Hg, or an interior containment cooldown from 120°F to 50°F. Therefore, it is not necessary to equalize containment pressure due to barometric pressure changes during normal operation or cooldown conditions.

5.5.3 LEAKAGE

A containment leakage rate of 0.2 weight percent of the contained air per 24 hours at an internal pressure of 60 psig under hypothetical accident conditions with 2 of 4 air recirculation units operating will maintain public exposure well below 10 CFR 50.67 values.

5.6 CONSTRUCTION

5.6.1 CONSTRUCTION METHODS

5.6.1.1 APPLICABLE CODES

The following codes of practice are used to establish standards of construction procedure:

ACI 301	-	Specification for Structural Concrete for Buildings (Proposed)
ACI 306	-	Recommended Practice for Cold Weather Concreting
ACI 318	-	Building Code Requirements for Reinforced Concrete
ACI 347	-	Recommended Practice for Concrete Formwork
ACI 605	-	Recommended Practice for Hot Weather Concreting
ACI 613	-	Recommended Practice for Selecting Proportions for Concrete
ACI 614	-	Recommended Practice for Measuring, Mixing and Placing Concrete
ACI 315	-	Manual of Standard Practice for Detailing Reinforced Concrete Structures
ASME	-	Boiler and Pressure Vessel Code, Sections III, VIII and IX
AISC	-	Steel Construction Manual
PCI	-	Inspection Manual

5.6.1.2 CONCRETE

Cast-in-place concrete was used to construct the containment shell. The base slab construction was performed utilizing large block pours. After the completion of the base slab steel liner erection and testing, an additional 18 in. thick concrete slab was placed to provide protection for the floor liner.

The concrete placement in the walls was done in 10 ft. high lifts with vertical joints at the radial center line of each of six buttresses. Cantilevered jump forms on the exterior face and the interior steel wall liner served as the forms for the wall concrete.

The dome liner plate, temporarily supported by 18 radial steel trusses and purlins, served as an inner form for the initial 8 in. thick pour in the dome. The weight of the subsequent pour was supported in turn by the initial 8 in. pour. The trusses were lowered away from the liner plate after the initial 8 in. of concrete reached design strength, but prior to the placing of the balance of the dome concrete.

The truss structures have remained in the lowered position since construction and are used as a support for containment spray piping, containment air recirculation cooling system (VNCC) ductwork, post-accident containment ventilation (PACV) piping, and miscellaneous lights and associated conduits. See Section A.5.10 for resolution of design code nonconformances associated with as-built discrepancies related to the truss structures and the ability of the truss structures to provide support to the associated components/structures.

The horizontal and the vertical construction joints were prepared by dry sandblasting followed by cleaning and wetting. Horizontal surfaces were covered with approximately 1/4 in. thick mortar of the same cement-sand ratio as used in the concrete immediately before concrete placing.

5.6.1.3 REINFORCING STEEL

Prior to placing, visual inspection of the shop fabricated reinforcing steel was performed to ascertain dimensional conformance with design specifications and the drawings. This was followed by a check "in place" performed by the placing inspector to assure the dimensional and location conformance.

Mill test results were obtained from the reinforcing steel supplier for each heat of steel to show proof that the reinforcing steel has the specified composition, strength, and ductility. Splices in reinforcing bar are lap splices in accordance with ACI 318-63.

Welding of reinforcing steel was not generally permitted but where required was performed by qualified welders in accordance with AWS D12.1, "Recommended Practice for Welding Reinforcing Steel, Metal Inserts, and Connections in Reinforced Concrete Construction." Tack welding was not permitted.

5.6.1.4 POST TENSIONING SYSTEM

The post tensioning system used is the BBRV system as furnished by the Inland-Ryerson Construction Products Company. (See Figure 5.6-1)

Each tendon consists of ninety 1/4 in. diameter button-headed wires, two anchor heads and two sets of shims. The tendon sheathing system consisting of spirally wound sheet metal tubing connects to a mild steel "Trumplate" (bearing plate and trumpet) at each end.

Tendons were delivered to the site coated with temporary rust preventive (Dearborn Chemicals NO-OX-ID 500) and encased in polyethylene bags. Each tendon was precut to exact length, with one end unfinished and the other end shop button-headed, and with its anchor head attached.

The tendon installation prestressing procedure was carried out as follows:

1. To assure a clear passage for the tendons, a "sheathing rabbit" was run through the sheathing following placement of the concrete.
2. Tendons were uncoiled and pulled through the sheathing unfinished end first.
3. The unfinished end of the tendons were pulled out with enough length exposed so that field attachment of the anchor head and buttonheading could be performed. To allow this operation, trumplates on the opposite end had an enlarged diameter to permit pulling in the shop finished ends with their anchor heads.
4. The anchor heads were attached and the tendon wires button-headed.
5. The shop finished end of the dome and hoop tendons were pulled back and the stressing jacks were attached to both ends. Vertical tendons were stressed only from the top end.

6. The post tensioning was done by jacking to the permissible overstressing force to compensate for friction and inserting shims under the anchor head. Proper tendon stress was achieved by comparing both jack pressure and tendon elongation against previously calculated values. The elongation of some of the post tensioned tendons exceeded the calculated value by more than the 5% allowed by the manufacturer's QA manual. Independent evaluations conducted by the manufacturer, Inland-Ryerson, and the principal architect-engineer, Bechtel Power Corporation, concluded that the variance in elongation was not detrimental but resulted in an increased strength of the structure. The vertical tendons were prestressed from one end, while the horizontal and dome tendons were tensioned from both ends.

7. The grease caps were bolted into anchorages at both ends and made ready for pumping the tendon sheathing filler material.

8. The tendon sheaths and grease caps were filled with sheathing filler and sealed.

5.6.1.5 LINER PLATE

Construction of the liner plate conforms to the applicable portions of Part UW of Section VIII of the ASME Code. Specifically, paragraphs UW-26 through UW-38, inclusive, applied in their entirety. In addition, the qualification of all welding procedures and welders was performed in accordance with Part A of Section IX of the ASME Code. All liner angle welding was visually inspected prior to, during and after welding to ensure that quality and general workmanship met the requirements of the applicable welding procedure specification.

The erection of the liner plate was as follows: After the floor insert plates on the foundation slab were placed and welded, and concrete was poured flush, the wall liner plates were erected in 60° segments and 10 ft. high courses. This pattern was followed to the dome spring line, and then the permanent steel dome trusses were placed. During the period of erection of wall liner plates, the floor liner plate was placed and welded.

The tolerances on liner plate erection are as follows:

The radial location of any point on the liner plate does not vary from design radius by more than ±1 1/2 in. A 15 ft. long template curved to the required radius was used to verify that the following tolerances were not exceeded:

1. A maximum 3/4 in. deviation when placed against the completed surface of the shell within a single plate section.

2. A maximum 1 in. deviation when placed across one or more welded seams.

Maximum measured inward deflection (toward the center of the Unit 1 structure) of the 1/4 in. plate between the angle stiffeners was 1/16 in. as measured using a 15 in. straightedge placed horizontally, and 1/8 in. with the straightedge placed across the welded seam at the buttresses.

5.6.1.6 TENDON SHEATHING FILLER MATERIAL

The material used in filling cavities in the tendons and as a protective and lubricating compound in the tendon conduits, as fabricated by Viscosity Oil Company, is essentially a modified refined petroleum oil base which contains no solvent. It contains certain proprietary chemical additives and inhibitors to prevent corrosion of the steel. It has a pour point of 110°F to 115°F and is applied at approximately 130°F to drive air and vapor from the voids before solidifying to a soft gel. It is pumped into all voids surrounding the tendon after installation. It is compatible to "NO-OX-ID 500," in which the tendons were dipped after fabrication.

In addition to factory quality control tests, samples were analyzed by an independent laboratory for field quality control and acceptance as follows:

> Water soluble chloride (Cl) was determined by ASTM
> Method D512-62T with a limit of accuracy of 0.5 ppm
> Water soluble nitrates (NO_3) were determined by ASTM
> Method D992-52 with a limit of accuracy of 0.01 mg per liter.
> Finally, water soluble sulfides (S) were determined by ASTM Method
> D-1255-65T with a limit of accuracy of 1 ppm.

Stability data going back ten years from the time of construction indicates that the filler material will not deteriorate during the 40-year life of the plant. Actually its chemical composition, being about 98% petroleum jelly, indicates that it would possess the normal stability of the linear hydrocarbons subjected to ambient temperature levels.

Galvanic corrosion normally occurs underground, under water or in the presence of a corrosive medium. Atmospheric conditions may cause surface attack but there is no galvanic corrosion unless metals of two different electrochemical levels are present and the medium between them permits current flow. Consequently if the materials used are steel, and precautions are taken to prevent water from providing a conducting path between them, there should be no galvanic corrosion (Reference 1).

If an electrolyte were to surround a stressed tendon, there is a possibility that the surface of the tendon would develop certain anodic corrosion centers (Reference 2). However, the corrosion would be caused by the fracturing of the naturally protecting oxide film on the surface of the steel. Work done by Greene (Reference 3) and Unz (Reference 4) indicates that there is very little change in electric potential by extremely high stresses.

5.6.1.7 MATERIALS

1. <u>Concrete</u>

Ingredients

Cement	ASTM C-150 Type II
Flyash	ASTM C-350 Air
Air Entraining Agent	ASTM C-260
Water Reducing Agent	ASTM C-494 Type D (Plastiment)
Aggregate	ASTM C-33 (Fine aggregate is alluvial sand. Coarse aggregate is crushed dolomite.)

No Calcium Chloride was used in the concrete.

Strengths

Base Slab	4,000 psi at 90 days
Walls and Dome	5,000 psi at 28 days

Principal Placement Properties

Slump, maximum	2-3 in. at form
Air Content	3-5% at mixer
Temperature	Max. 70°F

2. Reinforcing Steel

ASTM Specification for reinforcing steel is the following:
A-15 Billet Steel - Intermediate Grade
A-432 Billet Steel - High Strength

3. Prestressing Tendons and Associated Hardware

Material	Material Specifications
Tendon Wires	ASTM-A421
Bearing Plate	ASTM-A36
Anchor Head	AISI-1141-special quality
Shims	SISI-C1026
(from cut tubes)	AISI C 102 6
(from burned plates)	ASTM-A36
(stamped)	40/50 carbon steel

4. Liner Plate

Liner plate conforms to ASTM Specification A-442, Grade 60, flange quality.

5. Steel Foundation Piles

The type of pile chosen was standard steel H-pile with a nominal capacity of 200 tons. The pile material conforms to ASTM Standard A-572-66, Grade 55. The piles are approximately 65 to 75 feet long under the containment structure. These lengths exceeded permissible shipping lengths; therefore, the piles were field-spliced by full-penetration butt welding.

Mill test reports were submitted by the pile fabricator to verify that the chemistry, ductility, and strength of the piling material were as specified.

6. Penetrations and Assemblies

Elements resisting containment pressure:
Pipe Material ASTM-A333
Plate Material ASTM-A516, Grade 70, Fire Box Quality
In both of the above materials, impact specimens were Charpy V-Notch tested and met the requirements of Paragraph N-1211(a) of Section III of the ASME Code at a test temperature of -45°F.

Miscellaneous

Penetration Anchor Bolts	ASTM-A-307, Grade A
Penetration H. S. Anchor Bolts	ASTM-A193, Grade B7
Steel Arc-Welding Electrode	ASTM-A2333 and A599, Type E6010
Truss Bolts	ASTM-A325-64
Structural Steel for Inserts and Supports	ASTM-A36-63T
Flued Heads	ASTM A-350-LF 1 and ASTM-A182, Grade F304 or F316
Internal Caps	ASTM A420, WPL1 and ASTM A403, Type 304

7. Sheathing Filler

The tendon sheathing filler material used has the following limitations specified for deleterious water soluble salts:
Chlorides (Cl) 1 ppm ASTM D512-62T
Nitrates (NO_3) 4 ppm Hack Chemical Procedure
Sulfides (S) 1 ppm ASTM D1255

Temporary corrosion protection of the tendons and the interior face of sheathing was used.

5.6.1.8 QUALIFICATION OF CONCRETE MATERIALS

Aggregates

Acceptability of aggregates is based on the following ASTM tests. These tests were performed by Walter Flood and Co. in Chicago, Illinois.

TEST	ASTM
Los Angeles Abrasion	C-131
Clay Lumps Natural Aggregate	C-142
Material Finer than No. 200 Sieve	C-117
Mortar Making Properties	C-87
Organic Impurities	C-40
Potential Reactivity (Chemical)	C-289
Potential Reactivity (Mortar Bar)	C-227
Sieve Analysis	C-136
Soundness	C-88
Specific Gravity and Absorption	C-127
Specific Gravity and Absorption	C-128
Petrographic	C-295

Mixes

Design mixes and the associated tests were run by the concrete testing laboratory (Walter Flood & Co.) in accordance with ACI 613. During construction, the field inspection personnel made minor modifications that were necessitated by various aggregate gradation or moisture content. The following tests were run in determining the design mixes:

	ASTM
Air Content	C-231
Slump	C-143
Bleeding	C-232
Making and curing cylinders in Lab	C-192
Compressive Strength Tests	C-39

CONCRETE DESIGN MIXES

Concrete Strength	Cement Sks/Yd	Flyash* Sks/Yd	Sand	3/4"	1 1/2"	3"	Water
			PROPORTIONS BY WEIGHT				
3000 psi	4.47	0.79	1463	1940	-	-	231
@28 days	4.26	0.74	1338	1028	1063	-	222
4000 psi	4.13	1.37	1420	1960	-	-	234
@90 days	3.94	1.32	1283	1024	1091	-	228
	3.74	1.26	1149	662	761	906	217
5000 psi	5.82	1.03	1322	1793	-	-	280
@28 days	5.60	0.99	1210	937	1032	-	265

*Based on one sack = 94 lbs.

Water Reducing Agent

Walter Flood & Co. was engaged to perform the necessary strength and shrinkage tests of various water reducing agents to establish the particular additive with the most desirable characteristics for this application. On the basis of these tests, "Plastiment", manufactured by Sika Chemical Corporation, was selected.

Studies of concrete creep and other properties were conducted at the University of California in Berkeley under the direction of Professor David Pirtz.

5.6.2 MATERIALS OF CONSTRUCTION IN CONTAINMENT

All materials in containment are reviewed from the standpoint of insuring the integrity of equipment of which they are constructed and to insure that deterioration products of some materials do not aggravate an accident condition. In essence, therefore, all materials of construction in containment must exhibit resistance to the post accident environment or, at worst, contribute only insignificant quantities of trace contaminants which have been identified as potentially harmful to vital safeguards equipment. Table 5.6-1 lists typical materials of construction used in the reactor containment system. Examples of equipment containing these materials are included in the table.

Corrosion testing showed that of all the metals tested only aluminum alloys were found incompatible with the alkaline sodium borate solutions. Aluminum was observed to corrode at a significant rate, with the generation of hydrogen gas. Since hydrogen generation can be hazardous to containment integrity, a detailed survey was conducted to identify all aluminum components in containment.

Table 5.6-2 lists those aluminum components in the Units 1 and 2 containments that may be wetted by containment spray or submerged in the containment sump. The 1100 and the 6000 series aluminum alloys are generally the major types found in containment. This inventory reflects the determination to exclude as much as practicable the use of aluminum in the containment. (Reference 18 and Reference 20)

5.6.2.1 CORROSION OF METALS OF CONSTRUCTION IN DESIGN BASIS EMERGENCY CORE COOLING SOLUTION

Emergency core cooling components are austenitic stainless steel and, hence, are quite corrosion resistant to the alkaline sodium borate solution, as demonstrated by corrosion tests performed at Westinghouse Pressurized Water Reactor Division (PWRD) and Oak Ridge National Laboratory (ORNL) (Reference 5). The general corrosion rate, for Type 304 and 316 stainless steels, was found to be 0.01 mils/month in pH 10 solution at 200°F. Data on corrosion rates of these materials in the alkaline sodium borate solution have also been reported by ORNL (Reference 6, Reference 7) to confirm the low values.

Extensive testing was also performed on other metals of construction which are found in the reactor containment. Testing was performed on these materials to ascertain their compatibility with the spray solution at design post accident conditions and to evaluate the extent of deterioration product formation, if any, from these materials.

Metals tested include Zircaloy, Inconel, aluminum alloys, cupronickel alloys, carbon steel, galvanized carbon steel and copper. The results of the corrosion testing of these materials are reported in detail in Reference 1. Of the materials tested, only aluminum was found to be incompatible with the alkaline sodium borate solution. Aluminum corrosion is discussed subsequently. The following is a summary of the corrosion data obtained on various materials of construction exposed for several weeks in aerated alkaline (pH 9.3 - 10.0) sodium borate solution at 200°F. The exposure condition is considered conservative since the test temperature (200°F) is considerably higher than the long-term design basis accident temperature.

Material	Maximum Observed Corrosion Rate (mil/month)
Carbon Steel	0.003
Zr-4	0.004
Inconel 718	0.003
Copper	0.015
90 - 10 Cu-Ni	0.020
70 - 30 Cu-Ni	0.006
Galvanized Carbon Steel	0.031
Brass	0.010

Tests conducted at ORNL (Reference 6, Reference 7) also have verified the compatibility of various materials of construction with alkaline sodium borate solution. In tests conducted at 284°F, 212°F, and 130°F stainless steels, Inconel, cupronickels, Monel, and Zircaloy-2 experienced negligible changes in appearance and negligible weight loss.

Corrosion tests at both PWRD and ORNL have shown copper suffers only slight attack when exposed to the alkaline sodium borate solution at DBA conditions. The corrosion rate of copper, for example, in alkaline sodium borate solution at 200°F is ~ 0.015 mil/month (Reference 5). The corrosion of copper in an alkaline sodium borate environment under spray conditions at 284°F and 212°F have been reported by ORNL. Corrosion penetrations of less than 0.02 mil was observed after 24 hours exposure at 284°F (see Reference 7, Table 3.13) and a corrosion rate of less than 0.3 mil per month was observed at 212°F (see Reference 6, Table 3.6).

It can be seen therefore that the corrosion of copper in the post accident environment will have a negligible effect on the integrity of the material. Further, the corrosion product formed during exposure to the solution appears tightly bound to the metal surface and hence will not be released to the Emergency Core Cooling solution.

The corrosion rate of galvanized carbon steel in alkaline sodium borate (3,000 ppm B, pH 9.3) is also low. Tests conducted in aerated solutions showed the corrosion rate to be 0.031 mil/month for a temperatures of 200°F. It can be seen therefore that the corrosion of zinc (galvanized) in alkaline borate solution is minimal and will not contribute significantly to the post accident hydrogen buildup.

Consideration was given to possible caustic corrosion of austenitic steels by the alkaline solution. Data presented by Swandby (Reference 8) (Figure 5.6-4) show that these steels are not subject to caustic stress cracking at the temperature (285°F and below) and caustic concentrations (less than 1 weight percent) of interest. It can be seen from Figure 5.6-4 that the stress cracking boundary minimum temperature, as defined by Swandby, coincides with a high free caustic concentration (~40%) and is considerably above (~80°F) the long-term post accident design temperature. Further, from Figure 5.6-4 a temperature in excess of 500°F is required to produce stress corrosion cracking at sodium hydroxide concentration greater than 85%.

It should be noted when considering the possibility of caustic cracking of stainless steel that the sodium hydroxide - boric acid solution is a buffer mixture wherein no free caustic exists at the temperatures of interest - even should the solution be concentrated locally through evaporation of water and hence the above consideration is somewhat hypothetical with regard to the post accident environment.

5.6.2.2 CORROSION OF METALS OF CONSTRUCTION BY TRACE CONTAMINANTS IN EMERGENCY CORE COOLING SOLUTION

Of the various trace elements which could occur in the emergency core cooling (ECC) solution in significant quantities, only chlorine (as chloride) and mercury are adjudged potentially harmful to the materials of construction of the safeguards equipment.

The use of mercury or mercury-bearing items, however, is prohibited in containment. This includes mercury vapor lamps, fluorescent lighting and instruments which employ mercury for pressure and temperature measurements and for electrical equipment. Potential sources of mercury, therefore, are excluded from containment and hence no hazard from this element is recognized.

The possibility of chloride stress corrosion of austenitic stainless steels has also been considered. It is believed that corrosion by this mechanism will not be significant during the post accident period for the following reasons:

1. Low Temperature of ECC Solution

   The temperature of the ECC solution is reduced after a relatively short period of time (i.e., a few hours) to about 150°F. While the influence of temperature on stress corrosion cracking of stainless steel has not been unequivocally defined, significant laboratory work and field experience indicates that lowering the temperature of the solution decreases the probability of failure. Hoar and Hines (Reference 9) observed this trend with austenitic stainless steel in 42 weight percent solutions of $MgCl_2$ with temperature decrease from 310°F to 272°F. Staehle and Latanision (Reference 10) present data which also shows the decreasing probability of failure with decreasing solution temperature from about 392°F to 302°F. Staehle and Latanision (Reference 10) also report the data of Warren (Reference 11) which showed the significant change with decrease in temperature from 212°F to 104°F. The work of Warren, while pertinent to the present consideration in that it shows the general relationship of temperature to time to failure, is not directly applicable in that the chloride concentration (1,800 ppm Cl) believed to have effected the failure was far in excess of reasonable chloride contamination which may occur in the ECC solution.

2. Low Chloride Concentration of ECC Solution

   It is anticipated that the chloride concentration of the ECC solution during the post accident period will be low. Throughout plant construction, surveillance was maintained to ensure that the chloride inventory in containment would be maintained at a minimum. Controls on use of chloride-bearing substances in containment include the following:

   a. Restriction in chloride content of water used in concrete;

   b. Prohibition of use of chloride in cleaning agents for stainless steel components and surfaces;

   c. Prohibition of use of chloride on concrete etching for surface preparation;

   d. Use of non-chloride bearing protective coatings in containment;

   e. Restriction of chloride concentration in safety injection solution, 0.15 ppm chloride maximum.

   The effect on decreasing chloride concentration on decreasing the probability of failure of stressed austenitic stainless steel has been shown by many experimenters. Staehle and Latanision (Reference 10) present data of Staehle which shows the decrease in probability of failure with decrease in chloride concentration at 500°F. Edeleanu (Reference 12) shows the same trend at chloride concentrations from 40% to 20% as $MgCl_2$ and reported no failures in this experiment at less than about 5% $MgCl_2$.

Instances of chloride cracking at representative ECC solution temperatures and at low solution chloride concentration have generally been on surfaces on which concentration of the chloride occurred. In the ECC system, concentration of chlorides is not anticipated since the solution will operate subcooled with respect to the containment pressure and further the containment atmosphere will be 100% relative humidity.

3. Alkaline Nature of the ECC Solution

The ECC solution will have a solution pH within the acceptable range of 7.0 to 10.5 after the addition of spray additive (NaOH). The minimum pH in the containment sump needed to keep iodine in the iodate form is 7.0. A pH of greater than 7.0 assures the iodine removal effectiveness of the containment spray. The maximum pH is based on Equipment Qualification considerations and is set at 10.5 (Reference 19). Numerous investigators have shown that increasing the solution pH decreases the probability of failure. Thomas et al (Reference 13) showed that the failure probability decreases with increasing pH of boiling solutions of MgCl. More directly applicable, Scharfstein and Brindley (Reference 14) showed that increasing the solution pH to 8.8 by the addition of NaOH prevented the occurrence of chloride stress corrosion cracking in a 10 ppm Cl (as NaCl) solution at 185°F. Thirty stressed stainless steel specimens, including Type 304 as received, Type 347 as received and Type 304 sensitized, were tested. No failures were observed.

Other test runs by Scharfstein and Brindley showed the influence of solution pH on higher chloride concentrations, up to 500 ppm Cl; however, in these tests the pH adjusting agents were either sodium phosphate or potassium chromate. The authors express the opinion, however, that in the case of the chromate solution, chloride cracking inhibition was simply due to the hydrolysis yielding pH 8.8 and not to an influence of the chromate anion. A similar hydrolysis will occur in the borate solution.

Studies conducted at Oak Ridge National Laboratory by Griess and Bocarella (Reference 15) on Type 304 and Type 316 stainless steel U-bend stress specimens exposed to an alkaline borate solution (0.15M NaOH - 0.28M H_3BO_3) containing 100 ppm chloride (as NaCl) showed no evidence of cracking after 1 day at 140°C, 7 days at 100°C, 29 days at 55°C. These extreme test conditions, combined with the fact that some parts of the test specimens were subjected to severe plastic deformation and intergranular attack before exposure, show that the probability of chloride induced stress corrosion cracking in a post accident environment are very low indeed.

In summary, therefore, it is concluded that exposure of the stainless steel engineered safety feature components to the ECC solution during the post accident period will not impair its operability from the standpoint of chloride stress corrosion cracking. The environment of low temperature, low chlorides and high pH which will be experienced during the post accident period will not be conducive to chloride cracking.

5.6.2.3 CORROSION OF ALUMINUM ALLOYS

Corrosion testing has shown that aluminum alloys are not compatible with alkaline borate solution. The alloys generally corrode fairly rapidly, at the post accident condition temperatures, with the liberation of hydrogen gas. A number of corrosion tests were conducted in the PWRD laboratories and at ORNL facilities. A review of applicable aluminum corrosion data is given in Table 5.6-3 and Figure 5.6-2.

5.6.2.4 COMPATIBILITY OF PROTECTIVE COATINGS WITH POST ACCIDENT ENVIRONMENT

The investigation of materials compatibility in the post accident design basis environment also included an evaluation of protective coatings for use in containment.

The results of the protective coatings evaluation presented in WCAP-7198-L (Reference 16) showed that several inorganic zincs, modified phenolics and epoxy coatings are resistant to an environment of high temperature (320°F maximum test temperature) and alkaline sodium borate. Long-term tests included exposure to spray solution at 150-175°F for 60 days, after initially being subjected to a conservative DBA cycle. The protective coatings, which were found to be resistant to the test conditions, that is, exhibited no significant loss of adhesion to the substrate nor formation of deterioration products, comprise virtually all of the protective coatings recommended for use in containment. The Amercoat Corp. products, Dimetcote and Amercoat 66, were the primary protective coatings used in the containment, hence, the protective coatings will not add deleterious products to the core cooling solution. It should be pointed out that several test panels of the recommended types of protective coatings were exposed for two design basis accident cycles and showed no deterioration or loss of adhesion with the substrate.

Procedures and programmatic controls developed with consideration for the guidance provided in EPRI TR-109937, "Guideline on Nuclear Safety-Related Coatings," ensure that the applicable requirements for the procurement, application, inspection, and maintenance of Service Level I coatings in containment are implemented. Service Level I coatings are used in areas where coating failure could adversely affect the operation of post-accident fluid systems and, thereby, impair safe shutdown. For more information on committed standards relating to containment coatings, see Section 1.4.

5.6.2.5 EVALUATION OF THE COMPATIBILITY OF CONCRETE-ECC SOLUTION IN THE POST ACCIDENT ENVIRONMENT

Concrete specimens were tested in boric acid and alkaline sodium borate solutions at conditions conservatively (320°F maximum and 200°F steady state) simulating the post DBA environment. The purpose of this study was to establish:

1. The extent of debris formation by solution attack of the concrete surfaces; and

2. The extent and rate of boron removal from the ECC solution through boron - concrete reaction.

Tests were conducted in an atmospheric pressure, reflux apparatus to simulate long-term exposure conditions and in a high-pressure autoclave facility to simulate the DBA short-term, high-temperature transient.

For these tests the total surface area of concrete in the design containment which may be exposed to the ECC solution following a DBA was estimated at 6.3 x 10^4 sq. ft. This value includes both coated and uncoated surfaces. The ECC solution volume for a reference plant was considered at approximately 313,000 gallons and the surface-to-volume ratio from these values is ~29 in^2/gal. The surface-to-volume ratios for the concrete - boron tests used were between 28 and 78 in^2/gal. of solution. Table 5.6-4 presents a summary of the data obtained from the concrete-boron test series.

Testing of uncoated concrete specimens in the post accident environment showed that attack by both boric acid and the alkaline boric acid solution is negligible and the amount of deterioration product formation is insignificant. Other specimens covered with modified phenolic and epoxy protective coatings showed no deterioration product formation. These observations are in agreement with Orchard (Reference 17) who lists the following resistances of Portland Cement concrete to attack by various compounds:

Boric Acid	- Little or No Attack
Alkali Hydroxide Solution under 10%	- Little or No Attack
Sodium Borate	- Mild Attack
Sodium Hydroxide over 10%	- Very Little Attack

Exposure of uncoated concrete to spray solution between 320°F and 210°F has shown a tendency to remove boron very slowly, presumably precipitating an insoluble calcium salt. The rate of change of boron in solution was measured at about 130 ppm per month with pH 9 solution at 210°F for an exposed surface of about 36 sq. in. per gallon of solution (much greater than any potential exposure in the containment). The boron loss during the high-temperature transient test (320°F maximum) was about 200 ppm. Table 5.6-3 shows a representation of the boron loss from the ECC solution versus time by a boron-concrete reaction following a DBA. The time period from 0-6 hours shows the loss during a conservative high temperature transient test, ambient to 320°F to 285°F. The data from 6 hours to 30 days is based on 210°F data.

A depletion of boron at this rate poses no threat to the safety of the reactor because of the large shutdown margin and the feasibility of adding more boron solution should sample analysis show a need for such action.

5.6.2.6 MISCELLANEOUS MATERIALS OF CONSTRUCTION

1. <u>Sealants</u>

Candidate sealant materials for use in the reactor containment system were evaluated in simulated DBA environments. Cured samples of various sealants were exposed in alkaline sodium borate solution, pH 10.0, 3,000 ppm to a maximum temperature of 320°F.

Table 5.6-5 presents a summary of the sealant materials tested together with a description of the panel's appearance after testing. Three generic types of sealants were tested: butyl rubber, silicone, and polyurethane. Each of the materials was the “one package” type, i.e., no mixing of components was necessary prior to application. The materials were applied on stainless steel and allowed to cure well prior to testing.

The test results showed that silicone sealants tested were chemically resistant to the DBA environment and are acceptable for use in containment.

2. PVC Protective Coating

Tests were conducted to determine the stability of the polyvinyl chloride protective coating, of the type which might be used on conduit in the DBA environment. Samples of the PVC exposed to alkaline sodium borate solutions at DBA conditions showed no loss in structural rigidity and no change in weight or appearance.

A sample of PVC-coated aluminum conduit (1" O.D. x 8 in. length) was irradiated by means of a Co-60 source, at an average dose rate of 3.2×10^6 rads/hr to a total accumulated dose of 9.1×10^7 rads. The specimen was immersed in alkaline sodium borate solution (ph 10, b = 3,000 ppm) at 70°F. Visual examination of the coating after the test showed no evidence of cracking, blistering or peeling and the specimen appeared completely unaffected by the gamma exposure. Chemical analysis of the test solution indicated that some bond breakage had occurred in the PVC coating as evidenced by an increase in the chloride concentration. The gamma exposure of $\sim 10^8$ rad resulted in a release to the solution of 26 mg of chloride per sq. ft. of exposed PVC surface. Considering a total surface area of PVC coating present in containment (~500 ft^2) and an ECC solution volume of 313,000 gal., the chloride concentration increase in the ECC solution due to irradiation of the coating would be ~0.01 ppm.

It is concluded, therefore, that PVC protective coating will be stable in the DBA environment.

3. Fan Cooler Materials

Samples of the following air handling system materials were exposed in an autoclave facility to the DBA temperature-pressure cycle:

a. Moisture separator pad
b. High efficiency particulate filter media
c. Asbestos separator pads
d. Adhesive for joining separator pads and HEPA filter media corners
e. Neoprene gasketing material.

The materials were exposed in both the steam phase and liquid phase of a solution of sodium tetraborate (15 ppm B) to simulate the concentrations expected downstream of the fan cooler cooling coils. Examination of the specimens after exposure showed the following:

a. Moisture separator pads were somewhat bleached in color but maintained their structural form and showed good resiliency as removed in both liquid and steam phase exposure.

b. High efficiency particulate filter media maintained its structural integrity in both the liquid and steam phase. No apparent change.

c. Asbestos separator pads showed some slight color bleaching, however, both steam and liquid phase samples maintained their structural integrity with no significant loss in rigidity.

d. Adhesive material for the HEPA/separator pad edges showed no deterioration or embrittlement and maintained its adhesive property.

e. Neoprene gasketing material is also satisfactory in both the steam and liquid phase. The material showed only weight gain and a shrinkage of 15% to 30% based on a superficial, one flat side area. The gasket thickness decreased about 10%. The gasket material was unrestrained during the exposure and hence the dimensional changes experienced are greater than those which would result in the fan cooler unit.

4. Power and Instrumentation Cable

Power and instrumentation cables have been subjected to the following series of tests and have shown acceptable performance.

a. Thermal aging of the cable. (The EQ program will manage thermal aging, as described in Chapter 15. NRC SE dated 12/2005, NUREG-1839)
b. Exposure to radiation ranging up to 2.0 x 10^8 rads.
c. Exposure to temperature, steam and chemical environment simulating post accident conditions.

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Table 5.6-1 MATERIALS OF CONSTRUCTION IN REACTOR CONTAINMENT

Material	Equipment Application
300 Series Stainless Steel	Reactor coolant system, residual heat removal loop, spray system, safety injection system, CRDM shroud material.
400 Series Stainless Steel	Valve materials
Inconel (600, 718)	Steam generator tubing, reactor vessel nozzles, core supports, and fuel rod grids
Galvanized Steel	Ventilation duct work, I&C conduit, miscellaneous structural steel
Aluminum	See Table 5.6-2 for a detailed listing
Copper	Miscellaneous tubing, fan cooler material
70-30 Cu Ni	Fan cooler material
90-l0 Cu Ni	Fan cooler material
Carbon Steel	Component cooling loop, structural steel, main steam piping, etc.
Polyvinyl chloride	Conduit sheathing, electrical insulation
Protective Coatings	General use on carbon steel structures and equipment, concrete
Inorganic Zincs	
Epoxy	
Modified Phenolics	
Silicones-Neoprenes	Ventilation duct work gasketing, sealants

Table 5.6-2 UNIT 1 - INVENTORY OF ALUMINUM IN CONTAINMENT

Page 1 of 2

	ITEM	IN SPRAY MASS (lbs.)	IN SPRAY SURFACE AREA (in2)	IN SUMP MASS (lbs.)	IN SUMP SURFACE AREA (in2)
a.	Fuel Manipulator Crane Equipment	9.7	446	0	0
b.	Fuel Transfer Equipment	2	500	0	0
c.	Air Motor Covers for RC-552A, -552B	18.8	800	0	0
d.	Reflectors on Polar Crane Lights	60	27150	0	0
e.	Limit Switch Cases on RH-700, SI-841A/B	36	1260	0	0
f.	Limit Switch Cases on SI-852A/B	1	30	0	0
g.	Handwheels on Personnel & Escape Hatches	8.8	340	0	0
h.	Limit Switches on RC-552A & B, SI-835A, SI-844B, CV-312, CC-761A	12.0	840	0	0
i.	Fischer I/Ps: I/P-431A & I/P-431B, SI-957	13.2	522	0	0
j.	Air Regulators on RC-430, RC-431A, B, & C, RC-552A & B, SC-955, SI-835A, SI-844B, CV-312, CC-761A, SI-957, RM-3200C	16.25	2600	0	0
k.	ILRT Electrical & Brackets (Mod 85-280)	16.48	1600	0	0
l.	Snubber Components for 19-HS-15, 20-HS-16, 26-HS-2501R-43, 33-HS-601R-73, 34-HS-601R-80	7.5	192.3	0	0
m.	Reactor Cavity Neutron Dosimetry	3.5	265	0	0
n.	ASME Pressure Vessel Code Class Tags	0.044	25	0	0
o.	RE-102 housing & alarm horn	3.06	304	0	0
q.	Knobs on compressed gas bottles	2.42	104	0	0
r.	4-way valve knobs on PT-131 and FT-614	2	83	0	0
s.	PT-1004 & TT-1058 housings	0	0	26.2	2,148
t.	Operator on SC-955	6.8	278	0	0
u.	SG Channel Head Blowers & Receptacles	60.9	2236	0	0
v.	480 VAC receptacle PR-23	5.2	159	0	0
w.	PT-493	7.8	322	0	0
x.	RCP oil sump alarm panels	0.45	29.5	0	0
	Totals for metallic aluminum	294	40,085	26	2,148

Table 5.6-2 UNIT 2 - INVENTORY OF ALUMINUM IN CONTAINMENT

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		IN SPRAY		IN SUMP	
	ITEM	MASS (lbs.)	SURFACE AREA (in2)	MASS (lbs.)	SURFACE AREA (in2)
a.	Limit Switch case & knob on RH-720	12.5	435	0	0
b.	Fuel Manipulator Crane Equipment	12.3	515	0	0
c.	Fuel Transfer Equipment	2.00	500	0	0
d.	Air Motor Covers for RC-552A, -552B	0	0	18.8	800
e.	Reflectors on Polar Crane Lights	60.0	27,200	0	0
f.	Limit Switch Cases on RH-700, SI-841A/B	36.0	1,260	0	0
g.	Limit Switch Cases on SI-852A	0.450	14.7	0	0
h.	Handwheels on Personnel & Escape Hatches	8.82	340	0	0
i.	Limit Switches on RC-431A, RC-552A & B, RC-557, SI-835A, and SI-844A & B	10.0	700	4.00	280
j.	Fischer I/Ps: I/P-431A & I/P-431B	8.80	348	0	0
k.	Air Regulators on RC-430, RC-431A, B, & C, RC-552A & B, RC-557, CV-1296, CV-313A, SC-955, SI-835A, and SI-844A & B	12.5	2,000	3.75	600
l.	ILRT Electrical & Brackets (Mod 85-280)	16.5	1,600	0	0
m.	Snubber Components for 21-2HS-27, 20-2HS-26, 12-2HS-22, 23-2HS-30, and 13-2HS-23	8.68	274	1.27	30.3
n.	Reactor Cavity Neutron Dosimetry	3.50	265	0	0
o.	ASME Pressure Vessel Code Class Tags	0.0440	25	0	0
p.	4 aluminum ferrules (cable strain reliefs)	0.01	10	0	0
q.	RE-102 housing & alarm horn	3.06	304	0	0
r.	Knobs on compressed gas bottles	2.42	104	0	0
s.	4-way valve knobs on 2FT-413	2	83.1	0	0
t.	PT-1004 & TT-1058 housings	0	0	26.2	2,148
u.	480 VAC receptacles	10.5	318	0	0
v.	120 VAC receptacle	0.54	44.2	0	0
w.	SG Channel Head Blowers & Receptacles	60.9	2,236	0	0
x.	Operator on SC-955	6.80	278	0	0
y.	RCP oil sump alarm panels	0.450	29.5	0	0
	Totals for metallic aluminum	279	38,883	54	3,858

Table 5.6-3 CORROSION OF ALUMINUM ALLOYS IN ALKALINE SODIUM BORATE SOLUTION

Data Point	Temperature °F	Alloy Type	Test Duration	Corrosion Rate mg/ dm^2/hr	pH	Exposure Condition	Reference
1	275	5053	3 hrs.	96.2	9	Solution	WCAP-7153 Table 9
2	275	5005	3 hrs.	840	9	Solution	WCAP-7153 Table 9
3	200	6061	320 hrs.	15.4	9.3	Solution	WCAP-7153 Table 8 WCAP-7153 Figure 9
4	210	5052	7 days	53.0	9	Solution	WCAP-7153 Table 7 WCAP-7153 Figure 8
5	210	5052	2 days	14.0	9	Solution	WCAP-7153 Table 5
6	210	5005	2 days	27.1	9	Solution	WCAP-7153 Table 5
7	284	5052	1 day	54	9.3	Spray	ORNL-TM-2425, Table 3.13
8	284	5052	1 day	31.5	9.3	Solution	ORNL-TM-2425, Table 3.13
9	212	6061	3 days	126	9.3	Spray	ORNL-TM-2368, Table 3.6
10	212	6061	3 days	110	9.3	Solution	ORNL-TM-2368, Table 3.6
11	150	6061	7 days	2.9	9.3	Solution	PWRD recent data
12	150	5052	7 days	4.2	9.3	Solution	PWRD recent data

Table 5.6-4 CONCRETE SPECIMEN TEST DATA

Concrete-Boron Test No.	Total Exposure Period (Days)	Surface/Volume (in^2/gal).	Exposed Weight Change (Grams)	Initial Specimen Weight (Grams)	Visual Exam
1	24	28	-22.4	560.0	No apparent change
3	28	20	+21.5	404.0	Light, yellowish, deposit on specimen
4[(a)]	72	38	0	641.2	No apparent change - coating adhesion excellent
5	72	43	-0.2	769.5	Light, hard deposit on specimen
6	~4[(b)]	54	--	601.4	No apparent change - small amount of sand particles in test can
7	175	23	+11.0	457.0	No apparent change
8[(a)]	175	38	+26.5	751.0	No apparent change - coating adhesion excellent
9[(a)]	~5[(b)]	78	+4.0	702.0	No apparent change - coating adhesion excellent

(a) These specimens coated with Phenoline 305. All others were uncoated.
(b) These tests were high temperature DBA transient conditions. All others at 195-205°F.

Table 5.6-5 EVALUATION OF SEALANT MATERIALS FOR USE IN CONTAINMENT

Sealant Type	Manufacture	Post Test Appearance
Butyl Rubber	A	Unchanged, flexible
Silicone	B	Unchanged, flexible
Silicone	B	Unchanged, flexible
Polyurethane	C	Sealant bubbled and became very soft. Solution permeated into bubbles.
Polyurethane	C	Sealant swelled and became soft, solution permeated into material.
Polyurethane	C	Sealant swelled, very soft and tacky, solution permeated into material.

Figure 5.6-1 CONTAINMENT STRUCTURE - PRESTRESS TENDON HARDWARE ASSEMBLY (Sheet 1)

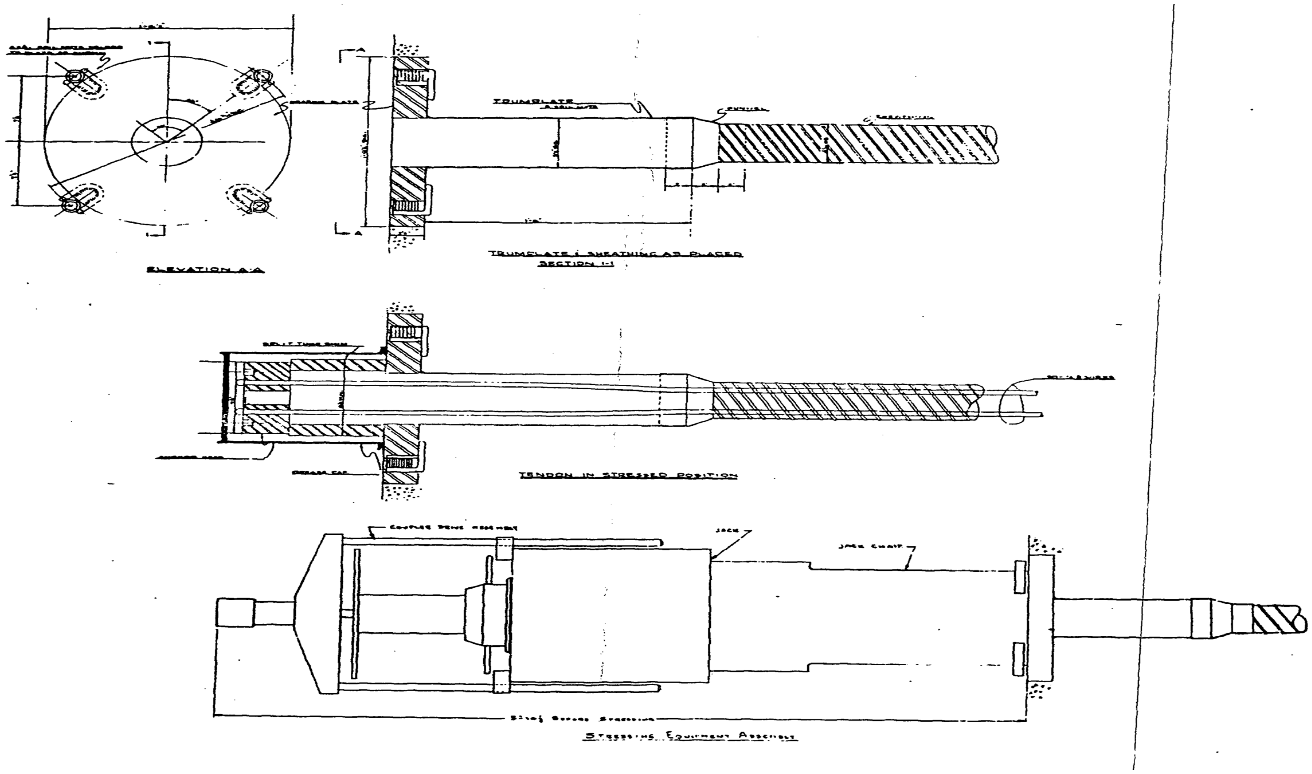


Figure 5.6-1 CONTAINMENT STRUCTURE - PRESTRESS TENDON HARDWARE ASSEMBLY (Sheet 2)

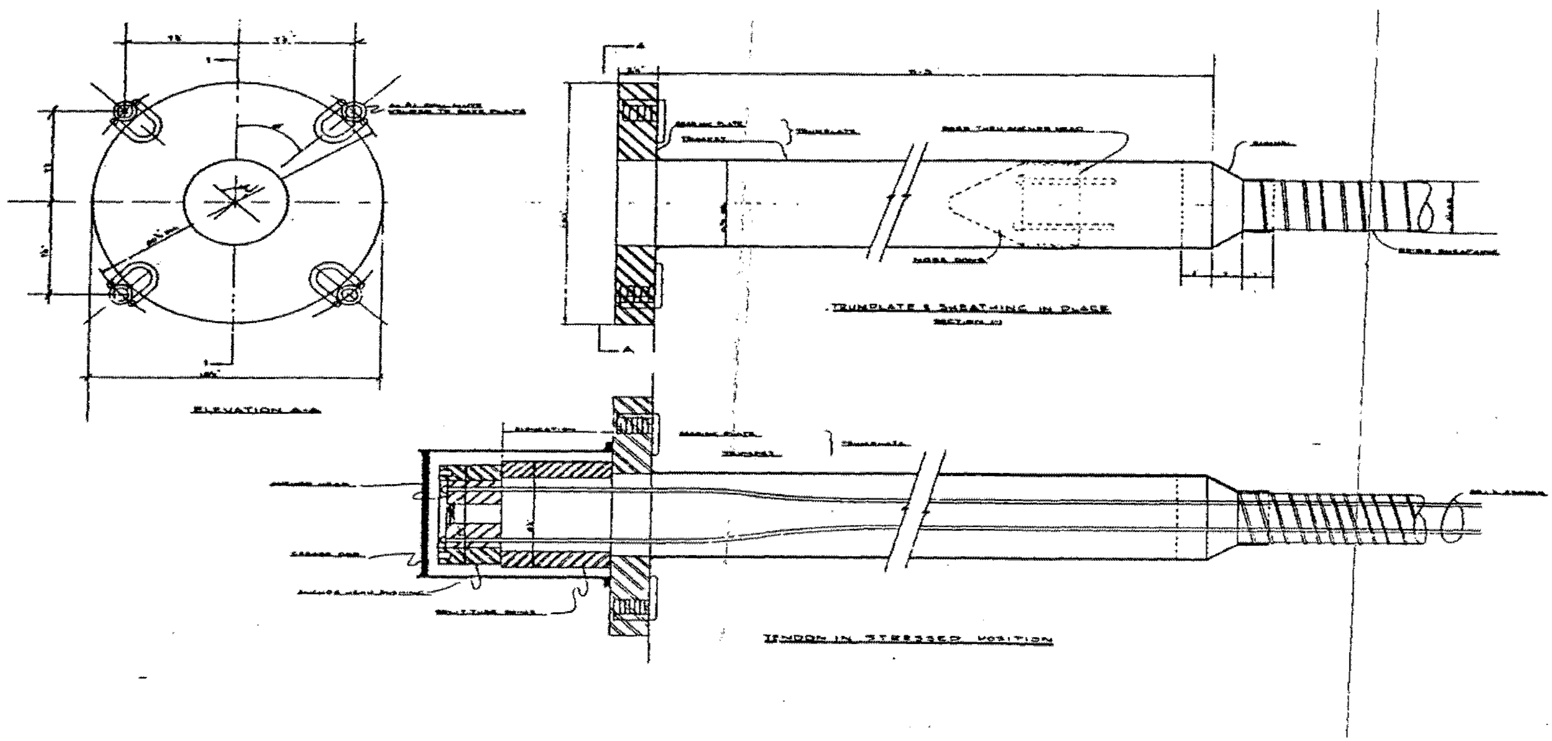


Figure 5.6-1 CONTAINMENT STRUCTURE - PRESTRESS TENDON HARDWARE ASSEMBLY (Sheet 3)

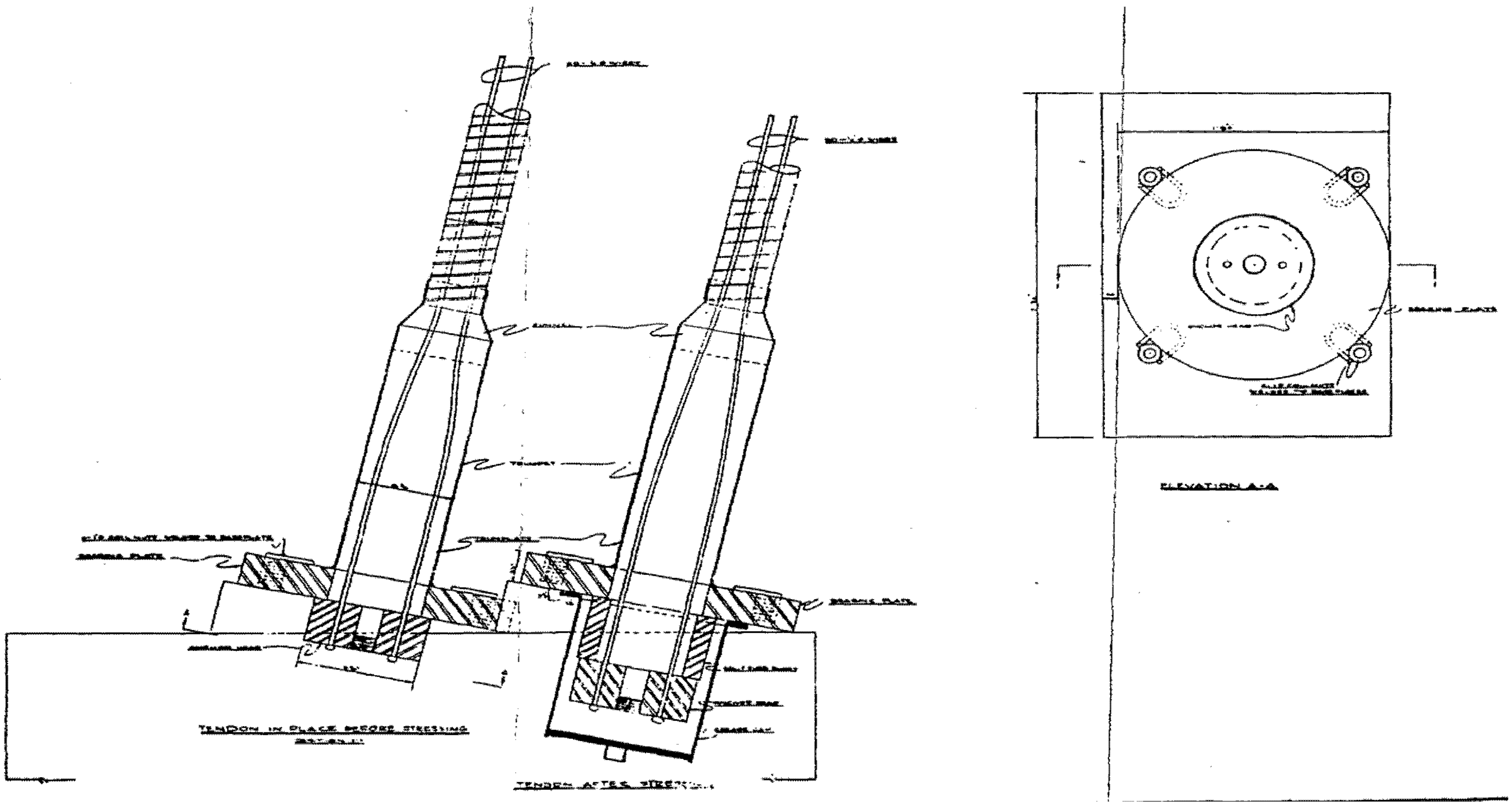


Figure 5.6-1 CONTAINMENT STRUCTURE - PRESTRESS TENDON HARDWARE ASSEMBLY (Sheet 4)

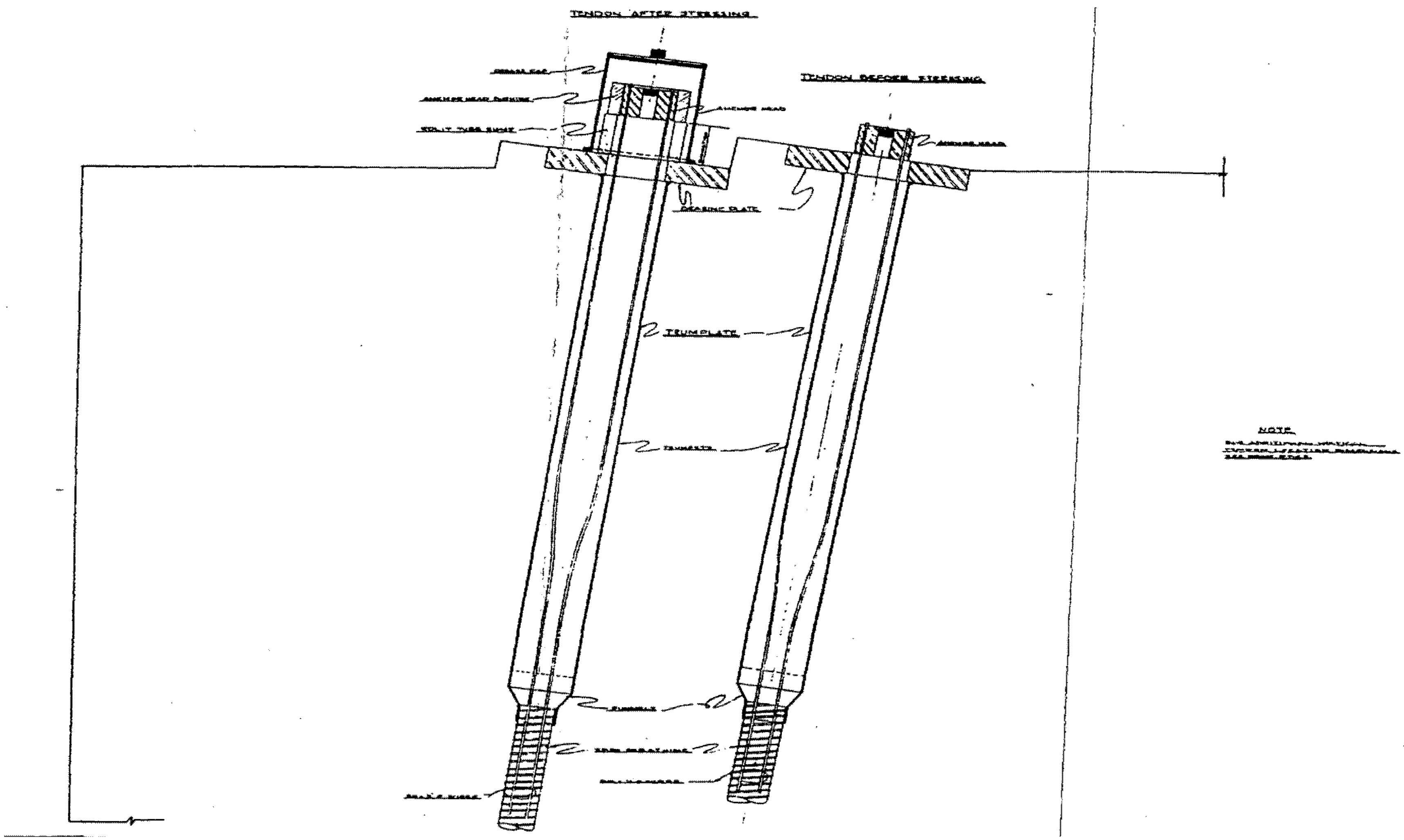


Figure 5.6-2 ALUMINUM CORROSION IN DBA ENVIRONMENT

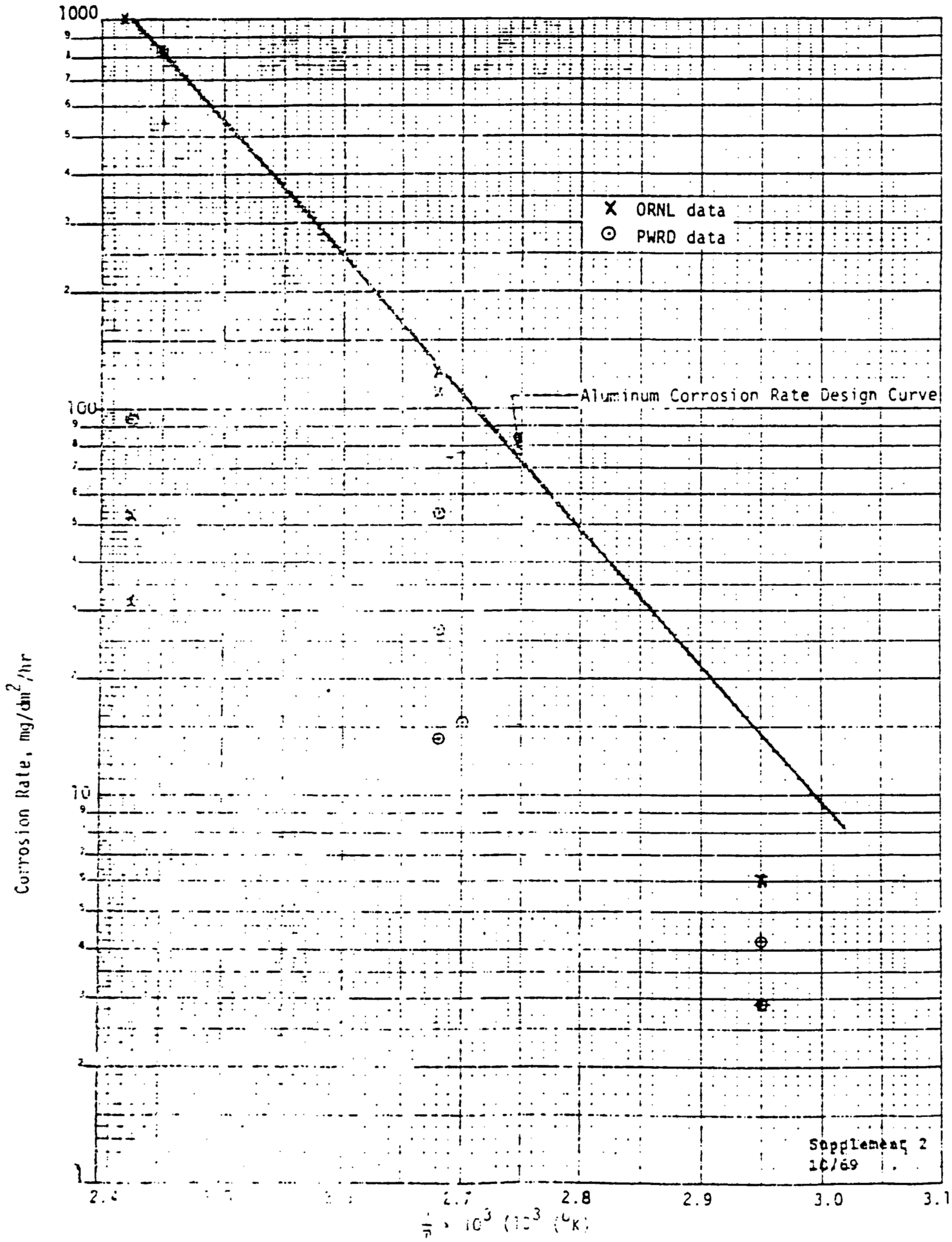


Figure 5.6-3 BORON LOSS FROM BORON - CONCRETE REACTION FOLLOWING A DBA

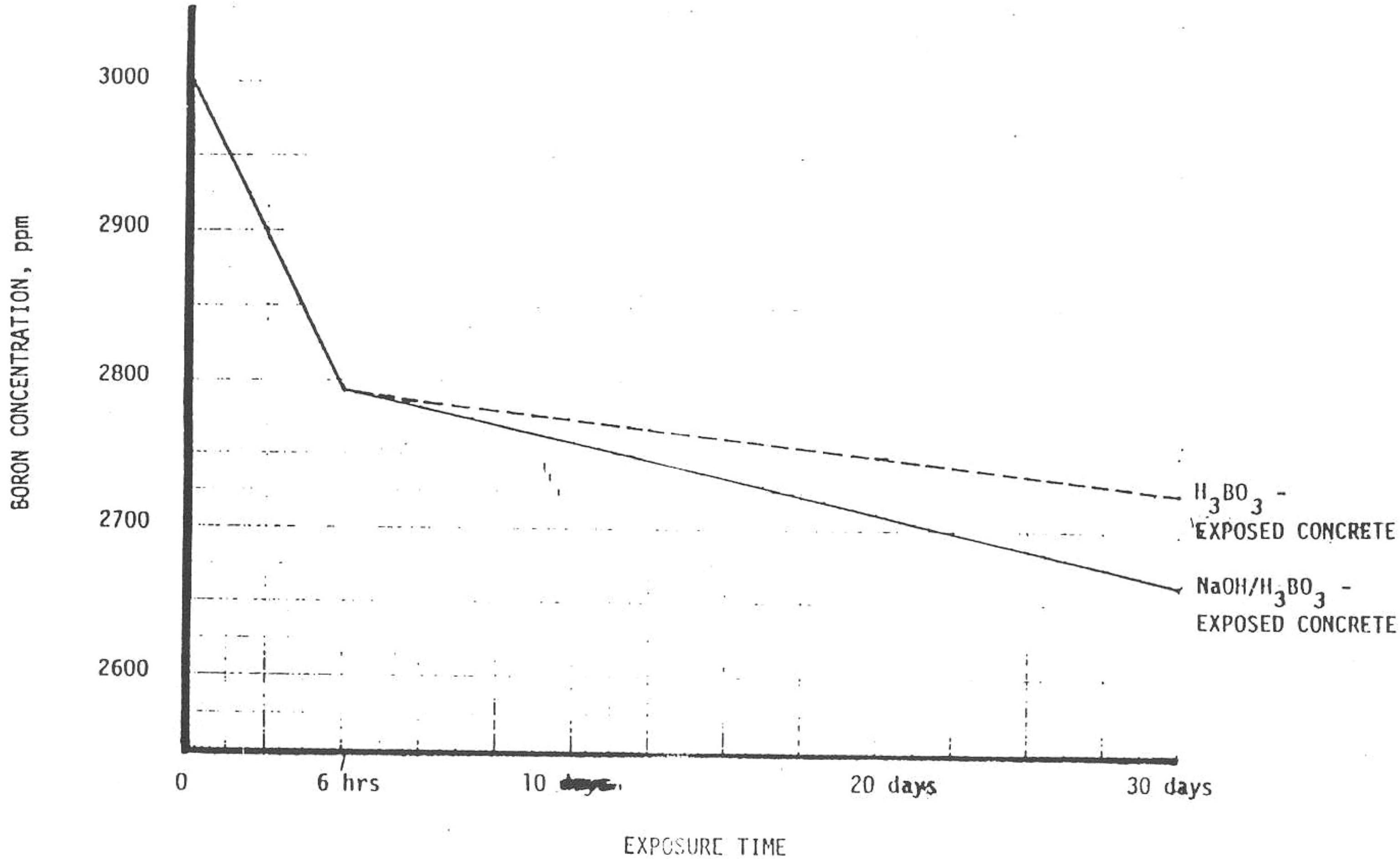
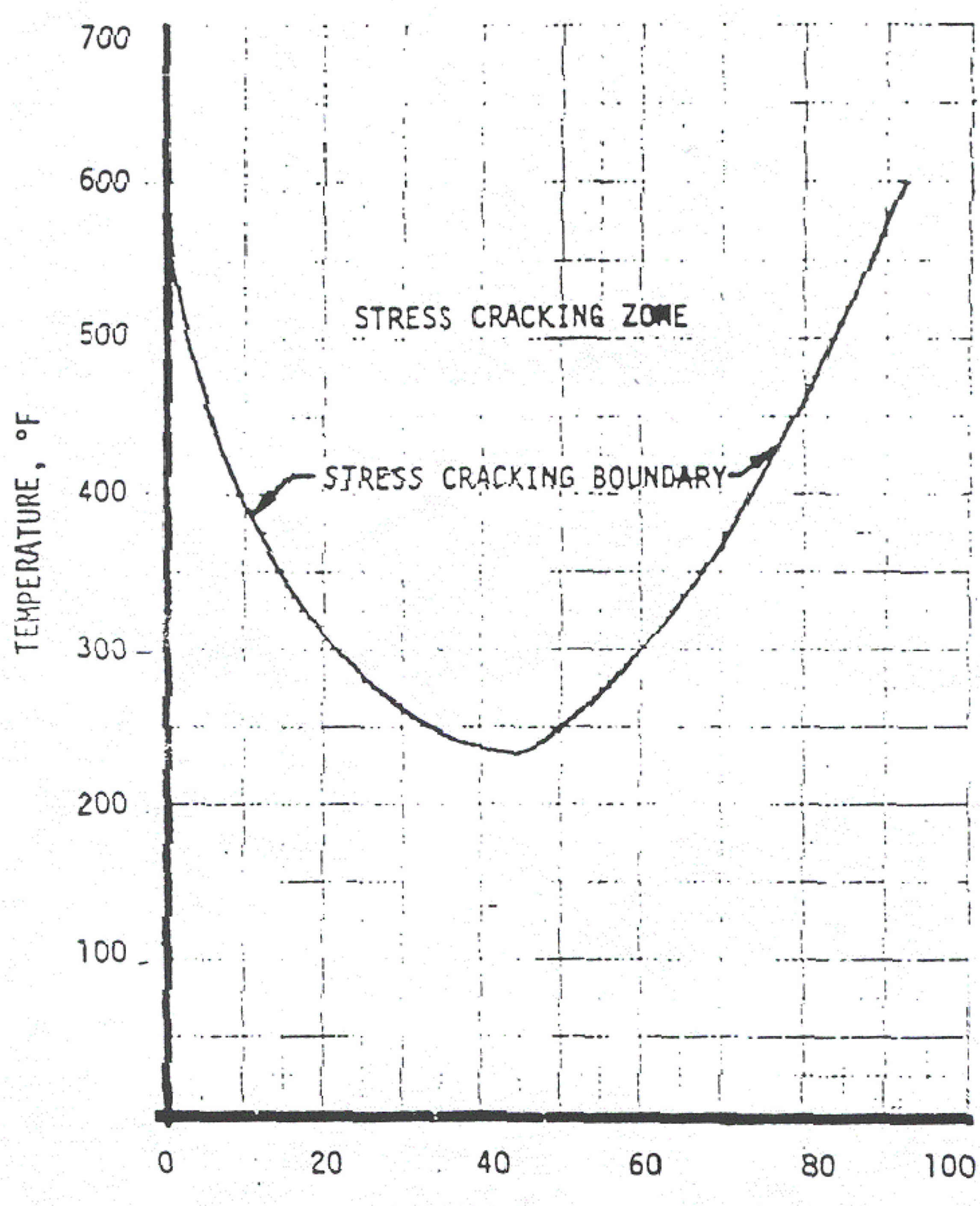


Figure 5.6-4 TEMPERATURE - CONCENTRATION RELATION FOR CAUSTIC CORROSION OF AUSTENITIC STAINLESS STEEL
(AFTER SWANDBY, R.K. CHEM. ENG. 69, 186 NOV. 12, 1962)



5.7 TESTS AND INSPECTIONS

Initial Containment Leakage Rate Testing

Criterion: Containment shall be designed so that integrated leakage rate testing can be conducted at the peak pressure calculated to result from the design basis accident after completion and installation of all penetrations and the leakage rate shall be measured over a sufficient period of time to verify its conformance with required performance. (GDC 54)

After completion of the containment structure and installation of all penetrations and weld channels, an initial integrated leakage rate test was conducted at 115% of the peak calculated accident pressure and maintained for a minimum of 24 hours, to verify that the leakage rate was within the acceptance criteria.

Periodic Containment Leakage Rate Testing

Criterion: The containment shall be designed so that an integrated leakage rate can be periodically determined by test during plant lifetime. (GDC 55)

A leak rate test is performed as per the requirements of 10 CFR Part 50, Appendix J and in accordance with Technical Specification Surveillance Requirement SR 3.6.1.1.

Provisions for Testing of Penetrations

Criterion: Provisions shall be made to the extent practical for periodically testing penetrations which have resilient seals or expansion bellows to permit leak tightness to be demonstrated at the peak pressure calculated to result from occurrence of the design basis accident. (GDC 56)

A piped connection is provided at each test point such that all penetrations with resilient seals or expansion bellows may be checked for leaktight integrity at any time throughout the operating life of the plant.

Most penetrations are designed with double seals or leak chase test channels so as to permit pressurization of the interior of the penetration or of potential leakage paths whenever a leak test is required (Reference 5). The large access openings, such as the equipment hatch and personnel air locks, are tested by pressurizing the entire hatch to test pressure. This procedure tests the door seals as well as all electrical and mechanical penetrations in the hatches.

Gross leakage from the piping or electrical penetrations is monitored by measurement of the makeup air flow. Penetrations are local leak tested separately.

Provisions for Testing of Isolation Valves

Criterion: Capability shall be provided to the extent practical for testing functional operability of valves and associated apparatus essential to the containment function for establishing that no failure has occurred and for determining that valve leakage does not exceed acceptable limits. (GDC 57)

Capability is provided to the extent practical for testing the functional operability of valves and associated apparatus during periods of reactor shutdown.

Initiation of containment isolation employs coincidence circuits which allows checking of the operability and calibration of one channel at a time. Removal or bypass of one signal channel places that circuit in the half-tripped mode.

Local leak tests of containment isolation valves are performed as required during periods of reactor shutdown.

The main steam and feedwater barriers and isolation valves in systems which connect to the reactor coolant system are hydrostatically tested to measure leakage.

Valves in the emergency core cooling systems (safety injection and residual heat removal) are not considered to be isolation valves in the usual sense inasmuch as the system would be in operation under accident conditions. The pressure boundary integrity of these closed systems outside containment is monitored by the leakage reduction and preventive maintenance program (FSAR Section 6.2.3).

5.7.1 PREOPERATIONAL TESTING

5.7.1.1 CONTAINMENT STRUCTURE INSTRUMENTATION

The purpose of instrumenting and testing a prestressed concrete containment structure is to provide a means for comparing the actual response of the structure to the loads induced during post tensioning and pressure testing with the predictions of the design calculations and known material capabilities. If the response is within the predicted ranges, the assumptions of the analyses are met; the design techniques are assumed to be verified.

The Point Beach containment structures are very similar to each other and to the Turkey Point and Palisades structures; but different in that the Point Beach containment structures are somewhat smaller and founded on piles. The Point Beach containment mat thickness is approximately equal to the maximum pile spacing, thus the design of the mat and the containment is not significantly different from the other containments cited.

The containment at Palisades and one containment at Turkey Point are extensively instrumented. At each of the containments, there are approximately 400 sensors. In addition, deformation measurements were made at about 25 locations on the structures. Testing demonstrated the validity of the design concepts and methods as well as provided a means for comparison of the differences between the predicted range of phenomena and that measured. Verification of the design concepts and methods for the containments cited provided verification for the same design concepts and methods used on Point Beach.

The tests at Palisades and Turkey Point were made to demonstrate that the design concepts and methods result in a containment that can withstand the applied loads. Since the Point Beach containment was designed with similar concepts and methods, the demonstration at Point Beach was not as extensive as that for Palisades and Turkey Point containments. There are therefore no provisions for strain gages to measure local strains for the Point Beach containment.

Prior to reactor fuel loading and operation, containment structural integrity was demonstrated by a pressure proof test. The post tensioning and the pressure test permitted verification that the structural response due to the induced loads was consistent with the predicted behavior and that of one or both of the extensively instrumented containments. The means for verification were obtained by measurements of the structure's deformation.

The measurements determined the deformations resulting from prestressing and pressure loads. Of necessity, the measurements included deformations resulting from thermal gradients caused by the unpredictable weather conditions which existed at the time of measurement.

The measurement techniques used allowed measurements of displacement to within 0.05 in. or less during post tensioning. The system for measuring the deflections employed electronic measuring devices located inside the containment. This method was capable of equal or better accuracy than the optical method initially proposed and was free of adverse effects due to the weather. These deflections, in turn, were correlated with measurements made on another containment structure for verification of consistency of structural behavior. The results of the tests are reported in Reference 1 and Reference 2.

5.7.1.2 LEAK TIGHT INTEGRITY TESTS

The objectives of these tests are:

1. To determine the initial integrated leak rate for comparison with the 0.4%/24 hr. of containment air weight at 60 psig and 286°F specified as the maximum permissible. Following License Amendments 240 and 244, the maximum permissible leak rate was changed to 0.2%/24 hr.

2. To determine the characteristic leak rate variation with pressure so as to allow retesting at pressures less than design pressure.

3. To institute a performance history summary of both local leak and integrated leak rate tests.

The guidelines established for the tests were:

1. The methods and equipment used during the initial tests were such that they could be used for subsequent retests, thus avoiding test result variations due to changes of the methods or equipment.

2. The leak test equipment is calibrated before the initial test and, if the equipment does not remain in place for subsequent retests, it is replaceable with either a similarly calibrated device or made such that it can be recalibrated in place.

3. The equipment consists of the necessary flowmeters, pressure, temperature sensors and moisture sensors.

4. The initial leak rate was measured using the Absolute Method of a period of not less than 24 hr. (unless proof has been established that the method allows measurement in a lesser time period). The integrated leakage was verified by adding to the integrated leakage (or

pumping back) a quantity of air that is measured by an independent measurement technique.

Prior to the integrated leak rate test, local leak testing is made on leak chase weld test channels, electrical penetrations, piping penetrations, across valve seats and along valve stems, and on equipment and personnel hatches where those items are a part of the containment envelope during the design basis accident. The test methods used are “soap bubble,” halogen leak detectors, pressure decay or rise, rotometers, or sonic detection, as appropriate, for the individual item being tested. The containment is pressurized to 5 psig and the local leak survey is made. The containment pressure is then increased for the pressure leak rate test.

An initial integrated leak rate test was performed at design pressure and at 50% design pressure, and is used for comparison with later containment pressure tests at 50% design pressure. The results of the initial integrated leak test are reported in Reference 3 and Reference 4.

Integrated leakage rate tests are performed as per the requirements of Appendix J to 10 CFR 50 and as specified in Technical Specification Surveillance Requirement SR 3.6.1.1.

5.7.1.3 STRUCTURAL INTEGRITY TESTS

After construction, the containment was pressurized to prove the structural integrity of the vessel. The objectives of these tests were:

1. To provide direct verification that the structural integrity as a whole is equal to or greater than necessary to sustain the forces imposed by test pressure.

2. To acquire deformation measurements for comparisons with calculated deformation.

To achieve the above objectives, the response of the structure was measured at selected pressure levels with the highest being 1.15 times the design pressure. De facto indication that the structure is capable of withstanding internal pressure results from these tests.

5.7.1.4 TEST PROCEDURES AND INSTRUCTIONS

In order that the structural and leak tight integrity tests could be carried out in the same time period, and to minimize the chances of test error, the test was specifically designed for this structure. To record and transmit the test requirements, a step-by-step test procedure was written and was complemented by data acquisition, verification, reduction and collation instructions as well as data interpretation standards.

5.7.1.5 TENDON SURVEILLANCE

Provisions are made for an in-service surveillance program, throughout the life of the plant, intended to provide sufficient in-service historical evidence to maintain confidence that the integrity of the containment structure is being preserved. This program consists of tendon surveillance supplemented by a corrosion inspection program.

To accomplish these programs, randomly selected tendons from each tendon group are inspected. The quantity selected from each tendon group is specified in accordance with ASME Section XI, Subsection IWL, as required by 10 CFR 50.55a.

The tendon surveillance program for structural integrity and corrosion protection consists of visual and physical inspections as described in the Technical Specifications. The visual inspection checks for indications of abnormal material degradation, generally without dismantling the tendon. The physical inspection is more comprehensive. It involves a visual inspection followed by: (1) a lift-off test of each surveillance tendon to measure its pre-stressing force, (2) a de-tensioning of one tendon from each group, (3) a wire removal from each de-tensioned tendon for corrosion and tensile inspections, and (4) grease inspections and tests.

The inspection of the randomly selected tendons is sufficient to indicate any tendon corrosion that could possibly appear.

The inspection intervals, measured from the date of the initial proof test, are as follows:

One year from initial testing;

Three years from initial testing; and

Every five years thereafter.

Section 15.2.2, ASME Section XI, Subsections IWE and IWL ISI Program, contains additional provisions for the period of extended operation. (NRC SE dated 12/2005, NUREG-1839)

REFERENCES

1. Report on Containment Structural Test B-SIT-4, Point Beach Nuclear Plant Unit 1, October 29, 1970.

2. Report on Containment Structural Test B-SIT-5, Point Beach Nuclear Plant Unit 2, June, 1971.

3. Initial Integrated Leak Rate Test of the Reactor Containment Building, Point Beach Nuclear Plant Unit 1, June 25, 1970.

4. Initial Integrated Leak Rate Test of the Reactor Containment Building, Point Beach Nuclear Plant Unit 2, March 12, 1971.

5. 50.59 Evaluation 2008-002, Rev. 0, "U2-2CPP28 and 2CPP34 Removal of Leak Chase Channel," approved April 17, 2008.

CHAPTER 6 TABLE OF CONTENTS

6.0 ENGINEERED SAFETY FEATURES

Independent and separate engineered safety features are provided for each unit. The description which is contained herein is applicable to either unit.

The central safety objective in reactor design and operation is control of reactor fission products. The methods used to assure this objective are:

1. Core design to preclude release of fission products from the fuel (Section 3.0).
2. Retention of fission products by the reactor coolant system boundary for whatever leakage occurs (Section 4.0 and Section 6.0).
3. Retention of fission products by the containment for operational and accidental releases beyond the reactor coolant boundary as well as detection of those releases. (Section 5.1 and Section 6.0).
4. Limit fission product release to minimize population exposure (Section 2.0 and Section 11.0).

The engineered safety features are the provisions in the plant which implement methods 2 and 3 (above) to prevent the occurrence or to minimize the effects of serious accidents.

The engineered safety features in this plant are the containment system, detailed in Section 5.1; the core safety injection system, detailed in Section 6.2; the containment air recirculation cooling system, detailed in Section 6.3; the containment spray system, detailed in Section 6.4; and the leak detection is detailed in Section 6.5.

Evaluation of techniques and equipment used to accomplish the central objective including accident cases are detailed in Section 5.0, Section 6.0 and Section 14.0.

6.1 CRITERIA

Criteria applying in common to all engineered safety features are given in Section 6.1.1. Thereafter, criteria which are related to engineered safety features, but are more specific to other plant features or systems, are listed and cross-referenced in Section 6.

Those criteria which are specific to one of the engineered safety features are discussed in the description of that system.

6.1.1 ENGINEERED SAFETY FEATURES CRITERIA

Engineered Safety Features Basis for Design

Criterion: Engineered safety features shall be provided in the facility to back up the safety provided by the core design, the reactor coolant pressure boundary, and their protection systems. Such engineered safety features shall be designed to cope with any size reactor coolant piping break up to and including the equivalent of a circumferential rupture of any pipe in that boundary, assuming unobstructed discharge from both ends. (GDC 37)

The design, fabrication, testing and inspection of the core, the reactor coolant system pressure boundary and their protection systems give assurance of safe and reliable operation under all anticipated normal, transient, and accident conditions. However, engineered safety features are provided in the facility to back up the safety provided by these components. These engineered safety features have been designed to cope with any size reactor coolant pipe break up to and including the circumferential rupture of any pipe assuming unobstructed discharge from both ends, and to cope with any steam or feedwater line break up to and including the main steam or feedwater headers.

The release of fission products from the reactor fuel is limited by the safety injection system which, by cooling the core, keeps the fuel in place and substantially intact and limits the metal-water reaction to an insignificant amount.

The safety injection system consists of high and low head centrifugal pumps driven by electric motors, and passive accumulator tanks which are self energized and which act independently of any actuation signal or power source.

The release of fission products from the containment is limited in three ways:

1. Blocking the potential leakage paths from the containment. This is accomplished by:

   a. A steel-lined, concrete reactor containment with testable liner weld channels.
   b. Isolation of process lines by the containment isolation system which imposes double barriers in each line that penetrates the containment.

2. Reducing the fission product concentration in the containment atmosphere by spraying chemically treated borated water which removes airborne elemental iodine vapor and particulates by washing action.

3. Reducing the containment pressure and thereby limiting the driving potential for fission product leakage by cooling the containment atmosphere using the following independent systems.

   a. Containment spray system
   b. Containment air recirculation cooling system

Reliability and Testability of Engineered Safety Features

Criterion: All engineered safety features shall be designed to provide such functional reliability and ready testability as is necessary to avoid undue risk to the health and safety of the public. (GDC 38)

A comprehensive program of plant testing is formulated for all equipment systems and system control vital to the functioning of engineered safety features. The program consists of performance tests of individual pieces of equipment in the manufacturer's shop, integrated tests of the system as a whole, and periodic tests of the actuation circuitry and mechanical components to assure reliable performance, upon demand, throughout the plant lifetime.

The initial tests of individual components and the integrated test of the system as a whole complement each other to assure performance of the system as designed and to prove proper operation of the actuation circuitry.

The engineered safety features components are designed to provide for routine periodic testing.

Missile Protection

Criterion: Adequate protection for those engineered safety features, the failure of which could cause an undue risk to the health and safety of the public, shall be provided against dynamic effects and missiles that might result from plant equipment failures. (GDC 40)

This plant-specific General Design Criterion is very similar to 10 CFR 50 Appendix A GDC 4. Under the provisions of that criterion, the dynamic effects associated with postulated pipe ruptures may be excluded from the design basis when appropriate analyses approved by the NRC demonstrate that the probability of such ruptures is extremely low. (Reference 2) Analyses have been completed for the Accumulator Injection Line piping, including a portion of the RHR return line piping (Reference 3). The NRC has approved the analyses (Reference 4 and Reference 5). As such, the original design features of the facility to accommodate the dynamic effects of an Accumulator Injection or RHR return line pipe rupture are no longer required. The balance of this section has been retained for historical perspective and to address how protection of engineered safety features from the dynamic effects of other high energy lines (main feedwater and main steam) is accomplished.

A loss-of-coolant accident or other plant equipment failure might result in dynamic effects or missiles. For engineered safety features which are required to ensure safety in the event of such an accident or equipment failure, protection is provided primarily by the provisions which are taken in the design to prevent the generation of missiles. In addition, protection is also provided by the layout of plant equipment or by missile barriers in certain cases. Reference is made to Section 5.1.2 for a discussion of missile protection.

Injection paths leading to unbroken reactor coolant loops are protected against damage as a result of the maximum reactor coolant pipe rupture by layout and structural design considerations. Injection lines penetrate the main missile barrier, which is the loop compartment wall, and the injection headers are located in the missile protected area between the loop compartment wall and the containment wall. Individual injection lines, connected to the injection header, pass through the barrier and then connect to the loops. Separation of the individual injection lines is provided to the maximum extent practicable. Movement of the injection line, associated with rupture of a reactor coolant loop, is accommodated by line flexibility and by the design of the pipe supports such that no damage outside the loop compartment is possible.

The containment structure is capable of withstanding the effects of missiles originating outside the containment and which might be directed toward it so that no loss-of-coolant accident can result.

All hangers, stops and anchors are designed in accordance with USAS B31.1, Code for Pressure Piping, and ACI 318, Building Code Requirements for Reinforced Concrete, which provide minimum requirements on material, design and fabrication with ample safety margin for both dead and dynamic loads over the life of the plant.

Engineered Safety Features Performance Capability

Criterion: Engineered safety features, such as the emergency core cooling system and the containment heat removal system, shall provide sufficient performance capability to accommodate the failure of any single active component without resulting in undue risk to the health and safety of the public. (GDC 41)

Engineered safety features provide sufficient performance capability to accommodate any single failure of an active component and still function in a manner to avoid undue risk to the health and safety of the public.

The extreme upper limits of public exposure are taken as the levels and time periods presently outlined in 10 CFR 50.67, i.e., a total effective dose equivalent (TEDE) dose in excess of 25 rem in any two hours at the exclusion radius and over the duration of the accident at the low population zone distance. The accident condition considered is the hypothetical case of a release of fission products per RG 1.183 concurrent with the total loss of all outside power. However, operation of the safety injection system, considering the single failure criterion, limits the release of fission products from the core to only the gap activity between the fuel pellet and clad.

Under the above accident condition, the containment air recirculation system and the containment spray system are designed and sized to supply the necessary post accident cooling capacity to rapidly reduce the containment pressure following blowdown and cooling of the core by safety injection. The spray system is designed to provide adequate removal of elemental iodine and particulates with partial system effectiveness. Partial effectiveness is defined as operation of a system with one active component failure. A separate reset and initiation switch for each train of safety injection allows direct manual initiation for all portions of the safeguards system.

<u>Engineered Safety Features Components Capability</u>

Criterion: Engineered safety features shall be designed so that the capability of these features to perform their required function is not impaired by the effects of a loss-of-coolant accident to the extent of causing undue risk to the health and safety of the public. (GDC 42)

All active components of the safety injection system (with the exception of injection line isolation valves) and the containment spray system are located outside the containment and not subject to containment accident conditions. The accumulators are located in a missile shielded area.

Instrumentation, motors, cables, penetrations, and other electrical equipment, located both inside and outside containment, are evaluated for their role in the mitigation of a design basis loss of coolant or high energy line break accident. If the equipment has an engineered safety related function and could be exposed to a potential harsh accident environment during such design basis events, it is designed and qualified to ensure the inherent capability for fulfilling the required engineered safety function throughout the equipment's installed lifetime, including the most adverse design basis environments. Current administrative procedures provide control and auditable documentation of qualification to ensure compliance with provisions and schedule requirements of applicable environmental qualification regulations.

Safety related electrical equipment purchased prior to May 23, 1980 is qualified in accordance with the provisions of the Division of Operating Reactors "Guidelines for Evaluating Environmental Qualification of 1E Electrical Equipment in Operating Reactors," (DOR Guidelines). During the purchase period of May 23, 1980 to February 21, 1983, such equipment is usually qualified in accordance with Category 1 of NUREG-0588, "Interim Staff Position on Environmental Qualification of Safety Related Electrical Equipment," which references IEEE Standard 323 1974, "Qualifying Class 1E Equipment for Nuclear Power Generating Stations." Such equipment purchased on or after February 22, 1983 is usually qualified in accordance with 10 CFR 50.49. In all cases, efforts are made to ensure compliance unless a sound reason to the contrary is demonstrated.

Each piece of electrical equipment identified as requiring environmental qualification has been evaluated for its associated design basis accident environment. Parameters typically include: temperature, pressure, chemical spray, humidity, submergence, and radiation exposure. The equipment is qualified for these parameters with appropriate margins, to ensure it will be able to fulfill its engineered safety function throughout its installed lifetime. Documentation of qualification is maintained in accordance with the provisions of 10 CFR 50.49, "Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants."

The safety injection system pipes serving each loop are anchored at the missile barrier in each loop area to restrict potential accident damage to the portion of piping beyond this point. The anchorage is designed to withstand, without failure, the thrust force of any branch line severed from the reactor coolant pipe and discharging fluid to the atmosphere. It is also desired to withstand a bending moment equal to the ultimate strength of the pipe or equivalent to that which produces failure of the piping under the action of free end discharge to atmosphere or motion of the broken reactor coolant pipe to which the emergency core cooling pipes are connected. This prevents possible failure at any point upstream from the support point, including the branch line connection, into the piping header.

Accident Aggravation Prevention

Criterion: Protection against any action of the engineered safety features which would accentuate significantly the adverse after-effects of a loss of normal cooling shall be provided. (GDC 43)

The reactor is maintained subcritical following a primary system pipe rupture accident. Introduction of borated cooling water into the core results in a net negative reactivity addition. The control rods insert and remain inserted.

The delivery of safety injection water to the reactor vessel following accidental expulsion of reactor coolant does not cause further loss of integrity of the reactor coolant system boundary.

Sharing of Systems

Criterion: Reactor facilities may share systems or components if it can be shown that such sharing will not result in undue risk to the health and safety of the public. (GDC 4)

The residual heat removal pumps and heat exchangers serve dual functions. Although the normal duty of the residual heat removal exchangers and residual heat removal pumps is performed during periods of reactor shutdown, during all plant operating periods this equipment is aligned to perform the low head safety injection function. In addition, during the recirculation phase of a loss-of-coolant accident, the capability of this system may be divided between the core cooling and the containment spray functions. Periodic demonstration testing of the system provides assurance of correct system alignment for the safety function of components.

During the injection phase, the safety injection pumps do not depend on any portion of other systems. During the recirculation phase, if reactor coolant system pressure stays high due to a small break accident, suction to the safety injection pumps is provided by the residual heat removal pumps.

During the injection phase, the containment spray pumps do not depend on any portion of other systems. During the recirculation phase of a large break LOCA, a portion of the recirculation flow from the discharge of the residual heat removal heat exchangers is provided to the suction of the containment spray pumps to support containment pressure reduction and iodine and particulate removal.

The containment air recirculation system also serves the dual function of containment cooling during normal operation and containment cooling after an accident. Since the method of operation for both cooling functions is essentially the same, the dual aspect of this system does not affect its function as an engineered safety feature.

6.1.2 RELATED CRITERIA

The following are criteria which, although related to all engineered safety features, are more specific to other plant features or systems, and therefore are discussed in other sections as listed.

Criteria	Discussion
Quality Standards (GDC 1)	Section 1.3

Performance Standards (GDC 2)	Section 4.1
Records Requirements (GDC 5)	Section 4.1
Instrumentation and Control Systems (GDC 12)	Section 7.1
Engineered Safety Features Actuation System (GDC 15)	Section 7.6
Emergency Power (GDC 39)	Section 8.1

6.1.3 GENERIC LETTER 2008-01

Generic Letter 2008-01, “Managing Gas Accumulation in Emergency Core Cooling, Decay Heat Removal, and Containment Spray Systems,” was issued to evaluate the systems to ensure gas accumulation is maintained less than the amount that challenges operability. The systems were evaluated and additional vents were installed as necessary. The Gas Accumulation Management Program (GAMP) ensures that gas accumulation within the safety injection and containment spray systems is identified, evaluated, trended and effectively controlled to prevent unacceptable degradation of performance. (Reference 6, Reference 7, Reference 8, and Reference 9)

6.1.4 REFERENCES

1. NRC Safety Evaluation, “Point Beach Nuclear Plant (PBNP), Units 1 and 2 -Issuance of License Amendments Regarding Use of Alternate Source Term (TAC Nos. ME0219 and ME0220),” dated April 14, 2011.

2. NRC letter, “Exemption from the requirements of 10 CFR 50 Appendix A, General Design Criterion 4,” dated May 6, 1986.

3. WCAP-15107-P-A, Revision 1 “Technical Justification for Eliminating Accumulator Lines Rupture as the Structural Design Basis for Point Beach Units 1 and 2 Nuclear Plants” dated June 1, 2001.

4. NRC SE “Safety Evaluation of the Request to Apply Leak-Before-Break Status to the Accumulator Line Piping at PBNP, Units 1 and 2,” dated November 7, 2000.

5. NRC SE “PBNP, Units 1 and 2 - Supplement to Safety Evaluation on Leak-Before-Break Regarding Correction of Leak Detection Capability,” dated February 7, 2005.

6. Letter NRC 2008-0075, “Nine-Month Response to NRC Generic Letter 2008-01 Managing Gas Accumulation in Emergency Core Cooling, Decay Heat Removal, and Containment Spray Systems,” dated October 14, 2008.

7. NRC letter, “Point Beach Nuclear Plant, Units 1 and 2 Closeout of Generic Letter 2008-01 Managing Gas Accumulation in Emergency Core Cooling, Decay Heat Removal and Containment Spray Systems” (TAC Nos. MD7864 and MD7865), dated January 7, 2010.

8. Letter NRC 2009-0015, “Point Beach Nuclear Plant, Unit 1, Nine-Month Supplemental (Post-Outage) Response to NRC Generic Letter 2008-01,” dated February 11, 2009.

9. NRC Safety Evaluation by the Office of Nuclear Reactor Regulation related to Amendment Nos. 251 and 255, “Managing Gas Accumulation,” dated January 27, 2015.

6.2 SAFETY INJECTION SYSTEM (SI)

6.2.1 DESIGN BASIS

Redundancy of Reactivity Control

Criterion: Two independent reactivity control systems, preferably of different principles, shall be provided. (GDC-27)

In addition to the reactivity control achieved by the rod cluster control (RCC) described in Section 3.0, and the chemical and volume control system described in Chapter 9, the safety injection system provides an alternative boration path for shutdown reactivity control.

The refueling water storage tank may be aligned to the suction of the safety injection pumps as an alternative to the CVCS system. Use of this lineup requires reactor coolant system pressure to be less than the shutoff head of the safety injection pumps.

Emergency Core Cooling System Capability

Criterion: An emergency core cooling system with the capability for accomplishing adequate emergency core cooling shall be provided. This core cooling system and the core shall be designed to prevent fuel and clad damage that would interface with the emergency core cooling function and to limit the clad metal-water reaction to acceptable amounts for all sizes of breaks in the reactor coolant piping up to the equivalent of a double-ended rupture of the largest pipe. The performance of such emergency core cooling system shall be evaluated conservatively in each area of uncertainty. (GDC 44)

Adequate emergency core cooling is provided by the safety injection system (which constitutes the emergency core cooling system) which operates in three modes. These modes are delineated as passive accumulator injection, active safety injection and residual heat removal recirculation.

The primary purpose of the safety injection system is to automatically deliver cooling water to the reactor core in the event of a loss-of-coolant accident. This limits the fuel clad temperature and thereby ensures that the core will remain intact and in place with its heat transfer geometry preserved. This protection is afforded for:

1. All pipe break sizes up to and including the hypothetical instantaneous circumferential rupture of a reactor coolant loop, assuming unobstructed discharge from both ends.

2. A loss of coolant associated with the rod ejection accident.

3. A steam generator tube rupture.

The basic design criteria for loss-of-coolant accident evaluations are: (Reference 2)

1. The calculated peak cladding temperature shall not exceed 2200°F.

2. The calculated total oxidation of the cladding shall nowhere exceed 0.17 times the total cladding thickness before oxidation.

3. The calculated total amount of hydrogen generated from the chemical reaction of the cladding with water or steam shall not exceed 0.01 times the hypothetical amount generated if all the cladding directly surrounding the fuel were to react.

4. Calculated changes in the core geometry shall be such that the core remains amenable to cooling.

5. After the initial successful operation of the ECCS, the calculated core temperature shall be maintained at an acceptable low value and decay heat shall be removed for the extended period of time required by the long-lived radioactivity remaining in the core.

For any rupture of a steam pipe and the associated uncontrolled heat removal from the core, the safety injection system adds shutdown reactivity so that with a stuck rod, no off-site power and minimum engineered safety features, there is no consequential damage to the reactor coolant system and the core remains in place and intact.

Redundancy and segregation of instrumentation and components are incorporated to assure that postulated malfunctions will not impair the ability of the system to meet the design criteria. The system is effective in the event of loss of normal plant auxiliary power coincident with the loss of coolant, and can accommodate the failure of any single component or instrument channel to respond actively in the system. During the recirculation phase of a loss-of-coolant accident, the system can accommodate a loss of any part of the flow path since backup alternative flow path capability is provided.

The ability of the safety injection system to meet its design criteria is presented in Section 6.2.3. The analysis of the accidents is presented in Section 14.0.

<u>Inspection of Emergency Core Cooling System</u>

Criterion: Design provisions shall, where practical, be made to facilitate inspection of physical parts of the emergency core cooling system, including reactor vessel internals and water injection nozzles. (GDC 45)

Design provisions are made to facilitate access to the critical parts of the reactor vessel internals, injection nozzles, pipes, valves and safety injection pumps for visual or boroscopic inspection for erosion, corrosion and vibration wear evidence, and for nondestructive inspection where such techniques are desirable and appropriate.

<u>Testing of Emergency Core Cooling System Components</u>

Criterion: Design provisions shall be made so that components of the emergency core cooling system can be tested periodically for operability and functional performance. (GDC 46)

The design provides for periodic testing of active components of the safety injection system for operability and functional performance. Power sources are arranged to permit individual actuation of each active component of the safety injection system.

The safety injection pumps can be tested periodically during plant operation using the full flow recirculation test lines provided. The residual heat removal pumps are used every time the residual heat removal system is put into operation. Remotely operated valves can be exercised and are tested in accordance with the Inservice Testing Program filed with the NRC and based on the ASME OM Code.

Testing of Emergency Core Cooling System

Criterion: Capability shall be provided to test periodically the operability of the emergency core cooling system up to a location as close to the core as is practical. (GDC 47)

An integrated system test can be performed during the late stages of plant cooldown when the residual heat removal system is in service. This test would not introduce flow into the reactor coolant system but would demonstrate the operation of the valves, pump circuit breakers, and automatic circuitry upon initiation of safety injection.

The accumulator tank pressure and level are continuously monitored during plant operation.

The safety injection piping up to the final isolation valve is maintained full of borated water and the accumulators are maintained filled at their designated levels with borated water while the plant is in operation. The source of borated water used to fill the safety injection piping and the accumulators is the refueling water storage tank. The accumulators and injection lines will be refilled with borated water as required by using the safety injection pumps to recirculate refueling water through the injection headers. A small bypass line and a return line are provided for this purpose.

Flow in each of the high head injection header lines and in the main flow line for the residual heat removal pumps is monitored by a flow indicator. Pressure instrumentation is also provided for the main flow paths of the high head and residual heat removal pumps. Level and pressure instrumentation are provided for each accumulator tank.

Testing of Operational Sequence of Emergency Core Cooling System

Criterion: Capability shall be provided to test initially, under conditions as close as practical to design, the full operational sequence that would bring the emergency core cooling system into action, including the transfer to alternate power sources. (GDC 48)

The design provides for capability to test initially, to the extent practical, the full operational sequence up to the design conditions for the safety injection system to demonstrate the state of readiness and capability of the system. Details of the operational sequence testing are presented in Section 6.2.4.

Codes and Classifications

Table 6.2-1 tabulates the codes and standards to which the safety injection system components are designed.

Service Life under Accident Conditions

All portions of the system located within the containment are designed to operate without benefit of maintenance and without loss of functional performance for the duration of time the component is required following the accident.

6.2.2 SYSTEM DESIGN AND OPERATION

System Description

Each of the Point Beach units is provided with similar, independent facilities for emergency core cooling as described in the following pages for one unit. Adequate emergency core cooling following a loss-of-coolant accident is provided by the safety injection system shown in Figure 6.2-1. The system components operate in the following possible modes:

1. Injection of borated water by the passive accumulators.

2. Injection by the safety injection pumps drawing borated water from the refueling water storage tank.

3. Injection by the residual heat removal pumps also drawing borated water from the refueling water storage tank.

4. Recirculation of spilled coolant, injected water, and containment spray system drainage back to the reactor from the containment sump by the residual heat removal pumps, or high head pumps on small break.

The initiation signal for core cooling by the safety injection pumps and the residual heat removal pumps is the safety injection signal which is actuated by any of the following:

1. Low pressurizer pressure (two out of three)

2. High containment pressure (two out of three)

3. Low steam line pressure in either loop (two out of three per loop)

4. Manual actuation.

The containment spray system is described in Section 6.4.

Injection Phase

The principal components of the safety injection system which provide emergency core cooling immediately following a loss of coolant are two accumulators (one for each loop), the two safety injection (high head) pumps and the two residual heat removal (low head) pumps.

The accumulators, which are passive components, discharge into the cold legs of the reactor coolant piping when pressure decreases to about 750 psig, thus rapidly assuring core cooling for large breaks. They are located inside the containment, but outside the shield wall; therefore, each is protected against possible missiles.

The safety injection signal opens the low head injection line isolation valves and starts the safety injection pumps and the residual heat removal pumps. The items on Figure 6.2-1 marked with an "S" receive the safety injection signal (refer also to Figure 7.3-1.) The safety injection and residual heat removal pumps take suction from the refueling water storage tank.

The residual heat removal pumps deliver through two nozzles that penetrate the reactor vessel and the core barrel. The high head safety injection pumps deliver through two separate headers into the containment. One of the headers divides into two injection lines each of which connects to an accumulator discharge pipe close to the reactor coolant cold leg piping. The second header from the pumps divides into two branch injection lines which can either join the low head injection lines to the reactor vessel safety injection nozzles or be cross-connected to the cold leg injection lines. The isolation valves in the high head injection lines are in the normally open position when the plant is in operation.

For large breaks, the reactor coolant system would be depressurized and voided of coolant rapidly (about 10 sec. for the largest break) and a high flow rate is required to quickly recover the exposed fuel rods and limit possible core damage. To achieve this objective, one residual heat removal pump (high flow, low head) is required to deliver borated water to the core. Two pumps are available for this purpose. Delivery from these pumps supplements the accumulator discharge.

In addition, the charging pumps of the chemical and volume control system are available but are not required to augment the flow of the safety injection system.

Because the injection phase of the accident is terminated before the refueling water storage tank is completely emptied, all pipes are kept filled with water before recirculation is manually initiated. Water level indication and alarms on the refueling water storage tank give the operator ample warning to terminate the injection phase. Additional level indicators are provided in the containment sump which also gives backup indication that injection can be terminated and recirculation initiated.

For small breaks, the depressurization of the reactor coolant system can be augmented by steam dump and auxiliary feedwater addition. As is demonstrated in Section 14.3.1, use of the steam dump is not required to meet the core cooling objectives. However, it is intended that for small breaks (4 in. and smaller) steam dump(s) will be employed to facilitate the recovery from the accident, and to reduce the reactor coolant pressure to the cut-in pressure of the residual heat removal pumps.

The decision to initiate steam dump(s) will be based on the rate of decrease of reactor coolant system pressure as indicated by the pressurizer pressure compared with steam generator pressure. For large breaks (6 in. and larger), the reactor pressure drops below the steam side pressure quite rapidly. Before any gap activity could be released due to clad bursting, the reactor coolant system pressure becomes less than the steam generator pressure. As discussed in Section 14.3.2, the expected clad temperatures for break sizes 4 in. and smaller are limited to a value below which clad bursting is expected. If a small tube leak existed prior to the accident, the only activity that could be released during a steam dump would be the activity initially in the coolant. The activity released in this manner would be a fraction of that released for a full tube rupture. The consequences of a steam generator tube rupture are discussed in Section 14.2.4.

Protection against containment over-pressure following a loss-of-coolant accident or a steam line break accident is provided by the containment air recirculation cooling system (Section 6.3) and the containment spray system (Section 6.4).

Recirculation Phase

After the injection phase, coolant spilled from the break and water collected from the containment spray is cooled and returned to the reactor coolant system by the residual heat removal pumps which are aligned to take suction on the containment recirculation sump. This water is pumped back to the core and/or to the suction of the containment spray pumps through the residual heat removal heat exchangers. The system is arranged to allow either or both of the residual heat removal pumps to take over the recirculation function.

The recirculation sump lines consist of two independent and redundant 10 in. lines which penetrate the containment. Each line has one remote hydraulically-operated valve located inside containment, and one remote motor-operated valve located outside containment. Each line is run independently to the suction of a residual heat removal pump. The 10 in. drain pipes pass through sleeves in the containment structure concrete. The sleeves are welded to the liner plate and to the drain pipe with all welds inspectable. The drains pass through a second set of sleeves between the tendon gallery and the auxiliary building. The system permits long-term recirculation in the event of a passive or active component failure.

Alternative flow paths are also provided from the discharge of the residual heat removal heat exchangers for both low and high head recirculation. This is evaluated in Section 6.2.3.

The design of the containment drains are shown in Figure 6.2-2 and Figure 6.2-3. As illustrated, the containment building serves as a sump that collects the spilled coolant, injected water and containment spray system drainage. This collected water is used during the recirculation phase.

During recirculation operation the collected water is filtered through a strainer assembly over each drain before leaving the containment sump. The individual cross sectional filter flow areas in each strainer assembly are no greater than a nominal 0.066 inch diameter opening. The size of the strainer openings restricts any sizable foreign matter from entering the recirculation system.

The high head recirculation flow path via the high head safety injection pumps is required for the range of small break sizes for which the reactor coolant system pressure remains in excess of the shutoff head of the residual heat removal pumps at the end of the injection phase. The high head recirculation flow path is also required following a large break LOCA to control boric acid precipitation in the reactor vessel.

Those portions of the safety injection system located outside of the containment which are designed to circulate, under post accident conditions, radioactively contaminated water collected in the containment, meet the following requirements:

1. Shielding to maintain radiation levels within the limits set forth in 10 CFR 50.67. See Section 11.6.

2. Collection of discharges from pressure relieving devices into closed systems.

3. Means to limit radioactivity leakage to the environs, within the limits set forth in 10 CFR 50.67.

Recirculation loop leakage is discussed in Section 6.2.3.

Each recirculation sump line has two remotely operated valves. The first valve (SI-850) is located adjacent to the end of the pipe in the containment floor. The second valve (SI-851) is located in the auxiliary building. Both the SI-850 and SI-851 valves perform a safety-related function to open to allow the RHR pumps to take a suction from the containment sump during the recirculation mode of Safety Injection. The SI-850 valve performs a safety-related function in the closed direction to isolate a passive failure in the containment sump recirculation line. If the passive failure were to occur post-accident a SI-850 valve could be closed in order to maintain containment Sump B inventory and to protect the RHR system and pumps from flooding. SI-851 can be isolated in the event of a downstream passive failure. This valve is also designated as the containment isolation valve for the containment penetration. The valves are designed to withstand the temperature, pressure, and radioactivity conditions occurring during a loss-of-coolant accident. The valve operators are designed for the ambient conditions of the tendon access gallery and auxiliary building. The operators are tested to verify that they can open the valves against pressures in excess of that occurring in the containment during a loss-of-coolant accident. The passive failure of one suction line (presumably excessive packing or weld leakage) will not impair the operation of the redundant valve.

During recirculation one recirculation train will be in service which includes either of the two residual heat removal pumps and its associated residual heat removal heat exchanger. The flow will go from the discharge of the residual heat removal pump through the residual heat removal heat exchanger and then into the reactor via either a low head injection path or a high head injection path via a safety injection pump.

During the recirculation phase of a large break LOCA, a portion of the recirculation flow from the discharge of a residual heat exchangers is provided to the suction of a containment spray pump to support containment pressure reduction or iodine removal.

In the event of a failure in the operating train during recirculation, the capability exists to switch to the other independent recirculation flow path.

<u>Cooling Water - Component Cooling Water System</u>

During the recirculation mode, the component cooling water system is used to cool the reactor coolant as it passes through the residual heat removal heat exchanger. The component cooling water system is also used to remove heat from the RHR, SI, and containment spray pump seal coolers to maintain the integrity of the pump seals.

One of the two component cooling water pumps and one of three component cooling water heat exchangers provide the core and containment cooling function during recirculation. A total of four component cooling water heat exchangers are provided for the two units: one per unit with two shared standby units. Refer to Section 9.1.

Service Water System

The service water system is provided with a ring header and valves such that the component cooling water heat exchangers which are supplied with service water for cooling can have flow directed to them from either side of the loop header. Three of the six service water pumps are required to operate during the recirculation phase to cool the recirculation fluid and containment atmosphere in the unit suffering the accident and provide the necessary cooling for the other unit.

Changeover from Injection Phase to Recirculation Phase

The sequence, from the time of the safety injection signal, for the changeover from the injection phase to the recirculation phase is detailed in plant procedures. A summary of this sequence is as follows:

1. First, sufficient water is delivered to the containment floor to provide the required net positive suction head (NPSH) of the residual heat removal pumps to change to recirculation.

2. When RWST level is less than 60% or a large break LOCA has been identified, initial steps are accomplished to prepare for containment sump recirculation.

3. When RWST level is less than or equal to 34%, and the containment sump contains enough water to provide sufficient net positive suction head for the RHR pumps, the RHR system is lined up to take a suction from the containment sump. This assures that adequate time is provided to changeover to the recirculation phase prior to the refueling water storage tank emptying.

The changeover from injection to recirculation is effected by the operator in the control room and the operator in the field via a series of manual operations. Core cooling flow is maintained and not interrupted during the transition. (Reference 3)

Remotely operated valves for the injection phase of the safety injection system (Figure 6.2-1) which are under manual control (i.e., valves which normally are in their ready position and do not receive a safety injection signal) have their positions indicated by lights on the ready status section of the control board. At any time during operation when one of these valves is not in the ready position for injection, it is shown visually on the board.

Boric Acid Precipitation

Due to concerns regarding possible boric acid precipitation in the core after the recirculation phase is established, there is a need to eventually establish simultaneous cold leg and upper plenum injection flow. For most Westinghouse plants, this is referred to as the hot leg injection switchover time. Since Point Beach is designed with upper plenum injection capability instead of hot leg injection, this term is not quite accurate, but is used to remain consistent with the industry. The intent of the hot leg injection switchover time requirement is to flush boron precipitate out of the core to prevent flow blockages that may inhibit post-LOCA cooling.

For breaks ≥ 5 inches in diameter the RCS will depressurize sufficiently to allow upper plenum injection flow from the low head pumps. The high and low head injection flows during the injection phase of the event are sufficient to prevent boric acid precipitation. Cold leg injection flow from the high head pumps is secured prior to the transfer to sump recirculation, but must be reinitiated prior to the occurrence of boric acid precipitation in the reactor vessel. Boric acid precipitation is not expected to occur before 4 hours and 30 minutes after the high head pumps are secured to establish sump recirculation. Alignment for high head recirculation to the cold legs can be accomplished within 10 minutes. Additional margin has been applied to the switchover time resulting in a requirement to initiate the alignment within 3 hours and 20 minutes after the start of the LOCA event such that high head recirculation is established within 3 hours and 30 minutes. (Reference 3 and Reference 5)

For breaks between approximately 1.2 inches and 5 inches in diameter the RCS must be depressurized to enable low head upper plenum injection before the precipitation limit is reached. This is accomplished by opening one or both main steam atmospheric dump valves no later than 1 hour into the event. This will reduce the RCS pressure enough to allow low head injection within 5 to 6 hours after opening the dump valve(s). (Reference 3)

For breaks between 1.2 inches to 0.9 inches in diameter, single phase natural circulation is lost, but regained before the precipitation limit is reached. For breaks less than 0.9 inches in diameter, natural circulation is not lost. (Reference 3)

In the event of a LOCA, injection of high concentration boric acid from the boric acid storage tanks (BAST) is secured to preclude the potential for early precipitation in the reactor vessel. Limitations on RCS cooldown rate also serve to keep boric acid in solution during a small break LOCA. (Reference 3)

Location of the Major Components Required for Recirculation

[redacted]

The service water pumps are located in the pumphouse and the redundant piping to the component cooling water heat exchangers is run underground through the Class I portion of the turbine building.

Components

All associated components, piping, structures, and power supplies of the safety injection system are designed to Class I seismic criteria.

All components inside the containment are capable of withstanding or are protected from differential pressure changes which may occur during the rapid pressure rise to 60 psig in 10 sec.

Motors which operate only during or after the postulated accident are designed as if used in continuous service. Periodic operation of the motors and the tests of the pump motors insulation will ensure that the motors remain in a reliable operating condition.

All motors, instruments, transmitters, and their associated cables located inside the containment which are required to operate following the accident are designed to function under the post accident temperature, pressure, and humidity conditions.

Emergency core cooling components in contact with borated water or spray solution are austenitic stainless steel or equivalent corrosion resistant material and hence are compatible with the spray solution over the full range of exposure in the post accident regime. While stainless steel is subject to crevice corrosions by hot, concentrated caustic solution, the NaOH additive cannot enter the containment or emergency core cooling systems without first being diluted and partially neutralized with boric acid to a mild solution. Corrosion tests performed with simulated spray showed negligible attack, both generally and locally, in stressed and unstressed stainless steel at containment and ECCS conditions. These tests are discussed in WCAP-7153 (Reference 1).

The inspections and tests of the safety injection system components described in Section 6.2.4.

Accumulators

The accumulators are pressure vessels maintained filled at their designated levels with borated water and pressurized with nitrogen gas. During normal plant operation, each accumulator is isolated from the reactor coolant system by two check valves in series.

Should the reactor coolant system pressure fall below the accumulator pressure, the check valves open and borated water is forced into the reactor coolant system. Mechanical operation of the swing-disc check valves is the only action required to open the injection path from the accumulators to the core via the cold leg.

The accumulators are passive engineered safety features because the nitrogen gas forces injection; no external source of power or signal transmission is needed to obtain fast-acting, high flow capability when the need arises. One accumulator is attached to each of the cold legs of the reactor coolant system.

The design capacity of the accumulators is based on the assumption that flow from one of the accumulators spills onto the containment floor through the ruptured loop, and the flow from the remaining accumulator provides sufficient water to fill the volume outside of the core barrel below the nozzles, the bottom plenum, and one-half the core. The accumulators are carbon steel, clad with stainless steel and designed to ASME Section III, Class C. Connections for remotely draining or filling the fluid space during normal plant operation are provided.

The level of borated water in each accumulator tank is adjusted remotely as required during normal plant operations. Borated water is added from the refueling water storage tank using a high head safety injection pump. Water level is reduced by draining to the reactor coolant drain tank. Local samples of the solution in the tanks are taken for periodic checks of boron concentration.

Redundant level and pressure indicators are provided with read-outs on the control board. Each indicator is equipped with high and low level alarms.

The accumulator design parameters are given in Table 6.2-3.

Refueling Water Storage Tank

In addition to its normal duty to supply borated water to the refueling cavity for refueling operations, this stainless steel tank provides borated water to the safety injection pumps, the residual heat removal pumps and the containment spray pumps for either a loss-of-coolant accident or a steam line break accident. During plant operation it is aligned to the suction of the above pumps. It may also be aligned to the suction of the safety injection pumps to provide an alternative boration path for shutdown reactivity control.

The capacity of the refueling water storage tank is based on the requirement for filling the refueling cavity during refueling operations. This requirement is greater than the capacity required for emergency core cooling in the event of either a LOCA or steam line break accident. The minimum volume of borated water maintained in the RWST (see Table 6.2-4) assures:

1. A volume sufficient to refill the reactor vessel above the nozzles;

2. The volume of borated refueling water needed to increase the concentration of initially spilled water to a point that assures no return to criticality with the reactor at cold shutdown and all full-length control rods, except the highest worth RCC assembly, inserted into the core; and

3. A sufficient volume of water within containment to permit the initiation of recirculation.

The water in the tank is borated to a concentration which assures reactor shutdown by at least 5% $\Delta k/k$ when all RCC assemblies are inserted and when the reactor is cooled down for refueling. The maximum boric acid concentration is approximately 1.8 weight percent boric acid. At 32°F, the solubility limit of boric acid is 2.2%. Therefore, the concentration of boric acid in the refueling water storage tank is well below the solubility limit of 32°F. The tank contents are heated and the piping is heat traced to prevent freezing of the water during cold weather. The tank is protected from wind chill by the containment facade.

Tank temperatures along with high and low temperature alarm lights and immersion heater control, are provided locally in the facade near the tank.

Two level indications with low level alert, low-level and low-low level alarms are provided.

A dynamic response analysis has been performed to determine the horizontal loads to be applied to this tank for the hypothetical safe shutdown earthquake. Vertical seismic loads have been applied simultaneously. Wave generation in the tank has been taken into account. A membrane stress analysis of the vertical cylindrical tank was performed considering the discontinuities at the base and top.

The design parameters are given in Table 6.2-4.

Safety Injection Pumps

The two high head safety injection pumps for supplying borated water to the reactor coolant system are horizontal centrifugal pumps driven by electric motors. Parts of the pump in contact with borated water are stainless steel or equivalent corrosion resistant material. A minimum flow bypass line is provided on each pump discharge to recirculate flow to the refueling water storage tank in the event the pumps are started under low flow or shutoff head conditions. The minimum flow line must be available for the Safety Injection pumps to be considered operable because some accidents and transients for which Safety Injection is required do not result in sufficient injection flow to provide adequate pump cooling. The nominal design parameters of these pumps are presented in Table 6.2-5 and Figure 6.2-4. The nominal pump curve is degraded when HHSI flow is credited in accident analyses (Reference 7).

Residual Heat Removal Pumps

The two residual heat removal (low head) pumps are used to inject borated water at low pressure to the reactor coolant system. They are also used to recirculate fluid from the containment floor and send it back to the reactor, to the suction of the spray pumps or to the suction of the high head safety injection pumps. These pumps are of the horizontal centrifugal type, driven by electric motors. Parts of the pumps which contact the borated water and sodium hydroxide solution during recirculation are stainless steel or equivalent corrosion resistant material. A minimum flow bypass line is provided on the discharge of the residual heat removal heat exchangers to recirculate cooled fluid to the suction of the residual heat removal pumps should these pumps be started with their normal flow blocked. The nominal design parameters of these pumps are presented in Table 6.2-5 and in Figure 6.2-5. The nominal pump curve is degraded when LHSI flow is credited in accident analyses (Reference 7).

The pressure containing parts of the pumps are castings conforming to ASTM A-351, Grade CF8 or CF8M. Stainless steel forgings are procured per ASTM A-182 Grade F304 or F316 or ASTM A336, Class F8 or F8M, and stainless plate conforms to ASTM A-240, Type 304 or 316. All bolting material conforms to ASTM A-193. Materials such as weld-deposited Stellite or Colmonoy are used at points of close running clearances in the pumps to prevent galling and to assure continued performance ability in high velocity areas subject to erosion.

All pressure containing parts of the pumps are chemically and physically analyzed and the results are checked to ensure conformance with the applicable ASTM specification. In addition, all pressure containing parts of the pump are liquid penetrant inspected in accordance with Appendix VIII of Section VIII of the ASME Boiler and Pressure Vessel Code. The acceptance standard for the liquid penetrant test is USAS B31.1, Code for Pressure Piping, Case N-10.

The pump design is reviewed with special attention to the reliability and maintenance aspects of the working components. Specific areas include evaluation of the shaft seal and bearing design to determine that adequate allowances have been made for shaft deflection and clearances between stationary parts.

Where welding of pressure containing parts is necessary, a welding procedure, including joint detail, is submitted for review and approval by Westinghouse Electric Corporation. The procedure is qualified in accordance with Section IX of the ASME Boiler and Pressure Vessel Code. This requirement also applies to any repair welding performed on pressure containing parts. The pressure-containing parts of the pump are assembled and hydrostatically tested to 1.5 times the design pressure for 30 minutes.

Each pump is given a complete shop performance test in accordance with Hydraulic Institute Standards. The pumps are run at design flow and head, shutoff head and three additional points to verify performance characteristics. Where NPSH is critical, this value is established at design flow by means of adjusting suction pressure during the shop test.

Details of the component cooling and service water pumps which serve the safety injection system are presented in Section 9.0.

Heat Exchangers

The two residual heat removal heat exchangers cool the recirculated sump water. These heat exchangers are sized for the normal cooldown of the reactor coolant system. Table 6.2-6 gives the design parameters of the heat exchangers.

The ASME Boiler and Pressure Vessel Code has strict rules regarding the wall thickness of all pressure containing parts, material specifications, weld joint design, radiographic and liquid penetrant examination of materials and joints, and hydrostatic testing of the unit as well as requiring final inspection and stamping of the vessel by as ASME Code inspector.

The designs of the heat exchangers also conform to the requirements of TEMA (Tubular Exchanger Manufacturers Association) for Class R heat exchangers. Class R heat exchangers are subject to the most rigid TEMA requirements and are intended for units where safety and durability are required under severe service conditions. Items such as: tube spacing, flange design, nozzle location, baffle thickness and spacing, and impingement plate requirements are set forth by TEMA standards.

In addition to the above, additional design and inspection requirements were imposed to ensure rugged, high quality heat exchangers such as: confined-type gaskets, main flange studs with two nuts on each end to ensure permanent leaktightness, general construction and mounting brackets suitable for the plant seismic design requirements, tubes and tubesheet capable of withstanding full shell side pressure and temperature with atmospheric pressure on the tube side, ultrasonic inspection in accordance with Paragraph N-324.3 of Section III of the ASME Code of all tubes before bending, penetrant inspection in accordance with Paragraph N-627 of Section III of the ASME Code of all welds and all hot or cold formed parts, a hydrostatic test duration of not less than thirty minutes, the witnessing of hydro and penetrant tests by a qualified inspector, a thorough final inspection of the unit for good workmanship and the absence of any gouge marks or other scars that could act as stress concentration points, a review of the radiographs and of the certified chemical and physical test reports for all materials used in the unit.

The residual heat removal heat exchangers are conventional vertical shell and U-tube type units. The tubes are seal welded to the tubesheet. The shell connections are flanged to facilitate shell removal for inspection and cleaning of the tube bundle. Each unit has a SA-285 Grade C carbon steel shell, SA-234 carbon steel shell end cap, SA-213 TP-304 stainless steel tubes, SA-240 Type 304 stainless steel channel, SA-240 Type 240 stainless steel channel cover and SA-240 Type 304 stainless steel tubesheet.

Valves

All parts of valves used in the safety injection system in contact with borated water are austenitic stainless steel or equivalent corrosion resistant material. The motor operators on the injection line isolation valves are capable of rapid operation. All valves required for initiation of safety injection or isolation of the system have remote position indication in the control room.

Valving is specified for exceptional tightness and, where possible, such as for instrument valves, packless diaphragm valves are used. All valves, except those which perform a control function, are provided with backseats which are capable of limiting leakage to less than 1.0 cc per hour per inch of stem diameter, assuming no credit taken for valve packing. This design feature provides a means to minimize leakage in the event the packing fails or leaks excessively. Backseats are not normally relied upon as the primary leakage barrier. Normally closed globe valves are installed with recirculation flow under the seat to prevent leakage of recirculated water through the valve stem packing. Relief valves are totally enclosed. Control and motor-operated valves with a diameter of 2½" or greater which are exposed to recirculation flow of the residual heat removal system have sufficient packing to minimize leakage to the atmosphere.

The check valves which isolate the safety injection system from the reactor coolant system are installed near the reactor coolant piping to reduce the probability of an injection line rupture causing a loss-of-coolant accident. The high head safety injection piping is protected by a relief valve inside the containment in the test line. The relieving capacity of this valve is based on a flow several times greater than the expected leakage rate through the check and isolation valves and will also prevent overpressurization due to thermal expansion. The valve relieves to the pressure relief tank. The residual heat removal loop is protected by a relief valve in the common header leading to the reactor vessel. A second pressure relief valve is located in the residual heat removal suction piping to provide reactor coolant system overpressurization protection when operating in the cold shutdown condition. The valves are located inside the containment and relieve to the pressurizer relief tank. An additional relief valve in the residual heat removal suction piping relieves to containment sump. The gas relief valves on the accumulators protect them from pressures in excess of the design value.

Motor Operated Valves

The pressure containing parts (body, bonnet, and discs) of the motor operated valves employed in the safety injection system are designed per criteria established by the USAS B16.5 or MSS SP-66 specifications. ANSI B16.34 has replaced the criteria of USAS B16.5 for the design of flanged and welded valves. The pressure containing parts of valves manufactured since approval of B16.34 shall meet the criteria of ANSI B16.34. The body and bonnet materials for these valves are procured per ASTM A-182, F316 or A351, Gr CF 8M, or equivalent specification, except that valves of 150 lb ASA B16.5 rating may conform to A-182, F304, A351 Gr CF8 or equivalent specification. All material in contact with the primary fluid except the packing, is austenitic stainless steel or equivalent corrosion resisting material. For cast carbon steel valves greater than class 150 lb and stainless steel valves in service conditions in excess of 200 psig and 200 ^{o}F, the pressure-containing cast components are radiographically inspected as outlined in ASTM E-71, Class 1 or Class 2, E446 or equivalent. The body, bonnet, and discs are liquid penetrant inspected in accordance with ASME Boiler and Pressure Vessel Code Section VIII, Appendix VIII. The liquid penetrant acceptable standard is as outlined in USAS B31.1, Case N-10.

When a gasket is employed, the body-to-bonnet joint is designed per ASME Boiler and Pressure Vessel Code Section VIII or USAS B16.5/ANSI B16.34 with a fully trapped, controlled compression, spiral wound gasket with provisions for seal welding, or of the pressure seal design with provisions for seal welding. The body-to-bonnet bolting and nut materials are procured per ASTM A 193 and A-194, respectively.

The entire assembled unit is hydrotested as outlined in MSS SP-61 with the exception that the test is maintained for a minimum period of 30 minutes. Any leakage is cause for rejection. The seating design is of the Darling parallel disc design, the Crane flexible wedge design, or the equivalent. These designs have the feature of releasing the mechanical holding force during the first increment of travel. Thus, the motor operator has to work only against the frictional component of the hydraulic unbalance on the disc and the packing box friction. The discs are guided throughout the full disc travel to prevent chattering and provide ease of gate movement. The seating surfaces are hard faced (Stellite No. 6 or equivalent) to prevent galling and reduce wear.

The stem material is ASTM A-276, Type 316, condition B, Haynes Alloy No. 25 precipitation hardened 17-4 PH stainless steel or an equivalent material. These materials are selected because of their corrosion resistance, high tensile properties, and their resistance to surface scoring by the packing. Motor-operated valves are provided with sufficient packing to minimize leakage to the atmosphere.

The motor operator is extremely rugged and is noted throughout the power industry for its reliability. The unit incorporates a “hammer blow” feature that allows the motor to impact the discs away from the fore or backseat upon opening or closing. This "hammer blow" feature not only impacts the disc but allows the motor to attain its operational speed. Each valve is assembled, hydrostatically tested, seat-leakage tested (fore and back), operationally tested, cleaned and packaged per specifications. All manufacturing procedures employed by the valve supplier during initial construction, such as hard facing, welding, repair welding and testing, were submitted to Westinghouse for approval. Subsequent manufacturing procedures rely on vendor quality assurance programs and procurement specifications for authorization.

For those valves (SI-852A, B) which are required to open automatically on the safety injection signal, “fast operators” are provided to satisfy their functions during the ECCS injection phase. The stroke time performance requirement for SI-852A, B is 21.7 seconds and is based on the large break LOCA evaluation documented in Section 14.3.2. The IST program stroke time acceptance criteria for these valves are conservative with respect to the stroke time performance requirement. For all other valves in the system, the valve operator stroke time acceptance criteria are established to ensure that the valves are capable of performing their design functions.

Valves which must function against system pressure are designed such that they function with a pressure drop equal to full system pressure across the valve disc.

Manual Valves

The stainless steel manual globe, gate and check valves are designed and built in accordance with the following requirements.

The pressure containing parts (body, bonnet, and discs) are designed per criteria established by the USAS B16.5 specification. ANSI B16.34 has replaced the criteria of USAS B16.5 for the design of flanged and welded valves. The pressure containing parts of valves manufactured since approval of B16.34 shall meet the criteria of ANSI B16.34. The body and bonnet materials for these valves are procured per ASTM A-182, F316 or A351, Gr CF 8M, or equivalent specification, except that valves of 150 lb ASA B16.5 rating may conform to A-182 F304, A351 Gr CF8 or equivalent specification. All material in contact with the primary fluid except the packing, is austenitic stainless steel or equivalent corrosion resisting material. The pressure-containing cast components of all gate valves and all other valves greater than 2 inch in size are radiographically inspected as outlined in ASTM E-71, E 446, E-186 or E 280, whichever is applicable or equivalent standard. The acceptance standard shall meet the requirement of severity level 2 except that D, E, F and G defects are not permissible. Radiographic inspection of reducer-to-body welds or stub-to-body welds (when employed) shall be per ASME Section VIII, UW-51 or equivalent. The acceptance standard shall be as outlined in UW-51 or equivalent. The body, bonnet, and discs are liquid penetrant inspected in accordance with ASME Boiler and Pressure Vessel Code Section III, Appendix IX. The liquid penetrant acceptable standard is as outlined in ASME Section III, USAS B31.1, Case N-10 or an equivalent standard.

When a gasket is employed, the body-to-bonnet joint is designed per ASME Boiler and Pressure Vessel Code Section VIII or USAS B16.5/ANSI B16.34 with a fully trapped, controlled compression, spiral wound gasket with provisions for seal welding, or of the pressure seal design with provisions for seal welding. A bonnetless design or a threaded connection body-to-bonnet joint with a welded canopy seal is an acceptable design. Valves smaller than 3/4 inch may have a threaded or union joint. Alternate body-to-bonnet joints that provide equivalent leak-tightness may be used as approved by the design change process. The body-to-bonnet bolting and nut materials are procured per ASTM A 193 and A-194, respectively.

The entire assembled unit is hydrotested as outlined in MSS SP-61 with the exception that the test is maintained for a minimum period of 30 minutes for gate valves and other manual valves greater than 2" in size, and a minimum period of five minutes for non-gate manual valves less than or equal to 2" in size. Any leakage is cause for rejection. The seating surfaces are hard faced (Stellite No. 6 or equivalent) to prevent galling and reduce wear.

The stem material is ASTM A-276, Type 316, condition B, Haynes Alloy No. 25 precipitation hardened 17-4 PH stainless steel or an equivalent material. These materials are selected because of their corrosion resistance, high tensile properties, and their resistance to surface scoring by the packing.

The carbon steel manual globe, gate and check valves are designed and built in accordance with the following requirements.

The carbon steel valves are built to conform with USAS B16.5. The materials of construction of the body and bonnet conform to the requirements of ASTM A105, Grade II, or A216, Grade WCB or WCC, or equivalent material specification. The carbon steel valves pass only nonradioactive fluids and are subjected to hydrostatic tests as outlined in MSS SP-61, except that the test pressure is maintained for minimum period of 30 minutes for gate valves and other manual valves greater than 2" in size, and a minimum period of five minutes for non-gate manual valves less than or equal to 2" in size.

When a gasket is employed, the body-to-bonnet joint is designed per ASME Boiler and Pressure Vessel Code Section VIII or USAS B16.5/ANSI B16.34 with a fully trapped, controlled compression, spiral wound gasket with provisions for seal welding, or of the pressure seal design with provisions for seal welding. A bonnetless design or a threaded connection body-to-bonnet joint with a welded canopy seal is an acceptable design. Valves smaller than 3/4 inch may have a threaded or union joint. Alternate body-to-bonnet joints that provide equivalent leak-tightness may be used as approved by the design change process. The body-to-bonnet bolting and nut materials are procured per ASTM A193 and A-194, respectively.

Accumulator Check Valves

The pressure-containing parts of this valve assembly are designed in accordance with MSS SP-66. All parts in contact with the operating fluid are of austenitic stainless steel or of equivalent corrosion resistant materials procured to applicable ASTM or WAPD specifications. The cast pressure-containing parts are radiographed in accordance with ASTM E-94 and the acceptance standard as outlined in ASTM E-71. The cast pressure-containing parts, machined surfaces, finished hard facings, and gasket bearing surfaces are liquid penetrant inspected per ASME B&PV Code, Section VIII, and the acceptance standard is as outlined in USAS B31.1 Code Case N-10. The final valve is hydrotested per MSS SP-66 except that the test pressure is maintained for at least 30 minutes. The seat leakage is conducted in accordance with the manner prescribed in MSS SP-61 except that the acceptable leakage is 2 cc/hr/in nominal pipe diameter.

The valve is designed with a low pressure drop configuration with all operating parts contained within the body, which eliminates those problems associated with packing glands exposed to boric acid. The clapper arm shaft is manufactured from 17-4 PH stainless steel heat treated to Westinghouse specifications. The clapper arm shaft bushings are manufactured from stellite No. 6 material. The various working parts are selected for their corrosion resistant, tensile, and bearing properties. The disc and seat rings are forged. The mating surfaces are hard faced with stellite No. 6 to improve the valve seating life. The disc is permitted to rotate, providing a new seating surface after each valve opening.

The valves are intended to be operated in the closed position with a normal differential pressure across the disc of approximately 1,500 psi. The valves shall remain in this position except for testing and safety injection. Since the valves will not be required to normally operate in the open condition and hence be subjected to impact loads caused by sudden flow reversal, it is expected that these valves will perform their required functions without difficulty.

When the valve is required to operate, a differential pressure of less than 25 psig will shear any particles that may otherwise prevent the valve from functioning. Although the working parts are exposed to the boric acid solution contained within the reactor coolant loop, a boric acid “freeze up” is not expected with the low boric acid concentrations used.

The experience derived from the check valves employed in the emergency injection system of the Carolina-Virginia Tube Reactor in a similar system indicates that the system is reliable and workable.

The CVTR emergency injection system, normally maintained at containment ambient conditions was separated from the main coolant piping by a single 6-in. check valve. A leak detection was provided at a proper elevation to accumulate any leakage coming back through the check valve and level alarm provided a signal on excessive leakage. The pressure differential was 1,500 psi and the system was stagnant. The valve was located 2 ft. to 3 ft. from the main coolant piping which resulted in some heatup and cooldown cycling. The CVTR went critical late in 1963 and operated until 1967 during which time the level sensor in the leak detector never alarmed due to check valve leakage.

Relief Valves

The accumulator relief valves are sized to pass nitrogen gas at a rate in excess of the accumulator gas fill line delivery rate. The relief valves will also pass water in excess of the expected leak rate, but this is not necessary because the time required to fill the gas space gives the operator ample opportunity to correct the situation. For an inleakage rate 15 times the manufacturing test rate, there will be in excess of 1,000 days before water will reach the relief valves. Prior to this, level and pressure alarms would have been actuated.

The safety injection test line relief valve is provided to relieve any pressure, above design, that might build up in the high head safety injection piping. The valve will pass a flow rate which is far in excess of the manufactured design leak rate of 24 cc/hr.

Leakage Limitations

Motor-operated valves in the residual heat removal loop that are exposed to recirculation flow are provided with sufficient packing to minimize leakage to the atmosphere.

The specified leakage across the valve disc required to meet the equipment specification and hydrotest requirements is as follows:

1. Conventional globe - 3 cc/hr/in. of nominal pipe size
2. Gate vales - 3 cc/hr/in. of nominal pipe size; 10 cc/hr/in. for 300 and 150 lb. USA standard
3. Motor-operated gate valves - 3 cc/hr/in. of nominal pipe size; 10 cc/hr/in. for 300 and 150 lb. USA standard
4. Check valves - 3 cc/hr/in. of nominal pipe size; 10 cc/hr/in. for 300 and 150 lb. USA standard
5. Accumulator check valves - 2 cc/hr/in. of nominal pipe size

Relief valves are totally enclosed. Leakage from components of the recirculation loop, including valves, is described later in this section under “Recirculating Loop Leakage.” Allowable through-seat leakage of the recirculation loop valves is controlled by the required ASME Section XI pressure test of the RHR system and the Leakage Reduction and Preventative Maintenance program. Operability determinations for these valves are made in accordance with the ASME Section XI code requirements.

Piping

All safety injection system piping in contact with borated water is austenitic stainless steel. Piping joints are welded except for the flanged connections.

The piping beyond the accumulator stop valves is designed for reactor coolant system conditions (2,485 psig, 650°F). All other piping connected to the accumulator tanks is designed for 800 psig and 300°F.

The safety injection pump suction piping (210 psig at 300°F) from the refueling water storage is designed for low pressure losses to meet NPSH (net positive suction head) requirements of the pumps.

The safety injection high pressure branch lines (1,745 psig at 300°F) are designed for high pressure losses to limit the flow rate out of a potential rupture of a branch line at the connection to the reactor coolant loop.

The safety injection test line piping (1750 psig at 100°F) is designed for the thermal operating mode during pump testing. The test line serves no other function to the safety injection system.

The piping is designed to meet the minimum requirements set forth in (1) the USAS B31.1 Code for the Pressure Piping, (2) Nuclear Code Case N-7, (3) USAS Standards B36.10 and B36.19, (4) ASTM Standards, and (5) supplementary standards plus additional quality control measures.

Minimum wall thicknesses are determined by the USAS Code formula in the power piping Section 1 of the USAS Code for the Pressure Piping. This minimum thickness is increased to account for the manufacturer's permissible tolerance of (-)12½% on the nominal wall. Purchased pipe and fittings have a specified nominal wall thickness that is no less than the sum of that required for pressure containment, mechanical strength, and manufacturing tolerance.

Thermal and seismic piping flexibility analyses are performed. Special attention is directed to the piping configuration at the pumps with the object of minimizing pipe imposed loads at the suction and discharge nozzles. Piping is supported to accommodate expansion due to temperature changes during the accident.

Pipe and fitting materials are procured in conformance with all requirements of the ASTM and USAS specifications. All materials are verified for conformance to specification and documented by certification of compliance to ASTM material requirements. Specifications impose additional quality control upon the suppliers of pipes and fittings as listed below.

1. Pipe branch lines between the reactor coolant pipes and the isolation stop valves conform to ASTM A376 and meet the supplementary requirement S6 Ultrasonic Testing.

2. Fittings conform to the requirements of ASTM A403. Fittings 3 in. and above have requirements for UT inspection similar to S6 of A376.

Shop fabrication of piping subassemblies is performed by reputable suppliers in accordance with specifications which define and govern material procurement, detailed design, shop fabrication, cleaning, inspection, identification, packaging and shipment.

Welds for pipes sized 2½ in. and larger are butt welded. Reducing tees are used where the branch size exceeds ½ of the header size. Branch connections of sizes that are equal to or less than ½ of the header size are of a design that conforms to the USAS rules for reinforcement set forth in the USAS B31.1 Code for Pressure Piping. Bosses for branch connections are attached to the header by means of full penetration welds.

All welding is performed by welders and welding procedures qualified in accordance with the ASME Boiler and Pressure Vessel Code Section IX, Welding Qualifications. The shop fabricator is required to submit all welding procedures and evidence of qualifications for review and approval prior to release for fabrication. All welding materials used by the shop fabricator must have prior approval.

All high pressure piping butt welds containing radioactive fluid, at greater than 600°F temperature and 600 psig pressure or equivalent, are radiographed. The remaining piping butt welds are randomly radiographed. The technique and acceptance standards are those outlined in UW-51 of the ASME B&PV Code, Section VIII. In addition, butt welds are liquid penetrant examined in accordance with the procedure of ASME B&PV Code, Section VIII, Appendix VIII and the acceptance standard as defined in the USAS Nuclear Code Case N-10. Finished branch welds are liquid penetrant examined on the outside and, where size permits, on the inside root surfaces.

A post bending solution anneal heat treatment is performed on hot-formed stainless steel pipe bends. Completed bends are then completely cleaned of oxidation from all affected surfaces. The shop fabricator is required to submit the bending, heat treatment and cleanup procedures for review and approval prior to release for fabrication.

General cleaning of completed piping subassemblies (inside and outside surfaces) is governed by basic ground rules set forth in the specifications. For example, these specifications prohibit the use of hydrochloric acid and limit the chloride content of service water and demineralized water.

Packaging of the piping subassemblies for shipment is done so as to preclude damage during transit and storage. Openings are closed and sealed with tight-fitting covers to prevent entry of moisture and foreign material. Flange facings and weld end preparations are protected from damage by means of wooden cover plates and securely fastened in position. The packing arrangement proposed by the shop fabricator is subject to approval.

Pump and Valve Motors - Motors in a Mild Environment

Engineered Safety Feature electrical equipment located in mild environments (i.e., an environment which does not vary significantly from normal service conditions during a design basis event) are supplied in accordance with USAS, IEEE, and NEMA standards and are periodically tested and operated as required by such standards to ensure that the motors remain in a reliable condition.

Although the motors, which are provided only to drive engineered safety features equipment, are normally run only for tests, the design loading and temperature rise limits are based on accident conditions. Normal design margins are specified for these motors to ensure that the expected lifetimes include allowance for the occurrence of accident conditions.

Motors in a Potentially Harsh Environment

Engineered Safety Feature electrical equipment located in potentially harsh environments (i.e., temperature, pressure, humidity, chemical spray or radiation changes as a result of a design basis accident) are designed and qualified to withstand their normal lifetime service environment followed by a design basis accident environment. This ensures that the equipment will be inherently capable of performing their required engineered safety function. Periodic maintenance and surveillance of the motors and their insulation systems are also accomplished to verify the reliable condition of the equipment.

Qualification tests and analysis are performed to demonstrate the adequacy of valve motor operators and motors used for engineered safety feature functions.

The normal service, harsh accident, and post-accident environments in the vicinity of the equipment are evaluated and used to develop performance specifications for the equipment. A test sample usually is then subjected to simulated accident conditions including radiation, temperature, pressure, relative humidity, and chemical spray. If aging is known to have a significant effect on equipment performance, the test sample is artificially aged prior to design basis accident exposure. The test sample's performance is evaluated during and after the simulation to ensure proper functioning.

Control of equipment qualification documentation is described in Section 6.1.1.

Electrical Supply

Details of the normal and emergency power sources for the safety injection system are presented in Section 8.0.

Protection Against Dynamic Effects

All four injection lines penetrate the containment adjacent to the auxiliary building.

The portion of the high head injection system within the containment is connected to the accumulator injection lines attached to each loop's cold leg piping and to the low head injection lines. The portion of the low head injection system within the containment is connected directly to the core deluge injection nozzles on the vessel.

For most of the routing, these lines are outside the reactor and steam generator shielding, and hence they are protected from missiles originating within these areas.

The coolant loop supports are designed to restrict the motion to about one-tenth of an inch, where as the attached safety injection piping can sustain a 3 in. displacement without exceeding the working stress range.

All hangers, stops and anchors are designed in accordance with USAS B31.1 1967 Edition, Code for Pressure Piping, and ACI 318 - 1963 Edition, Building Code Requirements for Reinforced Concrete, which provide minimum requirements on materials, design and fabrication with ample safety margins for both dead and operational dynamic loads over the life of the equipment. In addition to the normal load conditions, the requirements of Table A.5-3 for the loading combinations shown are used in design of supports. Specifically, these standards require the following:

1. All materials used are in accordance with ASTM specifications which establish quality levels for the manufacturing process, minimum strength properties, and for test requirements which ensure compliance with the specifications.

2. Qualification of welding processes and welders for each class of material welded and for types and positions of welds.

3. Maximum allowable stress values are established which provide an ample safety margin on yield strength for normal loads and ultimate strength for design basis accident or maximum hypothetical seismic loads.

NOTE: Safety related shock suppressers for Units 1 and 2 are listed in Table 6.2-11.

6.2.3 SYSTEM EVALUATION

Injection Connections and Flow to the Core

The injection lines from the accumulators, low head pumps and high head pumps are connected to the reactor coolant system to provide the maximum performance flexibility for a loss-of-coolant accident of any size or location. The performance flexibility is available not only during the injection phase, but also during the long-term recirculation.

Each accumulator is attached to a reactor coolant system cold leg. The core is therefore rapidly flooded from the bottom to provide the earliest possible cooling of the entire core and the attendant arresting of the clad temperature transient. When the accumulators reflood the bottom regions of the core, rapid steam generation causes a mixture of steam and entrained water droplets to flow through and cool the upper regions of the core.

The residual heat removal pumps (low head) deliver borated water to the core upper plenum through nozzles connected to the reactor vessel. The low head system thereby serves a basic injection function in the event of large breaks in the reactor coolant system. This function is to provide continued makeup following the successful cooling of the core by the accumulators. A second function of these pumps is to provide continued cooling during the recirculation phase.

The high head system connects to both the reactor vessel and cold legs to provide injection flow for both the steam line break and small loss-of-coolant accidents. Both high head pumps deliver to the two cold legs normally. The headers from each pump are cross connected to allow either pump to supply both the reactor vessel and cold leg connections.

Range of Core Protection

The measure of effectiveness of the safety injection system is the ability of the pumps and accumulators to keep the core flooded or to reflood the core rapidly where the core has been uncovered by (postulated) large area ruptures. The result of this performance is to sufficiently limit any increase in clad temperature below a value where emergency core cooling criteria are met (Section 6.2.1). Simulations of a sufficient number of break sizes were performed to demonstrate that the safety injection system components meet the emergency core cooling requirements. The results of the loss-of-coolant accident studies are presented in Section 14.3.

System Response

To provide protection for large area ruptures in the reactor coolant system, the safety injection system must respond to rapidly reflood the core following the depressurization and core voiding that is characteristic of large area ruptures. The accumulators act to perform the rapid reflooding function with no dependence on the normal or emergency power sources, and also with no dependence on the receipt of an actuation signal.

Operation of this system with one of the two available accumulators delivering their contents to the reactor vessel (one accumulator spilling through the break) prevents fuel clad melting and limits metal-water reaction to an insignificant amount (< 1%).

The function of the safety injection (or residual heat removal) pumps is to complete the refill of the vessel and ultimately return the core to a subcooled state. As discussed earlier, the flow from one safety injection pump or one residual heat removal pump is sufficient to complete the refill with no loss of level in the core. Moreover, there is sufficient excess water delivered by the accumulators to tolerate a delay in starting the pumps.

Initial response of the injection system is automatic, with appropriate allowance for delays in actuation of circuitry and active components. The active portions of the injection systems are automatically actuated by the safety injection signal (Section 7.0). In addition, manual actuation of the entire injection system and individual components can be accomplished from the control room. In analysis of system performance, delays in reaching the programmed trip points and in actuation of components are conservatively established on the basis that only emergency on-site power is available. The starting sequence of the safety injection pumps and related emergency power equipment is designed so that delivery of full rated flow is reached within 20 sec. after the process parameters reach the setpoints for the injection signal. See Section 8.0. The safety injection pump time delays that are used in the accident analyses include SI signal processing, sequencer time delay uncertainty, time for pump start to full flow, and emergency diesel generator delays as appropriate. The specific time delays that are assumed are discussed in Chapter 14, Section 14.2.5, Section 14.3.1 and Section 14.3.2.

Single Failure Analysis

A single active failure analysis is presented in Table 6.2-7(a). All credible active system failures are considered. The analysis of the loss-of-coolant accident presented in Section 14.0 is consistent with the single failure analysis. The most severe single failure assumed in the SI system for the small break loss-of-coolant accident (Section 14.3.1) is the loss of an electrical train due to the failure of an emergency diesel generator. This will result in the loss of one high head safety injection pump and one motor-driven AFW pump. Other equipment may also be lost (RHR pump, CCW, SW, etc.) but the high head safety injection pump and AFW pumps are the key components in providing short-term cooling capability for the SBLOCA. The most severe single failure assumed in the SI system for the large break loss-of-coolant accident (Section 14.3.2) is the loss of an RHR pump.

The failure analysis is based on the worst single failure (generally a pump failure) in both the safety injection and residual heat removal pumping systems. The analysis shows that the failure of any single active component will not prevent fulfilling the design function.

In addition, an alternative flow path is available to maintain core cooling if any part of the recirculation flow path becomes unavailable. This is evaluated in Table 6.2-7(b).

Failure analyses of the component cooling and service water system under loss-of-coolant accident conditions are described in Section 9.1 and Section 9.6, respectively.

Reliance on Interconnected Systems

During the injection phase, the high head safety injection pumps take suction on the refueling water storage tank. During the recirculation phase of the accident for small breaks, suction to a high head safety injection pump is provided by the associated residual heat removal pump.

The residual heat removal (low head) pumps are normally used during reactor shutdown operations. Whenever the reactor is at power, the pumps are aligned for low head safety injection.

Debris accumulation in the piping during construction is minimized by controlled cleanliness procedures. Moreover, the system was flushed with clean water after construction was completed to remove any debris that may have entered the system inadvertently.

Shared Function Evaluation

Table 6.2-8 is an evaluation of the main components, which have been previously discussed, and a brief description of how each component functions during normal operation and during the accident.

Passive Systems

The accumulators are a passive safety feature in that they perform their design function in the total absence of an actuation signal or power source. The only moving parts in the accumulator injection train are in the two check valves.

The working parts of the check valves are exposed to fluid of relatively low boric acid concentration contained within the reactor coolant loop. Even if some unforeseen deposition accumulated, calculations have shown that a differential pressure of about 25 psi will shear any particles in the bearing that may otherwise prevent the valve from functioning.

The isolation valve at each accumulator is closed only when the reactor is intentionally depressurized or momentarily for testing. The isolation valve is normally open and a monitor light in the control room indicates if the valve is inadvertently closed.

The check valves are normally closed, with a nominal differential pressure across the disc of approximately 1,550 psi. They remain in this position except for testing or when called upon to function. Since the valves are normally closed and are therefore not subject to the abuse of flowing fluids or impact loads caused by sudden flow reversal and seating, they do not experience any wear of the moving parts, and function as required. As the reactor coolant system is pressurized during the normal plant heatup operation, the check valves are checked for back leakage by monitoring RHR system pressure during heatup.

The accumulators can accept leakage back from the reactor coolant system without effect on their availability. Table 6.2-9 indicates that back leakage rates, over a given time period, require readjusting the level at the end of the time period. In addition, these rates are compared to the maximum allowed leak rates for manufacturing acceptance tests (20 cc/hr, i.e., 2 cc/hr/in.).

Back leakage at a rate of 5 cc/hr/in., 2½ times test, would require that the accumulator water volume be adjusted approximately once every 28 mo. This would indicate that level adjustments can be scheduled for normal refueling shutdowns and that this work can be done at the operator's convenience.

The accumulators are located inside the reactor containment and protected from the reactor coolant system piping and components by a missile barrier. Accidental release of the gas charge in the two accumulators would cause an increase in the containment pressure of approximately 0.1 psi.

During normal operation, the flow rate through the reactor coolant piping is approximately five times the maximum flow rate from the accumulator during injection. Therefore, fluid impingement on reactor vessel components during operation of the accumulator is not restricting.

Recirculating Loop Leakage

During the recirculation phase of a loss of coolant accident, the containment sump water is recirculated through portions of the Emergency Core Cooling System (ECCS) located in the operating areas of the primary auxiliary building (PAB). Postulated leakage from this equipment in the PAB or back leakage through the RWST may contribute to the offsite radiation dose and the dose received by plant operators during the accident. LOCA radiological analyses of offsite and control room dose due to this leakage conservatively assume a combined ECCS leak rate of 800 cc/min during the accident as described in FSAR Section 14.3.5. The airborne leakage from the ECCS may also contribute to the "passing plume" (radioactive cloud) which emanates direct radiation on control room operators. This direct radiation dose is analyzed in FSAR Section 11.6.

The actual ECCS leakage is not expected to exceed 400 cc/min.and is checked and controlled through the Leakage Reduction and Preventative Maintenance program. This program ensures that ECCS equipment leakage is As Low As Reasonably Achievable (ALARA), and remains below the value which forms the basis for the aforementioned radiological analyses.

During external recirculation, significant margin exists between the design and operating conditions of the residual heat removal system components, as shown in Table 6.2-10. In addition, during normal plant cooldown, operation of the residual heat removal system is initiated when the primary system pressure and temperature have been reduced to less than 400 psig and less than or equal to 350°F, respectively. Since the maximum operating conditions during recirculation are 200 psig and 250°F, significant margin also exists between normal operating and accident conditions.

Leakage detection exterior to containment is achieved through use of sump level detection. One or more pumps in the auxiliary building sump below the (-)19 ft. 3 in. level starts automatically in the event that liquid accumulates in the sump, and an alarm sounds in the control room if water accumulates above a fixed level in the sump.

Water leakage into the tendon gallery is normally pumped to the facade sump which will actuate an alarm in the control room on high level. If water begins to accumulate in the tendon gallery it will overflow through the openings in the Containment Sump A drain line-to-sleeve grout to the associated unit's A train RHR pipeway and then to the Train A RHR pump room. Openings in the Sump A drain-to-sleeve grout are required to be at least 0.8 square inches and no more than 15.2 square inches to provide sufficient area for drainage but not adversely affect the negative pressure in the primary auxiliary building (Reference 6 and Reference 8).

Each RHR pump is located in an individual compartment which is equipped with a floor drain and separated equipment drains. The floor drain from each compartment flows through an individual pipe to the sump. Two 75 gpm sump pumps transfer the leakage to the waste disposal system. Valving is provided to permit the operator to individually isolate the residual heat removal pumps. The supply and discharge piping and valves for the RHR pumps are located in a pipeway adjacent to the pump compartments. A seven foot high shield wall divides the pipeway into two sections, each of which drains into a pump compartment through a 4-inch by 4-inch opening at floor level. Openings in the wall have no effect on RHR pump protection from flooding events. The RHR pump seal failure rate is 50 gpm.

The RHR cubicle drain valves are maintained in the closed position. If a RHR pump seal failure occurred with the drain valves in the closed position, a RHR pump room high level alarm would eventually be indicated in the control room. The cubicle could then be drained to the sump by opening the drain valve. If flooding in EL.-19' occurred due to a source other than a failed RHR pump seal, the fluid would collect in the center cubicle (cubicle between the Unit 1 and Unit 2 RHR pumps) and flow to the sump via the floor drains. The flow path to the RHR pump cubicle would remain isolated.

Pump NPSH Requirements - Residual Heat Removal Pumps

The NPSH of the residual heat removal pumps is evaluated for normal plant shutdown operation, and both the injection and recirculation phase operation of the design basis accident. Recirculation operation gives the limiting NPSH requirement. The available NPSH is determined from the containment water level, and the pressure drop in the suction piping from the sump to the pumps. During recirculation phase of a large break LOCA where RHR pump flow is sent to both the reactor vessel and the suction of the containment spray pump, maximum RHR pump flow requirements are set by system alignment to ensure RHR pump NPSH. Status lights are available on the main control boards to allow the operator to confirm the proper alignment of the containment spray pump discharge valves and to confirm that the preset throttle position has been reached for the SI-852A & B RHR pump core deluge valves. Flow instrumentation is available on the main control boards to allow the operators to monitor the operation of the containment spray and RHR systems during the ECCS recirculation phase of a LOCA. (Reference 4)

Coating debris can also play a role in affecting the available NPSH during post-LOCA ECCS recirculation operation. A program has been instituted at PBNP that provides adequate assurance that the applicable requirements for the procurement, application, inspection, and maintenance of Service Level I coatings in containment are implemented, and that maintains a detailed inventory of degraded and non-conforming coatings to ensure the coatings are maintained within the evaluated limits of design basis analyses for the ECCS. Refueling frequency coatings inspections ensure the total inventory of coatings remain bounded by the analyses.

Safety Injection Pumps

The NPSH for the safety injection pumps is evaluated for both the injection and recirculation phase of operation of the design basis accident. The end of the injection phase operation gives the limiting NPSH requirement. The NPSH available is determined from the elevation head and vapor pressure of the water in the refueling water storage tank, and the pressure drop in the suction piping from the tank to the pumps.

6.2.4 REQUIRED PROCEDURES AND TESTS

Inspection Capability

All components of the safety injection system can be inspected periodically to demonstrate system readiness. The pressure containing systems can be inspected for leaks from pump seals, valve packing, flanged joints and safety valves during system testing.

In addition, to the extent practical, the critical parts of the reactor vessel internals, injection nozzles, pipes, valves and safety injection pumps can be inspected visually or by boroscopic examination for erosion, corrosion, and vibration wear evidence, and for nondestructive test inspection where such techniques are desirable and appropriate.

System Testing

Operational sequence testing of the safety injection system is performed during reactor shutdown in accordance with Technical Specification surveillance requirements. These tests demonstrate emergency diesel generator operation and automatic sequencing of safeguards loads during a loss of offsite power to each 4160 V emergency bus in conjunction with an ESF actuation signal (see Section 8.8.3 for description of emergency diesel generator loading). The tests also demonstrate that each automatic ECCS valve actuates in response to an actual or simulated SI signal.

The safety injection piping up to the final isolation valve is maintained full of borated water, and the accumulators are maintained filled at their designated levels with borated water, while the plant is in operation. The accumulator pressure and level are continuously monitoried during plant operation. The accumulators and injection lines are refilled with borated water as required by using a safety injection pump to recirculate refueling water through the injection lines. A small test line is provided for this purpose in each injection header.

Flow in each of the high head injection lines and in the flow lines for the residual heat removal pumps is monitored by flow indicators. Pressure instrumentation is also provided for the main flow paths of the safety injection and residual heat removal pumps.

Component Testing

Inservice testing requirements are described in the PBNP Inservice Testing Program and the IST Background Document.

Each active component of the safety injection system can be individually actuated on the normal power source at any time during plant operation to demonstrate operability. The test of the safety injection pumps employs the full flow recirculation test line which connects back to the refueling water storage tank. Remotely operated valves are exercised and actuation circuits tested. The automatic actuation circuitry, valves and pump breakers also may be checked during integrated system tests performed during a planned cooldown of the reactor coolant system.

A test system is provided to periodically verify back-leakage through each RCS Event V Pressure Isolation Valve (PIV) is within limits. The accumulator discharge check valves (SI-867A/B) are Event V PIVs and are tested with this system. (See TRM 4.16, RCS PIV Leakage Program).

If leakage through a check valve should become excessive, the isolation valve (SI-841A/B) would be closed and an orderly shutdown initiated to repair the check valve. The performance of the check valves in this application has been carefully studied and it is concluded that it is highly unlikely that the accumulator lines would have to be closed because of leakage.

The isolation valves are closed and de-energized when the reactor coolant system is intentionally depressurized to ≤1000 psig to allow for RCS cooldown and depressurization without discharging the accumulators into the RCS or requiring depressurization of the accumulators.

The recirculation piping was initially hydrostatically tested at 150% of design pressure of each portion of the loop. The entire loop is also pressurized during periodic testing of the engineered safety features components. The recirculation piping is also leak tested at the time of the periodic retests of the containment.

Since the recirculation flow path is operated at a pressure in excess of the containment pressure, it is hydrotested during periodic retests at the recirculation operating pressures. This is accomplished by running each pump utilized during recirculation (safety injection, spray, and residual heat removal pumps) in turn and checking the discharge and recirculation test lines. The suction lines are tested by running the residual heat removal pumps and opening the flow path to containment spray and safety injection pumps in the same manner as described above.

During the above test, all system joints, valve packings, pump seals, leakoff connections, or other potential points of leakage are visually examined. Valve gland packing, pump seals, and flanges are adjusted or replaced as required to reduce the leakage to acceptable proportions.

Emergency Operating Procedures

The requirement to establish simultaneous upper plenum injection and cold leg injection to control boric acid precipitation following a LOCA is incorporated into the emergency operating procedures. The transfer from containment spray recirculation to cold leg recirculation via the safety injection pumps within 10 minutes is considered to be a time critical operator action. The emergency operating procedures direct operators to prevent inadvertent precipitation by limiting depressurization and cooldown during small breaks in the event that boiling in the reactor vessel exists for an extended period of time with the RCS pressure above the shutoff head of the RHR pumps. The procedures also ensure that BAST injection is promptly terminated during all LOCAs to preclude early boric acid precipitation. (Reference 3)

6.2.5 REFERENCES

1. WCAP-7153, “Investigation of Chemical Additives for Reactor Containment Sprays,” M. J. Bell, et al, March 1968, (Proprietary).

2. 10 CFR 50.46, “Acceptance Criteria for Emergency Core Cooling Systems for Light Water Cooled Nuclear Power Reactors.”

3. NRC Safety Evaluation, “Point Beach Nuclear Plant (PBNP), Units 1 and 2 - Issuance of License Amendments Regarding Extended Power Uprate (TAC Nos ME1044 and ME1045),” dated May 3, 2011.

4. NRC Safety Evaluation, "Point Beach Nuclear Plant (PBNP), Units 1 and 2 - Issuance of License Amendments Regarding Use of Alternate Source Term (TAC Nos. ME0219 and ME0220)," dated April 14, 2011.

5. Westinghouse calculation CN-LIS-08-67, "Point Beach Units 1 and 2 (WEP/WIS) Extended power Uprate (EPU) Post-LOCA long Term Cooling (LTC)," Rev 2, dated April 16, 2011.

6. NRC SE dated September 18, 2006, "Point Beach Nuclear Plant, Units 1 and 2 - Evaluation of Event Notification 42129 (TAC Nos. MC9035 and MC9036)."

7. Calculation 2006-0021, ECCS System Accident Analysis Inputs, Revision 0.

8. Engineering Change EC, 11416, Revision 1, closed January 27, 2009.

Table 6.2-1 SAFETY INJECTION SYSTEM - CODE REQUIREMENTS

Component	Code
Refueling Water Storage Tank	API 650
Residual Heat Exchanger	
Tube Side	ASME Section III, Class C
Shell Side	ASME Section VIII
Accumulators	ASME Section III, Class C
Valves	USAS B16.5/ANSI B16.34
Piping	USAS B31.1

Table 6.2-2 (DELETED)

This information is considered historical information, and is described in FFDSAR Table 6.2-3.

Table 6.2-3 ACCUMULATOR DESIGN PARAMETERS

Number (per unit)	2
Type	Stainless steel clad/carbon steel
Design pressure, psig	800
Design temperature, °F	300
Operating temperature, °F	70-120
Normal pressure, psig	750
Minimum pressure, psig	700
Total volume, ft^3	1,750
Minimum water volume at operating conditions, ft^3	1,100
Boron concentration (as boric acid), ppm	2,700 to 3,100
Relief valve setpoint, psig*	800

* The relief valves have soft seats and are designed and tested to ensure they are leak tight such that the minimum accumulator pressure defined in Technical Specifications is maintained.

Table 6.2-4 REFUELING WATER STORAGE TANK DESIGN PARAMETERS

Number (per unit)	1
Material	Stainless steel
Total volume, gal.	289, 504
Minimum volume, (solution) gal.	275,000
Normal pressure, psig	Atmospheric
Minimum operating temperature, °F	40
Design pressure, psig	Atmospheric
Design temperature, °F	200
Boron concentration (as boron), ppm	2,800 to 3,200

Table 6.2-5 PUMP PARAMETERS

Safety Injection Pump Design Parameters	
Number (per unit)	2
Type	Horizontal Centrifugal
Design Pressure, psig	1,750
Design Temperature, °F	300
Design Flow Rate, gpm	700
Runout Flow Rate, gpm	1,233
Design Head, ft	2,600
Shutoff Head, ft	3,400
Material	11-13 Chrome
Motor H.P.	700
Residual Heat Removal Pump Design Parameters	
Number of Pumps (per unit)	2
Type	Horizontal Centrifugal
Design Pressure, psig	600
Design Temperature, °F	400
Design Flow, gpm	1,560
Design Head, ft.	280
Runout Flow Rate, gpm	2,500
Material	Austenitic Stainless Steel
Shutoff Head, ft.	335
Motor H.P.	200

Table 6.2-6 RESIDUAL HEAT EXCHANGERS DESIGN PARAMETERS

Number (per unit)	2	
Design Heat Duty, BTU/hr (Normal)	24.15×10^6	
Design UA, BTU/hr/°F	0.745×10^6	
Design Cycles (85°F-350°F)	200	
Type	Vertical Shell and U-Tube	
	Tube-Side	Shell-Side
Design Pressure, psig	600	150
Design Flow, lb/hr	0.763×10^6	1.375×10^6
Inlet Temperature, °F	160	100
Outlet Temperature, °F	128.4	117.3

Table 6.2-7(a) SINGLE FAILURE ANALYSIS - SAFETY INJECTION SYSTEM

Component	Malfunction	Comments
A. Accumulator (Injection phase)	Delivery to broken loop	Totally passive system with one accumulator per loop. Evaluation based on one accumulator delivering to the core and one spilling from ruptured loop.
B. Pump (Injection Phase):		
1. High Head Safety Injection	Fails to start	Two provided. Small break LOCA evaluation assumes operation of one pump based on loss of an electrical train due to failure of an emergency diesel generator. Large break LOCA evaluation does not assume a single failure of a high head SI pump, but assumes a single failure of an RHR pump which is more limiting.
2. Residual Heat Removal	Fails to start	Two provided. Evaluation based on operation of one.
3. Component Cooling*	Fails to start	Two provided. One required for recirculation cooling.
4. Service Water	Fails to start	Six provided. Evaluation based on operation of three. (See also Section 9.6.)
C. Automatically Operated Valves (Normally closed; open on SIS - Injection Phase)		
1. Residual Heat Removal Pump Discharge Isolation Valves to Reactor Vessel Injection (SI-852A/B)	One valve fails to open	One valve provided for each LHSI train: one train required for injection.
D. Manual and Remote-Manual Operated Valves (Repositioned for Recirculation Phase)		
1. Containment Sump Recirculation Isolation Valves (SI-850A/B, SI-851A/B)	One valve fails to open	Two valves provided in series in each independent sump recirculation line. One line (one pair of valves) required to open for recirculation.
2. RHR Heat Exchanger Discharge to SI Pump Suction Isolation Valves (SI-857A/B)	One valve fails to open	One valve provided for each SI train; one SI train required for piggyback operation.
3. SI Test Line to RWST Isolation Valves (SI-897A/B)	One valve fails to close	Two valves provided in series; One valve required to close for isolation.
4. SI Pump Suction from RWST Isolation Valves (SI-896A/B) for piggyback operation	One valve fails to close	One valve provided in each SI train; one SI train required for piggyback operation.
5. RHR Pump Suction from RWST Isolation Valves (SI-856A/B)	One valve fails to close	One valve provided in each LHSI train (in series with a check valve); one LHSI train required for recirculation.
6. Residual Heat Removal Pump Discharge Isolation Valves to Reactor Vessel Injection (SI-852A/B)	One valve fails to throttle	One valve provided for each LHSI train; one train required for piggyback operation.

* Recirculation Phase: The status of all active components of the safety injection system is indicated on the main control board.

Table 6.2-7(b) LOSS OF RECIRCULATION FLOW PATH

	Flow Path		Indication of Loss of Flow Path	Alternative Flow Path
A.	Low Head Recirculation			
	From containment to reactor core via one of the two residual heat removal pumps and the associated residual heat exchanger and a low head injection line.	1.	No flow in low head injection line associated with the operating residual heat removal pump. (Flow monitor in each injection line.)	Via the separate and independent low head recirculation train from containment to reactor core via the second residual heat removal pump, the associated residual heat exchanger, and the second low head injection header.
		2.	High flow in low head injection line as (1), above.	
B.	High Head Recirculation			
	From containment to high head injection lines via one of the two residual heat removal pumps, the associated residual heat exchanger, the associated high head injection pump suction line and the high head injection pump.	1.	No (or low) flow in the high head injection lines. (One flow monitor in each line.)	If flow to the high head injection lines is not established by opening the cross connection between the residual heat exchanger and the suction of the safety injection pump, then the separate and independent flow path to the second high head pump is established (from the containment via second residual heat removal pump, the associated residual heat exchanger and the associated high head injection pump suction line).
		2.	High flow in one high head injection line, low (or zero) flow in the second high head line.	Close the cross connect between the two discharges of the two injection pumps and utilize the injection pump (and associated supply train from containment) which is supplying the high head injection line which registered the low flow.

NOTE: As shown on Figure 6.2-1, there are valves at all locations where alternative flow paths are provided.

Table 6.2-8 SHARED FUNCTIONS EVALUATION

Component	Normal Operating Function	Normal Operating Arrangement	Accident Function	Accident Arrangement
Refueling Water Storage Tank (1/Unit)	Storage tank for refueling operations	Lined up to suction of safety injection residual heat removal, and spray pumps	Source of borated water for emergency core cooling systems	Lined up to suction of safety injection, residual heat removal, and spray pumps
Accumulators (2/Unit)	None	Lined up to cold legs of reactor coolant piping	Supply borated water to core promptly	Lined up to cold legs of reactor coolant piping
Safety Injection Pumps (2/Unit)	None	Lined up to reactor vessel and/or cold legs of reactor coolant piping	Supply borated water to core	Lined up to reactor vessel and/or cold legs of reactor coolant piping
Residual Heat Removal Pumps (2/Unit)	Supply water to loop to remove residual heat during shutdowns	Lined up to take suction from refueling water storage tank and deliver to reactor vessel Lineup for plant shutdowns is described in Section 9.2.	Supply borated water to core through reactor vessel nozzles and to containment spray pump or safety injection pump suction.	Lined up to take suction from refueling water storage tank and deliver to reactor vessel during injection phase. Lined up to take suction from the containment sump and deliver water to reactor vessel and containment spray pump suction or safety injection pump suction during recirculation.
Service Water Pumps [a](6)	Supply lake cooling water to component cooling heat exchangers	Two pumps in service during operation of both units (see Section 9.6.2)	Supply lake cooling water to component cooling heat exchangers and containment fan coolers. Also provides alternate source of water to AFW pump suction.	Three pumps in service during operation of both units (see Section 9.6.2)
Residual Heat Exchangers (2/Unit)	Remove residual heat from core during shutdown	Lined up for recirculation Lineup for plant shutdowns is described in Section 9.2.	Cool water in containment sump for core cooling and containment spray	Lined up for recirculation
Component Cooling Heat Exchangers (4)[b†]	Remove heat from component cooling water	One heat exchanger in service per unit	Cool water for residual heat exchangers, residual and S.I. pump seals and bearings (during recirculation)	One heat exchanger in service.

a. Shared
b. One for each unit during normal operation; two serve as shared standby heat exchangers
† One pump and one heat exchanger also required on the second Unit for both phases of the accident (injection and recirculation)

Table 6.2-9 ACCUMULATOR INLEAKAGE*

Time Period Between Level Adjustments	Observed Leak Rate cc/hr	(Observed Leak Rate) (Max. Allowed Design)
1 month	1,410	70.7
3 months	470	23.5
6 months	235	11.7
9 months	157	7.8
1 year	118	5.9
10 years	11.8	0.6

* A total of 36 cu. ft., added to the initial amount, can be accepted in each accumulator before an alarm is sounded.

Table 6.2-10 RESIDUAL HEAT REMOVAL SYSTEM DESIGN, OPERATION AND TEST CONDITIONS

	Pumps	Heat Exchangers	Valves	Pipes and Fittings
Design Conditions				
Pressure, psig	600	600	665	700
Temperature, °F	400	400	400	400
Operating Conditions (Max)*				
Pressure, psig	200	200	200	200
Temperature, °F	210	210	210	210
Test Pressure, psig	1200	900	1100	900
Allowable Pressure at Operating Temp, psig	>600	>600	>690	>850

* During post loss-of-coolant recirculation.
The maximum temperature downstream of RHR heat exchangers is 210°F. The maximum temperature from the containment sump to the RHR heat exchangers is 250°F.

Table 6.2-11 SAFETY RELATED SNUBBERS UNIT 1

Page 1 of 2

ID	LOCATION/ELEVATION	NOMINAL RATING
HS-1	"A" Main Steam Line-West/100′	497 kip
1HS-2	"A" Main Steam Line-East/100′	497 kip
1HS-3	"B" Main Steam Line-West/100′	497 kip
1HS-4	"B" Main Steam Line-East/100′	497 kip
1HS-5	"A" SG Side-North/66′	449 kip
1HS-6	"A" SG Side-Middle/66′	449 kip
1HS-7	"A" SG Side-South/66′	449 kip
1HS-8	"B" SG Side-North/66′	449 kip
1HS-9	"B" SG Side-Middle/66′	449 kip
1HS-10	"B" SG Side-South/66′	449 kip
1HS-11	"A" Main Feed Line Below 66′/61′	11 kip
1HS-12	SIS Line-Regen HX Cubicle/34′	11 kip
1HS-13	SIS Line at 21' in Overhead/40′	11 kip
1HS-14	REMOVED FROM SERVICE	
1HS-15	Containment Spray Header/120′	11 kip
1HS-16	Containment Spray Header/120′	11 kip
1HS-17	REMOVED FROM SERVICE	
1HS-18	REMOVED FROM SERVICE	
1HS-19	Incore Detector Tube Bundle in Keyway/3′	11 kip
1HS-20	Incore Detector Tube Bundle in Keyway/3′	11 kip
HS-601R-37A	PZR PORV Header/76′	3 kip
HS-601R-73	PZR SRV Relief Line/80′	11 kip
HS-601R-80	PZR SRV Relief Line/80′	11 kip
HS-601R-90	SRV Discharge Piping	27.3 kip
HS-601R-92A1	SRV Discharge Piping West	27.3 kip
HS-601R-92A2	SRV Discharge Piping East	27.3 kip
HS-2501R-15	PZR PORV Header/78′	11 kip
HS-2501R-22A	PZR PORV Header/78′	3 kip
HS-2501R-43	PZR PORV Header/77′	11 kip
HS-2501R-51	PZR PORV Header/77′	11 kip
EB-2-H7	REMOVED FROM SERVICE	
EB-2-H17	REMOVED FROM SERVICE	
R-EB-2-1	REMOVED FROM SERVICE	
R-EB-2-3	REMOVED FROM SERVICE	
R-EB-2-4	REMOVED FROM SERVICE	
R-EB-2-6	REMOVED FROM SERVICE	
R-EB-2-7	REMOVED FROM SERVICE	
AC-601R-3-R-350	REMOVED FROM SERVICE	
AC-601R-3-R-356	REMOVED FROM SERVICE	

Table 6.2-11 SAFETY RELATED SNUBBERS UNIT 2
Page 2 of 2

ID	LOCATION/ELEVATION	NOMINAL RATING
2HS-21	REMOVED FROM SERVICE	
2HS-22	Beneath Valve 2-541 in "A" Loop Cubicle/41′	11 kip
2HS-23	SIS Line-46' East Side/50′	11 kip
2HS-24	In Overhead by 21' Keyway Access/36′	11 kip
2HS-25	Regen HX Cubicle/34′	11 kip
2HS-26	SIS Line-46' Near East Stairs/34′	11 kip
2HS-27	In Keyway/3′	11 kip
2HS-28	REMOVED FROM SERVICE	
2HS-29	PZR SV Discharge Header in PZR Cubicle/80′	11 kip
2HS-30	PZR SV Discharge Header in PZR Cubicle/80′	11 kip
2HS-31	In Keyway/3′	11 kip
2HS-32	"A" Main Steam Line-East/100′	497 kip
2HS-33	"A" Main Steam Line-West/100′	497 kip
2HS-34	"B" Main Steam Line-East/100′	497 kip
2HS-35	"B" Main Steam Line-West/100′	497 kip
2HS-36	"A" SG Side-North/66′	449 kip
2HS-37	"A" SG Side-Middle/66′	449 kip
2HS-38	"A" SG Side-South/66′	449 kip
2HS-39	"B" SG Side-North/66′	449 kip
2HS-40	"B" SG Side-Middle/66′	449 kip
2HS-41	"B" SG Side-South/66′	449 kip
HS-601R-37	PZR PORV Header/78′	15 kip
HS-601R-93	PZR Safety Valve Discharge Line	17.6 kip
HS-601R-95B	PZR Safety Valve Discharge Line	23.7 kip
HS-2501R-15	PZR PORV Header/78′	11 kip
HS-2501R-21A	PZR PORV Header/78′	3 kip
HS-2501R-43	PZR PORV Header/77′	11 kip
HS-2501R-49	PZR PORV Header/77′	3 kip
2R-EB-2-1	REMOVED FROM SERVICE	
2R-EB-2-2	REMOVED FROM SERVICE	
2R-EB-2-3	REMOVED FROM SERVICE	
2R-EB-2-4	REMOVED FROM SERVICE	
2R-EB-2-5	REMOVED FROM SERVICE	
2R-EB-2-6	REMOVED FROM SERVICE	
2R-EB-2-7	REMOVED FROM SERVICE	
EB-8-H206	REMOVED FROM SERVICE	

Figure 6.2-1 UNIT 2 SAFETY INJECTION SYSTEM (Sheet 1)

[redacted]

Figure 6.2-1 UNIT 2 SAFETY INJECTION SYSTEM (Sheet 2)

[redacted]

Figure 6.2-1 UNIT 2 SAFETY INJECTION SYSTEM (Sheet 3)

[redacted]

Figure 6.2-2 SIS DRAINS - ELEVATION

[redacted]

Figure 6.2-3 CONTAINMENT DRAINS - PLAN

[redacted]

Figure 6.2-4 SAFETY INJECTION PUMP PERFORMANCE CHARACTERISTICS

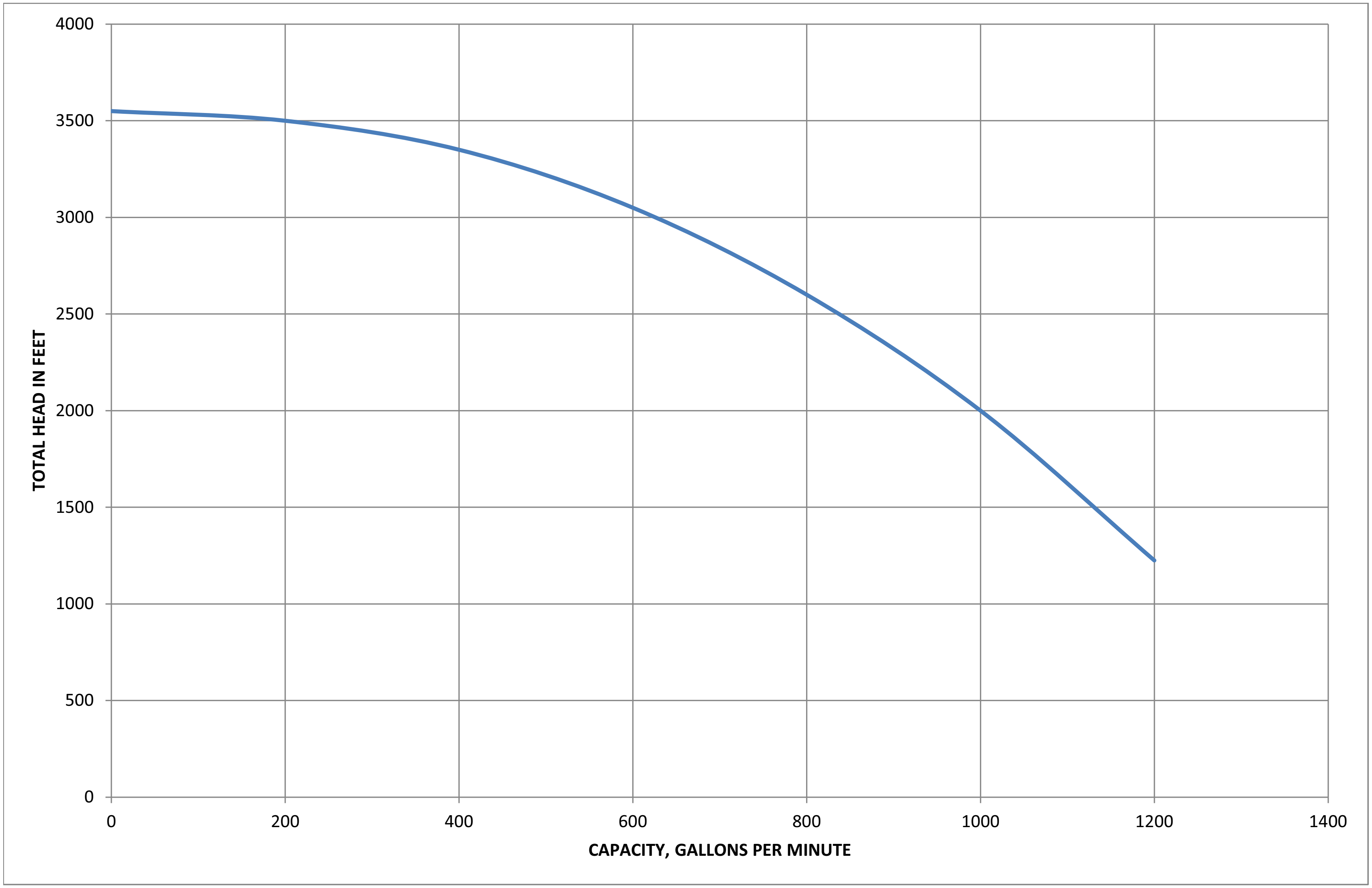
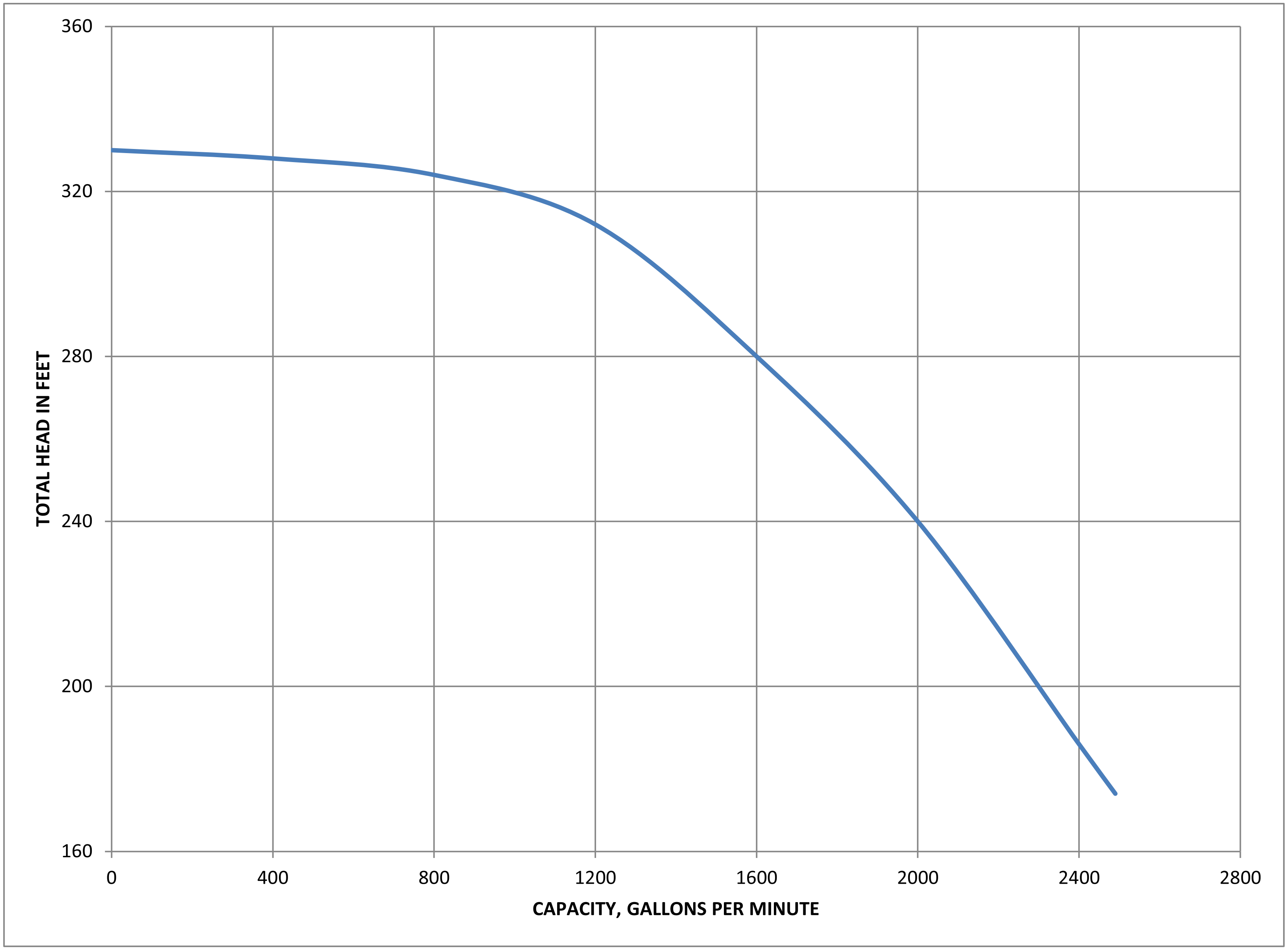


Figure 6.2-5 RHR PUMP PERFORMANCE CHARACTERISTICS



6.3 CONTAINMENT AIR RECIRCULATION COOLING SYSTEM (VNCC)

6.3.1 DESIGN BASES

Containment Heat Removal Systems

Criterion: Where an active heat removal system is needed under accident conditions to prevent exceeding containment design pressure, this system shall perform its required function, assuming failure of any single active component. (GDC 52)

Adequate heat removal capability for the containment is provided by two separate engineered safety features systems which use different engineering principles. These are the containment spray system, whose components are described in Section 6.4, and the containment air recirculation cooling system, whose components operate as described in Section 6.3.2.

The containment air recirculation cooling system is designed to recirculate and cool the containment atmosphere in the event of a loss-of-coolant accident and thereby ensure that the containment pressure cannot exceed its design value of 60 psig at 286°F (100% relative humidity). Although the water in the core after a loss-of-coolant accident is quickly subcooled by the safety injection system, the containment air recirculation cooling system is designed on the conservative assumption that the core residual heat is released to the containment as steam.

The design of the containment air recirculation cooling system also complies with GDC's 4, 37, 38 and 41 as described in Section 6.1.

Two of the four containment cooling units and one of two containment spray pumps will provide sufficient heat removal capability to maintain the post-accident containment pressure below the design value, assuming that the core residual heat is released to the containment as steam.

Portions of other systems which share functions and become part of this containment cooling system when required are designed to meet the criteria of this section. Neither a single active component failure in such systems during the injection phase nor an active or passive failure during the recirculation phase will degrade the heat removal capability of containment cooling.

Inspection of Containment Pressure-Reducing Systems

Criterion: Design provisions shall be made to the extent practical to facilitate the periodic physical inspection of all important components of the containment pressure-reducing systems, such as pumps, valves, spray nozzles, torus, and sumps. (GDC 58)

Design provisions are made to the extent practical to facilitate access for periodic visual inspection of all important components of the containment air recirculation cooling system.

Testing of Containment Pressure-Reducing Systems Components

Criterion: The containment pressure-reducing systems shall be designed to the extent practical so that components, such as pumps and valves, can be tested periodically for operability and required functional performance. (GDC 59)

The containment air recirculation cooling system is designed to the extent practical so that the components can be tested periodically and, after any component maintenance, for operability and functional performance.

Testing of Operational Sequence of Containment Pressure-Reducing Systems

Criterion: A capability shall be provided to test initially under conditions as close as practical to the design and the full operational sequence that would bring the containment pressure-reducing systems into action, including the transfer to alternate power sources. (GDC 61)

Means are provided to test initially to the extent practical the full operational sequence of the air recirculation cooling system, including transfer to the emergency power supply.

Combustible Gas Control

10 CFR 50.44(b)(1): All containments must have a capability for ensuring a mixed atmosphere.

A mixed atmosphere in the containment following a LOCA takes into consideration the layout and arrangement of the containment internal structures, and active and passive mixing mechanisms. Active mixing mechanisms include air recirculation via the VNCC system through the various containment compartments and areas, and mixing promoted by the momentum transfer due to spray droplets (Reference 17).

Performance Requirements

The VNCC System performs the following safety-related function:

The VNCC System shall remove heat from the containment following a loss of coolant accident or main steam line break inside containment to limit containment temperatures and pressures to less than containment design limits. These accidents are described in detail in FSAR Section 14.3.2 and Section 14.2.5. The containment LOCA integrity evaluation is described in Section 14.3.4. The fans and cooling coils continue to remove heat after the loss of coolant accident and support the reduction of containment pressure to less than half of the containment peak pressure within the first 24 hours.

The VNCC System also performs the non-safety related function of removing the normal heat loss from equipment and piping in the reactor containment during normal plant operation as described in FSAR Section 5.3.

The following objectives are met to provide the engineered safety features functions:

1. Each of the two fan cooler trains, consisting of two fan cooler units, must be capable of transferring heat at the rate of 60×10^6 BTU/hr from the containment atmosphere at the post accident design conditions, i.e., a saturated air-steam mixture at 60 psig and 286°F.

   The establishment of basic heat transfer design parameters for the cooling coils of the fan cooler units, and the calculation by computer of the overall heat transfer capacity are discussed in Reference 15, Reference 16, and Reference 19. Among the topics covered are selection of the tube side fouling factor, effect of air side pressure drop, effect of moisture entrainment in the air-steam mixture entering the fan coolers, and calculation of the various air side to water side heat transfer resistances.

2. In removing heat at the design basis rate, the cooling coils are capable of discharging the resulting condensate without impairing the flow capacity of the unit and without raising the exit temperature of the service water to the boiling point during steady-state conditions.

   The equipment is designed to operate at the post accident conditions at 60 psig and 286°F for three hours, followed by operation in an air-steam atmosphere at 20 psig and 220°F for an additional 21 hours. The equipment design will permit subsequent operation in the air-steam atmosphere at 5 psig and 155°F for an indefinite period.

All components are capable of withstanding or are protected from differential pressures which may occur during the rapid pressure rise to 60 psig in ten seconds.

Where other systems are required to function as part of the containment air recirculation cooling system, such systems are designed to meet the performance objective of this system.

Where portions of these systems are located outside of containment, the following features are incorporated in the design for operation under post accident conditions:

1. Means for isolation of any section, and
2. Means to detect and control radioactivity leakage into the environs, to the limits consistent with guidelines set forth in 10 CFR 50.67 (Reference 18).

6.3.2 SYSTEM DESIGN AND OPERATION

A schematic arrangement of a containment air recirculation cooling and filtration system is shown in Figure 6.3-1. Individual system components and their supports meet the requirement for Class I (Seismic) structures and each component is isolated from fan vibration.

Containment Cooling System Characteristics

The containment air recirculation system consists of four fan cooler units, a duct distribution system, and the associated instrumentation and controls.

The fan cooler units are located in a missile-protected area near the containment wall.

Each fan cooler unit consists of a roughing filter bank (filter media are installed during refueling outages with a significant potential for a dusty containment atmosphere), expanded metal screen, plate-fin cooling coils, and fan and motors. To meet the performance requirements during both normal and post accident conditions, each of the four fan cooler units is provided with two separate vane axial fans. The two fans operate in parallel, but are of different design. One fan (the accident fan) and motor are especially designed for the high pressure, temperature and density following a loss-of-coolant accident. The second fan (the normal fan) and motor in the unit are designed for normal operation, and are not required to operate in the post accident atmosphere.

Gravity-operated back-draft dampers in the discharge duct work of the units isolate any inactive air handling unit from the duct distribution system. In addition, a gravity-operated back-draft damper is installed on the normal fan discharge to prevent back flow through the normal fan when it is stationary and the accident fan is in operation. Dampers open automatically when the associated unit is started. Duct work distributes the cooled air to the various containment compartments and areas. The accident flow sequence through each air handling unit is as follows: expanded metal screen, cooling coils, accident fan, back-draft duct damper, distribution duct header.

The four containment cooling accident fans are of the vane axial, nonoverloading, direct drive type. In the post accident environment, each accident fan is capable of providing a minimum flow rate of 33,500 cfm. The heat sink for the fan coolers is provided by the service water system. See FSAR Table 14.3.4-24 and Table 14.3.4-25 for analysis parameters and fan cooler performance data for the LOCA containment integrity analysis (Reference 17, Reference 18).

In removing heat at the design basis rate, the cooling coils are capable of discharging the resulting condensate without impairing the flow capacity of the unit and without raising the exit temperature of the service water to the boiling point during steady-state conditions. Since condensation of water from the air-steam mixture is the principal mechanism for removal of heat from the post accident containment atmosphere by the cooling coils, the coil fins will operate as wetted surfaces under these conditions. Entrained water droplets added to the air-steam mixture, such as by operation of the containment spray system, will therefore have essentially no effect on the heat removal capability of the coils. To ensure no boiling (two-phase flow) occurs at the cooler outlets during the steady-state conditions, downstream service water valves are set in a throttled position to raise the pressure in the cooling coils. (Reference 2)

During the transient conditions which follow the LOCA coincident with a loss of offsite power (about the first minute), boiling may occur in the containment fan coolers. The loss of power to service water pumps may cause the service water flow to stop and the cooling coils to drain prior to the restoration of power. This high-temperature, low-pressure condition inside the cooling coils may cause a temporary boiling condition which would delay initiation of the heat removal function. This postulated delay has been evaluated. (Reference 2) In addition, Service Water pipe and pipe supports are designed to accommodate design basis load combinations described in FSAR Appendix A.5, including pipe displacements and hydraulic loads that may result from water hammer in the containment fan cooler return lines. (Reference 6 through Reference 13)

<u>Actuation Provisions</u>

During accident conditions, actuation of all four fan cooler units is by the automatic starting sequence initiated by the safety injection signal. Capability also exists for manual actuation from the control room. The flow path through the accident fan is the same for normal and post accident operation. Back flow through the normal fan when it is stationary and the accident fan is in operation is prevented by the gravity-operated back-draft damper in the normal fan discharge.

Only the accident fan in each fan cooler unit is connected to the emergency power bus. Depending on the availability of emergency power, either all four, or at least two of these accident fans will be started after an accident with loss of offsite power. Reference is made to Section 8.0.

The nonaccident fans are tripped off when the motor control centers serving them are tripped on safety injection initiation. Overload protection for all fan motors is provided at the switchgear by overcurrent trip devices. If offsite power were available and both the normal and accident fans in each fan cooler unit were operating, these overload devices would trip the fan and motor not designed for accident duty.

The breakers for all fan motors can be operated manually from the control room. The accident fans can also be operated by their 480 V feed breaker in the cable spreading room.

Flow switches and temperature elements for each fan cooler unit indicate air is circulating in accordance with the design arrangement. Temperature indicators and accident fan low flow alarms are provided in the control room. Periodic air flow measurements are taken to evaluate accident fan performance. Each fan, accident and normal, has a vibration alarm and light on the main control board C01 in the control room.

Flow Distribution and Flow Characteristics

The duct distribution system is designed to promote good mixing of the containment air and ensures that the recirculation cooled air will reach all areas requiring ventilation. The distribution system is represented schematically by the ventilation system flow diagram, Figure 5.3-1.

The system includes a ring header and branch ducts to the primary compartments for distribution of cooled air from the fan cooler discharge. The cooled air is circulated upward from the lower primary compartments, through the steam generator compartments to the operating floor level. The ring header also discharges air to the containment above the operating floor level. Air that has risen to the containment dome is drawn by the fans through two branch ducts which follow the contour of the containment dome upward on opposite sides of the containment. These ducts take suction at the highest point in the center of the containment. Since all four air handling units discharge into a common ring header, no space in the containment is dependent on a single air handling unit for cooling and ventilation.

The temperature of the air returning to the air handling units will be essentially the ambient existing in the containment vessel.

The steam-air mixture from the containment entering the fan cooler units during the accident will be at approximately 286°F and have a maximum density of 0.204 pounds per cu. ft. The fluid will enter the cooling coils at these conditions. Part of the water vapor will condense on the cooling coils, and the air leaving the coils will be saturated at a temperature slightly below 286°F.

The fluid will remain in this condition as it flows into the fan, but will pick up some sensible heat from the fan and fan motor before flowing into the distribution header. This sensible heat will increase the dry-bulb temperature slightly above 286°F and will decrease the relative humidity slightly below 100%.

Cooling Water for the Fan Cooler Units

The cooling water requirements for all four fan cooling units during a loss-of-primary-coolant accident and recovery are supplied by three of the six service water pumps. The service water system is described in Section 9.0.

Each fan cooler unit is supplied by a separate line from the containment service water header located outside the containment. (See Figure 9.6-2) Each supply line is provided with a shutoff valve and drain valve. Similarly, each fan cooler unit discharge line is provided with a shutoff valve and drain valve. This allows each cooler to be isolated individually for draining and maintenance.

The cooling water discharged from the cooling coils is monitored for radioactivity by routing a small bypass flow from each unit through a common radiation monitor. Upon indication of radioactivity in the effluent, each cooler discharge line is monitored individually to locate the defective cooling coil. The service water system is pressurized inside the containment. During normal operation the service water system supply and return pressure for the ventilation coolers can be above or below the containment design pressure of 60 psig. Following a loss-of-coolant accident, the service water supply and return pressure for the ventilation coolers is normally below the containment design pressure of 60 psig. However, since the cooling coils and service water lines form a closed system inside the containment, no contaminated leakage is expected into these units. Alarms are provided in the control room.

Flow and temperature indication is provided outside containment for service water flow from each cooling unit. In addition, service water inlet and outlet temperatures are indicated locally inside containment on one of the four cooling units.

During normal plant operation, flow through the cooling units is limited by an orifice in the common return header for containment temperature control purposes. There are two parallel bypass lines, each with an independent, full flow isolation valve which opens automatically in the event of an engineered safety feature actuation signal to bypass the orifice. Either valve is capable of passing the full flow required for all four fan cooling units. An alarm is provided in the control room which actuates on low flow in any of the cooling water return lines.

Environmental Protection

All system control and instrumentation devices required for containment accident conditions are located to minimize the danger of control loss due to missile damage.

All fan parts, back-draft dampers, cooling coils and fins and ducts in contact with the containment fluid are protected against corrosion. The fan motor enclosures, electrical insulation and bearings are designed for operation during accident conditions.

All of the air handling units are located outside the loop compartment wall (which serves as a missile barrier) at various elevations adjacent to the containment wall. The distribution header and service water cooling piping are also located outside the shield. This arrangement provides missile protection for all components.

Components - Roughing Filters

The roughing filters may be in service during refueling outages with a significant potential for a dusty containment atmosphere to remove dust and other particulate matter from the air stream before it enters the cooling coil section. They are efficient for removal of the larger dust particles, and offer a resistance to air flow of approximately 0.2 in. of water when installed.

The filters are of fire resistant construction, with the media composed of a removable glass fiber mat backed up by an expanded metal screen. The expanded metal screen is in continuous service during normal or accident modes of operation.

Accident Fan Motor Units

The accident fans are driven by totally enclosed, water cooled, 150 horsepower, induction type, 3 phase, 60 cycle, 460 volt, 1800 rpm motors with Westinghouse Thermalastic insulation. Significant motor details are as follows:

1. Insulation

   Class F (NEMA rated total temperature 155°C) Thermalastic. The basic MICA structure has high voltage turn-to-turn and coil-to-ground insulation. It is impregnated and coated to give a homogeneous insulation system which is highly impervious to moisture. Internal leads and the terminal box-motor interconnection are given special design consideration to assure that the level of insulation matches or exceeds that of the motor.

2. Heat Exchanger

   An air-to-water heat exchanger is connected to the motor to form an entirely enclosed cooling system. Air is ducted from the motor through the cooling coils and back to the motor. Two vent valves per unit permit accident ambient (increasing containment) pressure to enter the motor-air system so the bearings will not be subjected to differential pressure. It also assures pressure equalization as the containment pressure is reduced by the containment cooling systems. Water connections are welded throughout, except for the flanged connections to the heat exchanger, and are supplied from the service water header. The drain is piped to the containment fan cooler drain system.

3. Bearings

   The motors are equipped with high temperature grease-lubricated ball bearings as would be required if the bearings were subjected to incident ambient temperatures.

4. Conduit (Connection) Box

   The motor leads are brought out of the frame through a seal and into an oversized conduit box.

Cooling Coils

The coils are fabricated of copper plate fins vertically oriented on copper tubes. Air and water flow paths are arranged for counter flow. The coils are provided with drain pans and drain piping to prevent flooding during accident conditions. This condensate is drained to the containment sump.

Ducting

The ducts are designed to withstand the sudden release of reactor coolant system energy and energy from associated chemical reactions without failure due to shock or pressure waves by incorporation of pressure relieving devices along the ducts which open at slight overpressure, approximately 1.0 psi. The ducts are designed and supported to withstand thermal expansion during an accident. Where flanged joints are used, joints are provided with gaskets suitable for temperatures to 300°F.

Back-draft dampers are provided in the discharge ducting of the recirculation system to prevent backflow through an inactive unit. In addition, a damper is installed on the normal fan discharge to prevent back flow through the normal fan when it is stationary and the accident fan is in operation. All dampers are gravity operated, i.e., the damper opens due to the air pressure produced by the fan, and is counterbalanced with weights to close when this portion of the system is inactive.

All ductwork, damper blades, and seating surfaces are constructed of, or coated with, corrosion resistant surfaces.

Electrical Supply

Details of the normal and emergency power sources are presented in Section 8.0.

Further information on the components of the containment air recirculation cooling system is given in Section 5.3.

6.3.3 SYSTEM EVALUATION

Range of Containment Protection

The containment air recirculation cooling system provides the design heat removal capacity for the containment following a loss-of-coolant accident assuming that the core residual heat is released to the containment as steam. The system accomplishes this by continuously recirculating the air-steam mixture through cooling coils to transfer heat from containment to service water.

The performance of the containment air recirculation cooling system in pressure reduction is discussed in Section 14.3.4. Two of the four containment cooling fans and one of two containment spray pumps will provide sufficient heat removal capability to maintain the post accident containment pressure below the design value assuming that the core residual heat is released to the containment as steam.

The VNCC system provides a well mixed containment atmosphere with a turnover rate of approximately four air changes per hour based on 67,000 cfm flow per train and a containment volume of approximately 1 million cubic feet.

System Response

The starting sequence of the containment cooling fans and the related emergency power equipment is designed so that delivery of the minimum required air and cooling water flow is reached in a time consistent with plant design. In the analysis of the containment pressure transient, Section 14.3.4, a delay time of 84 sec. was assumed for the initiation of containment cooling fans.

Single Failure Analysis

A failure analysis has been made on all active components of the system to show that the failure of any single active component will not prevent fulfilling the design function. This analysis is summarized in Table 6.3-1. The analysis of the loss-of-coolant accident presented in Section 14.0 is consistent with the single failure analysis.

Reliance on Interconnected Systems

The containment air recirculation cooling system is dependent on the operation of the electrical and service water systems. Cooling water to the coils is supplied from the service water system. Six service water pumps are provided, only three of which are required to operate during the post accident period. One diesel generator is capable of supplying the required emergency power.

Shared Function Evaluation

Table 6.3-2 is an evaluation of the main components which have been discussed previously and a brief description of how each component functions during normal operation and during the accident.

Reliability Evaluation of the Accident Fan Cooler Motor

The basic design of the motor and heat exchanger, as described herein, is such that the accident environment is prevented, in any major sense, from entering the motor winding, or when entering in a very limited amount (equalizing motor interior pressure), the incoming atmosphere is directed to the heat exchanger coils where moisture is condensed. If some quantity of moisture should pass through the coil, the changed motor interior environment would "clean up" in that interior air continually recirculates through the heat exchanger.

It should be noted that the motor insulation hot spot is not expected to exceed normal temperature even under accident conditions.

During the lifetime of the plant, these motors perform part of the normal heat removal service and, as such, are loaded only to approximately 50 h.p.

The bearings are designed to perform in the accident ambient temperature conditions. However, the bearing housing internals are cooled by the heat exchanger. It is expected that bearing temperatures would not exceed 125°C by any significant amount even under accident conditions.

The insulation has high resistance to moisture, and tests performed indicate the insulation system would survive the accident ambient moisture condition without failure. The heat exchanger system for preventing moisture from reaching the winding therefore provides a design margin. In addition, it should be noted that at the time of the postulated accident, the load on the fan motor would increase, internal motor temperature would increase, and would therefore tend to drive any moisture present out of the windings. Additionally, the motors are furnished with insulation margin beyond the operating voltage of 460 V.

Following the accident rise in pressure, a rather slow rise, as far as equalizing pressure in the small volumes of the motor-heat exchanger is concerned, it is not expected that there will be significant mixing of the motor (closed system) environment and the containment ambient.

The heat exchanger has been designed using a very conservative fouling factor. However, if surface fouling reduces the capability of the heat exchanger by one-third, the motor would still have a normal life expectancy, even under accident conditions.

Environmental tests of the motor unit are described in Reference 4. Proof testing went beyond any simulation need to meet plant requirements, actually including nine separate accident cycles. To further demonstrate the ruggedness of the motor, windings were directly exposed to containment conditions in three of these cycles. Absence of damage from these rigorous tests confirms that the motor unit is more than adequate for the intended service.

Fan Cooler Motor Insulation Irradiation Testing

The testing program has been completed on the effects of radiation on the WF-8AC "Thermalastic" (Westinghouse Electric Corporation Trademark) epoxy insulation system used in the reactor containment fan cooler motor. Test description and results are presented in Reference 5.

Irradiation of form wound motor coil sections was accomplished up to exposure levels exceeding that calculated for the design basis loss-of-coolant accident. Three coil samples received the following treatment sequence: irradiation, high potential test, vibration test, high potential test and breakdown voltage test. Nine coil samples received an alternate treatment sequence: thermal aging, high potential test, irradiation, high potential test, vibration test. (Six of nine coil samples - high potential test and breakdown voltage test.)

All coil samples passed the high potential tests. The breakdown voltage levels of all coils were well in excess of those required by the design, and clearly indicate that the reactor containment fan cooler motor insulation system will perform satisfactorily following exposure to the radiation levels calculated for the design basis accident.

Fan Cooler Motor Lubricant Irradiation Testing

This section summarizes the results of tests performed on samples of unirradiated and irradiated Chevron BRB-2 lubricant, which is equivalent to grease used in the containment fan cooler fan bearing as well as the motor bearing (note that Chevron BRB-2 is now obsolete). The results of these tests indicate that the shear stability, or consistency, of the grease is increased by irradiation to levels anticipated in the containment following a design basis accident. The consistency of the grease following irradiation remained within the most common recommended consistency for ball bearing application (NLGI #2).

The purpose of this test program was to establish the effect of irradiation on the bearing lubricant used on both the containment fan cooler motor and fan bearing. The maximum calculated one year integrated dose on the bearing lubricant, using the design basis accident (TID-14844) with no credit for fission product removal from the containment atmosphere other than by natural decay, is 1.5×10^8 rads and would be experienced by the fan bearings. The motor bearings would receive a lesser exposure due to self shielding effects of the motor housings.

Samples of the lubricant were placed in a vented 1.5 in. × 12 in. aluminum tube. The tube was then placed adjacent to a 34 kilo-curie cobalt 60 source and irradiated for a period of 79 hours. Dosimetry measurements were made at various locations in the tube using Dupont light blue calibration paper 300 MS-C, #CB-91639.

Following exposures to average levels of 1.2×10^8 rads, 1.5×10^8 rads, and 1.8×10^8 rads, the irradiated grease along with unirradiated grease taken from the same supply were subjected to the Micro Cone Penetration Test using standard apparatus conforming to ASTM D1403-56T.

The results of the penetration test are presented on the table below. In general, it was found that as exposure was increased, the grease underwent a change in thickness function to the point that at 1.8×10^8 rads, sufficient change had taken place to cause the grease to increase in consistency to an NLGI #2 rating, as the grease was "worked" or sheared, rather than decrease as in the unirradiated grease. The most commonly used greases for ball bearing applications such as those in the containment fan cooler, have consistencies ranging between NLGI #1 and #3.

Understanding of the data listed in the Irradiation Testing table may be afforded by listing the industry standard for lubricating greases below:

NLGI Lubricating Grease Consistency Classification

Consistency Number	ASTM Worked Penetration at 77°F
0	355 to 385
1	310 to 340
2	265 to 295
3	220 to 250
4	175 to 205
5	130 to 160
6	85 to 115

A consistency of No. 0 implies a very soft semifluid grease, with numbers 1, 2, 3, etc., indicating progressively stiffer grease up to No. 6 which indicates a stiff, tacky water pump lubricant type material.

CONTAINMENT FAN COOLER - MOTOR AND FAN BEARING LUBRICANT IRRADIATION TESTING

Micro-Cone Penetration

Sample	Unworked	60 Strokes	500 Strokes	1,000 Strokes	50,000 Strokes
Unirradiated Chevron BRB-2	308	320	368	370	>400
Irradiated BRB-2 1.2×10^8R	300	300	308	324	400
Irradiated BRB-2 1.5×10^8R	308	288	292	298	364
Irradiated BRB-2 1.8×10^8R	340	320	304	296	280

Based on the test results from irradiation and ASTM micro-cone penetration measurements, Chevron BRB-2, undergoes no significant change in properties, as measured in terms of consistency.

6.3.4 REQUIRED PROCEDURES AND TESTS

Inspection Capability

Access is available for visual inspection of the containment air recirculation system components including fans, cooling coils, louvers and ductwork.

Testing - Component Testing

The containment cooling fans were shop tested for conformance to the AMCA (Air Moving and Conditioning Association) ratings performance criteria using air at standard conditions.

Application of conventional fan laws verify their ability to perform as designed under post accident conditions.

The fan motors are designed to operate in continuous normal service and under post accident containment conditions. Periodic operation of the motors and tests of the insulation ensure that the motors remain in a reliable operating condition. As described in Section 6.3.3, tests of a typical fan motor were conducted under conditions simulating the post accident environment in representative pressurized water reactor containments to verify the ability of the motors to operate through the peak accident conditions and to continue to operate thereafter under the post accident conditions.

System Testing

Each fan cooling unit was tested after installation for proper flow and distribution through the duct distribution system. Three of the fan cooling units are used during normal operation. The unit not in use can be started from the control room to verify readiness.

Each fan cooler unit is tested periodically to verify proper operation of the accident fans, backdraft dampers and service water bypass valves.

Operational Sequence Testing

Periodic tests can be conducted to demonstrate proper sequencing of the accident fan motor supplies to the emergency diesel generators in the event of loss of outside power. These tests can be conducted at the time the diesel generators are tested.

6.3.5 REFERENCES

1. VPNPD-96-081, Technical Specification Change Request 192, Modifications to Technical Specifications 15.3.3, "Emergency Core Cooling System Auxiliary Cooling Systems, Air Recirculation Fan Coolers, and Containment Spray," dated September 30, 1996

2. NRC Safety Evaluation Report dated July 9, 1997, "Issuance of Amendments Re: Technical Specification Changes For Revised System Requirements To Ensure Post-Accident Containment Cooling Capability."

3. NPL 97-0315, Supplement to Technical Specification Change Request 192, dated June 3, 1997

4. WCAP-7829, Fan Cooler Motor Unit Test, Westinghouse Proprietary, April 1972.

5. WCAP-7343-l, Topical Report - Reactor Containment Fan Cooler Motor Insulation Irradiation Testing, Westinghouse (Proprietary), July 1969.

6. SE 98-053, Unit 1 Service Water Pipe Support Modifications (Inside Containment) - Revised Thermal Mode and Hydraulic Loads, Approved March 26, 1998.

7. SE 97-191, Service Water Pipe Support Modifications (Unit 1 Outside Containment) - Revised Thermal Mode and Hydraulic Loads, Approved November 6, 1997.

8. SE 2001-0014, MR 98-024*J, Unit 1 Containment Fan Cooler and Fan Motor Cooler Replacement, Approved March 14, 2001.

9. SCR 2002-0093, MR 98-024*Y, Unit 1 "C" and "D" Containment Fan Cooler Replacement, March 22, 2002.

10. SE 98-141, MR 96-064*C, Service Water Pipe Support Modifications (Inside Containment) - Revised Thermal Mode and Hydraulic Loads, Approved October 29, 1998.

11. SE 98-142, MR 96-064*D, Service Water Pipe Support Modifications (Unit 2 Outside Containment) - Revised Thermal Mode and Hydraulic Loads, Approved October 29, 1998.

12. SE 2000-0099, MR 98-024*K, Unit 2 Containment Fan Cooler and Fan Motor Cooler Replacement, Approved October 6, 2000.

13. EVAL 2001-003, MR 98-024*X, Unit 2 “C” and “D” Containment Fan Cooler Replacement, Approved November 4, 2001.

14. Calculation 129187-M-0022, “Verification of Adequacy of Containment Fan Cooler Units During Normal Operation Under Extended Power Uprate (EPU) Conditions,” Revision 1, dated December 16, 2008.

15. Calculation 98-0172, “Containment Fan Cooler Service Water Acceptance Criteria,” Revision 4, dated September 2, 2011.

16. Holtec Report No. HI-2002418, “Thermal Performance of Containment Fan Coolers,” Revision 1, dated September 20, 2000.

17. NRC Safety Evaluation, “Point Beach Nuclear Plant (PBNP), Units 1 and 2 - Issuance of License Amendments Regarding Extended Power Uprate (TAC Nos. ME1044 and ME1045),” dated May 3, 2011.

18. NRC Safety Evaluation, “Point Beach Nuclear Plant (PBNP), Units 1 and 2 -Issuance of License Amendments Regarding Use of Alternate Source Term (TAC Nos. ME0219 and ME0220),” dated April 14, 2011.

19. Holtec Report No: HI-2002409-01, “Containment Fan Cooler Performance Testing,” dated June 7, 2000.

20. SCR 2013-0188-01, “Reduction of CFC Heat Removal Requirement,” dated November 21, 2013.

Table 6.3-1 SINGLE FAILURE ANALYSIS - CONTAINMENT AIR RECIRCULATION COOLING SYSTEM

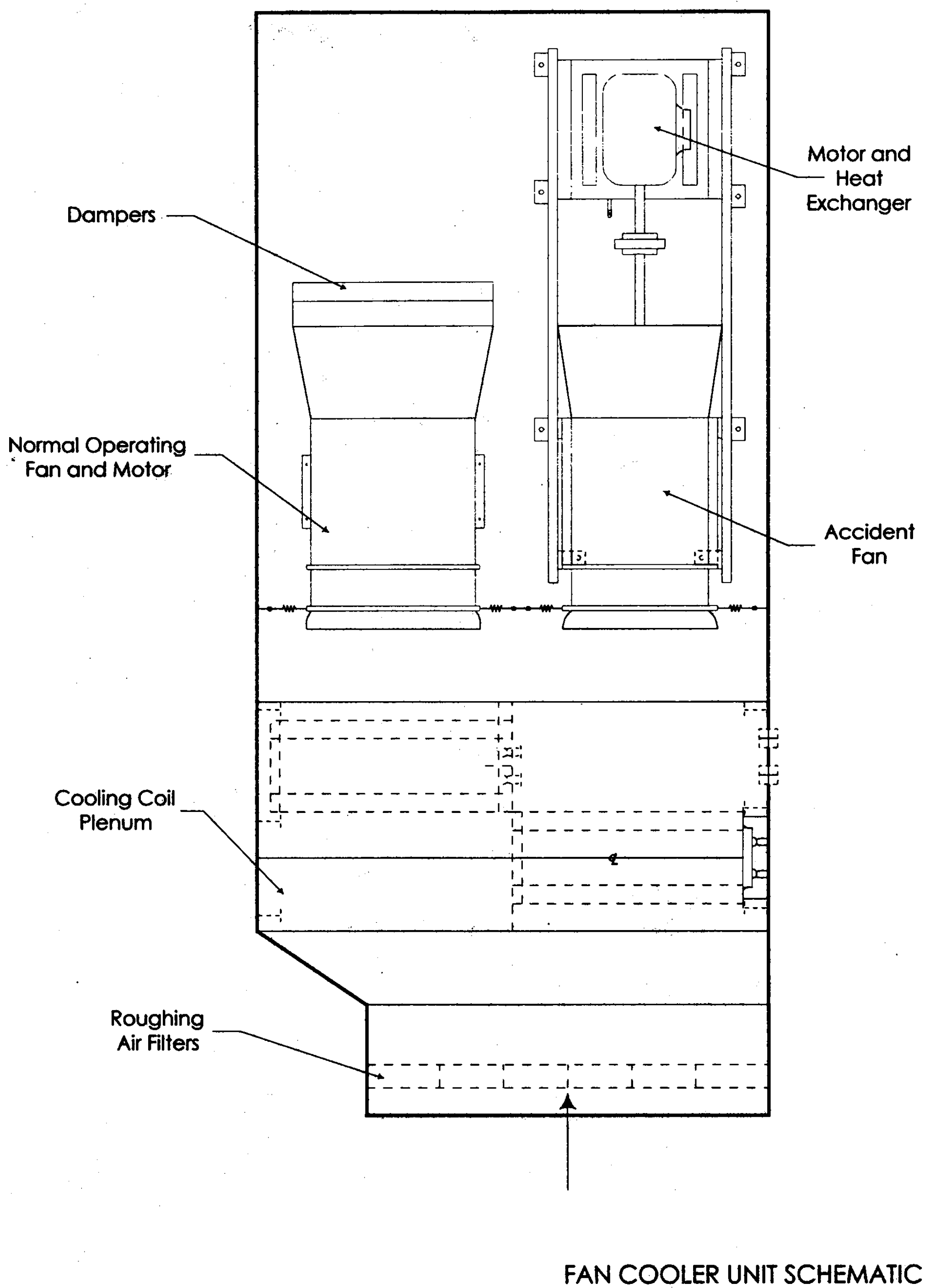
	Component	Malfunction	Comments and Consequences
A.	Containment Accident Fan Cooling	Fails to start	Four provided. Evaluation based on two fans and one containment spray pump operating
B.	Service Water Pumps	Fails to start	Six provided. Three required for operation.
C.	Automatically Operated Valves: (Open on automatic engineered safety features actuation sequence signal)		
	Service water discharge from fan cooler units	Fails to open	Two full-flow valves for four fan cooler units. Operation of one valve required.

Table 6.3-2 SHARED FUNCTION EVALUATION

	Containment Fan Cooling Unit	Service Water Pumps (6)
Normal Operating Function:	circulate and cool containment atmosphere	supply lake cooling water to fan units
Normal Operating Arrangement:	three fan cooler units in service*	two pumps in service
Accident Function:	circulate and cool containment	supply lake cooling water to CCW heat exchangers, containment fan coolers, and alternate suction source to AFW pumps
Accident Arrangement:	two fan cooler units in service with operation of the accident fan required	three pumps in service

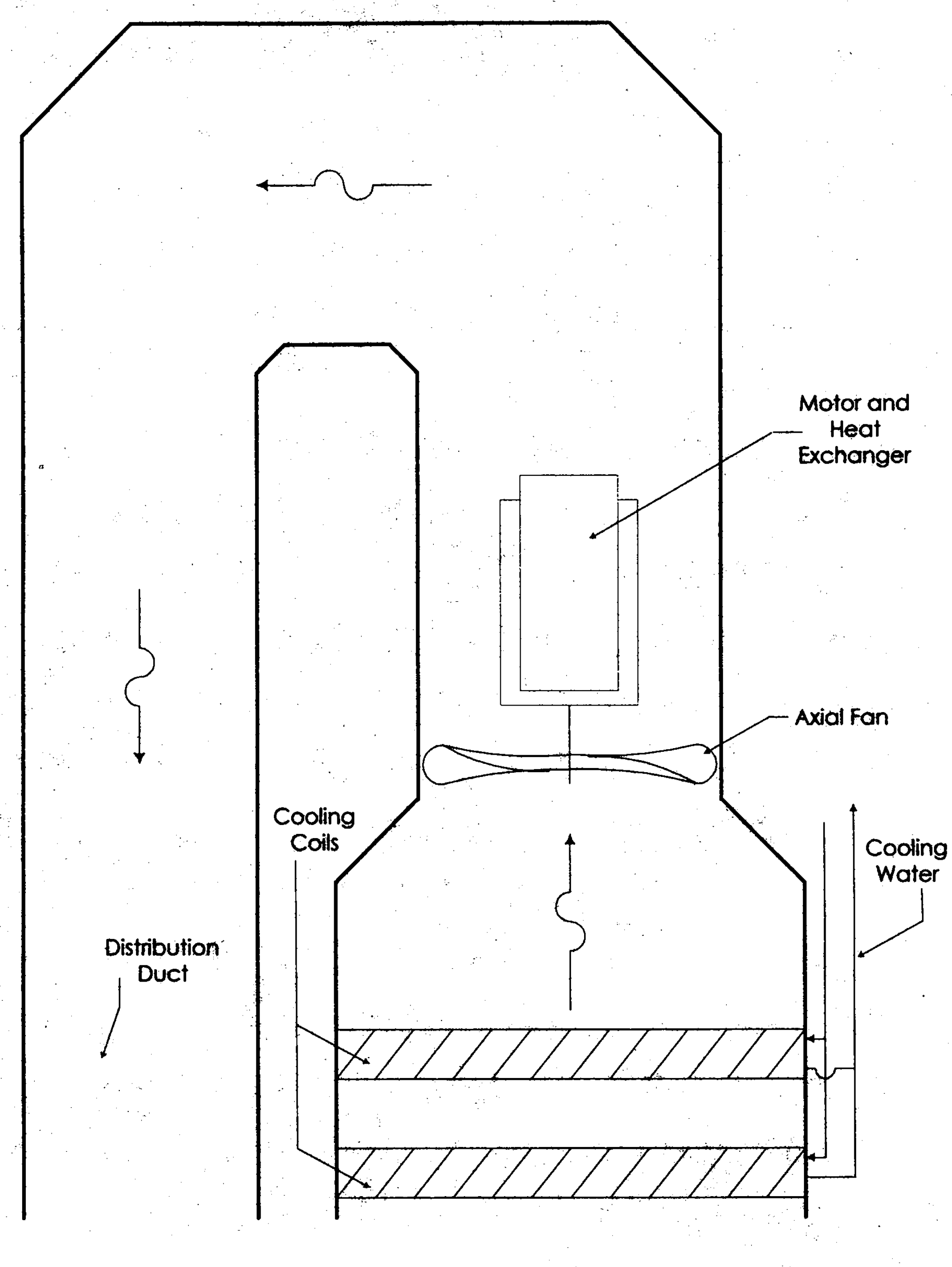
* Four air cooling units may be required to maintain containment temperature within Technical Specification limits if service water temperature increases beyond 75°F (Reference 14).

Figure 6.3-1 FAN COOLER UNIT SCHEMATIC
Sheet 1 of 2



FAN COOLER UNIT SCHEMATIC
FIGURE 6.3-1 (Sheet 1 of 2) (06/98)

Figure 6.3-1 FAN COOLER UNIT SCHEMATIC
Sheet 2 of 2



FAN COOLER UNIT SCHEMATIC
FIGURE 6.3-1 (Sheet 2 of 2) (06/98)

6.4 CONTAINMENT SPRAY SYSTEM

6.4.1 DESIGN BASES

The containment spray system has the following safety related functions:

1. Containment heat removal following a LOCA or main steam line break inside containment.

2. Iodine and particulate removal from the containment atmosphere following a LOCA.

3. Transfer of sodium hydroxide from the spray additive tank to the containment sump.

Containment Heat Removal System

A combination of one spray pump and two containment cooling fans will provide sufficient heat removal capability to maintain the LOCA post accident containment pressure below the design value of 60 psig at 286°F (100% R.H.), assuming that the core residual heat is released to the containment as steam. Containment pressure and temperature transients for loss-of-coolant accidents are presented in Section 14.3.4. The steam pipe rupture accident is discussed in Section 14.2.5.

Inspection of Containment Pressure Reducing Systems

Criterion: Design provisions shall be made to the extent practical to facilitate the periodic physical inspection of all important components of the containment pressure reducing systems, such as pumps, valves, spray nozzles and sumps. (GDC 58)

Where practicable, all active components and passive components of the containment spray systems are inspected periodically to assure system readiness. The pressure containing systems are inspected for leaks from pump seals, valve packing, flanged joints and safety valves. During operational testing of the containment spray pumps, the portions of the systems subjected to pump pressure are inspected for leaks. Design provisions for inspection of the safety injection system, which also functions as part of the containment spray system, are described in Section 6.2.4.

Testing of Containment Pressure - Reducing Systems Components

Criterion: The containment pressure reducing systems shall be designed, to the extent practical, so that active components, such as pumps and valves, can be tested periodically for operability and required function performance. (GDC 59)

All active components in the containment spray systems are adequately tested both in pre-operational performance tests in the manufacturer's shop and in-place testing after installation. Thereafter, periodic tests are also performed after any component maintenance. Testing of the components of the safety injection system used for containment spray purposes is described in Section 6.2.4.

The component cooling water pumps and the service water pumps which supply the cooling water to the residual heat exchangers are in operation on a relatively continuous schedule during plant operation. Those pumps not running during normal operation may be tested by changing the operating pump(s).

Testing of Containment Spray Systems

Criterion: A capability shall be provided to the extent practical to test periodically the delivery capability of the containment spray system at a position as close to the spray nozzles as is practical. (GDC 60)

Permanent test lines for all the containment spray loops are located so that all components up to the isolation valves at the containment may be tested. These isolation valves are checked separately.

The air test lines, for checking that spray nozzles are not obstructed, connect downstream of the isolation valves. Air flow through the nozzles is monitored by the use of a smoke generator or telltales.

Testing of Operational Sequence of Containment Pressure Reducing Systems

Criterion: A capability shall be provided to test initially under conditions as close as practical to the design and the full operational sequence that would bring the containment pressure-reducing systems into action, including the transfer to alternate power sources. (GDC 61)

Capability is provided to test initially, to the extent practical, the operational startup sequence beginning with transfer to alternate power sources and ending with near design conditions for the containment spray system, including the transfer to the alternate emergency diesel generator power source.

Inspection of Air Cleanup Systems

Criterion: Design provisions shall be made to the extent practical to facilitate physical inspection of all critical parts of containment air cleanup systems, such as ducts, filters, fans, and damper. (GDC 62)

Access is available for visual inspection of the containment spray system components.

Testing of Air Cleanup Systems Components

Criterion: Design provisions shall be made to the extent practical so that active components of the air cleanup systems, such as fans and dampers, can be tested periodically for operability and required functional performance. (GDC 63)

All active components of the containment spray system are adequately tested both in pre-operational performance tests in the manufacturer's shop and in-place testing after installation. Thereafter, periodic tests are also performed after component maintenance.

Testing Air Cleanup Systems

Criterion: A capability shall be provided, to the extent practical, for on-site periodic testing and surveillance of the air cleanup systems to ensure (a) filter bypass paths have not developed, and (b) filter and trapping materials have not deteriorated beyond acceptable limits. (GDC 64)

Permanent test lines are provided for the containment spray headers and located so that all components up to the isolation valve at the containment may be tested. These isolation valves are checked separately. Air test lines for checking the spray nozzles are connected downstream of the isolation valves. Air flow through the nozzles is monitored by a smoke generator or telltales.

Testing of Operational Sequence of Air Cleanup Systems

Criterion: A capability shall be provided to test initially under conditions, as close to design as practical, the full operational sequence that would bring the air cleanup systems into action, including the transfer to alternate power sources and the design air flow delivery capability. (GDC 65)

Means are provided to test initially under conditions, as close to design as is practical, the full operational sequence that would bring the containment spray system into action, including transfer to the emergency diesel generator power source.

Combustible Gas Control

10 CFR 50.44(b)(1): All containments must have a capability for ensuring a mixed atmosphere.

A mixed atmosphere in the containments following a LOCA takes into consideration the layout and arrangement of the containment internal structures, and active and passive mixing mechanisms. Active mixing mechanisms include air recirculation via the containment ventilation (VNCC) system through the various containment compartments and areas, and mixing promoted by the momentum transfer due to spray droplets. (Reference 9)

Performance Objectives

A design basis function of the containment spray system, in combination with the containment cooling fans, is to provide sufficient heat removal capability to maintain the post accident containment pressure below the design pressure assuming that the core residual heat is released to the containment as steam. This protection is afforded for all pipe break sizes up to and including the hypothetical instantaneous circumferential rupture of a reactor coolant pipe. Either of two trains containing a pump and associated valving and spray headers are independently capable of spraying 1070 gpm of borated water from the RWST into the containment building. During the recirculation phase of a LOCA response, either train can spray at least 900 gpm into the containment building.

A second function served by the containment spray system is to remove elemental iodine and particulates from the containment atmosphere should they be released in the event of a loss-of-coolant accident. The analysis showing the system's ability to limit off-site dose to within 10 CFR 50.67 limits after a hypothetical loss-of-coolant accident is presented in Section 14.3.5.

A third function of the containment spray system is to provide sufficient sodium hydroxide from the spray additive tank to achieve the required sump pH level in order to prevent chloride induced stress corrosion cracking and maintain iodine in the iodate form that will stay in solution.

The spray system is designed to operate over an extended time period, following a primary coolant system failure. It has the capability of reducing the containment post accident pressure and consequent containment leakage taking into account any reduction due to single failures of active components.

Portions of other systems which share functions and become part of the containment cooling system, when required, are designed to meet the criteria of this section. Any single failure of active components in such systems does not degrade the heat removal capability of containment cooling.

Those portions of the spray systems located outside of the containment which are designed to circulate radioactively contaminated water collected in the containment, under post accident conditions, meet the following requirements:

1. Adequate shielding to maintain radiation levels within the limits of 10 CFR 50.67 (Section 11.6).

2. Collection of discharges from pressure relieving devices into closed systems.

3. Means to limit radioactivity leakage to the environs, to maintain radiation dose within the limits set forth in 10 CFR 50.67.

Recirculation loop leakage is discussed in Section 6.2.3.

System active components are redundant. System piping located within the containment is redundant and separable in arrangement unless fully protected from damage which may follow any primary coolant system failure. System isolation valves relied upon to operate for containment cooling are redundant, with automatic actuation or manual actuation.

Service Life

All portions of the system located within containment are designed to withstand, without loss of functional performance, the post accident containment environment and operate without benefit of maintenance for the duration of time to restore and maintain containment conditions at near atmospheric pressure.

Codes and Classifications

Table 6.4-1 tabulates the codes and standards to which the containment spray system components are designed.

6.4.2 SYSTEM DESIGN AND OPERATION

System Description

Adequate containment cooling and removal of elemental iodine and particulates are provided by the Containment Spray System shown in Figure 6.2-1, whose components operate in sequential modes. These modes are:

1. Spray a portion of the contents of the refueling water storage tank into the entire containment atmosphere using the containment spray pumps. During this mode, the contents of the spray additive tank (sodium hydroxide) are mixed into the spray stream to provide adequate iodine removal from the containment atmosphere by a washing action.

2. Recirculation of water from the containment sump is provided by diversion of a portion of the recirculation fluid from the discharge of the residual heat removal heat exchanger to the suction of the respective spray pump after injection from the refueling water storage tank has been terminated.

The bases for the selection of the various conditions requiring system actuation are presented in Section 14.0.

The principal components of the containment spray system which provide containment cooling and removal of elemental iodine and particulates following a loss-of-coolant accident consist of two pumps, one spray additive tank, spray ring headers and nozzles, and the necessary piping and valves. The containment spray pumps and the spray additive tank are located in the auxiliary building and the spray pumps take suction directly from the refueling water storage tank. Each containment spray pump has two motor operated discharge valves configured in a parallel arrangement and powered from the same safeguards train as the associated pump. The flow path through one of the two discharge valves includes a flow restricting orifice.

The containment spray system also utilizes the two residual heat removal pumps, two residual heat exchangers and associated valves and piping of the safety injection system for the recirculation phase of containment cooling and iodine removal.

Injection Phase

During the period of time that the spray pumps draw from the refueling water storage tank, each spray pump will cause spray additive to be added to the refueling water by using a liquid eductor and the spray pump discharge. The fluid passing from the spray additive tank will then mix with the fluid entering the pump suction to produce a solution having an appropriate pH value. The pH of the sump contents must be high enough to maintain iodine in the iodate form that will stay in solution. The pH must be low enough to meet the environment qualification of equipment. The results will be a solution suitable for the removal of iodine. The minimum RWST level to ensure sufficient NPSH to the spray pumps is dependant on the number of pumps drawing water from the RWST (Reference 17).

The spray system will be actuated by the coincidence of two sets of two out of three hi-hi containment pressure signals. This starting signal will start the pumps and open the discharge valves to the spray header. The valves associated with the spray additive tank will be opened automatically two minutes after the containment spray signal is actuated. Sodium hydroxide will flow to the suction of the spray pumps and mix with refueling water prior to being discharged through the spray nozzle into the containment. If required, the operator can manually actuate the entire system from the control room and, periodically, the operator will actuate system components to demonstrate operability.

The system design conditions were selected to be compatible with the design conditions for the low pressure injection system since both of these systems share the same suction line.

The system is designed such that if the spray pump is running from a manual or automatic safeguards system start, and loss of all AC should occur, the spray pump will automatically restart when AC is restored. Also, if a containment spray signal occurs simultaneously with a safety injection signal and a loss of all AC, the spray pump will start in an appropriate time sequence to accommodate diesel loading.

Recirculation Phase

After the injection operation, it is expected that containment pressure reduction can be accomplished with the containment fan cooler units, and returning all of the recirculated water to the core. In this mode, the bulk of the core residual heat is transferred directly to the sump by the spilled coolant to be eventually dissipated through the residual heat exchanger once the sump water becomes heated. The heat removal capacity of two of the four fan coolers is sufficient to remove the corresponding energy addition to the vapor space resulting from steam boil off from the core assuming flow into the core from one residual heat removal pump at the beginning of recirculation without exceeding containment design pressure; hence, it is not expected that continued spray operation would be required for containment cooling. However, spray operation is required for a period of time during the recirculation phase for removal of elemental iodine and particulates after a hypothetical loss-of-coolant accident as discussed in Section 14.3.5. Spray flow during the recirculation phase is reduced by fully closing the spray pump discharge valve in the flow path not containing the flow restricting orifice.

Cooling Water

The cooling water for the residual heat removal heat exchangers has been described in Section 6.2.

Changeover

The procedure for the changeover of the residual heat removal pumps from injection to recirculation has been described in Section 6.2. The alignment of the containment spray pump suction to the discharge of the residual heat removal heat exchanger is accomplished manually by the operator from the control room via a series of valve alignments. RHR and spray flows are established by the preset throttle position of the SI-852A and SI-852B RHR to reactor vessel injection valves and the orifice in the open spray pump discharge valve flow path. The transfer from injection to recirculation spray can be accomplished within 20 minutes. (Reference 10)

Indication

Remotely operated valves of the containment spray system which are under manual control (i.e., valves which normally are in their ready position and do not receive a containment spray signal) have their positions indicated on a common portion of the control board. At any time during operation when one of these valves is not in the ready position for injection, it is shown visually on the control board. Flow indication is available on the main control boards to allow operators to monitor the operation of the containment spray and RHR systems during the recirculation phase.

Components

All associated components, piping, structures, and power supplies of the containment spray system are designed to Seismic Class I criteria.

The containment spray system shares the refueling water storage tank liquid capacity with the safety injection system. Refer to Section 6.2.2 for a detailed description of this tank.

Pumps

The two containment spray pumps are of the horizontal centrifugal type driven by electric motors. These motors can be powered from both normal and emergency power sources.

The design head of the pumps is sufficient to deliver rated capacity with a minimum level in the refueling water storage tank against a head equivalent to the sum of the design pressure of the containment, the head to the uppermost nozzles, and the line and the nozzle pressure losses. Pump motors are direct-coupled and large enough for the maximum power requirements of the pumps. The materials of construction are stainless steel or equivalent corrosion resistant materials. The nominal design parameters of these pumps are presented in Table 6.4-2 and in Figure 6.4-1. The nominal pump curve is degraded when containment spray flow is credited in accident analyses (Reference 11).

The containment spray pumps are designed in accordance to the specifications discussed for the pumps in the safety injection system, Section 6.2.

The pump motors are direct-coupled and nonoverloading to the end of the pump curve.

Details of the component cooling water pumps and service water pumps, which serve the safety injection system, are presented in Section 9.0.

Spray Nozzles

The spray nozzles, of the ramp bottom design, are not subject to clogging by particles less than 1/4 in. in maximum dimension, and are capable of producing a mean drop size of approximately 1,000 microns in diameter with the spray pump operating at design conditions and the containment at design pressure.

During spray recirculation operation, the water is filtered through a strainer assembly before leaving the containment sump. The individual cross sectional filter flow areas in the strainer assembly are no greater than a nominal 0.066 inch diameter opening. [redacted]

Spray Additive Tank

The capacity of the tank is sufficient to contain enough sodium hydroxide solution which, upon mixing with the refueling water from the refueling water storage tank and the borated water contained within the accumulators and primary coolant, will bring the concentration of sodium hydroxide in the containment to maintain a pH within the acceptable range of 7.0 to 10.5. The minimum pH in the containment sump needed to keep iodine in the iodate form is 7.0. A pH of greater than 7.0 assures the iodine removed by the spray is retained in the sump. The maximum pH is based on Equipment Qualification considerations and is set at 10.5 (Reference 16). The design pressure of the tank is greater than the sum of the refueling water storage tank head and the total developed head of the containment spray pumps at shutoff. A level indicating alarm is provided in the control room if, at any time, the solution tank contains less than the required amount of sodium hydroxide solution. Periodic sampling confirms that proper sodium hydroxide concentration exists in the tank.

The tank design parameters are given in Table 6.4-3.

A materials compatibility review for the spray additive tank and associated equipment during long-term storage of sodium hydroxide is presented below. The exposure conditions are shown in Table 6.4-4. The materials for the various components are shown in Table 6.4-5. The corrosion rates for the various materials at or near the long-term exposure conditions with air contamination are shown in Table 6.4-6. The resistance of most of the materials in Table 6.4-5 to caustic cracking at the exposure conditions listed in Table 6.4-4 has been reported by Logan (Reference 1) (See Figure 6.4-2). No caustic cracking of 17-4 PH (Reference 2) or stellite has been reported.

The effect of carbon dioxide from air exposure on corrosion of iron is shown in Figure 6.4-3 (Reference 3). At pH 14, no additional corrosion is observed over that observed in a carbon dioxide free solution. The spray additive tanks can be maintained with nitrogen or air over the sodium hydroxide solution.

The Nordel (Reference 4) rubber diaphragm material was exposed in 33 wt.% sodium hydroxide solution at 110^{o}F for six months and found to be unaffected by the simulated spray additive tank solution. The completely unchanged appearance of Nordel rubber after six months exposure in sodium hydroxide solution indicates that integrity of the Nordel rubber diaphragm in the spray additive tank valves is not affected by long-term exposure to spray additive solution.

The integrity of the structural materials in the spray additive tank system is not adversely affected using the corrosion rates presented in Table 6.4-6 where air contamination is present.

Diamond Shamrock Company (Reference 5) reported no galling of steel valves occurred after exposure to 50% sodium hydroxide at 120°F to 140°F for greater than three years. One would expect equivalent or superior performance for stainless steel valves.

The total corrosion product released to the spray additive tank as oxide would be less than 1,000 grams per year with aerated solution.

This small quantity of corrosion product should not present any problems with clogging of delivery lines.

No sodium hydroxide precipitation will occur for a 30 wt.% solution if the temperature of the tank and liners are maintained above 35°F. Since this system is located in an area of the auxiliary building which is continuously heated, no solid sodium hydroxide would be present and therefore no clogging of the lines could occur.

<u>Heat Exchangers</u>

The two residual heat removal heat exchangers which are used during the recirculation phase are described in Section 6.2.

Valves

The valves for the containment spray system are designed in accordance to the specifications discussed for the valves in the safety injection system. Valving descriptions and valve details are shown in Section 5.2.2 and 6.2.2.

Piping

The piping for the containment spray system is designed in accordance to the specifications discussed for the piping in the safety injection system (Section 6.2). The system is designed for 150 psig at 300°F on the suction side of the spray pumps and 300 psig at 300°F on the discharge side up to the nozzles in the containment. Test lines for the containment spray pumps are designed for 550 psig at 100°F. 100°F corresponds to the thermal operating mode of the pump test.

Motors for Pumps and Valves

The motors for the containment spray system are designed in accordance to the specifications discussed for motors in the safety injection system. Spray pump control is such that if the spray pump is running from an automatic or manual safeguards system start and a loss of AC occurs, the pump will be automatically restarted when AC is restored. Also, the spray pump control circuitry is such that if a containment spray signal simultaneous with a safety injection signal and loss of AC occurs, the pump will start in an appropriate sequence to accommodate diesel loading.

Electrical Supply

Details of the normal and emergency power sources are presented in the discussion of the electrical system, Section 8.0.

Environmental Protection

The spray headers are located outside and above the reactor and steam generator concrete shield. During operation, a missile shield also provides missile protection for the area immediately above the reactor vessel. The spray headers are therefore protected from missiles originating within the shield.

All of the active components of the containment spray system are located outside the containment, and hence are not required to operate in the steam-air environment produced by the accident.

Material Compatibility

Parts of the system in contact with borated water, the sodium hydroxide spray additive, or mixtures of the two are stainless steel or an equivalent corrosion resistant material.

6.4.3 SYSTEM EVALUATION

Range of Containment Protection

One containment spray pump and two of the four containment cooling fans will provide sufficient heat removal capability to maintain the post accident containment pressure below the design value, assuming that all the core residual heat is released to the containment as steam. This applies for all reactor coolant pipe sizes up to and including the hypothetical instantaneous circumferential rupture of a reactor coolant pipe. After the injection phase, either train of the recirculation system provides sufficient cooled recirculated water to keep the core flooded. With a recirculation train in operation, two of the four fan coolers are sufficient to remove the heat addition. It is not expected that continued spray operation would be required for containment cooling.

During the injection and recirculation phases, the spray water is raised to the temperature of the containment in falling through the steam-air mixture. The minimum fall path of the droplets is approximately 70 ft. from the lowest spray ring headers to the operating deck. The actual fall path is longer due to the trajectory of the droplets sprayed out from the ring header. Heat transfer calculations, based upon 1,000 micron droplets, show that thermal equilibrium is reached in a distance of approximately 5 ft. Thus, the spray water reaches essentially the saturation temperature. The model for spray droplet heat removal is discussed in Section 14.3.4.

At containment design pressure, 60 psig, 1,070 gpm of sodium hydroxide/ boric acid solution is injected into the containment atmosphere by one spray pump. At containment design temperature, 286^{o}F, the total heat absorption capability of one spray pump is about 110×10^6 BTU/hr based on addition of 100^{o}F refueling water. During the recirculation phase, spraying 900 gpm of water from the sump into the containment atmosphere can be continued with one spray pump. The sump water is cooled with a residual heat removal heat exchanger, and the resulting heat removal is sufficient to continue to limit the containment pressure well below design.

<u>Fission Product Removal Effectiveness</u>

In addition to heat removal, the spray system is effective in scrubbing fission products from the containment atmosphere. However, quantitative credit is taken only for absorption of reactive and/or soluble forms of inorganic iodine and particulates in the analysis of the hypothetical accident (Section 14.3.5). A discussion of the effectiveness of containment spray as a fission product trapping process is contained in Appendix C. The iodine and particulate spray coefficients, spray duration time, and other assumptions relating to the modeling of removal of activity from the containment following a large break LOCA are described in FSAR Section 14.3.5.

During post accident operation of the containment spray system, dilution and partial neutralization of the NaOH additive occurs in two stages: first, as the 30 wt.% NaOH mixes with refueling water in the spray pump suction piping, and, second, as the spray solution combines with emergency core cooling water in the containment sump. The protective coatings used within the containment will not deteriorate in a post accident environment in a manner that would reduce the performance capabilities of the engineered safety feature system as per the evaluation presented in WCAP-7198L (Reference 15), as well as the coating program described in Section 1.4 and 6.2.3.

In the early minutes of the sump mixing stage, there is potentially an excess of H_3BO_3 due to the introduction of the contents of the accumulators, the inventory of the reactor coolant system, and the contents of the RWST.

During the injection period, boric acid and sodium hydroxide are mixed and added to the containment via the spray headers. Approximately 30% of the available sodium hydroxide will enter the containment during the injection phase, during which time the spray pH will be between ~8.5 and 9.5. Prior to commencing containment sump recirculation, the flow of sodium hydroxide to the spray pump suction is stopped to prevent a high pH spray to containment that otherwise would occur during recirculation. During the recirculation period, the sump pH will be within the acceptable range of 7.0 to 10.5. The minimum pH in the containment sump needed to keep iodine in the iodate form is 7.0. The pH of the sump water will remain above 7 for 30 days post-LOCA. The maximum pH is based on Equipment Qualification considerations and is set at 10.5. (Reference 10, Reference 16)

The capacity of one containment spray pump will provide sufficient removal of elemental iodine and particulates to ensure post accident fission product leakage would not result in exceeding the dose limits of 10 CFR 50.67. This is evaluated in Section 14.3.5.

System Response

The starting sequence of the containment spray pumps and their related emergency power equipment is designed so that delivery of the minimum required flow is reached within the time assumed in the containment integrity analysis (Section 14.3.4). As described previously, the initiation of the addition of sodium hydroxide to the spray flow is automatic with capability for operator override.

Single Failure Analysis

A failure analysis has been made on all active components of the system to show that the failure of any single active component will not prevent fulfilling the design function. This analysis is summarized in Table 6.4-7.

In addition, each spray pump is supplied from the discharge of one of the two residual heat removal heat exchangers. As described in Section 6.2.3, these two heat exchangers are redundant and can be supplied with recirculated water via separate and redundant flow paths. The analysis of the loss-of-coolant accident presented in Section 14.0 reflects the single failure analysis.

Reliance on Interconnected Systems

The containment spray system initially operates independently of other engineered safety features following a loss-of-coolant accident. For extended operation in the recirculation mode, water is supplied through the residual heat removal pumps. Spray pump seal water cooling is supplied from the component cooling loop.

During the recirculation phase, some of the flow leaving the residual heat exchangers may be bled off and sent to the suction of either the containment spray pumps or the high head safety injection pumps. Minimum flow requirements will be set for the flow being sent to the core and for the flow being sent to the containment spray pump suction. Sufficient flow instrumentation is provided so that the operator can perform appropriate flow adjustments with the remote throttle valves in the flow path as shown in Figure 6.2-1.

Normal and emergency power supply requirements are discussed in Section 8.0.

Shared Function Evaluation

Table 6.4-8 is an evaluation of the main components which have been discussed previously and a brief description of how each component functions during normal operation and during the accident.

Containment Spray Pump NPSH Requirements

The Net Positive Suction Head (NPSH) for the containment spray pumps was evaluated for both the injection and recirculation phases of operation (Reference 17).

During the injection phase the spray pump takes suction from the RWST. Available NPSH is dependant on the RWST level, RWST temperature, and the number of systems taking water from the RWST. Plant operating procedures ensure adequate water levels are maintained in the RWST such that spray pump NPSH requirements are satisfied.

During the recirculation phase the spray pump takes suction from the RHR system (the discharge of the RHR heat exchangers) which takes suction from the containment sump. There is adequate NPSH for the Containment Spray pumps during recirculation spray operation, with both the RHR and the Containment Spray pumps injecting, as long as containment spray is aligned through the reduced flow path and the SI-852 valves are throttled to the intermediate position. The available NPSH is adequate without crediting containment sump suction pressure in excess of normal atmospheric pressure.

6.4.4 REQUIRED PROCEDURES AND TESTS

Inspection Capability

All components of the containment spray system can be inspected periodically to demonstrate system readiness. The pressure containing systems are inspected for leaks from pump seals, valve packing, flanged joints and safety valves during system testing. During the operational testing of the containment spray pumps, the portions of the system subjected to pump pressure are inspected for leaks.

Component Testing

All active components in the containment spray system are tested both in pre-operational performance tests in the manufacturer's shop and in-place testing after installation. The containment spray pumps can be tested singly using the full flow recirculation line. Each pump in turn can be started by operator action and checked for flow establishment. The spray injection valves can be tested with the pumps shut down.

The spray additive tank valves can be opened periodically for testing. The contents of the tank are periodically sampled to determine that the proper solution is present.

The containment spray nozzle availability is tested by blowing smoke or a gas mixture through the nozzles and observing the flow through the various nozzles in the containment visually or by telltales.

During these tests, the equipment was visually inspected for leaks. Leaking seals, packing, or flanges were tightened to eliminate any leak. Valves and pumps are operated and inspected after any maintenance to ensure proper operation.

System Testing

Permanent test lines for all containment spray loops are located so that the system, up to the isolation valves at the spray header, can be tested. These isolation valves can be checked separately.

The air test lines, for checking the spray nozzles, connect downstream of the isolation valves. Air flow through the nozzles is monitored by the use of a smoke generator or telltales.

Operational Sequence Testing

The functional test of the safety injection system described in Section 6.2.4 demonstrates proper transfer to the emergency diesel generator power source in the event of loss of power. A test signal simulating the containment spray signal is used to demonstrate operation of the spray system up to the isolation valves on the pump discharge.

6.4.5 REFERENCES

1. The Stress Corrosion of Metals by H. L. Logan, John Wiley & Sons, Inc. New York, 304 and 316 Stainless Steel, page 138, 410 Stainless Steel, page 101, A-516 - GR-70, Page 44.

2. Letter from R. R. Gaugh, Armco Steel of Data from an Armco Internal Report, dated September 26, 1969, to D. D. Whyte.

3. Corrosion Causes and Prevention by F. N. Speller, McGraw Hill Book Company, Inc., New York, 1951, page 195.

4. Nordel is a product of Dupont de Nemours and Company.

5. Personal communication with Robert Sheppard, Assistant Plant Manger, Divisional Technical Center of Diamond Shamrock Company, Painsville, Ohio.

6. A Guide to Corrosion Resistance, J. P. Polar (Climax Molybdenum).

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8. Metals Handbook, 8th Edition, Volume 1, Properties and Selection of Metals, Page 670 (American Society for Metals).

9. NRC Safety Evaluation, “Point Beach Nuclear Plant (PBNP), Units 1 and 2 - Issuance of License Amendments Regarding Extended Power Uprate (TAC Nos. ME1044 and ME1045),” dated May 3, 2011.

10. NRC Safety Evaluation, “Point Beach Nuclear Plant (PBNP), Units 1 and 2 -Issuance of License Amendments Regarding Use of Alternate Source Term (TAC Nos. ME0219 and ME0220),” dated April 14, 2011.

11. Calculation 2006-0021, ECCS System Accident Analysis Flow Inputs, Revision 0.

12. Not Used

13. Not Used

14. Not Used

15. WCAP-7198L, “Evaluation of Protective Coatings for Use in Reactor Containment,” Revision 0, April 1968.

16. Point Beach Calculation 2000-0036, “pH of Post LOCA Sump and Containment Spray,” Revision 2.

17. Calculation N-92-086, “ECCS Pump Protection,” Revision 4.

Table 6.4-1 CONTAINMENT SPRAY SYSTEM-CODE REQUIREMENTS

Component	Code
Spray Additive Tank	ASME Section III Class C
Valves	USAS B16-5/ANSI B16.34
Piping (including headers and spray nozzles)	USAS B31.1

Table 6.4-2 CONTAINMENT SPRAY PUMP DESIGN PARAMETERS

Quantity	2/Unit
Design pressure, discharge, psig	300
Design temperature, °F	300
Design flow rate, gpm	1200
Design head, ft.	475
Shutoff head, ft.	550
Motor HP	200
Type	Horizontal-Centrifugal

Table 6.4-3 SPRAY ADDITIVE TANK DESIGN PARAMETERS

Number	1/Unit
Total volume, gal.	5,100
Minimum volume at operating conditions (solution), gal.	2,675
NaOH concentration, wt. %	30
Design temperature, °F	300
Design pressure, psig	300
Material	304 stainless steel cladding on steel A-516, GR-70

Table 6.4-4 EXPOSURE CONDITIONS

Temperature, °F	110
Sodium Hydroxide Concentration, wt. %	30

Table 6.4-5 COMPONENT MATERIALS

Component	Material
Spray Additive Tank	304 stainless steel cladding on steel A-516, GR-70
Piping	304 stainless steel
Valve Bodies	304 and 316 stainless steel
Valve Seats	Austenitic stainless steel or Stellite
Valve Stems	17-4 PH and 410 stainless steel
Valve Diaphragm	Ethylene-Propylene Dipolymer (Nordel rubber by Dupont)

Table 6.4-6 CORROSION RATES

Material	Temperature F	NaOH Concentration wt.%	Aeration	Corrosion Rates, mils/yr	Reference No.
304 S/S	136	22 to 50	Yes	<0.1	6
316 S/S	125	30	Yes	<2	7
Steel	179	30 to 50	Yes	<20	7
410 S/S	125	30	Yes	<2	7
17-4 PH	176	30	Yes	3 to 6	2
Stellite	150	50	Yes	<0.6	8
Nordel Rubber	110	33	Yes	<0.004	9

Table 6.4-7 SINGLE FAILURE ANALYSIS - CONTAINMENT SPRAY SYSTEM

Component	Malfunction	Comments and Consequences
A. Spray Nozzles	Clogged	Large number of nozzles (180) renders clogging of a significant number of nozzles as incredible.
B. Pumps		
l. Containment Spray Pump	Fails to start	Two provided. Evaluation based on operation of one pump in addition to two out of four containment cooling fans operating during injection phase and operation of one pump in the recirculation phase.
2. Residual Heat Removal Pump	Fails to start	Two provided. Evaluation based on operation of one pump during recirculation phase.
3. Service Water Pump	Fails to start	Six provided. Operation of three pumps during recirculation required.
4. Component Cooling	Fails to start	Two provided. Operation of one pump during recirculation required.
C. Automatically operated valves: (Open on coincidence of two 2/3 high (Hi-Hi) containment pressure signals)		
1. Containment Spray Pump Discharge Isolation Valve	Fails to open	Four provided (two per train) Evaluation based on operation of one train in addition to two out of four containment cooling fans operating during injection phase.
D. Valve Operated from Control Room		
1. Injection		
a. Spray Additive Tank Outlet Isolation Valve	Fails to open	Two provided. Operation of one required.
2. Recirculation		
a. Containment sump recirculation isolation	Fails to open	Two lines in parallel each with two valves in series. One line required.
b. Containment spray pump isolation valve from residual heat exchangers	Fails to open	Two valves provided. One normally closed valve per line. Operation of one required.
c. Residual heat removal pump suction isolation from refu- eling water storage tank line	Fails to close	Check valve in series with an isolation valve in the suction line to each pump. Operation of one valve in each line required.

Table 6.4-8 SHARED FUNCTIONS EVALUATION

Component	Normal Operating Function	Normal Operating Arrangement	Accident Function	Accident Arrangement
Spray Additive Tank	None	Lined up for spray water diversion	Source of sodium hydroxide for spray water	Lined up to spray eductor
Containment Spray Pumps (2)	None	Lined up to spray headers	Supply spray water to containment atmosphere	Lined up to spray headers

NOTE: Refer to Section 6.2 for a brief description of the refueling water storage tank, residual heat removal pumps, service water pumps, component cooling pump, residual heat exchangers and component cooling heat exchangers which are also associated either directly or indirectly with the containment spray system.

Figure 6.4-1 CONTAINMENT SPRAY PUMP PERFORMANCE CHARACTERISTICS

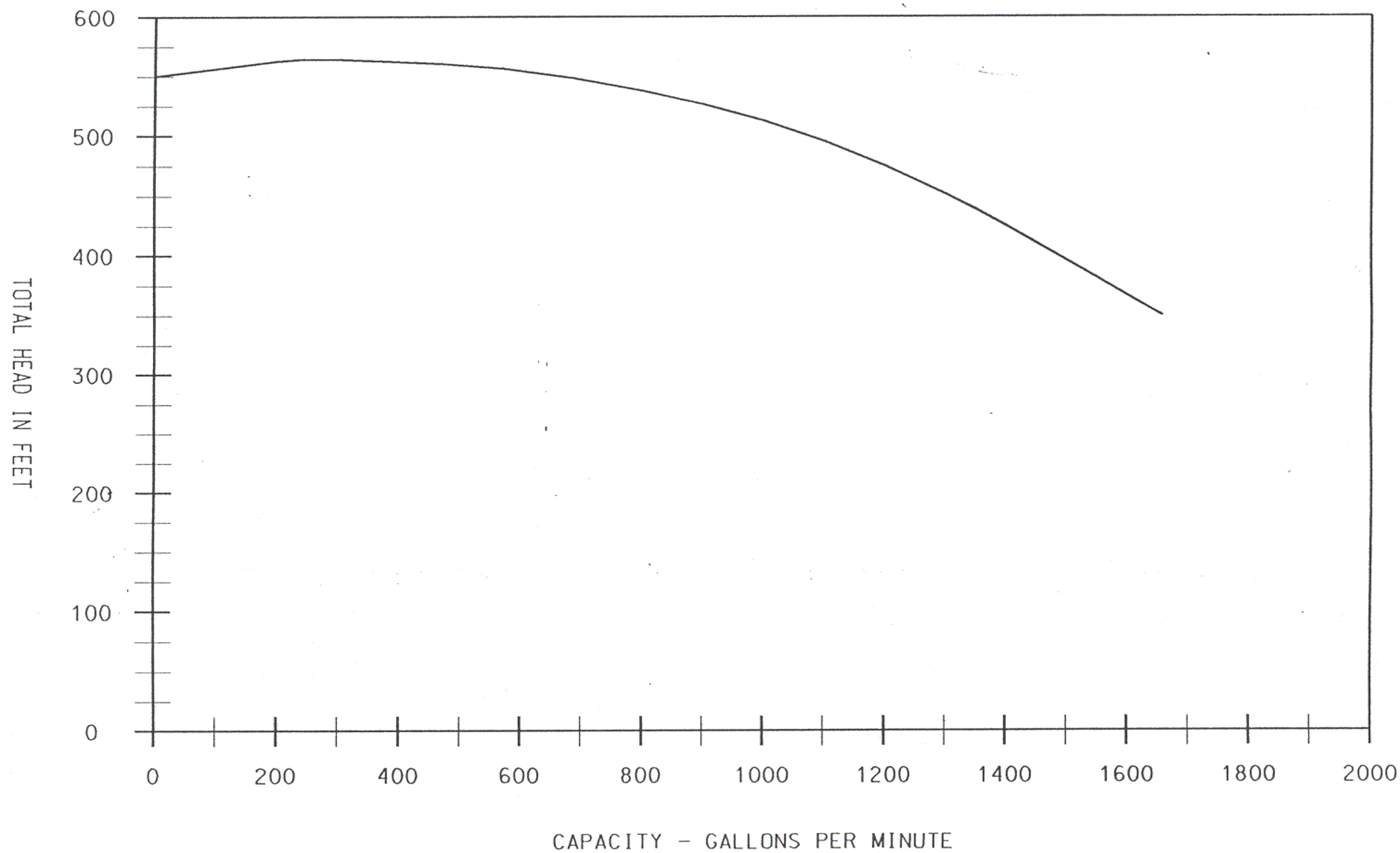


Figure 6.4-2 TEMPERATURE - CONCENTRATION RELATION FOR CAUSTIC CORROSION OF AUSTENITIC STAINLESS STEEL

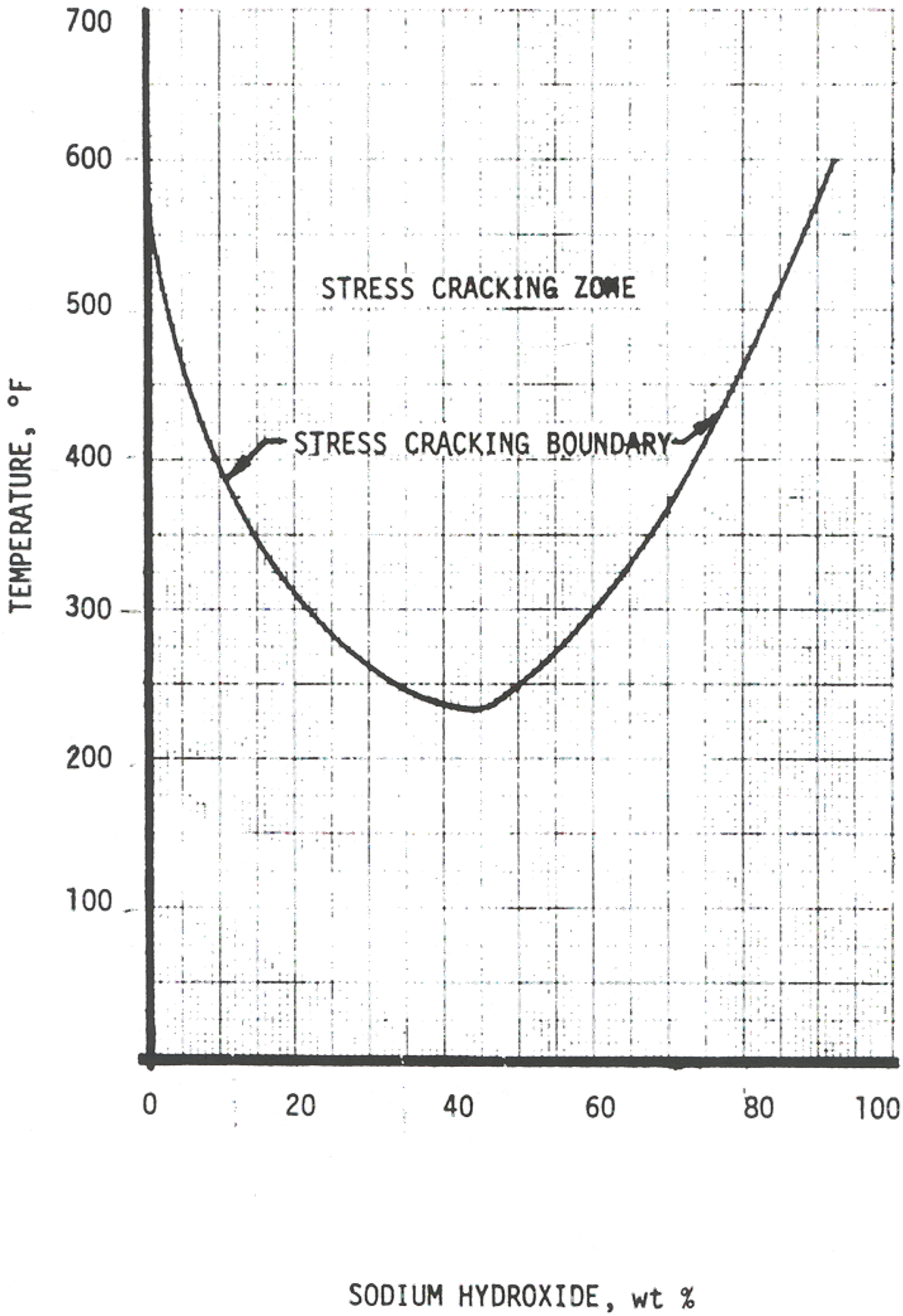
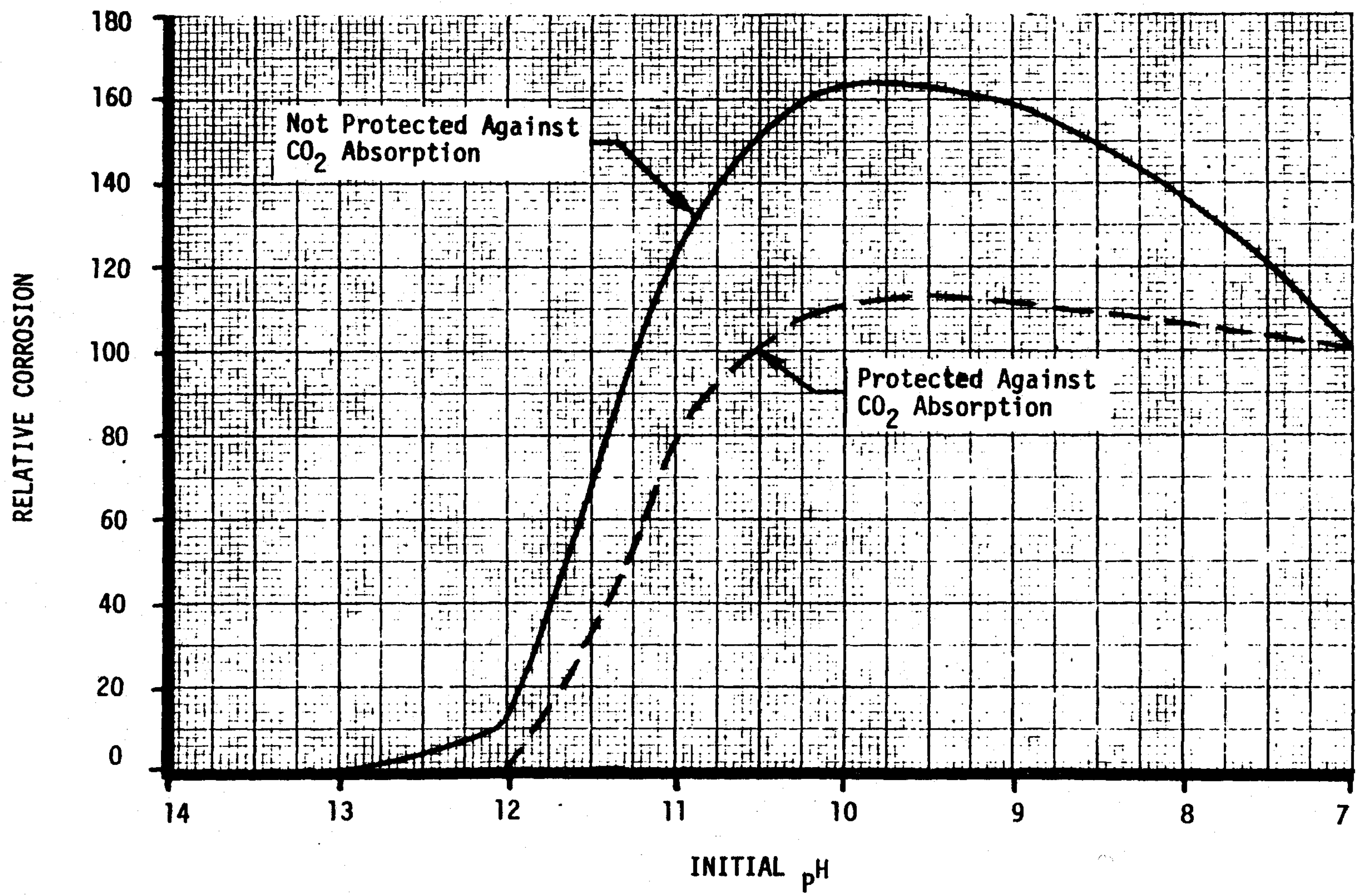


Figure 6.4-3 EFFECT OF CARBON DIOXIDE ON CORROSION OF IRON IN NaOH SOLUTION



6.5 LEAKAGE DETECTION SYSTEMS

The leak detection systems reveal the presence of significant leakage from the reactor coolant, residual heat removal, and component cooling systems.

6.5.1 DESIGN BASIS

Monitoring Reactor Coolant Leakage

Criterion: Means shall be provided to detect significant uncontrolled leakage from the reactor coolant pressure boundary. (GDC 16)

Positive indications in the control room of leakage of coolant from the reactor coolant system to the containment are provided by equipment which permits continuous monitoring of containment air activity and humidity, and of runoff from the air recirculation units and containment floor drains to containment Sump A. This equipment provides indication of normal background which is indicative of a basic level of leakage from primary systems and components. Any increase in the observed parameters is an indication of change within the containment, and the equipment provided is capable of monitoring this change. The basic design criterion is the detection of deviations from normal containment environmental conditions including air particulate activity, gaseous activity, humidity, condensate and floor drain runoff and, in addition, in the case of gross leakage, the liquid inventory in the process systems and containment sump. See Section 15.4.3 for additional information regarding leak detection requirements for leak-before-break analyses.

Criterion: Means shall be provided for monitoring the containment atmosphere and the facility effluent discharge paths for radioactivity released from normal operations, from anticipated transients, and from accident conditions. An environmental monitoring program shall be maintained to confirm that radioactivity releases to the environs of the plant have not been excessive. (GDC 17)

The following are monitored for radioactivity concentrations during normal operation, anticipated transients, and accident conditions: the containment atmosphere, the exhausts from the 54 in. auxiliary and service building vent, the 46 in. drumming area vent, the 36 in. containment area vents, the 4 in. combined air ejector exhaust vent, the service water discharge from the containment fan coolers, the component cooling loop liquid, the liquid phase of the secondary side of the steam generator, waste disposal system liquid discharge, spent fuel pool heat exchanger service water return, waste distillate discharge, gas stripper building ventilation exhaust, service water discharge, wastewater effluent, steam line atmospheric release, and the condenser air ejector. GDC 17 is also addressed in Section 11.4, Radiation Protection. A continuing environmental monitoring program, discussed in Section 2.0, is maintained.

Principles of Design

The principles for design of the leakage detection systems can be summarized as follows:

1. Increased leakage could occur as the result of failure of pump seals, valve packing glands, flange gaskets, or instrument connections. The maximum leakage rate calculated for these types of failures is 50 gpm which would be the anticipated flow rate of water through the pump seal if the entire seal were wiped out and the area between the shaft and housing were completely open.

2. The leakage detection systems shall not produce spurious annunciation from normal expected leakage rates but shall reliably annunciate increasing leakage.

3. Increasing leakage rate shall be annunciated in the control room. Operator action will be required to isolate the leak in the offending system.

6.5.2 SYSTEM DESIGN AND OPERATION

Various methods are used to detect leakage from either the reactor coolant, residual heat removal or component cooling systems. Although described to some extent under each system description, all methods are included here for completeness.

Reactor Coolant System

During normal operation and anticipated reactor transients, the following methods are employed to detect leakage from the reactor coolant system.

Containment Air Radiation Monitoring System

The Containment Air Radiation Monitoring System is a subsystem of the Radiation Monitoring System described in Section 11.5. The primary purpose of the equipment is to sample and monitor containment air for radioactive particulates and noble gases. Additional capability for sampling, venting, and quantifying releases and release rates is also provided by the system. The typical system alignment and essential components are shown in Figure 6.5-1.

The system is comprised of a particulate and noble gas sampling pallet, valving controls, flow instrumentation, tubing, and air pumps. The design of the system allows for continuous sampling of containment air, sampling of the containment purge exhaust stack, venting the containment air, sampling of containment air via test connections, obtaining a post accident sample of containment atmosphere, and flushing post accident atmosphere from sampling lines. Automatic valves providing remote alignment for most sampling MODES can be controlled from the Auxiliary Safety Instrumentation Panels (ASIP) in the control room. Manual operations are required at the RE-211/212 cubicles for samples taken either post accident or via test connections. For post accident sampling, manual operations are performed outside the RE-211/212 cubicle. Containment penetrations serve to provide containment air to the equipment and a return path for discharge to the containment.

The containment atmosphere post-accident sampling system, in conjunction with associated sampling equipment and procedure guidance, is designed to meet the requirements of NUREG-0737, Item II.B.3. This included obtaining and analyzing a sample without radiation exposure to any individual exceeding the criteria of 10 CFR 50, Appendix A, GDC 19, i.e., 5 rem whole body, 75 rem extremities. The system is designed to allow sampling containment up to containment pressure of 60 psig (Reference 2, Reference 3, Reference 6 and Reference 7).

The heart of the particulate-noble gas detection system lies in the sampler assembly and associated radiation detectors. Air is drawn into the system by activating a motor-driven sample pump. The sample pump takes a suction on the selected source (containment atmosphere, purge exhaust stack, facade) and draws the air through a dual-chamber sampler assembly. The two chambers of the sampler assembly are connected for series sample flow. Air entering the first chamber passes through a fixed filter paper assembly. Particles in the air are trapped on the filter paper which is monitored by a beta scintillation detector (RE-211). After passing through the filter paper, the air sample is then routed to the second chamber, a fixed, cylinder-shaped volume monitored by another beta scintillation detector (RE-212). This detector serves to monitor activity from activated noble gases.

The beta scintillation detectors used to detect activity in both the particulate and noble gas sampler assembly chambers are identical. They are aluminum, cylindrically shaped, 2-inch diameter scintillation detectors, utilizing an aluminized mylar (1.6 mg/cm^2) window and a 0.010 inch thick plastic beta crystal. These detectors are lead shielded to mitigate detection of area gamma radiation. The particulate monitor is capable of detecting particulate activity in concentrations as low as 10^{-8} μCi/cc, with a range of 10^{-8} to 10^{-3} μCi/cc. The noble gas monitor will sense gaseous activity in the range of 10^{-7} to 10^{-1} μCi/cc.

The output of the detectors is fed to interface boxes, which act as signal conditioners for input to a data acquisition module (DAM). The DAM is polled by control terminals (CTs), located in the control room and the Technical Support Center (TSC).

The system has the following modes of operation:

1. Containment Sample - Air from containment is drawn through the particulate and noble gas sampler and is pumped back into containment.

2. Containment Sample with Continuous Vent - Air from containment is drawn through the particulate and noble gas sampler and is pumped back into containment. In addition, a path for the discharge of containment air to the atmosphere through the containment purge exhaust stack filters is opened.

3. Stack Sample - Air from the containment purge exhaust stack is drawn through the particulate and noble gas sampler and is pumped back to the stack or containment.

4. Purge - Air from the facade is drawn through the particulate and noble gas sampler and is pumped to the purge exhaust stack or containment.

5. Independent Sample - Containment air is drawn through system test connections by sampling equipment independent of RE-211/212.

6. Post accident sample - RE-211/212 are isolated and an eductor is used to draw a sample from containment for lab analysis. After sampling, the system will be flushed with an inert gas.

The control function of the containment air monitors is to initiate containment ventilation isolation (CVI). The initiation of CVI is based upon a high alarm signal from the noble gas monitor (RE-212) only. The reason for using only the noble gas monitor vice using both monitors (particulate and noble gas) is that the particulate monitor (RE-211) is a fixed-filter monitor which would require an alarm output based on a trend.

The CVI signal based on the noble gas monitor high alarm will close the containment purge supply and exhaust duct valves. In addition, the CVI signal will also secure continuous vent operation. The CVI signal does not interrupt the monitoring of containment air.

Containment High Range Radiation Monitors

These radiation monitor channels are used for monitoring post-accident containment conditions. [redacted] The ion chambers have a range of 10^{0}-10^{8} R/hr with indication on 1(2) C20 in the control room.

Humidity Detector

The humidity detection instrumentation offers another means of detection of leakage into the containment. Although this instrumentation has not nearly the sensitivity of the air particulate monitor, it has the characteristics of being sensitive to vapor originating from all sources within the containment, including the reactor coolant, main steam, and feedwater systems. Plots of containment air dewpoint variations above a baseline maximum established by the cooling water temperature to the air coolers should be sensitive to incremental leakage equivalent to 2 to 10 gpm.

The sensitivity of this method depends on cooling water temperature, containment air temperature variation, and containment air recirculation rate.

Condensate Measuring System

This leak detection method is based on the principle that the condensate collected by the cooling coils under equilibrium conditions plus liquid collected by the containment floor drains matches the leakage of water and steam from systems within the containment.

The containment cooling coils are designed to remove the sensible heat generated within the containment. The resulting large coil surface area has the effect that the exit air from the coils has a dewpoint temperature which is very nearly equal to the cooling water temperature.

Measurement of the condensate drained from each of the fan cooler units is made to determine condensation rate. This volume in conjunction with the floor drain run-off to the condensate measuring system determines the leak rate.

Should a leak occur, the condensation rate will increase above the previous steady state due to the increased vapor content of the fan cooler air intake. The time required for the new equilibrium rate to be reached varies with the initial containment conditions, service water temperature and the conditions of the reactor coolant at the leak location (Reference 5). The condensate measuring system meets the leak before break performance requirement of detecting RCS leakage of 1 gpm in 4 hours (Reference 4). Readout of the condensate measuring device level channel is provided in the control room. A high level alarm is provided to alert the operator to significant increases in the condensate flow rate.

Component Cooling Liquid Monitor

This channel continuously monitors the component cooling system for activity indicative of a leak of reactor coolant from either the reactor coolant system or the recirculation or residual heat removal system. A scintillation counter is located in an inline well at the component cooling pump suction header. The detector assembly output is amplified by a preamplifier, processed by a discriminator and pulse shaper, and then is carried to its electronic channel on the data acquisition module (DAM) where it is counted and processed. Control terminals (CTs) in the control room and Technical Support Center (TSC) poll the DAMs for this information. A high activity alarm would be annunciated at the unit Auxiliary Safety Instrumentation Panel (ASIP) as well as the radiation monitoring system control terminals.

The range of this monitor is 10^{-5} to 10^{0} μCi/cc.

Condenser Air Ejector Gas Monitor

This channel monitors the discharge from the air ejector exhaust header of the condensers for gaseous radiation which is indicative of a primary-to-secondary system leak. The gas discharge is routed via a radioactivity decay duct to the auxiliary building vent.

The detector output is transmitted to the radiation monitoring system control terminal in the control room. High activity alarm indications are displayed on the ASIP annunciator in addition to the radiation monitoring system control terminals.

A beta sensitive plastic scintillation detector is used to monitor the gaseous radiation level. The detector is inserted into an inline fixed volume container which includes adequate shielding to prevent background radiation from interfering with detector sensitivity. The range of this monitor is 10^{-7} to 10^{-2} μCi/cc.

Steam Generator Liquid Sample Monitor

This channel monitors the liquid phase of the secondary side of the steam generator for radiation. Secondary side radiation indicates a primary-to-secondary system leak and provides backup information to that of the condenser air ejector gas monitor. Samples from the bottom blowdown lines of each of the two steam generators are mixed to a common header and the common sample is continuously monitored by a scintillation counter and holdup tank assembly. Upon indication of a high radiation level, each steam generator is manually sampled in order to determine the source. This sampling sequence is achieved by manually selecting the desired unit to be monitored and allotting sufficient time for sample equilibrium to be established (approximately 1 min.). A high radiation alarm is located near the detector. The range of this monitor is 10^{-7} to 10^{-2} μCi/cc.

A scintillation crystal (NaI)/photomultiplier tube combination, mounted in a sample well, is used to monitor liquid effluent activity. Lead shielding is provided to reduce the background level so it does not interfere with detector sensitivity. The inline, fixed-volume container is an integral part of the detector unit.

Leakage Detection

During hot shutdown, personnel can enter the containment and make a visual inspection for leaks. The location of any leak in the reactor coolant system would be determined by the presence of boric acid crystals near the leak. The leaking fluid transfers the boric acid outside the reactor coolant system and the process of evaporation deposits crystals.

If an accident involving gross leakage from the reactor coolant system occurred, it could be detected by the following methods.

Pump Activity

During normal operation, two charging pumps are operating with one in manual and one in automatic. If a gross loss of reactor coolant to another closed system occurred which was not detected by the methods previously described, the speed of the charging pump would indicate the leakage.

The leakage from the reactor coolant will cause a decrease in the pressurizer liquid level that is within the sensitivity range of the pressurizer level indicator. The speed of the charging pump in automatic will automatically increase to try to maintain the equivalence between the letdown flow and the combined charging line flow and flow across the reactor coolant pump seals. If the pump reaches a high speed limit, an alarm is actuated.

A break in the primary system would result in reactor coolant flowing into the containment sump. Gross leakage to this sump would be indicated by the frequency of operations necessary to clear the containment sump high liquid level alarms.

Liquid Inventory

Gross leaks might be detected by unscheduled increases in the amount of reactor coolant makeup water which is required to maintain the normal level in the pressurizer. This is inherently a low precision measurement, since makeup water is necessary as well for leaks from systems outside the containment.

A large tube side to shell side leak in the nonregenerative (letdown) heat exchanger would result in reactor coolant flowing into the component cooling water and a rise in the liquid level in the component cooling water surge tank. The operator would be alerted by a high water alarm for the surge tank and high radiation and temperature alarms actuated by monitors at the component cooling water pump suction header.

A high level alarm for the component cooling water surge tank and high radiation and temperature alarms actuated by monitors at the component cooling pump suction header could also indicate a thermal barrier cooling coil rupture in a reactor coolant pump. However, in addition to these alarms, high temperature and high flow on the component cooling outlet line from the pump would activate alarms.

Gross leakage might also be indicated by a rise in the normal containment sump level. High level in this sump will actuate an alarm.

Residual Heat Removal System

The residual heat removal system removes residual and sensible heat from the core and reduces the temperature of the reactor coolant system during the second phase of plant shutdown.

Leakage from the residual heat removal loop during normal operation would be detected by the component cooling system radiation monitor (see analysis of detection of leakage from the reactor coolant system in this section).

The two residual heat removal pumps are located in separate shielded and isolated rooms outside of the containment. Radiation monitoring of this area is provided by the plant vent gas monitoring system. Alarms in the control room alert the operator when the activity exceeds a preset level. Small leaks to the environment could be detected with these systems within a short time after they occurred.

Should a large tube side to shell side leak develop in a residual heat exchanger, the water level in the component cooling surge tank would rise, and the operator would be alerted by a high water alarm. Radiation and temperature monitors at the component cooling water pump suction header will also signal an alarm.

Leakage from the residual heat removal pumps is drained to one sump that serves both units. The sump is equipped with two sump pumps.

Component Cooling System

Leakage from the component cooling system inside the reactor containment might be detected by the humidity detector and/or the condensate measuring system (see section on reactor coolant system leak detection for a description of these systems).

Visual inspection inside the containment is possible during normal operations.

If the leakage is from a part of the component cooling system outside the containment, it would be directed by floor drains to an auxiliary building sump. The auxiliary building sump pumps then transfer the leakage to the waste holdup tank.

Service Water System

The containment fan cooler service water monitor checks the containment fan service water discharge lines for radiation indicative of a leak from the containment atmosphere into the service water. Upon indication of a high radiation level, each heat exchanger is individually sampled to determine which unit is leaking. This sampling sequence is achieved by manually selecting the desired unit to be monitored and allotting sufficient time for sample equilibrium to be established (approximately 1 minute).

The range of this monitor is 10^{-7} to 10^{-2} μCi/cc.

Gross leakage of service water due to a faulty cooling coil in the containment air recirculation cooling system can be detected by stopping the fans and continuing the cooling water flow. Any significant cooling water leakage would be seen as flow into a collecting pan.

6.5.3 SYSTEM EVALUATION

Provisions are made for the isolation and containment of any leakage. The provisions made for leakage are designed to prevent uncontrolled leaking of reactor coolant, residual heat removal or component cooling water. This is accomplished by (1) isolation of the leak by valves, (2) designing relief valves to accept the maximum flow of water from the worst possible leak, (3) supplying redundant equipment which allows a standby component to be placed in operation while the leaking component is repaired, and (4) routing the leakage to various sumps and holdup tanks.

Various provisions for leakage avert unmonitored leakage from the reactor coolant, residual heat removal, and component cooling systems.

<u>Reactor Coolant System</u>

When significant leakage from the reactor coolant system is detected, action is taken to prevent the release of radioactivity to the atmosphere outside the plant.

If the containment radiogas activity exceeds a preset level on the containment radiogas monitor, the containment vent valves are automatically closed (if open).

A high radiation alarm actuated by the steam generator liquid sample monitor initiates closure of the isolation valves in the blowdown lines, sample lines, and blowdown tank condensate drain lines.

If the component cooling system radiation monitor signals a high radiation alarm, the valve in the component cooling surge tank vent line automatically closes to prevent gaseous activity release.

If a leak from the reactor coolant system to the component cooling system was a gross leak, or if the leak could not be isolated from the component cooling system before the inflow completely filled the surge tank, the relief valve on the surge tank would lift. The discharge from this valve is routed to the waste holdup tank in the auxiliary building.

A large leak in the reactor coolant system pressure boundary, which does not flow into another closed loop, would result in reactor coolant flowing into the containment sump.

<u>Residual Heat Removal System</u>

If leakage from the residual heat removal system into the component cooling system occurs, the component cooling radiation monitor will actuate an alarm and the valve in the component cooling surge tank vent line is automatically closed to prevent gaseous radioactivity release. If the leaking component (i.e., a residual heat exchanger) could not be isolated from the component cooling system before the inflow completely filled the surge tank, the relief valve on the surge tank would lift and the effluent would be discharged to the waste holdup tank.

Gross leakage from the section of the residual heat removal system inside the containment, which does not flow into another closed loop, would result in reactor coolant flowing into the containment sump.

Other leakage provisions for the residual heat removal system are discussed in Section 9.2.

Component Cooling System

Gross leakage from the section of the component cooling system inside the containment which does not flow into another closed loop will flow into the containment sump. Outside the containment, major leakage would be drained to an auxiliary building sump. From here it is pumped to the waste holdup tank.

Other provisions made for leakage from the component cooling system are discussed in Section 9.1.

6.5.4 REQUIRED PROCEDURES AND TESTS

The inservice inspection requirements are described in the PBNP Inservice Testing Program.

6.5.5 REFERENCES

1. Regulatory Guide 1.97, “Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident”, Rev. 2.

2. NUREG 0737, Item II.B.3, “Post-Accident Sampling Capability”.

3. NRC Safety Evaluation “Post-Accident Sampling System (NUREG-0737, II.B.3),” dated December 22, 1982.

4. NRC SE, “PBNP, Units 1 and 2, Supplement to Safety Evaluation on Leak-Before-Break Regarding Correction of Leak Detection Capability (11/14/15-S1),” dated February 7, 2005.

5. Calculation 97-0117, Rev. 2, “Evaluation of Sump A Condensate Collection Provisions for Detection of Reactor Coolant System Leakage” and associated 50.59 screening SCR 2006-0235.

6. SE 97-096, “Unit 2 Post-Accident Sample System Upgrades (MR 97-057),” approved June 12, 1997.

7. SE 97-145, “Unit 1 Post-Accident Sample System Upgrades (MR 97-056),” approved July 24, 1997.

Figure 6.5-1 UNIT 1 CONTAINMENT RADIATION MONITORING SYSTEM

[redacted]

CHAPTER 7 TABLE OF CONTENTS

7.0 INSTRUMENTATION AND CONTROL

7.1 INTRODUCTION

Instrumentation is provided for automatic protection of each unit's reactor during accident conditions, in the form of the reactor protection system (for reactor trip) and the engineered safety features actuation system. In addition, instrumentation is provided for automatic and/or manual control of the nuclear (primary) and turbine-generator (secondary) portions of the plant during normal and off-normal operating conditions, and for monitoring essential plant systems operation during post-accident conditions.

Operation of both units is supervised from a common control room. Because unit-specific instrumentation is basically identical between units, this section typically describes the instrumentation and control systems for a single unit. Where applicable, instrumentation and controls that are shared between both units are also identified.

7.1.1 IDENTIFICATION OF SAFETY-RELATED INSTRUMENTATION SYSTEMS

Safety-related instrumentation systems include:
Reactor Protection System
Engineered Safety Features Actuation System
Nuclear Instrumentation System
Post-Accident Monitoring Instrumentation (Reg. Guide 1.97 Type A Variables)

The design of reactor protection, engineered safety features actuation, and nuclear instrumentation systems is similar to the R.E. Ginna plant.

7.1.2 GENERAL DESIGN CRITERIA

General design criteria (GDCs) that apply to instrumentation and control systems are discussed below.

Reactor Core Design (GDC 6)

The reactor core with its related controls and protection systems shall be designed to function throughout its design lifetime without exceeding acceptable fuel damage limits which have been stipulated and justified. The core and related auxiliary system designs shall provide this integrity under all expected conditions of normal operation with appropriate margins for uncertainties and for specified transient situations which can be anticipated.

DISCUSSION

The reactor control and protection systems are designed to function throughout their design lifetime to prevent exceeding acceptable fuel damage limits, and to actuate a reactor trip for any anticipated combination of plant conditions, when necessary, to ensure a departure from nucleate boiling (DNB) ratio equal to or greater than the limits specified for STD, OFA, upgraded OFA, and 422V+ fuel.

Suppression of Power Oscillations (GDC 7)

The design of the reactor core with its related controls and protection systems shall ensure that power oscillations, the magnitude of which could cause damage in excess of acceptable fuel damage limits, are not possible or can be readily suppressed.

DISCUSSION

Ex-core instrumentation is provided to obtain necessary information concerning axial neutron flux distributions. This instrumentation is adequate to enable the operator to monitor and control xenon-induced oscillations. In-core instrumentation is used to periodically calibrate and verify the axial flux information provided by the ex-core instrumentation. The analysis, detection, and control of these oscillations is discussed in Reference 2 of Section 3.2.1.

Control Room (GDC 11)

The facility shall be provided with a control room from which actions to maintain safe operational status of the plant can be controlled. Adequate radiation protection shall be provided to permit continuous occupancy of the control room under any credible post-accident condition or as an alternative, access to other areas of the facility as necessary to shut down and maintain safe control of the facility without excessive radiation exposures of personnel.

DISCUSSION

The plant is equipped with a common control room which contains those controls and instrumentation necessary for operation of each unit's reactor and turbine generator under normal and accident conditions. The control room is continuously occupied under all operating and accident conditions, except for the special case of a control room fire forcing evacuation and control of the plant from outside the control room. No other accident is required to be assumed during a control room evacuation due to fire.

Sufficient shielding, distance, and containment integrity are provided to assure that control room personnel shall not be subjected to a dose greater than 5 rem total effective dose equivalent (TEDE) under postulated accident conditions. This dose limit includes control room occupancy, ingress, and egress for the duration of the accident.

The control room ventilation system design normally combines outside makeup air with a large percentage of recirculated air. The radiation monitoring system monitors the control room and the control room air supply and automatically places the ventilation system in operating Mode 5 if a high radiation condition occurs. Refer to Section 9.8 for further discussion of control room ventilation system performance capability.

Instrumentation and Control Systems (GDC 12)

Instrumentation and controls shall be provided as required to monitor and maintain within pre-scribed operating ranges essential reactor facility operating variables.

DISCUSSION

Instrumentation and controls are provided to monitor and maintain important reactor parameters (including neutron flux, primary coolant pressure, loop flow rate, coolant temperatures, and control rod positions) within prescribed operating ranges. Other instrumentation and control systems are provided to monitor and maintain, within prescribed operating ranges, the temperatures, pressure, flow, and levels in the reactor coolant system, steam systems, containment, and other auxiliary systems. Process variables which are required on a continuous basis for the startup, power operation, and shutdown of the plant are indicated, recorded, and controlled from the control room, which is a controlled access area. The quantity and types of instrumentation provided are adequate for safe and orderly operation of all systems and processes over the full operating range of the plant.

Fission Process Monitors and Controls (GDC 13)

Means shall be provided for monitoring or otherwise measuring and maintaining control over the fission process throughout core life under all conditions that can reasonably be anticipated to cause variations in reactivity of the core.

DISCUSSION

Ex-core nuclear instrumentation is used primarily for reactor protection, by monitoring neutron flux and by generating appropriate trip and alarm functions for various phases of reactor operating and shutdown conditions. Nuclear instrumentation also provides a fission process control function and indicates reactor fission process status during startup and power operation. The nuclear instrumentation system supplies information from three separate types of flux detection channels to provide three discrete ranges and protection levels. Each range of instrumentation (source, intermediate, and power) provides the necessary overpower reactor trip protection during operation in that range. The overlap of instrument ranges provides reliable continuous protection from source to intermediate and low-power ranges. As the reactor power increases, the overpower protection level is increased administratively after satisfactory higher range instrumentation operation is obtained. Automatic restoration of the more restrictive trip protection is provided when reducing power. Section 7.6.1 includes additional information on the ex-core nuclear instrumentation system.

Core Protection Systems (GDC 14)

Core protection systems, together with associated equipment, shall be designed to prevent or to suppress conditions that could result in exceeding acceptable fuel damage limits.

DISCUSSION

If the reactor protection system sensors detect conditions which indicate an approach to unsafe operating conditions that require core protection, the system actuates alarms, prevents control rod motion, initiates load runback, and initiates reactor trip by opening the reactor trip breakers.

The basic reactor protection philosophy to prevent departure from nucleate boiling (DNB) is to define an allowable region of power and coolant temperature conditions. This allowable range is constrained by the primary reactor trip functions, including the overpower ΔT trip, the overtemperature ΔT trip and the nuclear overpower trip. The allowable operating region below these trip settings is designed so that no combination of power, temperature, and pressure could result in a DNB Ratio (DNBR) less than the design basis limit DNBR (approximate value of 1.3) with all reactor coolant pumps in operation. Other reactor trips are provided to back up the primary trips for specific abnormal conditions. A complete list of reactor trips may be found in Table 7.2-1.

Automatic rod stops are provided prior to reaching the nuclear overpower, overpower ΔT, and overtemperature ΔT reactor trip setpoints, to prevent abnormal power conditions which could result from excessive control rod withdrawal.

Engineered Safety Features Protection Systems (GDC 15)

Protection systems shall be provided for sensing accident situations and initiating the operation of necessary engineered safety features.

DISCUSSION

Instrumentation and controls provided for the engineered safety features actuation system are designed to automatically initiate engineered safety features (ESF) equipment during those accidents which are mitigated by automatic ESF equipment operation. Actuated ESF equipment (depending on the severity of the condition) includes the Safety Injection System, the Containment Air Recirculation Cooling System, containment isolation, and the Containment Spray System, as discussed in Section 6.0.

The engineered safety features actuation system consists of redundant analog channels, each containing sensors for different trip parameters, channel circuitry, and trip bistables. The trip bistable outputs are combined in coincident trip logic in two redundant actuation trains. Sufficient redundancy is provided so that a single failure will not defeat the actuation function. The arrangement of initiating sensors, bistables, and logic are shown in the figures included in the detailed Engineered Safety Features Instrumentation Description given in Section 7.3.

Protection Systems Reliability (GDC 19)

Protection systems shall be designed for high functional reliability and inservice testability necessary to avoid undue risk to the health and safety of the public.

DISCUSSION

A minimum of two independent protection channels are provided in the reactor protection system and engineered safety features actuation system for each trip variable, with most variables having three or four independent channels. Protection system reliability to avoid unnecessary trips is provided by redundancy within each tripping function and the use of coincidence trip logic. Each protection channel associated with any specific trip variable is provided with an independent source of electrical power and independent circuitry from the sensor through the trip bistable. Therefore, in the event that the loss of a single protection channel occurs, only that particular protection channel is affected, and coincidence logic is not satisfied to initiate a protective action (unless a one-out-of-two coincidence logic is employed). Most protection channels are designed so that on loss of power, the bistables fail in the tripped condition (the preferred failure direction for most protection channels).

Protection channels are designed with sufficient redundancy for individual channel calibration and testing during power operation without degrading the protection functions. To remove an analog channel from service for test, calibration, or maintenance, all of the associated channel's trip signals to the reactor protection system or engineered safety features actuation system are first placed in the tripped condition. This causes a two-out-of-three coincidence trip logic to become a one-out-of-two coincidence logic on the remaining (untripped) channels. Tripping a channel to be tested will not cause a reactor trip or ESF actuation unless a trip condition already exists in a redundant channel.

Protection Systems Redundancy and Independence (GDC 20)

Redundancy and independence designed into protection systems shall be sufficient to assure that no single failure or removal from service of any component or channel of such a system will result in loss of the protection function. The redundancy provided shall include, as a minimum, two channels of protection for each protection function to be served.

DISCUSSION

A minimum of two independent protection channels are provided in the reactor protection system and engineered safety features actuation system for each trip variable, with most variables having three or four independent channels. The design is such that no single failure within the protection systems or their supporting systems will defeat the overall protective function or violate protection system design criteria. The design includes redundant, independent channels extending from sensors to the trip bistable outputs, which are then combined into coincidence trip logic in two redundant logic trains that extend to the final actuated devices. Sufficient redundancy and coincidence logic is included to reliably accomplish the protective functions if a single failure should occur, while also minimizing unnecessary protective actions due to single failures.

Section 7.2 and Section 7.3 discuss certain protection system backup trips that may not fully meet the single failure criterion. However, failure of a backup trip does not prevent proper protective action of primary trips assumed in the accident analyses, and does not represent a loss of the protective function discussed in GDC 20.

Sensing lines installed between the process piping and the sensors for redundant protection channels are also independent and redundant. However, two exceptions exist where transmitters for redundant channels share common sensing lines (pressurizer pressure and reactor coolant flow). Refer to Section 7.2.1.2.c and Section 7.2.3.3 for justification of shared reactor protection system sensing lines.

When protection system sensors also supply signals for control functions, an isolation amplifier is used to isolate the control signal from the protection signal. Therefore, any control circuit failure is prevented from affecting the protection channel. In a few circuits which provide main control board annunciation and stop rod withdrawal, the safety and control functions are combined from the sensor through dual alarm units. In these circuits, a failure in the control portion of the circuit can cause the safety portion of the circuit to go to its trip position. This may result in initiation of protective action.

Further detail on protection system channel and train redundancy is provided in the descriptions of the respective systems in this chapter. Redundancy of the power supplies to the protection system channels and trains is discussed in Chapter 8.

Protection Against Multiple Disability for Protection Systems (GDC 23)

The effects of adverse conditions to which redundant channels or protection systems might be exposed in common, either under normal conditions or those of an accident, shall not result in loss of the protection function or shall be tolerable on some other basis.

DISCUSSION

Potentially adverse conditions to which redundant protection system equipment may be exposed include adverse environmental effects, fires, earthquakes, and missile hazards. The design and layout of protection system components precludes loss of the protection function as a result of adverse conditions to which the components may be exposed.

Physical and electrical separation of redundant protection system channels and trains is employed to reduce the probability of an external hazard, such as a fire or missile, impairing the protection function through a common mode failure. Separation of redundant analog channels originates at the process sensors and continues along the field wiring, through containment penetrations, to the analog protection racks. As mentioned previously under GDC 20, some sensors for pressurizer pressure and reactor coolant flow may share common sensing lines, but the consequence of a line failure (rupture) will not prevent a protective action from occurring.

Separation of redundant protection channel/train field wiring is achieved using separate wireways, cable trays, conduit runs, and containment penetrations for redundant channels and trains. Separate, dedicated racks for each channel and train are provided to terminate the field wiring, so that internal wiring within a rack is limited to a single channel or train. Power supplies to redundant channels and trains are provided from separate 120 VAC instrument buses and from separate DC buses, respectively.

Original plant design required separation of main control board power and control wiring that was associated with redundant safety-related train components. Cables for non-vital circuits were not excluded from wireways carrying train A or train B cables. Instrumentation wiring associated with reactor protection or safeguards channels was exempted from separation inside the main control boards because these wires are isolated from their associated safeguards or protection rack by isolation amplifiers or relays. The following instructions were established by Westinghouse during plant construction to effect the cable separation within the main control board in accordance with agreements with the AEC (Reference 1, Reference 2, Reference 3 and Reference 4).

- Wiring requiring separation shall use separate routing of wireways between devices. In no case shall wiring requiring separation be bundled together.
- Devices (switches for example) having connecting wiring requiring separation shall have that wiring separately bundled and routed to obtain physical separation immediately upon leaving the device terminals. Separate routing or wireways to terminal blocks shall be used.
- Wires requiring separation shall terminate on separate terminal blocks for field connections.

Confirmation that physical separation for wiring inside the main control boards is a licensing basis requirement was provided in a Wisconsin Electric letter to the NRC, dated April 16, 1997 (Reference 5). Modifications MR 93-025*A -*H were initiated to improve electrical separation in the main control board and included wrapping cables with a fire retardant material called Siltemp to provide a barrier between redundant trains where adequate physical separation was not practical. Wrapping cables with Siltemp does not satisfy NFPA 805 Section 4.2.3 separation requirments for a rated fire barrier or Electrical Raceway Fire Barrier System.

Section 7.2 and Section 7.3 discuss certain protection system backup trips that may not fully meet wiring separation criteria for redundant trains. However, failure of a backup trip circuit does not prevent proper protective action of primary trips assumed in the accident analyses, and does not represent a loss of the protective function discussed in GDC 23.

Refer to Section 8.0 for a discussion of cable and internal wiring separation criteria and environmental qualification criteria.

Environmental qualification of electrical/electronic equipment is addressed in Section 7.2.3.5.

Protection system components are designed to function under their normal service environments. Under accident conditions, protection system components are either located in a mild environment (such as the control room or cable spreading room) or are located in a potentially harsh accident environment (such as containment). Components in mild environments do not require formal environmental qualification. Protection system components located in potentially harsh environments only require formal environmental qualification if:

1. the component is required to mitigate the accident that creates the harsh environment <u>and</u> the harsh environment degrades the component performance before the protective function occurs, or

2. the component is used for post-accident functions not related to the protection function.

Seismic qualification of protection system components is addressed in Section 7.2.3.4. The seismic design requirement is that for the maximum potential earthquake, the equipment will not lose its capability to perform its protective function; namely, to shut the reactor down and/or maintain the unit in a safe shutdown condition. It is conceivable that protection system equipment may have permanent deformation due to stresses from the maximum potential earthquake; however, the deformation will not impede its ability to perform the protective function.

<u>Demonstration of Functional Operability of Protection Systems</u> (GDC 25)

Means shall be included for suitable testing of the active components of protection systems while the reactor is in operation to determine if failure or loss of redundancy has occurred.

<u>DISCUSSION</u>

During power operation, each reactor protection channel and logic train is capable of being calibrated and tripped independently by simulated signals to verify its operation, without tripping the plant. The testing scheme includes checking through the trip logic to the reactor trip breakers.

Thus, the operability of each channel and logic train can be determined conveniently and without ambiguity.

During power operation, each engineered safety features actuation channel and logic train is capable of being calibrated and tripped independently by simulated signals to verify its operation up to the final actuation device. Because ESF equipment actuation would adversely impact plant operation at power, the final ESF actuation devices are not cycled while the reactor is at power. A resistance check of the relay coils is performed at power, but actuation of ESF equipment is performed during refueling shutdowns, rather than at power.

Protection Systems Failure Analysis Design (GDC 26)

The protection systems shall be designed to fail into a safe state or into a state established as tolerable on a defined basis if conditions such as disconnection of the system, loss of energy (e.g., electrical power, instrument air), or adverse environments (e.g., extreme heat or cold, fire, steam, or water) are experienced.

DISCUSSION

Each reactor protection channel and train is designed on the “de-energize to operate” principle; an open circuit or loss of power causes the respective channel or train to go into its tripped condition (the “preferred failure” direction).

The analog channels for the engineered safety features actuation system, with the exception of containment spray actuation, are designed on the same “de-energize to operate” principle as the reactor protection channels. The high-high containment pressure channels for containment spray actuation are designed as energize-to-operate, to avoid spray operation on inadvertent channel power failures.

Regarding the two ESF actuation trains, the output relays are “energize-to-operate” and require power to actuate ESF equipment. This design prevents inadvertent ESF equipment actuation on power failure of an actuation train (the “preferred failure” direction).

Reactivity Shutdown Capability (GDC 29)

One of the reactivity control systems shall be capable of making the core subcritical under any anticipated operating condition (including anticipated operational transients) sufficiently fast to prevent exceeding acceptable fuel damage limits. Shutdown margin should assure subcriticality with the most reactive control rod fully withdrawn.

DISCUSSION

The reactor core, together with the reactor control and protection system, is designed so that the minimum allowable DNBR is no less than the design basis limit DNBR and there is no fuel melting during normal operation, including anticipated transients.

The shutdown rod groups are provided to supplement the control groups of rod cluster control assemblies (RCCAs) to make the reactor at least one percent subcritical ($K_{eff} = 0.99$) following a trip from any credible operating condition to the hot zero power condition, assuming the most reactive RCCA remains in the fully withdrawn position.

Sufficient shutdown capability is also provided to maintain the core subcritical, with the most reactive rod assumed to be fully withdrawn, for the most severe anticipated cooldown transient associated with a single active failure, e.g., accidental opening of a steam bypass (condenser steam dump) or relief valve. This is achieved with a combination of control rods and automatic boron addition via the safety injection system.

Reactivity Control Systems Malfunction (GDC 31)

The reactor protection system shall be capable of protecting against any single malfunction of the reactivity control system, such as unplanned continuous withdrawal (not ejection or dropout) of a control rod, by limiting reactivity transients to avoid exceeding acceptable fuel damage limits.

DISCUSSION

Continuous rod withdrawal accidents from both subcritical and at-power conditions are analyzed plant transients that rely on an automatic reactor trip for core protection. Automatic reactor trip is completely independent of the normal RCCA control functions, since the reactor trip breakers interrupt the power to the control rod drive mechanisms regardless of existing control signals.

Other General Design Criteria

The following GDCs broadly apply to plant equipment, including instrumentation and controls, and are discussed in other sections, as noted:

GDC 1	Quality Standards	Sections 4.1
GDC 2	Performance Standards	Sections 4.1
GDC 39	Emergency Power	Section 8.1
GDC 40	Missile Protection	Sections 4.1

7.1.3 OTHER CRITERIA

In addition to the General Design Criteria discussed above, the following criteria apply to specific instrumentation:

a. IEEE 279-1968, Proposed IEEE Criteria for Nuclear Power Plant Protection Systems.

The reactor protection system (Subsection 7.2), the engineered safety features actuation system (Subsection 7.3) and portions of the nuclear instrumentation system (Subsection 7.6) are required to meet the design criteria of IEEE 279-1968. The compliance of each system with IEEE 279 is discussed in the individual system subsection.

b. Regulatory Guide 1.97, Rev. 2, Instrumentation to Assess Plant and Environs Conditions during and following an Accident.

Post-accident monitoring instrumentation is required to meet the intent of Regulatory Guide 1.97, Rev. 2. Section 7.6.2 discusses the specific plant variables to which this regulatory guide applies and the type and category of each variable.

7.1.4 REFERENCES

1. Westinghouse Letter to Bechtel Corporation, PBW-B-3145, Point Beach Nuclear Plant Control Board Rerouting, dated February 25, 1970.

2. Westinghouse Engineering Change Notice, ECN-WEP-70083, Main Control Board, Initiated February 10, 1970.

3. Response to AEC Question 7.6, Cable Installation Design Criteria, January 16, 1970.

4. Response to AEC Question 7.3, Isolation of Reactor Protection and Engineered Safety Features Signals to Annunciators and Data Logger/Computer, January 16, 1970.

5. Wisconsin Electric Letter to NRC, Main Control Board Wiring Separation Operability Determination and Restoration Plan, Point Beach Nuclear Plant, Units 1 and 2, dated April 16, 1997.

7.2 REACTOR PROTECTION SYSTEM

The Reactor Protection System (RPS) monitors parameters related to safe operation and automatically trips the reactor to protect the reactor core against fuel rod cladding damage due to Departure from Nucleate Boiling (DNB). It also assists in protecting against Reactor Coolant System (RCS) damage caused by high system pressure by limiting energy input to the system through reactor trip action.

7.2.1 DESIGN BASES

The following PBNP General Design Criteria (GDC) as described in Section 7.1.2 are applicable to the Reactor Protection System:

Criterion 12: Instrumentation and Control Systems
Criterion 13: Fission Process Monitors and Controls
Criterion 14: Core Protection Systems
Criterion 19: Protection Systems Reliability
Criterion 20: Protection Systems Redundancy and Independence
Criterion 23: Protection Against Multiple Disability for Protection Systems
Criterion 25: Demonstration of Function Operability of Protection Systems
Criterion 26: Protection Systems Failure Analysis Design
Criterion 29: Reactivity Shutdown Capability
Criterion 31: Reactivity Control Systems Malfunction

In addition to the above mentioned GDC, the Reactor Protection System is also designed to IEEE 279, "Proposed IEEE Criteria for Nuclear Power Plant Protection Systems" dated August 1968.

7.2.1.1 Conformance to IEEE 279-1968

a. Plant Conditions that Require RPS

The Reactor Protection System is required to protect two of the three physical barriers that guard against the uncontrolled release of radioactivity; (1) fuel clad and (2) reactor coolant system pressure boundary. Chapter 14 describes the accidents that RPS is required to operate under to protect the above mentioned barriers. Note that different accidents may actuate different RPS trips and that not all accidents described in Chapter 14 require the operation of RPS.

b. Plant Variables that Cause Protective Action

The process variables that actuate each RPS trip are identified in Table 7.2-1.

c. Minimum Number of Sensors for Each Variable

The minimum number of sensors assigned to each RPS variable is listed in Technical Specifications.

d. Prudent Operational Limits for Each Variable

The normal operational limits for each RPS variable are defined in the plant operating procedures and Technical Specifications.

e. Margin Between Operational Limits and Onset of Unsafe Conditions

The margin between each RPS variable's operational limit and the analytical limit required for automatic RPS actuation is determined by the RPS setpoints established for the variable in Technical Specifications. (Reference Section 7.2.3.6)

f. Variable Levels that Require Protective Action

The analytical limits established in the accident analyses (Chapter 14) determine the point at which the variables require RPS actuation.

g. Condition for System Performance

The operational conditions (e.g., environmental, seismic, power source, etc.) under which the RPS equipment must function are discussed in Section 7.2.3.4 and Section 7.2.3.5.

h. Performance Requirements of RPS Variables

The range, response time and accuracy requirements of the RPS equipment are chosen to ensure the assumptions of the accident analysis for the variables being monitored are met.

i. Single Failure

No single failure within the reactor protection system or in an associated system, which supports its operation, shall prevent the operation of the reactor protection system.

j. Redundancy and Independence

The reactor protection system is redundant and independent for all primary inputs and functions. Each channel is functionally independent of every other channel and receives power from a separate AC power source. Each train is functionally independent of the redundant train and receives power from a separate DC power source.

k. Manual Actuation

Means are provided for the manual initiation of protective action. Failures in the automatic system will not prevent the manual actuation of protective functions.

l. Channel Bypass or Removal from Operation

The reactor protection system is designed to permit any one channel to be maintained, tested or calibrated during power operation without causing a system trip. During such operation, the active parts of the system continue to meet the single failure criterion, since the channel under test is either tripped or makes use of superimposed test signals, which do not prevent the process signal from actuating the channel.

EXCEPTION: Channels for “one-out-of-two” trip logic are permitted to violate the single failure criterion during channel bypass provided that acceptable reliability of operation can be otherwise demonstrated.

m. Capability for Test and Calibration

The bistable portions of the reactor protection system provide trip signals only after signals from the analog portions of the system reach a preset value. Capability is provided for calibrating and testing the performance of the bistable portion of protection channels and various combinations of the logic network during power operation.

The sensor portion of the protection channel provides an analog signal of the process parameter. The analog portion of a channel can be checked in various ways during power operation, for example:

- varying the monitored parameter,
- introducing and varying a substitute transmitter signal, and
- cross-checking between channels that bear a known relationship to each other and that have readouts available

The design of the system provides for administrative control for the purpose of manually bypassing channels for test and calibration purposes. The design also provides for administrative control of access to all trip settings, module calibration adjustments, test points, and signal injection points.

n. Information Readout

The reactor protection system provides the operator with complete information pertinent to system status and plant safety. All transmitted signals (flow, pressure, temperature, etc.), which can lead to a reactor trip are either indicated and/or recorded for every channel. All neutron flux power range currents (top detector, bottom detector, and algebraic difference and sum of the bottom and top detector currents) are indicated and/or recorded.

Alarms are also provided to alert the operator of deviation from normal operating conditions so that corrective action can be taken prior to reaching a reactor trip setting. In addition, any control rod stop or trip of any reactor trip channel will actuate an alarm.

o. Operating Bypasses

Where operating requirements necessitate automatic or manual bypass (block) of a protection function, the design is such that the bypass is automatically removed whenever the permissive conditions are not met. Devices used to achieve automatic removal of the bypass of a protection function are part of the protection system.

p. Indication of Bypasses

Indication is provided on the main control board if some part of the system has been administratively bypassed or taken out of service.

q. Multiple Trip Settings

When it is necessary to change to a more restrictive trip setting to provide adequate protection for a particular mode of operation or set of operating conditions, the design provides positive means of assuring that the more restrictive trip settings are used. The devices used to prevent improper use of less restrictive trip settings are considered a part of the protective system and are designed in accordance with the other provisions of the IEEE 279-1968. Multiple trip setpoints are used for monitoring neutron flux during the different modes of operation.

r. Completion of Protective Action

The reactor protection system is designed so that once initiated, the protective action goes to completion. Return to normal operation requires administrative action by the operator.

s. Protective Actions

The reactor protection system is designed to automatically trip the reactor under the conditions identified in Table 7.2-1.

Interlocking functions of the reactor protection system prevent control rod withdrawal (rod stops) when a specified parameter reaches a preset value, which is less than the value at which a reactor trip is initiated.

For anticipated abnormal conditions, the reactor protection system in conjunction with inherent plant characteristics and the engineered safety features are designed to assure that the limits for energy release to the containment and for radiation exposure are not exceeded.

t. Adverse Environment

The reactor protection system equipment is either located in a mild environment (such as the control room) or a potentially harsh environment (such as containment). The requirements of the equipment are discussed further in Section 7.2.3.5.

7.2.1.2 Exceptions to IEEE 279

a. Backup/Anticipatory Trips

Some of the backup/anticipatory reactor protection system functions that are not assumed in the accident analyses may not fully conform to the IEEE 279 criteria. The specific backup/ anticipatory trips that do not fully conform to IEEE 279 are:

Reactor coolant pump breaker position, Reactor trip on turbine trip (stop valve position and low turbine auto stop oil pressure) and Steam/Feedwater Flow Mismatch Trip.

The exceptions to IEEE 279 include circuits that contain non-safety-related contacts and/or field wiring that may not meet safety-related train separation criteria, and single failure scenarios that may defeat the backup trip functions. Exceptions to the separation criteria are allowed in these cases based on the electrical isolation of the non-conforming circuits such that an electrical fault in the backup trip field wiring will not propagate into and disable the primary trip circuits. Exceptions to single failure criteria in backup trips are allowed because the backup trip functions are not required for plant protection, and their failure will not affect the primary trip functions assumed in the accident analyses.

b. Permissives

Permissive P-9 logic does not fully comply with IEEE 279 due to the fact that the permissive is disabled by non-safety related, non-seismically qualified contacts (high condenser pressure and operating status of circulating water pumps). Exception to IEEE 279 is allowed because the failure of the P-9 permissive will result in a reactor trip, which is “fail-safe”. No failure associated with the P-9 permissive will prevent the RPS from performing its primary trip functions assumed in the accident analyses. Refer to Section 7.2.3.3.

c. Sensing Lines

Some of the sensors used to initiate reactor trips have shared sensing lines. The following two trip parameters share common sensing lines between redundant RPS transmitters:

- Low pressurizer pressure, and
- Low reactor coolant flow

The above trip parameter sensors are allowed to share common sensing lines because no credible failure associated with the sensing lines will prevent the primary trip functions assumed in the accident analyses. Refer to Section 7.2.3.3.

7.2.2 SYSTEM DESIGN

7.2.2.1 Reactor Protection System Description

The RPS limits the range of various core and coolant parameters so that the DNBR is not less than the safety limit value during anticipated operating transients. The parameter ranges were determined by a computer code which mathematically correlated the nuclear and thermal hydraulic properties of the reactor coolant system. The reactor core safety limits are shown in the Core Operating Limits Report (COLR), TRM Section 2.1, for each unit.

Since thermal core power may be represented by the increase in reactor coolant temperature across the core, it is possible to represent the correlation of core inlet temperature and core power in terms of measured plant variables, via reactor coolant temperature difference (ΔT) and the average reactor coolant temperature (T_{avg}). Therefore, the reactor core safety limit curve in TRM Section 2.1 can be included in Figure 7.2-2.

Since the thermal hydraulic properties of compressed water are nonlinear, linearization of Figure 7.2-2 is accomplished by linearizing the pressure level curves (bold solid lines). The linearization establishes pressure level lines in which the DNBR is greater than the safety limit value, thus introducing additional conservatism in the control and protection system design. This ensures that adequate margins exist between the maximum nominal steady state operating point (which includes allowance for temperature, calorimetric, and pressure errors) and the required reactor trip points to avoid a spurious plant trip during design transients.

A simplified block diagram illustrating the reactor protection system is shown in Figure 7.2-3. The reactor protection system consists of four instrument channels that monitor up to four various plant parameters, depending on the coincidence logic required for the specific trip. Each protection channel terminates at a channel trip bistable in the analog protection racks. Each channel trip bistable controls two independent and redundant logic relays associated with the two independent and redundant trains (“A” and “B”). The logic relays for each train are combined in a coincidence logic network (e.g., two-out-of-four). The coincidence logic networks terminate at parallel reactor trip relays as shown in Figure 7.2-6. The logic and reactor trip relays are located in the Train “A” and “B” logic racks.

Although a single reactor trip relay would be sufficient to trip the reactor, parallel reactor trip relays were installed for power generation reliability. The use of parallel relays prevents an unnecessary reactor trip should a single reactor trip relay fail.

Where redundant protective channels are combined to provide non-protective functions, the required signals are derived through isolation amplifiers. These devices are designed so that open or short circuit conditions, as well as the application of 120 VAC or 125 VDC, to the isolated side of the circuit will have no adverse effect on the input or protection side of the circuit. Therefore, failures on the non-protective side of the system will not affect the individual protection channels.

Two independent and redundant reactor trip breakers in series provide power to the control rod drive mechanisms. In addition, two independent and redundant bypass breakers are provided in parallel with the reactor trip breakers to allow for continued reactor operation during testing of the reactor trip breakers.

When the required number of channels (e.g., two-out-of-four) indicate that a plant parameter is outside its acceptable operating limit, their associated channel bistables are tripped. The tripping of the channel bistables result in the tripping of their associated coincidence logic relays for each train, which in turn results in de-energizing the reactor trip relays. De-energizing the reactor trip relays causes the associated train trip breaker to open by de-energizing its undervoltage trip coil and by energizing its shunt trip coil through an interposing relay. De-energizing the reactor trip relays also causes the opposite train bypass breaker to open by de-energizing its undervoltage trip coil.

The shunt trip attachment, which provides a diverse method from the undervoltage coil for tripping the reactor trip breakers, was installed in response to Generic Letter 83-28.

Manual reactor trip switches are also installed between the train logic and the reactor trip breakers, to allow the operator to initiate a reactor trip independent from an automatic reactor trip. When the reactor trip breakers are tripped, the power to the control rod drive mechanisms is interrupted, which allows the control rods to insert into the core by gravity. A simplified diagram is shown in Figure 7.2-4.

7.2.2.2 Protective Actions

Rapid reactivity shutdown is provided by the insertion of the rod control cluster assemblies (RCCAs) by gravity. Reactor Trip Breakers RTA and RTB are duplicate series-connected circuit breakers that provide the power to the control rod drive mechanisms. The control rod drive mechanism (CRDM) must be energized to keep the associated RCCAs withdrawn from the core. Automatic reactor trip occurs upon the loss of power to the RCCAs. The reactor trip breakers are opened by either their undervoltage or shunt trip coils. Any one of several trip signals will simultaneously de-energize the undervoltage coil and energize the shunt trip coil.

The components providing power to the circuit breakers' undervoltage and shunt trip attachment are designed to open the reactor trip breakers on a reactor trip signal. In addition, upon power loss, the undervoltage trip coils will cause the breakers to trip. The system is designed so that once a reactor trip is initiated, it cannot be bypassed and it goes to completion. Return to normal operation requires operator action to reset the reactor trip breakers and withdraw the control rods.

Certain reactor trip channels are automatically blocked below a certain power level, and some are manually blocked above a certain power level where they are not required for safety. Nuclear source range, intermediate range and power range (low setting) trips are specifically provided for protection at low power or subcritical operation; for higher power operations, they are blocked by manual action. The design provides for the automatic removal of the automatic and manual blocks whenever the permissive conditions are no longer met.

During power operation, a sufficient amount of rapid shutdown capability is provided in the form of control rods, whose positions are administratively maintained by means of the control rod insertion limits. Administrative controls require that all shutdown group rods be in the fully withdrawn position during power operation.

Interlocks are also provided to avoid a reactor trip by preventing control rod withdrawal (rod stop) when a specified parameter reaches a value which is less than the limit at which a reactor trip is initiated. These parameters are discussed in Section 7.7.1.

All transmitted signals (e.g., flow, pressure, temperature, etc.) which can result in a reactor trip are indicated and/or recorded for every channel. In addition, alarms are also used to alert the operator of a plant parameter that has deviated from its normal operating band, so that corrective action can be taken prior to reaching the reactor trip limit. In addition, the actuation of any control rod stop or the trip of any reactor protection channel will actuate an alarm.

A list of reactor trips, means of actuation, and the coincident circuit requirements is given in Table 7.2-1. The interlock circuits, referred to in Table 7.2-1 (e.g., P-7), are listed in Table 7.2-2.

a. Manual Trip

The manual reactor trip pushbuttons are independent of the automatic trip circuitry, and are not subject to failures which make the automatic circuitry inoperable. Any of four manual trip pushbuttons per unit (eight total) located in the control room can initiate a manual reactor trip.

b. High Nuclear Flux (Power Range) Trips

The purpose of these trips is to protect against reactivity excursions during subcritical to low power operation (low setting) and power operation (high setting) to prevent DNB. The reactor is tripped when two-out-of-four power range channels are above the trip setpoint. The low setting can be manually blocked when two-out-of-four power range channels are above the P-10 block setpoint of approximately 10% power. When three-out-of-four channels are below the P-10 unblock setpoint, the trip is automatically reinstated. This ensures that the more restrictive setting is used when required. The high setting is always active.

c. High Nuclear Flux (Intermediate Range) Trip

The purpose of this trip is to protect against reactivity excursions during subcritical to low power operation to prevent DNB. The reactor is tripped when one-out-of-two intermediate range channels are above the trip setpoint. This trip, which provides protection during reactor startup, can be manually blocked when two-out-of-four power range channels are above the P-10 block setpoint of approximately 10% power. When three-out-of-four channels are below the P-10 unblock setpoint, the trip is automatically reinstated. The intermediate range channels (including detectors) are separate from the power range channels.

d. High Nuclear Flux (Source Range) Trip

The purpose of this trip is to protect against reactivity excursions during reactor startup from subcritical conditions proceeding into the power range. The reactor is tripped when one-out-of-two source range channels are above the trip setpoint. This trip, which provides protection during reactor startup, can be manually blocked when one-out-of-two intermediate range channels are above the P-6 permissive setpoint. When both (two-out-of-two) intermediate range channels are below the P-6 permissive setpoint, the trip is automatically reinstated. This trip is also automatically blocked when two-out-of-four high power range signals are above the P-10 block setpoint of approximately 10% power.

The source range trip setpoint is between the P-6 permissive setpoint (P-6 allows the manual de-energization of the source range high voltage power supply) and the maximum source range power level detection limit.

e. Overtemperature ΔT Trip

The purpose of this "calculated" trip is to protect the core against DNB. The reactor is tripped when two-out-of-four signals, with two sets of temperature measurements per loop, are above the trip setpoint. Two setpoints for this reactor trip are continuously calculated for each loop by solving the following equation (simplified version):

$$\Delta T \text{ setpoint} = K_1 - K_2 T_{avg} + K_3 P - f(\Delta I)$$

Where:

T_{avg}	=	Average reactor coolant temperature (°F), four independent measurements (lead-lag compensated)
P	=	Pressurizer pressure, four independent measurements (psia)
K_1, K_2, K_3	=	Setpoint constants derived from Technical Specifications
$f(\Delta I)$	=	A function of flux difference between upper and lower detectors of the power range ion chambers, four independent measurements.

Each of the four power range ion chamber units separately feeds one overtemperature ΔT trip channel. Thus, a single failure neither defeats the trip function nor causes a spurious trip. Resultant changes in $f(\Delta I)$ can only lead to a decrease in trip setpoint.

In addition to the reactor trip on overtemperature ΔT, a rod stop and turbine runback are initiated when

$$\Delta T > \Delta T_{\text{rod stop}}$$

where

$\Delta T_{\text{rod stop}}$	=	$\Delta T_{\text{setpoint}} - B_P$
B_P	=	a setpoint bias

The turbine runback is continued until ΔT is equal to or less than $\Delta T_{\text{rod stop}}$. This function serves to maintain an essentially constant margin to trip. This gives the operator the opportunity to adjust the rods and reshape the flux before a reactor trip occurs.

f. Overpower ΔT Trip

The purpose of this "calculated" trip is to protect against excessive power level (fuel rod rating protection). The reactor is tripped when two-out-of-four signals, with two sets of temperature measurements per loop, are above the trip setpoint.

The setpoint for this reactor trip is continuously calculated for each channel by solving the following equation (simplified version):

$$\Delta T_{\text{setpoint}} = K_4 - f\,(T_{avg})$$

where:

K_4	=	A setpoint constant derived from Technical Specifications
$f(T_{avg})$	=	Function based on the effect of density and specific heat of water as a function of average temperature.

In addition to the reactor trip, a rod stop and turbine runback are initiated on approach to overpower ΔT trip actuation.

g. Low Pressurizer Pressure Trip

The purpose of this trip is to protect against excessive boiling in the core and limit the range of required protection from the overpower and overtemperature delta T trips. Above either P-7 permissive setpoint of approximately 10% reactor power or approximately 10% turbine power, the reactor is tripped when two-out-of-four low pressurizer pressure signals are below the setpont. This trip is automatically blocked by the P-7 permissive, when three-out-of-four power range channels and both turbine first stage pressure channels are below their respective P-7 permissive setpoints. When two-out-of-four power range channels or one-out-of-two turbine first stage pressure channels are above their respective P-7 setpoints, the reactor trip is automatically reinstated.

h. High Pressurizer Pressure Trip

The purpose of this trip is to limit the range of required protection from the overtemperature ΔT trip and to protect against reactor coolant system overpressure. The reactor is tripped when two-out-of-three high pressurizer pressure signals are above the setpoint.

i. High Pressurizer Water Level Trip

The trip is a backup to the high pressurizer pressure trip. Above either P-7 permissive setpoint of approximately 10% reactor power or approximately 10% turbine power, the reactor is tripped when two-out-of three high pressurizer water level signals are above the setpoint. This trip is automatically blocked by the P-7 permissive, when three-out-of-four power range channels <u>and</u> both turbine first stage pressure channels are below their respective P-7 permissive setpoints. When two-out-of-four power range channels or one-out-of-two turbine first stage pressure channels are above their respective P-7 setpoints, the reactor trip is automatically reinstated.

j. Low Reactor Coolant Flow Trip

This trip protects the core from DNB due to low coolant flow or loss-of-coolant flow. The means of sensing low coolant flow are as follows:

1. Measured Low Coolant Flow in the Reactor Coolant Piping.

   Above the P-8 permissive setpoint of approximately 35% reactor power, the reactor is tripped when two-out-of-three flow signals for either reactor coolant loop are below their low flow setpoint. This trip is automatically blocked when three-out-of-four power range channels are below the P-8 permissive setpoint. When two-out-of-four power range channels are above the P-8 permissive setpoint, the reactor trip is automatically reinstated.

   Above either P-7 permissive setpoint of approximately 10% reactor power or approximately 10% turbine power, the reactor is tripped when two-out-of-three flow signals for both reactor coolant loops are below their low flow setpoint. This trip is automatically blocked by the P-7 permissive, when three-out-of-four power range channels and both turbine first stage pressure channels are below their respective P-7 permissive setpoints. When two-out-of-four power range channels or one-out-of-two turbine first stage pressure channels are above their respective P-7 setpoints, the reactor trip is automatically reinstated.

   The elbow tap configuration used for reactor coolant loop flow measurement is discussed in Section 4.2.

2. Monitored Electrical (Voltage) Supply and Breaker Position to the Reactor Coolant Pumps.

   Above either P-7 permissive setpoint of approximately 10% reactor power or approximately 10% turbine power, the reactor is tripped when one-out-of-two undervoltage relays on both 4160 volt buses (A01 and A02) are below their setpoint. This trip is automatically blocked by the P-7 permissive, when three-out-of-four power range channels and both turbine first stage pressure channels are below their respective P-7 permissive setpoints. When two-out-of-four power range channels or one-out-of-two turbine first stage pressure channels are above their respective P-7 setpoints, the reactor trip is automatically reinstated.

   Above the P-8 permissive setpoint of approximately 35% power, the reactor is tripped when either reactor coolant pump breaker is open. This trip is automatically blocked when three-out-of-four power range channels are below the P-8 permissive setpoint. When two-out-of-four power range channels increase above the above the P-8 permissive setpoint, the reactor trip is automatically reinstated.

   Above either P-7 permissive setpoint of approximately 10% reactor power or approximately 10% turbine power, the reactor is tripped when both reactor coolant pump breakers are open. This trip is automatically blocked by the P-7 permissive, when three-out-of-four power range channels and both turbine first stage pressure channels are below their respective P-7 permissive setpoints. When two-out-of-four power range channels or one-out-of-two turbine first stage pressure channels are above their respective P-7 setpoints, the reactor trip is automatically reinstated.

A reactor coolant pump breaker is tripped (opened) when two-out-of-two undervoltage or one-out-of-one fault relays on the breaker's associated 4160 volt bus (A01 or A02) are below the trip setpoint. Both reactor coolant pump breakers are tripped when one-out-of-two underfrequency relays on both 4160 volt buses (A01 and A02) are below the trip setpoint.

k. Safety Injection System Actuation Trip

The reactor trip occurs when the safety injection system is actuated. The means of actuating safety injection is described in Section 7.3. Either Train "A" or "B" of safety injection will actuate a reactor trip signal in both Trains "A" and "B" of reactor protection.

l. Turbine Generator Trip

The reactor is tripped when two-out-of-three low pressure signals that monitor the turbine autostop oil pressure are below the setpoint or when two-out-of-two turbine stop valves close, which would indicate that the turbine has tripped. This trip is automatically blocked by the P-9 permissive when three-out-of-four power range detectors are below approximately 50% power, one-out-of-two circulating pumps are running, condenser vacuum exists and full power Tavg is ≥572°F. The trip is automatically reinstated when two-out-of-four power range detectors are above approximately 50% power or two-out-of-two circulating pumps are not running or condenser vacuum does not exist. When full power Tavg is <572°F the reactor trip is blocked and reinstated as described above except the P-9 power range detector setpoint is set at approximately 35% power.

This trip is also automatically blocked by the P-7 permissive, when three-out-of-four power range channels <u>and</u> both turbine first stage pressure channels are below their respective P-7 permissive setpoints. When two-out-of-four power range channels <u>or</u> one-out-of-two turbine first stage pressure channels are above their respective P-7 setpoints of approximately 10% reactor power or 10% turbine power, the reactor trip is automatically reinstated.

m. Steam/Feedwater Flow Mismatch Trip

The purpose of this trip is to protect the reactor from a sudden loss of its heat sink. The reactor is tripped when one-out-of-two circuits monitoring steam/feedwater flow for each steam generator indicate a flow mismatch and the corresponding loop low level steam generator signals are below the trip setpoint.

n. Low-Low Steam Generator Water Level Trip

The purpose of this trip is to protect the steam generators and to protect the reactor from a loss of its heat sink in the case of a sustained steam/feedwater flow mismatch of insufficient magnitude to cause a flow mismatch reactor trip. The reactor is tripped when two-out-of-three low-low steam generator water level signals in either steam generator are below the trip setpoint.

7.2.2.3 System Safety Features

a. Isolation of Redundant Protection Channels and Trains

The reactor protection system is designed to achieve isolation between redundant protection channels and trains. The channel design applies to the analog portions through the channel trip bistable and the train design applies to the logic portions as illustrated by Figure 7.2-4. Although the illustration is for a four channel coincidence, the design is also applicable to two and three channel coincidence logics.

The reactor protection system is comprised of identifiable channels which are physically, electrically and functionally separated and isolated from one another. Each channel is energized from a separate AC power feed. Isolation of redundant analog channels originates at the process sensors and continues along the field wiring and through containment penetrations to the analog protection racks. Isolation of field wiring is achieved using separate wireways, cable trays, conduit runs, and containment penetrations for each redundant channel. Analog equipment is isolated by locating redundant components in different protection racks.

The transition from channel identity to train identity occurs at the logic relay coil/relay contact interface. As such, there is both electrical and physical separation between the channel and the train portions of the protection system. The “coil side” of each logic relay is associated with the channel logic, and the “contact side” of each logic relay is associated with the train logic. The channel trip bistables are mounted in the analog protection racks and are the final operational component in an analog protection channel. Each bistable drives two logic relays, one for Train “A” and one for Train “B.”

Train separation is achieved by providing separate racks. Physical separation is provided between these racks. Each train is energized from a separate DC power feed. The contacts from the Train “A” relays are interconnected to form the required actuation logic for one reactor trip breaker.

The above configuration is duplicated for the other reactor trip breaker using the contacts from the Train “B” relays. Therefore, the two redundant reactor trip trains are physically separated and electrically isolated from one another.

b. Loss of Power

The four RPS channels are powered from four separate and independent 120 VAC instrument buses, which are battery backed. The logic racks for the two RPS trains are powered from separate and independent 125 VDC sources. See Chapter 8 for a further discussion on 120 VAC and 125 VDC buses.

Availability of power to the reactor protection system channels and trains is continuously indicated. Loss of AC power to an individual RPS channel will cause the channel’s bistables to trip, causing the affected channel to trip. The tripping of a channel is annunciated in the Control Room. All bistables are normally energized and de-energize to actuate. Therefore, the loss of power results in the channel going to its “fail-safe” state. Since the reactor protection system requires the tripping of at least two coincident channels, the loss of power to one reactor protection channel will not result in a reactor trip. However, the loss of DC power to an individual RPS train will result in the tripping of the reactor trip breakers, which will result in a reactor trip.

c. Reactor Trip Signal Testing

The train logic portion of the reactor protection system initiates a reactor trip only after signals from the analog channel portion of the system reach a preset value. Capability is provided for calibrating and testing the performance of the channel trip bistables, and various coincidence combinations of the train logic during reactor operation.

1. Analog Channel Testing

The basic elements comprising an analog protection channel are shown in Figure 7.2-5, and consist of a transmitter, power supply, bistable, bistable trip switch and proving lamp, test signal injection switch, test signal injection jack and test point.

Each protection rack includes a test panel containing those switches, test jacks and related equipment needed to test the channels contained in the rack. A hinged cover encloses the test panel. Opening the cover or placing the test-operate switch in the "TEST" position will initiate an alarm. These alarms are arranged on a rack basis to preclude entry to more than one redundant protection rack (or channel) at any time. The test panel cover is designed such that it cannot be closed (and the alarm cleared) unless the test signal plugs (described below) are removed. Closing the test panel cover will mechanically return the test switches to the "OPERATE" position.

During power operation, administrative procedures require that the affected channel is placed in its tripped state before that channel is taken out of service for repair or testing, so that the minimum degree of redundancy is met for its intended function. This places a proving lamp across the bistable output so that the bistable trip point can be checked during channel calibration. The bistable trip switches must be manually reset after completion of a test. Closing the test panel cover will not restore the bistable trip switches to the untripped mode. However, the annunciator on the main control board cannot be reset until these switches are returned to the untripped mode.

Provisions have been implemented for the insertion of test signals in each analog loop. Channel calibration consists of inserting a test signal from an external calibration signal source into the test signal injection jack. Where applicable, the channel power supply will serve as a power source for the calibration source and permit verifying the output load capacity of the power supply. Test points are located in the analog channel and provide an independent means of measuring the calibration signal level. Transmitters and sensors are checked against each other and/or precision test equipment during normal operation.

In the source and intermediate ranges where the trip logic is one-out-of-two for each range, bypasses are provided for testing and the trip logic reverts to one-out-of-one, which is allowed by Section 4.11 of IEEE 279-1968.

Nuclear instrument power range channels are tested by superimposing a test signal on the normal sensor signal so that the reactor trip function is not bypassed. Based upon the two-out-of-four logic, this will not trip the reactor; however, a reactor trip will occur if required.

2. Logic Testing

The general design features of the logic system are described below. Each analog channel trip bistable drives two logic relays (one for Train “A” and one for Train “B”). The typical two-out-of-three logic network (e.g., high pressurizer level) is represented by contacts “A” and “B”, whereas the typical two-out-of-four logic network (e.g., low pressurizer pressure) is represented by contacts “C” and “D” in Figure 7.2-6.

The parallel reactor trip relays are represented by “E” and “F” for Train “A”, and “G” and “H” for Train “B”. The reactor trip relays are de-energized when the required coincidence logic (e.g., two-out-of-three) is met, which results in the de-energization of the undervoltage coil and energization of the shunt trip attachment.

A series configuration is used for the reactor trip breakers so that no single failure will prevent the interruption of power to the control rod drive mechanisms. This approach is consistent with a de-energize-to-trip preferred failure mode. Each reactor trip breaker is tripped by removing power to its undervoltage trip coil as well as energizing its shunt trip coil.

The train logic testing includes exercising the reactor trip breakers to demonstrate their operability. Bypass breakers are provided to prevent an inadvertent reactor trip when the reactor trip breaker being tested is tripped; however, a valid reactor trip will still occur, if required, by tripping the reactor trip breaker not under test. During normal operation, the bypass breakers are open. Administrative control is used to minimize the amount of time these breakers are closed, and to prevent the simultaneous closure of both bypass breakers. Indication of a closed bypass breaker is provided locally, on the test panel, and on the main control board. Also, if both bypass breakers are simultaneously racked in, with one being used for the bypass function, a reactor trip will result.

As shown in Figure 7.2-6, the trip signal from the channel network for Train “A” is designed to trip (open) Reactor Trip Breaker RTA as well as the Bypass Breaker BYB. The Train “B” logic applies to the RTB and BYA. Therefore, if a valid trip signal occurs while BYA is closed to bypass RTA during testing, RTB and BYA will be tripped by the coincidence logic for Train “B”, which would result in the removal of power to the control rod mechanisms and a reactor trip. In addition, RTA would either have been tripped manually as part of the test or would be tripped through its associated coincidence logic.

An auxiliary relay is located in parallel with the undervoltage coil and shunt trip attachment of each reactor trip breaker. This relay is connected to the events recorder. In addition, lights are provided to indicate the status of the individual logic relays.

The following procedure illustrates the method used for testing RTA and its associated logic network.

1. With the bypass breaker (BYA) in the test position, locally close the BYA breaker. Trip BYA from the logic test panel to verify operation.

2. Rack in and close BYA.

3. Perform a verification of the shunt trip block mechanism. Then, with the shunt trip block actuated, do an independent test of the undervoltage trip mechanism.

   De-energize the logic relays (A1, A2, A3) for one logic combination (1 and 2, 1 and 3, or 2 and 3) and verify that the logic network de-energizes the undervoltage coil on RTA. The first combination tested will physically trip the breaker.

   Reclose the breaker and with the shunt trip block signal cleared, perform an independent check of the shunt trip coil by actuating the shunt trip pushbutton. This also physically trips the breaker. These two tests verify that the reactor trip breaker will be tripped either by the undervoltage or the shunt trip coils.

   The other two logic combinations are then tested to verify that the logic network de-energizes the undervoltage coil and would energize the shunt trip coil. Since the events recorder or white test light monitors the signal applied to the undervoltage coil, signal verification can be determined from the events recorder or the white test light.

4. Repeat step 3 for every logic combination associated with the logic network for the undervoltage coil test; however, the reactor trip breaker is not tested again.

5. Reset RTA. Trip and rack out BYA.

   In order to minimize the possibility of operational errors (such as tripping the reactor inadvertently or only partially checking all logic combinations), each train includes a logic channel test panel. This panel includes those switches, indicators and recorders needed to perform the logic system test. The arrangement is illustrated in Figure 7.2-7. The test switches used to de-energize the trip bistable relays operate through interposing relays as shown on Figure 7.2-5. This approach avoids violating the separation philosophy used in the analog channel design. Thus, although test switches for redundant channels are conveniently grouped on a single panel to facilitate testing, physical and electrical isolation of redundant protection channels are maintained by the inclusion of the interposing relay which is actuated by the logic test switches.

7.2.2.4 Conformance With Generic Letter 83-28

The following design features and maintenance requirements for the reactor trip and bypass breakers were credited or required for compliance with Generic Letter 83-28, Required Actions Based on Generic Implications of Salem ATWS Events.

Design (Reference 1)

- Implementation of automatic actuation of the shunt trip attachment on each reactor trip breaker when a reactor trip signal is generated by the associated train.
- The circuitry used to implement the shunt trip function is Class 1E (safety related) and the design of the circuits is consistent with the Westinghouse Owners Group (WOG) generic design.
- The WOG generic seismic, environmental and life cycle testing of the shunt trip components is applicable to Point Beach. This includes seismic qualification of the shunt trip components in accordance with the provisions of Regulatory Guide 1.100, Revision 1, which endorses IEEE Standard 344.

- Components of the shunt trip circuitry have the ability to perform their intended function up to a voltage of approximately 140 V DC. The voltage source for the undervoltage and shunt trip coils is from station batteries and the battery voltage is maintained less than 135 VDC.

- Field cables for redundant trains of the circuits used to manually initiate the shunt trip attachments are routed in separate raceways between the reactor trip switchgear and the main control board. In the main control board six inches of free air space or an intervening barrier is provided between redundant circuits which provide for manual initiation of the shunt trip attachments of the redundant trip breakers.

- Redundancy of the reactor trip breakers is maintained by using separate Class 1E 125 V DC power sources for the Train A and Train B shunt trips. Cables which are associated with both power supply circuits due to their presence in common enclosures or raceways were analyzed and it was determined that Class 1E circuits are not degraded below an acceptable level. This is in accordance with IEEE 384 and, is therefore, acceptable.

- Installation of bypass breaker position indication on the main control board and interlocking all remote bypass breaker indication with breaker cell switches.

Maintenance (Reference 2 and Reference 3)

- Periodic maintenance, inspection, and lubrication of reactor trip and bypass breakers and associated switchgear is based on the manufacturer's recommendations which include performing maintenance on a refueling outage interval.

- Trip force and breaker response time for UV trip of reactor trip and bypass breakers are recorded and compared to the maximum acceptable values of 31 ounces and 10 cycles respectively. Corrective action is taken if the recorded values are significantly in excess of those normally experienced.

- The UV trip attachment dropout voltage for the reactor trip and bypass breakers is trended as per the manufacturer's recommendations contained in the component instruction manual.

- Reactor trip breaker and bypass breaker insulation is inspected for cracks or other signs of deterioration.

Generic Letter 83-28 requirements for reactor trip and bypass breaker testing are included in Technical Specification 3.3.1, Reactor Protection System (RPS) Instrumentation, except that testing of the bypass breaker shunt trip attachment was removed during the conversion to Improved Technical Specifications.

7.2.3 SYSTEM EVALUATION

The design on the reactor protection system meets that applicable protection system General Design Criteria and IEEE 279-1968 criteria, except where exceptions have been identified in Section 7.2.3.3. The following sections describe specific areas related to these criteria.

7.2.3.1 <u>Reactor Protection System and DNB</u>

The following is a description of how the reactor protection system prevents DNB.

The plant variables affecting the DNB ratio are:

Thermal power
Coolant flow
Coolant temperature
Coolant pressure
Core power distribution (hot channel factors)

Figure 7.2-2 illustrates the actual core limits for different pressure ranges, where the DNBR for the hottest fuel rod is the DNB limit. The figure also shows the computed overpower and overtemperature ΔT reactor trips as a function of ΔT, T_{avg} and pressure. Figure 7.2-8 depicts the typical $T_{avg}/\Delta T$ control and protection system for each reactor coolant loop.

Variations in both flow and power are monitored by the overpower and overtemperature ΔT trips, because a decrease in flow has the same effect on the measured loop ΔT signal as an increase in power. It is the characteristic of the DNB limits that a reduction in flow of 10% would require a reduction in power of about 5% to maintain the same DNBR, all other variables remaining constant. Therefore, the allowed ΔT increases somewhat at a reduced flow. The trip setpoints are therefore conservatively based on maximum flow. A reduction in flow increases the margin between the trip point and the actual core limit. Periodic measurements using the incore instrumentation system are used to verify that the actual core power distribution is within design limits.

High pressurizer pressure and low pressurizer pressure trips are fixed to limit the pressure range over which core protection depends on the overpower and overtemperature ΔT trips.

Reactor trips on nuclear overpower and low reactor coolant flow are provided for direct, immediate protection against rapid changes in these parameters. However, for all cases in which the calculated DNBR approaches the DNBR limit, a reactor trip on overpower and/or overtemperature ΔT would also be actuated.

The reactor protection system actuates a reactor trip on "calculated" overpower ΔT and overtemperature ΔT setpoint based on the hottest fuel rod approaching the DNBR limit. Because of the statistical nature of the DNB correlation and the statistical makeup of a portion of the hot channel factors, there exists a finite probability that a few rods could experience DNB based on the identified hottest fuel rod.

For the anticipated abnormal conditions, it is highly unlikely that the exact combination of conditions (reactor coolant pressure, temperature and core power, instrumentation inaccuracies, etc.) that cause a DNBR equal to the limit will be approached before the reactor trips. The simultaneous loss of power to all of the reactor coolant pumps is the accident condition most likely to approach the DNBR limit for the calculated hottest fuel rod. In any event, the DNBR at the hottest fuel rod is near the limit for only a few seconds.

The hottest fuel rods are not adjacent to one another. They are located near the RCCA guide thimbles. Fuel rods located in the immediate vicinity of the hottest fuel rod have a DNBR higher than that rod.

The ΔT trip functions are based on the differences between measured hot leg and cold leg temperatures. These differences are approximately proportional to core power. Nonlinearities between ΔT and core power due to variations in specific heat are conservatively accounted for.

The overtemperature ΔT trip functions are provided with a neutron flux feedback to reflect a measure of axial power distribution. This assists in preventing an adverse axial distribution which could lead to exceeding the allowable core conditions.

In the event that the difference between the upper and lower power range ion chamber signals exceeds the desired range, automatic feedback signals are provided to reduce the overtemperature trip setpoints, block rod withdrawal and reduce the load to maintain appropriate operating margins for these trip setpoints.

7.2.3.2 Specific Control and Protection Interactions

Some of the control functions derive their signals from the reactor protection system through isolation devices. The isolation devices prevent any failure in the control system from propagating back into the protection system; therefore, no control system failure will adversely affect the protection system.

Certain failures in the protection system could conceivably prevent a particular protection channel from functioning. In addition, the failure could also cause spurious control actions that might require protective action to prevent the resultant spurious control action from exceeding design limits. IEEE 279-1968 Section 4.7 requires analysis for control/protection interactions when protection system variables also provide control signals. The analysis requires that a failure in the protection system that can cause spurious control actions be analyzed in conjunction with a second failure assumed in the protection system. RPS variables that supply control signals were evaluated in WCAP-7306.

a. Power Range Nuclear Flux

Four power range neutron flux channels are provided for overpower protection. Isolated outputs from all four channels are averaged to provide for automatic control rod regulation of power. If any channel fails in such a way as to produce a low output, that channel is incapable of proper overpower protection and may cause a rod withdrawal resulting in overpower. If a second failure is taken for a redundant channel failing to trip on high reactor power, the remaining two-out-of-four overpower trip channels satisfy IEEE 279 Section 4.7 and will ensure an overpower trip, if needed.

In addition, the rod control system will only respond to rapid changes in indicated neutron flux; slow changes or drifts are compensated by the temperature control signals. An overpower signal from any nuclear power channel will block both automatic and manual rod withdrawal. The setpoint for this rod stop is below the reactor trip setpoint.

b. Coolant Temperature

Two hot leg and two cold leg temperature measurements are made for each reactor coolant loop to provide reactor protection. In addition, the use of isolation amplifiers located in the temperature protection channel allow the temperature signals to also be used for reactor control. The temperature measurements, T_{avg} and ΔT, for each loop are used for the overpower and overtemperature ΔT reactor protection, with two channels per loop. The reactor control system uses the highest of the four isolated temperature measurements signal.

In addition, alarms are actuated in the reactor control system if any temperature channel deviates significantly from the others. Automatic rod withdrawal blocks also occur if any one of four nuclear power channels indicates an overpower condition, or if any two-out-of-four temperature channels indicates an overtemperature condition. Two-out-of-four coincidence logic is used to ensure that an overtemperature trip will occur, if needed, even with an independent failure in another channel. Finally, as shown in Section 14.1, the combination of trips on nuclear overpower, high pressurizer water level, and high pressurizer pressure also serve to limit an excursion for any rate of reactivity insertion.

The hot and cold leg resistance temperature detectors (RTDs) are installed in the reactor coolant bypass loops. A bypass loop from upstream of the steam generator to downstream of the steam generator is used for the hot leg RTDs and a bypass loop from downstream of the reactor coolant pump to upstream of the pump is used for the cold leg RTDs. The RTDs are located in manifolds and are directly inserted into the reactor coolant bypass loop flow without thermowells. Thermowells are not used in order to improve the detector's time response to temperature changes.

Three sampling probes are installed in a cross-sectional plane of each hot leg at approximately 120° intervals. Each sampling probe, which extends several inches into the hot leg coolant stream, contains five inlet orifices distributed along its length. Therefore, a total of fifteen locations in the hot leg stream are sampled to provide a representative reactor coolant temperature. The 2 inch diameter pipe leading to the manifold containing the RTDs provides mixing of the samples to give an accurate temperature measurement.

Care has been taken to distribute the flow evenly among the five orifices of each probe by effectively restricting the flow through the orifices. This has been done by designing a smaller overall orifice flow area than that of the common flow channel within the probe. This arrangement has also been applied to the flow transition from the three probe flow channels to the pipe leading to the temperature element manifold. The total flow area of the three probe channels has therefore been designed to be less than that of the 2 inch pipe connecting the probes to the manifold.

The cold leg primary coolant flow is well mixed by the reactor coolant pumps. Therefore, the cold leg sample is taken directly from a 2 inch pipe tap on the cold leg downstream of the pump.

The main requirement for reactor protection is that the temperature difference between the hot leg and cold leg vary linearly with power at high power levels near 100% power. All ΔT setpoints are in terms of the full power ΔT, and thus, accurate ΔT measurements are not required. Linearity of ΔT with power was verified during startup tests.

Reactor protection logic that uses reactor coolant loop temperatures consists of a two-out-of-four trip logic that consists of two channels per reactor coolant loop with separate RTDs for each reactor protection channel. This complies with all applicable IEEE 279 criteria.

Reactor control is based upon measurements from detector channels which are separate from those used for reactor protection. Since reactor control is based on the highest average temperature from the two loops, the control rods are always moved based upon the most conservative temperature measurement with respect to DNB margin. A spurious low average temperature (T_{avg}) signal from any temperature control channel will not result in any control action. A spurious high average temperature signal will cause control rod insertion, which results in reduced reactor power. Two-out-of-four trip logic is used to ensure that an overtemperature trip occurs, if needed, even with an independent failure in another channel; therefore, the reactor coolant temperature measurements meet the requirements of IEEE 279-1968 Section 4.7.

A common low flow alarm with an individual status light for each reactor coolant bypass loop is provided on the main control board. The alarm and status lights provide the operator with immediate indication of a low flow condition in the bypass loops associated with either reactor coolant loop.

Local indicators are provided to monitor total flow through the RTD bypass manifolds for each loop. The indicators are located inside containment, but are accessible during power operations. Flow is monitored:

1. Prior to restoring temperature channels to normal service whenever a bypass loop has been out of service;
2. On a periodic basis; and
3. Following any bypass loop low flow alarm.

The time delays associated with the temperature measurements used for reactor protection include RTD bypass loop fluid transport delay effect, bypass loop piping thermal capacity, RTD time response, and trip circuit channel electronics delay. The total time delay is measured from the time the temperature difference in the coolant loops exceeds the trip setpoint until the rods are free to fall.

Functional demonstration testing of the RTDs installed in the bypass lines in the Point Beach Nuclear Plant were conducted. The tests included both the incore thermocouple/RTD intercalibrations and load swing tests. Flow through the manifolds was checked and balanced. Consistency of the readings from the RTDs in the loops as well as reproducibility of the readings during power operation were checked. The load swing test demonstrated the response times were higher than the 2.3 seconds used in the accident analysis, which could have resulted in a reduction in DNBR to less than the 1.3 minimum ratio allowed by the accident analyses during a rod withdrawal accident at full power operation.

As a result of the testing, the lead time values used to calculate the overtemperature ΔT and overpower ΔT setpoints were increased to compensate for the slower than expected response times of the RTD bypass loops. The overtemperature and overpower ΔT instrumentation were adjusted for the more conservative settings prior to full power operation. This ensures that the reactor protection instrumentation will maintain the plant within the limits described in the accident analysis, Section 14.1. The values for the overtemperature ΔT and overpower ΔT setpoints are listed in the Technical Specifications.

c. Pressurizer Pressure

Four pressure channels are used for low pressure protection and as part of overtemperature protection. Three of the four pressure channels are used for high pressure protection. Isolated output signals from these channels also are used to control pressurizer spray, power-operated relief valves, and pressurizer heaters. (See Figure 7.2-10)

1. Low Pressure

   A spurious high pressure signal can cause low pressure by actuating the spray valves. Low pressure caused by spurious opening of a PORV is prevented by a two-out-of-two high pressure actuation logic. If a second failure is taken for a redundant pressure channel failing to trip on de-pressurization caused by the inadvertent spray valve actuation, the remaining two-out-of-four low pressure channels satisfy IEEE 279 Section 4.7 and ensures a reactor trip, if needed.

2. High Pressure

   The pressurizer heaters are incapable of overpressurizing the reactor coolant system. Maximum steam generation rate with heaters is about 8,200 lbs/hr, compared with a total relieving capacity of 576,000 lbs/hr for the two safety valves and a total relieving capacity of 358,000 lbs/hr for the two pressurizer power-operated relief valves. Therefore, overpressure protection is not required for a pressure control failure that could cause the heaters to energize. Two-out-of-three high pressure trip logic is therefore used.

   In addition, either of the two relief valves can easily maintain pressure below the high pressure trip point. The two relief valves are controlled by independent pressure channels, one of which is independent of the pressure channel used for heater control. Finally, the rate of pressure rise achievable with heaters is slow, and pressure alarms are available which provide ample time for operator action.

d. Pressurizer Level

   Three pressurizer level channels are used for high level reactor protection. Isolated output signals from these channels are used for volume control, increasing or decreasing water level. A level control failure could fill or empty the pressurizer at a slow rate (on the order of half an hour or more). (See Figure 7.2-11)

1. High Level

   A reactor trip on pressurizer high level is provided to prevent rapid thermal expansions of reactor coolant fluid from filling the pressurizer. The rapid change from high rates of steam relief to water relief can be damaging to the safety valves, the relief piping and pressure relief tank. A level control failure cannot actuate the safety valves because the high pressure reactor trip setpoint is below the safety valve setpoint. With the slow rate of charging available, the pressure overshoot before the high pressure reactor trip is much smaller than the difference between high pressure reactor trip and safety valve set pressure. Therefore, a control failure does not require protection system action.

   In addition, alarms are available and ample time exists for operator action.

2. Low Level

   For control failures which tend to empty the pressurizer, low level alarms provide ample time for operator action.

e. Steam Generator Water Level and Feedwater Flow

The basic function of the reactor protection trips associated with low steam generator water level and low feedwater flow is to preserve the steam generator heat sink for removal of long-term residual heat (See Figure 7.2-12). Should a complete loss of feedwater occur with no reactor protection action, the steam generators would boil dry and cause an overtemperature/overpressure excursion of the reactor coolant.

Reactor trips on temperature, pressure, and pressurizer water level will trip the plant before there is any damage to the core or reactor coolant system. However, the residual heat remaining after a trip would cause thermal expansion and discharge of the reactor coolant to containment through the pressurizer relief valves and pressurizer relief tank.

Redundant auxiliary feedwater pumps are provided to prevent the loss of steam generator inventory. Reactor trips act before the steam generators are dry, to reduce the required capacity and starting time requirements for the auxiliary feedwater pumps and minimize the thermal transient on the reactor coolant system and steam generators. Independent trip circuits are provided for each steam generator for the following reasons:

- Should severe mechanical damage (e.g., feedwater line break, etc.) occur to the feedwater line to one steam generator, it is difficult to ensure the functional integrity of the level and flow instrumentation for that steam generator.
- It is desirable to minimize thermal transients on a steam generator for credible loss of feedwater accidents.

It should be noted that controller malfunctions caused by a protection system failure would affect only one steam generator and would not impair the capability of the main feedwater system under either manual control or automatic control. The control and protection interactions associated with the steam generator and feedwater flow are as follows:

1. Feedwater Flow

   A spurious high signal from the feedwater flow channel being used for control would cause a reduction in feedwater flow and prevent that channel from tripping. A reactor trip on low-low water level, independent of indicated feedwater flow, ensures a reactor trip, if needed.

2. Steam Flow

   A spurious low steam flow signal would have the same affect as a high feedwater signal, discussed above.

3. Steam Generator Level

   A spurious high water level signal from the protection channel used for control will tend to close the main feedwater regulating valve. This level channel is independent of the level and flow channels used for reactor trip on low flow coincident with low level; therefore:

- A rapid increase in the level signal will completely stop feedwater flow and lead to an actuation of a reactor trip on low feedwater flow coincident with low level.
- A slow drift in the level signal may not actuate a low feedwater signal. Since the level decrease is slow, the operator has time to respond to low-level alarms. Since only one steam generator is affected, automatic protection is not mandatory and a reactor trip on two-out-of-three low-low level is acceptable.

Refer to Section 7.3.3 for a further discussion on control/protection interaction for the feedwater isolation function.

7.2.3.3 Specific Exceptions to IEEE 279-1968

a. Low Pressurizer Pressure Protection

Two of the four low pressurizer pressure transmitters share a common sensing line. There are two failure mechanisms that may be expected with a instrument sensing line:

- Broken line, and
- Blocked line

A broken sensing line would result in a reactor trip due to the two-out-of-four transmitters providing a low pressurizer pressure signal. Therefore, the failure of the sensing line would result in a reactor trip, and would not prevent the reactor protection system from meeting the assumptions in the accident analysis.

A blocked sensing line could result from a closed isolation valve. If the blocked line occurred on the shared sensing line, this could prevent the low pressurizer pressure trip from actuating when considered with a single active failure of another pressurizer pressure transmitter channel failing high. However, administrative procedures exist to ensure that the transmitter's valves are returned to correct position after calibration or maintenance. In addition, the failure of the transmitters to track the remaining redundant instrumentation during plant startup or operation would be identified. Therefore, the closure of an isolation valve is not considered a credible failure mechanism associated with the shared sensing line.

Based on the design of the protection system, its inability to withstand a pinched sensing line concurrent with a single active failure demonstrates that pinching of sensing lines due to accident effects was not considered as part of the original design for Point Beach; therefore, the pinching of the shared sensing line is not considered a credible failure mechanism.

Thus, no credible failure of the shared sensing line associated with the low pressurizer pressure trip will prevent the reactor protection system from tripping the reactor.

b. Coolant Flow

1. Measured Low Coolant Flow in Reactor Coolant Piping

   Three flow channels are used for the low reactor coolant flow reactor protection. The reactor coolant flow is determined by transmitters that measure the differential pressure (ΔP) associated with the elbow flow taps described in Section 4.2. The flow transmitters share a common high pressure sensing line, while the low pressure sensing lines are independent for each transmitter. There are two failure mechanisms that may be expected with an instrument sensing line:

- Broken line, and
- Blocked line

A broken high pressure sensing line would result in a reactor trip due to the three flow transmitters providing a low flow signal. Therefore, the failure of the sensing line would result in a reactor trip, and would not prevent the reactor protection system from meeting the assumptions in the accident analysis.

A blocked high pressure sensing line could result from a closed isolation valve. This could result in degraded performance of the low reactor coolant flow pressure trip. However, administrative procedures exist to ensure that the transmitter's valves are returned to the correct position after calibration or maintenance. In addition, the failure of the flow transmitters on one loop to track the flow instrumentation on the other loop during plant startup would be identified. Therefore, a blocked high pressure sensing line is not considered a credible failure mode associated with the shared sensing line.

Based on the design of the protection system, its inability to withstand a pinched sensing line concurrent with a single active failure demonstrates that pinching of sensing lines due to accident effects was not considered as part of the original design for Point Beach; therefore, the pinching of the shared sensing line is not considered a credible failure mechanism.

Thus, no credible failure of the shared sensing line associated with the low reactor coolant flow trip will prevent the reactor protection system from tripping the reactor.

2. Monitored Breaker Position to the Reactor Coolant Pumps

The reactor is tripped when either one-out-of-two reactor coolant pump breakers are open (tripped) above approximately 50% power and when two-out-of-two reactor coolant pump breakers are open below approximately 50% power. Some of the components in the reactor coolant pump breaker trip circuit are non-safety related, non-seismically qualified. In addition, the trip below approximately 50% power requires a two-out-of-two trip logic, which is not single failure proof.

The reactor trip on reactor coolant pump breaker position is considered an anticipatory (backup) trip for a complete loss of flow event and no credit is taken for the trip in the accident analysis. No failure associated with reactor coolant pump breakers will prevent the reactor protection system from tripping the reactor, although the failure could initiate a reactor trip via one or both reactor trip trains.

c. Turbine Trip

The reactor is tripped when either two-out-of-two turbine stop valves close or when two-out-of-three pressure switches indicate low turbine auto stop oil pressure. The position indication and oil pressure indication are initiated by non-safety related, non-seismic instrumentation whose circuits are not physically separated in accordance with IEEE 279. In addition, the circulating water pump operating status and the condenser vacuum status inputs to the P-9 permissive, which blocks the reactor trip on turbine trip as discussed in Section 7.2.2.2.1, are non-safety related, non-seismically qualified. Also, the stop valve position trip and the automatic removal of the P-9 permissive on loss of circulating water pumps relies on two-out-of-two logic, which is not single failure proof.

The reactor trip on turbine trip is considered an anticipatory trip and no credit is taken for this trip in any of the accident analyses. These trips consist of contacts connected to the train logic relays. No failure associated with the instrumentation, shared circuit routing or trip logic will prevent the reactor protection system from tripping the reactor, although the failures could initiate a reactor trip via one or both reactor trip trains. In addition, since these circuits do not provide input to the analog channel logic, no failure associated with these trips will adversely affect any primary reactor trip channel.

The failure of the inputs could prevent the P-9 permissive from energizing below its setpoint, which could result in a reactor trip. No failure associated with the P-9 permissive will prevent the reactor protection system from functioning. Therefore, the failure of the permissive is "fail-safe."

d. Steam/Feedwater Flow Mismatch Trip

The feedwater flow transmitters for Unit 1 and Unit 2 FT-466, FT-467, FT-476, and FT-477 are Seismic Class 3. These transmitters provide input to the reactor protective scheme to provide a reactor trip upon Steam Flow/Feed Flow mismatch coincident with a Low Steam Generator Water Level. Since the feed flow transmitters are not seismically qualified, they may not perform their functions during and after a seismic event as depicted in FSAR Section 7.2.3.4.

The reactor trip on Steam/Feedwater Flow Mismatch coincident with a Steam Generator Water Level Low condition is considered an anticipatory backup trip for a Loss of Normal Feedwater Event and is described as such in FSAR Section 7.2.3.2e and no credit is taken for the trip in the accident analysis. No failure associated with the feedwater flow transmitters will prevent other portions of the reactor protection system from tripping the reactor.

7.2.3.4 Seismic Qualification of Protection System Equipment

NOTE: The following describes the original method used to seismically evaluate reactor protection system equipment. Additional verification of the seismic adequacy of plant mechanical and electrical equipment was performed as discussed in Section A.5.6, "Verification of Seismic Adequacy of Equipment per Generic Letter 87-02."

Documentation of the seismic test program for protection system components is contained in Westinghouse WCAP-7397-L, "Topical Report Seismic Testing of Electrical and Control Equipment" dated January 1970, which summarizes the results as follows:

In a nuclear power plant, electrical and control equipment which initiates reactor trips, actuates safeguards systems, and/or monitors radioactive releases from the plant must be capable of performing their functions during and after an earthquake that has occurred at the plant site. To demonstrate the ability of this equipment to perform under earthquake conditions, selected types of this essential equipment representative of all protection and safeguards circuits and equipment were subjected to vibration tests which simulated the seismic conditions for the "low seismic" class of plants. During the tests, equipment operation was monitored to prove proper performance of function. The results show that there were no electrical malfunctions. Based on these results, it is concluded that the equipment will perform their design functions during, as well as following, a "low seismic" earthquake.

To apply WCAP-7397-L to the Point Beach design, the locations of the protection systems equipment were identified. Dynamic analysis of the buildings for the plant design basis earthquake shows that the horizontal and vertical accelerations of the buildings floors where the equipment is located are within the specific low seismic test envelope given in WCAP-7397-L, Figure B-2.

The protection or safeguard instrumentation systems are qualified to withstand a seismic event as follows:

A protection or safeguard signal is initiated by an instrument or transmitter, which has been demonstrated to withstand the seismic forces as identified in Section 4.8 of WCAP-7397-L.

The signal is carried by circuits installed in conduit and cable trays, which have been designed to withstand seismic forces. Appropriate supports have been added to typical configurations to withstand the accelerations determined for the building and elevation through which the circuit is routed.

The signal continues to the process control racks, which have been demonstrated to withstand the seismic forces as identified in Section 4.2 of WCAP-7397-L.

Then the signal proceeds to the actuation racks, which have been demonstrated to withstand the seismic forces as identified in Section 4.3 of WCAP-7397-L.

The actuation signal proceeds through a switch on the main control board to the appropriate switchgear (refer to Section 8.0 for switchgear discussion). The main control boards were specified to "be designed such that the maximum stresses, including simultaneous seismic accelerations of 5.2g in the horizontal and vertical directions, shall not dislodge or cause relative movement between components such as to impair the functional integrity of circuits or equipment." This acceleration exceeds that calculation as input to the boards from the floor of the main control room. In shipment, boards of this manufacturer and construction have recorded shocks of 8-10g and, when wired, the switches have operated without repair.

7.2.3.5 Environmental Qualification of Reactor Protection System Equipment

The reactor protection equipment that is located in a mild environment (e.g., an environment that would, at no time, be more severe that the normal service environment, such as the control room or cable spreading room) is not required to be environmentally qualified in accordance with 10 CFR 50.49. However, the design for normal service conditions and the PBNP quality assurance, maintenance, and surveillance programs ensure that the equipment is capable of performing its safety function on demand throughout its installed life.

The reactor protection equipment that is located in a potentially harsh environment, such as sensors inside containment, has to be environmentally qualified in accordance with 10 CFR 50.49 for reactor trip protection only if:

1. The equipment is the primary reactor trip assumed in the accident analysis for the accident that creates the harsh environment, and
2. The harsh environment degrades the equipment performance prior to initiating the reactor trip.

Therefore, if the equipment can be shown to not meet the above two requirements, the equipment does not need to be qualified from a reactor protection system standpoint. However, if the equipment is not required to be environmentally qualified for a reactor protection function, it may require qualification if it is used to provide post-accident monitoring.

a. Normal Operating Environment

A normal operating environment of ≤75°F is maintained in the control room. Protection equipment inside the control room is designed to operate within design tolerance over this temperature range and will perform its protection function in an ambient temperature range of 40°F to 120°F. Instrumentation and associated circuitry in the control room is generally rated for an ambient temperature range of 40°F to 120°F as discussed in Section 9.8.1.

The operating environment for equipment within containment is normally controlled to less than 105°F. The reactor protection system instrumentation within containment is designed for continuous operation. The temperature of the out-of-core neutron detectors is maintained at or below 135°F by the reactor cavity air cooling system. The detectors are designed for continuous operation of 135°F and will withstand operation at 175°F for short durations.

Typical test data (or reasonable engineering extrapolation based on test data) is used to verify that protection system's equipment meet, on a continuing basis, the functional requirements under the anticipated normal ambient conditions.

Table 7.2-3 provides information about the process instrumentation used to provide signals to the reactor protection system.

7.2.3.6 Methodology for Determination of RPS/ESFAS Setpoint Values (Reference 5)

The methodology for determining RPS/ESFAS protection system setpoints follows the guidance of PBNP Design Guide DG-I01, Instrument Setpoint Methodology. Applying the methodology, setpoint calculations are prepared to: 1) identify an analytical limit (AL) or process limit (PL) for the setpoint, 2) quantify the Total Loop Error (TLE) for the setpoint instrument string, 3) calculate the Limiting Safety System Setting (LSSS) / Limiting Trip Setpoint (LTSP), 4) select the Nominal Trip Setpoint (NTSP) based on the calculated LTSP, 5) determine as-left and as-found tolerances for the NTSP, and 6) determine the Allowable Value (AV).

The calculated values are determined such that there is a 95% probability and 95% confidence level that the instrument channel will trip prior to the process variable exceeding the established AL or PL.

a. Setpoint Determination

The AL is the limit of the process variable at which protective action is assumed to be initiated in the plant accident analyses. The setpoint must be chosen such that protective action occurs at or prior to reaching the AL, to assure that any associated analysis Safety Limit is protected. For backup, anticipatory, interlock or permissive functions that lack an AL, a PL or nominal setpoint value may be used instead.

The TLE is the combination of random (±) and non-random (bias) errors for the instrument string that provides the process signal to the trip bistable. Random errors are combined using the square root sum of squares (SRSS) method and bias terms are included algebraically to arrive at the TLE.

For primary trips, the LTSP is calculated by subtracting TLE from the AL for variables that increase toward the limit. For variables that decrease toward the limit, the TLE is added to the AL. The LTSP is the LSSS and represents the limiting value to which the field setpoint can be set within the as-left tolerance and still protect the AL, assuming worst case 95/95 instrument uncertainties. The Nominal Trip Setpoint (NTSP) that is published in the RPS/ESFAS Technical Specifications is equal to or more conservative than the LTSP. Typical practice is to round the calculated LTSP to arrive at the NTSP published in Technical Specifications. The value published in Technical Specifications is always rounded in a conservative (away from the AL) direction.

For backup or anticipatory trips that lack an AL, the same procedure is followed as for primary trips with the exception that the PL is used in place of the AL.

The AV is calculated from the LTSP, including all channel operational uncertainties measurable during a Channel Operational Test such that the as-found settings are within the AV. Typical practice is to round the calculated AV to arrive at the AV published in Technical Specifications. The value published in Technical Specifications is always rounded in a conservative (away from the AL) direction.

For interlocks and permissives, the NTSP is the nominal value assumed in the analysis.

Both the NTSPs and AVs are published in the RPS/ESFAS Technical Specifications. The actual field setting (Field Trip Setpoint or FTSP) is chosen to be equal to the NTSP, but may be set more conservative than the NTSP as necessary in response to plant conditions.

b. As-Left and As-Found Tolerances

As-left and as-found tolerances permitted during instrument calibration are symmetric values applied on each side of the NTSP. The NTSP is identified in the calibration procedures as the “ideal” setpoint value.

The methodology used to determine as-left and as-found tolerances in calibration procedures that accomplish RPS and ESFAS channel surveillance testing is described below. This methodology must be specified in FSAR Section 7.2 per notes in RPS and ESFAS Technical Specification Tables 3.3.1-1 and 3.3.2-1 issued for implementation of automatic AFW Pump suction transfer and power uprate to 1800 MWt.

1. As-Left Tolerances

As-left setting tolerances are applied to calibration settings for RPS/ESFAS components such as bistables, signal conditioning modules, and sensors that perform protective functions. A component’s as-left tolerance is determined in an associated uncertainty/setpoint calculation for the plant variable measured by the channel. The as-left tolerance is typically based on the reference accuracy of the component being calibrated. In some cases, the as-left tolerance may be a historically-chosen value based on limitations in adjusting the module and instrument performance. In those cases where the as-left tolerance is a historically-chosen value, the calculation provides a basis for using the historical value as the source for the setting tolerance, rather than using the component's reference accuracy.

If a single component (e.g., a bistable) is calibrated alone, the as left tolerance is typically the reference accuracy for the module. When a group of components are calibrated together (in a string calibration), the as-left tolerance is the square-root-sum-of-the-squares (SRSS) combination of the individual setting tolerances of components in the calibration string.

2. As-Found Tolerances

As-found setting tolerances (AF) are determined by calculation and are used during calibration to evaluate if a setting or output of a component or string of components is either behaving normally or has drifted excessively over the preceding calibration interval. The as-found tolerance accounts for the as-left tolerance plus the maximum 2σ drift expected to occur over the calibration interval when the component is behaving normally. As such, the AF is slightly larger than the as-left tolerance, and is also symmetric around the ideal setting or NTSP. As-found tolerances are determined as follows:

- If the expected component drift over the calibration interval is derived statistically from as-left/as-found data, the acceptable as-found tolerance can be calculated as the SRSS of the as-left setting tolerance (Rv) and the 2σ rack drift (Rd), as follows:

$$AF = \pm [Rv^2 + Rd^2]^{1/2}$$

- If the rack drift is not derived from actual as-left/as-found data, the acceptable as-found tolerance can be calculated as the SRSS of the as-left setting tolerance (Rv), predicted 2σ rack drift (Rd), and M&TE uncertainty (Rm), as follows:

$$AF = \pm [Rv^2 + Rd^2 + Rm^2]^{1/2}$$

By incorporating a 2σ drift value into the AF term, AF is a reasonable limit for evaluating that an individual module or a string of modules is behaving normally over the calibration interval. If the AF limit is exceeded when the as-found setting is measured, the excessive drift may be within 95/95 statistical probability, or the drift may indicate that the equipment is behaving erratically. An evaluation of an out-of-tolerance condition may include a review of calibration history and the drift magnitude as compared to predicted drift, to assess if the component is behaving within expected limits or is degrading such that repair or replacement may be necessary.

7.2.4 REFERENCES

1. NRC SE, “Wisconsin Electric Power Company, Point Beach Nuclear Plant Units 1 & 2, Generic Letter 83-28, Item 4.3, Reactor Trip Breaker Automatic Shunt Trip,” dated September 26, 1984.

2. NRC SE, “Wisconsin Electric Power Company, Point Beach Nuclear Plant Units 1 and 2, Reactor Trip System Reliability, Items 4.2.1 and 4.2.2 of Generic Letter 83-28,” dated May 16, 1985.

3. Commitment Change Evaluation CCE 98-001, dated September 24, 1998, for increase in preventive maintenance interval for reactor trip and bypass breakers.

4. NRC SE, Point Beach Nuclear Plant Units 1 and 2, “Issuance of License Amendments Regarding Extended Power Uprate,” dated May 3, 2011.

5. NRC SE, Point Beach Nuclear Plant Units 1 and 2, “Issuance of License Amendments Regarding Revision of Reactor Protection System (RPS) and Engineered Safety Features Actuation System (ESFAS) Setpoints,” dated March 25, 2011.

Table 7.2-1 LIST OF REACTOR TRIPS

REACTOR TRIP		COINCIDENCE CIRCUITRY AND INTERLOCKS	COMMENTS
1.	Manual	1/2, no interlocks.	
2a.	Power Range Nuclear Flux, High	2/4, no interlocks.	
2b.	Power Range Nuclear Flux, Low	2/4, manual block permitted by P-10.	Automatic unblock of low setting by P-10.
3.	Overtemperature ΔT	2/4, no interlocks.	
4.	Overpower ΔT	2/4, no interlocks.	
5.	Low Pressurizer Pressure	2/4, interlocked with P-7.	
6.	High Pressurizer Pressure	2/3, no interlocks.	
7.	High Pressurizer Water Level	2/3, interlocked with P-7.	
8a.	Low Reactor Coolant flow	2/3, per loop interlocked with P-8 or 2/3 both loops interlocked with P-7.	Both loops blocked below P-7. Single loop blocked below P-8.
8b.	RCP breakers only	1/1 per loop, interlocked with P-8 or 1/1 both loops interlocked with P-7.	
8b1.	RCP breaker trip, underfrequency	1/2 per bus on both buses, no interlocks.	Trips both RCPs.
8b2.	RCP breaker trip, undervoltage	2/2 per bus, no interlocks, approximately 5 second time delay.	Trips RCP on affected bus only.
8b3.	RCP breaker trip, A01 or A02 bus fault	1/1 per bus, no interlocks.	Trips RCP on affected bus only.
8c.	Undervoltage on A01 or A02	1/2 per bus interlocked with P-7.	
9.	Safety Injection Signal (Actuation)	1/2 manual, 2/3 low pressurizer, 2/3 high containment pressure, or 2/3 low steam line pressure (either loop).	Low pressurizer pressure and low steam line pressure SI signals may be manually blocked with RCS pressure below SI block setpoint, automatically unblocked above the setpoint.
10.	Turbine-Generator Trip	2/3 low auto stop oil pressure or 2/2 stop valve closure indication both interlocked with P-7 and P-9.	
11.	Steam/Feedwater Flow Mismatch	1/2, steam/feedwater flow mismatch (steam flow > feed flow) in coincidence with 1/2, low steam generator water level, per loop.	
12.	Low-Low Steam Generator Water Level	2/3, per loop.	
13.	Intermediate Range Nuclear Flux	1/2, manual block permitted by P-10.	Automatic unblock by P-10.
14.	Source Range Nuclear Flux	1/2, manual block permitted by P-6, interlocked with P-10.	Automatic unblock by P-10.

Table 7.2-2 INTERLOCK CIRCUITS

Interlock Number	Function	Required Input
P-1	Prevent rod withdrawal on overpower	1/4 high neutron flux (power range); or 1/2 high neutron flux (intermediate range); or 2/4 overtemperature ΔT; or 2/4 overpower ΔT.
P-2	Auto-rod withdrawal stop at low powers	Low MWe (15% power) load signal (turbine pressure)
P-5	Steam dump interlocks	Rapid decrease of MWe load signal (turbine pressure)
P-6	Manual block of source range trip	1/2 high intermediate range flux allows manual block, 2/2 low intermediate range defeats block
P-7	Block various trips at low power	3/4 low-low neutron flux (power range) and 2/2 low MWe load signal (turbine pressure)
P-8	Block single primary loop loss of low trip	3/4 low neutron flux (power range)
P-9	Block reactor trip following turbine trip	3/4 low neutron flux (power range) and low condenser pressure (2/2) and circulating water pump (1/2)
P-10	Manual block of power range trip (low setpoint); manual block of intermediate range trip; and automatic block of source range trip	2/4 high neutron flux allows manual block, 3/4 low neutron flux (power range) defeats manual block.

Table 7.2-3 RPS/ESFAS PRIMARY AND SECONDARY INSTRUMENTATION

Parameter	Transmitter/Sensor	Readout*	Power	Prot/Safeguards Use	Taps
Reactor Coolant temperature	4 RTD's/loop plus spares	C.B. Meter	Ext.	ΔT trips, T_{ave} Interlock	1 each
Pressurizer Pressure	4 transmitters	C.B. Meter	Ext.	Hi/low pressure trips, SIS(3)	3 (shared with level); one common for two transmitters
Pressurizer Level	3 DP transmitters	C.B. Meter	Ext.	Hi level trip	One pair each (shared with pressure)
Steam Flow	2 DP transmitters/loop	C.B. Meters	Ext.	Mismatch trip, steamline isolation	1 pair each
Feedwater Flow	2 DP transmitters/loop	C.B. Meter	Ext.	Mismatch trip	1 pair each
Steam Pressure	3 transmitters/loop	C.B. Meter	Ext.	SIS	1 each
Steam Generator Level	3 DP transmitters/SG	C.B. Meter	Ext.	Lo level coincidence with mismatch trip , Lo-Lo level trip, AFW actuation	3 pairs each S/G
Reactor Coolant Flow	3 DP transmitters/loop	C.B. Meter	Ext.	Low flow trip	1 common high pressure/loop; 1 each low pressure/loop
Containment Pressure	6 transmitters	C.B. Meter	Ext.	SIS (3); Spray (3+3), steamline isolation (3)	3 shared
Turbine 1st Stage Pressure	2 transmitters	Blind	Ext.	Rod control and PZR level control programs and turbine power permissives	1 each

*C.B. is Control Board

Figure 7.2-1 REACTOR CORE SAFETY LIMITS

See TRM Section 2.1, Core Operating Limits Report (COLR)

Figure 7.2-2 TYPICAL ILLUSTRATION OF HIGH ΔT TRIP (ΔT vs. T_{AVG})

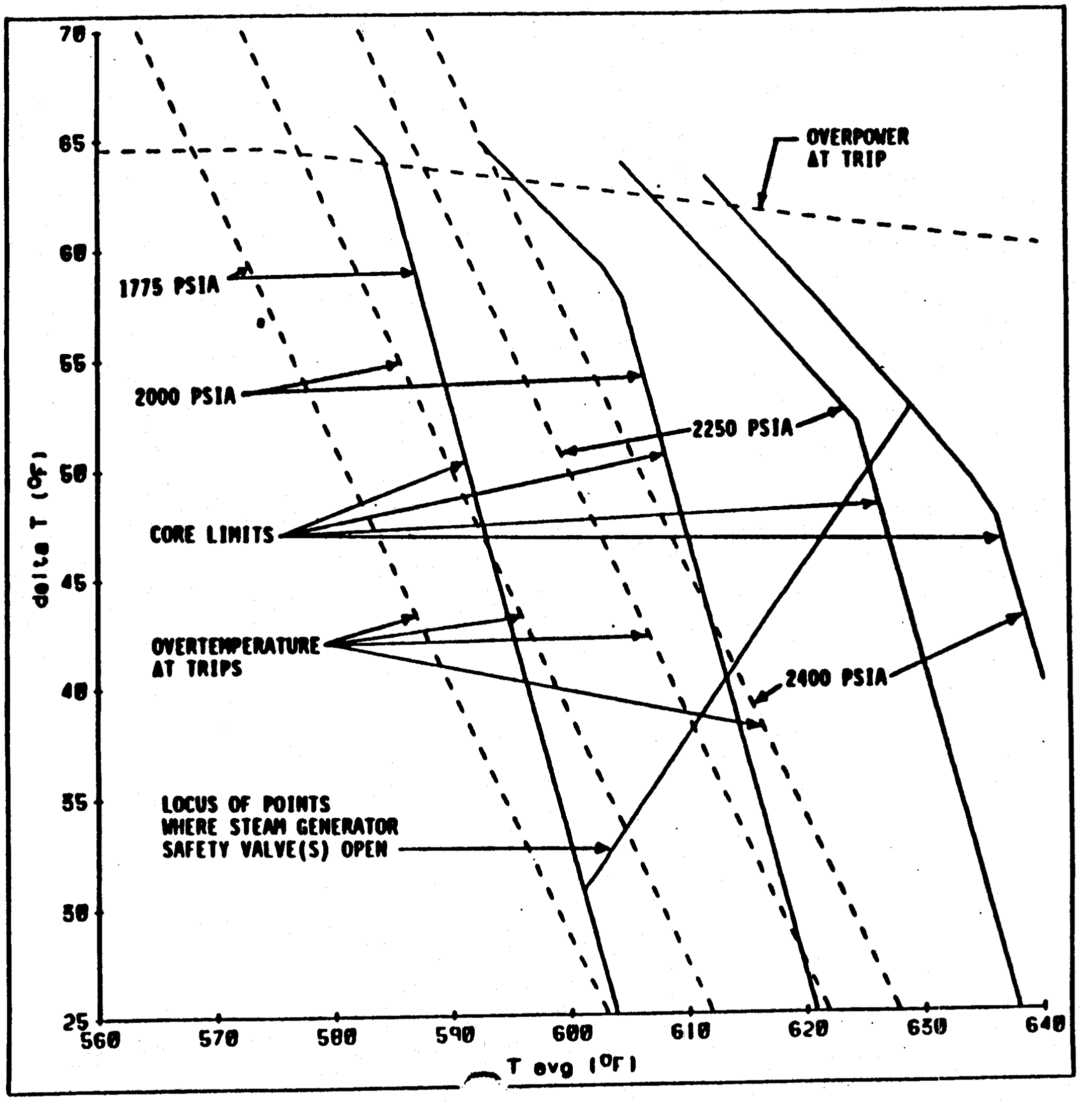


Figure 7.2-3 REACTOR PROTECTION SYSTEMS

[redacted]

Figure 7.2-4 DESIGN TO ACHIEVE ISOLATION BETWEEN CHANNELS

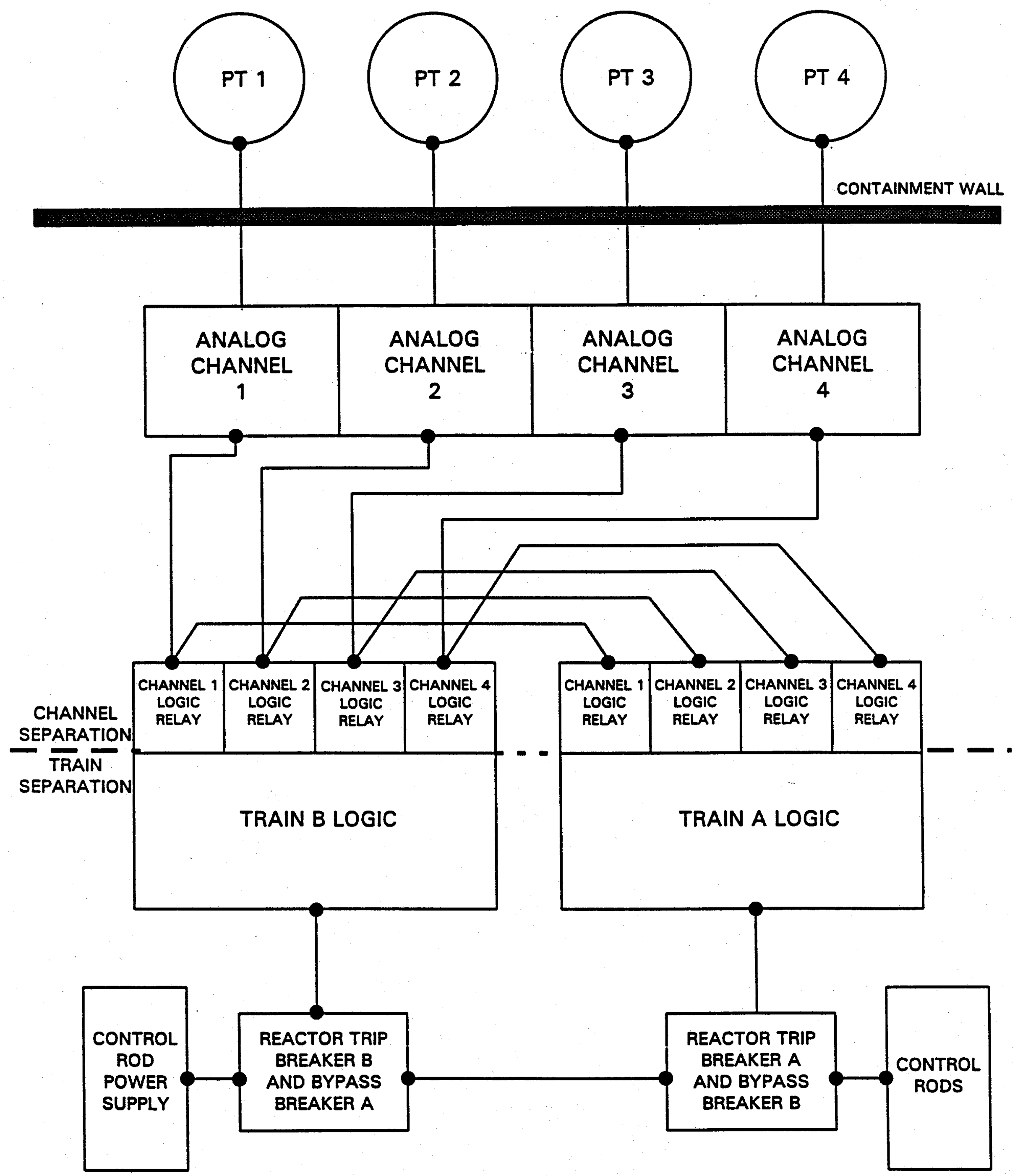


Figure 7.2-5 BASIC ELEMENTS OF AN ANALOG CHANNEL

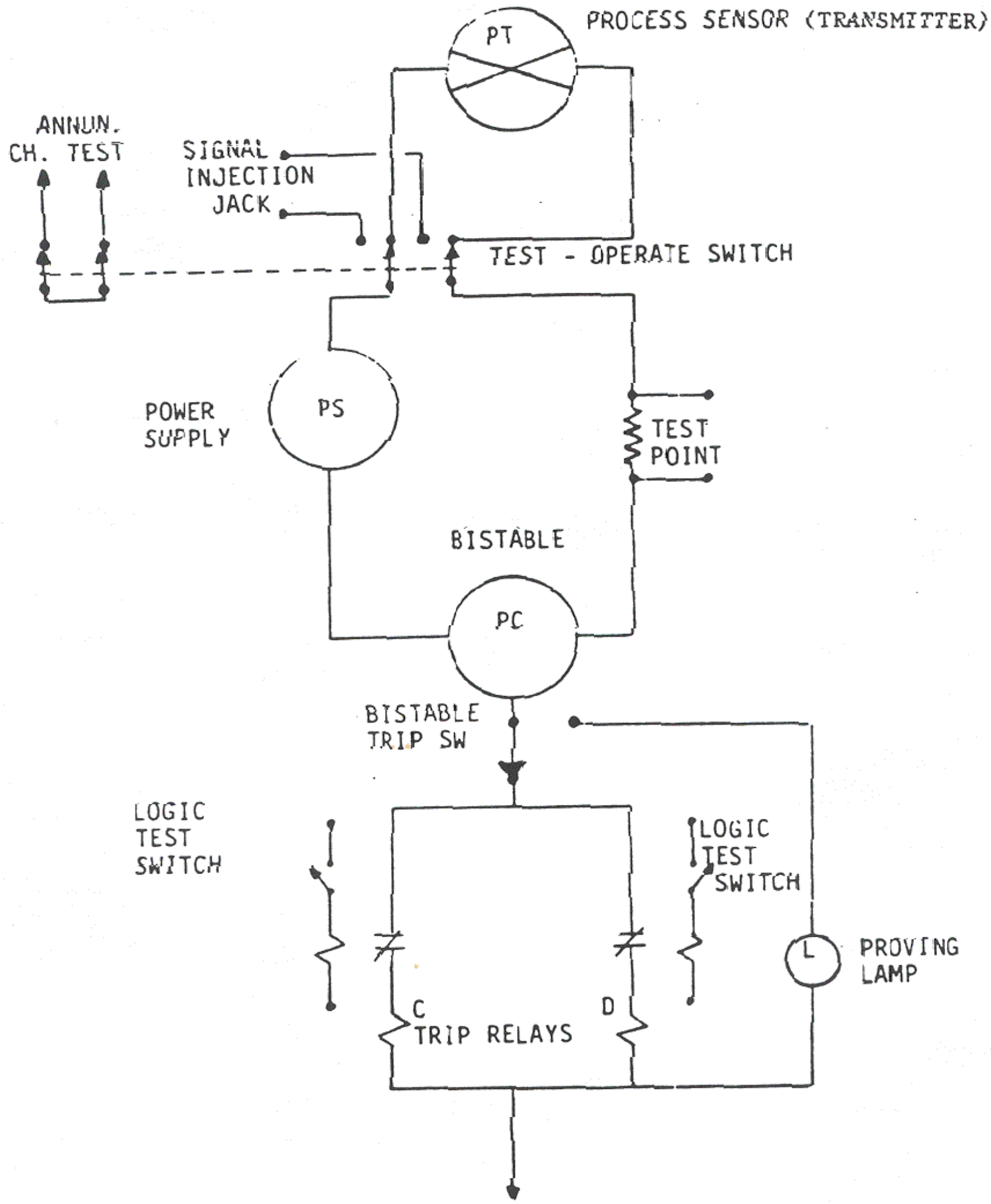


Figure 7.2-6 SIMPLIFIED TRIP LOGIC TRAINS

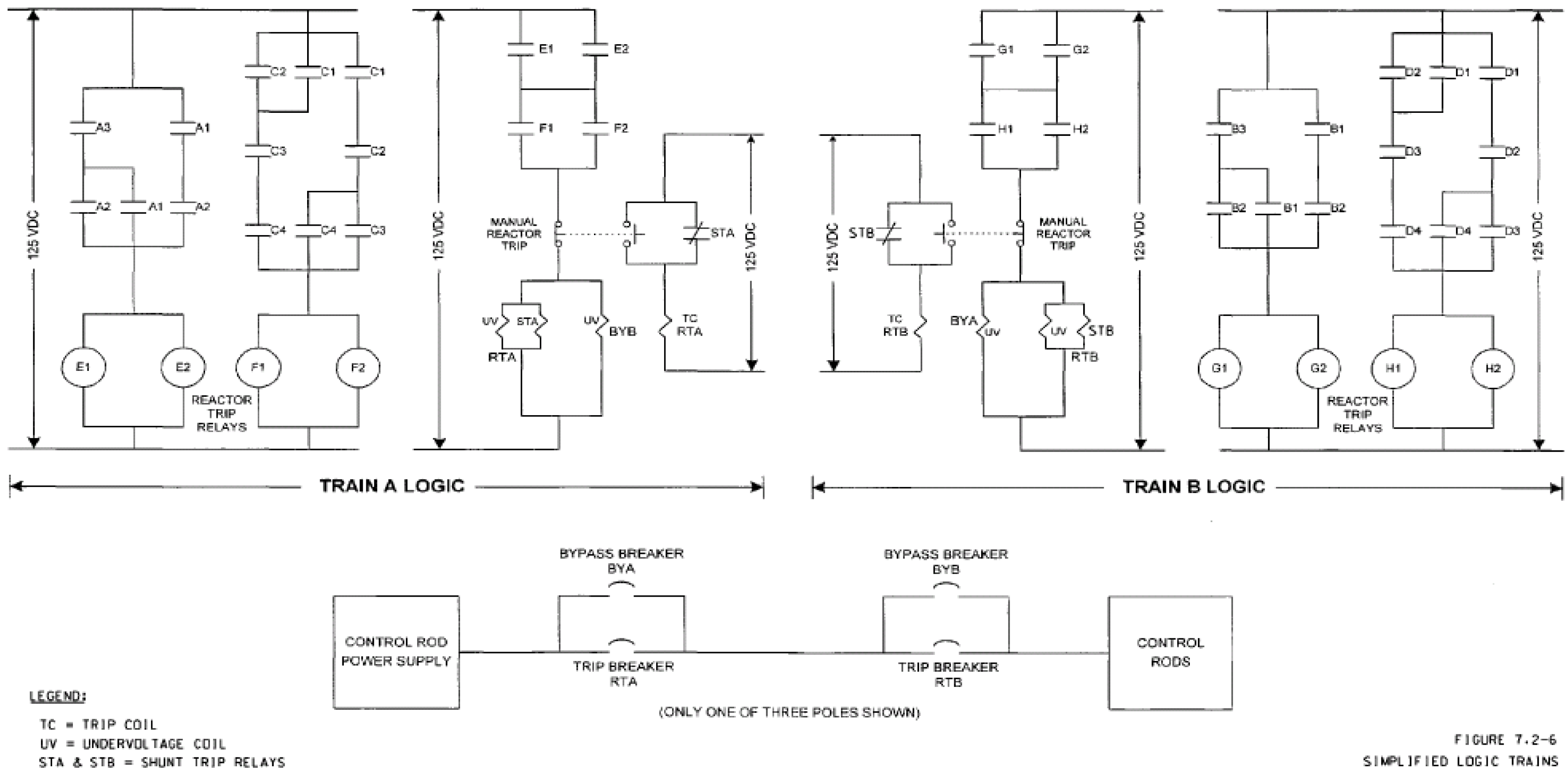
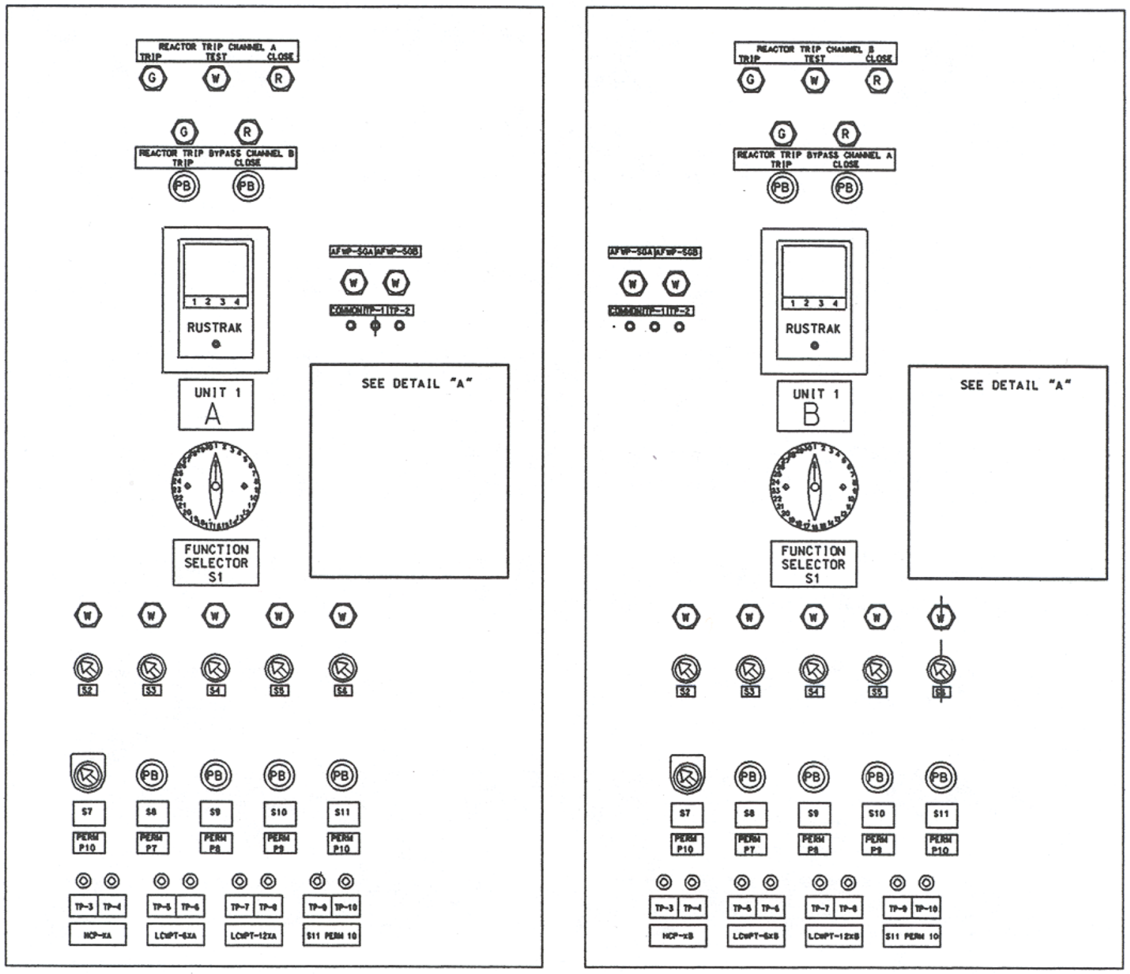


FIGURE 7.2-6
SIMPLIFIED LOGIC TRAINS

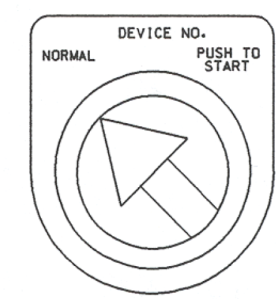
Figure 7.2-7 LOGIC CHANNEL TEST PANELS (UNIT 1)



DETAIL "A"

S1 SELECTOR SWITCH		TEST BUTTON				
POS.	FUNCTION	S2	S3	S4	S5	S6
1	HI-FLUX,SOURCE RANGE	1NC31D	1NC32D	1-1/N33A	1-1/N31B	1-1/N32B
2	HI-FLUX,INTERMEDIATE RANGE	1NC35F	1NC36F	1-1/N35A	1-1/N36A	1-1/N36A
3	POWER RANGE,HI-FLUX,LO TRIP	1NC41P	1NC42P	1NC43P	1NC44P	1-1/N47A
4	NUCLEAR PWR., ¢X%	1NC41M	1NC42M	1NC43M	1NC44M	
5	INTERMEDIATE RANGE,P6	1NC35D	1NC36D	1-1/N39A	1-1/N39B	
6	PRESSURIZER LOW PRESSURE	1PC429E	1PC430H	1PC431J	1PC449A	
7	OVERTEMPERATURE ΔT	1TC405C	1TC406C	1TC407C	1TC408C	
8	OVERPOWER ΔT	1TC405A	1TC406A	1TC407A	1TC408A	
9	LOW STM. GEN. FDW. FLOW/LEVEL	1FC466C	1FC467B	1LC462C	1LC463E	
10	LOW STM. GEN. FDW. FLOW/LEVEL	1LC472C	1LC473E	1FC476C	1FC477B	
11	POWER RANGE,HI FLUX,HI TRIP	1NC41R	1NC42R	1NC43R	1NC44R	
12	NUCLEAR POWER ¢2%	1NC41S	1NC42S	1NC43S	1NC44S	
13	NUCLEAR POWER ¢Y%	1NC41N	1NC42N	1NC43N	1NC44N	
14	4160 V BUS VOLTAGE	1-273/A01	1-274/A01	1-273/A02	1-274/A02	
15	PRESSURIZER HI WATER LEVEL	1LC426A	1LC427A	1LC428A		
16	REACTOR COOLANT FLOW	1FC411	1FC412	1FC413		
17	REACTOR COOLANT FLOW	1FC414	1FC415	1FC416		
18	PRESSURIZER HI PRESSURE	1PC429A	1PC430A	1PC431A		
19	TURBINE AUTO STOP	1-63/AST3	1-63/AST4	1-63/AST5		
20	LO LO STM.GEN.WATER LEVEL	1LC461B	1LC462A	1LC463C		
21	LO LO STM.GEN.WATER LEVEL	1LC472A	1LC473C	1LC471B		
22	LOSS OF CIRC.WATER PUMPS	1A52-06	1A52-12			
23	REACTOR COOLANT,LOSS OF PWR.	1RCPA	1RCPB			
24	CLOSE STOP VALVES,TURBINE	1-33AC-SL	1-33AC-SR			
25	TURBINE POWER ¢X%	1PC405A	1PC406A			
26	SAFETY INJECTION	1SI11X-A	1SI21X-B			
27	HIGH CONDENSER PRESSURE	1PC484A				
28						
29						
30						

CGS fig7_2_7.DGN



TYPICAL LEGEND PLATE MARKINGS

FIG. 7.2-7
UNIT 1
JUNE 1999

Figure 7.2-8 $T_{AVG}/\Delta T$ CONTROL AND PROTECTION SYSTEM

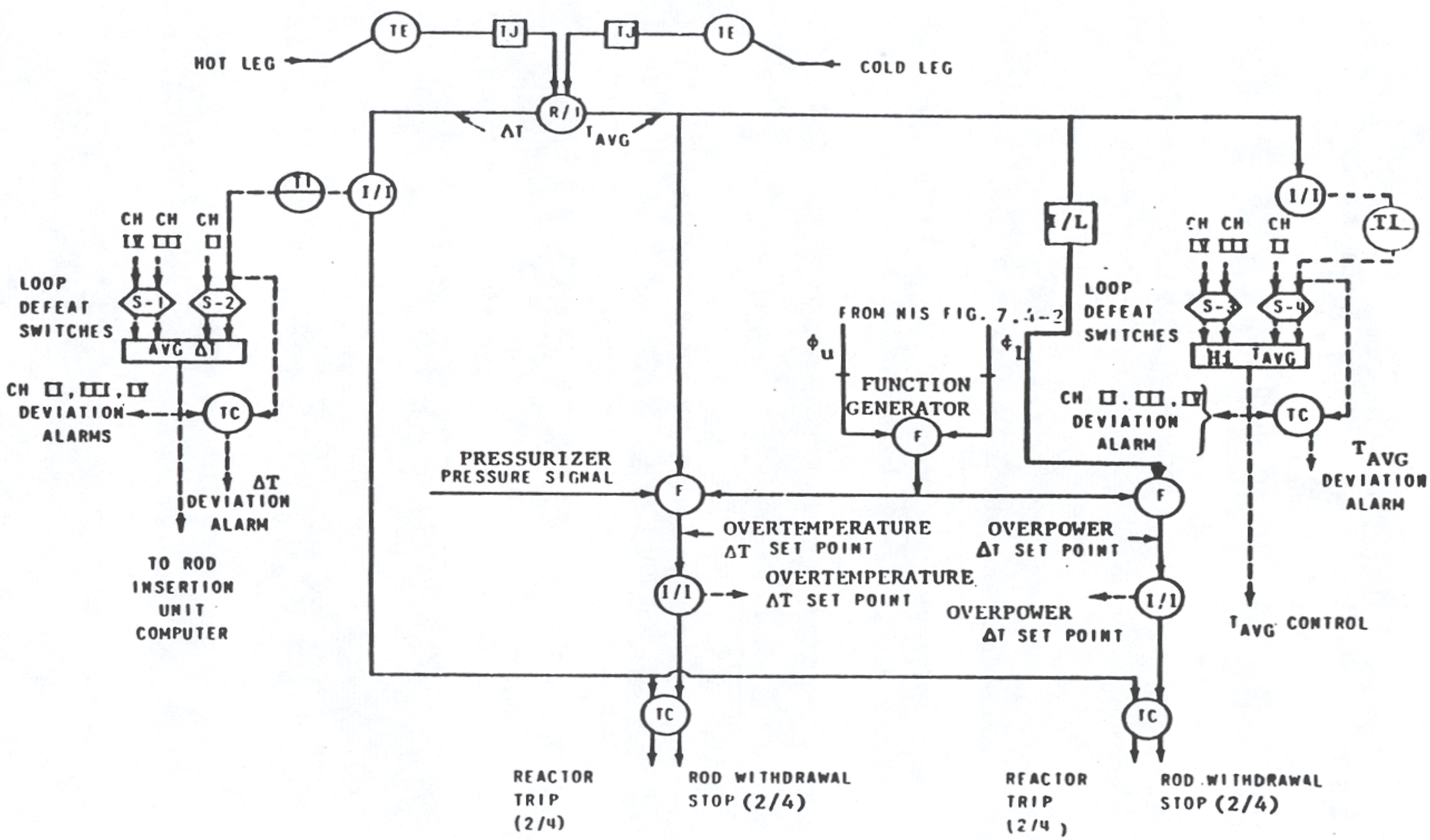


Figure 7.2-9 ANALOG SYSTEM SYMBOLS

Al	-	Alarm
BUF	-	Buffer
F	-	Special function (such as a pressure compensation unit lead/lag compensation, summer, etc.)
FC	-	Flow controller (off-on unless output signal is shown)
FI	-	Flow indicator
FT	-	Flow transmitter
Hi LRT	-	High level reactor trip
Hi PRT	-	High pressure reactor trip
I/I	-	Isolation current repeater
ISOL	-	Isolation (other than I/I)
LC	-	Level controller (off-on unless output signal is shown)
LI	-	Level indicator
L-Low	-	Low level
Lo L	-	Low level
Lo LRT	-	Low level reactor trip
Lo PRT	-	Low pressure reactor trip
L_{ref}	-	Programmed reference level
LT	-	Level transmitter
NC	-	Nuclear flux controller
NE	-	Nuclear detector
NI	-	Nuclear flux indicator
NQ	-	Nuclear Power supply
PC	-	Pressure controller (off-on unless output signal is shown)
PI	-	Pressure indicator
P_{ref}	-	Programmed reference pressure
PS	-	Power supply
PT	-	Pressure transmitter
R/I	-	Resistance to current connector
S	-	Control channel transfer switch (used to maintain auto channel during test of the protection channel)
SI	-	Safety injection
T	-	Built-in test point
TE	-	Temperature element
TJ	-	Test signal insertion jack
TP	-	Test point
$\phi_{U,L}$	-	Out of core upper or lower ion chamber flux signals

Figure 7.2-10 PRESSURIZER PRESSURE CONTROL AND PROTECTION SYSTEM

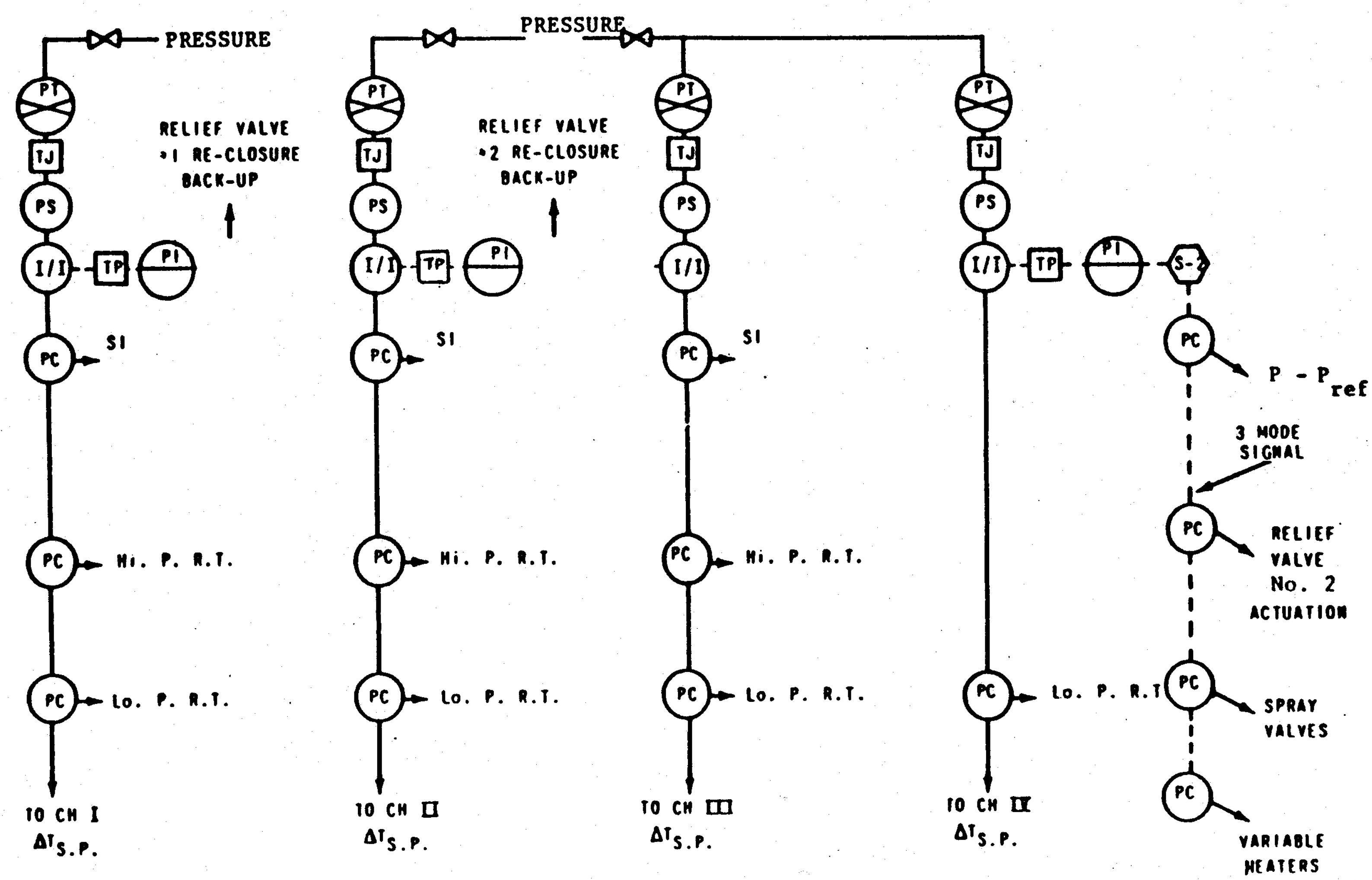


Figure 7.2-11 PRESSURIZER LEVEL CONTROL AND PROTECTION SYSTEM

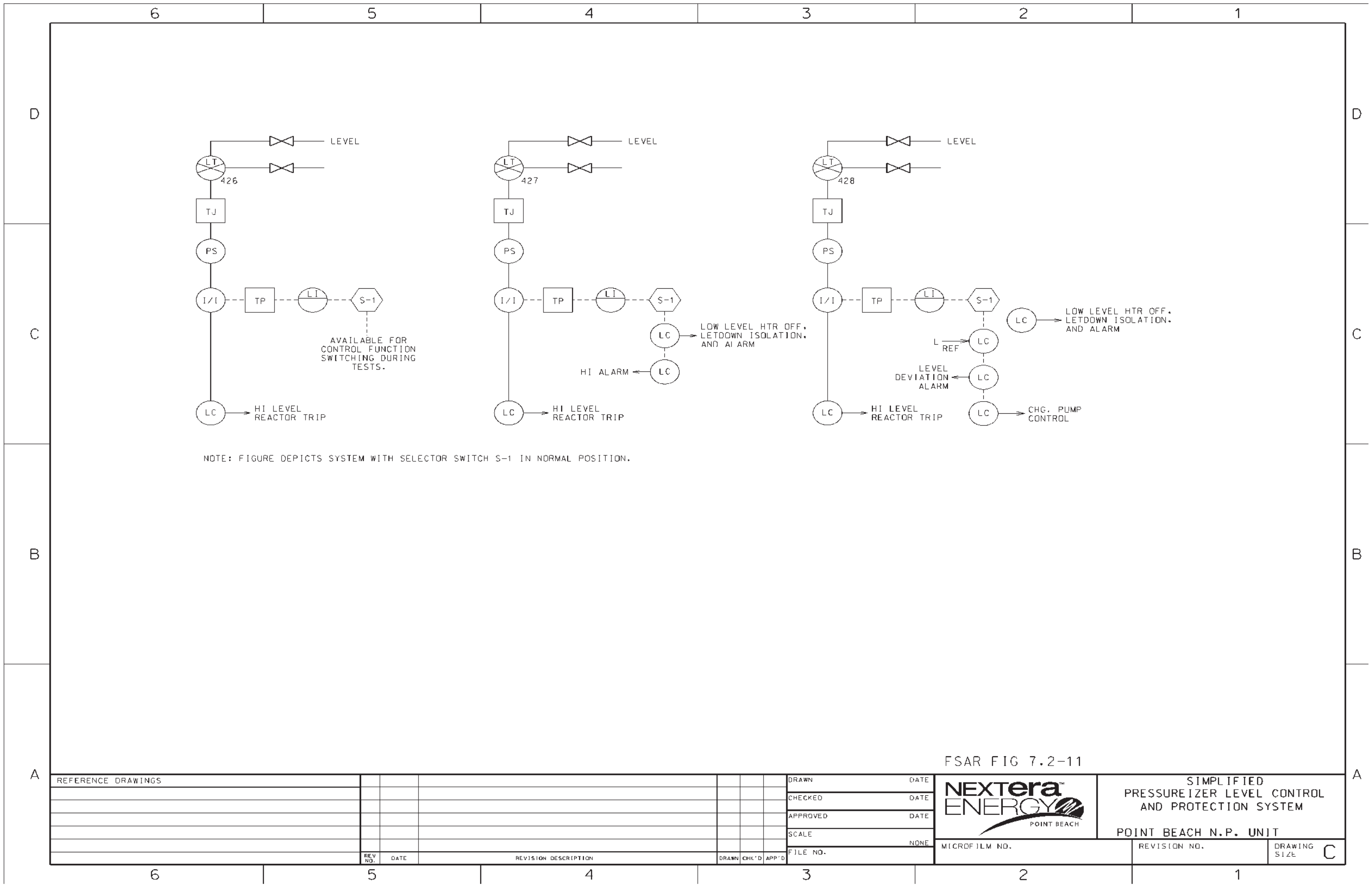
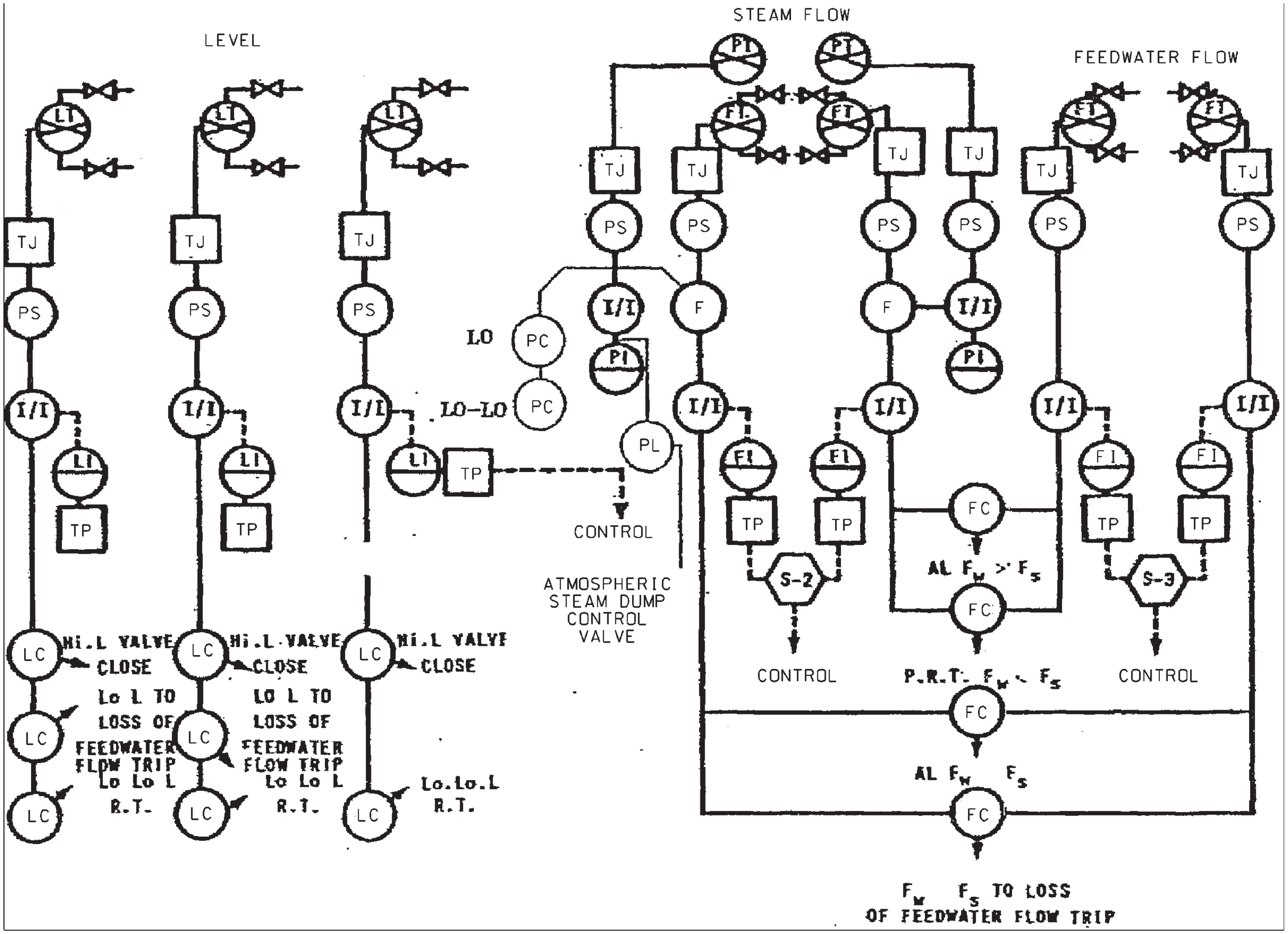


Figure 7.2-12 STEAM GENERATOR LEVEL CONTROL AND PROTECTION SYSTEM



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7.3 ENGINEERED SAFETY FEATURES ACTUATION SYSTEM

The Engineered Safety Features Actuation System (ESFAS) monitors plant conditions that require Engineered Safety Features (ESF) equipment actuation and automatically initiates ESF equipment to mitigate plant accidents. Actuated ESF equipment (depending on the type and severity of the accident) includes the Safety Injection System, the Containment Spray System, the Containment Air Recirculation Cooling System, Containment Isolation, Steam Line Isolation, Feedwater Isolation, and the Auxiliary Feedwater System.

7.3.1 DESIGN BASES

The following PBNP General Design Criteria (GDC) described in Section 7.1.2 are applicable to the Engineered Safety Features Actuation System:

Criterion 12	Instrumentation and Control Systems
Criterion 15	Engineered Safety Features Protection Systems
Criterion 19	Protection Systems Reliability
Criterion 20	Protection Systems Redundancy and Independence
Criterion 23	Protection Against Multiple Disability for Protection Systems
Criterion 25	Demonstration of Function Operability of Protection Systems
Criterion 26	Protection Systems Failure Analysis Design

In addition to the above GDCs, the Engineered Safety Features Actuation System is designed to IEEE 279, "Proposed IEEE Criteria for Nuclear Power Plant Protection Systems," dated August 1968.

7.3.1.1 Conformance to IEEE 279-1968

IEEE 279 Section 3 provides a list of design bases for a protection system, and IEEE 279 Section 4 lists protection system design requirements. The following criteria correspond to specific points in these IEEE 279 sections.

a. Plant Conditions that Require ESFAS Protective Action

The ESFAS protective action is automatic actuation of ESF equipment. ESF equipment actuation is necessary during certain accidents to protect each of the three physical barriers that guard against the uncontrolled release of radioactivity; (1) the fuel clad, (2) the reactor coolant system pressure boundary, and (3) the containment boundary. The plant conditions that require ESF equipment actuation are those plant accident analyses in Chapter 14 that credit automatic ESF actuation for accident mitigation. Note that different accidents may actuate different types of ESF equipment, and not all accidents described in Chapter 14 require automatic ESF actuation.

b. Plant Variables that Cause Protective Action

The ESFAS variables that actuate various ESF equipment are identified in Table 7.3-1.

c. Minimum Number of Sensors for Each Variable

The minimum number of sensors assigned to each ESFAS variable is listed in Technical Specifications.

d. Prudent Operational Limits for Each Variable

The normal operational limits for each ESFAS variable are defined in the plant operating procedures and Technical Specifications.

e. Margin Between Operational Limits and Onset of Unsafe Conditions

The margin between each ESFAS variable's operational limit and the analytical limit required for automatic ESF actuation is determined by the ESFAS setpoint established for the variable in the Technical Specifications.

f. Variable Levels that Require Protective Action

The analytical limits established in the accident analyses (Chapter 14) determine the point at which the variable requires ESFAS actuation.

g. Conditions for System Performance

The operational conditions (e.g., environmental, seismic, power source, etc.) under which the ESFAS equipment must function are discussed in Section 7.3.3.6 and Section 7.3.3.7.

h. Performance Requirements of ESFAS Variables

The range, response time, and accuracy requirements of the ESFAS equipment are chosen to ensure the assumptions of the accident analyses for the variable being monitored are met.

i. Single Failure

The ESFAS is designed such that any single failure within the protection system or in an associated system which supports its operation will not prevent the protective actions (ESF actuations) assumed in the accident analyses from occurring.

j. Redundancy and Independence

The protection system is redundant and independent for all vital inputs and functions. Each channel is functionally independent of every other channel and receives power from a separate AC power source. Each actuation train is functionally independent of the redundant train and receives power from a separate DC power source.

k. Manual Actuation

Means are provided for the manual initiation of protective actions. Failures in the automatic system will not prevent the manual actuation of protection functions. Manual actuation is designed to require the operation of a minimum of equipment.

l. Channel Bypass or Removal from Operation

The ESFAS is designed to permit any one channel to be maintained, tested, or calibrated during power operation without causing ESF actuation. During such operation, the active parts of the system continue to meet the single failure criterion, since the bypassed channel is placed in a tripped condition.

EXCEPTION: “One-out-of-two” trip logic is permitted to violate the single failure criterion during channel bypass provided that acceptable reliability of operation can be otherwise demonstrated.

m. Capability for Test and Calibration

The relay logic portions of the protection system provide trip signals only after signals from analog channels reach preset values. Capability is provided for calibrating and testing the performance of the analog channel trip bistables and various combinations of coincidence logic during reactor operation.

The sensor channels of the protection system provide an analog signal of the process parameter. The sensor channels can be checked in various ways during power operation, such as:

- Varying the monitored parameter;
- Introducing and varying a substitute transmitter signal; and
- Cross checking between channels that bear a known relationship to each other and that have readouts available.

The design of the system provides for administrative control for the purpose of manually bypassing channels for test and calibration purposes. The design also provides for administrative control of access to all trip settings, module calibration adjustments, test points, and signal injection points.

n. Information Readout

The protection system provides the operator with complete information pertinent to system status and plant safety. Indication is provided on the main control board if some part of the system has been administratively bypassed or taken out of service. The ESF logic cabinets are maintained locked to prevent an inadvertent bypass that could be unmonitored. ESF actuation is indicated and identified down to the channel level.

All transmitted signals (flow, pressure, temperature, etc.) which can lead to ESF actuation are either indicated or recorded for every channel.

Alarms are also provided to alert the operator of deviation from normal operating conditions so that corrective action may be taken prior to reaching an ESF actuation setting. Further, actuation of any ESFAS channel will actuate an alarm.

o. Operating Bypasses

Where operating requirements necessitate automatic or manual bypass of a protection function, the design is such that the bypass is automatically removed whenever the permissive conditions are not met. Devices used to achieve automatic removal of the bypass of a protection function are part of the protection system.

p. Indication of Bypasses

In addition to administrative controls (such as locked logic cabinets) to prevent inadvertent bypass, indication is provided on the main control board if some part of the system has been administratively bypassed or taken out of service.

q. Completion of Protective Action

The protection system is so designed that, once initiated, a protective action goes to completion. Return to normal operation requires administrative action by the operator.

r. Protective Actions

For anticipated abnormal conditions, protection systems in conjunction with inherent plant characteristics and engineered safety features are designed to assure that limits for energy release to the containment and for radiation exposure are not exceeded.

s. Adverse Environment

The ESFAS equipment is either located in a mild environment (such as the control room) or a potentially harsh environment (such as containment). The environmental qualification of the equipment is discussed further in Section 7.3.3.7.

7.3.1.2 Exceptions to IEEE 279

Some ESFAS functions (backup actuations that are not assumed in the accident analyses) may not fully conform to IEEE 279 criteria. Exceptions to IEEE 279 criteria in backup ESFAS functions are discussed in Section 7.3.3.2.

7.3.2 SYSTEM DESIGN

7.3.2.1 Engineered Safety Features Actuation System Description

The engineered safety features actuation system detects plant conditions that require automatic ESF equipment operation, and actuates the appropriate ESF equipment when preset limits are reached. ESFAS subsystems monitor plant parameters indicative of different accidents. When the minimum number of channels of a monitored variable reaches a preset limit, trip bistables satisfy coincidence logic for an individual subsystem and the subsystem is automatically initiated. ESFAS subsystems include:

- Safety Injection Actuation
- Containment Isolation
- Containment Ventilation Isolation
- Containment Spray Actuation
- Steam Line Isolation
- Auxiliary Feedwater Pump Start
- Feedwater Isolation

Figure 7.3-1 is a logic diagram for various ESFAS subsystems. A simplified block diagram illustrating the channel and relay logic architecture of the engineered safety features actuation system is shown in Figure 7.3-2. On the channel level, the four ESFAS channels share protection racks with the four Reactor Protection System channels, because some of the same plant variables used to initiate reactor trip also actuate ESFAS subsystems. Not all four channels are used for each ESFAS variable, because most ESFAS subsystem coincidence logics rely on less than four channels to actuate. Each channel is energized from a separate AC power feed.

On the train level, the racks for the two ESFAS logic trains in Figure 7.3-2 are independent and separate from the racks for the two Reactor Protection System logic trains. Each train is energized from a separate DC power feed.

To automatically actuate the various ESFAS subsystems above, the system monitors the following plant variables:

- pressurizer pressure
- steam line pressure
- containment pressure
- containment gaseous radioactivity
- steam line flow
- steam generator level
- RCS temperature (T_{avg})
- 4 kV bus voltage

The specific plant variables that initiate each ESFAS subsystem and their associated coincidence logic are listed in Table 7.3-1. The table also explains any other conditions or interlocks that must be satisfied for ESFAS subsystem actuation to occur.

7.3.2.2 Protective Actions

The following is a brief description of the protective actions performed by the ESFAS subsystems in response to the various plant variables listed in Table 7.3-1.

a. Safety Injection Actuation

A manual or automatic safety injection signal initiates:

1. High head safety injection and low head (RHR) pump start and valve stroking
2. Emergency diesel generator start
3. ESF (safeguards) load sequencing
4. Reactor trip
5. Motor-driven and turbine-driven auxiliary feedwater pump start
6. Service water pumps start
7. Containment fan cooler start and increased fan cooling water flow
8. Non essential service water branch isolation
9. Containment isolation of nonessential systems (from automatic SI signal only)
10. Containment ventilation isolation
11. Feedwater isolation
12. Permissive for Steam Line Isolation

13. Stripping non-safeguards equipment such as the Standby Steam Generator Feedwater Pumps and certain 480 V motor control centers.

A discussion of the ESF (safeguards) load sequencing that occurs on SI actuation may be found in Chapter 8.

b. Containment Isolation

A manual or automatic containment isolation signal closes normally-open power-operated containment isolation valves in the non-essential fluid lines passing through containment, to prevent the uncontrolled release of radioactivity from the containment atmosphere to the outside environment in the event of a Loss-of-Coolant Accident (LOCA). The containment isolation valves associated with each non-essential penetration are identified inSection 5.2.

c. Containment Ventilation Isolation

During shutdown/refueling conditions when the containment ventilation supply and exhaust penetrations may be open, the Train "A" Containment Ventilation Isolation signal (see Table 7.3-1) isolates valves in these penetrations to prevent the uncontrolled release of containment atmosphere radioactivity to the outside environment. Blank flanges are installed inside containment on these penetrations during power operation.

d. Containment Spray Actuation

A manual or automatic containment spray actuation signal starts the containment spray pumps and aligns the associated system valves to initiate containment spray.

e. Steam Line Isolation

A manual or automatic steam line isolation signal closes the main steam isolation valve associated with the loop (steam generator) which generates the signal (indicative of a steam line break).

f. Auxiliary Feedwater Pump Start

The turbine-driven and motor-driven auxiliary feedwater pumps are automatically started to supply emergency feedwater to the steam generators for primary system heat removal under various conditions. Refer to Table 7.3-1 for the conditions under which the pumps are started.

g. Feedwater Isolation

A Safety Injection Actuation signal will isolate the main feedwater lines by closing the Main Feedwater Isolation Valves and Main Feedwater Regulating Valves (main and bypass valves) and tripping the main feedwater pumps, thus closing the pump discharge valves. In addition, a high steam generator water level will close the Feedwater Regulating Valves to prevent steam generator overfill.

h. Auxiliary Feedwater Pump Suction Transfer

The turbine-driven and motor-driven auxiliary feedwater pumps' suction source is automatically transferred from the condensate storage tanks (CST) to service water on low pump suction pressure or low CST level. See Section 7.4.3.

7.3.2.3 System Safety Features

a. Isolation of Redundant Protection Channels and Trains

The same channel and train isolation and separation criteria as described for the reactor protection circuits in Section 7.2.2.3.a are applied to the engineered safety features actuation system.

b. Loss of Power

The four ESFAS channels, which share cabinets with the four Reactor Protection System channels, receive 120 VAC power from the four independent, battery-backed instrument buses. The logic racks for the two ESFAS trains that actuate ESF equipment receive battery-backed power from redundant 125 VDC sources.

Availability of power to the engineered safety features actuation channels and trains is continuously indicated. Loss of AC power to an individual ESFAS channel (except the containment spray actuation channels) will cause the associated channel's output bistables to trip. This “deenergize-to-operate” design is similar to the Reactor Protection System analog channels discussed in Section 7.2.2.3.b. Since a typical ESFAS coincidence trip logic requires more than one channel to cause an actuation, a power failure to a single channel will not cause inadvertent ESF actuation. The exception to this design is the containment spray actuation channels, which are “energize-to-operate” to avoid inadvertent containment spray operation on multiple analog channel power failures.

Two ESFAS actuation trains are provided to actuate the two ESF equipment trains associated with each unit. As an example, the ESFAS 'A' train Safety Injection Actuation signal actuates the 'A' SI pump and the 'B' train actuates the 'B' SI pump. The control circuit for a safety injection pump motor is typical of the control circuit for a large pump motor operated from switchgear. The normally-deenergized SI actuation output relay in the logic rack supplies a normally open contact to the SI pump motor control circuit. When an SI signal is generated from the coincidence logic, the SI actuation output relay is energized and the output contact closes to energize the circuit breaker closing coil, thus closing the breaker, energizing the motor, and starting the pump.

Because the ESFAS output relays are “energize-to-operate,” the consequence of a power failure to the ESFAS logic trains differs from the Reactor Protection System logic train's “deenergize-to-operate” design. Unlike the RPS, the ESF output relay design prevents inadvertent ESF equipment actuation on power failure of an actuation train. A single ESF actuation train failure due to loss of power is an acceptable single failure, because the unaffected ESFAS logic train will actuate sufficient engineered safety features to meet the minimum ESF equipment criteria for adequate core cooling and containment functions.

c. ESF Actuation Signal Testing

GDC 25 requires suitable testing of protection system components while the reactor is in operation to determine if failure or loss of redundancy has occurred.

During power operation, each engineered safety features actuation channel and logic train is capable of being calibrated and tripped independently by simulated signals to verify its operation up to the final actuation device (output relay). The at-power testing approach is similar to the analog channel testing and logic testing for the reactor protection system described in Section 7.2.2.3.c. However, it is not possible to test the ESFAS output relays at power to verify that individual ESF equipment actuation occurs, because actuating ESF equipment during normal operation would disrupt power operation. Instead, a resistance check is performed on the output relay coils to verify coil continuity during power operation, and a full verification of ESF equipment actuation is performed during refueling shutdowns.

d. Monitoring ESF Equipment Operation after Actuation

The post-accident monitoring instrumentation used to verify appropriate ESF equipment operation after actuation during an accident is discussed inSection 7.6.2.

7.3.3 SYSTEM EVALUATION

The design of the engineered safety features actuation system meets the applicable protection system General Design Criteria and IEEE 279-1968 criteria. The following sections describe specific areas related to these criteria. The methodology used for setpoint calculations is described in FSAR 7.2.3.6.

7.3.3.1 Specific Control and Protection Interactions

IEEE 279 Section 4.7 requires analysis for control/protection interactions when protection system variables also provide control signals. ESFAS variables that supply control signals were evaluated in WCAP-7306 as follows:

a. Steam Line Pressure

Three steam line pressure channels per loop are used for steam break protection (two-out-of- three low pressure in either steam line actuates safety injection). One of the three pressure channels per steam line is used to automatically control the atmospheric steam dump valve on that steam line, causing the valve to open on a high pressure condition. Each atmospheric steam dump valve is rated at approximately 5% of the full load steam flow. If a spurious high pressure signal occurs in the channel used for control, the associated atmospheric steam dump valve will open and cause low steam line pressure. The steam release rate caused by spurious opening of the dump valve is evaluated in Section 14.2.7. The hypothetical steamline break is limiting with respect to minimum DNBR, and bounds the inadvertent opening of a steam generator relief or safety valve. Therefore, the inadvertent opening of a steam generator relief or safety valve is no longer analyzed for Point Beach as discussed in Section 14.2.7. However, protective action for the spurious opening of an atmospheric steam dump valve can still be provided by other trip signals that are independent of the low steamline pressure trip (e.g., low pressurizer pressure), and is bounded by the hypothetical steamline break. Therefore, a control failure of a steam line pressure channel does not create a need for protective action that relies on the same variable, the IEEE 279 Section 4.7 criterion is met, and two-out-of-three coincidence logic for this variable is acceptable.

b. Pressurizer Pressure

Safety injection actuation occurs when two-out-of-three pressurizer pressure channels indicate low pressure. The three pressure channels also supply control signals for pressurizer pressure control, including signals that open the pressurizer spray valves and pressurizer power operated relief valves (PORVs) on high pressure. The PORV control logic is interlocked to prevent either PORV opening unless two independent pressure channels agree that a high pressure condition exists. As a result, a single pressure channel failing high will not fail a PORV open and initiate an RCS depressurization/blowdown transient requiring safety injection actuation on low pressurizer pressure. Therefore, PORV control does not create a control/protection interaction condition under IEEE 279 Section 4.7.

A single pressure channel failing high could also fail a pressurizer spray valve open, resulting in a gradual RCS depressurization transient as spray cools the pressurizer steam space. The resulting depressurization transient may cause both a reactor trip and safety injection actuation on low pressurizer pressure. However, because there is no mass loss from the RCS, a safety injection actuation signal is not required to mitigate this transient. As discussed in Section 7.2.3.2.c, the reactor trip on low pressurizer pressure is a two-out-of-four coincidence, which meets the control/protection interaction criterion for this transient. Because a failed-open spray valve transient does not require safety injection actuation to mitigate the transient, a control/protection interaction condition does not exist between spray valve control and the SI actuation logic.

Based on the above, the two-out-of-three coincidence logic for SI actuation on low pressurizer pressure meets the control/protection interaction criterion of IEEE 279 without the need for a fourth pressure channel and two-out-of-four coincidence.

c. Steam Generator Level

Feedwater isolation occurs on a two-out-of-three high-high steam generator water level in either steam generator. One of the three steam generator level channels is shared with the feedwater control function. If the shared channel failed low, control action would open the feedwater control valve associated with the steam generator, while at the same time failing to detect a high level condition. The two remaining level channels would both be required to detect high-high level and initiate feedwater isolation to prevent SG overfill. With an additional single failure required by IEEE 279, this arrangement would represent a violation of the control/protection criterion.

Steam generator overfill protection was reviewed generically for Westinghouse plants under NUREG-1217 and NUREG-1218 as part of the evaluation for Unresolved Safety Issue A-47, “Safety Implication of Control Systems in LWR Nuclear Power Plants.” NUREG-1218 Section 7, the existing logic arrangement was accepted because "changes to improve the existing overfill-protection systems from a two-out-of-three to a two-out-of-four steam generator high-high level trip do not significantly reduce risk." Therefore, this condition represents an allowable exception to the IEEE 279 control/protection interaction criterion for Westinghouse plants.

Unresolved Safety Issue A-47 resulted in the issuance of Generic Letter 89-19 (Reference 1). The PBNP overfill protection system design is consistent with the Westinghouse Group I design described in enclosure 2 to the generic letter, with the exception of not tripping the main feedwater pumps on SG water level. NRC acceptance of the steam generator overfill protection system design was based on: 1) the two credited SG level channels being separate from the feedwater control system with separate power supplies, 2) the components not being located in the same cabinets as the feedwater control system, and 3) because emergency procedures exist which specify operator actions to ensure feedwater isolation for fires which could affect both the feedwater control system and the overfill protection system simultaneously. Additionally, plant Technical Specifications ensure operability and provide surveillance requirements for the overfill protection system (Reference 2).

7.3.3.2 Specific Exceptions to IEEE 279-1968

a. Containment Gaseous Radioactivity

The containment radiation detectors that initiate containment ventilation isolation on high gaseous radioactivity are not classified as safety-related and are not seismically-qualified. Use of non-safety-related detectors for containment ventilation isolation is acceptable, because no Chapter 14 accident relies on these detectors to function for containment ventilation isolation. The offsite dose analysis for a fuel handling accident does not credit containment ventilation isolation, and conservatively assumes that all radioactivity released during the accident is vented from containment.

b. Auxiliary Feedwater Initiation Contacts

The field contacts that start Auxiliary Feedwater pumps on bus undervoltage are not classified as safety-related and are not seismically-qualified. Some AMSAC field contacts also may not be classified as safety-related or seismically-qualified. Use of non-safety-related contacts for starting AFW pumps is acceptable, because no Chapter 14 accident relies on these inputs to start the AFW pumps.

For both cases above, the field wiring between the non-safety-related detectors/contacts and the safety-related circuits that actuate ESF equipment may not fully meet separation criteria for safety-related wiring. The basis for allowing exceptions to separation criteria for this wiring is that the non-conforming circuits are electrically isolated such that an electrical fault in the non-safety-related field wiring will not propagate into and disable the primary actuation circuits. Therefore, any failure in the non-safety-related field wiring will not affect the primary actuation functions assumed in the accident analyses.

7.3.3.3 Operating Bypasses and Resets

a. SI Block Function

IEEE 279 Section 4.12 requires that where operating requirements necessitate automatic or manual bypass of a protective function, the design shall be such that the bypass will be removed automatically whenever permissive conditions are not met.

To prevent unnecessary safety injection actuation during normal plant shutdown/cooldown due to either low pressurizer pressure or low steam line pressure, a manual SI block function is provided. Blocking SI actuation on both variables allows the primary system to be depressurized for maintenance and refueling operations without causing safety injection actuation. This manual SI block function is permitted at a preset pressurizer pressure below normal operating pressure but above the setpoint for low pressurizer pressure SI actuation. The logic is designed so that the blocking action is automatically removed if operating pressure increases above the pressure at which the manual block is permitted. When the SI block condition is in effect, the condition is continuously annunciated in the control room, as required by IEEE 279 Section 4.13. The SI block function does not prevent SI actuation on high containment pressure.

b. SI Actuation Reset

IEEE 279 Section 4.16 requires that once initiated, a protective action shall go to completion, and return to operation shall require subsequent deliberate operator action. The SI actuation circuitry is provided with a reset function to allow the operator to regain control of equipment after SI actuation goes to completion. A time delay in the circuit prevents any operator interference in SI actuation for approximately 1-2 minutes after actuation occurs. After the time delay times out, the operator can manually reset the SI actuation circuitry to regain control of individual actuated equipment.

c. Containment Isolation and Containment Ventilation Isolation Reset

NUREG 0578 Item 2.1.4 and NUREG 0737 Item II.E.4.2 require that the containment isolation design shall be such that resetting the isolation signal will not result in the automatic reopening of containment isolation valves, and that reopening of containment isolation valves shall require deliberate operator action. Resetting of safety injection, containment ventilation isolation, or containment isolation will not automatically open any of the fluid paths to or from containment which are isolated upon receipt of the initiating signal. The valves must be individually opened by deliberate operator action. Resetting of Safety Injection does not reset containment ventilation isolation or containment isolation. Resetting containment isolation can only occur after safety injection has been reset. Resetting containment ventilation isolation can only occur if safety injection has been reset and if both high radiation signals that can initiate containment ventilation isolation are not present.

d. Containment Spray Reset

The containment spray actuation circuitry is provided with a manual reset function to allow the operator to regain control of equipment after the high-high containment pressure actuation signal has cleared. After containment spray is reset the spray additive tank outlet control valves will return to the preset position on their hand control station (normally closed).

e. General Design Features for Safety Injection, Containment Isolation, Containment Ventilation Isolation and Containment Spray Reset Circuits

The following common design features are applicable to the above safeguards reset circuits.

- Except for the spray additive tank outlet control valves, associated safety related equipment remains in its emergency mode upon reset of an ESF actuation signal (Reference 3).
- Resetting a safeguards circuit will not prevent subsequent manual actuation of the circuit.

- Separate reset switches are provided for each train and each reset switch is fitted with a cover to prevent inadvertent or accidental operation.

f. Feedwater Isolation Reset

Feedwater isolation reset capability is provided for Train A and B by a single pushbutton for each feedwater loop. Operating the pushbutton allows control of the feedwater regulating bypass valve by its auto/manual controller. Feedwater isolation reset does not affect the main feedwater regulating valves. Circuit design prevents feedwater isolation reset if SI has not been reset or if a high-high level exists in the associated steam generator.

7.3.3.4 Manual AFW Flow Control During Plant Shutdown

The successful operation of the engineered safety features only involves actuation, with one exception. This exception is manually controlling steam generator water level using the auxiliary feedwater pumps during plant shutdown, to remove reactor decay and sensible heat. This manual control involves positioning the auxiliary feedwater flow control valves in order to maintain proper steam generator water level. Steam generator water level indication and controls are located in the control room and at a local control station. Safety related backup pneumatic supplies are provided for the motor-driven auxiliary feedwater pump flow control valves and the motor-driven and turbine-driven auxiliary feedwater pump minimum flow recirculation valves (See Section 10.2.2). If a loss of operating air occurs, or an auxiliary feedwater pump minimum flow recirculation valve fails closed, manual operator action may be required to prevent the potential failure of the pump(s). By procedure, the operator will use the manual gag to open the minimum recirculation valve(s) to prevent pump damage that could be caused by overheating.

7.3.3.5 Separation of SI Reactor Trip Signals

The SI actuation contacts that supply a signal to the reactor trip logic originate in each of the two ESFAS logic trains. Each ESFAS logic train supplies a reactor trip signal to both trains of reactor protection logic. This leads to a unique condition where the ESFAS logic A train is communicating with the RPS logic B train (as well as with the A train), and the ESFAS B train is communicating with the RPS A train (as well as with the B train). This condition does not create an electrical separation conflict between redundant trains because the inputs to reactor protection are channel-related. Within each train of reactor protection, the two inputs from SI actuation train A & B enter two separate channel-related racks. There, the inputs drive separately fused isolation relays.

7.3.3.6 Seismic Qualification of ESF Actuation System Equipment

The protection system components seismic qualification test program described in Section 7.2.3.4 for reactor protection system components also applies to ESFAS components.

7.3.3.7 Environmental Qualification of Protection System Equipment

The protection system equipment that is located in a mild environment (an environment that would, at no time, be more severe than the normal service environment, such as the control room or cable spreading room) is not required to be environmentally qualified in accordance with 10 CFR 50.49. However, the design for normal service conditions and the PBNP quality assurance, maintenance, and surveillance programs ensure that the equipment is capable of performing its safety function on demand throughout its installed lifetime.

ESFAS equipment that is located in a potentially harsh environment (a design basis accident environment which is significantly more severe than normal service conditions), such as sensors inside containment, is designed to perform its safety function throughout its installed lifetime under the operating service conditions of its installed location. Regarding qualification to continue to function under a harsh post-accident environment, ESFAS components located in potentially harsh environments only require formal environmental qualification if: 1) the component is required to mitigate the accident that creates the harsh environment and the harsh environment degrades the component performance before the protective function occurs, or 2) the component is used for post-accident functions not related to the protection function.

7.3.3.8 Environmental Qualification of ESF Equipment

Engineered Safety Features electrical equipment has been evaluated with respect to its local design basis accident environment. The equipment is designed and qualified as necessary to ensure that it can perform its safety function in such conditions throughout its installed lifetime.

Electrical equipment which could be subjected to a harsh accident environment is listed in Table 7.3-2 with its general operating mode and time to complete its ESF function. This equipment is environmentally qualified in accordance with 10 CFR 50.49. The safety related electrical equipment qualification is controlled and documented in accordance with administrative procedures. Regulations governing qualification are described in Section 6.1.1.

Factors considered in qualification include aging in normal service, harsh post-accident environments, and the time required for performing the safety function. Environmental parameters evaluated are temperature, pressure, chemical spray, relative humidity, radiation exposure, and submergence, if applicable. The design considerations and specifications used in selection of motors which must function in a post-accident environment are discussed in Section 6.2, Section 6.3, and Section 6.4. Similar application criteria apply to the specifications of control, instrumentation, and other equipment.

Areas of high radiation would exist inside the containment and in those portions of the auxiliary building near emergency core cooling system equipment following a major loss-of-coolant accident. The maximum expected dose rate inside the containment would be in the range of 10^6 rads per hour. The maximum expected dose rate in high radiation areas of the auxiliary building (e.g., residual heat removal compartments) would be less than one percent as high. The ability of electrical equipment in the emergency core cooling system to withstand radiation exposure would be limited by radiation effects on electrical insulation materials and motor bearing lubrication.

The electrical equipment for the emergency core cooling system located in the containment uses inorganic, silicone, and epoxy plastic insulating materials. These materials have a threshold for radiation damage, which might affect their function, of 10^8 rad or higher. Therefore, considerable margin is provided above the maximum post-accident radiation dose that would result from the dose rates specified above and exposure times listed in Table 7.3-2. The lower ambient temperatures and radiation levels in the auxiliary building permit the use of normal elastomer or plastic insulation materials. These materials have a threshold for radiation damage of 10^6 rad or higher.

Where required, because of location in possible high radiation areas, motor bearings are lubricated with suitable environmentally qualified lubricants.

7.3.4 REFERENCES

1. Generic Letter 89-19, "Request for Action Related to Resolution of Unresolved Safety Issue A-47 - Safety Implication of Control Systems in LWR Nuclear Power Plants," dated September 20, 1989.

2. NRC Safety Evaluation dated December 8, 1994, "Safety Evaluation by the Office of Nuclear Reactor Regulation Related to Licensee Response to Generic Letter 89-19 and Proposed Technical Specification Upgrades."

3. NRC Safety Evaluation, "Licensee Response to I&E Bulletin 80-06, Engineered Safety Features (ESF) Reset Controls," enclosed with NRC Memorandum, Point Beach 1 and 2 -ESF Reset Control-I&E Bulletin 80-06, dated July 7, 1981.

4. NRC Safety Evaluation, PBNP Units 1 and 2- Issuance of License Amendments Regarding Extended Power Uprate, May 3, 2011.

5. NRC Safety Evaluation, "Point Beach Nuclear Plant Units 1 and 2- Issuance of License Amendments Re: Auxiliary Feedwater System Modification," dated March 25, 2011.

Table 7.3-1 LIST OF ENGINEERED SAFETY FEATURES ACTUATION SIGNALS
Sheet 1 of 3

ESFAS SUBSYSTEM	COINCIDENCE CIRCUITRY	COMMENTS
SAFETY INJECTION ACTUATION		
1. Low Pressurizer Pressure	Two-out-of-three (2/3)	Low pressurizer pressure and low steam line pressure SI signals may be manually blocked with RCS pressure below SI block setpoint. The block is automatically removed above the setpoint. SI in either unit trips both SSG Pumps if running.
2. Low Steam Line Pressure	Two-out-of-three (2/3) either loop	
3. High Containment Pressure	Two-out-of-three (2/3)	
4. Manual SI Actuation	One switch per train	
CONTAINMENT ISOLATION		
5. Safety Injection Signal	See Items 1-3	Auto SI only; manual SI does not initiate CI
6. Manual Containment Isolation	One switch per train	
CONTAINMENT VENTILATION ISOLATION		
7. Safety Injection Signal	See Items 1-4	Both auto and manual SI initiate CVI
8. Containment High Gaseous Activity	One-out-of-two (1/2)	
9. Manual Containment Spray	See Item 12	
10. Manual Containment Isolation	See Item 6	
CONTAINMENT SPRAY ACTUATION		
11. High-High Containment Pressure	Two-out-of-three (2/3) taken twice	
12. Manual Spray Actuation	Two-out-of-two (2/2) per train	

Table 7.3-1 LIST OF ENGINEERED SAFETY FEATURES ACTUATION SIGNALS
Sheet 2 of 3

ESFAS SUBSYSTEM	COINCIDENCE CIRCUITRY	COMMENTS
STEAM LINE ISOLATION		
13. High Steam flow coincident with low T_{avg}	One-out-of-two (1/2) per loop Two-out-of-four (2/4) low T_{avg} and Safety Injection signal	
14. High-High Steam Flow	One-out-of-two (1/2) per loop and Safety Injection signal	
15. High-High Containment Pressure	Two-out-of-three	
16. Manual Steam Line Isolation	One switch per steam line	
AUXILIARY FEEDWATER PUMP START		
17. Turbine-Driven Pump Start	Safety Injection, or 2/3 Low-Low S/G level in either S/G, or 1/2 loss of voltage on both A01 and A02 or AMSAC signal.	The turbine-driven AFW pump supplies both S/Gs; A01/A02 signals are non-safety grade
18. Motor-Driven Pump Start	Safety Injection, or 2/3 Low-Low S/G level in either S/G, or 1/2 loss of voltage on both A01 and A02, or AMSAC signal.	The motor-driven AFW pump supplies both S/Gs. Pump starts a nominal 10.5 seconds after any auto start signal with offsite power available and starts a nominal 32.5 seconds after closure of either of its associated EDGs' breaker (no auto start signal required) following a loss of offsite power. Automatic start signal trips both SSG feedwater pumps. A01/A02 signals are non-safety grade.

Table 7.3-1 LIST OF ENGINEERED SAFETY FEATURES ACTUATION SIGNALS
Sheet 3 of 3

FEEDWATER ISOLATION		
19. Safety Injection Signal	See Items 1-4	Both auto and manual SI initiate FW Isolation. Closes Main Feedwater Isolation Valves and MFW Regulating and Bypass Valves. Trips MFW pumps which generates a closure signal for the pump discharge valves, but these are not credited ESF functions.
20. High-High SG Level	2/3 per SG	Closes MFW Regulating and Bypass Valves.
AUXILIARY FEEDWATER PUMP SUCTION TRANSFER TO SERVICE WATER		
21. Turbine-Driven Pump	One-out-of-one low pump suction pressure	Suction transfer on low-low-low CST level is not a credited ESF actuation
22. Motor-Driven Pump	One-out-of-one low pump suction pressure	Suction transfer on low-low-low CST level is not a credited ESF actuation

Table 7.3-2 GENERAL OPERATING TIME REQUIREMENTS FOR ENVIRONMENTAL QUALIFICATION OF ELECTRICAL EQUIPMENT
Sheet1 of 3

Equipment Name	Operating Mode	Time to Operate[a]
Instrumentation		
Reactor Protection System	Continuous	30 minutes
Safeguards Protection System	Continuous	30 minutes
Post Accident Monitoring	Continuous	Available for one year (one day for Containment Spray System)
Valve Operators		
Air-Operated Containment Isolation Valves	Shut on Containment Isolation Signal	10 seconds
Safety Injection System Motor-Operated Valves	Open on Safety Injection Signal	30 minutes
RHR Heat Exchanger Discharge to SI Pump Suction Motor-Operated Valves	Open on Manual Signal for Boron Precipitation Control	Available for 7 hours [b]
Low-Head Reactor Vessel Injection Motor-Operated Valves	Throttle on Manual Signal for Boron Precipitation Control	Available for 7 hours [b]
Containment Sump Suction Isolation and Component Cooling Supply to RHR Heat Exchangers Motor-Operated Valves	Continuous	Available for one year
RHR Heat Exchanger Discharge and Bypass Air-Operated Throttle Valves	Continuous	Available for one year

a. This is the time after the accident in which it is expected that the item will have completed its safety function.
b. Conservatily based on time to initiate low-head vessel injection to preclude boric acid precipitation for a small break LOCA. See FSAR 6.2.2.

Table 7.3-2 GENERAL OPERATING TIME REQUIREMENTS FOR ENVIRONMENTAL QUALIFICATION OF ELECTRICAL EQUIPMENT
Sheet 2 of 3

Equipment Name	Operating Mode	Time to Operate[a]
Valve Operators, Continued		
Containment Spray Air-Operated and Motor-Operated Valves	Continuous	Available for one day
Sample System Air-Operated Valves for Post-Accident Sampling	Continuous	Available for one year
Steam Supply to Turbine-Driven Auxiliary Feed Water Pump Motor-Operated Valves	Open on Turbine-Driven AFW Pump Start Signal	10 minutes
Main Feedwater Regulating and Bypass Air-Operated Valves	Close on Safety Injection Signal	12 seconds (Includes 2 second signal processing delay)
Power Operated Relief Valve Blocking Motor Operated Valve	Continuous	Available for 4 hours
Reactor Coolant System Gas Vent System Solenoid Isolation Valve	Continuous	Available for one year
Motors		
Containment Emergency Fan Cooler Motors	Continuous	Available for one year
Safety Injection and RHR Pump Motors	Start on Safety Injection Signal	Available for one year
Component Cooling Water Pump Motors	Continuous	Available for one year

a. This is the time after the accident in which it is expected that the item will have completed its safety function.

Table 7.3-2 GENERAL OPERATING TIME REQUIREMENTS FOR ENVIRONMENTAL QUALIFICATION OF ELECTRICAL EQUIPMENT
Sheet 3 of 3

Equipment Name	Operating Mode	Time to Operate[a]
Miscellaneous Equipment		
Safeguard Equipment Power, Control, and Instrumentation Cable; Splices; Electrical Penetration Assemblies	Continuous	Consistent with Operating time of associated equipment

Note: Lubricants used in Safeguard Equipment are Environmentally qualified consistent with the operating time of the associated equipment.

a. This is the time after the accident in which it is expected that the item will have completed its safety function.

Figure 7.3-1 ENGINEERED SAFETY FEATURE LOGIC DIAGRAM

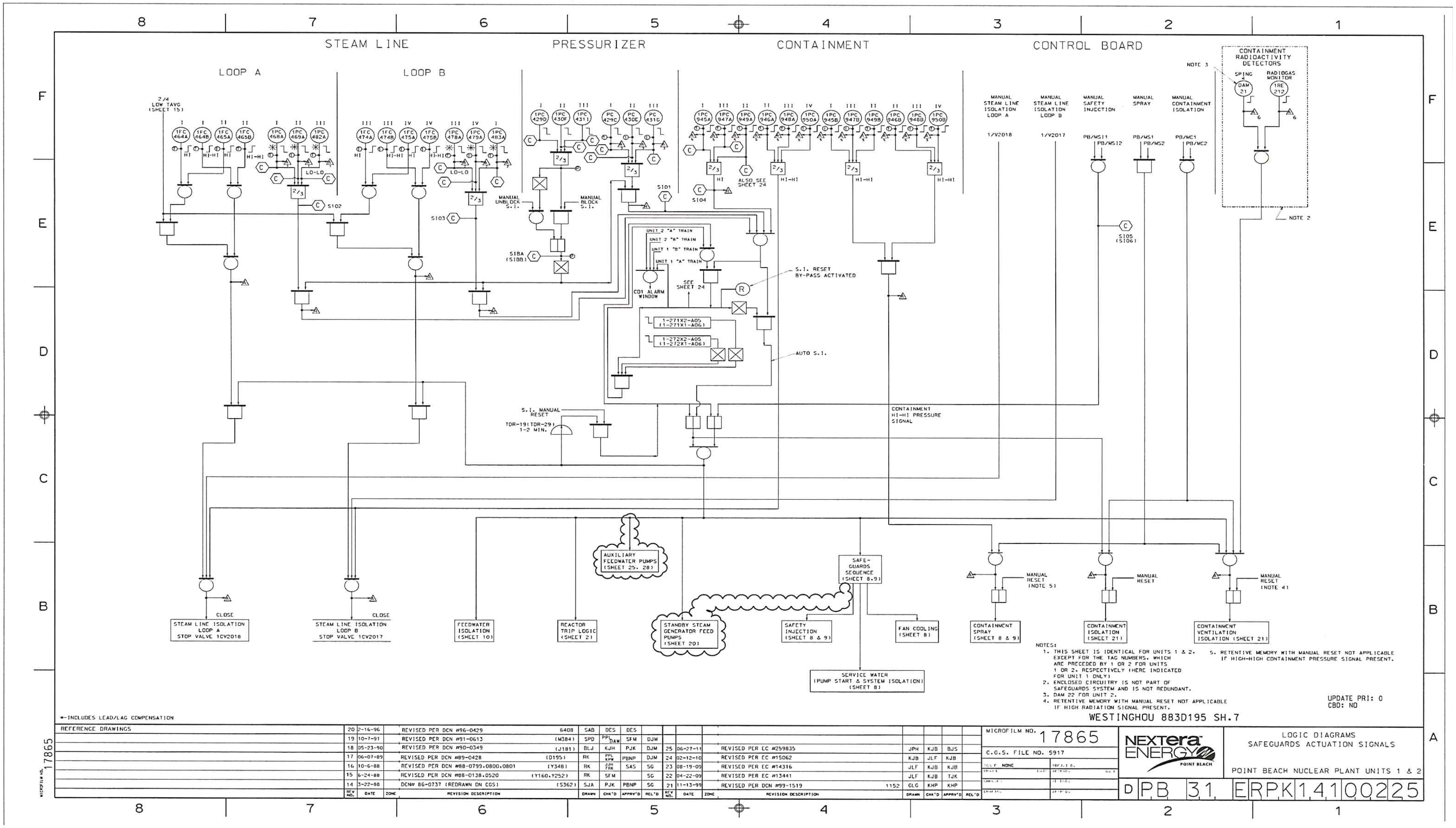
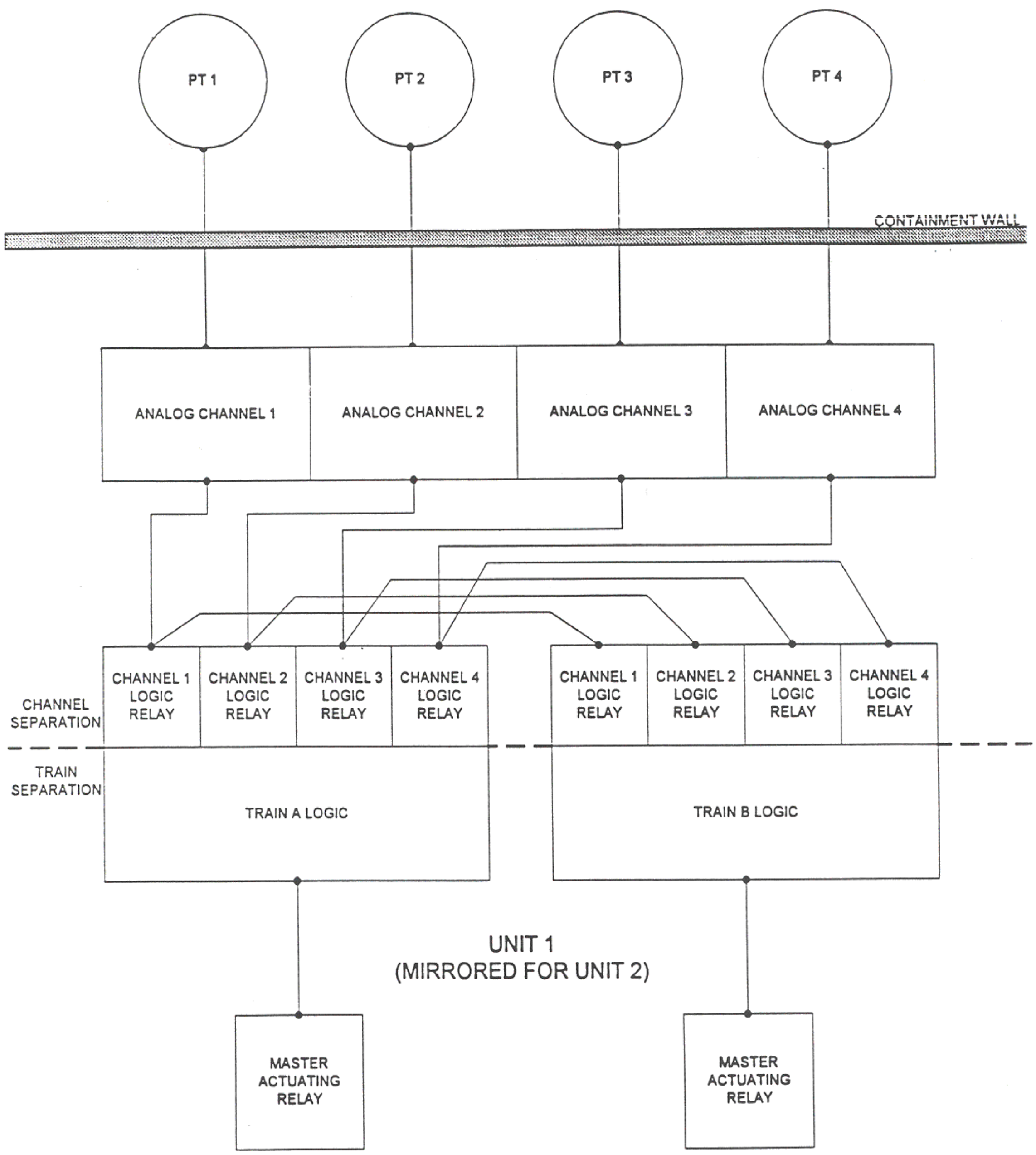


Figure 7.3-2 ENGINEERED SAFETY FEATURE LOGIC MATRIX



7.4 OTHER ACTUATION SYSTEMS

This section addresses actuation systems not included in the Reactor Protection System (RPS) or Engineered Safety Features Actuation System (ESFAS), discussed in Section 7.2 and Section 7.3.

7.4.1 AMSAC

AMSAC stands for an ATWS (Anticipated Transient Without Scram) Mitigating System Actuation Circuitry and is required per 10 CFR 50.62.

AMSAC is classified as Non-Class 1E, except for where it interfaces with the auxiliary feedwater pumps start circuits. The Class 1E, seismically qualified output relays are used to provide the isolation between the auxiliary feedwater pump start circuits and the AMSAC initiation circuitry.

7.4.1.1 Design Bases

The AMSAC System design is based on the requirements of 10 CFR 50.62 (c) (1), which requires a system that is independent and diverse from the Reactor Protection System that will automatically initiate the auxiliary feedwater system and initiate a turbine trip for an ATWS event. The AMSAC System must be capable of operating during a loss-of-offsite-power.

7.4.1.2 System Design

AMSAC, also known as the Loss of Feedwater Turbine Trip (LOFWTT), is designed to trip the main turbine and starts the motor-driven auxiliary feedwater pump and the turbine-driven auxiliary feedwater pump on loss of main feedwater when the reactor is above 40% nominal power. The AMSAC design is based on the conceptual design presented in Section 5.0 of WCAP-10858-P-A, Rev. 1, “AMSAC Generic Design Package.”

Turbine power is determined from turbine first stage pressure from which the AMSAC arming permissive P-20 is derived. A bistable actuates a time delay relay at approximately 30% turbine power and arms AMSAC. The 30 % turbine power setpoint ensures AMSAC is armed before exceeding 40% reactor power. On decreasing power the time delay relay keeps AMSAC armed for approximately 60 seconds after turbine power has decreased below the P-20 setpoint. The AMSAC design incorporates a nominal 30 second time delay from initially sensing the loss of main feedwater to initiating signals to trip the turbine and start the auxiliary feedwater pumps. An additional delay time of 60 seconds is assumed for auxiliary feedwater pump start response time as discussed in Section 10.2.1. The 30 second time delay was based on full power operating condition, and should allow the reactor protection system to actuate prior to AMSAC. However, at lower power levels above P-20 AMSAC may cause a turbine trip, and subsequent reactor trip prior to an RPS initiated reactor trip. A turbine trip caused by AMSAC appears no different than any other turbine trip, which has been analyzed as a Loss of Electrical Load in Section 14.1.9.

AMSAC monitors the availability of main feedwater by way of the main feedwater pumps breaker position and the valve position of the main feedwater regulating valves (MFRVs) and main feedwater isolation valves (MFIVs); refer to Figure7.4-1. Loss of main feedwater is identified when either:

- Both main feedwater pumps breaker's are open
- Both main feedwater regulating valves are shut
- Both main feedwater isolation valves are shut
- A MFRV and/or a MFIV in each feedwater line are shut

Each main feedwater pump breaker has two redundant, physically independent contacts that close when the pump breaker is open. The contacts are connected in a matrix arrangement that actuates AMSAC when one-out-of-two contacts associated with both breakers are closed. This configuration was used because no single failure of a contact will prevent AMSAC from actuating when both breakers are open, nor can a single contact failure cause AMSAC to actuate when both breakers are closed.

Each MFRV (CS-466 and CS-476) and MFIV (CS-3124 and CS-3125) has two redundant position (limit) switch contacts that close when the valve closes. The position switch contacts are connected in a matrix arrangement that actuates AMSAC when one-out-of-two switches associated with either valve in both feedwater lines are closed. Similar to the main feedwater pump breaker contacts, this configuration was used because no single failure of a switch contact will prevent AMSAC from actuating when both feedwater lines are isolated, nor can a single switch contact failure cause AMSAC to actuate when both feedwater lines are not isolated.

The MFRVs and MFIVs were chosen because one valve closing in both feedwater lines will result in the complete loss of feedwater flow at power. Since AMSAC is not armed until the plant is above permissive P-20 the main feedwater regulating bypass valves, which are normally closed at power level greater than 20% to 30%, did not need to be included in the AMSAC design. In addition, since the main feedwater pump discharge valves can only automatically close if the main feedwater pump breakers are open, and because AMSAC monitors the breaker position of the pumps, these valves did not need to be included in the AMSAC design.

Separate latching type relays are used for actuation of the motor-driven auxiliary feedwater pump, opening the turbine-driven auxiliary feedwater pump steam supply valve MS 2019 and opening the turbine-driven auxiliary feedwater pump steam supply valve MS 2020. Separate latching type relays are also used for initiating the main turbine auto stop trip (AST) and the main turbine emergency trip (ET).

The NRC staff reviewed the information submitted related to ATWS for the extended power uprate (EPU) and concluded that the effects on ATWS were adequately accounted for and that AMSAC will continue to meet the requirements of 10 CFR 50.62 following implementation of the EPU. The generic Westinghouse ATWS analyses was confirmed with plant-specific, bounding analyses to be reflective of uprated conditions and indicated that the peak primary system pressure following an ATWS event will remain below the acceptance limit of 3200 psig (Reference 1 and Reference 2).

7.4.1.3 System Evaluation (Reference 3)

a. Diversity

Reasonable equipment diversity between AMSAC equipment and RPS equipment, to the extent practical, is required to minimize the potential for common-cause failures.

The pressure transmitter (PT-5971) used to measure first stage turbine pressure (turbine power) and the bistable (PC-5971) used to provide the P-20 permissive within AMSAC are diverse from those used to provide permissives in the Reactor Protection System (RPS).

Latching relays and time delay relays are used in AMSAC. Latching relays and time delay relays are used in the Engineered Safety Features Actuating System (ESFAS); however, they are not used in RPS. Since AMSAC is only required to be diverse from RPS to minimize a common-cause failure, the use of the latching relays and time delay relays is acceptable.

Although AMSAC hardware not involved in the logic, such as switches, lights, wire and annunciators, are not diverse from those used in RPS, AMSAC has been determined to meet the requirements of diversity associated with the ATWS Rule (10 CFR 50.62).

b. Logic Power Supplies

AMSAC is not redundant and only has one source of power. Each unit's AMSAC is powered from its associated 120 VAC instrument bus (1Y-06 / 2Y-06), which is derived from a diesel generator backed bus (1B-03 / 2B-04) via a 480 VAC to 120 VAC transformers. The diesel generators supply rated voltage to these buses within 10 seconds after a Loss-Of-Offsite-Power (LOOP). This power is diverse and independent from the 125 VDC battery power and 120 VAC inverter power used in the RPS.

IF a unit's AMSAC is armed, the 60 second time delay dropout arming relay prevents it from disarming during a LOOP.

If ATWS conditions have been met for less than 30 seconds prior to a LOOP, the time delay actuation relay will lose power and reset. When the associated diesels restore electrical power AMSAC will function to start auxiliary feedwater pumps after ATWS conditions have been met for 30 seconds. Therefore, a LOOP could delay AMSAC actuation under ATWS conditions for 10 to 40 seconds. Upon actuation the output relays latch to provide a continuous AMSAC actuation signal, regardless of power until the circuit is manually reset.

c. Safety Related Interface

The AMSAC safety related interface is with the auxiliary feedwater pump starting circuits. This interface is through the latching relays. There is no direct interface between AMSAC and RPS; therefore, RPS will perform its required safety function without interference from AMSAC.

d. Quality Assurance

The AMSAC output relays that interface with the safety related Auxiliary Feedwater System and the wires used for the connections are QA components and are subject to the PBNP nuclear quality assurance program. The remainder of the AMSAC system is Augmented Quality (AQ). The controls applied to the AQ portions of the system meet the requirements of 10 CFR 50.62 and Generic Letter 85-06 as clarified in NRC Information Notice 92-06 (Reference 4).

e. Maintenance Bypasses

Key operated Bypass and Test switches are provided on the local AMSAC test panel. The switches allow for maintenance and partial testing of the AMSAC system. Placing the key switches in the Bypass or Test position, results in annunciation in the main control room.

f. Operating Bypasses

The AMSAC system is automatically armed at approximately 40% power, based on turbine first stage pressure, by the P-20 permissive, and automatically disarmed below approximately 40% power. The system remains armed for a nominal 60 seconds after power decreases below 40%. The status of the P-20 permissive signal is continuously indicated in the control room via the annunciator.

g. Means for Bypassing

The permanently installed key operated Bypass switch described above is used to bypass AMSAC during testing and maintenance. A human factors review was performed as part of the modification process.

h. Manual Initiation

No additional manual initiation switches or buttons were installed as part of the AMSAC System, because the control room operator can manually trip the turbine and start the auxiliary feedwater system from the main control room. Therefore, no additional manual initiation capability is required for the AMSAC System.

i. Electrical Independence from existing Reactor Protection System

Independence is required from the sensor output to the final actuation device at which point non-safety related circuits must be isolated from safety related circuits by qualified Class 1E isolators.

The inputs to AMSAC are separate from and independent of RPS. No sensors are common to the RPS and AMSAC Systems. The only safety related interface associated with AMSAC is at the Auxiliary Feedwater System. The isolation between AMSAC and the Auxiliary Feedwater System is through the Class 1E output latching relays, which were tested in accordance with Appendix A of the Safety Evaluation of Topical Report (WCAP-10858-P-A, Rev. 1), "AMSAC Generic Design Package" dated July 1987.

j. Physical Separation from existing Reactor Protection System

The AMSAC circuitry is physically isolated from the RPS circuitry. The equipment associated with AMSAC is located in a cabinet separate from the RPS cabinets. There are no incoming signals from the RPS System to the AMSAC cabinet; therefore, the existing separation criteria for the RPS is not compromised by AMSAC.

k. Environmental Qualification

The equipment installed for AMSAC does not require environmental qualification for the AMSAC function, since it is either located in a mild environment or is not required to operate during or following exposure to potentially harsh environments resulting from design basis accidents. The AMSAC components are qualified for all anticipated environments expected to occur prior to or during an ATWS event. Although environmental qualification is not a design requirement for AMSAC operation, the limit switches on the main feedwater regulating valves are environmentally qualified for High Energy Line Break (HELB) considerations, so that the limit switches added for AMSAC meet the same qualifications as the existing limit switches on the main feedwater regulating valves.

l. Testability at Power

Portions of the AMSAC System, such as the bistables, time delay relays and logic relays, can be tested at power by use of the Bypass and Test switches. These portions of the system are tested semi-annually. The remaining portion of the system, such as the output latching relays, valve position switch contacts and the main feedwater pump circuit breaker position can not be tested at power; therefore, a complete end-to-end test of the AMSAC System is performed during refueling outages.

m. Completion of Mitigative Action

The AMSAC output relays are latching type relays. Once set (actuated), the relay remains in the set position, even if the power is removed. Deliberate operator action is required to reset the relays.

The turbine remains tripped, even when the initiating signal is no longer present. Deliberate operator action is required to relatch the turbine after the trip signal has cleared.

The auxiliary feedwater pumps continue to run, even when the initiating signal is no longer present. Deliberate operator action is required to secure the auxiliary feedwater pumps once started by an automatic signal.

Therefore, once the AMSAC system is initiated it will go to completion until reset by the operator.

7.4.2 LOW TEMPERATURE OVERPRESSURE PROTECTION (LTOP)

7.4.2.1 Design Bases

A Low Temperature Overpressure Protection (LTOP) System is required to protect the reactor vessel from exceeding the 10 CFR 50, Appendix G allowable pressure limits at low temperatures.

7.4.2.2 System Design

The LTOP System is required to provide a diverse means of relieving pressure during periods of solid water operation when the reactor is ≤ LTOP enabling temperature as defined in TRM 2.2; Pressure Temperature Limits Report.

The diverse means of relieving pressure is provided by the two logic trains that open the two pressurizer Power Operated Relief Valves (PORVs) on increasing pressure when the LTOP System is armed. The PORVs are armed for low pressure relief via a key switch on section C04 of the main control board. An Indicating light located above the key switch on the main control board is provided, and is lit when the LTOP System is armed.

Pressure is monitored by a wide range reactor coolant system pressure transmitter (PT-420) to actuate one PORV, and by a pressurizer pressure transmitter (PT-493) to actuate the other PORV. Prior to actuation of the PORVs, an alarm is initiated to warn the operator of increasing pressure. If pressure continues to increase, the pressurizer PORVs will open at ≤ LTOP PORV lift setting limits as defined in TRM 2.2; Pressure Temperature Limits Report.

7.4.3 AFW PUMP SUCTION TRANSFER AND TRIP ON LOW SUCTION PRESSURE

7.4.3.1 Design Bases

Auxiliary Feedwater (AFW) pump trip on low suction pressure was installed on the four original AFW pumps (P38A/P-38B and 1/2P-29) to address Item II.E.1.1 of NUREG-0737. AFW system modifications associated with the extended power uprate (EPU) added unit specific electric AFW pumps 1/2 P-53 which replaced the shared motor-driven AFW Pumps (P-38A/P-38B) as the credited pumps. Low suction pressure trip on low suction pressure was provided for pumps 1/2P-53 and retained on P-38A/P-38B. Additionally, automatic suction transfer from condensate to service water was added for 1/2 P-53 and the steam-driven AFW pumps 1//2P-29.

7.4.3.2 System Design (P-53 and P-29)

The safety-grade automatic suction transfer to service water for AFW pumps P-53 and P-29 on low suction pressure or low-low-low level in either condensate storage tank is designed to provide a continued suction source for the pumps on a loss of condensate storage tank water supply, which could result from a tornado or seismic event.

The suction pressure for each pump is monitored by its associated pressure transmitter. A low suction pressure initiates two time delay relays. When sustained low suction pressure conditions exists the first time delay relay will provide a signal to open the pump's service water suction supply valve. If this action does not re-establish pump suction pressure, the second time delay relay trips the associated pump. A motor-driven pump is tripped by opening its supply breaker and a turbine-driven pump is stopped by isolating the steam supply to the pump by closing its trip throttle valve (MS-2082). No time delay is provided for suction transfer on low-low-low condensate storage tank level.

In addition to tripping the AFW pumps, the following additional actions are performed by the system:

- Blocks the start of the pump or the opening of the trip throttle valve,
- Provides annunciation in the main control room for suction pressure low, low suction pressure trip and suction pressure trip disabled
- Establishes a permissive to manually override the low suction pressure trip.

The trip is overridden by the associated control switch on the main control board, which is used for starting a motor-driven pump or opening the trip throttle valve associated with a turbine-driven pump. When the trip is disabled any subsequent low suction pressure trips associated with that pump are blocked. The trip disabled signal is cleared by operation of the control switch for a motor-driven pump or the override reset pushbutton for the turbine-driven pump.

The low suction pressure circuitry for each pump does not interfere with local operation of the AFW pumps.

7.4.4 REFERENCES

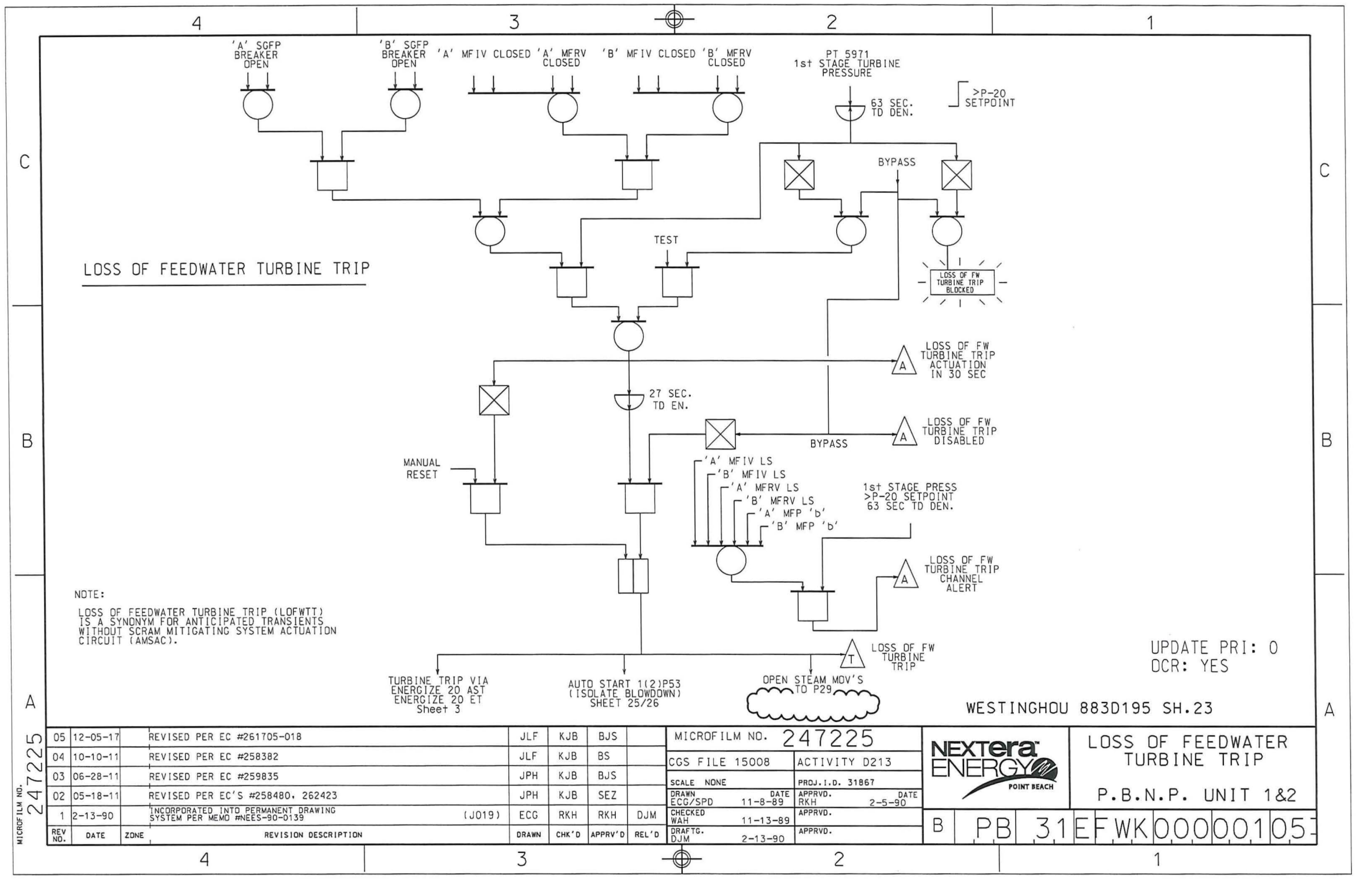
1. NRC SER, "Point Beach Nuclear Plant - Units 1 and 2, Issuance of License Amendments Regarding Extended Power Uprate, dated May 3, 2011

2. Westinghouse letter to NRC, NS-TSM-2182, "ATWS Submittal," dated December 30, 1979.

3. NRC Safety Evaluation "Compliance with ATWS Rule 10 CFR 50.62," dated August 4, 1988.

4. Commitment Change Evaluation 2000-003, dated May 18, 2000.

Figure7.4-1 LOSS OF FEEDWATER TURBINE TRIP



7.5 OPERATING CONTROL STATIONS

7.5.1 CONTROL STATIONS LAYOUT, INFORMATION DISPLAY AND RECORDING

The principal criterion of control station design and layout is that all controls, instrumentation displays and alarms required for the safe operation and shutdown of the plant are readily available to the operators in the control room.

7.5.1.1 Load Dispatching

FPLE Power Marketing, Inc., located at the FPL Corporate office in Juno Beach, FL, is responsible for generation planning, dispatch, and energy trading. The Point Beach units are generally base loaded with load swings performed by licensed plant operators at the request of the system control supervisor.

The Point Beach operator controls the 345 kV generator breakers, the 345 kV circuit switchers, and the 13.8 kV circuit breakers for the high voltage station auxiliary transformers in the switchyard. All 345 kV line and bus section breakers are controlled from the Pewaukee System Control Center by supervisory control.

7.5.1.2 Reactor and Turbine Generator Control Board

The reactor is controlled by the manipulation of the chemical shim (boron concentration) and control rods as discussed in Section 7.7. The control system allows the plant to accept step load changes of 10% and ramp load changes of 5% per minute over the load range of 15 to 100% power under nominal operating conditions. It is also designed to sustain operation following a rapid load decrease of 50% power at a rate up to 200% / minute (Reference 5).

Complete supervision of both the reactor and turbine generator is accomplished from the control room. Units 1 and 2 share a common control room, which is an integral part of the turbine hall. The control room layout including location of control boards for each unit is shown in Figure 7.5-1.

The Main Control Board design minimizes the amount of board area that the control operator needs to manage for the safe operation of both the Nuclear Steam System and conventional plant equipment. Control stations on the board are packaged in a modular concept and are grouped according to function to minimize the possibility of operator error. Mimic buses are also included, for critical systems, to assist the operator. In addition, control stations that consist of both automatic and manual positions are provided with “bumpless” transfer functions.

Indicators, recorders, and annunciator panels are incorporated in the vertical section of the Main Control Board to provide the operator with indication of the monitored plant parameters (e.g., flows, pressure, temperatures, etc.). In addition, alarms are provided by the annunciator panel to indicate parameters that are out-of-limit and which require operator action.

The console section of the Main Control Board contains control devices (switches and control stations) and related indicating lights.

Referring to Figure 7.5-1, sections 1C04 and 1C03 contain the controls, indications and alarms for the primary and secondary systems of Unit 1, respectively. Sections C01 and C02 contain the controls, indications and alarms for common systems as well as the engineered safeguards and electrical systems for both units. Sections 2C04 and 2C03 are the Unit 2 counterparts of 1C04 and 1C03, and are mirror images of sections 1C04and 1C03, respectively.

The rear panels of all the sections are used for controls and indications not normally requiring frequent use and/or observation during normal operation (e.g., bearing temperature recorders, protective relaying, and containment and auxiliary building ventilation, excluding the containment recirculation coolers).

Section 1C04 contains all the controls, indications and alarms required to control the Nuclear Steam supply system. The rod control and nuclear instrumentation systems are located on the left portion of this section, which includes the individual rod position indicators and bottom lights, and all of the controls and nuclear instrumentation required to operate the reactor. On the center and right portions are the controls, indications and alarms for the reactor subsystems (RCS and CVCS), which include the pressurizer pressure and level, and reactor makeup. Also in this section are the indication lights that monitor the bistables associated with the Reactor Protection and Safeguards logic systems, which allows the operator to monitor the status of these systems.

Section 1C03 contains the controls, indications and alarms for the auxiliary coolant system, and the secondary plant, which includes the condensate and feedwater systems, turbine and its auxiliaries, and the portion of the auxiliary feedwater system associated with the Unit 1 turbine driven and motor driven auxiliary feedwater pumps.

Section C01 contains the controls, indications and alarms associated with the engineered safeguards systems for both Unit 1 and Unit 2, which are completely separated between the units. Redundant indicators are provided where required for high reliability. Extensive use is made of mimics and indicating light arrays in order to provide a means of rapidly evaluating the status of these systems in both the active and standby modes. Also in this section are the controls, indications and alarms for those common secondary plant systems that have safeguards functions, which includes the service water system.

Section C02 contains the controls and indication for the electrical systems for both units, which includes the emergency diesel generators, the gas turbine and the 345 kV and 13.8 kV breakers as well as the 4.16 kV and 480 V distribution systems. Unit separation is again maintained. A unique mimic bus (candy stripe) provides for immediate recognition of the 4.16 kV and 480 V safeguards buses and their tie and supply breakers.

7.5.1.3 Auxiliary Safety Instrumentation Panels (ASIPs)

In addition to the controls, indications and alarms available to the operator on the main control board, the Auxiliary Safety Instrumentation Panels (ASIPs) have been installed for the primary purpose of assessing critical parameters in the reactor coolant system and containment structure post-accident. There is one ASIP primarily dedicated to each unit (1C20 and 2C20). These panels are located along the rear (east) wall of the control room as shown in the control room layout, Figure 7.5-1.

Each ASIP is a seismically designed, Class 1E panel which provides analog displays for an integrated set of plant parameters. Although its primary function is critical parameter display and recording for the post-accident environment, it is not intended to be an “isolated” display panel to be used only in that situation. Some of the displayed parameters and control functions are also applicable to routine operations of the plant, such as reactor vessel head and pressurizer vent controls used for startup and shutdown evolutions, and normal operating parameters such as subcooling, reactor vessel water level, RCS temperatures and pressures. Table 7.5-1 summarizes the indications and controls available at each ASIP. In addition to the unit specific indications and controls, the ASIPs also contain common instrumentation such as instrument bus power supply status indicators, meters and controls, and a remote panel for the control room fire detection system. Both ASIPs contain annunciators for these and other systems where this display location is appropriate. Some of the parameters associated with ASIP are described below:

a. RCS Gas Vent System

The RCS Gas Vent System is described in Section 4.2.

b. Reactor Coolant System Hot and Cold Leg Temperatures

Hot and cold leg temperatures are measured using dual-element platinum RTDs. The RTDs are inserted in wells penetrating the main reactor coolant system piping in both the hot and cold legs of the system. In addition to providing temperature indications at the ASIP, the hot leg RTDs can be operator selected as inputs to the Subcooling Monitor System.

c. Reactor Coolant System Wide Range Pressure

Three bourdon tube type transmitters provide pressure indication at the ASIP. Two sense pressure in loop A (cold leg and hot leg) while the third senses pressure in loop B (cold leg). These pressure detectors also provide input to the Subcooling Monitor System and the Reactor Vessel Water Level System.

d. Containment High-Range Radiation

Independent of the Radiation Monitoring System (RMS) described in Section 11.5, three radiation detectors per containment structure sense high radiation levels which might exist in the post-accident environment. Each detector feeds an indicator on the ASIP which indicate on a logarithmic scale over a range of 1 to 10^8 Roentgen/hr. An annunciator also alarms at the high setpoint.

e. Wide Range Containment Pressure

Two diaphragm type transmitters sense pressure in each containment structure. The transmitters are located outside containment and sense containment pressure through a containment penetration. Both indicators and recorders display containment pressure on the ASIP over a range of -5 to 195 psig.

f. Containment Hydrogen Concentration

Four detectors per containment monitor hydrogen concentration in the 0 to 10% range. The detectors input signals to two microprocessors. Each microprocessor receives signals from two detectors in each containment. Four indications per unit are available at the ASIP, corresponding to the four detector locations.

The detectors employ a platinum-based alloy in their sensing mechanism. The alloy generates an electrical potential in the presence of hydrogen proportional to the hydrogen concentration. The detector voltage is sensed and converted by the microprocessor to a value of hydrogen concentration at the sensor location.

g. Reactor Vessel Water Level

Four detectors per unit measure reactor vessel water level by sensing the differential pressure between the bottom of the reactor vessel and the bottom of a reference leg connected to the reactor vessel head via a seal chamber. The four detectors are differential pressure transmitters which share a common reference leg. Two detectors are designated wide range, and can be used when either or both reactor coolant pump(s) are running. They can also be used with reactor coolant pumps off, but with reduced sensitivity when compared with the narrow range instruments. Two detectors are designated narrow range, and are used when reactor coolant pumps are off. All four detectors provide independent indication on the ASIP.

Temperature and pressure are necessary inputs to the reactor vessel level computation. Temperature input is provided from incore thermocouples, while pressure input is obtained from the reactor coolant system wide range pressure detectors described above. The reference leg is density compensated, where density is calculated based on temperatures sensed by thermocouples located along the reference leg tubing.

h. Containment Sump Level

Four level detectors provide indication of water levels in sump A at the keyway below the vessel, and sump B above the containment base level (8 foot elevation). Two detectors are provided in each sump. The detectors in sump A overlap each other and overlap the sump B detectors to measure a continuous level from sump A to sump B. Both detectors in sump B measure the same level. The detectors are float-type devices. Sump level indication is provided on the ASIP.

i. RCS Subcooling

This digital display is used to provide an indication of the temperature differential existing between sensed conditions in the reactor coolant system and the calculated saturation temperature. This two-channel system inputs pressure information from the RCS wide-range pressure detectors and temperature information from one of two operator selected sources-incore thermocouples or hot leg RTDs.

The pressure signal is converted to an equivalent saturation temperature (T_{sat}) through a function generator. This T_{sat} is then compared to either of the temperature sources in a summing device. The temperature difference, or margin, is then displayed on the ASIP. Warning alarms are provided through ASIP mounted annunciators to alert operators to a low subcooling margin condition.

j. Containment Air Temperature

Four platinum RTDs monitor temperature in containment at the 66 foot level, 46 foot level, and two at the 11 foot level. The RTDs on the 11 foot level are labeled Containment Sump Temperature.

k. Steam Generator Wide Range Level

Four detectors (two for SG A and two for SG B) measure steam generator level and indicate on the ASIP. Each detector is a differential pressure transmitter and senses the differential pressure between the steam generator liquid volume (variable leg) and a reference leg.

Each reference leg is maintained in a constant full condition with water provided from a condensing pot.

l. Pressurizer Safety Valve Position Indicator

Lift Indicating Switch Assemblies (LISAs) provide independent and redundant position indication for the two pressurizer pressure relief safety valves. These assemblies operate using magnetically sensitive reed switches which open and shut based on valve position. Each LISA on a valve has two sets of three switches, providing redundant indication of the closed, intermediate, and open positions. A multiple position display is provided for each valve on the ASIP.

m. Core Exit Temperature

Core exit temperature indicating system is described in Section 7.6.

In addition to the indications provided on the ASIP, a list of post-accident monitoring variables, required to meet the intent of Regulatory Guide 1.97 is located in Table 7.6-1.

7.5.1.4 <u>Plant Process Computer System</u>

A scanning, monitoring, logging and historical data storing Plant Process Computer System (PPCS) is installed to assist the operator and technical support personnel in the surveillance of critical plant functions. The PPCS is used to provide supplementary information to the operator, to assist in the normal operation of the Nuclear Steam Supply System, and to inform the operator of off-normal conditions. The plant design includes adequate instrumentation for the operator to operate the plant in a safe manner at all times, regardless of the availability of the computer system.

The PPCS obtains plant data through data acquisition multiplexers located in the computer room and elsewhere within the plant boundaries including the ISFSI cask storage facility. Plant data that was connected to the original PPCS computer remains wired to the computer room multiplexers which are each powered by corresponding uninterruptible power supplies from Unit 1 and Unit 2. Data for both Unit 1 and Unit 2 is collected by the common multiplexing equipment, and transmitted to a fully-redundant distributed computer system. In addition, the PPCS obtains data from the Radiation Monitoring System through separate serial communication links. Application programs on the PPCS are also included for surveillance of reactor control and protection system operations, and for nuclear process calculations. All of this data is available on display/ keyboard stations located in the Control Room (CR). The same data is available to the Technical Support Center (TSC) and the Emergency Operations Facility (EOF) through a similar system which is populated with real-time PPCS data. The system was implemented to meet Cyber Security requirements found in 10 CFR 73.54.

PPCS data available in the control room includes logs, sequence of events reports, post-trip reviews, alarm transitions, primary to secondary leakage, wind direction/speed/atmospheric stability, heatup/cooldown rates and requested application program output.

The sequence of events and time history recording capabilities of PPCS, including the selection of parameters and the storage, retrieval, and presentation of the information, were evaluated as being acceptable for satisfying Item 1.2 of Generic Letter 83-28 (Reference 2).

a. Safety Assessment System

The Safety Assessment System (SAS) consists of function dedicated application programs on the PPCS. The SAS is designed to provide easily understandable information from the highly reliable PPCS data acquisition system in human engineered formats. SAS was designed to meet the SPDS (Safety Parameter Display System) requirements of NUREG-0696, NUREG-0737 Item I.D.2, and NUREG-0737 Supplement 1. Although primarily designed for use in accident situations, it can be used in normal day-to-day plant operation. Major features of the SAS include:

1. Plant mode dependent high level display of key parameters used to assess the safety status of the plant.
2. Thirty-minute trend graphs of groups of related parameters.
3. A Critical Safety Function Monitor which defines conditions to assess the status of six critical safety functions.

All SAS screens are available on any PPCS display station via the graphical user interface.

b. Feedwater Leading Edge Flow Measurement (LEFM) System

A LEFM Check-M3P feedwater leading edge flow measurement system was installed in both units to support a 10 CFR 50 Appendix K 1.4% power measurement uncertainty recapture (MUR) uprate. With the LEFM system in operation providing feedwater flow, temperature, and pressure inputs to the PPCS Reactor Thermal Output (RTO) program, operation at the licensed core power of 1800 MWt is allowed. For LEFM requirements, see TRM 3.3.2 Leading Edge Flow Meter (LEFM).

7.5.1.5 Local Control Stations

Local control stations are provided for certain systems and components, which do not require full time operator attendance, or are not used on a continuous basis. Such systems are the Waste Disposal System, Sampling System, Boron Recycle System, heating boilers and the Turbine-Generator Hydrogen Cooling System. Appropriate alarms are located in the control room and are activated to alert the operators of equipment malfunction or approach to unsafe conditions, for these systems.

The waste disposal control board is located in the auxiliary building, in the vicinity of the boric acid and waste evaporators. This board permits the auxiliary operator to control and monitor the processing of wastes from a central location in the general area where the associated equipment is located. Alarm signals from the waste disposal components annunciate on this board. Actuation of any alarm on this board actuates a general “Waste Disposal” alarm on the main control board. In this manner the control room operator can maintain oversight of the system from the control room, and by means of the public address system, dispatch an auxiliary operator to the waste disposal control board if necessary.

Although the waste disposal control board provides the instrumentation required to control the release of wastes, instrumentation provided to monitor activity release is indicated and/or alarmed in the control room. The auxiliary operator has complete knowledge of permissible discharge rates and quantities before any scheduled release is made, and the waste disposal board permits him to control those parameters. By monitoring the release from the control room, the control room operator maintains oversight of the activity.

7.5.2 COMMUNICATIONS SYSTEMS

Communications systems available to the Control Room are as follows:

- A five-channel page-party public address system is provided. This system permits communication from any plant area, including the control room, to all other plant areas by a speaker system. The five channels are separate, simultaneous communication party lines (Reference WE SER 95-012).
- Administrative control consists of the automatic telephone switchboard and the plant communication system outlined above.
- A separate communication system is provided for communication between the control room, the reactor area, and spent fuel pool area during refueling operations.
- AC powered phone jacks, together with an interconnecting wiring system, is provided at each main control panel and at several locations in the plant.
- The public address system is used for emergency alarm. The system is also used to communicate the reactor containment evacuation alarm during refueling or outage periods when containment evacuation becomes necessary. (Reference WE SER 95-012)
- FM radios link the Control Room to Plant Security and to the Manitowoc County Sheriff.

Additional FM radio systems are used throughout the plant and adjacent areas to enable operations, security, health physics, and maintenance personnel to communicate during normal and/or emergency situations.

7.5.3 OCCUPANCY

The General Design Criterion (GDC) for PBNP’s Control Room habitability is Criterion 11, which is described in Section 7.1.2. Safe occupancy of the control room during abnormal conditions have been provided for in the design.

7.5.3.1 Control Room Habitability

Adequate shielding has been provided to maintain tolerable radiation levels in the control room during accident conditions, as described in FSAR Section 11.6.

The control room ventilation system normally combines outside makeup air with a large percentage of recirculated air. The radiation monitoring system monitors radiation levels in the control room and in the air supply to the control room. The control room ventilation system is automatically placed in emergency Mode 5 by a high radiation signal from the control room area monitor RE-101, by a high radiation signal from the noble gas monitor RE-235 located in the supply duct to the control room or by a containment isolation signal. Refer to Section 9.8 for further discussion of control room ventilation system performance capability.

7.5.3.2 Fire Prevention Design

Refer to Fire Protection Program Design Document (FPPDD) (Reference 6).

7.5.3.3 Station Blackout (SBO)

a. Ventilation

Since control room ventilation will be lost during a station blackout event, openings equaling about 10% of the ceiling area exist to prevent the control room from overheating for the hour ventilation is assumed to be lost. Calculations have been documented which demonstrate that with the assumption of a one hour loss of control room ventilation resulting from a station blackout event, the control room temperature will remain acceptable.

b. Emergency Lighting

Emergency lighting is provided as follows:

Upon total loss of station power, the control room, vital switchgear rooms, diesel generator rooms, and passage ways between these rooms are illuminated by incandescent lighting fixtures which are supplied from the station batteries. These fixtures are normally deenergized and are transferred automatically to station batteries when AC supply to the transfer switch control circuit is lost. Fixed emergency lighting and portable lighting are relied upon for credited recovery actions. In addition, portable lanterns are available in the control room, auxiliary feedwater pump room, and the auxiliary building operators station. Upon availability of power from the diesel generators, additional illumination will be provided in the aforementioned areas, as well as throughout the plant, by a separate AC emergency lighting system.

7.5.4 EMERGENCY SHUTDOWN CONTROL

The Control Building, its equipment, and furnishings have been designed so that the likelihood of fire or other conditions which could render the control room inaccessible, even for a short time, is extremely small.

As a further measure to assure safety, provisions have been made so that plant operators can shut down and maintain the plant in a safe condition by means of controls located outside the control room. During such a period of control room inaccessibility, the reactor will be tripped and the plant maintained in the hot shutdown condition. If the period extends for a long time, the Reactor Coolant System can be borated to maintain shutdown as xenon decays.

Local controls are located such that the stations to be manned, and the times when attention is needed, are within the capability of the plant operating crew. The plant communication system provides communication among the personnel so that the operation can be coordinated.

The functions for which local control provisions have been made are discussed in Section 7.5.4.1 below. Indication and controls provided outside the control room are discussed in Section 7.5.4.2.

Refer to Fire Protection Program Design Document (FPPDD) (Reference 6).

7.5.4.1 Functions With Local Control Provisions

If the control room should be evacuated suddenly without any action by the operators, the reactor can be tripped by either of the following:

- Open rod control breakers at the reactor trip switch gear, or
- Actuate the manual turbine trip on the turbine (above 50% power).

Following evacuation of the control room the following systems and equipment are provided to maintain the plant in a safe shutdown condition and have provisions to allow operation from outside the control room:

- Residual heat removal
- Reactivity control; i.e., boron injection to compensate for fission product decay
- Pressurizer pressure and level control
- Other equipment, as described
- Electrical system as required to supply the above systems

a. Residual Heat Removal

Following a normal plant shutdown the condenser steam dump control system dumps steam to the condenser and maintains the reactor coolant temperature at its no load value. Redundancy and full protection where necessary is built into the system to ensure the continued operation of the steam generator units. If the automatic condenser steam dump control system is not available, power operated relief valves (one on the each main steam line) maintain the steam pressure. These relief valves are further backed up by safety valves on each main steam line. Numerous calculations, verified by startup tests on the Connecticut-Yankee and San Onofre Power Plants have shown that with only the main steam line safety valves, the reactor coolant system maintains itself close to the nominal no load condition. For decay heat removal it is only necessary to maintain the control on one steam generator.

For the continued use of the steam generators for decay heat removal, it is necessary to provide a source of water, a means of delivering that water, and finally, instrumentation for pressure and level indication.

During shutdown the source of water for steam generator makeup is the condensate storage tank with additional water available from the service water system. Feedwater may be supplied to the steam generators by the auxiliary feedwater pumps (electrical and/or steam driven). These pumps and associated valves have local controls.

b. Reactivity Control

Following a plant shutdown to hot shutdown condition, soluble poison (boron) is added to the primary system to maintain subcriticality. The chemical and volume control system is used for adding boron to the reactor coolant system. Boration requires the use of:

> Charging pumps and volume control tank with associated piping. Boric acid transfer pumps with tanks and associated piping, letdown station, nonregenerative heat exchanger and associated equipment, component cooling system, and the service water systems.

With the reactor held at hot shutdown conditions, boration of the plant is not required immediately after shutdown. The xenon transient does not decay to the equilibrium level until 10 to 15 hours after shutdown. Also, additional time will elapse before the 1% reactivity shutdown margin provided by the control rods is reduced. This delay would provide ample time for emergency measures.

c. Pressurizer Pressure and Level Control

Following a reactor trip, the reactor coolant temperature will automatically reduce to the no load temperature condition as dictated by the steam generator temperature conditions. This reduction in the reactor coolant temperature reduces the water volume in the system and requires water makeup if continued pressure control is to be maintained.

Makeup water to control pressurizer level is supplied by the chemical and volume control system during normal operation. The equipment required for boration is described above; however, makeup water is only required for level control. The makeup water is obtained from the normal source, the volume control tank.

d. Operation of Other Equipment

Technical Specification 3.6.5 requires the air temperature inside containment to be kept below 120°F. For this reason the containment air recirculation fan coolers and service water pumps must be operated as required.

e. Electrical Systems

Offsite or onsite emergency power must be available to supply the above systems and equipment for the hot shutdown condition.

7.5.4.2 <u>Indication and Controls Provided Outside the Control Room</u>

The specific indication and controls provided outside the control room for the above capability are summarized as follows:

a. Indication

1. Level Indication for the Individual Steam Generators.
   - One set in the room containing the Turbine Driven Auxiliary Feedwater (TDAFW) and Standby Steam Generator (SSG) Feedwater Pumps.

2. Pressure Indication for the Individual Steam Generators.
   - In the room containing the TDAFW and SSG Feedwater Pumps.

3. Pressurizer Level and Pressure Indicators.
    - One set near the charging pump local control point.

4. Pressurizer Level Indication
    - In the room containing the TDAFW and SSG Feedwater Pumps.

5. Reactor Coolant System Hot and Cold Leg Temperatures
    - In the room containing the TDAFW and SSG Feedwater Pumps.

6. Source Range Reactor Power (Count Rate and Startup Rate)
    - Each near charging pump local control point.
    - Each in the room containing the TDAFW and SSG Feedwater Pumps.

b. Controls

Local stop/start pushbutton motor control stations are provided at each of the following motors. The motor control stations are provided with a selector switch that will transfer control of the switchgear from the control room to local motor control stations at the motor. Placing the local selector switch in the local operating position will initiate an annunciator alarm in the main control room and will extinguish the motor control position lights on the main control room panel. The control function circuitry for each Motor Driven Auxiliary Feedwater Pump flow recirculation valve is isolated when the pump is operated from the local control station. Automatic speed control to maintain pressurizer level is also not available for any charging pump in local control.

- Motor Driven Auxiliary Feedwater Pumps.
- Charging Pumps.
- Boric Acid Transfer Pumps.

Local control of the service water pumps and containment cooling accident fans may be performed by operating their normal 480 V feed breaker in the cable spreading room.

[redacted]

Alternative motor control locations are not required for the following:

Component Cooling Water Pumps: Normally in operation. On loss of off-site power, the emergency diesel generators will automatically restore power to the safeguards buses. This will allow the associated CC Pump to automatically restart unless the loss of power is coincident with a safety injection.

Instrument Air Compressors: Normally in operation. Backup to instrument air for some components is provided by nitrogen bottles or air accumulators as discussed in Section 9.7, Instrument Air (IA)/Service Air (SA). On loss of off-site power, the emergency diesel generators will automatically restore power to the safeguards buses. The compressors may be manually energized. The control point is in the control room.

1. Speed Control

   Speed controls are provided locally for:

   - The Turbine Driven Auxiliary Feedwater Pump
   - The Charging Pumps

2. Valve Control

   Valve controls are provided locally for:

   - Main Feedwater Control Valves.
   - Auxiliary Feedwater Control Valves (These valves are located local to the auxiliary feed pumps).
   - Atmospheric Relief Valves (Auto control normally at hot shutdown).
   - All other valves requiring operation during hot standby can be locally operated at the valve.
   - Letdown orifices isolation valves locally to the charging pumps. Local pushbuttons with selector switch and position lamp.

3. Pressurizer Heater Control

   Stop/start buttons controls located near the charging pumps are provided to control two 200 kW backup heater groups. The local control station is provided with a selector switch that will transfer control of the heaters from the main control room to the local control station.

c. Lighting

   Emergency lighting is provided in all operating areas as identified under Section 7.5.3.3.b.

d. Communications

   The communication network described in Section 7.5.2 provides communications between the area of the auxiliary feedwater pumps and the charging pumps, boric acid transfer pumps, diesel generators, and the outside exchange without requiring the control room.

7.5.5 REFERENCES

1. NRC Safety Evaluation dated November 29, 2002, "Issuance of Amendments Re: Measurement Uncertainty Recapture Power Uprate (TAC Nos. MB4956 and MB4957)."

2. NRC Safety Evaluation dated September 25, 1990, "Safety Evaluation by the Office of Nuclear Reactor Regulation Related to Generic Letter 83-28, Item 1.2 - Post-Trip Review Data and Information Capability, Wisconsin Electric Power Company Point Beach Nuclear Plant, Unit Nos. 1 and 2."

3. NRC Safety Evaluation, PBNP Units 1 and 2 - Issuance of License Amendments Regarding Extended Power Uprate, May 3, 2011.

4. NRC Safety Evaluation, “Point Beach Nuclear Plant Units 1 and 2-Issuance of License Amendments Re: Auxiliary Feedwater System Modification,” dated March 25, 2011.

5. Westinghouse WCAP-16983-P, Point Beach Units 1 and 2 Extended Power Uprate (EPU) Engineering Report, September 2009.

6. NFPA 805 Fire Protection Program Design Document (FPPDD).

Table 7.5-1 UNITS 1 AND 2 ASIP INSTRUMENTATION, CONTROLS, AND INDICATION

1. Reactor Vessel Head and Pressurizer Vent System Valves
2. RCS Hot Leg Temperatures (Loops A and B)
3. RCS Cold Leg Temperatures (Loops A and B)
4. RCS Wide-Range Pressure (Loops A and B)
5. Containment High-Range Radiation
6. Wide-Range Containment Pressure
7. Containment Hydrogen Concentration
8. RCS Gas Vent Header Pressure
9. Reactor Vessel Water Level (Wide and Narrow Range)
10. Containment Sump Level (Sumps A and B)
11. Subcooling Monitor (Loops A and B)
12. Instrument Bus Power Supply (common)
13. Containment Air Temperature (46 and 66' Elevations)
14. Containment Sump Temperature
15. Steam Generator Wide-Range Level (Steam Generators A and B)
16. Containment Wide-Range Pressure Recorders
17. Containment Air Sampling System Controls
18. Pressurizer Safety Valve Position Indicators
19. Core Exit Temperature (4 Thermocouples Per Core Quadrant)

Figure 7.5-1 MAIN CONTROL ROOM LAYOUT

[redacted]

7.6 INSTRUMENTATION SYSTEMS

The instrumentation systems described in this section monitor plant conditions, provide signals for protection and control, or provide control room indication of variables for plant operation. The instrumentation systems include:

- Nuclear Instrumentation
- Post-Accident Monitoring Instrumentation
- Incore Instrumentation
- Loose Parts Monitoring

7.6.1 NUCLEAR INSTRUMENTATION SYSTEM

The Nuclear Instrumentation (NI) system consists of two subsystems:

The original Westinghouse-supplied NI system consists of eight out-of-core neutron detectors providing three overlapping ranges (source, intermediate, and power) of neutron flux monitoring. Outputs from the system are used for reactor protection and control, as well as neutron flux indication during reactor startup, operation, and shutdown.

An additional wide-range out-of-core neutron flux detector was added after TMI to provide post-accident neutron flux monitoring capability, to meet the intent of Regulatory Guide 1.97. The wide-range detector is used only for monitoring, and does not provide any protection or control function.

7.6.1.1 Design Bases

The following PBNP General Design Criteria (GDC) described in Section 7.1.2 are applicable to the Nuclear Instrumentation (NI) System:

Criterion 12 Instrumentation and Control Systems
Criterion 13 Fission Process Monitors and Controls

For those portions of the Nuclear Instrumentation System associated with the Reactor Protection System, the design is also required to comply with IEEE 279-1968. In addition, the wide-range detector is required to meet the intent of Regulatory Guide 1.97 design criteria for Type B Category 2 post-accident monitoring instrumentation.

7.6.1.2 System Design

a. Original Westinghouse-supplied NI System

A block diagram of the original NI system is shown in Figure 7.6-1. The system consists of eight neutron flux monitoring channels divided into three overlapping ranges: two source range channels, two intermediate range channels, and four power range channels. The three ranges combine to provide a continuous, overlapping measurement of approximately eleven decades of reactor power, from a completely shutdown condition to 120% of full power. The power range channels are capable of recording overpower excursions up to 200% of full power. The relationship and approximate overlap between the three monitoring ranges is shown in Figure 7.6-2.

The source, intermediate, and power range channels provide control room indication and recording of reactor neutron flux during core loading, shutdown, startup, and power operation. Reactor trip and rod stop control and alarm signals are provided by this system for safe plant operation. Control and permissive signals are transmitted to the reactor control systems and reactor protection system for automatic plant control. Information on equipment failures and test status is annunciated in the control room.

Source Range Channels

Two independent source range channels are provided covering the lowest six decades of leakage neutron flux. Each channel receives pulse-type signals from a proportional counter. The preamplified detector signal is received by the source range instrumentation conditioning equipment located in control room racks. The detector signal, which is a random count rate proportional to leakage neutron flux, is converted to an analog signal proportional to the logarithm of the neutron flux count rate.

Isolated analog signals from each channel are sent to recording and indicating devices to provide the operator with necessary startup information. Startup rate indication is also provided for each source range channel on the main control board. Bistable units located in the racks generate alarms and reactor trip signals if limits are exceeded during reactor startup. Trip signals from the bistables are transmitted to relays in the reactor protection relay racks, where the necessary reactor trip logic is performed. Section 7.2.2.2 describes the source range reactor trip function and source range block function once source range protection and indication is no longer needed during reactor startup.

An isolated count rate signal derived from either source range channel is connected to a scaler-timer. The scaler-timer feeds an audio count rate channel that provides an audible count rate signal proportional to the neutron flux. Speakers are provided both in the containment and in the control room.

Intermediate Range Channels

Two independent compensated ionization chambers provide eight decades of flux coverage from the upper end of the source range to approximately 100% power. The equipment for each channel, including the high voltage and compensating voltage power supplies, is located in a separate drawer. To maintain separation between these redundant channels, the drawers are mounted in separate racks. The signal conditioning equipment furnishes an analog output voltage proportional to the logarithm of the neutron flux. Isolation amplifiers (for startup rate circuits, remote recording, remote indication, etc.) and bistables (for permissives, rod stop and reactor trip) use this analog voltage to indicate plant status and provide the necessary plant control and protection functions. Startup rate indication is also provided for each intermediate range channel on the main control board.

Bistable units located in the intermediate range channels generate alarms and reactor trip signals during reactor startup. Trip signals from the bistables are transmitted to relays in the reactor protection relay racks, where the necessary reactor trip logic is performed. Section 7.2.2.2 describes the intermediate range reactor trip function and intermediate range block function, once intermediate range protection is no longer needed during reactor startup.

Power Range Channels

Four independent, dual-section, uncompensated ionization chambers monitor slightly more than two decades of power range flux leakage. One section of each chamber monitors lower core flux and the other section monitors upper core flux. Each chamber provides two current signal outputs (one from each section) to signal conditioning equipment in the control room racks. Each chamber has an independent high voltage power supply. The individual current signals obtained from each section of the detector are proportional to upper core and lower core neutron flux, respectively. These signals provide core flux status information locally at the instrument racks and remotely, through isolation amplifiers, at the control console. A separate output furnishes bias signals used in the overtemperature ΔT reactor trip function. The individual current signals are combined to provide an average signal proportional to average core flux in the associated core quadrant. This average signal is conditioned to provide an analog voltage signal for use in permissive, control, and protection bistables.

The average power analog signal also provides isolated control signals and core power status information to the operator and computer. The four power range channels are powered from separate vital 120 VAC instrument buses and are housed in separate racks so that a single failure will not affect more than one channel nor cause loss of protection functions.

Isolated analog outputs from each power range channel are compared in a separate auxiliary channel drawer. This comparator provides the operator with annunciation of deviations in average power between the four power range channels. Switches are provided to defeat this comparison for a failed channel, so that subsequent deviations or failures among the three remaining channels are annunciated.

Bistable units located in the four power range channels generate alarms and reactor trip signals during reactor power operation. Trip signals from the bistables are transmitted to relays in the reactor protection relay racks, where the necessary reactor trip logic is performed. Section 7.2.2.2 describes the reactor trip functions which rely on power range channels, including the trip functions for overtemperature ΔT.

If a power range channel failure occurs, switches are provided to permit the failed power range channel's overpower rod stop function to be bypassed, and its average power signal to the reactor control system to be replaced by a signal derived from an active channel. This allows normal power operation to continue while the failed channel is repaired.

Neutron Detector Locations

The neutron detectors for each of the three measurement ranges are mounted in the primary shield wall external to the reactor vessel. The detector locations relative to the reactor core are shown on Figure 7.6-3. The eight detectors are located in six radial locations peripheral to the vessel (two proportional counters shared with two compensated ionization chambers, and four dual-section uncompensated ionization chamber assemblies). Windows in the primary shield wall facing the reactor vessel minimize leakage flux attenuation and distortion.

The two source range proportional counters are located 180 degrees apart on opposite "flat" sections of the reactor core. The source range detectors have a nominal thermal neutron sensitivity of 10 counts per neutron per square centimeter per second, and provide pulse signals to the source range channels. The source range detectors are installed at an elevation approximating the lower quarter core height.

Two intermediate range compensated ionization chambers are installed above the source range detectors in the same detector wells. The intermediate range detectors have a nominal thermal neutron sensitivity of 4×10^{-14} amperes per neutron per square centimeter per second. Gamma sensitivity is less than 3×10^{-11} amperes per Roentgen per hour when operated uncompensated, and is reduced to approximately 3×10^{-13} amperes/R/hr in compensated operation. The detectors are positioned at an elevation approximating the core center height.

The shared detector assemblies each contain one source range and one intermediate range detector. High-density polyethylene, used as a moderator-insulator within the detector assemblies, will be confined at temperatures associated with a loss-of-coolant accident. The detectors are connected to the junction box at the top of the detector well by special high temperature, radiation resistant cables.

The four dual-section power range detector assemblies are mounted at 90 degree intervals around the core, approximately 45 degrees from the two source/intermediate range detector locations, as shown in Figure 7.6-3. These detectors have a total neutron sensitive length of ten feet and a nominal thermal neutron sensitivity for each section of 1.7×10^{-13} amperes per neutron per square centimeter per second. Gamma sensitivity of each section is approximately 10^{-10} amperes per Roentgen per hour. The detectors are located within one foot of the reactor vessel to minimize neutron flux pattern distortions. Signal cables from power range detector wells to the containment penetrations and to the instrument racks in the control room are routed in individual conduits, with physical separation between the penetrations and conduits associated with redundant reactor protection channels.

Protection Philosophy

Redundant channels of the three nuclear instrumentation ranges each support the reactor protection system, as described in Section 7.2. Separation of redundant NI channels in each range is maintained from the neutron sensor to the signal conditioning equipment in the control room and to isolated output devices.

Reactor trips supported by the nuclear instrumentation include source range high level, intermediate range high level, power range high level (low setting), and power range high level (high setting). In addition, the power range channels provide flux difference signals to the overtemperature ΔT trip.

During reactor startup, the source range, intermediate range, and power range (low setting) reactor trips provide low power core protection until reactor power increases sufficiently to allow these trips to be manually bypassed (blocked). Blocking of these low power trips is necessary for full power operation. Two permissive circuits, P-6 and P-10, are used to allow manual blocking of the source range reactor trip (on P-6) and the intermediate and power range (low setting) reactor trips (on P-10). The reactor protection provided by the power range high flux (high setting) trip is never blocked or bypassed.

A P-6 permissive signal would occur during startup when one-of-two intermediate range channels increase above the P-6 setpoint. Above the P-6 setpoint, the operator depresses the manual block switches associated with the source range reactor trip logic circuitry, causing source range detector voltage cutoff and blocking the source range reactor trip function. The P-6 permissive status is continuously displayed by control board status lights.

As power continues to increase during startup, a P-10 permissive signal would occur when two-of-four power range channels exceed approximately 10% of full power. The operator would be alerted to this condition by a control board P-10 permissive status light. Indicators (one per power range channel) and a recorder also provide percent full power indication. If the operator does not initiate manual blocking of the intermediate range trip at this point and continues power escalation, a rod stop will automatically occur from either of the intermediate range channels. Depressing the manual block switches for the intermediate range block above P-10 will block the intermediate range rod stop and the intermediate range reactor trip function. Similarly, depressing the manual block switches for the power range block above P-10 will block the power range (low setting) reactor trip function. If the source range reactor trip was not manually blocked at P-6, the P-10 permissive will also automatically block the source range trip and initiate source range detector voltage cutoff. Blocking of any reactor trip function is indicated by control board status lights.

Automatic removal of the above reactor trip blocks when they are no longer needed is a protection system requirement of IEEE 279. Automatic trip block removal on decreasing power level is discussed under the system evaluation in Section 7.6.1.3.

Where redundant protective channels are combined to provide non-protection functions, the required signals are derived through isolation amplifiers. These amplifiers are designed so that open or short circuit conditions, as well as the application of 120 VAC or 125 VDC, to the isolated side of the circuit will have no effect on the input or protection side of the circuit. As such, failures on the non-protection side will not affect the individual protection channels. Redundant channels are powered from independent power sources, each channel being provided with the necessary power supplies for its detectors, signal conditioning equipment, trip bistables and associated trip relays. The nuclear instrumentation channels are mounted in four separate racks to provide the necessary physical separation between redundant channels.

Testing and Calibration Features

On-line testing and calibration features are provided for each NI channel. The test signals are superimposed on the normal sensor signal during plant operation. This permits valid trip conditions to override the test signal since the sensing elements are never removed from the circuit.

Source and intermediate range channels which provide reactor protection through one-of-two coincidence logic matrices are equipped with positive detent type trip bypass switches to enable a channel to be tested without initiating a reactor trip. The trip-bypass condition for individual channels is indicated at the control board and at the nuclear instrumentation racks.

A test-calibrate module is included in each source range drawer for self-checking of that particular channel. A multi-position switch on the source range drawer front panel controls this module and also the operation of the built-in test oscillator circuits in the source range pre-amplifiers (one per channel), located just outside of containment in the pipeways. The module is capable of injecting test signals of either 60, 10^3, 10^5 and 10^6 cps (counts per second) at the input to the drawer post amplifier, or a variable DC voltage corresponding to 1 to 10^6 cps at the input to the source range pre-amplifier.

An interlock between the trip bypass switch and the source range test-calibrate switch prevents inadvertent actuation of the reactor trip circuits, (i.e., the channel cannot be put in the test mode unless the trip is defeated). Trip bypass is annunciated on the source range drawer and on the main control board per IEEE 279 Section 4.13. Operation of the test-calibrate module is annunciated on the control board as "NIS Channel Test." This common annunciator for all NI channels is alarmed when any channel is placed in the test position, and alerts the operator that a test is being performed at the NI racks.

A built-in test-calibrate module that injects a test signal at the input to the log amplifier provides administrative testing of each intermediate range channel. The signal is controlled by a multiposition switch on the front of each intermediate range drawer. A fixed 10^{-11} ampere signal is available along with a variable 10^{-10} through 10^{-3} signal, selectable in one decade increments.

As in source range testing, the test switch on the intermediate range must be operated in coincidence with a trip bypass on the drawer. An interlock between these switches prevents injection of a test signal, until the trip bypass is in operation. Removal of the trip bypass also removes the test signal. The test-calibrate module provided on each power range is capable of injecting test signals at several points in the channel. In all cases, the test signals are superimposed on the normal signal. The bypass switch from each power range channel activates a common annunciator, "NIS Rod Drop Bypass," but individual bypass status lights identify the particular channel in test. The bistables for the remaining channels not under test do not require bypasses, since the power range reactor trips operate on two-out-of-four coincidence logic. Test signals can be injected independently or simultaneously at the input of either ammeter-shunt assembly to appear as the individual ion chamber currents. Operation of the test-calibrate switch on any power range channel causes the common "Channel Test" annunciator to be alarmed on the main control board.

b. Wide-range Neutron Detector

In addition to the NI system described above, an additional wide-range neutron detector manufactured by Gamma-Metrics was added to each unit after TMI for post-accident monitoring of core neutron flux. The new detector was necessary because the original Westinghouse-supplied NI detectors were not qualified for containment post-accident harsh environment conditions. The Wide Range Neutron Detectors (N-40) may be used to provide visual neutron indication in conjunction with N-31 or N-32 while core geometry changes are in progress.

The location of the wide-range detector relative to the reactor core is shown in Figure 7.6-3. The detector is mounted in its own well in the primary shield wall, 90 degrees from the opposing source/intermediate range detector wells.

The approximate detector range is shown on Figure 7.6-2. The dual fission chamber detector provides neutron flux measurements up to 100% power over twelve decades using two overlapping ranges (source range and percent log power). Each fission chamber is an ion chamber consisting of two uranium-coated aluminum electrodes, insulators, and fill gas. The fission chambers have a sensitive length greater than 40 inches and provide a neutron sensitivity of 2.0 cps/nv or greater.

Equipment for the wide-range channel includes the detector assembly and in-containment cable assembly, an amplifier cable assembly (from containment penetration to pre-amplifier), a pre-amplifier, a signal processor, and an output expansion module. The detector and cable assemblies are environmentally qualified for operation in a harsh containment environment. All electrical equipment is seismically supported. The channel is designed to operate under normal conditions and to survive a loss-of-coolant accident, providing reliable flux measurement before, during, and after an accident. The qualification of this equipment (detector and cable assemblies only) will be maintained during the period of extended operation by the EQ Program. (NRC SE dated 12/2005, NUREG-1839)

[redacted] The pre-amplifier panel houses the power supplies and electronics which condition the detector signal for transmission to the signal processor panel. Signal conditioning includes amplification, pulse shaping, and discrimination against alpha, gamma and electronic noise. Circuitry in the pre-amplifier panel provides continuous self-diagnostics of the integrity of the detector, cables, and power supplies. The signal processor converts the signal from the pre-amplifier into signals that represent the source range count rate, the reactor power level, and the rate-of-change of the reactor power level. The output expansion module provides electrical isolation of output signals from the signal processor.

The wide-range channel function is indication only, and does not provide input to the reactor control or protection systems. The wide-range channel provides indication on the main control board and at four local safe-shutdown panels (two per unit), and also provides inputs to the plant process computer. Indicators provided on the main control board include source range count rate, source range start-up rate, wide range start-up rate, and wide range percent log power. Indicators provided on local safe-shutdown panels include source range count rate and source range start-up rate.

The wide-range channel is powered from the blue instrument bus supply. An alternate supply independent from the normal supply is provided via station batteries and a local inverter.

The wide range detection channel is environmentally qualified for operation in a harsh environment (detector and cable assemblies only). All electrical equipment is seismically supported. The system is designed to operate under normal conditions and to survive a loss-of-coolant accident (LOCA) environment, providing reliable measurement before, during, and after the LOCA. The qualification of this equipment (detector and cable assemblies only) will be maintained during the period of extended operation by the EQ Program. (NRC SE dated 12/2005, NUREG-1839)

7.6.1.3 System Evaluation

a. Conformance to IEEE 279-1968

Protection Philosophy

During plant shutdown and operation, three discrete independent levels of nuclear protection are provided from the three ranges of out-of-core nuclear instrumentation. The basic protection philosophy is that the three ranges each provide reliable, rapid, and restrictive level-trip protection (as opposed to startup rate protection) which is not dependent upon operation of higher range instrumentation.

Reliability is obtained by providing redundant channels which are physically and electrically separated. Fast trip response is an inherent advantage of using level-trip protection in lieu of startup rate protection (with a long time constant) during plant startup. More restrictive operation is an inherent feature, since an increase in plant power cannot be performed until satisfactory operation is obtained from higher range instrumentation, which permits administrative bypass of the lower range instrumentation. On decreasing power level, protection is automatically made more restrictive. Startup accidents while in the source range are rapidly terminated without significant increases in neutron flux and with essentially no power generation or reactor coolant temperature increase.

The indications and administrative actions required by this protection system during reactor startup are readily available to the operator and result in safe, uncomplicated power escalation.

Reactor Trip Block Removal

IEEE 279 Section 4.12 requires that operating bypasses of protective actions must be automatically restored when the conditions requiring the bypass no longer exist. When reactor power drops to the level that the reactor trip blocks manually installed for the source, intermediate, and power range (low setting) trips are no longer necessary, the reactor trips are automatically restored. The intermediate range and power range (low setting) trips are restored on decreasing power when three of four power range channels are below the P-10 permissive setpoint. The source range trip is restored when two of two intermediate range channels are below the P-6 permissive. The P-6 and P-10 permissive circuitry associated with administrative blocking of reactor trips and the automatic reactivation of the trips on decreasing power is designed to the same separation and redundancy criteria as the reactor trip functions.

b. Rod-Drop Indication

The nuclear instrumentation rod drop indication is provided by comparison of the average nuclear power signal with the same signal which is conditioned by an adjustable lag network. This method provides a response to dynamic signal changes associated with a dropped rod condition, but does not respond to the slower signal changes associated with normal plant operation. A power range rod drop alarm from at least one of the four power range channels will occur for any dropped rod condition.

c. Control and Alarm Functions

Various control and alarm functions are obtained from the three ranges of out-of-core nuclear instrumentation during shutdown, startup and power operation. These functions are used to alert the operator of conditions which require administrative action and alert personnel of unsafe reactor conditions. They also provide signals to the rod control system for automatic blocking of rod withdrawal during plant operation to avoid unnecessary reactor trips.

1. Source Range

No control functions are obtained from the source range channels. Alarm functions are provided, however, to alert the operator of any inadvertent changes in shutdown reactivity. Visual annunciation of this condition is at the control board, with audible annunciation performed in the containment and control room. This alarm can either be blocked prior to startup or can serve as the startup alarm in conjunction with administrative procedures.

2. Intermediate Range

Both alarm and control functions are supplied by the intermediate range channels. Blocking of rod withdrawal is initiated by either intermediate range on high flux level. This condition is alarmed at the control board to alert the operator that rod stop has been initiated. In addition, the intermediate ranges provide an alarm when either channel exceeds permissive P-6 level. This alerts the operator to the fact that he must take administrative action to manually block the source range trips to prevent an inadvertent trip during normal power increase.

3. Power Range

The power range channels provide alarm and control functions similar to those in the intermediate ranges. An overpower rod stop function from any of the four power range channels blocks rod withdrawal and is alarmed at the control board. The power ranges also provide an alarm function when 2 of 4 channels exceed the P-10 permissive level. As in the case of P-6 in the intermediate range, this alerts the operating personnel that administrative action (namely, blocking of intermediate and power range (low setting) trips) is required before any further power increase may take place.

The power range channels also support two additional permissive functions. The P-8 and P 9 permissives bypass certain reactor trips at low power levels based on plant conditions that include 3 of 4 power range channels less than approximately 35% for P-8 and 50% (35% if Tavg < 572°F) for P-9. A permissive status light is provided for P-8, "Nuclear Power Below P-8". The extinguishing of the P-8 permissive status light alerts the operator that certain reactor trips on low loop flow and open RCP breakers are now active. These trips are blocked at low power while the status light is on.

d. Loss of Power

The nuclear instrumentation draws its primary power from the vital instrument buses whose reliability is discussed in Section 8.0. Redundant NI channels are powered from separate buses.

Loss of a single vital instrument bus would result in the initiation of reactor trips signals associated with the channel deriving power from that source. During power operation, the loss of a single bus would not result in a reactor trip since the source and intermediate range trips are bypassed and the power range high flux reactor trip function operates from a 2 of 4 logic. If the bus failure occurred during low power operation while the source or intermediate range trips (1 of 2 logic) are in effect, a reactor trip would result.

e. Power Range Channel Accuracy

The relation of the power range channels to the Reactor Protective System has been described in Section 7.2. To maintain the desired accuracy in trip action, the total error from drift in the power range channels is held to ±1.0% at full power. Routine tests and recalibration ensure that this degree of deviation is not exceeded. Bistable trip set points of the power range channels are also held to an accuracy of ±1.0% of full power.

7.6.2 POST-ACCIDENT MONITORING INSTRUMENTATION

7.6.2.1 Design Basis

The General Design Criterion (GDC) applicable to the post-accident monitoring instrumentation is Criterion 12, Instrumentation and Control Systems, described in Section 7.1.2.

In addition to GDC 12, the post accident monitoring instrumentation is also required to meet the intent of Regulatory Guide 1.97, Rev. 2, “Instrumentation to Assess Plant and Environs Conditions during and following an Accident.”

7.6.2.2 System Design

Consistent with Regulatory Guide 1.97, the post-accident monitoring instrumentation is grouped into five types related to the importance of the information to the operator, as follows:

TYPE A variables are those variables that provide the primary information required to permit the control room operator to take specific manually controlled actions for which no automatic control is provided and that are required for safety systems to accomplish their safety functions for design basis accident events.

TYPE B variables are those variables that provide information to indicate whether plant safety functions are being accomplished.

TYPE C variables are those variables that provide information to indicate the potential for being breached or the actual breach of the barriers to fission product releases.

TYPE D variables are those variables that provide information to indicate the operation of individual safety systems and other systems important to safety.

TYPE E variables are those variables to be monitored as required for use in determining the magnitude of the release of radioactive materials and continually assessing such releases.

The post-accident monitoring instrumentation is also separated into three qualification categories, depending on the importance of the variable:

Category 1 provides the most stringent requirements and is intended for key variables. Full qualification, redundancy and continuous real-time display are provided and battery-backed (standby) power is required.

Category 2 provides less stringent requirements and generally applies to instrumentation designated for indicating system operating status. This category provides for qualification, although it is less stringent than Category 1. Category 2 may require seismic qualification if the instrumentation is part of a safety related system; redundancy; or continuous display. A high reliability power source (not necessarily standby power) is also required.

Category 3 is intended to provide requirements that will ensure that high-quality off-the-shelf instrumentation is obtained and applies to backup and diagnostic instrumentation. It is also used where the state of the art will not support requirements for higher qualified instrumentation.

Refer to Table 7.6-1 for a complete listing of post-accident monitoring instrumentation variables and their associated type and category.

7.6.2.3 System Evaluation

The post-accident monitoring instrumentation meets the intent of Regulatory Guide 1.97, Rev. 2. The original response to Generic Letter 82-33 on RG 1.97 implementation dated 9/1/83 identified specific exceptions taken to the regulatory guidance, including the justification for those exceptions. Table 7.6-1 reflects the current list of post-accident monitoring variables that meet the commitments made in the GL 82-33 response.

7.6.3 INCORE INSTRUMENTATION

7.6.3.1 Design Basis

The in-core instrumentation is designed to yield information on the neutron flux distribution and fuel assembly outlet temperatures at selected core locations. Using the information obtained from the in-core instrumentation system, it is possible to confirm the reactor core design parameters and calculated hot channel factors. The system provides means for acquiring data and performs no operational plant control.

7.6.3.2 System Design

The in-core instrumentation system consists of thermocouples, positioned to measure fuel assembly coolant outlet temperature at preselected locations, and flux thimbles, which run the length of selected fuel assemblies to measure the neutron flux distribution within the reactor core.

The measured data obtained from the in-core temperature and flux distribution instrumentation system, in conjunction with previously determined analytical information, can be used to determine the fission power distribution in the core at any time throughout core life. This method is more accurate than using calculational techniques alone. Once the fission power distribution has been established, the maximum power output is primarily determined by thermal power distribution and the thermal and hydraulic limitations determine the maximum core capability.

The in-core instrumentation provides information which may be used to calculate the coolant enthalpy distribution, the fuel burnup distribution, and an estimate of the coolant flow distribution.

Both radial and azimuthal symmetry of power may be evaluated by combining the detector and thermocouple information from the one quadrant with similar data obtained from the other three quadrants.

a. Thermocouples

Chromel-alumel thermocouples are threaded into guide tubes that penetrate the reactor vessel head through seal assemblies, and terminate at the exit flow end of the fuel assemblies. The pressure boundary between the reactor vessel head seal assembly and the thermocouple column is formed by the compression of grafoil packing rings. (See Figure 7.6-4) The thermocouples are enclosed in stainless steel sheaths within the above tubes to allow replacement if necessary. Outputs from 16 thermocouples per unit (4 per core quadrant) are displayed on direct indicating devices on the ASIP Panels. Core exit thermocouples are provided as inputs to the plant computer system. The computer provides display and recording functions. The support of the thermocouple guide tubes in the upper core support assembly is described in Section 3.0.

There are 39 thermocouple locations per reactor, however some thermocouples are no longer operable. Due to reactor coolant leaks that have occurred in some thermocouple sheaths, several thermocouples in each reactor have been cut or removed and permanent caps or plugs installed to seal the thermocouple assembly.

b. Movable Miniature Neutron Flux Detectors

Four fission chamber detectors (employing U_30_8 which is 93% enriched in U_{235}) can be remotely positioned in retractable guide thimbles to provide flux mapping of the core. Approximate chamber dimensions are 0.188 in. in diameter and 2.10 inches in length. The stainless steel detector shell is welded to the leading end of the helical wrap drive cable and the stainless steel sheathed coaxial cable. Each detector is designed to have a minimum thermal neutron sensitivity of 1.0×10^{-17} amps/nv and a maximum gamma sensitivity of 3×10^{-14} amps/R/hr. Operating thermal neutron flux range for these probes is 1×10^{11} to 5×10^{15} nv. Other miniature detectors, such as gamma ionization chambers and boron-lined neutron detectors, can also be used in the system. Retractable thimbles into which the miniature detectors are driven are pushed into the reactor core through conduits which extend from the bottom of the reactor vessel down through the concrete shield area and then up to a thimble seal zone.

The thimbles, which are dry inside, are closed at the leading ends and serve as the pressure barrier between the reactor water pressure and the atmosphere. Mechanical seals between the retractable thimbles and the conduits are provided at the seal line.

During reactor operation, the retractable thimbles are stationary. They are extracted downward from the core during refueling to avoid interference within the core during fuel movement. A space above the seal line is provided for the retraction operation.

The drive system for the insertion of the miniature detectors consists basically of four drive assemblies, four path group selector assemblies and four rotary selector assemblies. The drive system pushes hollow helical-wrap drive cables into the core with the miniature detectors attached to the leading ends of the cables and small diameter sheathed coaxial cables threaded through the hollow centers back to the trailing ends of the drive cables. Each drive assembly generally consists of a gear motor which pushes a helical-wrap drive cable and detector through a selective thimble path by means of a special drive box and includes a storage device that accommodates the total drive cable length. Further information on mechanical design and support is described in Section 3.0.

c. Control and Readout Description

The control and readout system provides means for inserting the miniature neutron detectors into the reactor core and withdrawing the detectors at a selected speed while plotting a level of induced radioactivity versus detector position. Each detector can be driven in or out at speeds of 72 feet per minute or 12 feet per minute outside the reactor core and 12 feet per minute when scanning the neutron flux. The average path length external to the core is 120 feet.

Four separate fuel assemblies can be scanned simultaneously. A full core map is read in approximately 2 hours. The control system consists of two sections, one physically mounted with the drive units, and the other contained in the control room. Limit switches in each drive conduit provide means for pre-recording detector and cable positioning in preparation for a flux mapping operation. Each gear box drives an encoder for positional data plotting. One group path selector is provided for each drive unit to route the detector into one of the flux thimble groups. A rotary transfer assembly is a transfer device that is used to route a detector into any one of up to ten selectable paths. Ten manually operated isolation valves allow free passage of the detector and drive wire when open, and prevents leakage of coolant in case of a thimble rupture, when closed. A path common to each group of flux thimbles is provided to permit cross calibration of the detectors.

The control room contains the necessary equipment for control, position indication, and flux recording. Panels are provided to indicate the core position of the detectors, and for plotting the flux level versus the detector position. Additional panels are provided for such features as drive motor controls, core path selector switches, plotting and gain controls. A “flux-mapping” consists, briefly, of selecting (by panel switches) flux thimbles in given fuel assemblies at various core quadrant locations. The detectors are driven or inserted to the top of the core and stopped automatically. An x-y plot (position vs. flux level) is initiated with the slow withdrawal of the detectors through the core from top to a point below the bottom. In a similar manner other core locations are selected and plotted.

Each detector provides axial flux distribution data along the center of a fuel assembly. Various radial positions of detectors are then compared to obtain a flux map for a region of the core.

7.6.3.3 System Evaluation

The thimbles are distributed nearly uniformly over the core with about the same number of thimbles in each quadrant. The number and location of thimbles have been chosen to permit measurement of hot channel factors with uncertainty of less than 5% for the Heat Flux Hot

Channel Factor and less than 4% for the Enthalpy Rise Hot Channel Factor (95% confidence). Measured nuclear peaking factors will be increased as described in the Technical Specifications Bases to allow for possible instrument error. The DNB ratio calculated with the measured hot channel factor will be compared to the DNB ratio calculated from the design nuclear hot channel factors. If the measured power peaking is larger than expected, power capability will be reduced.

7.6.4 LOOSE PARTS MONITORING

7.6.4.1 Design Basis

The loose parts monitoring system (LPMS) is designed to provide reliable detection of loose metallic debris impacting within the reactor coolant system (RCS).

Metallic impacts within the RCS generate a pressure wave within the coolant. The pressure wave is detected as an acceleration by strategically placed accelerometers that are part of the LPMS. Other sources of pressure waves, such as pumps starting and control rods stepping, are also present in the RCS. The LPMS differentiates between pressure waves caused by metallic impacts and other pressure waves by comparing the detected acceleration to a typical signature of a metallic impact. Pressure-wave-caused accelerations that are not caused by metallic impacts are ignored. Detected metallic impacts initiate an alarm indication and are recorded on the systems event recorder.

7.6.4.2 System Design

The LPMS consists of specially designed high sensitivity transducers at the natural collection points of the RCS, preamplifiers, connection panel, data input boards, data acquisition computer, video monitor, keyboard/mouse, and audio/alarm board. A block diagram of the system is shown in Figure 7.6-5.

Metallic impacts within the RCS cause a small electrical charge proportional to acceleration to be generated by piezoceramic accelerometers. The charge is transmitted by noise-resistant cable to the charge preamplifier inside containment where it is converted to a voltage signal. The voltage signal is transmitted by normal shielded instrumentation cable to the data acquisition system for processing in the LPMS cabinet located in the computer room and recorded by the data acquisition computer. Historical information can be downloaded for records storage and to remove the records from the LPMS computer.

a. Accelerometer Locations

The LPMS has the capability to monitor 16 channels constantly. Two accelerometers per unit are mounted to the transition sleeves of the flux thimble guide tubes at the reactor vessel bottom. Each steam generator has three accelerometers mounted directly to the shell on the hot leg side: one just above the tubesheet, one on the same elevation as the tubesheet, and one just below the tubesheet.

b. System Electronics Cabinet

Signals from the in-containment preamplifiers are carried through containment penetrations to the system electronics cabinet. The cabinet includes a connection panel, data input boards, data acquisition computer, video monitor, keyboard/mouse, and audio/alarm board.

One input channel is provided for each charge preamplifier. The input channel provides energizing current for the preamplifier, filters the preamplifier output to remove high-frequency noise and signals outside the range of interest, and scales the received accelerometer signal. The scaled and filtered acceleration signal from the input channel is transferred to the computer.

The heart of the system is a central processor unit (CPU). The acceleration signal from one of the channels is selected under CPU control. The frequency and relative amplitude are made available to the microprocessor, which inspects the signal for the characteristics of a metal impact. If it is determined that the accelerometer signal represents a metal impact, the microprocessor communicates this to the audio/alarm board.

c. Displays

In the central cabinet, a monitor (operator interface) displays system operating parameters and the results of automated data analysis. On the events reports displays, essential information needed for fast evaluation of metal impacts is continuously updated and provided automatically to the operator for multiple events, single events, or historical events. Key parameters and setpoints as well as current background noise levels are available on the systems status display. Printouts of each display are available on demand.

The Auxiliary Safety Instrument Panel (ASIP) 1C20 Annunciator Window, which is located in the control room, contains remote alarm indication.

7.6.4.3 System Evaluation

The LPMS provides early detection of loose metallic parts in the primary system. Early detection can provide the time required to avoid or minimize damage to primary system components (e.g., the steam generator tubesheets). The LPMS can also minimize radiation exposure to station personnel by providing for the early detection and general location of abnormal structural conditions within the RCS or S/G secondary side.

The initial system calibration has provided a set of “signatures” from various sized weights striking the surface of the reactor and steam generator vessels near the accelerometers. By analyzing the information from the hard drive and comparing this to the signatures, the approximate mass of the object may be determined. The arrangement of the accelerometers on the steam generators has the additional benefit of providing the approximate location of the loose part. Through the use of triangulation and timing data from recorded metal impact signatures, an approximate location and size of the source can be determined.

Table 7.6-1 POST-ACCIDENT MONITORING VARIABLES

Sheet 1 of 5

POST-ACCIDENT MONITORING VARIABLE	Type and Category	Instrument Description (See Note 1)
Refueling Water Storage Tank Level	A, 1	1(2)-LT-972, 1(2)-LT-973
RCS Pressure (wide-range)	A, 1	1(2)-PT-420A, 1(2)-PT-420B, 1(2)-PT-420C
Containment Pressure (low and intermediate range)	A, 1	1(2)-PT-945. 1(2)-PT-947, 1(2)-PT-949 1(2)-PT-946, 1(2)-PT-948, 1(2)-PT-950
Condensate Storage Tank Level	A, 1	LT-4038, LT-4040 LT-4039, LT-4041
Steam Generator Water Level (narrow-range)	A, 1	1(2)-LT-461, 1(2)-LT-462, 1(2)-LT-463 1(2)-LT-471, 1(2)-LT-472, 1(2)-LT-473
Auxiliary Feedwater Flow to Steam Generators	A, 2	1(2)-FT-4036, 1(2)-FT-4037
Core Exit Temperature	A, 1	1(2)-TR-1A(B) and associated core exit thermocouples
Degrees of Reactor Coolant Subcooling	A, 1	1(2)-TM-970, 1(2)-TM-971, 1(2)-PT-420 A&B, TE-450D & 451D and associated core exit thermocouples
Steam Generator Pressure	A, 1	1(2)-PT-468, 1(2)-PT-469, 1(2)-PT-478, 1(2)-PT-479, 1(2)-PT-482, 1(2)-PT-483
Pressurizer Water Level	A, 1	1(2)-LT-426, 1(2)-LT-427, 1(2)-LT-428
Neutron Flux	B, 2 & 3	1(2)-N-40, 1(2)-N-31 & 32, 1(2)-N-35 & 36
Control Rod Position	B, 3	1(2)-RPI-XY, where XY=Core Position Coordinates
Core Exit Temperature	B, 3	1(2)-TE-1 through 1(2)-TE-39
RCS Soluble Boron Concentration	B, 3	Grab Sample Analysis
RCS Cold Leg Water Temperature	B, 1	1(2)-TE-450A, 1(2)-TE-450C, 1(2)-TE-451A, 1(2)-TE-451C
RCS Hot Leg Water Temperature	B, 1	1(2)-TE-450B, 1(2)-TE-450D, 1(2)-TE-451B, 1(2)-TE-451D
RCS Pressure (narrow-range)	B, 1	1(2)-PT-429, 1(2)-PT-430, 1(2)-PT-431, 1(2)-PT-449
Reactor Vessel Water Level	B, 1	1(2)-LT-494, 1(2)-LT-495 1(2)-LT-496, 1(2)-LT-497
Containment Sump Water Level	B, 1 & 2	1(2)-LT-958, 1(2)-LT-959 1(2)-LT-960, 1(2)-LT-961
Containment Isolation Valve Position (for valves that receive an automatic containment isolation signal)	B, 1	Valves Identified in FSAR Section 5.2

Table 7.6-1 POST-ACCIDENT MONITORING VARIABLES

Sheet 2 of 5

Containment Pressure (wide-range)	B, 1	1(2)-PT-968, 1(2)-PT-969
Radioactivity Concentration in Circulating Primary Coolant	C, 1	Grab Sample Analysis
Analysis of Primary Coolant (Gamma Spectrum for Isotopic Analysis)	C, 3	Grab Sample Analysis
Containment Area Radiation (high range)	C, 1	1(2)-RE-126, 1(2)-RE-127, 1(2)-RE-128
Containment Area Radiation	C, 3	1(2)-RE-102, 1(2)-RE-107
Effluent Radioactivity-Noble Gas Effluent from Condenser Air Removal System Exhaust	C, 3	1(2)-RE-215, RE-225
Core Exit Temperature	C, 1	1(2)-TE-1 through 1(2)-TE-39
Containment Hydrogen Concentration	C, 3	1(2)-HYA-964, 1(2)-HYA-965, 1(2)-HYA-966, 1(2)-HYA-967
Containment Effluent Radioactivity-Noble Gases from Identified Release Points	C, 2	RM-SPING-21 & 22 (U1 & U2 Containment Purge Exhaust)
Radiation Exposure Rate (Inside Buildings or Areas in Direct Contact with Primary Containment near Penetrations and Hatches)	C, 3	Applicable monitors in FSAR Table 11.5-1A, RMS Area Monitors
Effluent Radioactivity-Noble Gases (From Buildings as Indicated Above)	C, 2	RM-SPING-23 & 24 (PAB & Drumming Area Vents)
RHR System Flow	D, 2	1(2)-FT-626
RHR Heat Exchanger Outlet Temperature	D, 2 & 3	1(2)-TE-622, 1(2)-TE-623, 1(2)-TE-627, 1(2)-TE-630
RHR Pump Discharge Pressure	D, 2	1(2)-PT-628, 1(2)-PT-629
Accumulator Tank Level	D, 3	1(2)-LT-934 & 935 (Tank B), 1(2)-LT-938 & 939 (Tank A)
Accumulator Tank Pressure	D, 3	1(2)-PT-936 & 937 (Tank B), 1(2)-PT-940 & 941 (Tank A)
Accumulator Isolation Valve Position	D, 3	1(2)-MOV-841A & B
Boric Acid Charging Flow	D, 2	1(2)-FT-128
Flow in HPI System	D, 2	1(2)-FT-924 & 925
HP Safety Injection Pump Discharge Pressure	D, 2	1(2)-PT-922 & 923
Flow in LPI System (Train B)	D, 2	1(2)-FT-928
RHR Heat Exchanger Inlet Temp. (Containment Sump Water During ECCS Recirculation)	D, 2	1(2)-TE-3294, 1(2)-TE-3295

Table 7.6-1 POST-ACCIDENT MONITORING VARIABLES

Sheet 3 of 5

Reactor Coolant Pump Status	D, 3	1(2)-P-1A & B (Motor Current)
Reactor Coolant System Loop Flow	D, 3	1(2)-FT-411 through 416
Reactor Coolant System Code Safety Valve Position	D, 2	1(2)-RC-434-LISA, 1(2)-RC-435-LISA
Pressurizer Power-Operated Relief Valve (PORV) Position	D, 2	1(2)-POS-430, 1(2)-POS-431C
Pressurizer Power-Operated Relief Valve (PORV) Block Valve Position	D, 2	1(2)-RC-515, 1(2)-RC-516
RCS Code Safety Valve and Pressurizer PORV Discharge Line Fluid Temperature	D, 3	1(2)-TE-436, 1(2)-TE-437, 1(2)-TE-438
Pressurizer Heater Status	D, 2 & 3	1(2)-T-1A, B, C, D, E (Breaker Position)
Pressurizer Temperature	D, 3	1(2)-TE-424, 1(2)-TE-425
Pressurizer Relief Tank Water Level	D, 3	1(2)-LT-442
Pressurizer Relief Tank Temperature	D, 3	1(2)-TE-439
Pressurizer Relief Tank Pressure	D, 3	1(2)-PT-440
RCS Gas Vent Isolation Valve Position	D, 3	1(2)-RC-570A & B, 1(2)-RC-575A & B, 1(2)-RC-580A & B
RCS Gas Vent System Pressure	D, 3	1(2)-PT-498
Steam Generator Water Level (wide-range)	D, 1	1(2)-LT-460A, 1(2)-LT-460B 1(2)-LT-470A, 1(2)-LT-470B
Main Steam Flow	D, 2	1(2)-FT-464 & 465, 1(2)-FT-474 & 475
Main Feedwater Flow	D, 3	1(2)-FT-466 & 467, 1(2)-FT-476 & 477
Auxiliary Feedwater Pump Discharge Line Flow	D, 2	1(2)-FT-4002, 1(2)-FIT-4073
Auxiliary Feedwater Pump Discharge Line Pressure	D, 3	1(2)-PT-4005, 1(2)-PT-4071
Auxiliary Feedwater Pump Suction Line Pressure	D, 2	1(2)-PT-4044, 1(2)-PT-4069
Service Water Header Pressure	D, 2	PT-2844, PT-2845
Containment Spray Flow	D, 2	1(2)-FT-962 & 963
Containment Spray Additive Tank Water Level	D, 2	1(2)-LT-931

Table 7.6-1 POST-ACCIDENT MONITORING VARIABLES

Sheet 4 of 5

Heat Removal by the Containment Emergency Fan Coolers	D, 3	1(2)-TE-3270, 3272, 3274 & 3276 1(2)-FS-3225, 3229, 3239 & 3240 1(2)-W-1A1, 1B1, 1C1 & 1D1 Breaker Position 1(2)-FT-2896, 2898, 2900 & 2902 1(2)-TIS-2893, 2901, 2903 & 2972
Containment Atmosphere Temperature	D, 2	1(2)-TE-3292 & 3293
Letdown Line Flow	D, 2	1(2)-FT-134
Volume Control Tank Water Level	D, 2	1(2)-LT-112 & 141
Component Cooling Water Heat Exchanger Outlet Temperature (Cooling Water to ECCS)	D, 2	1(2)-TE-621
Component Cooling Water Flow	D, 2	1(2)-FT-619
High-Level Radioactive Liquid Tank Level	D, 3	LIT-1001 (Waste Holdup Tank)
Radioactive Gas Decay Tank Pressure	D, 3	PT-1036, 1037, 1038, 1039
Emergency Ventilation Damper Positions	D, 2	VNSSB-3246 & 3247; VNPAB-3258-A1, A2, B1 & B2; VNCOMP-4849A, B & D; VNCR-4849C, E & F; VNCSR-4850, 4850B & 4850C; VNCR-4851A, B, C & D, 6748 & 6748A
Station Battery Discharge Rate	D, 2	D-05, D-06, D-105, D-106 & D-305 Ammeters
125 Volt DC Bus Voltage	D, 2	D-01, D-02, D-03, D-04 Voltmeters
120 Volt AC Instrument Bus Voltage	D, 2	1(2)-Y-01 through Y-04 and 1(2)-Y-101 through Y-104 Voltmeters
4160 Volt AC Safeguards Bus Voltage	D, 2	1(2)-A-05 & A-06 Voltmeters
480 Volt AC Safeguards Bus Voltage	D, 2	1(2)-B-03 & B-04 Voltmeters
Emergency Diesel Generator Voltage, Frequency, Loading	D, 2	G-01, G-02, G-03 & G-04
Emergency Diesel Generator Starting Air Pressure Alarm	D, 2	G-01-AP1 & AP2, G-02-AP1 & AP2, PS-6358A & B, PS-6359A & B
Diesel Fuel Oil Day Tank Level	D, 2	LT-3932 & 3934, LS-3932 & 3934, LS-3930A & B, LS-3931A & B, LIT-3992A & B, LS-3935A & B
Instrument Air Pressure	D, 2	PT-3083 & 3084
Process Radiation Monitor from Steam Generator Safety and Atmospheric Dump Valves	E, 2	1(2)-RE-231, 1(2)-RE-232

Table 7.6-1 POST-ACCIDENT MONITORING VARIABLES

Sheet 5 of 5

Particulate and Halogen Sampling from All Other Identified Release Points, with On-site Analysis Capability	E, 3	Grab Samples From PAB & Drumming Area Isokinetic Stack Sampling System
Airborne Radiohalogens and Particulates Sampling	E, 3	Grab Sample Analysis
Plant and Environs Radiation	E, 3	Portable Survey Instruments, TLDs
Plant and Environs Radioactivity (Isotopic Analysis)	E, 3	Grab Sample Analysis
Wind Direction	E, 3	See Note 2
Wind Speed	E, 3	See Note 2
Estimation of Atmospheric Stability (Vertical Temperature Gradient and Standard Deviation of Wind Direction)	E, 3	See Note 2
Primary Coolant and Sump Grab Samples	E, 3	Gross Activity, Isotopic Analysis, Boron, Chloride, Dissolved Hydrogen, pH
Containment Air Grab Samples	E, 3	Hydrogen, Isotopic Analysis

Notes:

1 Instruments credited for more than one variable are generally listed for the highest applicable type and category. The instrument description is not intended to be a list of all components in each instrument loop that are necessary to perform the monitoring function.

2 Refer to Emergency Plan, Appendix L for detailed description of Meteorological System.

Figure 7.6-1 NUCLEAR INSTRUMENTATION SYSTEM

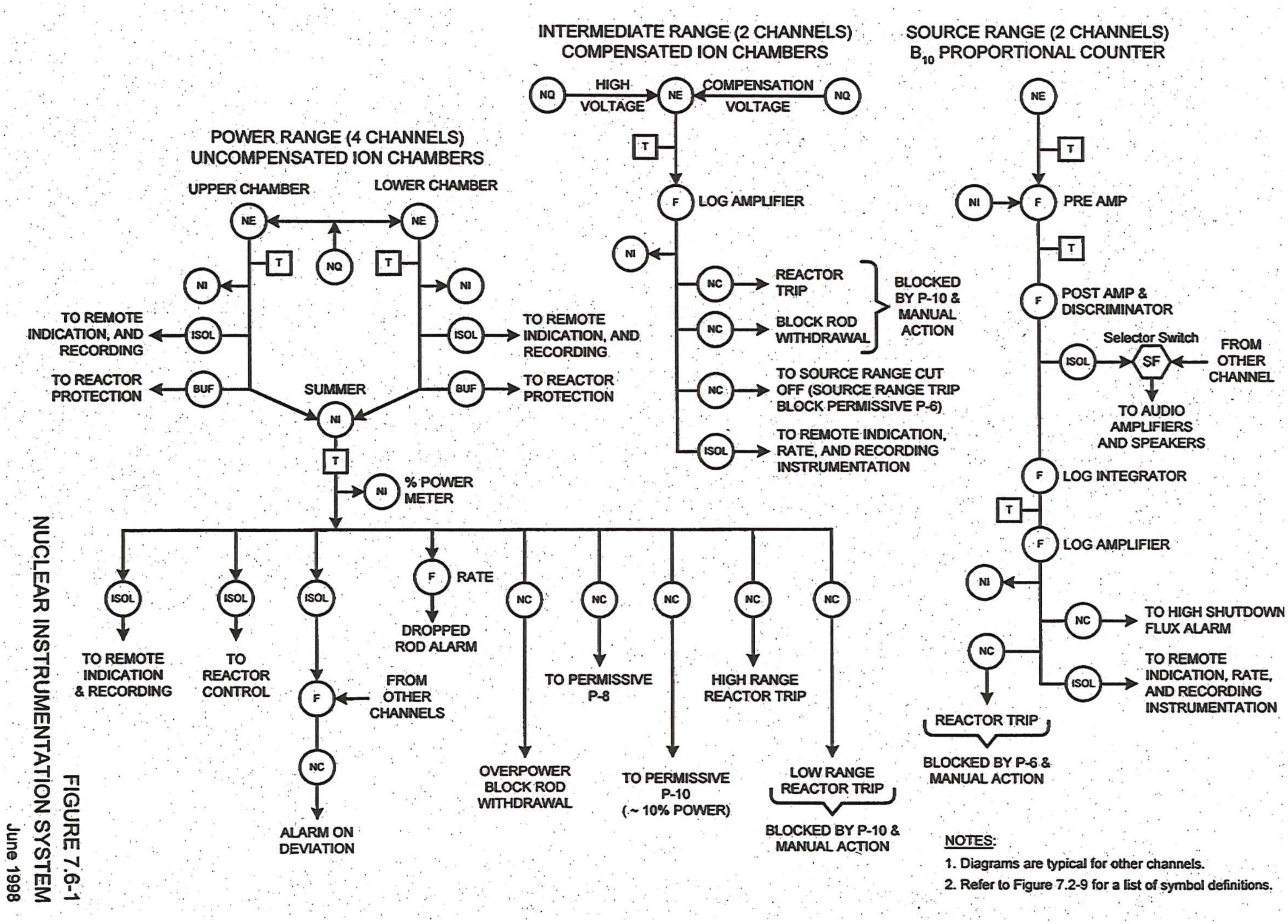


Figure 7.6-2 NEUTRON DETECTORS AND RANGE OF OPERATION

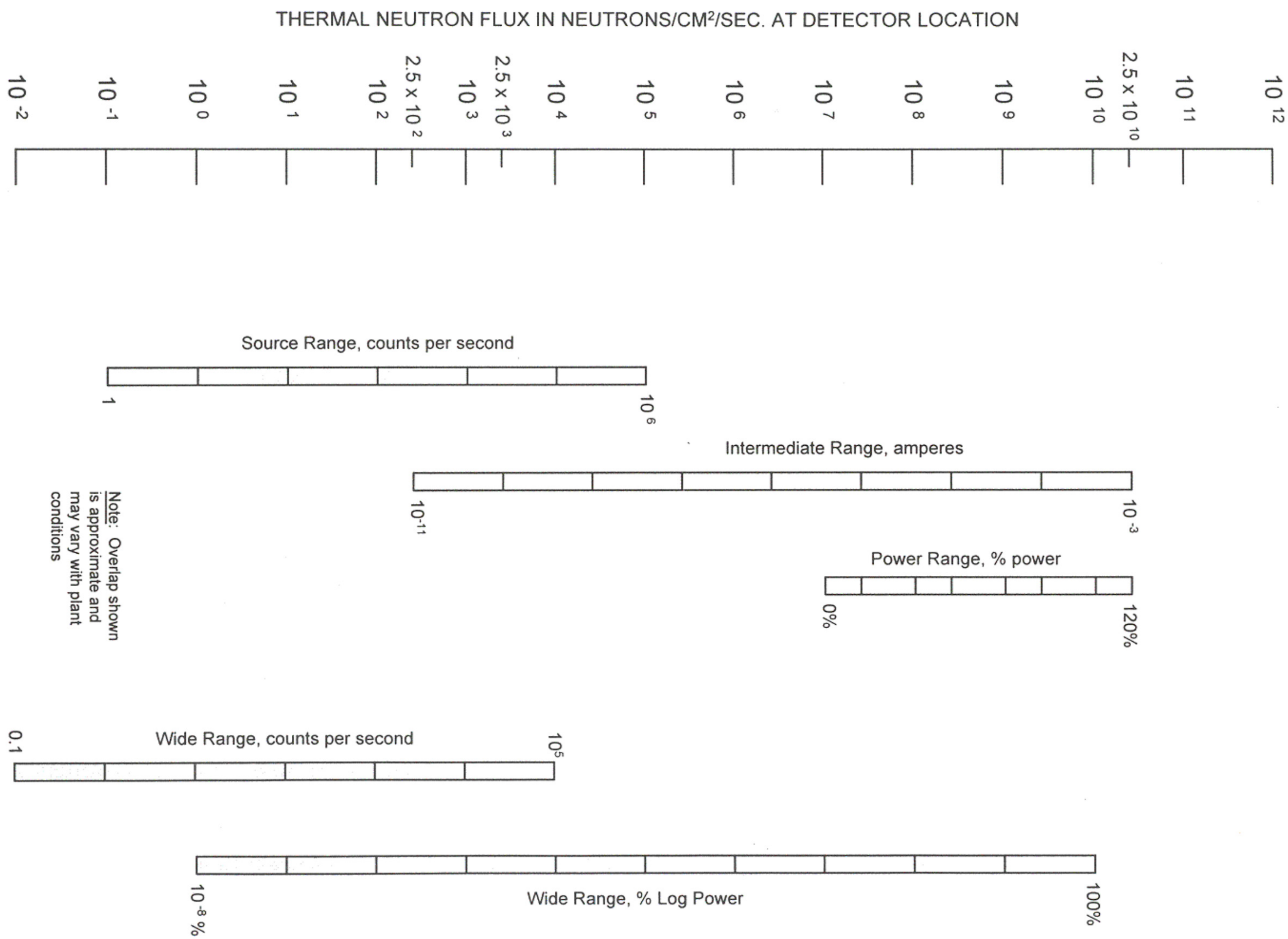
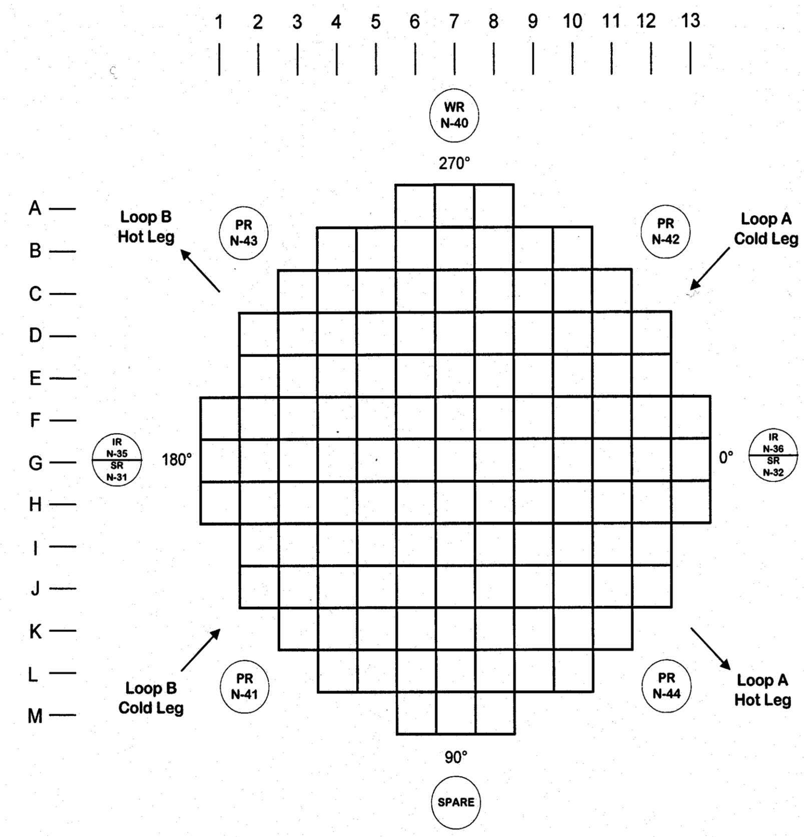


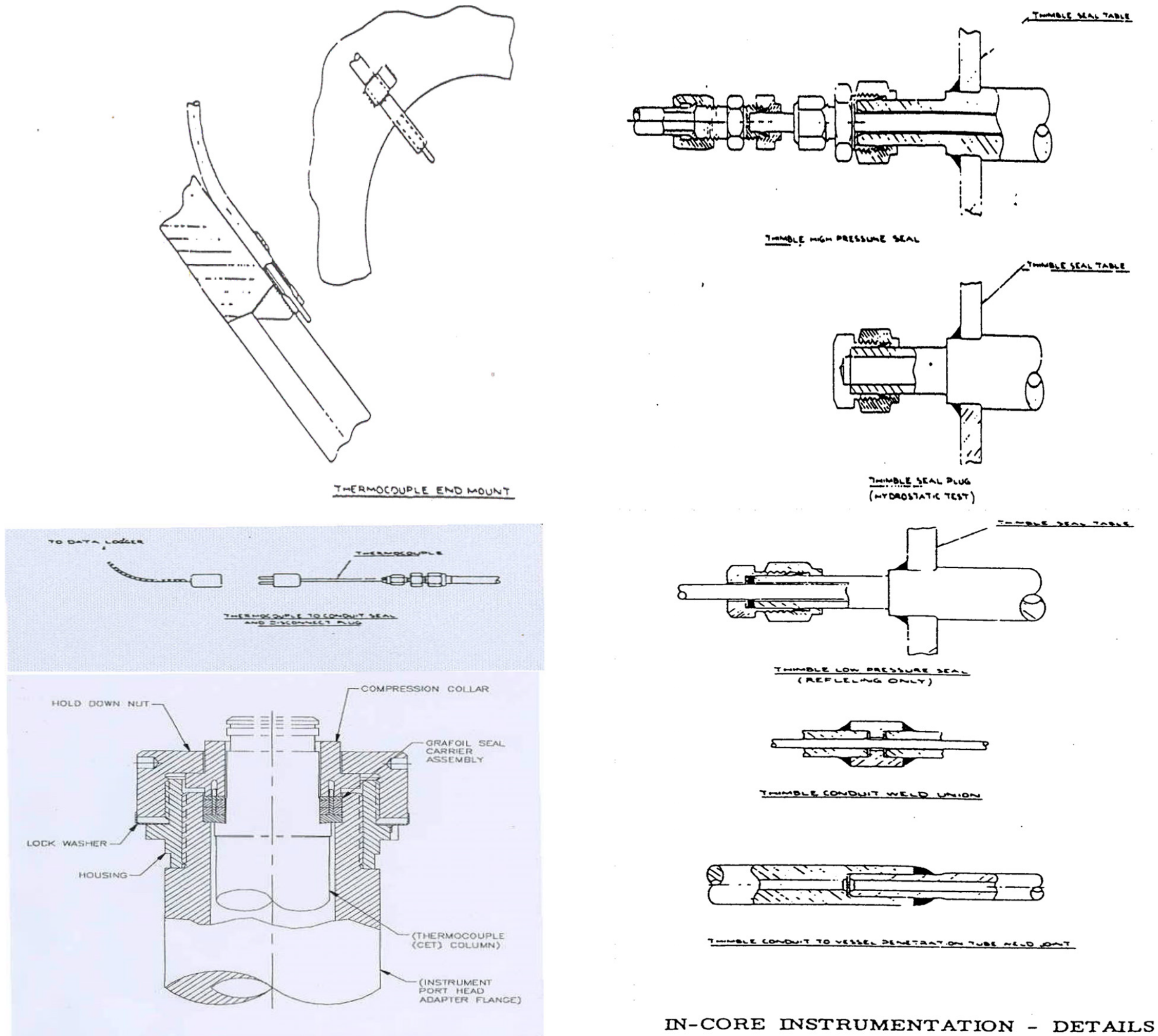
Figure 7.6-3 EX-CORE DETECTOR LOCATIONS RELATIVE TO CORE



NOTES:

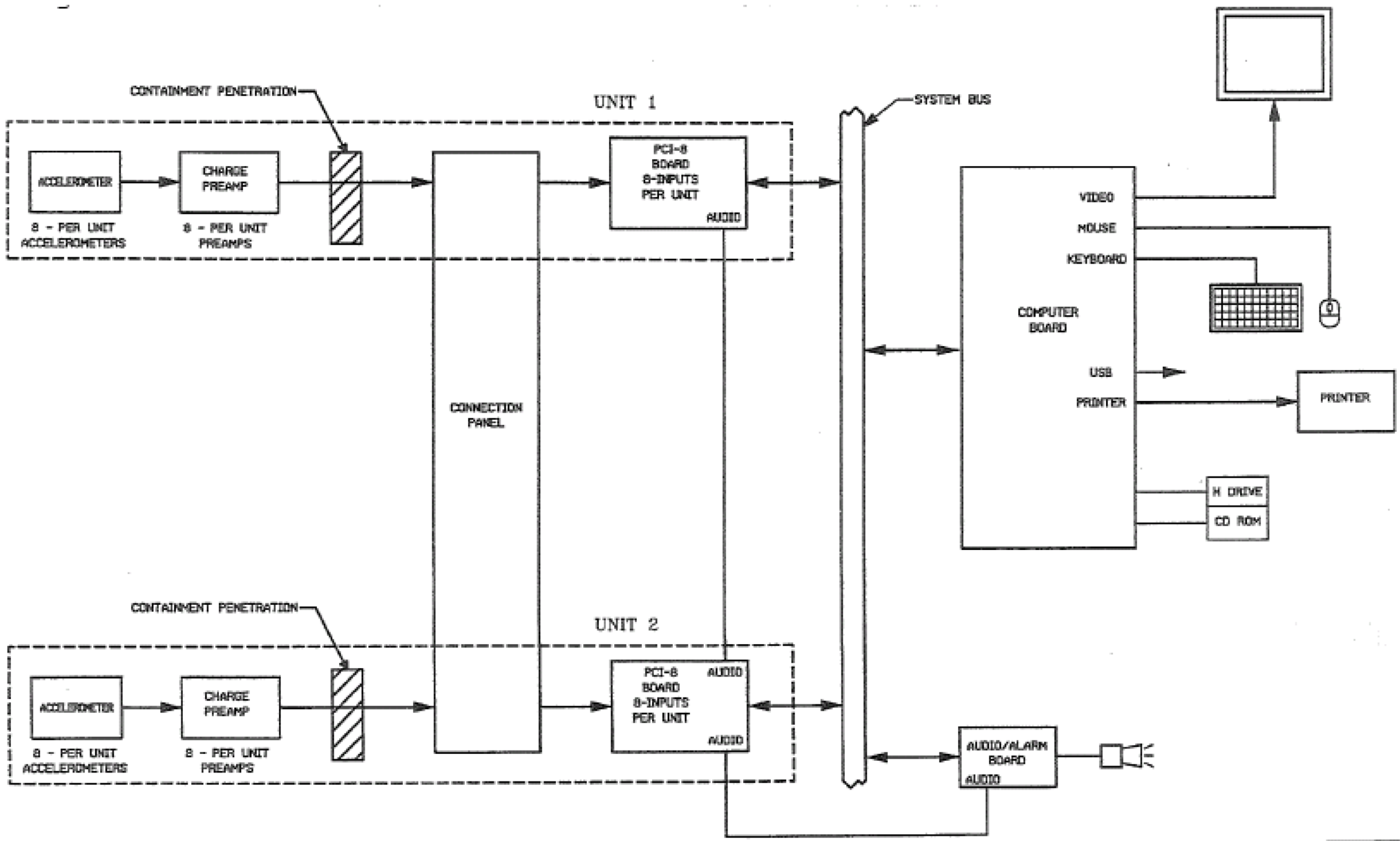
PR: Power Range - Uncompensated Ion Chamber
IR: Intermediate Range - Compensated Ion Chamber
SR: Source Range - Proportional Counter
WR: Wide Range - High Sensitivity Fission Chamber

Figure 7.6-4 IN-CORE INSTRUMENTATION - DETAILS



IN-CORE INSTRUMENTATION - DETAILS

Figure 7.6-5 BLOCK DIAGRAM OF THE LOOSE PARTS MONITORING SYSTEM



7.7 CONTROL SYSTEMS

The basic control system design requirement is to maintain essential reactor facility operating variables within prescribed operating ranges for steady-state operation and for the designed load perturbations, to prevent unnecessary reactor trips.

The control systems are designed to operate as stable systems over the full range of automatic control throughout core life without requiring operator adjustment of setpoints other than the normal calibration procedures. The following sections discuss these control systems.

7.7.1 ROD CONTROL SYSTEM

Overall reactivity control is achieved by the combination of "chemical shim," which is accomplished by injecting boron into the reactor coolant system in the form of boric acid, and RCCAs (Rod Cluster Control Assemblies), also referred to as control rods. Long-term regulation of core reactivity is accomplished by adjusting the concentration of boron in the reactor coolant system, via the chemical and volume control system, which is discussed in Chapter 9.0. Short-term reactivity control for power changes or reactor trip is accomplished by movement of the control rods. Refer to Chapter 3.0 for the design requirements associated with the RCCAs.

The function of the rod control system is to provide automatic control of the control rods during power operation of the reactor. The rod control system uses input signals from different plant parameters, including neutron flux, reactor coolant temperature, and plant turbine load to maintain an average reactor coolant temperature (T_{avg}). T_{avg} increases linearly from zero power to full power.

The rod control system will compensate for reactivity changes caused by fuel depletion and/or xenon transients. Final compensation for these two effects is made by adjusting the boron concentration. The control system then readjusts the control rods in response to changes in T_{avg} resulting from changes in boron concentration.

The rod control system is designed to allow the reactor to follow load changes automatically when the plant output is above approximately 15% of nominal power. Control rod positioning may be performed automatically when plant output is above this value, and manually at any time.

The system enables the nuclear plant to accept a step load increase of 10% and a ramp increase of 5% per minute within the load range of 15% to 100% without a reactor trip, subject to possible xenon limitations. Similar step and ramp load reductions are possible within the range of 100% to 15% of nominal power. The condenser steam dump control system, which is discussed in Section 7.7.2, permits the plant to accept a 50% rapid load decrease at a rate of 200% per minute without a reactor trip. The reactor control system is capable of restoring T_{avg} to within the programmed temperature deadband, following any of the above changes in load. A simplified block diagram of the reactor control system is shown in Figure 7.7-1.

Any unexpected change in the position of the control group under automatic control or a change in reactor coolant temperature under manual control provides a direct and immediate indication of a change in the reactivity status of the reactor. In addition, periodic samples of reactor coolant are taken to monitor boron concentration. The variation in concentration during core life provides a further check on the reactivity status of the reactor including core depletion.

7.7.1.1 System Design

a. RCCA Grouping

There are 33 RCCAs. The rods are divided into two groups:

- a shutdown group comprising one bank of 8 rod clusters and one bank of 4 rod clusters, and
- a control group comprising 4 control banks (A, B, C, and D), which contain 8, 4, 5, and 4 rod clusters, respectively. Figure 3.2-1 shows the location of the rods in the core.

The four control group banks are the only rods that can be manipulated under automatic control. Two banks are divided into subgroups to obtain smaller incremental reactivity changes. All RCCAs in a subgroup are electrically paralleled to step simultaneously. Position indication for each RCCA type is the same. The drive mechanisms used in conjunction with the shutdown and control RCCAs are the same and are capable of permitting free fall of the assemblies.

1. Shutdown Groups

The shutdown groups, together with the control groups, are capable of shutting the reactor down. They are used in conjunction with the adjustment of the chemical shim and the control groups to provide a shutdown margin of at least 1% Δk/k following a reactor trip, even if the rod with the greatest rod worth is fully withdrawn. The shutdown margin varies over core life. The maximum shutdown margin is required at the end of core life and is based on the value used in the steam line break accident analysis.

The shutdown groups are manually controlled during normal operation and are moved at a constant speed. Any reactor trip signal causes them to insert into the core. They are fully withdrawn during power operation and are withdrawn first during startup. Criticality is always approached with the control groups after withdrawal of the shutdown groups.

2. Control Groups

The control groups are divided into four banks (A, B, C and D), with two banks further divided into two subgroups, to allow the system to follow load changes over the full range of power operation. Each subgroup in a bank is driven by the same variable speed rod drive control unit which moves the subgroups sequentially one step at a time. The sequence of motion is reversible; that is, a withdrawal sequence is the reverse of the insertion sequence. The variable speed sequential rod control affords the ability to insert a small amount of reactivity at low speed to accomplish fine control of T_{avg} about a small temperature deadband.

The operator is able to select either automatic or manual control. In either case, significant motion of the control banks can only be accomplished in their normal sequence, but with some overlap as one bank approaches its fully withdrawn position and the next bank begins to withdraw. The overlap between successive control banks is provided to compensate for low differential rod worth near the top and bottom of the core.

Manual control is provided to move a control bank in or out at a pre-selected fixed speed. Only a single bank of rods can be selected at a time during manual control. This is accomplished with a multi-position switch that allows only one bank to be selected.

Proper sequencing of the control rods is assured by; (1) automatic programming equipment in the rod control system, and (2) through administrative control.

Startup of the plant is accomplished by first manually withdrawing the shutdown rods to the full out position. This action requires that the operator select the SHUTDOWN BANK position on a control board mounted selector switch and then position the IN-HOLD-OUT lever (which will spring return to the HOLD position) to the OUT position.

The control banks are then withdrawn manually by the operator by first selecting the MANUAL position on the control board mounted selector switch and then positioning the IN-HOLD-OUT lever to the OUT position. In the MANUAL selector switch position, the rods are withdrawn (or inserted) in a predetermined programmed sequence by the automatic programming equipment.

When the reactor power reaches approximately 15%, the operator may select the AUTOMATIC position, where the IN-HOLD-OUT lever is out of service, and control rod motion is controlled by the rod control system. An interlock limits automatic control rod withdrawal to reactor power levels above 15%. In the AUTOMATIC position, the control rods are again withdrawn (or inserted) in a predetermined programmed sequence by the automatic programming equipment.

The automatic programming equipment is set so that when the first bank being withdrawn reaches a preset position near the top of the core, the second bank begins to move out simultaneously with the first bank. This staggered withdrawal sequence continues until the plant reaches the desired power level. The staggered insertion sequence is the opposite of the withdrawal sequence, such that the last control bank out is the first control bank in.

With the simplicity of the rod program, the minimal amount of operator selection, and two separate position indications available to the operator, there is very little possibility that rearrangement of the control rod sequencing could be made without rewiring the programmer.

b. Interlocks

Interlocks (permissives), designed to meet the single failure criterion, are provided to preclude simultaneous withdrawal of more than one group of control and shutdown rods except in the overlap regions.

The control rod groups used for automatic control are interlocked with measurements of turbine-generator load to prevent automatic control rod withdrawal below 15% of nominal power. The manual and automatic controls are further interlocked with measurements of nuclear flux and ΔT to prevent approaching an overpower condition. See Table 7.2-2 for a listing of the interlocks.

c. Rod Stops

Rod stops are provided to block the withdrawal of the RCCAs to prevent an unnecessary reactor trip or an abnormal condition from increasing in magnitude. Rod stop contacts are located in the rod control logic cabinet and in the rod speed control analog rack.

A list of rod stops is given in Table 7.7-1. Some of these have been previously noted under the interlocks in Table 7.2-2, but are listed again for completeness.

d. Rod Drive Control

The control banks are driven by a sequencing, variable speed rod drive programmer. In a control bank of RCCAs, control subgroups (each containing a small number of RCCAs) are moved sequentially in a cycle such that all subgroups are maintained within one step of each other.

The sequence of motion is reversible, such that withdrawal sequence is the reverse of the insertion sequence. The sequencing speed is proportional to the control signal from the rod control system. This provides control group speed proportional to the demand signal from the rod control system.

The rod drive mechanism control center receives the signals from the programmer and actuates the Silicon Control Rectifiers (SCRs), which are in series with the coils of the rod drive mechanisms, allowing the control rods to move. The power to the coils is supplied through the two reactor trip breakers, which are discussed in Section 7.2.

The rod control system maintains a programmed T_{avg} by providing speed and direction signals to the control banks, based on High T_{avg} and power mismatch signals. Refer to Figure 7.7-1 for the following descriptions:

1. High T_{avg} Signal

   The average reactor coolant temperature is used to maintain the programmed T_{avg} as accurate as possible. The reactor coolant temperatures are measured by the hot leg and the cold leg reactor protection system resistance temperature detectors (RTDs), which provides two average temperature measurements per loop. The highest of four measured average reactor coolant temperature (HI T_{avg}) is the main control signal. This signal is sent through a lead/lag compensation unit to the T_{avg} summing circuitry where it is compared with the power mismatch signal and the reference average reactor coolant temperature T_{ref}, which is based on turbine first stage pressure and represents turbine power.

   The HI T_{avg} signal is also supplied to the condenser steam dump control system, which is discussed in Section 7.7.2.

2. Power Mismatch Signal

   A power mismatch signal is also employed as a control signal to improve the plant performance. The nuclear power is determined from the signals of the four reactor trip system power range neutron flux instrumentation. The average of the four power range signals is used as the control signal. The power mismatch signal is determined from a comparison of the average nuclear flux signal and the turbine first stage pressure signal, which represents turbine power.

The power mismatch signal is sent to a variable gain unit, which increases the signal based on turbine power. This serves to speed up system response and reduce transient peaks. This signal is sent to the T_{avg} summing circuitry where it is compared with the HI T_{avg} signal and the reference average temperature T_{ref}, which is based on turbine power.

The above signals are combined by the summing circuitry and the output signal is used to control the direction and speed of control groups, to maintain T_{avg} at its programmed setting.

e. Control Group Rod Insertion Limits

The control group rod insertion limits ensure that the control rods are withdrawn far enough to provide the necessary shutdown margin to achieve hot shutdown following a reactor trip at any time, assuming that the highest worth control rod remains fully withdrawn.

The rod insertion limits, Z_{LL}, are calculated as a linear function of power. The equation is:

$$Z_{LL} = A\ (\Delta T)_{avg} + C$$

where A is a preset manually adjustable gain and C is a preset manually adjustable bias. The $(\Delta T)_{avg}$ is the average of four ΔT measurements based on the reactor coolant hot leg (T_{HOT}) and the cold leg (T_{COLD}) temperatures.

An insertion limit monitor with two alarm setpoints is provided for control banks B, C and D. A single "Bank A Not Fully Withdrawn" alarm is provided for Bank A. A description of control and shutdown rod groups is provided in Section 7.7.1.1. The "Low" alarm alerts the operator of an approach to a reduced shutdown reactivity situation requiring boron addition. If the actuation of the "Low-Low" or "Bank A Not Fully Withdrawn" alarm occurs, the operator should take immediate action to add boron to the system as necessary.

f. RCCA Position Indication

No direct method for monitoring the boron concentration in the reactor coolant system is provided; therefore, the reactivity status of the core is determined by monitoring the position of the control rods in relation to plant power and T_{avg} when the reactor is critical. There is a direct relationship between control rod position and power and it is this relationship which establishes the lower insertion limit calculated by the rod insertion limit monitor. There are two alarm setpoints, as described above, to alert the operator to take corrective action in the event a control group approaches or reaches its lower limit.

Two separate systems are provided to measure and display control rod position:

1. Analog System

This system derives the position signal directly from measurements of the drive rod position utilizing a linear variable differential transmitter (LVDT) as a detector. An analog signal is produced for each RCCA by the LVDT. An electrical coil stack is placed above the stepping mechanisms of the control rod magnetic jacks, and is external to the pressure housing.

The drive shaft varies the amount of coupling between the primary and secondary windings of the coils and generates an analog signal proportional to rod position. When the associated control rod is at the bottom of the core, the magnetic coupling between the primary and secondary windings is small and there is a small voltage induced in the secondary winding. As the control rod is raised by the magnetic jacks, the relatively high permeability of the lift rod causes an increase in magnetic coupling. Thus, an analog signal proportional to rod position is derived. The LVDT signal is conditioned and displayed on individual meters mounted on the control board and on the Plant Computer display.

Direct, continuous readout of every RCCA position is presented to the operator by individual meters. Since each RCCA is provided with a separate indication, no manipulation is required to determine rod position. In addition, the individual rod position signals are provided to the plant computer, which provides additional indication and alarms. The analog Rod Position Indication displayed on the plant computer may be used to satisfy Technical Specification surveillance requirements.

Indication is provided for rod bottom positions for each rod. The indications are operated by the digital Rod Position Indicating Recorders (RPIR) with input from the analog system.

2. Digital System

The bank demand position signal counts pulses generated in the rod drive control system. Readout of the bank demand position is provided from an add-subtract pulse counter, which measures the number of steps that the rods are withdrawn. One bank demand counter is associated with each group (or subgroups) of RCCAs. These readouts are mounted on the control panel.

The reactor operator can compare the digital and analog readings upon receiving a rod deviation alarm. Since the digital and analog systems are separate systems, with each serving as a backup for the other, a single failure in rod position indication does not, in itself, lead the operator to take erroneous action in the operation of the reactor.

g. Rod Deviation

Both the actual rod position (analog system) and the demand position signals (digital system) are monitored by a rod deviation monitoring system. A deviation monitor alarm within the computer is actuated if an individual rod deviates from its subgroup position by a pre-selected distance.

h. Dropped Rod Indication

Two independent and diverse systems are provided to sense a dropped rod:

- a system which senses sudden reduction in out-of-core neutron flux, and
- a rod bottom position detection system.

The primary indication for a dropped RCCA is provided by use of the out-of-core power range nuclear detectors. A backup indication for a dropped RCCA is the rod bottom signal derived from each rod's individual position indication system. With the position indication system, dropped RCCA indication is not dependent on location, reactivity worth or power distribution changes.

The rod drop detection circuit, which is based on neutron flux, consists of a comparison of each of the four power range ion chamber signals with the same signal taken through a first order lag network. Since a dropped RCCA will rapidly depress the local neutron flux, the decrease in flux will be detected by one or more of these circuits. Such a sudden decrease in the power range ion chamber current will be seen as an error signal. Figure 7.6-1 indicates schematically the nuclear instrumentation system, including the dropped RCCA alarm.

i. Rod Drive Power Supply

The control rod drive power supply system consisting of a single scram bus configuration has been successfully employed on all Westinghouse PWR plants. Potential fault conditions with a single scram bus system are discussed in WCAP-90120L. The unique characteristics of the latch-type mechanisms with its relatively large power requirements with the redundant series reactor trip breakers make this system particularly desirable.

The solid state rod control system is operated from two parallel connected 400 kVA generators which provide 260 volt line-to-line, three-phase, four-wire power to the rod control circuits through the two series connected reactor trip breakers. This AC power is distributed from the reactor trip breakers to a lineup of identical solid state power cabinets using a single overhead run of enclosed bus duct which is bolted to, and therefore comprises part of, the power cabinet arrangement. Alternating current from the motor-generator sets is converted to a profiled direct current by the power cabinet and is then distributed to the control rod drive mechanisms (see Figure 7.7-2). A detailed description of the control rod drive power supply is available in "Topical Report, Solid State Rod Control System, Full Length," WCAP-90120L, January 1970 (Westinghouse Proprietary, Class 2).

1. Maintenance Holding Supply

   Each complete rod control system includes a single 70-volt DC power supply, which is used for holding the rod mechanisms in position during maintenance of the normal power supply. This DC power supply and associated switches have been provided to avoid the need to bring a separate DC power source to the rod control system during maintenance on the power cabinet circuits.

   This 70 volt supply, which receives its input from the AC power source downstream of the reactor trip breakers, is distributed to each power cabinet and permits holding of the rod mechanisms in groups of four by manually positioning switches located in the power cabinets. The 30 ampere output capacity limits the holding capacity to eight rods.

2. Trip Breaker Arrangement

   The trip breakers are arranged in the reactor trip switchgear in individual metal enclosed compartments. The 1,000 amp bus work, which makes up the connections between the reactor trip breakers, is separated by metal barriers to prevent the possibility that any conducting object could short circuit, or bypass, the reactor trip breakers contacts.

3. Reactor Trip

Power to the rod drive mechanisms is interrupted by opening either of the reactor trip breakers. The 70 volt DC maintenance supply is also interrupted, since this supply receives its power through the reactor trip breakers.

7.7.1.2 Generic Letter 93-04

Generic Letter 93-04, "Rod Control System Failure and Withdrawal of Rod Cluster Assemblies," was issued to all licensees with Westinghouse rod control systems. The letter discussed a potential single failure concern with the rod control system as a result of an event at another plant. In response to the generic letter, PBNP submitted a summary of the applicability of WCAP -13803, "Generic Assessment of Asymmetric Rod Cluster Control Assembly Withdrawal," in support of the conclusion that DNB would not have occurred for the worst-case asymmetric rod withdrawal (Reference 1). PBNP also modified the rod control system logic timing in accordance with Westinghouse recommendations and committed to implement enhanced rod control system surveillance testing which meets the intent of Westinghouse Owners Group MUHP 6002, "Recommended Rod Control Surveillance Test." The PBNP surveillance is equivalent to MUHP 6002 Test C; is capable of detecting timing, communication, and regulation failures; and is performed each refueling outage (Reference 2 and Reference 3). The NRC determined that the corrective actions implemented by PBNP in response to GL 93-04 were acceptable (Reference 4).

7.7.2 CONDENSER STEAM DUMP CONTROL

The function of the Condenser Steam Dump (turbine bypass) Control System is to:

- Permit the acceptance of sudden large load decreases without a reactor trip,
- Remove stored energy and residual heat following a reactor trip without actuation of the steam generator safety valves with the plant at equilibrium no-load condition,
- Permit a controlled cooldown to cold shutdown, and
- Provides a means of controlling plant temperature during startup and hot shutdown.

The condenser steam dump system is provided to increase plant operating flexibility for large load reductions of up to 50% of full power at a rate up to 200% per minute. The condenser steam dump system removes steam to reduce the transient imposed upon the reactor coolant system. The control rod system can then reduce the reactor power to a new equilibrium value without causing overtemperature and/or overpressure conditions, which would result in a reactor trip. The condenser steam dump system controls the steam dump valves discussed in Section 10.1.2.

Condenser steam dump can be controlled either by T_{avg} in the automatic mode or main steam header pressure in the manual mode:

7.7.2.1 Automatic Control

In the Automatic Control mode, condenser steam dump is controlled by the error signal between the HI T_{avg} signal, described in Section 7.7.1.1, and the programmed reference temperature (T_{ref}), which is based on turbine first stage pressure (turbine power).

For sudden small changes in load, a difference (error) will exists between the Hi T_{avg} signal and T_{ref}, which will cause the steam dump valves to modulate open. The condenser steam dump flow decreases proportionally as the control rods act to reduce T_{avg} to restore it to within the programmed value of T_{ref}. A deadband is provided to allow the control rods to attempt to control T_{avg} prior to actuating condenser steam dump.

For larger sudden load changes or turbine trips, the error between the Hi T_{avg} signal and T_{ref} becomes larger, which results in the dump valves tripping full open. This allows the sensible heat stored in the reactor coolant to be removed by controlling the steam dump to the condenser and supplying feedwater to the steam generators without actuating the steam generator safety valves. After a reactor and turbine trip the reactor coolant system temperature is reduced to the no-load condition and may be maintained by the steam dump to the condensers, which removes the residual heat.

7.7.2.2 Manual Control

In the Manual Control mode, steam dump is controlled by main steam header pressure. This mode is used for long term removal of residual heat at hot shutdown, or during plant startups or cooldowns.

7.7.3 PRESSURIZER CONTROL

The pressurizer has two separate control systems, which are described below:

7.7.3.1 Pressurizer Pressure Control

The pressurizer pressure control system acts to maintain the reactor coolant pressure within the normal operating band in order to prevent DNB on low pressure and to protect the reactor coolant system from overpressurization due to high pressure. Pressure is controlled by electric immersion heaters, spray valves and power-operated relief valves (PORVs).

The pressurizer pressure is programmed to be controlled to a specified pressure and initiates methods of increasing or decreasing pressure based on the comparison of the programmed value to the measured pressure.

Pressure is normally maintained by automatic control of the heaters, which are located near the bottom of the pressurizer. The heaters are energized and de-energized based on pressurizer pressure, such that the heaters are energized on decreasing pressure and de-energized on increasing pressure. A variable heater is proportionally controlled to correct for small pressure variations due to heat losses, including the heat loss due to a small continuous spray. A small continuous spray is normally maintained to reduce thermal stresses and thermal shock, and to help maintain uniform water chemistry and temperature in the pressurizer. The backup heaters are energized when pressurizer pressure signal is below a given value.

During steady-state operation, the heaters will be energized and de-energized to maintain the programmed pressure value. On decreasing pressure, the heaters are energized. The energization of the heaters cause boiling of the water in the pressurizer, which generates steam and increases the vapor pressure (steam bubble) in the pressurizer, thereby increasing system pressure to the programmed value. On increasing pressure the heaters are de-energized. If system pressure continues to increase, the spray valve, which is located at the top of the pressurizer, will modulate open and inject subcooled water to condense the steam, thereby reducing the system pressure to the programmed value. The spray rate increases proportionally with pressure until it reaches a maximum value.

Changes in plant load can result in changes in the average reactor coolant temperature (T_{avg}), which will either result in decreases or increases in pressure.

Increases in plant loads result in decreases of T_{avg}, which result in an increase in reactor coolant density and a decrease in volume. The decrease in reactor coolant volume results in an outsurge of reactor coolant from the pressurizer, which expands the steam bubble and decreases system pressure. The difference between the programmed pressure and measured pressure will result in the energization of the heaters and the increase in vapor pressure (steam bubble).

Decreases in plant loads result in increases of T_{avg}, which result in a decrease in reactor coolant density and an increase in volume. The increase in reactor coolant volume results in an insurge of reactor coolant into the pressurizer, which compresses the steam bubble and increases system pressure. The difference between the programmed pressure and measured pressure will cause the variable heaters to de-energize and result in the opening of the spray valve, which will condense the steam bubble.

Large reductions in plant loads can result in increases of pressure until it increases to the point at which the two PORVs would open to limit the system pressure to 2,335 psig and allow the pressure in the system to decrease back to the steady-state operating value. Two-out-of-two pressure channels must be above the pressure setpoint to open each PORV. Two spring-loaded safety valves limit the system pressure to 2,485 psig following a complete loss of load without a direct reactor trip or steam dump (turbine bypass).

7.7.3.2 Pressurizer Level Control

The pressurizer level control system monitors the level and automatically maintains the level at a variable programmed value. The level control system varies the charging pump speed to maintain the programmed variable level.

Changes in load result in changes in pressurizer volume. Rather than maintaining a constant level in the pressurizer, level is programmed to be a function of the high average reactor coolant temperature (High T_{avg}). This function will minimize the water inventory adjustments associated with charging and letdown and minimize the requirements on the chemical and volume control and waste disposal system resulting from coolant density changes during loading and unloading from full power to zero power.

7.7.4 STEAM GENERATOR CONTROL

The steam generator level is controlled in order to insure the proper water inventory for various operational and possible accident conditions. The control is achieved by varying feedwater flowrate. The feedwater system is discussed in Section 10.1.

Steam generator level is controlled by two means:

7.7.4.1 Main Feedwater Flow Control

The level in each steam generator is controlled by two programmable indicating controllers, one primary controller and one secondary controller. Each three-element control system continuously compares the feedwater flow signal, the steam generator water level signal and the main steam flow signal (see Figure 7.2-12), which is compensated by a steam pressure signal, and regulates its associated feedwater control valve accordingly. In the unlikely event of a failure of a primary controller, steam generator level control automatically transfers to the secondary controller and initiates a control room alarm. The 1st stage turbine pressure signal, which is proportional to reactor power, changes the controller response to enhance steam generator level stability at various reactor power levels. A failure of the 1st stage steam pressure signal high or low causes the controller to switch to pre-established default values. Two selectable feedwater flow and main steam flow signals are provided for each steam generator level controller

The controllers have the ability to operate in a “single element mode.” In this mode, only the steam generator level signal inputs are used to control steam generator level. The single element mode allows the MFRV control system to modulate the MFRVs to maintain steam generator levels at low power. The controllers will automatically switch to single element mode if a steam flow or feedwater flow input fails off-scale high or low. Manual override of the feedwater controllers is also provided.

The three-element control system is overridden during the following by actuation of solenoid valves in the air supply to the valve actuators:

1. The main feedwater control valves close on a reactor trip signal to minimize the plant cooldown from the reactor trip transient.

2. In order to prevent excessive moisture carryover to the turbine caused by high steam generator level, a high-high level signal will override the control system and close the feedwater control valve. The signal is derived from a two-out-of-three coincidence logic. This override is automatically removed as the water level drops below the high-high setpoint.

3. A safety injection signal trips the main feedwater pumps and closes the MFRVs to minimize feedwater addition. This prevents additional cooldown and reduces containment pressure increase for the steam line rupture analysis (see Section 14.2.5).

Each feedwater flow channel is compared with a main steam flow channel for any mismatch above or below an adjustable value. An alarm is initiated if feedwater flow is greater than main steam flow. A reactor trip is initiated if feedwater flow is less than main steam flow coincident with low steam generator level. See Section 7.2.

7.7.4.2 Bypass Feedwater Flow Control

For low power operation of less than approximately 15% power, a bypass control valve may be used to control steam generator level. The bypass control valve is closed during normal power operation. The bypass control valve is controlled by a controller, which provides either automatic or manual control of the valve. In automatic control, the valve is modulated to control a programmed level based on the difference between the measured level and the referenced programmed level ($L - L_{ref}$).

The bypass valves are closed and prevented from opening either on a safety injection signal or on high steam generator level in the associated loop.

7.7.5 AUTOMATIC TURBINE LOAD RUNBACK

Automatic turbine load runback is initiated by an approach to an overpower or overtemperature condition prior to reaching the overpower and overtemperature ΔT trip setpoints. This feature prevents high power operation which could lead to a DNBR less than 1.30.

As identified in Section 7.2.2.2.e and Section 7.2.2.2.f, an automatic turbine runback is initiated when two-out-of-four channels indicate increasing overpower ΔT or overtemperature ΔT. The turbine runback acts by reducing the load reference setpoint of the turbine Electro-Hydraulic (E-H) controller by a preset amount. This is accomplished by reducing the setpoint at a constant rate for a present time in cycles, until the runback condition clears.

7.7.6 SYSTEM EVALUATION

7.7.6.1 Plant Stability

The rod control system is designed to limit the amplitude and the frequency of continuous oscillation of the average reactor coolant temperature (T_{avg}) about the control system setpoint within acceptable values. Continuous oscillation can be induced by a feedback control loop with a loop gain, which is either too large or too small with respect to the process transient response, such that the instability is induced by the control system itself. Because stability is more difficult to maintain at lower power under automatic control, automatic control is prevented below approximately 15% of power.

The control system is designed to operate as a stable system over the full range of automatic control throughout core life.

7.7.6.2 Step Load Changes Without Condenser Steam Dump (Turbine Bypass)

A typical power control requirement is to restore equilibrium conditions, without a plant trip, following a plus or minus 10% step change in load demand, over the 15 to 100% power range for automatic control. The design must necessarily be based on conservative conditions and a greater transient capability is expected for actual operating conditions.

The function of the rod control system is to avoid reactor trips by maintaining the average reactor coolant temperature (T_{avg}) deviation during the transient within a given value and to restore T_{avg} to the programmed setpoint within a given time. Excessive pressurizer pressure variations are prevented by using spray and heaters in the pressurizer.

The margin between the overtemperature ΔT setpoint and the measured ΔT is of primary concern for the step load changes. This margin is influenced by nuclear flux, pressurizer pressure, T_{avg}, and temperature rise across the core.

7.7.6.3 Loading and Unloading

Ramp loading and unloading is provided over the 15% to 100% power range under automatic control. The function of the control system is to maintain T_{avg} and pressure as functions of turbine-generator load. The minimum control rod speed provides a sufficient reactivity rate to compensate for the reactivity changes resulting from the moderator and fuel temperature changes.

T_{avg} increases during loading and causes a continuous insurge to the pressurizer as a result of coolant expansion. The pressurizer spray limits the resulting pressure increase. Conversely, as T_{avg} is decreasing during unloading, there is a continuous outsurge from the pressurizer resulting from coolant contraction. The heaters limit the resulting system pressure decrease. The pressurizer level is programmed such that the water level is above the setpoint at which the heaters cut out during the loading and unloading transients.

The primary concern for the loading rate is to limit the overshoot of T_{avg} so that a margin is provided for the overtemperature ΔT setpoint.

7.7.6.4 Loss of Load with Condenser Steam Dump (Turbine Bypass)

The reactor control system is designed to accept a net loss of electrical load below the permissive P-9 setpoint and a 50% rapid load reduction at a rate of 200% per minute from any power level, such that no reactor trip should be actuated. The automatic condenser steam dump system is able to accommodate this abnormal load rejection and to reduce the effects of the transient imposed upon the reactor coolant system. The reactor power is reduced at a rate consistent with the capability of the rod control system. Reduction of the reactor power is automatic down to 15% of full power. Manual control must be used when the power is below this value. The reduction of steam dump flow is limited by the rate of inserting negative reactivity via control rods.

The ability of the plant to withstand the design load rejection without a trip was verified by analysis (Reference 6). The relieving capacity of the power-operated relief valves (PORVs) is adequate to limit the system pressure to prevent actuation of high pressure reactor trip for the 50% rapid load reduction. The PORVs are not challenged for a turbine trip without a reactor trip below the P-9 Setpoint.

7.7.6.5 Turbine Generator Trip with Reactor Trip

Whenever the turbine generator trips at an operating level above the P-9 permissive setpoint, the reactor also trips (see Section 7.2). The plant is operated with a programmed average reactor coolant temperature (T_{avg}) as a function of load, with the full load T_{avg} significantly greater than the saturation temperature corresponding to the steam generator pressure at the safety valve setpoint. The thermal capacity of the reactor coolant system is greater than that of the secondary system, and because the full load T_{avg} is greater than the no-load steam temperature, a heat sink is provided by the combination of controlled release of steam to the condenser, by makeup of cold feedwater to the steam generators, and by relief through the atmospheric relief valves as necessary.

The condenser steam dump system is controlled from T_{avg} signal whose setpoint values are reset upon trip to the no-load value. Actuation of the condenser steam dump (turbine bypass) must be rapid enough to prevent actuation of the steam generator safety valves. With the condenser steam dump valves open, T_{avg} starts to reduce quickly to the no-load setpoint. A direct feedback of temperature acts to proportionally close the valves to minimize the total amount of steam which is bypassed.

Following the turbine trip, the steam voids in the steam generators will collapse and the main feedwater regulating valves will close following the reactor trip. The MFRV bypass valves will open to control steam generator level at their setpoint and auxiliary feedwater will actuate if the steam generator low-low level setpoint is reached.

Residual heat removal is maintained by the steam generator pressure controller (manually selected) which controls the amount of steam flow to the condensers. This controller operates the same condenser dump valves to the condensers which are used during the initial transient following turbine and reactor trip.

The pressurizer pressure and level fall rapidly during the transient because of coolant contraction. If heaters become uncovered following the trip, the chemical and volume control system will provide full charging flow to restore water level in the pressurizer. Heaters are then energized to restore pressurizer pressure to normal.

The condenser steam dump and feedwater control systems are designed to prevent T_{avg} from falling below the programmed no-load temperature following the trip to ensure adequate reactivity shutdown margin.

7.7.6.6 Rod Control System Construction

The rod control system equipment is assembled in enclosed steel cabinets. Three phase power is distributed to the equipment through a steel enclosed bus duct, bolted to the cabinets. DC power connections to the individual mechanisms are routed to the reactor head area from the solid state cabinets through insulated cables, enclosed junction boxes, enclosed reactor containment penetrations, and sealed connectors. In view of this type of construction, any accidental connection of either an AC or DC power source, either internal or external to the cabinets, is not considered credible and were evaluated in WCAP-90120L, "Topical Report, Solid State Rod Control System, Full Length," dated January 1970 (Westinghouse Proprietary, Class 2).

7.7.7 REFERENCES

1. VPNPD-93-138, “Response to Generic Letter 93-04, Rod Control System Failure and Withdrawal of Rod Cluster Control Assemblies, Point Beach Nuclear Plant, Units 1 and 2,” dated August 5, 1993.

2. NRC Letter to WEPCo, “Request for Additional Information Regarding Generic Letter 93-04, Rod Control System Failure and Withdrawal of Rod Cluster Control Assemblies, 10 CFR 50.54(f), TAC Nos. M86858 and M86859,” dated December 12, 1994.

3. NPL 95-0324, “Generic Letter 93-04, Rod Control System Failure and Withdrawal of Rod Cluster Control Assemblies, Additional Information, Point Beach Nuclear Plant, Units 1 and 2,” dated July 13, 1995.

4. NRC Letter to WEPCo, “Resolution of Generic Letter 93-04, Rod Control System Failure and Withdrawal of Rod Cluster Control Assemblies, 10 CFR 50.54(f), Point Beach Nuclear Plant, Units 1 and 2, (TAC Nos. M86858 and M86859)” dated August 21, 1995.

5. NRC Safety Evaluation, PBNP Units 1 and 2 - Issuance of License Amendments Regarding Extended Power Uprate, May 3, 2011.

6. Westinghouse Calculation Note CN-CPS-08-20, EC10001/257453 Plant Operabiltiy Margin to Trip and EOC Coastdown Analysis for Point Beach Units 1 and 2 Extended Power Uprate, April 26, 2011.

Table 7.7-1 ROD STOPS

Rod Stop	Actuation Signal	Rod Motion to be Blocked
1. Nuclear Overpower	l/4 high power range neutron flux or l/2 high intermediate range neutron flux	Automatic and manual withdrawal
2. High ΔT	2/4 overpower ΔT or 2/4 overtemperature ΔT	Automatic and manual withdrawal
The actuation signals for item 2 also initiate a turbine load reduction		
3. Low Power	Low turbine load signal (below l5%) from low turbine impulse pressure	Automatic withdrawal

Figure 7.7-1 SIMPLIFIED BLOCK DIAGRAM OF REACTOR CONTROL SYSTEM

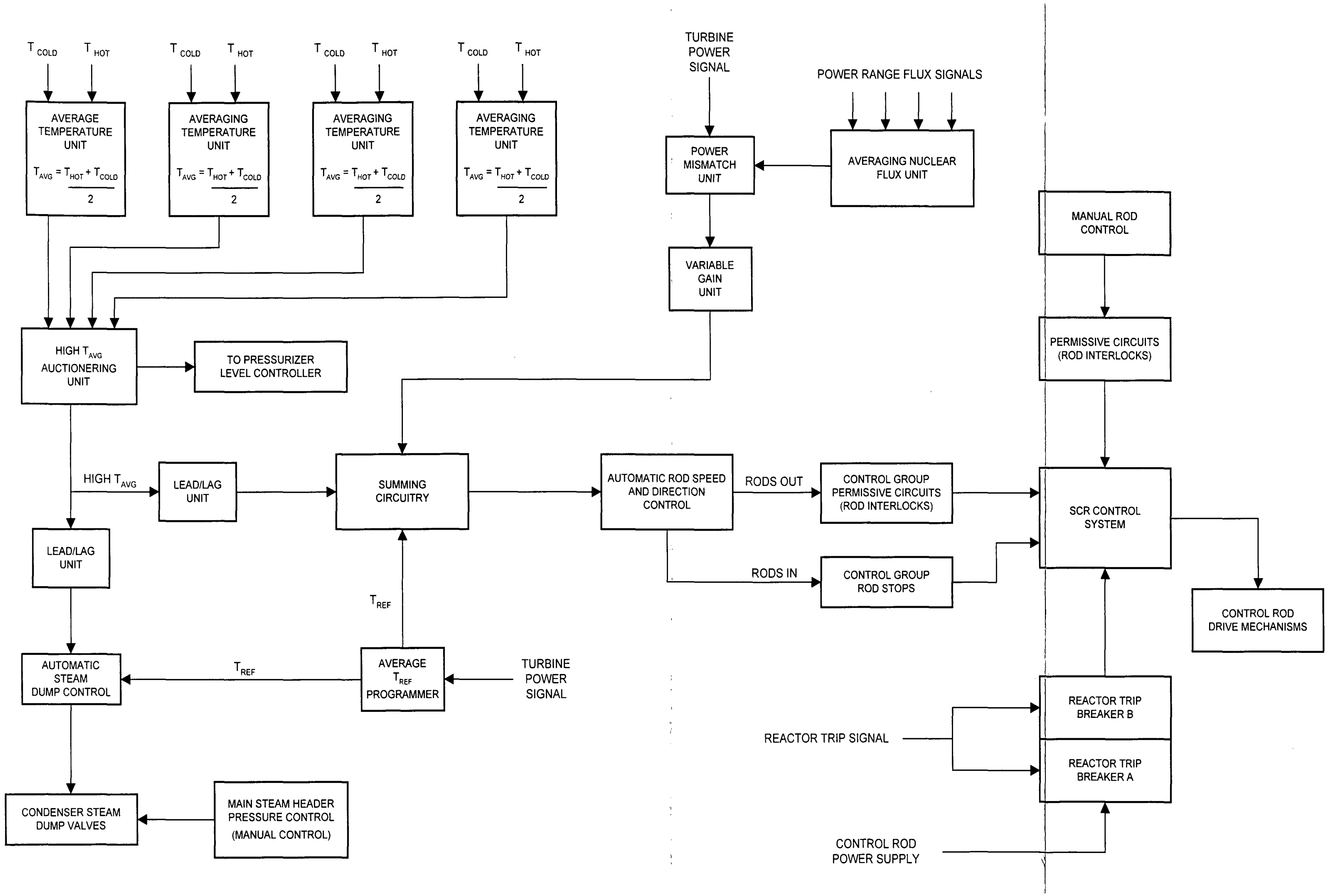
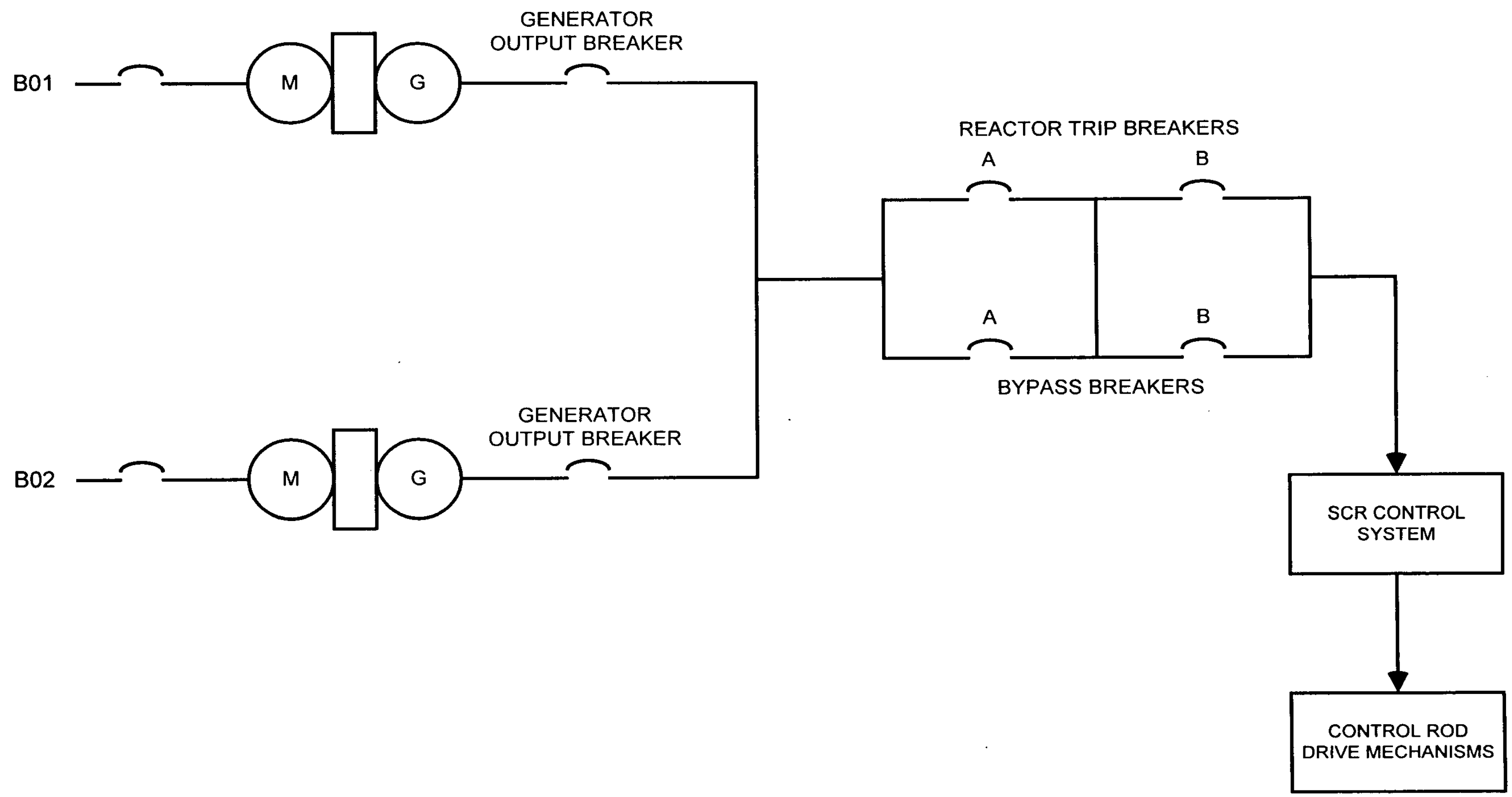


Figure 7.7-2 POWER SUPPLY TO ROD CONTROL EQUIPMENT AND CONTROL ROD DRIVE MECHANISMS



CHAPTER 8 TABLE OF CONTENTS

8.0 INTRODUCTION TO THE ELECTRICAL DISTRIBUTION SYSTEMS

Chapter 8 of the Point Beach Nuclear Plant (PBNP) Final Safety Analysis Report (FSAR) describes the Electrical Distribution systems. This chapter has been divided into individual system divisions, based on the system designators, which comprise the electrical distribution system. The major systems sections of Chapter 8 are; 345 kV, 19 kV, 13.8 kV, 4.16 kV, 480V, 125V, 120 VAC Vital Instrument Bus Power (Y), Diesel Generator (DG), and Gas Turbine (GT).

The Chapter 8 sections of the FSAR describe each system in an appropriate level of detail based on the safety significance of the system. Each system section is divided into; Design Basis, Description and Operation, System Evaluation, and Reference section. The Design Basis section gives the functional and relevant information on the design basis of the system. The system's Description and Operation section presents the normal and emergency operations which support the functions as described in the design basis section and provides a clear understanding of the system's operation.

The purpose of the electrical distribution systems is to distribute power from the main generator to the Northeast Wisconsin 345 kV AC transmission system, to PBNP, and from offsite sources during times when adequate onsite power is not available. The integrated design of the Electrical Distribution systems provide sufficient independence and redundancy to supply those PBNP loads which are important to plant safety under all postulated conditions.

Onsite and offsite sources of electrical power and various portions of the major systems sections described in Chapter 8 are credited in the event of a fire and have been evaluated in the at-power and non-power analyses and are documented in the Fire Protection Program Design Document (FPPDD) (Reference 5).

8.0.1 PRINCIPAL DESIGN CRITERIA

Performance Standards

Criterion: Those systems and components of reactor facilities which are essential to the prevention or to the mitigation of the consequences of nuclear accidents which could cause undue risk to the health and safety of the public shall be designed, fabricated, and erected to performance standards that will enable such systems and components to withstand, without undue risk to the health and safety of the public the forces that might reasonably be imposed by the occurrence of an extraordinary natural phenomenon such as earthquake, tornado, flooding condition, high wind or heavy ice. The design bases so established shall reflect: (a) appropriate consideration of the most severe of these natural phenomena that have been officially recorded for the site and the surrounding area; and (b) an appropriate margin for withstanding forces greater than those recorded to reflect uncertainties about the historical data and their suitability as a basis for design. (GDC 2)

All electrical systems and components vital to plant safety, including the emergency diesel generators, are designed as Class I and designed so that their integrity is not impaired by the maximum potential earthquake, wind storms, floods or disturbances on the external electrical system. Power, control and instrument cabling, motors and other electrical equipment required for operation of the engineered safety features are suitably protected against the effects of either a nuclear system accident or of severe external environmental phenomena in order to assure a high degree of confidence in the operability of such components in the event that their use is required.

Emergency Power

Criterion: An emergency power source shall be provided and designed with adequate independency, redundancy, capacity, and testability to permit the functioning of the engineered safety features and protection systems required to avoid undue risk to the health and safety of the public. This power source shall provide this capacity assuming a failure of a single active component. (GDC 39)

Independent alternate power systems are provided with adequate capacity and testability to supply the required engineered safety features and protection systems.

Offsite Power

Subsequent to the issuance of the original plant license, the NRC performed an evaluation (GL79-36) of the offsite power supply relative to the requirements of 10 CFR 50, Appendix A, GDC-17, "Electrical Power Systems." The NRC evaluation determined that the offsite power supply design was in compliance with 10 CFR 50, Appendix A, GDC-17 with the exception of the winding arrangement and proximity of the 1-X04 and 2-X04 low voltage station auxiliary transformers. These exceptions to 10 CFR 50, Appendix A, GDC-17 were determined to be acceptable based on the technical specification restrictions on plant operation with an inoperable X04 transformer, the installed X04 transformer fire deluge sprinkler system, the capability to supply either units A03 and A04 4.16 kV busses from the opposite units X04 transformer via manually closed tie breakers, the development of procedures to back feed offsite power through the X01 main step up transformers, and the procurement of a spare X04 transformer (Reference 1, Reference 2). Subsequesnt to this NRC evaluation, the original 13.8 kV bus H01 has been relocated to a separate building and replaced with three busses H01, H02, and H03. A reinforced concrete fire wall has also been erected between the 1-X04 and 2-X04 transformers. These changes have further improved the physical independence of the offsite power supplies (Reference 3, Reference 4). Note that although the design is in compliance with some aspects of 10 CFR 50, Appendix A, GDC-17, PBNP was licensed prior to Appendix A being issued and never committed to GDC-17 in whole or in part.

In addition to the principal design criteria, the following general requirements are applied to the systems found in Chapter 8 where applicable. (See also Appendix D regarding general requirements associated with the installation of G03 and G04 emergency diesel generators).

1. The application and routing of control, instrumentation and power cables are such as to minimize their vulnerability to damage from any source. All cables are designed using conservative margins with respect to their current-carrying capacities, insulation properties, and mechanical construction. All engineered safeguards power cable insulation and all power cables in the reactor building have fire resistant sheathing selected to minimize the harmful effects of radiation, heat, and humidity. Appropriate instrumentation cables are shielded to minimize induced voltage interference. Wire and cables related to engineered safeguard and reactor protective systems are routed and installed to maintain the integrity of their respective redundant channels and protect them from physical damage.

2. Supports for cable trays are designed in accordance with the tray manufacturer's recommendation based upon 100% tray load. In general, cable trays are loaded such that

power and control trays are filled less than 30% and instrument trays less than 40%. The fill factor represents:

$$\frac{\text{Sum of Cross Sectional Areas of All Cables In Tray}}{\text{Cross Sectional Area of Tray}}$$

Cables in trays are derated by factors recommended by Insulated Cable Engineers Association (ICEA). Derating factors used for conduit installations are in accordance with the National Electric Code.

3. Separate wireways are provided for medium voltage power cables (4 kV and 13.8 kV). Lower voltage power cables (480 V and 125 VDC) and control cables (120 VAC and 125 VDC) may be placed in the same wireways. Separate wireways are maintained for instrumentation cables. Separation is maintained such that redundant protection channels or trains are not intermixed within the same wireway. (Note clarification on Separation of Safety Injection Reactor Trip Signals in Section 7.3.3). Cables for nonvital circuits have not been excluded from wireways carrying protection system cabling.

4. When loading the cables into the trays, the height of cable bundles is maintained equal to, or below, the height of the tray except when special evaluations prove acceptability under other conditions. (Reference SER 93-025-17) More cable tray loading criteria are located in this section.

5. All wireways are identified by a unique number. In addition, all cable trays containing engineered safeguards or protection circuits are marked by a color which designates the particular channel for which it serves.

6. Minimum separation between the two penetration areas is 20 ft. Within each area, penetrations for cables which serve engineered safeguards and reactor protection circuits are located below cabling for nonessential services. Cables which contain mutually redundant circuits do not share a common penetration. Penetrations for safeguards or protection circuit must be separated from penetrations with mutually redundant circuits by a minimum distance of 24 in. or a metal barrier.

7. Insulation for cables rated 5 kV are heat, ozone and moisture resistant. Insulation for cables rated l5 kV are also heat, ozone, and moisture-resistant. Insulation for power cables rated 600 v, which are used for engineered safeguards services, are ozone and moisture-resistant with flame retardant overall jacket.

8. Insulation for control cables which are used for safeguards and protection circuits are 600 v ozone-resistant. Individual conductors are covered with a flame retarding and moisture-resisting insulation material. Multiconductor cables are provided with overall flame retarding jacket.

9. Insulation for the various categories of cables is selected on the basis of utility practice, with special considerations given to flame retardant properties of insulation and jackets for cables which serve engineered safeguards or protection functions.

10. All cables are protected against overload in accordance with the National Electrical Code.

11. Wiring between vital elements of the system outside of equipment housing is routed and protected so as to maintain the true redundancy of the systems with respect to physical hazards.

12. No provisions are made for temperature monitoring of cables.

13. During selection of insulation materials for the various categories of cables, the environmental effects of cables have been taken into account. Specific attention was given to the effects of radiation, high ambient temperatures and moisture. In addition, provisions are made to protect against mechanical damage, where necessary.

14. Each cable is identified at both terminations by a unique number. In the case of cables containing engineered safeguards or reactor protective circuits, the cable number includes two additional characters, one identifying a cable as a safeguard or protective cable, the other identifying the actual channel with which it is associated. In addition, a color coded marking is placed on or near the cable label for additional channel identification.

15. During construction and subsequent modifications, verification of the proper routing of cables was made through independent inspections by site personnel. During original plant construction, when a safeguards circuit was randomly selected for inspection, the routing of its companion circuit was inspected to assure that separation had been accomplished.

NOTE: The following describes the original method used to seismically evaluate electrical equipment. Additional verification of the seismic adequacy of plant mechanical and electrical equipment was performed as discussed in Section A.5.6, Verification of Seismic Adequacy of Equipment per Generic Letter 87-02.

16. An evaluation of electrical equipment ability to withstand seismic events is documented in Westinghouse report WCAP-7397-L, titled “Topical Report Seismic Testing of Electrical and Control Equipment” E.L. Vogeding, dated January 1970. Refer to Section 7.2.3.4 for additional seismic qualification requirements.

    The switchgear equipment has been specified to withstand accelerations in excess of 0.15g horizontally and 0.10g vertically. This capability was a matter of procurement specification of Westinghouse and its design agents and design action of the vendors. The safeguards circuits employ Westinghouse Series W motor control centers, DB and DH circuit breakers and associated metal-enclosed or metal-clad switchgear. Review of these switchgear for proof of adequacy of the seismic resistant design determined that the Series W motor control centers and DB breakers, mounted in the metal enclosures, have been shock tested and proven to remain fully operable for shocks of at least 3g in any direction. Proof of resistance of the DH metal-clad switchgear to a seismic response spectrum established for Point Beach has been demonstrated by vibration testing of typical, equivalent metal-clad switchgear, incorporating the DHP circuit breaker. The DH circuit breakers installed in Point Beach are an earlier design than the DHP. However, the general configuration, weight distribution, and vibration resistant design approach of the DH are essentially identical to the DHP. When subjected to a spectrum equivalent to or greater than Figure B-2, there was no loss of function of the DHP metal-clad switchgear.

The power supply leaving the switchgear operates the safeguards equipment completing the actuation train. The DC power supply may be considered as a branch to this main train of actuation. The source of DC power may be either the battery chargers or the station batteries. The batteries and battery racks present a simple structural problem which was analyzed and found adequate for the forces imparted by the floor upon which they are located. The conduit and cable trays carrying the DC power to the main station train received the same study for seismic support as described above.

17. Local or remote control is provided to key safeguards breakers to prevent a casualty from disabling the safeguards power supplies. Separation is maintained in both the 4.16 kV and the 480V systems to allow the plant auxiliary equipment to be arranged electrically so that redundant items receive their power from the two different buses. [redacted] and so forth. Redundant valves are supplied from motor control centers 1-B32 and 1-B42 for Unit 1 and 2-B32 and 2-B42 for Unit 2.

18. In order to prevent propagation of cable fire in the event that such a fire occurs, fire stops are placed at the following locations: all cable trays entering the main control room, cable spreading room, vital switchgear room and other areas with high concentrations of cables. (For additional information see the Fire Protection Program Design Document (FPPDD) (Reference 5).

19. In addition, fire stops are placed in all vertical cable tray risers, and all trays which contain engineered safeguards or protection circuits, and where such trays penetrate a wall.

20. Fire stops are designed to provide an effective barrier against propagation of flames, heat, gases and smoke.

21. Fire detectors are placed in the following critical areas: cable spreading room, switchgear rooms, diesel generator rooms and electrical equipment rooms. The detectors operate on the ionization principle actuated by the presence of combustion products or gases, except for the G03 and G04 rooms which have rate-of-rise heat detectors.

8.0.2 REQUIRED PROCEDURES AND TESTS

Tests are specified to demonstrate that the diesel generators (DG) will provide power for operation of equipment. The tests also assure that the emergency generator system controls and the control systems for safeguards equipment will function automatically when required. The tests are performed in accordance with the Point Beach Nuclear Plant Technical Specifications.

8.0.3 SINGLE LINE DIAGRAMS

The basic components of the station electrical system are shown on the Electrical One Line or Single Line Diagrams, Figure 8-1 through Figure 8-8, including the main one line, the 480 volt and 120 volt AC instrument bus systems and the 125 volt DC system.

8.0.4 REFERENCES

1. NRC Safety Evaluation "Safety Evaluation of the Preferred Power Systems Conformance to General Design Criteria 17," dated August 29, 1983.

2. NRC Safety Evaluation "Adequacy of Station Electric Distribution System Voltages," dated August 29, 1983.

3. 10 CFR 50.59 Evaluation 87-022, "MR 87-002 (Common) 13.8 kV H01 Switchgear Replacement (Three Bus Sections)," dated April 6, 1987.

4. 10 CFR 50.59 Evaluation 87-022-02, "1-X04 and 2-X04 Transformer Fire Wall," dated September 30, 1991.

5. NFPA 805 Fire Protection Program Design Document (FPPDD).

Figure 8-1 UNITS 1 & 2 MAIN ONE LINE DIAGRAM

[redacted]

Figure 8-2 UNIT 1 480 VOLT ONE LINE DIAGRAM

[redacted]

Figure 8-3 UNIT 2 480 VOLT ONE LINE DIAGRAM (Sheet 1)

[redacted]

Figure 8-3 UNIT 2 480 VOLT ONE LINE DIAGRAM (Sheet 2)

[redacted]

Figure 8-3 UNIT 2 480 VOLT ONE LINE DIAGRAM (Sheet 3)

[redacted]

Figure 8-4 480V ONE LINE DIAGRAM ALTERNATE SHUTDOWN SYSTEM

[redacted]

Figure 8-5 UNITS 1 & 2 125 V ONE LINE DIAGRAM

[redacted]

Figure 8-6 UNITS 1 & 2 125 VDC ONE LINE DIAGRAM

[redacted]

Figure 8-7 125V ONE LINE DIAGRAM

[redacted]

Figure 8-8 UNITS 1 & 2 INSTRUMENT BUS ONE LINE DIAGRAM

[redacted]

8.1 345 kV AC ELECTRICAL DISTRIBUTION SYSTEM (345 kV)

The main transmission lines to PBNP and other Eastern Wisconsin power companies operate at 345 kV AC. The Point Beach Nuclear Plant has two main generators that produce electrical power at 19 kV AC. The output of the main generators is stepped up to 345 kV AC by the main transformers 1/2-X01. Unit output circuit breakers F52-122 for Unit 1 and F52-142 for Unit 2, are on the 345 kV side of the main transformers and connect to the 345 kV AC Switchyard Bus Sections 2 and 4 respectively.

8.1.1 DESIGN BASIS

The 345 kV system does not perform any safety related function and is classified non-safety related. The 345 kV distribution system performs the following functions:

1. Transmits power generated at PBNP to the 345 kV grid.
2. Provides standby power to PBNP auxiliaries during unit(s) startup, shut down, and after reactor trip.
3. Provides a reliable source of normal power to PBNP engineered safeguards equipment.
4. Acts as an interconnecting terminal for the four 345 kV lines at PBNP.

The design of the system is such that sufficient independence or isolation between the various sources of electrical power is provided in order to guard against concurrent loss of all auxiliary power. Safety related auxiliary electrical loads are normally powered from offsite power supplies (through the high voltage and low voltage station auxiliary transformers) to ensure continuity of power during plant transients.

The 345 kV AC system is credited in the event of a fire and has been evaluated in the at-power and non-power analyses (Reference 3).

8.1.2 SYSTEM DESCRIPTION AND OPERATION

In each unit, electrical energy generated at 19 kV AC is transformed to 345 kV AC by the main transformer banks, (rated 756 MVA at 65°C rise) and delivered through the unit output circuit breaker (rated at least 345 kV, 15,000 MVA, 2 KA) to the 345 kV switchyard located at the plant site. The switchyard is located on the west side of PBNP adjacent to the protected area fence. The unit output circuit breakers F52-122 and F52-142 are located in the switchyard and the control power for these breakers is derived from the switchyard batteries. These breakers remain closed following a unit trip in order to provide power to the unit's auxiliary loads by back feeding through the X01 main transformer. The electrical output of both units is integrated into Northeast Wisconsin's 345 kV AC transmission system which presently has 345 kV interconnections with other Wisconsin utilities as well as Illinois and Minnesota utilities.

The 345 kV system consists of 4 lines connected to the plant switchyard. Each line is carried on a separate line structure in order to minimize the possibility of losing more than one circuit at a time. One of the four 345 kV transmission lines can supply all of the plant auxiliary power. The output of the main generator is connected to the 345 kV system through the 19 kV generator output breaker and the X-01 transformer. Control power for the 19 kV generator output breaker is obtained from the station batteries. Figure 8.1-1 depicts the 345 kV system and electrical connections.

The 345 kV system supplies the high voltage station auxiliary transformers (1/2-X03) which provide the interface to the 13.8 kV system and are the normal offsite power supply for auxiliary loads associated with plant engineered safeguards. Under some conditions, if the normal offsite supply is not available, safeguards equipment can also be supplied from offsite power by back feeding through the main transformer. Refer to FSAR 8.3 and FSAR 8.4 for further discussion on this alternate offsite power line up.

Lightning arresters are used for lightning protection. All oil filled transformers, except the high voltage station auxiliary transformers, are covered by automatic water spray systems to extinguish oil fires quickly and prevent the spread of fire. Transformers are spaced to minimize exposure to fire, water and mechanical damage. The X03 high voltage station auxiliary transformers, located in the 345 kV switchyard, are separated by the full length of the switchyard, approximately 600 ft.

The 345 kV switchyard utilizes two batteries to improve the reliability of the 125 VDC control system. All 345 kV breakers are provided with redundant trip-coils; each trip-coil of a particular breaker is deliberately supplied from a separate battery. Reliability is further enhanced by providing each battery with separate battery chargers; sufficient charger capacity exists to supply the DC loads and maintain a float charge on each battery.

8.1.3 SYSTEM EVALUATION

Analysis of the interconnected 345 kV system shows that a fault on any one of the four transmission lines or any bus section at Point Beach, or the loss of both Point Beach units will not cause a cascading failure of the 345 kV AC transmission system, provided all four transmission lines and five bus sections at Point Beach are in service.

Additional studies show that when one or more of the four transmission lines is out of service, there is the potential for cascading failure of the 345 kV AC transmission system, given the loss of one of the remaining transmission lines or the occurrence of a fault on one of the remaining transmission lines or any bus section at Point Beach. The potential for such a cascading failure of the 345 kV AC transmission system is dependent upon the level of generation at Point Beach and the transmission load at the time of the failure or fault. These studies also show that the Power System Stabilizers (PSS) installed at Point Beach would improve the response of the main generators to external 345 kV system disturbances by dampening system transients. Operating Procedures have been developed and implemented which limit operation of the Point Beach Units, such that a cascading failure of the 345 kV AC transmission system described above will be minimized. The Operating Procedures include conditions for both with and without the PSS in service at Point Beach. The off-site power supply to the plant for any of the aforementioned failures is therefore assured (Reference 2).

Comprehensive studies of the interconnected transmission network in the American Transmission Company (ATC) / Midcontinent Independent System Operator (MISO) footprint under contingency conditions have been made. These studies showed that the sudden loss of any single unit will not affect the ability of the 345 kV AC transmission system to supply power to the Point Beach Nuclear Plant auxiliary systems. A simplified one line diagram of the 345 kV system interconnections is shown on Figure 8.1-2.

The physical locations of electrical distribution system equipment is such as to minimize vulnerability of vital circuits to physical damage as a result of accidents. The main transformers and high voltage station auxiliary transformers are located outdoors and are physically separated from each other.

If either 125 VDC switchyard system battery should become open circuited, which is the most likely failure mode, the control voltage supply would be maintained by the associated battery charger. If, however, a battery becomes short circuited the associated control supply will fail. Loss of both local and remote operability is highly unlikely since simultaneous short circuits on both batteries or on the battery leads must take place. Any short circuit of an individual control feeder would clear through individual fusing provided; the remainder of the control supplies would remain intact.

Assuming that both switchyard batteries become short circuited and that a fault occurs on a 345 kV bus or line connected to the switchyard, protection is obtained by second zone protective relay schemes at the remote line end terminals which will trip the remote end breakers connected to the fault. The unit affected would be tripped by any of several protective schemes depending on the type and location of the fault. These schemes include a negative sequence relay, turbine overspeed trip device or, if an underfrequency condition exists, the main coolant pumps will be tripped. Any of these protection systems will trip the reactor, the turbine and the generator field breaker.

Reference 1 provides additional information regarding the site's response to a Station Blackout (SBO).

Open Phase Protection

Analyses were performed to evaluate the impact of open phase conditions on safeguards equipment. The open phase conditions analyzed are those on the high side of offsite power sources 1X-03 and 2X-03 (1X-01 and 2X-01 for back feed) where one or two of the three incoming phases are open circuited. The open phase conditions considered include all loading conditions. Evaluations show that safeguards equipment will be protected for applicable open phase conditions, or that the amount of unbalance is tolerable, without equipment damage, for a period of time that would allow for identification of the open phase condition. This protection is provided via the following station equipment:

- Degraded Voltage Relays for 4160V safeguards buses 1A-05, 1A-06, 2A-05, and 2A-06
- Loss of Voltage Relays for 4160V safeguards buses 1A-05, 1A-06, 2A-05, and 2A-06
- Transformer Neutral Overcurrent Relays for transformers 1X-03 and 2X-03 (1X-01 and 2X-01 for back feed)

For certain double open phase conditions without a safety injection signal present, it is possible for motors to trip on overcurrent. For this scenario, Operations will have sufficient time to restart the motors as applicable.

In addition, Open Phase Detection (OPD) monitoring systems are installed for each of the offsite power sources 1X-03 and 2X-03 (1X-01 and 2X-01 for back feed) to identify open phase conditions. When an open phase condition is detected by an OPD system, an alarm is provided in the control room.

References 4 through 6 provide additional information regarding Open Phase Protection.

8.1.4 REFERENCES

1. FSAR Appendix A.1 "STATION BLACKOUT"
2. Procedure OP 2B, "345 KV Transmission System Impacts Upon PBNP Station Operation"
3. NFPA 805 Fire Protection Program Design Document (FPPDD)
4. NEI Industry Initiative on Open Phase Condition, dated September 20, 2018
5. Calculation 0292-0056-CALC-005
6. Calculation 0292-0056-CALC-006

Figure 8.1-1 345 kV SWITCHYARD AND INTERCONNECTIONS

[redacted]

Figure 8.1-2 PBNP 345 kV INTERCONNECTIONS

[redacted]

8.2 13.8K VAC ELECTRICAL DISTRIBUTION SYSTEM (13.8kV)

The 345 kV system and the Gas Turbine (G05) are the sources of power to the 13.8 kV system. The 13.8 kV electrical distribution system is the intermediate voltage power distribution system which provides the normal offsite power supply to the 4.16 kV safeguard buses during power operations and during plant startup, shutdown and following main generator trips. The 13.8 kV system also supplies safe-shutdown buses (via X08), various plant support loads (via X27), G05 auxiliaries (via X500), 345 kV switchyard auxiliaries (via X48), Nuclear Engineering Services Building (via X65), Training Building (via X66), and Sewage Treatment Plant (via X72).

8.2.1 DESIGN BASIS

The 13.8 kV system does not perform any safety related functions. The 13.8 kV system shall distribute power from the Gas Turbine (GT) to those loads required during a station blackout, to achieve and maintain safe reactor shutdown (Reference 1). The 13.8 kV system is credited in the event of a fire and has been evaluated in the at-power and non-power analyses (Reference 3).

8.2.2 SYSTEM DESCRIPTION AND OPERATION

Figure 8.2-1 is a sketch of the 13.8 kV system showing its interconnections to the station and to the 345 kV switchyard. The 13.8 kV system boundaries include the high voltage station auxiliary transformer (1/2X03) up to the high side connection of the low voltage station auxiliary transformers (1/2X04), and various 480V transformers.

The 13.8 kV system supplies offsite power to the Point Beach Nuclear Plant via the 4.16 kV and 480V systems. The 13.8 kV system is divided into three buses which are designated H01, H02, and H03. The H02 bus supplies Unit 1 and is normally served by the high voltage station auxiliary transformer 1X03. The H02 bus supplies power to the low voltage station auxiliary transformer 1X04. In a like manner, the H03 bus supplies Unit 2 and is normally served by the high voltage station auxiliary transformer 2X03. The H03 bus supplies power to the low voltage station auxiliary transformer 2X04. The units can be interconnected to alternate supplies by arranging bus tie breakers to connect H02 to H01 and H03 to H01. The power generated by the Gas Turbine can be delivered to either unit by also arranging the13.8 kV tie breakers of the H01, H02, and H03 buses.

The normal 13.8 kV electrical arrangement is to have one of the two bus tie breakers (H52-21 or H52-31) closed supplying power to the H01 tie bus. The H01 bus supplies the gas turbine auxiliaries as well as the north service building transformer X27 and the alternate shutdown transformer X08. The gas turbine generator G05 is connected to the tie bus H01 through breaker H52-10 (see Section 8.9 for GT startup requirements).

In addition, a three phase, 15 MVAR capacitor bank has been added to 13.8 kV bus H01. Aligning bus H01 to either bus H02 (Unit 1) or H03 (Unit 2) could then align this capacitor bank to either unit's offsite connection. Under certain conditions, the capacitor bank will permit a lower offsite 345 kV grid voltage while still maintaining adequate voltage at the 4160V safety buses (A-05 and A-06) such that the degraded grid relays will not actuate and transfer the safety buses to the onsite emergency diesel generators. Procedural controls prevent the capacitor bank from operating simultaneously with the gas turbine generator G-05 (Reference 2).

The H01, H02 and H03 bus configuration allows a high voltage station auxiliary transformer (X03) to be removed from service and its associated low voltage auxiliary transformer to be supplied through the H01 bus from the other X03 transformer or Gas Turbine. When a high voltage station transformer (X03) experiences a fault, the tie breakers between H02 and H01; and H03 and H01, receive an automatic transfer signal to restore power to the respective low voltage station transformer. Additional protective relaying exist to protect the 13.8 kV buses by preventing closure of circuit breakers to faulted buses. The closing of the tie breakers into a common fault is prevented by trip and lockout interlocks in the breaker control circuits. Auto closure of the tie breakers can be defeated by placing the remote control switches in pullout, or transferring to local control.

The local control panels for the H01, H02 and H03 buses are C221, C222 and C223 respectively. The metering and relaying for each breaker associated with the switchgear is located on the local control panels. Each breaker of the switchgear has local control switches located on their respective control panels with the main feeder and tie breakers having additional remote control switches on Control Room Panel C02. Remote control and metering circuits are separately fused so that a control or cable spreading room fire can not disable local operation.

The 13.8 kV switchgear is controlled by 125 VDC power supplied from plant station batteries D105 and D106. Each bus section has a separate DC supply panel with an associated manual transfer switch which allows for selection of one of the two independent supplies. These supplies are separated and fused so that a fire in any of the three rooms (H01, H02, or H03 switchgear sections) will not disable both supplies for the other two rooms. Each circuit within the DC panels has separate fuse monitor relays which input to a common control room annunciator.

The 13.8 kV breakers are manually synchronized by utilizing synchronizing scopes and switches. The synchronizing switch provides interlocks to prevent manual breaker closure without the synchroscope and incoming and running voltmeters being turned on.

The primary protective relaying for each 13.8 kV bus section is provided by bus differential relays (87). The secondary protective relaying for bus H02 and bus H03 is provided by inverse time overcurrent relays (51) connected to the transformer side of the feeder breakers in H05 and H06. The differential and overcurrent relays for the buses operate manually reset lockout relays (86) which trip and lockout each breaker on the bus section. The lockout relays (86) for the H02 and H03 buses also trip and lockout their associated feeder breakers located in H05 and H06 respectively. Ground fault protection is provided for H03 and H02 by a low voltage pickup overvoltage relay (59) connected across the break in a grounded wye-broken delta voltage transformer circuit. This relay activates an alarm.

Power supplied by circuit breakers H52-11 (X08), H52-16 (X27), and H52-23 (H08 and H09) is protected by inverse time overcurrent phase relays (51) connected to the bus-side current transformers of the feeder breaker.

The primary protective relaying for the High and Low Voltage Station Auxiliary Transformers is provided by transformer differential relays (87). Backup protection for the transformers is provided by sudden pressure relays (63). Further backup protection is given by overcurrent relays (51). These relays actuate the respective transformer manually reset lockout relays (86). The transformer manually reset lockout relays trip low voltage breakers of the affected voltage transformers. The lockout relays (86) also trip the high voltage breaker of the affected Low Voltage Station Auxiliary Transformer and the high voltage circuit switcher for the affected High Voltage Station Auxiliary Transformer.

Breaker failure relays (62BF) are installed in the system to avoid significant problems caused by the failure of primary protection. The additional protection is required due to the automatic bus crosstie logic of the 13.8 kV system where one fault could cause the loss of all offsite power for both Units.

8.2.3 SYSTEM EVALUATION

The normal offsite power supply for safeguards equipment is supplied from the 345 kV AC transmission system via the high voltage and low voltage station auxiliary transformers (X03) and (X04), respectively. The 13.8 kV system can also be used to provide offsite power to non-safety related electrical loads via the X03 and X04 transformers during startup and shutdown, although this is not the normal alignment. Each low voltage station auxiliary transformer can supply all the auxiliary loads for its unit. Refer to FSAR 8.3 for a description of the unit auxiliaries normally supplied by the 19 kV system via the unit auxiliary transformer (1/2-X02).

Two separate outside sources can serve either unit's low voltage station auxiliary transformer. The primary source of power to the safeguards buses for each unit, is a low voltage station auxiliary transformer aligned with its respective high voltage station auxiliary transformer. Alternate power may also be supplied by aligning the 13.8 kV buses to the opposite unit’s high voltage station auxiliary transformer or to the Gas Turbine Generator. Transfer from the normal to the alternate high voltage station auxiliary transformer is accomplished automatically if the normal high voltage station auxiliary transformer is tripped.

The system is designed to minimize, to the extent practical, the likelihood of a simultaneous loss of offsite power to Units 1 and 2 due to any single credible incident to any component or at any location. This is achieved by physical separation of the bus sections, transformers, duct runs, manholes, cables, etc. The H01, H02, and H03 switchgear sections are located in the 13.8 kV Switchgear Building. This building is divided using one hour fire walls into separate rooms for each bus which include local panels for relaying and control.

Through equipment selection and administrative controls, the 13.8 kV system has adequate protective relaying and interrupting capability to properly interrupt all possible faults, assuming any of the above described alignments. Additional, controls exist to limit the paralleling of the high voltage station auxiliary transformers (1/2X03) during transfer of the H01 tie bus.

8.2.4 REFERENCES

1. FSAR Appendix A.1 “Station Blackout”
2. PBNP 10 CFR 50.59 Evaluation EVAL 2009-013-01, PBNP EC 13600 Capacitor Bank Addition,” October 14, 2009.
3. NFPA 805 Fire Protection Program Design Document (FPPDD).

Figure 8.2-1 13.8 kV SIMPLIFIED ONE LINE DIAGRAM

[redacted]

8.3 19K VAC ELECTRICAL DISTRIBUTION SYSTEM (19 kV)

The 19 kV AC Electrical Distribution System (19 kV) distributes the energy developed by the unit's main generator (1/2-TG01) to the main transformer (1/2-X01) and the unit's auxiliary transformer (1/2-X02) via the main generator output circuit breaker (1/2-G52-TG01). This section of the FSAR presents both the 19 kV Electrical Distribution system as well as portions of the unit's main generator (1/2-TG01).

8.3.1 DESIGN BASIS

The 19 kV system does not perform any safety related function and is classified non-safety related. The 19 kV AC distribution system performs the following functions:

1. Transmit the power generated by the main generator (1/2-TG01) to the main (1/2-X01) and unit auxiliary (1/2-X02) transformers.

2. Provide power to unit auxiliaries via 1/2-X02 during normal plant operations, startup, shut-down and following a unit trip.

3. Provide a means to step up the output voltage of the main generator, from 19 kV to 345 kV, for use in the 345 kV AC transmission system.

4. Provide a means to isolate the main generator from the 345 kV AC transmission system and to phase the unit on line.

5. Provide a means to back feed power from the 345 kV AC transmission system to the 4160 VAC safeguard buses via the 1/2-X01 and 1/2-X02 transformers when the 1/2-X04 transformer is out of service.

The 19 kV system is credited in the event of a fire and has been evaluated in the at-power and non-power analyses (Reference 1).

8.3.2 SYSTEM DESCRIPTION AND OPERATION

Each unit is equipped with one Westinghouse hydrogen inner-cooled turbine generator. Each generator produces and delivers 19 kV, 3 phase, 60 Hz. electric power to the main transformer (X01) where it is stepped up to 345 kV AC. The Unit's main transformer output is connected to the 345 kV AC transmission system. Each generator output also feeds the associated unit auxiliary transformer (X02) where the voltage is stepped down to 4160 VAC for use within the station. Each generator is rated at 684 MVA at a power factor of 0.94. The rotor (field), rotating through the 4-pole per phase armature at 1800 RPM, produces a 60 Hz alternating current.

During normal operation each generator delivers power to the main and auxiliary transformers through isolated phase buses (1/2 Z-117A, B, C). The isolated phase bus is a force-cooled metal clad bus which connects the output of the main generator to the main transformer (X01) via the generator output circuit breaker (1/2-G52-TG01). The service water (SW) system provides the cooling for the isolated phase bus through an air-to-water cooler.

The unit's main transformer (X01) steps up the main generator output voltage for use in the 345 kV AC transmission system. The main transformer consists of a bank of three separate transformers, one for each phase. Each transformer is a cooling class ODAF, outdoor, shell form power transformer. The ODAF class is cooled by forced oil which in turn is cooled by forced air.

The main transformers are located outside and adjacent to their respective turbine buildings (South for Unit 1 and West for Unit 2).

The bulk of the power required for station auxiliaries during normal operation of either unit is supplied by an auxiliary transformer (1/2-X02) connected to the isolated phase bus of that unit. The 1/2-X02 transformers are also located outside, in close proximity to their respective main transformers (1/2-X01). The unit auxiliary transformers (1/2-X02) are part of the 4.16 kV system and are described in FSAR 8.4.

Protective relaying for the 1/2-X01 and 1/2-X02 transformers is provided by primary and backup transformer lockout relays (86). The lockout relays will isolate the transformers in the event of fault or failure of the 19 kV or connected 345 kV system. Protective relaying for the main generator is provided by primary and backup generator lockout relays (86). These lockout relays will open the main generator breaker and main generator field breaker to isolate the generator in the event of a generator fault or turbine trip.

Following a turbine generator trip, the 19 kV main generator breaker (1/2G52- TGO1) opens. The auxiliaries on the 4.16 kV non-safeguards buses remain fed by the unit auxiliary transformer (1/2X-02) via the main transformer (1/2X-01). With a low voltage station auxiliary transformer (1/2X-04) out of service, the 19 kV system can also be used to provide offsite power to the shutdown unit's 4.16 kV buses by back feeding from the 345 kV system through the X-01 and X-02 transformers.

8.3.3 SYSTEM EVALUATION

There are no Technical Specification requirements placed on the 19 kV system, however portions of the system may be used to satisfy the offsite power requirements of Technical Specification 3.8.1, “AC Source - Operating,” and Technical Specification 3.8.2, “AC Source - Shutdown” when a low voltage station auxiliary transformer (1/2X-04) is out of service. Periodic testing of the 19 kV system is performed per the applicable maintenance procedures.

8.3.4 REFERENCES

1. NFPA 805 Fire Protection Program Design Document (FPPDD)

8.4 4.16K VAC ELECTRICAL DISTRIBUTION SYSTEM (4.16 kV)

The majority of electrical loads, used for both safety and non-safety related applications, at PBNP are powered by the 480V AC system. The various sources, used to supply the 480V AC system, are rated at different voltages and the 4.16 kV system provides the primary means to interconnect the onsite and offsite power sources and distribute the power to the 480V AC system.

8.4.1 DESIGN BASIS

The 4.16 kV system provides a reliable source of power to the safety related loads during all normal and emergency plant operating conditions. During station blackout conditions the 4.16 kV system shall supply power to those loads required to achieve and maintain safe reactor shutdown (See Reference 1 for additional Station Blackout information). The 4.16 kV system has sufficient independence from offsite sources to be rapidly isolated to protect the safeguard buses in the event of a design basis accident. The 4.16 kV system is designed with redundant loads to ensure a single failure will not prevent a safety related component from performing its intended function.

The 4.16 kV system is credited in the event of a fire and has been evaluated in the at-power and non-power analyses (Reference 5).

8.4.2 SYSTEM DESCRIPTION AND OPERATION

Each unit's main generator serves as the main source of electrical power for the non-safety related auxiliary loads during "on-the-line" operation of the unit. Power is supplied, to the 4.16 kV system, via a 19/4.16 kV three winding unit auxiliary transformer that is connected to the main leads from the unit's generator. Upon a generator trip, offsite auxiliary electric power is backfed from the 345 kV AC transmission system via transformers X01 and X02.

The 4.16 kV system is comprised of six buses per unit (A01 through A06), the unit auxiliary transformer (X02), and the low voltage auxiliary transformer (X04). Figure 8-1 shows the station's electrical interconnection, and the 4.16 kV distribution system is shown in Figure 8.4-1. Two buses per unit, A03 and A04, are connected to the 13.8 kV system via bus supply breakers to the independent windings of the low voltage station auxiliary transformer (X04). Buses A03 and A04 serve buses A05 and A06 respectively. Buses A05 and A06 are connected to buses A03 and A04 using manually closed tie breakers. A05 and A06 supply all of the safety-related loads (4.16 kV and 4.16kV/480V transformers).

During unit operation the output of the unit's main generator supplies power to the primary side of the unit auxiliary transformer (X02) which is directly connected to the 19 kV system bus between the generator output circuit breaker (G52-TG01) and the main step up transformer (X01). The 4.16 kV buses A01 and A02 are then connected to the independent windings of the secondary side of the unit auxiliary transformer (X02). All normal operating non-safety related 4.16 kV auxiliaries are split between buses A01 and A02. In addition, buses A01 and A02 each serve one 4160/480 volt station service transformer. Buses A0l and A03 or buses A02 and A04 can be tied together via bus tie breakers. The normal at-power alignment is with the tie breakers between A01 and A03 (A02 and A04) open. Following a turbine generator trip, the 19 kV main generator breaker (G52-TG01) opens. The auxiliaries on the 4.16 kV non-safeguards buses remain fed by the unit auxiliary transformer (X02) via the main transformer (X01). Control power for the 4.16 kV breakers is obtained from the station batteries.

If either low voltage station auxiliary transformer 1-X04 or 2-X04 is removed from service, tie breakers between buses 1-A03 and 2-A03 and between 1-A04 and 2-A04 can be manually closed. Offsite power can also be provided to the A03 and A04 buses from the A01 and A02 buses respectively when back fed from the 345 kV system through the X01 and X02 transformers. A spare X04 transformer is maintained in a condition which will allow expeditious repair or replacement of 1-X04 or 2-X04 (Reference 3).

Buses A05 and A06 each serve one of the two 4160/480 volt station service transformers for the unit's 480 volt safeguards equipment and one of the two safety injection pumps. Buses 1A-06 and 2A-05 each serve one motor driven auxiliary feedwater pump. No transfer is required for the safeguards equipment in the event of a turbine generator trip. In addition to being served by buses A-03 and A-04, buses A-05 and A-06 are directly served by the Train A and Train B emergency diesel generators respectively.

[redacted] The overhead bridge and associated towers are non-safety related seismic Class III structures designed to AISC Steel Specifications to withstand the design bases wind speed of 100 mph. Strategically located bollards prevent accidental impact to the tower legs from limited height moving vehicles, such as fork-lift trucks. The design and location of the overhead bridge structure is such that any postulated failure would not affect the offsite power supply from the opposite unit’s X04 transformer (Reference 2, Reference 4).

8.4.3 SYSTEM EVALUATION

The auxiliary electrical system is designed to provide a simple arrangement of buses requiring the minimum of switching to restore power to a bus in the event that the normal supply to that bus is lost.

The 4.16 kV system has a series of relays which automatically initiate features designed to provide protection to the safety related buses and loads, and to ensure that all safety-related loads are capable of starting and operating continuously to perform their safety functions. The 4.16 kV relaying scheme is designed to detect abnormal conditions of frequency and voltage, including degraded voltage and loss of voltage, and effect compensatory actions (i.e. tripping/closing tie breakers, tripping feeder breakers, starting the emergency diesel generators, etc.). The 4.16 kV relaying scheme is also designed to prevent premature or unnecessary separation from offsite power. 4.16 kV system components receive various actuation signals including; Safety Injection (SI), Containment Pressure Condensate Isolation (CPCI), Steam Generator Feedpump Trips, Heater Drain Tank low level, Motor Driven AFW pump low suction pressure, and AMSAC. Additionally, the 4.16 kV system provides input to various systems including; the Safety Injection (SI) reset logic, reactor trip logic, Diesel Generator (DG) starting logic, and AMSAC. Bus supply breakers from offsite power are tripped on loss of bus voltage and they must be manually reclosed upon restoration of offsite power. Manual alignment of alternate shutdown buses B-08 and B-09 (breaker B52-59B) to the 4.16 kV bus 2A-06 (breaker 2A52-94) via alternate power transformer (X-05) is allowed during NFPA-805 events where supply via X-08 is not available. Breakers B52-59B and 2A52-94 are administratively controlled in the

OPEN position during the normal plant operation. In an emergency condition, (i.e., loss of 4160V bus voltage), breaker 2A52-94 is tripped automatically.

The 4.16 kV buses are located in areas which minimize their exposure to mechanical, fire and water damage. This equipment is designed to permit safe operation of the equipment under normal conditions and to provide protection for short circuits. This equipment is electrically coordinated to limit the extent of equipment affected by a short circuit, sufficient to maintain plant safety.

8.4.4 REFERENCES

1. FSAR Appendix A.1 "Station Blackout"

2. 50.59 Evaluation 2008-003, Rev. 1, "Installation to Replace Portions of Power Cables from 2X-04 to 2A-03 and 2A-04," dated December 11, 2009.

3. NRC Safety Evaluation, Safety Evaluation of the Preferred Power Systems Conformance to General Design Criterion 17," dated August 29, 1983.

4. 50.59 Evaluation 2010-002, Rev. 0, "EC 13251 - Reroute of 1X04 Low Voltage Side power Cables to Facade," dated November 15, 2010.

5. NFPA 805 Fire Protection Program Design Document (FPPDD).

Figure 8.4-1 4.16 kV AC DISTRIBUTION SYSTEM

[redacted]

8.5 480 VOLT AC ELECTRICAL DISTRIBUTION SYSTEM (480V)

The majority of the electrical loads used for normal and emergency plant operations are powered by the 480 Volt AC Distribution System (480V). The 480V system is supplied primarily from the 4.16 kV system, although some non-safety related portions are supplied by the 13.8 kV system. This section describes the 480V system and components, the types of loads, system protective features, and the 480V electrical interconnections.

8.5.1 DESIGN BASIS

The 480V system provides a means to reliably distribute 480 VAC power to those loads required during normal and emergency plant conditions; including those loads required to mitigate the consequences of all postulated accidents. Circuit protection is provided to the loads supplied by the 480V system. Portions of the 480V system are required to provide power to essential safe shutdown equipment during Station Blackout (SBO) conditions (See Reference 1 for additional Station Blackout information). The 480V system is credited in the event of a fire and has been evaluated in the at-power and non-power analyses (Reference 2).

8.5.2 SYSTEM DESCRIPTION AND OPERATION

The 480V system buses and switchgear are supplied by the 4.16 kV system through the 4160/480 VAC station service transformers (1/2X-11 through X-14) and diesel generator building transformers (1/2X-06). The alternate shutdown transformer (X-08) supplies the alternate shutdown buses, B-08 and B-09, from the 13.8 kV system. Manual alignment of alternate shutdown buses B-08 and B-09 to the 4.16 kV System via alternate power transformer (X-05) is allowed during NFPA-805 events where supply via X-08 is not available.

The 480V system is shown in Figure 8-2 through Figure 8-4. The 480V system is divided into four buses per unit. The buses for Unit 1 are supplied from the 4,160 volt buses as follows: 1B-0l from 1A-01, 1B-02 from 1A-02, 1B-03 from 1A-05, and 1B-04 from 1A-06. Tie breakers are provided between 480 volt buses 1B-01 and 1B-03, buses 1B-02 and 1B-04, and buses 1B-03 and 1B-04. No synchronization ability has been provided with the 480 volt tie breakers, and they accordingly utilize a dead bus transfer scheme. The Unit 2 480 volt buses have the same arrangement as described for Unit 1.

The 480 volt safeguards equipment is connected to buses B-03 and B-04. Power for safeguards valve motors is supplied from the motor control centers B-32 and B-42 which in turn are served from buses B-03 and B-04, respectively. Since the normal source of power for these buses is the 345 kV system (via station auxiliary transformers X-03 and X-04; 4160 volt buses A-03, A-05 and A-04, A-06; and station service transformers X-13 and X-14), no transfer is required in the event of a turbine generator trip.

Auxiliary equipment (fuel oil pumps and fuel oil pump room heaters) for the Train A emergency Diesel Generators (DG) is powered from 1B-30 and 2B-30. These emergency diesel generator motor control centers are powered from the motor control centers 1B-32 and 2B-32, respectively. The auxiliary equipment for the Train B emergency diesel generators (DG) is powered from 1B-40 and 2B-40. These emergency diesel generator motor control centers are powered by transformers from the 1A-06 and 2A-06 buses, respectively. 1B-40 and 2B-40 are each divided into a safety related and a non-safety related section. The non-safety related portion of these motor control centers is isolated from the safety related section by an undervoltage signal on the associated 4.16 kV bus. (Reference 3)

The alternate shutdown buses (B-08 and B-09) are supplied from the 13.8 kV bus (H-01), via the X-08 transformer. Alternate shutdown equipment can be powered from the G-05 Gas Turbine (GT) through 480V buses B-08 and B-09 and alternate transfer switches located at remote shutdown stations throughout the plant (Reference 2). Alternate shutdown buses (B-08 and B-09) to be manually aligned to the 4.16 kV bus (2A-06) via the X-05 transformer is allowed during NFPA-805 events when supply via X-08 is not available.

The 480 volt motor control centers are located in areas of electrical load concentration. Those loads associated with the turbine-generator auxiliary system in general are located in the turbine building. Those loads associated with the nuclear steam supply system are located in the Auxiliary Building. Those loads associated with the emergency diesel generators (G-03 and G-04) are located in the Emergency Diesel Generator building.

There are various other 480 VAC transformers, buses, and power panels used throughout the site that are not directly relied on for plant operation. These 480 volt components are only mentioned in this section to describe how they are supplied from the onsite/offsite electrical distribution systems. Table 8.5-1 is a listing of the associated 480 volt loads, supply transformer, and transformer's supply bus. These 480 volt associated loads are considered non-critical and are not discussed in any further detail.

8.5.3 SYSTEM EVALUATION

The 480 V load centers are located in areas which minimize their exposure to mechanical, fire and water damage. This equipment is designed to permit safe operation of the equipment under normal conditions and to provide protection for short circuits. This equipment is electrically coordinated to limit the extent of equipment affected by a short circuit, sufficient to maintain plant safety. The electrical system equipment is arranged so that no single contingency can inactivate enough safeguards equipment to jeopardize the plant safety.

The 480 V system provides undervoltage protection of the loads on the safeguards buses B-03 and B-04. The undervoltage devices on the 480 V system controls the load shedding on the 480 V buses and determines when the load sequencing timers can begin timing after a Diesel Generator (DG) start. The 480V undervoltage devices are disabled for ‘A’ train buses when powered by the emergency diesel generator.

B-03 and B-04 bus tie breakers (1B52-16C and 1B52-19B for Unit 1 and 2B52-40C and 2B52-30A for Unit 2) are supplied to facilitate maintenance of the normal supplies to the buses. The use of these breakers is limited to certain circumstances defined in the Technical Specifications to minimize the probability of failure propagation that could disable both 480 volt safeguards buses in a unit in recognition of the need to maintain operability of shared safety features for any operating unit and operability of decay heat removal for any shutdown unit. These breakers are administratively controlled in the open position with their control power fuses removed. In an emergency condition, i.e., loss of 480 volt safeguards bus voltage or safeguards actuation in a unit, tie breaker 1B52-16C for Unit 1 or 2B52-40C for Unit 2 will be tripped automatically.

The safeguards equipment (listed in Section 8.8.3) which are automatically sequenced during an undervoltage occurrence have feeder circuit breakers which can be reclosed from the control room should they trip due to overcurrent. Overload trip elements on the reversing starters associated with the various motor-operated valves can be reset at the motor control centers.

The 480V system requirements to meet Station Blackout (SBO) are outlined in FSAR Appendix A.1 (Reference 1).

8.5.4 REFERENCES

1. FSAR Appendix A.1 "Station Blackout"
2. NFPA 805 Fire Protection Program Design Document (FPPDD).
3. SCR 2007-0223, "Design Detail for MCCs 1B-40 and 2B-40," dated January 9, 2008.

Table 8.5-1 ASSOCIATED 480 VOLT SOURCES

DESCRIPTION	SUPPLIED BY TRANSFORMER	TRANSFORMER SUPPLY
B-60	X-65	H-08
TRAINING BUILDING	X-66	H-08
MAUSOLEUM	X-24	A-08
TRAILERS	POLE TRANSFORMERS	A-08
QUONSET HUTS	X-42	A-08
MET TOWER	X-25	A-08
B-07	X-27	H-01
SOUTH GATE HOUSE	1X-704	1A-04
SWITCHYARD AUX.	X-48	H-01
WAREHOUSE 3	X-07 & X-90	2A-04 & A-09

8.6 120 VAC VITAL INSTRUMENT POWER (Y)

The 120 VAC Vital Instrument Power (Y) is supplied from the 125V DC and 480V AC systems. The 120 VAC Vital Instrument (Y) system provides power to both safety and non-safety related systems and is used throughout the plant.

8.6.1 DESIGN BASIS

During normal, abnormal, or emergency conditions the 120 VAC Vital Instrument Power system (Y) shall continuously provide power of adequate voltage and quality to connected safety related loads. During a design basis accident combined with a loss of offsite power and a single failure, the Vital 120 VAC Instrument Power system shall continuously provide power to the Engineering Safety Feature (ESF) Actuation System to ensure a spurious Safety Injection actuation does not occur in the non-accident unit. During a Station Blackout (SBO) or plant fires, the vital 120 VAC Instrument Power system shall continuously supply power to those instrument loads necessary to achieve and maintain safe reactor shutdown (See Reference 1 for additional station blackout information and Reference 2 for fire related issues).

8.6.2 SYSTEM DESCRIPTION AND OPERATION

The 120V AC vital instrument power system (Y) distributes power to safety related and non-safety related systems from diverse power sources (AC and DC).

The 120V AC vital instrument power system provides and distributes reliable 120 VAC power to plant instruments and controls. The system consists of sixteen buses, divided among four instrument channels. Each of the four channels (red, white, blue, and yellow) are allocated four buses. The distribution buses are further subdivided into two bus groups, one group serving Unit 1 and the other serving Unit 2.

Each channel is powered by three inverters (see Figure 8.6-1 and Figure 8.6-2). One inverter is dedicated to the Unit 1 bus group and a second inverter is dedicated to the Unit 2 bus group. The third inverter is an alternate, and can swing between the Unit 1 and Unit 2 buses. Shifting between normal and alternate inverters is accomplished using manual make-before-break transfer switches. Use of the alternate inverter allows either dedicated inverter to be removed from service for maintenance.

The function of the inverters is to convert 125 volt DC from station batteries to 120 volt AC. The inverters are therefore powered from the 125 volt DC system. The three inverters powering any one instrument channel share a common supply from one of the main 125 volt DC buses.

The red channel inverters (1/2DY-01 and DY-0A) are powered from bus D-01 through panels D-11, D-12, and D-26. The blue channel inverters (1/2DY-02 and DY-0B) are powered from bus D-02 through panels D-13, D-14, and D-27. The white (1/2DY-03 and DY-0C) and yellow channel (1/2DY-04 and DY-0D) inverters are powered directly from buses D-03 and D-04, respectively.

Although normally powered from an inverter supply, each instrument channel can be powered from a backup power source. The backup power source is from non-safety-related Y-15 or Y-16 buses which are supplied from 480V bus B-09 via regulating transformer XY-08. The output of each inverter is connected to a static transfer switch that will automatically transfer the associated instrument buses to the backup power source in the event of an inverter failure, with little or no power interruption. Signals causing the transfer of the static switches include low voltage, current overload, and inverter failure signal (anticipatory to loss of voltage). The backup source is designed to maintain power to affected buses only until they can be manually transferred back to an operable inverter. The backup source is designed to supply the Unit 1 and Unit 2 loads of one instrument bus channel. It will therefore maintain power to the affected instrument bus channel in the case of a main DC bus failure. Electrical interlocks are in place to prevent static switches from more than one instrument bus channel from transferring to the backup source at the same time.

The White and Yellow instrument channels supply 1/2XY-113 and 1/2XY-114 isolation transformers which supply the Radiation Monitoring (RM) Systems non-safety-related instrument panels 1/2Y-113 and 1/2Y-114. Panels 1/2Y-113 and 1/2Y-114 supply instrument panels 1/2Y-11, 1/2Y-21, 1/2Y-31 and 1/2Y-41 which supply other non-safety related loads. The isolation transformers are used to prevent remote faults from non-safety related components from feeding back to the protection buses.

In the event of an inverter or bus failure of a 120V instrument protection channel(s), multiple alarms will sound in the control room. The alarms are located on the auxiliary safety instrument panel (ASIP), panel C20 in the control room. The inverters are operated locally at the inverter panels.

In addition to the four 120 volt instrument channels there are two (per unit) non-safety related portions of the 120 VAC Instrument power system (Y). These four additional instrument buses supply power to non-protection, non-redundant instruments. Each bus is energized from a single 480/120 volt transformer with no alternate sources of power from the 480V system (see Figure 8.6-3). Transformers 1/2XY-05 supply power to distribution panels 1/2Y-05 and transformers 1/2XY-06 supply power to distribution panels 1/2Y06. These buses reduce the required load on the static inverters supplying the protection channels.

The 120V AC Vital Instrument System (Y) provides power to various instrument racks for the Reactor Protection System (RPS), the Engineered Safety Feature (ESF) Actuation System, the Nuclear Steam Supply System (NSSS) Controls, and other miscellaneous instrumentation and control systems.

8.6.3 SYSTEM EVALUATION

Instrument Buses Y-01/Y-101, Y-02/Y-102, Y-03/Y-103, and Y-04/Y-104 must each be supplied by independent, battery-backed sources to ensure that a single failure combined with a loss of offsite power will not prevent mitigation of a design basis accident. Upon a loss of an inverter, the instrument bus will automatically transfer to a non-safety-related 120 VAC bus (Y-15 or Y-16) if available. The amount of time that an instrument bus may be operated on a non-safety-related 120 VAC source is outlined by Technical Specification. Monitoring of instrument bus voltage and alarm indication each shift ensures that any loss or transfer of an instrument bus to non-safety related source is detected.

The 120 VAC Vital Instrument Power (Y) system configuration prevents any instrument bus inverter from supplying more than one instrument channel bus. Electrical separation (for DY-01 through DY-04) and administrative controls (for DY-0A through DY-0D) prevent any instrument bus inverter from supplying more than one unit's instrument channel. Electrical interlocks prevent more than one instrument channel (two units, same color) from being supplied by the non-safety-related source (Y-15 and Y-16).

8.6.4 REFERENCES

1. FSAR Appendix A.1 “Station Blackout”

2. NFPA 805 Fire Protection Program Design Document (FPPDD).

Figure 8.6-1 INSTRUMENT POWER RED AND BLUE CHANNELS

[redacted]

Figure 8.6-2 INSTRUMENT POWER WHITE AND YELLOW CHANNELS

[redacted]

Figure 8.6-3 INSTRUMENT POWER NON-PROTECTION SECTION

[redacted]

8.7 125 VDC ELECTRICAL DISTRIBUTION SYSTEM (125V)

The 125 VDC Electrical Distribution system (125V) provides a reliable source of power for safety and non-safety related loads of both PBNP units. The system includes six separate, independent DC distribution buses, each capable of being connected to a common "swing" bus. Four of the six buses and the swing buses are safety related and shared between the units. The other two buses are non-safety related and each is dedicated to a single unit.

Each DC bus is powered by at least one AC-to-DC battery charger (eight total), backed up by a station battery (seven total). The swing buses have two chargers and one battery that are sized to carry any one of the six independent buses.

8.7.1 DESIGN BASIS

During normal operation each safety-related DC bus shall supply uninterruptible DC power of adequate voltage and quality to support systems that monitor for abnormal/accident conditions and initiate protective actions. During abnormal or emergency conditions, with or without a concurrent loss of offsite power, each safety-related DC bus shall supply uninterruptible DC power of adequate voltage and quality to safety-related loads for accident mitigation. During station blackout, the system shall continuously supply power to those loads required to achieve and maintain safe reactor shutdown during the blackout period (See Reference 1 for additional Station Blackout information). During normal plant operation, the system shall continuously supply power of adequate voltage and quality to connected loads. The 125 VDC system is credited in the event of a fire and has been evaluated in the at-power and non-power analyses (Reference 2).

8.7.2 SYSTEM DESCRIPTION AND OPERATION

The safety-related 125V system consists of four main distribution buses: D-01, D-02, D-03, and D-04 (see Figure 8.7-1). The D-01 (train A) and D-02 (train B) main DC distribution buses supply power for control, emergency lighting, and the red and blue 120 VAC Vital Instrument bus (Y) inverters. The D-03 (train A) and D-04 (train B) main DC distribution buses supply power for control and the white and yellow 120 VAC Vital Instrument bus (Y) inverters.

Each of the four main distribution buses is powered by a battery charger (D-07, D-08, D-107 and D-108) and is backed up by a station battery (D-05, D-06, D-105, and D-106). The function of the battery chargers is to supply their respective DC loads, while maintaining the batteries at full charge. All of the battery chargers are powered from the 480V AC system. The battery chargers have been sized to recharge any of their respective partially discharged batteries within 24 hours while carrying normal loads.

The battery chargers are interlocked such that a loss of offsite power will disconnect the battery chargers from their 480V AC source. A coincident safety injection signal would prevent restoration of the battery chargers unless offsite power is restored to the safeguards buses or safety injection is reset. This limits the loading on the standby emergency power supply during the period immediately following a safety injection signal. During this period the 125V DC loads are supplied by their associated station battery until such time as power to the chargers is restored.

In addition to the four 125V safety related main distribution buses, there exist two safety-related swing DC distribution buses (D-301 and D-302) which permit the connection of a swing battery and/or a swing charger to one of the four main distribution buses. Two swing battery chargers are available through one of the swing DC distribution buses. Swing charger D-09 is connected to swing DC distribution bus D-301 and can provide a source of DC power to distribution buses D-01 or D-02. Likewise, swing charger D-109 is connected to swing DC distribution bus D-302 and can provide a source of DC power to distribution buses D-03 or D-04.

In addition, there exists a swing safety-related battery D-305 which is connected to swing DC distribution bus D-301. This swing battery is capable of being aligned to any one of the four main distribution buses to take the place of the normal battery. Mechanical interlocks exist on swing DC distribution buses D-301 and D-302 which prevent the paralleling of redundant DC buses.

The swing bus D-301 can be connected with two non-safety related buses designated 1/2D-201. The two D-201 buses are connected to two non-safety related batteries 1/2D-205 respectively and powered from chargers 1/2D-207.

The 480V AC supplies for chargers designated D-07, D-08 and D-09 are from motor control centers 1B-39, 2B-49, 1B-49, and 2B-39 in the control building (see Figure 8.7-1). Motor control centers 1B-39, 2B-49, 1B-49, and 2B-39 are supplied by 480 volt buses 1B-03, 2B-04, 1B-04, and 2B-03, respectively. The 480V AC supplies for chargers designated D-107, D-108 and D-109 are from motor control centers 2B-39, 1B-49, 1B-32, and 2B-42 in the control or primary auxiliary building (See Figure 8.7-1). Motor control centers 2B-39, 1B-49, 1B-32, and 2B-42 are supplied by 480 volt buses 2B-03, 1B-04, 1B-03, and 2B-04 respectively. Interlocks are provided to assure that Train and divisional separation is maintained when supplying power from the swing buses D-301 and D-302 to the safety related main distribution buses.

Emergency power supply for vital instruments, control power, and for some DC emergency lighting of both units is supplied from [redacted] which are common to both units. Additional emergency lighting, provided in “safe shutdown” areas and access routes to and from these areas, [redacted]

There are two non-safety related 125V distribution buses (1/2D-201), batteries, and battery charges installed. These buses and ancillary equipment are dedicated to a specific unit, and supply power to non-safety related loads. A connection is provided from swing bus D-301 to both non-safety related buses to allow the power of non-safety related loads while performing maintenance on the associated battery charger and/or battery. Test connections are also provided.

The PAB battery and electrical equipment room ventilation system (VNBI) maintains the station batteries (D-105 and D-106), inverters, and other safety-related components within established temperature limits. This system also prevents hydrogen buildup in the battery rooms. An annunciator in the Control Room will alert the operators of a ventilation system failure or high room temperature.

8.7.3 SYSTEM EVALUATION

Safety related station batteries D-05, D-06, D-105, and D-106 have been sized to carry their expected shutdown loads following a plant trip/LOCA and loss of offsite power or following a station blackout for a period of one hour without battery terminal voltage falling below either: (1) the design minimum battery terminal voltage (equivalent to 1.75 volts per cell for battery considerations), or (2) the minimum battery terminal voltage required to maintain the most limiting component, and therefore all fed components, operable. D-05, D-06, D-105, and D-106 are 60 cell, lead acid station batteries. The safety related swing station battery D-305 is a 60 cell, lead acid station battery sized to carry the expected loads and provide adequate voltage when aligned to any one of the four main DC buses. Load profiles for D-05, D-06, D-105, D-106, and D-305 are provided in the design basis sizing, voltage drop and short circuit calculations (Reference 3, Reference 4, Reference 5, and Reference 6). Each station battery is located in a separate room.

One battery charger is in service on each battery so that the batteries are always at full charge in anticipation of loss of AC power incident. This ensures that adequate DC power is available to initiate the starting of the emergency generators and other emergency uses. A description of the station batteries requirements for station blackout can be found in Reference 1

The swing battery chargers and the swing battery allow the normally on-line battery chargers and batteries to be removed from service for maintenance that can not be performed with the equipment on-line.

To ensure the quality of DC power on a bus powered by a station battery charger, the charger should be connected to a station battery. A connected battery will filter the output of the charger. In any configuration, the quality of the battery charger output and battery charger operability may be ascertained from control room annunciation of the following conditions on a common “Battery Charger Trouble” alarm; AC Power Failure, Low DC Volts, High DC Volts, DC Ground, Output Breaker Open.

The unit specific non-safety related DC buses and batteries are of adequate size to supply power to the currently connected loads and additional non-safety related loads which may be rewired from the safety related buses.

8.7.4 REQUIRED PROCEDURES AND TESTS

Periodic testing, including discharges that envelope the calculated service test duty cycle associated with each battery, is performed for each battery in accordance with Technical Specification surveillance requirements. Each battery’s service test duty cycle is based on the bounding load profile from its design basis battery calculation (Reference 3, Reference 4, Reference 5, and Reference 6). The service test duty cycle for swing battery D-305 is required to bound the most limiting load profile of the four battery sizing calculations.

8.7.5 REFERENCES

1. FSAR Appendix A.1 “Station Blackout”

2. NFPA 808 Fire Protection Program Design Document (FPPDD).

3. PBNP Calculation N-93-056, “Battery D05 System Sizing, Voltage Drop and Short Circuit Calculations.”

4. PBNP Calculation N-93-057, “Battery D06 System Sizing, Voltage Drop and Short Circuit Calculations.”

5. PBNP Calculation N-93-058, “Battery D105 System Sizing, Voltage Drop and Short Circuit Calculations.”

6. PBNP Calculation N-93-059, “Battery D106 System Sizing, Voltage Drop and Short Circuit Calculations.”

Figure 8.7-1 125 VDC ELECTRICAL DISTRIBUTION

[redacted]

8.8 DIESEL GENERATOR (DG) SYSTEM

The normal source of power to safety related 4.16 kV and 480V buses is from offsite through the station low voltage auxiliary transformers. If this normal source should fail, the standby source of emergency power is the diesel generating (DG) system. The DG system is composed of four diesel generators that directly supply the safety related 4.16 kV electrical distribution system. Each diesel engine is supported by its own dedicated auxiliary systems for maintaining the start readiness, starting, and continued operation. The independent design of the diesel generator engine and auxiliary systems precludes any single failure from preventing the DG system from performing its intended safety related function.

8.8.1 DESIGN BASIS

Each Emergency Diesel Generator (EDG) is capable of sequentially starting and supplying the power requirement of one complete set of safeguards equipment for one reactor unit and providing sufficient power to allow the second reactor unit to be placed in a safe shutdown condition. Each diesel generator provides the necessary power to cool the core and maintain the containment pressure within the design value for a loss of coolant accident (coincident with a loss of offsite power) in addition to supplying sufficient power to shut down the unaffected unit (no accident is assumed in the second unit). Each diesel generator will be started upon the receipt of an undervoltage condition signal on either its primary or opposite unit same train 4160 volt bus, and re-energize its 4160 volt bus. All four diesel generators will start when a safety injection (SI) signal is received from either unit. The EDGs are required to start and be ready for loading within 10 seconds after receiving a start signal. Sufficient fuel oil is maintained by each train to provide for a 6 day run of one EDG at rated design load. The DG system is credited in the event of a fire and has been evaluated in the at-power and non-power analyses (Reference 2). During a station blackout (SBO), an EDG from the non-blacked out unit can be used as an Alternate AC (ACC) source. An EDG will start, accelerate to rated frequency and voltage, and can be connected to an emergency AC (EAC) bus in either unit within ten minutes of SBO initiation. Additional detail is included in Reference 1.

8.8.2 SYSTEM DESCRIPTION AND OPERATION

The emergency diesel generator configuration consists of four shared emergency diesel generators. The diesel generators are divided into two trains, "A" and "B." The two Train A emergency diesel-generator sets are located in separate rooms in the seismic Class I section of the turbine building and are connected to the Train A 4160 volt auxiliary system safeguards buses of both units. The two Train B emergency diesel-generator sets are located in separate rooms in the seismic Class I Emergency Diesel Generator Building (DGB) and are connected to both Train B 4160 volt auxiliary system safeguards buses of both units. All four emergency diesel generators are normally available. The target reliability for each EDG is 97.5% (Reference 1 and Reference 3).

The emergency diesel generators are General Motors Corporation, Electro-Motive Division, Model 20-645E4 diesel engine-generator units.

The two Train A emergency diesels are G-01 and G-02. The two Train A diesels are normally aligned as standby emergency power, G-01 to the Unit 1 Train A 4160 volt bus (1A-05) and G-02 to the Unit 2 Train A 4160 volt bus (2A-05). The two Train B EDGs are normally aligned as standby emergency power, G-03 to the Unit 1 Train B 4160 volt bus (1A-06) and G-04 to the Unit 2 Train B 4160 volt bus (2A-06). G-01 will automatically provide power to 1A-05 if power is lost on 1A-05, G-02 will automatically provide power to 2A-05 if power is lost on 2A-05. G-01 may be manually connected to provide power to 2A-05, and G-02 may be manually connected to provide power to 1A-05. Additionally, if G-01 is out of service, G-02 may be placed in a mode that will allow it to automatically provide power to 1A-05 or 2A-05 or both, if either or both buses lose power. When G-02 is out of service, G-01 can be aligned in the same manner as G-02, described above. Emergency diesel generators G-03 and G-04 have similar capabilities for the B Train, as the A train EDG. Unintentional paralleling of two EDGs is controlled by the use of key switches for the EDG output breakers to the opposite units' same train 4160 volt bus and with interlocks which prevent the automatic closure of two EDGs to the same 4160 volt bus (Reference 3). Offsite power is not locked out upon emergency generator operation.

The DG system has several auxiliary support systems that must function in order to perform its safety related function, including; Diesel Starting Air (DA) system, engine fuel oil system (FO), engine cooling system, engine lubricating system, and room ventilation system (VNDG).

Train A Emergency Diesel Generators

The Train A units are rated at 2,850 kw for 2000 hours, 0.8 power factor, 900 rpm, 4160 volts, 3-phase, 60 cycle AC. Additional ratings for the Train A units include 2963 kw for 200 hours, 3000 kw for 4 hours and 3050 kw for a 30-minute period.

The Train A emergency diesels are automatically started by two pairs of air motors. Each engine has its own independent starting system, including two banks of three air storage tanks and two compressor systems powered from a 480 volt safeguards bus. By manually aligning the pulley belt, one air compressor in each unit may be powered by its own independent auxiliary diesel engine. Each bank of air receivers has sufficient storage to crank the engine five times for the normal cranking duration. The starting air systems are completely redundant for each diesel generator.

Starting air for the Train A emergency diesels is admitted from the storage tanks at a nominal working pressure of 196 psi to the starting system through two-way solenoid valves. Sufficient air storage is provided to permit at least 5 starts before the tanks are exhausted. When the signal to start the diesel is initiated, a motor driven fuel pump and governor booster pump will start, and the solenoid valves for both air banks will be energized to open. When the starter motor pinions are engaged, both banks of starter motors will crank the engine.

Cranking continues until either the engine starts or until the start failure time delay has elapsed. At this time, the start failure alarm will be initiated and start attempts will be automatically repeated until either the engine starts or the start lockout time delay expires. At least 3 start attempts will be made on an initiated start signal. Upon start lockout, operator action is required prior to additional start attempts. The emergency diesel generators are capable of being started and ready to accept load within 10 seconds (i.e., fast start).

One of the two motor-driven starting air compressors associated with each diesel is fed from the emergency bus supplied from a B train diesel. Using a B train power supply for the A train diesel generator starting air compressor provides additional assurance that starting air will be available to start the diesel generator. Each of the two motor driven compressors associated with each A train diesel is stripped upon an undervoltage condition on the related motor control center and requires manual action to reset (Reference 9). The control voltage for the diesel starting system is backed up by a manually switched 125 V DC power supply from an alternate station battery.

To ensure rapid start, each diesel unit is equipped with an immersion heater which furnishes heat to the engine cooling water when the engine is shut down. Thermosyphon flow of hot water through the oil cooler heats the lube oil. The warmed oil is circulated through the engine and turbocharger by lube oil circulating pumps and is returned to the engine lube oil sump.

Low lube oil pressure, overspeed, reverse power, and loss of generator field protective interlocks are incorporated in the diesel generators control systems.

For low lube oil pressure, three pressure switches are connected such that actuation of any combination of two are required to stop the engine. Faulty action of one switch will not result in engine shutdown. The reason for the 2-out-of-3 trip function is to prevent destruction of the bearings, a condition which would rapidly occur and would quickly result in power failure while leading to further engine damage.

Overspeed will shut down the engine. Overspeed would rapidly lead to engine destruction.

Electrical protection for emergency diesel generators G-01 and G-02 include time overcurrent, reverse power, loss of field, ground fault, and overload relays. The time overcurrent, reverse power, and loss of field relays trip and lockout the affected diesel generator's output circuit breaker until the condition clears (along with triggering various alarms). The overload and ground fault relays provide alarms only.

The audible and visual alarm system is located in the main control room and will alarm off-normal conditions which include engine starting and operating parameters, loss of DC control power and control switches that are not in the auto position. Overload/overpower alarms are provided via Overload Relays 67P-1 and 67P-3 to alert operators when the diesel generator is overloaded.

A ground fault alarm is provided for G-01 and G-02 by a low voltage pickup overvoltage relay (59) connected across the break in a grounded WYE-broken delta voltage transformer circuit.

Auxiliary equipment (fuel oil pumps and fuel oil pump room heaters) for the Train A emergency diesel generators is powered from 1B-30 and 2B-30 which are powered from the motor control centers 1B-32 and 2B-32, respectively.

<u>Train B Emergency Diesel Generators</u>

The Train B units are rated at 2848 kw for 2000 hours, 0.8 power factor, 900 rpm, 4160 volts, 3 phase, 60 cycle AC. Additional ratings for the Train B units include 2951 kw for 200 hours, and 2987 kw for 4 hours.

The Train B emergency diesels are automatically started by two pairs of air motors. Each engine has its own independent starting system, including two banks of two air storage tanks and two compressors, one powered from the associated 480 volt emergency diesel generator MCC and the other from a fuel oil powered diesel engine. Each bank of air receivers has sufficient storage to crank the engine five times for the normal cranking duration. The starting air systems are completely redundant for each diesel generator.

Starting air for the Train B emergency diesels is admitted from the storage tanks at a nominal working pressure of 240 psi, applied to the starting system at 196 psi through a pressure regulator and two-way solenoid valve. When the signal to start the diesel is initiated, a motor driven fuel pump and governor booster pump will start, and the solenoid valves will be energized to open. When the starter motor pinions are engaged, the starter motors will crank the engine. Cranking continues until either the engine starts or until a predetermined time period of 5 seconds has elapsed. At this time, the start failure alarm will come on. Although sufficient air storage is provided to permit at least 5 starts before the tanks are exhausted, operator action is required for additional start attempts. The emergency diesel generators are capable of being started and ready to accept load within l0 seconds (i.e., fast start).

One of the two motor-driven starting air compressors associated with each diesel is driven by a fuel oil powered diesel engine. This provides additional assurance that, if a diesel fails to start, its air storage tanks can be replenished.

Train B 125 V DC distribution panels D-28 and D-40 are located in the DGB and are supplied by safety related DC buses D-04 and D-02 respectively. D-28 provides DC control and auxiliary power for G-03 and 1A-06. D-40 provides DC control and auxiliary power for G-04 and 2A-06. Each distribution panel has a manually switched alternate feed from the opposite panel and interlocks are provided to prevent the panels from being energized simultaneously from both the normal and alternate supplies.

To ensure rapid start, each diesel unit is equipped with an immersion heater which furnishes heat to the engine cooling water when the engine is shut down. Thermosyphon flow of hot water through the oil cooler heats the lube oil. The warmed oil is circulated through the engine and turbocharger by lube oil circulating pumps and is returned to the engine lube oil sump.

Local/Remote Control Switches located in the DGB are used to transfer control between the DGB (local) and the Main Control Room (remote). When the switches are in the local position, control of the G-03 and G-04 EDGs is from the DGB only and all control signals from the Main Control Room will be isolated. Controls and indication are sufficient to allow an EDG to be started, synchronized and loaded to the normal and/or alternate 4.16 kV buses manually from either the Main Control Room or locally in the DGB. The EDGs can also be manually fast started locally or from the Main Control Room.

A normal or emergency shutdown of the EDG will automatically trip the generator output breaker. A normal shutdown of an EDG can be initiated locally or from the Main Control Room if an automatic fast start signal is not present. A normal shutdown results in a cooldown run at idle speed for approximately 15 minutes before the engine is shutdown. If an automatic fast start signal is received during cooldown, the normal shutdown is defeated and the diesel will enter the fast start mode of operation.

An emergency shutdown of an EDG is initiated by the following protective trips: low lube oil pressure, high jacket water temperature, generator differential current, and overspeed. An emergency shutdown can also be initiated via an emergency stop pushbutton located on the engine control cabinet independent of the position of the Local/ Remote transfer switch.

The three low lube oil pressure switches are connected such that actuation of any combination of two are required to stop the engine. Faulty action of one switch will not result in engine shutdown. The reason for the 2-out-of-3 trip function is to prevent destruction of the bearings, a condition which would rapidly occur and would quickly result in power failure while leading to further engine damage.

The overspeed trip function provides protection against engine destruction caused by an overspeed condition. The overspeed trip results in the injectors being mechanically held in the no fuel position using mechanical components independent of those used to control the injectors during a normal or other type of emergency shutdown.

Electrical protection for diesel generators G-03 and G-04 includes differential current, time overcurrent, reverse power, loss of field, ground fault, overload, and voltage monitoring relays. The time overcurrent, reverse power, and loss of field relays trip the affected diesel generator's output circuit breaker. The overload and ground fault relays provide alarms and the voltage monitoring relay provides a permissive to allow closing the diesel generator output circuit breaker.

All protective trips other than overspeed, low lube oil pressure, and generator differential current are bypassed upon receipt of an automatic emergency start signal and will be annunciated in the Control Room.

The audible and visual alarm system is located in the main control room and will alarm off-normal conditions which include engine starting and operating parameters, loss of DC control power and control switches that are not in the auto position. Overload/overpower alarms are provided via Overload Relays 67P-1 and 67P-2 to alert the operators when the diesel generator is overloaded. A ground fault alarm is provided for G-03 and G-04 by a low voltage pickup ground detection relay (64) connected across the break in a grounded WYE-broken delta voltage transformer circuit. Abnormal operating conditions and all trip functions are also alarmed locally.

The auxiliary equipment for the Train B emergency diesel generators is powered from 1B-40 and 2B-40 which are located in the DGB and powered by transformers from the 1A-06 and 2A-06 buses, respectively. 1B-40 and 2B-40 are each divided into two sections, a safety-related section and a non-safety-related section. The non-safety-related section is fed from its associated safety-related section via a circuit breaker that is tripped on an undervoltage actuation signal from the associated 4.16 kV bus. All safety-related loads in the DGB are fed from the safety-related portion of the MCC. The cooling water immersion heaters and generator space heaters for G-03 and G-04, and the G-04 fuel oil day tank room space heaters are stripped upon an undervoltage condition on the associated motor control center and require manual action to reset (Reference 9).

See Reference 1, Reference 2, and Appendix D for additional system design and/or operational information.

8.8.3 SYSTEM EVALUATION

Loading Description

Each emergency diesel generator is automatically started on the occurrence of either of the following incidents:

1. Initiation of safety injection operation from either unit; or

2. Loss of Voltage on either of the two 4160 volt safeguards buses (1A-05 or 2A-05 for G-01 and G-02 and 1A-06 or 2A-06 for G-03 and G-04) to which the emergency generator is associated.

With the occurrence of undervoltage on a 4160 volt safeguards bus and loss of voltage on the associated 480 volt safeguards bus, the automatic sequence is as follows:

1. Trip 4160 volt safeguards bus supply breaker to isolate the bus from offsite power.

2. If running, the motor driven auxiliary feedwater pump 4160 volt breaker will trip (only applicable to Unit 1 B train and Unit 2 A train buses).

3. All feeder breakers on the associated 480 volt safeguards bus, except for the component cooling pump motor, standby steam generator (SSG) feedwater pump motor (if applicable), and feeder breakers to safeguards motor control centers and distribution panels are tripped. The tie breakers to non-safeguards buses receive a trip signal. One of the tie breakers between opposite train safeguards buses (1B52-16C in Unit 1 or 2B52-40C in Unit 2) receive a trip signal. These breakers are tripped by 480 VAC Loss of Voltage Relays. For the train A 480 VAC buses, this load shedding function is blocked after the associated 4160 volt safeguards bus emergency diesel generator output circuit breaker closes. This is necessary to prevent inadvertent load shedding during load sequencing. For the train B buses, this load shedding function is not blocked. The train B emergency diesel generator transient voltage response is sufficient to maintain bus voltage above the 480 VAC Loss of Voltage Relays' setting during load sequencing. A minimum time delay is required to ensure that proper coordination is maintained between the 4.16kV and 480V Loss of Voltage functions. Proper coordination is required to prevent the 4.16kV function from occurring faster than the 480V function. This is required to prevent the EDG from reenergizing the safeguards bus prior to the actuation of the 480V load shedding function, which will allow the ESF loads to be sequenced as analyzed.

4. Start the associated emergency diesel generator.

5. When the emergency diesel generator reaches its rated speed (as determined by the engine speed sensing switches) and voltage (as determined by the presence of generator field voltage for G-01 and G-02), the associated emergency diesel generator output breaker automatically closes to re-energize the safeguards bus.

Note: The time from receipt of start signal (i.e. following 4.16 kV Loss of Voltage relay actuation) to emergency diesel generator ready to accept load shall not exceed 10 seconds.

6. If the standby steam generator (SSG) pump or the component cooling pump had been operating prior to the loss of voltage, they would restart upon return of bus voltage. If the component cooling pump had not been running, it would be subject to its automatic starting logic.

7. Manually start any auxiliary as required for safe plant operation. If there is a requirement for engineered safety features operation coincident with undervoltage, step 5, above, is automatically followed by the sequential starting of engineered safety features equipment. This loading sequence for a single EDG providing power to both the Unit 1 and Unit 2 safeguard buses is as follows, continuing from step 5.

		Time Lapse After Step 5*
a.	Start Safety Injection Pump	0 sec.
b.	Start Residual Heat Removal Pump	5.5 sec.
c.	Start Containment Spray Pump	>10.25 sec.
d.	Start Service Water Pump	15.5 sec.
e.	Start Service Water Pump	20.5 sec.
f.	Start Service Water Pump	25.75 sec.
g.	Start Auxiliary Feedwater Pump (U1 B train or U2 A train only)	32.5 sec.
h.	Start Containment Ventilation Fan	39.4 sec.
i.	Start Containment Ventilation Fan	46.75 sec.

* Nominal time delays for initiation of the load breaker closing signal after the emergency diesel generator energizes the bus (Reference 3).

Starting of containment spray pumps is independent of the starting sequence listed above. It occurs 10.25 seconds after a containment high pressure signal with the supply bus energized. It may occur simultaneously with the start of any other load sequenced after 10.25 seconds. The emergency generator automatic loading sequence, including engine starting, will be accomplished in approximately 60 seconds.

If running, the standby steam generator (SSG) pumps will be stripped from the bus upon a motor driven AFW pump automatic start signal or either unit’s safety injection signal. The SSG pumps do not receive any automatic start signals.

Component cooling water pumps will strip and will not automatically restart upon a safety injection signal coincident with a loss of voltage on the associated 480 VAC bus.

Safeguards motor control centers are energized and injection valves are opened at the same time that the safety injection pump is energized.

Automatic start of the control room recirculation and filter fans is initiated by a containment isolation signal, a control room high radiation signal, or a loss of offsite power. EDG load analysis supports the starting of these fans at anytime during the EDG loading sequence (Reference 9).

If the emergency generator is overloaded, an alarm is annunciated in the control room.

Each diesel generator set will start automatically on a safety injection signal from either unit or upon the occurrence of undervoltage on either of its corresponding 4160 volt auxiliary buses. Each diesel has adequate capacity to supply the engineered safety features for the hypothetical accident in one unit and to allow the second unit to be placed in a safe shutdown condition in the event of loss of offsite electrical power. No accident is assumed in the second unit. These loads are tabulated in Table 8.8-1.

Tests are performed to demonstrate assurance that upon the initiation of a start signal the diesel generator will start and assume the required load in the timing sequence listed above. The frequency for performing surveillances required by Technical Specifications will be in accordance with the Surveillance Frequency Control Program (Reference 10).

Dynamic loading calculations for G-01, G-02, G-03 and G-04 establish the link between the required Technical Specification refueling interval testing and the design basis accident loading. The EDG load analysis includes consideration of EDG frequency variations and worst case loading and voltage drop for large motors. The analysis addresses the effects of the EDG dynamic load response on components such as contactors, control fuses, inverters, battery chargers, solenoids, MOVs, thermal overloads, and solid state devices. The operation of critical MOVs was evaluated in detail for meeting the stroke time requirements consistent with accident analysis assumptions, including the potential for stalling and overheating during voltage transients (Reference 7).

Fuel Oil Supply

No. 2 fuel oil is used for the emergency diesel generators. (See TRM 4.12, "Diesel Fuel Oil" regarding the use of blended No. 1 and 2 fuel oil). A 12,000 gallon non-safety related fuel oil fill tank, which is common for both trains, is provided to receive and hold fuel oil from delivery trucks for testing prior to placing the fuel oil into the fuel oil storage tanks.

A 550 gallon "day tank" is located near each diesel generator. The capacity of each day tank will allow its associated EDG to run continuously at 100% rated load for at least 120 minutes without makeup. An additional 550 gallon storage tank is located in the base of each of the Train A diesels.

Two underground fuel oil storage tanks on site (one Train A, one Train B) each have a capacity of approximately 35,000 gallons. Sufficient fuel is normally maintained between the two tanks to allow one diesel to operate continuously at the required load for 7 days. At the minimum Technical Specification required level, one tank could provide enough fuel for an emergency diesel generator to operate for 6 days at rated load (Reference 6). Transfer of oil from each fuel oil storage tank to automatically maintain level in the associated day tanks is accomplished by two 100% capacity motor-driven pumps in each train. Either fuel oil transfer pump is capable of serving either emergency generator in the same train by the use of normally closed manual cross-connect valves between the associated train day tanks. Fuel oil can also be transferred from one underground fuel oil storage tank to the other via the use of a fuel oil transfer pump and normally closed manual cross connect valves. The fuel oil transfer pump controls for G-01 and G-02 are located in the Main Control Room. The fuel oil transfer pump controls for G-03 and G-04 are located in the DGB.

The tanks and piping needed for emergency diesel operation are designated as safety related and meet Class I seismic criteria.

Approximate Fuel Oil Usage Rates

Diesel Generator at rated load: 210 - 220 gal/hr.

8.8.4 REFERENCES

1. FSAR Appendix A.1 "Station Blackout"

2. NFPA 805 Fire Protection Program Design Document (FPPDD).

3. Calculation 2005-0014, "Instrument Uncertainty of Safeguards Sequence Time Delay Relays," Rev. 1, dated August 8, 2005.

4. SE 93-025-26, "Nuclear Power Department Safety Evaluation Report, MR 91-116, Two Additional Diesel Generators, Final Configuration," dated March 28,1996.

5. Calculation 2004-0002, "AC Electrical System Analysis," Revision 4, dated March 26, 2011.

6. NRC Safety Evaluation, "Point Beach Nuclear Plant, Units 1 and 2 - Issuance of Amendments RE: Diesel Fuel Oil Storage Requirements (TAC Nos. ME3282 and ME 3283)," dated August 4, 2011.

7. NRC Safety Evaluation, "Point Beach Nuclear Plant (PBNP), Units 1 and 2 -Issuance of License Amendments Re: Auxiliary Feedwater System Modification (TAC Nos. ME1081 and ME1082)," dated March 25, 2011.

8. NRC Safety Evaluation, "Point Beach Nuclear Plant (PBNP), Units 1 and 2 -Issuance of License Amendments Regarding Use of Alternate Source Term (TAC Nos. ME0219 and ME0220)," dated April 14, 2011.

9. EC 262738, "Alternate Source Term Implementation and CREFS Upgrades to Support Alternate Source Term License Amendment Request."

10. NRC Safety Evaluation, "Point Beach Nuclear Plant Units 1 and 2 - Issuance of Amendments Regarding Relocation of Surveillance Frequencies to Licensee Control (TAC NOS. MF4379 and MF4380)," dated July 28, 2015.

Table 8.8-1 EMERGENCY DIESEL GENERATOR LOADING FOLLOWING A LOSS OF COOLANT ACCIDENT

Automatic Loads

Accident Unit and Common Loads:
- Safety Injection Pump (700 HP)
- Residual Heat Removal Pump (200 HP)
- Three Service Water Pumps (300 HP each)
- Two Containment Fans (150 HP each)
- Containment Spray Pump (200 HP)
- Auxiliary Feedwater Pump (350 HP)
- Safeguards 480V MCC and EDG Auxiliary Loads
- Transformer and Conductor Losses
- Control Room Charcoal Filter Fan (7.5 HP)
- Control Room Recirculation Fan (15 HP)

Non-Accident Unit Loads (Hot or Cold Shutdown):
- Component Cooling Water Pump (250 HP)
- Transformer and Conductor Losses

Manual Loads

Accident Unit and Common Loads:
- PAB Exhaust Stack Fan (60 HP)
- PAB Filter Fan (75 HP)
- Two Battery Chargers
- Component Cooling Water Pump (250 HP) or Charging Pump (100 HP)

Non-Accident Unit Loads (Hot Shutdown):
- Charging Pump (100 HP)
- Containment Fan (150 HP)
- Instrument Air Compressor (100 HP)

Non-Accident Unit Loads (Cold Shutdown):
- Residual Heat Removal Pump (200 HP)

Notes to Table 8.8-1 (Reference 5, Reference 7 and Reference 8)

1. The worst-case EDG load results from a loss of coolant accident on one unit, with the other unit in cold shutdown with residual heat removal (RHR) required. A unit in cold shutdown on RHR results in higher EDG loading than a unit in hot shutdown because of the additional loading due to an RHR pump, which is required for shutdown cooling. For the non-accident unit in hot shutdown, sufficient time exists to restore a charging pump, containment fan, and instrument air compressor under EDG load management procedures. Worst case EDG loading is expected to occur during the initial phases of a loss of coolant accident. As conditions are stabilized, EDG loads such as a safety injection pump and an

auxiliary feedwater pump may be secured to increase EDG load margin. Under EDG load management procedures, all required loads to support the accident and non-accident units can be started within the required time.

2. EDG loading is evaluated during the injection and recirculation phases of a loss of coolant accident, as well as the transition period between injection and recirculation.

3. The worst-case EDG load results when only a single EDG is available and supplying both units A train or B train safety related buses. If more than one EDG is available, additional load margin and flexibility regarding load management exists.

4. The maximum total EDG load during the event is within the 2000 hour load rating.

5. Plant Operators may add optional loads to the emergency diesel generator(s) for mitigation of the event under EDG load management procedures.

6. The EDG steady-state loading analysis is consistent with plant emergency operating procedures and evaluates EDG loading based upon the required engineered safety features for an accident in one unit and to allow the other unit to be placed in a safe shutdown condition, coincident with a loss of offsite power.

7. Horsepower values shown in the table are nominal values. Maximum EDG loading values for all loads are evaluated throughout the event.

8. The motor driven AFW pump will automatically start on the non-accident unit upon a loss of offsite power and subsequent EDG breaker closure, however this will only effect the loading of the EDG train opposite to the train supplying the motor driven AFW pump on the accident unit.

8.9 GAS TURBINE SYSTEM (GT)

The gas turbine generator (G-05) is nominally rated at 20 MW and can be connected to 13.8 kV Bus H01. It can be paralleled with the normal source of plant startup power or as standby power. It may also be paralleled with, or serve in lieu of, (under certain conditions) standby power to provide the first source of power to plant electrical loads. G-05 can supply power to either unit through 13.8 kV/4160 V low voltage station auxiliary transformers (1X04 or 2X04), to the power grid through 13.8 kV/345 kV high voltage station auxiliary transformers (1X03 or 2X03), to the north service building through 13.8 kV/480 V transformer X27, and to provide alternate shutdown power independent of the 4160 V system through 13.8 kV/480 V transformer X08.

8.9.1 DESIGN BASIS

The gas turbine performs no safety-related functions.

G-05 performs the following augmented quality functions:

During a station blackout (SBO), G-05 is relied on as an Alternate AC power source. As such, G-05 must be capable of providing AC power to safe shutdown loads within one hour of the onset of the SBO and supply those loads for the duration of the SBO coping period (4 hours) and subsequent recovery (under certain circumstances, a non-blacked-out emergency diesel generator may be credited as an Alternate AC power source in addition to or in lieu of G-05). (Reference 1)

The Gas Turbine System is credited in the event of a fire and has been evaluated in the at-power and non-power analyses (Reference 2).

8.9.2 SYSTEM DESIGN AND OPERATION

In addition to the four rapid starting emergency generators, there is a gas turbine generator installed at the site. This unit is rated approximately 23.1 MVA and is normally used for spinning reserve, station blackout, and for peaking purposes. This gas turbine unit is connected to the auxiliary electrical system such that it can be paralleled with the normal source of plant startup or standby power. It may also be paralleled with, or serve in lieu of, (under certain conditions) standby power to provide the first source of power to plant electrical loads. The unit is capable of being started and accepting load within one hour of the onset of the SBO using the “Normal” start method. It could be considered a small power plant within itself, fully capable of operating independent of the remainder of the plant.

The gas turbine (G-05) is of the single cycle, heavy-duty type, containing only compressor, combustor, and exhaust sections. It contains a single shaft, terminating at the exhaust end in an overriding clutch, to which a starter diesel engine is attached. The turbine shaft rotates at 4910 rpm, and is coupled to a main reduction gear which drives a conventional 3-phase AC generator and exciter at 900 rpm.

Startup power for G-05 and its auxiliaries is normally supplied by 13.8 kV bus H01 through a 13.8 kV/480 V auxiliary transformer. Bus H01 is energized from one of the high voltage station auxiliary transformers (1/2 X03) when G-05 is shutdown. When G-05 is running, it supplies its own auxiliaries through the same 13.8 kV bus, transformer, and breaker. Because G-05 is designed for startup during a loss of offsite power, the auxiliary loads can also be powered from a separate auxiliary diesel generator located in the gas turbine building. An undervoltage device on the secondary of the transformer will sense a loss of normal power and will start the auxiliary diesel generator and align it to supply the G-05 auxiliaries. Once G-05 is supplying power to bus H01, its auxiliary loads can be transferred back from the auxiliary diesel to bus H01.

The auxiliary diesel generator also serves as a backup power supply to the Technical Support Center (TSC) through breaker 52T and a normal seeking automatic transfer switch. Normal power to the TSC is from buss 1B01. On loss of the normal power supply, control circuitry senses the loss, starts the diesel generator, closes breaker 52T, and operates the automatic transfer switch. The automatic control logic on breaker closure is arranged such that the need for the auxiliary diesel generator to supply gas turbine auxiliaries has priority over the need to supply the TSC loads.

G-05 can be operated from a local control panel located in the gas turbine building or remotely from control room panel C02R. For a startup during a loss of offsite power, automatic synchronization of the generator will not occur and it will be necessary to close breaker 52-G-05 manually onto the dead bus. Required shutdown loads can then be reenergized through their respective low voltage station auxiliary transformer (1/2 X04) or through alternate shutdown transformer (X08) as required.

An air inlet weather hood structure has been installed over the existing G-05 air intake structure. The air inlet weather hood is a non-safety related seismic Class III structure designed to AISC Steel Specifications to withstand the design bases wind speed of 100 mph. The design and location of the air inlet weather hood is such that any postulated failure would not affect the offsite power supply from the opposite unit's X04 (see Section 8.4.2 for 4.16 kV System Description and Operation).

8.9.3 SYSTEM EVALUATION

Although the gas turbine system has no safety related functions, it is relied on to provide backup power during some abnormal situations. During a station blackout, G-05 is designated as an alternate AC power source to supply safe-shutdown loads through the low voltage station auxiliary transformers to each unit. G-05 is also capable of supplying safe-shutdown loads through transformer X08 to the alternate shutdown panels (Reference 2). These loading requirements are significantly less than the original G-05 design capacity.

On a loss of normal power to the Technical Support Center, the G-05 auxiliary diesel generator will start and supply this load.

A supply of diesel fuel oil is maintained on the site in two 60,000 gallon storage tanks to supply the gas turbine and indirectly the heating boilers, and diesel fire pump. An adequate supply of fuel oil is maintained in these tanks to ensure the availability of G-05 for design function performance.

When additional fuel oil is needed to fill an on-site bulk storage tank, the fuel oil may be provided by local suppliers under a purchase order. Local suppliers within 35 miles of Point Beach have bulk storage capacity of about 12.6 million gallons and the capability to provide emergency delivery at any time.

The number of days that equipment consuming fuel oil can operate is dependent upon the weather, the amount of fuel available, and the specific loads connected to the gas turbine generator.

8.9.4 REQUIRED PROCEDURES AND TESTS

Although no Technical Specification surveillance testing is required, minimum reliability requirements must be satisfied to meet SBO commitments. SBO and Alternate AC power are discussed further in Appendix A.1.

8.9.5 REFERENCES

1. PBNP FSAR Appendix A.1, Station Blackout

2. NFPA 805 Fire Protection Program Design Document (FPPDD).

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9.0 AUXILIARY AND EMERGENCY SYSTEMS

The auxiliary and emergency systems are supporting systems required to insure the safe operation or servicing of the reactor coolant system (described in Section 4.0). Various components in some of these systems are shared by Unit l and Unit 2. Appendix A6 discusses this sharing and lists the shared components.

In some cases, the dependable operation of several systems is required to protect the reactor coolant system by controlling system conditions within specified operating limits. Certain systems are required to operate under emergency conditions.

This section considers systems in which component malfunctions, inadvertent interruptions of system operation, or a partial system failure must be designed for, to prevent a hazardous or unsafe condition.

The systems considered under this category are:

Chemical and Volume Control System: This system provides for boric acid injection, chemical additions for corrosion control, reactor coolant cleanup and degasification, reactor coolant makeup, reprocessing of water letdown from the reactor coolant system, and reactor coolant pump seal water injection.

Residual Heat Removal System: This system removes the residual heat from the core and reduces the temperature of the reactor coolant system during the second phase of plant cooldown.

Spent Fuel Cooling System: This system removes the heat generated by spent fuel elements stored in the spent fuel pool.

Component Cooling System: This system removes heat from the reactor coolant system, via the residual removal system during plant shutdown, cools the letdown flow to the chemical and volume control system during power operation and provides cooling to dissipate waste heat from various primary plant components.

Sampling System: This system provides the equipment necessary to obtain liquid and gaseous samples from the reactor plant systems.

Facility Service Systems: These systems include fire protection and service water systems.

Fuel Handling System: This system provides for handling fuel assemblies, control rod assemblies, and material irradiation specimens.

Missile Protection

Criterion: Adequate protection for those engineered safety features, the failures of which could cause an undue risk of the health and safety of the public, shall be provided against dynamic effects and missiles that might result from plant equipment failures. (GDC 40)

This plant-specific General Design Criteria is very similar to 10 CFR 50 Appendix A GDC 4. Under the provisions of that criterion, the dynamic effects associated with postulated pipe ruptures of the RCS may be excluded from the design basis when appropriate analyses approved by the NRC demonstrate that the probably of such ruptures is extremely low. Analyses have been completed for PBNP for the RHR return line, and the RHR suction line (Reference 1 and Reference 2). The NRC has approved the analyses (Reference 3, Reference 4 and Reference 5). As such, the original design features of the facility to accommodate the dynamic effects of a pipe rupture are no longer applicable for these lines.

9.0.1 GENERAL DESIGN CRITERIA

Criteria which are specific to one of the auxiliary or emergency systems are listed and discussed in the appropriate system design basis subsection. Criteria which apply primarily to other systems (and are discussed in other sections) are also listed and cross-referenced below because details of closely related systems and equipment are given in this section.

Reactivity Control Systems Malfunction

Criterion: The reactor protection systems shall be capable of protecting against any single malfunction of the reactivity control system, such as unplanned continuous withdrawal (not ejection or dropout) of a control rod, by limiting reactivity transients to avoid exceeding acceptable fuel damage limits. (GDC 31)

As described in Section 7.0 and justified in Section 14.0, the reactor protection systems are designed to limit reactivity transients to DNBR no less than the design basis limit due to any single malfunction in the deboration controls.

Engineered Safety Features Performance Capability

Criterion: Engineered Safety Features, such as the emergency core cooling system and the containment heat removal system, shall provide sufficient performance capability to accommodate the failure of any single active component without resulting in undue risk to the health and safety of the public. (GDC 41)

Each of the auxiliary cooling systems which serves an emergency function provides sufficient capability in the emergency mode to accommodate any single failure of an active component and still function in a manner to avoid undue risk to the health and safety of the plant personnel and the public.

Containment Heat Removal Systems

Criterion: Where an active heat removal system is needed under accident conditions to prevent exceeding containment design pressure, this system shall perform its required function, assuming failure of any single active component. (GDC 52)

Each of the auxiliary cooling systems, which serves an emergency function to prevent exceeding containment design pressure, provides sufficient capability in the emergency mode to accommodate any single failure of an active component and still perform its required function.

REFERENCES

1. WCAP-15107-P-A, Revision 1 “Technical Justification for Eliminating Accumulator Lines Rupture as the Structural Design Basis for Point Beach Units 1 and 2 Nuclear Plants” (Proprietary) dated June 1, 2001.

2. WCAP-15105-P-A, Revision 1 “Technical Justification for Eliminating Residual Heat Removal (RHR) Lines Rupture as the Structural Design Basis for Point Beach Units 1 and 2 Nuclear Plants” (Proprietary) dated June 1, 2001.

3. NRC SER 2000-0011 “Safety Evaluation of the Request to Apply Leak-Before-Break Status to the Accumulator Line Piping at PBNP, Units 1 and 2,” dated November 7, 2000.

4. NRC SER 2000-0014, “Safety Evaluation of the Request to Apply Leak-Before-Break Status to Portions of the Residual Heat Removal Piping at Point Beach Nuclear Plant, Units 1 and 2,” December 18, 2000.

5. NRC SER 2000-0011/14/15-S1, PBNP, Units 1 and 2, Supplement to Safety Evaluation on Leak-Before-Break Regarding Correction of Leak Detection Capability,” February 7, 2005.

9.1 COMPONENT COOLING WATER (CC)

The component cooling water system consists of four pumps, four heat exchangers, two surge tanks and the piping, valves, instrumentation, and controls necessary to provide the heat removal capability to support the operation of the units and equipment. The component cooling water loop in each unit consists of two pumps (P-11A&B), two heat exchangers (HX-12A&B in Unit 1 and HX-12C&D in Unit 2), a surge tank (T-12), a supply header, and a return header. Heat exchangers HX-12B&C may be used in either loop as cooling conditions require. The capability to use the pumps assigned to one loop to supply both loops is also provided.

9.1.1 DESIGN BASIS

The CC system performs the following safety-related functions (Reference 8, Reference 9, Reference 10, and Reference 11):

- Remove residual and sensible heat from the reactor coolant system, via the residual heat removal (RHR) heat exchangers during the recirculation phase of Safety Injection to support long-term core cooling.
- Remove heat from the RHR heat exchangers to terminate the steam releases associated with the license basis dose analyses for the postulated rupture of a steam pipe (MSLB; Chapter 14.2.5), steam generator tube rupture (SGTR; Chapter 14.2.4), and reactor cooling pump locked rotor (Chapter 14.1.8) accidents.
- Remove heat from the RHR, SI, and containment spray pump seal coolers to maintain the integrity of the pump seals.
- Preclude leakage of the containment atmosphere into the CC system piping to limit the release of radioactive materials.

The CC system is credited in the event of a fire and has been evaluated in the at-power and non-power analyses (Reference 3).

9.1.2 SYSTEM DESIGN AND OPERATION

Normally the component cooling loops of each of the two units operate independently such that two component cooling pumps and one component cooling heat exchanger, HX-12A in Unit 1 and HX-12D in Unit 2, are available for use, and two heat exchangers, HX-12B&C, serve as shared standby units. The description contained herein applies to the component cooling loop of one unit operating independently of the component cooling loop of the second unit. The sharing of components is discussed further in Appendix A.6 (Reference 1).

One pump and one heat exchanger are normally operated to provide cooling water for various components located in the auxiliary and containment buildings. The second pump is in standby and will auto start on low discharge pressure and a second heat exchanger is normally aligned to the unit with CC flow cut in and service water isolated at the discharge. The automatic start function of the CC pumps on low pressure is provided for operational convenience and is not relied upon by the safety analyses to mitigate accidents or events (Reference 16). During the recirculation phase following a loss-of-coolant accident, either or both component cooling water pumps deliver flow to the shell side of the RHR heat exchangers. With the exception of the CC supply to the RHR heat exchangers, cooling water is normally supplied to components served by CC even though a component may be out of service.

Component cooling is provided for the following components:

1. Residual heat exchangers (RHR)
2. Reactor coolant pumps (RCS)
3. Nonregenerative heat exchanger (CVCS)
4. Excess letdown heat exchanger (CVCS)
5. Seal water heat exchanger (CVCS)
6. Sample heat exchangers (SG blowdown and SC)
7. Waste evaporator (WDS) (abandoned in place)
8. Waste gas seal water heat exchangers (WDS)
9. Residual heat removal pumps (RHR)
10. Safety injection pumps (SI)
11. Containment spray pumps (SI)
12. Blowdown Evaporator (abandoned in place with CC isolated)
13. Cryogenic gas compressors
14. Cryogenic after coolers (abandoned in place)
15. Letdown gas stripper condensers

Although component cooling water piping is still in place for Items 7 Waste evaporator (WDS) and 14 Cryogenic after coolers, these components are considered abandoned and therefore do not require component cooling water.

Makeup water is normally taken from the plant makeup water system by manual valve operation as required and delivered to the component cooling surge tank via the surge line. An emergency backup source of water is provided from the reactor makeup water tank by remote operation of a motor operated valve.

The operation of the loop is monitored with the following instrumentation:

1. A temperature detector in the outlet line for the component cooling heat exchangers
2. A pressure detector on the line between the component cooling pumps and the component cooling heat exchangers
3. A flow indicator in the outlet line from the component cooling heat exchangers
4. A radiation monitor on the return header to the component cooling pumps.

The component cooling loop serves as an intermediate system between the reactor coolant and service water systems during cooldown, transferring heat from the reactor coolant to the service water system. This double barrier arrangement reduces the potential for leakage of radioactive reactor coolant to the service water system.

During normal full power operation, one component cooling pump and one component cooling heat exchanger accommodate the heat removal loads and the standby pump and the shared heat exchangers provide 100% backup. Two pumps and two heat exchangers are used to remove the residual and sensible heat during plant shutdown. If one of the pumps or two of the heat exchangers are not operable, safe shutdown of the plant is not affected; however, the time for cooldown is extended.

The component cooling surge tank accommodates expansion, contraction, and inleakage of water, providing a reservoir for continuous component cooling water supply until either a leaking cooling line can be isolated, or system make-up can be initiated. System overpressure protection is provided by a relief valve. A radiation monitor in the component cooling system return header annunciates in the control room and closes the surge tank vent valve in the unlikely event that the radiation level reaches a preset level above the normal background.

The component cooling system branches to and from the above listed Radwaste Equipment (Items 12, Blowdown Evaporator isolated (abandoned in place with CC isolated) through 15, Letdown gas stripper condensers) are seismic Class III piping. Class change isolation valves are provided for both the supply and return headers; equipped with control room control, control room indication, and a containment isolation actuation signal. This provides the class break isolation required by Appendix A.5 (Reference 2).

Component Cooling Loop Components

Several of the components in the component cooling loop are fabricated from carbon steel. The component cooling water contains a corrosion inhibitor to protect the carbon steel. Welded joints and connections are used except where flanged closures are employed to facilitate maintenance. The system is Seismic Class I design with the exception of CC branch lines to radwaste equipment. Design parameters for the component cooling loop components are presented in Table 9.1-1

In addition, the components are not subjected to any high pressure or stresses, hence a rupture or failure of the system is very unlikely. Active components which are relied upon to perform the emergency core cooling function are redundant. The design provides for detection of radioactivity and also provides for isolation means.

The component cooling water system is normally aligned such that Unit 1 and Unit 2 have hydraulically independent systems. However, the CC systems for each unit were designed with the capability to be hydraulically connected under abnormal conditions. Therefore, CC loop components are discussed below at a plant-level.

Component Cooling Heat Exchangers

Four component cooling heat exchangers are of the shell and straight tube (fixed tubesheet) type. Service water circulates through the tubes while component cooling water circulates through the shell side. Normally one heat exchanger is used with each unit with the two idle heat exchangers serving as standby units. The standby unit alignment is CC water cut in and service water isolated at the discharge. The tubes are SA-268 (26-3-3) metal and the shells are carbon steel.

Component Cooling Pumps

The four component cooling pumps, which circulate component cooling water through the component cooling water system, are horizontal, centrifugal units. The pump casings are made from cast iron (ASTM A48) or carbon steel (ASTM A216) based on the corrosion-erosion resistance and the ability to obtain sound castings. The material thickness is dictated by high quality casting practice and ability to withstand mechanical damage and as such are substantially overdesigned from a stress level standpoint. Normally two pumps are designated to each unit, but a crosstie may be opened under abnormal conditions to allow unit-designated pump(s) to supply both units.

Component Cooling Surge Tank

The component cooling surge tank, one per each unit, accommodates changes in component cooling water volume and is constructed of carbon steel. Potassium Chromate is added to the component cooling loops to prevent corrosion.

Component Cooling Valves

The valves used in the component cooling loop are constructed of carbon steel with bronze or stainless steel trim. Since the component cooling water is not normally radioactive, special valve features (such as leakoff connections to the waste disposal system) to prevent leakage to the atmosphere are not provided.

Several component cooling water air operated valves are provided with Close/Auto/Open switches which provide the following control functions when in Auto: (1) the excess letdown HX cooling water outlet valve (CC-769) closes on a containment isolation signal, (2) the “A” and “B” reactor coolant pump thermal barrier cooling water outlet valves (CC-761A&B) close on a high flow signal, and (3) the radwaste component cooling water supply and return valves (LW-63&64) close on a Unit 2 containment isolation signal. The auto closure of LW-63&64 enhances CC system integrity. This feature is not credited for the mitigation of any analyzed accident. Manual action, including completely securing the CC system for repairs, is the analyzed method for CC system restoration, even under DBA conditions (Reference 16). The non-regenerative HX cooling water flow control valve (CC-130) has an Auto/Manual switch which, when in Auto, controls letdown temperature. This is a fail open valve with a manual gag red-locked to limit flow.

Self-actuated spring loaded relief valves are provided for piping and components that could be pressurized to their design pressure.

Component Cooling Piping

All component cooling loop piping is carbon steel with welded joints and connections except at certain components where flanged connections are used to facilitate maintenance. All component cooling lines inside containment have been analyzed for protection from missiles, pipe whip, and jet impingement. Using Leak-Before-Break methodology, no credible missiles exist and therefore the component cooling piping is considered missile protected. The component cooling water system is considered a closed system inside containment with respect to containment isolation capability (Reference 5, Reference 6, Reference 7, Reference 8, Reference 12, and Reference 13).

9.1.3 SYSTEM EVALUATION

For continued cooling of the reactor coolant pumps and the excess letdown heat exchanger inside the containment, most of the piping, valves, and instrumentation are located outside the primary system concrete shield at an elevation well above the anticipated post-accident water level in the bottom of the containment. Cooling lines and equipment in the annular area near the reactor coolant pumps are protected against credible missiles and from being flooded during post-accident operation. Also, this location provides radiation shielding which allows maintenance and inspections to be performed during power operation. The only component cooling water lines that are not shielded by the primary system concrete shield wall are the cooling lines near the reactor coolant pumps. These lines have been analyzed for protection from missiles, pipe whip, and jet impingement. Using Leak-Before-Break methodology, no credible missiles exist and therefore, the component cooling piping is considered missile protected (Reference 5, Reference 6, Reference 7, Reference 8, Reference 12 and Reference 13). Additionally, system leakage would be detected and these lines can be isolated, if necessary, by two valves in series.

Outside the containment, the component cooling pumps and heat exchangers, and associated valves, piping and instrumentation can be maintained and inspected during power operation. System design provides for the replacement of one pump or one heat exchanger while the other units are in service.

Welded construction is used where possible throughout the component cooling loop piping, valves and equipment to minimize the possibility of leakage.

The component cooling water could become contaminated with radioactive water due to a leak in any heat exchanger tube in the chemical and volume control system, the sampling system, the residual heat removal system, or a leak in the cooling coil for the reactor coolant pump thermal barrier. Tube or coil leaks in components being cooled would be detected during normal plant operation by the leak detection system described in Section 6.5. Such leaks are also detected by a radiation monitor located on the main return header.

Should a large tube-side to shell-side leak develop in a residual heat exchanger, the water level in the component cooling surge tank would rise or fall, depending on RCS conditions, and the operator would be alerted by a level alarm. The atmospheric vent on the tank is automatically closed (if the vent was open) in the event of high radiation level at the component cooling water pump suction header. If the leaking residual heat exchanger is not isolated from the component cooling loop before the inflow completely fills the surge tank, the relief valve on the surge tank lifts. The discharge of this relief valve is routed to the auxiliary building waste holdup tank.

The relief valves on the component cooling water header downstream from each of the reactor coolant pumps are designed with a capacity equal to the maximum rate at which reactor coolant can enter the component cooling loop from a severance type break of the reactor coolant pump thermal barrier cooling coil. The valve set pressure is less than or equal to the design pressure of the component cooling piping.

The relief valves on the cooling water lines downstream from the sample, excess letdown, seal water, nonregenerative and residual heat exchangers are sized to relieve the volumetric expansion occurring if the heat exchanger shell side is isolated when cool, and high temperature coolant flows through the tube side. The set pressure is less than or equal to the design pressure of the shell side of the heat exchangers.

The relief valve on the component cooling surge tank is sized to relieve the maximum flow rate of water which enters the surge tank following a rupture of a reactor coolant pump thermal barrier cooling coil.

Leakage from the component cooling loop can be detected by a falling level in the component cooling surge tank. The rate of water level decrease and the area of the water surface in the tank permit determination of the leakage rate. Normal makeup is from the demineralized water header through a manual valve at the tank. Emergency makeup is from reactor makeup water through an isolation valve which is remotely operated from the control room. The component which is leaking can be located by sequential isolation or inspection of equipment in the loop. If the leak is in the on-line component cooling water heat exchanger, a standby exchanger would be placed in service and the leaking heat exchanger isolated. Two standby heat exchangers can be used on either unit in the event the normal heat exchanger develops a leak during a high heat load period when two heat exchangers are desired.

Each of the cooling water supply lines to the reactor coolant pumps contains a check valve inside and a remotely operated valve outside the containment. The cooling water supply line to the excess letdown heat exchanger contains a check valve inside and a manual valve outside the containment. The common supply line to both the reactor coolant pumps and the excess letdown heat exchanger also contains a remotely operated valve outside containment. Additionally, these lines have been analyzed for protection from missiles, pipe whip, and jet impingement. Using Leak-Before-Break methodology, no credible missiles exist and therefore, the component cooling piping is considered missile protected (Reference 5, Reference 6, Reference 7 and Reference 8).

Except for the normally closed makeup lines and equipment vent and drain lines, there are no direct connections between the component cooling water and other systems. The equipment vent and drain lines outside the containment have manual valves which are normally closed unless the equipment is being vented or drained for maintenance or repair operations. The vent lines are also capped when not in use as an additional leakage protection feature.

Following a loss-of-coolant accident, one component cooling pump and one component cooling heat exchanger can accommodate the heat removal loads. If either a component cooling pump or component cooling heat exchanger fails, the standby pump and one of two standby heat exchangers provide 100% backup. Valves in the component cooling supply and return lines for the safety injection, containment spray, and residual heat removal pump seal coolers are normally open. However, each of the component cooling inlet lines to the residual heat exchangers has a normally closed remotely operated valve. If one of those valves fails to open at initiation of long-term recirculation, the other RHR heat exchanger will be provided with sufficient cooling to remove the heat load.

Additional information concerning component cooling design requirements during a loss-of-coolant accident can be found in FSAR Section 6.2, Safety Injection System.

A break of a component cooling line occurring outside the containment could either be isolated and repaired, or the system could be shutdown for repairs, depending on the location at which the break occurred. Although it is anticipated engineering controls would be required, access is available to required components. Once the leak is isolated or the break has been repaired, makeup water is supplied from the plant makeup water system or by the reactor makeup water tank. During the recirculation phase of an accident, repairs to the component cooling system (loss) would not significantly impair reactor core cooling if, Containment Fan Coolers operate to remove containment heat, and core decay heat is transferred to the containment atmosphere by coolant boiling.

The normal power supplies for the component cooling water pumps P-11A and P-11B are safety-related 480 volt buses B-03 and B-04 respectively. In the event of a loss of off-site power without a coincident safety injection signal, at least one CC pump will be automatically started immediately when power is restored to the safeguards buses. If the loss of off-site power is coincident with a safety injection signal, automatic starting of the CC pumps will be blocked on the unit with the safety injection signal. The CC pumps are anticipated to be operating for the recirculation phase of an accident, with the alignment accomplished by operator action. The pumps also have a designated alternate source of power via B-08 or B-09 and an electrical disconnect switch. The alignment requires alternate power supply cables to be run from the disconnect switches to the pump motors.

A failure analysis of pumps, heat exchangers, and valves is presented in Table 9.1-2.

9.1.4 REQUIRED PROCEDURES AND TESTS

The active components of the component cooling system are in either continuous or intermittent use during normal plant operation. Periodic visual inspections and preventive maintenance can be conducted as necessary without interruption of cooling system operation. The inservice testing requirements are described in the PBNP Inservice Testing Program and the IST Background Document. The Closed-Cycle Cooling Water System Surveillance Program (FSAR Section 15.2.10) will be implemented during the period of extended operation (NRC SE dated 12/2005, NUREG-1839)

9.1.5 REFERENCES

1. PBNP FSAR Appendix A.6, Shared Systems Analysis

2. PBNP FSAR Appendix A.5, Seismic Design Analysis

3. NFPA 805 Fire Protection Program Design Document (FPPDD).

4. Not Used

5. "Safety Evaluation of the Request to Apply Leak-Before-Break Status to the Accumulator Line Piping at Point Beach Nuclear Plant, Units 1 and 2," November 7, 2000.

6. "Safety Evaluation of the Request to Apply Leak-Before-Break Status to Portions of the Residual Heat Removal Piping at Point Beach Nuclear Plant, Units 1 and 2," December 18, 2000.

7. "Safety Evaluation of the Request to Apply Leak-Before-Break Status to the Pressurizer Surge Line Piping at Point Beach Nuclear Plant, Units 1 and 2," December 15, 2000.

8. PBNP SE 2001-007, "Component Cooling Water System Closed Loop Inside Containment," February 24, 2001.

9. VPNPD-92-378, B. Link to NRC, “Classification of Auxiliary Systems Necessary to Assure Safe Plant Shutdown at Point Beach, Units 1 and 2,” December 22, 1992.

10. VPNPD-93-115, B. Link to NRC, “Classification of Auxiliary Systems Necessary to Assure Safe Plant Shutdown at Point Beach, Units 1 and 2,” June 17, 1993.

11. NPL 97-0401, D.F. Johnson to NRC, “Component Cooling Water System Issues Update, Point Beach Nuclear Plant, Units 1 and 2,” July 7, 1997.

12. “PBNP, Units 1 and 2, Issuance of Amendments Re: Leak-Before-Break Evaluation for Primary Loop Piping, (TAC NOS. MC1279 and MC1280)” June 6, 2005.

13. “PBNP, Units 1 and 2, Supplement to Safety Evaluation on Leak-Before-Break Regarding Correction of Leak Detection Capability,” February 7, 2005.

14. Not Used.

15. Not Used.

16. “Safety Evaluation by the Office of Nuclear Reactor Regulation Related to Amendment No. 201 to Facility Operating License No. DPR-24 and Amendment 206 to Facility Operating License No. DPR-27 NMC, LLC PBNP, Units 1 and 2” dated August 8, 2001.

17. Calculation CN-SEE-III-08-10, “Point Beach Units 1 and 2 RHRS Cooldown Analysis for EPU to 1806 MWT NSSS Power,” approved February 1, 2013.

Table 9.1-1 COMPONENT COOLING SYSTEM COMPONENT DATA

Component Cooling Pumps	
Quantity	4*
Type	Horizontal centrifugal
Nominal flow rate (each), gpm	3650
Total developed head, ft H_2O	220
Motor horsepower, hp	250
Casing material	Cast iron or Carbon steel
Design pressure, psi	250
Design temperature, °F	200
Component Cooling Heat Exchangers	
Quantity	4**
Type	Fixed tube sheet, horizontal
Design heat transfer, BTU/hr.	50.1×10^6 ******
Code Requirements	ASME VIII ****
Shell side (component cooling water)	
Design inlet Temp., °F	158 ******
Design flow rate, lb/hr	1.346×10^6 ******
Design temperature, °F	200
Design pressure, psig	250
Material	Carbon steel
Tube side (service water)	
Design inlet temperature, °F	85 ******
Design flow rate, lb/hr	1.446×10^6 ******
Design pressure, psig	150
Design temperature, °F	200
Material	SA-268 (26-3-3,Trent Sea-Cure)
Component Cooling Surge Tank	
Quantity (per unit)	1
Volume, gal.	2000
Normal water volume, gal.	1000
Design pressure (internal), psig	100
Design pressure (external), psig	Vacuum breaker provided
Design temperature, °F	200
Material	Carbon steel
Code Requirement	ASME VIII ****
Component Cooling Loop Piping and Valves	
Design pressure, psig	150
Design temperature, °F	200
Code Requirement	USAS B31.1 *****

* Two pumps are normally used with each unit. The capability exists for sharing of the 4 pumps between the two units.

** One heat exchanger is normally used with each unit. Two heat exchangers are used as shared standby units.

**** ASME VIII - American Society of Mechanical Engineers, Boiler and Pressure Vessel Code, Section VIII.

***** USAS B31.1 - Code for Pressure Piping, and special nuclear cases where applicable.

****** The heat transfer value is the design basis value that is used to ensure that the CC HXs can perform their design function. They are dependent on the denoted fluid mass flowrates and inlet temperatures. They are determined in accordance with Reference 17.

Table 9.1-2 FAILURE ANALYSIS OF PUMPS, HEAT EXCHANGERS, AND VALVES

	Components	Malfunction	Comments and Consequences
1.	Component cooling water pumps	Rupture of a pump casing	The casing is designed for 250 psi and 200°F which exceeds maximum operating conditions. Pump is inspectable and protected against missiles. Rupture due to missiles is not considered credible. Each unit is isolable. The second unit can carry the total decay heat load.
2.	Component cooling water pumps	Pump fails to start	One operating pump supplies sufficient water for emergency cooling.
3.	Component cooling water pumps	Manual valve on a pump suction line closed	This is prevented by prestartup and operational checks. Further, during normal operation, each pump is checked on a periodic basis which would show if a valve is closed.
4.	Component cooling water pumps	Valve on discharge line sticks closed	The valve is checked open during periodic operation of the pumps during normal operation.
5.	Component cooling heat exchanger	Tube or shell rupture	Rupture is considered improbable because of low operating pressures. Each unit is isolable. Either of two standby units can carry total emergency heat load.
6.	Demineralized water makeup line check valve	Sticks open	The check valve is backed up by the manually operated valve. The manual valve is normally closed.
7.	Component cooling heat exchanger vent or drain valve	Left open	This is prevented by prestartup and operational checks. On the operating unit such a situation is readily assessed by makeup requirements to system. On the standby unit such a situation is ascertained during periodic testing or startup.
8.	Component cooling water valve to residual heat exchanger	Fails to open	There is one valve on each inlet line to each heat exchanger. One heat exchanger remains in service and provides adequate heat removal during long term recirculation. During normal operation the cooldown time is extended.

Figure 9.1-1 UNIT 1 AUXILIARY COOLANT SYSTEM

[redacted]

Figure 9.1-2 UNIT 1 AUXILIARY COOLANT SYSTEM

[redacted]

9.2 RESIDUAL HEAT REMOVAL (RHR)

The residual heat removal system is designed to remove decay heat from the core and reduce the temperature of the reactor coolant system during the second phase of plant cooldown. During the first phase of cooldown, the temperature of the reactor coolant system is reduced by transferring heat from the reactor coolant system to the steam and power conversion system. Separate and independent residual heat removal systems are supplied for the two units. The description contained herein is equally applicable to either unit.

The equipment utilized for residual heat removal is also used for emergency core cooling during loss-of-coolant accident conditions. All active system components which are relied upon to perform the emergency core cooling function during an accident are redundant. Components not required for this function may or may not be redundant.

9.2.1 DESIGN BASIS

The residual heat removal system is designed to provide the following safety-related functions: (1) deliver borated cooling water to the reactor coolant system during the injection phase of safety injection, (2) recirculate and cool the water that is collected in the containment sump and return it to the reactor coolant system or containment spray pump suction during the recirculation phase of safety injection, (3) provide the means to preclude containment leakage through the RHR system piping penetrations following accidents, and (4) for piping and components that are part of the reactor coolant pressure boundary, maintain pressure boundary integrity during all MODES of plant operation.

The RHR system is credited in the event of a fire and has been evaluated in the at-power and non-power analyses (Reference 1). It is also designed to provide the following augmented quality functions; (1) provide low temperature overpressure protection of the reactor coolant system when the reactor coolant system is solid and the RHR system is in operation, and (2) provide indication of plant conditions during accident situations.

9.2.2 SYSTEM DESIGN AND OPERATION

The residual heat removal system is a dual purpose system. During power operation, the system is aligned to perform its low head safety injection function. As such, the system is split providing two independent trains, each containing a pump and heat exchanger. Suction and discharge valves for this function and long term sump recirculation are part of the safety injection system as described in Chapter 6. During a plant shutdown to cold shutdown conditions, the RHR pumps and heat exchangers perform the residual heat removal functions for the reactor. To accomplish this alignment, several manual valves must be opened to cross-connect the outlet of the heat exchangers and the discharge of the pumps and to provide a suction path for each of the pumps. After the reactor coolant system temperature and pressure have been reduced to less than or equal to 350°F and less than 400 psig respectively, residual heat removal is initiated by aligning the pumps to take suction from the “A” hot leg reactor coolant loop and discharge through the heat exchangers into the “B” cold leg reactor coolant loop. If only one pump and one heat exchanger are available, reduction of reactor coolant temperature is accomplished at a lower rate.

A connection between the residual heat removal system and the reactor coolant system letdown line permits purification of the reactor coolant when the reactor coolant system temperature and pressure is reduced. The system design includes provisions to enable hydrostatic testing to applicable test pressures during shutdown. System components, whose design pressure and temperature are less than the reactor coolant system design limits, are provided with overpressure protective devices and redundant isolation means. All piping and components of the residual heat removal system are designed to the applicable codes and standards listed in Table 9.2-1. Austenitic stainless steel piping is used in the residual heat removal loop, which contains reactor coolant.

The residual heat removal system consists of heat exchangers, pumps, piping and the necessary valves and instrumentation. During plant shutdown reactor coolant flows from the reactor coolant system to the residual heat removal pumps, through the tube side of the residual heat removal heat exchangers and back to the reactor coolant system. The inlet line to the residual heat removal system starts at the hot leg of one reactor coolant loop and the return line connects to the cold leg of the other loop. The heat loads are transferred by the residual heat removal heat exchangers to the component cooling water. The residual heat removal heat exchangers are also used to cool the recirculated water during the recirculation phase of safety injection system operation. These duties are defined in Chapter 6.

During plant shutdown, the cooldown rate of the reactor is controlled by regulating the reactor coolant flow through the tube side of the residual heat removal heat exchangers. A bypass line and an automatic flow control valve around the residual heat removal heat exchangers are used to maintain a constant flow through the residual heat removal system.

RHR system operational methods preclude any significant reduction in the overall design reactor shutdown margin when the loop is brought into operation for residual heat removal, or for emergency core cooling by recirculation.

Redundant, remotely operated valves (RH-700 and RH-701) in the residual heat removal system inlet line are provided to isolate the system from the reactor coolant system. A remotely operated valve (RH-720) and a check valve (SI-867B) isolate the return line to the reactor coolant system cold leg from the residual heat removal system. When reactor coolant system pressure exceeds the design pressure of the residual heat removal system, an interlock between the reactor coolant system wide range pressure channel (PT-420) and valves RH-700 and RH-720 prevents them from opening. Overpressure in the system is further prevented by two relief valves in the inlet piping to the residual heat removal system (valves RH-861B and RH-861C) and by a relief line from the outlet piping of the residual heat removal system to the CVCS letdown line.

Relief valve RH-861B is set at 600 psig and discharges to the pressurizer relief tank. Relief valve RH-861C is a high capacity relief valve. This relief valve is adjusted to open at 500 psig and provides a relief flow rate of 1106 gpm at 10% accumulation. This capacity was set to handle the maximum assumed injection flow which could occur by operation of a single safety injection pump and two charging pumps (Reference 4). The RH-861C valve discharges to the containment sump B.

In addition to protecting the residual heat removal system from overpressure, these relief valves are also available for water relief whenever the residual heat removal system is connected to the reactor coolant system i.e., during low temperature and low pressure conditions. These relief valves can thus be considered a diverse relief system and backup to the overpressure mitigating system for low temperature overpressure protection of the reactor coolant system during cold shutdown and solid pressurizer conditions (Reference 2).

To minimize the effects of pressure locking and to provide overpressure protection for the section of piping between the two residual heat removal loop suction isolation valves, a 3/8-inch hole has been drilled in the RCS-side disc of each of the RHR loop isolation motor-operated valves (RH-700 and RH-701). A 3/8-inch hole has also been drilled in the RCS-side disc of the RHR return isolation valve (RH-720) to minimize the effects of pressure locking.

Residual Heat Removal System Components

Each unit is provided a residual heat removal (RHR) system that is independent of the other unit's RHR system. The components are discussed below on a per-unit basis.

Residual Heat Removal Heat Exchangers

The two residual heat removal heat exchangers are of the shell and U-tube type with the tubes welded to the tube sheet. Reactor coolant circulates through the tubes, while component cooling water circulates through the shell side. The tubes and other surfaces in contact with reactor coolant are austenitic stainless steel and the shell is carbon steel.

Residual Heat Removal Pumps

The two residual heat removal pumps are horizontal, centrifugal units with mechanical seals to limit reactor coolant leakage to the atmosphere. All pump parts in contact with reactor coolant are austenitic stainless steel or equivalent corrosion resistant material.

Residual Heat Removal Valves

The valves used in the residual heat removal system are constructed of austenitic stainless steel or equivalent corrosion resistant material. Manual stop valves are provided to isolate equipment for maintenance. Throttle valves are provided for remote and manual control of the residual heat exchanger tube side flow. Check valves prevent reverse flow through the residual heat removal pumps.

Valves that perform a modulating function or have a diameter greater than 2 1/2 in. are equipped with sufficient packing to minimize leakage to the atmosphere. Manually operated valves have backseats to facilitate repacking and to limit the stem leakage in the event the packing fails or leaks excessively. Backseats are not normally relied upon as the primary leakage barrier.

Residual Heat Removal Piping

All residual heat removal system piping is austenitic stainless steel. The piping is welded with flanged connections at some components for ease of maintenance.

9.2.3 SYSTEM EVALUATION

Two pumps and two heat exchangers are provided to remove residual and sensible heat during plant cooldown. If one of the pumps and/or one of the heat exchangers is not operative, safe operation of the plant is not affected; however, the time for cooldown is extended. The function of this equipment following a loss-of-coolant accident is discussed in Chapter 6. The entire system is seismic Class I design. The components are designed to the codes given in Table 9.2-1.

Welded construction is used where possible throughout the residual heat removal system piping, valves, and equipment to minimize the possibility of leakage. During reactor operation all equipment of the residual heat removal system is idle, and the associated isolation valves are closed. During the loss-of-coolant accident condition, water from the containment sump is recirculated through the outside containment piping system. Both of the lines from the containment sump to the individual residual heat removal pumps have two remotely operated isolation valves in series. To quantify the possible total radiation dose to the public due to leakage from this system, the potential leaks have been evaluated and are discussed in Chapter 6 and Chapter 14.

Each RHR pump is located in an individual shielded compartment which is equipped with a floor drain and separated equipment drains. The floor drain from each compartment flows through an individual pipe to the sump. Two 75 gpm sump pumps transfer the leakage to the waste disposal system. The supply and discharge piping and valves for the RHR pumps are located in a pipeway adjacent to the pump compartments. A seven foot high shield wall divides the pipeway into two sections, each of which drains into a pump compartment through a 4-inch by 4-inch opening at floor level. Openings in the wall have no effect on RHR pump protection from flooding events. The RHR pump seal failure rate is 50 gpm.

The RHR cubicle drain valves are maintained in the closed position. If a RHR pump seal failure occurred with the drain valves in the closed position, a RHR pump room high level alarm would eventually be indicated in the control room. The cubicle could then be drained to the sump by opening the remotely operated drain valve. If flooding in EL.-19′ occurred due to a source other than a failed RHR pump seal, the fluid would collect in the center cubicle (cubicle between the Unit 1 and Unit 2 RHR pumps) and flow to the sump via the floor drains. The flow path to the RHR pump cubicle would remain isolated.

The residual heat removal system is connected to the hot leg of one reactor coolant loop on the suction side and to the cold leg of the other reactor coolant loop on the discharge side. On the suction side, the connection is through two electric motor operated gate valves in series with the first valve interlocked with reactor coolant system pressure. On the discharge side, the connection is through a check valve in series with an electric motor operated gate valve which is also interlocked with reactor coolant system pressure. All of these valves are closed during normal operation and the power to the MOVs is removed.

The RHR pumps are powered from 480 Volt safety-related buses with emergency diesel generator backup.

A reactor power of 1800 MWt was used for evaluation of the RHR system for the extended power uprate for the normal cooldown requirements (Reference 2, Reference 3, Reference 5).

9.2.4 REQUIRED PROCEDURES AND TESTS

The residual heat removal pump's flow instrument channels can be calibrated during shutdown. Periodic visual inspections and preventive maintenance can be conducted as necessary without interruption of cooling system operation. The inservice testing requirements are described in the PBNP Inservice Testing Program and the IST Background Document.

Generic Letter 2008-01, “Managing Gas Accumulation in Emergency Core cooling Decay Heat Removal, and Containment Spray Systems,” was issued to evaluate the systems to ensure gas accumulation is maintained less than the amount that challenges operability. The Gas Accumulation Management Program (GAMP) ensures that gas accumulation within the RHR system is identified, evaluated, trended and effectively controlled to prevent unacceptable degradation of performance. (Reference 7, Reference 8, Reference 9, and Reference 10)

9.2.5 REFERENCES

1. NFPA 805 Fire Protection Program Design Document (FPPDD).
2. NRC Safety Evaluation by the Office of Nuclear Regulation related to Amendment No. 45 to Facility Operating License No. DPR-24 and Amendment No. 50 to Facility Operating License No. DPR-27, dated May 20, 1980.
3. NRC Safety Evaluation “Point Beach Nuclear Plant (PBNP), Units 1 and 2 - Issuance of License Amendments Regarding Extended Power Uprate (TAC Nos. ME1044 and ME1045),” dated May 3, 2011.
4. Calculation M11165-112-RH.1, Relief Valve 1/2 RH-00861C Setpoint and Capacity Determination, Approved May 22, 2009.
5. Westinghouse Calculation CN-SEE-III-08-10, “Point Beach Units 1&2 RHR Cooldown Analysis for EPU to 1806 MWt NSSS Power,” Rev 3, Approved April 27, 2011.
6. Not Used
7. Letter NRC 2008-0075, “Nine-Month Response to NRC Generic Letter 2008-01 Managing Gas Accumulation in Emergency Core Cooling, Decay Heat Removal, and Containment Spray Systems,” dated October 14, 2008.
8. NRC letter, “Point Beach Nuclear Plant, Units 1 and 2 Closeout of Generic Letter 2008-01 Managing Gas Accumulation in Emergency Core Cooling, Decay Heat Removal and Containment Spray Systems” (TAC Nos. MD7864 and MD7865), dated January 7, 2010.
9. Letter NRC 2009-0015, “Point Beach Nuclear Plant, Unit 1, Nine-Month Supplemental (Post-Outage) Response to NRC Generic Letter 2008-01,” dated February 11, 2009.
10. NRC Safety Evaluation by the Office of Nuclear Reactor Regulation related to Amendment Nos. 251 and 255, “Managing Gas Accumulation,” dated January 27, 2015.

Table 9.2-1
RESIDUAL HEAT REMOVAL LOOP COMPONENT DATA

Reactor coolant temperature at startup of residual heat removal, °F	350
Time to cool reactor coolant system from 350°F to 140°F, hr (single RHR train while in MODE 4, 72°F SW temp)****	113
Decay heat generation standard****	ANS 5.1-1979
Reactor cavity fill time, hr	1.5
Reactor cavity drain time, hr	4
H_3BO_3 concentration in refueling water storage tanks, ppm boron	2800-3200
Residual heat removal pumps	
Quantity (per unit)	2
Type	Horizontal centrifugal
Design flow rate (each), gpm	1560
Total developed head, ft of water	280
Motor horsepower, hp	200
Material	Stainless Steel
Design pressure, psig	600
Design temperature, °F	400
Residual heat removal pump room sump pumps (WL System)	
Quantity	2
Type	Vertical, duplex
Capacity, gpm	75
Head, ft of water	55
Material (wetted surface)	Stainless steel
Residual Heat Removal Heat Exchangers	
Quantity (per unit)	2
Type	Shell and U-tube, vertical
Design heat transfer, Btu/hr	24.15×10^6
Shell side (component cooling water)	
Design inlet temperature, °F	100
Design outlet temperature, °F	117.3
Design flow rate, lb/hr	1.375×10^6
Design pressure, psig	150
Design temperature, °F	350
Material	Carbon steel
Tube side (reactor coolant)	
Design inlet temperature,°F	160
Design outlet temperature, °F	128.4
Design flow rate, lb/hr	7.63×10^5
Design pressure, psig	600
Design temperature, °F	400
Material	Stainless steel
Code Requirements	
Piping and valves	USAS B31.1*
RHR heat exchangers	ASME III**, Class C, tube side ASME VIII***, shell side

* USAS B31.1 - Code for Pressure Piping, and special nuclear cases where applicable
** ASME III - American Society of Mechanical Engineers, Boiler and Pressure Vessel Code, Section III
*** ASME VIII - American Society of Mechanical Engineers, Boiler and Pressure Vessel Code, Section VIII
**** Reference 5

Figure 9.2-1 UNIT 1 AUXILIARY COOLANT SYSTEM

[redacted]

9.3 CHEMICAL AND VOLUME CONTROL SYSTEM (CV)

The chemical and volume control system described in this section includes descriptions of the boron recycle (BS), reactor makeup water (RMW), and boric acid heat tracing (HTRACE) systems.

The chemical and volume control system (CVCS) (a) adjusts the concentration of chemical neutron absorber for chemical reactivity control, (b) maintains the proper water inventory in the reactor coolant system (RCS), (c) provides the required seal water flow for the reactor coolant pump shaft seals, (d) maintains the desired concentration of corrosion controlling chemicals in the reactor coolant, (e) keeps the reactor coolant activity to within the design levels and (f) provides for RCS degasification. The system is also used to fill, drain, and hydrostatically test the reactor coolant system.

To accomplish the above functions, this system has provisions for supplying:

1. Hydrogen to the volume control tank.

2. Nitrogen to the volume control tank (for purging during shutdown operations).

3. Chemicals, as required, via the chemical mixing tank to the charging pumps' suction.

9.3.1 DESIGN BASES

The CVCS System performs the following safety-related functions:

a. CVCS System piping and components interfacing with pressure boundaries for the (1) reactor coolant system, (2) component cooling water system, (3) safety injection system (refueling water storage tank), and (4) residual heat removal system shall maintain the pressure boundary integrity to support the safety function of these systems.

b. CVCS System containment isolation valves and portions of the CVCS System that function as a closed system outside containment shall maintain containment integrity following accidents that require containment isolation.

The CVCS System is credited in the event of a fire and has been evaluated in the at-power and non-power analyses (Reference 6).

Redundancy of Reactivity Control

Criterion: Two independent reactivity control systems, preferably of different principles, shall be provided. (GDC 27)

In addition to the reactivity control achieved by the rod cluster control (RCC) described in Section 3.0, reactivity control is provided by the CVCS which regulates the concentration of boric acid solution neutron absorber in the reactor coolant system. The system is designed to prevent uncontrolled or inadvertent reactivity changes which might cause system parameters to exceed design limits.

Reactivity Hot Shutdown Capability

Criterion: The reactivity control system provided shall be capable of making and holding the core subcritical from any hot standby or hot operating condition. (GDC 28)

The reactivity control systems provided are capable of making and holding the core subcritical from any hot standby or hot operating condition, including conditions resulting from power changes. The maximum excess reactivity expected for the core occurs for the cold, clean condition at the beginning of life of the core.

The rod cluster control assemblies (RCCAs) are divided into two categories comprising control and shutdown groups. The control group, used in combination with chemical shim, provides control of the reactivity changes of the core throughout the life of the core at power conditions. This group of RCCAs is used to compensate for short term reactivity changes at power such as those produced due to variations in reactor power requirements or in coolant temperature. The chemical shim control (CVCS) is normally used to compensate for the more slowly occurring changes in reactivity throughout core life such as those due to fuel depletion, fission product buildup and decay, and load follow. The safety injection system, used in conjunction with the reactor vessel head vent system, provides a safety-related backup for CVCS.

Reactivity Hold-Down Capability

Criterion: The reactivity control systems provided shall be capable of making the core subcritical under credible accident conditions with appropriate margins for contingencies and limiting any subsequent return to power such that there will be no undue risk to the health and safety of the public. (GDC 30)

Normal reactivity shutdown capability is provided by control rods, with boric acid injection used to compensate for the xenon transients, and for plant cooldown. When the plant is at power, the quantity of boric acid retained in the boric acid tanks and/or the refueling water storage tank (RWST) and ready for injection will always exceed that quantity required for the normal cold shutdown. This quantity will always exceed the quantity of boric acid required to bring the reactor to hot shutdown and to compensate for subsequent xenon decay.

The boric acid solution is transferred from the boric acid tanks by boric acid transfer pumps (or via gravity feed from the RWST) to the suction of the charging pumps which inject the solution into the reactor coolant. Any charging pump and any boric acid transfer pump can be manually transferred to diesel generator power on loss of off-site AC power. Boric acid can be injected by one charging pump and one boric acid transfer pump at a rate which shuts the reactor down, with no control rod insertion, in less than 150 minutes. In 150 additional minutes, enough boric acid can be injected to compensate for xenon decay although xenon decay below the equilibrium operating level will not begin until approximately 12-15 hours after shutdown. If two boric acid pumps and two charging pumps are available, the injection time periods are halved. Additional boric acid is employed if it is desired to bring the reactor to cold shutdown conditions.

On the basis of the above, the injection of boric acid is shown to afford backup reactivity shutdown capability, independent of control rod clusters which normally serve this function in the short term situation. Shutdown for long term and reduced temperature conditions can be accomplished with boric acid injection using redundant components.

9.3.2 SYSTEM DESIGN AND OPERATION

Various components of the chemical and volume control system are shared by the two units. These components are shown in Table 9.3-3 and a discussion concerning the sharing is given in Appendix I.6. The following discussion is for the CVCS for one unit but applies equally to either unit.

The CVCS, shown in Figure 9.3-1 through Figure 9.3-5, provides a means for injection of the neutron control chemical in the form of boric acid solution, chemical additions for corrosion control, and reactor coolant cleanup and degasification. This system also adds makeup water to the reactor coolant system, reprocesses water letdown from the reactor coolant system, and provides seal water injection to the reactor coolant pump seals. Materials in contact with the reactor coolant are austenitic stainless steel or equivalent corrosion resistant materials. System components whose design pressure and temperature are less than the reactor coolant system design limits are provided with overpressure protective devices. System discharges from overpressure protective devices (safety valves) and system leakages are directed to closed systems. Effluents removed from such closed systems are monitored and discharged under controlled conditions.

During normal plant operation, reactor coolant flows through the letdown line from the ‘B’ loop cold leg on the suction side of the reactor coolant pump and, after processing is returned either to the cold leg of the ‘A’ loop on the discharge side of the reactor coolant pump via a charging line, or via reactor coolant pump seal injection. An alternate charging connection is provided on the cold leg of the ‘B’ loop (on the discharge side of the pump). An excess letdown line is also provided for removing coolant from the reactor coolant system when normal letdown is not available.

Each of the connections to the reactor coolant system has an isolation valve located close to the loop piping. In addition, a check valve is located downstream of each charging line isolation valve. Reactor coolant letdown entering the CVCS flows through the shell side of the regenerative heat exchanger where its temperature is reduced. The coolant then flows through letdown flow control orifices which reduce the coolant pressure. The cooled, low pressure water leaves the reactor containment and enters the auxiliary building where it undergoes a second temperature reduction in the tube side of the nonregenerative heat exchanger. Following that cooling, a second pressure reduction is accomplished in the low pressure letdown valve. Mixed bed, cation, and deborating demineralizers follow. Normally one mixed bed demineralizer is aligned for ionic impurity control. Coolant then flows through a reactor coolant filter, and letdown gas stripper before entering the volume control tank.

A letdown gas stripper is located downstream of the letdown demineralizers and prior to the volume control tank. The letdown gas stripper is capable of removing entrained gasses from the letdown stream. The degassed water is then returned to the volume control tank. The stripped gasses (primarily hydrogen, but including any fission gasses) from both units are drawn from the gas stripper towers by a compressor. The discharge of the compressors is routed to heavily shielded delay/decay tanks, where a backpressure is maintained to achieve the desired radioactive decay of the gas. The gas exits the delay/decay tanks to be recycled into the volume control tanks to again establish an excess of hydrogen in the reactor coolant.

The letdown gas decay portion of the system additionally has a section (unused) capable of noble gas retention by cryogenic adsorption. Utilizing the cryogenic capability of the system would have resulted in accumulation of long-lived and highly radioactive noble gasses, which would require continuous maintenance of cryogenic conditions, and a leak tight noble gas container. There are therefore, no plans to utilize the cryogenic capability of the system.

The letdown gas stripper and gas recycle system are more completely described in Section 11.2.

Hydrogen is automatically supplied, as determined by pressure control, to the vapor space in the volume control tank. The VCT vapor space is predominantly hydrogen and water vapor. The hydrogen overpressure within the tank causes its absorption into the reactor coolant to aid in maintaining a low oxygen concentration.

From the volume control tank the coolant flows to the charging pumps which raise the pressure above that in the reactor coolant system. The coolant then enters the containment, passes through the tube side of the regenerative heat exchanger, and is returned to the reactor coolant system.

A cation bed demineralizer, located downstream of the mixed bed demineralizers, is used intermittently to control cation activity in the coolant, primarily to remove excess lithium formed from the B^{10} (n, a) Li^{7} reaction, or cesium.

A pair of deborating demineralizers, also located downstream of the mixed beds, are aligned near the end of core life (low boron concentration) to achieve reduction in RCS boron concentration which would be otherwise unattainable without significant reductions in desirable chemicals, given the high volume dilution required for a similar change in boron concentration.

Boric acid is dissolved in heated water in the batching tank to the desired concentration. The lower portion of the batching tank is jacketed to permit heating of the batching tank solution with low pressure steam. A transfer pump may be used to transfer the batch to the boric acid tanks or a gravity drain process may be used. Electric immersion heaters may be used to maintain the temperature of the boric acid tanks solution high enough to prevent precipitation. The boric acid solution is metered from the discharge of an operating transfer pump and either blended with reactor makeup water as makeup for system level control, or added without dilution if reactor coolant boron concentration is being increased.

Excess liquid effluents from the reactor coolant system are collected in the holdup tanks. As liquid enters the holdup tanks, the cover gas is displaced to the gas decay tanks in the waste disposal system through the waste gas vent header. The concentration of boric acid in the holdup tanks varies throughout core life from the refueling concentration to essentially zero at the end of the core cycle. A recirculation pump is provided to transfer liquid from one holdup tank to another and to recirculate the contents of individual holdup tanks.

A holdup tank can be aligned in a recirculation line-up through demineralizers and back to the holdup tank to allow for cleanup and sampling. Processing can be performed either as a batch operation or as a continuous bleed operation. In either case, liquid is pumped through ion exchangers which primarily remove lithium hydroxide and fission-products such as long-lived cesium. Following the ion exchangers, flow can be routed to the monitor tanks, for reuse or release assessment.

Subsequent handling of the holdup tank water is dependent on the results of sample analysis. Discharge from the monitor tanks may be pumped to the reactor makeup water storage tank, recycled through demineralizers, returned to the holdup tanks for reprocessing, or discharged to the environment (via the condenser circulating water system and the service water return header,) when within the allowable activity concentration as discussed in Section 11.1. If the sample analysis of the monitor tank contents indicates that it may be discharged to the environment, at least two valves must be opened to provide a discharge path. As the effluent leaves, it is continuously monitored by the waste disposal system liquid effluent monitor. If an unexpected increase in radioactivity is sensed, one of the valves in the discharge line to the service water discharge header closes automatically and an alarm sounds in the control room.

When the residual heat removal loop is operating and the reactor coolant system is depressurized, a flow path is provided to remove corrosion impurities and fission products. A portion of flow leaving the residual heat removal pumps can be directed through the nonregenerative heat exchanger, mixed bed demineralizers, and reactor coolant filter. The fluid can then bypass the volume control tank, pass through the charging pumps, and then either through normal or auxiliary charging lines, into the RCS. A flow path can also be provided to the CVCS to remove corrosion impurities and fission products via the refueling water circulating pump.

Expected Operating Conditions

Table 9.3-2, Table 9.3-3, Table 9.3-4 and Table 9.3-5 list the system performance requirements, data for individual system components and reactor coolant equilibrium activity concentration.

Reactor Coolant Activity Concentration

The parameters used in the calculation of the reactor coolant fission product inventory, including pertinent information concerning the coolant cleanup flow rate and demineralizer effectiveness, are presented in Table 9.3-4. The results of the calculations are presented in Table 9.3-5. In these calculations, 1% defects in the fuel rods are assumed to be present at initial core loading and are uniformly distributed throughout the core. (Reference 3) The fission product escape rate coefficients are therefore based upon an average fuel temperature.

Tritium is produced in the reactor from ternary fission in the fuel, irradiation of boron in the burnable poison rods and irradiation of boron, lithium and deuterium in the coolant. The parameters used in the calculation of tritium production rate and results are presented in Table 9.3-6. This table reflects tritium produced from twice and thrice burned IFBA fuel assembles at a power level of 1650 MWt. RCS tritium level was not specifically evaluated for EPU conditions, but can be expected to increase approximately proportional to the power level. Tritium effluents at EPU conditions are discussed in Section 11.2 and Appendix I.3.

Reactor Makeup Control

The reactor makeup control consists of a group of instruments arranged to provide a manually preselected makeup water composition to the charging pump suction header or the volume control tank. The makeup control functions are to maintain desired operating fluid inventory in the volume control tank and to adjust reactor coolant boron concentration for reactivity control. Makeup for normal plant leakage is regulated by the reactor makeup control which is set by the operator to blend water from the reactor makeup water tank with concentrated boric acid from the BAST to match the reactor coolant boron concentration.

The makeup system also provides concentrated boric acid or reactor makeup water to either increase or decrease the boric acid concentration in the reactor coolant system. Since a constant volume is maintained in the reactor coolant system by the pressurizer level control system, it is the volume control tank level which will rise or fall as makeup is added or leakage occurs. If volume control tank level increases to beyond the control band, letdown will be diverted to the holdup tanks until level returns to within the control band. If volume control tank level decreases to the lower limit of the control band, an automatic makeup will occur to ensure charging pump suction is maintained. Should the letdown line be out of service during operation, sufficient volume exists in the pressurizer to accept into the reactor coolant system the amount of borated water necessary for hot shutdown. Makeup to the reactor coolant system is provided by the chemical and volume control system from the following sources:

1. The reactor makeup water tank, which provides water for dilution when the reactor coolant boron concentration is to be reduced.

2. The boric acid storage tanks, which supply concentrated boric acid solution when reactor coolant boron concentration is to be increased.

3. The refueling water storage tank, which supplies borated water for emergency makeup.

The reactor makeup control is operated from the control room by manually preselecting makeup composition to the charging pump suction header or the volume control tank. Makeup is provided to maintain the desired operating fluid inventory in the reactor coolant system and to adjust the reactor coolant boron concentration for reactivity control. The operator can stop the makeup operation at any time in any operating mode. One reactor makeup water pump and one boric acid transfer pump are normally lined up for automatic operation as required by the makeup controller.

A portion of the high pressure charging flow is injected into the reactor coolant pumps between the pump impeller and the No. 1 shaft seal. The seal supply flow is greater than seal leakage flow so that the seals are not exposed to high temperature reactor coolant. The flow which does not leave the system via the RCP controlled leakage seal, enters the RCS through a labyrinth seal surrounding the pump shaft. The shaft seal leakage flow cools the lower radial bearing, passes through the seals, is cooled in the seal water heat exchanger, filtered, and returned to the volume control tank.

In the event of a loss of seal injection and CCW flow to the thermal barrier heat exchanger, reactor coolant begins to travel along the RCP shaft and displace the cooler seal injection water. The shut down seal (SDS) is designed to function only when exposed to an elevated fluid temperature downstream of the RCP number 1 seal. The SDS deploys via retraction of a thermal actuator, which causes the SDS seal ring to constrict around the pump shaft. SDS deployment controls shaft seal leakage and limits the loss of reactor coolant via the RCP seal package.

Seal water inleakage to the reactor coolant system requires a continuous letdown of reactor coolant to maintain the desired inventory. In addition, bleed and feed of reactor coolant are required for removal of impurities, chemical control, and adjustment of boric acid in the reactor coolant. The excess letdown line is sized to accommodate seal injection flow if normal letdown is out of service.

Automatic Makeup

The "automatic makeup" mode of operation of the reactor makeup control provides boric acid solution preset by the operator to match the boron concentration in the reactor coolant system when VCT level reaches preset values. The automatic makeup compensates for minor leakage of reactor coolant without causing significant changes in the coolant boron concentration.

Under steady state plant operating conditions, the mode selector switch is set in the "automatic makeup" position. When the low level signal from the volume control tank level controller reaches a preset low setpoint, it causes the automatic makeup control action to open the makeup stop valve to the charging pump suction, open the concentrated boric acid control valve, and the reactor makeup water control valve. A boric acid transfer pump and reactor makeup water pump will start automatically. The flow controllers then blend the makeup stream according to the preset concentration. Makeup addition to the charging pump suction header causes the water level in the volume control tank to rise. At a preset high level setpoint, the makeup is stopped; the reactor makeup water control valve closes, the concentrated boric acid control valve closes, the makeup stop valve to charging pump suction closes, and the reactor makeup water and boric acid transfer pumps stop automatically if they were started automatically.

Dilution

The "dilute" mode of operation permits the addition of a preselected quantity of reactor makeup water at a preselected flow rate to the reactor coolant system. The operator sets the mode selector switch to "dilute," the reactor makeup water flow controller set point to the desired flow rate, and the reactor makeup water batch integrator to the desired quantity. Upon manual start of the system the makeup stop valve opens, the reactor makeup water control valve opens, and a reactor makeup water pump starts. Makeup water is added at the volume control tank inlet. Excessive rise of the volume control tank water level is prevented by automatic actuation (by the tank level controller) of a three-way diversion valve, which routes the reactor coolant letdown flow to the holdup tanks. When the preset quantity of reactor makeup water has been added, the batch integrator causes the reactor makeup water pump to stop, the makeup stop valve to close, and the reactor makeup water control valve to close.

Alternate Dilute

The "alternate dilute" mode is similar to the dilute mode except that the dilution water splits after passing through the blender. A portion flows directly to the charging pump suction and a portion flows into the volume control tank inlet. The operator sets the mode selector switch to "alternate dilute," the primary makeup water flow controller set point to the desired flow rate, the reactor makeup water batch integrator to the desired quantity and actuates the makeup start. The start signal causes the makeup control action to start a selected reactor makeup water pump and opens the makeup stop valve to the volume control tank and the makeup stop valve to the charging pump suction header and the reactor makeup control valve. Reactor makeup water is simultaneously added to the volume control tank and to the charging pump suction header. This mode is used for load follow and permits the dilution water to follow the initial xenon transient and simultaneously dilute the volume control tank. Excessive water level in the volume control tank is prevented by automatic actuation of the volume control tank level controller which routes the reactor coolant letdown flow to the holdup tanks. When the preset quantity of reactor makeup water has been added, the batch integrator causes the reactor makeup water pump to stop and the reactor makeup water control valve and the reactor makeup stop valves to close. The operation may be stopped manually by actuating the makeup stop valve.

Boration

The “borate” mode of operation permits the addition of a preselected quantity of concentrated boric acid solution at a preselected flow rate to the reactor coolant system. The operator sets the mode selector switch to “borate,” the concentrated boric acid flow controller set point to the desired flow rate, and the concentrated boric acid batch integrator to the desired quantity. Upon manual start of the system, the stop valve to the charging pumps opens, the selected boric acid transfer pump starts, if not already running, and the concentrated boric acid is added to the charging pump suction header. The total quantity added in most cases is so small that it has only a minor effect on the volume control tank level. When the preset quantity of concentrated boric acid solution has been added, the batch integrator causes the boric acid transfer pump to stop, the boric acid control valve to close and the makeup stop valve to the charging pump suction to close.

Concentrated boric acid can be injected into the primary coolant system via several different flow paths. Boric acid storage tank level meters and in-line flow meters allow the operator to verify injection of concentrated boric acid into the primary system.

The capability to add boron to the reactor coolant is such that it imposes no limitation on the rate of cooldown of the reactor upon shutdown. The maximum rates of boration and the equivalent coolant cooldown rates are given in Table 9.3-2. One set of values is given for the addition of boric acid from a boric acid storage tank at 3.5 weight percent boric acid with one transfer and one charging pump operating. The other set assumes the use of refueling water but with two of the three charging pumps operating. The rates are based on hot zero power temperature and on the end of the core life when the moderator temperature coefficient is most negative.

By manual action of the operator, the boric acid transfer pump can discharge directly to the charging pump suction and bypass the blender and volume control tank.

Blend

The “blend” mode of operation provides for manually initiated makeup of boric acid solution preset by the operator. The operator sets the mode selector switch to “blend,” the reactor makeup water flow controller setpoint to the desired flow rate, and the boric acid flow controller setpoint to the desired flow rate. Upon a manual start of the system, the makeup stop valve opens (to charging pump suction), the reactor makeup water control valve opens, and the boric acid control valve opens. A boric acid transfer pump and reactor makeup water pump will start automatically. The flow controllers blend the makeup stream according to the preset concentration. Makeup addition causes the water level in the volume control tank to rise. The operator manually stops the “blend” function when desired. The boric acid control valve closes, the reactor makeup control valve closes, and the reactor makeup water and boric acid transfer pumps stop.

The “blend” mode of operation may also be used to provide blended makeup to other plant systems.

Alarm Functions

The reactor makeup control is provided with alarm functions to call the operator's attention to the following conditions:

1. Deviation of reactor makeup water flow rate from the control set point.
2. Deviation of concentrated boric acid flow rate from the control set point.
3. Low level in the volume control tank. This alarm alerts the operator to a failure in the auto makeup controls or improper selector switch position.
4. Dilution in progress while at cold shutdown with the control rods inserted.

Charging Pump Control

Three positive displacement variable speed (capacity) drive charging pumps are available to supply charging flow to the reactor coolant system. The speed of each pump can be controlled manually or automatically. One charging pump normally operates with the pump control switch in START and its speed controller in MAN, a second charging pump operates with its control switch in START and its speed controller in AUTO, and a third charging pump is normally in STOP. The pump in MAN pumps at a constant rate, normally 18 gpm. The pump in AUTO pumps at a variable rate in response to pressurizer level differences.

The pressurizer level set point is varied by changes in average coolant temperature. If the pressurizer level increases above the setpoint, the speed of the pump decreases; likewise, if the level decreases below the setpoint, the speed increases. If the charging pump under automatic control reaches the high or low speed limit, an alarm is actuated. Each charging pump has a suction pressure stabilizer and discharge pulsation dampener to minimize vibration and pump inlet chamber pressure fluctuations.

To ensure that the charging pump flow is always sufficient to meet the seal water flow requirements, the pump has a low speed stop which does not permit pump flow lower than the seal injection minimum.

The charging pump controls include an automatic trip on low suction pressure trip to protect the pumps due to a loss of suction source from the volume control tank or refueling water storage tank. The controls consist of the tripping function on sustained low pressure and the capability to manually override the trip after adequate suction pressure has been verified.

Components

A summary of principal component data is given in Table 9.3-3.

Regenerative Heat Exchanger

The regenerative heat exchanger is designed to recover the heat from the letdown stream by reheating the charging stream during normal operation. This exchanger also limits the temperature rise, which occurs at the letdown orifices during periods when letdown flow exceeds charging flow by a greater margin than at normal letdown conditions. The letdown stream flows through the shell of the regenerative heat exchanger and the charging stream flows through the tubes. The unit is made of austenitic stainless steel, and is of all-welded construction.

Letdown Orifices

One of three letdown orifices can control flow of the letdown stream during normal operation, reducing letdown pressure to a value which maintains subcooling and is compatible with the nonregenerative heat exchanger design. Either of two letdown orifices, each 40 gpm, is used to pass normal letdown flow. The third orifice, 80 gpm, is designed to be used for maximum purification flow at normal reactor coolant system operating pressure. The orifices are placed in and taken out of service by remote manual operation of their respective isolation valves. One or both of the standby orifices may be used in parallel with the normally operating orifice in order to provide normal letdown flow when the reactor coolant system pressure driving force is below normal. This arrangement provides a full standby capacity for control of letdown flow. Each orifice consists of bored stock made of austenitic stainless steel.

Nonregenerative (Letdown) Heat Exchangers

The nonregenerative heat exchangers cool the letdown stream to the operating temperature of the mixed bed demineralizers. Reactor coolant flows through the tube side of the exchanger while component cooling water flows through the shells. The letdown stream outlet temperature is automatically controlled by a temperature control valve in the component cooling water outlet stream. This temperature control valve has a handwheel installed. This handwheel serves as a mechanical gag to limit the maximum flow to 685 gpm, the design flow, should a loss of instrument air occur. The unit is a multiple-tube, multiple-pass two-shell heat exchanger. All surfaces in contact with the reactor coolant are austenitic stainless steel, and the shells are carbon steel.

Mixed Bed Demineralizers

Two flushable mixed bed demineralizers maintain reactor coolant purity. A lithium-7 (or H^+ form) cation resin and a hydroxyl form anion resin are initially charged into one of the demineralizers. Both forms of resin remove fission and corrosion products, and in addition, the reactor coolant causes the anion resin to be converted to the borate form. The resin bed is designed to reduce the concentration of ionic isotopes in the purification stream, except for cesium, yttrium, and molybdenum, by a minimum factor of 10.

Each demineralizer is sized to accommodate the normal letdown flow. One demineralizer serves as a standby unit for use should the operating demineralizer become exhausted during operation and as the preferred method to remove lithium ions from the reactor coolant.

The demineralizer vessels are made of austenitic stainless steel, and are provided with suitable connections to facilitate resin replacement when required. The vessels are equipped with a resin retention screen. Each demineralizer has sufficient capacity, after operation for one core cycle with one per cent defective fuel rods, to reduce the activity of the primary coolant to refueling concentration.

Cation Bed Demineralizer

A flushable cation resin bed in the hydrogen form is located downstream of the mixed bed demineralizers and is used as a method to control the concentration of lithium-7 which builds up in the coolant from the B^{10} (n, a) Li^7 reaction. The demineralizer also has sufficient capacity to maintain the cesium-137 concentration in the coolant below 1.0 µCi/cc with one percent defective fuel. The demineralizer is used intermittently to control cesium. The demineralizer is made of austenitic stainless steel and is provided with suitable connections to facilitate resin replacement when required. The vessel is equipped with a resin retention screen.

Deborating Demineralizers

When required, two demineralizers are available to be aligned to remove boric acid from the reactor coolant system fluid. The demineralizers are provided for use near the end of a core cycle, but can be used at any time. Hydroxyl-form ion-exchange resin can be used to reduce reactor coolant system boron concentration when loaded into these demineralizers. Facilities are provided for regeneration; however, the resin is normally flushed to the spent resin transfer cask for processing in the waste disposal system. Each demineralizer can remove the quantity of boric acid that must be removed from the reactor coolant system to maintain full power operation near the end of core life without the use of the holdup tanks.

Resin Fill Tank

The resin fill tank is no longer used. The resin fill tank was used to charge fresh resin to the demineralizers. The line from the conical bottom of the tank is fitted with a dump valve and may be connected to any one of the demineralizer fill lines. The demineralized water and resin slurry can be sluiced into the demineralizer by opening the dump valve. The tank is made of austenitic stainless steel.

Reactor Coolant Filter

The filter collects resin fines and particulates larger than 5 microns from the letdown stream. The vessel is made of austenitic stainless steel, and is provided with connections for draining and venting. Design flow capacity of the filter is equal to the maximum purification flow rate. Disposable filter elements are used. The bases for determining when the reactor coolant filter is replaced are pressure differential across the filter, and/or radiation levels.

Volume Control Tank

The volume control tank collects the excess water released from zero power to full power that is not accommodated by the pressurizer. It also receives the excess coolant release caused by the deadband in the reactor control temperature instrumentation. Overpressure of hydrogen gas is maintained in the volume control tank to control the hydrogen concentration in the reactor coolant to the specification listed in the EPRI PWR Primary Water Chemistry Guidelines (Reference 5).

A spray nozzle is located inside the tank on the inlet line from the reactor coolant filter. This spray nozzle provides intimate contact to equilibrate the gas and liquid phases. A remotely operated vent valve discharging to the waste disposal system permits removal of gaseous fission products which are stripped from the reactor coolant and collected in this tank. The volume control tank also acts as the suction supply for the charging pumps and a reservoir for the leakage from the reactor coolant pump controlled leakage seal. The tank is constructed of austenitic stainless steel.

Charging Pumps

Three charging pumps inject coolant into the reactor coolant system. The pumps are the variable speed positive displacement type, and all parts in contact with the reactor coolant are fabricated of austenitic stainless steel or other materials of adequate corrosion resistance. Special low-chloride packing is used in the pump glands. These pumps have mechanical packing followed by a leakoff to collect reactor coolant before it can leak to the outside atmosphere. Pump leakage is piped to a local drain for disposal to the waste disposal system. The pump design precludes the possibility of lubricating oil contaminating the charging flow, and the integral suction and discharge valves (check valves) allow water to pass through the pumps when idle, if the RCS is depressurized.

Each pump is designed to provide the full charging flow and the reactor coolant pump seal water supply during normal seal leakage. Each pump is designed to provide rated flow against a pressure equal to the sum of the reactor coolant system maximum pressure (existing when the pressurizer power operated relief valve is operating) and the piping, valve and equipment pressure losses of the charging system at the design charging flows. Any of the three charging pumps can be used to hydrotest the reactor coolant system. Additionally, a small motor can be directly coupled to one pump if hydrostatic test requirements demand.

The charging pump controls include an automatic trip on low suction pressure trip to protect the pumps due to a loss of suction source from the volume control tank or refueling water storage tank. The controls consist of the tripping function on sustained low pressure and the capability to manually override the trip after adequate suction pressure has been verified.

Chemical Mixing Tank

The primary use of the chemical mixing tank is in the preparation of pH control chemical solutions, hydrazine for oxygen scavenging, and hydrogen peroxide for cold shutdown corrosion product source term reduction or hydrogen removal. The capacity of the chemical mixing tank is determined by the quantity of 35% hydrazine solution necessary to increase the concentration in the reactor coolant by 10 ppm. This capacity is more than sufficient to prepare the solution of pH control chemical for the reactor coolant system. The chemical mixing tank is made of austenitic stainless steel.

Excess Letdown Heat Exchanger

The excess letdown heat exchanger is capable of cooling a reactor coolant letdown flow stream equal to the nominal injection rate through the reactor coolant pump labyrinth seals. The unit is designed to reduce the excess letdown stream temperature from the cold leg temperature to 195°F. The excess letdown stream flows through the tube side and component cooling water is circulated through the shell side. All surfaces in contact with reactor coolant are austenitic stainless steel and the shell is carbon steel. All tube joints are welded.

RCP Seal Water Heat Exchanger

The seal water heat exchanger removes heat from the reactor coolant pump seal water and from the excess letdown heat exchanger flow stream, prior to returning them to the volume control tank. Reactor coolant flows through the tubes and component cooling water is circulated through the shell side. The unit is designed to cool the excess letdown flow and the seal water flow to the temperature normally maintained in the volume control tank if all the reactor coolant pump seals are leaking at the maximum design leakage rate. The tubes are welded to the tube sheet to prevent leakage in either direction, which would result in undesirable contamination of the reactor coolant or component cooling water. All surfaces in contact with reactor coolant are austenitic stainless steel and the shell is carbon steel.

RCP Seal Water Return Filter

The filter collects particulates from the reactor coolant pump seal water return and from the excess letdown heat exchanger flow. The filter is designed to pass the sum of the excess letdown flow and the maximum design leakage from the reactor coolant pump controlled leakage seals. The vessel is constructed of austenitic stainless steel and is provided with connections for draining and venting. Disposable synthetic filter cartridges are used.

Seal Water Injection Filters

Two filters are provided in parallel, each sized for the injection flow. They collect particulates from the water supplied to the reactor coolant pump seal.

Boric Acid Filter

The boric acid filter collects particulates from the boric acid solution being pumped to the charging pump suction line. The filter is designed to pass the design flow of two boric acid transfer pumps operating simultaneously. The vessel is constructed of austenitic stainless steel and the filter elements are disposable synthetic cartridges. Provisions are available for venting and draining the filter.

Boric Acid Storage Tanks

Either the refueling water storage tank or the boric acid storage tanks may be used to contain the Technical Requirements Manual (TRM) required volume of borated water needed for cold shutdown. This volume is sufficient to provide the required shutdown margin at cold shutdown; xenon-free conditions with the most reactive RCCA not inserted from any expected operating condition.

The concentration of boric acid solution in the boric acid storage tanks is maintained within one of the operational bands described in the TRM. The nominal concentration of these bands varies from 3.25% to 12% by weight. Periodic sampling is performed in accordance with the TRM to ensure the desired concentration range is maintained. As a consequence, measured amounts of boric acid solution can be delivered to the reactor coolant to control the chemical poison concentration. The combination overflow and breather vent connection has a water loop seal to minimize vapor discharge during storage of the solution. The tanks are constructed of austenitic stainless steel.

Each of the three boric acid storage tanks has a capacity of 5000 gallons. The tank capacities can be shared by Unit 1 and Unit 2. The tanks have sufficient capacity for the TRM cold shutdown volume for one unit plus load follow capability volume for both units. One tank is normally aligned to each unit of the two-unit station and the third tank acts as a standby.

Each tank is provided with two level indicators and differential pressure cells. If the boric acid storage tanks are being relied upon for the TRM cold shutdown volume, the operator may enable a low level computer alarm that will alert him to an approach to the TRM minimum volume requirement. Level indication is provided in the control room and locally.

Boric Acid Storage Tank Heaters

Two 100% capacity electric immersion heaters located near the bottom of each boric acid storage tank are designed to maintain the temperature of the boric acid solution at 165°F with an ambient air temperature of 40°F; thus ensuring a temperature in excess of the solubility limit. Preferentially, plant parameters are controlled such that the required boric acid concentration in the tank is soluble at room temperatures. Operating at lower boric acid concentrations will reduce the need for tank heating. The temperature is monitored and is alarmed (high and low temperature alarms) in the control room. The heaters are sheathed in austenitic stainless steel.

Batching Tank

The batching tank, shared by Units 1 and 2 will hold about 2 1/2 day's makeup supply of 3% boric acid solution for the boric acid tank. The basis for makeup is reactor coolant leakage of ½ gpm near the beginning of core life. The tank may also be used for solution storage. A local sampling point is provided for verifying the solution concentration prior to transferring it to the boric acid storage tank. The tank manway is provided with a removable screen to prevent entry of foreign material. In addition, the tank is provided with an agitator to improve mixing during batching operation. The tank is constructed of austenitic stainless steel, and is not used to handle radioactive substances. The tank is provided with a steam jacket for heating the boric acid solution up to 165°F.

Boric Acid Transfer Pumps

Two canned centrifugal pumps are used to circulate or transfer boric acid. The pumps circulate boric acid solution through the boric acid storage tanks and inject boric acid into the charging pump suction header.

Although one pump may be used for boric acid batching and transfer and the other for boric acid injection, either pump may function as standby for the other. The design capacity of each pump is equal to the normal letdown flow rate. The design head is sufficient, considering line and valve losses, to deliver rated flow to the charging pump suction header when volume control tank pressure is at the maximum operating value (relief valve setting). All parts in contact with the solutions are austenitic stainless steel or other adequately corrosion-resistant material.

The transfer pumps are operated either automatically or manually from the main control room or from a local control point. The reactor makeup control operates one of the pumps automatically when boric acid solution is required for makeup or boration.

Boric Acid Recirculation Pump

One pump per unit can be used to continuously circulate boric acid. The pumps circulate boric acid from the boric acid storage tanks, throughout most of the piping, then back to the boric acid storage tanks to assure temperature equalization and positive evidence of boric acid fluidity throughout the piping.

The design capacity of the pump is based on providing uniform concentration and temperature. The design head is sufficient to overcome recirculation line losses. A minimum recirculation line from the discharge of the pump to the pump suction is provided to prevent pump damage should a boric acid transfer pump start and be aligned to the charging pump suction header while the recirculation pump is running. All parts in contact with the solutions are austenitic stainless steel or other adequately corrosion-resistant material. The recirculation pumps are manually operated from a local control point.

Boric Acid Blender

The boric acid blender promotes thorough mixing of boric acid solution and reactor makeup water from the reactor makeup supply circuit. The blender consists of a conventional pipe tee fitted with a perforated tube insert. The blender decreases the pipe length required to homogenize the mixture. All material is austenitic stainless steel.

Recycle Process - Holdup Tanks

Three holdup tanks can be shared by Units 1 and 2, to contain radioactive liquids from the letdown line and other sources. Most of the liquid is released from the reactor coolant system during startup, shutdown, load changes, and from boron dilution to compensate for burnup. The contents of one tank are normally being processed by at least a portion of the ion exchanger train while another tank is available as a standby. The tanks are constructed of austenitic stainless steel. A pressure switch on each tank will trip the Holdup Tank Recirculation Pump to provide vacuum protection for the tank.

Holdup Tank Recirculation Pump

The holdup tank (HUT) recirculation pump is shared between Units 1 and 2 and is used to mix the contents of a holdup tank or transfer the contents of one holdup tank to another or transfer the spent fuel pool transfer canal water to the HUTs or spent fuel pool. This pump can also be used to transfer water from a holdup tank to the spent fuel pool to increase pool inventory as required. The wetted surface of this pump is constructed of austenitic stainless steel.

Recycle Process Gas Stripper Feed Pumps

The two recycle process gas stripper feed pumps can be shared by Units 1 and 2, to supply feed from a holdup tank to the ion exchanger process train. The nonoperating pump is a standby and is available for operation in the event the operating pump malfunctions. These canned centrifugal pumps are constructed of austenitic stainless steel.

Evaporator Feed Ion Exchangers

Four flushable ion exchangers are shared by Units 1 and 2 to remove ionic impurities from the holdup tank effluent. The ion exchangers may be operated in parallel or in series with the alignment chosen given the ion load in the water, and the type and location of the resin needed to reduce that ion load. Each vessel is constructed of austenitic stainless steel and contains a resin retention screen.

The ion exchanger effluent may be routed directly to the monitor tanks, where sampling and a determination concerning environmental release or reprocessing can be made. Once approved for release, a monitor tank may be discharged utilizing the waste disposal system release point.

Ion Exchanger Filters

The filters collect resin fines and particulates from the evaporator feed ion exchangers. The vessel is made of austenitic stainless steel and is provided with connections for draining and venting. Disposable synthetic filter cartridges are used.

Boric Acid Gas Stripper Equipment

The boron recycle gas strippers were abandoned-in-place and bypassed in about 1972, after determining the quantity of entrained gasses were very low, and that the strippers were difficult to operate. Entrained gasses were low due to the combination of low cover gas pressures in the waste gas system and the 'bottom suction' utilized by the gas stripper feed pumps.

Evaporator Condensate Demineralizers

The evaporator condensate demineralizers are no longer used.

Condensate Filter

The condensate filters are no longer used.

Monitor Tanks

Four monitor tanks can be shared by Unit 1 and Unit 2. The monitor tanks accept processed water from the holdup tanks and provide a location where sampling and a determination concerning environmental release can be made. Once approved for release, a monitor tank may be discharged utilizing the waste disposal system release point. When tanks are filled, the contents are analyzed and either reprocessed, discharged via the waste disposal system, or pumped to the reactor makeup water tank. The monitor tanks can also be filled with water from the makeup water treatment plant. These tanks contain a diaphragm membrane and are constructed of stainless steel.

Monitor Tank Pumps

Two monitor tank pumps, shared by Units 1 and 2, discharge water from the monitor tanks. The pumps are constructed of austenitic stainless steel.

Reactor Makeup Water Tank

One reactor makeup water tank can be shared between the two units and is used to store makeup water, which is primarily supplied from the water treatment plant, but can also be supplied from the monitor tanks. The tank contains a diaphragm membrane and is constructed of coated carbon steel.

Reactor Makeup Water Pumps

Two reactor makeup water pumps, shared between Unit 1 and Unit 2, take suction from the reactor makeup water tank. These pumps are used to feed dilution water to the boric acid blender and are also used to supply makeup water for intermittent flushing of equipment and piping.

Each pump is sized to match the combined maximum letdown flow from each unit. One pump serves as a standby for the other. These centrifugal pumps are constructed of austenitic stainless steel.

Concentrates Filter

The concentrates filters are no longer used.

Concentrates Holding Tank

The concentrates holding tank is no longer used.

Concentrates Holding Tank Transfer Pumps

The concentrates holding tank transfer pumps are no longer used.

Electrical Heat Tracing

Electrical heat tracing is installed under the insulation on piping, valves, line-mounted instrumentation, and components that may contain highly concentrated boric acid solution (up to 12 weight percent). The heat tracing provides the capability to prevent boric acid precipitation due to cooling of highly concentrated solution, by compensating for heat loss. Exceptions are:

1. Lines which may transport concentrated boric acid but are subsequently flushed with reactor coolant or other liquid of low boric acid concentration during normal operation.

2. The boric acid storage tanks, which are provided with immersion heaters.

3. The batching tank, which is provided with a steam jacket.

4. Various pumps, which normally contain concentrated boric acid solution, are installed in electrically heated enclosures.

5. Portions of system containing boric acid at concentrations less than approximately 4 weight percent where ambient temperatures are adequate to prevent boric acid precipitation.

Valves

Valves that perform a modulating function and utilize packing are equipped with sufficient packing to minimize leakage to the atmosphere. Basic material of construction is stainless steel for all valves except the batching tank steam jacket valves, which are carbon steel.

Isolation valves are provided at all connections to the reactor coolant system. Lines with flow into the reactor containment also have check valves inside the containment to prevent reverse flow from the containment.

Relief valves are provided for lines and components that might be pressurized above design pressure by improper operation or component malfunction. Pressure relief for the tube side of the regenerative heat exchanger is provided by the auxiliary spray line isolation valve, which is designed to open to limit the upstream pressure.

Piping

All chemical and volume control system piping handling radioactive liquid is austenitic stainless steel. All piping joints and connections are welded, except where flanged connections are required to facilitate equipment removal for maintenance and hydrostatic testing. Piping which normally contains concentrated boric acid solution is temperature monitored to verify solubility of boric acid. Low temperatures are alarmed in the control room.

Codes and Classifications

All pressure retaining components (or compartments of components) which are exposed to reactor coolant, comply with the following codes:

1. System pressure vessels - ASME Boiler and Pressure Vessel Code, Section III, Class C, including Para. N-2113.

2. System valves, fittings and piping - USAS B31.1, including nuclear code cases.

System component code requirements are tabulated in Table 9.3-1.

The tube and shell sides on the regenerative heat exchanger and the tube side of the excess letdown heat exchanger are designed to ASME III, Class C. This designation is based on the following considerations: (a) each exchanger is connected to the reactor coolant system by lines equal to or less than 3", and (b) each is located inside the reactor containment. Analyses show that the accident associated with a 3" line break does not result in clad damage or failure. Additionally, previously contaminated reactor coolant, escaping from the reactor coolant system during such accident is confined to the reactor containment building and no public hazard results.

9.3.3 SYSTEM EVALUATION

Availability and Reliability

A high degree of functional reliability is assured in this system by providing standby components where performance is vital to safety and by assuring failsafe response to the most probable mode of failure. Solubility of boric acid at concentrations of less than about 4 weight percent is maintained at ambient temperature without additional heating. The system has three high pressure charging pumps, each capable of supplying the normal reactor coolant pump seal and makeup flow.

The electrical equipment of the chemical and volume control system is arranged so that multiple items receive their power from various 480 volt buses (See Figure 8-2). Two of the three charging pumps are powered by a 480 volt bus while the third charging pump is powered from a separate 480 volt bus.

The two boric acid transfer pumps are powered from separate 480 volt buses. One charging pump and one boric acid transfer pump are capable of meeting cold shutdown requirements shortly after full-power operation. In cases of loss of A.C. power, a charging pump and a boric acid transfer pump can be manually started if necessary after their buses have been reenergized by the emergency diesel generators. The transfer pumps are powered from MCCs that are stripped from their normal power supply by a safety injection signal. They can be recovered, but are not automatically re-energized from emergency diesels.

Control of Tritium

The chemical and volume control system is used to control the concentration of tritium in the reactor coolant system. Essentially all of the tritium is in chemical combination with oxygen as a form of water. Therefore, any leakage of coolant to the containment atmosphere carries tritium in the same proportion as it exists in the coolant. Thus, the level of tritium in the containment atmosphere, when it is sealed from outside air ventilation, is a function of tritium level in the reactor coolant, the cooling water temperature at the cooling coils, (which determines the dew point temperature of the air), and the presence of leakage other than reactor coolant as a source of moisture in the containment air.

There are two major considerations with regard to the presence of tritium:

1. containment atmosphere. It is desirable to limit the accumulation to allow containment access for periodic equipment inspection.)

2. Possible release of tritium to the environment.

Neither of these considerations is limiting at Point Beach Nuclear Plant. The concentration of tritium in the reactor coolant is maintained at a level which precludes personnel hazard during access to the containment. Acceptable tritium levels are achieved by eliminating a portion of the processed letdown stream from the recycle process.

The refueling water surface ventilation system can be utilized during refueling operations to minimize containment air tritium concentrations. Periodic determinations of tritium concentrations may be made by liquid scintillation counting of condensed water vapor from the containment and by calculations based on humidity measurements. Tritium release to the atmosphere via the containment purge system will be made in accordance with limits given in the Technical Specifications. Normally, tritium releases are much lower than allowed by the referenced limits. During periods other than refueling, personnel exposure to tritium while in the containment will be limited in accordance with applicable sections of 10 CFR 20.103.

Leakage Prevention

Quality control of the material and the installation of the chemical and volume control system valves and piping, which are designated for radioactive service, is provided in order to essentially eliminate leakage to the atmosphere. Except for component maintainability concerns, components designated for radioactive service are normally provided with welded connections to prevent leakage to the atmosphere. Flanged connections are provided in each charging pump suction and discharge, including the pressure fluctuation dampeners, on each boric acid pump suction and discharge, on relief valve inlets and outlets, on three-way valves, on the flow meters and elsewhere where necessary for maintenance. The positive displacement charging pumps stuffing boxes are provided with leakoffs to floor drains.

All valves which are larger than 2″ and are designated for radioactive service at an operating fluid temperature above 212°F are provided with sufficient packing to minimize leakage to the atmosphere. Leakage to the atmosphere is essentially zero for these valves.

All control valves are either provided with stuffing box and leakoff connections or are totally enclosed. Leakage to the atmosphere is essentially zero for these valves. Diaphragm valves are provided where the operating pressure and the operating temperature permit the use of these valves. Leakage to the atmosphere is essentially zero for these valves.

Incident Control

The letdown line penetrates the reactor containment building. The letdown line contains one motor-operated valve inside the reactor containment and three parallel air-operated orifice block valves for isolation from the RCS. Additionally, an automatic containment isolation signal closes an air-operated valve inside the reactor containment and another outside containment.

The reactor coolant pumps seal water return line contains one motor-operated isolation valve outside the reactor containment and an air-operated valve inside containment which are automatically closed by the containment isolation signal.

The two seal water injection lines to the reactor coolant pumps, the normal charging line, and the auxiliary charging line are inflow lines penetrating the reactor containment. Each line contains redundant containment isolation features to accommodate a potential break in these lines outside the reactor containment. Refer to Section 5.2.

Malfunction Analysis

To evaluate system safety, failures or malfunctions were assumed concurrent with a loss-of-coolant accident and the consequences analyzed and presented in Table 9.3-7. As a result of this evaluation, it is concluded that proper consideration has been given to plant safety in the design of the system.

If a rupture were to take place between the reactor coolant loop and the containment isolation valve or check valve, this incident would result in an uncontrolled loss of reactor coolant. The analysis of loss of coolant accidents is discussed in Section 14.

Should a rupture occur in the chemical and volume control system outside the containment, or at any point beyond the first check valve or containment isolation valve, actuation of the valve would limit the release of coolant and assure continued functioning of the normal means of heat dissipation from the core. For the general case of rupture outside the containment, the largest source of radioactive fluid subject to release is the contents of the volume control tank. The consequences of such a release are considered in Section 11. Should a LOCA occur, piping inside containment which is isolated in accordance with procedural system alignments, is protected against thermal overpressurization by relief devices.

When the reactor is subcritical, i.e., during cold or hot shutdown, refueling and approach to criticality, the relative reactivity status (neutron source multiplication) is continuously monitored and indicated by BF_3 counters and count rate indicators. Any appreciable increase in the neutron source multiplication, including that caused by the maximum physical boron dilution rate is slow enough to give ample time to start a corrective action (boron dilution stop and/or emergency boron injection) to prevent the core from becoming critical. The maximum dilution rate is based on the abnormal condition of two charging pumps operating at full speed delivering unborated primary water to the reactor coolant system at a particular time during refueling when the boron concentration is at the maximum value and the water volume in the system is at a minimum (see Section 14.1.4).

At least three separate and independent flow paths are available for reactor coolant boration from the CVCS system; i.e., the charging line, the auxiliary charging line, or the reactor coolant pump labyrinth seals. The malfunction or failure of one component will not result in the inability to borate the reactor coolant system. An alternate flow path is always available for emergency boration of the reactor coolant. As backup to the boration system the operator can align the refueling water storage tank outlet to the suction of the charging pumps, or can depressurize the RCS to utilize the safety injection system.

Boration during normal operation to compensate for power changes is indicated to the operator from two sources: (a) the control rod movement and (b) the flow indicator in the boric acid transfer pump discharge line. When the emergency boration path is used, two indications to the operator are available. The charging line flow indicator could indicate boric acid flow if the charging pump suction is aligned to the boric acid transfer pump suction alone, and the change in boric acid tank level is another indication of boric acid injection.

On loss of seal injection water to the reactor coolant pump seals, seal water flow may be reestablished by manually starting a standby charging pump. Even if the seal water injection flow is not reestablished, the plant can be operated indefinitely since the thermal barrier cooler has sufficient capacity to cool the flow passing through the RCP seals, as long as that leakage flow remains within the range of seal leak-off indications.

Galvanic Corrosion

The only types of materials which are in contact with each other in borated water are stainless steels, Inconel, Stellite valve materials, Zircaloy (STD & OFA fuel) and ZIRLO®/Optimized ZIRLO™ (422V+ fuel) fuel element cladding. Stainless steels, Inconel, Stellite and Zircaloy have been shown (Reference 2) to exhibit only an insignificant degree of galvanic corrosion when coupled to each other. This is also true for the ZIRLO® or Optimized ZIRLO™ fuel element claddings, which when coupled with the materials noted above, exhibit an insignificant amount of galvanic corrosion. 422V+ fuel uses ZIRLO® or Optimized ZIRLO™ instead of Zircaloy for cladding and ZIRLO for other fuel assembly components. The use of ZIRLO® was approved for use commencing with Unit 1, Cycle 27 and Unit 2, Cycle 25. The use of Optimized ZIRLO™ fuel cladding was approved for use commencing with Unit 1, Cycle 37 and Unit 2, Cycle 35 (See FSAR Section 3.3).

For example, the galvanic corrosion of Inconel versus 304 stainless steel resulting from high temperature tests (575°F) in lithiated, boric acid solution was found to be less than -20.9 mg/dm^2 for the test period of 9 days. Further galvanic corrosion would be trivial since the cell currents at the conclusion of the tests were approaching polarization. Zircaloy versus 304 stainless steel was shown to polarize in 180°F lithiated, boric acid solution in less than 8 days with a total galvanic attack of -3.0 mg/dm^2. Stellite versus 304 stainless steel was polarized in 7 days at 575°F in lithiated boric acid solution. The total galvanic corrosion for this couple was -0.97 mg/dm^2.

As can be seen from the tests, the effects of galvanic corrosion are insignificant to systems containing borated water.

9.3.4 REQUIRED PROCEDURES AND TESTS

The inservice testing requirements are described in the PBNP Inservice Testing Program and the IST Background Document.

9.3.5 REFERENCES

1. Westinghouse Report, WEP-98-077, “Wisconsin Electric Power Company Point Beach Units 1 and 2 Chapter 9 and 11 - FSAR Updates,” December 8, 1998.

2. WCAP 1844 “The Galvanic Behavior of Materials in Reactor Coolants,” D. G. Samarone, August, 1961.

3. Calculation CN-REA-08-7, “RCS, VCT, and GDT Sources for the Point Beach EPU,” Westinghouse Electric Co. LLC, Revision 0, dated September 19, 2008.

4. NRC Safety Evaluation, “Point Beach Nuclear Plant (PBNP), Units 1 and 2 - Issuance of License Amendments Regarding Extended Power Uprate (TAC Nos. ME1044 and ME1045),” dated May 3, 2011.

5. EPRI 1014986, “Pressurized Water Reactor Primary Water Chemistry Guidelines.”

6. NFPA 805 Fire Protection Program Design Document (FPPDD).

Table 9.3-1 CHEMICAL AND VOLUME CONTROL SYSTEM CODE REQUIREMENTS

Regenerative heat exchanger	ASME III*, Class C
Nonregenerative heat exchanger	ASME III, Class C, tube side, ASME VIII, shell side
Mixed bed demineralizers	ASME III, Class C
Reactor coolant filter	ASME III, Class C
Volume control tank	ASME III, Class C
Seal water heat exchanger	ASME III, Class C, tube side, ASME VIII, shell side
Excess letdown heat exchanger	ASME III, Class C, tube side, ASME VIII, shell side
Chemical mixing tank	ASME VIII
Deborating demineralizers	ASME III, Class C
Cation bed demineralizer	ASME III, Class C
Seal water injection filters	ASME III, Class C
Holdup tanks	ASME III, Class C
Boric acid filter	ASME III, Class C
Gas stripper package	ASME III, Class C
Evaporator condensate demineralizers	ASME III, Class C
Concentrates filter	ASME III, Class C
Evaporator feed ion exchanger	ASME III, Class C
Ion exchanger filter	ASME III, Class C
Condensate filter	ASME III, Class C
Piping and valves	USAS B31.1**

* ASME III - American Society of Mechanical Engineers, Boiler and Pressure Vessel Code, Section III, Nuclear Vessels.

** USAS B31.1 - Code for Pressure Piping and special nuclear cases where applicable.

Table 9.3-2 CHEMICAL AND VOLUME CONTROL SYSTEM PERFORMANCE REQUIREMENTS*

Original plant design life, years	40
Seal water supply flow rate, normal, gpm	16
Seal water return flow rate, normal, gpm	6
Normal letdown flow rate, gpm	40
Maximum letdown (purification) flow rate, gpm	120
Normal charging pump flow (one pump), gpm	46
Normal flow to reactor coolant pumps, gpm	16
Normal charging line flow, gpm	30
Maximum rate of boration with one transfer and one charging pump, ppm/min (EOL)	7.1
Equivalent cooldown rate to above rate of boration, °F/min (EOL)	2.1
Maximum rate of boron dilution (two charging pumps), ppm/min (BOL)**	5.9
Two-pump rate of boration, using refueling water, ppm/min (EOL)	9.8
Equivalent cooldown rate to above rate of boration, °F/min (EOL)	2.9
Design temperature of reactor coolant entering system at full power, °F	559.5
Design temperature of coolant return to reactor coolant system at full power, °F	509.5
Normal coolant discharge temperature to holdup tanks, °F	127.0

* Volumetric flow rates in gpm are based on 127°F and 15 psig.

** At HFP, Equilibrium Xenon, 1673 ppm boron.

Table 9.3-3 PRINCIPAL COMPONENT DATA SUMMARY

Heat Exchangers	Quantity[1]	Design Heat Transfer Btu/hr	Flow lb/hr	Letdown ΔT °F	Letdown Pressure psig Shell/tube	Design Temperature °F Shell/tube
Regenerative	1	$5.81x10^6$	19,760	268.5	2485/2735	650/650
Nonregenerative	2	$10.1x10^6$	19,760	164	150/600	250/400
Seal water	1	$1.137x10^6$	79,040	14.5	150/150	250/250
Excess letdown	1	$1.92x10^6$	4,940	364	150/2485	250/650

Pumps	Quantity[1]	Type	Capacity Each gpm	Head ft	Design Pressure psig	Design Temperature °F
Charging	3	Pos.displ.	60.5	2385 psi	3000	250
Boric acid transfer	2	Canned	40	152	150	250
Holdup tank recirc.	1*	Centrifugal	500	100	75	200
Reactor makeup water	2*	Centrifugal	270	300	150	250
Monitor tank	2*	Centrifugal	60	235	150	250
Concentrates holding tank transfer**	2*	Canned	20	150	100	250
Gas stripper feed**	2*	Canned	25	183	150	200
Gas stripper bottoms**	2	Canned	12.5	93	75	300

Tanks	Quantity[1]	Type	Volume, Each Gal. or as noted	Design Pressure psig	Design Temperature °F
Volume control	1	Vertical	220 ft^3	75Int/15Ext	250
Charging pump suction stabilizer	3	Vertical	5.0	150	250
Charging pump discharge pulsation dampener.	3	Vertical	2.5	3000	250
Boric acid	3*	Vertical	5000	Atmos.	250
Chemical mixing	1	Vertical	3.0	200	200
Batching	1*	Jacket Btm.	800	Atmos.	250
Holdup	3*	Vertical	7800 ft^3	15	200
Reactor makeup water	1*	Diaphragm	100,000	Atmos.	125
Concentrates holding	1**	Vertical	900	Atmos.	250
Monitor	4*	Diaphragm	10,000	Atmos.	125

Demineralizers	Quantity[1]	Type	Resin Volume ft^3	Flow gpm	Design Pressure psig	Design Temperature °F
Mixed bed	2	Flushable	20	90	200	250
Cation bed	1	Flushable	12	40	200	250
Evaporator feed	4*	Flushable	12	12.5	200	250
Evaporator condensate	3**	Fixed	12	12.5	200	250
Deborating	2	Fixed	30	109	200	250

1 Quantity per unit unless otherwise specified.
* Shared or capable of being shared by Unit 1 and Unit 2; items not marked are duplicated for each unit.
** Equipment no longer used.

Table 9.3-4 PARAMETERS USED IN THE CALCULATION OF REACTOR COOLANT FISSION PRODUCT ACTIVITIES (Reference 3)

1.	Core thermal power, MWt	1810.8
2.	Fraction of fuel containing clad defects	0.01
3.	Reactor coolant liquid volume/mass, ft^3/g	$5689/1.147 \times 10^8$
4.	Reactor coolant core average temperature, °F	581
5.	Purification flow rate (normal), gpm	40
6.	Effective cation demineralizer flow, gpm	4
7.	Volume control tank volumes	
	a. Vapor, cu ft	122
	b. Liquid, cu ft	98
8.	Fission product escape rate coefficients:	
	a. Noble gas isotopes, sec^{-1}	6.5×10^{-8}
	b. Br, I and Cs isotopes, sec^{-1}	1.3×10^{-8}
	c. Te isotopes, sec^{-1}	1.0×10^{-9}
	d. Mo isotopes, sec^{-1}	2.0×10^{-9}
	e. Sr and Ba isotopes, sec^{-1}	1.0×10^{-11}
	f. Y, La, Ce and Pr isotopes, sec^{-1}	1.6×10^{-12}
9.	Mixed bed demineralizer decontamination factors:	
	a. Noble gases	1.0
	b. Br ,I, Sr, Ba isotopes	10.0
	c. Other isotopes	1.0
10.	Cation bed demineralizer decontamination factor for Rb-86, Cs-134, Cs-137	10.0
11.	Volume control tank noble gas stripping fraction (closed system):	

Isotope	Stripping Fraction
Kr-83m	7.5×10^{-1}
Kr-85	5.8×10^{-5}
Kr-85m	5.5×10^{-1}
Kr-87	8.1×10^{-1}
Kr-88	6.6×10^{-1}
Kr-89	9.9×10^{-1}
Xe-131m	1.3×10^{-2}
Xe-133	2.9×10^{-2}
Xe-133m	6.6×10^{-2}
Xe-135	2.9×10^{-1}
Xe-135m	9.4×10^{-1}
Xe-137	9.8×10^{-1}
Xe-138	9.4×10^{-1}

Table 9.3-5 REACTOR COOLANT SYSTEM EQUILIBRIUM ACTIVITIES (Reference 3)

Activation Products

	(µCi/gm)
Cr-51	5.40E-03
Mn-54	1.60E-03
Fe-55	2.10E-03
Fe-59	5.10E-04
Co-58	1.40E-02
Co-60	1.30E-03

Gaseous Fission Products

	(µCi/gm)
Kr-83m	5.30E-01
Kr-85	1.05E+01
Kr-85m	2.17E+00
Kr-87	1.44E+00
Kr-88	4.01E+00
Kr-89	1.15E-01
Xe-131m	3.23E+00
Xe-133	2.91E+02
Xe133m	5.23E+00
Xe-135	9.25E+00
Xe-135m	5.96E-01
Xe-137	2.20E-01
Xe-138	7.94E-01

Nonvolatile Fission Products

	(µCi/gm)
Br-83	1.12E-01
Br-84	5.81E-02
Br-85	6.87E-03
Rb-86	2.72E-02
Rb-88	4.97E+00
Rb-89	2.31E-01
Sr-89	4.57E-03
Sr-90	2.15E-04
Sr-92	1.44E-03
Y-90	5.96E-05
Sr-91	6.66E-03
Y-91	5.88E-04
Y-91m	3.56E-03

Nonvolatile Fission Products(cont'd)

	(µCi/gm)
Y-92	1.25E-03
Y-93	4.23E-04
Zr-95	6.68E-04
Nb-95	6.65E-04
Mo-99	8.50E-01
Tc-99m	7.83E-01
Ru-103	5.64E-04
Rh-103m	5.64E-04
Ru-106	1.79E-04
Rh-106	1.79E-04
Ag-110m	1.07E-03
Te-125m	3.85E-04
I-127[a]	8.57E-11
Te-127	1.17E-02
Te-127m	3.35E-03
Te-129	1.28E-02
Te-129m	1.13E-02
I-129	5.02E-08
I-130	2.16E-02
I-131	2.82E+00
Te-131	1.45E-02
Te-131m	3.38E-02
I-132	3.17E+00
Te-132	3.15E-01
I-133	4.90E+00
Te-134	3.76E-02
I-134	7.46E-01
Cs-134	2.46E+00
I-135	2.81E+00
Cs-136	2.57E+00
Cs-137	2.09E+00
Ba-137m	1.98E+00
Cs-138	1.21E+00
Ba-140	4.26E-03
La-140	1.40E-03
Ce-141	6.39E-04
Ce-143	5.69E-04
Pr-143	6.32E-04
Ce-144	4.88E-04
Pr-144	4.88E-04

[a] Gram of I-127 per gram of coolant.

Table 9.3-6 TRITIUM PRODUCTION IN THE REACTOR COOLANT ONE UNIT (Reference 1)
Note: RCS tritium level was not specifically evaluated for EPU conditions, but can be expected to increase approximately proportional to the power level. Tritium effluents at EPU conditions are discussed in Section 11.2 and Appendix I.3.

Basic Assumptions (Plant Parameters):

1.	Core thermal power, MWt	1650
2.	RCS water volume (at T_{HOT}), ft^3	5880
3.	RCS core water mass, kg	6990
4.	Plant full power operating time for equilibrium (days)	500
5.	Boron Concentrations (equilibrium cycle), ppm	1435
6.	Fuel Rod / burnable poison release fraction	0.1
7.	RCS lithium concentration, ppm	2.2
8.	Li purity (atom percent Li-7)	99.9

RESULTS

Tritium Source	Total Produced Ci/cycle	Design Release to Coolant Ci/cycle
Ternary fission	8250	825
Fuel containing boron	882	88
Coolant soluble boron	286	286
Coolant soluble lithium	76	76
Coolant deuterium	2	2
TOTALS	9495	1277

Table 9.3-7 MALFUNCTION ANALYSIS OF CHEMICAL AND VOLUME CONTROL SYSTEM

	Component	Failure	Comments and Consequences
1.	Letdown line	Rupture in the line inside the reactor containment	The remote motor-operated valve located near the main coolant loop is closed on low pressurizer level to prevent supplementary loss of coolant through the letdown line rupture. The orifice block valves are closed when the motor operated valve closes. The containment isolation valves in the letdown line inside and outside the reactor containment are automatically closed by the containment isolation signal initiated by the safety injection signal. The closure of either containment isolation valve prevents leakage of the reactor containment atmosphere to the outside atmosphere.
2.	Normal and auxiliary charging line	See above	The check valves located near the main coolant loops prevent supplementary loss of coolant through the line rupture. The remote-operated valve located upstream of the check valve in the defective line also may be closed to isolate the reactor coolant system from the rupture. The check valves located at the boundary of the reactor containment prevent leakage of the reactor containment atmosphere outside the reactor containment.
3.	Seal water return line	See above	The motor-operated isolation valve located outside the containment and the air-operated valve located inside containment are manually closed or are automatically closed by the containment isolation signal initiated by the safety injection. The closure of either valve prevents leakage of the reactor containment atmosphere outside the reactor containment.

Figure 9.3-1UNIT 1 CHEMICAL AND VOLUME CONTROL

[redacted]

Figure 9.3-2 UNIT 1 CHEMICAL AND VOLUME CONTROL

[redacted]

Figure 9.3-3 UNIT 1 CHEMICAL AND VOLUME CONTROL

[redacted]

Figure 9.3-4 UNIT 1 CHEMICAL AND VOLUME CONTROL

[redacted]

Figure 9.3-5 UNIT 1 CHEMICAL AND VOLUME CONTROL

[redacted]

9.4 FUEL HANDLING SYSTEM (FH)

The fuel handling system provides a safe and effective means of transporting and handling fuel from the time it reaches the plant in an unirradiated condition until it leaves the plant after postirradiation cooling. The system is designed to minimize the possibility of mishandling or maloperations that cause fuel damage and potential fission product release.

The fuel handling system consists basically of:

1. The reactor cavity, which is flooded only during plant shutdown for refueling

2. The spent fuel pool, shared by the two units, which is kept full of water during and after the first refueling and is always accessible to operating personnel

3. The fuel transfer system, consisting of an underwater conveyor that transports fuel assemblies between the reactor cavity and the spent fuel pool.

9.4.1 DESIGN BASIS

Prevention of Fuel Storage Criticality

Criterion: Criticality in the new and spent fuel storage pits shall be prevented by physical systems or processes. Such means as geometrically safe configurations shall be emphasized over procedural controls. (GDC 66)

The new fuel storage area has accommodations as defined in Table 9.4-1 and is designed so it is impossible to insert assemblies in locations other than storage locations in the new fuel racks. Administrative controls are used to ensure that fuel stored in the new fuel storage racks complies with the requirements of the criticality analyses described in FSAR Section 9.4.2, including the use of a 3 out of 4 checkerboard arrangement when required. The fuel in the New Fuel Storage Vault is stored vertically and in an array with sufficient center-to-center distance between assemblies to assure $k_{eff} \leq 0.95$ as described in Technical Specification 4.3.1.

The spent fuel storage pool has accommodations as defined in Table 9.4-1. A criticality analysis was performed in Reference 1, submitted in Reference 11 with addendum in Reference 19 and approved in Reference 17. This amendment changed the licensing basis for spent fuel pool criticality requirements to 10 CFR 50.68(b) (Reference 8). The criticality analysis demonstrates that the spent fuel pool meets the requirements of 10 CFR 50.68(b)(4) to maintain keff less than 1.0 if filled with unborated water and keff less than or equal to 0.95 (including all biases and uncertainties) by maintaining at least 402 ppm boron in the spent fuel pool (Technical Specification 4.3.1.1 (c)). The analysis in Reference 1 assumes no Boraflex is present in the spent fuel storage racks to maintain subcriticality. Subcritical requirements are maintained by storing fuel in the “Acceptable” range of Technical Specification 3.7.12, Figure 3.7.12-1, considering initial enrichment, burnup and decay time of each fuel assembly. Fuel in the “Unacceptable” range is stored in accordance with Technical Specification 4.3.1.1.

Reference 1, Figure 3-5 also identified allowable IFBA patterns of 52 or less IFBA pins that can be credited for determining acceptable storage in the Point Beach spent fuel pool. IFBA patterns of 52 or less IFBA pins other than those shown in Reference 1 will require a 10 CFR 50.59

evaluation to validate that the conclusions from the analysis documented in Reference 1 remain unchanged. Such an evaluation was performed in Reference 21 and Reference 22. This evaluation identified additional IFBA patterns, with less than 52 pins that can be credited for acceptable storage in the Point Beach spent fuel pool. Any IFBA loadings of greater than 52 pins per assembly up to 120 pins are allowed with no IFBA pattern restrictions (Reference 23). Note that any IFBA length 120 inches or greater and any loading of 1.OX IFBA or greater (e.g., 1.5X, 2.OX, etc) are acceptable, as identified in Reference 1.

Reference 1 also considered the amount of soluble boron necessary to mitigate a misloaded 5.0 w/o fresh fuel assembly into a location intended for a burned fuel assembly. The amount of boron necessary to mitigate this accident and maintain the spent fuel pool keff less than or equal to 0.95 (including all biases and uncertainties) is 664 ppm. 664 ppm is well within the 2100 ppm minimum boron concentration required in the spent fuel pool by Technical Specification 3.7.11. Administrative controls ensure that fuel stored in the spent fuel pool meets the requirements of Technical Specifications and the criticality analysis described above and meets the requirements of 10 CFR 50.68(b)(1).

Because Reference 1 credits soluble boron, an additional analysis for boron dilution was included in Reference 11. The analysis concluded that a substantial volume of water is required to dilute the spent fuel pool from 2100 ppm to 664 ppm. This volume of water would be detected by the high level alarm, plant flooding or by operator rounds through the spent fuel pool area.

The Fuel Upgrade/Power Uprating Reload Transition Safety Report (Reference 18) concluded that the storage of 422V+ fuel also meets the required criteria for spent fuel and new fuel storage.

In addition, the spent fuel pool has an area set aside for accepting spent fuel shipping casks or dry storage casks. Cask loading is also done under water. Borated water is used to fill the spent fuel storage pool at a concentration to match or exceed that used in the reactor cavity and refueling canal during refueling operations. The fuel in the spent fuel pool is stored vertically in an array with sufficient center-to-center distance to assure keff <1.0 even if unborated water were to fill the space between the assemblies. The maximum nominal U-235 enrichment of the fresh fuel assemblies is limited to five (5.0) weight by percent per the requirements of 10 CFR 50.68(b)(7) and Technical Specification 4.3.

Detailed instructions are available for use by refueling personnel. These instructions, the minimum operating conditions, and the design of the fuel handling equipment incorporating built-in interlocks and safety features, provide assurance that no incident could occur during the refueling operations that would result in a hazard to public health and safety.

Fuel and Waste Storage Decay Heat

Criterion: Reliable decay heat removal systems shall be designed to prevent damage to the fuel in storage facilities and to waste storage tanks that could result in radioactivity release which would result in undue risk to the health and safety of the public. (GDC 67)

The refueling water provides reliable and adequate cooling medium for spent fuel transfer. Heat removal from the spent fuel pool is provided by the spent fuel cooling system specifically installed for this purpose. Natural radiation and convection is adequate for cooling the holdup tanks.

Fuel and Waste Storage Radiation Shielding

Criterion: Adequate shielding for radiation protection shall be provided in the design of spent fuel and waste storage facilities. (GDC 68)

Adequate shielding for radiation protection is provided during reactor refueling by conducting all spent fuel transfer and storage operations under water. This permits visual control of the operation at all times while maintaining low radiation levels, typically <5 mr/hr, for periodic occupancy of the area by operating personnel. Spent fuel pool water level is indicated by a level transmitter which causes an audible alarm in the control room on high or low level, and water removed from the pool must be pumped out since there are no gravity drains. Shielding is provided for waste handling and storage facilities to permit operation within requirements of 10 CFR 20.

Gamma radiation is continuously monitored in the auxiliary building. A high level signal is alarmed locally and is annunciated in the control room.

Protection Against Radioactivity Release From Spent Fuel and Waste Storage

Criterion: Provisions shall be made in the design of fuel and waste storage facilities such that no undue risk to the health and safety of the public could result from an accidental release of radioactivity. (GDC 69)

All fuel storage facilities are contained and equipment designed so that accidental releases of radioactivity directly to the atmosphere are monitored and do not exceed the dose criteria of 10 CFR 50.67 (Reference 20).

The reactor cavity, refueling canal and spent fuel storage pool are reinforced concrete structures with seam-welded stainless steel plate liners. These structures are designed to withstand the anticipated earthquake loadings as Class I structures so that the liner prevents leakage even if the reinforced concrete develops cracks. All operating areas in the fuel storage facilities are adequately ventilated. The exhausts of the ventilation system in the waste storage and drumming areas are monitored for radioactivity and are discharged via stacks through the top of the auxiliary building and facade.

All vessels in the waste disposal system which are used for waste storage are Class I seismic design.

9.4.2 SYSTEM DESIGN AND OPERATION

Various sections of the fuel handling system are shared by Units l and 2. These include a common spent fuel storage pool and a common new fuel storage area. This is discussed further in Appendix A.6.

The reactor is refueled with equipment designed to handle the spent fuel under water from the time it leaves the reactor vessel until it is placed in a cask for shipment from the site. Boric acid is added to the water to ensure subcritical conditions during refueling.

The fuel handling system, shown in Figure 9.4-1, may be generally divided into two areas: the refueling cavity (which is flooded only during plant shutdown for refueling) and the spent fuel pool (which is full of water during and after the first refueling and is always accessible to operating personnel). These two areas are connected by the fuel transfer system consisting of an underwater conveyor that carries the fuel through an opening in the units containment.

The refueling cavity is flooded with borated water from the refueling water storage tank. In the refueling cavity, fuel is removed from the reactor vessel, transferred through the water and placed in the fuel transfer system by a manipulator crane. In the spent fuel pool the fuel is removed from the transfer system and placed in storage racks with a long manual tool suspended from an overhead hoist. After a sufficient decay period, the fuel may be removed from storage and loaded into a shipping cask for removal from the site or loaded into a dry storage cask for temporary storage at the Point Beach Independent Spent Fuel Storage Installation (ISFSI) under 10 CFR 72. Both the manipulator crane and the long handled tool can handle only one fuel assembly at a time.

New fuel assemblies are received and stored in racks in the new fuel storage area or in the spent fuel pool. New fuel is delivered to the reactor by transferring it into the spent fuel pool and taking it through the transfer system. The new fuel storage area is sized for storage of the fuel assemblies and control rods normally associated with the replacement of one-third of a core plus space for another one-third core. Fuel handling data are given in Table 9.4-1.

Major Structures Required for Fuel Handling

Refueling Cavity

The refueling cavity is a reinforced concrete structure that forms a pool above and adjacent to the reactor when it is filled with borated water for refueling. The cavity is filled to a depth that limits the radiation at the surface of the water to less than 5 millirems per hour during fuel assembly transfer.

The reactor vessel flange is sealed to the bottom of the upper refueling cavity by a clamped, gasketed seal ring which prevents leakage of refueling water from the cavity. This seal is fastened and closed after reactor cooldown but prior to flooding the cavity for refueling operations. Potential leakage past the seal would go to the keyway under the reactor vessel and cause an alarm on the sump level instrument.

The lower refueling cavity is large enough to provide storage space for the reactor upper and lower internals, several control cluster drive shafts removed from the upper internals, and miscellaneous refueling tools. The floor and sides of the refueling cavity are lined with stainless steel. A skimmer pump system improves the surface water conditions during refueling.

Transfer Canal

The transfer canal is a passageway extending from the lower refueling cavity to the inside surface of the reactor containment where it aligns with the transfer tube and from the outside surface of containment along the East side of the spent fuel pool. The transfer canal walls and floor are lined with stainless steel.

In containment, the floor of the canal is approximately five feet below the floor of the lower refueling cavity to provide the greater depth required for the fuel transfer system upending device. The containment side of the transfer canal is drained after a refueling.

Outside containment, the walls of the transfer canal extend upward to the same elevation as the top of the spent fuel pool. Two gates in the wall between the transfer canal and the spent fuel pool allow for transfer of fuel assemblies from one area to the other while maintaining the fuel assembly below water for shielding purposes. The gates maintain spent fuel pool inventory and allow the transfer canal to be drained for maintenance of fuel handling equipment. The elevation of the bottom of the gates is above the top of the spent fuel racks. The gates employ inflatable seals supplied by Instrument Air and a redundant static seal that is seated to the door jamb by hydrostatic force.

The transfer tube connects the two portions of the transfer canal and is isolated by a Transfer Tube Closure assembly inside containment and a gate valve outside containment. Each unit has a transfer tube going from containment to the transfer canal.

Refueling Water Storage Tank

The normal function of the refueling water storage tank is to supply borated water to the refueling cavity for refueling operations. In addition, the tank provides borated water for delivery to the core following either a loss-of-coolant or a steam line rupture accident. This is described in Section 6.2.

The capacity of the tank is based upon the requirement for filling the refueling cavity. The water in the tank is borated to a concentration which assures reactor shutdown by at least 5% $\delta k/k$ when all RCC assemblies are inserted and when the reactor is cooled down for refueling. The tank design parameters are given in Section 6.2.

Spent Fuel Storage Pool

The spent fuel storage pool is designed for the underwater storage of spent fuel assemblies and control rods and other inserts after their removal from the reactor. New fuel assemblies may also be stored in the pool. Spent fuel pool accommodations are listed in Table 9.4-1. Spent fuel assemblies are handled by a long-handled tool suspended from an overhead hoist and manipulated by an operator standing on the movable bridge over the pool. Storage racks are provided to hold spent fuel assemblies and are erected on the pool floor. Fuel assemblies are held in a rectangular array, and placed in vertical cells. The racks are designed so that it is impossible to store fuel assemblies within the racks in other than a storage module, thereby ensuring the necessary spacing between assemblies. Control rod clusters are stored in place inside the spent fuel assemblies. One inspection location in the spent fuel pool allows rotation of a fuel assembly for visual inspection, but not for storage. The spent fuel storage pool is constructed of reinforced concrete and is Class I seismic design. The entire interior basin face and transfer canal is lined with stainless steel plate.

The spent fuel pool is divided into two parts by an internal dividing wall whose lowest point is approximately 3 ft. above the top of the stored spent fuel. The north portion of the pool contains an area reserved for the loading of the spent fuel shipping cask or dry storage cask. Administrative controls are such that no heavy loads, such as a spent fuel shipping cask or spent resin shipping cask, are transported over or placed in either part of the pool when fuel is stored in that part, unless suitable precautions are taken.

The spent fuel storage racks for the Point Beach Nuclear Plant are designed in accordance with Regulatory Guide 1.29, Revision 2, as seismic Category I components. The structural analysis of the racks has considered all the loads and load combinations specified in the NRC Standard Review Plan. The steel structure of the rack not only provides a smooth, all welded stainless steel box structure to preclude damage during normal and abnormal load conditions, but also provides an additional margin of safety in the form of internal structural damping created by the large areas of bearing surface between boxes in the array.

Auxiliary Building Crane

The auxiliary building crane has been modified to conform with single-failure-proof criteria. This modification evolved as a result of concern over the movement of heavy loads over or near the spent fuel pool when spent fuel is stored there (Reference 2 and Reference 5). The crane is designed to not allow a load drop as a result of any single constituent component failure.

The PAB superstructure has been analyzed for the capability of the structure to support and hold the crane with its full rated lift load of 125 tons plus a roof snow load and a concurrent seismic (OBE or SSE) event or a lift of 125 tons plus a roof snow load and design wind loads. (Reference 15)

New Fuel Storage

New fuel assemblies and control rods can be stored in a separate area that facilitates the unloading of new fuel assemblies or control rods from trucks. This storage vault is designed to hold new fuel assemblies in specially constructed racks and is utilized primarily for the storage of the replacement fuel assemblies. The new fuel assemblies are stored in dry racks arranged to space the fuel assemblies such that the maximum k_{eff} should the new fuel storage area be inadvertently filled with the most reactive water density is less than 0.95.

The new fuel storage area was evaluated by Westinghouse calculation CAB-98-292 submitted by Westinghouse letter 98WE-G-0052 (Reference 10). The analysis has shown that based on a center to center distance of 19 inches, k_{eff} remains below 0.95 for the fully flooded condition, and 0.98 for the optimum moderation condition. This meets the requirements of 10 CFR 50.68(b)(2) and 10 CFR 50.68(b)(3) and Technical Specification 4.3.1.2. All new fuel assemblies with an enrichment of 5 w/o U-235 or less and containing a minimum of 32 1.25X IFBA rods may utilize all available storage locations in the new fuel storage area.

The new fuel storage area was also evaluated by Westinghouse calculation CAB-99-318 submitted by Westinghouse letter 99WE-G-0043 (Reference 16). The analysis has shown that based on a center to center distance of 19.5 inches, k_{eff} remains below 0.95 for the fully flooded condition, and 0.98 for the optimum moderation condition. This meets the requirements of 10 CFR 50.68(b)(2) and 10 CFR 50.68(b)(3) and Technical Specification 4.3.1.2. All new fuel assemblies with an enrichment of 5.00 w/o U-235 or less may occupy cells in a 3 out of 4 checkerboard arrangement. The 3 out of 4 storage arrangement with empty cell means that three fuel assemblies can occupy three storage cells with the other cell being empty in any 2 x 2 array of storage cells. This analysis is valid for Westinghouse STD, OFA, and various advanced fuel products.

Major Equipment Required for Fuel Handling

Reactor Vessel Stud Tensioner

The stud tensioner is a hydraulically operated (oil is the working fluid) device provided to permit preloading and unloading of the reactor vessel closure studs at cold shutdown conditions. Stud tensioners were chosen in order to minimize the time required for the tensioning or unloading operations. Three tensioners are applied simultaneously to three studs 120° apart. One hydraulic pumping unit operates the tensioners which are hydraulically connected so equal pressure is applied simultaneously to the three studs. The studs are tensioned to their operational load using a controlled procedure to prevent high stresses in the reactor vessel and head flange region and unequal loadings in the studs.

A pressure control valve and relief valve are provided on the hydraulic pump assembly to prevent over tensioning the studs due to excessive hydraulic pressure.

Tables of tensioning sequence and oil pressure are included in the operating instructions. Stud elongation measuring equipment is provided to measure the elongation of the studs after tensioning to determine the acceptability of the final tensioning.

Reactor Vessel Head Lifting Device

The reactor vessel head lifting device consists of a welded and bolted structural steel frame with lifting tripod to enable the crane operator to lift the head and store it during refueling operations. The lifting device, including the lifting tripod, remains attached to the reactor vessel head during power operation. (Reference 13 and Reference 14)

Reactor Internals Lifting Device

The reactor internals lifting device is a fixture provided to remove the upper reactor internals package and to move it to a storage location in the refueling cavity. The device is lowered onto the guide tube support plate of the internals and is manually bolted to the support plate by three bolts. The bolts are controlled by long torque tubes extending up to an operating platform on the lifting device. Bushings on the fixture engage guide studs mounted on the vessel flange to provide close guidance during removal and replacement of the internals package. This lifting device can also be used to remove the lower internals once the vessel has been cleared of all fuel assemblies.

Manipulator Crane

The manipulator crane is a rectilinear bridge and trolley crane with a vertical mast extending down into the refueling water. The bridge spans the reactor cavity and runs on rails set into the floor along the edge of the reactor cavity. The bridge and trolley motions are used to position the vertical mast over a fuel assembly in the core. A long tube with a pneumatic gripper on the end is lowered out of the mast to grip the fuel assembly. The gripper tube is long enough so the upper end is still contained in the mast when the gripper end contacts the fuel. A hoist mounted on the trolley raises the gripper tube and fuel assembly up into the mast tube. The fuel is transported while inside the mast tube to its new position. The manipulator can lift only one fuel assembly at a time. An unlatching stand is installed in the cavity to enable unlatching the gripper underwater and avoid having to drain the cavity should the gripper be accidentally put into the latch position while not engaged in a fuel assembly.

All controls for the manipulator crane are mounted on a console on the trolley. The bridge is positioned on a coordinate system consisting of index plates installed along the refueling cavity. A video camera located on the bridge truck indicates the position of the bridge via a TV monitor located on the control console. The trolley is positioned with the aid of a scale on the bridge structure. The scale is read directly by the operator at the console. The bridge, trolley, and hoist motors are controlled with a variable frequency drive. This allows for variable speed control of the motors as well as separate slow speed (jog) control for each motor. Electrical interlocks and limit switches on the bridge and trolley drives protect the equipment. In an emergency, the bridge, trolley, and hoist can be operated manually using a handwheel on the motor shaft.

The suspended weight on the gripper tool is monitored by an electric load cell indicator mounted on the control console. An excessive load stops the hoist drive from moving in the up direction. The gripper is interlocked through a weight sensing device and also a mechanical spring lock so that it cannot be opened when supporting a fuel assembly.

Safety features are incorporated in the system as follows:

1. Travel limit switches on the bridge and trolley drives.

2. Bridge, trolley, and hoist drives which are mutually interlocked to prevent simultaneous operation of any two drives.

3. A position safety switch (GRIPPER TUBE UP) prevents bridge and trolley motion when the gripper is in the ENGAGED position on a fuel assembly except when it is actuated. Also, a geared limit position switch allows for bridge and trolley motion when the inner mast is just inside the outer mast and the gripper is in the DISENGAGED position without the weight of an assembly added to the mast. This allows for faster refueling movements as an empty inner mast is not required to travel to the top of the outer mast before the bridge and trolley are allowed to move.

4. An interlock which prevents the opening of a solenoid valve in the air line to the gripper except when a programmed suspended weight is indicated by a digital readout on the control console. As backup protection for this interlock, the mechanical weight-actuated lock in the gripper prevents operation of the gripper under load even if air pressure is applied to the operating cylinder.

5. The OVERLOAD interlock switch, which opens the hoist drive circuit in the up direction when the loading is excessive.

6. An interlock on the hoist drive circuit in the up direction, which permits the hoist to be operated only when either the ENGAGED or DISENGAGED indicating switch on the gripper is actuated.

7. An interlock of the bridge and trolley drives, which prevents the bridge drive from traveling beyond the edge of the core unless the trolley is aligned with the refueling canal centerline. The trolley drive is locked out when the bridge is beyond the edge of the core.

Suitable restraints are provided between the bridge and trolley structures and their respective rails to prevent derailing. The manipulator crane is designed to prevent disengagement of a fuel assembly from the gripper in the event of a maximum potential earthquake. The auxiliary hoist is used for the rod latching tool, plug device tool, and other tools used in the refueling cavity.

Spent Fuel Pool Bridge

The spent fuel pool bridge is a wheel-mounted walkway, spanning the spent fuel pool which carries an electric monorail hoist on an overhead structure. A fuel assembly is moved within the spent fuel pool by means of a long handled tool suspended from the hoist. The hoist travel and tool length are designed to limit the maximum lift of a fuel assembly to a safe shielding depth.

The engineering specification for the design of the Spent Fuel Bridge included a 0.20g seismic loading in the horizontal and vertical directions. The limiting stress criteria employed with this seismic load results in a 3 to 1 factor of safety with respect to yield of the bridge steel. The maximum floor horizontal acceleration at the point of bridge support for the Design Basis Earthquake is 0.22g.

Fuel Transfer System

The fuel transfer system, shown in Figure 9.4-1 is an alternating current (AC) motor driven conveyor car that runs on tracks extending from the lower refueling cavity through the transfer tube and into the transfer canal next to the spent fuel pool. The conveyor car receives a fuel assembly in the vertical position from the manipulator crane. The fuel assembly is lowered to a horizontal position for passage through the tube, and then is raised to a vertical position for transfer to the spent fuel pool.

During plant operation, the conveyor car is stored in the fuel transfer canal outside of containment. The gate valve is closed and the Transfer Tube Closure hatch is installed on the transfer tube to seal the reactor containment.

Rod Cluster Control Changing Fixture

A fixture is mounted on the refueling cavity wall for removing rod cluster control (RCC) elements from spent fuel assemblies and inserting them into new fuel assemblies for reuse. The fixture consists of two main components; a guide tube mounted to the wall for containing and guiding the RCC element, and a wheel-mounted carriage for holding the fuel assemblies and positioning fuel assemblies under the guide tube. The guide tube contains a pneumatic gripper on a winch that grips the RCC element and lifts it out of the fuel assembly. By repositioning the carriage, another fuel assembly is brought under the guide tube and the gripper lowers the RCC element and releases it. There is a third position in the basket used for a temporary storage of an insert. The manipulator crane loads and removes the fuel assemblies into and out of the carriage. The gripper is also used for source and power suppression assembly changes.

9.4.3 SYSTEM EVALUATION

Underwater transfer of spent fuel provides safety in handling operations. Water is an effective and transparent radiation shield and a reliable cooling medium for removal of decay heat.

Basic provisions to ensure the safety of refueling operations are:

1. Gamma radiation levels in the containment, control room, and fuel storage areas are continuously monitored (see Section 11.5). These monitors provide an audible alarm at the initiating detector indicating an unsafe condition. Continuous monitoring of reactor neutron flux provides immediate indication and alarm in the control room, and in the containment, of an abnormal core flux level.

2. A minimum boron concentration, specified in the COLR, is required for MODE 6 refueling operations.

3. Whenever fuel is added to the reactor core, the source range neutron count rate is monitored to verify the subcriticality of the core.

Incident Protection

Direct communication between the control room and the operating floor of the containment is available whenever changes in core geometry are taking place. This provision allows the control room operator to inform the core loading supervisor of any impending unsafe condition detected from the main control board indicators during fuel movement.

The walls and the base of the pool will withstand all design tornado missiles. Calculations demonstrate that tornado generated winds will not remove any critical amount of water from the spent fuel pool. Any water removed in this way will leave adequate coverage to maintain cooling of the stored fuel elements. (Reference 12)

No special design features had been made for the spent fuel pool as far as turbine missiles were concerned because it had been believed that the worst low-trajectory missile could not have sufficient translational kinetic energy to reach the spent fuel pool. However, model tests initiated by Westinghouse contradicted this theory in the case of a turbine overspeed. Therefore, a completely independent turbine speed detection and valve trip initiation system for the turbine generators of Units 1 and 2 was provided to minimize the likelihood of a turbine generator unit overspeeding above the design speed. FSAR Section 14.1.12 gives more insight into this event.

Malfunction Analysis

An analysis is presented in Section 14.2.1 concerning damage to all of the fuel rods in an assembly, assumed as a conservative limit for evaluating the environmental consequences of a fuel handling accident.

9.4.4 REQUIRED PROCEDURES AND TESTS

Calibrations and operational tests of the fuel handling equipment are performed as required by the Technical Requirements Manual.

The minimum boron concentration in the spent fuel pool is monitored in accordance with Techncial Specification 3.7.11. (Reference 8)

9.4.5 REFERENCES

1. Westinghouse Report WCAP-16541-P, Revision 2, Point Beach Units 1 and 2 Spent Fuel Pool Criticality Safety Analysis, dated June 2008.
2. NUREG-0612, Control of Heavy Loads at Nuclear Power Plants
3. WE letter VPNPD-96-029, Response to NRC Bulletin 96-02, Movement of Heavy Loads Over Spent Fuel, Over Fuel in the Reactor Core, or Over Safety-Related Equipment, dated May 9, 1996.
4. NRC SER, Re NUREG-0612, Control of Heavy Loads at Nuclear Power Plants, dated March 27, 1984.
5. NRC SER, Re Amendment Nos. 96 and 100, dated September 3, 1985.
6. NRC SER, Re Issuance of Amendments Nos. 35 and 41, dated April 4, 1979.
7. NRC SER, Re Issuance of Amendments Nos. 77 and 81, dated October 5, 1983.
8. 10 CFR 50.68, Criticality Accident Requirements.
9. NRC Letter to WE, Issuance of the Exemption from the Requirements of 10CFR70.24, dated October 6, 1997.
10. Westinghouse Letter 98WE-G-0052, Fresh Fuel Rack Criticality Analysis, dated October 21, 1998.
11. NRC 2008-0044, License Amendment Request 247, Spent Fuel Pool Storage Criticality Control, July 24, 2008.
12. Bechtel Topical Report B-TOP-3, Design Criteria for Nuclear Power Plants Against Tornadoes, (Proprietary) dated March 12, 1970.
13. Westinghouse Calculation CN-RVHP-04-10, “Point Beach Units 1 and 2 HAUP - Missile Impact Analysis,” (Westinghouse Proprietary), Rev 5, dated May 18, 2006.
14. Westinghouse Calculation CN-RVHP-04-12, “Point Beach HAUP Structural Analysis,” (Westinghouse Proprietary), Rev 2, dated March 24, 2006.
15. Automated Engineering Services Corp. Calculation PBNP-305336-S01, Rev. 1, “Structural Analysis of Central PAB with Crane Load of 125 Tons,” dated April 3, 2006.
16. Westinghouse Letter 99WE G 0043, Point Beach Fresh Fuel Storage 3-out-of-4 Configuration Final Criticality Analysis Report, dated August 23, 1999.
17. NRC Safety Evaluation, “Point Beach Nuclear Plant, Units 1 and 2 - Issuance of Amendments Re: Spent Fuel Pool Storage Criticality Control,” dated March 5, 2010.
18. Westinghouse Fuel Upgrade/Power Uprating Reload Transition Safety Report for Point Beach Units 1 and 2, Revision 2, dated November 1, 1999.
19. Westinghouse Report WCAP-16541-NP Revision 2, Addendum 1, Point Beach Units 1 and 2 Spent fuel Pool Criticality Analysis - Addendum, dated November 2009.

20. NRC Safety Evaluation, "Point Beach Nuclear Plant (PBNP), Units 1 and 2 -Issuance of License Amendments Regarding Use of Alternate Source Term (TAC Nos. ME0219 and ME0220)," dated April 14, 2011.

21. Point Beach Nuclear Plant Evaluation 2011-007, "10 CFR 50.59 Evaluation - Justification of IFBA fuel rod patterns for the SFP Criticality Analysis."

22. Engineering Evaluation EC 273511, Revision 0, "Justification of IFBA Pattern for the SFP Criticality Analysis."

23. FPL Energy Point Beach Letter to NRC, NRC 2009-0057, "Response to Request for Additional Information, License Amendment Request 247, Spent Fuel Pool Storage Criticality Control," dated May 22, 2009.

Table 9.4-1 FUEL HANDLING DATA

New Fuel Storage Area

Core storage capacity	≈2/3
Equivalent fuel assemblies	84
Center-to-center spacing of assemblies, in.	19 (min)
Maximum k_{eff} with the most reactive water density	<0.95
Maximum keff with optimum moderation	<0.98

Spent Fuel Storage Pool

South pool fuel assembly storage capacity	803
North pool fuel assembly storage capacity	699
Number of space accommodations for spent fuel cask loading	1
Maximum k_{eff} with borated water (402 ppm)	≤0.95
Maximum k_{eff} with unborated water	<1.0

Miscellaneous Details

Width of transfer canal, ft.	3
Wall thickness for spent fuel storage pool, ft.	4 to 6
Weight of fuel assembly with RCC (dry), lb.	1750
Capacity of refueling water storage tank, each, gal.	289,504
Quantity of water required for refueling, gal.	275,000

Figure 9.4-1 FUEL TRANSFER SYSTEM

[redacted]

9.5 PRIMARY AUXILIARY BUILDING VENTILATION SYSTEM

9.5.1 DESIGN BASIS

The Primary Auxiliary Building Ventilation (VNPAB) system is not required to perform any Safety Related functions. VNPAB system operation is credited for Primary Auxiliary Building (PAB) heat removal. No credit is taken in any accident analysis or habitability study for the filtration capability of the system. The PAB Ventilation system is credited in the event of a fire and evaluated in the at-power and non-power analyses (Reference 5).

9.5.2 SYSTEM DESIGN AND OPERATION

The auxiliary building ventilation air is supplied by a central supply fan which includes an air filter, heating coils, and service water supplied cooling coils. Sufficient outside air is supplied to maintain a once-through system with provisions available to recirculate air from the PAB central area. The system is balanced to maintain the auxiliary building at slightly negative pressure with respect to outside pressure and adjacent building pressures. This is accomplished by providing an exhaust flow capacity larger than the supply capacity. All the exhaust air is filtered through roughing and high efficiency filters for removal of particulates. Areas which have possible contamination from iodine vapor have the capability to be exhausted through activated carbon beds in addition to high efficiency filters if required. All air exhausted from these areas is then discharged through the auxiliary building vent stack, which is monitored for radiation. A radiation detector output above its set point will initiate exhaust filtration through the activated charcoal beds. The discharge of the combined air ejector is vented into the auxiliary building stack downstream of the filters.

The VNPAB exhaust system consists of two filter fans (W-30A&B), two stack fans (W-21A&B), and the associated ductwork, filter housings, and dampers necessary to ensure the required exhaust flow path can be maintained. Each of the two filter fans and each of the two stack fans are powered by independent safety related power supplies with EDG backup. Exhaust stack fan W-21A and exhaust filter fan W-30A are powered from the safety-related Class 1E, 480 V Motor Control Center (MCC) 1B-42. Exhaust stack fan W-21B and exhaust filter fan W-30B are powered from the safety-related Class 1E, 480 V MCC 2B-32. The filter and stack fan control switches are located in the control room on the back of the main control board. One filter fan and one stack fan are normally in operation. A low exhaust flow condition is indicated and alarmed in the control room.

Primary Auxiliary Building Battery and Inverter Room Ventilation system is discussed in FSAR Section 8.7.

9.5.3 SYSTEM EVALUATION

The Auxiliary Building Ventilation System provides sufficient control of building temperatures during normal, abnormal, and accident conditions to maintain equipment within operational temperature limits. This system also filters the exhaust from rooms potentially containing iodine vapor, and rooms potentially containing particulates, during normal and accident conditions to limit offsite releases, and support auxiliary building habitability.

The drumming station supply and exhaust systems are similar to the auxiliary building ventilation system with the exception that the exhaust system has no provision for iodine removal and is discharged via a separate, monitored vent stack.

No credit is given for the VNPAB exhaust system in the control room or offsite dose bounding analysis described in FSAR Chapter 14.3.5, Radiological Consequences of a Loss of Coolant Accident (Reference 1).

Restoration of the VNPAB system within two hours of a LOOP assures adequate cooling for PAB safety related equipment during the worst case design basis accident (Reference 4).

The VNPAB system is classified as non-safety related, however components in the exhaust system required to direct radioactive releases in the PAB to the vent stack are classified as AQ (Augmented Quality). The seismic adequacy of the VNPAB exhaust system has been demonstrated using a methodology that follows the guidelines of Reference 2 and Reference 3. The VNPAB exhaust system design provides redundancy for all active mechanical components and active and passive electrical components needed to provide PAB exhaust flow. The design considers relay failures; failures of contacts to change state; and the shorting of relay, solenoid, or starter coils that could cause a damper to change to an undesirable state or prevent starting of a fan. The failure analysis does not include conductor short circuits or failure of one conductor, cable or device causing a failure of another conductor, cable, or device in the same location or raceway. The VNPAB exhaust system fans are supplied from the safety related Class 1E system by safety related circuit breakers which will isolate a fault on the non-safety related portions of the system and keep it from propagating to the Class 1E system. The fan motors and power cables located in potentially harsh environments are qualified for the expected environmental conditions (Reference 1).

9.5.4 REQUIRED PROCEDURES AND TESTS

Gaseous waste monitoring of the Primary Auxiliary Building ventilation system is performed per the requirements of the Offsite Dose Calculation Manual (ODCM).

The VNPAB exhaust system is included in the scope of the Maintenance Rule (10 CFR 50.65) and the License Renewal (10 CFR 54.37(b)) programs. The W-30A&B filter fan motors and associated power cables, and the power cables to the W-21A&B stack fans are included in the scope of the EQ Program (10 CFR 50.49).

9.5.5 REFERENCES

1. NRC Safety Evaluation, “Point Beach Nuclear Plant (PBNP), Units 1 and 2 -Issuance of License Amendments Regarding Use of Alternate Source Term (TAC Nos. ME0219 and ME0220),” dated April 14, 2011.

2. Seismic Qualification Utility Group (SQUG), “Generic Implementation Procedure (GIP) For Seismic Verification of Nuclear Plant Equipment,” Revision 2, Corrected February 14, 1992.

3. Electric Power Research Institute Final Report 1014608, “Seismic Evaluation Guidelines for HVAC Duct and Damper Systems: Revision to 1007996,” dated December, 2006.

4. NRC Safety Evaluation, “Point Beach Nuclear Plant (PBNP), Units 1 and 2 -Issuance of License Amendments Re: Auxiliary Feedwater System Modification (TAC Nos. ME1081 and ME1082),” dated March 25, 2011.

5. NFPA 805 Fire Protection Program Design Document (FPPDD).

9.6 SERVICE WATER SYSTEM (SW)

9.6.1 DESIGN BASIS

The Service Water (SW) system shall provide sufficient flow to support the heat removal requirements of components required to mitigate the consequences of a Loss of Coolant Accident (LOCA) in one unit, while supporting the normal flow of the unaffected unit. Although SW is required to mitigate other plant accidents as well, a LOCA combined with normal operation of the unaffected unit is the most limiting event for the heat load imposed on the SW system.

The SW system shall provide sufficient flow to the spent fuel pool heat exchangers to provide adequate heat removal of spent fuel decay heat (see Section 9.9, Spent Fuel Pool Cooling and Filtration). The SW system shall provide a long term makeup water source to the suction of the auxiliary feedwater (AF) pumps when the normal makeup source (the CSTs) is not available.

The service water system also has the following augmented quality functions. The SW system shall supply water to safe shutdown equipment and fire suppression in the G-01 and G-02 diesel generator rooms and containment hose reels during plant fires (Reference 5).

The service water system is sized to ensure adequate heat removal based on the highest expected temperatures of cooling water, maximum loading and leakage allowances. Calculations show that adequate service water flow is available at 85°F indicated temperature to transfer the design basis accident heat loads during the post-DBA injection and recirculation phases with three service water pumps in operation. All essential safety related heat exchangers have been demonstrated by analysis to be capable of transferring their design basis heat loads at 85°F (Reference 3).

The pumphouse structure has been designed to remain intact under a tornado wind having a tangential velocity of 300 mph plus a forward progress of 60 mph. The structure is capable of remaining intact for a pressure drop of 1/2 psi. Before this pressure drop is realized, the building would be vented by the failure of the louvers and doors. Interior missile shield walls and exterior walls protecting the service water pumps are constructed of reinforced concrete with a minimum thickness of 12”. The internal missile shield walls have been located to preclude the possibility of damage from a missile passing through a louver or door. Reinforced concrete walls of 12” thickness cannot be penetrated by the design tornado missiles (Reference 8 and Reference 9).

9.6.2 SYSTEM DESIGN AND OPERATION

The service water (SW) system flow diagrams are shown in Figure 9.6-1 through Figure 9.6-7. The service water system has six electric motor driven centrifugal pumps which take a suction from the pump bays in the Circulating Water (CW) pump house. Two service water pumps are connected to separate 480 volt buses (2B-03 and 1B-04), one per bus. The four remaining pumps are connected, two per bus, to two separate 480 volt buses (1B-03 and 2B-04). In the event of a loss of normal electrical power to the safeguard buses, each of the emergency diesel-generator units are sized to supply three service water pumps in addition to the other vital engineered safeguards loads powered from that train for the unit in which the event occurred, as well as, the loads required by the other unit to maintain a hot shutdown condition. Four service water pumps (P-32B, C, E, F) can be supplied power from the X-08 transformer when normal power is unavailable.

The service water pumps supply a header which exits the pumphouse through two below ground pipelines leading to the Class I section of the control building. The two pipelines, called North and South headers, run to the auxiliary building where they rejoin to form the West header. The West header consists of the piping between MOVs SW-2869 and SW-2870. Motor operated valves (SW-2869, 2870, 2890, and 2891) allow isolation of the main loop headers in the event of a piping failure such that the safe shutdown function of the SW system can be retained. The piping failure is considered a passive failure and is not assumed to occur concurrent with a design basis accident. The return lines are manifolded by areas and are discharged to the condenser circulating water discharge in either Unit 1 and/or Unit 2.

The SW system, serving both units, supplies cooling water to equipment in the steam plant, to the containment ventilation coolers and to the reactor auxiliary systems. Non-essential services in each unit receive water from their respective header (North or South).

Supply of service water for essential services is redundant and can be maintained in case of failure of one loop section header (Reference 3 and Reference 4). Table 9.6-1 is a list of the essential service loads supplied by the service water (SW) system. Return service water is directed to the return line of the circulating water (CW) system.

The service water system pumps and motor operated valves are operated from the C01 control panel in the control room. The service water system is normally operated with both the North and South supply header cross connect valves open and the West Header cross connect valves open. Normally, two of the six pumps are capable of carrying the required normal cooling load for the two units. During periods of higher lake temperatures or when RHR cooling is in service, operation of three pumps is normally necessary. Service water pump flowrate is dependent upon the number of pumps running, the system valve lineup and positioning. Typical flowrates for the system in accident conditions vary from about 3,000 gpm to 21,000 gpm. Control room operators can shift SW pumps, split the SW headers, and isolate various SW loads as the plant requires.

The service water pumps are connected to the 480 volt safeguards buses and can be supplied by the Emergency Diesel Generators (DG) in the event of loss of offsite power. Under the conditions of a loss-of-coolant accident (LOCA) and concurrent loss-of-offsite power (LOOP), any three SW pumps are capable of providing the necessary cooling capacity for the essential loads for the affected unit and supply service water for the normal operation of the unaffected unit (Reference 3).

With a Safety Injection (SI) signal present, the containment cooler outlet valves (1/2SW-2907 and 1/2SW-2908) open, non-essential service water load valves close, and all six service water pumps receive start signals on a timed sequence. In the case of an undervoltage condition coincident with an SI signal, bus voltage must be restored before these actions begin. Table 9.6-2 lists the valves that close to isolate non-essential service water loads.

The containment ventilation coolers (HX-15) are supplied in pairs from the service water loop. The redundant motor operated valves in the containment cooler service water discharge lines (1/2SW-2907,2908) will automatically open on a safeguards actuation signal. Each cooler inlet and outlet are provided with a manual shutoff and drain capability. Manual valves allow each cooler to be isolated individually for leak testing. Service water to each cooler is isolated during the performance of the integrated leakage rate test. The containment ventilation cooler SW discharge lines are continuously monitored for radioactivity. A small bypass flow from the return line of each cooler is diverted through a common header to radiation monitor 1/2RE-216. Upon indication of radioactivity in the common monitor, each cooler discharge line could be monitored individually to locate a defective cooler. The defective cooler might then be removed from service with its manual isolation valves.

The containment cooling coils are completely closed inside containment and no leakage is expected from these units. During normal operation the service water system supply and return pressure for the ventilation coolers can be above or below the containment design pressure of 60 psig. Following a loss-of-coolant accident, the service water system supply and return pressure for the ventilation coolers is normally below the containment design pressure of 60 psig. The service water system is considered a closed system inside containment.

The essential loads of the SW system are designed to minimize any sedimentary blockage of the service water side. The automatic initiating valves for essential loads are generally located on the service water discharge side of heat exchangers. Table 9.6-3 shows a listing of the valves that are automatically opened when required.

The diesel generators (G-01 and G-02) employ jacket cooling and shell and tube heat exchangers. The Service Water system provides the source of cooling for the engine heat exchangers (G-01 and G-02 only). In the event of a loss of power to the safeguards buses, service water is not immediately available for cooling G-01 and G-02 until the buses are restored. Adequate heat absorption capacity is provided to operate the diesel generators (G-01 and G-02) until the service water system starts.

The service water system is the safety related water supply for the auxiliary feedwater pumps (1/2 P-29 and 1/2 P-53). Normally closed motor-operated valves (1/2 AF-4006 and 1/2 AF-4067) are provided to allow the suction supply for the AF pumps to be transferred to the SW system. The AF pump suctions are automatically transferred to the service water system as described in Section 10.2 (Reference 1).

The service water system is capable of supplying water to the suction of the non-essential Standby Steam Generator (SSG) pumps (P-38 A&B) via normally closed, manually actuated motor operated valves AF-4009 and AF-4016.

The spent fuel (SF) pool cooling system is not considered an essential load and cooling for this system may be interrupted. Service water will be interrupted during an accident after a SI signal from either unit. It will be necessary to manually restore spent fuel pool cooling following service water isolation.

The service water headers in the auxiliary building primarily supply cooling water to the; four component cooling heat exchangers, containment fan coolers, and the spent fuel pool cooling system. The component cooling heat exchangers are utilized to remove heat from the primary coolant system through the residual heat (RH) removal loop. The residual heat (RH) removal loop is employed during normal shutdown operations, and would also be placed in service following a loss-of-coolant accident for cooling of the recirculation flow from the reactor containment sump.

The service water system is treated to control biological fouling in the system piping and heat exchangers. Sodium hypochlorite, Sodium Bromide, Nalco 73551 (bio-detergent), and Nalco 3DT121 (silt dispersant) have been approved as system additives to prevent the buildup of slime and algae in the system and to minimize zebra mussel colonization. In addition, a chemical called EVAC has been approved for use in periodic treatments to kill any adult zebra mussels which have settled in the system. Other treatments may be considered in the future and will be evaluated prior to implementation. All treatments must be performed within the requirements of our Department of Natural Resources (DNR) Discharge Permit under the Wisconsin Pollutant Discharge Elimination System (WPDES).

9.6.3 SYSTEM EVALUATION

The service water system is designed to prevent a component failure from curtailing normal station operation. The service water loop can be aligned to provide two independent systems. In the event of a major malfunction, it is possible to isolate the portion of the system affected and maintain essential services to the plant. In addition to the header isolation valves, each component also has individual isolation valves to permit removing any piece of equipment from the system.

Service water pumps are normally controlled from main control room panel C-01, (see Section 7.5.4 for description of local controls). The SW pump capacity is sufficient to simultaneously meet the flow requirements of a design basis accident, together with failed closure of one train of the motor operated valves for isolation of nonessential services.

Service water piping beyond the Class-1 structures only supplies non-essential equipment. That piping can be isolated by the safeguards sequence automatically, by remote manual actuation of powered isolation valves, and by local manual valves. Both the powered and manual isolation valves are located within the Class-1 structure.

The service water piping in the Control Room Heating, Ventilation and Air Conditioning Room is Category I (seismic).

Evaluation of the internals of the North Service Water Header Zurn Strainer, SW-2911-BS, and the South Service Water Header Zurn Strainer, SW-2912-BS, determined that the internal components will not fail during or after a seismic event and cause blockage of flow. Operation of the backwash function is not part of the evaluation (Reference 6 and Reference 7).

Almost all of the motor-operated valves in the service water system are supplied with electrical power from the safeguards buses. There are two exceptions; MOV-2818 (service water isolation to cable spreading room air conditioning) is supplied from MCC B-21 which is supplied by 480V AC safeguards bus 2B-04. MCC B-21 is stripped from 2B-04 on a Unit 2 Safety Injection signal or on loss of AC power. MOV-2819 (service water isolation to the control room air conditioning) is powered from MCC B-22 which is supplied by 480V AC non-safeguards bus 2B-02.

The service water system is in operation at all times during plant operation and shutdown, and therefore is in a high state of readiness for any abnormal or emergency plant conditions.

9.6.4 REQUIRED PROCEDURES AND TESTS

The SW system components are tested and inspected in accordance with Technical Specification surveillance criteria and surveillance frequencies by the Surveillance Frequency Control Program (Reference 10). Testing verifies motor-driven pump operability, and operability of all required valves.

The passive portions of the system are monitored in accordance with the Open-Cycle Cooling (Service) Water System Surveillance Program (Section 15.2.14) during the period of extended operation. (NRC SE dated 12/2005, NUREG-1839)

The originally installed service water pumps underwent a hydrostatic test in the vendor shop at a test pressure of one and one-half times the shutoff head of the pump. In addition, the normal capacity vs. head characteristics were determined for each pump. During plant construction, the service water piping was hydrostatically tested in the field at one and one-half times design pressure. The welds in the shop fabricated service water piping were randomly radiographed in accordance with ASME Boiler and Pressure Vessel Code, Section VIII. Repair, replacement, and modification work on the service water system components is completed in accordance with the requirements of 10 CFR 50 Appendix B and ASME Section XI.

9.6.5 REFERENCES

1. NRC Safety Evaluation, "Point Beach Nuclear Plant (PBNP), Units 1 and 2 - Issuance of License Amendments Re: Auxiliary Feedwater System Modification (TAC Nos. ME1081 and ME1082)," dated March 25, 2011.

2. Not Used

3. 10 CFR 50.59/72.48 Screening (SCR) 2013-0024, "Revise TRM 3.7.7, OI 70, TS 33, TS 34, AOP 13A, AOP 8F, FSAR 9.6.1, OI 155, PC 97 Parts 1-8, and 1(2)-SOP-VNCC-001-4 to Allow 85F SW Inlet Temperature and to specify operability limits on low pump bay level for the G01/G02 EDGs and the lower elevation CFCs," dated March 15, 2013.

4. NRC Safety Evaluation, "Point Beach Nuclear Plant, Units 1 and 2 - Issuance of Amendments Re: Service Water System Operability (TAC Nos. MB4630 and MB4631), dated August 29, 2002.

5. NFPA 805 Fire Protection Program Design Document (FPPDD).

6. Screening Evaluation Work Sheet SQ-002126, "North Service Water Header Zurn Strainer, SW-2911-BS," Revision 1, 03/07/03.

7. Screening Evaluation Work Sheet SQ-002127, "South Service Water Header Zurn Strainer, SW-2912-BS," Revision 1, 03/07/03.

8. Bechtel Topical Report B-TOP-3, "Design Criteria for Nuclear Power Plants Against Tornadoes," (Proprietary) dated March 12, 1970.

9. Amirikian, Araham, "Design of Protective Structures, A New Concept of Structural Behavior," Bureau of Yards and Docks, Department of the Navy, P 51, August 1950.

10. NRC Safety Evaluation, "Point Beach Nuclear Plant Units 1 and 2 - Issuance of Amendments Regarding Relocation of Surveillance Frequencies to Licensee Control (TAC NOS. MF4379 and MF4380)," dated July 28, 2015.

Table 9.6-1 ESSENTIAL SERVICE WATER LOADS

PAB Battery Room Coolers
Emergency Diesel Generator Engine Coolant Heat Exchanger (G-01 & G-02)
Component Cooling Water (CC) Heat Exchangers
Containment Ventilation Coolers (HX-15)
Turbine Driven Auxiliary Feedwater Pumps (Pump Suction Supply)
Motor Driven Auxiliary Feedwater Pumps (Pump Suction Supply)
Containment Ventilation Fan Motor Coolers

Table 9.6-2 NON-ESSENTIAL LOAD ISOLATION VALVES

VALVE	DESCRIPTION
SW-2816 AND SW-4479	Service Building Isolation
SW-2817 AND SW-4478	Water Treatment Area Isolation
SW-2927A and SW-2930A	Spent Fuel Pool Isolation
SW-2927B and SW-2930B	Spent Fuel Pool Isolation
SW-LW-61/62	Radwaste System Isolation

Table 9.6-3 ESSENTIAL SW AUTOMATIC VALVES

VALVE DESIGNATION	DESCRIPTION
1/2SW-2907 & 2908	Containment Fan Coolers (OUTLET MOVs)
1/2 AF-4067	1/2 P-53 Motor Driven AFW Pump Suction
1/2 AF-4006	1/2 P-29 Turbine Driven AFW Pump Suction

Figure 9.6-1 UNIT 1 SERVICE WATER SYSTEM

[redacted]

Figure 9.6-2 UNIT 1 SERVICE WATER SYSTEM

[redacted]

Figure 9.6-3 UNIT 1 SERVICE WATER SYSTEM

[redacted]

Figure 9.6-4 UNIT 1 SERVICE WATER SYSTEM

[redacted]

Figure 9.6-5 UNIT 1 SERVICE WATER SYSTEM

[redacted]

Figure 9.6-6 UNIT 2 SERVICE WATER SYSTEM

[redacted]

Figure 9.6-7 UNIT 2 SERVICE WATER SYSTEM

[redacted]

9.7 INSTRUMENT AIR (IA) / SERVICE AIR (SA)

There are two compressed air systems that supply air plant-wide; the instrument air (IA) system and the service air (SA) system. Nitrogen gas bottles or IA accumulator tanks are used as backup pneumatic sources for some plant equipment.

9.7.1 DESIGN BASIS

The IA and SA systems perform the following functions:

Safety Related Functions:

1. Portions of the IA and SA systems form part of the containment pressure boundary.

2. IA system backup accumulators provide the pneumatic motive force for AFW pump minimum recirculation and flow control air operated valves (AOV).

3. The IA system provides the pneumatic motive force for the PORVs when aligned for LTOP protection. (See AQ classification discussion in Section 9.7.3).

4. IA system backup accumulators provide the pneumatic motive force for closure of the main feedwater isolation valves (MFIV).

Augmented Quality Functions:

1. An IA system accumulator provides the pneumatic motive force for the cross-over steam dump valves to provide turbine generator over speed protection.

2. The IA system is credited in the event of a fire and has been evaluated in the at-power and non-power analyses (Reference 1).

3. The IA system provides valve position indication for the associated containment isolation valves (PAM, type B variable).

Non-Safety Related, Non-QA Functions:

1. The IA system supplies dry, oil-free air to pneumatic controllers and control valves required for the normal operation of both units.

2. The SA system provides non-dried, oil-free air to the plant services header for equipment not requiring the dry air provided by the IA system. However, the SA system is capable of providing dried air through the SA dryer.

3. The SA system can be cross-tied to provide a backup supply to the IA system automatically or manually.

4. The IA system provides pressure indication which can be used to indicate the operation of safety systems and other systems important to safety (PAM, type D variable).

5. The IA system provides the pneumatic motive force to allow remote operation of the steam generator (SG) atmospheric dump valves (ADV) from the control room.

9.7.2 SYSTEM DESIGN AND OPERATION

The instrument air system consists of two water-cooled air compressors (K-2A and K-2B) which take filtered suction from room air and discharge through their associated aftercooler. The air passing through the aftercoolers is cooled, the moisture is removed, and the air stream is then routed to the associated air receiver (T-33B and T-33C). The air compressors and aftercoolers are cooled with water from the service water system. A single IA compressor is capable of supplying the necessary air supply to serve both units. The air receivers act as a reservoir to store the pressurized air for use in the system. The air receivers each have a separate, normally cross-connected, discharge line with in-line filters which feed its respective air dryer unit (Z-31 and Z-39). An electrically operated dryer bypass valve for each dryer unit is energized closed during normal operation. The dryer bypass valve will open on loss of power to the in-service dryer or on low instrument air header pressure.

Both air dryer units are normally in service. Each unit consists of two parallel dryer towers with one lined up to accept air from the receivers and the other off-line for regeneration. The dryer towers are filled with desiccant which absorbs moisture from the air stream. Regeneration of the desiccant is accomplished by heating with electric heaters while maintaining a continuous air purge. Switching dryer towers is accomplished automatically. Abnormal operation of the dryer is annunciated in the control room. The dryer unit is designed to produce instrument air with a dewpoint of -40 degrees F from saturated air at 100 degrees F. Air leaving the drying towers passes through afterfilters which collect any desiccant dust prior to supplying the north and south instrument air headers. The north header supplies air to the auxiliary building, Unit 2 containment, Unit 2 turbine hall, water treatment area, and the north service building. The south header supplies the auxiliary building, Unit 1 containment, Unit 1 turbine hall, and the circulating water pump house.

Instrument air is supplied to instrumentation, valves, dampers, and pneumatic controllers throughout Unit 1 and Unit 2. Branch lines are taken off the main headers which are equipped with manual isolation valves permitting isolation of the branch line in the event of a rupture downstream of the isolation valve. Instrument air to each containment is routed through two parallel paths, each containing a manual isolation valve, an air-operated isolation valve, and a check valve outside containment. The parallel flow paths are cross-connected in containment through a manual isolation valve to supply a common header.

Each instrument air compressor has a three-position control switch (OFF-AUTO-CONSTANT) located in the control room. Normally one instrument air compressor controlling in CONSTANT, which allows the compressor to run constantly and load and unload as system demand requires, is sufficient to supply the system. The second air compressor is normally in AUTO control and will start when pressure drops to a preset pressure. After the standby compressor starts, it will run constantly loading and unloading as necessary until it is manually secured. K-2A and K-2B IA compressors are powered from safety related motor control centers 1B-32 and 2B-42 respectively. Upon loss of power, the compressors will stay deenergized until they are manually restored via the control switch. Additional backup is supplied by the service air system to the inlet of the dryers by two automatic 2-inch pressure controlled cross-connect valves (IA-3014 and IA-3079) or two 3-inch manual valves.

In order to maintain operability on loss of instrument air, some components use nitrogen bottles, regulators, and check valves or air accumulators and check valves to maintain pressure at the component for varying periods of time. Nitrogen fixed gas bottles are provided for instrument air backup; (1) to the pressurizer power operated relief valves for low temperature overpressure protection (LTOP), (2) to the pressurizer spray valves, and (3) to the standby steam generator pump (P-38 A&B) discharge and minimum recirculation valves. For fire scenarios, additional nitrogen supply to the standby steam generator feed pump valves is available using the plant nitrogen storage tank. Instrument air accumulators are provided for the main steam isolation valves, and the crossover steam dump valves.

Each unit's motor driven AFW pump (1/2P-53) has two air accumulators to provide a safety related backup air supply for its minimum recirculation and discharge flow control AOVs. Each unit's turbine driven AFW pump (1/2P-29) has an air accumulator to provide a safety related backup air supply for its recirculation AOV. These accumulators are normally supplied with air from the IA system through an air-amplifier device which steps up the air pressure in the accumulator to a level significantly higher than that provided by the IA system compressors. The SA system provides the motive force for the air-amplifier devices. Regulators are used to provide the proper air pressure to the AOVs. Isolation check valves are provided to isolate the accumulator tanks from the rest of the instrument air system.

Each main feedwater isolation valve (MFIV) has an accumulator to provide a safety related pneumatic supply for the closure function of the valve. These accumulators can be supplied with air from the IA system through an air-amplifier device which steps up the air pressure in the accumulator to a level higher than that provided by the IA system compressors. The IA system provides the motive force for the air-amplifier devices. Regulators are used to provide the proper air pressure to the MFIV. The IA system also provides the motive force for the non-safety related function of opening each of the MFIVs. A high pressure nitrogen supply is also provided to the accumulator and to the portion of the pneumatic system used to open the valve. Isolation check valves are provided to isolate the accumulators from the rest of the instrument air system and from the nitrogen supply (Reference 6, Reference 7).

The service air system consists of two air compressors (K-3A and K-3B), which take filtered suction from room air and discharge through their associated aftercooler. Air leaving the aftercoolers is routed to receivers (T-33A and T-33D), through a heatless, desiccant air dryer, and then to the main service air header which runs throughout the plant and branch lines which supply individual components. The air dryer is provided with inlet coalescing filters, after filters (to collect any desiccant dust), and an automatic bypass line. The service air containment isolation valves (1/2 SA-17 and 1/2 SA-27) are manual valves which are locked shut during power operation.

Service air compressor K-3A is powered from 480 VAC bus 1-B04 and both the compressor and aftercooler are air cooled. Service air compressor K-3B, intercooler, and aftercooler are cooled with water from the service water (SW) system. Normally one service air compressor is running and the other aligned to start automatically when service air or instrument air pressure drops to a preset level. When running, the compressor will load and unload as system demand requires. The service air system functions include; backup supply to instrument air, supply to service air loads, and means for supplying compressed air to support containment integrated leak rate testing.

9.7.3 SYSTEM EVALUATION

Plant cool down via operation of the atmospheric steam dump valve (ADV) on the intact steam generator (SG) is credited in the SGTR overfill analysis. The analysis assumes a concurrent loss-of-offsite-power (LOOP) and that the cool down is initiated within 17 minutes following isolation of the ruptured SG. In order to meet the assumed initiation time, the ADV must be capable of remote operation from the control room which requires the availability of IA. On a LOOP, the IA compressors initially load shed from the safety related MCCs and can be restarted from the control room when emergency diesel generator (EDG) loading allows. The use of the non-safety related IA system for operation of the ADV is justified based on the defense-in-depth provided by the following: (Reference 3 and Reference 4).

1. With a LOOP on the affected unit only, the instrument air compressor powered from the other unit would be available.

2. With a LOOP on both units, there is available volume in the IA receiver(s). In the meantime, the IA compressors are loaded on the EDGs by steps in the applicable abnormal operating procedure and alarm response procedure.

3. Local manual operation of the ADV is available if required.

The AFW pump backup air accumulators provide enough air to allow operation of the associated discharge flow control and recirculation AOVs for 24 hours without relying on operator action to manually gag the recirculation valves in the correct position as required by specific operating license conditions. Four hours of backup air is required for pump operability. If instrument air is lost and the safety related backup supply is depleted, the operators will be required to manually throttle the flow control and recirculation valves consistent with decay heat removal requirements (Reference 2, Reference 5).

The MFIV accumulators provide the pneumatic supply for MFIV closure. The associated air amplifiers compensate for system leakage and maintain the operating pressure in the accumulators. Low accumulator pressure is alarmed in the control room. Either the high pressure nitrogen system or IA amplifier are designed to maintain accumulator pressure. A lower pressure backup nitrogen system provides pressure to the MFIV actuators to ensure the MFIVs do not close in the event IA is lost when a MFIV closure signal is not present.

The design basis function of containment isolation for instrument air is provided by two air operated isolation valves (IA 3047 and 3048) in parallel for each unit. The valves are seismic Class I and will automatically shut on a containment isolation signal. The valves are normally held open by instrument air pressure and will fail shut on loss of instrument air. These containment penetrations are also provided with check valves which provide backup for the automatic isolation function.

When aligned for LTOP protection, nitrogen fixed gas bottles provide a backup pneumatic supply for the PORVs. Generic Letter 90-06 characterizes the LTOP function as safety related, but allows non-safety related quality components to be used to perform the function. Those IA system components used to provide support for the LTOP function are classified as Augmented Quality (AQ).

The capability to isolate the instrument air supply to certain air-operated valves inside containment is credited in the event of a fire and has been evaluated in the at-power and non-power analyses (Reference 1).

Air cooled SA compressor K-3A can be powered by emergency diesel generator G-03 or G-04 which do not rely on service water for cooling. K-3A provides a source of backup air to the IA system which is independent of service water and is normally aligned for automatic operation (Reference 3, Reference 8).

9.7.4 REQUIRED PROCEDURES AND TESTS

The inservice inspection requirements are described in the PBNP Inservice Testing Program. Plant procedures provide guidance on the returning of an IA compressor to service after a LOOP.

9.7.5 REFERENCES

1. NFPA 805 Fire Protection Program Design Document (FPPDD).

2. NRC Safety Evaluation, "Point Beach Nuclear Plant (PBNP), Units 1 and 2 - Issuance of License Amendments Re: Auxiliary Feedwater System Modification (TAC Nos. ME1081 and ME1082)," dated March 25, 2011.

3. NRC Safety Evaluation, "Point Beach Nuclear Plant (PBNP), Units 1 and 2 -Issuance of License Amendments Regarding Extended Power Uprate (TAC Nos. ME1044 and ME1045)," dated May 3, 2011.

4. NRC Safety Evaluation, "Point Beach Nuclear Plant (PBNP), Units 1 and 2 -Issuance of License Amendments Regarding Use of Alternate Source Term (TAC Nos. ME0219 and ME0220)," dated April 14, 2011.

5. NRC 2009-0116, "License Amendment Request 261 - Extended Power Uprate Response to Request for Additional Information," dated November 21, 2009.

6. EC 12052 (258480), EPU - Feedwater Isolation Valve Addition - Unit 2.

7. EC 12054 (258482), EPU - Feedwater Isolation Valve Addition - Unit 1.

8. 50.59 Screening SCR 2010-0159-01, EC 13506, "Self-Cooled Air Compressor," dated October 13, 2010.

9.8 CONTROL ROOM VENTILATION SYSTEM (VNCR)

The Control Room Ventilation System (VNCR) is designed to provide heating, ventilation, air conditioning, and radiological habitability for the control and computer rooms, which are both within the Control Room Envelope (CRE). The Control Room Emergency Filtration System (CREFS) is a subset of the VNCR system that is associated with the equipment necessary to ensure the habitability of the control room during challenges from radioactivity, hazardous chemicals, and fire byproducts, such as fire suppression agents and smoke, during both normal and accident conditions. CREFS consists of one emergency air filtration unit, two emergency fans, two recirculation fans, and required ducts, valves, instrumentation, doors, barriers, and dampers necessary to establish the required flowpaths and isolation boundaries that recirculate and filter the air within the CRE. CREFS also includes the doors, walls, floor, roof, penetrations, and barriers that form the CRE boundary that limits the inleakage of unfiltered air. CREFS is an emergency system, parts of which operate during normal operation. (Reference 3, Reference 4)

9.8.1 DESIGN BASIS

The following General Design Criteria are applicable to CREFS as described in Reference 4.

GDC 2 Performance Standards

GDC 11 Control Room

GDC 37 Engineered Safety Features

GDC 38 Reliability and Testability of Engineered Safety Features

GDC 70 Control of Releases of Radioactivity to the Environment

The VNCR system equipment was designed to be capable of maintaining a room temperature of 75°F, with outside air temperatures varying from -15°F to 95°F. Instrumentation and associated circuitry in the control room is generally rated for an ambient temperature range of 40°F to 120°F.

The control room HVAC system was not designed or built as a safeguards system. The basis for this decision was that equipment in the control room would operate for some time without cooling and there would be no danger to personnel in the room (Reference 8). However, current analysis has demonstrated the need for an active cooling source during prolonged design basis conditions to satisfy GDC 11 (Reference 2). Since original construction, various upgrades to the system have been made to improve reliability of the system and make it easier to restore control room HVAC following a loss of off-site power. These upgrades included providing emergency diesel generator backed power for the HVAC supply fans, filter fans and control panel C-67; new higher capacity chillers; and control room envelope boundary upgrades. The chillers, chilled water pumps and other equipment which provide heating, cooling and humidification for the control room are powered from the non-safety related electrical distribution system (Reference 9, Reference 10, Reference 11 and Reference 12).

The Service Water (SW) System provides an alternate compensatory measure using an active cooling source that maintains adequate temperature and is available during loss of offsite power assuming a single emergency train failure. This alignment satisfies GDC 11. (Reference 16)

VNCR is capable of operating in five different modes as described in Section 9.8.2. Mode 5 places the system in the configuration necessary for radiological habitability by providing for control room pressurization to limit inleakage, makeup and recirculation through HEPA and charcoal filters to remove contaminates. Calculations referenced in Section 14.3.5 demonstrate that the system is capable of meeting the dose limits of 10 CFR 50.67. The design factors affecting the systems ability to meet the above dose limits include automatic actuation on a containment isolation signal, high radiation signal from a control room area monitor, or high radiation signal from a noble gas monitor in the control room supply duct; emergency filtration flow rate 4950 cfm ± 10%, with a minimum filtered recirculation flow of 1955 cfm; maintaining a positive pressure within the CRE; meeting CRE unfiltered inleakage limits; and meeting minimum filtration efficiencies for the HEPA and charcoal filters. (Reference 3)

The limiting design basis accident for the control room dose is the large break LOCA. PBNP is analyzed for a loss of offsite power with a LOCA for control room dose calculations (Reference 3).

The VNCR System is credited in the event of a fire and has been evaluated in the at-power and non-power analyses (Reference 17).

9.8.2 SYSTEM DESIGN AND OPERATION

The control room ventilation system is located in the Mechanical room above the Control Room and is controlled from control room panel C-67. The system is designed for 5 modes of operation. Mode 1 is normal operation, Mode 2 is 100% recirculation, Mode 3 is 25% filtered return air / 75% recirculation, Mode 4 is 25% filtered outside air / 75% recirculation, and Mode 5 allows a combination of outside air and return air to pass through the emergency HEPA/charcoal filter unit. Flow paths for these 5 modes are depicted in Figure 9.8-1.

For Mode 1, one of the two normal supply/recirculation fans (W-13B1 or W-13B2) is started. A maximum of 2000 cfm of outside air is provided to the fan suction from an intake penthouse located on the roof of the auxiliary building. The make-up air and the return air from the control and computer rooms passes through roughing filter F-43 and cooling units HX-100 A&B before entering one of the normal recirculation fans. Room thermostats and/or humidistats control operation of the chilled water unit supplying the cooling units. After leaving the normal recirculation fan, filtered and cooled air is supplied to the mechanical room and through separate heating coils, HX-92 and HX-91 A&B, and humidifiers, Z-78 and Z-77, to the computer and control rooms respectively. Room thermostats and humidistats also control the operation of the heating coils and humidifiers. Also operating in Mode 1 are computer room supplementary air conditioning unit W-107A/HX-190A/HX-191A or W-107B/HX-190B/HX-191B and control room washroom exhaust fan W-15.

Mode 2 operation is 100% recirculation of the air and is aligned manually from panel C-67. When this mode is aligned, the outside air damper closes, the washroom exhaust fan is de-energized, the washroom exhaust fan dampers close, and the damper supplying the reactor engineering room opens.

Mode 3 operation employs one of two control room emergency filter fans (W-14A or W-14B) and filtration unit, F-16, which includes a roughing filter, a HEPA filter, and a charcoal filter. This mode is aligned from panel C-67. A portion (approximately 25%) of the recirculated air is directed through filter bank F-16 and the operating filter fan back to the suction of the normal recirculation fan. Operation in this mode also de-energizes the washroom exhaust fan W-15, closes the washroom exhaust fan dampers, and opens the damper supplying the reactor engineering room. This mode of operation can be used for smoke removal in the event of a fire. (Reference 4).

Mode 4 is similar to Mode 3 except return air inlet damper VNCR-4851B to the emergency filter fans is closed and outside air supply damper VNCR-4851A is open. This allows approximately 4950 cfm of make-up air to pass through filter F-16 and the emergency fan to the suction of the normal recirculation fan, ensuring a positive pressure is maintained in the control and computer rooms to limit in-leakage. This mode is aligned manually from panel C-67.

Mode 5 (emergency HEPA/charcoal filtered outside air and HEPA/charcoal filtered return air) operation is similar to Mode 4 except that the return air inlet damper VNCR-4851B to the makeup fans opens. This allows a combination of outside air and return air to pass through the emergency HEPA/charcoal filter unit to the suction of the control room recirculation fan (total filtered flow ≥4455 cfm). The makeup flow rate is sufficient to assure a positive pressure that will prevent excessive unfiltered in-leakage into the control room ventilation boundary. Mode 5 is automatically initiated by a containment isolation signal, by a high radiation signal from the control room monitor RE-101, or by a high radiation signal from the noble gas monitor RE-235 located in the supply duct to the control room. The transfer to Mode 5 operation is completed within 60 sec. from receiving the actuation signal. A filter fan and a recirculation fan will automatically load onto an EDG if offsite power is lost. These fan loads have been included in the emergency diesel generator loading tabulation during a loss of coolant accident (FSAR Table 8.8-1). This mode of operation can also be manually initiated from panel C-67. Redundancy is provided for active components that must reposition from their normal operating position. (Reference 3)

The control room ventilation system contains a backup filtration system that can be manually aligned and operated if necessary when CREFS is not functional. The backup system includes the F-280 filtration unit with pre-filter, HEPA filter, and charcoal filter; W-275 filter fan; and associated ductwork with bubble tight dampers to provide the CRE boundary when the system is not in service. A manual transfer switch allows the use of the starter and controls for the CREFS W-14A fan to be used to power and control the W-275 backup system fan. The W-275 fan motor has electrical characteristics equivalent to the W-14 fan motors such that diesel loading will not be adversely affected when the backup filtration unit is placed into service. The backup filtration system is classified as Augmented Quality (AQ) and is designed for external pressurization and jet impingement loading due to a high energy line break (HELB) in the turbine building to ensure the CRE boundary is not affected. The backup filtration system can provide a minimum of 2,000 cfm of filtered outside air directly into the control room. This flow rate is sufficient to assure a positive pressure within the CRE that will prevent excessive unfiltered in-leakage. (Reference 1, Reference 3, Reference 14)

See Appendix A.5, Section A.5.2 and Section A.5.6.3 for seismic adequacy of the CREFS system.

Other features of the control room ventilation system include the capability to exhaust smoke from the control room, computer room, or cable spreading room through dedicated smoke and heat vent fan, W-13C. The associated dampers for this evolution are interlocked so that only one room can be lined up for smoke and heat removal at a time. This operation precludes smoke damage to the air filters in the recirculation system. The controls for smoke and heat removal are from panel C-67A located on the exterior north wall of the control room. The computer room has supplementary air conditioning units, W-107A/HX-190A/HX-191A and W-107B/HX-190B/HX-191B to assist the normal control room ventilation system in maintaining computer room temperatures below equipment design limits. Filter F-16 has an automatically initiated water suppression system to mitigate a fire in the charcoal bed.

Moisture elements and flow switches at the outlets of humidifiers Z-77 and Z-78 send a signal to stop humidification if duct humidity gets too high or air flow gets too low in order to prevent condensation in the duct work. A flow switch downstream of each emergency fan W-14A, B and each supplementary air conditioning fan W-107A, B and flow switches downstream of normal/recirculation fans W-13B1, B2 automatically start(s) the standby fan on a low flow condition.

9.8.3 SYSTEM EVALUATION

Note: See Appendix A.1 for a description of the effects of a station blackout (SBO) on control room and computer room ventilation.

The original specification for the control room ventilation system was to maintain a room temperature of 75°F with outside air temperatures varying from -15°F to 95°F with a single train in continuous operation. Continuous room temperatures are normally maintained ≤75°F to provide assurance that personnel and equipment temperature limits can be maintained during a temporary (2 hour or less) loss of the control room ventilation system.

<u>Control Room Equipment Ambient Temperature Design Limits</u>

Instrumentation and associated circuitry in the control room is generally rated for an ambient temperature range of 40°F to 120°F. Following a loss of the control room ventilation system, room heat loads would most likely prevent the room temperature from ever reaching 40°F, however, 120°F could be reached during a prolonged unavailability of the system.

<u>Computer Room Equipment Ambient Temperature Design Limits</u>

The computer room multiplexers (MUX) are the most temperature sensitive components, with an inlet air ambient temperature limit of 95°F. In the event that elevated temperatures in the computer room lead to eventual MUX failures, contingency actions provide for monitoring the minimum required post-accident in-core thermocouple temperatures on dedicated recorder displays located on the ASIP panels. Manual monitoring of in-core thermocouple temperatures at the MUX input terminals is possible using portable M&TE. The SPEC 200 racks have an internal temperature limit of 140°F.

<u>Radiological Dose Limits</u>

An evaluation of CREFS ability to maintain the LOCA radiological dose of control room occupants to within the 5 rem total effective dose equivalent (TEDE) allowable limit of 10 CFR 50.67 is provided in Section 14.3.5.

With CREFs inoperable, the backup filtration system, in combination with the ingestion of potassium iodide (KI), is also capable of maintaining the radiological dose of control room occupants to within the 5 rem TEDE limit if placed into service within 1 hour after the start of an accident. (Reference 1, Reference 3, Reference 7)

Chemical Hazards and Smoke

Low CRE unfiltered air inleakage limits the infusion of toxic chemicals and smoke by-products into the CRE, thereby promoting habitability. Additionally, SCBAs and portable smoke ejection equipment is available and can be used if the CRE boundary is not functional. The VNCR system provides for smoke removal in the event of a fire in the control room.

9.8.4 REQUIRED PROCEDURES AND TESTS

Required procedures and tests are identified in Technical Specification (TS) 3.3.5, "Control Room Emergency Filtration System (CREFS) Actuation Instrumentation," TS 3.7.9, "Control Room Emergency Filtration System (CREFS)," TS 5.5.10, "Ventilation Filter Testing Program (VFTP)," and Technical Requirements Manual (TRM) 4.10, "Ventilation Filter Testing Program (VFTP)," TS 5.5.18, "Control Room Envelope Habitability Program," and TRM 4.18, "Control Room Envelope Habitability Program." TRM 3.7.9, "Control Room Emergency Filtration System (CREFS)" describes the required mitigating actions when CREFS is not functional.

Procedures are in place to prevent either the control room or the computer room from exceeding their temperature limitations under accident conditions, coincident with a LOOP and single train failure (Reference 16). Abnormal operating procedures direct operators to take compensatory measures if control room cooling is lost and cannot be restored. Potential compensatory measures include restoring power to the control room chiller HX-038B, restoring power to the cable spreading room chiller HX-038A and opening cross-tie valves between the cable spreading room and the control room chilled water systems, and aligning service water directly to the control room cooling coils (HX-100A/B) (Reference 15).

Augmented testing of the control room chilled water pumps is performed quarterly under the Inservice Testing Program to ensure pump flow requirements are met (Reference 13).

9.8.5 REFERENCES

1. SCR 2009-0148-08, EC 11690 - Alternate Source Term Implementation and CREFS Upgrade to Support Alternate Source Term License Amendment Request, December 22, 2011.

2. Calculation Number 2005-0054, Control Building GOTHIC Temperature Calculation.

3. NRC Safety Evaluation, "Point Beach Nuclear Plant (PBNP), Units 1 and 2 -Issuance of License Amendments Regarding Use of Alternate Source Term (TAC Nos. ME0219 and ME0220)," dated April 14, 2011.

4. NRC Safety Evaluation, "Point Beach Nuclear Plant (PBNP), Units 1 and 2 - Issuance of License Amendments Regarding Extended Power Uprate (TAC Nos. ME1044 and ME1045)," dated May 3, 2011.

5. Not Used

6. Not Used

7. Calculation CN-CRA-10-43, Point Beach Control Room Dose Sensitivity to Changes in the Modeling of the Control Room Emergency Filtration System Out of Service, Revision 1, dated April 28, 2011.

8. Westinghouse Letter to Wisconsin Electric, Control Room H&V and AC Power Supply, May 18, 1970.

9. SER 96-004, Control Room HVAC Upgrade Modifications, January 22, 1996.

10. SE 2000-0121, Replacement of Control and Computer Room Ventilation System Chiller Unit HX-38B, December 1, 2000.

11. SE 2000-0106, Replacement of Cable Spreading Room Ventilation System Chiller Unit HX-38A, October 18, 2000.

12. SE 2001-0049, Upgrade Control Room Envelope Boundary, August 17, 2001.

13. SCR 2010-0018, Revision to Section 9.8.4 of PBNP FSAR, January 20, 2010.

14. SCR 2010-0234-04, EC 15414 - CREFS Backup Filtration System, December 22, 2011.

15. 50.59 Evaluation 2010-003, EC 15413 “Control Room Alternate Cooling,” November 1, 2010.

16. SCR 2012-0026, “FSAR Section 9.8, Control Room Ventilation System (VNCR) Change Concerning Temperature,” dated March 12, 2012.

17. NFPA 805 Fire Protection Program Design Document (FPPDD).

Figure 9.8-1 CONTROL ROOM VENTILATION OPERATING MODES (Sheet 1)

[redacted]

Figure 9.8-1 CONTROL ROOM VENTILATION OPERATING MODES (Sheet 2)

[redacted]

Figure 9.8-1 CONTROL ROOM VENTILATION OPERATING MODES (Sheet 3)

[redacted]

Figure 9.8-1 CONTROL ROOM VENTILATION OPERATING MODES (Sheet 4)

[redacted]

Figure 9.8-1 CONTROL ROOM VENTILATION OPERATING MODES (Sheet 5)

[redacted]

9.9 SPENT FUEL COOLING & FILTRATION (SF)

The spent fuel pool cooling system, common to Units 1 and 2, is designed to remove decay heat from fuel assemblies stored in the spent fuel pool after removal from the reactor vessel. A discussion of the sharing of the components of this system between the two units is given in Appendix A.6.

The spent fuel pool cooling system consists of two separate cooling trains, with a common suction and return header, each having an identical heat exchanger and pump. Water from the pool is pumped through one or both heat exchangers for cooling and returned to the pool. When purification is required, a portion of the flow may be diverted through the interconnecting spent fuel pool purification system. Service Water (SW) provides the heat exchange medium for removal of decay heat (Reference 4).

9.9.1 DESIGN BASIS

Fuel and Waste Storage Decay Heat

The following PBNP General Design Criteria (GDC) are applicable to the Spent Fuel Cooling and Filtration System (Reference 8):

Criterion 4: Sharing of Systems
Criterion 67: Fuel and Waste Storage Decay Heat
Criterion 68: Fuel and Waste Storage Radiation Shielding
Criterion 69: Protection Against Radioactivity Release from Spent Fuel and Waste Storage

The refueling water provides reliable and adequate cooling medium for spent fuel transfer and heat removal from the spent fuel pool is provided by the Spent Fuel Pool Cooling System.

The Spent Fuel Pool (SFP) Cooling System is designed to remove the decay heat produced by irradiated fuel assemblies stored in the spent fuel pool. The heat removal capabilities for the cooling system are: (Reference 1, Reference 2, Reference 7, and Reference 8)

1. Capable of maintaining the temperature in the spent fuel pool less than or equal to 120°F during normal refueling operations with one cooling loop in operation ("normal refueling" is a fuel shuffle with only a partial core offloaded into the pool);

2. Capable of maintaining the temperature in the spent fuel pool less than or equal to 120°F following a full core off load with two cooling loops in operation; and

3. Capable of maintaining the temperature in the spent fuel pool less than or equal to 145°F following a full core off load with one cooling loop in operation.

Decay heat load is calculated before each refueling to ensure it is within the Spent Fuel Pool Cooling System capacity (Reference 7, Reference 8, Reference 12).

The calculated values for the bulk water temperature of the SFP are not safety limits, and the nominal conditions assumed in the analysis are not operational limits.

In the event of complete failure of the cooling system for a long period of time, the fuel pool water inventory can be maintained with borated water from the refueling water storage tank or chemical and volume control system (CVCS), or non-borated water from the de-ionized water, reactor make up water, SW, or fire protection systems (Reference 8).

As discussed in Reference 3, the late 1970's design criteria for the SFP thermal and hydraulic analyses were derived from the NRC position paper "Position for Review and Acceptance of Spent Fuel Storage and Handling Applications," which include (with updates):

a. Decay heat loads are calculated using the methods found in ANSI/ANS-5.1-1979 (Reference 7, Reference 8).

b. Boiling shall not occur in the water within the fuel assembly and the adjacent water/poison boxes (Reference 3).

c. Adequate time exists for an alternate cooling method to be implemented in the event of a complete loss of SFP Cooling System capability. The heat-up rate is to be calculated and the time required for pool boiling to occur will also be found (Reference 3).

SFP piping and the SW piping supplying the SFP heat exchangers are classified Safety Related and Seismic Class I (Reference 8).

All piping and components of the spent fuel cooling system are designed to the applicable codes and standards listed in Table 9.9-1. Austenitic stainless steel piping is used in the spent fuel pool cooling system, for the piping to and from the pool. Piping is arranged so that a failure of any one pipe will not drain the water in the spent fuel pool below the top of the fuel elements.

The Spent Fuel Cooling and Filtration System is credited in the event of a fire and has been evaluated in the at-power and non-power analyses (Reference 12).

9.9.2 SYSTEM DESIGN AND OPERATION

The spent fuel pool cooling pumps take suction through branch lines off a common header from beneath the surface of the north half of the spent fuel pool, pump the water through the tube side of the spent fuel pool cooling heat exchangers, and return it via a common header to the south half of the spent fuel pool. The system piping is arranged so that either pump can supply either heat exchanger. The clarity and purity of the spent fuel pool water are maintained by passing up to the design flow of 60 gallons per minute through a filter and demineralizer. The spent fuel pool cooling heat exchangers are cooled by service water on the shell side. The SFP Cooling system is shown as a portion of Figure 9.9-1, and the service water system associated with the spent fuel pool cooling system is shown in Figure 9.6-4. Service water can be supplied by either the North or West service water supply header, and is discharged to the Unit 1 or Unit 2 circulating water overboard through redundant return headers.

The spent fuel pool cooling system piping and the service water system piping supplying the spent fuel pool heat exchangers are classified Safety-Related, Seismic Class I. Although the branch lines serving the spent fuel pool heat exchangers were extensively modified using primarily ASME Section III Class 3 requirements, system code requirements are established by the original design basis and code of construction (USAS B31.1.0-1967).

The spent fuel cooling system is operated intermittently or continuously whenever there are spent fuel assemblies in the spent fuel pool. Cooling requirements are dependent upon the number of spent fuel assemblies stored in the spent fuel storage racks and the elapsed time that the spent fuel has been in storage. Clarification and purification requirements are a function of various conditions such as atmospheric contamination, fuel rod leakage, and work being performed in the pool or pool area.

The spent fuel pool cooling pumps and heat exchangers are normally operated as independent trains designated as Train “A” (P-12A and HX-13A) and Train “B” (P-12B and HX-13B). After locally starting the pump in the selected train, the heat exchanger inlet valve is positioned to control the pump discharge pressure. Purification of the spent fuel pool water is accomplished by establishing flow through the demineralizer and filter. Temperature is controlled by manually positioning the service water flow control valve(s) (SW-661 and 746) located in the service water return lines.

The fuel pool purification system interfaces with the spent fuel pool cooling system as shown on Figure 9.9-1. The purification system inlet taps off the cross-connect line between the “A” and “B” cooling trains at the discharge of the fuel pool cooling pumps. The purification system return line connects with the cooling system return header. The purification system is not safety related.

The refueling water circulation pump is used to circulate the water in the refueling water storage tank in a cleanup loop through the spent fuel pool demineralizer and filter and back to the refueling water storage tank (RWST). The refueling water circulating pump may also be aligned to take suction from the refueling canal through the drain connection and discharge through the spent fuel pool demineralizer and filter, or through the CVCS primary demineralizers. The return flow from these cleanup loops to the reactor is directed to the suction of the residual heat removal pumps. If the transfer canal is washed after refueling, the water can be flushed through the refueling water circulating pump to the drumming station. The refueling water circulating pump can also take suction from the boric acid blender of Unit 1 in order to increase the boron concentration in the spent fuel pool or take suction from the refueling cavity and discharge to the RWST. The refueling water circulating pump discharge piping is used for reflood of a dry cask storage container using the spent fuel pool as a reflood source.

Spent Fuel Pool Cooling System Components

Spent Fuel Pool Cooling Heat Exchanger

Each fuel pool cooling heat exchanger is a U-tube heat exchanger with service water on the shell side and fuel pool water on the tube side. All surfaces wetted by the borated fuel pool water are of stainless steel or stainless steel clad carbon steel. The tubes are rolled and seal welded to the tube sheet. The shell is made of carbon steel.

Spent Fuel Pool Cooling Pumps

The fuel pool pumps are centrifugal, horizontal pumps with stainless steel casings and a design flow rate of 1,250 gpm at rated head. Mechanical seals are used for shaft sealing. Each fuel pool pump is driven by an electric motor. Both pumps are flanged for convenient removal from the system for maintenance, and casings are provided with drain connections.

Piping and Valves

All fuel pool cooling system piping and fittings are stainless steel with standard wall thickness. Construction is welded throughout, except where flanged joints are provided for a flow measuring orifice, connections to the pumps and heat exchangers, and one set of flanges to accommodate initial pressure testing of the suction piping. All fuel pool cooling piping and fittings are 150 lb pipe class.

Fuel pool cooling system valves are stainless steel, 150 lb rating with trim suitable for borated water.

Spent Fuel Pool Filter

The spent fuel filter removes particulate material from the spent fuel pool water. The filter cartridge is synthetic fiber and the vessel shell is stainless steel.

Spent Fuel Pool Demineralizer

The demineralizer is sized to pass approximately 60 gallons per minute to provide adequate purification of the fuel pool water for unrestricted access to the working area, and to maintain optical clarity.

Refueling Water Circulating Pump

The refueling water circulating pump is used primarily to circulate water in a loop between the refueling water storage tank and the spent fuel pool demineralizer and filter. All wetted surfaces of the pump are austenitic stainless steel. The pump is operated manually from a local station.

Spent Fuel Pool Skimmer

A skimmer pump and strainer are provided for surface skimming of the spent fuel pool water. Flow from this pump is returned to the spent fuel pool.

9.9.3 SYSTEM EVALUATION

The spent fuel pool cooling system is provided with two pumps and two heat exchangers. The electrical components of the two trains are supplied with power from separate vital buses. The pumps and heat exchangers are provided with cross connecting piping so that either pump may be used with either heat exchanger to maximize system availability and reliability. The spent fuel pool cooling system operates intermittently or continuously whenever there are spent fuel assemblies in the fuel pool dependent upon heat removal requirements.

Manual flow control valves located in the heat exchanger service water return header may be throttled to control spent fuel pool water heat exchanger outlet temperatures. The following parameters are monitored or alarmed to determine the need for cooling system operation:

1. Fuel Pool Temperature (High temperature alarmed in control room)
2. Fuel Pool Level (High/Low level alarmed in control room)
3. Spent fuel pool cooling system flow (locally)
4. Spent fuel pool temperature (locally)

5. Heat exchanger outlet temperature (locally)

6. Heat exchanger service water inlet and outlet temperature (locally)

The normal operating pressure of the service water system is higher than the normal operating pressure of the spent fuel pool cooling system. In the event of a heat exchanger tube break, differential pressure will normally result in leakage from the service water system to the spent fuel pool cooling system. Under certain conditions, for example during refueling when higher service water flowrates to the spent fuel pool heat exchangers are required, service water pressure may fall below spent fuel pool cooling system pressure. Under these conditions, a heat exchanger tube break will result in leakage from the spent fuel pool cooling system into the service water system. A spent fuel pool heat exchanger tube rupture is considered improbable based upon the low operating pressures, the seismic installation of the heat exchanger, and the heat exchanger design specifications. If a tube break were to occur, indication of the break would be provided by process radiation monitoring equipment in the downstream service water piping, which monitors the service water system for released radioactivity.

The probability of inadvertently draining the water from the cooling loop of the spent fuel pool is exceedingly low. In the unlikely event of the cooling loop of the spent fuel pool being drained, the spent fuel storage pool itself cannot be drained and no spent fuel is uncovered since the spent fuel pool cooling suction and return connections terminate or contain a siphon breaker that would limit water drawdown to a level approximately 21 feet 11 inches above the active fuel. (Reference 6)

Whenever a leaking fuel assembly is transferred from the fuel transfer canal to the spent fuel storage pool, a small quantity of fission products may enter the spent fuel pool water. A small purification loop consisting of filtration and ion-exchange is provided for removing these fission products and other contaminants from the water.

A fuel pool high temperature alarm, located in the control room, will notify the operator of a fuel pool cooling malfunction. In the event of a failure of the operating pump, the standby pump may be started. In the event of loss of service water flow through the on-line heat exchanger due to a malfunction of a service water component in that train, the operating pump may be cross-connected with the standby heat exchanger. In the event of complete failure of the cooling system for a long period of time, the fuel pool water inventory can be maintained with borated water from the RWST or CV system, or non-borated water from the de-ionized water (DI), RMW, SW, or FP systems.

Assuming a loss of SFP cooling in the worst case conditions of a full core offload 5 days after reactor shutdown and an initial SFP temperature of 145ºF, the time-to-boil is approximately 8 hrs (Reference 9 and Reference 10). This is sufficient time for plant personnel to take corrective actions to establish a means of spent fuel pool cooling. A makeup water supply of 50 gpm is adequate to maintain SFP level at the evaluated heat loads (Reference 8).

9.9.4 REQUIRED PROCEDURES AND TESTS

The active components of the spent fuel pool cooling system are in either continuous or intermittent use during normal plant operation. Periodic visual inspections and preventive maintenance can be conducted as necessary without interruption of cooling system operation. The inservice testing requirements are described in the PBNP Inservice Testing Program and the IST Background Document.

The decay heat load is calculated prior to each refueling based on decay time, power history, and SFP inventory from previous outages. The calculated heat load is compared to the ability of the SFP cooling system based on the expected SW temperature at the time of fuel transfer to ensure the outage load is within the capability of the system (Reference 8).

Corrective actions to address a loss of spent fuel pool cooling are procedurally controlled and include: (Reference 5)

1. Restoring spent fuel pool cooling water flow (e.g., starting a standby pump)
2. Restoring service water flow (e.g., cross connecting trains)
3. Establishing alternative cooling by maximizing ambient losses (e.g., with SFP ventilation system)
4. Maintaining water level with the use of the borated or unborated water sources
5. Making necessary repairs to restore spent fuel pool cooling

9.9.5 REFERENCES

1. NRC Safety Evaluation Report dated April 4, 1979, "Safety Evaluation Relating to the Modification of the Spent Fuel Storage Pool."
2. Wisconsin Electric Letter to NRC, "Spent Fuel Storage Expansion Modification to Change Request No. 54," dated September 29, 1978. Attachment A is the "Spent Fuel Storage Modification Description," Revision 2, dated September 29, 1978. Attachment B is Wachter Report, "Design and Analysis of High Density Spent Fuel Storage Racks for Point Beach Nuclear Plant," Revision 2, dated September 29, 1978.
3. Wachter Report, "Thermal and Hydraulic Analysis Report, Spent Fuel Storage Pool," WEP-T-12, dated May 23, 1978.
4. Wisconsin Electric Letter to NRC, "Docket Nos. 50-266 and 50-301 Amendment No. 24 to Final Facility Description and Safety Analysis Report Point Beach Nuclear Plant, Units 1 and 2", dated June 30, 1978.
5. WE Letter to NRC, VPNPD-96-094, "Response to Resolution of Spent Fuel Storage Pool Safety Concerns", dated November 13, 1996.
6. PBNP Calculation 2005-0037, "Spent Fuel Pool Anti-siphon Provisions," dated December 2, 2005.
7. FPL Energy Point Beach, LLC letter NRC 2009-0030, "License Amendment Request 261, Extended Power Uprate," dated April 7, 2009.
8. NRC Safety Evaluation, Issuance of Amendments Regarding Extended Power Uprate, dated May 3, 2011.

9. Reactor Operating Data (ROD) 1.4 unit 1, "Spent Fuel Pool Heatup Data [cycle dependent]

10. Reactor Operating Data (ROD) 1.4 unit 2, "Spent Fuel Pool Heatup Data [cycle dependent]

11. Calculation 2016-0008 PBNP SFP Heat Exchanger Proto-HX Model and Convective Heat Transfer Film Coefficient Calculation, Rev 0.

12. Procedure REI 47.7, Spent Fuel Pool Decay Heat Determination.

Table 9.9-1 SPENT FUEL POOL COOLING SYSTEM COMPONENT DATA*
Sheet 1 of 4

System cooling capacity, 2 pumps/2 heat exchangers, BTU/hr	31.2×10^6
Spent fuel pool heat exchanger	
Quantity	2
Type	Shell and U-tube, horizontal
Nominal design heat transfer per heat exchanger, BTU/hr	15.6×10^6
Shell side (service water)	
Design inlet temperature, °F	65
Design flow rate, lbm/hr	620,000
Design pressure, psig	150
Operating pressure, psig	50
Design temperature, °F	200
Material	Stainless steel
Tube side (Spent fuel pool water)	
Design inlet temperature, °F	120
Design flow rate, lbm/hr	620,000
Design pressure, psig	150
Operating pressure, psig	50
Design temperature, °F	212
Material	Stainless steel
Spent Fuel Pool Pump Data	
Quantity	2
Type	Horizontal centrifugal
Design flow rate, gpm	1250
Discharge pressure, psig	26
Motor horsepower	25
Design pressure, psig	150
Design temperature, °F	200
Material	Stainless steel

* Note: The SF System is shared by Unit 1 and Unit 2. Note that the information in this table represents the design characteristics of the listed components based on particular conditions assumed during the specification/ procurement phase, and in most cases are derived from the vendor's data sheets. These parameters should not be construed as operating or design limits.

Table 9.9-1 (continued) SPENT FUEL POOL COOLING SYSTEM COMPONENT DATA
Sheet 2 of 4

Spent Fuel Storage Pool	
Pool volume, ft^3	48283
Boron concentration, ppm boron	2100 to 4000
Spent Fuel Pool Filter	
Quantity	1
Type	Replaceable cartridge
Internal design pressure of housing, psig	200
Design temperature, ºF	250
Design flow rate, gpm	60
Maximum differential pressure across filter element at rated flow (clean cartridge), psi	5
Spent Fuel Pool Demineralizer	
Quantity	1
Type	Flushable
Design pressure, psig	200
Design temperature, ºF	250
Design flow rate, gpm	60
Resin volume, $ft.^3$	20
Vessel volume, $ft.^3$	27
Spent Fuel Pool Skimmer	
Quantity	1
Design flow rate gpm	100
Vertical fluctuation range:	
Floating, inch	4
Manual adjustment, feet	2
Spent Fuel Pool Skimmer Strainer	
Quantity	1
Type	Basket
Design flow rate, gpm	100
Design pressure, psig	50
Design temperature, ºF	200
Maximum differential pressure across the strainer element at rated flow, clean, psi	1
Perforation, inch	1/8

Table 9.9-1 (continued) SPENT FUEL POOL COOLING SYSTEM COMPONENT DATA
Sheet 3 of 4

Spent Fuel Pool Skimmer Pump	
Quantity	1
Type	Horizontal centrifugal
Design flow rate, gpm	100
Total developed head, ft H_2O	50
Design pressure, psig	150
Design temperature, ºF	200
Material	Stainless steel
Refueling Water Circulating Pump	
Quantity	1
Type	Horizontal centrifugal
Design flow rate, gpm	100
Total developed head, ft H_2O	150
Design pressure, psig	150
Design temperature, ºF	200
Spent Fuel Pool Cooling Loop Piping and Valves	
Design pressure, psig	150
Design temperature, ºF	200
Spent Fuel Pool Skimmer Loop Piping and Valves	
Design pressure, psig	150
Design temperature, ºF	200
Refueling Water Purification Loop Piping and Valves	
Design pressure, psig	150
Design temperature, ºF	200

Table 9.9-1 (continued) SPENT FUEL POOL COOLING SYSTEM COMPONENT DATA
Sheet 4 of 4

Code Requirements

Spent fuel pool filter	ASME III**, Class C
Spent fuel pool heat exchanger	ASME III, Class 3, 1974 Edition, Summer 1975 Addenda
Spent fuel pool demineralizer	ASME III, Class C
Spent fuel pool loop piping and valves	USAS B31.1.0, 1967 Edition
Spent fuel pool pump motor	NEMA MG-1 IEEE 334-1974
Spent fuel pool pump	ASME III, Class 3, 1974 Edition, Summer 1975 Addenda
Service water lines serving spent fuel pool cooling system	USAS B31.1.0, 1967 Edition

** ASME III - American Society of Mechanical Engineers, Boiler and Pressure Vessel Code, Section III

Figure 9.9-1 UNIT 1 SPENT FUEL POOL COOLING SYSTEM

[redacted]

9.10 FIRE PROTECTION SYSTEM (FP)

The design philosophy and specifics of the fire protection program are contained in the FPPDD, "NFPA 805 Fire Protection Program Design Document" (Reference 6), and NP 1.9.14, "PBNP Fire Protection Plan" (Reference 7), as described below.

9.10.1 FIRE PREOTECTION

The fire protection program is based on the NRC requirements, Nuclear Electric Insurance Limited (NEIL) Property Loss Prevention Standards and related industry standards. With regard to NRC criteria, the fire protection program meets 10 CFR 50.48(c), which endorses, with exceptions, the National Fire Protection Association's (NFPA) 805, "Performance-Based Standard for Fire Protection for Light Water Reactor Electric Generating Plants - 2001 Edition," (Reference 2). Point Beach Nuclear Plant Units 1 and 2 (PBNP) has further used the guidance of NEI 04-02, "Guidance for Implementing a Risk-Informed, Performance-Based Fire Protection Program under 10 CPR 50.48(c)," (Reference 4) as endorsed by Regulatory Guide 1.205, "Risk-Informed, Performance Fire Protection for Existing Light-Water Nuclear Power Plants," (Reference 3) (Reference 5).

Adoption of NFPA 805, "Performance-Based Standard for Fire Protection for Light Water Reactor Electric Generating Plants," 2001 Edition in accordance with 10 CFR 50.48(c) serves as the method of satisfying 10 CFR 50.48(a) and General Design Criterion (GDC) 3.

NFPA 805 does not supercede the requirements of GDC 3 (see Table 1.3-1), 10 CFR 50.48(a) or 10 CFR 50.48(f). Those regulatory requirements continue to apply. However, under NFPA 805, the means by which GDC 3 or 10 CFR 50.48(a) requirements are met may be different than under 10 CFR 50.48(b). NFPA 805 identifies fire protection systems and features required to meet Chapter 1 performance criteria through the methodology in Chapter 4 of NFPA 805. Also, under NFPA 805, the 10 CFR 50.48(a)(2)(iii) requirement to limit fire damage to SSCs important to safety so that the capability to safely shut down the plant is satisfied by meeting the performance criteria in Section 1.5.1 of NFPA 805.

A Safety Evaluation was issued on September 8, 2016, by the NRC, that transitioned the existing fire protection program to a risk-informed, performance-based program based on NFPA 805, in accordance with 10 CFR 50.48(c). (Reference 1)

9.10.1.1 DESIGN BASIS SUMMARY

9.10.1.1.1 Defense-In-Depth

The fire protection program is focused on protecting the safety of the public, the environment, and plant personnel from a plant fire, and its potential effect on safe reactor operations. The fire protection program is based on the concept of defense-in-depth. Defense-in-depth shall be achieved when an adequate balance of each of the following elements is provided:

1. Preventing fires from starting,
2. Rapidly detecting, controlling, and extinguishing those fires that do occur, thereby limiting fire damage,

3. Providing an adequate level of fire protection for SSCs important to safety, so that a fire that is not promptly extinguished will not prevent essential plant safety functions from being performed.

9.10.1.1.2 NFPA 805 Performance Criteria

The design basis for the fire protection program is based on the following nuclear safety and radiological release performance criteria contained in Section 1 of NFPA 805:

1. Nuclear Safety Performance Criteria: Fire protection features shall be capable of providing reasonable assurance that, in the event of a fire, the plant is not placed in an unrecoverable condition. To demonstrate this, the following performance criteria shall be met.

    a. Reactivity Control: shall be capable of inserting negative reactivity to achieve and maintain subcritical conditions. Negative reactivity insertion shall occur rapidly enough such that fuel design limits are not exceeded.

    b. Inventory and Pressure Control: with fuel in the reactor vessel, head on and tensioned, inventory and pressure control shall be capable of controlling coolant level such that subcooling is maintained and fuel clad damage as a result of a fire is prevented for a PWR.

    c. Decay Heat Removal: shall be capable of removing sufficient heat from the reactor core or spent fuel such that fuel is maintained in a safe and stable condition.

    d. Vital Auxiliaries: shall be capable of providing the necessary auxiliary support equipment and systems to assure that the systems required under (a), (b), (c), and (e) are capable of performing their required nuclear safety function.

    e. Process Monitoring: shall be capable of providing the necessary indication to assure the criteria addressed in (a) through (d) have been achieved and are being maintained.

2. "Radioactive Release Performance Criteria: radiation release to any unrestricted area due to the direct effects of fire suppression activities (but not involving fuel damage) shall be as low as reasonably achievable and shall not exceed applicable 10 CFR, Part 20, Limits.

Chapter 2 of NFPA 805 establishes the process for demonstrating compliance with NFPA 805.

Chapter 3 of NFPA 805 contains the fundamental elements of the fire protection program and specifies the minimum design requirements for fire protection systems and features.

Chapter 4 of NFPA 805 establishes the methodology to determine the fire protection systems and features required to achieve the nuclear safety performance criteria outlined above. The methodology shall be permitted to be either deterministic or performance-based. Deterministic requirements shall be "deemed to satisfy" the performance criteria, defense-in-depth, and safety margin and require no further engineering analysis. Once a determination has been made that a fire protection system or feature is required to achieve the nuclear safety performance criteria of Section 1.5 of NFPA 805, its design and qualification shall meet the applicable requirement of Chapter 3 of NFPA 805.

9.10.1.1.3 Code of Record

The codes and standards used for the design and installation of credited fire protection systems are listed in FPPDD, NFPA 805 Fire Protection Program Design Document (Reference 6).

9.10.1.2 SYSTEM DESCRIPTION

9.10.1.2.1 Required Systems

Nuclear Safety Capability Systems, Equipment, and Cables

Section 2.4.2 of NFPA 805 defines the methodology for performing the nuclear safety capability assessment. The systems, equipment, and cables required for at-power and non-power analyses comprising the nuclear safety capability assessment are contained in FPTE 2016-003, PBN NFPA 805 Nuclear Safety Capability Assessment (Reference 8), and FPTE 2016-004, Non-Power Operation Modes Transition Review (Reference 9), respectively.

Fire Protection Systems and Features

Chapter 3 of NFPA 805 contains the fundamental elements of the fire protection program and specifies the minimum design requirements for fire protection systems and features. Compliance with Chapter 3 is documented in FPPDD, NFPA 805 Fire Protection Program Design Document.

Chapter 4 of NFPA 805 establishes the methodology and criteria to determine the fire protection systems and features required to achieve the nuclear safety performance criteria of Section 1.5 of NFPA 805. These fire protection systems and features shall meet the applicable requirements of NFPA 805 Chapter 3. These fire protection systems and features are documented in FPPDD, NFPA 805 Fire Protection Program Design Document (Reference 6).

Radioactive Release

Structures, systems, and components relied upon to meet the radioactive release criteria are documented in FPPDD, NFPA 805 Fire Protection Program Design Document (Reference 6).

9.10.1.2.2 Definition of “Power Block” Structures

Where used in NFPA 805 Chapter 3 the terms “Power Block” and “Plant” refer to structures that have equipment required for nuclear plant operations. For the purposes of establishing the structures included in the fire protection program in accordance with 10 CFR 50.48(c) and NFPA 805, the plant structures listed in the FPPDD, NFPA 805 Fire Protection Program Design Document (Reference 6) are considered to be part of the ‘power block.’

9.10.1.3 SAFETY EVALUATION

The FPPDD, NFPA 805 Fire Protection Program Design Document (Reference 6) documents the achievement of the nuclear safety and radioactive release performance criteria of NFPA 805 as required by 10 CFR 50.48(c). This document fulfills the requirements of Section 2.7.1.2 “Fire Protection Program Design Basis Document” of NFPA 805. The document contains the following:

1. Identification of significant fire hazards in the fire area. This is based on NFPA 805 approach to analyze the plant from an ignition source and fuel package perspective.
2. Summary of the Nuclear Safety Capability Assessment (at power and non-power) compliance strategies.
   a. Deterministic compliance strategies
   b. Performance-based compliance strategies (including defense-in-depth and safety margin)
3. Summary of the Non-Power Operations Modes compliance strategies.
4. Summary of the Radioactive Release compliance strategies.
5. Summary of the Fire Probabilistic Risk Assessments.
6. Key analysis assumptions to be included in the NFPA 805 monitoring program.

9.10.1.4 FIRE PROTECTION PROGRAM DOCUMENTATION, CONFIGURATION CONTROL AND QUALITY ASSURANCE

In accordance with Chapter 3 of NFPA 805 a fire protection plan documented in NP 1.9.14, PBNP Fire Protection Plan (Reference 7), defines the management policy, program direction and defines the responsibilities of those individuals responsible for the plan's implementation.

The PBNP Fire Protection Plan:

1. Designates the senior management position with immediate authority and responsibility for the fire protection program.
2. Designates a position responsible for the daily administration and coordination of the fire protection program and its implementation.
3. Defines the fire protection interfaces with other organizations and assigns responsibilities for the coordination of activities.
4. Identifies the appropriate authority having jurisdiction for the various areas of the fire protection program.
5. Identifies the procedures established for the implementation of the fire protection program, including the post-transition change process and the fire protection monitoring program.
6. Identifies the qualifications required for various fire protection program personnel.
7. Identifies the quality requirements of Chapter 2 of NFPA 805.

Detailed compliance with the programmatic requirements of Chapters 2 and 3 of NFPA 805 are contained in the PBN Fire Protection Plan.

9.10.2 REFERENCES

1. NRC Safety Evaluation, “Point Beach Nuclear Plant, Units 1 and 2 - Issuance of Amendments Regarding Transition to a Risk-Informed, Performance-Based Fire Protection Program in Accordance with 10 CFR 50.48(c) (CAC Nos. MF2372 and MF2373),” dated September 8, 2016.

2. National Fire Protection Association Standards, NFPA 805, “Performance-Based Standard for Fire Protection for Light Water Reactor Electric Generating Plants,” 2001 Edition.

3. Regulatory Guide 1.205, “Risk-Informed, Performance-Based Fire Protection for Existing Light-Water Nuclear Power Plants,” Revision 1, dated December 2009.

4. NEI 04-02, “Guidance for Implementing a Risk-Informed, Performance-Based Fire Protection Program under 10 CFR 50.48(c),” Revision 2, dated April 2008.

5. FAQ 12-0062, “Updated Final Safety Analysis Report (UFSAR) Standard Level of Detail,” Revision 1, dated May 21, 2012.

6. NFPA 805 Fire Protection Program Design Document (FPPDD).

7. NP 1.9.14, “PBNP Fire Protection Plan.”

8. FPTE 2016-003, “PBN NFPA 805 Nuclear Safety Capability Assessment.”

9. FPTE 2016-004, “Non-Power Operation Modes Transition Review.

9.11 SAMPLING SYSTEM (SC)

This system provides samples for laboratory analysis to evaluate reactor coolant, and other reactor auxiliary systems chemistry during normal operation, and to evaluate the reactor coolant system chemistry during post-accident conditions. Each unit has a similar sampling system and no installed equipment is shared between units except the drains and vents to the waste disposal system. The description contained herein is equally applicable to either unit. A description of the containment atmosphere sampling system is provided in Section 6.5.

9.11.1 DESIGN BASIS

The sample system is designed to provide a means for obtaining a post accident sample as required by NUREG-0737. It is possible to obtain and analyze a sample without radiation exposures to any individual exceeding the criteria of GDC-19 (10 CFR 50 Appendix A) (Reference 1 and Reference 2).

The hot leg sample line is normally open and is continuously monitored by RE-109, Failed Fuel Monitor, except during periods of sampling or during periods of low pressure cold shutdown operations. This provides a remote method of evaluating for failed fuel. Sampling system discharge flows are limited under normal and anticipated fault conditions (malfunctions or failure) to preclude any fission product releases beyond the limits of 10 CFR 20.

The steam generator sample line is normally open with a small flow continuously monitored by RE-219, Steam Generator Blowdown Liquid Monitor. This flow is normally discharged to the service water system, and flow is automatically isolated on a high radiation signal from RE-219 (Reference 3).

Safety-related isolation functions of the sampling system include: (1) automatic isolation of sample lines penetrating containment (valves SC-951, 953, 955, 966A, 966B, 966C, and MS-2083 and 2084) on a containment isolation signal to prevent the release of radioactivity to the environment, and (2) automatic isolation of steam generator sample lines (valves MS-2083, and 2084) during a steam generator tube rupture event to isolate the ruptured steam generator and terminate the release.

9.11.2 SYSTEM DESIGN AND OPERATION

The system is capable of obtaining reactor coolant samples during reactor operation, during cooldown when the system pressure is low and the residual heat removal loop is in operation, and during post-accident conditions. Access is not required to the containment. Sampling of other process water, such as tanks in the waste disposal system, is accomplished locally. Equipment for sampling secondary and nonradioactive fluids is separated from the equipment provided for reactor coolant samples. Leakage and drainage resulting from the sampling operations are collected and drained to tanks located in the waste disposal system.

Two types of samples are obtained by the system: high temperature, high pressure reactor coolant system and steam generator blowdown samples which originate inside the reactor containment, and low temperature, low pressure samples from the chemical and volume control and residual heat removal systems.

High Pressure, High Temperature Samples

A sample connection is provided from each of the following:

1. The pressurizer steam space
2. The pressurizer liquid space
3. One primary coolant hot leg
4. Blowdown from each steam generator

Low Pressure, Low Temperature Samples

A sample connection is provided from each of the following:

1. The mixed bed demineralizer inlet header
2. The mixed bed demineralizer outlet header
3. The residual heat removal system, just downstream of the heat exchangers
4. The residual heat removal system, upstream of the heat exchangers
5. The volume control tank gas space
6. Charging pumps discharge header (high pressure, low temperature)

The high pressure, high temperature samples and the residual heat removal system samples leaving the sample heat exchangers are held to a temperature at or below approximately 130^{o}F to minimize the generation of radioactive aerosols.

The sampling system, shown in Figure 9.11-1, provides the representative samples for laboratory analysis. Analysis results provide guidance in the operation of the reactor coolant, residual heat removal, steam and power conversion, and chemical and volume control systems. Analyses show both chemical and radiochemical conditions. Typical information obtained includes reactor coolant boron and chloride concentrations, fission product radioactivity level, hydrogen, oxygen, and fission gas content, corrosion product concentration, and chemical additive concentration.

The information is used in regulating boron concentration adjustments, evaluating fuel element integrity and CVCS demineralizer performance, and regulating additions of corrosion controlling chemicals to the systems. The sampling system is designed to be operated manually, on an intermittent basis. Samples can be withdrawn under conditions ranging from full power to cold shutdown.

Reactor coolant liquid lines, which are normally inaccessible and require frequent sampling, are sampled by means of permanently installed tubing leading to the sampling room. Sampling system equipment is located inside the auxiliary building with most of it in the sampling room. The delay coil and sample lines with remotely operated valves are located inside the reactor containment.

Reactor coolant pressurizer steam, pressurizer liquid, and hot leg liquid samples originating inside the reactor containment flow through separate sample lines to the sampling room. Each of these connections to the reactor coolant system has a remote operated isolation valve (SC-951, 953, and 955 respectively), located close to the sample source. The samples pass through the reactor containment and a second remote operated isolation valve (SC-966A, B, and C respectively), to the auxiliary building, and into the sampling room, where they are cooled (pressurizer steam samples condensed and cooled) in the sample heat exchangers. The sample stream pressure is reduced by a manual throttling valve located downstream of each sample pressure vessel. The sample stream is purged to the volume control tank in the chemical and volume control system until sufficient purge volume has passed to permit collection of a representative sample. If the volume control tank is unavailable or isolated, the sample purge may be accomplished to the sample sink or to the waste disposal system. After sufficient purging, the sample pressure vessel is isolated and then disconnected for laboratory analysis of the contents.

Alternatively, liquid samples may be collected by bypassing the sample pressure vessels. If the volume control tank is unavailable or isolated, the sample purge may be accomplished to the sample sink or to the waste disposal system. After sufficient purge volume has passed to permit collection of a representative sample, either a portion of the sample flow is diverted to the sample sink where the sample is collected or the sample is collected from the purge stream.

The reactor coolant sample originating from the residual heat removal system has a remote operated, normally closed isolation valve (SC-959) located close to the sample source. The sample line from this source is connected into the sample line coming from the primary system hot leg at a point upstream of the sample heat exchanger. Samples from this source can be collected either in the sample pressure vessel or at the sample sink as with hot leg samples.

Required post-accident sampling can be accomplished from the primary system hot leg or the residual heat removal system. The sampling stations are located at accessible locations on the outside wall of the Unit 1 and Unit 2 sample rooms. Sampling is accomplished with a sample vessel, constructed of stainless steel and shielded with approximately 2-3/4 inches of lead, which is connected to the sampling station with compression fittings. The valving of the sample lines and the sample vessel allows recirculation with the sample vessel installed, ensures that sample flow is forced through the vessel when the sample is collected, and provides double valve protection against leakage when the vessel is removed. The sample vessel is transported to and from the sample station on a standard industrial four-wheel cart modified with special provisions for lifting and holding the sample vessel. The post-accident reactor coolant sample lines are purged and recirculated prior to obtaining a sample and are flushed with demineralized water as required subsequent to obtaining a sample. The isolation valve arrangement and the valve operating sequence minimize the possibility of sample loss (Reference 2 and Reference 4).

Samples originating at the chemical and volume control system letdown line at the mixed bed demineralizer inlet and outlet pass through the purge line to the volume control tank. If the volume control tank is unavailable or isolated or the pressure of the sample is low such that an adequate flow rate cannot be established, the sample purge may be accomplished to the sample sink or to the waste disposal system. Samples are obtained by diverting a portion of the flow to the sample sink where liquid and gas samples are obtained or the sample is collected from the purge stream.

The charging pump sample line, originating from the header on the discharge side of the pumps, is connected into the sample line coming from the mixed bed demineralizer inlet and outlet. Liquid samples from the charging pump discharge header pass directly through the purge line to the volume control tank. If the volume control tank is unavailable, the sample purge may be accomplished to the sample sink or waste disposal system. Samples are obtained by diverting a portion of the flow to the sample sink or the sample is collected from the purge stream.

The sample sink, which is contained in the laboratory bench as a part of the sampling hood, contains a drain line to the waste disposal system. Local instrumentation is provided to permit manual control of sampling operations and to ensure that the samples are at suitable temperatures and pressures before diverting flow to the sample sink.

Samples of the steam generator liquid are obtained from the blowdown lines of each steam generator by separate sample lines. These lines are equipped with a remote operated isolation valve (MS-2083 and 2084) and manual isolation valve (MS-316 and 317) in each line immediately outside the containment. The remote operated valve is automatically closed upon the receipt of a signal from the blowdown sample radiation monitor or the containment isolation system.

The sample lines are routed to the sample room where the liquid is cooled. Each individual sample is then split into three routes: one goes to the sample sink to provide periodic samples for chemical analysis as required or preferred, a second goes to radiation monitor RE-219, and a third line handles a continuous flow for a constant reading of conductivity, pH, and sodium. This third line also provides a sample for routine lab analyses or other in-line monitors at the secondary sample panel in the turbine hall.

Components

A summary of principal component data is given in Table 9.11-2.

Sample Heat Exchangers

Five sample heat exchangers reduce the temperature of samples from the pressurizer steam space (HX-14A), the pressurizer liquid space (HX-14B), each steam generator (HX-59A&B) and the reactor coolant (HX-14C) to approximately 130^{o}F before samples reach the sample vessels and sample sink. The tube side of the heat exchangers is austenitic stainless steel, the shell side is carbon steel. The inlet and outlet tube sides have socket-weld joints for connections to the high pressure sample lines. Connections to the component cooling water lines are socket-weld joints. The samples flow through the tube side and component cooling water circulates through the shell side.

Delay Coil

The reactor coolant hot leg sample line contains a delay coil, consisting of coiled tubing, which has sufficient length to provide at least a 40 second sample transit time within the containment and an additional 20 second transit time from the reactor containment to the sampling hood.

This allows for decay of the short-lived N-16 isotope to a level that permits normal access to the sampling room.

Sample Pressure Vessels

The high pressure coolant sample trains, the residual heat removal sample train, and the volume control tank gas space sample train each contain provisions for the installation of sample pressure vessels which are used to obtain liquid or gas samples. The hot leg and the residual heat removal system sample lines have a single sample pressure vessel in common. Integral isolation valves are furnished with the vessel and couplings are connected to nipples extending from the valves on each end with compression fittings. The vessels, valves and couplings are austenitic stainless steel.

Sample Sink

The sample sink is located in a hooded enclosure which is equipped with an exhaust ventilator that discharges to the auxiliary building ventilation system. The work area around the sink and the enclosure is large enough for sample collection and storage for radiation monitoring equipment. The sink perimeter has a raised edge to contain any spilled liquid.

Piping and Fittings

All liquid and gas sample lines are austenitic stainless steel tubing and are designed for high pressure service. Socket-welded joints are used in the portions of the sampling lines which experience severe thermal transients. Lines are so located as to protect them from accidental damage during routine operation and maintenance.

Valves

Remotely operated stop valves are used to isolate all sample lines leaving containment and the residual heat removal system. Manual stop valves are provided for component isolation and flow path control at all normally accessible sampling system locations. Manual throttle valves are provided to adjust the sample flow rate as indicated on Figure 9.11-1. All valves in the system are constructed of austenitic stainless steel or equivalent corrosion resistant material.

Remotely operated isolation valves are provided inside and outside the reactor containment on all reactor coolant sample lines leaving the containment. Each valve is provided with and will trip closed upon receipt of a containment isolation signal. The steam generator blowdown sample lines leaving containment have a remotely operated isolation valve outside containment. These valves will trip closed upon receipt of a containment isolation signal or a steam generator blowdown high radiation signal from RE-219.

9.11.3 SYSTEM EVALUATION

Leakage Provisions

Leakage of radioactive reactor coolant from this system within the containment is evaporated to the containment atmosphere and removed by the cooling coils of the containment air recirculation and cooling system or collected in floor drains, which is then directed to containment Sump A. Leakage of radioactive material from the most likely places outside the containment is collected by placing the entire sampling station under a hood provided with a connection to the auxiliary building ventilation system. Liquid leakage from the valves in the hood is drained to the waste disposal system.

Incident Control

The system operates on an intermittent basis, and under administrative manual control.

Malfunction Analysis

To evaluate system safety, the failures or malfunctions are assumed concurrent with a loss-of-coolant accident, and the consequences analyzed. The malfunctions analyzed include failure of the coolant sample isolation valves inside containment to isolate and a sample line break inside containment. The radiological consequences of both of these malfunctions are mitigated by the automatic closure of the isolation valves outside containment on a containment isolation signal.

Codes and Standards

System component code requirements are given in Table 9.11-1.

9.11.4 REQUIRED PROCEDURES AND TESTS

The inservice inspection requirements are described in the PBNP Inservice Testing Program.

9.11.5 REFERENCES

1. NRC Safety Evaluation dated December 22, 1982.

2. WE letter to NRC, “NUREG-0737 Item II.B.3 Post Accident Sampling System,” dated September 30, 1982.

3. WE Safety Evaluation 91-051.

4. PBNP Emergency Plan Implementing Procedures.

5. NUREG 0737, Item II.B.3, “Post-Accident Sampling Capability.”

Table 9.11-1 SAMPLING SYSTEM CODE REQUIREMENTS

Sample heat exchanger	ASME VIII, (no stamp required)
Sample pressure vessels	ASME III*, Class C
Piping and valves	USAS B31.1**

* ASME III - American Society of Mechanical Engineers, Boiler and Pressure Vessel Code, Section III, Nuclear Vessels.

** USAS B31.1 - Code for Pressure Piping and special nuclear cases where applicable.

Table 9.11-2 SAMPLING SYSTEM COMPONENTS
Sheet 1 of 2

Sample Heat Exchanger	
General	
Number	5 per unit
Type	Shell and coiled-tube
Design heat transfer rate (duty for 652.7°F sat. steam to 127°F liquid), each, BTU/hr	2.14×10^5
Shell	
Design pressure, psig	150
Design temperature, °F	350
Total Component cooling water flow to the 5 heat exchangers (minimum), gpm	75
Operating cooling water temperature, in (maximum), °F	105
Material	Carbon steel
Tubes	
Tube diameter O.D., in.	3/8
Design pressure, psig	2485
Design temperature, °F	680
Sample flow, normal, each, lb/hr.	209
Maximum allowable pressure loss, each 209 lb/hr, psi	10
Operating sample temperature, in (maximum), °F	652.7
Operating sample temperature, out (maximum), °F	127
Material	Austenitic stainless steel

Table 9.11-2 (Continued)

Sheet 2 of 2

Sample Pressure Vessels

Number, total	5 per unit
Approx. Volume, pressurizer steam sample, 2 supplied, ml	85
Approx. Volume, pressurizer liquid sample, 2 supplied, ml	85
Approx. Volume, reactor coolant hot leg sample, 2 supplied, ml	85
Approx. Volume, volume control tank sample, 2 supplied, ml	85
Approx. Volume, high radiation sample, 2 supplied, ml	19
Design pressure, psig	2485
Design temperature, °F	680

Piping

Liquid and gas sample line internal diameter, in.	0.245
Design pressure, psig	2485
Design temperature, °F	680

Figure 9.11-1 UNIT 1 SAMPLING SYSTEM

[redacted]

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10.0 STEAM AND POWER CONVERSION

The steam and power conversion systems of Units 1 and 2 are essentially identical. For each unit, the turbine generator systems consist of components of conventional design, designed for use in large central power stations. The equipment is arranged to provide high thermal efficiency with no sacrifice to safety. The component design parameters are given in Table 10.1-1.

The steam and feedwater system is designed to remove heat from the reactor coolant in the two steam generators, producing steam for use in the turbine generator. The steam and feedwater system can receive and dispose of, in the cooling systems and through atmospheric relief valves, the total heat existent or produced in the reactor coolant system following an emergency shutdown of the turbine generator from a full load condition.

Each unit has undergone a low pressure turbine retrofit which replaced the original Westinghouse BB80 low pressure turbine rotors with newly designed Westinghouse BB80R (Ruggedized) monoblock rotors. The replacement included rotors, inner cylinders and all stationary and rotating blading. The design incorporated state-of-the-art turbine technology to improve reliability and thermal performance.

All of the equipment in the turbine generator systems was originally designed to produce a maximum calculated gross output of 537,960 kWe. Significant modifications to secondary plant equipment were necessary as a result of the increase in reactor thermal power to 1800 MWt for the Extended Power Uprate (EPU).

The original Westinghouse double flow BB95 high pressure (HP) turbine was modified by replacing the rotor and internals such that the HP turbine is equivalent to a BB95A design. Similar to the previous low pressure (LP) turbine rotor retrofit, the inner cylinders and all stationary and rotating blading were replaced. The HP casings have been retained but modified to accommodate a higher exhaust pressure. In addition the LP turbine blowout panels have been replaced to accommodate the increase in steam flow at EPU conditions.

Significant modifications to the condensate and feedwater system for EPU included higher capacity main feedwater pumps, higher capacity condensate pumps, higher capacity condensate coolers, replacement of all feedwater heaters, new valve trim and actuators for the main feedwater regulating valves and installation of new main feedwater isolation valves.

10.1 STEAM AND POWER CONVERSION SYSTEM

10.1.1 DESIGN BASIS

Load Change Capability

The plant has the capability to provide load changes up to step load increase of 10% and ramp increases of 5% per minute within the load range of 15% to 100% of full load without reactor trip subject to possible xenon limitations late in core life. Similar step and ramp load reductions are possible within the range of full power to 15% nominal power. The reactor coolant system will accept a complete loss of load from full power with reactor trip. In addition, the steam dump system makes it possible to accept a rapid load decrease of 50% at a rate up to 200%/minute without reactor trip providing condenser vacuum is maintained (Reference 1).

Functional Limits

The system design incorporates backup means (Atmospheric Steam Dump Valves and Main Steam Safety Valves) for heat removal under any loss of normal heat sink (i.e., main steam isolation valves trip, condenser isolation, loss of circulating water flow) to accommodate reactor shutdown heat rejection requirements.

Secondary Functions

The steam and power conversion system also provides steam for driving the turbine-driven auxiliary feedwater pump and for turbine gland steam, reheater steam, the two-stage steam-jet air ejectors, the two priming ejectors, waste evaporator, letdown gas strippers and tank, and building heating.

Codes And Classifications

The pressure retaining components (or compartment of components) comply with the codes given in Table 10.1-2.

10.1.2 SYSTEM DESIGN AND OPERATION

Schematic Flow Diagrams

The main and reheat steam, the condensate and feedwater, the extraction steam, the feedwater heater drains, the auxiliary feedwater, the circulating water, the feedwater heater vents and reliefs, and the gland steam and drains flow diagrams are given in Figure 10.1-1 through Figure 10.1-8, respectively.

Design Features - Steam and Feedwater System

Steam from each of the two steam generators supplies the turbine, where the steam expands through the double flow high pressure turbine, and then flows through moisture separator reheaters (MSRs) to two, double flow, low pressure turbines, all in tandem. Five stages of extraction are provided, two from the high pressure turbine, one of which is the exhaust, and three stages from the low pressure turbines as shown in Figure 10.1-3. The feedwater heaters for the lowest three stages are located in the condenser neck. All feedwater heaters are horizontal, half-size units. The feedwater string is the closed type with deaeration accomplished in the condenser.

Condensate is taken from the condenser hotwell by the condensate pumps and pumped through the hydrogen coolers, air ejector condensers, gland steam condenser, and low pressure heaters to the suction of the feedwater pumps. The feedwater pumps then send feedwater through the high-pressure heaters to each steam generator.

The four MSRs drain to the high pressure heaters. Drains from the high pressure heaters are cascaded through No. 4 feedwater heaters to the heater drain tank. The moisture separators also drain to this tank. The heater drain pumps take suction from the drain tank and discharge to the feedwater pump suction. Drains from the three lower pressure heaters cascade to the condenser.

The steam and feedwater lines from the steam generators up to and including the steam line non-return check valves and the main feedwater isolation valves are seismic Class I. A failure of any Class I main steam or feedwater line or malfunction of a valve installed therein will not impair the reliability of the auxiliary feedwater system, render inoperative any engineered safeguard feature, initiate a loss of coolant condition, or cause failure of any other steam or feedwater line.

The main steam system conducts steam in a 30 in. pipe from each of the two steam generators within the reactor containment through a swing disc-type isolation valve and a swing-disc type nonreturn valve to the turbine stop and control valves. The main steam isolation and nonreturn valves are located outside of the containment. The two lines are interconnected locally to the turbine. The design pressure of this system is 1085 psig at 555°F. Steam pressure is measured upstream of the main steam isolation and non-return valves. A steam flowmeter is provided in the line from each steam generator upstream of the main steam isolation and nonreturn valves to measure steam flow from each steam generator. Steam flow signals are used by the automatic feedwater flow control system (see Section 7.0). The flow venturi also serves to limit steam flow rate in the event of a steam line break downstream of the venturi. In addition to this venturi, the steam generators have a steam flow limiter located in the steam nozzle.

Each main steam isolation valve contains a swing disc which is normally held out of the main steam flow path by an air piston. This valve is closed by a spring when the air supply is shut off by a signal from the steam line break protection system, and the piston is vented by redundant valves actuated by the same signal, as described in Section 7.0. The main steam isolation valve is designed to close in less than five seconds.

The nonreturn valves prevent reverse flow of steam. If a steam line ruptures between a main steam isolation valve and a steam generator, the affected steam generator will blow down. The nonreturn valve in the line will prevent blowdown (reverse flow) from the other steam generator. The steam break incident is analyzed in Section 14.0.

Steam Dump to Atmosphere

If the condenser heat sink is not available during a turbine trip or during a unit startup, excess steam, generated as a result of reactor coolant system sensible heat and core decay heat, is discharged to the atmosphere.

There are four 6 in. by 10 in. Main Steam Safety Valves (MSSVs) located on each of the two 30 in. main steam lines outside the reactor containment and upstream of the main steam isolation and nonreturn valves. Discharge from these safety valves is carried to atmosphere through individual vent stacks. The lift settings for the main steam safety valves are specified in Technical Specification 3.7.1. The MSSVs have sufficient relieving capacity so that the main steam pressure does not exceed 110 % of the steam generator shell-side design pressure for the worst-case loss-of-heat sink event (Reference 1).

In addition, one 6 in. Atmospheric Steam Dump Valve (power operated relief valve) is provided in each main steam line which is capable of releasing the sensible and core decay heat to the atmosphere. These valves are automatically controlled by pressure or may be manually operated from the main control board. Combined, the valves will be capable of passing no less than 10% of the maximum calculated steam flow at no-load steam pressure. Discharge from each atmospheric steam dump valve is carried to atmosphere through an individual vent stack. In addition, the atmospheric steam dump valve may be used to release the steam generated during reactor physics testing and plant hot standby operation if the condenser is not available.

The atmospheric steam dump lines are relied upon, following a steam generator tube rupture coincident with a loss of A.C. power, to cool down the reactor coolant system to RHR entry conditions. Further discussion of this event can be found in FSAR Section 14.2.4, "Steam Generator Tube Rupture."

Condenser Steam Dump System

Excess steam generated by the reactor coolant system is bypassed, during conditions described below, to the condenser by means of two 16 in. main steam dump lines, one for each condenser. From each 16 in. line four 6 in. lines are taken, each with a 6 in. control valve installed. Each valve discharges through a 10 in. pipe into the condenser through a perforated diffuser. The capacity of the condenser dump system (as a percentage of full-load steam flow) decreases as full-load steam pressure decreases and full-load steam flow increases. The steam dump system capacity is adequate to prevent reactor trip for a steep ramp load reduction of 50% over 15 seconds from the EPU power level and is adequate to prevent exceeding MSSV setpoints following a reactor trip from full EPU power. This capacity also exceeds that necessary for prompt cooldown to RHR system operation entry conditions (Reference 1, Reference 2 and Reference 3). The smaller size valves are provided to limit the maximum steam flow should one valve stick open. A potential hazard in the form of an uncontrolled plant cooldown is thus minimized. Manual isolation valves are provided at each control valve.

The operation of the condenser steam dump valves is initiated by the error signal from the reactor coolant average temperature or header pressure. After initial opening, the valves are modulated by the T_{avg} signal to reduce the average temperature to the correct value. This is further described in Section 7.0. The valves are designed to rapidly open and fail in a closed position.

During a normal orderly shutdown of the turbine generator leading to plant cooldown, the operator may select pressure control for more accurate maintenance of no-load conditions using the condenser steam dump valves to release steam generated by the residual heat. Plant cooldown, programmed to minimize thermal transients and based on residual heat release is effected by a gradual manual adjustment of this pressure setpoint until the cooldown process is transferred to the residual heat removal system.

During startup, hot standby service or physics testing, the condenser steam dump valves may be remotely controlled from the main control board. The steam dump valves are prevented from opening on loss of condenser vacuum; they are also blocked on trip of both circulating water pumps that supply water to that unit.

Steam for Auxiliaries

The steam for the turbine-driven auxiliary feedwater pump is obtained from both main steam lines, upstream of the main steam isolation valves. Each steam supply is through a motor- operated stop check valve which prevents reverse flow between the steam generators.

Main steam for the turbine gland steam supply control valve, the two stage air ejectors, the reheater section of the four moisture-separator-reheaters and the two priming ejectors is obtained from branches on the main steam lines ahead of the turbine stop valves. Pressure reducing stations are used for the priming and main air ejectors. Temperature control valves are located in the main steam lines to the reheaters.

Steam from the five stages of extraction is piped from the turbine casings to the shells of the two parallel strings of feed water heaters. The first point extraction originates at the high pressure turbine casing and supplies steam to the shell of the No. 5 (high pressure) feedwater heater. The second point extraction originates in the high pressure turbine exhaust piping ahead of the moisture separators, and supplies steam to the No. 4 (low pressure) feedwater heater. The third, fourth, and fifth point extractions all originate at the low pressure turbine casings and supply steam to the No. 3, No. 2, and No. 1 (all low pressure) feedwater heaters, respectively.

To prevent turbine overspeed from backflow of flashed condensate from the heaters after a turbine trip, bleeder trip valves are provided in the extraction lines to heaters No. 4 and 5 and in the moisture separator drain lines. The bleeder trip valves are air-cylinder operated valves which are closed automatically upon a signal from the turbine trip circuit.

Steam Generator Blowdown

Each steam generator is provided with two 2½ in. bottom blowdown connections for shell-side solids concentration control. The two connections are at the same level, but on opposite sides of the shell. Piping from the two connections join to form a 2 in. blowdown header for each steam generator. The bottom of each steam generator is also provided with a drain connection which discharges into the blowdown line.

Each blowdown line is provided with a hand shutoff valve and an air operated trip valve. Each blowdown line includes, in addition to these shutoff valves, a manually-operated needle-type flow control valve for blowdown flow adjustment. A steam generator sample line, also provided with a trip valve, is taken from the blowdown line inside containment. A slip stream from each sample line is monitored for radiation. In the event of a high radiation signal, the trip valves in the sample and blowdown lines, and a trip valve in the blowdown tank drain line will close.

Downstream of the blowdown line trip valves, the blowdown from each steam generator can be aligned to pass through the blowdown heat exchangers. Each heat exchanger is composed of two shell and tube heat exchangers connected in series. The blowdown normally passes through the tube side of the heat exchangers and is cooled by water from the main condensate system, and then passes to the blowdown tank. It is also possible to align the blowdown from each steam generator directly to the blowdown tank, or only the blowdown heat exchangers.

In order to reduce the iodine quantity leaving in the flashed steam from the steam generator blowdown tank vent, a situation which could occur with a high secondary water activity due to potential primary to secondary steam generator tube leakage, vent condensers have been added to condense most of the steam which would otherwise leave the tank vent. The water from blowdown may be further processed before release (see Chapter 11).

Turbine Generator

Each turbine is a three-element, tandem-compound, four-flow exhaust, 1800 rpm unit, and has moisture separation and live steam reheat between the HP and LP elements. Steam is admitted to the turbine through two stop valves and four control valves. The A.C. generator and rotating rectifier exciter are direct-connected to the turbine shaft. The turbine consists of one double flow, HP element in tandem with two double flow, LP elements. Four combination moisture-separator, live-steam reheater assemblies are located along side the turbine.

Each turbine is designed to operate with inlet steam conditions of 802 psia/518.5 F (Unit 1) / 806 psia/519.1 F (Unit 2), exhausting at 1.47 in. of Hg absolute, and with five stages of feedwater heating in service. Operating at design conditions with 8,111,883 lbm/hr inlet steam flow, 0% makeup flow, and 75°F circulating water temperature, the calculated gross output of each unit is ~607,000 kWe at a reactor power of 1806 MWt (1800 MWt reactor power plus 6 MWt pump heat).

High-Pressure Turbine

The high-pressure turbine has full arc steam admission and a double flow element, consisting of 11 stages of reaction blading in each end of the element. The steam enters the high pressure element from two main stop-control valve assemblies. The control valve outlets are connected to the high pressure casing through four inlet pipes. Two of these inlet connections are in the base and two are in the cover. The steam flows axially in both directions through the flow guide and reaction blading to the moisture separator reheaters, through four exhaust openings in the casing base. Crossover pipes return the steam to the two low pressure turbines.

The high pressure cylinder consists of an outer casing of carbon steel and is split at the horizontal centerplane to form a base and cover. The high pressure blading is carried in blade rings or guide blade carriers which are separate elements supported in the casing at the horizontal joint. They are guided at the top and bottom by dowel pins to retain correct position with respect to the turbine axis, while allowing free expansion and contraction in response to temperature changes. The high pressure turbine rotor is machined from an alloy steel forging. A separate extension shaft is bolted to the governor end of the rotor to carry the main oil pump and overspeed trip weight.

Low-Pressure Turbine

The double flow low pressure turbine incorporates high efficiency blading, diffuser type exhaust and liberal exhaust hood design. The low pressure turbine cylinders are fabricated from steel plate to provide uniform wall thickness thus reducing thermal distortion to a minimum. The entire outer casing is subjected to low temperature exhaust steam. The temperature drop from the cross-over steam temperature to the exhaust steam temperature is taken across the inner cylinder and thermal shield. The inner cylinder is surrounded by the thermal shield. This precludes a large temperature drop except across the thermal shield (which is not a structural element) thereby virtually eliminating thermal distortion. The fabricated inner cylinder is supported by the outer casing at the horizontal centerline and is fixed transversely at the top and bottom and axially at the centerline of the steam inlet, thus allowing freedom of expansion independent of the outer casing. The steam leaving the last row of blades flows into the diffuser where the velocity energy is converted to pressure energy, thus improving efficiency and reducing the excitation forces on the last rotating row of blades.

As part of a LP Turbine retrofit on each unit, the original LP turbine rotors (Westinghouse BB80) and low pressure turbine sections have been replaced with newly designed Westinghouse BB80R (Ruggedized) low pressure turbine rotors and low pressure turbine sections. The replacement ruggedized monoblock rotors have integrally forged “discs” made of highly corrosion-resistant material which eliminates the primary risk for stress corrosion cracking. The last 3 rows of the bladepath incorporate interlocking blades. The number of blade rows has been reduced from11 to 10 with the last stage blade length increased from 40 inches to 47 inches due to the added structural capability of the interlocking blades. The replacement low pressure equipment was manufactured to fit within the dimensions of the existing outer cylinders, bearing housings, coupling guards and hood sprays.

The hydrogen inner cooled generator is rated at 684,000 KVA at 0.94 power factor and 75 psig hydrogen gas pressure.

There are four, horizontal-axis, cylindrical-shell, combined moisture-separator, live-steam reheater assemblies. Steam from the exhaust of the HP turbine element enters the shell side of each assembly at one end. The steam is deflected down to the lower section of the vessel from which it rises through chevron type moisture separators. The moisture is collected from the chevrons in a trough and drained to the heater drain tank. Live steam from the steam generators enters at the other end of each assembly, passes through the tubes and leaves as condensate. Condensate from the reheater assemblies drains to the high pressure heaters. The lower pressure steam leaving the chevron separators flows over the tube bundle where it is reheated. This reheated steam leaves through openings in the top of the assemblies and flows to the LP turbines.

The crossover steam dump system is located on the crossover piping between the moisture separator reheaters and the LP turbines. The purpose of the system is to provide a means of energy removal from the turbine in the event of a unit trip and is designed to assure that the maximum overspeed of 132% will not be exceeded. The system consists of four air pilot-operated dump valves located in the HVAC equipment room. Discharge from these dump valves is carried to the atmosphere through individual vent stacks. The system is armed at 540 MW equivalent load and actuated upon turbine trip at 104% of design speed (Reference 11).

The dump valves are reseated by applying reseat steam pressure following a time delay after the required blowdown. Service air may be used as an alternative administrative pressure source to assist in closing a stuck open dump valve. Any three of the four dump valves will provide the design capacity to prevent exceeding the turbine maximum overspeed.

Turbine Oil System

The turbine oil system is of a conventional design. It consists of three parts: 1) a high pressure oil system, 2) lubrication system, and 3) Electro-Hydraulic (E/H) control system. The E/H control system is completely separate from the other two parts. Lube oil is also used to seal the generator glands to prevent hydrogen leakage from the machine. The fluid used for the E/H control system is a fire-resistant synthetic oil. The maximum available steam temperature is not capable of initiating a fire in the E/H oil system.

The turbine oil system supplies all of the oil required for the emergency trip and lubrication system during normal operation. A “Bowser” type oil conditioner is used for purifying oil in the reservoir and all makeup oil before it is added to the system.

The turbine has low speed, motor-driven, spindle-turning gear equipment which is mounted outboard of the No. 2 low pressure turbine generator end bearing (No. 6 bearing).

Condensate and Feedwater

The feedwater train is the closed type with deaeration accomplished in the condenser. Condensate is taken from the condenser hotwell by the condensate pumps and pumped through the condensate cooler, hydrogen coolers, air ejectors, gland steam condenser, and low pressure heaters to the suction of the feedwater pumps. The feedwater pumps then send feedwater through the high pressure heaters to the steam generators.

The main condenser is in two sections, one under each LP turbine. Each section is a single pass, radial flow condenser with semicylindrical water boxes at both ends. Each main condenser section has two condensate outlets with coarse strainers and antiswirl devices. Each hotwell is baffled with provisions for separate conductivity measurements on each half to locate leaking tubes.

There are two multistage, vertical pit-type, centrifugal condensate pumps with vertical motor drives. Each pump is half capacity with the turbine operating at the maximum calculated rating. The pumps deliver condensate to the system at approximately 11,064 gpm, including up to 3280 gpm of condensate to the generator hydrogen coolers. Oil in the upper motor bearing reserviour is cooled by condensate supplied from the pump discharge. The condensate pumps are started and stopped by manual controls on the main control board.

The steam jet air ejector maintains a vacuum in the condenser. The steam jet air ejector has four first stage elements and two second stage elements mounted on the shells of the intermediate and after condensers. The ejector is supplied with steam from the main steam line. During startup, one priming ejector of the low-head high-flow type is used to evacuate the condenser. A second originally installed priming ejector has been disabled to allow the option to use a mechanical vacuum pump to evavuate the condenser during startup when main steam is unavailable (Reference 12).

The reheaters, the moisture separators and all feedwater heaters (except the No. 4 heaters) are provided with duplex level controls. The Nos. 1 and 2 low-pressure heaters are combined into one heater shell. The level controllers also operate the emergency dump valves which dump the drains directly to the condenser in case of abnormally high level. There are no level controls for the No. 4 heaters which drain to the heater drain tank by gravity flow.

Three half-capacity, multistage, vertical, centrifugal heater drain tank pumps are provided for pumping the heater drainage into the suction line of the feedwater pumps. The pumps are started and stopped from the main control board. Heater drain tank level is controlled by a control valve in the discharge line.

A gland steam condenser maintains a pressure slightly below atmospheric in the turbine gland leakoff system. Sealing steam and air leakage along the shaft at each turbine gland is fed to this condenser, thus preventing any leakage of steam into the turbine room. A motor-driven exhauster is mounted on the gland condenser to remove noncondensable gases.

The Containment Pressure Condensate Isolation (CPCI) circuit trips the two condensate pumps and the three heater drain tank pumps upon sensing a high pressure in containment. The circuit trips the pumps on high containment pressure (2/3 logic). The purpose of this circuit was to prevent overpressurization of containment assuming one of the main feedwater regulating valves fails to close during a steamline break inside containment. However, this function is no longer credited in the steamline break analysis (FSAR 14.2.5) due to installation of the main feedwater isolation valves (MFIVs).

Main Feedwater System

Two motor-driven main feedwater pumps increase the pressure of the condensate for delivery through one stage of feedwater heating, the feedwater regulating valves and the feedwater isolation valves to the steam generators. The pumps have capacity to deliver 50% each of combined condensate discharge flow from the number 4 feedwater heaters and heater drain tank pumps for 100% power (1806 MWt). Each pump is capable of supplying 60% of feedwater flow during single pump operation.

The main feedwater pumps are single-stage, centrifugal pumps. Shaft sealing is accomplished by seal water injection with flow regulated by temperature control valves based on seal water leakoff temperature. Bearing lubrication for the motor and pump is accomplished by an integral lubricating oil system mounted on the pump base. Normal circulation of the lubricating oil is by a shaft-driven pump. The lubricating oil system includes a reservoir, two 100% capacity heat exchangers cooled by condensate, an AC motor-driven auxiliary oil pump and an immersion heater. Main feedwater pump bearing temperatures are recorded in the main control room. The steam generator feedwater pumps are started and stopped from the main control board. A modulated minimum flow control system is provided to ensure 4000 gpm flow during low system flow conditions. Sustained low suction pressure sounds an alarm on the main control board and trips the feedwater pumps after two minutes.

An automatic bypass is provided around the low-pressure heaters to ensure sufficient suction pressure at the feed pumps during a transient when flashing may occur in the heater drain tank and affect the drain pumps performance.

The two main feedwater pumps operate in series with the condensate and the heater drain pumps, discharging through check valves and motor operated gate valves into a common header. The feedwater then flows through the two parallel, high-pressure feedwater heaters and flows into a common header. Two 16 in. lines containing the feedwater control stations feed the two steam generators from the header. The control station consists of one main feedwater control valve and one bypass feedwater control valve in parallel.

The steam generator feedwater control system measures, indicates, records and controls the water level in each of the two steam generators. A conventional three element system is used.

Bypass valves together with shutoff valves at the inlets and outlets of the feedwater heaters are provided to permit heaters to be taken out of service.

Reactor trip is actuated either on a coincidence of sustained steam flow - feedwater flow mismatch, coupled with low level in any steam generator or by a low-low steam generator water level. These trips are discussed in further detail in Section 7.2.

The sizing and control capability of the main feedwater regulating valves (MFRVs), together with the hydraulic operation of the condensate pumps and feedwater pumps, provides sufficient flexibility to accommodate plant load rejection transients by providing 95% of rated flow with a steam generator pressure increase of 100 psi. This is based on the limiting normal condition transient of a 50 % load rejection which causes a decrease in steam generator water level concurrent with an increase in steam pressure.

The MFRVs fail closed on loss of control power or air and close on a reactor trip, safety injection or steam generator High-High water level. The minimum specified valve closure time of 3 seconds was considered in the EPU dynamic valve closure analysis and the maximum closure time of 10 seconds was considered for the EPU main steam line break analysis (FSAR 14.2.5). The bypass feedwater control valves also fail closed on loss of power or air and close on safety injection or an abnormally high steam generator water level.

A three-element primary and secondary programmable indicating controller is provided for each main feedwater control valve and a single-element controller is provided for each bypass feedwater control valve. See Section 7.7.4, Steam Generator Level Control, for additional information on the control systems.

The MFRVs and associated bypass valves are credited for isolation of condensate and feedwater flow for a faulted steam generator, but are considered the backup means rather than the primary means of isolation. The MFRVs are the primary device for feedwater isolation on steam generator High-High water level and reactor trip. The bypass feedwater control valves are a primary isolation device for Feedwater Isolation on steam generator High-High water level.

The MFRVs and bypass valves are classified as non-safety-related because the valves are not considered the primary means of feedwater isolation for a faulted steam generator. The solenoid valves required to trip the main feedwater control and bypass valves for feedwater isolation are safety-related, powered from a safety-related DC power source and receive a safety-related SI signal from both train A and B.

The main feedwater isolation valves (MFIVs) are located downstream of the feedwater control valves (closer to containment) and are credited as the primary means of isolating main feedwater flow to a faulted steam generator. The MFIVs are pnuematically operated and each have two redundant solenoid valves which energize to close the associated MFIV on a safety injection signal. See Section 9.7 for a description of the pneumatic system used to operate the MFIVs. The MFIVs fail as-is on loss of air and are safety-related, seismic Category I. They are designed to close in greater than 3 seconds and less than 5 seconds. The 3 second closure time was used in the dynamic valve closure analysis for both the MFIVs and MFRVs. The maximum closure time of 5 seconds satisfies the assumptions of the containment steam line break safety analysis (Section 14.2.5).

A venturi is installed in each main feedwater line and an acoustic leading edge flowmeter (LEFM) is installed in the common main feedwater line downstream of the number 5 feedwater heaters for flow measurement. The LEFM is more accurate and allows operation at higher power level. See Section 7.5.1.4 and TRM 3.3.2 for additional information.

Circulating Water System

The circulating water system circulates water from Lake Michigan through the main condensers to condense the steam exhausting from the turbines. The water is discharged back to the lake through discharge flumes. Two circulating water pumps per unit are used to circulate the water (see Figure 10.1-6). Travelling screens and a screen wash system remove debris from the water (see Figure 10.1-6B). The circulating water system also supplies cooling water to the condensate cooler for maintaining the main generator hot gas temperature.

The circulating water intake system, common to both units, is designed to provide a reliable supply of Lake Michigan water, regardless of weather or lake conditions, to the suction of four circulating water pumps, six service water pumps, two fire water pumps, two screenwash pumps, and one jockey fire pump. The pumphouse is Class I. The intake crib is located 1750 ft. from the shore in a water depth of 22 ft. The structure consists of two annular rings of 12 in. structural steel H pile driven to a minimum depth of 23 ft. below lake bed and reinforced with walers fabricated from 12 in. structural steel H pile. The annulus is filled with individually placed limestone blocks having two approximately parallel surfaces and weighing between 3 and 12 tons. The structure has an outside diameter of 110 ft., an inside diameter of 60 ft. and a top elevation of approximately -11′-0″. Water enters the intake crib primarily through the 60 ft. opening above the intake cones. The 60 ft. opening is covered with a trash rack having approximately 7 in. x 18 in. openings. The intake crib has been designed to reduce the likelihood of ice blockage during the wintertime.

Water flows from the intake crib to the pumphouse forebay through two 14 ft. diameter, corrugated, galvanized, structural plate pipes buried to a minimum depth of 3 ft. below lake bed. Flow through either pipe can be reversed during winter operation to recirculate warm condenser discharge water to the intake to prevent freezing in the system. Water flows from the forebay through bar grates and through travelling screens having 3/8 in. mesh to the suction of the pumps.

The circulating water is periodically treated to control biological fouling in system piping and in the condensers. Sodium hypochlorite, Nalco 73551 (bio-detergent), and Nalco 3DT121 (silt dispersant) are currently added to the system intermittently to prevent the buildup of slime and algae in the system and to minimize zebra mussel colonization. Sodium bisulfite is simultaneously injected at the outlet end of the condensers to dechlorinate the discharge circulating water. Other treatments may be considered in the future and will be evaluated prior to implementation. All treatments must be performed within the requirements of our Department of Natural Resources (DNR) Discharge Permit under the Wisconsin Pollutant Discharge Elimination System (WPDES).

Plant internal flooding due to postulated loss of circulating water system integrity in the turbine building is discussed in Appendix A.7.

Turbine Controls

High-pressure steam enters the turbine through two turbine stop valves and four governing valves. One turbine stop and two governing valves form a single assembly which is anchored above the turbine room floor line. An electro-hydraulic servo-actuator controls each turbine stop valve so that it is either in the wide open or closed position. The control signal for this servo-actuator comes from the mechanical hydraulic overspeed trip portion of the electro-hydraulic control system. The major function of these turbine stop valves is to shut off the flow of steam to the turbine in the event the unit overspeeds beyond the setting of the overspeed trip. These valves are also tripped when the protective devices function. The governing valves are positioned by a similar electro-hydraulic servo-actuator acting in response to an electrical signal from the main governor portion of the electro-hydraulic control system. Upon loss of load, the auxiliary governor portion of the electro-hydraulic control will act to close the governor valves rapidly.

The electro-hydraulic turbine control system combines a solid state electronic controller with a high pressure fire resistant fluid supply system which is independent of the lubricating oil. The design features and response characteristics of the system increase the reliability and availability of the power plant.

The electro-hydraulic control system includes the following features:

1. Governor valve controller
2. Load limit controller
3. Auxiliary governor
4. Speed controller
5. Load controller
6. Operators panel on the RTG control board
7. High pressure hydraulic fluid pumping unit
8. Turbine protective devices, including function limits trips, and extraction line nonreturn valves closing signal.

The mechanical overspeed trip mechanism consists of an eccentric weight mounted in the end of the turbine shaft, which is held in position by a spring until the speed reaches approximately 105% of rated speed. Its centrifugal force then overcomes the spring and the weight strikes a trigger which trips the overspeed trip valves and causes the autostop fluid to drain. The resulting decrease in autostop pressure causes the governing emergency trip valve to release the control oil pressure, closing the turbine stop and governing control valves. An air pilot valve is used to close the nonreturn valves in the H.P. turbine extraction lines and in the moisture separator drain lines.

The auxiliary governor provides overspeed protection via the overspeed protection circuitry (OPC) and the EH high pressure fluid system. It will close the governor valves by energizing the OPC solenoid valves if the turbine speed, as sensed from the auxiliary speed tachometer, exceeds

103% of rated speed. By means of the load drop anticipator, it will shut the governor valves by energizing the OPC solenoid valves following a complete load separation. The load drop anticipator measures the mismatch (~30%) between the reheat pressure and the megawatt signals provided the reheat pressure is above a preset value.

The independent overspeed protection system (IOPS) monitors speed electronically and causes a trip signal to be generated should turbine speed exceed 104%. There are 3 identical independent speed channels. The signal for each channel originates from a magnetic pickup mounted adjacent to the shaft turning gear. AC pulses, whose frequency is dependent on turning gear RPM, are generated by the magnetic pickup as the teeth of the turning gear pass. These pulses are transmitted to the speed circuit. The speed circuit generates a fixed-width filtered pulse which is proportional to turbine speed. For reliability, trip signals are generated only when any 2 of 3 channels sense overspeed. Also built into the speed measuring circuitry is a failure detection system which detects failure of the speed pickup, speed wiring or speed amplifier. Failure detection in 2 of 3 speed channels will also trip the turbine. The overspeed trip signals and failure detection signals operate 2 independent relay trains which in turn operate turbine-mounted solenoid valve fluid dump systems, closing the stop and governor valves. Thus failure of one of the 2 relay trains to operate will not prevent this device from tripping the turbine. Test circuitry is provided to test operation of all components without actually tripping the turbine.

In the steam admission system, any steam path has two valves in series which are controlled by completely independent systems. Furthermore, the high pressure oil system that actuates the steam valves is completely independent of the low pressure lubrication oil. The turbine control and protection system is fail-safe. Any loss of oil pressure or voltage causes closure of the steam valves.

The autostop drain valve is also tripped when any one of the protective trip devices is actuated. The protective devices are all included in a separate assembly, but connected hydraulically to the overspeed trip relay.

Trip of the turbine generator when operating above the permissive P-9 setpoint initiates a reactor trip to prevent excessive reactor coolant temperature and/or pressure.

On each unit, two relays have been connected in parallel with the green open light on each main steam line isolation valve (MSIV). One relay on each valve will trip the autostop trip solenoid on the turbine and the other relay will trip the emergency turbine trip solenoid whenever a steam line isolation valve leaves the full open position.

These trip relays function to reduce the closure shocks and frequency of main steam line stop valve closing by:

1. Causing a sudden turbine trip and cessation of main steam flow whenever either main steam line isolation valve moves away from the wide open position. Therefore, if a valve air piston starts to lose air by air failure, or solenoid valve unlatching, the trip signal rapidly acts and can cause turbine trip even before air pressure is so reduced as to allow "wipe in" closure of the main stop valve.

2. Causing a sudden turbine trip and cessation of rapidly increasing flow in the second steam line, when for some reason the first steam line stop has suddenly closed. This trip circuit then prevents much greater than 100% flows from occurring in the second steam line and the wipe in of the second stop valve under conditions of aggravated stress at abnormally high flows.

Chemistry And Radioactivity

Chemistry control specifications for the steam generators, condensate, and feedwater are listed in Table 10.1-3.

Under normal operating conditions, there are no radioactive contaminants present in the steam and power conversion system unless steam generator tube leaks develop. In this event, monitoring of the steam generator shell side sample points and the air ejector off-gas will detect any contamination. A radioactivity monitor is provided for both steam generator blowdown sample lines. A high activity signal initiates closure of remotely operated stop valves in both the blowdown and sample lines. Refer to Chapter 11 for the radiation monitoring system description. The combined air ejector off-gas discharges through the auxiliary building vent stack. A radioactivity monitor in the off-gas line initiates an alarm in the control room in the event that high activity is present.

Shielding

No radiation shielding is required for the components of the steam and power conversion system. Continuous access to the components of this system is possible during normal conditions, except for the steam generator and flow nozzle located inside the containment.

10.1.3 SYSTEM EVALUATION

Safety Features - Variables Limit Functions

Trips, automatic control actions and alarms will be initiated by deviations of system variables within the steam and power conversion system. The more significant malfunctions or faults which cause trips or automatic actions in the steam and power conversion system are:

Turbine Trips

1. Generator/electrical faults;
2. Low condenser vacuum;
3. Thrust bearing failure;
4. Low lubricating turbine bearing oil pressure;
5. Turbine overspeed;
6. Reactor trip;
7. Manual trip;
8. Loss of both main feedwater pumps via AMSAC;
9. Closure of either the main feedwater regulating valve or feedwater isolation valve in both main feedwater lines via AMSAC;
10. Loss of EH system internal power; and
11. Either steam line isolation valve leaves the full open position.

Transient Effects

A reactor trip from power requires subsequent removal of core decay heat. Immediate decay heat removal requirements are normally satisfied by the steam dump to the condensers. Thereafter, core decay heat can be continuously dissipated via the steam dump to the condenser as feedwater in the steam generator is converted to steam by heat absorption.

In the unlikely event of complete loss of offsite electrical power to the station and concurrent reactor trip, decay heat removal would continue to be assured by the availability of the auxiliary feedwater system, and steam discharge to atmosphere via the main steam safety valves and the atmospheric steam dump valves.

The analysis of the effects of loss of full load on the reactor coolant system is discussed in Section 14.0. Analysis of the effects of partial loss of load on the reactor coolant system is discussed in Section 14.1.10.

Secondary-Primary Interactions

The automatic condenser steam dump system has been included to increase the transient capability of the plant to provide a means for an orderly reactor power reduction in the event the load is suddenly decreased. The time for a return to full power operation is therefore minimized. The condenser steam dump capacity is discussed in Section 10.1.2. Condenser steam dump is initiated by coincidence of a large rapid load change together with a large error signal between T_{avg} (reactor coolant system average temperature) and T_{ref} (program reference average coolant temperature which is based on turbine power) at the new load condition. As the control group is inserted by the reactor control system, reactor power is reduced thereby reducing T_{avg}. The steam dump modulation is proportional to the difference between measured T_{avg} and T_{ref} and is thus reduced as rapidly as the rods are able to reduce core power. The transient is terminated with the plant at equilibrium the new load conditions and there is no further steam dump to the condenser. The transient response to a 50% rapid load reduction would consist of the full condenser steam dump actuated in a few seconds and fully closing in about 10 minutes.

If the condenser heat sink is not available during a turbine trip, excess steam, generated as a result of reactor coolant system sensible and core decay heat, is discharged to the atmosphere.

If the atmospheric steam dump valves should fail to dump steam, the loss of load transient will be accommodated by steam discharge through the main steam safety valves. If a valve would operate to dump steam inadvertently, the result would be a load increase equivalent to a small steam break. In either case, the reactor control and protection system precludes unsafe operation. These protection systems are provided to trip the reactor in the event of a sustained load mismatch between the reactor and turbine.

Normal turbine overspeed protection and the main steam safety valves provide protection for these systems completely independent of any steam dump valve operation.

Following a turbine trip from power levels above the P-9 setpoint, the control system reduces reactor power output immediately by a reactor trip. The steam dump can handle all the steam generated without lifting the main steam safety valves.

In the event of failure of one feedwater pump, the feedwater pump remaining in service will carry approximately 60% of full load feedwater flow. If both main feedwater pumps fail, the turbine will be tripped, and the auxiliary feedwater pumps start automatically. If reactor coolant system conditions reach trip limits, the reactor will trip.

Pressure relief is required at the system design pressure of 1085 psig, and the first main steam safety valve is set to relieve at this pressure. Additional main steam safety valves are set at pressures up to 1105 psig, as allowed by the ASME Code. In addition to the main steam safety valves, one atmospheric steam dump valve is installed for each steam generator which can be manually operated from the control room. The atmospheric steam dump valves are set to open at a pressure slightly below that of the main steam safety valves. The pressure relieving capacity of the main steam safety valves is equal to the steam generation rate at maximum calculated conditions.

Single Failure Analysis

A single failure analysis has been made for all active components of the system which have an emergency function. The analysis, which is presented in Table 10.1-4 shows that the failure or malfunction of any single active component will not reduce the capability of the system to perform its emergency function.

10.1.4 REQUIRED PROCEDURES AND TESTS

The main steam isolation valves, main steam safety valves, atmospheric dump valves, main feedwater isolation valves and main feedwater regulating valves are tested and/or inspected in accordance with the Technical Specifications to ensure proper operation.

The turbine stop and governor valves are tested for proper operation in accordance with the TRM section 3.7.6.

A review of the turbine valve failure-rate data will be conducted at least once every three years to determine if the testing frequency requires modification. A review of the turbine valve failure-rate data will be conducted whenever major changes to the turbine system are made or a significant upward trend in turbine valve failure rate is identified, to determine if the testing frequency requires modification.

10.1.5 REFERENCES

1. NRC SER, “Point Beach Nuclear Plant- Units 1 and 2, Issuance of License Amendments Regarding Extended Power Uprate,” dated May 3, 2011.

2. Westinghouse letter WEP-08-173, Point Beach Units 1 and 2-Westinghouse NSSS/BOP Interface System Evaluations-Steam Generator Blowdown System & Turbine Bypass/ Steam Dump System, dated December 23, 2008. (Accepted per PBNP letter PB-EPU-08-2370)

3. Westinghouse internal letter SEE-111-08-095, Point Beach Units 1 and 2- NSSS/BOP Interface System Evaluations-Steam Generator Blowdown System & Turbine Bypass/ Steam Dump System, dated June 6, 2008. (submitted by Reference 2 above)

4. Screening 2010-0120-01, Engineering Design Changes EC 12042, "Replacement of Unit #2 Steam Generator Main Feedwater Pumps and Motor Sets" & EC 09998 "Replacement of Unit #2 Steam Generator Main Feedwater Pumps Minimum Flow Recirculation System," May 26, 2011.

5. Screening 2010-0147, Engineering Design Changes EC 12052 (2558480), "Feedwater Isolation Valve Addition," dated May 7, 2011.

6. Screening 2010-0002, Engineering Design Change EC 12054, Rev 2, "Feedwater Regulating Valve Upgrade," May 9, 2011.

7. Unit 1 SCR 2011-0153, Engineering Design Change 11954 (258382) "Feedwater Isolation Valve Addition," July 26, 2011.

8. SCR 2009-0189, Engineering Design Changes EC 12041,"Replacement of Unit #1 Steam Generator Main Feedwater Pumps and Motor Sets" and EC 09997, "Replacement of Unit #1 Steam Generator Main Feedwater Pumps Minimum Flow Recirculation System," July 7, 2011.

9. Unit 1 SCR 2010-0001, "EC 258481 (12053) Rev 2 Feedwater Regulating Valve Upgrade Unit 1s," August 25, 2011.

10. SCR 2011-0060-01, CN-CPS-08-20, Rev 3, "Plant Operability Margin to Trip and EOC Coastdown Analysis for Point Beach Units 1 and 2 Extended Power Uprate Program," July 13, 2011.

11. Siemens Letter TL-SPG-FPLE PB 0120, Steam Dump System Arming Setpoint, dated June 8, 2009.

12. Modification Request MR 83-70, "2HB7B-6" Tie Line Between Existing 2HB7A-12" Heating Building Steam Piping and Tuirbine Gland Seal Steam," approve August 7, 1985.

Table 10.1-1 STEAM AND POWER CONVERSION SYSTEM COMPONENT DESIGN PARAMETERS

Turbine-Generator	
Turbine	Three element, tandem-compound four-flow exhaust
Turbine Capacity (KW)	
Maximum calculated @ 1806 MWt	641,600
Generator Rating (KVA)	684,000
Turbine Speed (rpm)	1800
Main Condenser	
Type	Single pass, radial flow, semicylindrical water boxes, deaerating
Number of Sections	2
Rated Capacity (lbs of steam/hr)	3,545,820 @ 999.7 BTU/lb
Circulating Water Pumps	
Type	Single stage, vertical centrifugal
Number	2
Design Capacity (each gpm)	178,000 @ 29.9 ft. TDH
Motor Type	Vertical
Motor Rating (hp)	1750
Condensate Pumps	
Type	Multi-stage, vertical, pit-type, centrifugal
Number	2
Design Capacity (each-gpm)	5700 @ 760 ft. TDH
Motor Type	Vertical
Motor Rating (hp)	1500
Feedwater Pumps	
Type	Single stage, centrifugal
Number	2
Design Capacity (each gpm)	9300 @ 2200 ft. TDH
Motor Type	Horizontal
Motor Rating (hp)	6200

Table 10.1-2 STEAM AND POWER CONVERSION SYSTEM CODE REQUIREMENTS

Steam Pressure Vessels	ASME VIII*
Steam Generator Vessel	ASME III, Class A, tube side**
	ASME III, Class C, shell side***
System Valves, Fittings and Piping	USAS B31.1****

* American Society of Mechanical Engineers, Boiler and Pressure Vessel Code. Section VIII.

** American Society of Mechanical Engineers, Boiler and Pressure Vessel Code. Section III, Nuclear Vessels.

*** The shell side of the steam generator conforms to the requirements of Class A vessels and is so stamped as permitted under the rules of Section III.

**** Code for Pressure Piping.

Table 10.1-3 AVT CONTROL, SECONDARY CHEMISTRY CONTROL GUIDELINES[1]
Sheet 1 of 2

Steam Generator Blowdown Control

Parameter	Power Operation Normal Value	Hot Standby[3] Normal Value	Cold Shutdown (Wet Layup)[2] Normal Value
pH at 25ºC[4]	----	----	9.8 - 10.5
Organic Corrected Cation Conductivity, µS/cm, at 25ºC	≤0.8	≤2.0	----
Sodium, ppb Na	≤20	≤100	≤1000
Chloride, ppb Cl	≤20	≤100	≤1000
Sulfate, ppb SO_4	≤20	≤100	≤1000
Dissolved Oxygen, ppb O_2	----	----	≤100
Oxygen Scavenger[6]	----	----	----
Ammonia[4]	----	----	----
Corrosion Control Additive(s)[5]	----	----	----

(1) These chemistry control guidelines have been formulated to minimize steam generator tube degradation and secondary system corrosion while maintaining operating flexibility. The normal values are based on the current understanding of corrosion behavior, chemical transport, impurity concentrations, materials, and chemical analysis methods; on industry practices; and on plant-specific experience. Because the steam generator is most susceptible to corrosion from impurity ingress while at power, the power operation normal values are the most stringent. In the event the monitored parameters are observed and confirmed to be outside normal operating values, action levels are implemented and corrective actions are executed in accordance with plant procedures.

(2) The steam generator is placed in a cold wet layup condition with chemically treated water whenever practical during outages to minimize surface corrosion. Impurity levels introduced from hideout return during power reduction to shutdown are reduced by feed and bleed, flushing, or drain and refill.

(3) When not at power with the reactor coolant system hot, the steam generator is maintained in the hot standby condition. The steam generator is essentially ready for steaming and power operation while in hot standby. Impurity inventories are reduced prior to proceeding to power by feed and bleed (blowdown and makeup).

(4) Values for these parameters are listed in NP 3.2.3, “Secondary Water Chemistry Monitoring Program.”

(5) The corrosion control additive(s) and values are listed in NP 3.2.3, “Secondary Water Chemistry Monitoring Program.”

(6) The oxygen scavenger additive(s) and values are listed in NP 3.2.3, “Secondary Water Chemistry Monitoring Program.”

Table 10.1-3 AVT CONTROL, SECONDARY CHEMISTRY CONTROL GUIDELINES
Sheet 2 of 2

Feedwater

	Power Operation	Hot Standby	Cold Shutdown (Wet Layup)
pH at 25ºC(1)	---		
Dissolved Oxygen, ppb O_2	≤5	<100(3)	<100(3)
Oxygen Scavenger(2, 5)	---		
Total Iron, ppb	≤5		
Total Copper, ppb	≤1		
Ammonia(1)	---		
Corrosion Control Additive(s)(4)	---		

(1) Values for these parameters are listed in NP 3.2.3, “Secondary Water Chemistry Monitoring Program.”

(2) As measured at the feed pump suction or equivalent feed pump discharge sample point.

(3) As measured at the condensate storage tanks (CST's) or auxiliary feed pump suction.

(4) The corrosion control additive(s) and values are listed in NP 3.2.3, “Secondary Water Chemistry Monitoring Program.”

(5) The oxygen scavenger additive(s) and values are listed in NP 3.2.3, “Secondary Water Chemistry Monitoring Program.”

Condensate

Dissolved Oxygen, ppb O_2	≤10

Table 10.1-4 STEAM AND POWER CONVERSION SYSTEM SINGLE FAILURE ANALYSIS

Component or System	Malfunction	Comments and Consequences
Steam Line Isolation System	Failure of steam line isolation valve to close (following a main steam line rupture)	Each steam line contains an isolation valve and a nonreturn valve in series. Hence, a failure of an isolation (or non-return) valve will not permit the blowdown of more than one steam generator irrespective of the steam line rupture location.
Steam Dump System	Steam dump valve sticks open (following operation of the system resulting from a turbine trip)	The steam dump system is comprised of 8 bypass valves. Hence, one valve passes less than 5% of the steam generator steam flow and there is a reduced potential for a hazard in the form of an uncontrolled plant cool-down if a steam dump valve sticks open.
Feedwater Isolation System	Failure of Feedwater Isolation Valve to close (following a main steam line rupture)	Main feedwater regulating valve closes to stop flow. Two trains of containment fan coolers and spray credited for containment response (Reference Section 14.2.5 C).
	Failure of main feedwater regulating valve to close (following a main steam line rupture)	Feedwater isolation valve closes to stop flow. Feedwater, condensate, and heater drain pumps trip on high containment pressure to stop flow.

Figure 10.1-1 UNITS 1 & 2 MAIN AND REHEAT STEAM FLOW DIAGRAM (Sheet 1)

[redacted]

Figure 10.1-1 UNIT 1 MAIN AND REHEAT STEAM FLOW DIAGRAM (Sheet 2)

[redacted]

Figure 10.1-1 UNIT 1 MAIN AND REHEAT STEAM FLOW DIAGRAM (Sheet 3)

[redacted]

Figure 10.1-1A UNIT 2 MAIN AND REHEAT STEAM FLOW DIAGRAM (Sheet 1)

[redacted]

Figure 10.1-1A UNIT 2 MAIN AND REHEAT STEAM FLOW DIAGRAM (Sheet 2)

[redacted]

Figure 10.1-1A UNIT 2 MAIN AND REHEAT STEAM FLOW DIAGRAM (Sheet 3)

[redacted]

Figure 10.1-2 UNIT 1 CONDENSATE AND FEEDWATER FLOW DIAGRAM (Sheet 1)

[redacted]

Figure 10.1-2 UNIT 1 CONDENSATE AND FEEDWATER FLOW DIAGRAM (Sheet 2)

[redacted]

Figure 10.1-2 UNIT 1 CONDENSATE AND FEEDWATER FLOW DIAGRAM (Sheet 3)

[redacted]

Figure 10.1-2A UNIT 2 CONDENSATE AND FEEDWATER FLOW DIAGRAM (Sheet 1)

[redacted]

Figure 10.1-2A UNIT 2 CONDENSATE AND FEEDWATER FLOW DIAGRAM (Sheet 2)

[redacted]

Figure 10.1-2A UNIT 2 CONDENSATE AND FEEDWATER FLOW DIAGRAM (Sheet 3)

[redacted]

Figure 10.1-3 UNIT 1 EXTRACTION STEAM FLOW DIAGRAM (Sheet 1)

[redacted]

Figure 10.1-3 UNIT 1 EXTRACTION STEAM FLOW DIAGRAM (Sheet 2)

[redacted]

Figure 10.1-3A UNIT 2 EXTRACTION STEAM FLOW DIAGRAM (Sheet 1)

[redacted]

Figure 10.1-3A UNIT 2 EXTRACTION STEAM FLOW DIAGRAM (Sheet 2)

[redacted]

Figure 10.1-4 UNIT 1 FEEDWATER HEATER DRAINS FLOW DIAGRAM (Sheet 1)

[redacted]

Figure 10.1-4 UNIT 1 FEEDWATER HEATER DRAINS FLOW DIAGRAM (Sheet 2)

[redacted]

Figure 10.1-4 UNIT 1 FEEDWATER HEATER DRAINS (Sheet 3)

[redacted]

Figure 10.1-4A UNIT 2 FEEDWATER HEATER DRAINS FLOW DIAGRAM (Sheet 1)

[redacted]

Figure 10.1-4A UNIT 2 FEEDWATER HEATER DRAINS FLOW DIAGRAM (Sheet 2)

[redacted]

Figure 10.1-4A UNIT 2 FEEDWATER HEATER DRAINS FLOW DIAGRAM (Sheet 3)

[redacted]

Figure 10.1-6 UNIT 1 CIRCULATING WATER CONDENSER AIR REMOVAL

[redacted]

Figure 10.1-6A UNIT 2 CIRCULATING WATER CONDENSER AIR REMOVAL

[redacted]

Figure 10.1-6B UNITS 1 & 2 CIRCULATING WATER SYSTEM SCREEN WASH (Sheet 2)

[redacted]

Figure 10.1-7 UNIT 1 FEEDWATER HEATER VENTS AND RELIEFS FLOW DIAGRAM

[redacted]

Figure 10.1-7A UNIT 2 FEEDWATER HEATER VENTS AND FLOW DIAGRAM

[redacted]

Figure 10.1-8 UNIT 1 GLAND STEAM AND DRAINS FLOW DIAGRAM

[redacted]

Figure 10.1-8A UNIT 2 GLAND STEAM AND DRAINS FLOW DIAGRAM

[redacted]

10.2 AUXILIARY FEEDWATER SYSTEM (AF)

Due to required increase in pump capacity for the EPU LAR and the unitization of the AFW system, new 100 % capacity motor-driven AFW Pumps (1(2)P-53) replaced the shared motor-driven AFW Pumps (P-38A/P-38B) as the credited motor-driven pumps (Reference 19). P-38A/B were then renamed Standby Steam Generator (SSG) Feedwater Pumps. The SSG pumps no longer have automatic start circuitry and are only available by manual operator action at Main Control Board C-01 and local control panels N-01 (N-02).

Previous automatic actuation signals to the P-38A/B pumps from safety injection, AMSAC, and steam generator A/B low-low level were removed. The SSG pump start circuits consist solely of manual control switch manipulation between "Normal" and "Override" positions on Main Control Board C-01. If running, the SSG pumps will be stripped by an automatic start signal for 1P-53 or 2P-53 or an automatic or manual SI signal from either unit. This feature is used to control loading on the EDG and 480V buses and to prevent excess flow to a faulted steam generator in a main steam line break or steam generator tube rupture event. To prevent inadvertent starting of an SSG pump while the new MDAFW pumps are operating, restart of a tripped SSG pump requires administrative controls and manual action by the operator.

Service water suction valves AF-4009 for P-38A and AF-4016 for P-38B remain unchanged in the transition to SSG pumps. P-38A AFW discharge valves AF-4023 for Steam Generator (SG) 1HX-1A and valve AF- 4022 for SG 2HX-1A as well as P-38B AFW discharge valves AF-4021 for SG 1HX-1B and valve AF-4020 for SG 2HX-1B have their respective automatic open and close functions removed from their control circuits. All other functionality and terminations remain unchanged in the transition to SSG pumps.

The SSG pumps are normally used during plant startup and shutdown and during hot shutdown or hot standby conditions when chemical additions or small feedwater flow requirements do not warrant the operation of the main feedwater and condensate systems.

NOTE: Unless indicated otherwise, the remaining portion of Section 10.2 applies only to portions of the AFW system credited for safety related functions.

10.2.1 DESIGN BASIS

The Auxiliary Feedwater System consists of one full-capacity MDAFW pump system and one full-capacity TDAFW pump system for each unit to ensure that adequate feedwater is supplied to the steam generators for heat removal under all circumstances, including loss of offsite power and normal heat sink. Feedwater flow can be maintained until power is restored or reactor decay heat removal can be accomplished by other systems. The auxiliary feedwater system is designed as a seismic Class I system and normally takes suction from the condensate storage tanks (CSTs). A backup supply of auxiliary feedwater is provided by automatic or manual switchover to the seismic Class I portion of the service water system (see Figure 10.2-1). The MDAFW pump discharge piping for each unit can be cross-tied by opening normally closed manual valves to feed the SGs on the opposite unit (Reference 16). The MDAFW cross-tie performs a safety-related function to provide pressure boundary and separation between the two pumping systems (Reference 23).

Each auxiliary feedwater pump system is required to supply 275 gpm high-pressure feedwater to the steam generators in order to maintain a water inventory for removal of heat energy from the reactor coolant system by secondary side steam release in the event of inoperability or unavailability of the main feedwater system. Redundant supplies are provided by two 100% capacity pump systems using different sources of power for the pumps and different trains of DC for valve and control power. DC power for the Unit 1 and 2 TDAFW pumping systems are also from different trains. The design capacity of each pump system is set so that the steam generators will not boil dry nor will the primary side relieve fluid through the pressurizer relief or safety valves, following a loss of main feedwater flow with a reactor trip (Reference 16).

The AF system performs the following safety-related functions:

The AF system shall automatically start and deliver adequate AF system flow to maintain adequate steam generator levels during accidents which may result in main steam safety valve opening. Such accidents include; Loss of Normal Feedwater (LONF), FSAR Chapter 14.1.10, and Loss of All AC Power To The Station Auxiliaries (LOAC), FSAR Chapter 14.1.11, events. LONF and LOAC are time-sensitive to AF system start-up.

The AF system shall automatically start and deliver sufficient system flow to maintain adequate steam generator levels during accidents where AF flow is credited to cool down the reactor coolant system to RHR initiation conditions within the limits of the analysis assumptions. Such accidents include; steam generator tube rupture (SGTR), FSAR Chapter 14.2.4, and Rupture of a Steam Pipe (MSLB), FSAR Chapter 14.2.5.

The AF system shall be capable of isolating the AF steam and feedwater supply lines from the ruptured or faulted steam generator following a SGTR or MSLB event. Steam to the TDAFW pump can be isolated by closing the steam supply MOVs or manually tripping the overspeed trip throttle valve. Each AF pumping system has two diverse ways to stop auxiliary feedwater flow when required. Flow from the MDAFW can be stopped by closing the flow control valve (FCV) to the affected steam generator via 120 VAC power or tripping the pump via 125V DC control power. Flow from the TDAFW pump can be isolated by closing the pump's discharge MOV for the affected steam generator using 125V DC control power or by tripping the pump via a diverse 125 VDC supply to the trip throttle valve (Reference 16).

The safety-related portions of the AFW system are designed as Seismic Class I, and are capable of withstanding design basis earthquake accelerations without a loss of system performance capability.

The AF system also performs the following augmented quality functions related to regulatory commitments:

In the event of a station blackout (prolonged loss of offsite and onsite AC power), the AF system is capable of automatically supplying sufficient feedwater to remove decay heat from both units without any reliance on AC power for one hour. This independence from AC power was initially two hours as documented in the NRC safety evaluation dated April 21, 1982 (Reference 8). This was subsequently superseded by the re-licensing of PBNP via acceptance of the Station Blackout Coping Analysis in NRC safety evaluation dated October 3, 1990 (Reference 9), which concluded that PBNP is a one-hour coping plant.

While this subsequent safety evaluation did not explicitly supersede the requirement from NUREG-0737, the submittal of a one-hour coping assessment for a loss of all AC power under the requirements of 10 CFR 50.63 (the station blackout rule) was reviewed and approved by the NRC. The subject is discussed in the Point Beach FSAR, Appendix A.1.

The AF system is credited in the event of a fire and has been evaluated in the at-power analysis (Reference 2). The MDAFW pumps and TDAFW pumps are located in separate fire areas. Power and control cables are routed and associated motor control centers are located to ensure adequate separation of the TDAFW and MDAFW systems (Reference 16).

In the event of an Anticipated Transient Without Scram (ATWS), the AF system shall be capable of automatic actuation by use of equipment that is diverse from the reactor trip system. This is accomplished by the AMSAC system described in FSAR Section 7.4. An AFW pump start delay time of less than or equal to 90 seconds is assumed in the ATWS analysis. This delay time consists of a 30 second AMSAC time delay plus a 60 second AF system pump start response time (Reference 4).

The safety related auxiliary feedwater system has no functional requirements during normal, at power, plant operation. It may be used during plant startup and shutdown and during hot shutdown or hot standby conditions when small feedwater flow requirements do not warrant the operation of the main feedwater and condensate systems.

10.2.2 SYSTEM DESIGN AND OPERATION

The safety related auxiliary feedwater system consists of one electric motor-driven pump and one steam turbine-driven pumps per unit, pump suction and discharge piping, and the controls and instrumentation necessary for operation of the system. Redundancy is provided by utilizing two 100% capacity pumping systems, two different sources of power for the pumps, and two sources of water supply to the pumps. The system is categorized as seismic Class I and is designed to ensure that a single active failure will not obstruct the system function.

The system utilizes a steam turbine-driven pump (1/2P-29) with the steam capable of being supplied from either or both steam generators. This system is capable of supplying 275 gpm combined flow to both steam generators through normally throttled MOVs AF-4000 and AF-4001. The feedwater flowrate from the turbine-driven auxiliary feedwater pump depends on the throttle position of these DC powered MOVs. Check valves are provided to help prevent backflow when the pumps are not in service. The pump drive is a single-stage turbine, capable of quick starts from cold standby and is directly connected to the pump. The turbine is started by opening either one or both of the isolation valves (MS-2019 and MS-2020) between the turbine supply steam header and the main steam lines upstream of the main steam isolation valves. These valves are DC powered motor operated stop check valves which prevent reverse flow between the steam generators. The turbine is cooled via AFW, drawn through the pump via a first stage tap connection, and returned to the pump suction. The pump does not require cooling water.

Alternate DC power is provided for the manual trip capability of the TDAFW pump by means of its redundant trip control switch 1(2) MS-2082S-CS located in the main control room. The switch provides a means of transferring the overspeed trip valve 1(2) MS-2082 solenoid power from its normal supply, battery D105(D106), to its alternate supply, battery D05 (D06), to manually trip the pump from either power supply in case a single failure prevents stopping flow by closing the steam generator inlet isolation MOV(s) or the pump steam inlet MOVs (Reference 16).

The electric-motor driven auxiliary feedwater pumps (1/2P-53) are 350 horsepower, 4160 volt and powered from safeguards buses 1A-06 and 2A-05 for Unit 1 and 2 respectively. The pumps are designed to supply a total of 275 gpm to their associated units' steam generators through fail-open discharge flow control valves (FCVs) 1(2) AF-4074A and 1(2) AF-4074B. The FCVs will maintain flow approximately split between the two SGs regardless of SG pressure. This limits the flow to a ruptured SG in a main steam line break (MSLB) accident, thereby limiting the uncontrolled cooldown. Cavitating venturis (1/2 RO 4088A(B)) are installed downstream of each of the flow control valves. The cavitating venturis are designed to prevent excessive flow to a faulted steam generator in the event of a failure of the associated flow control loop. During a steam generator tube rupture the venturis allow feeding up to approximately 230 gpm to the intact steam generator for decay heat removal (Reference 20 and Reference 21).

The MDAFW pumps have a shaft mounted cooling fan, eliminating the need for any external fluid to provide shaft or seal cooling, or motor cooling. The pump motors are not environmentally qualified (EQ) because they are not needed for a large break LOCA and are located in a mild environment for small break LOCA, SG tube rupture, MSLB, loss of normal feedwater and loss of AC events (Reference 16).

The water supply source for the auxiliary feedwater system is redundant. The normal source is by gravity feed from two nominal capacity 45,000 gallon condensate storage tanks while the safety-related seismic Class I (Reference 3) supply is taken from the plant service water system whose pumps are powered from the diesel generators if station power is lost. The turbine driven and motor driven pumps take suction from the CSTs through separate headers (Reference 16).

It is possible that a loss of normal feedwater initiated by a seismic event could also result in the interruption of the normal source of auxiliary feedwater from the condensate storage tanks because the condensate storage tanks are not classified as seismic Class I. The plant operators would be alerted to this problem by receipt of low suction pressure alarms on the auxiliary feedwater pumps. Seperate and redundant level instrumentation including both alarms and indication for both condensate storage tanks is available in the control room (Reference 8 and Reference 13). Missile shielding is provided on certain AFW pump suction piping from the CST to ensure sufficient water volume for AFW pump suction prior to low suction pressure trip (Reference 12).

Automatic switchover of AFW pump suction from the CSTs to Service Water is initiated by low pump suction pressure to restore suction pressure prior to consumption of the available condensate water in the protected section of suction piping upstream of the service water supply connection. The low pump suction pressure circuit includes a time delay to ensure that the suction transfer will not be inadvertently initiated due to temporary low suction pressure that occurs during normal pump start-up transients.

The time delay to initiate tripping of the operating AFW pumps on low suction pressure has been selected to ensure the pumps are secured prior to depletion of the condensate inventory in the protected section of suction piping if the SW transfer were to fail. Adequate safety margin is provided by making allowance for the maximum opening time of the SW supply valve, uncertainty in the timing circuits for both initiation of suction transfer and AFW pump trip, and the time for the pump trip time delay relay to reset after full opening of the SW supply valve and associated restoration of suction pressure. Therefore, adequate margin will remain between the maximum time to restore suction pressure and the minimum time for initiation of the AFW pump trip, and an inadvertent AFW pump trip would be unlikely with SW available to the suction of the pumps (Reference 16).

The AFW pump suction also automatically transfers to service water upon low-low-low CST level. This circuitry is not credited in the safety analyses. See Sections 7.3.2.2.h and 7.4.3.

The TDAFW pump has a single minimum flow recirculation line, isolated by a fail-closed AOV (1/2AF-4002) and the MDAFW pump has two parallel minimum flow recirculation lines, each isolated by a fail-closed AOV (1/2 AF 4073 A(B)). The recirculation lines direct recirculation flow to the CSTs. Each of the MDAFW recirculation lines is designed to ensure the minimum flow rate to protect the pump is provided in the event of a failure of one of the recirculation valves to open. The minimum flow recirculation AOVs have a safety-related function to close to ensure the required AFW flow is not diverted away from the steam generators. These valves also have a safety-related function to open to ensure that a minimum flow is maintained through the pumps to prevent damage due to hydraulic instabilities or increased temperature (Reference 16).

Safety-related backup pneumatic systems are provided for the system's air operated valves. The pneumatic systems permit operation at hot shutdown for at least four hours followed by cooldown to the RHR cut-in temperature from the control room with only safety grade equipment, assuming the worst-case single failure in accordance with Branch Technical Position (BTP) 5-4. Although designed for 24 hours of operation, these backup air supplies are only credited for four hours of minimum recirculation AOV operability if instrument air is lost. Manual gags permit operators to open the recirculation AOVs and throttle the MDAFW pump flow control valves consistent with decay heat requirements prior to depletion of the backup pneumatic supply (Reference 16 and Reference 17).

Flow- restricting orifices (1/2RO-4003, 1/2RO-4075 A(B)) installed in the pump recirculation lines facilitate pressure reduction for pumping back to the CSTs (at atmospheric pressure). These orifices have a safety function to restrict the flow to an appropriate value to ensure pump operability. A recirculation flow larger than what is assumed in the AFW pump coastdown analysis for a seismic-induced loss of CSTs (Reference 7 and Reference 18) could result in one or both units having no auxiliary feedwater capability. Additionally, a recirculation flow that is too high could reduce forward flow to a point that the recirculation AOVs may not shut, and the pump will not be capable of delivering the required 275 gpm flow to the steam generators. These orifices also have a safety function to pass the minimum flow required to prevent pump damage. The orifices are sized so as to not be susceptible to clogging by service water debris. This debris size is limited by the size of the service water strainers (Reference 10, Reference 11 and Reference 16).

The minimum flow recirculation lines are safety-related up to the flow restricting orifices, but are considered augmented-quality downstream of the orifices to the CSTs, even though the recirculation lines have a safety function to provide a recirculation flowpath as described above. Operability of the AFW pumps is dependent upon a recirculation flowpath being available. The augmented-quality classification is appropriate since failure could result in a loss of water from the CST that is essential to mitigate station blackout (SBO).

During normal plant operations, the auxiliary feedwater system is maintained in a standby condition ready to be placed in operation automatically when conditions require. The turbine-driven and motor-driven auxiliary feedwater pumps are automatically started on receipt of any of the following signals (Reference 16):

1. Low-low water level in either steam generator.

2. Loss of voltage on both 4.16 kv buses supplying the main feedwater pump motors.

3. Trip or shutdown of both feedwater pumps or closure of either a feedwater isolation valve or a feedwater regulating valve in both main feedwater lines. These signals are processed through AMSAC at reactor power levels above 40% (Reference Section 7.4).

4. Automatic or manual safety injection. In conjunction with a loss of AC the MDAFW pump start is sequenced a nominal 32.5 seconds after EDG breaker closure. The MDAFW pump will also start anytime the corresponding 4.16 kv bus is islanded on EDG power, but will run on minimum recirculation until a valid AFW start signal is initiated.

The steam generator blowdown isolation valves are configured to close automatically based upon start of the associated unit's steam driven or motor-driven auxiliary feedwater pump. A bypass switch allows defeating this function for testing and normal operation of the auxiliary feedwater pump.

Operator action is required to maintain proper steam generator levels and control auxiliary feedwater flow. In the event that both auxiliary feedwater pumps start and run as designed, the initial auxiliary feedwater flow will be significantly greater than the design basis flow. Auxiliary feedwater pump flow and direct flow indication for each steam generator is provided in the control room. Flow indication is also available locally at the discharge of each motor-driven pump. Auxiliary feedwater flow instrumentation is powered from highly reliable battery backed Class 1E power sources. Alarms are available in the control room to indicate that the automatic initiation of the auxiliary feedwater system is disabled (Reference 14).

Both the MDAFW pump and TDAFW pump have local control stations located near the pumps, so that auxiliary feedwater can be supplied to the steam generators from outside the control room. Local control panels 1(2)N-05 are installed just outside of the MDAFW pump rooms and provide controls for starting and stopping the MDAFW pumps. Local control panels 1(2) RK-38 and 1(2) C-205 are located in the vicinity of the TDAFW pumps and include steam generator level indication for local control of AFW flow. Operators for the steam supply valves to the TDAFW pump, steam generator flow control valves and minimum recirculation valves are provided with hand wheels to allow local manual positioning as necessary (Reference 16).

10.2.3 SYSTEM EVALUATION

In the event of complete loss of offsite electrical power to the station, decay heat removal would continue to be assured for each unit by the availability of either the turbine-driven auxiliary feedwater pump or the motor-driven auxiliary feedwater pump, and discharge to the atmosphere via the main steam safety valves or atmospheric relief valves. Either AFW pump is capable of supplying sufficient feedwater for removal of decay heat from a unit operating at 100.6% of 1806 MWt Core Power (includes 6 MWt pump heat). In this case, feedwater is available from the condensate storage tanks by gravity feed to the auxiliary feedwater pumps. When the water in the condensate storage tanks is depleted, suction for the pumps automatically shifts to the service water system to provide makeup water from the lake for an indefinite time period.

During a Station Blackout (SBO) event, only the turbine-driven pumps would be available for decay heat removal. The turbine-driven pumps are capable of supplying feedwater to the steam generators without an AC power source. Each of the two steam supply valves and each of the two auxiliary feedwater discharge valves are powered from diverse sources of vital 125V DC, i.e., two different buses on the same DC train. The Technical Specification minimum amount of water in the condensate storage tanks provides adequate makeup to the steam generators to maintain each unit in a hot shutdown condition for at least one hour concurrent with a loss of all AC power. Further information on the SBO event is provided in Appendix A.1 (Reference 1).

In order to meet the design basis, the Loss of Normal Feedwater (Section 14.1.10) and Loss of All AC Power to Station Auxiliaries (Section 14.1.11) accident analyses assume that the auxiliary feedwater system provides 275 gpm of flow split between two steam generators. The Loss of Normal Feedwater analysis assumes flow starts within 30 seconds following receipt of a low-low steam generator water level setpoint signal and reaches 100% within 120 seconds. The Loss of AC Power to Station Auxiliaries analysis assumes flow starts within 60 seconds following receipt of a low-low steam generator water level setpoint signal and reaches 100% within 150 seconds. These minimum parameters are met or exceeded by system design and verified by required testing (see Section 10.2.4).

The loss of main feedwater due to a seismic/tornado event (Reference 7) is not equivalent to the Loss of Normal Feedwater (LONF) and Loss of All AC Power to Station Auxiliaries (LOAC) events discussed above. The purpose of the seismic/tornado event analysis is to ensure the AFW pumps are not damaged by low suction pressure resulting from damage to the suction supply piping from the CSTs. In the case of the LONF/LOAC analyses, conservative initial conditions and assumptions are used to ensure that a bounding analysis results. These conservative conditions and assumptions include conservative decay heat rates, credit for only 275 gpm of AFW flow, no credit for the automatic reactor trip on steam flow / feedflow mismatch coincident with a low steam generator level and no credit for a manual reactor trip.

The two other accident analyses which assume auxiliary feedwater system operation are Steam Generator Tube Rupture (Section 14.2.4) and Rupture of a Steam Pipe (Section 14.2.5). For the Steam Generator Tube Rupture analysis auxiliary feedwater is isolated to the affected steam generator and used for RCS cooldown using the unaffected steam generator. The core power and reactor coolant system transient portion of the Rupture of a Steam Pipe analysis assumes a conservatively high auxiliary feedwater flow rate to the affected steam generator that continues for the duration of the transient. The containment response portion of the Rupture of a Steam Pipe analysis assumes auxiliary feedwater flow is manually realigned to prevent further water addition to the faulted steam generator.

Although the auxiliary feedwater system may be initiated during a Small Break LOCA (Section 14.3.1) or a Loss of External Electrical Load (Section 14.1.9), the events have been analyzed with no credit for auxiliary feedwater.

The system is categorized primarily as safety related, Seismic Class I and is designed to ensure that a single active failure will not adversely affect the reliability or function of the system. The

AFW system is designed so a single active failure will not disable more than one pump system in each unit. Each of the two AFW pump systems (i.e., a TDAFW pump and a MDAFW pump) in each unit has some shared discharge piping with instrumentation and controls necessary for operation of the pump system. The two MDAFW pumps (one per unit) share a CST suction header. The two TDAFW pumps (one per unit) share the second CST suction header.

A system level Failure Modes and Effects Analysis for the AFW System has been performed and the results are shown in Table 10.2-1. A component level Failure Modes and Effects Analysis for the new components installed in the EPU AFW Margin Improvement Modification was also performed and verified that no individual component (or connection of system components) results in a common mode failure between redundant pump systems.

10.2.4 REQUIRED PROCEDURES AND TESTS

The AF system components are tested and inspected in accordance with Technical Specification 3.7.5 surveillance criteria and surveillance frequencies by the Surveillance Frequency Control Program (Reference 22). Testing verifies motor-driven pump operability, turbine-driven pump operability including a cold start and operability of all required automatic valves. Control circuits, starting logic, and indicators are verified operable by their respective functional test.

Procedures provide guidance for recognizing steam binding of the AFW pumps and for restoring the AFW system to operable status should steam binding occur. The AFW pump discharge piping temperature is monitored shiftly for temperatures in excess of ambient which may be indicative of potential steam binding of an AFW pump (Reference 15).

Isolation valves for the MDAFW and TDAFW pump discharge flow transmitters and the steam generator flow transmitters are locked per the Auxiliary Feedwater valve lineup checklists which require independent operator verification (Reference 13).

10.2.5 Generic Letter 81-14

Generic Letter 81-14, “Seismic Qualification of Auxiliary Feedwater Systems,” was issued to evaluate the seismic qualifications of AFW systems and to correct deficiencies, where practical, such as to provide reasonable assurance that the AFW system is able to function following the occurrence of earthquakes up to and including the design Safe Shutdown Earthquake (SSE). In response to GL 81-14, PBNP provided existing design information, performed additional evaluations, and performed plant modifications to correct identified deficiencies.

NOTE: Check valves 1/2AF-191, manual valves 1/2AF-190 and the automatic suction transfer feature mentioned in the following paragraph were installed later by the AFW capacity upgrade modification for EPU.

The AFW system pumps, motors, safety related piping, valves and actuators, power supplies, initiation and control systems are all qualified to withstand a SSE. The condensate storage tank (CST), which is the primary water source of the AFW system, is not seismically qualified. The Service Water system is the safety related, seismic Class I water source for the AFW system. Protection of the Service Water system source from failure of non-seismic branch piping in the supply from the CST, is provided by a safety related, seismically qualified check valve

(1/2AF-0111, AF-0112, AF-0113, and 1/2AF-191) in the CST supply piping to the pump suctions. A normally open, seismically qualified manual valve in series with the check valve (1AF-0026, 2AF-0064, AF-0039, AF-0052, and 1/2-AF-190) provides for additional isolation capabilities. The AFW pump low suction pressure trip and automatic transfer to service water is described in Section 10.2.2. Flooding concerns related to postulated CST failure during a seismic event are discussed in Appendix A.7 (Reference 5).

The major portions of the AFW system reside within seismic Class I structures. Portions of the steam supply lines to the turbine driven AFW pumps run through the facades and portions of the PAB steel frame superstructure. Neither the facades, nor the PAB steel frame superstructures, are seismic Class I structures (Reference 5).

The facade structures were designed for loads which can be reasonably expected to envelope the SSE loads. The auxiliary building central superstructure was analyzed for seismic loads and found capable of withstanding an SSE. At least three sides of the PAB north/south wing superstructures have been analyzed for SSE or designed for loads which can be reasonably expected to envelope SSE loads. However, even if the wing superstructures would not withstand an SSE, at least one steam supply line to the turbine driven AFW pump for each unit is routed through structures capable of withstanding SSE loads. Should the steam supply line in the north/south PAB wing be lost, the failed line can be isolated from the control room by closing the associated steam supply motor operated valve which is located in the seismic Class I portion of the PAB. Further, there is no loss of available steam to the surviving supply lines considering loss of main steam lines located in the north/south PAB wings since the main steam isolation valves (MSIV) are located upstream in the facade structures (Reference 5).

Portions of the AFW system are located in the turbine building. The turbine building is not a seismic Class I structure but was seismically analyzed during original design and found capable of withstanding SSE loads (Reference 5).

The NRC concluded that the AFW system design provides reasonable assurance that the AFW system will perform its required safety function following a SSE (Reference 6).

10.2.6 REFERENCES

1. FSAR Appendix A.1, Station Blackout.
2. NFPA 805 Fire Protection Program Design Document (FPPDD).
3. NRC Safety Evaluation "Safety Evaluation on the Resolution of Unresolved Safety Issue A-46 at Point Beach Nuclear Plant Units 1 and 2," Enclosure Page 3 of 10, dated July 7, 1998.
4. NRC Safety Evaluation "ATWS RULE (10 CFR 50.62)," August 4, 1988.
5. Wisconsin Electric Letter to the NRC dated April 26, 1985, "Final Resolution of Generic Letter 81-14 Seismic Qualification of Auxiliary Feedwater System Point Beach Nuclear Plant, Units 1 and 2."
6. NRC Safety Evaluation, "Seismic Qualification of the Auxiliary Feedwater System at Point Beach Nuclear Plant, Units 1 and 2." dated September 16, 1986.

7. Calculation 97-0215, “Water Volume Swept by all Four AFW Pumps Following a Seismic/ Tornado Affecting Both Units.”

8. NRC Safety Evaluation, “NUREG-0737 Item II.E.1.1, Auxiliary Feed Water System Evaluation for Point Beach Nuclear Plant Units 1 and 2,” dated April 21, 1982.

9. NRC Safety Evaluation, “Safety Evaluation of the Point Beach Response to the Station Blackout Rule,” dated October 3, 1990.

10. NMC Letter to NRC dated January 12, 2004, “Reply to Notice of Violation EA-03-057 NRC Inspection Report No. 50-266/02-15 (DRP); 50-301/02-15 (DRP).”

11. NMC Safety Evaluation SE 2003-001, dated October 1, 2003, “Crediting of Auxiliary Feedwater Pump Minimum Flow Recirculation Line Flow Restricting Orifices Installed by MR 02-039*A/B/C/D and OPR000031 Compensatory Action Removal.”

12. LER 266/97-031-00, “Non-conservative Setpoint for Auxiliary Feedwater Pump Low Suction Pressure Trip,” July 21, 1997

13. NRC Safety Evaluation, “Point Beach Nuclear Plant, Units 1 and 2 Implementations of Recommendations for Auxiliary Feedwater Systems,” dated January 27, 1981.

14. NRC Safety Evaluation, “NUREG-0737 Item II.E.1.2 Auxiliary Feedwater Automatic Initiation and Flow Indication,” dated May 3, 1982.

15. NRC letter to C. W. Fay, “Response To Generic Letter 88-03,” dated April 12, 1988.

16. NRC Safety Evaluation, “Point Beach Nuclear Plant Units 1 and 2-Issuance of License Amendments Re: Auxiliary Feedwater System Modification,” dated March 25, 2011.

17. NRC Letter NRC 2009-0116, “License Amendment Request 261, Extended Power Uprate, Response to request for Additional Information, dated November 21, 2009.

18. Calculation 2009-06582, Rev 0, “Available Water Volume of Piping in the Protected Portion of Motor Driven Auxiliary Feedwater Pump Suction,” dated May 17, 2011.

19. Engineering Change (EC) 259835, Transition to Replacement MDAFW Pump Train.

20. NextEra Energy letter, NRC 2011-0086, “Clarification/Comments on NRC Safety Evaluation Report Amendment Nos. 238 (Unit 1) and 242 (Unit 2) Auxiliary Feedwater System Modification,” dated September 16, 2011.

21. NRC Letter to NextEra Energy, “Point Beach Nuclear Plant, Units 1 and 2 - NRC Staff Response to Clarification/Comments Related to the Safety Evaluation Report Associated with the Auxiliary Feedwater System Modification License Amendment,” dated December 6, 2011.

22. NRC Safety Evaluation, “Point Beach Nuclear Plant Units 1 and 2 - Issuance of Amendments Regarding Relocation of Surveillance Frequencies to Licensee Control (TAC NOS. MF4379 and MF4380),” dated July 28, 2015.

23. AR 02073664, “AFW Cross-tie Piping Evaluation,” dated September 14, 2015.

Table 10.2-1 AFW SYSTEM LEVEL FAILURE MODES AND EFFECTS ANALYSIS

Component	Failure Mode	Effect
Isolation valve for AFW safety related suction supply	Fails to open	Two AFW pumps provided; either one of the two AFW pump systems provide the required feedwater flow to remove sufficient decay heat.
Auxiliary feedwater pump	Failure to start	Two AFW pumps provided; either one of the two AFW pumps provide the required feedwater flow to remove sufficient decay heat.
Auxiliary feedwater pump	Failure to trip on low suction pressure	Two AFW pumps provided; each AFW pump is provided with low suction pressure protection; separate suction supply headers for two pumps; either one of the two AFW pumps provide the required feedwater flow to remove sufficient decay heat.
MDAFW Pump Recirculation Valve	Fails to open	Two recirculation paths provided per MDAFW pump; either recirculation path has sufficient capacity to support short term pump operation.
MDAFW Pump Recirculation Valve	Fails to close	Two AFW pumps provided; either one of the two AFW pump systems provide the required feedwater flow to remove sufficient decay heat.
MDAFW pump discharge control valve on either of the steam generator supply lines	Fails to control flow	Redundant flow path from TDAFW pump is available; either one of the two AFW pump systems provide the required feedwater flow to remove sufficient decay heat.
MDAFW pump discharge control valve on line leading to faulted steam generator	Fails to close	Operator to trip pump; two AFW pumping systems provided; either one of the two AFW pump systems provide the required feedwater flow to remove sufficient decay heat.
TDAFW Pump Recirculation Valve	Fails to open	Two AFW pumps provided; either one of the two AFW pump systems provide the required feedwater flow to remove sufficient decay heat.
TDAFW Pump Recirculation Valve	Fails to close	Two AFW pumps provided; either one of the two AFW pump systems provide the required feedwater flow to remove sufficient decay heat.
TDAFW pump discharge throttle valve on line leading to faulted steam generator	Fails to close	Operator to trip pump; two AFW pumps provided; either one of the two AFW pump systems provide the required feedwater flow to remove sufficient decay heat.

Figure 10.2-1 UNITS 1 & 2 AUXILIARY FEEDWATER SYSTEM FLOW DIAGRAM (Sheet 1)

[redacted]

Figure 10.2-1 UNITS 1 & 2 AUXILIARY FEEDWATER SYSTEM FLOW DIAGRAM (Sheet 2)

[redacted]

Figure 10.2-1 UNIT 1 AUXILIARY FEEDWATER SYSTEM FLOW DIAGRAM (Sheet 3)

[redacted]

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11.0 WASTE DISPOSAL SYSTEMS AND RADIATION PROTECTION

Liquid, gaseous, and solid waste disposal facilities are designed so that discharge of effluents and off-site shipments are in accordance with applicable governmental regulations. Measures provided for the purpose of keeping releases of radioactive materials to unrestricted areas during normal reactor operations, including expected operational occurrences, as low as reasonably achievable are presented in Section 11.1, Section 11.2, and Section 11.3 to this document.

The waste disposal system collects and processes all potentially radioactive reactor plant wastes for disposal within limitations established by applicable governmental regulations. The waste disposal system includes the Waste Liquid (WL), Waste Gas (WG), and Waste Solid (WS) Systems. The waste disposal system outside containment is common to both units. Liquid and gaseous wastes are sampled and analyzed to determine the quantity of radioactivity, with an isotopic breakdown, if necessary. Depending on the results of the analysis, these wastes are processed further as required.

Liquid and gaseous wastes are released under controlled conditions. Radiation monitors are provided to maintain surveillance over the release operation, and a permanent record of activity releases is provided by radiochemical analysis of known quantities of waste. The system is capable of processing all wastes generated during continuous operation of the primary system assuming that fission products escape to the reactor coolant by diffusion through defects in the cladding of l% of the fuel rods.

The system is primarily controlled from a central panel in the auxiliary building. However, some equipment is provided with local control panels. Malfunction of the system is alarmed in the auxiliary building, and annunciated in the control room. All system equipment is located in or near the auxiliary building, except for the reactor coolant drain tanks which are located in the reactor containments. The blowdown evaporator, which is located in a separate building in the Unit 2 facade, has been abandoned in place (Reference 2).

The waste disposal system obtains cooling water from the Unit 2 Component Cooling System. This cooling supply is automatically isolated by a Unit 2 Containment Isolation. Loss of the cooling supply will cause an automatic shutdown of the waste disposal system equipment that could be damaged by a loss of cooling.

11.0.1 REFERENCE

1. FPL Energy Point Beach Letter to NRC, NRC 2009-0030, "License Amendment Request 261 Extended Power Uprate," dated April 7, 2009.

2. EC 283847, Abandonment of the Blowdown Evaporator.

Table 11.0-1 WASTE DISPOSAL QUANTITIES

Annual liquid discharge	
Volume[1]	124.1E06 gal
Activity	See Table 11.1-3 for estimate
Annual gaseous discharge	
Activity	See Table 11.2-2 for estimate
Annual solids prepared for burial shipment	
Volume, not compacted[1]	12,337 ft^3
Activity[1]	92 curies

(1.) Based on the average annual values for both units during the 2002-2006 time period (Reference 1).

Table 11.0-2 WASTE DISPOSAL SYSTEM COMPONENT SUMMARY DATA
(Also See Table 11.1-1 and Table 11.2-1)

Tanks	Quantity	Type	Volume	Design Pressure	Design Temp	Material(1)
Reactor Coolant Drain (per unit)	1	Horiz	350 gal	25 psig	267	ss
Laundry & Hot Shower	1*	Vert	600 gal	Atm	180	ss
Chemical Drain	1*	Vert	600 gal	Atm	180	ss
Sump Tank	1*	Vert	600 gal	Atm	180	ss
Waste Holdup	1*	Horiz	21,444 gal	5 psig	200	ss
Waste Condensate	2*	Vert	1000 gal	Atm	180	ss
Reagent Tank	1*	Vert	6 gal	150 psig	250	ss

Pumps	Quantity	Type	Flow gpm	Head ft	Design Pressure	Design Temp	Material(1)
Reactor Coolant Drain (A) (per unit)	1	Horiz cent canned	50	175	150	267	ss
Reactor Coolant Drain (B) (per unit)	1	Horiz cent canned	150	175	150	267	ss
Chemical Drain	1*	Horiz cent(2)	20	100	150	150	ss
Laundry	1*	Horiz cent(2)	20	100	150	150	ss
Sump Tank	2*	Horiz cent(2)	20	100	150	150	ss
Waste Evaporator Feed	1*	Horiz cent(2)	20	100	150	150	ss
Waste Condensate	2*	Horiz cent(2)	20	100	150	150	ss

(1) Material contacting fluid
(2) Mechanical seal provided
* Shared by Units 1 and 2

11.1 LIQUID WASTE MANAGEMENT SYSTEM (WL)

The WL System collects, processes, and prepares for disposal potentially radioactive liquid wastes produced as a result of reactor operation.

11.1.1 DESIGN BASIS

The facility design shall include those means necessary to maintain control over the plant radioactive liquid effluents. Appropriate holdup capacity shall be provided for retention of liquid effluents, particularly where unfavorable environmental conditions can be expected to require operational limitations upon the release of radioactive effluents to the environment. In all cases, the design for radioactivity control must be justified on the basis of 10 CFR 20 requirements, for both normal operations and for any transient situation that might reasonably be anticipated to occur (GDC 70). A controlled release of liquid waste from the waste disposal system requires that at least two valves be manually opened, of which one of these valves is normally locked shut. In addition, a discharge control valve is provided which is designed to trip shut on an effluent high radioactivity signal from the discharge radiation monitor, thus preventing a release in excess of calculated amounts.

Radioactive fluids entering the waste disposal system are processed or collected in tanks until determination of subsequent treatment can be made. They are sampled and analyzed to determine the quantity of radioactivity, with an isotopic breakdown if necessary. Liquid wastes are processed as required and then released under controlled conditions. The system design and operation are directed toward minimizing releases to unrestricted areas. Discharge streams are appropriately monitored and safety features are incorporated to preclude releases in excess of the limits of 10 CFR 20.

11.1.2 SYSTEM DESIGN AND OPERATION

During normal plant operation, the waste disposal system processes liquids from the following sources:

1. Equipment drains, vents, and leaks;
2. Chemical laboratory drains;
3. Radioactive laundry and hot shower drains;
4. Decontamination area drains;
5. Chemical and Volume Control System (CVCS);
6. Sampling system drains and local sample sinks;
7. Normal letdown;
8. Steam generator blowdown (if required by radioactivity content);
9. Floor drains from the controlled areas of the plant; and
10. Liquids used to transfer solid radwaste.
11. Steam Generator Storage Facility sump (if required by radioactivity content)
12. Warehouse 7 sump (if required by radioactivity content)

The system also collects and transfers liquids from the following sources directly to the CVCS, to the -19' 3" auxiliary building sump, or back to the refueling water storage tank (depending on fluid content) for processing:

1. Pressurizer relief tank;
2. Reactor coolant pump secondary seals;
3. Excess letdown (during startup);
4. Accumulators;
5. Valve and reactor vessel flange leakoffs; and
6. Refueling canal drains.

These liquids flow to the reactor coolant drain tank and are discharged either directly to the CVCS holdup tanks or to the -19' 3" auxiliary building sump by either of the two reactor coolant drain tank pumps which are operated to control level in the tank. These pumps also may be aligned to return water from the refueling canal and lower cavity back to the refueling water storage tank. There is one reactor coolant drain tank inside each containment with the two reactor coolant drain tank pumps located outside each containment.

Where possible, other waste liquids drain to the waste holdup tank by gravity flow. Other waste liquids drain to the sump tank and are discharged to the waste holdup tank by pumps operated to control level in the tank.

Laundry and hot shower waste is pumped from the laundry and hot shower tank to the waste holdup tank via the laundry pump for processing with other waste liquids. Facilities are provided for discharging low-level waste from the waste holdup tank.

Liquids requiring cleanup before release are processed in batches by a filtration/demineralization system. The processed liquid is routed to one of the two waste distillate tanks. When one tank is filled, it is isolated and sampled for analysis while the second tank is in service. If analysis confirms that the activity level is suitable for discharge, the processed liquid is pumped through a flow meter and a radiation monitor to the service water discharge header. Exhausted filtration and demineralization media from this system is dewatered and packaged for shipping.

All routine liquid radioactive releases are made from waste disposal system distillate tanks or from CVCS monitor tanks. Prior to release, samples of the tank contents are taken and are analyzed for radioactivity by chemistry personnel. Results of analysis, waste liquid volume, dilution flow available, discharge rate, and total activities are recorded on a waste discharge permit. Administrative controls require comparison of analysis results with allowable limits by chemistry personnel and an authorizing signature of an operations group supervisor prior to initiation of waste liquid release. Although the radiochemical analysis forms the basis for recording activity releases, the radiation monitoring provides surveillance over the operation by closing the discharge valve if the liquid activity level exceeds a preset value.

Two blowdown vent condensers, one for each steam generator blowdown tank, condense the steam which would otherwise leave the tank vents. The condensers operate to maintain a pressure of one atmosphere in the tank and to return the condensate from flashed steam back to the tank. The vent from these condensers is piped to the plant vent header. Steam generator chemistry treatment is all-volatile chemistry (AVT). Heat recovery exchangers for the steam generator blowdown allows for heat recovery, and in the event of primary to secondary leakage, cooled blowdown from the affected steam generator can be routed to the Waste Holdup Tank for processing by the filtration/demineralization system. Steam generator blowdown rates routed to the Waste Holdup Tank are limited to ≤ 35 gpm and 120°F.

The performance of the filtration and demineralization media in the filtration/demineralization system is monitored through periodic sampling of the process effluent stream. Filtration and demineralization media are changed out when required, based on either the level of contaminants in the effluent stream or on a maximum activity level consistent with ALARA exposure while processing spent media. Exhausted filtration and demineralization media is dewatered and packaged for shipment off-site.

When miscellaneous waste liquids are processed, batch control of both the processed liquid and bottoms is exercised. If necessary, processed liquid can be returned for reprocessing.

The following components are used in the Waste Liquid System. Additional component detail is provided in Table 11.0-2 and Table 11.1-1:

Laundry and Hot Shower Tank - One stainless steel tank collects liquid wastes originating from the laundry and hot shower. When the tank has been filled, its contents can be analyzed for gross beta-gamma activity. The tank contents are pumped to the waste holdup tank.

Chemical Drain Tank - The chemical drain tank is stainless steel and collects drainage from the chemistry laboratory. The tank contents are pumped to the waste holdup tank. A gross beta-gamma activity analysis can be obtained from the chemical drain tank to determine the radioactivity level.

(The above two tanks may be cross-connected for operational flexibility.)

Reactor Coolant Drain Tanks - The reactor coolant drain tanks are right circular cylinders with spherically dished heads. The tanks, which are all welded stainless steel, serve as a drain collecting point for the reactor coolant systems and other equipment located inside the reactor containments. The tank contents can be discharged to the CVCS holdup tanks, to the -19' 3" auxiliary building sump, or to the refueling water storage tanks.

Waste Holdup Tank - The waste holdup tank receives radioactive liquids from the chemical and volume control system, sump tank, chemical drain tank, -19' 3" auxiliary building sump, intermediate and operating floor drains, laundry and hot shower tank, and optionally either units steam generator(s). The tank is of welded stainless steel construction. The tank contents may be drained to the sump tank or pumped to the filtration/demineralization system.

Sump Tank and Pumps - The sump tank serves as a collecting point for waste discharged to the ground floor drain header. Two horizontal centrifugal sump pumps drain this tank to the waste holdup tank. All wetted parts of the pumps are stainless steel. The tank is all welded stainless steel.

Filtration/Demineralization System - The filtration/demineralization system is the primary means of processing radioactive liquid waste effluents. Through the use of deep bed filtration vessels and demineralization vessels, the filtration/demineralization system is designed to remove suspended particulate and ionic impurities from radioactive liquid waste. The system is common to both units. The major components include two stainless steel deep bed filtration vessels, four stainless steel demineralization vessels, a booster pump, stainless steel interconnecting piping and valves, and local instrumentation for process monitoring and control. The filtration/demineralization system has a maximum process capacity of 35 gpm.

Pumps - The wetted surfaces of all pumps are stainless steel or other materials of appropriate corrosion resistance. All pumps are either the canned motor type or mechanically sealed to minimize leakage.

Piping - Piping carrying liquid wastes is stainless steel, except blowdown. Piping connections are welded except where flanged connections are necessary to facilitate equipment maintenance.

Valves - All valves exposed to liquid wastes are stainless steel, except blowdown. All valves have stem leakage control. Globe valves are installed with flow over the seats when such an arrangement reduces the possibility of leakage. Isolation valves are provided to isolate each piece of equipment for maintenance, to direct the flow of waste through the system, and to isolate storage tanks for radioactive decay. Relief valves are provided for tanks containing radioactive wastes if the tanks might be overpressurized by improper operation or component malfunction. Tanks containing wastes which are normally free of gaseous activity are vented locally.

11.1.3 SYSTEM EVALUATION

Liquid wastes are generated primarily by plant maintenance and service operations, and consequently, the quantities and activity concentrations of influents to the system vary.
A conservative estimate of the system's ability to limit dissolved and suspended activity released in the liquid phase is summarized in Table 11.1-3, Estimated Liquid Release by Isotope. The values in this table are for an annual release based on a thermal power level of 1811 MWt (1800 + 0.6% uncertainity.) (Reference 1) Refer to Appendices I.3 and I.9 for discussion of EPU impact on liquid and gaseous effluents. Activity concentrations in plant liquid effluents are monitored and controlled in accordance with the Offsite Does Calculation Manual (ODCM) and are reported to the NRC.

Steam generator blowdown is also released to the plant discharge system. Normally, blowdown does not require processing due to the high fuel integrity and steam generators which have very low leakage. However, if blowdown sampling showed elevated activities, the blowdown can be processed through the Waste Holdup Tank and filtration/demineralization system until the levels are low enough to release. In addition, many controls such as Technical Specification limits on leak rate and activity levels are in place that administratively and procedurally inhibit high blowdown activities.

Verification will be made to ensure that dilution flow sufficient to meet the requirements of 10 CFR 20 is available whenever radioactive liquid wastes are released to the plant discharge system. All liquid waste releases will be continuously monitored for gross activity during discharges to ensure that the activity limits specified in 10 CFR 20 for unrestricted areas are not exceeded. All radioactive liquid wastes will be sampled and analyzed prior to release to the plant discharge system.

Those secondary-side liquid wastes containing only tritium (for example, condenser hotwells) may be discharged without being continuously monitored if the volume of liquid to be released is a batch release and the amount of tritium has been isotopically quantified.

During release of liquid radioactive waste, the following conditions shall be met:

1. At least one condenser circulating water pump shall be in operation and the service water return header shall be lined up to the unit(s) whose circulating water pump is operating.

2. If the gross activity monitor in the discharge line is not operable or if the discharge is made via a pathway without an RMS monitor, the volume of liquid to be released is to be isotopically quantified pursuant to the ODCM prior to release and periodically sampled during release.

11.1.4 REQUIRED PROCEDURES AND TESTS

The inservice testing requirements are described in the PBNP Inservice Testing Program and the IST Background Document.

11.1.5 ACCIDENTAL RELEASE-RECYCLE OR WASTE LIQUID

Accidents in the auxiliary building which would result in the release of radioactive liquids are those which may involve the rupture or leaking of system pipe lines or storage tanks. The largest vessels are the three CVCS hold up tanks, each sized to hold more than one reactor coolant liquid volume, which are used to process the normal recycle or waste fluids produced. The contents of one tank can be passed through the liquid processing train while another tank is being filled.

All liquid waste components except the reactor coolant drain tank and the abandoned in place blowdown evaporator are located in the auxiliary building and any leakage from the tank or piping will be collected in the building sump to be pumped back into the liquid waste system. Blowdown evaporator building drains will be directed to the liquid waste system via the sump tank. The PAB building sump and basement volume are sufficient to hold the full volume of a CVCS hold up tank without overflowing to areas outside the building. The full volume of either the volume control tank or the waste hold-up tank will be contained in the auxiliary building.

The CVCS holdup tanks are also equipped with safety pressure relief and designed to accept the established seismic forces at the site. Liquids in the chemical and volume control system flowing into and out of these tanks are controlled by manual valve operation and governed by prescribed administrative procedures.

The volume control tank design philosophy is similar in many respects to that applied for the holdup tanks. Level alarms, pressure relief valves and automatic tank isolation and valve control assure that a safe condition is maintained during system operation. Excess letdown flow is directed to the holdup tanks via the reactor coolant drain tank. The waste holdup tank is a horizontal tank which is continuously maintained at atmosphere pressure. Its vent is routed to the atmosphere through the auxiliary building exhaust ducts.

The potential hazard from these process or waste liquid releases is derived only from the volatilized components. The releases are described and their effects summarized in Section 11.2.5.

The evaluation of the credibility of the accidental release of radioactive fluids above the maximum permissible concentration from the waste disposal system discharge is based upon the following review of waste discharge operating procedure, monitoring function description, monitor failure mode and the consequences of a monitor failure.

The procedure for discharging liquid wastes is as follows:

1. A batch of waste is collected in a tank.

2. The tank is isolated.

3. The tank contents are recirculated to mix the liquid.

4. A sample is taken for radiochemical analysis.

5. Based on the analysis, the limiting discharge rate required to be in compliance with the PBNP Technical Specification upper discharge limit is calculated. If analysis indicates that release can be made within permissible limits, a discharge permit is completed indicating the quantity of activity to be released based on the liquid volume in the tank and its activity concentration. If release cannot be made within permissible limits, the waste is returned to the waste holdup tank for further processing.

6. To release the liquid, the last stop valve in the discharge line (which is normally locked shut) must be unlocked and opened; a second valve, which trips shut automatically on high radiation signal from the monitor, must be opened manually; and finally the recirculation valve must be closed.

7. Before the release, the operator verifies that the selected release path is isolated from all sources of potential discharge except the authorized source.

8. Soon after starting the discharge, the tank liquid levels are checked to ensure that discharge is occurring only from the approved tank and a calculation is performed to verify the discharge rate. The discharge rate is checked periodically during the discharge.

As the operating procedure indicates, the release of liquid waste is under administrative control. The monitor is provided to maintain surveillance over the release.

The monitor is provided with the following features:

1. A calibration source is provided to permit the operator to check the monitor before discharge by pressing a button in the control room to activate the circuitry.

2. If the monitor falls off scale at any time, an indicator visible to the operation in the control room lights.

3. If the power supply to the monitor fails a high radiation alarm is annunciated. The trip valve also closes.

4. The radiation trip valve fails closed, normally closed.

The administrative controls imposed on the operator combined with the safety features built into the equipment provide a high degree of assurance against accidental release of waste liquids.

Should a complete failure of any tank located in the auxiliary building occur, its content will remain in this building. Any subsequent discharge of radioactive liquid to the lake will be conducted under administrative controls and will not result in activity concentration into the lake in excess of the limits given in the Technical Specifications.

Dilution of off-site liquid releases to the lake are discussed in Section 2.5.

11.1.6 REFERENCES

1. Westinghouse Calculation Note, CN-CRA-99-15, Revision 1, September 30, 2009. (Confidential)

2. Westinghouse Report, WEP-98-077, "Wisconsin Electric Power Company Point Beach Unit 1 and 2 Chapter 9 and 11 – FSAR Updates," December 8, 1998.

Table 11.1-1 COMPONENT DESIGN DATA FOR RADIOACTIVE LIQUID TREATMENT (Also See Table 11.0-2)

Sheet 1 of 6

Booster Pumps (abandoned in place)

Number	2
Type	Centrifugal
Motor Horsepower	7.5
Seals	Mechanical
Capacity, gpm	36.5
Developed head at rated capacity, ft	135.6
Design Pressure, psig	150
Design Temperature, °F	300
Materials:	
Pump casing	Ductile Iron
Shaft	Carbon Steel
Impeller	Cast Iron

Blowdown Surge Tank (abandoned in place)

Number	1
Capacity, gal	500
Design Pressure, psig	50 and Full Vacuum
Design Temperature, °F	300
Material	Carbon Steel
Code	ASME VIII

Blowdown Evaporator (abandoned in place)

Number	1
Capacity, gpm	35
Design Pressure, psig	103 and Full Vacuum at 100°F
Design Temperature, °F	340
Material	Stainless Steel and Incoloy 825
Code	ASME VIII

Auxiliary Condensate Pump

Number	1
Type	Centrifugal
Motor Horsepower	100
Seals	Mechanical
Capacity, gpm	78
Developed Head, ft	822
Design Pressure, psig	600
Design Temperature, °F	307
Materials:	
Pump casing	Carbon Steel
Shaft	Carbon Steel
Impeller	Carpenter 20

Table 11.1-1 COMPONENT DESIGN DATA FOR RADIOACTIVE LIQUID TREATMENT
Sheet 2 of 6

<u>Blowdown Evaporator Circulating Pump</u> (abandoned in place)

Number	1
Type	Centrifugal
Motor Horsepower	50
Seals	Double Mechanical
Capacity, gpm	4,570
Developed head at rated capacity, ft	16
Design Pressure, psig	150
Design Temperature, °F	300
Materials:	
Pump casing	Carpenter 20
Shaft	Carbon Steel
Impeller	Carpenter 20

<u>Blowdown Evaporator Reboiler</u> (abandoned in place)

Number	1
Design Duty, Btu/hr	20,697,000

	Shell	Tube
Fluid	Steam	Evaporator Feed
Design Pressure, psig	150 and Full Vacuum	150 and Full Vacuum
Design Temperature, °F	375	375
Material	Carbon Steel	Incoloy 825
Design Code	ASME VIII	ASME VIII

<u>Blowdown Evaporator Bottoms Pump</u> (abandoned in place)

Number	1
Type	Centrifugal
Motor Horsepower	2
Seals	Double Mechanical
Capacity, gpm	10
Developed head at rated capacity, gpm	80.5
Design Pressure, psig	150
Design Temperature, °F	375
Materials:	
Pump casing	Carpenter 20
Shaft	Carbon Steel
Impeller	Carpenter 20

Table 11.1-1 COMPONENT DESIGN DATA FOR RADIOACTIVE LIQUID TREATMENT
Sheet 3 of 6

Blowdown Evaporator Bottoms Cooler Circulating Pump (abandoned in place)

Number	1
Type	Centrifugal
Motor Horsepower	2
Seals	Mechanical
Capacity, gpm	48.5
Developed head at rated Capacity, ft	49
Design Pressure, psig	200
Design Temperature, °F	250
Materials:	
Pump casing	Ductile Iron
Shaft	Carbon Steel
Impeller	Cast Iron

Blowdown Evaporator Distillate Pump (abandoned in place)

Number	1
Type	Centrifugal
Motor Horsepower	7.5
Seals	Mechanical
Capacity, gpm	40.7
Developed head at rated Capacity, ft	120
Design Pressure, psig	150
Design Temperature, °F	300
Materials:	
Pump casing	Stainless Steel
Shaft	Carbon Steel
Impeller	Stainless Steel

Blowdown Evaporator Distillate Cooler (abandoned in place)

Number	1	
Design Duty, Btu/hr	2,100,000	
	Shell	Tube
Fluid	Service Water	Distillate
Design Pressure, psig	150	150
Design Temperature, °F	200	300
Material	Carbon Steel	Stainless Steel
Design Code	ASME VIII	ASME VIII

Table 11.1-1 COMPONENT DESIGN DATA FOR RADIOACTIVE LIQUID TREATMENT
Sheet 4 of 6

Blowdown Evaporator Bottoms Cooler Preheater (abandoned in place)

Number	1
Fluid	Component Cooling Water
Design Pressure, psig	150
Design Temperature, °F	200
Material	Carbon Steel
Design Code	ASME VIII

Blowdown Evaporator Overhead Condenser (abandoned in place)

Number	1	
Design Duty, Btu/hr	18,200,000	
	Shell	Tube
Fluid	Distillate	Service Water
Design Pressure, psig	150	150
Design Temperature, °F	300	200
Material	Stainless Steel	Stainless Steel
Design Code	ASME VIII	ASME VIII

Blowdown Evaporator Distillate Accumulator (abandoned in place)

Number	1
Capacity, gal	500
Design Pressure, psig	50 and Full Vacuum
Design Temperature, °F	300
Material	Stainless Steel
Design Code	ASME VIII

Blowdown Vent Condensers

Number	2	
Design Duty, Btu/hr	970,000	
	Shell	Tube
Fluid	Saturated Steam	Service Water
Design Pressure, psig	150	150
Design Temperature, °F	300	200
Material	Carbon Steel	Carbon Steel
Design Code	ASME VIII	ASME VIII

Table 11.1-1 COMPONENT DESIGN DATA FOR RADIOACTIVE LIQUID TREATMENT
Sheet 5 of 6

Blowdown Evaporator Bottoms Cooler (abandoned in place)

Number	1	
Design Duty, Btu/hr	424,000	
	Shell	Tube
Fluid	Comp Cooling Water	12% Boric Acid
Design Pressure psig	150	150
Design Temperature, °F	200	300
Material	Carbon Steel	Incoloy 825
Design Code	ASME VIII	ASME VIII

Waste Distillate Pump

Number	1
Type	Centrifugal
Motor Horsepower	5
Seals	Mechanical
Capacity, gpm	75
Developed head at rated Capacity, ft	87.5
Design Pressure, psig	150
Design Temperature, °F	180
Materials:	
Pump casing	Stainless Steel
Shaft	Carbon Steel
Impeller	Stainless Steel

Blowdown Evaporator Sample Cooler (abandoned in place)

Number	1	
	Coolant Side	Process Side
Fluid	Comp Cooling Water	Evaporator Bottoms
Design Pressure, psig	225	100
Design Temperature, °F	200	300
Material	Cast Steel	Stainless Steel

Waste Distillate Tanks

Number	2
Capacity, gal	10,000
Design Pressure, psig	0.5
Design Temperature, °F	200
Material	Carbon Steel with Corrosion Resistant Lining
Design Code	AP1 650

Table 11.1-1 COMPONENT DESIGN DATA FOR RADIOACTIVE LIQUID TREATMENT
Sheet 6 of 6

Condensate Receiver

Number	1
Design Pressure, psig	150 & Full Vacuum
Design Temperature, °F	370
Material	Carbon Steel
Design Code	ASME VIII

Deep Bed Filtration Vessel

Number	2
Capacity, Gal	225
Design Pressure, psig	150
Design Temperature, °F	150
Material	Stainless Steel
Design Code	ASME Section VIII

Demineralizer Vessel

Number	4
Capacity, Gal	225
Design Pressure, psig	150
Design Temperature, °F	150
Material	Stainless Steel
Design Code	ASME Section VIII

Filtration/Demineralizer Booster Pump

Number	1
Type	Centrifugal
Motor Horsepower	5
Seal	Mechanical
Capacity, gpm	35
Developed Head, ft	275
Design Pressure, psig	150
Design Temperature, °F	150
Materials:	
Pump casing	Stainless steel
Shaft	Stainless steel
Impeller	Stainless steel

Table 11.1-2 ESTIMATED LIQUID DISCHARGE TO WASTE DISPOSAL

The information that was provided in this table is historical and can be found in FFDSAR Table 11.1-4.

Table 11.1-3 ESTIMATED LIQUID RELEASE BY ISOTOPE (TWO UNITS) (Reference 1)

ISOTOPE	Curies/year
Na-24	0.04766
Cr-51	0.0165
Mn-54	0.01034
Fe-55	0.00788
Fe-59	0.00172
Co-58	0.02774
Co-60	0.0035
Zn-65	0.00328
W-187	0.00362
Np-239	0.00518
Br-84	0.00062
Rb-88	0.04408
Sr-89	0.00082
Sr-90	0.00008
Y-90	0.00006
Sr-91	0.00068
Y-91m	0.00034
Y-91	0.00006
Y-93	0.00306
Zr-95	0.00234
Nb-95m	0.00002
Nb-95	0.00192
Mo-99	0.01632
Tc-99m	0.01524
Ru-103	0.0423
Rh-103m	0.04036
Ru-106	0.58396
Rh-106	0.56026
Ag-110m	0.00836
Ag-110	0.00104
Te-129m	0.00104
Te-129	0.0029
Te-131m	0.00252
Te-131	0.00064
I-131	0.02642
Te-132	0.00462
I-132	0.02836
I-133	0.04958
I-134	0.01988
Cs-134	0.83184
I-135	0.058
Cs-136	0.04858
Cs-137	1.11744
Ba-137m	1.02154
Ba-140	0.05726
La-140	0.08638
Ce-141	0.00082
Ce-143	0.00498
Pr-143	0.00086
Ce-144	0.02516
Pr-144	0.02414
Total release excluding tritium	4.862 Ci/yr
Tritium release	1300 Ci/yr

Table 11.1-4 ACTIVITY FROM STEAM GENERATOR BLOWDOWN WITHOUT AND WITH PROCESSING (Historical) (4)

Isotope	Blowdown Activity (1) µCi/cc	Activity in Circ Water Discharge Without Processing (2) µCi/cc	Activity in Circ Water Discharge With Processing (3) µCi/cc
Br-84	4.92E-05	4.77E-08	3.18E-11
I-131	9.25E-03	8.97E-06	5.98E-09
I-132	6.97E-03	6.76E-06	4.51E-09
I-133	1.43E-02	1.38E-05	9.20E-09
I-134	9.12E-04	8.85E-07	5.90E-10
I-135	6.63E-03	6.43E-06	4.29E-09
Rb-88	2.78E-03	2.70E-06	1.80E-09
Rb-89	1.30E-04	1.26E-07	8.40E-11
Sr-89	2.53E-05	2.45E-08	1.63E-11
Sr-90	1.31E-06	1.27E-09	8.47E-13
Sr-91	2.82E-05	2.74E-08	1.83E-11
Sr-92	4.12E-06	4.00E-09	2.67E-12
Y-90	2.23E-07	2.16E-10	1.44E-13
Y-91m	1.38E-05	1.34E-08	8.93E-12
Y-91	1.84E-06	1.78E-09	1.19E-12
Y-92	2.68E-06	2.60E-09	1.73E-12
Zr-95	2.13E-06	2.06E-09	1.37E-12
Nb-95	2.14E-06	2.07E-09	1.38E-12
Mo-99	2.67E-03	2.59E-06	1.73E-09
Tc-99m	2.47E-03	2.40E-06	1.60E-09
Te-132	1.07E-03	1.04E-06	6.93E-10
Te-134	3.86E-05	3.74E-08	2.49E-11
Cs-134	1.45E-02	1.14E-05	9.40E-09
Cs-136	1.52E-02	1.48E-05	9.87E-09
Cs-137	1.19E-02	1.15E-05	7.67E-09
Cs-138	1.29E-03	1.26E-06	8.40E-10
Ba-137m	1.11E-02	1.07E-05	7.13E-09
Ba-140	1.35E-05	1.31E-08	8.73E-12
La-140	4.81E-06	4.66E-09	3.11E-12
Ce-144	1.60E-06	1.55E-09	1.03E-12
Pr-144	1.60E-06	1.55E-09	1.03E-12
Cr-51	1.77E-05	1.71E-08	1.14E-11
Mn-54	1.31E-06	1.27E-09	8.47E-13
Mn-56	4.99E-05	4.84E-08	3.23E-11
Re-59	1.67E-06	1.62E-09	1.08E-12
Co-58	4.59E-05	4.45E-08	2.97E-11
Co-60	4.29E-06	4.16E-09	2.77E-12

1. Activity based on design parameters of 1650 MWt, 1% fuel defect, 1000 gpd leakage, and 100 gpm blowdown rate per unit. (Reference 2)

2. Apply a dilution factor for circulating water discharge of 9.70E-04, and no evaporator processing. (Reference 2)

3. Apply a decontamination factor of 1500 for the evaporator (Appendix I.2) and circ water dilution (Reference 2). The filtration/demineralization system meets or exceeds this decontamination factor.

4. This table was not updated for EPU. Table 11.1-3 does include expected blowdown system releases at EPU conditions but with different parameters from that used in this table.

Figure 11.1-1 UNITS 1 & 2 WASTE DISPOSAL SYSTEM PROCESS FLOW DIAGRAM (Sheet 1)

[redacted]

Figure 11.1-1 UNITS 1 & 2 WASTE DISPOSAL SYSTEM PROCESS FLOW DIAGRAM (Sheet 2)

[redacted]

Figure 11.1-2 UNITS 1 & 2 BLOWDOWN EVAPORATOR SYSTEM

[redacted]

Figure 11.1-3 UNITS 1 & 2 CONDENSATE WASTE POLISHING DEMINERALIZER

[redacted]

11.2 GASEOUS WASTE MANAGEMENT SYSTEMS (WG)

Various systems are provided for the processing of waste gases including: gas stripping and cryogenic separation* which remove radioactive gases and hydrogen from the primary coolant, condenser air ejector exhaust filtration and delay ductwork systems, which reduce radioactive gases in air ejector effluent in the event of primary-to-secondary leakage, and gas decay tanks which hold gases for an adequate period of time to allow decay. Cover gases are also considered part of the Waste Gas System and include the nitrogen blanketing system and parts of the hydrogen gas system.

11.2.1 DESIGN BASIS

The facility includes those means necessary to maintain control over the plant gaseous radioactive effluents. Appropriate holdup capacity shall be provided for retention of gaseous effluents, particularly where unfavorable environmental conditions can be expected to require operational limitations upon the release of radioactive effluents to the environment. In all cases, the design for radioactivity control must be justified on the basis of 10 CFR 20 requirements, for both normal operations and for any transient situation that might reasonably be anticipated to occur (GDC 70). Radioactive gases are processed to prevent their unmonitored release to the atmosphere. Gases are discharged intermittently at a controlled rate from the gas decay tanks through the monitored plant vent when required by plant inventory. A controlled release of gaseous waste from the waste disposal system requires that at least two valves be manually opened, one of which is normally locked shut. In addition, a discharge control valve is provided, which will trip shut on an effluent high radioactivity signal, thereby preventing an unanticipated release. Additional safety margin is provided by the use of ASME III, Class C materials and construction standards on significant components containing radioactive gases and USAS-B31.1 Section 1 piping and valves throughout the system.

11.2.2 SYSTEM DESIGN AND OPERATION

During plant operations, gaseous wastes will originate from:

1. Degassing reactor coolant discharged to the CVCS;
2. Displacement of cover gases as liquids accumulate in various tanks;
3. Miscellaneous equipment vents and relief valves; and
4. Sampling operations and gas analysis for hydrogen and oxygen in cover gases and gas decay tanks.

During normal operation, the waste disposal system also supplies nitrogen and hydrogen to primary plant components. The nitrogen gas system is divided into a low pressure and a high pressure side. The low pressure side (normally 40-70 psig) is supplied with nitrogen from the 3,000 gallon liquid nitrogen tank. Low pressure nitrogen can also be supplied from the high pressure side through pressure control valves. The low pressure nitrogen is used primarily in various tanks as a blanket above the liquid level to prevent air from entering the tanks and being absorbed into the liquid. The high pressure side is supplied from one or more clusters of 12 high pressure nitrogen bottles, or other pressurized nitrogen source, and is used to charge the safety injection system accumulators.

Most of the gas received by the waste disposal system during normal operation is cover gas displaced from the CVCS holdup tanks as they fill with liquid. Since this gas must be replaced when the tanks are emptied during processing, facilities are provided to return gas from the gas decay tanks to the holdup tanks. A backup supply from the nitrogen header is provided for makeup if return flow from the gas decay tanks is not available. Since the hydrogen concentration may exceed the combustible limit during this type of operation, components discharging to the vent header system are restricted to those containing minimal oxygen or aerated liquids and the vent header itself is designed to operate at a slight positive pressure (0.5 psig minimum to 2.0 psig maximum) to prevent in-leakage. Out-leakage from the system is minimized by using diaphragm valves, bellows seals, self-contained pressure regulators and soft-seated packless valves throughout the radioactive portions of the system.

Gases vented to the vent header flow to the waste gas compressor suction header. The waste gas compressors are operated only when conditions require their use. From the compressors, gas flows to one of four gas decay tanks. The control arrangement on the gas decay tank inlet header allows the operator to place one tank in service and to select one tank for backup. When the tank in service becomes pressurized to approximately 95 psig, a pressure transmitter automatically closes the inlet valve to that tank, opens the inlet valve to the backup tank and sounds an alarm to alert the operator so he may select a new backup tank. Pressure indicators are provided to aid the operator in selecting the backup tank. Gas held in the gas decay tanks can either be returned to the CVCS holdup tanks, or discharged to the atmosphere if it has decayed sufficiently for release. Generally, the last tank to receive gas will be the first tank emptied back to the holdup tanks which permits the maximum decay time before releasing gas to the environment. However, the header arrangement at the tank inlet gives the operator the option to fill, reuse, or discharge gas to the environment simultaneously without restriction by operation of the other tanks. During degassing of the reactor coolant prior to a cold shutdown, for example, it may be desirable to pump the gas purged from the volume control tank into a particular gas decay tank and isolate that tank for decay rather than reuse the gas in it. This is done by aligning the system to open the inlet valve to the desired tank and closing the outlet valve to the reuse header. Simultaneously, one of the other tanks can be opened to the reuse header if desired, while another is discharged to atmosphere.

Before a tank is discharged to the environment, it is sampled and analyzed to determine and record the radioactivity to be released, and then is discharged to the plant vent at a controlled rate through a radiation monitor. Results of analysis, waste gas volume, dilution flow available, discharge rate, and total activity are recorded on a waste discharge permit. Samples are taken manually by opening the appropriate sample isolation valve and permitting gas to flow to the gas analyzer and/or sampling hood where it can be collected in one of the sampling system gas sample vessels. After sampling, the isolation valve is closed until the tank contents are released. During release, a trip valve in the discharge line is closed automatically by a high radioactivity level indication in the plant vent.

During operation, gas samples can be drawn automatically from the gas decay tanks and automatically analyzed to determine their hydrogen and oxygen content. Manual sampling and analysis equipment is also available. The on-service gas decay tank is routinely sampled for oxygen in accordance with the Technical Specifications. The oxygen concentration is limited to avoid accumulation of explosive gas mixtures.

Separation and segregation of fission gases is accomplished by a high flow rate gas stripper for each unit and gas decay capabilities. Long lived fission gases may be removed by the cryogenic absorption system.* Following removal of fission gases, the remaining stripped gas is normally recycled to the reactor coolant systems. Should the plant gas inventory and requirements become unbalanced, this treated gas may be discharged under controlled conditions to the atmosphere following sampling and analysis. Decay of short-lived isotopes from a leaking steam generator to the condenser air ejector is accomplished by providing decay ductwork and an in-line filtration system for condenser air ejector exhaust gases prior to release. The effect of primary-to-secondary system leakage is minimized by continuous removal of coolant fission gases in the gas strippers and treatment of steam generator blowdown by use of vent condensers on the steam generator blowdown tanks.

Gaseous waste disposal system piping from the branch downstream of each reactor coolant filter through the strippers, charcoal decay tanks (CDT), and cryogenic separation system* to the stripped liquid return connections upstream of the 3-way valves for control of high level in the volume control tanks, the common supply and return line from the noble gas storage tank and the hydrogen recycle headers is considered Class I for seismic design purposes. The entire evaporator system and the condenser air ejection system are considered Class III for seismic design.

In order to reduce the reactor coolant fission gas inventory to its lowest equilibrium level and so that full letdown flows from each unit can be stripped during load follow operation, the gas strippers are sized to handle the maximum expected continuous letdown rates from each unit. The full letdown flow from each reactor plant, containing dissolved hydrogen and fission gases is directed from a point downstream of the reactor coolant filter to a gas stripper. Dissolved gases are separated from the liquid in the stripper, which is run continuously or intermittently depending on activity level in the primary coolant and up to a maximum flow of 90 gpm. Stripped liquid is pumped from the stripper back to the letdown line and is directed to either the volume control tank or to a CVCS holdup tank. Noncondensable hydrogen and fission gases from each stripper are pumped to a common decay system by a compressor. The gases may also be vented through a cryogenic separation system.*

The noncondensable gases are compressed, dehydrated, and passed through a system capable of removing by decay nearly all the Xenon-133. The decay system consists of a series of vertical tanks filled with charcoal (CDT) which causes a differential holdup of hydrogen and noble gases. This allows a decay of nearly all the Xenon-133 while allowing the hydrogen to pass quickly through the charcoal. The gases leaving the decay system are recycled to the volume control tank.

To reduce the condenser air ejector radioactivity releases which may be partially short-lived isotopes, decay ductwork is sized on the basis of 18 scfm of saturated air flow per unit, for two units, to decay all of the nuclides with half-lives less than about 15 minutes essentially to zero before release.

The following components are used in the Waste Gas System. Additional component detail is provided in Table 11.2-1:

Gas Decay Tanks - Four welded gas decay tanks are provided to contain compressed waste gases (hydrogen, nitrogen, and fission gases). After a period for radioactive decay, these gases may be released at a controlled rate to the atmosphere through the auxiliary building exhaust vent. All discharges to the atmosphere will be monitored.

Noble Gas Storage - One of the four carbon steel tanks located inside the gas decay tank cubicle can be used for noble gas storage from the cryogenic gas separation system.*

Waste Gas Compressors - Two compressors are provided for removal of gases from equipment that contains or can contain radioactive gases. These compressors are of the water-sealed centrifugal displacement type. The operation of the compressors can be controlled by the gas manifold pressure. Construction is primarily of carbon steel. A mechanical seal is provided to minimize leakage of seal water.

Letdown Gas Stripper - The letdown gas stripper system is designed to remove radioactive gases and hydrogen from the primary coolant normal letdown. The system consists of two trains which can be cross connected and have a common interface with the cryogenic gas separation system.* The major component of each gas stripper train is the gas stripper unit in which the process liquid is flashed to steam and then recondensed in an attached condenser. This effectively strips entrained gases from the primary coolant. The coolant is then returned to the letdown system and the stripped gases are directed to the cryogenic gas separation system.*

*Cryogenic Gas Separator - (The cryogenic separation system has never been used at PBNP but was installed to provide an additional means of removing radioactive krypton-85 gas. The required equipment is currently abandoned in place, however, the following functional description is provided for historical reference.)

The cryogenic gas separation system can be used to remove the radioactive krypton-85 from the process gases of the gas decay tanks and gas stripper system prior to exhausting to the atmosphere. This is accomplished by decay in decay and holdup tanks of short lived fission gases and by adsorption of long lived fission gases. The cryogenic gas separation system consists of two trains with common holdup and decay tanks. Major components of one train include one water separator and gas cooler; a series of three holdup and four gas decay tanks which allows the decay of the short lived xenon and krypton isotopes; a silver aluminum silicate adsorber which adsorbs the iodine isotopes which do not decay in the holdup and gas decay tanks; a catalytic recombiner which removes any oxygen and thus eliminates the potential explosion hazard in the charcoal of the cryosorber; a process gas dryer; a cryosorber unit which removes the long lived krypton-85 isotope by adsorption on activated charcoal; and a liquid nitrogen system which maintains the cryosorber at the required temperature to effectively remove the krypton-85 isotope.

Condenser Air Ejector Filtration - The filtration unit removes radioiodine and radioactive particulates which may be present in condenser air ejector offgas when significant primary to secondary leakage is present. The filtration unit is in line with the combined condenser air ejector vent line and consists of a moisture separator heater, high efficiency particulate air filter, and carbon adsorber bed. The moisture separator and heater are required to reduce relative humidity in order to keep this adsorbent dry, thereby preserving its function of radioiodine removal.

Nitrogen Manifold - High pressure nitrogen can be used as a backup supply to the low pressure system through a dual manifold and pressure control valves. The manifold is brass with brazed brass fittings. Nitrogen is supplied to the manifold from gas cylinders. The manifold and cylinders are located inside the west wall of the auxiliary building truck access area.

Hydrogen Manifold - Hydrogen is supplied to the volume control tanks and each generator from a central storage facility located outside the east wall of the turbine building. The facility includes a rack of six ASME vessels mounted horizontally and a pressure reducing station to maintain header gas pressure. Pressure controllers at each generator and the volume control tanks maintain required hydrogen pressure.

Gas Analyzer - A continuous gas analyzer is provided to monitor the concentrations of oxygen and hydrogen in the cover gas of tanks and vessels which might accumulate a hazardous mixture of the two gases. Upon indication of a high oxygen level, provisions are made to purge the equipment to the gaseous waste system with nitrogen gas.

11.2.3 SYSTEM EVALUATION

Gaseous wastes consist primarily of hydrogen stripped from coolant discharged to the CVCS holdup tanks during boron dilution, nitrogen and hydrogen gases purged from the CVCS volume control when degassing the reactor coolant, and nitrogen from the closed gas blanketing system. The gas decay tank capacity will permit 45 days decay of waste gas before discharge. Activity concentrations in plant effluents are monitored and controlled in accordance with the Offsite Dose Calculation Manual (ODCM) and reported to the NRC. Table 11.2-2 contains an estimate of annual gaseous activity release based on 1811 MWt power (Reference 2).
Table 11.2-3 details the failure analysis of the Waste Gas System components.

Condenser air ejector exhaust gases are filtered in order to prevent the release of radioactive isotopes to the atmosphere during periods when significant primary to secondary leakage exists. This filtration system consists of a moisture separator heater, HEPA, and charcoal filters. The removal of entrained water and reduction of relative humidity ensures that the charcoal bed will remain dry, thereby enabling effective removal of radioiodine.

During release of gaseous radioactive waste to the plant vent, the following conditions shall be met:

1. At least one PAB exhaust stack fan will be in operation.

2. The plant vent radioactivity monitor shall be operating.

The maximum allowable release rates of radioactive liquid and gaseous wastes are specified in the Technical Requirements Manual and the ODCM.

11.2.4 REQUIRED PROCEDURES AND TESTS

The inservice testing requirements are described in the PBNP Inservice Testing Program and the IST Background Document.

11.2.5 ACCIDENTAL RELEASE-WASTE GAS

Gas Decay Tank Rupture - Causes and Assumptions

The gas decay tanks contain the gases vented from the reactor coolant system, the volume control tank, and the liquid holdup tanks. Sufficient volume is provided in each of four tanks to store the gases evolved during a reactor shutdown. The system is adequately sized to permit storage of these gases for 45 days prior to discharge. This period is selected as the maximum foreseeable holdup time because in this period the shorter-lived radioactive gaseous isotopes received by the waste system will have decayed to a level which is less significant than that of long-lived Kr-85.

The waste gas accident is defined as an unexpected and uncontrolled release to the atmosphere of the radioactive xenon and krypton fission gases that are stored in the waste gas storage system. Failure of a gas decay tank or associated piping could result in a release of this gaseous activity. This analysis shows that even with the worst expected conditions, the off-site doses following release of this gaseous activity would be very low.

The leakage of fission products through cladding defects can result in a buildup of radioactive gases in the reactor coolant. Based on experience with other operational, closed cycle, pressurized water reactors, the number of defective fuel elements and the gaseous coolant activity is expected to be low. The principal source of radioactive gases in the waste disposal system is the bleeding of effluents from the reactor coolant system.

Nonvolatile fission product concentrations are greatly reduced as the cooled coolant is passed through the purification demineralizers. The removal factor for iodine, for example, is at least 10. The decontamination factor for iodine between the liquid and vapor phases, for example, is expected to be on the order of 10,000. Based on the above analysis and operating experience at Yankee-Rowe and Saxton, activity stored in a gas decay tank consists of that from the noble gases released from the processed coolant and only negligible quantities of the less volatile isotopes.

As the components of the waste gas system are not subjected to any high pressures or stresses, are Class I seismic design, and are designed to the standards given in Table 11.2-1, a rupture or failure is highly unlikely. However, a rupture of a gas decay tank is analyzed to define the limit of the hazard that could result from any malfunction in the radioactive waste disposal system.

Gas Decay Tank Activity Release Characteristics

The activity in the gas decay tank (GDT) is taken to be the maximum amount that could accumulate from operation at the Technical Specification limit for reactor coolant system noble gas activity. The maximum activity concentration is obtained by assuming the noble gases, xenon and krypton, are accumulated with no release over a full core cycle of 18 months at 1810.8 MWt with a letdown flow of 120 gpm and no gas stripping. Table 11.2-4 lists the primary input parameters important to the source term development, (Reference 6).

Samples taken from gas storage tanks in pressurized water reactor plants in operation show no appreciable amount of iodine.

To define the maximum doses, the release is assumed to result from gross failure of any process system storage tank, here represented by a gas decay tank giving an instantaneous release of its volatile and gaseous contents to the atmosphere.

Volume Control Tank Rupture - Causes and Assumptions

The volume control tank contains fission gases and low concentrations of halogens which are normally a source of waste gas activity vented to a gas decay tank. The iodine concentrations and volatility are quite low at the temperature, pH and pressure of the fluid in the volume control tank. The same assumptions are detailed in the preceding subsection also apply to this tank.

As the volume control tank and associated piping are not subjected to any high pressures or stresses, failure is very unlikely. However, a rupture of the volume control tank is analyzed to define the limit of the exposure that could result from such an occurrence.

Volume Control Tank Activity Release Characteristics

The volume control tank (VCT) is assumed to fail, releasing the stored noble gas activity and a portion of the iodine in the tank instantaneously to the environment. In addition, it is assumed that the letdown flow to the VCT continues for 30 minutes before isolation would occur. All of the noble gas and 10 percent of the iodine activity in the letdown flow is released to the environment. The activity in the VCT is based on operation with cladding defects in 1% of the fuel elements at a core power level of 1810.8 MWt over a nominal 18-month fuel cycle. Table 11.2-5 lists the primary input parameters important to the VCT accident scenario.

The noble gas activity in the VCT is conservatively determined based on operation with a conservatively high letdown flow of 132 gpm (120 gpm + 10% uncertainty) and assuming no gas stripping of the letdown stream. It is further assumed the RCS activity is based on operation with no gas stripping such that the concentration is maximum. The iodine concentration in the RCS is assumed to be at the TS limit for equilibrium operation (i.e., equal to the limit for DE I-131). Credit is taken for the demineralizer in the letdown line reducing the coolant concentration by a factor of 10. Thus, the iodine concentration in the VCT liquid is 10% of the RCS activity, as is the concentration in the letdown flow that is released as a result of the accident.

It is conservatively assumed that all activity released to the environment is released instantaneously. This assumption is also applied to the activity releases associated with the thirty minutes of letdown flow (i.e., the activity in the thirty minutes of letdown flow is all released at time-zero).

Method of Analysis

In calculating offsite plume center-line exposure for both the GDT and VCT ruptures, it is assumed that the activity is discharged to the atmosphere at ground level and is dispersed as a Gaussian plume downwind taking into account building wake dilution. No credit is taken for the buoyant lift effect of the hydrogen present in the released gas. The Site boundary atmospheric dispersion factors (X/Q) are described in Table 14.3.5-2.

The whole body and thyroid doses are calculated using the dose conversion factors from Federal Guidance Reports 11 and 12 (Reference 3 and Reference 4).

Summary of Calculated Doses

The site boundary whole body doses are 0.08 rem and 0.1 rem due to the releases as described in the GDT accident scenario and the VCT accident scenario, respectively. The thyroid dose at the site boundary due to the release described in the VCT accident scenario is 0.04 rem. The whole body does meet the Branch Technical Position 11-5 (Reference 5) limit of 0.1 rem.

It is concluded that a rupture in the waste gas system or in the volume control tank would present no undue hazard to public health and safety.

Method of Analysis and Summary of Calculated Doses - Charcoal Decay Tank

An investigation was made of the off-site radiological doses resulting from a burst of both the charcoal-filled decay tank and the cryogenic absorber vessel, assuming the cryogenic separation system had been in use.

A rupture is assumed to occur in one of the three connected charcoal decay tanks or their associated piping resulting in the release of a portion of the activity stored on the charcoal in the tanks. The activity is assumed to be released instantaneously.

It is conservatively assumed that the RCS noble gas activity for both Unit 1 and 2 is based on operation at 1810.8 MWt with no gas stripping such that the RCS is at its maximum. It is then assumed that Units have gas stripping initiated combined with a conservatively high letdown flow rate of 132 gpm (120 gpm + 10% uncertainty). Table 11.2-6 lists the primary input important to the charcoal filled decay tank release. The stripped gases are directed to the shared charcoal decay tanks. In addition to the initial inventory of activity in the primary coolant, noble gas activity continues to enter the RCS from the fuel. This activity is also available to be stripped from the letdown flow and delivered to the charcoal decay tanks.

The whole body doses are calculated using the dose conversion factors from Federal Guidance Report 12 (Reference 4). The Site Boundary atmospheric dispersion factors (X/Q) are described in Table 14.3.5-2. The site boundary whole body dose is 0.07 rem.

Table 11.2-7 shows a summary of the calculated doses for GDT, VCT, and CDT ruptures at the site boundary (EAB), low population zone (LPZ), and control room (CR). The acceptance criteria for the EAB and LPZ doses are the 10 CFR Part 20 dose limits and NUREG-800 Standard Review Plan section 6.4 provides the appropriate accident-specific dose acceptance criteria for the control room (Reference 7).

The following information describes two accident scenarios involving the cryogenic absorber vessel. The cryogenic system was installed in the early 1970’s, however, was never used and is currently abandoned in place. The system description currently remains in the FSAR. Similarly, the accident analyses for the cryogenic absorber vessel is maintained for historical purposes and reflects power operations at 1518.5 MWt.

For the cryogenic vessel burst it is assumed that the cryogenic system has been in operation for a total of 180 days, at which time the noble gas inventory in the absorb vessel consists of 1,725 curies of Krypton-85 and 1,070 curies of Xenon-133, and the entire inventory is released instantaneously. The site boundary whole body dose resulting from the above assumptions, and using the most conservative X/Q values shown in Figure 2.6-8, is less than 0.03 rem.

This discussion is provided for historical purposes. The cryogenic system was never used, and is not operational. Major portions of the system have been abandoned in place. Thus, the reference to a 40-year operating period would still bound a 60-year plant operating period (NRC SE dated 12/2005, NUREG-1839).

The noble gases absorbed in the cryogenic absorber vessel can be desorbed at the end of each 180 day cryogenic cycle and stored in one of the existing gas decay tanks. The resulting activity would, if accumulated over a 40-year period in this single gas decay tank, reach a maximum value of 50,000 curies Krypton-85. Xenon-133 would reach a maximum value of 2,100 curies. The whole body dose resulting from an instantaneous release of the gas decay tank contents would be 0.7 rem, which is less than that described previously for a single gas decay tank rupture.

11.2.6 REFERENCES

1. Letter PBW-WMP-416, Westinghouse to WE dated December 4, 1967.

2. Westinghouse Calculation Note, CN-CRA-99-15, WEP/WIS Annual Releases (GALE Code Analysis), Revision 1, September 30, 2009.

3. K.F. Eckerman et al, “Limiting Values of Radionuclide Intake and Air Concentration and dose Conversion Factors for Inhalation, Submersion, and Ingestion,” Federal Guidance Report No. 11, Environmental Protection Agency, September 1988.

4. K.F. Eckerman and J.C. Ryman, “External Exposure to Radionuclides in Air, Water, and Soil,” Federal Guidance Report No. 12, Environmental Protection Agency, September 1993.

5. Branch Technical Position 11-5, Revision 3, “Postulated Radioactive Releases due to a Waste Gas System Leak or Failure,” March 2007. (Contained in NUREG-0800.)

6. Westinghouse Calculation CN-REA-08-7, RCS, VCT, and GDT Sources for the Point Beach EPU, Revision 0, September 19, 2008.

7. NRC Safety Evaluation, “Point Beach Nuclear Plant (PBNP), Units 1 and 2 - Issuance of License Amendments Regarding Extended Power Uprate (TAC Nos. ME1044 and ME1045),” dated May 3, 2011.

8. Westinghouse Calculation, CN-CRA-08-45, Charcoal Delay Tank Doses for the Extended Power Uprate, Revision 1.

9. Westinghouse Calculation, CN-CRA-08-44, Volume Control Tank Rupture and Waste Gas Decay Tank Rupture Radiological Doses for the Extended Power Uprate, Revision 1.

Table 11.2-1 COMPONENT DESIGN DATA FOR RADIOACTIVE GAS TREATMENT
Sheet 1 of 8

Gas Decay Tanks

Number	4
Capacity, ft^3	525
Design Pressure, psig	150
Design Temperature, °F	150
Material	Carbon Steel
Design Code	ASME III-Class C

Waste Gas Compressor

Number	2
Type	Centrifugal, Liquid Ring
Motor Horsepower	25
Capacity, SCFM	40
Discharge Pressure at Capacity, psig	110
Design Pressure, psig	150
Design Temperature, °F	180
Materials	Carbon Steel

Air Ejector Iodine Filter

Number	1
Capacity, SCFM	40
Design Pressure, psig	150
Design Temperature, °F	125
Materials:	
Absorbent	Charcoal
Housing	Carbon Steel
Design Code	ANSI B31.1.0

Gas Stripper Recovery Heat Exchangers

Number	2	
Design Duty, Btu/hr	3,190,000	
	Shell	Tube
Fluid	Stripper Feed	Stripper Liquid Eff.
Design Pressure, psig	150	150
Design Temperature, °F	250	250
Material	Stainless Steel	Stainless Steel
Design Code	ASME III-Class 3	ASME III-Class 3

Table 11.2-1 COMPONENT DESIGN DATA FOR RADIOACTIVE GAS TREATMENT
Sheet 2 of 8

Gas Stripper Preheaters

Number	2	
Design Duty, Btu/hr	3,295,000	
	Shell	Tube
Fluid	Steam	Stripper Feed
Design Pressure, psig	Full vacuum & 150	150
Design Temperature, °F	375	375
Material	Carbon Steel	Stainless Steel
Design Code	ASME VIII	ASME III-Class 3

Gas Stripper Vent Coolers

Number	2	
Design Duty, Btu/hr	11,900	
	Shell	Tube
Fluid	Stripper Gas Eff.	Comp Cooling Water
Design Pressure, psig	Full vacuum & 150	150
Design Temperature, °F	300	300
Materials	Stainless Steel	Stainless Steel
Design Code	ASME III-Class 3	ASME VIII

Gas Strippers

Number	2
Capacity, gpm	90
Design Pressure, psig	103 & Full vacuum
Design Temperature, °F	340
Material	Stainless Steel
Design Code	ASME III-Class 3

Gas Stripper Circulating Pumps

Number	2
Type	Centrifugal
Motor Horsepower	20
Seals	Mechanical with Lip Seal
Capacity, gpm	87.5
Developed head at rated capacity, ft	236
Design Pressure, psig	150
Design Temperature, °F	300
Materials:	
Pump Casing	Stainless Steel
Shaft	Carbon Steel
Impeller	Stainless Steel

Table 11.2-1 COMPONENT DESIGN DATA FOR RADIOACTIVE GAS TREATMENT
Sheet 3 of 8

Regeneration Heater

Number	1
Design Duty, Btu/hr	900
Type	Tube enclosing heating element
Fluid	Nitrogen
Design Pressure, psig	250
Design Temperature, °F	750
Material	Stainless Steel

Gas Stripper Trim Coolers

Number	2	
Design Duty, Btu/hr	955,000	
	Shell	Tube
Fluid	Component Cooling Water	Stripper Liquid Eff.
Design Pressure, psig	150	150
Design Temperature, °F	200	200
Material	Carbon Steel	Stainless Steel
Design Code	ASME VIII	ASME III-Class 3

Gas Stripper Prefilters

Number	2
Retention Size, microns	2
Capacity, gpm	80
Design Pressure, psig	150
Design Temperature, °F	250
Materials: Housing	Stainless Steel
Design Code	ASME III-C

Gas Stripper Condensers

Number	2	
Design Duty, Btu/hr	1,700,000	
	Shell	Tube
Fluid	Component Cooling Water	Stripper Gas
Design Pressure, psig	150	Full vacuum & 150
Design Temperature, °F	200	200
Material	Carbon Steel	Stainless Steel
Design Code	ASME VIII	ASME III-Class 3

Table 11.2-1 COMPONENT DESIGN DATA FOR RADIOACTIVE GAS TREATMENT
Sheet 4 of 8

Chiller Pumps

Number	2
Type	Centrifugal
Motor Horsepower	1/8
Seals	Mechanical
Capacity, gpm	3
Design Pressure, psig	150
Design Temperature, °F	200
Material	Stainless Steel

Gas Subcoolers & Water Separators

Number	4	
Capacity, gpm	1.2	
	Shell	Tube
Fluid	Gas Effluent	Freon
Design Pressure, psig	200	200
Design Temperature, °F	150 & 35	150 & 35
Material	Stainless Steel	Stainless Steel
Design Code	ASME III-C	ASME III-C

Decay Tanks

Number	3
Capacity, ft^3	46
Design Pressure, psig	200
Design Temperature, °F	150
Material	Carbon Steel
Design Code	ASME III-Class C

Gas Afterfilters

Number	2
Retention size, microns	5
Capacity, scfm	1.2
Design Pressure, psig	200
Design Temperature, °F	150
Materials:	
Filter Element	Stainless Mesh
Housing	Stainless Steel
Design Code	ASME III-C

Table 11.2-1 COMPONENT DESIGN DATA FOR RADIOACTIVE GAS TREATMENT
Sheet 5 of 8

Gas Dryer

Number	2
Capacity, scfm	1.2
Absorbent Active Volume	4 cu ft
Design Pressure, psig	200
Design Temperature, °F	500
Materials:	
Absorbent	Silica Gel & Molecular Sieve
Housing	Stainless Steel
Design Code	ASME III-C

Cryogenic Precooler

Number	2
Design Duty, Btu/hr	250

	Shell (Stream #1)	Tube (Stream #2)	Tube (Stream #3)
Fluid	Gas Effluent In	Gas Effluent Out	Nitrogen
Design Pressure, psig	1,000	1,000	100
Design Temperature, °F	-320 & 500	-320 & 500	-320 & 500
Material	Stainless Steel	Stainless Steel	Stainless Steel
Design Code	ASME III-C	ASME III-C	ASME III-C

Cryogenic Absorber

Number	2
Capacity, scfm	1.2
Absorber Active Volume	0.25 cu ft
Design Pressure, psig	1,000
Design Temperature, °F	-320 & 400
Materials:	
Absorbent	Coconut Charcoal
Housing	Stainless Steel
Design Code	ASME III-C

De-Oxo Units

Number	2
Capacity, scfm	1.2
Catalyst Volume, cu ft	0.1
Design Pressure, psig	200
Design Temperature, °F	1100
Materials:	
Catalyst	Palladium Catalyst
Housing	Stainless Steel
Design Code	ASME III-C

Table 11.2-1 COMPONENT DESIGN DATA FOR RADIOACTIVE GAS TREATMENT
Sheet 6 of 8

Gas Prefilter

Number	2
Retention size, microns	5
Capacity, scfm	1.2
Design Pressure, psig	200
Design Temperature, °F	150
Materials:	
Housing	Stainless Steel

Cryogenic Gas Compressors

Number	2
Type	Diaphragm
Motor Horsepower	5
Capacity, scfm	1.2
Discharge Pressure at capacity, psig	150
Max. Design Pressure, psig	250
Materials:	
Diaphragm and parts contacting gas	Stainless Steel

De-Oxo Preheater

Number	2
Design Duty, Btu/hr	350
Type	Tubing coiled around heater element
Design Pressure, psig	200
Design Temperature, °F	1000
Material	Stainless Steel

Liquid Nitrogen Storage Tank

Number	1
Capacity, gal	3,000
Fluid	Liquid Nitrogen
Material	Stainless Steel
Design Code	ASME VIII

Table 11.2-1 COMPONENT DESIGN DATA FOR RADIOACTIVE GAS TREATMENT
Sheet 7 of 8

Liquid Nitrogen Surge Tank

Number	1	
Capacity, gal	50	
	Inner Dewar	Shell
Fluid	Liquid Nitrogen	Air
Design Pressure, psig	100	Full Vacuum and Atmospheric
Design Temperature, °F	-320 and 150	150
Material	Stainless Steel	Carbon Steel
Design Code	ASME VIII	ASME VIII

De-Oxo Aftercoolers

Number	2	
Design Duty, Btu/hr	750	
	Shell	Tube
Fluid	Comp. Cooling Water	Gas Effluent
Design Pressure, psig	200	200
Design Temperature, °F	1,100	1,100
Material	Stainless Steel	Stainless Steel
Design Code	ASME VIII	ANSI B31.1.0

Chiller Storage

Number	1	
Design Duty, Btu/hr	400	
	Shell	Tube
Fluid	Freon 11	Nitrogen
Design Pressure, psig	100	100
Design Temperature, °F	-200	-200
Material	Stainless Steel	Stainless Steel

Preabsorbers

Number	2
Capacity, scfm	1.2
Absorbent Volume, cu ft	0.2
Design Pressure, psig	200
Design Temperature, °F	500
Materials:	
Catalyst	Silver Treated Aluminum Silicate
Housing	Stainless Steel
Design Code	ASME III-C

Table 11.2-1 COMPONENT DESIGN DATA FOR RADIOACTIVE GAS TREATMENT
Sheet 8 of 8

Floor Equipment Drainage Sump Pumps

Number	2
Type	Vertical sump
Motor Horsepower	1
Capacity, gpm	30
Developed Head at Rated Capacity, ft	30
Materials:	
Pump Casing	Iron
Shaft	Carbon Steel
Impeller	Cast Iron

Table 11.2-2 ESTIMATED ANNUAL GASEOUS RELEASE BY ISOTOPE (TWO UNITS)

Isotope	Curies/yr
H-3	1.44E2
Ar-41	6.8E1
Kr-85m	4.4E1
Kr-85	7.4E2
Kr-87	8.0E0
Kr-88	2.0E1
Xe-131m	8.4E2
Xe-133m	4.0E0
Xe-133	8.0E2
Xe-135m	8.0E0
Xe-135	5.8E1
Xe-138	8.0E0
I-131	3.0E-1
I-133	9.4E-1
Cr-51	2.6E-4
Mn-54	1.3E-4
Co-57	1.6E-5
Co-58	1.3E-3
Co-60	3.2E-4
Fe-59	6.4E-5
Sr-89	4.6E-4
Sr-90	1.78E-4
Zr-95	2.0E-4
Nb-95	9.0E-5
Ru-103	3.8E-5
Ru-106	2.6E-6
Sb-125	1.92E-6
Cs-134	1.92E-4
Cs-136	7.4E-5
Cs-137	3.0E-4
Ba-140	8.0E-5
Ce-141	3.2E-5

Summary of Releases

Tritium release	1.44E2 Ci/yr
Total gaseous release	2.61E3 Ci/yr
Total iodine release	1.24E0 Ci/yr
Total particulate release	3.74E-3 Ci/yr

Table 11.2-3 GAS TREATMENT SYSTEM MALFUNCTION ANALYSIS

Components	Malfunction	Comments & Consequences
Entire gas treatment system modification	Fails to function	The cover gas, stripping and gas decay system is retained, so previously licensable performance is not affected by shutdown of modification equipment.
One gas stripper and associated exchangers, pumps and controls	Fails to function	Two stripper subsystems are provided, each at a capacity sufficient to process the normal letdown rate from both Unit 1 and Unit 2 reactors.
One gas compressor	Fails to function	Two units are provided; one in service, one in standby.
Decay tanks, surge tank and cryogenic absorber bed	Leak	These tanks are located in a tornado-proof Class I structure and are protected from overpressure by automatic controls and relief valves. Vent monitors and gas samples are used to detect leaks.
Cryogenic separation system	Fails to function	More than 90% of the fission gas removal is accomplished by components other than the cryogenic separation equipment. If the cryogenic portion were not operated, buildup of long-lived Krypton-85 in the reactor coolant would be very gradual. Alternatives to cryogenic processing and storage of fission product gases include controlled release methods and other processes described in this section.

Table 11.2-4 GAS DECAY TANK ACCIDENT ANALYSIS INPUT PARAMETERS

RCS Concentration Basis	
Power Level	1810.8 MWt
RCS Mass	1.147E8 gm
DE Xe-133	300 mCi/gm
Letdown Flow	120 gpm
Gas Stripping Rate	0 gpm
Releasable Activity from GDT	
Kr-85m	5.00E1 Ci
Kr-85	1.41E3 Ci
Kr-87	8.19E0 Ci
Kr-88	6.38E1 Ci
Xe-131m	2.07E2 Ci
Xe-133m	2.89E2 Ci
Xe-133	1.78E4 Ci
Xe-135	3.02E2 Ci
Xe-135m	1.33E1 Ci
Xe-138	9.66E-1 Ci

Table release values are from Reference 6 and modified by Reference 9. Reference 9 values were 42% of the Reference 6 values to account for the change RCS TS activity limit for DEX from 520 uCi/gm to 300 uCi/gm and corresponding change in the fuel defect level from 1% to 0.42%.

Table 11.2-5 VOLUME CONTROL TANK ACCIDENT ANALYSIS INPUT PARAMETERS

VCT Source Term Basis	
Power Level	1810.8 MWt
Fuel Cladding Defects	1%
Letdown Gas Stripping Rate	0 gpm
Noble Gas Basis (in the tank)	
Letdown Flow	132 gpm
Letdown Concentration Basis	
Letdown Flow	132 gpm
DE I-131	0.5 µCi/gm
Demineralizer DF for Iodine	10
DE Xe-133	520 µCi/gm
VCT Releasable Activities	
Kr-85m	96.7 Ci
Kr-85	1020 Ci
Kr-87	35.8 Ci
Kr-88	145 Ci
Xe-131m	195 Ci
Xe-133m	319 Ci
Xe-133	17800 Ci
Xe-135	503 Ci
Xe-135m	39.7 Ci
Xe-138	11.0 Ci
I-131	0.134 Ci
I-132	0.151 Ci
I-133	0.233 Ci
I-134	0.0355 Ci
I-135	0.134 Ci

Releasable Activity values are from Reference 9.

Table 11.2-6 CHARCOAL FILLED DELAY TANK ACCIDENT ANALYSIS INPUT PARAMETERS

CDT Source Term Basis	
Power Level	1810.8 MWt
DE Xe-133	300 µCi/gm
Letdown Gas Stripping Rate	132 gpm per Unit
CDT Releasable Activity	
Kr-85m	163 Ci
Kr-85	1806 Ci
Kr-87	46.3 Ci
Kr-88	231 Ci
Xe-131m	53.5 Ci
Xe-133m	84.0 Ci
Xe-133	4800 Ci
Xe-135	115 Ci
Xe-135m	0.86 Ci
Xe-138	0.64 Ci

Releasable Activity values are from Reference 8.

Table 11.2-7 CALCULATED DOSES FOR GDT, VCT, AND CDT RUPTURES

	Whole Body Dose (rem)	Thyroid Dose (rem)	Beta-Skin Dose (rem)
Gas Decay Tank (GDT) Rupture			
EAB	0.08	NA	NA
LPZ	0.02	NA	NA
CR	0.08	NA	2.2
Volume Control Tank (VCT) Rupture			
EAB	0.1	0.04	NA
LPZ	0.006	0.003	NA
CR	0.09	0.05	2.2
Charcoal Decay Tank (CDT) Rupture			
EAB	0.07	NA	NA
LPZ	0.01	NA	NA
CR	0.08	NA	1.5
Acceptance Criteria			
EAB	0.1	1.5	NA
LPZ	0.1	1.5	NA
CR	5.0	30	30

Figure 11.2-1 UNITS 1 & 2 WASTE GAS DISPOSAL SYSTEM PROCESS FLOW DIAGRAM (Sheet 1)

[redacted]

Figure 11.2-1 UNITS 1 & 2 WASTE GAS DISPOSAL SYSTEM PROCESS FLOW DIAGRAM (Sheet 2)

[redacted]

Figure 11.2-1 UNITS 1 & 2 WASTE GAS DISPOSAL SYSTEM PROCESS FLOW DIAGRAM (Sheet 3)

[redacted]

Figure 11.2-2 UNITS 1 & 2 GAS STRIPPER SYSTEM

[redacted]

Figure 11.2-3 UNITS 1 & 2 CRYOGENIC GAS SEPARATION SYSTEM (Sheet 1)

[redacted]

Figure 11.2-3 UNITS 1 & 2 CRYOGENIC GAS SEPARATION SYSTEM (Sheet 2)

[redacted]

Figure 11.2-4 UNITS 1 & 2 CONDENSER AIR REMOVAL DECAY SYSTEM

[redacted]

11.3 SOLID WASTE MANAGEMENT SYSTEM (WS)

The Waste Solid System design and operation are directed toward minimizing releases of radioactive materials to unrestricted areas. The equipment is designed and operated to process solid radioactive wastes which result in a form which minimizes potential harm to personnel or the environment. Handling areas are appropriately monitored and safety features are incorporated to preclude releases in excess of the limits of 10 CFR 20.

11.3.1 DESIGN BASIS

The facility includes those means necessary to maintain control over the plant solid radioactive effluents. Appropriate holdup capacity shall be provided for retention of all solid effluents, particularly where unfavorable environmental conditions can be expected to affect the release of radioactive effluents to the environment. In all cases, the design for radioactivity control must be justified on the basis of 10 CFR 20 requirements, for both normal and transient operations. (GDC 70)

11.3.2 SYSTEM DESIGN AND OPERATION

Spent resins from the demineralizers and filter cartridges are packaged and stored on-site until shipment off-site for disposal. Miscellaneous materials such as paper, plastic, wood, and metal are collected and shipped offsite for vendor supplied volume reduction (i.e., incineration, supercompaction, metal melt, decon, etc.) followed by disposal.

Spent resins from CVCS and other system demineralizers are flushed to a shielded, lined stainless steel storage tank located in the auxiliary building basement. When the tank is full, the resin is dewatered and liquids from the dewatering operation are sent to the waste holdup tank. Following resin dewatering, the tank and its shield are transferred by the seismically qualified auxiliary building crane to the new fuel storage area where the resin is sluiced to a disposable cask liner. Spent filtration media and resin from the filtration/demineralization system is sluiced directly to a disposable cask liner in the truck access area. When a disposable liner is full, the liner is dewatered to meet disposal site or processor criteria. The disposable liner is then shipped offsite for processing or shipped offsite for disposal at a suitable burial site.

Dry radioactive material waste may be stored in designated locations outside the RCA. Routine surveys and inspections are performed to verify the control of radioactive material (Reference 1 and Reference 2).

11.3.3 SYSTEM EVALUATION

The quantity of solid radioactive waste shipped from PBNP is reported in the Annual Monitoring Report in accordance with the Offsite Dose Calculation Manual (ODCM). The typical solid radioactive waste volume shipped for offsite processing and disposal is given in Table 11.0-1.

11.3.4 REQUIRED PROCEDURES AND TESTS

The inservice testing requirements are described in the PBNP Inservice Testing Program and the IST Background Document.

11.3.5 REFERENCES

1. NRC Generic Letter 80-51: On-Site Storage of Low-Level Waste

2. NRC Generic Letter 81-38: Storage of Low Level Radioactive Wastes at Power Reactor Sites

11.4 RADIATION PROTECTION PROGRAM

11.4.1 ENSURING THAT OCCUPATIONAL RADIATION EXPOSURE IS AS LOW AS IS REASONABLY ACHIEVABLE (ALARA)

Policy Considerations

It is the policy of FPL Energy Point Beach to maintain occupational radiation exposure as low as is reasonably achievable (ALARA), consistent with plant construction, maintenance, and operational requirements, and within the applicable regulations. Regulatory Guide 8.8 is used as a basis for developing the ALARA and radiation protection programs.

FPL Energy Point Beach ALARA policy applies to total person-rem accumulated by personnel, as well as to individual exposures. FPL Energy Point Beach management provides the environment for this policy to function in a proper manner. Management's commitment to this policy is reflected in the design of the plant, the careful preparation of plant operating and maintenance procedures, the provision for review of these procedures and for review of equipment design to incorporate the results of operating experience, and most importantly, the establishment of an ongoing training program. Training is provided for all personnel so that each individual is capable of carrying out their responsibility for maintaining their own exposure ALARA consistent with discharging their duties and also that of others. The development of the proper attitudes and awareness of the potential problems in the area of radiation protection is accomplished by proper training of all plant personnel. The organizational structure related to assuring that occupational radiation exposure be maintained ALARA is described below.

Organization Structure

The operating organization structure of the Point Beach Nuclear Plant is described in Chapter 12. Reporting to the Radiation Protection Manager (RPM) are health physicists, radiological engineers, radiation protection specialists, supervisors and technicians.

The RPM is responsible for the overall radiation protection and ALARA programs. The RPM reports to the Site Director who reports to the President Nuclear Division and Chief Nuclear Officer. The RPM is a member of Senior Management. Radiation protection concerns are discussed at the Senior Management meetings. Also, the ALARA Review Board Chairperson holds periodic meetings to discuss ALARA concerns. Several station groups (e.g., Operations, Maintenance, station management, etc.) participate in these meetings.

Personnel Activities and Responsibilities

The RPM is responsible for the radiation protection program and for handling and monitoring radioactive materials, including source and byproduct materials.

Administrative Concerns

The radiation protection (health physics) program is based on regulations and experience which includes or considers the following:

a. Sufficiently detailed procedures are prepared and approved for radiation protection and are a part of the station health physics program.

b. Sufficiently detailed procedures are prepared approved for receiving and shipping of radioactive material and radioactive waste ensure compliance with 10 CFR and 49 CFR.

c. Radiological incidents are thoroughly investigated and documented in order to minimize the potential for recurrence. Reports are made to the NRC in accordance with 10 CFR 20.

d. Periodic radiation, contamination, and airborne activity surveys are performed and recorded to document radiological conditions. Records of the surveys are maintained in accordance with 10 CFR 20.

e. Records of occupational radiation exposure are maintained and reports are made to the NRC as required by 10 CFR 20, and to individuals as required by 10 CFR 19.13.

f. Posted areas are segregated and identified in accordance with 10 CFR 20. Positive control is exercised for each individual entry into high radiation and very high radiation areas.

g. Personnel are provided with personnel radiation monitoring equipment to measure their radiation exposure in accordance with 10 CFR 20.

h. Process radiation, area radiation, portable radiation, and airborne radioactivity monitoring instrumentation are periodically calibrated as required.

i. Access control points are established to separate potentially contaminated areas from uncontaminated areas of the station.

j. Protective clothing is used as required to help prevent personnel contamination and the spread of contamination from one area to another.

k. Tools and equipment used in radiologically controlled areas are surveyed for contamination before removal to an uncontrolled area. Contaminated tools and equipment removed from a contaminated area are packaged as necessary to prevent the spread of contamination to uncontrolled areas.

l. All entries to radiologically controlled areas at PBNP are controlled by a Radiation Work Permit (RWP). Personnel must be signed in on an RWP to perform work of any type in radiologically controlled areas. Jobs involving significant radiation exposure to personnel are pre-planned. Where available, mock-ups may be used for practice to reduce exposure time on the actual job. The use of special tools and temporary shielding to reduce personnel exposure is evaluated on a job-by-job basis.

m. A bioassay program is included as part of the radiation protection program. This program includes air sampling, whole body screens and counting, and/or in vitro analysis to determine the intake of radioactive material.

n. An environmental radiological monitoring program is in operation to measure any effect of the station on the surrounding environment.

o. All significant radioactive effluent pathways from the station are monitored and records are maintained.

p. “Hot spot” labeling is utilized on some localized radiation sources, as deemed appropriate, in efforts to reduce personnel time in regions of the exposure field and increase personnel distance from the source of exposure.

Implementation of Procedures and Techniques

The criteria or conditions under which various operating procedures and techniques for ensuring that occupational radiation exposures are ALARA for systems associated with radioactive liquids, gases, and solids, along with the means for planning and developing procedures for radiation exposure-related operations, are given in the following:

a. Section 11.4.1, Ensuring That Occupational Radiation Exposure are as ALARA;

b. Section 11.4.2, Radiation Protection

c. Section 11.5, Radiation Monitoring System

d. Section 11.6, Shielding Systems

Implementation of Exposure Tracking and Exposure Reduction Program

Self-reading dosimeters are used at Point Beach to record estimates of daily exposure received by each individual worker. This information enables the Radiation Protection group to spot significant individual exposures prior to processing other monitoring dosimetry. Work group person-rem summaries are generated by a computerized dose tracking program. The summaries serve to alert the plant radiation protection staff of the trends in person-rem expenditures. Point Beach tracks and reports occupational dose by work group, and the dose expenditure resulting from work performed on various plant systems and components.

The computerized dose tracking program applications are:

a. To provide timely radiological feedback information to the various work groups.

b. To identify and compile dose histories on specific sources of occupational dose that might be reduced through improved plant working and shielding procedures and training programs.

c. To provide data for comparison studies of specific sources of occupational exposure among similar nuclear stations with relevant factors such as reactor equipment and plant layout, etc., taken into account.

A plant ALARA Review Board meets periodically to discuss matters related to ALARA. The ARB advises the senior responsible site leader, and includes the RPM and representatives of plant departments; e.g., Operations, Maintenance, Engineering. The ARB reviews and approves plant and department dose goals and major plant work scope additions or deletions for potential radiological consequences.

Training Program

The radiation protection training program covers the following:

a. Plant/Contractor employee radiation worker training

b. Plant/Contractor employee respiratory protection training

c. Plant/Contractor radiation protection technician training

All personnel must understand how radiation protection relates to their jobs and have reasonable opportunities to discuss radiation protection safety with a member of the Radiation Protection group whenever the need arises. Plant personnel are made aware of FPL Energy Point Beach's commitment to keep occupational radiation exposure as low as reasonably achievable.

11.4.2 RADIATION PROTECTION

Organization

The administrative organization of the radiation protection program and personnel responsibilities are referenced in Section 11.4.1.

The experience and qualifications of all station personnel are given in Technical Specifications, Section 5.3, Facility Staff Qualifications.

Facilities and Access Provisions, Equipment and Instruments

The plant site is divided into two categories, the Clean Area and the Radiation Control Area (RCA) as shown on Figure 11.4-1 through Figure 11.4-8 (RCA is shown cross-hatched).

The RCA encompasses the Primary Auxiliary Building, both facades and Containment Buildings, portions of the South Service Building and outside yard area. Access to the RCA is limited to those persons authorized for entry by plant supervisors and radiation protection personnel. Entry to and exit from the RCA is normally through the designated access control point.

Radioactive materials may be stored in designated locations outside the RCA. Entry to and exit from these storage areas is controlled in accordance with radiation protection procedures.

The general arrangement of the service facilities is designed to provide adequate personnel decontamination and change areas. The clean locker rooms are used to store items of personal clothing not required or allowed in the RCA. These locker rooms are employed as change areas from street clothes to modesty garments.

Several wall-mounted frisker-type monitors are available at strategic locations, particularly at or near the normal exit point of contaminated areas, to enable personnel to check themselves for contamination. Automated personnel contamination monitors are provided at the exit of the RCA. All personnel are to use the personnel contamination monitors (or Geiger-Mueller count rate meters) to monitor themselves upon leaving the RCA or other posted radiologically controlled areas as required by radiation protection procedures.

Decontamination showers are located in the RCA. The decontamination of personnel is performed in accordance with the instructions listed in approved radiation protection procedures. The auxiliary building has facilities to handle the decontamination of large items or equipment. The decontamination area contains service facilities. A decontamination area is also provided within the RCA machine shop for the decontamination of tools and equipment.

Strict administrative control of radiation exposure includes those methods described in Section 11.4.3. Other administrative controls include locked high radiation areas, radiation work permits, timekeeping of personnel in high radiation areas when required by RWP, and measures including escorts for visitors within the plant radiologically controlled areas.

Locations where the dose to the whole body may exceed 1 rem in 1 hour are conspicuously posted, and have locked accesses to prevent unauthorized entry or are equipped with red flashing warning lights. Keys to these accesses are kept under special administrative control.

Facilities provided for the Chemistry and Radiation Protection groups, include the chemistry laboratories, counting rooms, the calibration and source storage room, and the Radiation Protection station. Laboratory radiation measuring instrumentation in the Radiation Protection count room is supplemented by chemistry laboratory and counting room instrumentation.

These facilities are equipped to conduct radiation protection and chemistry programs for the station; to detect, analyze, and measure ionizing radiation; and to evaluate any radiological problem that may reasonably be expected.

The chemistry lab is equipped with fume hoods, which exhaust through high efficiency particulate and charcoal filters to the auxiliary building vent stack. Other typical chemistry laboratory equipment includes analytical instruments and sample preparation equipment.

The Chemistry counting room is provided with walls sufficiently shielded to reduce background count rates to acceptable values. Counting room typical equipment includes gamma, and beta detection and quantification equipment.

The Radiation Protection count room is equipped to count routine air samples and contamination smear surveys for beta/gamma and alpha radiation. It also serves as a central location for Radiation Protection instrumentation and equipment, including: portable radiation survey instruments and air sampling equipment.

A variety of instruments are used to perform radiation measurements at Point Beach Nuclear Plant. These include instruments to detect and measure alpha, beta, gamma, and neutron radiation. Various isotopic sources are available for instrument calibration and functional tests. Calibration sources for chemistry laboratory radiation detection equipment conform to the various counting geometries used.

Assorted low volume and high volume gaseous, particulate, and iodine sampling equipment is available for routine use as well as for special purpose and emergency airborne radiation surveys. Table 11.4-1 lists the normal storage location of respiratory protection equipment, protective clothing, and portable and laboratory technical equipment and instrumentation.

Respiratory protection equipment is provided in sufficient quantities to meet personal needs.

Typical detectors and monitors and the quantity, range, and frequency and methods of calibration for radiation protection instrumentation and technical equipment are specified in Table 11.4-2.

Radiation protection and radio chemistry facilities are described in Table 11.4-3.

Procedures

All personnel who are to work in the Radiation Control Area (RCA) receive radiation protection general access training prior to their assignment to work in the RCA. Radiation protection general access training includes all pertinent radiation practices and procedures to a degree that allows an employee to perform his/her assignment without incurring unnecessary radiation exposure.

In addition to general access training and periodic safety meetings, radiation safety instructions, policies, and procedures are made available to plant workers. Radiation control standards and procedures for working with radioactive materials are designed for protection of all personnel involved in the operating and maintenance of the facility. The Radiation Protection group provides additional detailed operational health physics procedures for use.

11.4.3 PERSONNEL MONITORING

Personnel External Exposure Program

The personnel external exposure program consists of multiple methods of reviewing external radiation levels and controls within the plant. These provide plant personnel status information required to maintain an ALARA program.

Area radiation monitors are located throughout the plant and provide general area indication of gamma radiation levels. These levels are continuously monitored and are alarmed in the Control Room. Some monitors also have local indication and alarm at certain in-plant locations. Process radiation monitors with control room indication and alarms also provide for immediate recognition of significant increases in in-plant dose rate levels.

Routine radiation surveys are made of general access areas of the plant. This provides detailed dose rate information for normal in-plant exposure evaluation. The surveys are reviewed to note unusual trends and for determination of additional controls that may be required due to new or increased radiation dose rates.

Special radiation surveys are made on an as-needed basis for jobs that take place in normally inaccessible (i.e., high radiation) areas. These areas may not normally be surveyed on a routine basis to keep doses as low as possible. Continuous or intermittent surveys are provided on an as-needed basis as determined by radiation protection for radiation work permits.

Neutron radiation surveys and personnel neutron dose monitoring is performed when entrance is made into neutron areas as required by radiation protection procedures.

Radioactive materials and special nuclear materials are handled and stored under the direction of personnel as specified in Section 11.4.1.

Dosimeter records furnish data for administrative control of radiation exposure. The official and permanent record of accumulated external radiation exposure is obtained principally from the dosimeter of legal record (DLR). The DLRs are normally processed at routine frequencies. DLR results are reviewed and are entered in a computerized radiation exposure records system. These official and permanent records furnish the exposure data for the administrative control of radiation exposure. Required reports are made by radiation protection personnel through use of this records system.

DLRs of personnel who have been or may have been overexposed are processed immediately. Self-reading dosimeter (SRD) also may be used to provide an indication of external radiation exposure. Additional monitoring devices are issued as required by radiation protection personnel to provide further monitoring under special conditions.

The use and issuance of personnel monitoring equipment as well as the evaluation and recording of personnel monitoring data are controlled by written procedures. All persons subject to occupational radiation exposure and having authorized access to radiologically controlled areas are required to be monitored whenever they enter a radiologically controlled area. The RP Manager may make exceptions to this on a case basis. Some situations that may be appropriate include rescue and medical emergency situations, and others that are deemed appropriate and documented in accordance with radiation protection procedures. Persons not subject to occupational radiation exposure and who do not enter radiologically controlled areas may be exempted from the use of personnel monitoring devices. Area DLRs are used to ensure compliance with the exemption monitoring requirements of 10 CFR 20 for those personnel exempted from monitoring.

The NRC has approved the use of a multiple dosimetry method for determining external radiation exposure using the weighting factors listed in Table 1 of ANSI/HPS N13.41-1997, “Criteria for Performing Multiple Dosimetry” as an optional means of demonstrating compliance with the TEDE based requirements in 10 CFR Part 20 (Reference 3).

Personnel Internal Exposure Program

The personnel internal exposure program consists of multiple methods of reviewing airborne radioactivity concentrations and controls within the plant. These provide plant personnel status information required to maintain an ALARA program.

The plant vent stack monitors (one for each of the two containment vent stacks) have detectors for air particulate, gas (low, mid, and high range), and iodine. These detectors are monitored by control room operators.

Continuous air monitors also monitor auxiliary building ventilation exhausts, containment purge systems, and the drumming area/spent fuel pool ventilation exhausts. These are used to measure, indicate, and record levels of airborne radioactivity in air exhausted from plant areas.

Portable grab samples are normally taken in accessible areas of the plant on a periodic basis. Special samples are taken as required by radiation protection personnel prior to issuing Radiation Work Permits and before other jobs as necessary. These air sample results are reviewed by radiation protection personnel and are used to determine respiratory protective equipment requirements in accordance with the plant radiation control standards and procedures.

Personnel Bioassay Program

The personnel bioassay program at Point Beach Nuclear Plant is administered by radiation protection management personnel. Bioassay (in vivo measurement and in vitro measurement of radioactive material) are conducted as necessary to aid in determining the extent of an individual's internal exposure to concentrations of radioactive material. The need for and frequency of bioassay are determined by the duration that a person works with radioactive materials or in an airborne radioactive materials area. Specific frequencies are determined and controlled by procedures. Bioassay results are recorded when required by radiation protection procedures.

1. Whole Body Screen

   Portal Monitors are used to qualitatively detect internal contamination greater than one percent of an ALI (passive monitoring). Entrance and exit whole body screens are performed and documented in accordance with radiation protection procedures.

2. Bioassay Techniques

   Bioassay techniques may include any or all of the following: whole body counting, urinalysis or fecal sampling and analysis.

The internal radiation exposure assessment program is implemented in compliance with 10 CFR 20. Work restrictions shall be imposed as needed to ensure that occupational radiation doses are minimized. External and internal doses are limited pursuant to 10 CFR 20. Evaluation of bioassay results is primarily based upon the identification and quantification of radioactive material intake. At the discretion of radiation protection management, on a case basis, dose equivalents are estimated from bioassay data. The actual calculation methods utilized are based on EPA Federal Guidance Reports and International Commission on Radiological Protection (ICRP) reports.

11.4.4 CONTAMINATION CONTROL PROGRAM

The contamination control program consists of multiple methods of controlling the spread of contamination to personnel and equipment within the plant. Routine contamination surveys are periodically made of normally accessible areas of the plant and are recorded. These results are reviewed by a radiation protection supervisor. Special contamination surveys are performed as required by Radiation Work Permits and for unconditional release of equipment, tools, and materials being removed from radiologically controlled areas. Items which are contaminated are required to be decontaminated to within release limits or packaged and tagged in accordance with the plant radiation protection procedures.

Workers in contaminated areas are required to be monitored for contamination as soon as possible after leaving a contaminated area and prior to exiting the RCA. Additionally, portal-type monitors are utilized to monitor individuals leaving the RCA via the main access area and again when leaving the site (in the security gatehouse). Actual instrumentation used for the contamination surveys is determined by plant radiation protection personnel.

Personnel Protective Equipment

The nature of the work to be done is the governing factor in the selection of protective clothing to be worn by individuals. The protective apparel available are shoe covers, head covers, gloves and coveralls or lab coats. Additional items of specialized apparel such as plastic suits, face shields, and respirators are available for operations involving high level contamination. Radiation Protection personnel evaluate the radiological conditions and specify the required items of protective clothing to be worn.

Personnel Respiratory Protection

The Point Beach Nuclear Plant is designed to minimize concentrations of airborne radioactivity due to inadvertent leaks, spills or other causes through filtered ventilation systems and isolation of equipment in compartments. Further, a radiation protection program is provided to minimize airborne concentrations by detecting and controlling potential sources of airborne radioactivity. The normal concentrations present in areas occupied by personnel are much less than derived air concentration (DAC) levels, and the use of respiratory protective equipment is, therefore, normally not necessary.

Respiratory protective devices are required, in any situation arising from plant operations in which airborne radioactivity exceeds or is expected to exceed the airborne concentration action levels. In such cases, the airborne concentrations are monitored by radiation protection personnel and the necessary protective devices specified according to concentration and type of airborne contaminants present.

Several types of respiratory protective equipment are utilized for radiological control in the respiratory protection program. The type used for a particular circumstance will be determined by the concentration in the air and the protection factor needed to prevent personnel from breathing or being exposed to airborne radioactivity in excess of that specified by 10 CFR 20.

The specifics of the respiratory protection program are directed by Radiation Protection procedures that are maintained current to the Code of Federal Regulation and OSHA requirements using NRC NUREGs, IE Circulars, and Information Notices for guidance, as well as Industry Events and NIOSH notices.

The use of Delta Protection Mururoa V4 F1 and V4 MTH2 supplied air suits has been approved for use at Point Beach with an assigned protection factor (APF) of 2,000. The use of Delta Protection Mururoa V4 F1 R supplied air suits has been approved for use at Point Beach with an assigned protection factor (APF) of 5,000. Approval of the Mururoa suits was based on testing which demonstrated the suits met the applicable European standard for the requirements and test methods for ventilated protective clothing used against particulate radioactive contamination. The testing demonstrated the suits have an overall measured fit factor of 50,000. The Mururoa suits will not be used in an environment immediately deleterious to life and health and will be discarded after one use. Any problems with the suits will be documented in the site's corrective action program and communicated to the manufacturer and to the US nuclear industry.

Additional commitments were made regarding suit use, system testing, procedures and training. The requirement of 10 CFR 20.1703(f), to provide standby rescue persons whenever one-piece atmosphere supplying suits are used, does not apply when the Mururoa suits are used in accordance with the manufacturer's instructions because of the suit's self-rescue features. (Reference 1 and Reference 2)

In addition, Self Contained Breathing Apparatuses (SCBAs) that are used for fire-fighting and emergency situations are maintained by the Operations group in accordance with Operations procedures.

11.4.5 CORRESPONDENCE AND COMMITMENTS

1. NRC Information Notice 90-33: Sources of Unexpected Occupational Radiation Exposures At Spent Fuel Storage Pools.

2. NRC Generic Letter 94-04: Voluntary Reporting of Additional Occupational Radiation Exposure Data.

3. NRC Information Notice 97-036: Unplanned Intake by Worker of Transuranic Airborne Radioactive Materials and External Exposure Due to Inadequate Control of Work.

4. NRC Information Notice 97-066: Failure to Provide Special Lenses for Operators Using Respirator or Self-Contained Breathing Apparatus During Emergency Operations.

11.4.6 REFERENCES

1. NRC Safety Evaluation, Duane Arnold Energy Center, Monticello Nuclear Generating Plant, Palisades Nuclear Plant, Point Beach Nuclear Plant, Units 1 and 2, Prairie Island Nuclear Generating Plant, Units 1 and 2 - Use of Delta Protection Respiratory Protection Equipment (TAC NOS. MC8744, MC8745, MC8746, MC8747, MC8748, MC8749, and MC8750), dated December 28, 2005.

2. NRC Safety Evaluation, St. Lucie Nuclear Plant, Units 1 and 2; Turkey Point Nuclear Plant, Units 3 and 4; Seabrook Station; Duane Arnold Energy Center; and Point Beach Nuclear Plant, Units 1 and 2, Request for the Use of Delta Protection Mururoa V4F1 R Supplied Air Suits (TAC Nos. ME1156 through ME1163) dated, August 31, 2009.

3. NRC Safety Evaluation, Safety Evaluation by the Office of Nuclear Reactor Regulation Related to Approval to Use Effective Dose Equivalent Weighting Factors for External Radiation Exposure, dated July 13, 2009.

Table 11.4-1 STORAGE LOCATION OF EQUIPMENT

Equipment	Normal Storage Location
Various Respiratory Equipment (Negative Pressure, SCBA, Hoods, etc.)	RP Area/ Emergency Planning Storage Areas
Protective Clothing	RP Area/ Emergency Planning Storage Areas
ß-γ Air Ionization Chambers G-M Survey Instruments Neutron Detectors	RP Area/ Emergency Planning Storage Areas
Chemical Analysis equipment	Hot Laboratory, Cold Laboratory

Table 11.4-2 RADIATION PROTECTION EQUIPMENT

Type Detector/Monitor	Estimated Number	Range[1]	Calibration Frequency[2]	Calibration Method
Multichannel Analyzer	1	Various	Annual	Standard Reference Materials
Air Ion Chamber Exposure Rate meter	30	Various	Annual	Standard Reference Materials
G-M Survey Count Rate Instrument	50	Various	Annual	Standard Reference Materials
Alpha Detector	1	0-2E6 cpm	Annual	Standard Reference Materials
High Range, Exposure rate	25	Various	Annual	Standard Reference Materials
Neutron Detector	2	0-5 rem/hr minimum	Annual	Standard Reference Materials
Air Sampler	10	Various	Annual	Standard Reference Materials
Portable Area Radiation Monitors	15	Various	Annual	Standard Reference Materials
Portable Continuous Air Monitor	5	Various	Annual	Standard Reference Materials
Self-Reading Dosimeter	300	0.001-1000 rem; 0.003 - 100 rem/hr	Annual	Standard Reference Materials

(1) A variety of models are in use with a variety of ranges.

(2) Denotes minimum requirement. More frequent calibrations may be required by Radiation Protection Instrument Calibration procedures.

Table 11.4-3 RADIATION PROTECTION AND RADIOCHEMICAL FACILITIES

Name	Location	Primary Function
Calibration Facility	South Service Building	Calibration and Storage of Portable Radiation Survey and Air Sampling Equipment
Hot Laboratory	South Service Building	Chemical Analysis and Radiochemical Separations
Cold Laboratory	North Service Building	Chemical Analysis
Counting Rooms	South Service Building	Radioactivity and Radiological Determination of Samples
Laundry and Respirator Cleaning Facility	South Service Building	Cleaning, Inspection, and Storage of Respiratory Protection Equipment
Radiation Protection Offices	South Service Building	Location of Radiation Protection Information

Figure 11.4-1 UNIT 1 CONTAINMENT OPERTING FLOOR AND MISCELLANIOUS UPPER FLOORS SOUTH

[redacted]

Figure 11.4-2 UNIT 1 RADIATION CONTROL AREA - OPERATING FLOOR

[redacted]

Figure 11.4-3 UNIT 1 RADIATION CONTROL AREA - INTERMEDIATE FLOOR

[redacted]

Figure 11.4-4 UNIT 1 RADIATION CONTROL AREA - GROUND FLOOR

[redacted]

Figure 11.4-5 UNIT 2 CONTAIMENT OPERATING FLOOR AND MISCELLANOUS UPPER FLOORS NORTH

[redacted]

Figure 11.4-6 UNIT 2 OPERATING FLOOR LEVELS NORTH

[redacted]

Figure 11.4-7 UNIT 2 INTERMEDIATE FLOOR LEVELS NORTH

[redacted]

Figure 11.4-8 UNIT 2 GROUND FLOOR NORTH

[redacted]

11.5 RADIATION MONITORING SYSTEM

11.5.1 DESIGN BASES

Monitoring Radioactivity Releases

Criterion: Means shall be provided for monitoring the containment atmosphere and the facility effluent discharge paths for radioactivity released from normal operations, from anticipated transients, and from accident conditions. An environmental monitoring program shall be maintained to confirm that radioactivity releases to the environs of the plant have not been excessive. (GDC 17)

The containment atmosphere, the auxiliary building vent, the drumming area vent, the condenser air ejector exhaust, the gas stripper building exhaust, the containment fan-coolers service water discharge, blowdown from the steam generators, the steam relief lines to atmosphere, the component cooling water, the waste disposal system liquid effluent, the spent fuel pool heat exchanger service water discharge, and the service water discharge are monitored for radioactivity concentration during normal operations, anticipated transients, and accident conditions. High radiation in any of these is indicated and alarmed in the control room.

All gaseous effluent from possible sources of accidental radioactive release external to the reactor containment (e.g., the spent fuel pool and waste handling equipment) are exhausted from vents which are monitored. All accidental spills of liquids are contained within the reactor auxiliary building and collected in a sump. Any contaminated liquid effluent released to the condenser circulating water is monitored. For any leakage from the reactor containment, under accident conditions, the plant radiation monitoring system supplemented by portable survey equipment provides adequate monitoring of radioactivity release during an accident. An outline of the procedures and equipment to be used in the event of an accident is presented in Section 11.5 and Section 11.6. The environmental monitoring program is described in Section 2.7.

Radiation Monitoring for leakage detection is described in Section 6.5.

Monitoring Fuel and Waste Storage Areas

Criterion: Monitoring and alarm instrumentation shall be provided for fuel and waste storage and associated handling areas for conditions that might result in loss of capability to remove decay heat and to detect excessive radiation levels (GDC 18).

Monitoring and alarm instrumentation is provided for fuel and waste storage and handling areas to detect inadequate cooling and excessive radiation levels. Radiation monitors are provided to maintain surveillance over the release of radioactive gases and liquids, and the permanent record of activity releases is provided by radiochemical analysis of known quantities of waste.

The spent fuel pool cooling system is flow monitored to ensure proper operation, as described in Section 9.9. Radiation monitors are provided in the storage and associated handling areas when fuel is present to detect excessive radiation levels and to initiate appropriate safety actions as required by 10 CFR 50.68(b)(6) (Reference 3 and Reference 4).

A controlled ventilation system removes gaseous radioactivity from the atmosphere of the fuel storage and waste treating areas of the auxiliary building and discharges it to the atmosphere via the drumming area vent. Radiation monitors are in continuous service in these areas to actuate high radiation alarms in the control room as described in Section 11.5.2.

Protection Against Radioactivity Release from Spent Fuel and Waste Storage

Criterion: Provisions shall be made in the design of fuel and waste storage facilities such that no undue risk to the health and safety of the public could result from an accidental release of radioactivity. (GDC 69)

Waste handling and storage facilities located within the containment building or primary auxiliary building are contained and equipment is designed so that accidental releases directly to the atmosphere are monitored and will not exceed the limits of 10 CFR 20, Subpart D as discussed in Section 11.1.5, and Section 11.2.5.

Radioactive material storage facilities located outside the containment building or primary auxiliary building that are not monitored are controlled such that accidental releases directly to the atmosphere will not exceed a small fraction of the dose limits of 10 CFR 100, and will not exceed the dose limits of 40 CFR 190 and 10 CFR 20 (Reference 5 and Reference 6).

11.5.2 SYSTEM DESIGN AND OPERATION

The radiation monitoring system monitors radiation levels and fluid activities at various locations throughout the plant. It is designed to accomplish three functions under normal and accident conditions:

1. Provide direct indication of and, if necessary, warning of radiation levels in the plant;
2. Measure gas releases from the plant vent stacks to provide indication of potential airborne activity; and
3. Initiate isolation and control functions on certain effluent streams.

In conjunction with regular and special radiation surveys and with radio-chemical analyses performed by the plant staff, the radiation monitoring system provides information to the operator to determine plant conditions and/or emergency status. It also provides adequate information and warning for the safe operation of the plant and assurance that personnel exposure does not exceed 10 CFR 20 limits.

Radiation detectors, microprocessors, and operator input/output terminals are integrated in the radiation monitoring system in order to achieve the desired functions. Figure 11.5-1 and Figure 11.5-2 provide block diagrams of the radiation monitoring system and illustrate the functional relationships of the components.

The radiation detectors sense radiation through one of the physical processes of either ionization or scintillation. The radiation detectors can be further characterized by their monitoring function:

1. Area Monitor
2. Process Monitor
3. System-Level Particulate, Iodine, and Noble Gas Monitor (SPING)

Area monitors calibrated in mR/hour (or mrem/hr) provide direct indication of area radiation dose rates in various parts of the plant. Table 11.5-1A and Table 11.5-1B provide a description, i.e., monitor name, location, indication, and control function; detector type and range; and associated alarm units, of the area monitors.

The process monitors in the radiation monitoring system provide an indication of increasing radiation levels in various fluid streams. Table 11.5-2A and Table 11.5-2B provide a description of the process monitors in format similar to that provided for the area monitors.

The SPING monitors measure particulate, iodine and noble gas discharges from the plant. This provides an indication of potential airborne activity in areas surrounding the plant. Table 11.5-3 provides a description of the SPING monitors.

The radiation monitoring system is a microprocessor-based radiation detection system. Eight Data Acquisition Modules (DAMs) and four SPING monitors provide the necessary microprocessing capability for the plant's radiation detectors. Each SPING has a DAM built into it, and each DAM is capable of serving nine detector (digital) inputs and six analog inputs. Each DAM also has a microcomputer which performs the tasks of data acquisition, history file management, operational status check, alarm determination and interface with the input/output terminals.

The operator has three interfaces with the Radiation Monitoring System: a) plant process computer system (PPCS), b) system server (SS), and c) annunciator panels. The PPCS is designed to be the primary operator interface with RMS. The PPCS polls the SS for information and status. The SS, also an operator interface, has a primary function of polling the DAMs and SPINGs. Annunciator panels are provided that alert the operator to system high alarms.

The only components of this system which are located in the containment are the detectors for certain area monitoring channels. Except for the containment high range monitors which are part of a separate qualified system, they would not be expected to operate following a major loss-of-coolant accident and are not designed for this purpose.

The entire radiation monitoring system is powered from vital busses. The instrument bus provides power to each DAM; the DAM provides power to each of its associated channels. In addition; each DAM is equipped with a battery which provides for eight hours of continuous operation in the event of a power failure.

As can be seen in Figure 11.5-2, the radiation monitoring system consists of eight data acquisition modules (DAMs); four system-level particulate, iodine and noble gas monitors (SPINGs); two system servers (SSs); and interfaces to the PPCS.

The RMS detectors sense radiation either through ionization or scintillation. The detector produces a pulse output that is related to the radiation detected. This signal is input to an interface box, which acts as a signal conditioner for the DAM channel. The interface box regulates voltage to the detector and amplifies the detector signal for input to the DAM/SPING microprocessor.

The microcomputer in the DAM/SPING counts these pulse inputs and converts them into a count rate. The microcomputer performs mathematical calculations to convert the count rate to proper units and to apply a background compensation factor, if required.

Each DAM/SPING is designed to operate its detectors in a stand alone manner. It is capable of doing the following major functions:

1. Accumulate and store historical information from its detectors in the form of 24-one minute, ten minute, one hour and one day average detector readings.

2. Provide instantaneous detector readings on demand.

3. Provide alarm indication and/or control function actuation if the instantaneous detector reading exceeds the programmed alarm setpoint. Detectors that are connected to a DAM or SPING will also provide control function actuation when in a fail low or fail high status.

4. Provide a trend alarm if the rate of change of averaged readings exceeds a programmed trend alarm setpoint.

5. Provide an alert alarm if the instantaneous detector reading exceeds a programmed alert alarm setpoint.

6. Provide an external failure, a low or high fail alarm if a detector system parameter indicates the detector is inoperable.

7. For each detector, maintain a programmed file which serves as the source of detector calibration constants, engineering units, various alarm setpoints and channel file number.

8. Communicate RMS data and alarm information to SS's for audio and visual display and printout.

9. Operate detector check sources.

10. Provide remote on-off control of one pallet-mounted sample pump.

Four DAMs are located in each of the Unit 1 and Unit 2 rod drive rooms. Three SPINGs are also located in the Unit 1 and Unit 2 rod drive rooms; one SPING is located near the drumming area vent stack. Each DAM and SPING has a local readout panel. The local readout device is capable of accessing the current status of any channel associated with that particular DAM.

The DAMs are also connected to two SSs. The SSs provide RMS data to the plant process computer system (PPCS). The Point Beach control room and Technical Support Center are each equipped with a SS.

Each SS has its own keyboard, printer, and system status annunciator. The SS provides a redundant communication and display capability with each DAM/SPING. The SS also has a microcomputer which provides the following functions:

1. Remote programming capability of each DAM channel file.
2. Automatic logging of one minute, ten minute, one hour, or one day averages, if desired.
3. Logging and, on demand, printout of history files.
4. Printout of alarm or failure data when transmitted by DAMs.
5. Printout of current values on demand.
6. Audible and visual alarm indications and reset functions.
7. Annunciating communications error messages.
8. Provides data transmission to the PPCS.

The PPCS operates independently of the SS and has access to all of the SS information. It is programmed to process and display RMS data in an efficient manner which allows the operator rapid and easy access to all system data. The PPCS may be used to display all channels which are in alarm and gives the operator the capability of graphically trending any channel.

The PPCS displays information in the form of status grids. Status grids are block diagrams of the plant showing the detectors in their appropriate locations in the plant. Color coding is employed to show monitor status.

Area Radiation Monitoring System

This system consists of multiple channels which monitor radiation levels in various areas of the plant. These areas are as follows:

Area Monitor
Control Room
Containment 66′ El (one per unit)
Radiochemistry Laboratory
Charging Pump Area (one per unit)*
Spent Fuel Pool Area*
Sampling Room (one per unit)*
Seal Table Containment 46′ El (one per unit)
Drumming Station
Letdown Line (one per unit)
SI Pump Area*
C-59 Area
Central Auxiliary Building Area
CVCS Holdup Tank Area
Valve Gallery

* A redundant high range radiation monitor is also installed in these areas.

Each low range channel contains a fixed position gamma sensitive G-M tube detector assembly. In addition to the G-M tube, the detector assembly also contains its own high voltage supply, pulse amplifier, low voltage regulator, line driver and check source assembly. The high voltage supply develops the potential applied to the G-M detector. When radiation reacts in the detector a negative pulse is generated and coupled to the amplifier. This pulse is amplified and processed by the line driver. The signal is then carried on a twisted, shielded cable pair to its electronics channel on the DAM where it is further processed.

The high range detectors are pressurized ion chamber types, designed to be used in high-level gamma fields of 1 mR/hr to 10,000 R/hr. The detector assembly, like the low range detectors, contains its own high voltage power supply, amplifier, low voltage regulator, line driver, and check source plus a charge-to-pulse converter. The detecting element, an ion chamber, operates in the proportional region. When radiation reacts in the chamber, a current flow is developed that is proportional to the intensity of the radiation field. The charge-to-pulse rate converter develops a pulse rate proportional to the current. The pulses are amplified and then processed by the line driver. A twisted, shielded pair cable then carries the signal to the appropriate electronics channel in the DAM.

Radioactive check sources, 0.5 µCi $(Sr\text{-}Y)^{90}$, are provided with each detector to enable periodic checking of the detectors and electronics for proper response.

The range of all the area radiation detectors is provided in Table 11.5-1B.

Remote alarm for the low range area monitors are provided by an Area Monitor Alarm Unit (AMAU). When high alarm condition exists in the detector channel, a red beacon will flash and a horn will sound on the AMAU. The audible alarm can be silenced on the AMAU by pressing the alarm acknowledge switch. The high alarm condition, through the DAM-SS network, also causes an annunciator in control to alarm. Area Monitor Beacon Units (AMBU), installed in areas where the AMAU beacon and horn are not visible and audible throughout the area being monitored, also respond to the high alarm condition and further serve to alert plant operators to high radiation conditions in the plant.

Process Radiation Monitoring System

This system consists of channels which monitor radiation levels in various plant operating systems. Table 11.5-2A lists the detectors and the systems which are monitored.

The liquid process monitors used for effluent monitoring are "offline samplers." The sampler is typically a lead shielded detector housing and a sample container for monitoring gamma emitters in liquids. The lead shield configuration is such that the container can be easily changed should it become contaminated.

Each liquid monitor is normally equipped with two detectors. One resides in the lead shielded sampler well and measures the activity of the liquid. The other detector is a general area monitor and measures ambient radiation levels. The detector that is inserted in the liquid sample chamber is a scintillation counter. The detector assembly consists of a photomultiplier tube, high voltage power supply, preamplifier, and discriminator and pulse shaper. In a scintillation detector, when radiation reacts with an inorganic crystal such as NaI, it causes emission of light from the crystal. The photomultiplier tube "sees" this light, amplifies current through electron multiplication, and develops a pulse output. The detector output is then amplified by a preamplifier, processed by a discriminator and pulse shaper and then carried to its electronics channel on the DAM where it is counted and processed. The background detector for each liquid monitor is a G-M tube type detector. The operation of this type of detector is like that explained previously for the area monitor G-M tube detectors.

The gaseous process monitors may be either scintillation or G-M tube type detectors. Some of the detector channels do not contain a background compensation channel.

The primary function of the process monitors is to monitor effluent streams and provide a control function should radiation levels exceed applicable setpoints. Table 11.5-2A lists the control function of the various process monitors. The process monitors are not nuclide specific. Nuclide concentrations are determined by routine analysis of reactor coolant samples for fission and corrosion product activities.

Radiation Monitoring System - SPING Monitors

The SPING monitors (see Table 11.5-3) are used to monitor the exhaust gas of the:

1. Unit 1 containment purge exhaust stack *
2. Unit 2 containment purge exhaust stack *
3. Auxiliary building exhaust stack
4. Radwaste packaging (drumming) area exhaust stack **

* Although blind flanges are installed inside containment on the purge supply and exhaust penetrations during normal operation the containment purge exhaust stacks are monitored because some exhaust gas discharges from RE211/212 through them in order to maintain containment atmosphere at a reduced pressure.

** The radwaste packaging area SPING is the only SPING not equipped with a high range noble gas chamber.

The SPING is used to sample and monitor particulates, iodine and noble gas in the air. The sample connect points for each of these monitors is downstream of the exhaust stack filters. The sample intake goes through a filter paper on which particulates are deposited, then through a charcoal cartridge to trap iodines and then into the gas chamber for low and medium range noble gas measurement. The sample then passes through a high-range noble gas chamber, through the pump and to the sample outlet.

The SPING features stainless steel plumbing through the sampler stages, a photohelic flow indicator with low and high flow setpoints, remote flush valves, a manual grab sample port with hose barbs and an air pump and a connection plug for a portable terminal.

Instrumentation

1. The particulate filter is monitored by a beta scintillation detector. Counts from the beta detector are a measure of the amount of beta-emitting isotopes on the filter.

2. The charcoal cartridge is monitored by a 2″ × 2″ NaI gamma scintillation detector. This detector is gain stabilized to minimize the effects of drift caused by fluctuations in temperature and/or aging. The measurement is accomplished using a single channel analyzer with its window calibrated to the 364 keV energy of I-131.

3. The low-range noble gas monitor is a beta scintillation detector.

4. An energy compensated G-M detector monitors the gas volume for the medium-range noble gas measurement. Its output is proportional to the gamma emission of the sample.

5. An energy compensated G-M detector monitors the gas volume of a section of 1″ stainless steel tubing in the high-range noble gas sampler of the SPING. Its output is proportional to the gamma emission of the sample.

6. Each SPING is equipped with a local area monitor. This detector is an energy compensated G-M tube which is calibrated in radiation dose rate and provides a measure of the gamma field at the instrument.

7. Radioactive check sources are provided to enable periodic checking of the detectors and electronics for proper response. The following list summarizes the channels with check sources.

	CHANNEL	CHECK SOURCE
1.	Beta Particulate	30 μCi Cs-137
3.	Iodine	0.5 μCi Ba-133
5.	Low-Range Noble Gas	30 μCi Cs-137
6.	Area Monitor	0.5 μCi Sr-90, Y-90
9.	High-Range Noble Gas	0.5 μCi Sr-90, Y-90

The upper counting range of the particulate, iodine, and low-range noble gas channels is 5.1×10^5 cpm. The beta particulate channel is approximately 3% (4π) efficient for Tc-99 beta particles. The I-131 gamma scintillation channel is approximately 3% (4π) efficient for the 364 keV gamma from I-131 decay. The low-range noble gas channel's useable range is approximately from 1×10^{-7} to 2×10^{-2} μCi/cc for Xe-133. The medium-range noble gas channels range is approximately from 3×10^{-3} to 1×10^{3} μCi/cc for Xe-133. The high-range noble gas channel has an approximate range of 1×10^{1} to 5×10^{5} μCi/cc for Xe-133. An area monitor measures ambient radiation levels and has an approximate range of 0.01 mR/hr. to 1000 mR/hr.

The radiation monitoring system also includes monitors for each steam line of each unit. The monitors are comprised of a lead-shielded detector which monitors the main steam line upstream of the safety valves for gamma radiation. The detector is an energy compensated G-M tube; its output, therefore, is proportional to the gamma emission from the steam line. The detector output is input to a single electronics channel on a data acquisition module (DAM). The purpose of this detector is to monitor steam line activity in the event steam reliefs are challenged and steam is dumped to the atmosphere.

Radiation Monitoring System Detector Alarms

The radiation monitoring system has the possibility of having three setpoints for each channel: alert alarm, trend alarm, and high alarm. The applicability of each alarm is determined for every monitor. Similarly, the determination of the appropriate setpoint is dependent on the monitor in question.

For the low range area monitors, in general, the high alarm setpoints are chosen to signal unusual radiation conditions. In the event that unusual conditions would persist for a long period of time the alarm setpoint may be raised with proper administrative approval and after appropriate HP precautions have been taken. The setpoint is returned to its normal value after conditions return to normal.

Each liquid process monitor is normally equipped with two detectors: one to measure activity of the liquid and the other monitors ambient radiation levels.

The SPINGs have multiple monitors with a variety of considerations affecting the alarm setpoints. The particulate monitor is a fixed filter type monitor. Therefore, the setpoints for the particulate monitor must accommodate the accumulation of particulates. Similarly, the iodine monitor has a fixed filter and, therefore, the setpoints must accommodate the accumulation of iodine. The noble gas monitor is equipped with a sampler assembly. In general, purpose of the monitor, location and shielding, range, and sensitivity and ambient background are considered in determining the alarm setpoints. Both liquid and gaseous monitors at release points have setpoints conservatively based on not exceeding Technical Specification limits.

Isokinetic Stack Sampling System

An Isokinetic Stack Sampling System (ISSS) has been installed providing the capability to sample both the Auxiliary Building Vent Stack and the Drumming Area Vent Stack for iodine and particulates during normal operations and accident conditions. One system is installed in each of the above locations.

An air pump draws a suction on a probe inserted in the stack. The air is drawn through a filter where particulates in the stack atmosphere are deposited. The air flowrate is determined by a solenoid operated flow control valve. Both stack velocity and probe velocity signals are sent to a flow controller which controls the position of the flow control valve. The controller matches probe velocity with stack velocity, thus providing a truly representative isokinetic sampling of stack particulate. The filter must be removed manually for laboratory analysis.

Accident Monitoring - Containment High-Range Radiation Monitor

In addition to the low-range radiation monitors in containment, three high-range radiation monitors per containment are provided for accident monitoring. Though the high-range radiation monitors are assigned RMS sequential detector numbers, they do not interface with the DAM-SS network in the radiation monitoring system. Three detectors per containment with an eight decade range are located on floor or beam-mounted seismic supports located on the 66′ El. in each containment. Power for each detector is via a separate safety-grade instrument bus. Separation and seismic support provide IE qualification for the detector channels. The output of the detector is supplied to the plant computer and the respective unit ASIP.

Emergency Plan Facility Monitoring

Radiation monitoring is provided for the Technical Support Center. The monitoring meets the requirements of NUREG-0696 and is described in the Emergency Plan.

11.5.3 SYSTEM EVALUATION

All liquid waste releases shall be continuously monitored for gross activity during discharge to ensure that the activity limits specified in 10 CFR 20 for unrestricted areas are not exceeded.

Those secondary-side liquid wastes containing only tritium (for example, condenser hotwells) may be discharged without being continuously monitored if the volume of liquid to be released is a batch release and the amount of tritium has been isotopically quantified.

11.5.4 REQUIRED PROCEDURES AND TESTS

Monthly checks of all process and area radiation monitors are performed using remotely operated or portable radioactive check sources. Results of the monthly checks are used to determine the need for recalibration or maintenance of the monitors. Calibration of the process and area radiation monitors is done at refueling intervals as a minimum, and may be more frequent as required by maintenance or replacement of instrumentation.

11.5.5 REFERENCES

1. Regulatory Guide 1.97, "Instrumentation for Light Water Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident," Revision 2.

2. WE Letter to NRC, "Implementation of Regulatory Guide 1.97," dated September 1, 1983.

3. 10 CFR 50.68, Criticality Accident Requirements.

4. NRC 2008-0044, License Amendment Request 247: Spent Fuel Pool Storage Criticality Control, dated July 24, 2008.

5. NRC Generic Letter 80-51: On-Site Storage of Low-Level Waste dated June 9, 1990

6. NRC Generic Letter 81-38: Storage of Low Level Radioactive Wastes at Power Reactor Sites dated November 10, 1981

Table 11.5-1A RADIATION MONITORING SYSTEM AREA MONITORS

Sheet 1 of 3

DETECTOR NUMBER	NAME	LOCATION	INDICATION	CONTROL FUNCTION
RE-101	Control Room Area Monitor	West wall of control room.	Indicates dose rates in control room.	Shifts control room ventilation to Mode 5.
1/2-RE-102	Containment Low-Range Area Monitor	El. 66′ near access hatch on east side.	Provides dose rates within containment near access hatch.	
RE-103	Chemistry Lab Area Monitor	East wall of chemistry lab near counting room door.	Provides indication of dose rates in chemistry lab and associated hallways.	
1/2-RE-104	Charging Pump Room Low-Range Area Monitor	West side of shield wall east of cubicles on El. 8′ of aux. bldg.	Indicates dose rates in hallways east of charging pump cubicles.	
RE-105	Spent Fuel Pool Low-Range Area Monitor	Mounted on railing just northeast of spent fuel pool on El. 66′ of aux. bldg.	Provides indication of dose rates in the vicinity of the spent fuel pool.	
1/2-RE-106	Primary Side Sample Room Low-Range Area Monitor	West wall towards north corner of sample room on El. 26′ of aux. bldg.	When sampling system is in operation, it indicates dose rate inside sample room.	
1/2-RE-107	Seal Table Area Monitor	Mounted on wall just above table on El. 46′ of containment	Provides an indication of general area dose rate near seal table.	
RE-108	Drumming Station Area Monitor	Mounted inside the drumming station area waste processing cubicle.	Provides dose rate indication within the drumming station.	
1/2-RE-109	Post-Accident Sample Line Monitor	South wall near east corner of primary side sample room on El. 26′ of aux. bldg.	Provides an indication of failed fuel by monitoring the primary coolant sample activity.	

Table 11.5-1A RADIATION MONITORING SYSTEM AREA MONITORS

Sheet 2 of 3

DETECTOR NUMBER	NAME	LOCATION	INDICATION	CONTROL FUNCTION
RE-110	Safety injection Pump Room Low-Range Monitor	North wall just west of passageway in SI pump room.	Provides an indication of the dose rate in general area of SI pumps.	
RE-111	C-59 Panel Area Monitor	Mounted on top of C59 instrument panel on El. 26′ of aux. bldg.	Provides general area dose rate near C59 panel.	
RE-112	Central Aux. Bldg. Area Monitor	North wall just east of pipeway No. 3 on El. 8′ of aux. bldg.	Indicates general area dose rate on El. 8' on aux. bldg.	
RE-113	Aux. Bldg. El. 19' Area Monitor	General area of El. 19′ aux. bldg.	Provides an indication of the dose rate in aux. bldg. sump and general area of El. 19′.	
RE-114	CVCS Holdup Tank Area Monitor	Mounted on wall at entrance of cubicle	Indicates general area dose in cubicle.	
RE-116	Letdown System Valve Gallery Area Monitor	Mounted by north entrance to valve gallery on El. 26′ of aux. bldg.	Indicates general area dose rate in letdown demin valve gallery.	
1/2-RE-126 1/2-RE-127 1/2-RE-128	Unit 1/2 Containment High-Range Radiation Monitors	Containment El. 66′ spaced approximately 120º apart along the outer wall.	Indicates and alarms in computer room and on ASIP panels 1(2) C20.	
1/2-RE-134	Charging Pump Room High-Range Area Monitor	Next to RE-104 on west side of shield wall.	Provides an indication of general area dose rates in the event low-range monitor saturates.	
RE-135	Spent Fuel Pit High-Range Area Monitor	Next to RE-105 on railing just northeast of spent fuel pit.	Provides an indication of general area dose rates in the event low-range monitor saturates.	

Table 11.5-1A RADIATION MONITORING SYSTEM AREA MONITORS

Sheet 3 of 3

DETECTOR NUMBER	NAME	LOCATION	INDICATION	CONTROL FUNCTION
1/2-RE-136	Primary Side Sample Room High-Range Area Monitor	Mounted next to RE-106 on west wall.	Provides an indication of general area dose rates in the event low-range monitor saturates.	
RE-140	Safety Injection Pump Room High-Range Area Monitor	Next to RE-110 on north wall just west of passageway.	Provides an indication of general area dose rates in the event low-range monitor saturates.	
RE-239	TSC Area Monitor	North wall of TSC	Indicated general area TSC dose rates	
RE-240	TSC El. 18.5′ Assembly Area Monitor	North wall of 18.5′ assembly area	Indicates general area El. 18.5′ dose rates	

Table 11.5-1B RADIATION MONITORING SYSTEM AREA MONITORS

Sheet 1 of 2

DETECTOR NUMBER	NAME	DAM UNIT-CHANNEL	DETECTOR TYPE	DETECTOR RANGE	AMAU	AMBU (# OF UNITS)
RE-101	Control Room	07-09	G-M Tube (DA1-6CC)	10^{-1}-10^{4}mR/hr		
1-RE-102	Unit 1 Containment Low Range	03-01	G-M Tube (DA1-6CC)	10^{-1}-10^{4}mR/hr	Yes	
2-RE-102	Unit 2 Containment Low Range	04-01	G-M Tube (DA1-6CC)	10^{-1}-10^{4}mR/hr	Yes	
RE-103	Radiochemistry Lab	05-06	G-M Tube (DA1-6CC)	10^{-1}-10^{4}mR/hr	Yes	
1-RE-104	Unit 1 Charging Pump Room Low Range	01-01	G-M Tube (DA1-6CC)	10^{-1}-10^{4}mR/hr	Yes	Yes (3)
2-RE-104	Unit 2 Charging Pump Room Low Range	02-01	G-M Tube (DA1-6CC)	10^{-1}-10^{4}mR/hr	Yes	Yes (3)
RE-105	Spent Fuel Pool Low Range	06-05	G-M Tube (DA1-6CC)	10^{-1}-10^{4}mR/hr	Yes	
1-RE-106	Unit 1 Sampling Room Low Range	03-04	G-M Tube (DA1-6CC)	10^{-1}-10^{4}mR/hr	Yes	
2-RE-106	Unit 2 Sampling Room Low Range	04-04	G-M Tube (DA1-6CC)	10^{-1}-10^{4}mR/hr	Yes	
1-RE-107	Unit 1 Seal Table	01-09	G-M Tube (DA1-6CC)	10^{-1}-10^{4}mR/hr	Yes	
2-RE-107	Unit 2 Seal Table	02-09	G-M Tube (DA1-6CC)	10^{-1}-10^{4}mR/hr	Yes	
RE-108	Drumming Station	07-07	G-M Tube (DA1-6CC)	10^{-1}-10^{4}mR/hr	Yes	Yes (1)
1-RE-109	Unit 1 Sample Line	05-01	G-M Tube (DA1-6CC)	10^{-1}-10^{4}mR/hr		
2-RE-109	Unit 2 Sample Line	06-01	G-M Tube (DA1-6CC)	10^{-1}-10^{4}mR/hr		
RE-110	S.I. Pump Room Low Range	08-09	G-M Tube (DA1-6CC)	10^{-1}-10^{4}mR/hr	Yes	
RE-111	C-59 Panel Area	08-07	Ion Chamber (DA1-4CC)	10^{-2}-10^{2} R/hr	Yes	
RE-112	Central PAB	08-04	Ion Chamber (DA1-4CC)	10^{-2}-10^{2} R/hr	Yes	

Table 11.5-1B RADIATION MONITORING SYSTEM AREA MONITORS
Sheet 2 of 2

DETECTOR NUMBER	NAME	DAM UNIT-CHANNEL	DETECTOR TYPE	DETECTOR RANGE	AMAU	AMBU (# OF UNITS)
RE-113	Auxiliary Building Sump	08-01	G-M Tube (DA1-6CC)	10^{-1}-10^{4}mR/hr	Yes	
RE-114	CVCS Holdup Tank	07-08	Ion Chamber (DA1-4CC)	10^{-2}-10^{2} R/hr	Yes	
RE-116	Valve Gallery	05-05	Ion Chamber (DA1-4CC)	10^{-2}-10^{2} R/hr	Yes	Yes (1)
1-RE-126 1-RE-127 1-RE-128	Unit 1 Containment High Range	None	Ion Chamber	10^{0}-10^{8} R/hr		
2-RE-126 2-RE-127 2-RE-128	Unit 2 Containment High Range	None	Ion Chamber	10^{0}-10^{8} R/hr		
1-RE-134	Unit 1 Charging Pump Room High Range	03-08	Ion Chamber (DA1-5CC)	10^{0}-10^{4} R/hr		
2-RE-134	Unit 2 Charging Pump Room High Range	04-08	Ion Chamber (DA1-5CC)	10^{0}-10^{4} R/hr		
RE-135	Spent Fuel Pool High Range	08-08	Ion Chamber (DA1-5CC)	10^{0}-10^{4} R/hr		
1-RE-136	Unit 1 Sampling Room High Range	01-08	Ion Chamber (DA1-5CC)	10^{0}-10^{4} R/hr		
2-RE-136	Unit 2 Sampling Room High Range	02-08	Ion Chamber (DA1-5CC)	10^{0}-10^{4} R/hr		
RE-140	S. I. Pump Room High Range	05-09	Ion Chamber (DA1-5CC)	10^{0}-10^{4} R/hr		
RE-239	TSC Area	None	GM Tube (DA1-6CS)	10^{-1}-10^{4} mR/hr		
RE-240	TSC El. 18.5′ Assembly Area	None	GM Tube (DA1-6CS)	10^{-1}-10^{4} mR/hr		

AMAU - Area Monitor Alarm Unit: Provides primary alerting beacon and horn and acknowledge and testing switches for the unit.

AMBU - Area Monitor Beacon Unit: Provides secondary, remote alerting beacon for high radiation levels where the primary beacon is not visible throughout the area being monitored.

Table 11.5-2A RADIATION MONITORING SYSTEM PROCESS MONITORS

Sheet 1 of 5

DETECTOR NUMBER	NAME	LOCATION	INDICATION	CONTROL FUNCTION
1/2-RE-211	Containment Air Particulate Monitor	In cubicle on east side of containment façade at El. 52′	Indicates particulate activity inside containment, or in purge exhaust stack when on purge supply & exhaust.	
1/2-RE-211B	Background Monitor for RE-211	Next to RE-211	Indicates ambient radiation levels around RE-211/RE-212 pallet	
1/2-RE-212	Containment Noble Gas Monitor	Located in series with RE-211 on detector skid in the same cubicle on El. 52′ of containment façade	Indicates noble gas activity inside containment, or in purge exhaust stack when on purge supply & exhaust.	Initiates containment ventilation isolation upon high activity, which in turn will close purge valves, and secure continuous vent.
RE-214	Aux. Bldg. Vent Stack Noble Gas Monitor	On aux. bldg. exhaust stack at about El. 80′ in Unit 1 façade just south of elevator	Indicates gaseous activity from the primary auxiliary building, service building, chemistry laboratory, SGBD tank vent condensers, or air ejectors.	Shuts vent gas release valve (WG-014) and initiates exhaust vent filtration through filter bank F-23
1/2-RE-215	Condenser Air Ejector Noble Gas Monitor	West wall of turbine hall on El. 46′ west of MSR's	Indicative of steam generator primary-to-secondary leak. May be indicative of a potential airborne radiation exposure in turbine hall.	
1/2-RE-216	Containment Fan Coolers Liquid Process Monitor	Unit 1 - West and slightly south of C59 panel Unit 2 - West and slightly north of C59 panel	Provides indication of potential contamination of service water outlet from containment fan coolers.	
1/2-RE-216B	Background Monitor for RE-216	Next to RE-216	Monitors radiation levels near RE-216.	

Table 11.5-2A RADIATION MONITORING SYSTEM PROCESS MONITORS
Sheet 2 of 5

DETECTOR NUMBER	NAME	LOCATION	INDICATION	CONTROL FUNCTION
1/2-RE-217	Component Cooling Water Liquid Process Monitor	Unit 1 - In overhead pipe just north of stairs going from El. 8′ of aux. bldg. to panel C59 Unit 2 - In overhead pipe just west of Unit 2 component cooling water pumps	Provides indication of component cooling water contamination	Shuts component cooling water surge tank vent valve, CC-017.
RE-218	Waste Disposal System Discharge Liquid Process Monitor	East wall of waste condensate tank cubicle across from component cooling water pump, El. 8′ of aux. bldg.	Monitors waste condensate tank or monitor tank activity being discharged.	Secures waste condensate tank or monitor tank discharge by shutting WL-018.
RE-218B	Background Monitor	Next to RE-218	Monitors radiation levels near RE-218.	
1/2-RE-219	Steam Generator Blowdown Liquid Process Monitor	Outside of each primary side sample room on El. 26′ of aux. bldg.	Provides indication of steam generator blowdown activity and steam generator tube leak rates.	Shuts steam generator blowdown and blowdown tank outlet valves: MS-5958/5959, 2040, and steam generator blowdown sample valves 2083/2084.
1/2-RE-219B	Background Monitor for RE-219	Next to RE-219	Monitors radiation levels near RE-219.	
RE-220	Spent Fuel Pool Heat Exchanger Service Water Liquid Process Monitor	North wall just west of door to Unit 2 containment façade on El. 46′ of aux. bldg.	Provides indication of service water contamination from a spent fuel pool heat exchanger tube leak.	
RE-220B	Background Monitor for RE-220	Next to RE-220	Monitors radiation levels near RE-220.	

Table 11.5-2A RADIATION MONITORING SYSTEM PROCESS MONITORS
Sheet 3 of 5

DETECTOR NUMBER	NAME	LOCATION	INDICATION	CONTROL FUNCTION
RE-221	Drumming Area Vent Stack Noble Gas Monitor	In exhaust ducting above drumming area SPING in northwest corner of Unit 1 façade	Indicates noble gas activity released from spent fuel pool and drumming area, which may be indicative of a potential aux. bldg. airborne release.	
1/2-RE-222	Steam Generator Blowdown Tank Outlet Liquid Process Monitor	East side of steam generator blowdown tank on El. 26′ of aux. bldg.	Indicates activity level in blowdown tank.	Shuts steam generator blowdown and blowdown tank outlet valves: MS-5958/5959, and 2040.
RE-223	Waste Distillate Discharge Liquid Process Monitor	East side of “D” component cooling water heat exchanger on El. 46′ of aux. bldg.	Monitors activity of waste distillate being discharged.	Shuts discharge valve, BE-LW15.
RE-223B	Background Monitor for RE-223	Next to RE-223	Monitors radiation levels near RE-223.	
RE-224	Gas Stripper Bldg. Exhaust Noble Gas Monitor	In exhaust duct in northeast corner of Unit 2 containment façade, ~ El. 87'.	Indicates activity of gaseous release from letdown gas stripper bldg.	
RE-225	Combined Air Ejector Low-Range Noble Gas Monitor	Above door on El. 46′ of Unit 1 turbine hall west of MSR's.	Indicative of primary-to-secondary leak in steam generators. May also indicate potential radiation exposure sources within turbine bldg.	
RE-226	Combined Air Ejector High-Range Noble Gas Monitor	Refer to RE-225	Refer to RE-225.	

Table 11.5-2A RADIATION MONITORING SYSTEM PROCESS MONITORS
Sheet 4 of 5

DETECTOR NUMBER	NAME	LOCATION	INDICATION	CONTROL FUNCTION
1/2-RE-229	Service Water Discharge Liquid Process Monitor	Unit 1: On El. 8′ of aux. bldg. in vent area Unit 2: In aux. feed pump room on east side of tunnel.	Monitors activity of service water discharge.	
1/2-RE-229B	Background Monitor for RE-229	Next to RE-229	Monitors radiation levels near RE-229.	
RE-230	Wastewater Effluent Process Monitor	El. 8′ of turbine hall outside the entrance to water treatment.	Monitors activity level in wastewater effluent.	
RE-230B	Background Monitor for RE-230	Next to RE-230	Monitors radiation levels near RE-230.	
1/2-RE-231	Steam Line “A” Monitor	El. 88′ of containment façade in area of atmospheric steam reliefs.	Monitors activity of Steam Line A.	
1/2-RE-232	Steam Line “B” Monitor	El. 88′ of containment façade in area of atmospheric steam reliefs.	Monitors activity of Steam Line B.	
RE-234	Control Room Iodine Monitor	Top of control room bldg. El. 46′ of turbine hall	Monitors Iodine activity in control room.	
RE-235	Control Room Noble Gas Monitor	Adjacent to RE-234	Monitors noble gas activity in control room.	Shifts control room ventilation to Mode 5.

Table 11.5-2A RADIATION MONITORING SYSTEM PROCESS MONITORS

Sheet 5 of 5

DETECTOR NUMBER	NAME	LOCATION	INDICATION	CONTROL FUNCTION
RE-237	Technical Support Center (TSC) Iodine Monitor	In HVAC ductwork in northwest corner of TSC bldg. at El. 18.5′	Monitors the iodine activity of the supply air to the TSC, displayed locally only.	
RE-238	Technical Support Center (TSC) Noble Gas Monitor	Adjacent to RE-237	Monitors the noble gas activity of the supply air to the TSC.	

Table 11.5-2B RADIATION MONITORING SYSTEM PROCESS MONITORS

Sheet 1 of 3

Detector Number	Name	DAM Unit-Channel	Detector Type	Medium
1(2)RE-211	Containment Air Particulate Monitor	01-02 (02-02)	Scintillation (RDA-3)	Air
1(2)RE-211B	Background Monitor for 1(2)RE-211	01-04 (02-04)	GM Tube (DA1-1)	Air
1(2)RE-212	Containment Noble Gas Monitor	01-03 (02-03)	Scintillation (RDA-3)	Air
RE-214	Aux. Bldg. Exhaust Ventilation Gas Monitor	07-04	Scintillation (RDA-3)	Air
1(2)RE-215	Condenser Air Ejector Gas Monitor	03-05 (04-05)	Scintillation (RDA-3)	Air
1(2)RE-216	Containment Fan Coolers Liquid Monitor	01-05 (02-05)	Scintillation (RDA-5)	Water
1(2)RE-216B	Background Monitor for 1(2)RE-216	01-06 (02-06)	GM Tube (DA1-1)	
1(2)RE-217	Component Cooling Water Liquid Monitor	03-06 (04-06)	Scintillation (RDA-5)	Water
RE-218	Waste Disposal System Liquid Monitor	07-02	Scintillation (RDA-5)	Water
RE-218B	Background Monitor for RE-218	07-03	GM Tube (DA1-1)	
1(2)RE-219	S/G Blowdown Liquid Monitor	05-03 (06-03)	Scintillation (RDA-5)	Water
1(2)RE-219B	Background Monitor for 1(2)RE-219	05-04 (06-04)	GM Tube (DA1-1)	

Table 11.5-2B RADIATION MONITORING SYSTEM PROCESS MONITORS
Sheet 2 of 3

Detector Number	Name	DAM Unit-Channel	Detector Type	Medium
RE-220	Spent Fuel Pool Liquid Monitor	07-05	Scintillation (RDA-5)	Water
RE-220B	Background Monitor for RE-220	07-06	GM Tube (DA1-1)	
RE-221	Drumming Area Vent Gas Monitor	05-07	Scintillation (RDA-3)	Air
1(2)RE-222	Blowdown Tank Outlet Monitor	01-07 (02-07)	GM Tube (DA1-6)	
RE-223	Waste Distillage Overboard Liquid Monitor	08-05	Scintillation (RDA-5)	Water
RE-223B	Background Monitor for RE-223	08-06	GM Tube (DA1-1)	
RE-224	Gas Stripper Building Exhaust Monitor	06-06	Scintillation (RDA-3)	Air
RE-225	Combined Air Ejector Low Range Monitor	07-01	Scintillation (RDA-3)	Air
RE-226	Combined Air Ejector High Range Monitor	05-08	Ion Chamber (DA1-4)	Air
1(2)RE-229	Service Water Discharge Monitor	03-02 (04-02)	Scintillation (RDA-5)	Water
1(2)RE-229B	Background Monitor for 1(2)RE-229	03-03 (03-04)	GM Tube (DA1-1)	
RE-230	Wastewater Effluent Monitor	08-02	Scintillation (RDA-5)	Water
RE-230B	Background Monitor for RE-230	08-03	GM Tube (DA1-1)	

Table 11.5-2B RADIATION MONITORING SYSTEM PROCESS MONITORS

Sheet 3 of 3

Detector Number	Name	DAM Unit-Channel	Detector Type	Medium
1(2)RE-231	Steam Line Monitors - Line A	03-09 (04-09)	GM Tube	
1(2)RE-232	Line B	05-02 (06-02)	GM Tube	
RE-234	Control Room Iodine Monitor	06-07	Scintillation (RDA-2)	Air
RE-235	Control Room Noble Gas Monitor	06-09	Scintillation (RDA-3)	Air
RE-237	TSC Iodine Monitor	None	Scintillation (RDA-2)	Air
RE-238	TSC Noble Gas Monitor	None	Scintillation (RDA-3)	Air

RDA-2 2″ diameter X 2″ thick NaI(TI) crystal with an AM-241 seed embedded for automatic gain stabilization. The TI is an impurity added for low energy gamma stabilization.

RDA-3 2″ diameter X.01″ thick plastic crystal.

RDA-5 Same as an RDA-2 minus the Am-241 seed.

Table 11.5-3 RADIATION MONITORING SYSTEM SPECIAL PARTICULATE IODINE AND NOBLE GAS MONITORS SPINGS
Sheet 1 of 2

Number	Name	SPING Number	Location	Detector Type
			Unit 1(2) Containment Purge Exhaust Monitor	
1(2)RE-301	Beta Particulate	21-01 (22-01)	Unit 1(2) Rod Drive Room	RDA-3
1(2)RE-303	Iodine	21-03 (22-03)	Unit 1(2) Rod Drive Room	RDA-2
1(2)RE-305	Low Range Gas	21-05 (22-05)	Unit 1(2) Rod Drive Room	RDA-3
1(2)RE-306	Area Monitor	21-06 (22-06)	Unit 1(2) Rod Drive Room	DA1-1
1(2)RE-307	Mid Range Gas	21-07 (22-07)	Unit 1(2) Rod Drive Room	GM Tube
1(2)RE-309	High Range Gas	21-09 (22-09)	Unit 1(2) Rod Drive Room	GM Tube

Table 11.5-3 RADIATION MONITORING SYSTEM SPECIAL PARTICULATE IODINE AND NOBLE GAS MONITORS SPINGS
Sheet 2 of 2

Number	Name	SPING Number	Location	Detector Type
			Auxiliary Building Exhaust Monitor	
RE-311	Beta Particulate	23-01	Unit 1 Rod Drive Room	RDA-3
RE-313	Iodine	23-03	Unit 1 Rod Drive Room	RDA-2
RE-315	Low Range Gas	23-05	Unit 1 Rod Drive Room	RDA-3
RE-316	Area Monitor	23-06	Unit 1 Rod Drive Room	DAI-1
RE-317	Mid Range Gas	23-07	Unit 1 Rod Drive Room	GM Tube
RE-319	High Range Gas	23-09	Unit 1 Rod Drive Room	GM Tube
			Drumming Area Exhaust Monitor	
RE-321	Beta Particulate	24-01	Top of Drumming Area	RDA-3
RE-323	Iodine	24-03	Top of Drumming Area	RDA-2
RE-325	Low Range Gas	24-05	Top of Drumming Area	RDA-3
RE-326	Area Monitor	24-06	Top of Drumming Area	DA1-1
RE-327	Mid Range Gas	24-07	Top of Drumming Area	GM Tube

Figure 11.5-1 TYPICAL RMS CHANNEL FUNCTIONAL BLOCK DIAGRAM

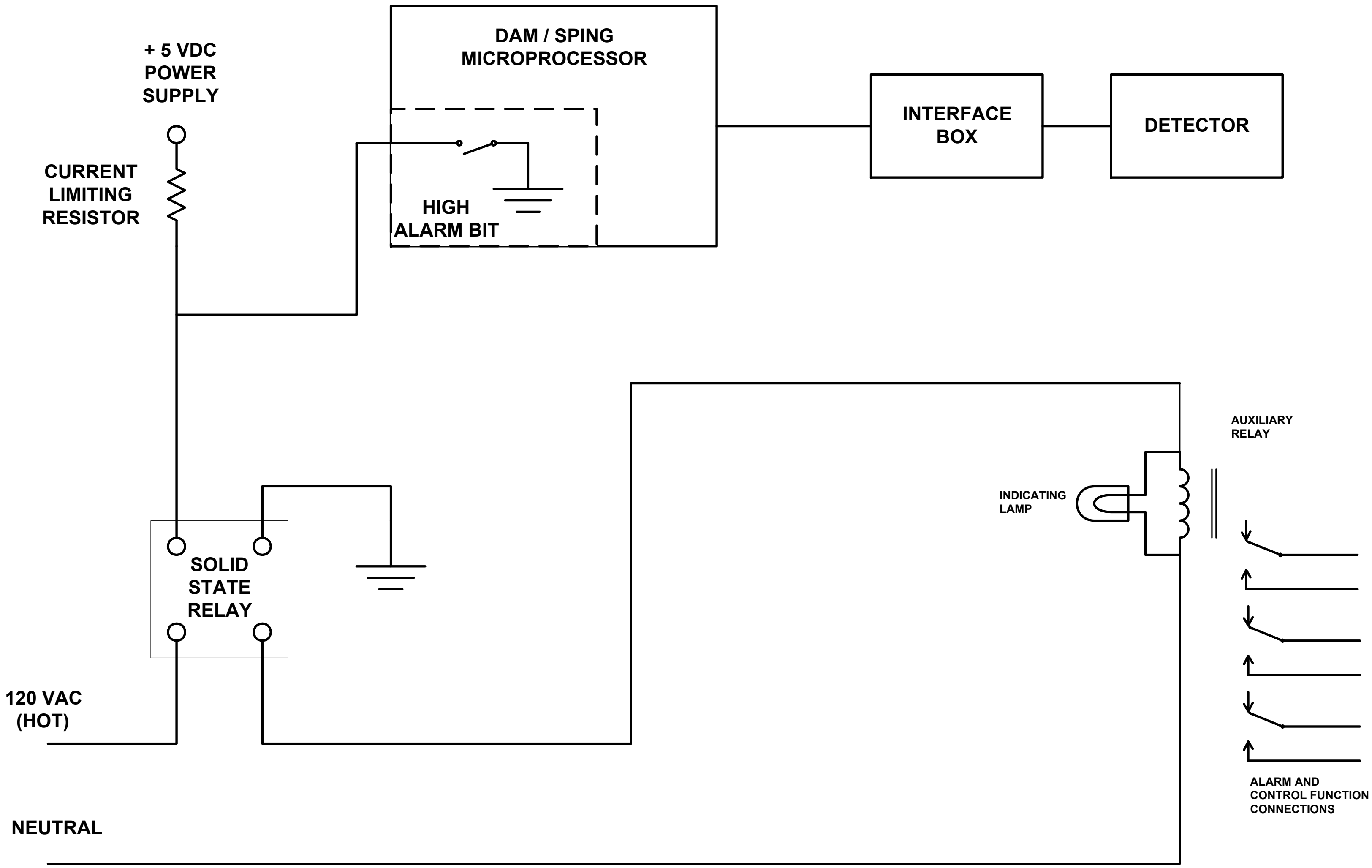
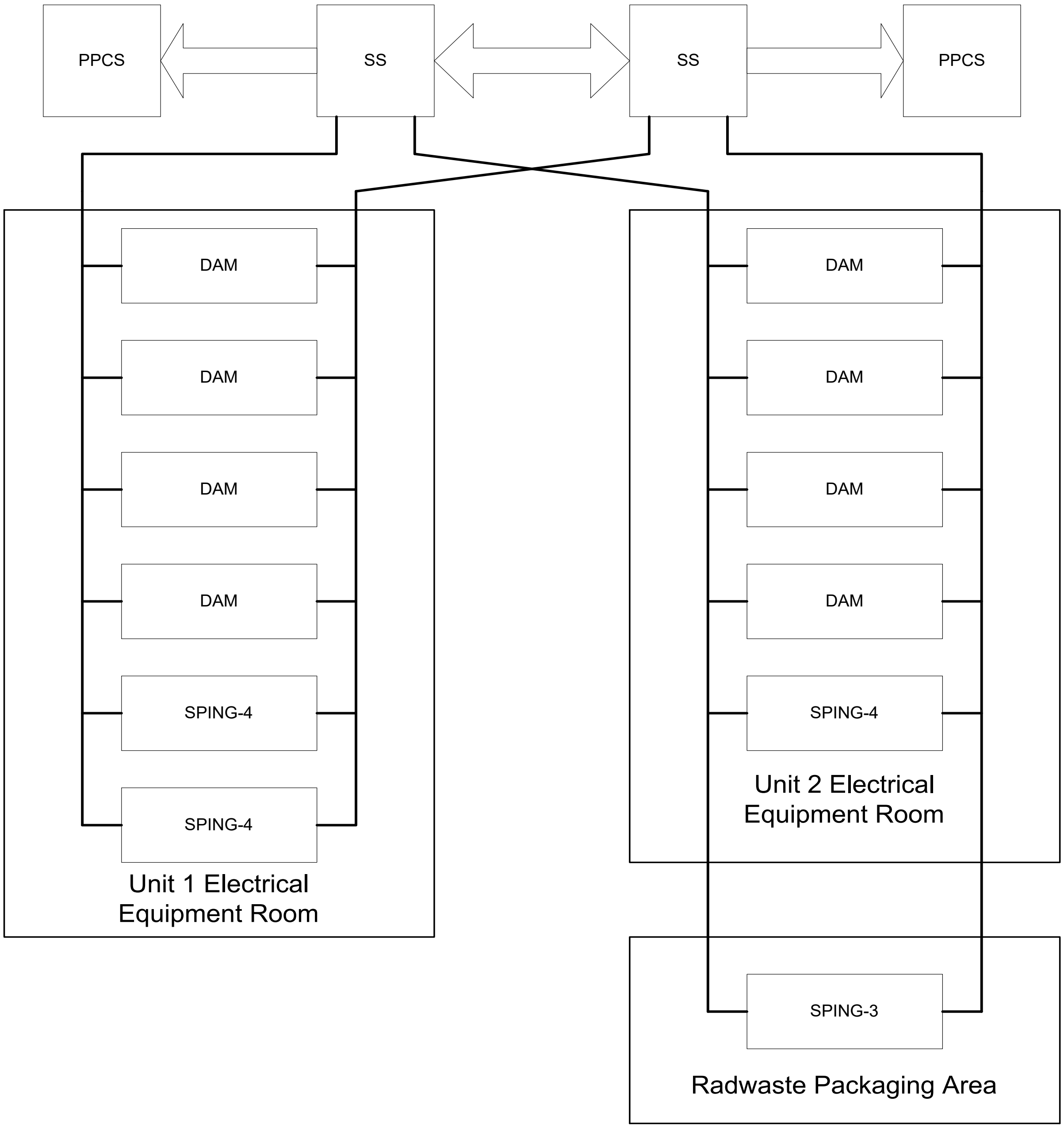


Figure 11.5-2 RADIATION MONITORING SYSTEM FUNCTIONAL BLOCK DIAGRAM



11.6 SHIELDING SYSTEMS

11.6.1 DESIGN BASES

Fuel and Waste Storage Radiation Shielding

Criterion: Adequate shielding for radiation protection shall be provided in the design of spent fuel and waste storage facilities. (GDC 68)

Auxiliary shielding for the waste disposal system and its storage components is designed to limit the dose rate to levels not exceeding 1 mr/hr in normally occupied areas and to levels typically <5 mr/hr in periodically occupied areas. Areas having levels in excess of 100 mr/hr, for example, the packaged waste storage area, are posted and barricaded.

Gamma radiation is continuously monitored in the auxiliary building. A high level signal is alarmed locally and annunciated in the control room.

11.6.2 SYSTEM DESIGN AND OPERATION

Radiation shielding is designed for operation at maximum calculated thermal power and to limit the normal operation radiation levels at the site boundary to below those levels allowed for continuous non occupational exposure. The plant is capable of continued safe operation with 1% fuel element defects.

In addition, the shielding provided ensures that in the unlikely event of a maximum design accident, the contained activity does not result in any harmful off-site radiation exposures.

Original design of the plant shielding was performed for a licensed core power level of 1518.5 MWt and a 12-month fuel cycle length. The plant shielding was re-evaluated for the extended power uprate (EPU) assuming a core thermal power of 1810.8 MWt and an 18-month fuel cycle using scaling techniques and the information presented in the following sections and original design reports. Taking into consideration the conservative analytical techniques used to establish the original shielding design and the plant Technical Specifications, which restrict the reactor coolant activity to levels significantly less than 1% fuel defects, it is concluded that the increase in the core power level and in the fuel cycle length will have no significant impact on plant shielding adequacy and safe plant operation. (Reference 12, Reference 13, Reference 16)

Operating personnel at the plant are protected by adequate shielding, monitoring, and operating procedures. Each area in the plant is classed according to the dose rate allowable in the area, based on the expected frequency and duration of occupancy. All plant areas capable of personnel occupancy are classified as one of the five zones of radiation level listed in Table 11.6-1.

Typical Zone 0 areas are the turbine building and turbine plant service areas. Typical Zone I areas are the offices and control room. Zone II areas include the local control spaces in the auxiliary building, and the operating deck of the containment during reactor shutdown. Areas designated Zone III include the sample room, valve galleries, fuel handling areas, and intermittently occupied work areas. Typical Zone IV areas are the shielded equipment compartments in the Auxiliary Building, waste drum storage area, and the primary loop compartments after shutdown.

All radiation and high radiation areas are appropriately marked and isolated in accordance with 10 CFR 20 and other applicable regulations.

The shielding is divided into five categories according to function. These functions include the primary shielding, the secondary shielding, the accident shielding, the fuel transfer shielding, and the auxiliary shielding.

11.6.2.1 Shielding Functions

Primary Shielding

The primary shielding is designed to:

1. Reduce the neutron fluxes incident on the reactor vessel to reduce neutron embrittlement of the reactor vessel beltline region.

2. Attenuate the neutron flux sufficiently to prevent excessive activation of plant components.

3. Limit the gamma flux in the reactor vessel and the primary concrete shielding to avoid excessive temperature gradients or dehydration of the primary shield.

4. Reduce the residual radiation from the core, reactor internals and reactor vessel to levels which will permit access to the region between the primary and secondary shields after plant shutdown.

5. Reduce the contribution of radiation leaking to obtain optimum division of the shielding between the primary and secondary shields.

Secondary Shielding

The main function of the secondary shielding is to attenuate the radiation originating in the reactor and the reactor coolant. The major source in the reactor coolant is the Nitrogen-16 activity, which is produced by neutron activation of oxygen during passage of the coolant through the core. The secondary shielding will limit the full power dose rate outside the containment building from radioactivity inside the containment to less than 1 mr/hr.

Accident Shield

The main purpose of the accident shield is to ensure safe radiation levels outside the containment building following a maximum design accident.

Fuel Handling Shield

The fuel handling shield permits the safe removal and transfer of spent fuel assemblies and control rod clusters from the reactor vessel to the spent fuel pool. It is designed to attenuate radiation from spent fuel, control clusters, and reactor vessel internals to less than 2.5 mr/hr at the refueling cavity water surface and less than 1.0 mr/hr in the auxiliary building.

Auxiliary Shielding

The function of the auxiliary shielding is to protect personnel working near various system components in the chemical and volume control system, the residual heat removal system, the waste disposal system and the sampling system. The shielding provided for the auxiliary building is designed to limit the dose rate to less than 1 mr/hr in normally occupied areas, and at or below 2.5 mr/hr in periodically occupied areas.

11.6.2.2 Shielding Design

Primary Shielding

The primary shielding consists of the reactor internals, the reactor vessel wall, and a concrete structure surrounding the reactor vessel.

The primary shielding immediately surrounding the reactor vessel consists of a reinforced concrete structure extending from the base of the containment to an elevation of 66.0 ft. The lower portion of the shield is a minimum thickness of 6.5 ft. of concrete and is an integral part of the main structural concrete support for the reactor vessel. It extends upward to the operating floor, forming a portion of the refueling cavity. This cavity is approximately rectangular in shape, and has concrete sidewalls which are 5 ft. 5 in. thick adjacent to areas in which fuel is transported.

The primary concrete shielding is air cooled to prevent overheating and dehydration from the heat generated by radiation absorption in the concrete. Eight "windows" have been provided in the primary shield for insertion of the out-of-core nuclear instrumentation. Cooling for the primary shield concrete, nuclear instrumentation, and vessel supports is provided by circulating 26,000 cfm of containment air between the reactor vessel wall and the surrounding concrete structure.

The original primary shield neutron fluxes and design parameters are listed in Table 11.6-2. The parameters listed in Table 11.6-2 are the original design parameters used to assess the adequacy of the Primary Shielding while operating at 1518.5 MWt. The calculations of neutron and gamma ray leakage from the reactor were based on a design basis core configuration that included fresh fuel on the periphery of the core, thus maximizing the neutron and gamma radiation levels external to the reactor vessel. In actual operations, low-low leakage fuel management is used which places burned fuel on the periphery of the core. This fuel management strategy acts to reduce radiation leakage by at least a factor of two. With continued use of low leakage fuel management, the original primary shielding remains adequate following EPU (Reference 12).

Secondary Shield

The secondary shield surrounds the reactor coolant loops and the primary shield. It consists of interior walls within the containment building, the operating floor, and the reactor containment building itself. The containment building also serves as the accident shield.

The lower portion of the secondary shield above grade consists of the 3 ft. 6 in. thick cylindrical portion of the reactor containment and a minimum of 3 ft. thick concrete interior walls surrounding the reactor coolant loops. The secondary shield will attenuate the radiation levels in the primary loop compartment from a value of 25 rem/hr to a level of less than 1 mr/hr outside the reactor containment building. Penetrations in the secondary shielding are protected by supplemental shields.

The original secondary shield design parameters are listed in Table 11.6-3. The parameters listed in Table 11.6-3 are the original design parameters used to assess the adequacy of the Secondary Shielding while operating at 1518.5 MWt. As discussed earlier, the secondary shielding was designed to attenuate the radiation originating from the N-16 activity. N-16 is produced as the oxygen in the water moderator is exposed to the neutron flux present in the reactor core. The amount of activation is defined by the flux (or power) density of the core and the amount of time the moderator is resident in the core. After the moderator exits the core (and neutron field), decay of the N-16 will occur. The amount of decay at any given point in the coolant loop is defined by the time subsequent to exiting the core.

The key parameter affected by power uprate is the change (increase) in the core flux level. This is quantified by the "Core Power Density" design parameter. The change in this parameter will be directly proportional to the change in core power; therefore, the amount of N-16 would also be expected to increase in the same proportion as the core power density and in turn the dose rates in areas inside the secondary shielding surrounding the reactor coolant loops would increase in the same proportion. At EPU conditions, the N-16 source is estimated to increase by approximately 19% compared to original design. The N-16 activity level is not impacted by fuel cycle length. The impact of the estimated 19% increase in source terms is bounded by the conservative analytical techniques typically used to establish plant shielding design (such as ignoring the shadow shielding effect of the neighboring sources, rounding up the calculated shield thickness to a higher whole number, etc.). The current reactor coolant loop shielding and containment structure is determined to be adequate for safe operation following EPU (Reference 12).

Accident Shield

The accident shield consists of the 3 ft. 6 in. prestressed concrete cylinder capped by a shallow, prestressed concrete dome 2 ft. 6 in. thick. Supplemental shielding has been provided for the containment penetrations.

The equipment access hatch is shielded by a 3 ft. thick concrete shadow shield, and a 1 ft. concrete roof to reduce scattered radiation. The personnel lock is provided with an internal lead shield, 3 inches thick, to reduce streaming through the hatch doors following an accident. Smaller penetrations associated with piping and electrical cables are directed into pipe tunnels which are shielded with a minimum of 18 in. of concrete. The control room is protected with concrete sidewalls 18 in. thick, and a concrete roof 14 in. thick.

The original accident shield design parameters are listed in Table 11.6-4.

The post EPU contribution of direct radiation from the radioactivity inside containment on control room dose and the habitability of other plant areas following a LOCA are discussed in Section 11.6.3.

Fuel Handling Shield

The refueling cavity is formed by the upper portions of the primary shield concrete, and other sidewalls of varying thicknesses. A portion of the cavity is used for storing the upper and lower internals packages; these are shielded with concrete walls 5 ft. thick. The remaining walls vary from 3 ft. to 5 ft. 5 in. thick, and provide the shielding required for handling spent fuel.

The refueling cavity, flooded with borated water during refueling operations, provides a temporary water shield above the components being withdrawn from the reactor vessel. The water height during refueling is greater than 21 ft. above the reactor vessel flange. This height ensures that a more than 8 ft. of water will be above the top of a withdrawn fuel assembly. Under these conditions, the dose rate is less than 2.5 mr/hr at the water surface, due to the fuel assembly.

The spent fuel assemblies and control rod clusters are remotely removed from the reactor containment through the horizontal spent fuel transfer tube and placed in the spent fuel pool. The spent fuel transfer tube shielding is designed to protect personnel from radiation during the time a spent fuel assembly is passing through the main concrete support of the reactor containment and the transfer tube.

Radial shielding during fuel transfer is provided by the water and concrete walls of the fuel transfer canal. Sufficient shielding is provided to ensure a maximum dose value of 1.2 mr/hr. in the auxiliary building areas adjacent to the spent fuel pool, next to the exterior of the vertical pool walls.

Spent fuel is stored in the spent fuel pool which is located adjacent to the containment building. Radial shielding for the spent fuel is provided by 5 ft. thick concrete walls plus a minimum of 4 in. of water. The pool is flooded with borated water to a level such that the water height above the stored fuel assemblies is approximately 25 ft. The shielding design parameters for the spent fuel pool include a core unload of 121 assemblies with a cooling time of three days and a pre-EPU average burnup of 40,000 MWD/MTU for all assemblies.

Level and radiation alarms provide assurance that exposure of fuel assemblies cannot occur during transfer operations. A water level sensor in the spent fuel pool provides a low level alarm in the plant control room at a water elevation of 62 ft. 8 in. At this low level alarm point, there would still be more than 7 ft. of water over any withdrawn fuel assembly. A radiation monitor located on the bridge of the fuel handling and transfer manipulator crane alarms locally when radiation levels increase to a pre-determined level above normal background. If an irradiated fuel assembly were to approach the surface of the refueling cavity, the monitor would sense the increase in radiation level and actuate the alarm.

With the analyzed core power increase to 1810.8 MWt, the gamma source from the irradiated fuel is estimated to increase by approximately 19%. The 18-month fuel cycle will also increase the inventory of long-lived isotopes in the irradiated fuel. However, this is not a concern as the estimated maximum dose rates near the refueling canal and the spent fuel pool are dominated by the shorter half-life isotopes in the freshly discharged spent fuel assemblies. The impact of the estimated 19% increase in source terms used in the EPU analysis versus the original shielding analysis is bounded by the conservative analytical techniques which were used to establish plant shielding design. Consequently, the current spent fuel shielding is determined adequate for safe operation following EPU. (Reference 12)

Auxiliary Shielding

The auxiliary shield consists of concrete walls around certain components and piping which process reactor coolant. In some cases, the concrete block walls are removable to allow personnel access to equipment during maintenance periods. Each equipment compartment is individually shielded so that compartments may be entered without having to shut down and, possibly, to decontaminate the adjacent system.

The shield material provided throughout the auxiliary building is concrete. The principal original auxiliary shielding provided is tabulated in Table 11.6-5.

A power uprate will impact the radiation source terms in the core and the "expected" radiation source terms in the coolant. "Expected" source terms are generally less than those allowed by the plant Technical Specifications and are usually significantly less than the "design basis" source terms.

The EPU assessment concluded that the estimated increase in the dose rate for shielded configurations based on the design basis EPU reactor coolant activity versus the pre-uprate coolant activity is compensated by the plant Technical Specifications that will limit the EPU reactor coolant source terms and associated dose rates to less than the original design basis values. Therefore the shielding design based on the original design basis primary coolant activity remains acceptable for the EPU condition. (Reference 12)

11.6.3 SYSTEM EVALUATION

CONTROL ROOM HABITABILITY

In accordance with the requirements set forth in NUREG-0737, the habitability of the PBNP control room has been evaluated. With respect to radiological conditions, the habitability of the control room is most challenged by the large break loss of coolant accident (LOCA) described by FSAR Chapter 14.3. This evaluation and subsequent evaluations have taken credit for the shielding features described in this chapter to evaluate the direct radiation dose and have taken credit for the ventilation-filtration features described in FSAR Chapter 9.8 to evaluate the dose to the control room operator caused by the radioactivity introduced to the control room atmosphere. Refer to FSAR Chapter 9.8 and FSAR Chapter 14.3.5 for more detailed analysis of the post-accident dose caused by radioactivity introduced to the control room. The following discussion generally describes the contributing factors which ensure the habitability of the control room following a design basis accident.

Habitability analyses consider the following contributions to control room operator radiation dose:

1. Inhalation of radioactivity emitted from the post-LOCA containment atmosphere. Leakage from containment is postulated to escape to the environment and then be drawn into the control room through the control room ventilation system. The performance of the control room ventilation system and the assumptions of the analysis are described in FSAR Chapter 9.8 and Chapter 14.3.5.

2. Inhalation of radioactivity emitted from emergency core cooling system (ECCS) piping leaks during the recirculation phase of the accident. Leakage from the ECCS into the primary auxiliary building (PAB) atmosphere and leakage from the refueling water storage tank (RWST) vent is postulated. Some of the activity is released to the environment and then drawn into the control room through the control room ventilation system. The performance of the control room ventilation system and the assumptions of the analysis are described in FSAR Chapter 9.8 and Chapter 14.3.5.

3. Direct radiation from the cloud of radioactivity inside the containment. This is not a significant contribution, but has been calculated in Reference 5.

4. Direct radiation from the cloud of radioactivity that may escape the containment. This contribution has been calculated in Reference 5.

5. Direct radiation from the cloud of radioactivity that may escape from ECCS piping leaks in the PAB. This contribution has been calculated in Reference 5.

6. Direct radiation from the control room emergency filter source. This contribution has been calculated in Reference 5.

In addition, the contribution of scattered radiation from air (“sky-shine”) and scattering from large surfaces in the vicinity of containment had been considered in original analyses. However, estimates indicated that the scattered radiation levels would contribute less than 10% of the direct dose. Therefore, scattered radiation has not been considered to be a contributor to control room dose analyses.

Direct Radiation Dose Due to the Radioactive Cloud Inside Containment

Radiation emitted directly from containment is a contributor to post-accident control room gamma doses. The direct dose rate in the control room due to the activity dispersed within the containment is calculated by a computer program which is based on a point kernel attenuation model. The source region is divided into a number of incremental source volumes and the associated attenuation, gamma ray buildup, and distance through regions between each source point and the control room are computed.

The source term for this evaluation is based on operation at 1810.8 MWt for 18 months, and release to the reactor containment of fission products with the fractions and the timing/duration of releases as described in RG 1.183. The fission products are assumed to be homogeneously distributed within the free volume of the reactor containment.

The calculated thirty-day integrated gamma dose to general areas of the control room attributable to direct containment radiation is insignificant. The containment wall, control room wall, and other major intervening walls and floors were considered as shielding. (From Reference 5).

Direct Radiation Dose Due to Control Room Emergency Ventilation Filters

The halogens and particulates in the plume resulting from containment leakage and the halogens in the ECCS/RWST leakage plume are transported to the control room intake and deposited in the emergency ventilation filters. The control room filter unit is located in the northeast corner of the equipment room, shielded from the control room by 4-inch concrete pads below the filter unit and the nearby heat exchanger units, and by the 14-inch control room concrete ceiling. The point-kernel computer code QAD-CGGP (Reference 6) was used to calculate the direct radiation dose due to the filter source. The calculated 30-day dose is 0.04 rem at the northeast corner of the control room. The contribution of the filter source to the rest of the control room is negligible. (Reference 5)

Direct Radiation Dose Due to the Radioactive Cloud from ECCS Leakage in PAB

Analyses have conservatively included the direct radiation dose from a postulated cloud which may form from the ECCS piping leakage during the recirculation phase of the accident. The equipment leakage rate is assumed to be 300 cc/minute (See Table 14.3.5-5 for clarification) for this analysis. The source term for this evaluation is based on operation at 1810.8 MWt. The fraction of core inventory of iodine in the recirculation water is assumed to be 40 percent. It is assumed that the cloud formed from this leakage is dispersed toward the control room. The contribution of this leakage is added to the postulated radioactive cloud formed from the containment leakage. The analysis of that cloud and the total radiation dose from the radioactive clouds are described below.

Direct Radiation Dose Due to the Radioactive Cloud from Back-Leakage into RWST

Following a postulated loss-of-coolant accident, a small amount of recirculating sump water may back-leak into the Refueling Water Storage Tank (RWST). Some of the radioiodines from the RWST liquid phase may become airborne and be released to the atmosphere. Analysis have conservatively included the direct radiation dose from a postulated cloud which may form from this release. The back-leakage rate is assumed to be 500 cc/minute (See Table 14.3.5-5 for clarification). The source term is based on operation at 1810.8 MWt. The fraction of core inventory of iodine in the recirculating water is assumed to be 40 percent. The contribution of this leakage is added to the postulated radioactive cloud formed from the containment leakage. The analysis of that cloud and the total radiation dose from the radioactive clouds are described below.

Direct Radiation Dose Due to the Radioactive Cloud Which Escapes Containment

The direct radiation dose due to the postulated radioactive cloud outside of the control room (also called the “passing plume”) was calculated using the computer program QAD-CGGP (Reference 6), a point-kernel code. The contribution from the postulated containment leakage, ECCS equipment leakage, and RWST back-leakage were summed. The assumed radioactive source terms are based on those used in the large break LOCA dose calculations described in Chapter 14.3.5. The source term for this evaluation is based on operation at 1810.8 MWt. (Reference 5)

Radiation from the passing plume may stream through the control room doors and window. The “door” relates to the 9 x 10 foot bullet-proof fire wall structures used for ingress and egress located at the northeast and southeast corners of the control room. The “window” relates to the 9 × 12 foot bullet-proof fire wall structure on the east wall of the control room. The post-accident dose rates resulting from radiation emissions from the passing plume decrease considerably with increasing distances inside the control room doors and window. Dose rates near the control room window are also more restrictive because radiation emanating through the window impinges on central areas of the control room where occupancy times are expected to be higher. Areas located immediately inside the control room doors are expected to be occupied for limited and infrequent periods. To facilitate the calculation of estimated integrated doses, it is necessary to assume conservative occupancy factors. Dose rates inside the control room were calculated at locations 10 feet from the north and south control room doors, and 5 feet from the control room window. The dose resulting from an operator occupancy time of 100% at a location 5 feet from the control room window is used in the control room total dose determination. (Reference 5)

Analyses assume placement of 3 inches of steel shielding for the window and 2 inches of steel shielding (7 inches of concrete equivalent) for the south door to reduce the post-accident dose from the passing plume (Reference 5). Portable lead shielding was originally used to shield the window and south door but was replaced by permanent shielding per Engineering Change EC 11691 (Reference 11). The equivalent-lead thickcness of the permanent shielding exceeds that of the portable lead shielding.

Conclusions

Analyses showed that the direct radiation dose accumulated over the 30-day duration of the accident will be less than 0.32 rem (Reference 5). To address the remaining contributors to the control room radiation, FSAR Chapter 14.3.5 describes the dose contributed from radioactivity which is drawn into the control room during the accident. As described therein, the 30-day Total Effective Dose Equivalent (TEDE) dose from the radionuclides within the control room for the large break LOCA event is 4.4 rem.

Therefore, the direct radiation dose to operators from radiation outside the control room in combination with the radiation dose from radioactivity inside the control room is maintained below the 5 rem TEDE dose limit for the duration of the event.

Habitability of Other Operating Areas: Prior to NUREG-0737 (Historical)

Although the whole body dose rate to personnel entering and exiting the facility buildings would be expected to be higher than that in the control room, two factors assure that the applicable criterion will not be exceeded. First the times required for entry and exit are short. Secondly, the selection of entry and exit times can make use of favorable atmospheric dispersion conditions and wind directions, and information available from activity monitors.

To determine the possible dose that an operator could receive under accident conditions while operating a manual backup item (e.g., valve), it is estimated rather conservatively that it will require 15 minutes to operate the valve. In addition, it is assumed that an additional 15 minutes is required to get to and from the manual equipment. The total integrated whole body dose that an operator would receive performing the above operation would be about 8 rem. This dose is calculated for the first half hour immediately following the accident and assumes that the equipment being operated or services is adjacent to the containment surface. Doses in the vicinity of equipment located within the auxiliary building would be much less due to the shielding afforded by the concrete walls of the auxiliary building.

All components necessary for the operation of the external recirculation loop following a loss-of-coolant accident are capable of remote manual operation from the control room and can be powered by the emergency diesel-generators so that it should not be necessary to enter the auxiliary building in the vicinity of the recirculation loops.

The radiation sources used with the auxiliary shielding design criteria result from a loss of coolant accident caused by a double-ended rupture of a reactor coolant loop where the engineered safety features function to prevent melting of fuel cladding and to limit the cladding metal-water reaction to a negligible amount. This would result in only the fission products which are in the fuel rod gaps being released to the containment. The nongaseous activity would be absorbed in the sump water which flows in the residual heat removal loop and associated equipment. The radiation sources circulating in the residual heat removal loop, shown in Table 11.6-6, form the basis for radiation doses in the auxiliary building.

The radioactivity in the containment building could be an additional source of radiation to the auxiliary building following a loss-of-coolant accident. However, the radiological exposure rate in the auxiliary building from this source would be less than 1% of that from heat removal system piping.

An evaluation was made of direct radiation levels surrounding a 14 in. RHR pipe. The evaluation was based on the radiation sources and evaluation parameters tabulated in Table 11.6-6.

The results of the evaluation are presented in Figure 11.6-1, showing the dose rates for an unshielded and shielded pipe as function of distance. The sensitivity of radiation levels external to the pipe to different degrees of activity released is expressed in Figure 11.6-2. The dose ratio obtained from Figure 11.6-2 may be multiplied by dose rates from Figure 11.6-1 to account for activity levels in the piping which are different from activities resulting from release of fuel rod clad gap activity.

If maintenance of equipment near the recirculation loop is absolutely essential to the continued operation of the engineered safety features during the recirculation phase, local shielding would permit some operations in vicinity of the loop with attendant dose rates of less than 25 rem per hour within one hour following the accident.

If maintenance directly on the loop proper is required, such operations would be limited in duration as radiation levels adjacent to equipment containing the sump water and fission products might be as high as 200 to 300 rem per hour shortly after the initiation of recirculation. Any such emergency maintenance operations described above could be carried out using portable breathing equipment to limit the inhalation hazard from possibly leaking components.

The RHR piping direct doses were performed assuming a power level of 1518.5 MWt. Increasing the power by 2% (~1548.9 MWt) would not result in direct dose rates in excess of those presented in Figure 11.6-1 because of the conservatism in the original assumption made for the RHR piping diameter. The RHR piping associated with recirculation of sump water has a maximum diameter of ten inches as opposed to fourteen inches as assumed in the original design evaluation. The source term assuming power operations at 1518.5 MWt and a 14-inch diameter pipe is large enough to bound a source term assuming 1548.9 MWt and 10 inch pipe.

<u>Habitability of Other Operating Areas: NUREG-0737 Requirements</u>

Additional shielding has been installed in areas of the plant identified by a design review per the requirements NUREG-0737, Item II.B.2 (Reference 9, Reference 10). The purpose of the design review of plant shielding was to identify the location of vital areas and equipment in which personnel occupancy may be unduly limited or safety equipment may be unduly degraded during post-accident operations. The criteria for dose rates and for accessibility to vital areas are based on 10 CFR 50, Appendix A, GDC 19, which limits the dose to an operator to 5 rem TEDE during the course of an accident in accordance with 10 CFR 50.67. Following changes associated with EPU implementation, there are no vital areas requiring short-term access during the post LOCA recirculation phase other than the control room and technical support center. (Reference 13, Reference 14, Reference 15).

11.6.4 REQUIRED PROCEDURES AND TESTS

Complete radiation surveys were made throughout the plant containment and auxiliary building during initial phases of plant startup. Survey data were taken and compared to design levels at power levels ranging from approximately .01% to 100% rated full power. Survey data at each power level were reviewed for conformance to design before increasing to a higher power level.

11.6.5 REFERENCES

1. NRC Information Notice 83-064: Lead Shielding Attached to Safety-Related Systems Without 10 CFR 50.59 Evaluations, dated September 29, 1983.

2. NRC Information Notice 90-033: Sources of Unexpected Occupational Radiation Exposures At Spent Fuel Storage Pools, dated May 9, 1990.

3. NRC Information Notice 93-039: Radiation Beams from Power Reactor Biological Shields dated May 25, 1993.

4. WE Letter to NRC, “Additional Response To NUREG-0737,” dated September 4, 1984.

5. Calculation 129187-M-0105, “Control Room Direct Shine Dose Due to Loss of Coolant Accident Following Extended Power Uprate and Using Alternate Source Term Methodology,” Revision 1, dated April 27, 2011.

6. QAD-CGGP, “A Combinatorial Geometry Version of QAD-P5A, A Point Kernel Code System for Neutron and Gamma-Ray Shielding Calculations Using the GP Buildup Factor.”

7. WE Letter to NRC, NPL-97-0315, “Supplement to Technical Specifications Change Request 192,” dated June 3, 1997.

8. Westinghouse Report, WEP-98-077, “Wisconsin Electric Power Company, Point Beach Units 1 and 2 Chapter 9 and 11 - FSAR Updates,” December 8, 1998.

9. NUREG-0737, “Clarification of TMI Action Plan Requirements,” dated October 31, 1980.

10. NRC Safety Evaluation of NUREG-0737 Item II.B.2.2, “Plant Shielding Modifications for Vital Area Access,” Point Beach Nuclear Plant, Unit Nos. 1 and 2, dated November 3, 1983.

11. Engineering Change EC 11691 (258119), Revision 1, “Addition of Control Room Shielding,” Approved March 30, 2010.

12. FPL Energy Point Beach Letter to NRC, NRC 2009-0030, "License Amendment Request 261 Extended Power Uprate," dated April 7, 2009.

13. NRC Safety Evaluation, "Point Beach Nuclear Plant (PBNP), Units 1 and 2 - Issuance of License Amendments Regarding Extended Power Uprate (TAC Nos ME1044 and ME1045)," dated May 3, 2011.

14. NRC Safety Evaluation, "Point Beach Nuclear Plant (PBNP), Units 1 and 2 - Issuance of License Amendments Regarding Use of Alternate Source Term (TAC Nos. ME0219 and ME0220)," dated April 14, 2011.

15. Nextera Energy Point Beach Letter to NRC, NRC 2010-0042, "License Amendment Request 261 Extended Power Uprate Response to Request for Additional Information," dated May 14, 2010.

16. SCR 2011-0275, "Revise FSAR 14.3.5, Radiological Consequences of a LOCA for EPU per AR 1688483," dated October 18, 2011.

Table 11.6-1 SHIELDING DESIGN ZONE CLASSIFICATIONS

Zone	Condition of Occupancy	Maximum Dose Rate (1% failed fuel) mrem/hr
0	Unlimited occupancy	0.1
I	Normal continuous occupancy	1.0
II	Periodic occupancy	2.5
III	Controlled occupancy	15
IV	Controlled access	>15

Table 11.6-2 ORIGINAL PRIMARY SHIELD NEUTRON FLUXES AND DESIGN PARAMETERS (Historical)

Calculated Neutron Fluxes

Energy Group	Incident Fluxes ($n/cm^2/sec$)	Leakage Fluxes ($n/cm^2/sec$)
E < 1 Mev	2.2×10^9	7.5×10^2
5.3 Kev ≤ E ≤ 1 Mev	2.3×10^{10}	1.6×10^3
.625 ev ≤ E ≤ 5.3 Kev	1.4×10^{10}	2.7×10^3
E < .625 ev	1.9×10^{10}	9.8×10^5

Design Parameters

Core thermal power	1518.5 MW
Active core height	144 in.
Effective core diameter	96.50 in.
Baffle wall thickness	1.125 in.
Barrel wall thickness	1.75 in.
Thermal shield wall thickness	3.50 in.
Reactor vessel I.D.	132.0 in.
Reactor vessel wall thickness	6.50 in.
Reactor coolant cold leg temperature	559.5°F
Reactor coolant hot leg temperature	614.5°F
Maximum thermal neutron flux exiting primary concrete	10^6 $n/cm^2/sec$.
Reactor shutdown dose exiting primary concrete	<15 mR/hr

Table 11.6-3 ORIGINAL SECONDARY SHIELD DESIGN PARAMETERS (Historical)

Core power density	85 w/cc
Reactor coolant liquid volume	6450 ft^3
Reactor coolant transit times:	
Core	0.9 sec.
Core exit to steam generator inlet	2.0 sec.
Steam generator inlet channel	0.6 sec.
Steam generator tubes to vessel inlet	2.6 sec.
Vessel inlet to core	2.2 sec.
Total out of core	10.6 sec.
Full power dose rate outside secondary shielding	<1 mR/hr.

Table 11.6-4 ORIGINAL ACCIDENT SHIELD DESIGN PARAMETERS (Historical)

Core thermal power	1518.5MW
Minimum full power operating time	1000 days
Equivalent fraction of core melting	1.0
Fission product fractional releases:	
Noble gases	1.0
Halogens	0.5
Remaining fission product inventory	0.01
Clean up rate following accident	0
Maximum integrated dose (infinite exposure) in the control room	<2 rem

Table 11.6-5 ORIGINAL PRINCIPAL AUXILIARY SHIELDING (Historical)

Component	Concrete Shield Thickness, Ft. - In.
Demineralizers	4 - 0
Charging pumps	2 - 2
Liquid holdup tanks	2 - 6
Volume control tank	3 - 6
Reactor coolant filter	2 - 9
Gas stripper	2 - 6
Gas decay tanks	3 - 6
Gas compressor	3 - 0
Waste evaporator	2 - 0
Liquid waste holdup tank	2 - 0

Design parameters for the auxiliary shielding include:

Core thermal power	1518.5 MWt
Fraction of fuel rods containing small clad defects	0.01
Reactor coolant liquid volume	6450 ft^3
Letdown flow (normal purification)	40 gpm
Effective cesium purification flow (intermittent)	4.0 gpm
Cut-in concentration deborating demineralizer	160 ppm
Dose rate outside auxiliary building	1 mR/hr
Dose rate in the building outside shield walls	2.5 mR/hr

Table 11.6-6 ORIGINAL RESIDUAL HEAT REMOVAL SYSTEM RADIATION SOURCES AND EVALUATION PARAMETERS (Historical)

Radiation Sources - MEv/cc-sec

Energy	Time After Release					
Mev	0	1 hr	2 hrs	8 hrs	24 hrs	32 hrs
0.4	6.04+7	8.88+6	8.28+6	7.08+6	6.60+6	6.48+6
0.8	8.28+7	7.32+7	6.60+7	4.92+7	4.47+7	4.35+7
1.3	5.46+6	3.95+6	2.94+6	4.57+5	3.09+4	1.54+4
1.7	3.13+6	2.21+6	1.62+6	2.65+5	1.17+4	1.13+4
2.2	2.94+6	2.34+6	1.92+6	3.59+5	1.12+5	5.40+4
2.5	1.38+6	9.06+5	6.55+5	9.90+4	4.56+4	3.14+4

Note: $1.04+7=1.04 \times 10^7$

Evaluation Parameters

Core thermal power, MWt	1518.5
Percent of gap activity absorbed by the sump water	
Noble gases	0
All others	100
Fission product clean-up rate	0
Reactor coolant volume, ft^3	6450
Refueling water volume, ft^3	38,100

Figure 11.6-1 MAXIMUM RADIATION LEVELS SURROUNDING 14 IN. DIAMETER R.H.R. PIPE CIRCULATING WATER CONTAINING FISSION PRODUCT ACTIVITY FROM FUEL ROD GAPS (Historical)

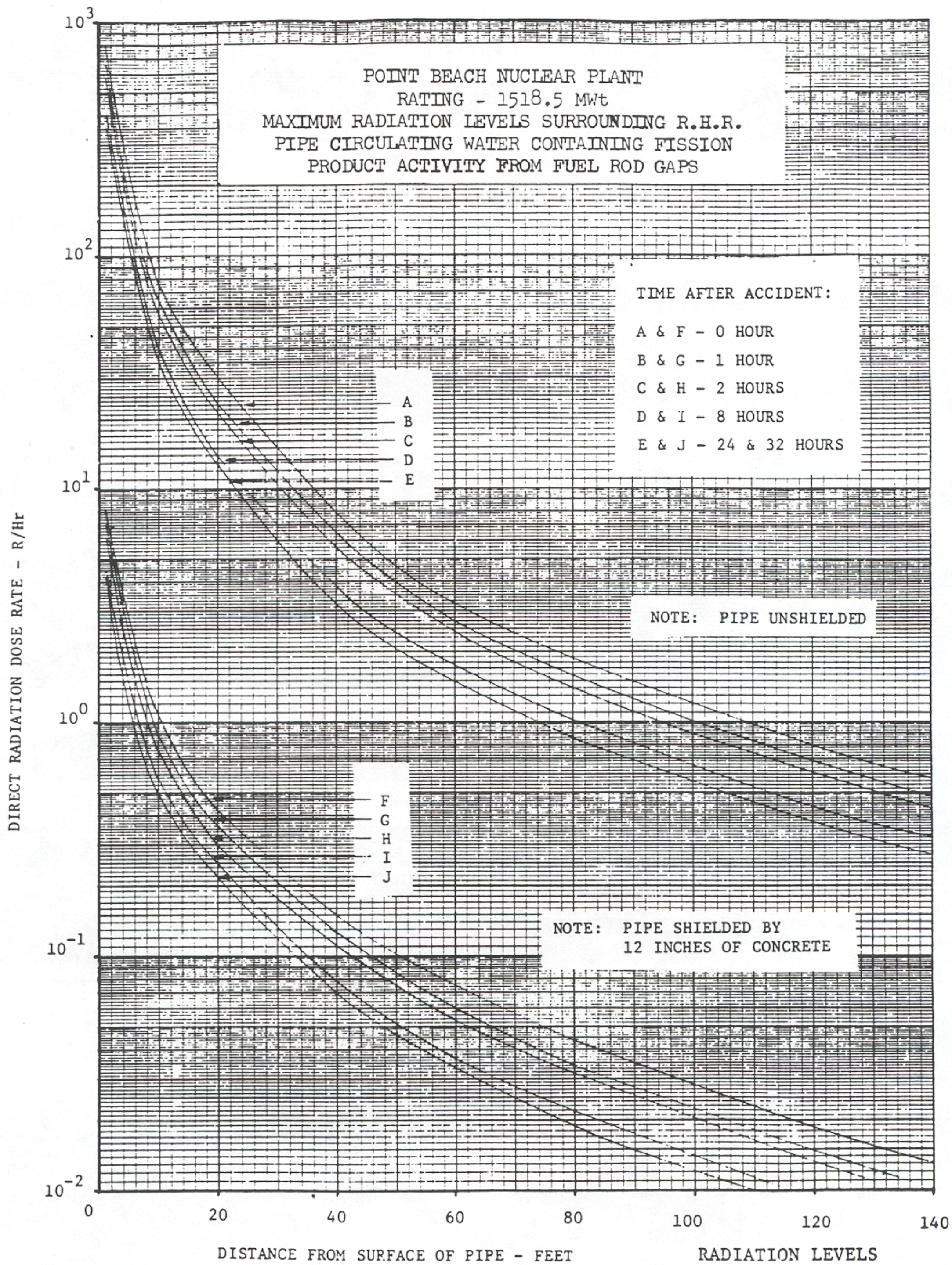
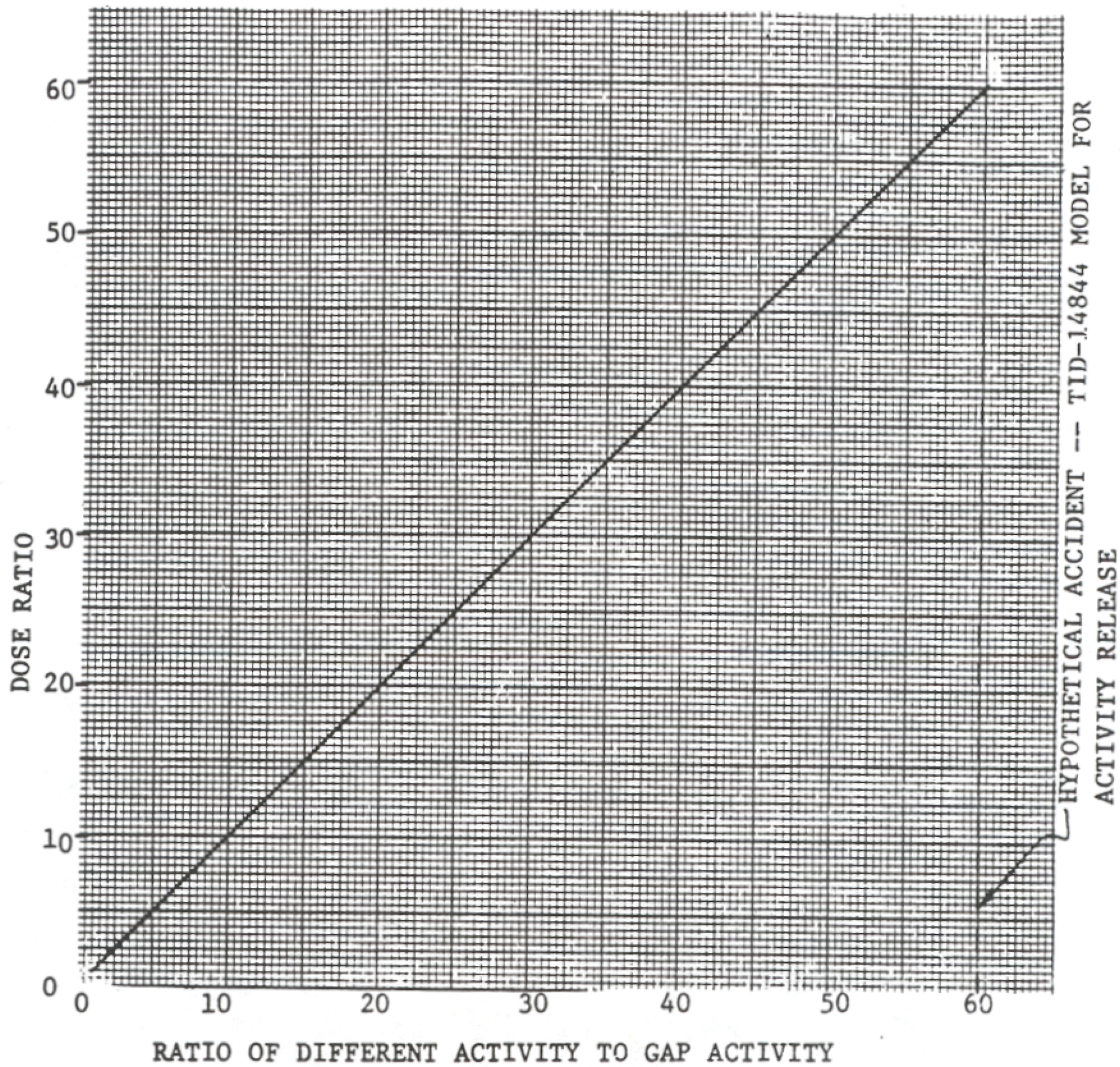


Figure 11.6-1

Figure 11.6-2 SENSITIVITY OF DOSE TO ACTIVITY IN THE RESIDUAL HEAT REMOVAL WATER (Historical)



11.7 EQUIPMENT AND SYSTEM DECONTAMINATION

11.7.1 CONTAMINATION SOURCES

Activity outside the core could result from fission products from defective fuel elements, fission products from tramp uranium left on the cladding in small quantities during fabrication, products of n - γ or n - p reactions on the water or impurities in the water, and activated corrosion products. Fission products in the reactor coolant associated with normal plant operation and tramp uranium are generally removed with the coolant or in subsequent flushing of the system to be decontaminated. The products of water activation are not long lived and may be removed by natural decay during reactor cooldown and subsequent flushing procedures. Activated corrosion products are the primary source of the remaining activity.

The corrosion products contain radioisotopes from the reactor coolant which have been absorbed on, or have diffused into, the oxide film. The oxide film, essentially magnetite (Fe_3O_4) with oxides of Cr and Ni, can be removed by chemical means presently used in industry.

Water from the primary coolant system and the spent fuel pool is the primary potential source of contamination outside of the corrosion film of the primary coolant system. The contamination could be spread by various means when access is required. Contact while working on primary system components could result in contamination of the equipment, tools and clothing of the personnel involved in the maintenance. Also, leakage from the system during operation or spillage during maintenance could contaminate the immediate areas and could contribute to the contamination of the equipment, tools, and clothing.

11.7.2 METHODS OF DECONTAMINATION

Surface contaminants which are found on equipment in the primary system and the spent fuel pool that are in contact with the water are removed by conventional techniques of flushing and scrubbing as required. Tools are decontaminated by flushing and scrubbing since the contaminants are generally on the surface only of nonporous materials. Personnel and their clothing are decontaminated according to the standard health physics requirements.

Those areas of the plant which are susceptible to spillage of radioactive fluids are painted with a sealant to facilitate decontamination that may be required. Generally, washing and flushing of the surfaces are sufficient to remove any radioactivity present.

The corrosion films generally are tightly adhering surface contaminants, and must be removed by chemical processes. The removal of these films is generally done with the aid of commercial vendors who provide both services and formulations. Since decontamination experience with reactors is continually being gained, specific procedures may change for each decontamination case. For corrosion films, the APAC (alkaline permanganate-diammonium citrate) treatment, or an organic acid variation of the APAC treatment, is considered to be the most effective for removal.

Portable components may be cleaned with a combination of chemical and ultrasonic methods if required.

11.7.3 DECONTAMINATION FACILITIES

Decontamination facilities on site consist of an equipment cleaning room in the machine shop and a cask pit located adjacent to the spent fuel storage pool. These facilities are shared by Units 1 and 2.

In the cask decontamination pit, the outside surfaces of the shipping casks are decontaminated, if required, by using water detergent solutions and manual scrubbing to the extent required. When the outside of the casks are decontaminated, the casks are removed from the pit area by the auxiliary building crane, loaded on an approved shipping trailer, and shipped offsite.

The decontamination pit is also used for decontamination of the spent fuel dry storage casks used for temporary storage of spent fuel at the Point Beach Independent Spent Fuel Storage Installation. When the outside of the storage cask is decontaminated, the storage cask is removed from the decontamination pit, loaded into an overpack, and moved to the ISFSI.

In the equipment cleaning room, located in the machine shop area, small equipment and tools can be decontaminated by using water, detergent solutions, and manual scrubbing to the extent required.

A decontamination shower for contaminated personnel is available.

11.8 RADIOACTIVE MATERIALS SAFETY

11.8.1 MATERIALS SAFETY

Procedures are implemented at Point Beach Nuclear Plant to assure safe storage, handling, and use of sealed and unsealed source, special nuclear, and by-product materials.

Special Nuclear Material

To minimize the possibility of diversion of special nuclear material for unauthorized use, to detect any potential diversion as quickly and accurately as possible, and to provide information for fuel management purposes, responsibilities and procedures for handling special nuclear material are provided in the Point Beach Administrative procedures. Primary responsible groups include Reactor Engineering, Radiation Protection, Operations, and Maintenance Instrumentation and Control.

In addition, both normal plant procedures and policies under the control of Chemistry and Radiation Protection address responsibilities for the radiological control of special nuclear materials for receipt, handling, storage, surveillance, and shipment.

The licensing basis for these materials and their storage is based upon the requirements of 10 CFR 50.68. This license basis was approved by the NRC in March of 2010. (Reference 1)

By-product Materials

Responsibilities and procedures for the handling, transfer, storage, and use of radioactive by-product materials are provided in the Chemistry and Radiation Protection groups procedures. Compliance with all applicable regulations and conditions is assured by the Chemistry and Radiation Protection groups.

All non-exempted sealed sources are leak tested as required by the PBNP Technical Requirements Manual (TRM), Section 3.7.4.

Radioactive source inventories and methods for leak testing radioactive sources, shipment and receipt of radioactive materials, and control and accountability of radioactive materials are discussed in policy documents and procedures under the control of Chemistry and Radiation Protection.

11.8.2 REQUIRED MATERIALS

By-product, source, and special nuclear materials are retained by Point Beach Nuclear Plant in amounts required for reactor operation in the form of reactor fuel, startup sources, neutron flux detectors, and sealed sources for calibration of reactor instrumentation and radiation monitoring equipment. In addition, certain by-product, source, and special nuclear materials are required for calibration of other plant instrumentation not directly associated with reactor operation. These sources and by-product material are discussed in and controlled under applicable Chemistry and Radiation Protection procedures.

11.8.3 REFERENCE

1. NRC Safety Evaluation, "Point Beach Nuclear Plant, Units 1 and 2 - Issuance of Amendments Re: Spent Fuel Pool Storage Criticality Control," dated March 5, 2010.

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12.1 GENERAL

Point Beach Nuclear Plant (PBNP) Units 1 and 2 are normally base loaded at or near 100% power. Generation and transmission of power from PBNP is coordinated with FPL Energy, We Energies and American Transmission Company (ATC). The electric output is sold to We Energies under a long-term power purchase contract and integrated into Northeast Wisconsin's 345 kV AC transmission system. Certain transmission and distribution assets on the site are owned by ATC, the transmission system operator, and are operated under an Interconnection Agreement between ATC and FPL Energy Point Beach which assures compliance with NRC requirements.

12.2 ORGANIZATION

Management

Ownership and operation of Point Beach was transferred from We Energies and the Nuclear Management Company (NMC) respectively to FPL Energy Point Beach on September 28, 2007. FPL Energy Point Beach name was changed to NextEra Energy Point Beach, LLC on May 13, 2010 (Reference 3). NextEra Energy Point Beach is designated as the licensee authorized to use and operate the Point Beach Nuclear Plant (PBNP) in accordance with the terms and conditions of the operating licenses (Reference 1 and Reference 2). NextEra Energy Point Beach is a Wisconsin limited liability company (LLC) and a direct, wholly owned subsidiary of NextEra Energy Resources, LLC, which is a direct wholly owned subsidiary of NextEra Energy Capital Holdings Inc. which is a direct, wholly owned subsidiary of NextEra Energy, Inc. NextEra Energy, Inc. is a public utility holding company incorporated in 1984 under the laws of the State of Florida. Through its various subsidiaries, NextEra Energy, Inc. owns and operates six other nuclear power plants at four sites, which include the following:

St. Lucie Nuclear Power Plant, Units 1 and 2

Turkey Point Nuclear Plant, Units 3 and 4

Seabrook Station

Duane Arnold Energy Center

The Point Beach on-site nuclear organization reports operationally through the Site Director. The corporate and site management structure is described in the Quality Assurance Topical Report (QATR) discussed in Section 1.4, “Quality Assurance Program.” The organization section of the QATR is incorporated by reference.

Consultants

The following consultants were engaged by We Energies (Wisconsin Electric Power Company) in the following areas for specialized services during the design of the plant, and many have continued on a consulting capacity during plant operation:

1. NUS Corporation - Site and general.
2. Stone and Webster Engineering Corporation - Radwaste modification design, construction, startup and quality control.
3. Murray and Trettel, Inc. - Meteorology.
4. Dr. Ralph Grunewald - Associate Professor, University of Wisconsin - Milwaukee - Site and radiological monitoring and health physics.
5. Westinghouse Electric Corporation - Overall design, operations, and fuel.
6. Southwest Research Institute - Specialized quality control and reactor vessel inspection.
7. Battelle Memorial Institute, Columbus Laboratories - Analysis of specimens.
8. Limnetics, Inc. - Environmental research and investigation.
9. Bechtel Corporation - Plant design, economics and quality control.
10. Sargent and Lundy - Circulating and service water system overall design and construction.

11. Nuclear Technologies, Inc. - Study of possible methods of transportation and disposal of spent nuclear fuel and design of spent storage and transfer system.
12. Nuclear Surveillance and Auditing Corporation - Isotopic analysis.
13. Nuclear Audit and Testing Co. - Nuclear fuel quality assurance audit.
14. Nuclear Assurance Corporation - Nuclear fuel cycle general information.
15. Nuclear Exchange Corporation - Nuclear fuel transactions.

Periodically, new consultants are contracted to perform specific functions or projects.

Plant Organization

The two-unit plant organization evolved from the single plant organization of Unit 1. Onsite training of personnel, startup, and operation of Unit 1 commenced about January 1, 1969. Subsequently, Unit 2 was started up and commenced operations employing experienced personnel from Unit 1 plus additional augmentation personnel trained in the same programs used for Unit 1. Currently, all regularly assigned personnel (with the exception of security personnel - (Section 12.7) are employees of NextEra Energy Point Beach, LLC and function on an integrated basis between both PBNP units. The two-unit PBNP organization is under the direction of the PBNP Site Vice President.

The Operations Shift Manager performs the Duty Shift Superintendent (DSS) function described in Technical Specification 5.1.2, and is responsible for the control room command function.

See Technical Specification 5.3.1 for facility staff qualification requirements.

New and spent fuel is handled under the direction of a fuel handling supervisor who holds an active Senior Reactor Operator’s (SRO) license. If not active, they must stand one 8-hour shift under instruction from a licensed active SRO to perform active SRO duties limited to fuel handling. During alteration of the reactor core (including fuel loading or transfer), a person holding a SRO license or a SRO license limited to fuel handling shall directly supervise the activity and, during this time, the licensee shall not assign other duties to this person.

See Technical Specification 5.3.3 for Health Physicist qualifications.

The Shift Technical Advisor shall have a bachelor's degree or equivalent in a scientific or engineering discipline with specific training in plant design and response and analysis of the plant for transients and accidents. The Shift Technical Advisor shall also receive training in plant design and layout including the capabilities of instrumentation and controls in the control room. See Technical Specification 5.2.2.e for additional requirements for shift technical support personnel.

Medical direction of Point Beach is handled by FPL’s Occupational Health Representative. Responsibilities include implementation of health surveillance programs, post-offer physical examinations, radiological medical aspects and injury management. This position functions closely with Industrial Health & Safety and Radiation Protection.

REFERENCES

1. NRC Letter, "Order Approving Transfer of Licenses and Conforming Amendments Relating to Point Beach Nuclear Plant, Units 1 and 2, (TAC Nos. MD4112 and MD4113)," dated July 31, 2007.

2. NRC Letter, "Point Beach Nuclear Plant -License Transfer-Issuance of Conforming Amendments Re: Transfer of Ownership and Operating Authority (TAC Nos. MD4112 and MD4113)," dated September 28, 2007.

3. NRC Safety Evaluation, "Point Beach Nuclear Plant, Units 1 and 2 - Issuance of Amendments Re: Name Change of Licensee and Correction of the Appendix C License Condition Typographical Error (TAC NOS. ME1119 and ME1120," dated May 13, 2010.

12.3 TRAINING

Personnel for the Point Beach Nuclear Plant, Units 1 & 2 are selected on the basis of criteria which include pre-employment examinations as required and a review of previous experience and education.

Training programs, supportive courses, units of instruction, lesson plans and other controlled training procedures used at PBNP are designed in accordance with industry accepted principles and standards of training.

Approved training procedures give specific guidance on the analysis, design, development, implementation, and evaluation activities employed to ensure that the training provided to PBNP personnel is performance-based, professional, satisfies federal regulations, and supports maintaining INPO accreditation. In doing so, appropriate knowledge, skills and abilities will be developed that are necessary for safe and efficient support of plant operations.

A continuing training program for licensed operators and senior licensed operators is monitored under the direction of the Training Manager which meets or exceeds the requirements and recommendations of Section 5.5 of ANSI N18.1-1971 and 10 CFR 55. The present continuing training program is described in PBNP and NextEra Energy training program documents and procedures.

NextEra Energy requires that no employees will be regularly employed within the nuclear plant without instruction or training with respect to his or her personal conduct and the use of radiological protective devices. All employees of the plant are instructed, as required, in the following areas:

Fire protection	Radiological Health & Safety
Emergency plan	Use of Protective Clothing & Equipment
Dosimeters	Plant Controlled & Clean Areas
Industrial safety	

12.4 WRITTEN PROCEDURES

NextEra Energy Point Beach, LLC nuclear plant operational and support activities are conducted under FPL Quality Assurance Topical Report (QATR), FPL-1. Controlled Document processes are established and implemented to specify the format and content, and control the development, review, approval, issue, use and revision, of documents that specify quality requirements or prescribe activities affecting quality or safe operation to assure the correct documents are being employed. These provisions assure that specified documents are reviewed for adequacy, approved prior to use by authorized persons, and distributed according to current distribution lists and used at the location where the prescribed activity takes place.

Documents subject to control provisions include, but are not limited to, drawings (design, as-built), engineering documents (calculations, analyses, specifications, computer codes, Updated Final Safety Analysis Reports, Plant Technical Specifications), and procedures (administrative, operating, emergency operating, maintenance, calibration, surveillance, inspection, test). Other documents, such as those related to procurement, corrective actions, and assessments, are controlled as defined by the provisions and commitments cited in the applicable sections of the QATR, FPL-1.

12.4.1 Emergency Operating Procedures

These include procedures necessary to ensure that proper action with respect to equipment and systems is taken to handle malfunctions that may occur to either or both operating units.

These procedures deal primarily with actions to be taken for emergencies that might occur in the nuclear portion of the plant. Procedures are also included for those secondary plant emergencies that could affect the overall plant in such a way as to affect public health and safety and affect the nuclear portion of the plant.

These procedures are to be implemented at the earliest possible time after a malfunction has occurred. They are specifically formulated to provide positive operator action for verifying that the plant is in, or is placed in, a safe condition with the minimum hazard to the general public, plant personnel, and equipment. They do not in any way negate the fact that the plant design is based on assuming credible initiating accidents and that protective and engineering safeguards systems are provided to limit the consequences of these unlikely accidents. Suitable redundancy of active components is provided in the protective and engineered safeguards systems. In addition, suitable equipment and a centralized control room are provided for the operator to take action through the implementation of these emergency operating procedures to insure that the potential risks to public safety and Company financial risk are reduced to the lowest practical level. These procedures do not replace any of the required protective equipment or circuits used to control or limit incidents or equipment failure, but rather serve as a backup to verify that the plant is in, or placed in, a safe condition. These procedures are applicable to both units at Point Beach because of the identical nature of the two units. Action to be taken on each individual unit differs, based upon the initiating accident and credible compounding between units. As an example, in a loss of coolant accident on one unit, the unaffected unit should normally not be shut down or cooled down. In fact, the continued presence on-line of the second unit enhances the assurance of continuous electrical power to the affected unit. This does not mean that the other unit cannot be simultaneously shut down, should it be desirable to do so, even under the condition of loss of all outside AC power.

Even though the maximum hypothetical accident (major loss of coolant) is not considered credible, emergency operating procedures are included for this accident. The simultaneous or sequential occurrence of loss of coolant accidents in more than one unit is not considered credible, and plant safeguards systems and emergency procedures are not designed to cope with compounding of accidents.

Plant emergency operating procedures are an integrated set of: A) symptom oriented, event-related Emergency Operating Procedures (EOPs) and Emergency Contingency Actions (ECAs); B) symptom oriented, function-related Critical Safety Procedures (CSPs); and C) Critical Safety Function Status Trees (STs). All are based on the Westinghouse Emergency Response Guidelines - Low Pressure.

EOPs and ECAs provide directions for the optimal recovery of the plant. EOPs address the higher probability events while ECAs address low probability and unique event scenarios.

Critical Safety Function Status Trees are used to monitor indications for a challenge to one or more of the barriers to fission product release independent of event sequence. The status trees prioritize this challenge and direct the operator to the applicable Critical Safety Procedure. The CSP is then used to restore the plant to a safe state from which optimal recovery may continue using the EOPs and ECAs.

Plant emergency operating procedures are divided into three areas; purpose, symptoms or entry conditions, and operator actions. Table 12.4-1 lists all the emergency operating procedures as well as the related emergency contingency actions, critical safety procedures, and status trees.

Purpose

This area gives an outline of the basic situation, the objectives of the procedure, and a discussion of information useful to the operator in understanding plant response and actions taken to respond to the accident.

Symptoms or Entry Conditions

This area describes the various indications which cause, lead to, or represent the situation. In all cases, the operator will rely on this indication until it is proven incorrect. In many cases, the symptoms could represent several possible situations. The procedures are structured to deal with the worst possible situation until proven otherwise. Other instrumentation will be checked to corroborate the symptoms. The steps from other Emergency Operating Procedures that direct entry into each procedure are also listed.

Operator Actions

Operator action steps are presented in a two column format. The left-hand column, titled Action/ Expected Response, contains directions for the operator and the expected plant response. The right-hand column, Response Not Obtained, provides contingency actions which are to be taken in the event a stated condition or task in the left-hand column does not represent or achieve the expected response. Operator action steps designated as immediate actions are placed at the beginning of the procedures, and will be completed as rapidly as possible in a safe and judicious manner. Operator actions are expected to be performed in the indicated order, however, actions are not required to be completed prior to continuing with the next step. If a step is required to be completed prior to continuing, this is stated in the procedure. Operators are trained to use written procedures and other supportive sources of information as necessary while performing operator actions to ensure complete and proper performance of all actions.

Table 12.4-1 EMERGENCY OPERATING PROCEDURES (EOPs)
EMERGENCY CONTINGENCY ACTIONS (ECAs)
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Number	Name
EOP-0	Reactor Trip or Safety Injection
EOP-0.0	Rediagnosis
EOP-0.1	Reactor Trip Response
EOP-0.2	Natural Circulation Cooldown
EOP-0.3	Natural Circulation Cooldown With Steam Void in Vessel (With RVLIS)
EOP-0.4	Natural Circulation Cooldown With Steam Void in Vessel (Without RVLIS)
EOP-1	Loss of Reactor or Secondary Coolant
EOP-1.1	SI Termination
EOP-1.2	Post LOCA Cooldown and Depressurization
EOP-1.3	Transfer to Containment Sump Recirculation-Low Head Injection
EOP-1.4	Transfer to Containment Sump Recirculation-High Head Injection
EOP-2	Faulted Steam Generator Isolation
EOP-3	Steam Generator Tube Rupture
EOP-3.1	Post-Steam Generator Tube Rupture Cooldown Using Backfill
EOP-3.2	Post-Steam Generator Tube Rupture Cooldown Using Blowdown
EOP-3.3	Post-Steam Generator Tube Rupture Cooldown Using Steam Dump
ECA-0.0	Loss of All AC Power
ECA-0.1	Loss of All AC Power Recovery Without SI Required
ECA-0.2	Loss of All AC Power Recovery With SI Required
ECA-1.1	Loss of Containment Sump Recirculation
ECA-1.2	LOCA Outside Containment
ECA-1.3	Containment Sump Blockage
ECA-2.1	Uncontrolled Depressurization of Both Steam Generators
ECA-3.1	SGTR With Loss of Reactor Coolant-Subcooled Recovery Desired
ECA-3.2	SGTR With Loss of Reactor Coolant-Saturated Recovery Desired
ECA-3.3	SGTR Without Pressurizer Pressure Control

Table 12.4-2 STATUS TREES (STS) CRITICAL SAFETY PROCEDURES (CSPS)
Page 2 of 2

Number	Name
CSP-ST.0	Critical Safety Function Status Trees
CSP-S.1	Response to Nuclear Power Generation/ATWS
CSP-S.2	Response to Loss of Core Shutdown
CSP-C.1	Response to Inadequate Core Cooling
CSP-C.2	Response to Degraded Core Cooling
CSP-C.3	Response to Saturated Core Cooling
CSP-H.1	Response to Loss of Secondary Heat Sink
CSP-H.2	Response to Steam Generator Overpressure
CSP-H.3	Response to Steam Generator High Level
CSP-H.4	Response to Loss of Normal Steam Release Capabilities
CSP-H.5	Response to Steam Generator Low Level
CSP-P.1	Response to Imminent Pressurized Thermal Shock Condition
CSP-P.2	Response to Anticipated Pressurized Thermal Shock Condition
CSP-Z.1	Response to High Containment Pressure
CSP-Z.2	Response to Containment Flooding
CSP-Z.3	Response to High Containment Radiation Level
CSP-I.1	Response to High Pressurizer Level
CSP-I.2	Response to Low Pressurizer Level
CSP-I.3	Response to Voids in Reactor Vessel

12.5 RECORDS

During normal operation, daily logs are provided for the most part by an installed computer data logger on each plant unit. Other records and recorder charts required by 10 CFR 100 are provided by strip recorders and by appropriate records provided by the Chemistry and Radiation Protection Group. Reactor data is provided by the Reactor Engineering Group using the computer and the informational output of the in-core instrumentation system. The Operational Phase Records are maintained by the Operations Group and submitted to Records Management for retention.

During startup operations, discrepancy reports, installation surveillance and test reports, and functional test reports were produced and placed in plant files.

Record retention requirements and plant reporting requirements are all specified in the Quality Assurance Topical Report (QATR) as referenced in FSAR Section 1.4.

12.6 EMERGENCY PLAN

General

The Emergency Plan, contained in a separate volume and filed in accordance with 10 CFR Part 50, defines the actions and responsibilities of Point Beach Nuclear Plant personnel in the event of an emergency and delineates the support required from offsite groups during certain specific emergency situations. Emergency classifications graded by increasing severity are incorporated in the Emergency Plan. These classifications describe the degree of response by onsite and offsite personnel and agencies. The Emergency Plan is based on the following key objectives:

1. Identification and evaluation of various types of emergencies which could potentially occur at the plant and which could affect members of the public or plant personnel and equipment.

2. Organization and direction of plant personnel actions to limit the consequences of an incident.

3. Organization and control of onsite and offsite surveillance activities to assess the extent and significance of any release of radioactive material.

4. Delineation of protective actions and measures based on the protection of the public and/or plant personnel and equipment in the event of an accident, including measures for recovery of and reentry to the facility.

5. Notification of offsite authorities as required, and coordination of response activities with offsite support groups.

Medical Preparedness

General safety and first aid practices adopted for use in conventional plants are in effect at Point Beach Nuclear Plant. Since the possibility exists that treatment of an injured person may be complicated by radioactive contamination, steps have been taken to provide a fully equipped, isolated, and controlled access treatment room at Aurora Medical Center - Manitowoc County in Two Rivers, Wisconsin. This room is equipped with sink, decontamination materials, protective clothing, signs, radiation monitoring equipment, and other necessary equipment. The Aurora Medical Center - Manitowoc County staff is trained in radiological health and contamination control by the state of Wisconsin's Radiation Protection Section with assistance from cognizant Company personnel.

On-Site Medical Capability

The Point Beach organization includes persons experienced in first aid procedures who are called in the event of injury. The plant has an emergency shower for use with a severely contaminated, but less severely injured, person. A first aid room is available for medical evaluations.

Off-Site Medical Capability

Arrangements have been made for off-site emergency medical transportation for seriously injured personnel who may or may not be contaminated. Arrangements have also been made with area physicians for treatment of Point Beach Nuclear Plant personnel. Serious radiation injuries would be treated at Madison hospitals.

12.7 SECURITY

Point Beach Nuclear Plant Security personnel are responsible for protection of plant personnel and company assets. Access to the Protected Area (PA) of the plant is controlled by Security and only authorized personnel are allowed access to the PA. Personnel granted unescorted access to the PA can be identified by a photo ID badge. There are Vital Areas within the Protected Area of Point Beach that house equipment important to the safe operation of the plant. Vital Area access is controlled by card readers, which allow only authorized personnel entry into these areas. The PBNP Security Plan contains detailed information regarding the security measures for Point Beach Nuclear Plant. This information is limited to individuals with a need-to- know who have been appropriately screened by Security.

There are three principal means by which physical changes to the plant can be detected: first, the design of the plant; secondly, by suitable locking devices when required; and thirdly, by the use of checkoff lists prior to performing certain tests and procedures.

1. Design: The design of the plant includes a number of provisions to aid in the assurance of component condition. The main control board is laid out in a mimic bus fashion to allow quick analysis of any change in a monitored plant condition. Certain systems, such as safety injection, are monitored by a “ready status” system on the main control board. This status system includes four panels per unit which monitor the status of pumps and valves for the safety injection system and containment isolation.

2. Locking Devices: Certain valves are locked in position by a chain lock device to insure their position. The actual reason for locking may be one of several, including such things as Company financial risk, personnel safety, and system integrity.

3. Checkoff Lists: A portion of many procedures in the “Initial Condition” section includes the checkoff lists which are required to be completed or verified prior to the commencement of the procedure. Periodic reexamination of device position discloses whether or not problems of tampering are in existence. Checkoff lists include valve positions, breaker positions, and control power for the system under examination.

CHAPTER 13 TABLE OF CONTENTS

13.0 SITE SURVEILLANCE AND TESTING PROGRAMS (Historical)

This section pertains to the original plant construction and pre-operational and start-up testing. The entire chapter is considered to be historical information as defined and discussed in NEI 98-03, Revision 1.

13.1 OBJECTIVES AND SCOPE (Historical)

These programs were the final portions of the Owner's Overall Surveillance Program, and as such have the same objectives as the Design and Vendor Surveillance Programs described in Chapter 1.0; namely “to insure that the owners will procure a safe, complete, licensable, well designed and operable plant that can be operated without undue risk to the health and safety of the public.”

These objectives are met at the site location by the proper functioning of the owners' and contractors' groups, as described below. These groups must perform their functions at the site during four distinct phases of plant construction. These phases are described as follows:

1. Construction - Installation, Surveillance and Test Program.
2. Startup Surveillance and Pre-Core Loading Functional Testing.
3. Core Loading and Low Power Physics Testing Programs.
4. Power Testing.

The Site Surveillance and Testing Organization consisted of a General Superintendent in overall charge of the project. Reporting to the Superintendent were the respective group heads including: Operations Superintendent, I&C Supervisor, Reactor Engineer, Resident Engineer, Maintenance Superintendent, and Southwest Research Institute.

The Electrical Startup group reported to the Electrical Design Engineer under the Maintenance Superintendent while the various Operations group Supervisors reported directly to the Operations Superintendent.

13.2 GENERAL (Historical)

The owner's and contractor's programs during each phase consisted of the following:

CONSTRUCTION - INSTALLATION, SURVEILLANCE, AND TESTS

The objective of this phase was to provide a clear, logical, and documented surveillance program during the actual on-site construction period up to the point defined as “End of Construction.” “End of Construction” was defined as occurring after the systems and equipment have been hydro-statically tested, initially filled and drained, the motors bumped, instruments calibrated, and equipment adjustments made.

This phase covers the construction of buildings and installation of mechanical and electrical systems and associated equipment. The following basic areas fall within its scope:

1. Receipt and storage of equipment and material at the plant site.
2. Construction of buildings and structures.
3. Installation, initial cleaning, flushing, and pressure testing of piping systems including the associated pumps, pressure vessels and valves.
4. Installation, wiring, and operation of electrical equipment including motors, controllers, switchgear, transformers, etc.
5. Installation of instrumentation and control systems.

Owners Program

The structures, systems, and equipment under construction were divided into clearly defined sections using the contractor's drawings and specifications. The various systems were assigned to specific supervisory personnel of Wisconsin Michigan Power Co. who implemented and conducted this surveillance program for this assigned systems under the overall direction of the General Superintendent.

In order to provide history, records and continuity to the job with its expanding numbers of new supervisors and employees, Wisconsin Michigan Power Company established and maintained a central plant file for each system at the job outset. This central file contained a technical section, a specification section, and a drawing file section. The technical section contained a complete history of all correspondence between the owner and the contractor concerning the system and a copy of all instruction manuals for the equipment in the system. The specification section contained a current copy of the latest specification, records to indicate the location of obsolete specifications, and, to a limited extent, information on procurement effort associated with the system. This phase of the Surveillance and Test Program used the central file records and built upon and added to them with the records of:

1. Weekly Reports.
2. Weekly Comment Reports on Bechtel Quality Assurance.
3. Discrepancy Reports.
4. Construction-Installation Surveillance and Test Reports.
5. Equipment Record Cards.
6. Surveillance Test Folders.

The owners' plant Construction-Installation, Surveillance and Test Program was divided into areas of specific individual supervisory responsibility as follows:

1. <u>Resident Engineer</u>

   A. Receipt and storage of construction materials.

      1. Concrete components, including concrete testing.
      2. Structural steel.
      3. Piping and conduit, etc.

   B. Structures and their components.

   C. Electrical

      1. The Electrical Design Engineer and assigned startup personnel were responsible for accepting the installation of equipment in the following systems:

         a. 345 KV equipment directly associated with the plant. (The balance of the 345 KV switchyard was the responsibility of the Wisconsin Electrical Power System Electrical Department).
         b. 15 KV, 4.16 KV, 480 volt, 120 volt AC, and 125 volt DC.
         c. Generators and associated excitation.
         d. Protective relaying of plant equipment with the exception of reactor control systems, generator, isolated phase bus and unit transformers.
         e. Electrical system controls.
         f. Cathodic protection and station ground grid (non-buried portion).

         The plant maintenance group assisted the Electrical Design Engineer during this phase. All equipment was visually inspected for cleanliness and handling damage, and the method of storage was evaluated. Installation surveillance assured that equipment was properly handled and that equipment was installed according to specification and drawings.

      2. After equipment was in place, the Installation and Test Program assured that the following was done on each type of major equipment and obtained pertinent test data from the contractor:

         a. Transformers

            1. Oil sample test and proper procedures used in filling the transformers.
            2. Insulation tests
            3. Polarity and phasing checks
            4. Current transformer ratio checks

b. Motors
   1. Insulation tests
   2. Rotation
   3. Lubrication system check
   4. Phase balance
c. Switchgear
   1. Operations check
   2. Insulation tests
   3. Current transformer ratio checks
   4. Overload settings
d. Generators (Main), Emergency Diesel, Gas Turbine and Power Supply
   1. Insulation checks
   2. Phase rotation checks
   3. Current transformer ratio checks
   4. Brushes
   5. Excitation
   6. Balance
e. Protective Relaying
   1. Calibration tests
   2. Circuitry checkout
   3. Phasing
f. Wiring
   1. Proper insulation types
   2. Proper sizing
   3. Termination inspection
g. Electrical Equipment Control and Instrumentation
   1. Interlocking checks
   2. Alarm checks
   3. Instrument calibration

D. Records

The following records comprised the commissioning and maintenance history of equipment:

1. Equipment Record Cards

   These cards contain data on the equipment item of a general nature, and tabulated routine maintenance call up cards issued on the item. Data relating to initial assembly of the item was filed together with the equipment record card and is part of the permanent record.

2. Construction-Installation Discrepancy Reports

   A copy of this report was filed with the equipment record card where it related to a particular equipment item.

3. Tests carried out by the contractor which were part of the commissioning procedure were endorsed by owner's representatives, and such records became an integral part of the plant records for that equipment or system.

2. <u>Instrument and Control Engineer</u>

A. The Instrument and Control Engineer was responsible for accepting the installation of equipment in the following systems:

1. Reactor control and protection
2. Nuclear instrumentation
3. In-core instrumentation
4. Rod position indication
5. Rod control
6. Pressurizer instrumentation and control
7. Radiation monitoring
8. Feedwater control
9. Digital computer
10. Chemical and volume control
11. Safeguards instrumentation
12. Containment instrumentation
13. Miscellaneous primary and secondary systems
14. Electro-hydraulic turbine governor (electrical portion)
15. Turbine supervisory instrumentation
16. Miscellaneous secondary instrumentation
17. Communications equipment

B. The Installation and Test Program assured that the following was done on each instrumentation and control system:

1. Checks against specifications and drawings

2. Operational checks
3. Proper installation
4. Proper calibration

C. All inspections and calibrations were filed in the Instrumentation Calibration and Maintenance Record Files. This filing system consisted of a file folder for each instrumentation channel and contained all necessary specifications, procedures, records, etc.

D. Installation discrepancies were noted on Construction-Installation Discrepancy Reports.

3. Operations Superintendent

The Operations Group was responsible for accepting the installation cleanliness, pressure testing, and operational checkout of all piping, valves, pumps and motors of the following systems:

A. Reactor coolant
B. Chemical and volume control
C. Waste disposal
D. Safety Injection
E. Sampling system
F. Auxiliary coolant
G. Main and reheat steam
H. Condensate and feedwater
I. Extraction steam
J. Feedwater heater vents, reliefs, and miscellaneous drains
K. Feedwater heater drains
L. Gland steam and drains
M. Service water
N. Fire water (non-buried portion)
O. Instrument and service air
P. Plant makeup water and treatment
Q. Heating and ventilation air flow
R. Circulating water, condenser air removal and priming (M-212)
S. Lube oil system
T. Heating system
U. Heating and ventilation
V. Turbine plant chemical treatment
W. Auxiliary feedwater
X. Hydrogen and seal oil system
Y. Fuel oil system
Z. Turbine governing system
AA. Sewage treatment plant
BB. Circulating water piping
CC. Fuel handling equipment
DD. Potable water

The plant systems listed above were assigned to individual operating supervisory personnel. It was the responsibility of the specified supervisor to implement and conduct the initial acceptance program for his assigned systems under the overall direction of the Operations Superintendent.

A system file was established and maintained for each system that included the necessary drawings, specifications, inspection records, etc. Any condition that indicated an actual or possible discrepancy was promptly reported to the Operations Superintendent on a Construction-Installation Discrepancy Report. If the condition required action by the contractor, the Operations Superintendent assigned a number to the report and forwarded it to Westinghouse via the General Superintendent. Surveillance on each system encompassed the following general areas:

A. <u>Storage Surveillance</u> - All plant equipment other than that assigned to the responsibility of the Resident Engineer, was checked by the assigned supervisory personnel for the following conditions:

   1. Shipping damage
   2. Method of storage
   3. Protective covers
   4. Adequacy of inert atmosphere, if required
   5. Protection of carbon steel parts against corrosion
   6. Protection of stainless steel parts from possible chloride- bearing materials or liquids

B. <u>Installation Surveillance</u> - This area covered the actual installation of the equipment such as piping, pumps, motors, valves, wiring, etc.

   1. Piping
      a. Specification - compliance in regard to schedule, type and pressure rating
      b. Piping drawing (including hangers).
      c. Process drawing
      d. Installation and removal of special connections for testing and/or flushing
   2. Equipment
      a. Pumps
         1. Specification
         2. Piping connections
         3. Foundations
         4. Alignment
         5. Rotation
         6. Packing (material and procedures)

7. Maintainability

8. Lubrication (amount and type)

9. Vibration

A check of the maintenance group records was conducted for items 3, 4, 5, 6, 7, 8, and 9.

b. Valves

1. Specification and drawings

2. Direction of flow

3. Operability

4. Maintainability

5. Packing (Materials and procedure)

6. Materials of construction

Results of this evaluation were recorded on the Construction-Installation Surveillance Test Report Forms.

c. Cleanliness

All equipment piping was inspected to insure removal of any dirt or foreign material which could have adversely affected the operation of the system.

This inspection was performed prior to initial filling and flushing of the system. Results were recorded on Construction-Installation Surveillance and Test Report Forms.

d. Flushing and hydrostatic testing

This area of surveillance was closely related to the Startup Surveillance and Pre-Core Loading Functional Testing Program of the Owners Surveillance and Test Program, and in some cases the testing performed fell into both programs.

Flushing procedures clearly defined the systems or portions of systems involved, flushing points, strainer locations, etc. The procedures further defined the exact conditions to be established after the flushing operation (i.e. removal of temporary strainers, fittings, etc).

The hydrostatic, or system integrity, tests clearly defined the systems or portions of systems under test, the test condition, conditions of acceptance, etc. Results of this evaluation were recorded on Construction-Installation Surveillance and Test Report Forms.

4. <u>Southwest Research Institute</u>

This company was retained by the owner to function as their agent in the following critical welding areas:

A. Containment Liner

B. Primary Coolant Piping

C. Primary System Tanks

D. Reactor Vessel, Steam Generators, and Reactor Coolant Pump Supports.

Their surveillance consisted of reviewing welding procedures, records, welder qualifications, and nondestructive testing.

Contractor's Program

A. Inspection and Installation of Equipment in the Field

For components and equipment supplied by Westinghouse or its subcontractors, specifications were prepared not only for design, manufacturing, cleanliness requirements, and shipment, but also specifications and procedures were provided for on-site storage, erection, quality control, and testing.

During component installation, the Westinghouse project organization provided a capable and experienced group of specialists to monitor all construction related activities on the Nuclear Steam Supply System, Engineered Safeguards and Critical Structures. This group was staffed to provide coverage in all phases of construction such as welding, mechanical, electrical, systems, instrumentation and control and startup. The primary responsibility of this staff was to insure proper erection of the Nuclear Steam Supply System, Engineered Safeguards and Critical Structures as outlined by Westinghouse specifications and procedures. This surveillance included visits to selected shops of suppliers to ensure that established procedures of inspection and documentation were properly followed. Secondary functions of this staff were to provide technical direction and assistance to the constructor during critical operations and to ensure that adequate documentation was maintained. This staff was responsible for quality and documentation of all construction activities on the Nuclear Steam Supply System. This documentation was monitored by qualified quality assurance personnel operating independently of the construction group and reporting to the Project Manager. Such personnel provided additional surveillance of critical operations, followed problems or deficiencies until disposition, aided staff specialists in the performance of their duties when necessary, and monitored construction records for completeness.

B. Nonconforming Components or Material

All nonconforming components or material, whether discovered at the supplier's facility or at the construction site, were documented, reviewed and disposed of in accordance with approved procedures.

In all cases, the nonconforming component or material was positively identified and separated where applicable from acceptable items or items awaiting inspection. All cases of nonconforming components or material were reviewed by Westinghouse Design and Quality Control engineers for resolution. Westinghouse's management was kept informed of all cases of major importance with recommendations for proper disposition.

Constructor's Program

In the capacity of Architect-Engineer, Bechtel was responsible for the design of all systems and structures which were not designed by Westinghouse as a part of the Nuclear Steam Supply System and associated Engineered Safeguard System, and Turbine Generator. In addition, Bechtel specified and purchased all equipment within their scope of design responsibility. Furthermore, they prepared all construction drawings and specifications and managed all construction work.

In its construction management capacity, Bechtel carried out much of the “first line” on-site quality compliance, including receipt inspection, identification, on-site storage, and initial inspection and testing during erection. Receipt inspection was carried out to determine whether the particular item was ready for installation, including checking for damage, sealing, completeness and cleanliness. Equipment was labeled or segregated, where appropriate, to assure that proper identification was maintained.

If erection could not proceed immediately, the small items were placed in a temporary warehouse, and the very large items were stored outdoors, off the ground, and covered when appropriate for quality control reasons. Openings remained sealed until erection, except when further inspection or preerection work was required; afterwards, they were resealed until installed.

Desiccants were used and periodically monitored in components which were susceptible to damage by moisture. Heaters installed in equipment for moisture control were kept energized when required. Special precautions were taken to assure that the desiccant was removed prior to system operation.

The requirements for the highest grade commercial cleanliness which could be obtained practically were observed during construction. Cleanliness specifications were prepared with full awareness of the constraints imposed by the field conditions. The necessity of removing foreign material which could cause difficulties during operation was stressed. Gross dirt and debris were removed continually from the building area during erection. Equipment was protected as required and kept reasonably clean. Systems that would contain main coolant or were connected to the main coolant system were cleaned and rinsed with demineralized water as the final cleaning operation. Temporary screens were installed in pump suction lines during the initial flush utilizing demineralized water, as required.

The equipment and materials were installed in accordance with prescribed erection procedures. These procedures included such items as sequence of installation and specifications for welding, which included paying particular attention to methods that were not standard to the construction industry. Included in the welding specifications were nondestructive tests, such as liquid dye penetrant and radiography.

The work was done by craftsmen skilled in their respective trades. Welders were given the necessary qualification tests as required by the applicable codes. Bechtel maintained an on-site quality compliance group which was independent of construction management and which monitored the construction activity at the site.

STARTUP SURVEILLANCE AND PRECORE LOADING FUNCTIONAL TESTING

Test Procedures

The following tabulation is the sequence of major start up tests and operations performed to place all equipment in the specified system in service. The systems and items tested are listed below. Wisconsin Michigan Power Company and Westinghouse Electric Corporation prepared detailed test procedures prior to scheduled initial testing of systems. Table 13.2-1 lists the test objective, deviation from design operating conditions, if any, and the acceptance criteria for each test.

1. Switchgear System
2. Reactor Protection System
3. Service Water System
4. Fire Protection System
5. Circulating Water System
6. Feedwater System
7. Auxiliary Coolant System
8. Condensate Circulation System
9. Feedwater Control System
10. Chemical & Volume Control System*
11. Safety Injection System
12. Fuel Handling System
13. Steam Dump Control System
14. Reactor Containment High Pressure Test
15. Cold Hydrostatic Tests
16. Instrument and Service Air Systems
17. Reactor Control System
18. Rod Control System
19. Reactor Containment Air Circulation System
20. Radiation Monitoring System
21. Nuclear Instrumentation System
22. Radioactive Waste Disposal System
23. Sampling System*
24. Reactor Coolant System*
25. Primary System Safety Valves Tests
26. Control Room Ventilation System
27. Rod Position Indication System
28. Emergency Diesel-Electric System
29. In-Core Instrumentation System

* Performed during the Hot Functional Testing period.

Owners' Program

The objective of this phase was to ensure that the necessary systems and subsystems were properly prepared and tested so that the initial fuel loading and subsequent power operation could be safely performed. Where feasible, the systems were operated at full load conditions of pressure, temperature, flow, or voltage prior to core loading.

Wisconsin Michigan Power Company had the ultimate responsibility of preparing the plant for core loading and was significantly involved in the testing and performance evaluation of the plant systems. This involvement was in all portions of the plant since economic reasons required the owner to ensure that the contractors delivered an efficient and well-designed plant, but even more important was the need to ensure that the sensitive portions of the plant that could affect the safety of its operations were tested in depth so that the remaining phases of construction and testing could be performed safely.

WMPCo personnel prepared detailed test procedures for each portion of the plant using the following sources of information:

1. Design drawings and Process Flow Sheets
2. Design specifications for specific equipment and systems
3. System descriptions supplied by the Contractor
4. Component instruction books
5. General test procedures supplied by Westinghouse Electric Corporation and Bechtel
6. Surveillance reports obtained from the Construction-Installation, Surveillance and Test Program
7. Experience gained on previous nuclear power plant construction, startup, and operation.

Those WMPCo personnel who were responsible for the construction phase were, in most cases, the ones responsible for preparing the test procedures, check-off lists, and other supportive documents, necessary to evaluate the same systems during this program. Each procedure was reviewed and approved by Wisconsin Michigan Power Company through the General Superintendent Supervisory Staff. Prior to test performance, WMPCo submitted the detailed test procedures to Bechtel or Westinghouse for review. Bechtel Corporation or Westinghouse Electric Corporation provided technical direction for testing; however, all tests and procedures were performed by qualified WMPCo personnel. The General Superintendent, or designated alternate, ensured that each test was reviewed by all responsible parties, that initial plant conditions and prerequisites to the test were met, that proper personnel were available and understood the test procedures and precautions, and that proper emphasis was placed on safety during the tests.

If at any time during testing the reactor operators or other responsible cognizant personnel felt that an unsafe condition prevailed or could occur or the test was not done in accordance with procedure, they advised the appropriate person of this condition such that steps could be taken to interrupt the test and put the plant in a safe condition. The questionable condition would then be reviewed by WMPCo through the General Superintendent's Supervisory Staff with assistance from Bechtel Corporation or Westinghouse Electric Corporation as needed. If the questionable condition was considered unsafe, the appropriate procedure was rewritten in a safe manner before the test could be continued or reperformed. If substantial revision was required, the General Superintendent, or designated alternate, reviewed the change with the same approach as a new test procedure before the test could be continued or reperformed.

The primary organizational positions are described below:

Operations Manager (Westinghouse)

Maintained total Westinghouse project responsibility for startup and testing. He coordinated the overall startup program between the site groups and Westinghouse in Pittsburgh, PA. He was responsibile for approval of test procedures and startup program scheduling.

Shift Startup Engineer (Westinghouse)

Carried out the directions of the Operations Manager. Provided continuous coverage at the site for Westinghouse representation during testing of the plant initial operations phase. Coordinated the startup effort between the WMPCo shift supervisor and all Bechtel and Westinghouse personnel, including their vendor's representatives.

Project Startup Engineer (Bechtel)

Carried out the technical directions of the Operations Manager. Directed all startup effort relative to the scope of Bechtel. (In general, this was the portion of the plant outside the scope of the Nuclear Steam Supply System.)

Startup Engineers (Bechtel)

Carried out the directions of the Project Startup Engineer. For startup activities, coordinated the efforts of Bechtel Construction, Engineering and vendors personnel.

GENERAL SUPERINTENDENT - Nuclear Power Division
(Wisconsin Michigan Power Company)

Administratively responsible for all primary and secondary plant operation. He exercised direct supervisory control over licensee's personnel and their support groups. He controlled execution of startup programs and tests with the coordination and technical advice of the Westinghouse Operations Manager. He had final authority on operating safety and assignment of Licensee plant and headquarters staff personnel assigned to the site.

Table 13.2-1 PREOPERATIONAL TESTS

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System	Deviations from Design Conditions	Objectives	Acceptance Criteria
Reactor Coolant*	None	To verify that all instrumentation and control functions of the system were operating properly and that system flows were correct.	Technical Specifications. Precautions, Limits and Set-Points.
Auxiliary Coolant			
Component Cooling System	None	To verify component cooling flow to components served by the system and proper operations of valves, instrumentation and alarms associated with the system.	Technical Specifications. Precautions, Limits and Set-Points.
Residual Heat Removal System	None	To verify proper operation of valves, instrumentation and alarms associated with the system and the ability of the system to cool the plant from 350°F to 140°F in 20 hours.	Technical Specifications. Precautions, Limits and Set-Points.
Spent Fuel Pool Cooling	Spent fuel will not be in pool	To verify proper operation of valves, instrumentation and alarms associated with the system and proper flow paths for cooling.	Technical Specifications. Precautions, Limits and Set-Points.
Chemical and Volume Control System*	None	To verify that the system performed the following functions: maintain reactor coolant system water inventory, borate and dilute the reactor coolant system, supply reactor coolant pump seal water, maintain primary water chemistry within acceptable limits.	Technical Specifications. Precautions, Limits and Set-Points.
Sampling System*	None	To verify that a specified quantity of representative fluid and gases could be obtained safely at design conditions from each sampling point.	Westinghouse design drawings. Precautions, Limits and Set-Points.

*Performed during the Hot Functional Testing period.

Table 13.2-1

(Sheet 2 of 7)

System	Deviations from Design Conditions	Objectives	Acceptance Criteria
Waste Disposal System	None	To demonstrate that the system was capable of processing all radioactive liquids, gases and solids associated with plant operation.	Technical Specifications. Westinghouse design drawings. Westinghouse and Bechtel specifications.
Safety Injection System	Not necessarily at normal operating temperature and pressure	To verify proper response of the system to actuating signals in regards to pump, valve, instrumentation and alarms associated with system. Specifically that: a) all manual and remotely operated valves were operable manually and/or remotely, b) pumps performed their design functions satisfactorily, c) redundant flow path valves were operable if one valve in pair was disabled, d) proper sequencing of valves and pumps on receipt of a safety injections signal, e) failure position on loss of power for each remotely operated valve was verified, f) instrumentation, alarms, and controls functioned properly, g) setpoints and time required to actuate within design specifications.	Technical Specifications. Precautions, Limits and Set-Points.
Fuel Handling	None	To demonstrate that the system was capable of handling fuel in all circumstances which would occur from receipt of fuel to return of fuel in a safe and orderly manner.	Westinghouse Specifications.
Reactor Protection System	None	To verify the reactor tripping circuitry by operationally checking the analog system tripping and the A and B logic trains.	Technical Specifications. Precautions, Limits and Set-Points.
Rod Control System	None	To verify the rod control system satisfactorily performed the required stepping operations for each individual rod under both cold and hot shutdown conditions and to determine the rod drop time for each full length RCCA, and to check out the part-length rod drive system.	Rod Control System technical manual. Part-Length Rod Control System technical manual.
Rod Position Indication System	None	To verify the rod position indication system satisfactorily performed the required indication and control for each individual rod under hot shutdown conditions.	Precautions, Limits and Set-Points. Component instruction manual.

Table 13.2-1

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System	Deviations from Design Conditions	Objectives	Acceptance Criteria
Feedwater Control System	None	To demonstrate that the steam generator water level could be controlled in the manual and the automatic mode of operation and to insure that all alarms and trips were functioning properly.	Precautions, Limits and Set-Points.
Steam Dump Control System	None	To verify proper settings of the steam dump control system and the capability of the steam dump system to reduce the transient conditions imposed as a result of a load cutback or rejection up to 50% without a reactor trip.	Precautions, Limits and Set-Points.
Nuclear Instrumentation System	None	To verify the proper operation of the Nuclear Instrumentation System.	Technical Specifications. Nuclear Instrumentation System Manual. Precautions, Limits and Set-Points.
Radiation Monitoring System	None	To verify that all channels were operable and alarm and recording functions were responding properly.	Technical Specifications.
In-Core Instrumentation System	None	To perform checkout and demonstration of the in-core thermocouple system and the in-core flux mapping system.	Component Instruction Manual.
Service Water System	None	To verify that the system would supply the required water flow through all equipment supplied with service water and that all instrumentation and controls functioned as designed.	Technical Specifications. Bechtel Functional Description.
Fire Protection System	As required by insurance inspectors. Sprinkler head will not be tested.	To verify proper operation of the system and to check all automatic functions.	Bechtel Functional Description. As designated by the manuals of the National Fire Protection Assoc.
Circulating Water System	None	To verify proper operation of pumps, valves and control circuitry; proper priming of the system, and proper flow through the condensers and the condensate cooler.	Bechtel Functional Description.

Table 13.2-1

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System	Deviations from Design Conditions	Objectives	Acceptance Criteria
Instrument and Service Air System	None	To verify: a) the proper operation of all compressors to design specifications, b) the manual and automatic operation of controls at design setpoints, c) design air dryer cycle time and moisture content of discharge air, d) proper air pressure to each instrument and equipment served by the system.	Technical manuals. Bechtel Functional Description.
Reactor Containment Air Circulating System	Unable to test at design temperature and pressure	To verify the proper operation of: a) all fans, filters, heating and cooling coils, b) automatic and manual controls to maintain containment atmosphere within design specifications, c) proper operation of recirculation fans and coolers on a safety injection signal, d) purge valve isolation, e) all interlocks and alarms.	Technical Specifications.
Feedwater and Condensate System	None	To verify pump, valve, and control operability and set-points. Functional testing was performed when a steam supply was available.	Technical Specifications.
Control Room Ventilation System	None	To demonstrate the control room ventilation system could perform its designed function during normal plant operations and during postaccident plant conditions by checking out each mode of operation.	Component Instruction Manual. Bechtel Functional Description.
Emergency Diesel Electric System	None	To assure that the emergency diesel-generators were installed in accordance with the design specifications and operated as described in the functional description to satisfactorily accept the safeguard system load upon failure of the normal power supply.	Approved Schematic Circuit Diagrams . Vendor's instructions. Bechtel Functional Description.
Switchgear System	None	To verify that the electrical, auxiliary, and safeguard systems were installed and operated in accordance with accepted electrical standard and design and thereby provided reliable power to auxiliaries required during any normal or emergency mode of plant operation.	ASA and IEEE Standards. Approved schematic circuit diagrams. Manufacturer's equipment instructions.
Primary System Safety Valves Tests	Tested at room temperature	To ascertain the popping and reseat pressure settings of the valves and establish that zero leakage conditions existed across the seating face.	Westinghouse Equipment Specifications.

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System	Deviations from Design Conditions	Objectives	Acceptance Criteria
Reactor Containment High Pressure Test and Leakage Test	Tested at room temperature	To verify the structural integrity and leak tightness of containment.	Technical Specifications. Precautions, Limits and Set-Points.
Cold Hydrostatic Tests	Pressure above design	To verify the structural integrity and leak tightness of the particular system.	Technical Specifications. Precautions, Limits and Set-Points.
RCC Unit Drop Tests	a. Cold, Shutdown b. Hot, Shutdown	To measure the drop times of all RCC units from loss of coil voltage to dashpot entry at cold and hot conditions with full flow. Selected rods will be dropped at no flow conditions.	Drop times less than 1.85 seconds from loss of coil voltage to dashpot entry for all rods at full flow and operating temperature.
Thermocouple/RTD Intercalibration	Various temperatures during initial system heatup.	To verify RTD calibration data and to determine in-place isothermal correction constants for all core exit thermocouples.	Acceptable behavior within manufacturer's tolerances of ±2°F for the RTD measuring system ±3/8% of the reading for the thermocouples.
Nuclear Design Check Tests	All RCC control and shut-down group configurations at hot, zero power	To verify that the nuclear design predictions for endpoint boron concentrations, isothermal temperature coefficients, RCC bank differential and integral worths and power distributions are valid.	Reasonable agreement with design values. FFD and SAR limiting values of F^N = 2.72, F^N_Δ H = 1.58, Sp/ST = -5.0 pcm/°F, and Sp/ST = 60 pcm/sec will not be exceeded at applicable conditions.
Plant Trip	Full load rejection from approximately 30% and 100% of rated power.	To verify reactor control performance control and steam dump performance.	No safety criteria applicable. Reasonable agreement with setpoint study responses. Turbine overspeed 132% or less.

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System	Deviations from Design Conditions	Objectives	Acceptance Criteria
Plant Calormetric and Power Range Instrumentation Calibration	During static and/or transient conditions at approximately: 40%, 70%, 90%, 100%	To calibrate power range channels such that total core thermal output is indicated and that the detectors indicated the relationship between incore and excore axial offsets and quadrant tilts.	Encore detectors indicate incore distribution within reasonable agreement, the even function of the indicated difference between top and bottom detectors used in the overpower and overtemperature ΔT protection can be set such that: a. for measured incore power in the top minus power in the bottom within 20% of rated power, no change in ΔT setpoints occur b. for each percent that the incore power difference exceeds 20%, setpoint is reduced by 2% power.
Load Swing and Load Reduction Test	a. ± 10% at approximately 25%, 60% and 100% of rated power b. Load reduction of approximately 50% from 55% and 100% power level c. Ramp load increase and decrease between 40% and 90% at the rate of 5%/minute.	To verify reactor control performance.	No safety criteria applicable. Reasonable agreement with setpoint study responses.
Dynamic RCC Drop Test	Approximately 50% of rated power	To verify automatic detection of dropped rod by bottom and power range detector indication for selected rods. A minimum of one drop be accompanied with turbine runback and automatic rod withdrawal stop.	Proper indication of a dropped rod, blocking of automatic rod withdrawal and turbine power reduction.

Table 13.2-1

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System	Deviations from Design Conditions	Objectives	Acceptance Criteria
Static RCC Insertion and Drop Tests	Approximately 50% of rated power	To verify that a single RCC unit when misaligned with the control bank can be detected by individual rod position indication or by incore instrumentation if required. To determine the effect of a single full inserted RCC unit on core reactivity and core power distribution.	Misaligned rod detectable by individual rod position indication and incore instrumentation when out of position by 24 steps or greater. The worth of the highest inserted rod would not cause a reduction in power greater than the turbine runback power reduction. The flux tilt, coolant temperature, and pressure response to dropping the worst rod, when extrapolated to rated power, will not result in a condition of DNB.
Radiation Shielding Effectiveness Test	a. 10^{-8} - 10^{-7} amps b. 1 - 3% c. 30 - 40% d. 100%	Measure neutron and gamma shielding effectiveness in the containment.	The desired areas of the containment are within design and personnel exposure limits.

13.3 FINAL PLANT PREPARATION (Historical)

Staffing

The initial five Shift Supervisors had 46 man-years of nuclear experience and related technical training not associated with the Point Beach Nuclear Plant programs. Four of the five had U.S. Nuclear Navy backgrounds and one of these also had Argonne National Laboratory background. The fifth was a graduate of the Westinghouse off-site training school for Point Beach Nuclear Plant Supervisors. In addition, all had completed nearly 600 hours of on-site formal training prior to startup. On the job training was not logged here as it was not needed for qualification requirements.

The initial five Operating Supervisors had a total of 50 man-years of nuclear experience and related technical training not associated with the Point Beach Nuclear Plant programs. All five of these had U.S. Nuclear Navy background and one had completed the Westinghouse off-site school for Point Beach Nuclear Plant Supervisors. These supervisors completed the identical 600 hours of on-site formal training described for the Shift Supervisors.

Two supervisors were assigned to each of the five shift teams. The total man-years of experience and related technical training (including Point Beach Nuclear Plant) for the teams, ranged from a minimum of 13 to a maximum of 25½.

All Westinghouse and Bechtel personnel who participated in or acted as support personnel during the initial tests and operation of the reactor exceeded the qualification criteria as set forth by the Atomic Energy Commission.

The General Superintendent had overall responsibility and direction of all phases of testing. Technical responsibility at each individual phase of actual startup rested with the functional group most directly concerned with the results of the phase. Westinghouse Electric Corporation had on-site representatives of supporting functional groups to provide technical advice, recommendations, and assistance in planning and executing the respective phases of plant startup.

The Test and Operations Management Group, consisting of the General Superintendent - Wisconsin Michigan Power Company Nuclear Power Division, the Operations Superintendent and the Reactor Engineer made the final acceptance of plant components, systems, and operating characteristics. The Operations Superintendent with the General Superintendent was responsible for accepting the final installation and performance of mechanical systems and components. The Reactor Engineer with the General Superintendent was responsible for accepting and for approving performance characteristics of the nuclear cores, computers and in-core instrumentation. The Test and Operations Management Group reviewed the test results as well as consulted with Wisconsin Michigan Power Company surveillance supervisors, technical assistants and applicable Westinghouse startup and construction personnel.

Core Loading

The overall responsibility and direction for initial core loading was exercised by the General Superintendent. The overall process of initial core loading was, in general, directed from the charging floor of the containment. The Wisconsin Michigan Power Company Senior Reactor Operator licensed Shift Supervisor had direct supervision over and responsibility for the operation of core loading which included: fuel handling in the new and spent fuel storage areas, transfer of fuel from these areas to the containment, fuel handling by the manipulator crane, and placement of the fuel in the proper core location. The Wisconsin Michigan Power Company Reactor Engineering personnel were responsible for core loading procedures and loading monitoring. Westinghouse Electric Corporation provided technical advisors to assist Wisconsin Michigan Power Company personnel during the initial core loading operation.

The as-loaded core configuration was specified as part of the fuel core design studies conducted well in advance of plant startup. In the relatively unlikely event that mechanical damage would be sustained during core loading operations by a fuel assembly of a type for which no spare was available on-site, a previously examined alternate core loading scheme whose characteristics closely approximate those of the initially prescribed pattern would have been invoked.

The core was assembled in the reactor vessel in water containing enough dissolved boric acid (at least 2000 ppm boron) to maintain the core effective multiplication constant at 0.90 or lower. Core moderator chemistry conditions (particularly boron concentration) were prescribed in the core loading procedure document and were verified periodically by chemical analysis of moderator samples taken during core loading operation.

Core loading instrumentation consisted of two permanently installed plant source range (pulse-type) nuclear channels and two temporary in-core source range channels plus a third temporary channel used as a spare. The permanent channels were monitored in the control room by a licensed plant operator; the temporary channels were installed in the containment and were monitored by Licensee personnel. At least one plant channel and one temporary channel were equipped with audible count range indicators. Both plant channels and both regular temporary channels displayed neutron count rate on count rate meters and strip chart recorders. Minimum count rates attributable to core neutrons were required on at least two of the four available nuclear channels at all times during core loading operations.

Two neutron sources were introduced into the core at appropriate specified points in the core loading program to ensure a neutron population large enough for adequate monitoring of the core.

Fuel assemblies together with inserted components (RCC units, burnable poison inserts, source spider, or thimble plugging device) were placed in the reactor vessel one at a time according to a previously established and approved sequence which had been developed to provide reliable core monitoring with minimum possibility of core mechanical damage. The core loading procedure documents included a detailed tabular check sheet which prescribed and verified the successive movements of each fuel assembly and its specified inserts from its initial position in the storage racks to its final positions in the core. Multiple checks were made of component serial numbers and types at successive transfer points to guard against possible inadvertent exchanges or substitutions of components.

An initial nucleus of eight fuel assemblies was determined to be the minimum source-fuel nucleus which would permit subsequent meaningful inverse count rate monitoring. This initial nucleus was known by calculation and previous experience to be markedly subcriticality (k_{eff}<0.90) under the required conditions of loading.

Each subsequent fuel addition, one fuel assembly at a time, was accompanied by detailed neutron count rate monitoring to determine that the just loaded fuel assembly had not greatly increased the count rate and that the extrapolated inverse count rate ratio, as plotted, was not decreasing for unexplained reasons. The results of each loading step was evaluated by Licensee Reactor Engineering personnel or technical advisors of Westinghouse Electric Corporation before the next prescribed step could be started.

Criteria for safe loading required that loading operations stop immediately if:

1. The neutron count rates on all responding nuclear channels doubled during any single loading step after the initial nucleus of eight fuel assemblies had been loaded.

2. The neutron count rate on any individual nuclear channel increased unexpectedly by a factor of five during any single loading step.

An alarm in the containment and control room was coupled to the plant source range channels with a set point at five times the current count rate. This alarm automatically alerted the loading operation to an indication of high count rate and required an immediate stop of all operations until the incident had been evaluated.

In the event that the licensed plant operator in the control room determined that an unacceptable increase in count rate was being observed on any or all responding nuclear channels, he would execute one of, or combinations of, the special procedures which may involve fuel withdrawal from the core, manually actuating the containment evacuation alarm or charging of concentrated boric acid into the moderator.

Core loading procedures specified alignment of fluid systems to prevent inadvertent dilution of the reactor coolant, restricted the movement of fuel to minimize the possibility of mechanical damage, prescribed the conditions under which loading would proceed, identified chains of responsibility and authority and provided for continuous and complete fuel and core component accountability.

Postloading Tests

Upon completion of core loading and installation of the reactor upper internals and the pressure vessel head, certain mechanical and electrical tests were performed prior to initial criticality. The final cold leakage tests were conducted after filling and venting was completed.

Mechanical and electrical tests were performed on the RCC unit drive mechanisms. Tests included a complete operational checkout of the mechanisms. Checks were made to ensure that the rod position indicator coil stacks were connected to their proper position indicators. Similar checks were made on the RCC unit drive coils.

Tests were performed on the reactor trip circuits to test manual trip operation. Actual RCC unit drop times were measured for each rod control cluster. By use of dummy signals, the reactor control and protection system was made to produce trip signals for the various plant abnormalities that required tripping. Complete electrical and mechanical check was made on the in-core nuclear flux mapping system and the in-core thermocouples.

13.4 INITIAL TESTING IN THE OPERATING REACTOR (Historical)

Initial Criticality

Initial criticality was established by withdrawing the shutdown and control groups of RCC units from the core, leaving the last withdrawn control group inserted far enough to provide effective control when criticality was achieved, and then slowly and continuously diluting the heavily borated reactor coolant until the chain reaction was self-sustaining.

Successive stages of RCC group withdrawal and of boron concentration reduction were monitored by observing change in neutron count rate as indicated by the regular plant source range nuclear instrumentation as functions of RCC group position and, subsequently of primary water addition to the reactor coolant system and reactor coolant boron concentration during dilution.

Primary safety reliance was based on inverse count rate ratio plots as an indication of the nearness and rate of approach of criticality of the core during RCC group withdrawal and during reactor coolant boron dilution. The rate of approach toward criticality was reduced as the reactor approached extrapolated criticality to ensure that effective control was maintained at all times.

Relevant procedures specified alignment of fluid systems to allow controlled start and stop and adjustment of the rate of which the approach to criticality proceeded, indicated values of core conditions under which criticality was expected and identified chains of responsibility and authority during reactor operations.

Initial Plant Verification Tests

Upon establishment of criticality, a series of tests was initiated to determine the overall unit behavior and systems performance under operating conditions. The initial tests consisted of selected low power physics measurements and power escalation tests to insure safe reactor operation while performing the overall unit checkout.

The low power measurements were made at or near operating temperature and pressure and consisted of the worth of the control bank, boron concentration worth determined from data taken during the RCC measurement, an isothermal temperature coefficient, and all rods out critical boron concentration and power distribution. Concurrent tests were conducted on the plant instrumentation including the source and intermediate range nuclear channels. RCC unit operation and the behavior of the associated control and indicating circuits were demonstrated and the adequacy of the control and protection systems were verified under low power operating conditions. The results of these tests and measurements were compared to the expected design behavior and a decision could be made whether to continue with the Initial Plant Verification Tests or to do the complete low power testing to better verify design values. The remainder of the initial plant verification tests were performed during power escalation to no more than 40% of rated power level.

The main purpose of the above tests was to determine and locate possible inadequate design and faulty construction work which could be rectified during the low power physics measurements program if required. Detailed procedures specified the sequence of tests and measurements to be conducted and the conditions under which each was to be performed. Should deviations from design predictions exist, unacceptable behavior be revealed, or apparent anomalies develop during this phase or subsequent phases of testing, the situation would be reviewed by the General Superintendent's Supervisory Staff to determine action in consideration of the facility license, the technical specifications, and the expertise of each group in the Supervisory Staff. If necessary, the tests themselves would be carefully repeated or supporting tests made to verify the results.

If the apparent discrepancy or anomaly was found to be real and it was outside the scope of the Supervisory Staff for resolution, the situation would be evaluated at the appropriate level of review.

Low Power Testing

A prescribed program of reactor physics measurements was undertaken to verify that the basic static and kinetic characteristics of the core were as expected and that the values of the kinetic coefficients assumed in the safeguards analysis were indeed conservative.

The measurements were made at low or nearly zero power and primarily at or near operating temperature and pressure. Measurements included verification of calculated values of RCC group and unit worths, of isothermal temperature coefficient under various core conditions, of differential boron concentration worth and of critical boron concentrations as a function of RCC control group configuration. Relative power distribution checks were made in normal and abnormal RCC unit configurations.

Detailed procedures specified the sequence of tests and measurements to be conducted and the conditions under which each was to be performed to ensure the relevancy and consistency of the results obtained.

Power Level Escalation

After the operating characteristics of the reactor and plant had been verified by the Initial Verification and Low Power Tests, a program of power level escalation in successive stages was undertaken to bring the plant to its full rated power level. Both reactor and plant operational characteristics were closely examined at each stage and the relevance of the safeguards analysis was verified before escalation to the next programmed level was effected. Based upon data obtained from low power tests, the first escalation was to approximately 40% reactor thermal power. The data obtained at each level was analyzed to determine what indications would be when reactor thermal power was at the next escalation level. Succeeding levels were at approximately 70% power, 90% power and 100% core thermal power (1518 MWt).

Reactor physics measurements were made to determine the magnitudes of the power coefficient of reactivity, of xenon reactivity effects, of RCC control group differential worth and of relative power distribution in the core as functions of power level and RCC control group position.

Concurrent determinations of primary and secondary heat balances were made to ensure that the several indications of plant power level were consistent and to provide bases for calibration of the power range nuclear channels. The ability of the reactor control and protection system to respond effectively to signals from plant primary and secondary instrumentation under a variety of conditions encountered in normal operations was verified.

At prescribed power levels the response characteristics of the reactor coolant and steam systems to dynamic stimuli were evaluated. The responses of system components were measured for 10% loss of load and recovery, 40% loss of load and recovery, turbine trip, loss of flow and trip of a single RCC unit.

A series of load follow tests were performed at selected power level escalation steps and after rated power level had been achieved. The results of these tests gave actual reactor and plant behavior under operating conditions and were used to verify predicted load follow capabilities.

Adequacy of radiation shielding was verified by gamma and neutron radiation surveys inside the containment and throughout plant buildings and yard areas.

The sequence of tests, measurements and intervening operations were prescribed in the power escalation procedures together with specific details relating to the conduct of the several tests and measurements. The measurements and test operations during power escalation were similar to normal plant operations.

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14.0 SAFETY ANALYSIS

This section evaluates the safety aspects of either Unit 1 or Unit 2 of the plant, demonstrates that either or both units can be operated safely and that exposures from credible accidents do not exceed the guidelines of 10 CFR 50.67 or other applicable acceptance criteria.

This section is divided into three subsections, each dealing with a different behavior category:

Core and Coolant Boundary Protection Analysis, FSAR 14.1

With the exception of the Locked Rotor Accident, the abnormalities presented in FSAR 14.1 have no off-site radiation consequences. Radiological consequences, resulting from fuel cladding damage and a radioactivity release to the outside atmosphere, are assumed to occur as a result of the Locked Rotor Accident, presented in FSAR 14.1.8.

Standby Safety Features Analysis, FSAR 14.2

With the exception of the Locked Rotor Accident, the accidents presented in FSAR 14.2 are more severe than those discussed in FSAR 14.1 and may cause release of radioactive material to the environment.

Rupture of a Reactor Coolant Pipe, FSAR 14.3

The accident presented in FSAR 14.3, the rupture of a reactor coolant pipe, is the worst case accident and is the primary basis for the design of engineered safety features. It is shown that even the consequences of this accident are within the guidelines of 10 CFR 50.67.

Parameters and assumptions that are common to various accident analyses are described below to avoid repetition in subsequent sections.

Steady State Errors

For most accidents which are DNB limited, nominal values of initial conditions are assumed. The allowances on power, temperature, and pressure are determined on a statistical basis and are included in the limit DNBR, as described in WCAP-11397 (Reference 1). This procedure is known as the "Revised Thermal Design Procedure," and is discussed more fully in FSAR 3.2.

For accidents in which the Revised Thermal Design Procedure is not employed, the initial conditions are obtained by adding the maximum steady state errors to rated values. The following conservative steady state errors were assumed in the analyses:

1.	Core Power	± 0.6%	allowance for calorimetric error
2.	Average Reactor Coolant Temp	± 6.4°F	allowance for controller deadband and measurement error
3.	Pressurizer Pressure	± 50 psi	allowance for steady state fluctuations and measurement error

Table 14.0-1 and Table 14.0-2 summarize initial conditions and computer codes used in the accident analyses, and show which accidents employed a DNB analysis using the Revised Thermal Design Procedure (RTDP).

Power Distribution

The transient response of the reactor system is dependent on the initial power distribution. The nuclear design of the reactor core minimizes adverse power distribution through the placement of control rods and operating instructions. Power distribution may be characterized by the radial peaking factor ($F_{\Delta H}$) and the total peaking factor (F_Q). The peaking factor limits are given in the Technical Specifications.

For transients which may be DNB limited, the radial peaking factor is of importance. The radial peaking factor increases with decreasing power level due to rod insertion. This increase in $F_{\Delta H}$ is included in the core limits illustrated in Figure 14.0-1. All transients that may be DNB limited are assumed to begin with a $F_{\Delta H}$ consistent with the initial power level defined in the Technical Specifications. The axial power shape used in the DNB calculation is discussed in FSAR 3.2.

The radial and axial power distributions described above are input to the VIPRE code as described in FSAR 3.2.

For transients which may be overpower limited, the total peaking factor (F_Q) is of importance. All transients that may be overpower limited are assumed to begin with plant conditions, including power distributions, which are consistent with reactor operation as defined in the Technical Specifications.

For overpower transients which are slow with respect to the fuel rod thermal time constant (for example, the Chemical and Volume Control System malfunction which results in a decrease in the boron concentration in the reactor coolant, lasting many minutes, and the excessive increase in secondary steam flow incident which may reach equilibrium without causing a reactor trip), the fuel rod thermal evaluations are performed as discussed in FSAR 3.2. For overpower transients which are fast with respect to the fuel rod thermal time constant (for example, the uncontrolled rod cluster control assembly bank withdrawal from subcritical and rod cluster control assembly ejection incidents which result in a large power rise over a few seconds), a detailed fuel heat transfer calculation must be performed. Although the fuel rod thermal time constant is a function of system conditions, fuel burnup and rod power, a typical value at beginning-of-life for high power rods is approximately five seconds.

Reactivity Coefficients Assumed in the Accident Analyses

The transient response of the reactor system is dependent on reactivity feedback effects, in particular the moderator temperature coefficient and the Doppler power coefficient. These reactivity coefficients and their values are discussed in detail in FSAR 3.2.

In the analysis of certain events, conservatism requires the use of large reactivity coefficient values, whereas in the analysis of other events, conservatism requires the use of small reactivity coefficient values. Some analyses such as loss of coolant from cracks or ruptures in the Reactor Coolant System do not depend on reactivity feedback effects. The justification for use of conservatively large versus small reactivity coefficient values is treated on an event-by-event basis. In some cases conservative combinations of parameters are used to bound the effects of core life, although these combinations may represent unrealistic situations.

Rod Cluster Control Assembly Insertion Characteristics

The negative reactivity insertion following a reactor trip is a function of the position versus time of the rod cluster control assemblies and the variation in rod worth as a function of rod position. With respect to accident analyses, the critical parameter is the time of insertion up to the dashpot entry or approximately 85 percent of the rod cluster travel. The rod cluster control assembly position versus time assumed in accident analyses is shown in Figure 14.0-2. The rod cluster control assembly insertion time to dashpot entry is taken as 2.2 seconds.

Figure 14.0-3 shows the fraction of total negative reactivity insertion versus normalized rod position for a core where the axial distribution is skewed to the lower region of the core. An axial distribution which is skewed to the lower region of the core can arise from an unbalanced xenon distribution. This curve is used to compute the negative reactivity insertion versus time following a reactor trip which is input to all point kinetics core models used in transient analyses. The bottom-skewed power distribution itself is not input into the point kinetics core model. There is inherent conservatism in the use of Figure 14.0-3 in that it is based on a skewed flux distribution which would exist relatively infrequently. For cases other than those associated with unbalanced xenon distributions, significant negative reactivity would have been inserted due to the more favorable axial distribution existing prior to trip.

The normalized rod cluster control assembly negative reactivity insertion versus time is shown in Figure 14.0-4. The curve shown in this figure was obtained from Figure 14.0-2 and Figure 14.0-3. A total negative reactivity insertion following a trip of 5 percent ΔK/K is assumed in the transient analyses except where specifically noted otherwise. This assumption is conservative with respect to the calculated trip reactivity worth available. For Figure 14.0-2 and Figure 14.0-3, the rod cluster control assembly drop is normalized to 2.2 seconds, unless otherwise noted for a particular event.

Reactor Trip

A reactor trip signal acts to open the two series trip breakers feeding power to the control rod drive mechanisms. The loss of power to the mechanism coils causes the mechanisms to release the control rods, which then fall by gravity into the core. There are various instrumentation delays associated with each tripping function, including delays in signal actuation, in opening the trip breakers, and in the release of the rods by the mechanisms. The total delay to trip is defined as the time delay from the time that trip conditions are reached to the time the rods are free and begin to fall. The time delay assumed for each tripping function is given in Table 14.0-3.

Reference is made in Table 14.0-3 to overtemperature and overpower ΔT trip points shown in Figure 14.0-1. Figure 14.0-1 presents the allowable reactor coolant loop average temperature and ΔT for the design flow and power distribution, as described in FSAR 3.2, as a function of primary coolant pressure. The boundaries of operation defined by the overpower ΔT trip and the overtemperature ΔT trip are represented as "Protection Lines" on this diagram. The protection lines are drawn to include all adverse instrumentation and setpoint errors so that under nominal conditions a trip would occur well within the area bounded by these lines. The utility of this diagram is in the fact that the limit imposed by any given DNBR can be represented as a line. The DNB lines represent the locus of conditions for which the DNBR equals the safety analysis limit value. All points below and to the left of a DNB line for a given pressure have a DNBR greater than the limit value. The diagram shows that DNB is prevented for all cases if the area enclosed with the maximum protection lines is not traversed by the applicable DNBR line at any point.

The area of permissible operation (power, pressure, and temperature) is bounded by the combination of reactor trips: high neutron flux (fixed setpoint); high pressure (fixed setpoint); low pressure (fixed setpoint); overpower and overtemperature ΔT (variable setpoints).

The limit value, which was used as the DNBR limit for all accidents analyzed with the Revised Thermal Design Procedure (see Table 14.0-1), is conservative compared to the actual design DNBR value required to meet the DNB design basis as discussed in FSAR 3.2.

The difference between the limiting trip point assumed for the analysis and the normal trip point represents an allowance for instrumentation channel error and setpoint error. Nominal trip setpoints are specified in the plant Technical Specifications.

Determining Reactor Power Level through Secondary Calorimetric

To assure that the initial reactor power level prior to an overpower transient is maintained within the accident analysis assumption of 100.6%, a secondary plant calorimetric is performed on a periodic basis to determine core thermal power and to set the power range flux instruments to this measured power. The calorimetric power level is calculated using measurement of secondary parameters such as feedwater flow, feedwater inlet temperature to the steam generators and steam pressure. High accuracy instrumentation is provided for these measurements, such that total instrument error is less than or equal to 0.6%. If the Leading Edge Flow Meter (LEFM) used to measure feedwater flow is out of service, the operating reactor power level is reduced to account for increased calorimetric measurement uncertainty of the feedwater flow venturis, so that reactor power continues to be maintained within the accident analysis assumption for initial reactor power level. (Reference 12) (Reference 13)

Plant-to-Plant Interaction

The safety evaluation of a two unit plant, where two reactors are situated in close physical proximity on the same site, sharing certain facilities and operated as combined power producing units, requires that the safety assessment treat the plant as a two unit facility rather than as two individual single unit facilities. However, for the reasons discussed below, the nature of the two unit plant design confines the location of a reactor fault condition to one of the two units at any time (with the exception of possible faults arising in the electrical grid system to which both units are connected, and these have no off-site radiation consequences). Thus, for the two unit plant, the potential consequences of each and every credible reactor fault condition are no different than those for a single unit plant.

Possible sources of interaction between the two units are discussed below:

Sharing of Systems

As noted in FSAR 1.0, FSAR 9.0, FSAR 10.0, and FSAR 11.0, all or part of certain systems (e.g., Chemical and Volume Control System, Waste Disposal System) are shared by the two units. A functional evaluation of the components of those systems which are shared by the two units is given in Appendix A.6.

The plant is provided with a control room which is common to both units. Physical separation of control panels in the control room essentially eliminates interaction of the control systems of the two units. The two units are connected to the same external electrical grid, and it is therefore possible that the following transients could affect both units simultaneously:

1. Loss of external electrical load (FSAR 14.1.9)
2. Loss of all AC power to the station auxiliaries (FSAR 14.1.11)

The design is such that the occurrence of either of these two transients, in both units simultaneously, can be accommodated without an unsafe condition arising in either unit.

Except for the electrical grid conditions noted above, all systems which are shared by both units are designed such that a shared system can neither cause a simultaneously unsafe condition in both units, nor propagate an accident condition, which may arise in one unit, to the other unit.

Physical Proximity

The positioning of the two units in close physical proximity introduces no possibility of external interaction. For each unit, the integrity of all systems whose functions are necessary to maintain the safety of the reactor is ensured by the nature of the design: e.g., through separation of redundant components such as wiring, and missile shielding both inside and outside the containment. Thus, with the exception of the electrical faults already noted, the two unit plant precludes by the nature of its design, any possibility of either (a) simultaneous occurrence in both units of fault conditions having a common origin, (b) the propagation from one unit to the other unit of a fault condition.

In addition, it is not considered credible that both units could develop unrelated accidents, either of the same or a different nature simultaneously. Thus, the criteria for plant design require the capability to deal with the affected unit while maintaining safe control of the other unit. Although these criteria do not directly imply that the other unit must be shut down following the occurrence of an accident condition in one unit, the two unit plant design includes the capability to meet all safety criteria in the affected unit, and simultaneously shut the second unit down and maintain it at hot shutdown, if required. In fact, continued on-line operation of the adjacent unit enhances the assurance of a continuous supply of electrical power for the engineered safety features of the affected unit.

In a two unit plant, the overall design of each unit represents no essential departure from the current design of the unit which comprises a single unit plant. Thus, the methods and techniques for the safety assessment of a single unit plant are directly applicable to a two unit plant. Further, since both units of a two unit plant are nearly identical, the safety assessment (presented in this section for a single unit) is equally applicable to either unit.

Computer Codes Utilized

Summaries of some of the principal computer codes used in transient analyses are given below. Other codes, in particular very specialized codes in which the modeling has been developed to simulate one given accident, such as those used in the analysis of the primary system pipe rupture (FSAR 14.3), are summarized in their respective accident analyses sections. The codes used in the analyses of each transient have been listed in Table 14.0-1.

Advanced Nodal Code (ANC) / SPNOVA (Reference 7, Reference 10, and Reference 11)

ANC is an advanced nodal code capable of two-dimensional (2-D) and three-dimensional (3-D) neutronics calculations. ANC is the reference model for certain safety analysis calculations, power distributions, peaking factors, critical boron concentrations, control rod worths, reactivity coefficients, etc. In addition, 3-D ANC validates 1-D and 2-D results and provides information about radial (x-y) peaking factors as a function of axial position. It can calculate discrete pin powers from nodal information as well.

The SPNOVA code utilizes the same Westinghouse standard core design methodology with three-dimensional (3-D) nodal expansion methodology for static analysis of cores that is incorporated into the ANC computer program (Reference 11). SPNOVA includes a neutron kinetics capability and uses the Stiffness Confinement Method to solve time dependent equations.

The ANC licensing topical report, WCAP-10965 (Reference 7), was approved by the NRC via an SER from C. Berlinger (NRC) to E. P. Rahe (Westinghouse), dated June 23, 1986. The SPNOVA licensing topical report, WCAP-12983 (Reference 10), was approved by the NRC via an SER from A. C. Thadani (NRC) to W. J. Johnson (Westinghouse), dated November 26, 1990. A process improvement that has resulted in streamlining and consolidating the Westinghouse neutronics code system was discussed in a letter (Reference 11) from N. J. Liparulo (Westinghouse) to R. C. Jones (NRC), dated March 29, 1996. As concluded in that letter, the implementation of the ANC solution method in SPNOVA eliminated the solution differences between ANC and SPNOVA, and also eliminated the SPNOVA normalization step to the ANC conditions, addressing the SPNOVA SER conditions imposed due to the solution differences between ANC and SPNOVA.

FACTRAN (Reference 2)

FACTRAN calculates the transient temperature distribution in a cross section of metal clad UO_2 fuel rod and the transient heat flux at the surface of the cladding using as input the nuclear power and time-dependent coolant parameters (pressure, flow, temperature, and density). The code uses a fuel model which exhibits the following features simultaneously:

1. A sufficiently large number of radial space increments to handle fast transients such as rod ejection accidents.

2. Material properties which are functions of temperature and a sophisticated fuel-to-cladding gap heat transfer calculation.

3. The necessary calculations to handle post-DNB transients: film boiling heat transfer correlations, Zircaloy-water reaction and partial melting of the materials.

LOFTRAN (Reference 3)

The LOFTRAN program is used for studies of transient response of a PWR system to specified perturbations in process parameters. LOFTRAN simulates a multiloop system by a model containing reactor vessel, hot and cold leg piping, steam generator (tube and shell sides) and the pressurizer. The pressurizer heaters, spray, and relief and safety valves are also considered in the program. Point model neutron kinetics, and reactivity effects of the moderator, fuel, boron, and rods are included. The secondary side of the steam generator utilizes a homogeneous, saturated mixture for the thermal transients and a water level correlation for indication and control. The

Reactor Protection System is simulated to include reactor trips on high neutron flux, overtemperature ΔT, overpower ΔT, high and low pressurizer pressure, low flow, and high pressurizer level. Control systems are also simulated including rod control, steam dump, feedwater control, and pressurizer pressure control. The Emergency Core Cooling System, including the accumulators and upper head injection, is also modeled.

LOFTRAN is a versatile program which is suited to both accident evaluation and control studies as well as parameter sizing. It also has the capability of calculating the transient value of DNBR based on the input from the core limits illustrated in Figure 14.0-1. The core limits represent the minimum value of DNBR as calculated for typical or thimble cell.

RETRAN (Reference 8)

RETRAN is used for studies of transient response of a pressurized water reactor (PWR) system to specified perturbations in process parameters. This code simulates a multi-loop system by a lumped parameter model containing the reactor vessel, hot- and cold-leg piping, RCPs, steam generators (tube and shell sides), main steam lines, and the pressurizer. The pressurizer heaters, spray, relief valves, and safety valves can also be modeled. RETRAN includes a point neutron kinetics model and reactivity effects of the moderator, fuel, boron, and control rods. The secondary side of the steam generator uses a detailed nodalization for the thermal transients. The RPS simulated in the code includes reactor trips on high neutron flux, high neutron flux rate, OTΔT, OPΔT, low reactor coolant flow, high- and low-pressurizer pressure, high pressurizer level, and low-low steam generator water level. Control systems are also simulated including rod control and pressurizer pressure control. Parts of the safety injection system (SIS), including the accumulators, are also modeled. Also, a conservative approximation of the transient DNBR, based on the core thermal limits, is calculated via RETRAN.

TWINKLE (Reference 4)

The TWINKLE program is a multi-dimensional spatial neutron kinetics code, which is patterned after steady state codes presently used for reactor core design. The code uses an implicit finite-difference method to solve the two-group transient neutron diffusion equations in one, two and three dimensions. The code uses six delayed neutron groups and contains a detailed multi-region fuel-cladding-coolant heat transfer model for calculating pointwise Doppler and moderator feedback effects. The code handles up to 8000 spatial points, and performs its own steady state initialization. Aside from basic cross-section data and thermal-hydraulic parameters, the code accepts as input basic driving functions such as inlet temperature, pressure, flow, boron concentration, control rod motion, and others. Various edits are provided, e.g., channelwise power, axial offset, enthalpy, volumetric surge, pointwise power, and fuel temperatures.

The TWINKLE code is used to predict the kinetic behavior of a reactor for transients which cause a major perturbation in the spatial neutron flux distribution.

THINC

The THINC Code is described in Reference 7 and Reference 21, of FSAR 3.2.

VIPRE (Reference 9)

The VIPRE computer program performs thermal-hydraulic calculations. This code calculates coolant density, mass velocity, enthalpy, void fractions, static pressure, and DNBR distributions along flow channels within a reactor core.

The VIPRE licensing topical report, WCAP-14565 (Reference 9), was approved by the NRC via an SER from T. H. Essig (NRC) to H. Sepp (Westinghouse), dated January 19, 1999.

14.0.1 REFERENCES

1. Friedland, A. J., Ray, S., "Revised Thermal Design Procedure," WCAP-11397 (Proprietary), February 1987.

2. Hargrove, H. G., "FACTRAN - A Fortran-IV Code for Thermal Transients in a UO2 Fuel Rod," WCAP-7908 (Proprietary), June 1972.

3. Burnett, T. W. T., et al., "LOFTRAN Code Description," WCAP-7907-P-A, April 1984.

4. Risher, D. H. Jr. and Barry, R. F., "TWINKLE - A Multi-Dimensional Neutron Kinetics Computer Code," WCAP-7979-P-A (Proprietary), and WCAP-8028-A (Non-Proprietary), January 1975.

5. WE letter to NRC, VPNPD-96-051, "Supplement to Technical Specifications Change Requests 188 and 189," dated August 5, 1996.

6. NRC SE for License Amendment Nos. 207 and 212, "Measurement Uncertainty Recapture Power Uprate," dated November 29, 2002.

7. Liu, Y. S., et al., "ANC: A Westinghouse Advanced Nodal Computer Code," WCAP-10965-P-A, December 1985.

8. Huegel, D. S., et al., "RETRAN-02 Modeling and Qualification for Westinghouse Pressurized Water Reactor Non-LOCA Safety Analyses," WCAP-14882-P-A, April 1999.

9. Sung, Y. X., et al., "VIPRE-01 Modeling and Qualification for Pressurized Water Reactor Non-LOCA Thermal-Hydraulic Safety Analyses," WCAP-14565-P-A, October 1999.

10. Chao, Y. A., et al., "SPNOVA - A Multidimensional Static and Transient Computer Program for PWR Core Analysis," WCAP-12394-A (Proprietary) and WCAP-12983-A (Non-proprietary), June 1991.

11. Letter from Liparulo, N. J. (Westinghouse) to Jones, R. C. (NRC), "Process Improvement to the Westinghouse Neutronics Code System," NTD-NRC-96-4679, March 29, 1996.

12. WCAP-14787, "Westinghouse Revised Thermal Design Procedure Instrument Uncertainty Methodology for Point Beach 1 & 2 Power Uprate (1775 MWt - Core Power with Feedwater Venturis, or 1800 MWT - Core Power with LEFM on Feedwater Header," Revision 3.

13. EC 285809, Fleet CI Project: PB Calorimetric Calculation Enhancement.

Table 14.0-1 SUMMARY OF INITIAL CONDITIONS AND COMPUTER CODES USED
Page 1 of 2

Event	Computer Codes Used	DNB Correlation	RTDP	Initial Power, %	Vessel Coolant Flow (gpm)	Vessel Average Coolant Temp.(°F)	RCS Pressure (psia)
Uncontrolled Rod Withdrawal from Subcritical	TWINKLE FACTRAN VIPRE	W-3(1) WRB-1(2)	No	0 (1,800 MWt - Core power)	79,922 (3)	547	2,200
Uncontrolled Rod Withdrawal at Power - Minimum DNBR Cases	RETRAN VIPRE	WRB-1	Yes	100, 60, 10 (1,806 MWt - NSSS power)	186,000	578.4 (100%) 566.4 (60%) 551.4 (10%)	2,250
Uncontrolled Rod Withdrawal at Power - Peak RCS Pressure Cases	RETRAN	N/A	No	100.6, 70, 55, 50, 45, 40, 35, 25, 8 (1,806 MWt - NSSS power)	178,000	583.4 (100.6%) 574.4 (70%) 569.9 (55%) 568.4 (50%) 566.9 (45%) 565.4 (40%) 563.9 (35%) 560.9 (25%) 555.8 (8%)	2,200
RCCA Drop	LOFTRAN(4) ANC VIPRE	WRB-1	Yes	100 (1,800 MWt - Core power)	186,000	577.0	2,250
Chemical and Volume Control System Malfunction	N/A	N/A	N/A	100 (MODE 1) 5 (MODE 2) 0 (MODES 5 and 6) (1,800 MWt - Core power)	N/A	583.4 (MODE 1) 554.9 (MODE 2) 200.0 (MODE 5) 140.0 (MODE 6)	2,250 (MODE 1) 2,250 (MODE 2) 14.7 (MODES 5 and 6)
Startup of an Inactive Reactor Coolant Loop				See FSAR 14.1.5			
Reduction in Feedwater Enthalpy Incident				Bounded by Excessive Load Increase Incident			
Excessive Load Increase Incident	RETRAN	WRB-1	Yes	100 (1,806 MWt - NSSS power)	186,000	578.4	2,250
Loss of Reactor Coolant Flow - All Cases	RETRAN SPNOVA VIPRE	WRB-1	Yes	100 (1,806 MWt - NSSS power)	186,000	578.4	2,250

Table 14.0-1 SUMMARY OF INITIAL CONDITIONS AND COMPUTER CODES USED
Page 2 of 2

Event	Computer Codes Used	DNB Correlation	RTDP	Initial Power, %	Vessel Coolant Flow (gpm)	Vessel Average Coolant Temp.(°F)	RCS Pressure (psia)
Locked Rotor - DNB Case	RETRAN SPNOVA VIPRE	WRB-1	Yes	100 (1,806 MWt - NSSS power)	186,000	578.4	2,250
Locked Rotor - Peak RCS Pressure Case	RETRAN SPNOVA VIPRE	N/A	No	100.6 (1,806 MWt - NSSS power)	178,000	583.4	2,300
Loss of External Electrical Load - Minimum DNBR Case	RETRAN	WRB-1	Yes	100 (1,806 MWt - NSSS power)	186,000	578.4	2,250
Loss of External Electrical Load - Peak RCS Pressure Case	RETRAN	N/A	No	100.6 (1,806 MWt - NSSS power)	178,000	577.0 (Unit 1)(5) 583.4 (Unit 2)(5)	2,200
Loss of External Electrical Load - Peak MSS Pressure Case	RETRAN	N/A	No	100.6 (1,806 MWt - NSSS power)	178,000	583.4	2,200
Loss of Normal Feedwater	RETRAN	N/A	No	100.6 (1,806 MWt - NSSS power)	178,000	570.6	2,300
Loss of All AC Power to Station Auxiliaries	RETRAN	N/A	No	100.6 (1,806 MWt - NSSS power)	178,000	570.6	2,300 (Unit 1) 2,200 (Unit 2)
Steam System Piping Failure - Zero Power (Core response only)	RETRAN ANC VIPRE	W-3	No	0 (1,806 MWt - NSSS power)	178,000	547.0	2,250
Steam System Piping Failure - Full Power (Core response only)	RETRAN ANC VIPRE	W-3(1) WRB-1(2)	Yes	100 (1,806 MWt - NSSS power)	186,000	578.4	2,250
Rupture of a Control Rod Mechanism Housing (RCCA Ejection)	TWINKLE FACTRAN	N/A	No	102 (HFP) 0 (HZP) (1,800 MWt - Core power)	178,000 (HFP) 79,922 (3) (HZP)	583.4 (HFP) 547.0 (HZP)	2,200

Notes:
(1) Below the first mixing vane grid.
(2) Above the first mixing vane grid.
(3) Flow from one loop = 0.449* TDF.
(4) The LOFTRAN portion of the analysis was generic; the DNB evaluation performed with VIPRE utilized the plant-specific values presented.
(5) Unit specific values are based on sensitivity studies performed to address issues related to initial vessel average coolant temperature for this event.

Table 14.0-2 NOMINAL VALUES OF PERTINENT PLANT PARAMETERS FOR NON-LOCA ACCIDENT ANALYSES

Parameter	Max T-avg With RTDP	Max T-avg non-RTDP	Min T-avg With RTDP	Min T-avg non-RTDP
Thermal Output of NSSS (MWt)	1806	1806	1806	1806
Maximum Core Power (MWt)	1800	1800	1800	1800
Vessel Coolant Average Temperature (°F) [1]	577.0	577.0±6.4	558.0	558.0±6.4
Reactor Coolant System Pressure (psia)	2250	2250±50	2250	2250±50
Reactor Coolant Flow Per Loop (gpm)	93000	89000	93000	89000
Steam Generator Tube Plugging	0 to 10%	0 to 10%	0 to 10%	0 to 10%
Steam Generator Outlet Pressure (psia)	755 (0% SGTP) 727 (10% SGTP)	755 (0% SGTP) 727 (10% SGTP)	626 (0% SGTP) 601 (10% SGTP)	626 (0% SGTP) 601 (10% SGTP)
Assumed Feedwater Temperature at Steam Generator Inlet (°F)	390.0/458.0	390.0/458.0	390.0/458.0	390.0/458.0
Average Core Heat Flux [2] (BTU/hr-ft^2)	209848	209848	209848	209848

(1) Accident analyses support a range of full-power T-avg from 558.0°F to 577.0°F.

(2) Average Core Heat Flux = (1800 MWt * 0.974 * 156.401E6)/(121 * 179* 0.422 * 143.25/1.002), where, 1800 MWt is core power, 0.974 is the fraction of heat generated in the pellet, 156.401E6 is a conversion factor, 121 is the number of fuel assemblies, 179 is the number of rods per fuel assembly, 0.422 is the clad diameter in inches, 143.25 is the active fuel length in inches, and 1.002 is the fuel densification factor.

Table 14.0-3 TRIP POINTS AND TIME DELAYS TO TRIP ASSUMED IN ACCIDENT ANALYSES

Trip Function	Limiting Trip Point Assumed in Analysis for 2250 psia Oper.	Time Delay (seconds)
Power range high neutron flux, high setting	116%	0.5
Power range high neutron flux, low setting	35%	0.5
Overtemperature DT	Variable see Figure 14.0-1	7.0(1)*
Overpower DT	Variable see Figure 14.0-1	7.0(1)
High pressurizer pressure	2418 psia	1.0
Low pressurizer pressure	1855 psia	2.0
Low reactor coolant flow (from loop flow detectors)	87% loop flow	1.0
Turbine trip	N/A	2.0
Low-low steam generator level (% of level span)	20% of narrow range	2.0

(1) Total time delay (including RTD bypass loop fluid transport delay effect, bypass loop piping thermal capacity, RTD time response, and trip circuit, channel electronics delay) from the time the temperature difference in the coolant loops exceeds the trip setpoint until the rods are free to fall.

* For the Loss of Load (LOL) peak MSS pressure case, the limiting analysis is done with the total time delay of 5.0 seconds with the OTΔT $\tau 4$ of 2.0 seconds. This analysis bounds the replaced RTD total time delay of 7.0 seconds with the OTΔT $\tau 4$ of 0.75 seconds. For the Uncontrolled Rod Withdrawal at Power MDNBR case, the limiting analysis is done with the total time delay of 7.0 seconds with the OTΔT $\tau 4$ of 2.0 seconds.

Figure 14.0-1 ILLUSTRATION OF OVERTEMPERATURE AND OVERPOWER DELTA-T PROTECTION

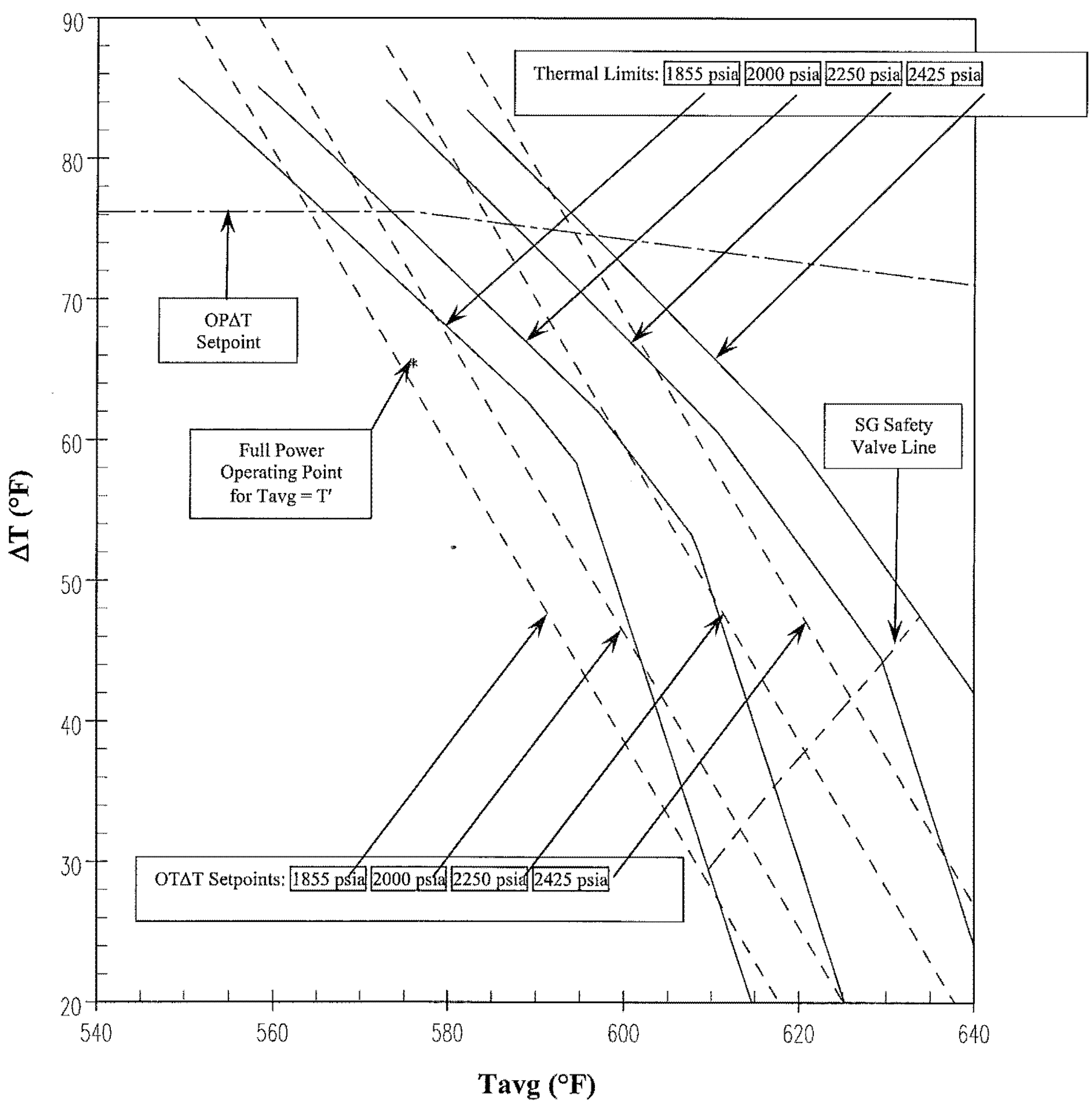


Figure 14.0-2 RCCA NORMALIZED ROD POSITION VS. TIME CURVE

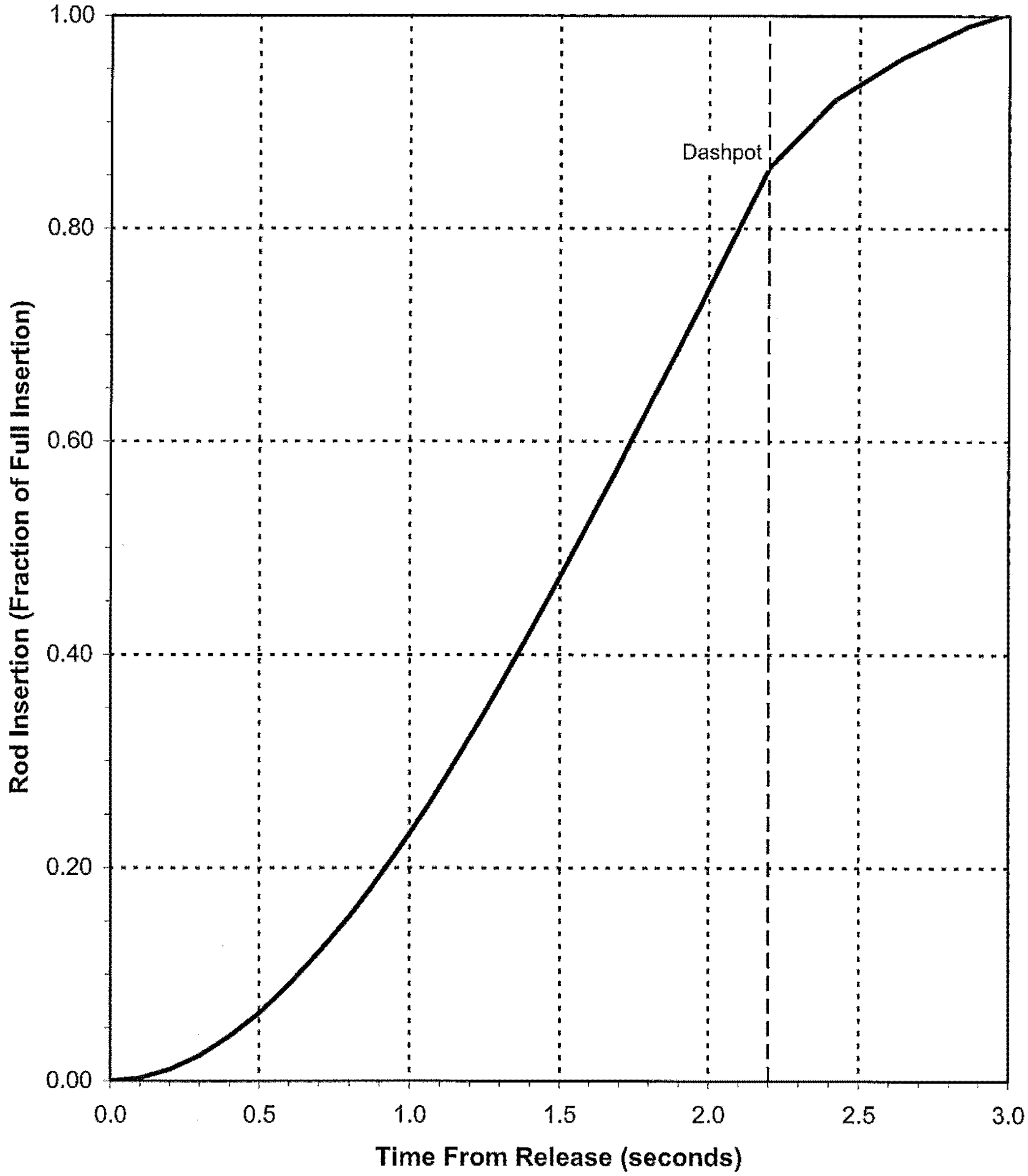


Figure 14.0-3 NORMALIZED REACTIVITY VS ROD POSITION

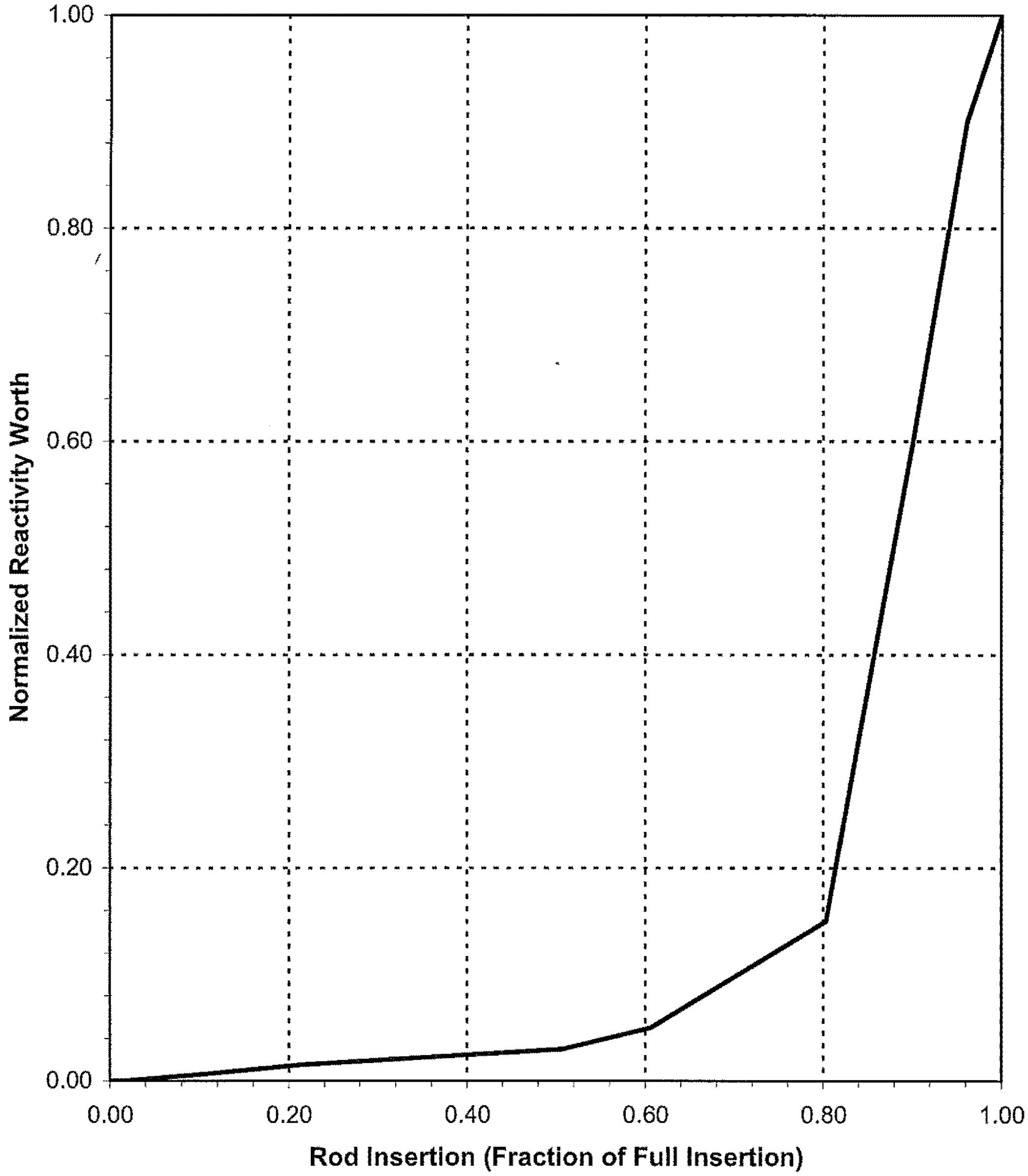
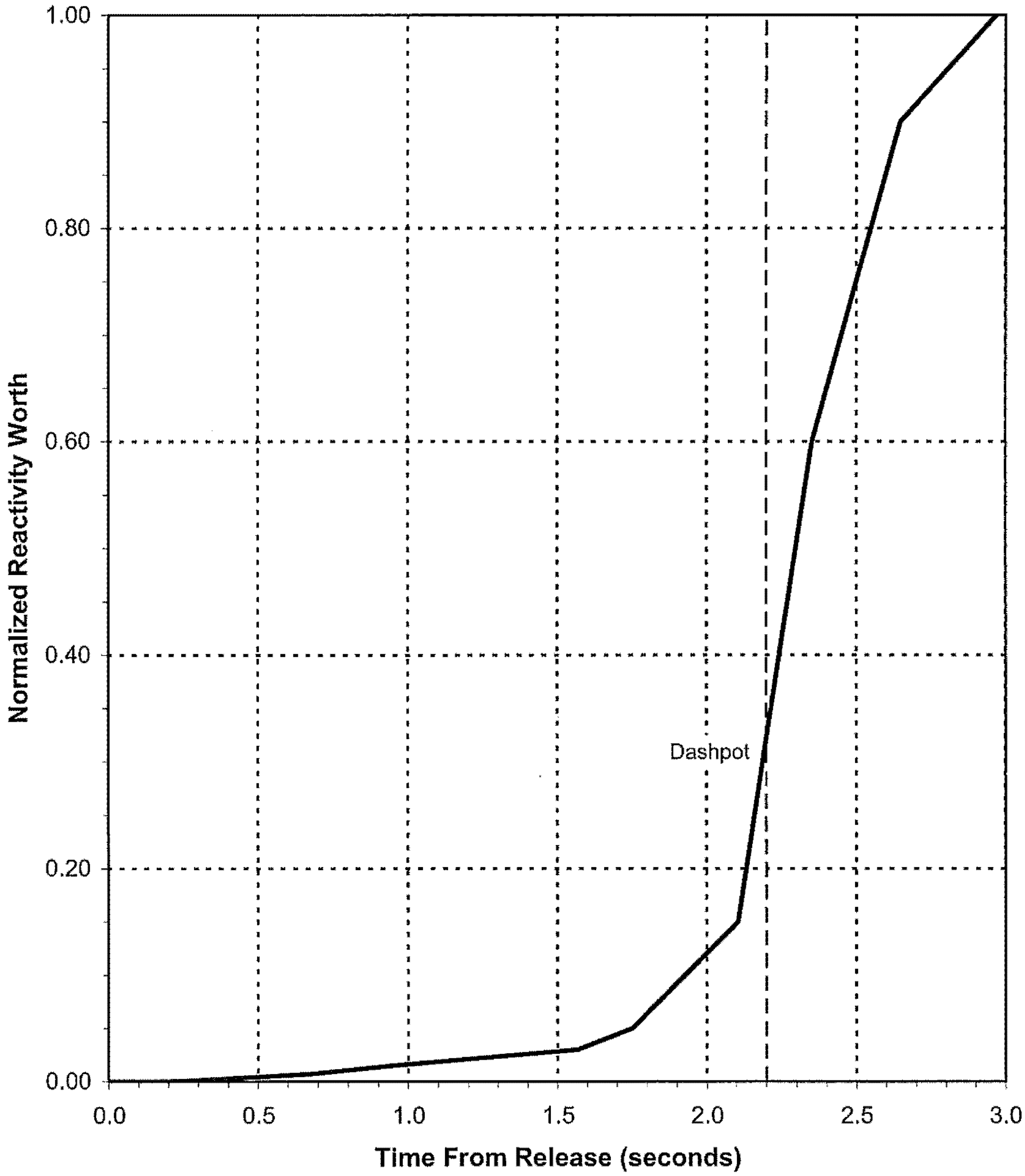


Figure 14.0-4 NORMALIZED TRIP REACTIVITY VS TIME



14.1 CORE AND COOLANT BOUNDARY PROTECTION ANALYSIS

14.1.1 UNCONTROLLED ROD WITHDRAWAL FROM SUBCRITICAL

An RCCA withdrawal incident is defined as an uncontrolled addition of reactivity to the reactor core caused by withdrawal of RCCAs resulting in a power excursion. Such a transient could be caused by a malfunction of the reactor control or rod control systems. This could occur with the reactor subcritical, at hot zero power or at power. The "at power" case is discussed in Section 14.1.2. Although the reactor is normally brought to power from a subcritical condition by means of RCCA withdrawal, procedures for the initial startup following refueling call for boron dilution. The maximum rate of reactivity increase in the case of boron dilution is less than that assumed in this analysis (Section 14.1.4).

The rod cluster drive mechanisms are wired into preselected banks, and these bank configurations are not altered during core life. The rods are therefore physically prevented from withdrawing in other than their respective banks. Power supplied to the rod banks is controlled such that no more than two banks can be withdrawn at any time. Additionally, with the Bank Selector Switch in either the Automatic (AUTO) or Manual (MAN) position, the banks can be withdrawn only in their proper withdrawal sequence. The rod drive mechanism is of the magnetic latch type and the coil actuation is sequenced to provide variable speed rod travel. The maximum reactivity insertion rate is analyzed in the detailed plant analysis assuming the simultaneous withdrawal of the combination of the two control banks with the maximum combined worth at maximum speed.

The neutron flux response to a continuous reactivity insertion is characterized by a very fast rise terminated by the reactivity feedback effect of the negative Doppler coefficient. This self limitation of the power excursion is of primary importance since it limits the power to an acceptable level during the delay time for protective action. Should a continuous RCCA withdrawal accident occur, the transient will be terminated by the following automatic features of the reactor protection system:

1. Source range high neutron flux reactor trip.

   Actuated when either of two independent source range channels indicates a flux level above a preselected manually adjustable setpoint. This trip function may be manually blocked only after an intermediate range flux channel indicates a flux level above a specified level. It is automatically reinstated when both intermediate range channels indicate a flux level below a specified level.

2. Intermediate range high neutron flux reactor trip.

   Actuated when either of two independent intermediate range channels indicates a flux level above a preselected manually adjustable level. This trip function may be manually blocked only after two out of four power range channels are reading above approximately 10 percent of full power and is automatically reinstated when three of the four channels indicate a power level below this value.

3. Power range high neutron flux reactor trip (low setting).

   Actuated when two out of the four power range channels indicate a power level above approximately 25 percent of full power. This trip function may be manually blocked when two out of the four power range channels indicate a power level above approximately 10 percent of full power and is automatically reinstated only after three out of the four channels indicate a power level below this value.

4. Power range high neutron flux reactor trip (high setting).

   Actuated when two out of the four power range channels indicate a power level above a preset setpoint. This trip function is always active.

   In addition, control rod stops on high intermediate range flux level (one of two) and high power range flux level (one of four) serve to discontinue rod withdrawal and prevent the need to actuate the intermediate range flux level trip and the power range flux level trip, respectively.

Method of Analysis

The analysis of the uncontrolled RCCA bank withdrawal from subcritical accident is performed in three stages: first an average core nuclear power transient calculation, then an average core heat transfer calculation, and finally the DNBR calculation. The average nuclear power transient with respect to time calculation is performed using a spatial neutron kinetics code, TWINKLE, which includes the various total core feedback effects, i.e., Doppler and moderator reactivity. The FACTRAN code is then used to calculate the thermal heat flux transient, based on the nuclear power transient calculated by TWINKLE. FACTRAN also calculates the fuel and cladding temperatures. The average heat flux is next used in VIPRE, Reference 43 and Reference 44, (Section 3.2) for transient DNBR calculation.

Plant characteristics and initial conditions are discussed in Section 14.0. In order to give conservative results for a startup accident, the following assumptions are made.

1. Since the magnitude of the nuclear power peak reached during the initial part of the transient for any given rate of reactivity insertion is strongly dependent on the Doppler-only power defect, conservatively low (lowest absolute magnitude) values are used.

2. Contribution of the moderator reactivity coefficient is negligible during the initial part of the transient because the heat transfer time between the fuel and the moderator is much longer than the nuclear flux response time. However, after the initial nuclear flux peak, the succeeding rate of power increase is affected by the moderator reactivity coefficient. The most positive value of the moderator temperature coefficient is used in the analysis to yield the maximum peak heat flux.

3. The reactor is assumed to be at hot zero power. This assumption is more conservative than that of a lower initial system temperature. The higher initial system temperature yields a larger fuel-water heat transfer coefficient, larger specific heats, and a less negative (smaller absolute magnitude) Doppler coefficient, all of which tend to reduce the Doppler feedback effect thereby increasing the neutron flux peak. The initial effective multiplication factor is assumed to be 1.0 since this results in maximum neutron flux peaking and, thus, the most severe nuclear power transient.

4. Reactor trip is assumed to be initiated by power range flux (low setting). The most adverse combination of instrument and setpoint errors, as well as delays for trip signal actuation and RCCA release, is taken into account. A 10 percent increase is assumed for the power range flux trip setpoint, raising it from the nominal value of 25 percent to 35 percent. Since the rise in the neutron flux is so rapid, the effect of errors in the trip setpoint on the actual time at which the rods are released is negligible. In addition, the reactor trip insertion characteristic is based on the assumption that the highest worth RCCA is stuck in its fully withdrawn position.

5. The maximum positive reactivity insertion rate assumed is greater than that for the simultaneous withdrawal of the combination of the two sequential control banks having the greatest combined worth at maximum speed (45 inches/minute).

6. The most limiting axial and radial power shapes, associated with having the two highest combined worth sequential banks in their highest worth position, are assumed for DNB analysis.

7. The initial power level was assumed to be below the power level expected for any shutdown condition (10^{-9} of nominal power). The combination of highest reactivity insertion rate and lowest initial power produces the highest peak heat flux.

8. One reactor coolant pump is assumed to be in operation. This lowest initial flow minimizes the resulting DNBR.

9. The RCS pressure is 50 psi below nominal pressure.

Results

Figure 14.1.1-1 through Figure 14.1.1-3 show the transient behavior for the uncontrolled RCCA bank withdrawal with the accident terminated by reactor trip at 35 percent nominal power. The reactivity insertion rate used is greater than that calculated for the two highest worth sequential control banks, both assumed to be in their highest incremental worth region. Figure 14.1.1-1 shows the neutron flux transient.

The energy release and the fuel temperature increases are relatively small. The thermal flux response, of interest for departure from nucleate boiling considerations, is shown on Figure 14.1.1-2. The beneficial effect of the inherent thermal lag in the fuel is evidenced by a peak heat flux less than the full-power nominal value. The minimum DNBR at all times remains above the safety analysis limit value and there is a high degree of subcooling at all times in the core. Figure 14.1.1-3 shows the response of the hot spot average fuel and cladding temperature. The average fuel temperature increases to a value lower than the nominal full-power value.

The calculated sequence of events for this accident is shown in Table 14.1.1-1. With the reactor tripped, the plant returns to a stable condition. The plant may subsequently be cooled down further by following normal plant shutdown procedures.

Conclusion

In the event of a RCCA withdrawal accident from the subcritical condition, the core and the reactor coolant system are not adversely affected. The minimum departure from nucleate boiling ratio remains above the safety analysis limit value and thus, no fuel or clad damage is predicted.

Reference

1. NRC Safety Evaluation 2011-0004, "Issuance of License Amendments Regarding Extended Power Uprate," dated May 3, 2011.

Table 14.1.1-1 TIME SEQUENCE OF EVENTS FOR UNCONTROLLED RCCA WITHDRAWAL FROM A SUBCRITICAL CONDITION

Event	Time of Each Event (Seconds)
Initiation of uncontrolled rod withdrawal from 10^{-9} of nominal power	0
Power range high neutron flux low setpoint reached	10.0
Peak nuclear power occurs	10.11
Rods begin to fall into core	10.48
Peak heat flux occurs	11.93
Minimum DNBR occurs	11.93
Peak cladding temperature occurs	12.23
Peak average fuel temperature occurs	12.43

Figure 14.1.1-1 UNCONTROLLED RCCA BANK WITHDRAWAL FROM SUBCRITICAL NUCLEAR POWER TRANSIENT

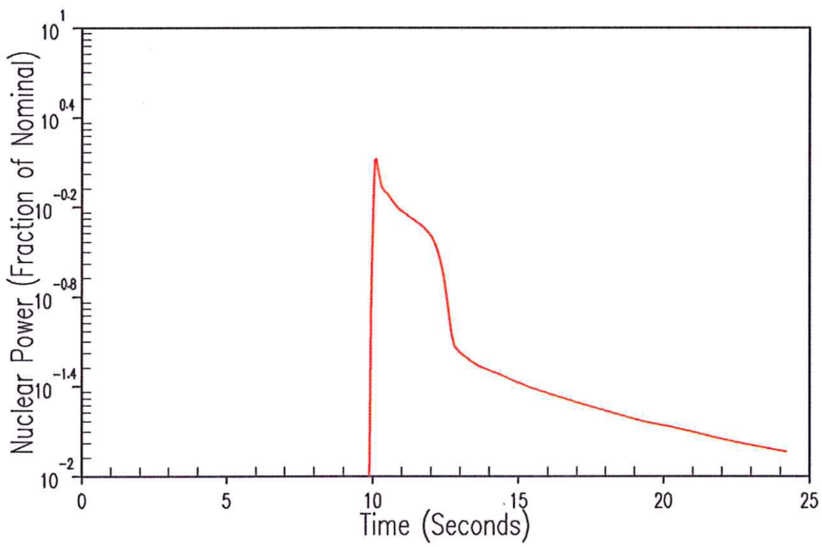


Figure 14.1.1-2 UNCONTROLLED RCCA BANK WITHDRAWAL FROM SUBCRITICAL HEAT FLUX TRANSIENT

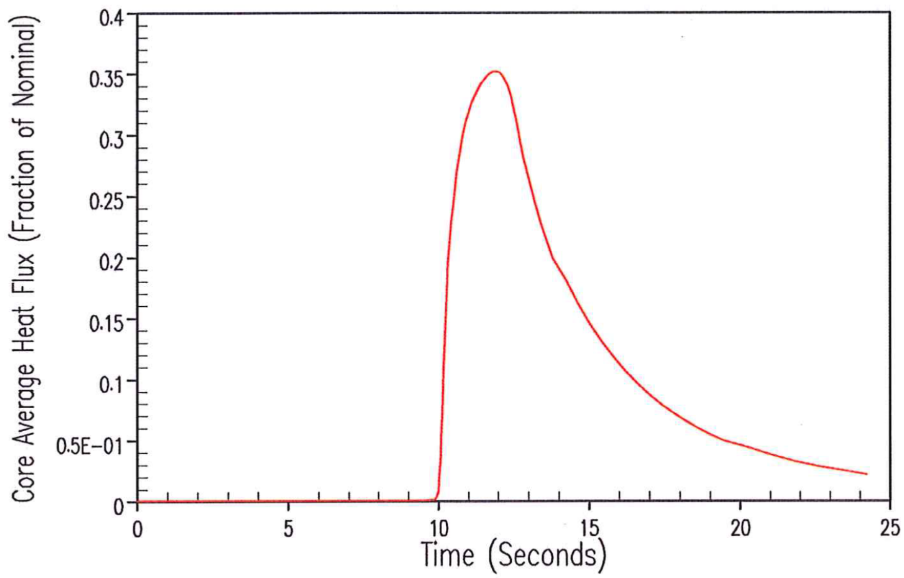
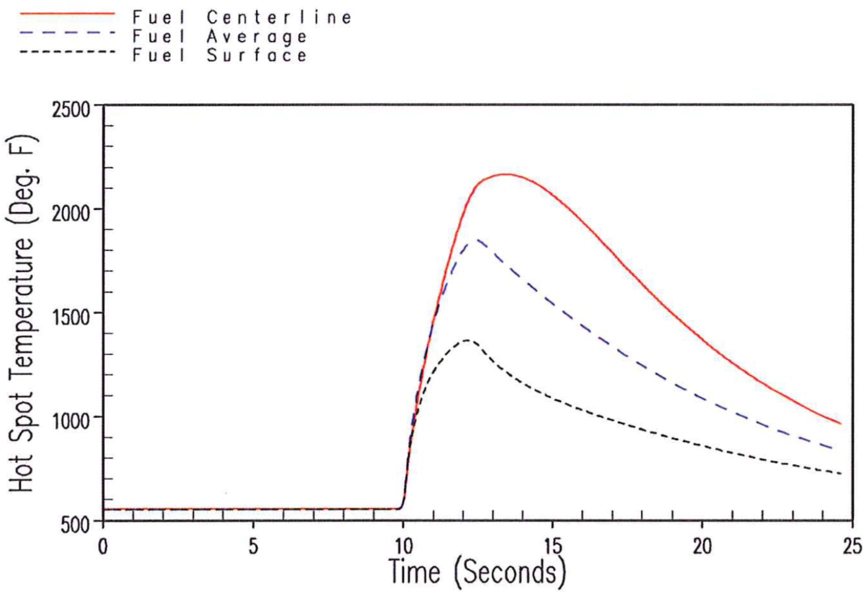


Figure 14.1.1-3 UNCONTROLLED RCCA BANK WITHDRAWAL FROM SUBCRITICAL FUEL TEMPERATURE TRANSIENT



14.1.2 UNCONTROLLED ROD WITHDRAWAL AT POWER

An uncontrolled RCCA withdrawal at power results in an increase in core heat flux. Since the heat extraction from the steam generator remains constant, there is a net increase in reactor coolant temperature. Unless terminated by manual or automatic action, this power mismatch and resultant coolant temperature rise would eventually result in DNB. Therefore, to prevent the possibility of damage to the cladding, the Reactor Protection System is designed to terminate any such transient with an adequate margin to DNB.

The automatic features of the Reactor Protection System which prevent core damage in a rod withdrawal accident at power include the following:

1. Nuclear power range instrumentation actuates a reactor trip if two out of the four channels exceed an overpower setpoint.

2. Reactor trip is actuated if any two out of four ΔT channels exceed an overtemperature ΔT setpoint. This setpoint is automatically varied with power distribution, temperature and pressure to protect against DNB.

3. Reactor trip is actuated if any two out of four ΔT channels exceed an overpower ΔT setpoint. This setpoint is automatically varied with temperature to ensure that the allowable full power rating is not exceeded.

4. A high pressure reactor trip, actuated from any two out of three pressure channels, is set at a fixed point. This set pressure will be less than the set pressure for the pressurizer safety valves.

5. A high pressurizer water level reactor trip, actuated from any two out of three level channels, is actuated at a fixed setpoint. This affords additional protection for RCCA withdrawal accidents.

The manner in which the combination of overpower and overtemperature ΔT trips provide protection over the full range of reactivity insertion rates is illustrated in Section 14.0. Figure 14.0-1 represents the possible conditions of reactor vessel average temperature and ΔT with the design power distribution in a two-dimensional plot. The boundaries of operation defined by the overpower ΔT trip and the overtemperature ΔT trip are represented as "protection lines" on this diagram. These protection lines are drawn to include all adverse instrumentation and setpoint errors, so that under nominal conditions trip would occur well within the area bounded by these lines. A maximum steady state operating condition for the reactor is also shown on the figure.

The utility of the diagram just described is in the fact that the operating limit imposed by any given DNB ratio can be represented as a line on this coordinate system. The DNB lines represent the locus of conditions for which the DNBR equals the safety analysis limit value. All points below and to the left of this line have a DNB ratio greater than this value. The diagram shows that DNB is prevented for all cases if the area enclosed within the maximum protection lines is not traversed by the applicable DNB ratio line at any point.

The region of permissible operation (power, pressure and temperature) is completely bounded by the combination of reactor trips: high neutron flux (fixed setpoint); high pressure (fixed setpoint); low pressure (fixed setpoint); overpower and overtemperature ΔT (variable setpoints). These trips are designed to prevent overpower and a DNB ratio of less than the limit value.

Method of Analysis

Uncontrolled rod cluster control assembly bank withdrawal is analyzed by the RETRAN code. This code simulates the neutron kinetics, reactor coolant system, pressurizer, pressurizer relief and safety valves, pressurizer spray, steam generator, and steam generator safety valves. The code computes pertinent plant variables, including temperatures, pressures, and power level. The core limits, as illustrated in Figure 14.0-1, are used as input to RETRAN to determine the minimum departure from nucleate boiling ratio during the transient. Although RETRAN has the capability of conservatively approximating the transient value of the DNBR, a detailed DNB analysis was performed for the limiting cases with the VIPRE thermal-hydraulic computer code. This accident is analyzed with the Revised Thermal Design Procedure as described in Reference 22, Section 3.2. Plant characteristics and initial conditions are discussed in Section 14.0.

In order to obtain conservative values of departure from nucleate boiling ratio, the following assumptions are made:

1. Initial Conditions - Cases are analyzed at three initial power levels (100%, 60%, and 10%). Both minimum and maximum nominal RCS average temperature are analyzed at a power level of 100% with minimum reactivity feedback. Uncertainties in the initial conditions are included in the limit DNBR as described in Reference 22, of Section 3.2.

2. Reactivity Coefficients - Two cases are analyzed.

   a. Minimum Reactivity Feedback - A positive (5 pcm/°F) moderator coefficient of reactivity is assumed, corresponding to the beginning of core life. A variable Doppler power coefficient with core power is used in the analysis. A conservatively small (in absolute magnitude) value is assumed.

   b. Maximum Reactivity Feedback - A conservatively large positive moderator density coefficient and a large (in absolute magnitude) negative Doppler power coefficient are assumed.

3. The rod cluster control assembly trip insertion characteristic is based on the assumption that the highest worth assembly is stuck in its fully withdrawn position.

4. The reactor trip on high neutron flux is assumed to be actuated at a conservative value of 116% of nominal full power. The overtemperature ΔT trip includes all adverse instrumentation and setpoint errors; the delays for trip actuation are assumed to be the maximum values. No credit was taken for the other expected trip functions.

5. The maximum positive reactivity insertion rate is greater than that for the simultaneous withdrawal of the combination of the two control banks having the maximum combined worth at maximum speed.

The uncontrolled RCCA bank withdrawl at-power accident was also analyzed to ensure that the RCS and MS peak pressures did not exceed 110% of the respective design pressures. Reactivity insertion rates at various power levels were analyzed. These cases were initiated from conditions that include uncertainties on power, RCS pressure, and RCS temperature.

The effect of rod cluster control assembly movement on the axial core power distribution is accounted for by causing a decrease in the overtemperature ΔT trip setpoint proportional to a decrease in margin to DNB.

Results

Figures shown are for Unit 1. Unit 2 is similar, but in the analysis Unit 1 is slightly more limiting.

Figure 14.1.2-1 shows the response of neutron flux, DNBR, pressurizer pressure, pressurizer water volume, and vessel T-avg to a rapid rod cluster control assembly withdrawal incident starting from full power. Reactor trip on high neutron flux occurs shortly after the start of the accident. Since this is rapid with respect to the thermal time constants of the plant, small changes in T-avg and pressure result, and a large margin to DNB is maintained.

The response of neutron flux, DNBR, pressurizer pressure, pressurizer water volume, and vessel T-avg for a slow control rod withdrawal from 100% power is shown in Figure 14.1.2-2. Reactor trip on overtemperature ΔT occurs after a longer period, and the rise in temperature and pressure is consequently larger than for rapid rod cluster control assembly withdrawal. Again, the minimum DNBR is greater than the limit value.

Figure 14.1.2-3 shows the minimum departure from nucleate boiling ratio as a function of the reactivity insertion rate for the three initial power levels (100%, 60%, and 10%), minimum and maximum reactivity feedback. It can be seen that the high neutron flux (HNF) and the overtemperature ΔT trip channels provide protection over the whole range of reactivity insertion rates. For the cases that violated the safety analysis DNBR limit using the conservative RETRAN DNBR approximation model (Figure 14.1.2-3 Sh. 3), the DNBR response was recalculated using the detailed thermal-hydraulic computer code VIPRE in order to obtain acceptable results. Thus, in all cases, the DNBR remained above the safety analysis limit.

In the referenced figures, the shape of the curves of minimum departure from nucleate boiling ratio versus reactivity insertion rate is due both to reactor core and coolant system transient response and to protection system action in initiating a reactor trip.

Referring to Figure 14.1.2-3 (sheet 3) for example, it is noted that:

1. For high reactivity insertion rates (i.e., between ~100 pcm/second and ~20 pcm/second), reactor trip is initiated by the high neutron flux trip. The neutron flux level in the core rises rapidly for these insertion rates, while core heat flux and coolant system temperature lag behind due to the thermal capacity of the fuel and coolant system fluid. Thus, the reactor is tripped prior to significant increase in heat flux or water temperature with resultant high minimum departure from nucleate boiling ratios during the transient. Within this range, as the reactivity insertion rate decreases, core heat flux and coolant temperatures can remain more nearly in equilibrium with the neutron flux; minimum DNBR during the transient thus decreases with decreasing insertion rate.

2. With further decrease in reactivity insertion rate, the overtemperature ΔT and high neutron flux trips become equally effective in terminating the transient. The overtemperature ΔT reactor trip circuit initiates a reactor trip when measured coolant trip ΔT exceeds a setpoint based on measured reactor coolant system average temperature and pressure. It is important in this context to note, however, that the average temperature contribution to the circuit is lead-lag compensated in order to decrease the effect of the thermal capacity of the reactor coolant system in response to power increases.

   For reactivity insertion rates between ~20 pcm/second and ~10 pcm/second, the effectiveness of the overtemperature ΔT trip increases (in terms of increased minimum departure from nucleate boiling ratio) due to the fact that, with lower insertion rates, the power increase rate is slower, the rate of rise of average coolant temperature is slower, and the system lags and delays become less significant.

3. For reactivity insertion rates less than ~10 pcm/second, the rise in reactor coolant temperature is sufficiently high so the steam generator safety valves relieve a significant amount of steam prior to trip. Opening these valves, which act as an additional heat sink on the reactor coolant system, sharply decreases the rate of rise of reactor coolant system average temperature. This causes the overtemperature ΔT trip setpoint to be reached later with resulting lower minimum departure from nucleate boiling ratios.

The results obtained for the cases that were analyzed to address RCS and MS peak pressure concerns demonstrate that the limits were not exceeded when the maximum permissible insertion rate was conservatively limited to 50 pcm/second.

Conclusions

In the unlikely event of an at power (either from full power or lower power levels) control rod bank withdrawal incident, the core and reactor coolant system are not adversely affected since the minimum value of DNB ratio reached is in excess of the DNB limit value for all rod reactivity rates. Protection is provided by high neutron flux and overtemperature ΔT reactor trips. The peak RCS and MS pressures do not exceed 110% of the respective design pressures. Additional protection would be provided by the high pressurizer level, overpower ΔT and high pressurizer pressure reactor trips. The preceding sections have described the effectiveness of these protection channels.

References

1. Deleted.

2. Deleted.

Table 14.1.2-1 TIME SEQUENCE OF EVENTS FOR UNCONTROLLED RCCA WITHDRAWAL AT POWER (maximum nominal RCS Tavg; Minimum Feedback) (These are Unit 1 values; Unit 2 is similar but Unit 1 is slightly more limiting)

Event	Time of Each Event (Sec.)
Case A:	
Initiation of uncontrolled rod cluster control assembly withdrawal at full power and maximum reactivity insertion rate (100 pcm/sec)	0
Power range high neutron flux high trip point reached	1.7
Rods begin to fall into core	2.2
Minimum departure from nucleate boiling ratio occurs	3.0
Case B:	
Initiation of uncontrolled rod cluster control assembly withdrawal at 100% power and at a small reactivity insertion rate (1 pcm/sec)	0
Overtemperature ΔT reactor trip signal initiated	80.2
Rods begin to fall into core	82.2
Minimum departure from nucleate boiling ratio occurs	82.5

Figure 14.1.2-1 ROD WITHDRAWAL AT POWER 100%, MINIMUM FEEDBACK 100 PCM/SECOND

Sheet 1 of 3

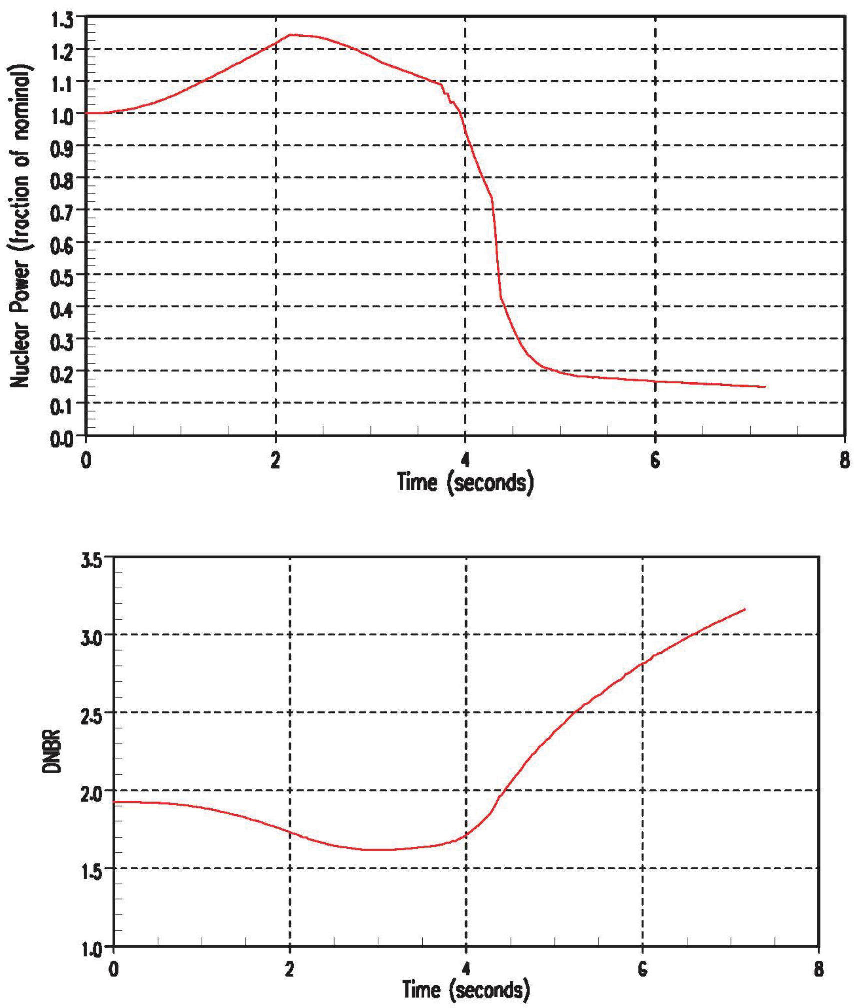


Figure 14.1.2-1 ROD WITHDRAWAL AT POWER 100%, MINIMUM FEEDBACK
100 PCM/SECOND

Sheet 2 of 3

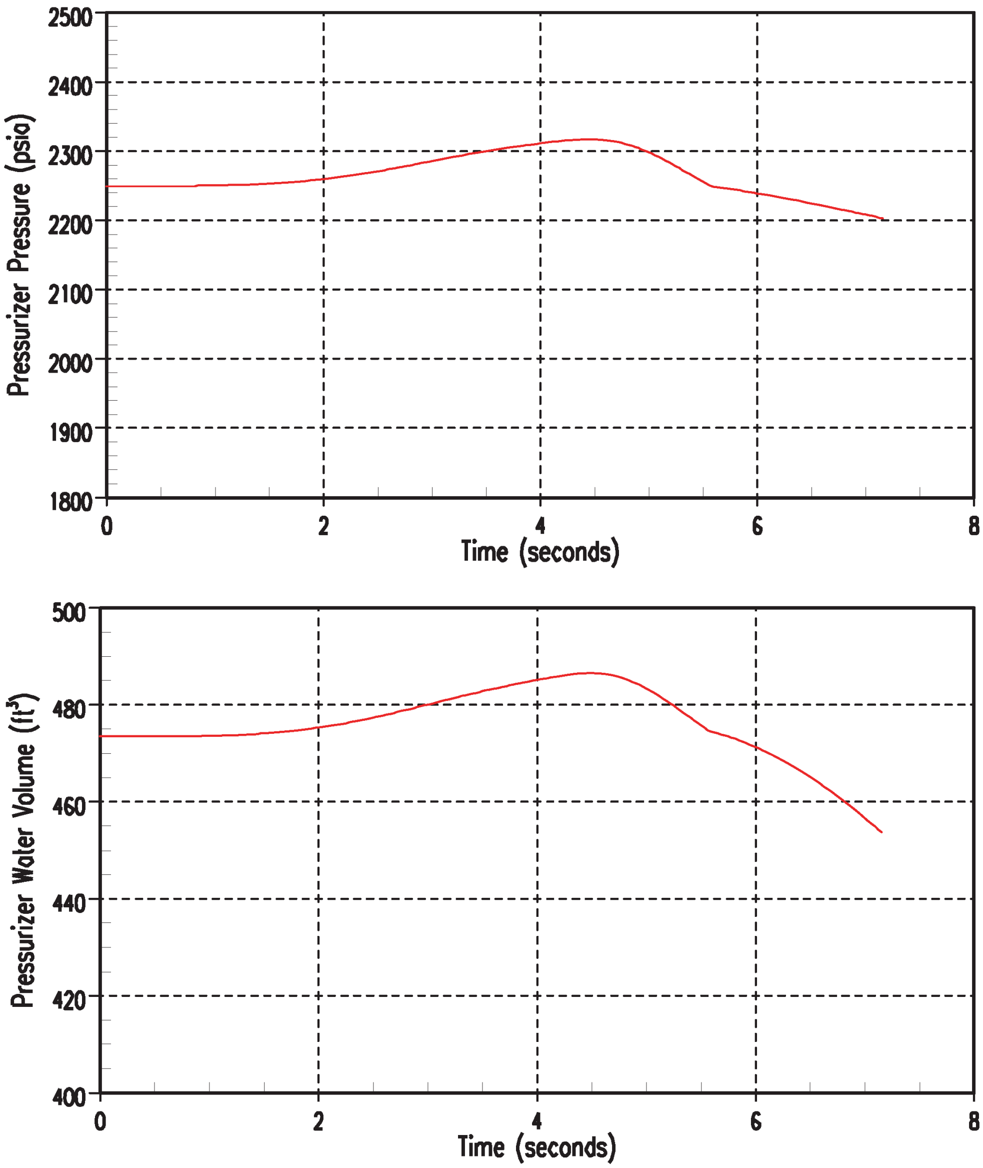


Figure 14.1.2-1 ROD WITHDRAWAL AT POWER 100%, MINIMUM FEEDBACK 100 PCM/SECOND

Sheet 3 of 3

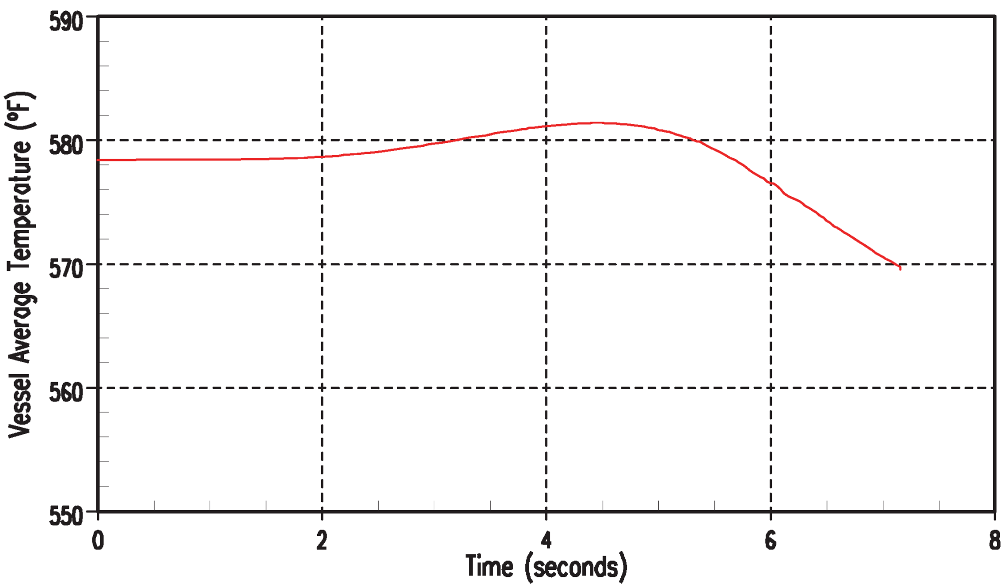


Figure 14.1.2-2 ROD WITHDRAWAL AT POWER 100%, MINIMUM FEEDBACK
1 PCM/SECOND

Sheet 1 of 3

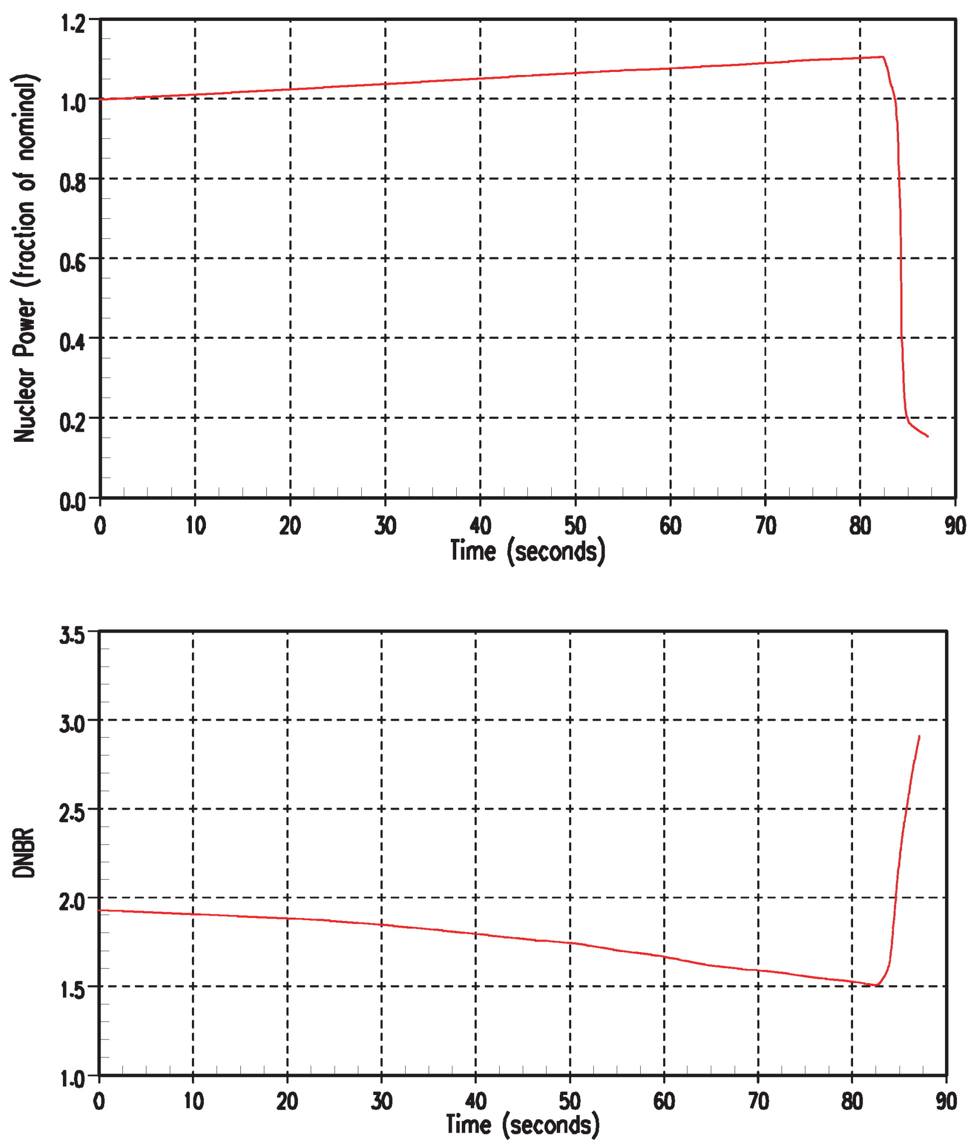


Figure 14.1.2-2 ROD WITHDRAWAL AT POWER 100%, MINIMUM FEEDBACK
1 PCM/SECOND

Sheet 2 of 3

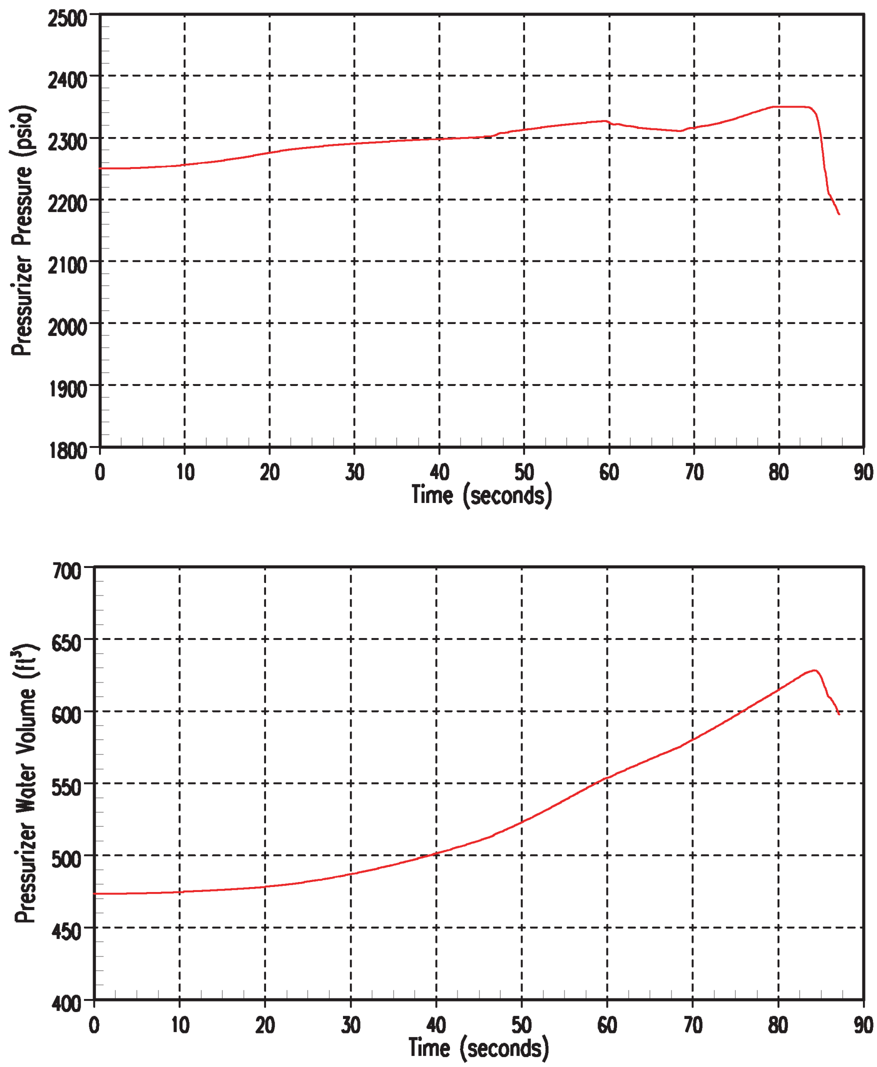


Figure 14.1.2-2 ROD WITHDRAWAL AT POWER 100%, MINIMUM FEEDBACK
1 PCM/SECOND

Sheet 3 of 3

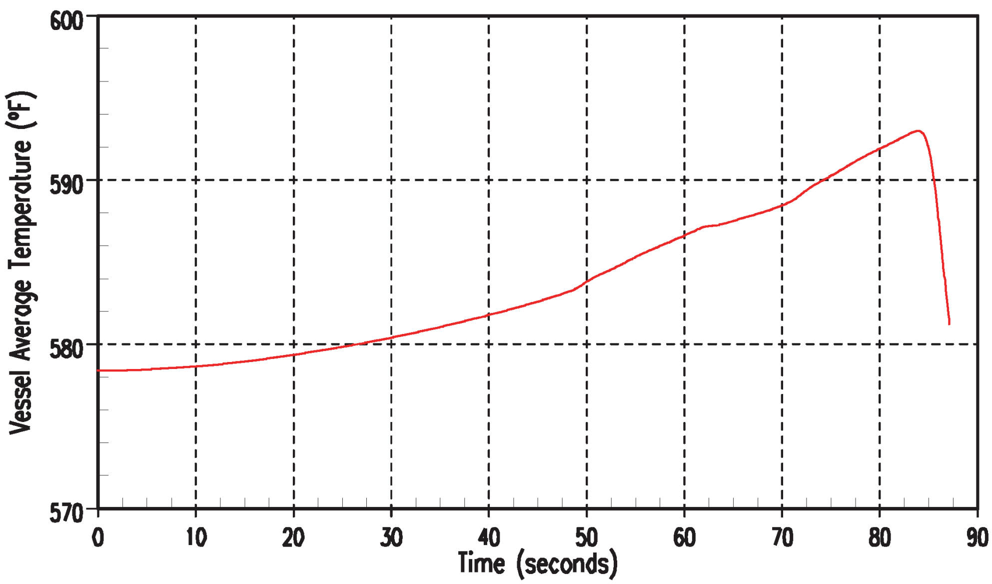


Figure 14.1.2-3 ROD WITHDRAWAL AT POWER 100%
Sheet 1 of 3

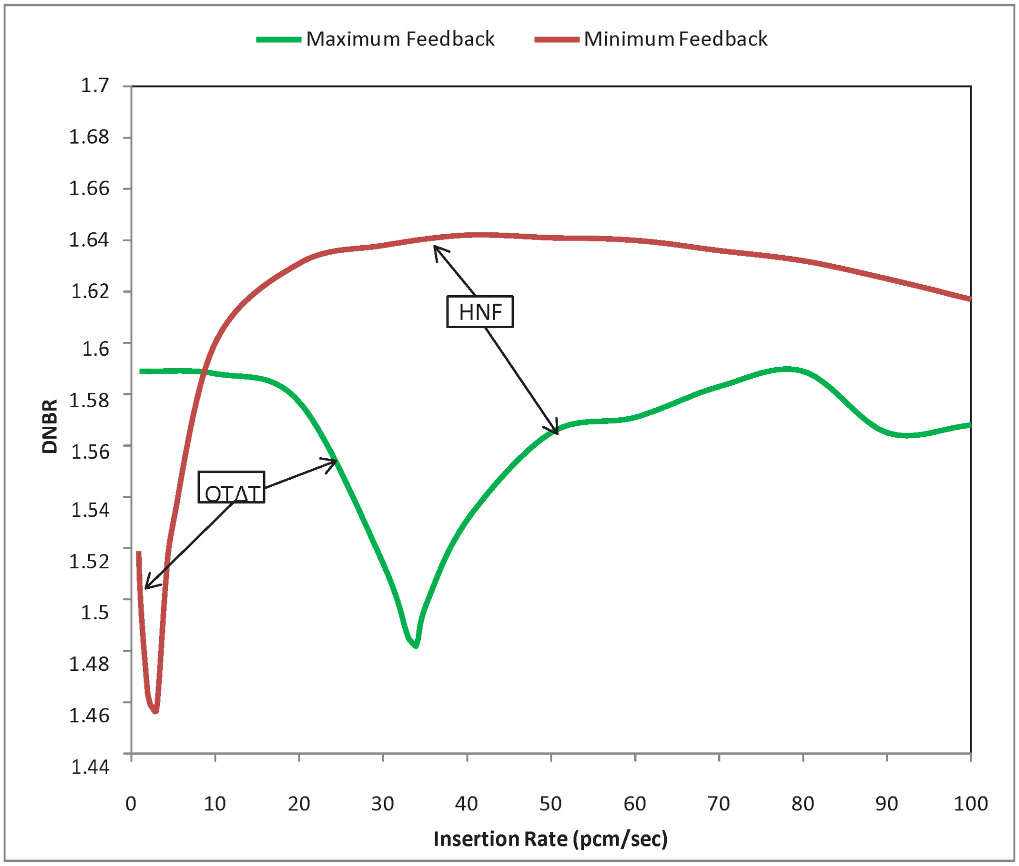


Figure 14.1.2-3 ROD WITHDRAWAL AT POWER 60%
Sheet 2 of 3

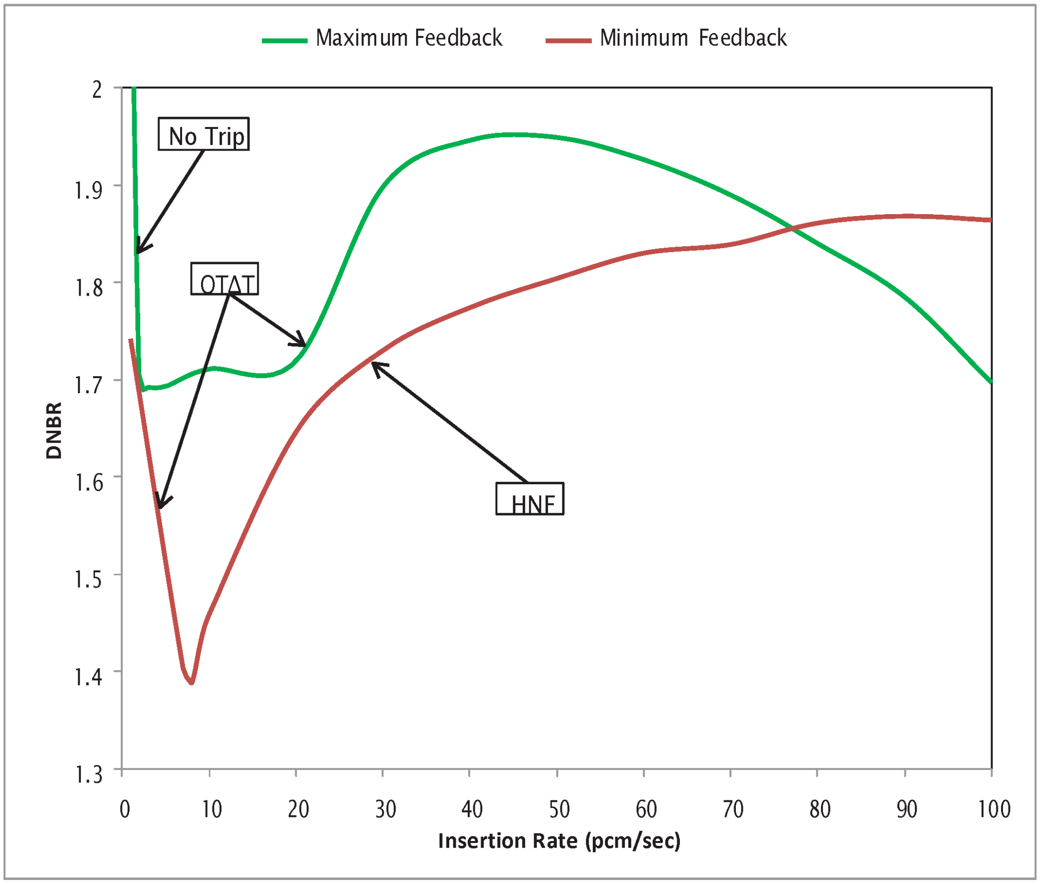
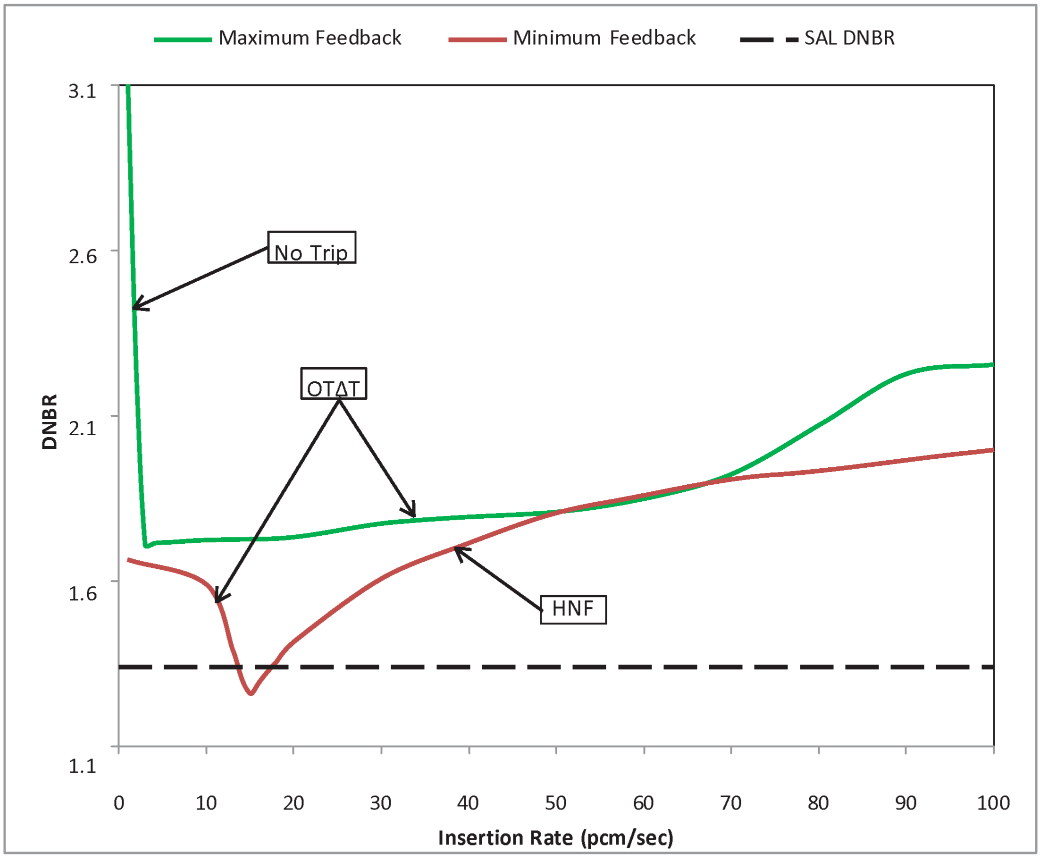


Figure 14.1.2-3 ROD WITHDRAWAL AT POWER 10%
Sheet 3 of 3



14.1.3 ROD CLUSTER CONTROL ASSEMBLY DROP

Dropping of a full length RCCA occurs when the drive mechanism is deenergized. The dropped RCCA causes a power reduction and an increase in the hot channel factor. The automatic rod control system tries to restore the power to the level which existed before the incident by withdrawing rods. An increased hot channel factor and automatic rod withdrawal may lead to a reduced safety margin depending upon the magnitude of the dropped RCCA worth.

Indication of an RCCA dropping into the core during power operation would be by either a rod bottom signal, by an out of core ion chamber, or both. The rod bottom signal device provides an indication signal for each RCCA. The other independent indication of a dropped RCCA is obtained by using the out of core power range channel signals. The rod drop detection circuit is actuated upon sensing a rapid decrease in local flux and is designed such that normal load variations do not cause it to be actuated.

Method of Analysis

For the evaluation of the dropped RCCA(s), the transient response is calculated using the LOFTRAN code. The code simulates the neutron kinetics, reactor coolant system, pressurizer, pressurizer relief and safety valves, pressurizer spray, steam generators, and steam generator safety valves. The code computes pertinent plant variables including temperatures, pressures and power level.

Statepoints are calculated and nuclear models are used to obtain a hot channel factor consistent with the primary system conditions and reactor power. By incorporating the primary conditions from the transient and the hot channel factor from the nuclear analysis, the DNB design basis is shown to be met using the VIPRE code (Reference 2). The transient response, nuclear peaking factor analysis, and DNB design basis confirmation are performed in accordance with the methodology described in WCAP-11394-A (Reference 1).

Results

For the dropped RCCA event, power may be reestablished either by reactivity feedback or control bank withdrawal.

Following a dropped RCCA(s) in manual rod control, the plant will establish a new equilibrium condition. The equilibrium process without control system interaction is monotonic, thus removing power overshoot as a concern and establishing the automatic rod control mode of operation as the limiting case.

For a dropped RCCA(s) event in the automatic rod control mode, the rod control system detects the drop in power and initiates control bank withdrawal. Power overshoot may occur due to this action by the automatic rod controller after which the control system will insert the control bank to restore nominal power. Figure 14.1.3-1 and Figure 14.1.3-2 show a typical transient response to a dropped RCCA(s). Uncertainties in the initial conditions are included in the DNB evaluation as described in Reference 1 In all cases, the minimum DNBR remains greater than the limit value.

Conclusions

For all cases the DNB design is met by demonstrating that the DNBR is greater than the limit value.

References

1. Westinghouse Licensing Topical Report WCAP 11394-P-A (Proprietary), and WCAP 11395-A (Non-proprietary), "Methodology for the Analysis of the Dropped Rod Event," October 23, 1989.

2. NRC Safety Evaluation 2011-0004, "Issuance of License Amendments Regarding Extended Power Uprate," dated May 3, 2011.

Figure 14.1.3-1 NUCLEAR POWER TRANSIENT AND CORE HEAT FLUX TRANSIENT FOR DROPPED RCCA

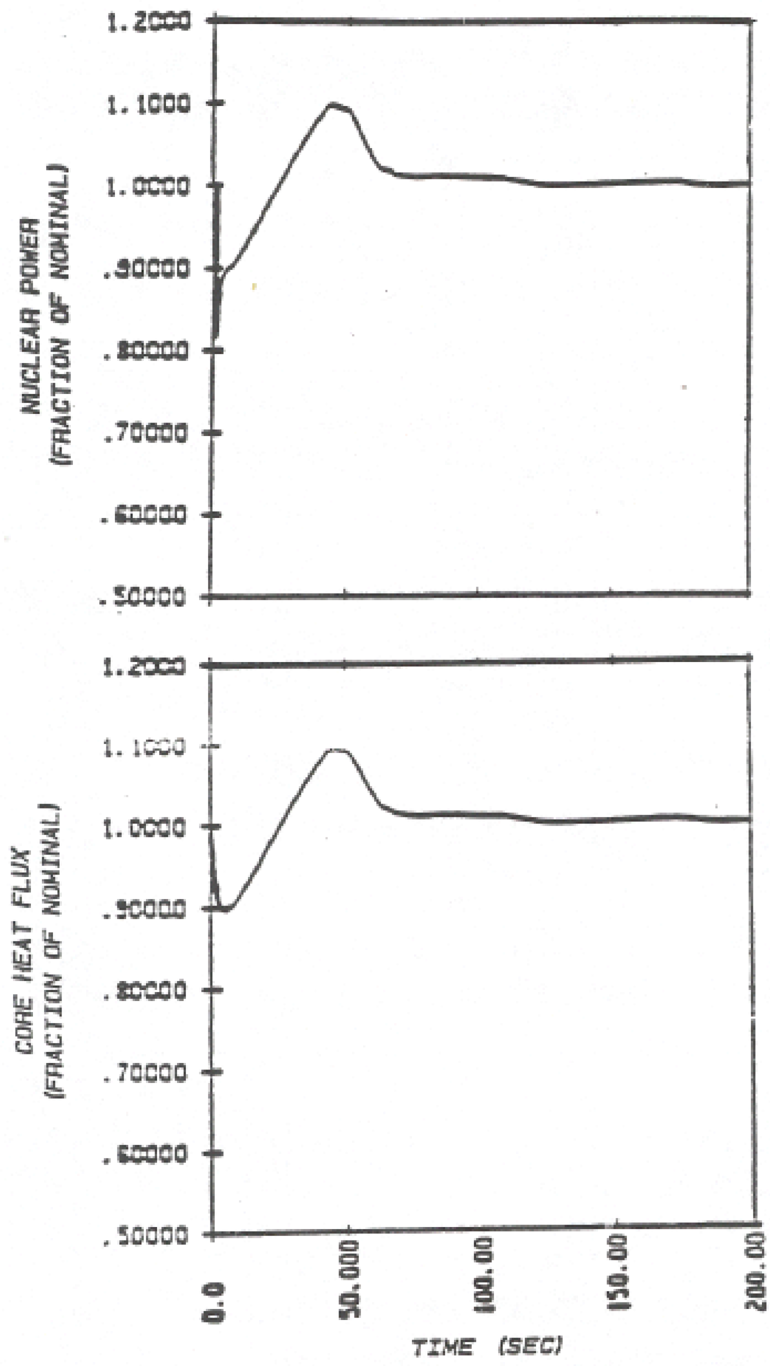
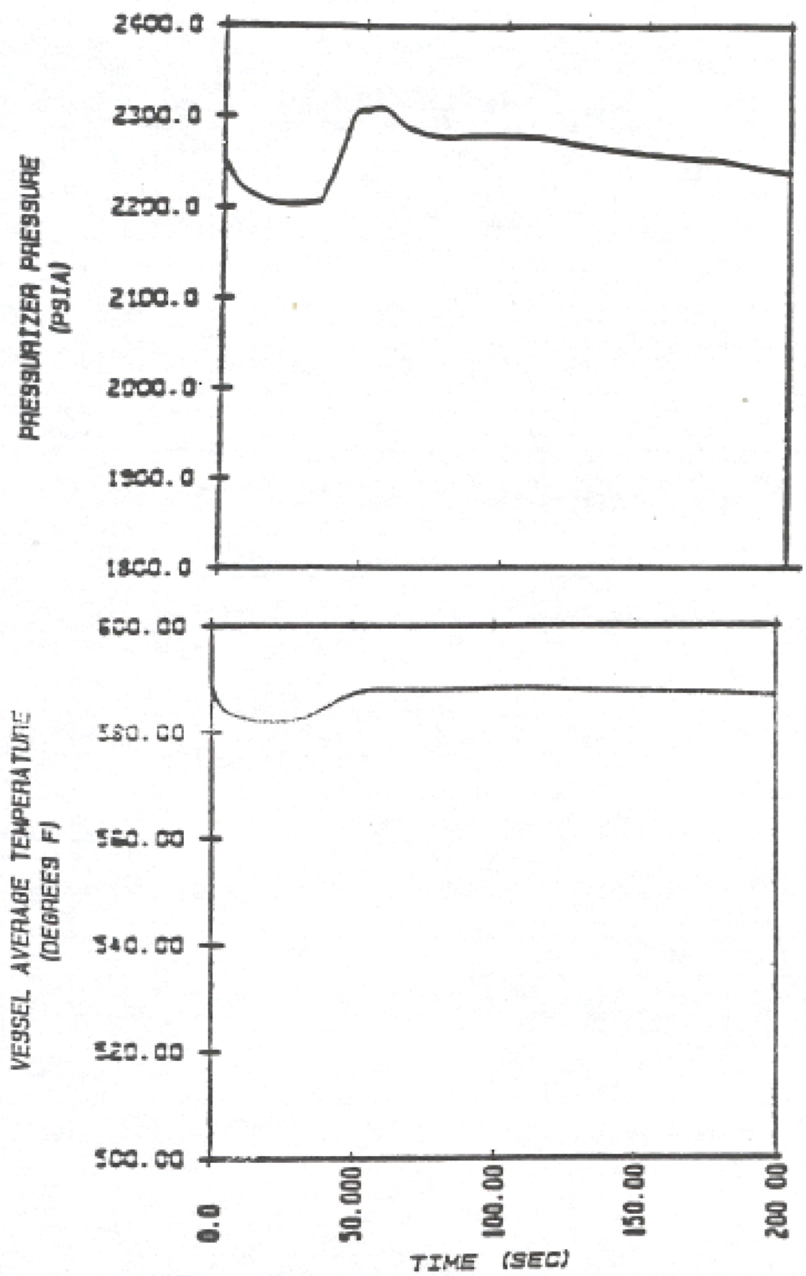


Figure 14.1.3-2 PRESSURIZER PRESSURE TRANSIENT AND VESSEL AVERAGE TEMPERATURE TRANSIENT FOR DROPPED RCCA



14.1.4 CHEMICAL AND VOLUME CONTROL SYSTEM MALFUNCTION

Positive reactivity can be added to the core with the Chemical and Volume Control System by feeding reactor makeup water into the Reactor Coolant System via the reactor makeup control system. The normal dilution procedures call for a limit on the rate and magnitude for any individual dilution, under strict administrative controls. Boron dilution is a manual operation. A boric acid blend system is provided to permit the operator to match the boron concentration of reactor coolant makeup water to that existing in the coolant at the time. The Chemical and Volume Control System is designed to limit, even under various postulated failure modes, the potential rate of dilution to a value which, after indication through alarms and instrumentation, provides the operator sufficient time to correct the situation in a safe and orderly manner.

The most limiting credible source of reactor makeup water to the reactor coolant system is from the reactor makeup water storage tank using the reactor makeup water pumps. Dilution via this pathway can be readily terminated by isolating this source.

The rate of addition of unborated makeup water to the reactor coolant system is limited to the capacity of the CVCS charging pumps and FCV-111. Normally one charging pump is operating in manual mode and one pump is operating in the automatic mode, responding to pressurizer level changes.

The boric acid from the boric acid tank is blended with the reactor makeup water in the blender and the composition is determined by the preset flow rates of boric acid and reactor makeup water on the reactor makeup control system. Two separate operations are required. First, the operator must switch from the automatic makeup mode to the dilute mode. Second, a manual start of the system is required. Omitting either step would prevent dilution. This makes the possibility of inadvertent dilution very small.

Information on the status of the reactor coolant makeup is continuously available to the operator. Lights are provided on the control board to indicate the operating condition of pumps in the chemical and volume control system. Alarms are actuated to warn the operator if boric acid or demineralized water flow rates deviate from preset values as a result of system malfunction. An additional alarm is available to warn the operator of a potential dilution condition.

To cover all phases of plant operation, boron dilution during refueling, startup, and power operation are considered in this analysis.

Method of Analysis and Results

Dilution During Refueling

During refueling the following conditions exist:

1. One residual heat removal pump is running to ensure continuous mixing in the reactor vessel,

2. The valves on the suction side of the charging pumps are adjusted for addition of concentrated boric acid solution.

3. The boron concentration of the refueling water corresponds to a shutdown margin of at least that required by COLR 2.12; periodic sampling ensures that this concentration is maintained, and

4. Neutron sources can be installed in the core, if necessary, during startup to provide a minimum count rate. However, neutron source assemblies are not currently used in Unit 1 or Unit 2. BF_3 detectors connected to instrumentation giving audible count rates are installed to provide direct monitoring of the core.

A minimum active water volume in the reactor coolant system of 1884 ft^3 is considered. This corresponds to the volume necessary to fill the reactor vessel up to the midplane of the nozzles plus the volume of one RHR train. This ensures mixing via the residual heat removal loop.

The maximum dilution flow of 121 gpm and uniform mixing are also considered. Administrative procedures limit the charging flow available during this condition. The maximum dilution flow assumes a single failure, such that two pumps are delivering maximum flow. The actual amount of reactor makeup water delivered to the suction of the charging pumps would be determined by the position of FCV-111 which is normally set at no more than 40 gpm. At the full open position, FCV-111 would pass approximately 100 gpm.

The operator has prompt and definite indication of any boron dilution from the audible count rate instrumentation. High count rate is alarmed in the reactor containment and the main control room. The count rate increase is proportional to the inverse multiplication factor.

The Technical Specifications require that one source range audible count rate circuit be operable during MODE 6. If the required audible count rate circuit becomes inoperable, then actions are immediately taken to isolate all sources of unborated water. Isolating these flow paths ensures that an inadvertent dilution of the reactor coolant boron concentration is prevented. Therefore, the mitigative function of the audible count rate circuit is ensured to be available, or else conditions are established to prevent a boron dilution, through the control of the Technical Specifications (Reference 1).

A ratio of the initial refueling water boron concentration to the critical boron concentration that is greater than or equal to 1.3125 corresponds to more than 30 minutes before the loss of all shutdown margin. This is ample time for the operator to recognize the audible high count rate signal and isolate the reactor makeup water source by closing valves and stopping the reactor makeup water pumps.

<u>Dilution During Cold Shutdown</u>

This analysis was performed to determine the required boron concentration necessary to prevent criticality from an inadvertent boron dilution event with a reduced RCS volume for a duration of 15 minutes.

The analysis used a conservative RCS and RHR combined volume by assuming that the RCS is drained to the midplane of the nozzles (1884 ft^3). The RCS volume when drained to the midplane of the nozzles is the smallest volume that can result from any allowable scenario while in Cold Shutdown. Mixing of the diluting water (boron free) and the RCS water was assumed to take place at the vessel inlet nozzle which then proceeds in a “wave front fashion” through the rest of the RCS. A maximum RCS temperature of 200°F is assumed and a minimum temperature is assumed for the dilutant. The dilution flow rate is conservatively increased to compensate for the density differences.

These calculations determine what boron concentration is required to ensure that the operator has 15 minutes to identify and terminate the boron dilution prior to a complete loss of shutdown margin. The calculations cover one, two or three charging pumps in operation and RHR flow rates up to approximately 6000 gpm. The results of the analysis are presented in Figure 14.1.4-1.

The assumptions and conclusions of this analysis are maintained by administratively limiting charging pump operation in accordance with Figure 14.1.4-1. A limit switch on the valve for the reactor makeup water pump is also provided to warn the operators of a potential dilution in progress. The limit switch will activate an alarm in the control room whenever the valve is not closed.

Dilution During Startup

Prior to refueling, the reactor coolant system is filled with borated water from the refueling water storage tank. Core monitoring is by external BF_3 detectors. Mixing of reactor coolant is accomplished by operation of the reactor coolant pumps. Again the maximum dilution flow (181.5 gpm) is considered. The volume of reactor coolant is the volume of the reactor coolant system excluding the pressurizer. The volume has been calculated taking into account steam generator tube plugging. High source level and all reactor trip alarms are effective.

The minimum time required to reduce the reactor coolant boron concentration from 1800 to 1600 ppm, where the reactor could go critical with all rods at the insertion limits, is greater than 15 minutes. Once again, this should be more than adequate time for operator action due to the high count rate signal, and for termination of dilution flow.

Dilution at Power

For dilution at power, it is necessary that the time to lose shutdown margin be sufficient to allow identification of the problem and termination of the dilution. As in the dilution during startup case, the RCS volume reduction due to steam generator tube plugging is considered. The effective reactivity addition rate is a function of the reactor coolant temperature and boron concentration. The reactivity insertion rate calculated is based on a conservatively high charging flow rate capacity (181.5 gpm). The reactor is assumed to have all rods at the insertion limits in either automatic or manual control. With the reactor in manual control and no operator action to terminate the transient, the power and temperature rise will cause the reactor to reach the reactor protection (i.e., OTΔT, high nuclear flux) trip setpoint, resulting in a reactor trip. After reactor trip there are greater than 15 minutes for operator action prior to return to criticality. The boron dilution transient in this case is essentially equivalent to an uncontrolled rod withdrawal at power. A minimum reactivity insertion rate for a boron dilution transient is used to determine a conservative reactor trip time based on the results of the uncontrolled rod withdrawal at power transient analysis. Prior to reaching the reactor protection trip, the operator will have received an alarm on overtemperature ΔT and turbine runback.

With the reactor in automatic control, a boron dilution will result in a power and temperature increase such that the rod controller will attempt to compensate by slow insertion of the control rods. This action by the controller will result in rod insertion limit and axial flux alarms. If the reactor is shutdown, the minimum time for operator action prior to return to criticality would be greater than 15 minutes.

Conclusions

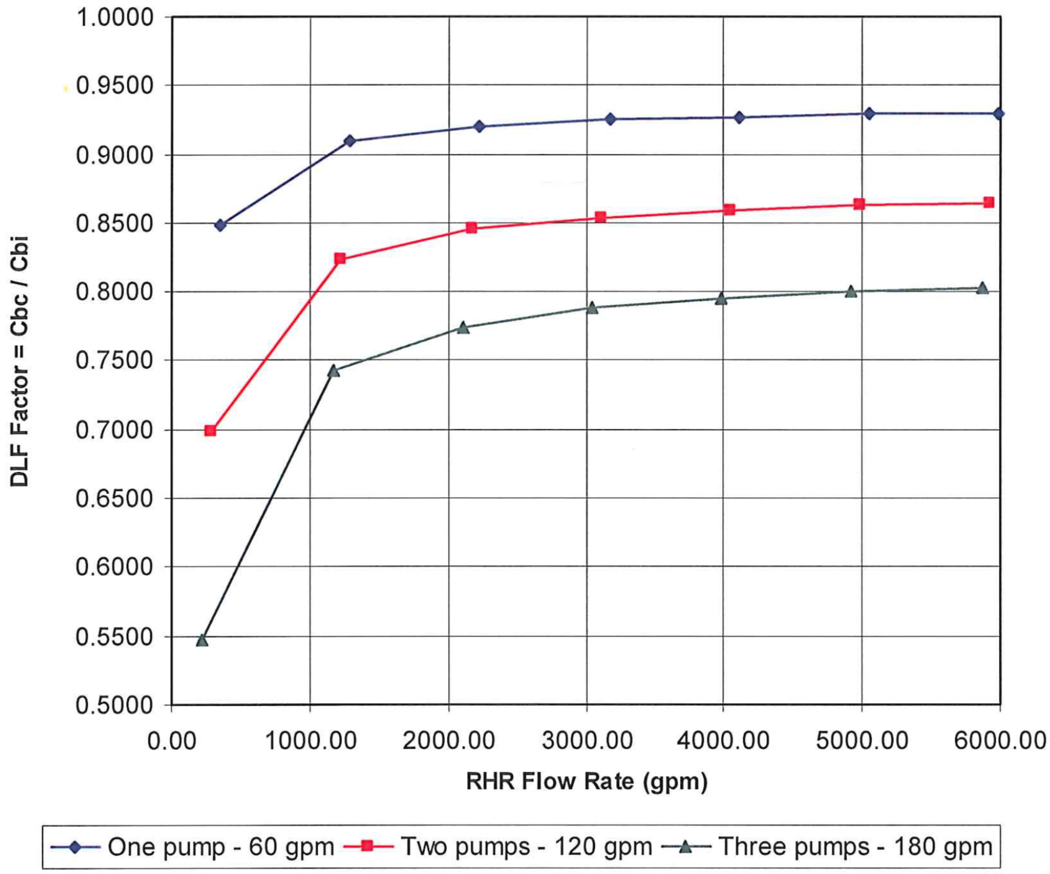
Because of the procedures involved in the dilution process, an erroneous dilution is not considered credible. Nevertheless, if an unintentional dilution of boron in the reactor coolant does occur, numerous alarms and indications are available to alert the operator to the condition. The maximum reactivity addition due to the dilution is slow enough to allow the operator to determine the cause of the addition and take corrective action before the required shutdown margin is lost.

Reference:

1. Technical Specification 3.9.2, Nuclear Instrumentation.

2. NRC Safety Evaluation 2011-004, "Issuance of License Amendments Regarding Extended Power Uprate," dated May 3, 2011.

Figure 14.1.4-1 RATIO OF THE INITIAL BORON CONCENTRATION TO THE CRITICAL BORON CONCENTRATION (DILUTION FACTOR, DLF) AS A FUNCTION OF RHR FLOW RATE



14.1.5 STARTUP OF AN INACTIVE REACTOR COOLANT LOOP

Operation of the plant with an inactive loop causes reversed flow through the inactive loop because there are no isolation valves or check valves in the reactor coolant loops.

If the reactor is operated at power in this condition, there is a decrease in the coolant temperature in that loop in comparison with the other loop. The subsequent startup of the idle reactor coolant pump, would result in the injection of colder water into the core. This colder water and increased flow rate causes an increase in reactivity and therefore a power increase.

The Point Beach Nuclear Plant Technical Specifications do not permit the reactor to be taken critical with only one reactor coolant pump (RCP) in operation. Because of this, an analysis of this event was determined not to be necessary. The discussion presented below corresponds to an analysis previously performed assuming a nominal initial power level of 10% and is retained for historical purposes.

Method of Analysis and Assumptions

This transient is analyzed by three digital computer codes. The LOFTRAN code (Reference 1) is used to calculate the loop and core flow, nuclear power and core pressure and temperature transients following the startup of an idle pump. FACTRAN (Reference 2) is used to calculate the core heat flux transient based on core flow and nuclear power from LOFTRAN. The THINC code is then used to calculate the DNBR during the transient based on system conditions (pressure, temperature, and flow) calculated by LOFTRAN and heat flux as calculated by FACTRAN.

The reverse flow in the inactive loop is calculated to be 15% of the nominal loop flow, which carries about 10% of the heat generated in the core to the secondary system and causes a temperature difference of -8.2°F between the temperature in the cold leg of the active loop and the temperature in the “hot” leg of the inactive loop. The cold water is introduced into the core upon the startup of the inactive loop.

The following assumptions are made:

1. The idle pump, on starting, accelerates to full flow in 20 seconds.
2. A conservative maximum moderator density coefficient of .43 Δk/gm/cc is assumed.
3. A conservative large (absolute value) Doppler coefficient of -2.9×10^{-5} Δk/°F is taken.
4. The water entering the core is assumed to exhibit the temperature of the water in the inactive loop. This assumption provides the analysis with a high degree of conservatism.

Results

Figure 14.1.5-1 through Figure 14.1.5-4 show the plant transients. The cold water slug reaches the reactor core with a delay of approximately 7 seconds and is sustained for 14 seconds. It decreases the core water temperature and causes the nuclear power excursion. The peak power is 30% of full power and does not cause a reactor trip.

The average temperature of the reactor coolant water increases due to the heating up of the cold water which existed in the inactive loop and this leads to the increase in the pressurizer pressure. The maximum pressure for this transient does not actuate the pressurizer relief valves.

Conclusion

The results show that for startup of an inactive loop at 10% power, the power and temperature excursions are not severe. These transients are given only to indicate the transient behavior of the reactor following an incident of this type. The conclusion is that the transient effects of this accident are not severe and place no undue restrictions on the plant, when operating at 10% power.

The Point Beach Nuclear Plant Technical Specifications do not permit the reactor to be taken critical with only one reactor coolant pump (RCP) in operation. Because of this, the startup of an inactive loop is non-limiting with respect to minimum DNBR. No analysis is required to show that the minimum DNBR is satisfied for this event.

REFERENCES

1. Burnett, T. W. T., et.al., "LOFTRAN Code Description," WCAP-7907-P-A, April 1984.

2. Hargrove, H. G., "FACTRAN - A Fortran - IV Code for Thermal Transients in a UO2 Fuel Rod," WCAP-7908 (Non-Proprietary), July 1972.

3. NRC Safety Evaluation 2011-004, "Issuance of License Amendments Regarding Extended Power Uprate," dated May 3, 2011.

Figure 14.1.5-1 START-UP OF AN INACTIVE REACTOR COOLANT LOOP

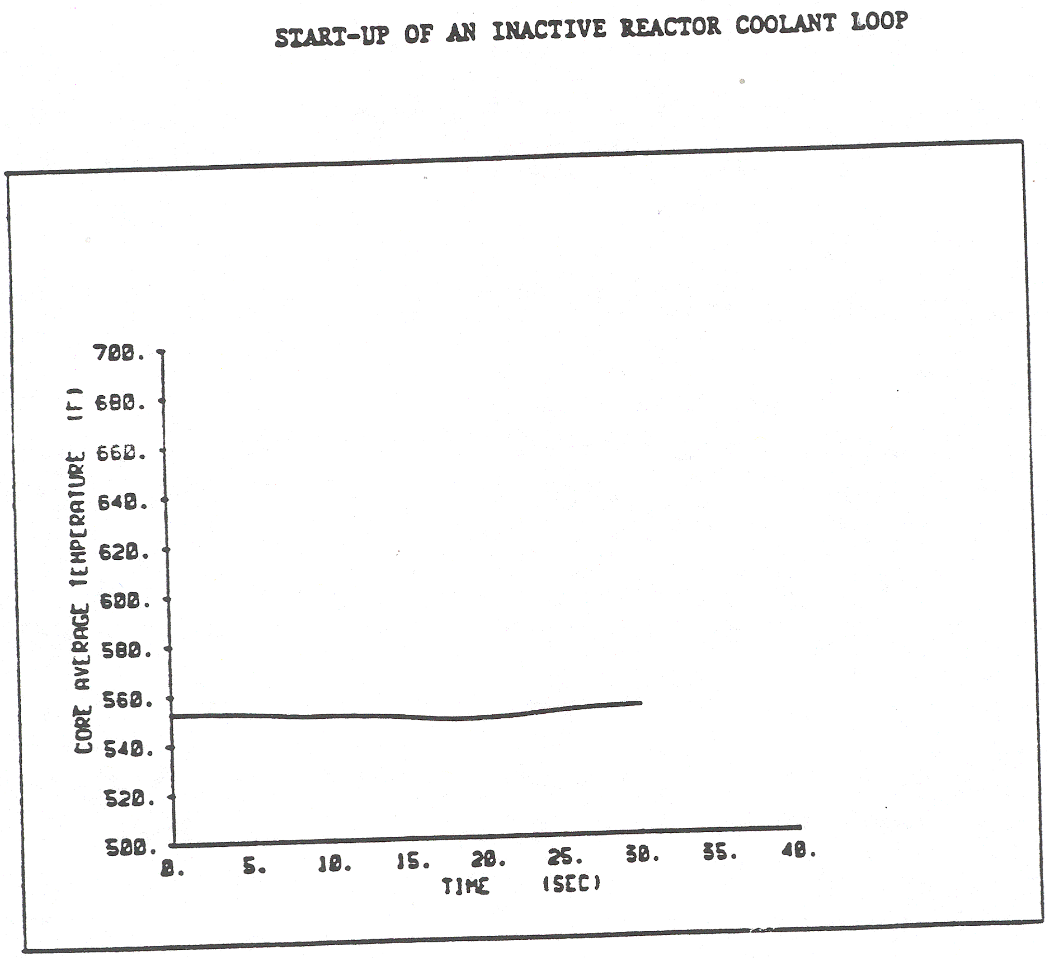


FIGURE 14.1.5-1

Figure 14.1.5-2 START-UP OF AN INACTIVE REACTOR COOLANT LOOP

START-UP OF AN INACTIVE REACTOR COOLANT LOOP

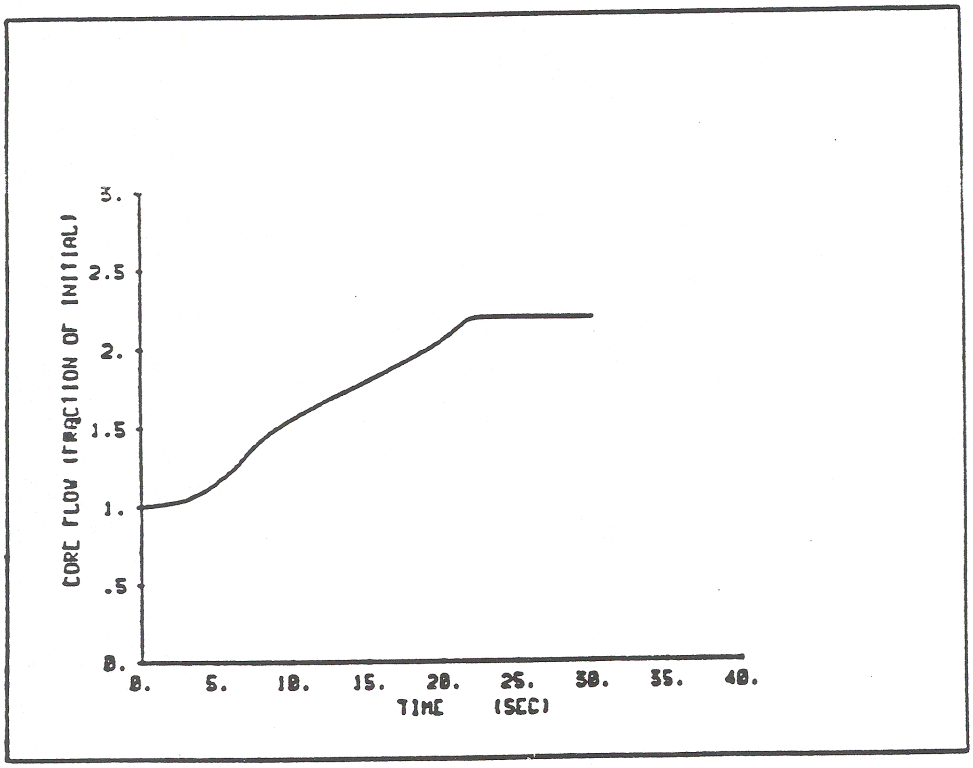


FIGURE 14.1.5-2

Figure 14.1.5-3 START-UP OF AN INACTIVE REACTOR COOLANT LOOP

START-UP OF AN INACTIVE REACTOR COOLANT LOOP

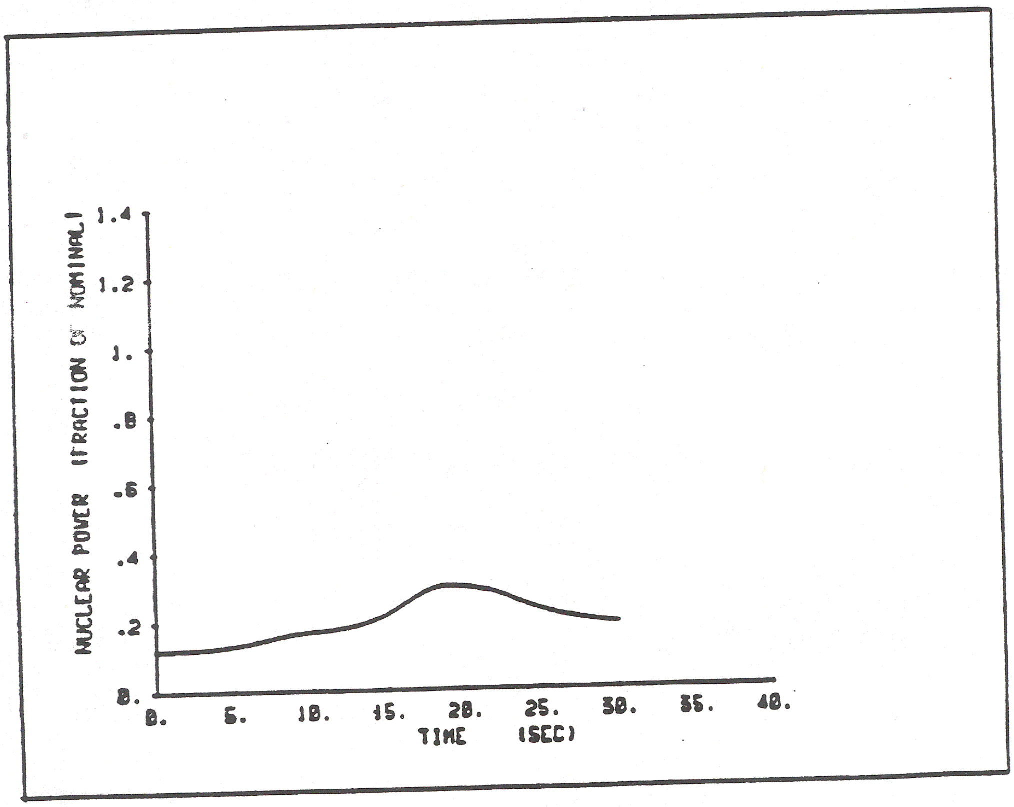


FIGURE 14.1.5-3

Figure 14.1.5-4 START-UP OF AN INACTIVE REACTOR COOLANT LOOP

START-UP OF AN INACTIVE REACTOR COOLANT LOOP

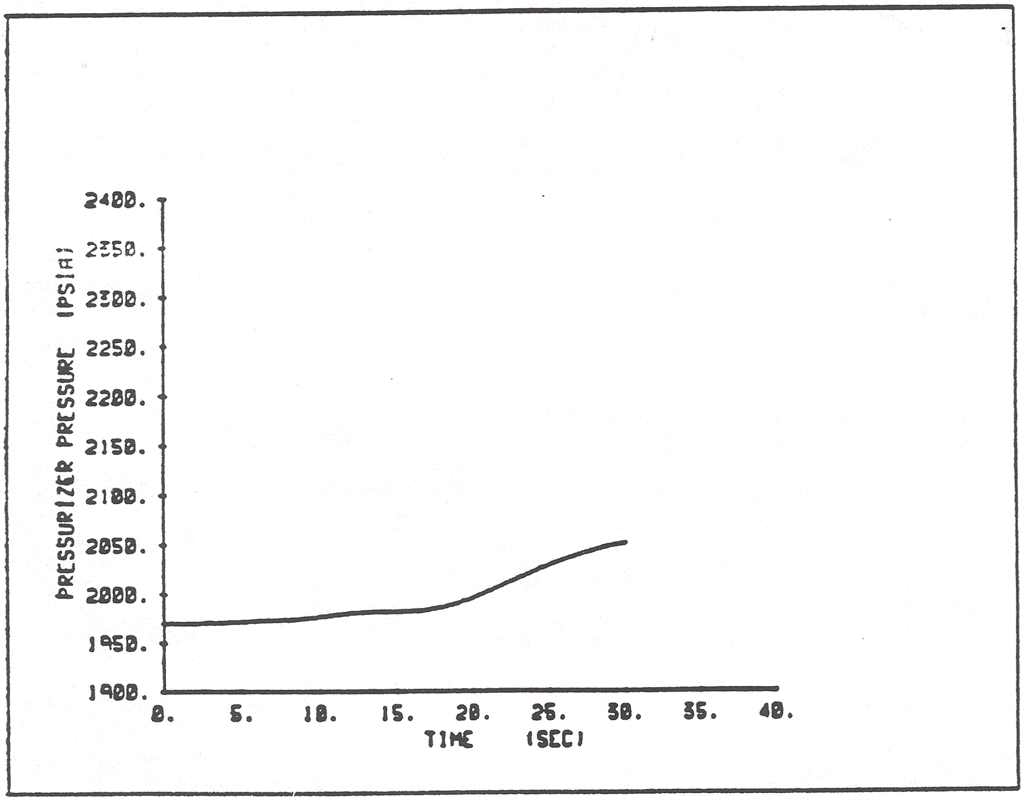


FIGURE 14.1.5-4

14.1.6 REDUCTION IN FEEDWATER ENTHALPY INCIDENT

The reduction in feedwater enthalpy is another means of increasing core power above full power. Such increases are attenuated by the thermal capacity in the secondary plant and in the reactor coolant system. The overpower-overtemperature protection (nuclear overpower and ΔT trips) prevents any power increase which could lead to a DNBR less than the safety analysis limit DNBR.

An extreme example of excess heat removal by the feedwater system is the transient associated with the accidental opening of the feedwater bypass valve which diverts flow around the low pressure feedwater heaters. The function of this valve is to maintain net positive suction head on the main feedwater pump in the event that the heater drain pump flow is lost, e.g., during a large load decrease.

In the event of accidental opening, there is a sudden reduction in inlet feedwater temperature to the steam generators. The increased subcooling will create a greater load demand on the primary system which can lead to a reactor trip.

With the plant at no-load conditions, the addition of cold feedwater may cause a decrease in RCS temperature and thus a reactivity insertion due to the effects of the negative moderator temperature coefficient. However, the rate of energy change is reduced as load and feedwater flow decrease, so that the transient is less severe than the full power case.

The net effect on the RCS due to a reduction in feedwater enthalpy is similar to the effect of increasing secondary steam flow, i.e., the reactor will reach a new equilibrium condition at a power level corresponding to the new steam generator ΔT.

The protection available to mitigate the consequences of a decrease in feedwater enthalpy is the same as that for an excessive load increase, as discussed in Section 14.1.7.

Method of Analysis

This transient is analyzed by computing conditions at the feedwater pump inlet following opening of the heater bypass valve. These feedwater conditions are then used to recalculate a heat balance through the high pressure heaters. This heat balance gives the new feedwater conditions at the steam generator inlet.

The following assumptions are made:

A. Plant initial power level of 1806 MWt.

B. Low pressure heater bypass valve opens, resulting in condensate flow splitting between the bypass line and the low pressure heaters; the flow through each path is proportional to the pressure drops.

Results

Opening of a low pressure heater bypass valve causes a reduction in feedwater temperature which increases the thermal load on the primary system. The reduction in feedwater temperature is less than 40°F (Reference 1) resulting in an increase in heat load on the primary system of less than

10% of full power. The reduction in feedwater temperature due to a 10% step load increase is 69°F. The increased thermal load, due to opening of the low pressure heater bypass valve, thus results in a transient very similar (but of reduced magnitude) to that present in Section 14.1.7 for an excessive load increase, which evaluates the consequences of a 10% step load increase. Therefore, the transient results of this analysis are not presented.

No explicit analysis was performed. However, an engineering evaluation performed at current and uprated power showed the 40°F evaluated was conservative even for the uprated power and the event remained bounded by the excessive load incident in Section 14.1.7.

Conclusions

The decrease in feedwater enthalpy incident is less severe than the excessive load increase incident (see Section 14.1.7). Based on results presented in Section 14.1.7, the applicable acceptance criteria for the reduction in feedwater enthalpy incident have been met.

References

1. Shaw Calculation 129187-M-0001, Revision 0, "Condensate, Feedwater, and Heater Drain Systems Hydraulic Model for NSSS Power Level of 1806 MWt," November 24, 2008.

2. NRC Safety Evaluation 2011-004, "Issuance of License Amendments Regarding Extended Power Uprate," dated May 3, 2011.

14.1.7 EXCESSIVE LOAD INCREASE INCIDENT

An excessive load increase incident is defined as a rapid increase in steam generator steam flow that causes a power mismatch between the reactor core power and the steam generator load demand. The reactor control system is designed to accommodate a 10% step load increase and/or a 5% per minute ramp load increase (without a reactor trip) in the range of 15 to 100% full power. Any loading rate in excess of these values may cause a reactor trip actuated by the reactor protection system. If the load increase exceeds the capability of the reactor control system, the transient is terminated in time to prevent DNBR less than the limiting value, by a combination of the nuclear overpower trip and the overpower-overtemperature ΔT trips, as discussed in Section 7.0. An excessive load increase incident could result from either an administrative violation such as excessive loading by the operator or an equipment malfunction such as steam bypass control or turbine speed control.

To avoid excessive load increases, either by manual operator action or by automatic system demand, the normal configuration at full load is for the turbine valve position limiter to be set slightly above the full load governor valve position.

During power operation, steam bypass to the condenser is controlled by reactor coolant condition signals, i.e., abnormally high reactor coolant temperature indicates a need for steam bypass. A single controller malfunction does not cause steam bypass; an interlock is provided which blocks the control signal to the valves unless a large turbine load decrease or a turbine trip has occurred.

Method of Analysis

This accident is analyzed using the RETRAN code. The code simulates the neutron kinetics, reactor coolant system, pressurizer, pressurizer relief and safety valves, pressurizer spray, steam generator, steam generator safety valves, and feedwater system. The code computes pertinent plant variables, including temperatures, pressures, and power level.

Four cases are analyzed to demonstrate the plant behavior following a 10% step-load increase from rated load. These cases are as follows:

1. Reactor control in manual with minimum reactivity feedback.
2. Reactor control in automatic with minimum reactivity feedback.
3. Reactor control in manual with maximum reactivity feedback.
4. Reactor control in automatic with maximum reactivity feedback.

For the minimum reactivity feedback cases, the core has the least negative moderator temperature coefficient (0 pcm/°F) of reactivity and the least negative Doppler only power coefficient; therefore, the least inherent transient response capability. For the maximum reactivity feedback cases, the moderator temperature coefficient of reactivity has its most negative value and the most negative Doppler only power coefficient. This results in the largest amount of reactivity feedback due to changes in coolant temperature.

A conservative limit on the turbine valve opening is assumed, and all cases are studied without credit being taken for pressurizer heaters. This accident is analyzed with the Revised Thermal Design Procedure as described in Reference 1, Section 14.0. Plant characteristics and initial conditions are as discussed in Section 14.1. Initial reactor power, pressure, and RCS temperatures are assumed to be at their nominal values. Uncertainties in initial conditions are included in the limit DNBR, as described in Reference 1, Section 14.0.

Results

Figure 14.1.7-1 and Figure 14.1.7-3 illustrate the transient with the reactor in the manual control mode. For the beginning-of-life case, there is a slight power increase, and the average core temperature shows a large decrease. This results in a departure from nucleate boiling ratio that increases above its initial value. For the end-of-life, manually controlled case, there is a much larger increase in reactor power due to the moderator feedback. A reduction in departure from nucleate boiling ratio is experienced, but the departure from nucleate boiling ratio remains above the limit value. Figure 14.1.7-2 and Figure 14.1.7-4 illustrate the transient when the reactor is assumed to be in the automatic control mode. Both the beginning-of-life and the end-of-life cases show that core power increases, thereby reducing the rate of decrease in coolant average temperature and pressurizer pressure. For both the beginning-of-life and the end-of-life cases, the minimum departure from nucleate boiling ratio remains above the limit value. The calculated sequence of events is shown in Table 14.1.7-1.

The excessive load increase incident is an overpower transient for which the fuel temperatures rise. When a reactor trip does not occur, the plant reaches a new equilibrium condition at a higher power level corresponding to the increase in steam flow.

Conclusions

The result of the analysis presented above indicate that no applicable acceptance criterion is challenged during this event. The thermal core limit lines are not challenged, and that the minimum DNBR during this transient remains above the safety analysis limit value.

Table 14.1.7-1 TIME SEQUENCE OF EVENTS FOR EXCESSIVE LOAD INCREASE INCIDENT

Case		Event	Time of Event (Seconds)
1.	Beginning of Core Life, Manual Reactor Control	10% step load increase	0
		Steady-state conditions reached (approximate)	250 (U1) 200 (U2)
2.	Beginning of Core Life, Automatic Reactor Control	10% step load increase	0
		Steady-state conditions reached (approximate)	200
3.	End of Core Life, Manual Reactor Control	10% step load increase	0
		Steady-state conditions reached (approximate)	200
4.	End of Core Life, Automatic Reactor Control	10% step load increase	0
		Steady-state conditions reached (approximate)	200

Figure 14.1.7-1 EXCESSIVE LOAD INCREASE BOL, MANUAL CONTROL
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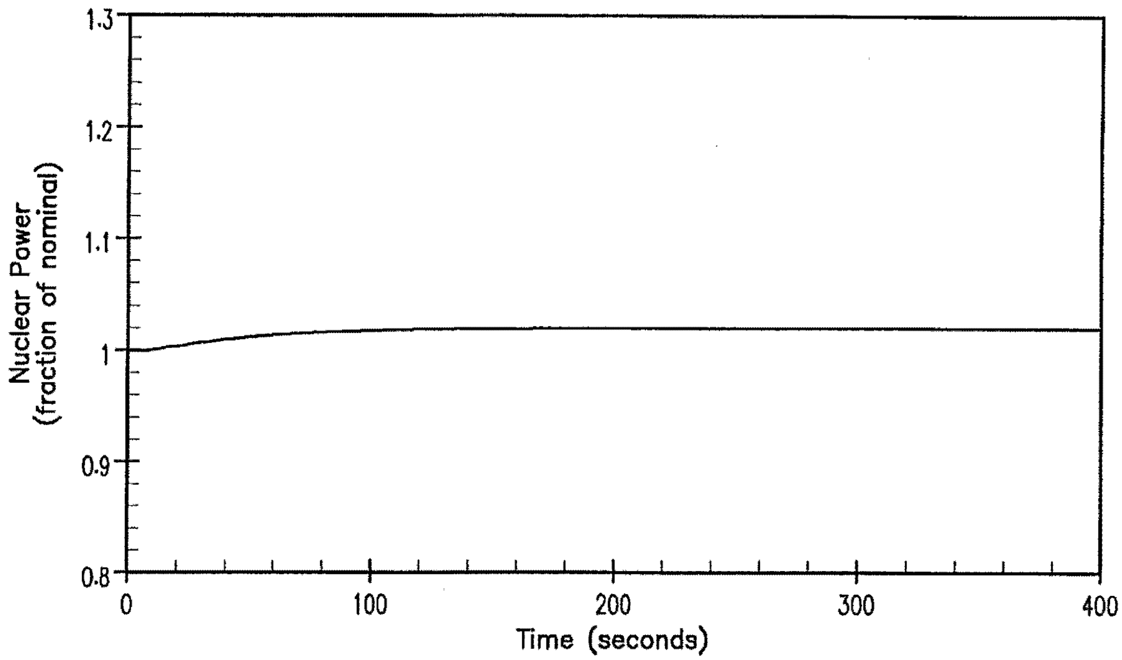

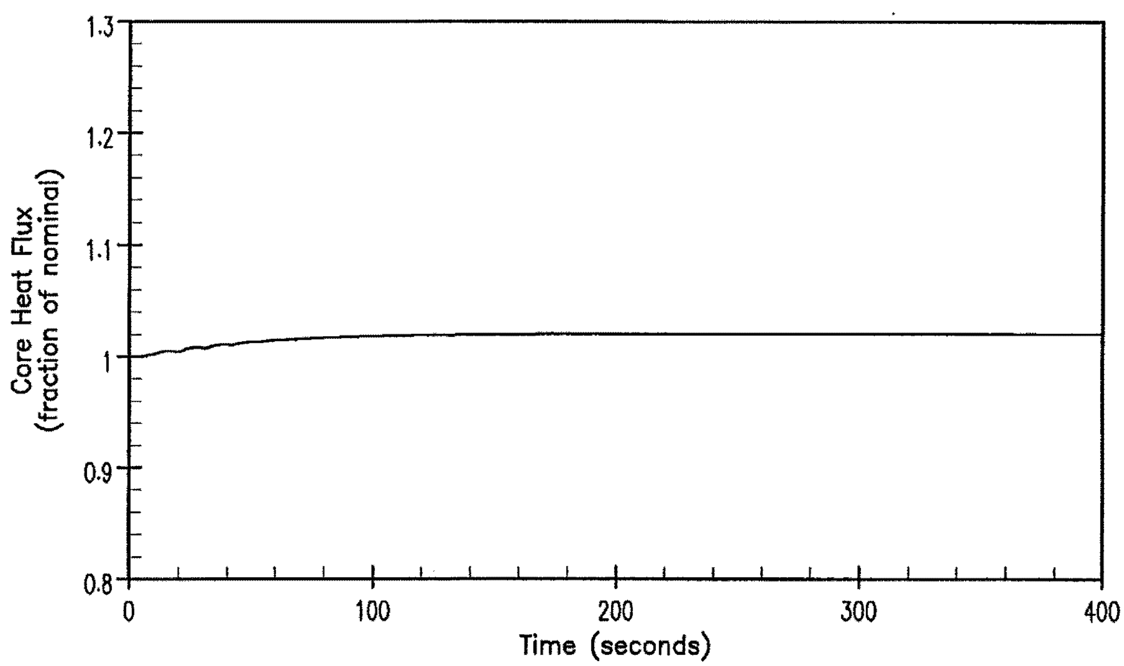

Figure 14.1.7-1 EXCESSIVE LOAD INCREASE BOL, MANUAL CONTROL
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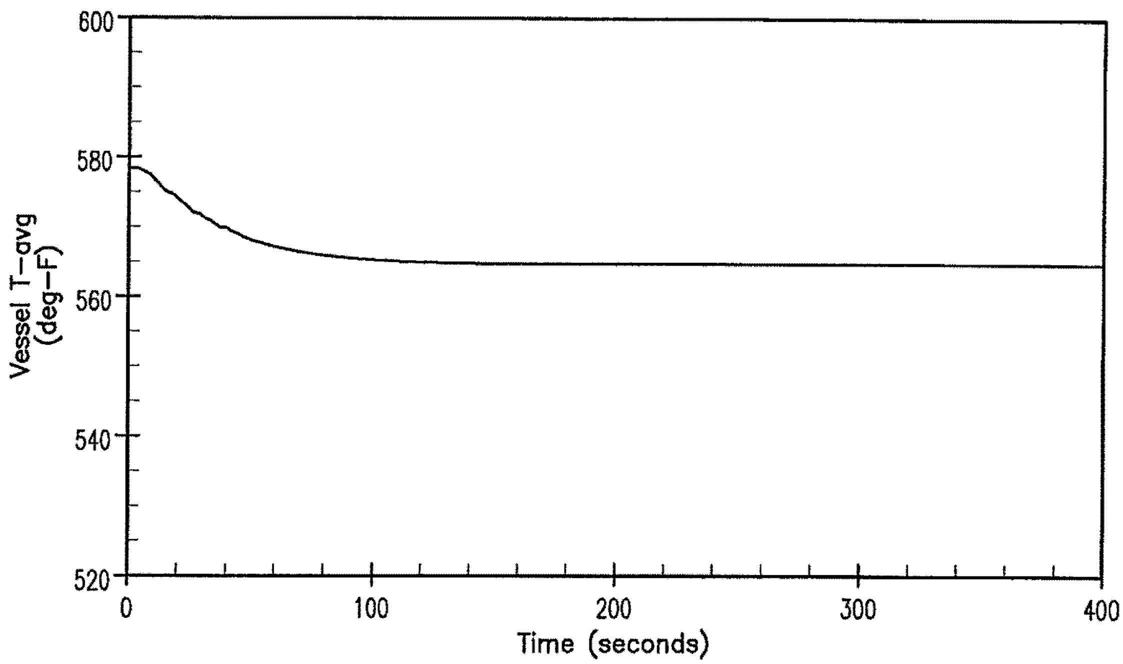

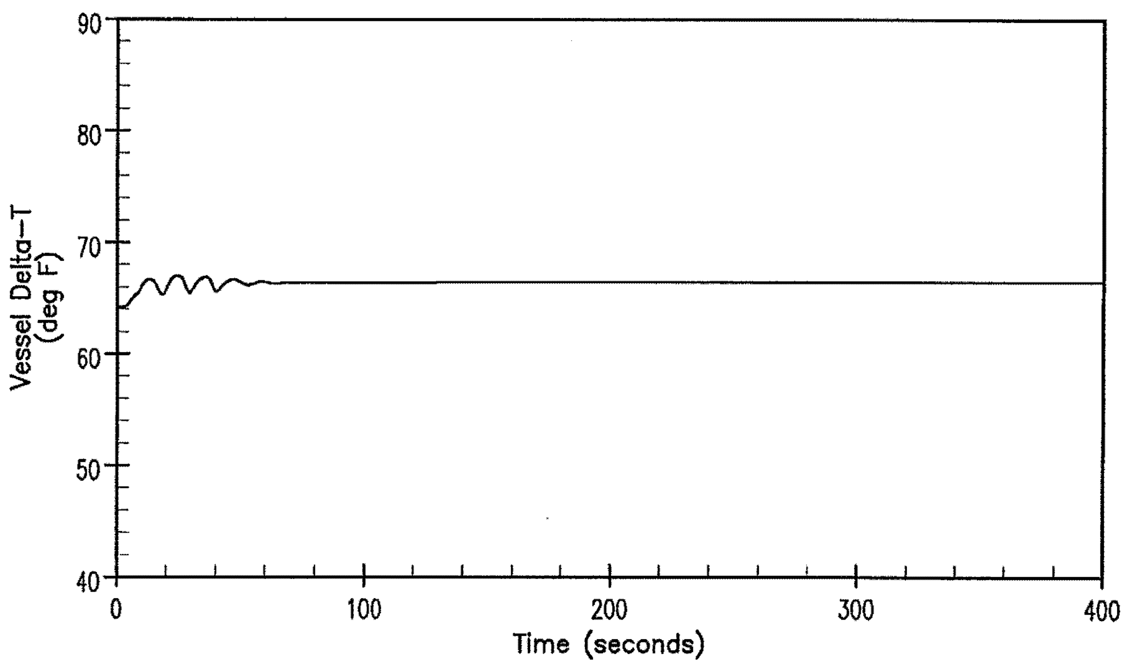

Figure 14.1.7-1 EXCESSIVE LOAD INCREASE BOL, MANUAL CONTROL
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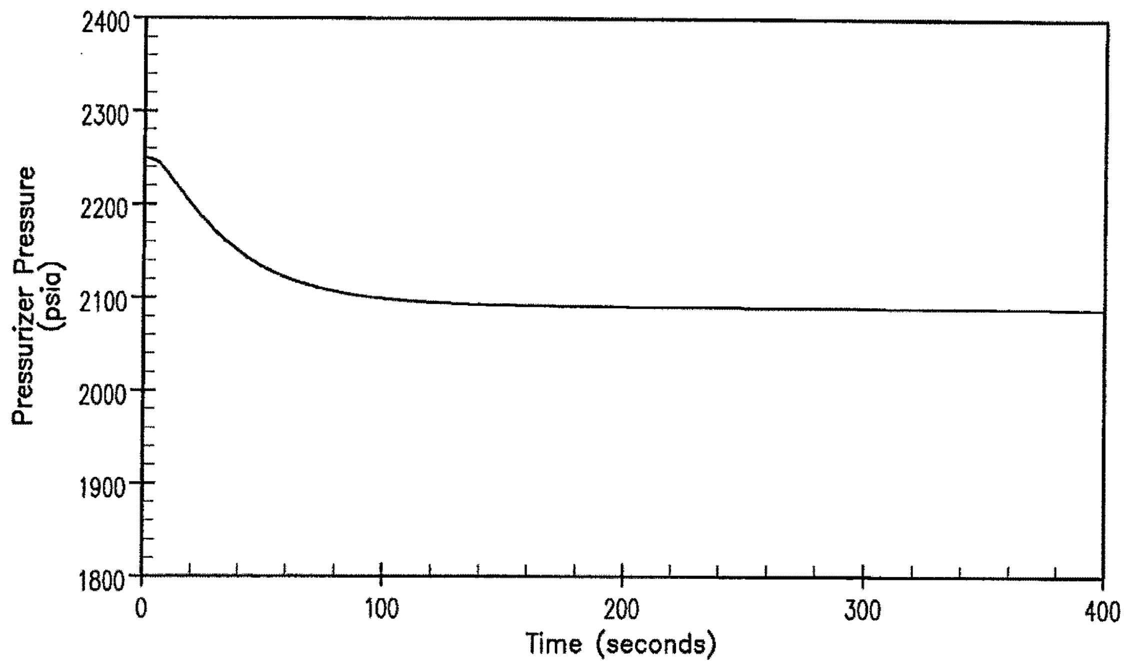

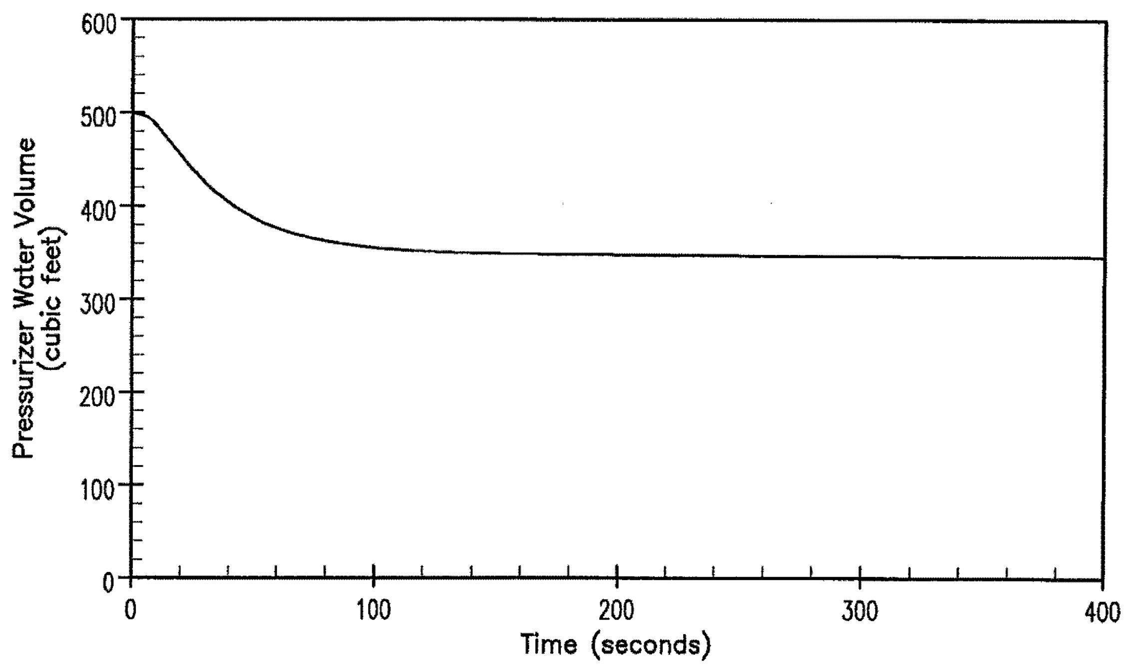

Figure 14.1.7-1 EXCESSIVE LOAD INCREASE BOL, MANUAL CONTROL
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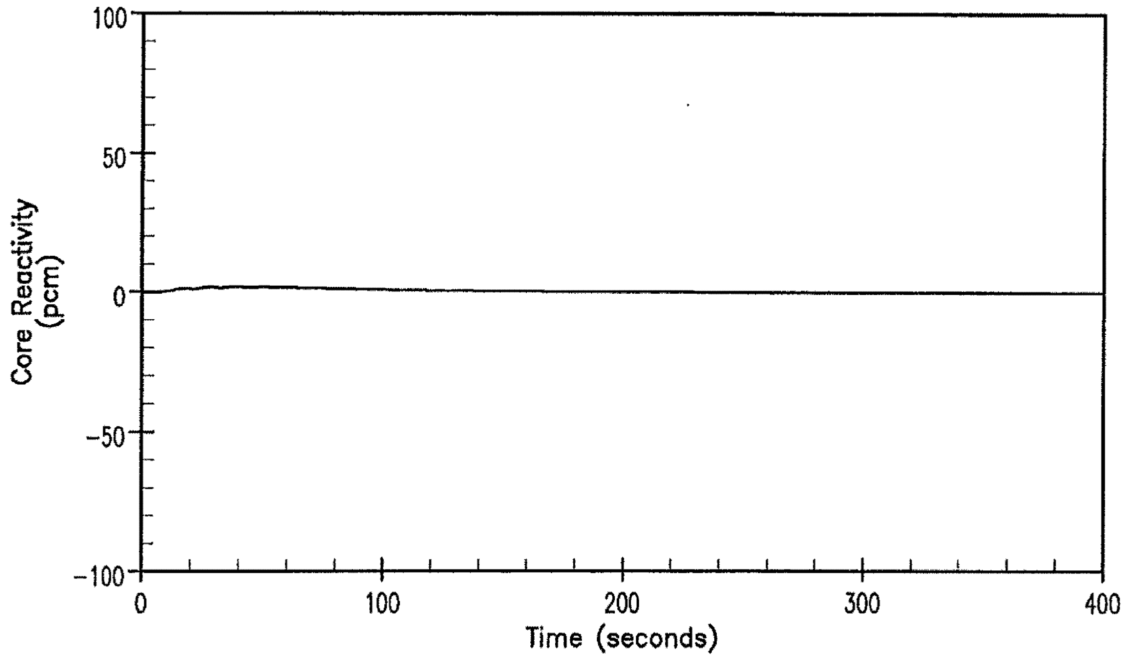


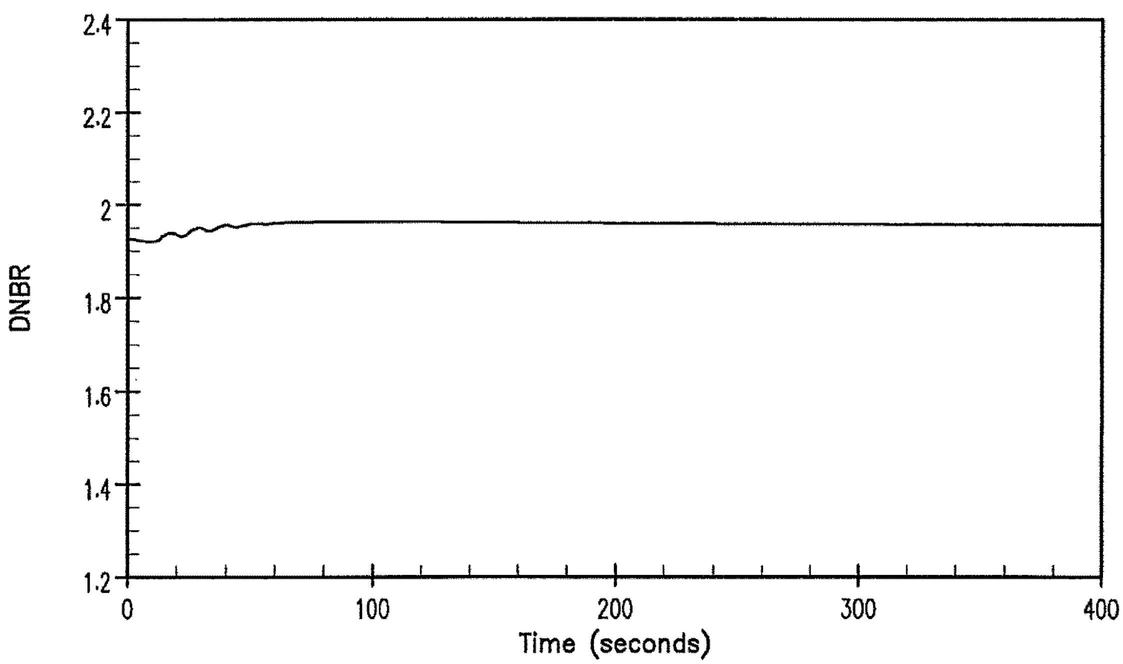
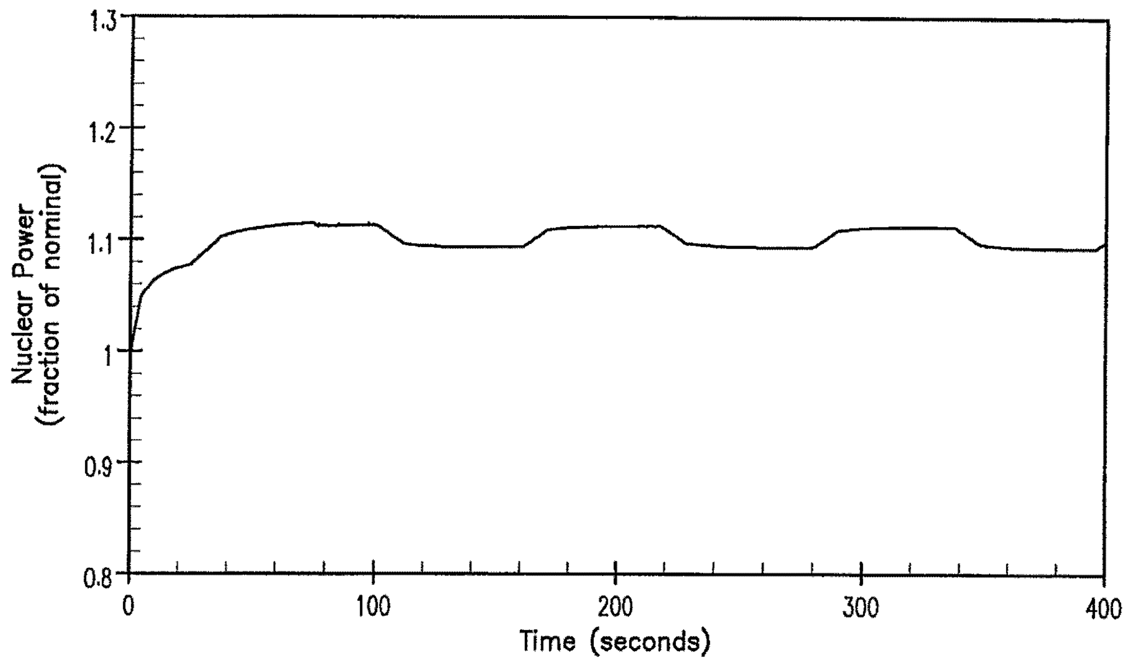


Figure 14.1.7-2 EXCESSIVE LOAD INCREASE BOL, AUTO CONTROL
Sheet 1 of 4



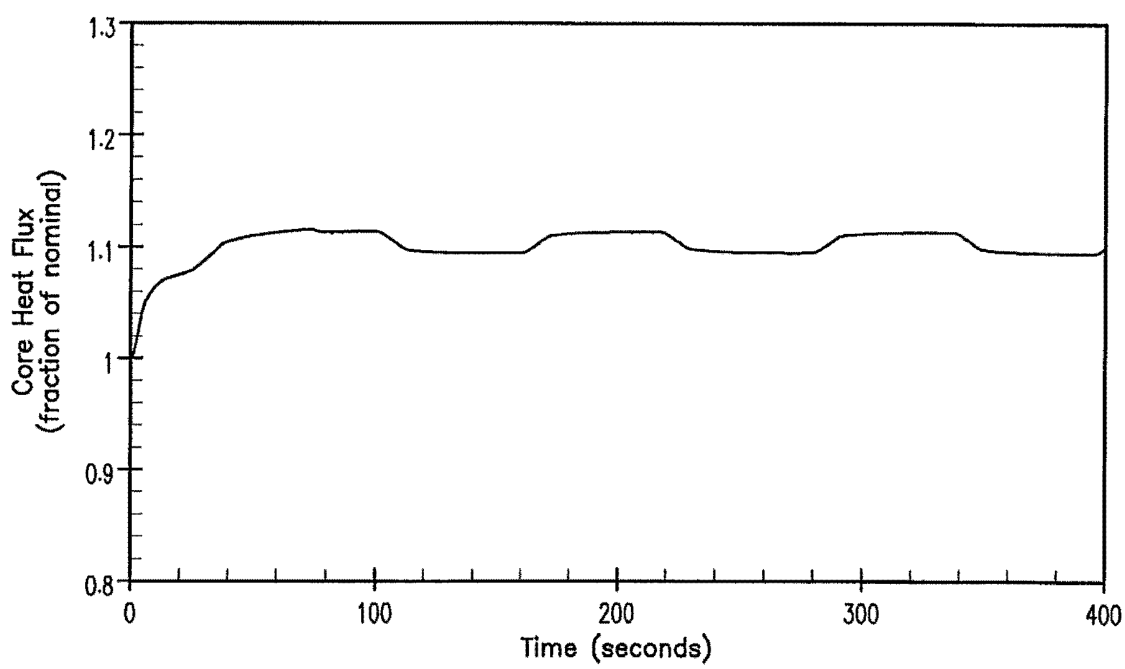


Figure 14.1.7-2 EXCESSIVE LOAD INCREASE BOL, AUTO CONTROL
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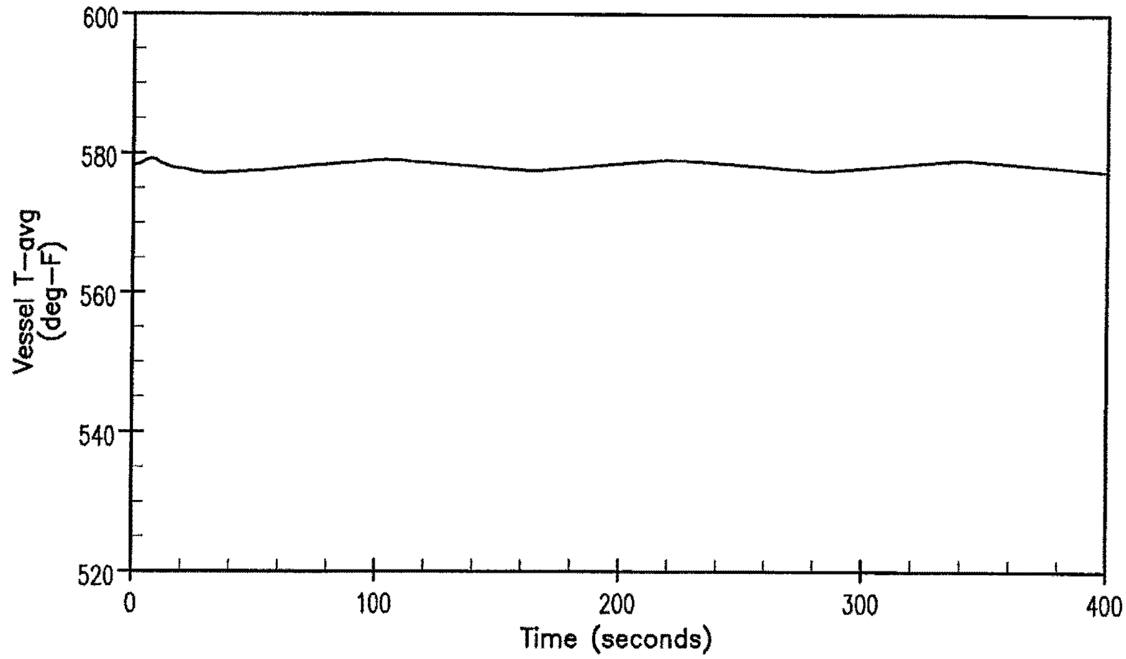

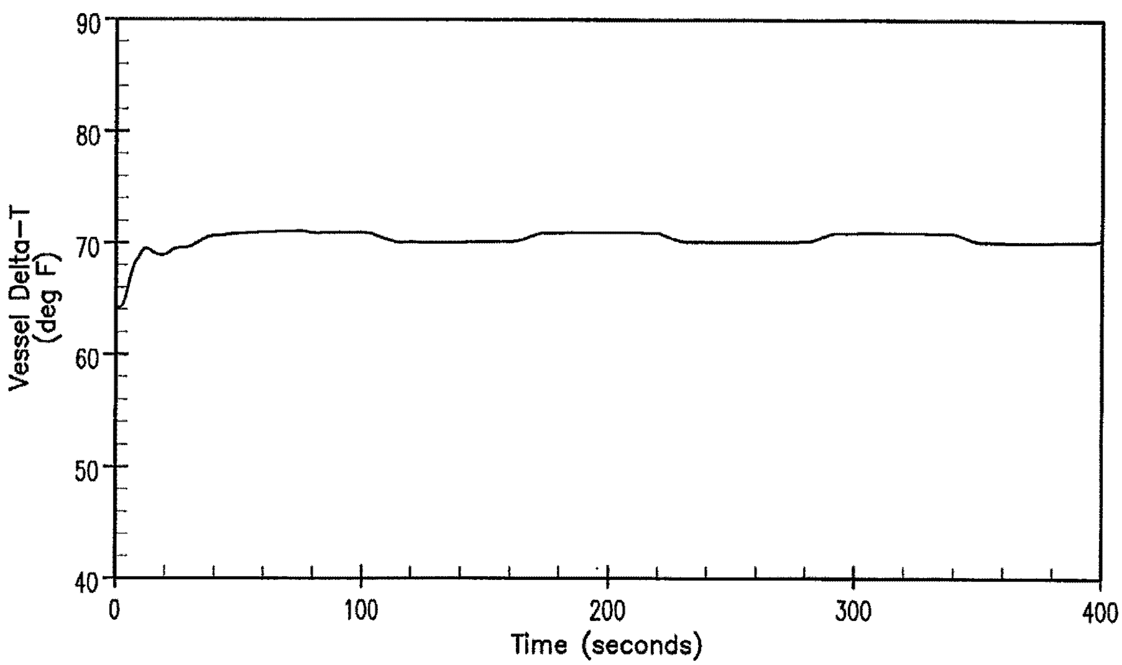

Figure 14.1.7-2 EXCESSIVE LOAD INCREASE BOL, AUTO CONTROL
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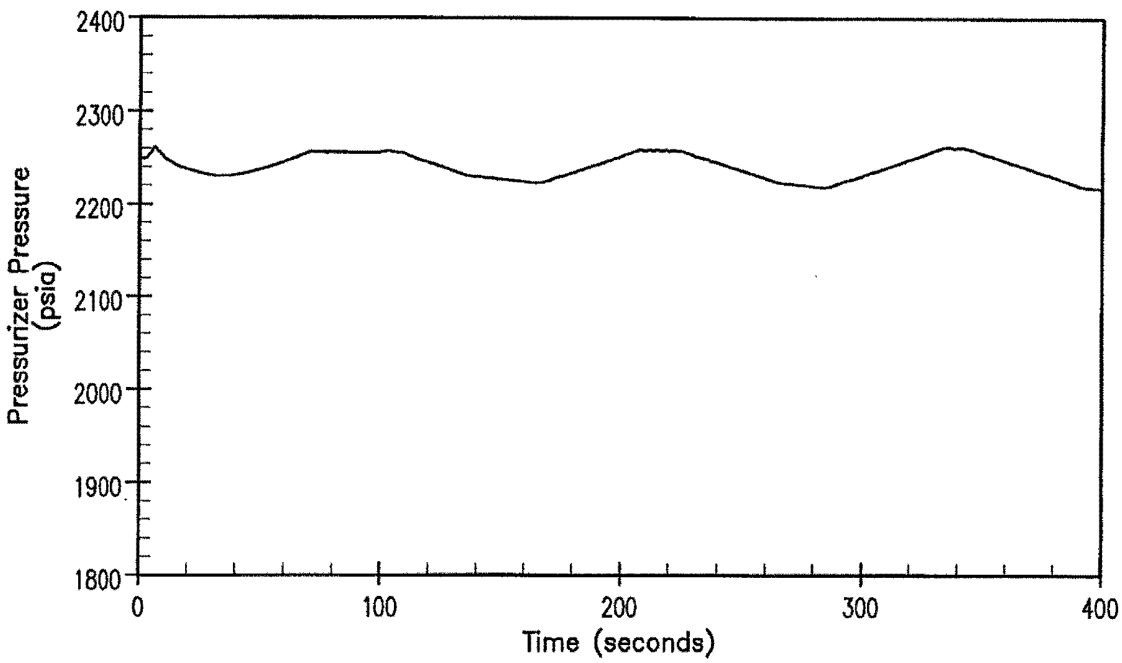

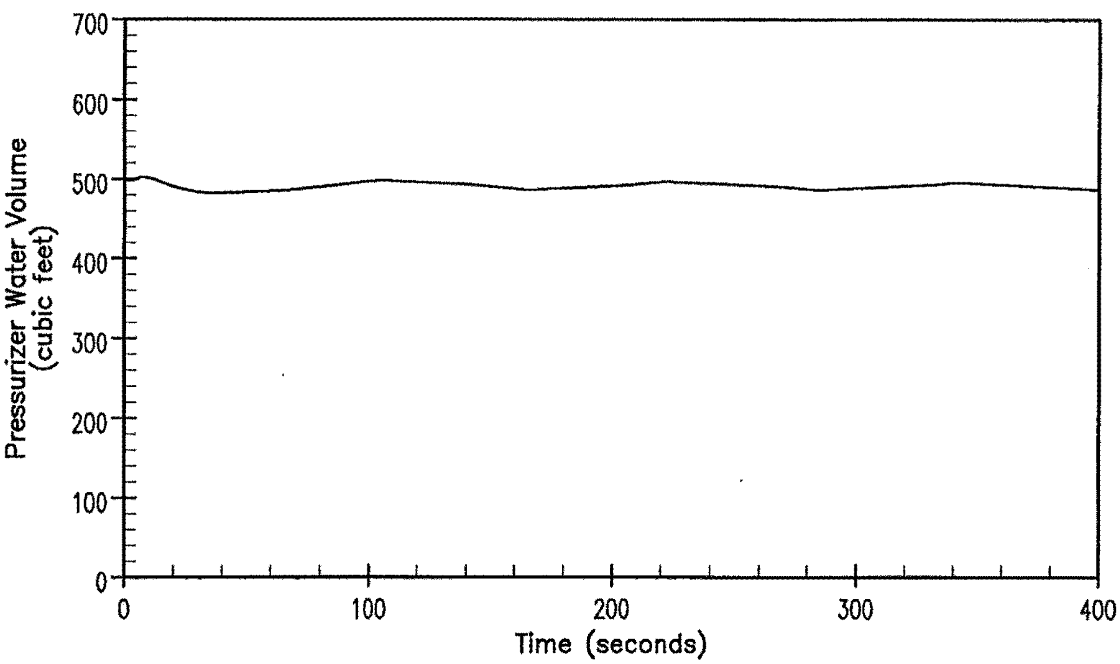

Figure 14.1.7-2 EXCESSIVE LOAD INCREASE BOL, AUTO CONTROL
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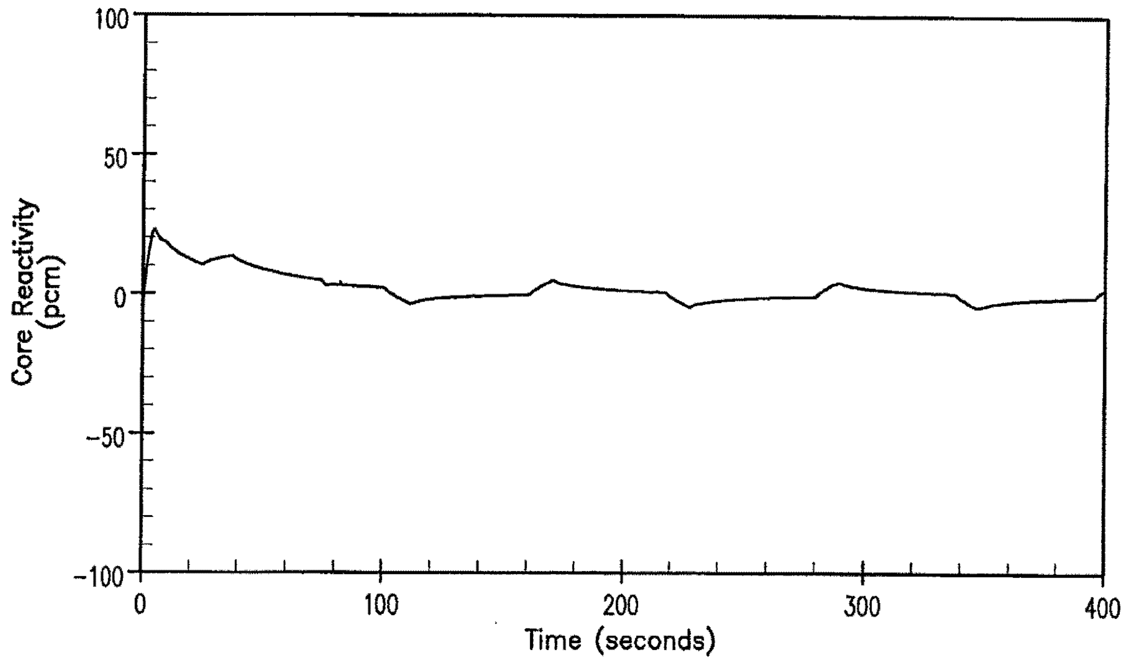


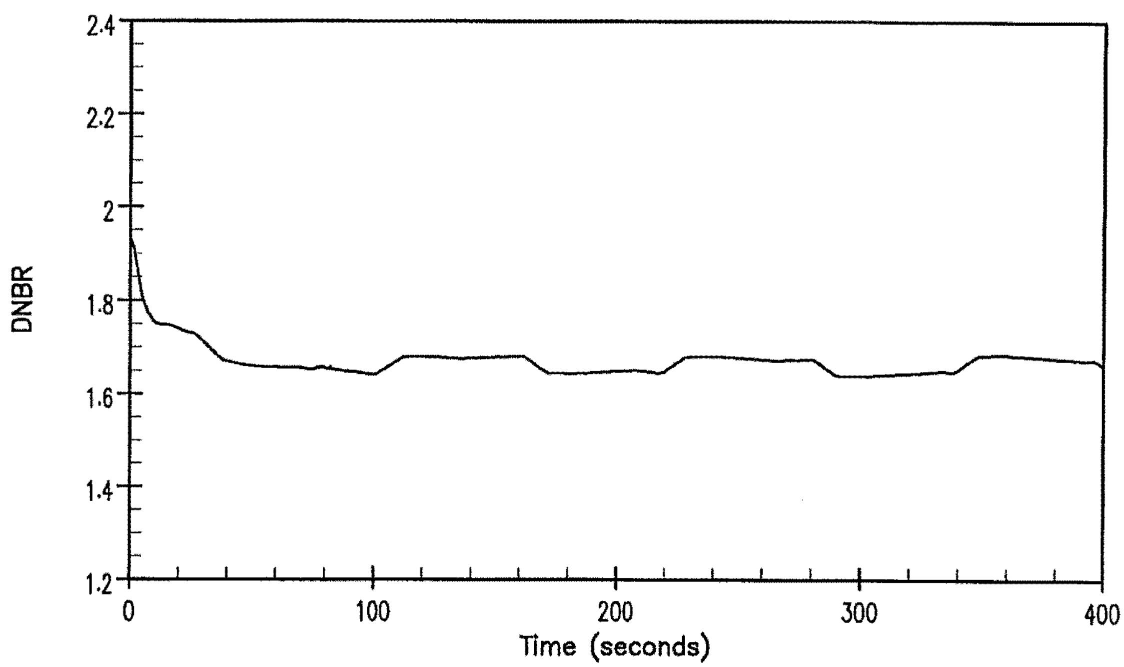
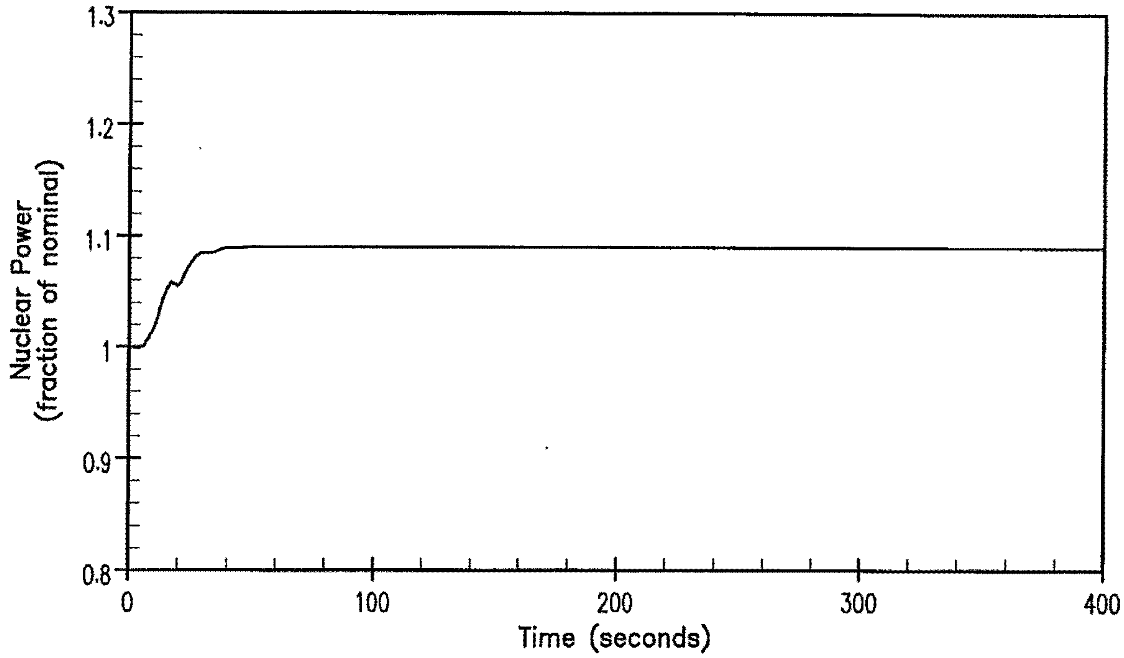


Figure 14.1.7-3 EXCESSIVE LOAD INCREASE EOL, MANUAL CONTROL
Sheet 1 of 4



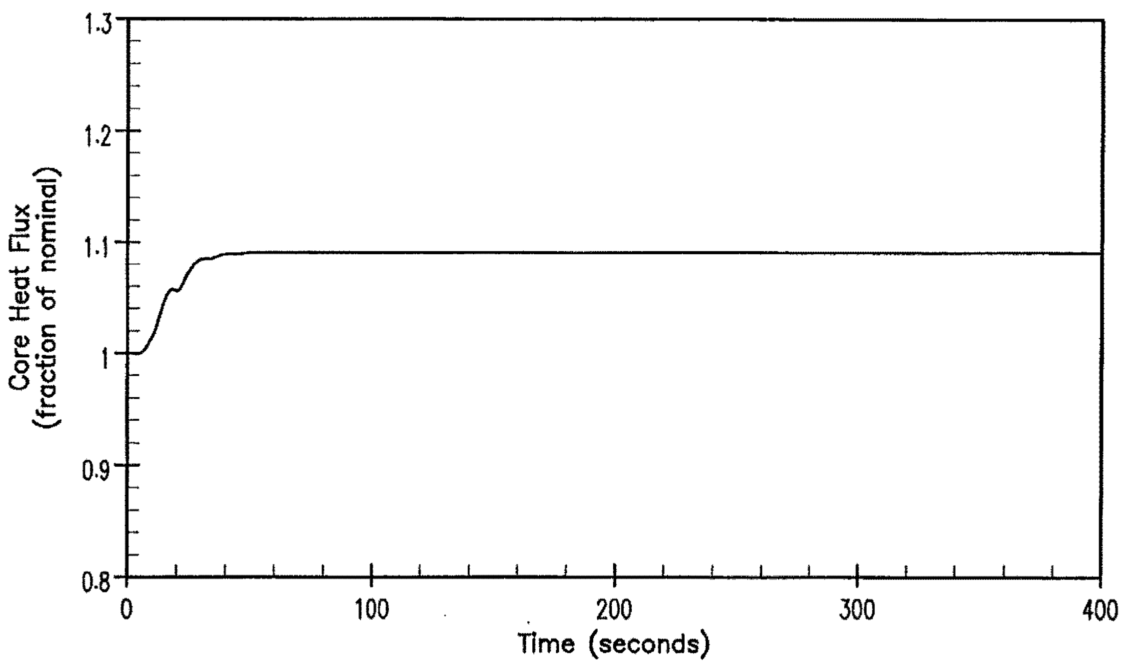


Figure 14.1.7-3 EXCESSIVE LOAD INCREASE EOL, MANUAL CONTROL
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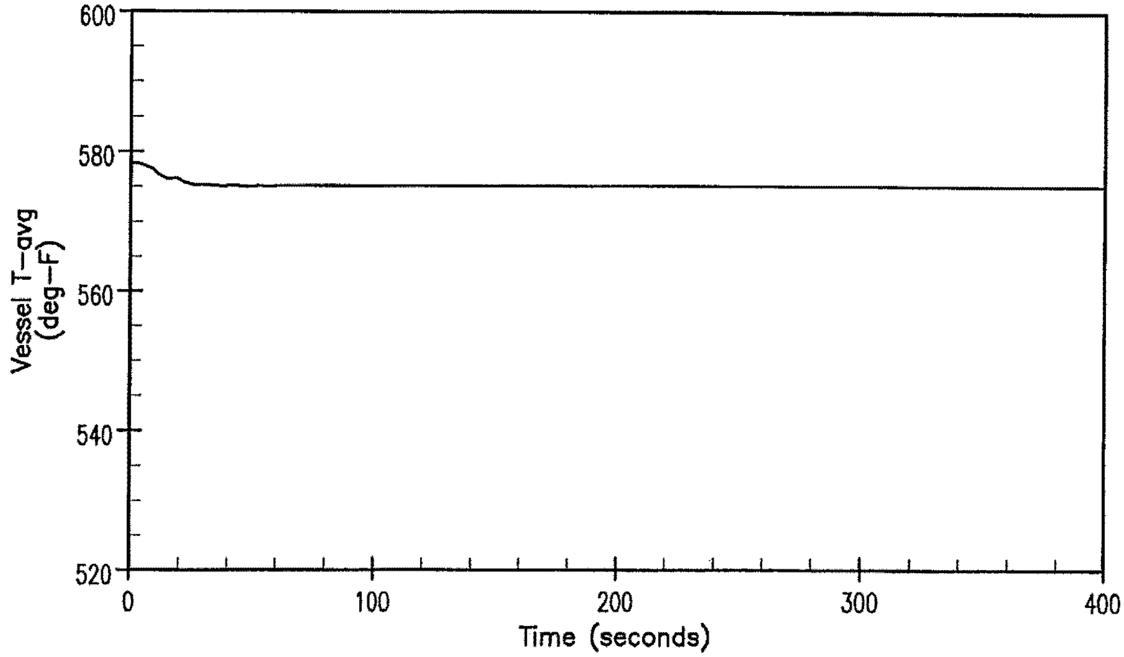

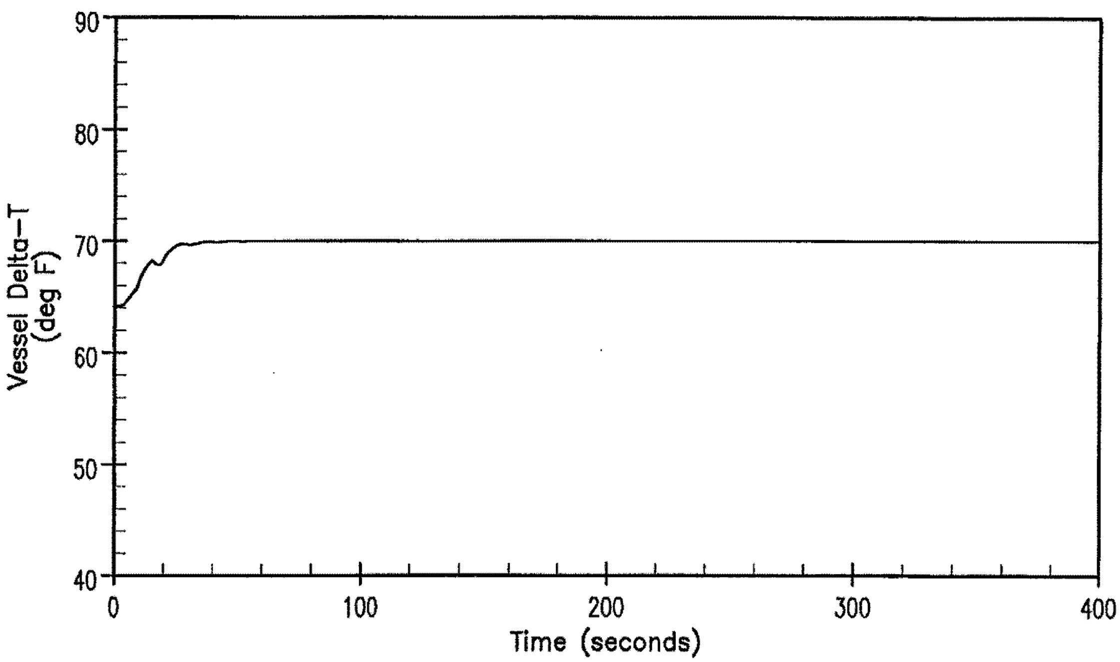

Figure 14.1.7-3 EXCESSIVE LOAD INCREASE EOL, MANUAL CONTROL
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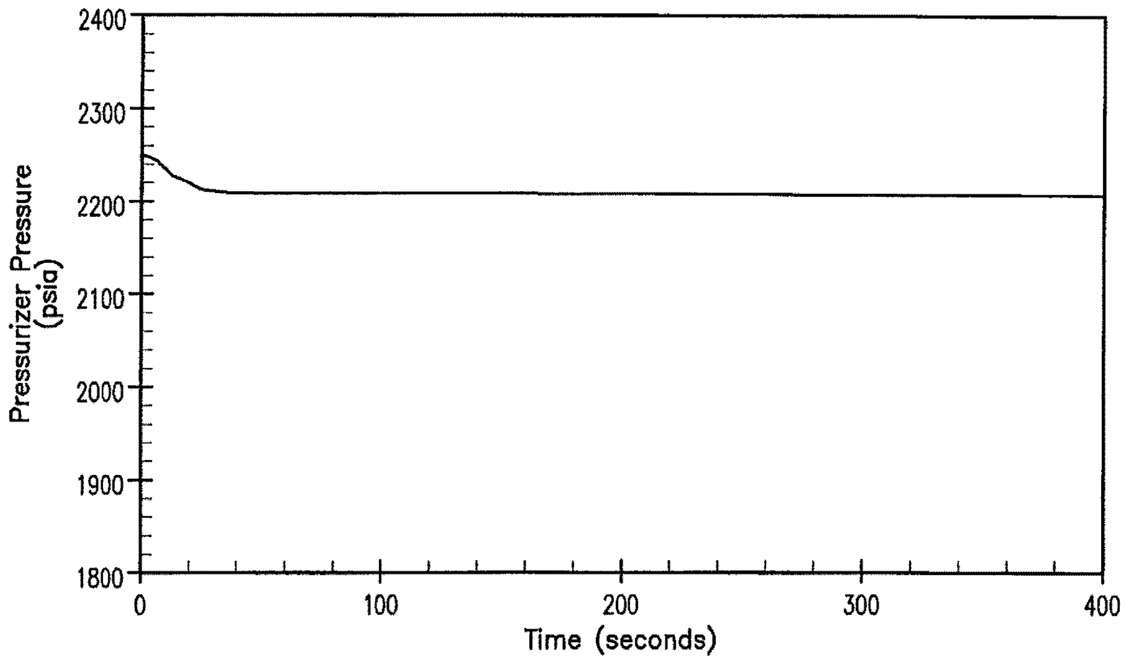

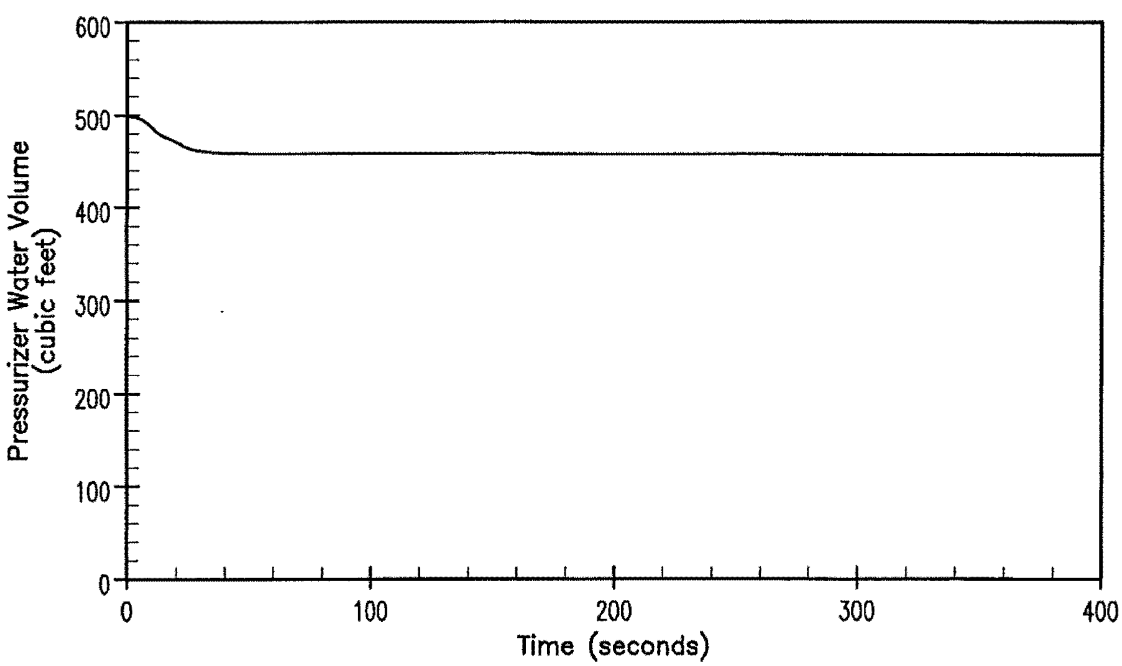

Figure 14.1.7-3 EXCESSIVE LOAD INCREASE EOL, MANUAL CONTROL
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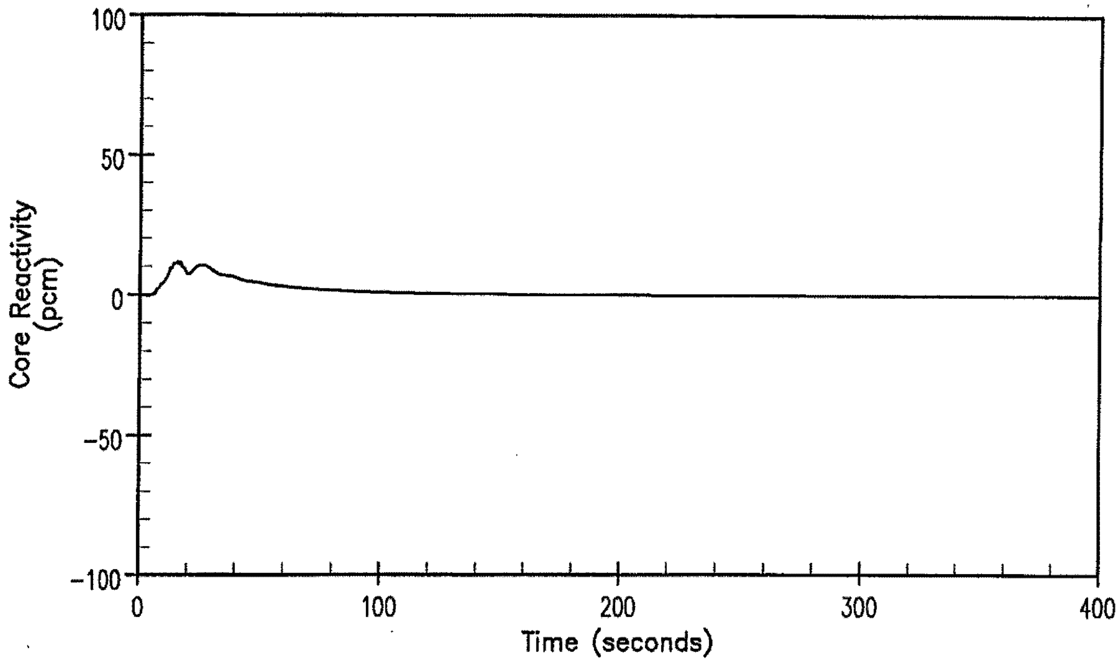


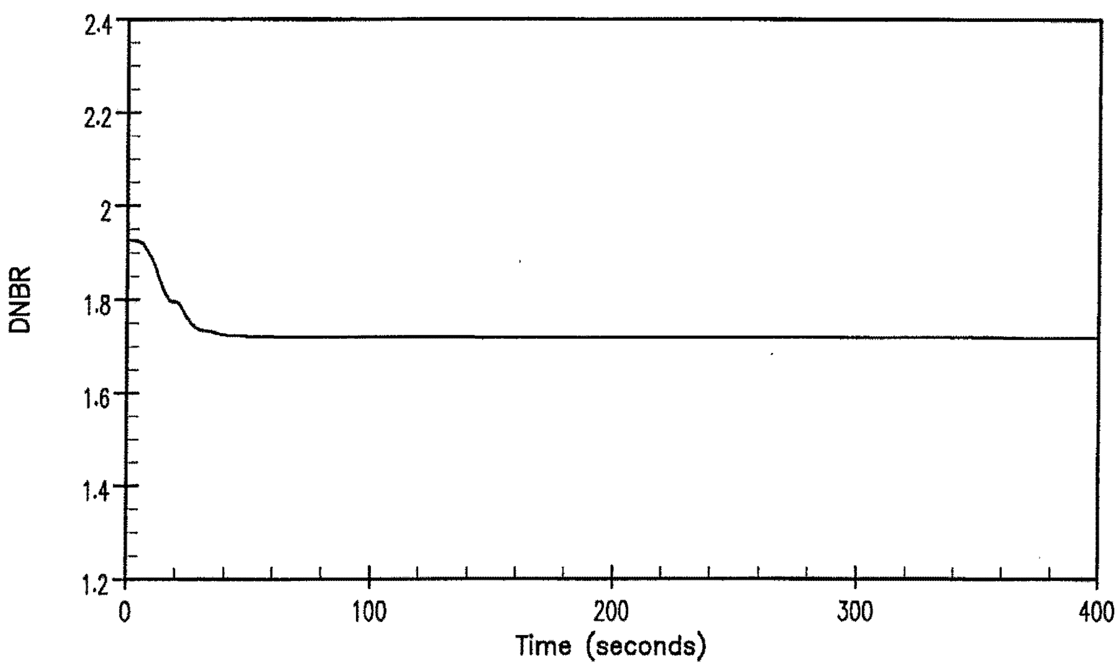
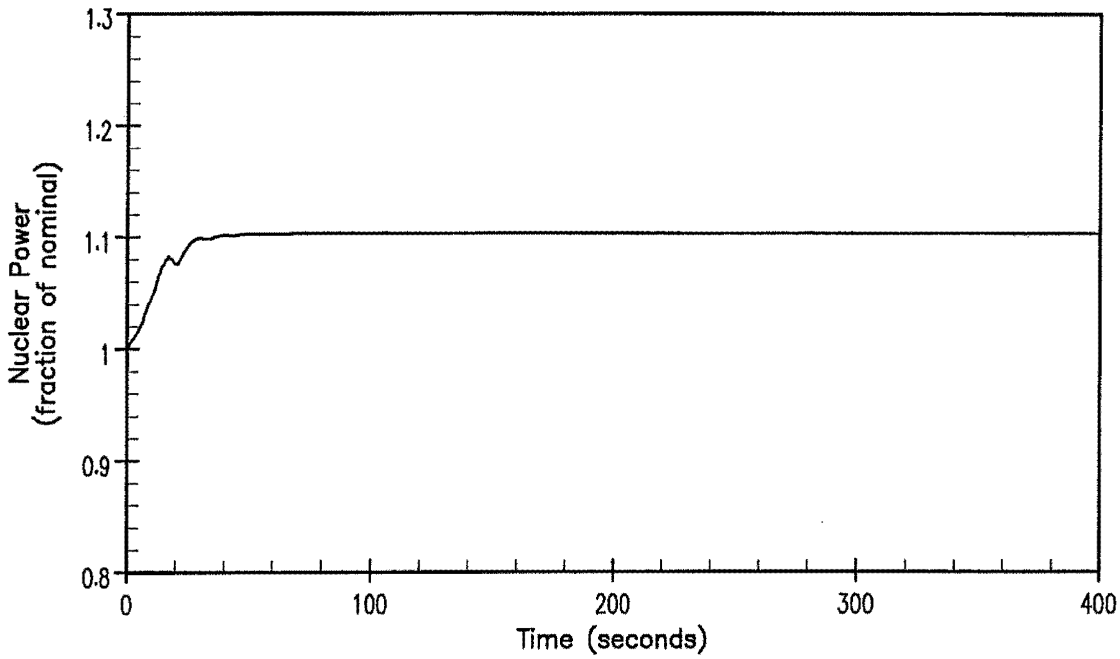


Figure 14.1.7-4 EXCESSIVE LOAD INCREASE EOL, AUTO CONTROL
Sheet 1 of 4



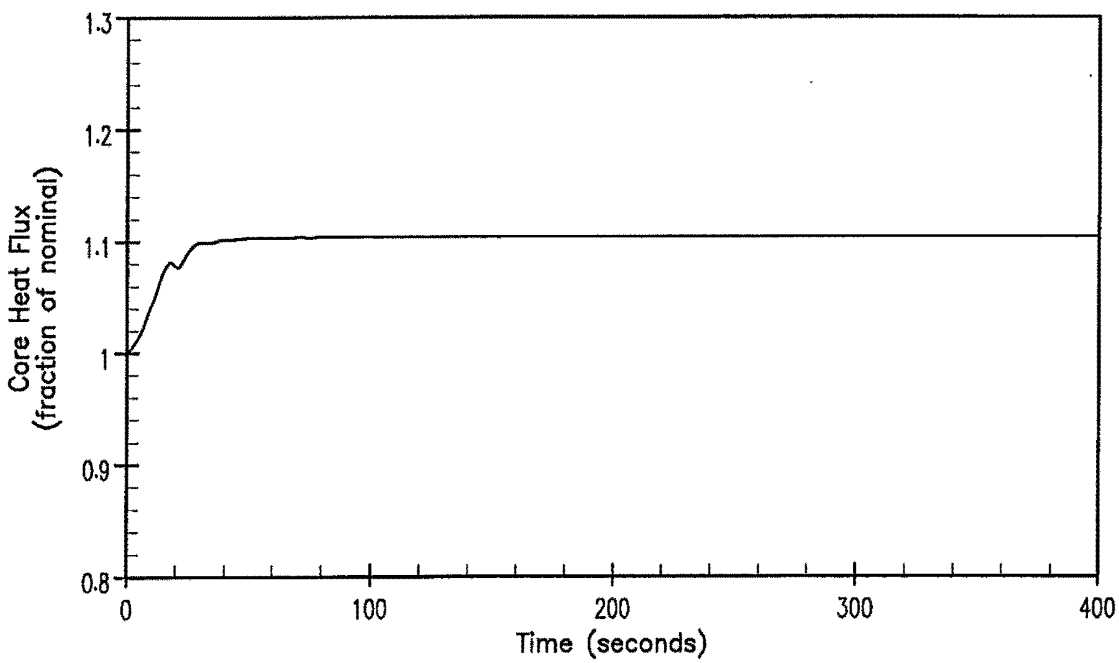


Figure 14.1.7-4 EXCESSIVE LOAD INCREASE EOL, AUTO CONTROL
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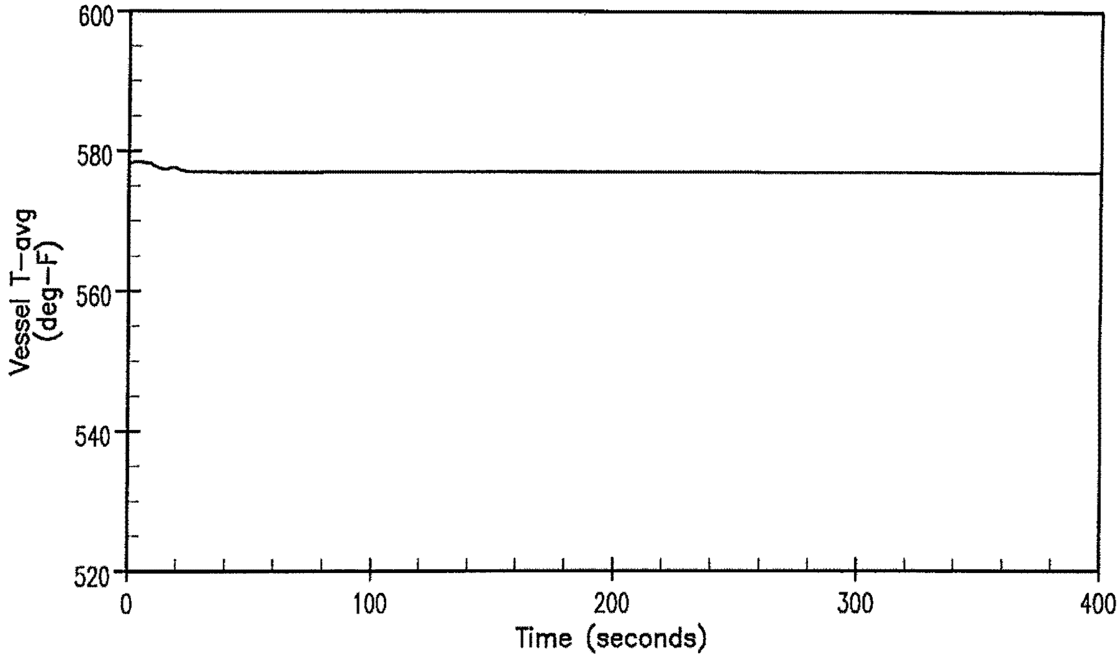

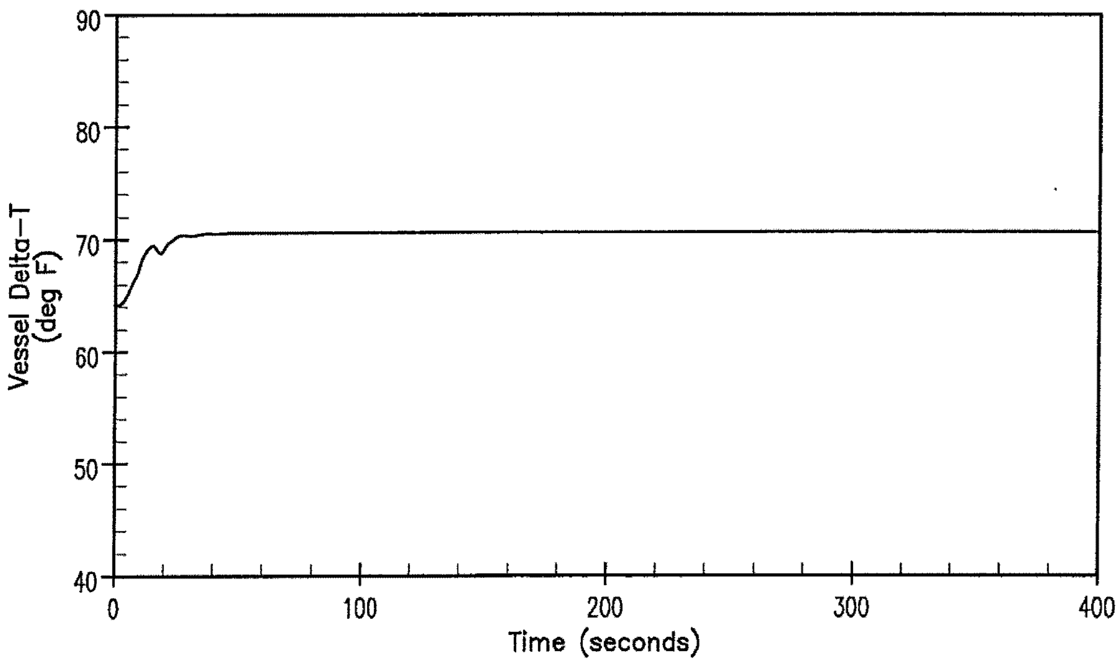

Figure 14.1.7-4 EXCESSIVE LOAD INCREASE EOL, AUTO CONTROL
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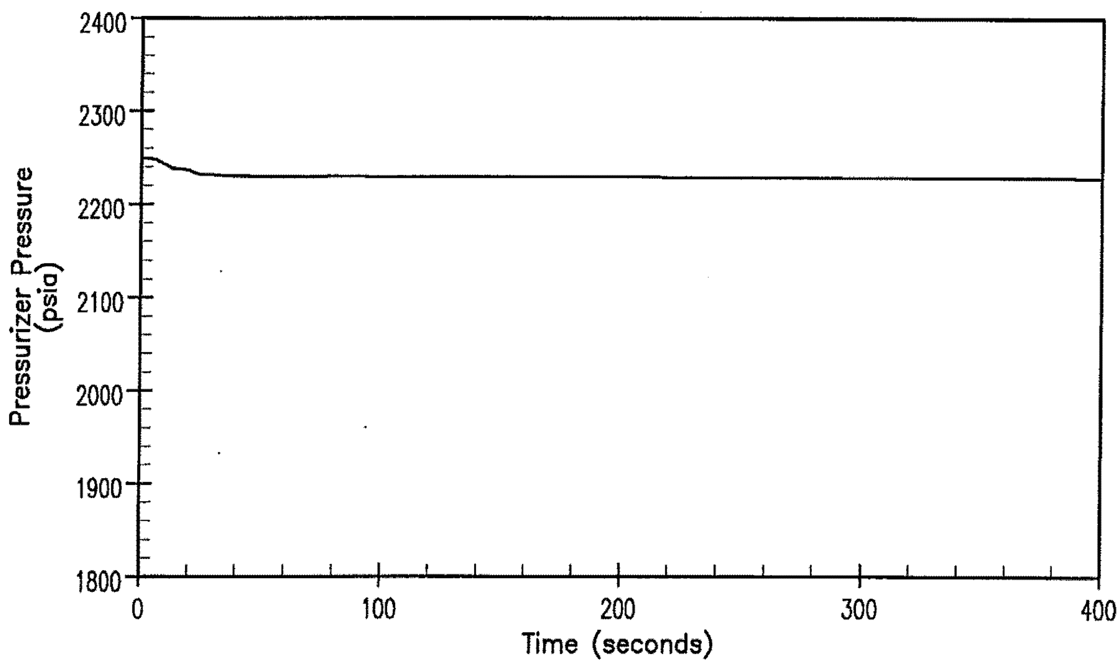


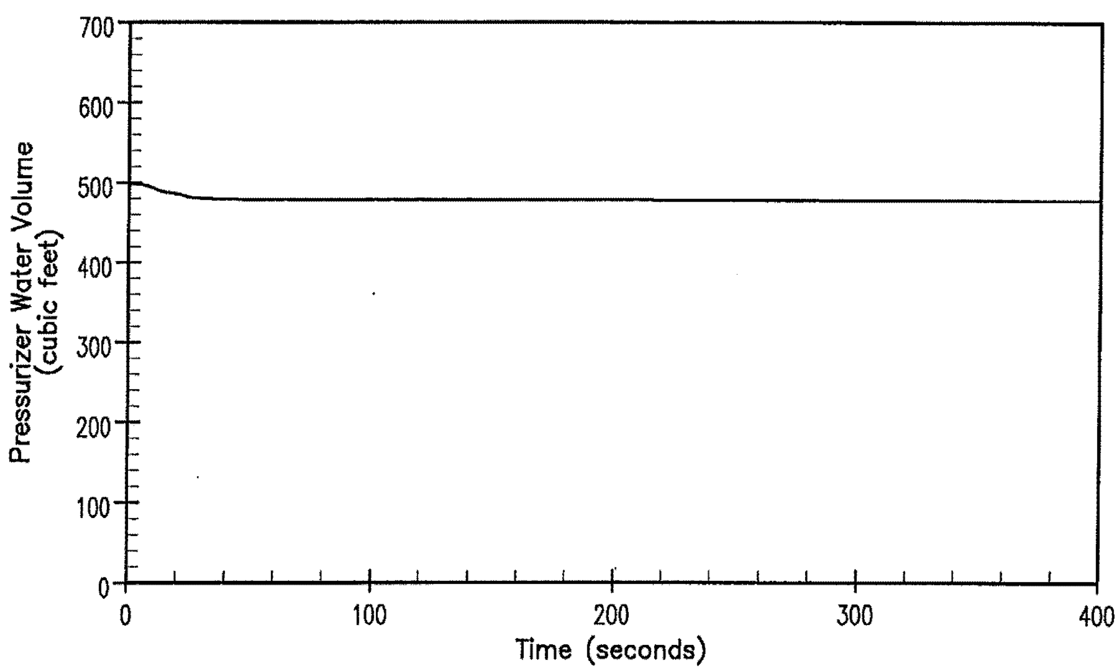
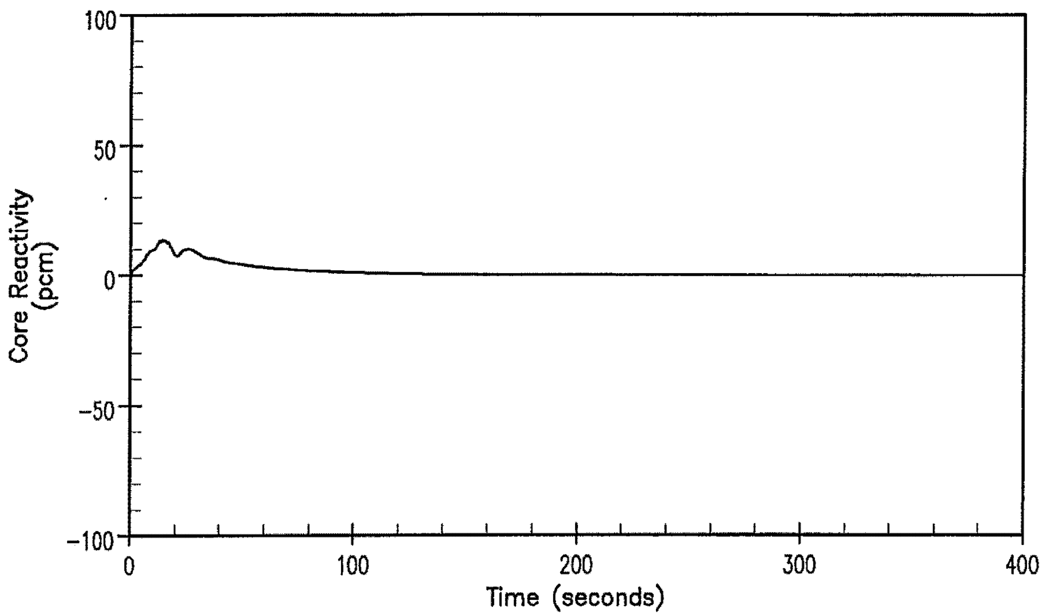
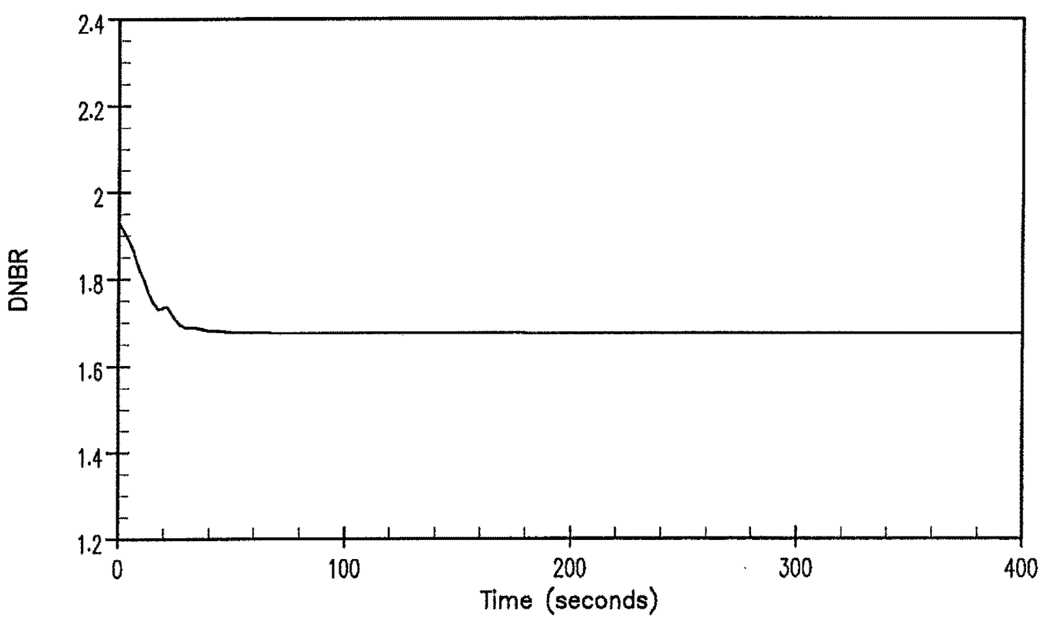


Figure 14.1.7-4 EXCESSIVE LOAD INCREASE EOL, AUTO CONTROL
Sheet 4 of 4





14.1.8 LOSS OF REACTOR COOLANT FLOW

Flow Coastdown Events

A loss of coolant flow incident can result from a mechanical or electrical failure in one or more reactor coolant pumps, or from a fault in the power supply to these pumps. If the reactor is at power at the time of the incident, the immediate effect of loss of coolant flow is a rapid increase in coolant temperature. This increase could result in departure from nucleate boiling (DNB) with subsequent fuel damage if the reactor is not tripped promptly. Trip circuits provide the necessary protection against a loss of coolant flow incident and are actuated by:

1. Low voltage on pump power supply bus;

2. Pump circuit breaker opening (low frequency on pump power supply bus opens pump circuit breaker); or

3. Low reactor coolant flow.

These trip circuits and their redundancy are further described in Section 7.2, Reactor Protection System.

Frequency decay for both reactor coolant pumps during full power operation is the most severe credible loss-of-coolant flow condition. For this condition reactor trip together with flow sustained by the inertia of the coolant and rotating pump parts will be sufficient to prevent fuel failure, reactor coolant system overpressure and prevent the DNB ratio from going below the limit value.

Method of Analysis

The loss of flow analysis is performed for the following cases:

- pump bus frequency decay (underfrequency) event,
- loss of pump power supply voltage (undervoltage) event,
- partial loss of flow (PLOF) event, and
- complete loss of flow (CLOF) (reference case; bounds the undervoltage and partial loss of flow events).

The limiting loss of flow transient is the pump bus frequency decay (underfrequency) event with a 5 Hz/s frequency decay rate which conservatively does not credit the RCP underfrequency trip. The reactor trip occurs on a low flow signal. This underfrequency event is assumed to begin after a one-second null transient. The pumps slow down at a frequency decay rate of 5 Hz/s. The flow decreases as a response to the slower pump rotation throughout the transient and the reactor trips on a low flow signal at 87% of nominal flow.

A complete loss of flow (CLOF) reference case is analyzed for a loss of both RCPs with both reactor coolant loops in operation. This case bounds the undervoltage and the PLOF events. This CLOF event is assumed to initiate at 1.0 second and both RCPs start to coastdown. In order to bound the undervoltage event, the undervoltage trip is delayed until the low flow reactor trip signal is reached.

The normal power supplies for the pumps are the two buses connected to the generator, each of which supplies power to one of the two pumps. Following a turbine generator trip, the 19 kV main generator breaker opens. The auxiliaries on the 4.16 kV non-safeguards buses remain fed by the unit auxiliary transformer (X02) via the main transformer (X01). Therefore, the simultaneous loss of power to all reactor coolant pumps is a highly unlikely event.

Following any turbine trip, where there are no electrical faults which require tripping the generator from the network, the generator remains connected to the network for approximately one minute. Since both pumps are not on the same bus, a single bus fault would not result in the loss of both pumps.

The complete loss of flow transients were analyzed using the Westinghouse advanced 3-D methodology with three computer codes, linked by an external communication interface (Reference 3). The RETRAN code is used to calculate the RCS conditions versus time, including the reactor vessel, RCS loops, pressurizer, and steam generators. The RETRAN code also models the reactor trips, engineered safety feature (ESF) functions, and the RCS control functions. The SPNOVA code is used to perform steady-state and transient 3-D core neutronics calculations, using the VIPRE code to calculate the transient local coolant density and fuel effective temperature (Teff) for the core feedback calculations. The VIPRE code is used to calculate the local heat flux to the coolant in the RETRAN core model. The VIPRE code obtains its core inlet conditions (core inlet flow and temperature) and core exit pressure from the RETRAN calculation. Using boundary conditions from the core feedback calculations (SPNOVA/ RETRAN/VIPRE linked run), the VIPRE code is also used in a separate hot rod calculation to determine the minimum DNBR versus time.

Initial Operating Conditions

Initial reactor power, RCS temperature and pressure are assumed to be at the most limiting nominal conditions, i.e. 100% power, maximum RCS temperature, and reduced pressure operation. Uncertainties in initial conditions are included in the DNBR limits as described in Reference 2.

Initial Core Conditions

The loss of flow analysis was performed at Beginning of Cycle (BOC) Hot Full Power (HFP) conditions. The analysis used minimum moderator temperature feedback, maximum Doppler feedback and a maximum value of the delayed neutron fraction. The control rods were initially assumed to be at their fully withdrawn position to minimize the initial rate of reactivity insertion following a reactor trip. A conservative rod position vs. time curve was assumed for the reactor trip.

Flow Coastdown

The flow coastdown analysis is based on a momentum balance around each reactor coolant loop and across the reactor core. This momentum balance is combined with the continuity equation, a pump momentum balance and the pump characteristics and is based on high estimates of system pressure losses.

No single active failure in the plant systems and equipment which are necessary to mitigate the effects of the accident will adversely affect the consequences of the accident during the transient.

Fuel Type and SG Tube Plugging Level

The loss of coolant flow analysis is performed to bound operation with 422V+ fuel and an effective (i.e. sleeved and/or plugged) uniform steam generator tube plugging level of up to 10% for Units 1 and 2, with a maximum loop-to-loop steam generator tube plugging asymmetry of 10%.

Results

The limiting loss of flow event is the pump bus frequency decay (underfrequency) event. The transient results for this limiting case are presented in Figure 14.1.8-1. The transient results for the complete loss of flow case (bounding both the undervoltage and partial loss of flow cases) are presented in Figure 14.1.8-2. The sequence of events for the limiting frequency decay case and the reference complete loss of flow case are presented in Table 14.1.8-1.

Conclusions

Since the minimum DNBR remains above the design DNBR limit for all cases, there is no cladding damage and no release of fission products into the reactor coolant. Therefore, once the fault is corrected, the plant can be returned to service in the normal manner. The absence of fuel failures would, of course, be verified by analysis of reactor coolant samples.

Locked Rotor Accident

A hypothetical transient analysis is performed for the postulated instantaneous seizure of a reactor coolant pump rotor. Flow through the reactor coolant system is rapidly reduced, leading to a reactor trip on a low-flow signal. Following the trip, heat stored in the fuel rods continues to pass into the core coolant, causing the coolant to heat up and expand. At the same time, heat transfer to the shell side of the steam generator is reduced, first because the reduced flow results in a decreased tube side film coefficient and then because the reactor coolant in the tubes cools down while the shell side temperature increases (turbine steam flow is reduced to zero upon plant trip). The rapid expansion of the coolant in the reactor core, combined with the reduced heat transfer in the steam generator causes an insurge into the pressurizer and a pressure increase throughout the reactor coolant system. The insurge into the pressurizer compresses the steam volume, actuates the automatic spray system, opens the power-operated relief valves, and opens the pressurizer safety valves, in that sequence. The two power-operated relief valves are designed for reliable operation and would be expected to function properly during the accident. However, for conservatism, their pressure-reducing effect is not included in the peak RCS pressure and peak cladding temperature (PCT) cases.

There are no credible sources of shaft seizure other than impeller rubs. Any seizure of the pump bearing is precluded by the graphite in the bearing. Any seizure in the seals results in a shearing of the anti-rotation pin in the seal ring. An inadvertent actuation of the shut down seal (SDS) on a rotating assembly will not have any measurable impact on RCP coastdown or on the pump's capability to provide sufficient cooling flow to the reactor core. The motor has adequate power to continue pump operation even after the above occurrences. Indications of pump malfunction in these conditions are first, by high-temperature signals from the bearing water temperature detector and second, by excessive No. 1 seal leakoff indications. Along with these signals, pump vibration levels are checked. When there are indications of a serious malfunction, the pump is shut down for investigation.

Method of Analysis

The locked rotor transients were analyzed using the Westinghouse advanced 3-D methodology with three computer codes, linked by an external communication interface (Reference 3). The RETRAN code is used to calculate the RCS conditions versus time, including the reactor vessel, RCS loops, pressurizer and steam generators. The RETRAN code also models the reactor trips, engineered safety feature (ESF) functions, and the RCS control functions. The SPNOVA code is used to perform steady-state and transient 3-D core neutronics calculations, using the VIPRE code to calculate the transient local coolant density and fuel effective temperature (Teff) for the core feedback calculations. The VIPRE code is used to calculate the local heat flux to the coolant in the RETRAN core model. The VIPRE code obtains its core inlet conditions (core inlet flow and temperature) and core exit pressure from the RETRAN calculation. Using boundary conditions from the core feedback calculations (SPNOVA/RETRAN/VIPRE linked run), the VIPRE code is also used in separate hot rod calculations to determine the minimum DNBR versus time and peak cladding temperature (PCT).

There were three locked rotor cases analyzed: one to determine the percentage of rods-in-DNB, a second to determine the peak RCS pressure and a third to determine the PCT.

The first case was run to establish the percentage of rods-in-DNB in support of the radiological analysis. One locked rotor and shaft break was assumed with both reactor coolant loops in operation. This case made assumptions designed to maximize the number of rods-in-DNB. Initial core power was assumed to be at its nominal value consistent with steady-state, full-power operation. The reactor coolant system pressure and vessel average temperature were assumed to be at their nominal values. Minimum Measured Flow (MMF) was also assumed. Uncertainties in initial conditions were accounted for in the DNBR limit value as described in the Revised Thermal Design Procedure (RTDP) (Reference 2). The pressure-reducing effects of the PORVs and the automatic pressurizer spray system were modeled in the rods-in-DNB analysis for conservatism.

The second and third cases were performed to evaluate the peak RCS pressure and PCT. As in the rods-in-DNB case, one locked rotor and shaft break was assumed with both reactor coolant loops in operation. These cases made assumptions designed to maximize the RCS pressure and cladding temperature, using the Standard Thermal Design Procedure (STDP). Initial core power, reactor coolant temperature, and pressure include allowances for calibration and instrument errors. Thermal Design Flow (TDF) was also assumed. The pressure-reducing effects of the pressurizer PORVS and automatic pressurizer spray system were not modeled.

The pressure response shown in Figure 14.1.8-3 is the response at the point in the reactor coolant system having the maximum pressure.

Evaluation of the Pressure Transient - The locked rotor peak RCS pressure and PCT calculations were performed at Beginning of Cycle (BOC) Hot Full Power (HFP) conditions. The analyses used minimum moderator temperature feedback and maximum Doppler feedback. The analyses assumed a maximum value of the delayed neutron fraction. The control rods were initially assumed to be at their fully withdrawn position to minimize the initial rate of reactivity insertion following a reactor trip. A conservative rod position vs. time curve was assumed for the reactor trip.

Since the Locked Rotor peak RCS pressure and PCT cases are analyzed using the Standard Thermal Design Procedure (STDP), the analysis was performed using a +0.6% uncertainty in the initial reactor power, a ±6.4°F combined uncertainty and bias in RCS temperature, and a +50 psi uncertainty in pressurizer pressure. The RCS flow rate was set to the Thermal Design Flow (TDF).

No credit is taken for the pressure-limiting effects of the pressurizer PORVs, pressurizer spray, steam dump or controlled feedwater flow after plant trip. Although these operations are expected to occur and would result in a lower peak pressure, an additional degree of conservatism is provided by ignoring their effects.

The lift pressure of the pressurizer safety valves is assumed to be 3.4% above the nominal set pressure of 2500 psia, including +0.9% set pressure shift due to the presence of pressurizer safety valve loop seals (Reference 3). The safety valve steam relief capacity is 288,000 lbm/hr per valve.

The accident was initiated by causing an immediate halt in the rotational speed of one RCP. A loss of offsite power was conservatively assumed to occur at the time of reactor trip (control rod release), causing the unaffected RCP to lose power and coast down freely. Reactor trip occurs on the low flow reactor trip function at 87% flow with a trip delay time of 1.0 second.

A separate VIPRE hot rod calculation to determine the peak cladding temperature is performed assuming that the hot rod is experiencing DNB throughout the flow transient. The initial hot rod power was increased such that the initial hot spot power was at the plant F_Q limit.

Evaluation of Departure from Nucleate Boiling in the Core During the Accident - Since the locked rotor rods-in-DNB evaluation is analyzed using the Revised Thermal Design Procedure (Reference 2), the core feedback calculations were performed using nominal HFP conditions for reactor power, RCS average temperature, and pressurizer pressure. The RCS flow rate was set to the Minimum Measured Flow (MMF). All other RCS initial conditions (pressurizer water volume, steam generator level, etc.) were also set to nominal conditions.

The VIPRE code was used in a separate time-dependent DNBR calculation to determine the number of rods-in-DNB. The DNBR calculation was based on the core average power, power distribution, inlet temperature, core inlet flow, and core exit pressure vs. time. The core average power and power distributions were obtained from the core feedback calculations, including the time-dependent changes in radial enthalpy rise hot channel factor (FDH) and the axial power distributions. The design pin-by-pin radial power distribution, with the peak rod power raised to a value consistent with the limit allowed by the plant Technical Specifications, was used as the initial condition for the DNBR calculations. The reactor coolant conditions (inlet temperature, core inlet flow and core exit pressure vs. time) were obtained from the core feedback calculations.

Film Boiling Coefficient - The film boiling coefficient is calculated in the VIPRE code using the Bishop-Sandberg-Tong film boiling correlation. The fluid properties are evaluated at film temperature, which is the average between the wall and bulk temperatures. The program calculates the film coefficient at every time step, based on the actual heat transfer conditions at the time. The nuclear power, system pressure, bulk density, and mass flow rate as a function of time were based on the core feedback calculations.

Fuel - Cladding Gap Coefficient - The magnitude and the time dependence of the heat transfer coefficient between fuel and cladding (gap coefficient) have a pronounced influence on the thermal results. The larger the value of the gap coefficient, the more heat is transferred between the pellet and the cladding. Based on investigations of the effect of the gap coefficient on the maximum cladding temperature during the transient, the gap coefficient is assumed to increase from a steady-state value consistent with an initial fuel temperature to 10,000 Btu per hour-square foot-°F at the initiation of the transient. Thus, the large amount of energy stored in the fuel because of the small initial value is released to the cladding at the initiation of the transient.

Zirconium-Steam Reaction - The zirconium-steam reaction can become significant above a cladding temperature of 1800 °F. The Baker-Just parabolic rate equation shown below is used to define the rate of the zirconium-steam reaction:

$$\frac{d(w^2)}{dt} = 33.3 \times 10^6 \exp\frac{(-45{,}500)}{1.986T}$$

where:

w	=	amount reacted (mg/cm^2)
t	=	time (seconds)
T	=	temperature (°K).

The reaction heat is 1510 cal/gm.

Results

Figure 14.1.8-3 shows the core flow and loop flow transients, the nuclear power and maximum pressure transients, the average channel heat flux transient, and the cladding temperature transient. The results of these calculations are summarized in Table 14.1.8-2. The sequence of events is shown in Table 14.1.8-1.

Conclusions

Since the peak cladding surface temperature calculated for the hot spot during the more severe transient remains considerably less than the PCT non-LOCA limit of 2700 °F for ZIRLO® and 2375 °F for Optimized ZIRLO™ and the amount of zirconium-water reaction is small, the core remains in place and intact with no consequential loss of core cooling capability.

Since the peak cladding surface temperature calculated for the hot spot during the more severe transient remains considerably less than the PCT non-LOCA limit of 2700 °F and the amount of zirconium-water reaction is small, the core remains in place and intact with no consequential loss of core cooling capability.

Radiological Consequence of the Locked Rotor Accident

An instantaneous seizure of a reactor coolant pump rotor is assumed to occur, which rapidly reduces flow through the affected reactor coolant loop. Fuel clad damage is assumed to occur as a result of the reduced flow. Due to the pressure differential between primary and secondary systems, and assumed steam generator tube leaks, fission products are discharged from the primary into the secondary system. A portion of this radioactivity is released to the outside atmosphere through either the atmospheric dump valves or main steam safety valves. In addition, it is postulated that some of the activity contained in the secondary coolant prior to the accident is released to atmosphere as a result of steaming of the steam generators following the accident.

This section describes the assumptions and analyses performed to determine the amount of radioactivity released and the offsite and control room doses resulting from the release. The specific analyses conducted for the PBNP dose consequences were accepted by the NRC (Reference 6).

Input Parameters and Assumptions

The analysis of the locked rotor radiological consequences uses the analytical methods and assumptions outlined in the RG 1.183 (Reference 4).

It is conservatively assumed that 30% of the fuel rods in the core suffer damage as a result of the locked rotor sufficient that all of their gap activity is released to the reactor coolant system. The fuel clad gap activity fractions from Table 3 of RG 1.183 are applied in the analysis. The damaged rods are high power first or second cycle rods which meet the burnup criteria of RG 1.183, Table 3, Footnote 11. The activity released from the damaged fuel reflects a radial peaking factor of 1.7.

The concentrations of iodines and noble gasses in the RCS at time the accident occurs are based on the Technical Specification limits of 0.5 μCi/gm of dose equivalent (DE) 1-131 and 520 μCi/gm of DE Xe-133. The DE Xe-133 value is a pre-EPU limit, and is conservative. The alkali metal concentration in the RCS is based on the fuel defect level that corresponds to 0.5 μCi/gm of DE 1-131. The iodine activity concentration of the secondary coolant at the time the accident occurs is assumed to be equivalent to the Technical Specification limit of 0.1 μCi/gm of DE 1-131. The alkali metal activity concentration of the secondary coolant at the time the accident occurs is assumed to correspond to 0.1 μCi/gm of DE 1-131. The core activity and equilibrium nuclide concentrations are presented in Table 14.1.8-4.

An accident-induced primary-to-secondary leak rate of 1000 gm/min per SG is assumed for the duration of the accident.

An iodine partition factor in the SGs of 0.01 (curies iodine/gm steam) / (curies iodine/gm water) is used. Per RG 1.183, the retention of particulates in the SG is limited by moisture carry over which is modeled by a retention factor of 0.0025. This is the estimated full power moisture carryover fraction. All noble gas activity transferred to the secondary side of the SG through SG tube leakage is assumed to be directly released to the outside atmosphere. Plant cooldown to RHR operating conditions can be accomplished within 14 hours after initiation of the event. At 30 hours after the accident the RHR system is assumed to be placed into service, after which there is no further steam release to the atmosphere from the secondary system.

The specific assumptions applied to PBNP are summarized in Table 14.1.8-3, Table 14.1.8-4 and Table 14.1.8-5. The dose conversion factors, breathing rates, and atmospheric dispersion factors used in the dose calculations are given in Table 14.1.8-3. The core and coolant activities used in the radiological calculations are given in Table 14.1.8-4. The remaining major assumptions and parameters used specifically in the locked rotor analysis are itemized in Table 14.1.8-5.

Control Room Model

For the locked rotor accident it is assumed that the HVAC system begins in Mode 1 (normal operating Mode). The dose rates in the control room trip the control room monitors within 1 minute, switching the system to Mode 5 (emergency Mode) where it remains throughout the event. The parameters associated with the control room HVAC Modes assumed for the locked rotor accident are summarized in Table 14.1.8-6. FSAR 9.8 provides a complete description of the control room HVAC system.

Acceptance Criteria

The Standard Review Plan (SRP) 15.0.1 (Reference 5) offsite dose acceptance criterion for a locked rotor is 2.5 rem TEDE, which is 10% of the 10 CFR 50.67 limit of 25 rem TEDE. The control room personnel dose acceptance criterion is 5 rem TEDE per 10 CFR 50.67.

Results/Conclusions

The results of the offsite and control room dose analyses are provided in Table 14.1.8-2, and indicate that the acceptance criteria are met. The exclusion area boundary doses reported are for the worst 2 hour period, determined to be from 28 to 30 hours.

REFERENCES

1. Goldberg, G., Westinghouse Electric Corporation, letter to E. J. Lipke, "Wisconsin Electric Power Company Point Beach Units 1 and 2 Final Reports for RCP Bus Frequency Decay Analysis," WEP-91-196, August 19, 1991.

2. Friedland, A. J., Ray, S., "Revised Thermal Design Procedure," WCAP-11397-P-A (Proprietary), WCAP-11397-A (Non-Proprietary), April 1989.

3. Beard, L.C., et al., "Westinghouse Methodology for Application of 3-D Transient Neutronics to Non-LOCA Accident Analysis," WCAP-16259-P-A (Proprietary) and WCAP-16259-NP-A (Non-Proprietary), August 2006.

4. USNRC, Regulatory Guide 1.183, "Alternative Radiological Source Terms for Evaluating Design Basis Accidents at Nuclear Power Reactors," July 2000.

5. US NRC, NUREG 0800, Standard Review Plan (SRP) Section 15.0.1, "Radiological Consequence Analyses Using Alternative Source Terms," July 2000.

6. NRC Safety Evaluation 2011-0003, "Issuance of License Amendments Regarding Use of Alternate Source Term," April 14, 2011.

7. NRC Safety Evaluation 2011-0004, "Issuance of License Amendments Regarding Extended Power Uprate," dated May 3, 2011.

Table 14.1.8-1 LOSS OF FORCED REACTOR COOLANT FLOW TIME SEQUENCE OF EVENTS

Case	Event	Time (Seconds)
Complete Loss of Forced Reactor Coolant Flow	Transient begins	0.00
	Both operating RCPs lose power and begin coasting down	1.00
	RCP undervoltage trip setpoint reached	1.00
	Low flow reactor trip setpoint reached	2.93
	Rods begin to drop	3.93
	Minimum DNBR occurs	4.60
Underfrequency Event	Transient begins	0.00
	Frequency decay begins and RCPs begin to decelerate	1.00
	Low RCS flow reactor trip setpoint reached	2.76
	Rods begin to drop	3.76
	Minimum DNBR occurs	4.55
Locked RCP Rotor	Transient begins	0.00
	Rotor on one RCP locks	1.00
	Low RCS flow reactor trip setpoint reached	1.1
	Rods begin to drop	2.1
	Remaining pump loses power and begins to coast down	2.1
	Maximum cladding temperature occurs	4.5
	Maximum RCS pressure occurs	5.1

Table 14.1.8-2 SUMMARY OF LIMITING RESULTS FOR LOCKED ROTOR ACCIDENT

Reactor Plant Results	
Maximum Reactor Coolant System Pressure	2653 psia
Maximum Cladding Temperature at Core Hot Spot	1810°F
Zr-H_2O Reaction at Core Hot Spot	0.4% by weight
Rods in DNB	25%
Radiological Results	
Site Boundary (28 - 30 hr)	2.0 rem TEDE
Low Population Zone (0 - 30 hr)	0.5 rem TEDE
Control Room	4.6 rem TEDE

Table 14.1.8-3 ASSUMPTIONS USED FOR DOSE ANALYSES

RCP LOCKED ROTOR ACCIDENT (14.1.8)
STEAM GENERATOR TUBE RUPTURE ACCIDENT (14.2.4)
MAIN STEAM LINE BREAK ACCIDENT (14.2.5)
CONTROL ROD EJECTION ACCIDENT (14.2.6)

DOSE CONVERSION FACTORS, BREATHING RATES, ATMOSPHERIC DISPERSION FACTORS

Isotope	Committed Effective Dose Equivalent (Sv/Bq)	Effective Dose Equivalent (Sv-m3/Bq-sec)
I-130	7.14E-10	1.04E-13
I-131	8.89E-9	1.82E-14
I-132	1.03E-10	1.12E-13
I-133	1.58E-9	2.94E-14
I-134	3.55E-11	1.30E-13
I-135	3.32E-10	7.98E-14
Kr-85m	NA	7.48E-15
Kr-85	NA	1.19E-16
Kr-87	NA	4.12E-14
Kr-88	NA	1.02E-13
Xe-131m	NA	3.89E-16
Xe-133m	NA	1.37E-15
Xe-133	NA	1.56E-15
Xe-135m	NA	2.04E-14
Xe-135	NA	1.19E-14
Xe-138	NA	5.77E-14
Cs-134	1.25E-8	7.57E-14
Cs-136	1.98E-9	1.06E-13
Cs-137	8.63E-9	2.88E-14
Cs-138	2.74E-11	1.21E-13
Rb-86	1.79E-9	4.81E-15

Time Period	Breathing Rate (m^3 / second)
0 - 8 hr	3.5E-4*
8 - 24 hr	1.8E-4
24 - 720 hr	2.3E-4

Location	Atmospheric Dispersion Factors (second / m^3)
Site Boundary	5.0E-4*
Low Population Zone	
0 - 8 hr	3.0 E-5
8 - 24 hr	1.6 E-5
24 - 96 hr	4.2 E-6
96 -720 hr	8.6 E-7

* The breathing rate and site boundary atmospheric dispersion factor are held constant at the initial value for all time intervals in the determination of the limiting 2-hour period for the site boundary.

Table 14.1.8-4 ASSUMPTIONS USED FOR DOSE ANALYSES

RCP LOCKED ROTOR ACCIDENT (14.1.8)
STEAM GENERATOR TUBE RUPTURE ACCIDENT (14.2.4)
MAIN STEAM LINE BREAK ACCIDENT (14.2.5)
CONTROL ROD EJECTION ACCIDENT (14.2.6)

CORE AND COOLANT ACTIVITIES

Isotope	Total Core Activity at Shutdown (Ci)	Coolant Activity (µCi/gm)*
I-130	1.05E+06	2.89E-03
I-131	5.10E+07	3.77E-01
I-132	7.47E+07	4.24E-01
I-133	1.06E+08	6.55E-01
I-134	1.19E+08	9.97E-02
I-135	1.01E+08	3.76E-01
Kr-85m	1.36E+07	1.58E+00
Kr-85	6.15E+05	7.63E+00
Kr-87	2.68E+07	1.05E+00
Kr-88	3.60E+07	2.92E+00
Xe-131m	5.55E+05	2.35E+00
Xe-133m	3.21E+06	3.80E+00
Xe-133	1.02E+08	2.12E+02
Xe-135m	2.20E+07	4.33E-01
Xe-135	2.17E+07	6.72E+00
Xe-138	9.05E+07	5.77E-01
Cs-134	9.52E+06	3.29E-01
Cs-136	2.14E+06	3.44E-01
Cs-137	6.27E+06	2.79E-01
Cs-138	9.89E+07	1.62E-01
Rb-86	9.95E+04	3.64E-03

* Iodine activity corresponds to 0.5 µCi/gm dose equivalent (DE) I-131, noble gas activity is based on 520 µCi/gm DE Xe-133 and alkali metal activity is based on the fuel defect level that corresponds to 0.5 µCi/gm DE I-131. Values for other assumed DEs are multiples of these values.

Table 14.1.8-5 ASSUMPTIONS USED FOR DOSE ANALYSES
(Page 1 of 2)
RCP LOCKED ROTOR ACCIDENT

PARAMETER	VALUE
Initial Power	1811 MWt
Fraction of Fuel Rods in Core Assumed to Fail for Dose Considerations	30% of Core
Gap Fractions	
I-131	0.08
Kr-85	0.10
Other Iodines and Noble Gases	0.05
Alkali Metals	0.12
Radial Peaking Factor	1.7
RCS Activity Prior to Accident	
Iodine	0.5µCi/gm of DE I-131
Noble Gas	520 µCi/gm of DE Xe-133
Alkali Metals	Corresponds to 0.5 µCi/gm of DE I-131
Secondary Coolant Activity Prior to Accident	
Iodine	0.1 µCi/gm of DE I-131
Alkali Metals	Corresponds to 0.1 µCi/gm of DE I-131
Total SG Tube Leak Rate During Accident	2000 gm/min
Steam Release to Environment	See page 2
SG Iodine Partition Factor	0.01
SG Alkali Metal Retention Factor	0.0025
Iodine Species Released to the Atmosphere	
Elemental	97%
Organic	3%
RCS Mass	1.06E8 gm
Secondary Side Mass	
0-2 hours	5.98E7 gm
> 2 hours	7.37E7 gm

Table 14.1.8-5 ASSUMPTIONS USED FOR DOSE ANALYSES
(Page 2 of 2)

LOCKED ROTOR DOSE ANALYSIS STEAM RELEASE TO ENVIRONMENT

Hours	Mass (lbm)	Hours	Mass (lbm)
0-2	213,295	16-17	37,245
2-3	75,645	17-18	36,821
3-4	70,441	18-19	36,116
4-5	65,672	19-20	35,461
5-6	63,060	20-21	34,969
6-7	60,838	21-22	34,969
7-8	58,305	22-23	34,109
8-9	57,015	23-24	33,595
9-10	55,886	24-25	33,595
10-11	54,629	25-26	33,595
11-12	53,326	26-27	33,595
12-13	52,514	27-28	33,595
13-14	51,714	28-29	33,595
14-15	38,508	29-30	33,595
15-16	37,749		

Table 14.1.8-6 CONTROL ROOM PARAMETERS USED FOR DOSE ANALYSES

RCP LOCKED ROTOR ACCIDENT (14.1.8)
STEAM GENERATOR TUBE RUPTURE (14.2.4)
MAIN STEAM LINE BREAK ACCIDENT (14.2.5)
CONTROL ROD EJECTION ACCIDENT (14.2.6)

Volume	65,243 ft^3
Control Room Unfiltered In-Leakage	200 cfm[(1)]
Normal Ventilation Flow Rates (Mode 1)	
Filtered Makeup Flow Rate	0 cfm
Filtered Recirculation Flow Rate	0 cfm
Unfiltered Makeup Flow Rate	2000 cfm
Emergency Mode Flow Rates (Mode 5)	
Filtered Makeup Flow Rate	2500 cfm
Filtered Recirculation FLow Rate	1955 cfm
Unfiltered Makeup Flow Rate	0 cfm
Filter Efficiencies	
Elemental Iodine	95%
Organic (Methyl) Iodine	95%
Particulate	99%
Delay to Switch CR HVAC from Normal Operation to Post Accident Operation after receiving an isolation signal (sec)	60 seconds
Breathing Rate - Duration of the Event	3.5E-04 m^3/second
Atmospheric Dispersion Factors	(second/m^3)
Steam Generator Safety Valves [(2)]	
0-2 hr	4.66E-3
2-8 hr	3.40E-3
8-24 hr	1.17E-3
24-96 hr	1.07E-3
96-720 hr	9.05E-4
Facade [(3)]	
0-2 hr	1.87E-2
2-8 hr	1.50E-2
8-24 hr	5.11E-3
24-96 hr	4.94E-3
96-720 hr	4.23E-3
Containment Surface [(4)]	
0-2 hr	1.39E-3
2-8 hr	9.80E-4
8-24 hr	3.84E-4
24-96 hr	3.46E-4
96-720 hr	3.02E-4
Occupancy Factors	
0-24 hours	1.0
1-4 days	0.6
4-30 days	0.4

Notes:
(1) some analyses modeled a bounding flow rate of 300 cfm
(2) used secondary releases except for steam line break faulted steam generator releases
(3) used for steam line break faulted steam generator releases
(4) used for control rod ejection containment leakage releases

Figure 14.1.8-1 UNDERFREQUENCY EVENT (5 Hz/sec FREQUENCY DECAY RATE)
Sheet 1 of 3

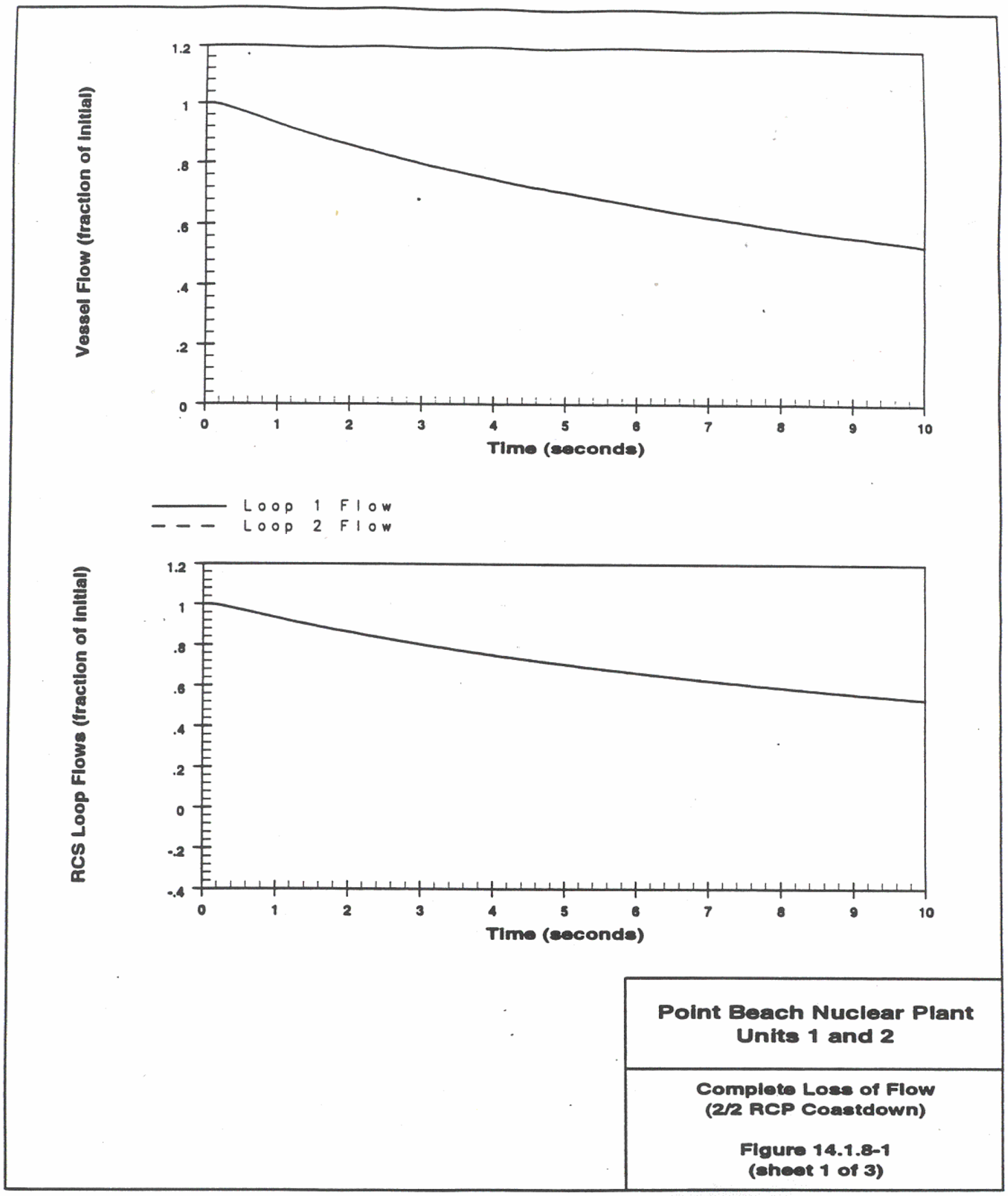
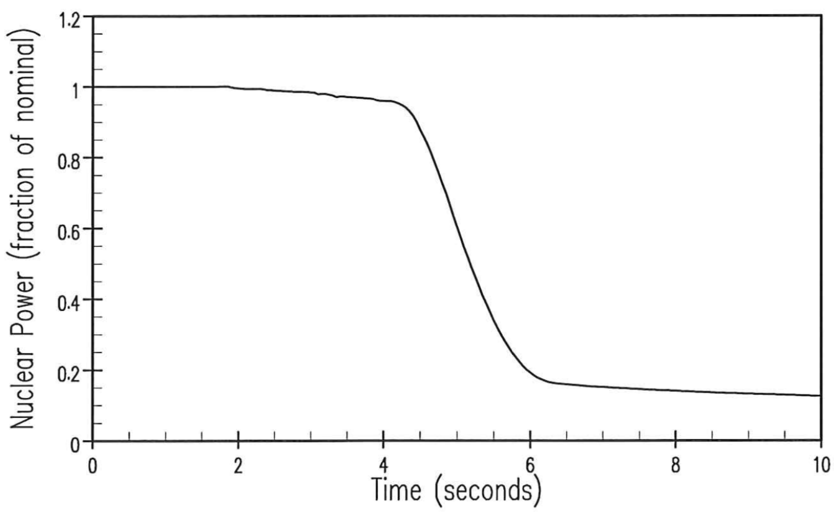


Figure 14.1.8-1 UNDERFREQUENCY EVENT (5 Hz/sec FREQUENCY DECAY RATE)
Sheet 2 of 3



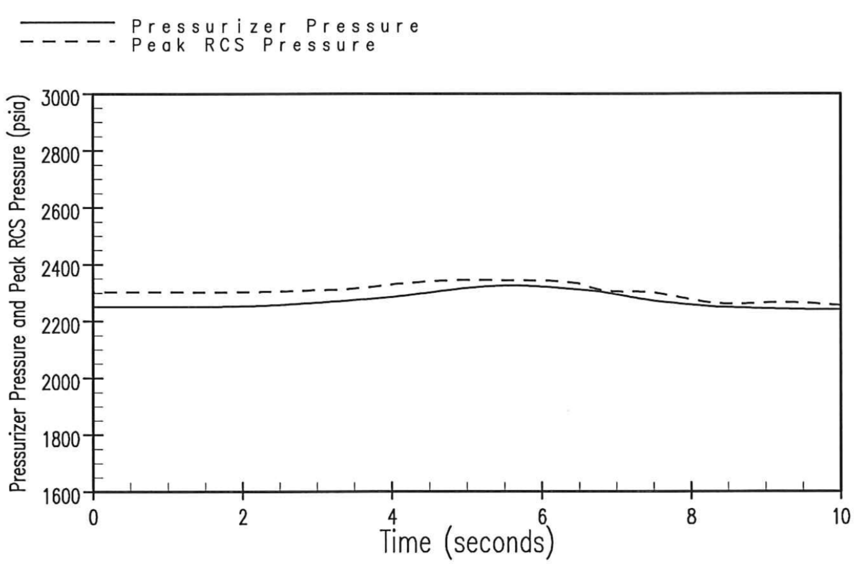
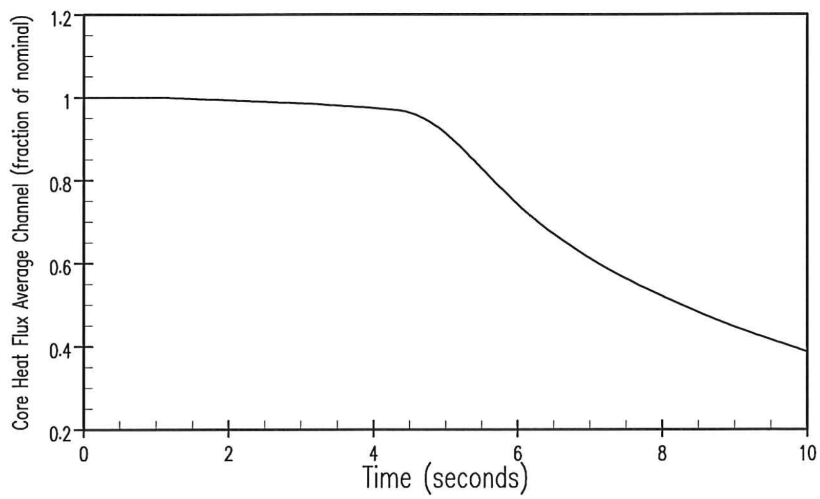


Figure 14.1.8-1 UNDERFREQUENCY EVENT (5 Hz/sec FREQUENCY DECAY RATE)
Sheet 3 of 3



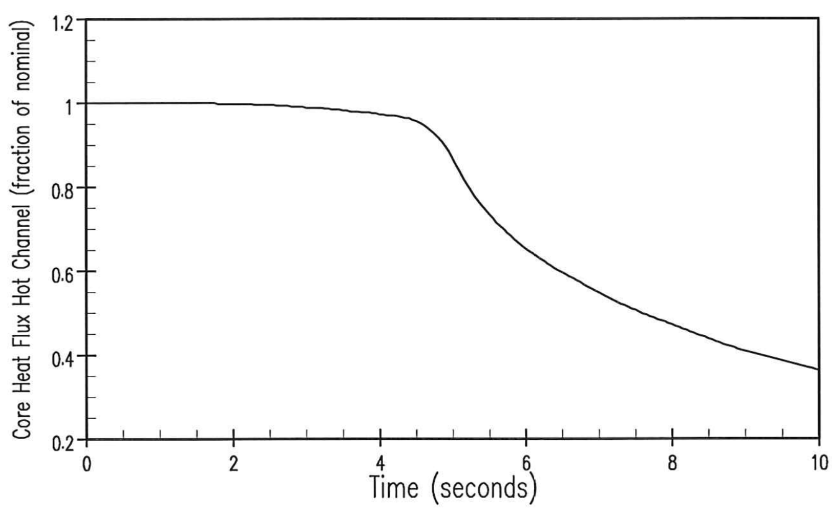
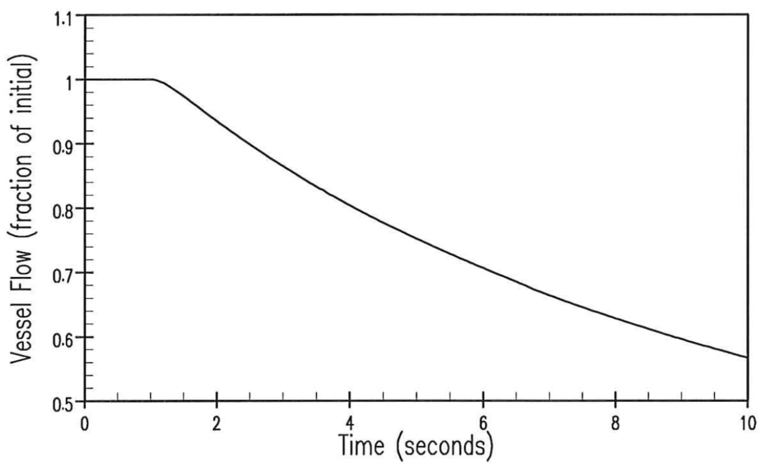


Figure 14.1.8-2 COMPLETE LOSS OF FLOW (2/2 RCP COASTDOWN)
Sheet 1 of 3



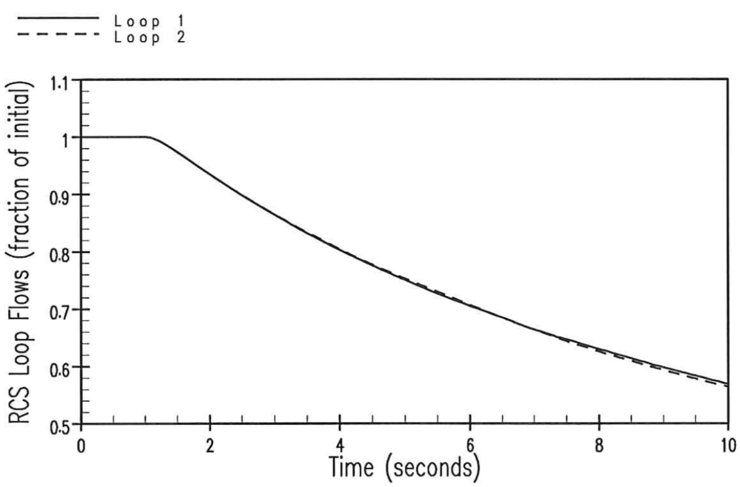
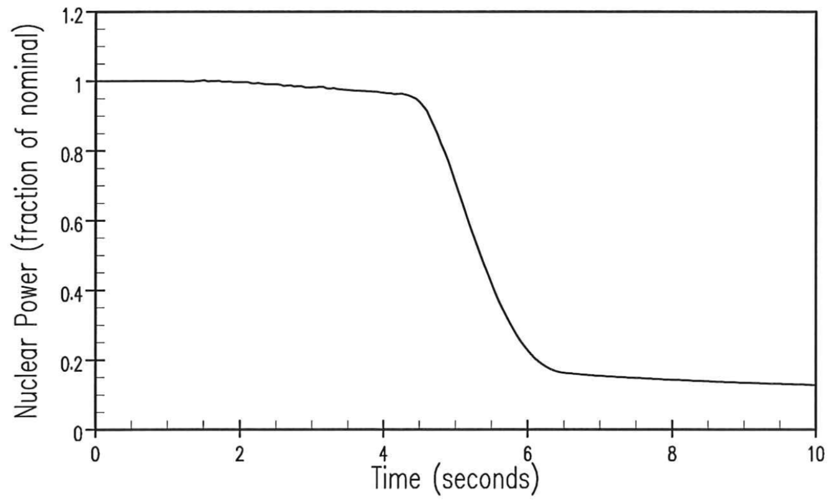


Figure 14.1.8-2 COMPLETE LOSS OF FLOW (2/2 RCP COASTDOWN)
Sheet 2 of 3



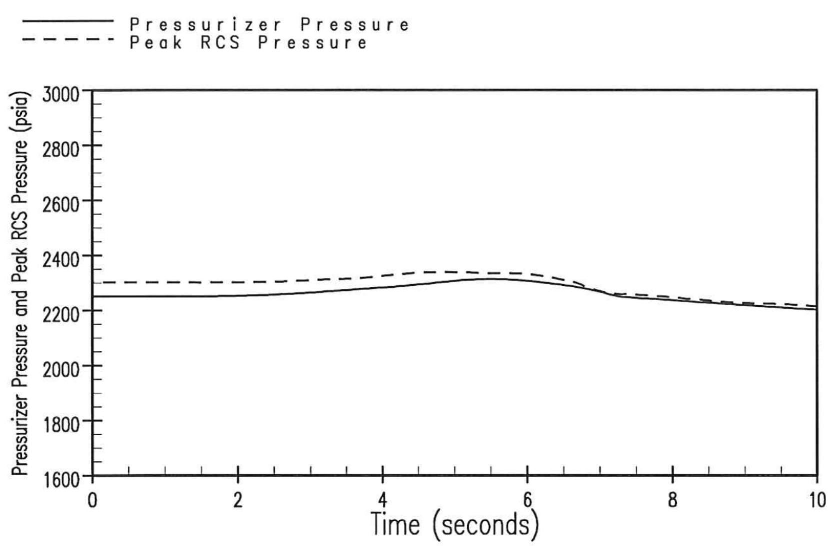
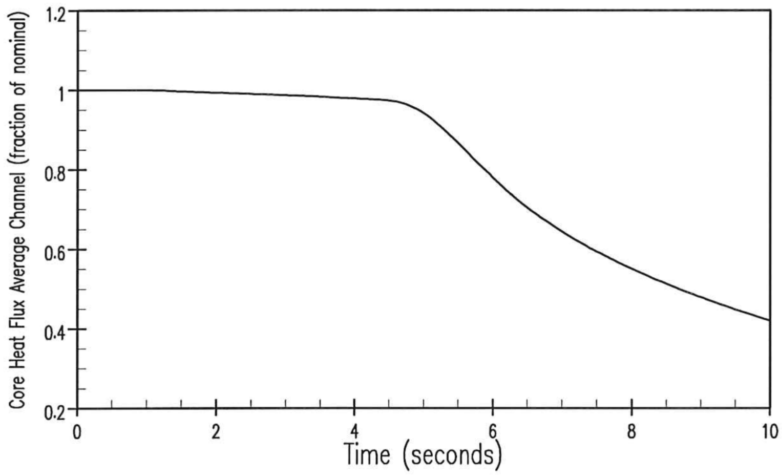


Figure 14.1.8-2 COMPLETE LOSS OF FLOW (2/2 RCP COASTDOWN)
Sheet 3 of 3



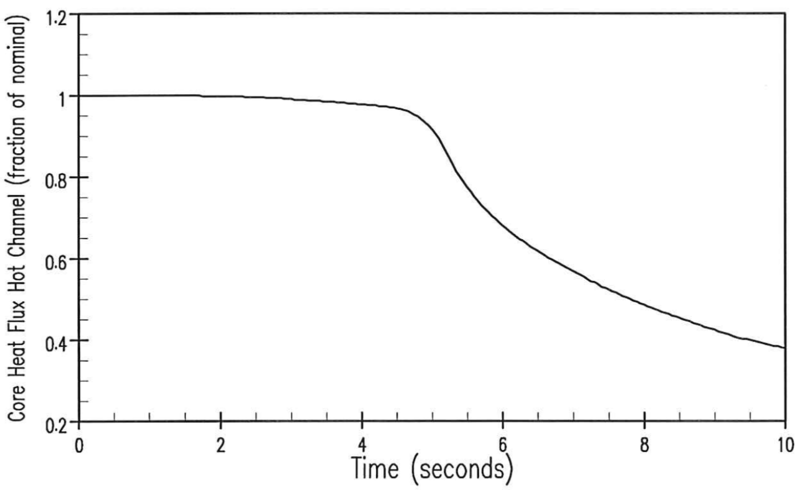
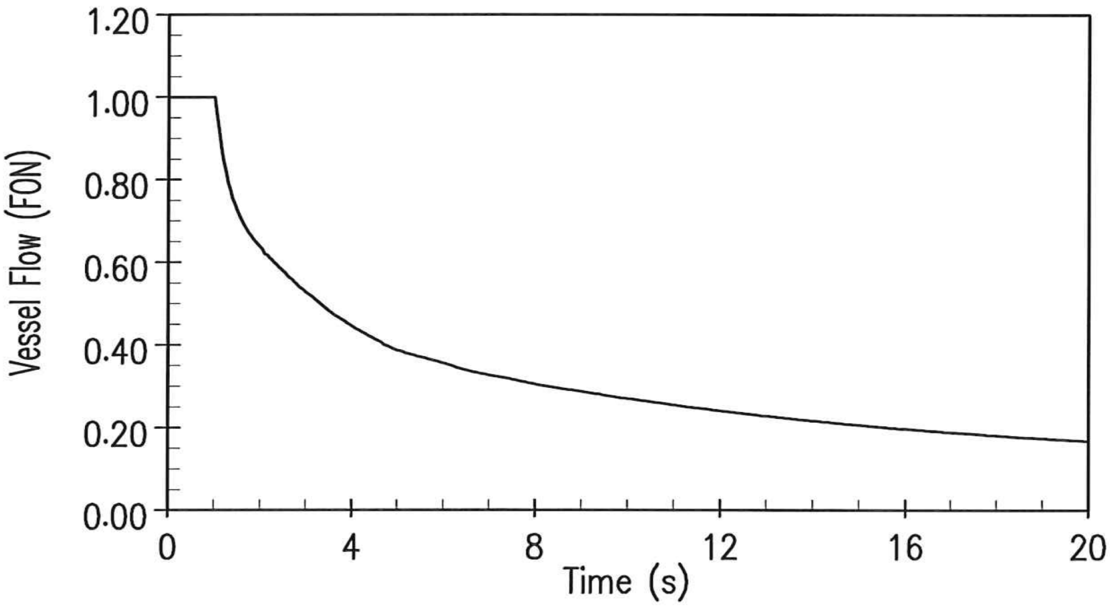


Figure 14.1.8-3 RCP LOCKED ROTOR

Sheet 1 of 3



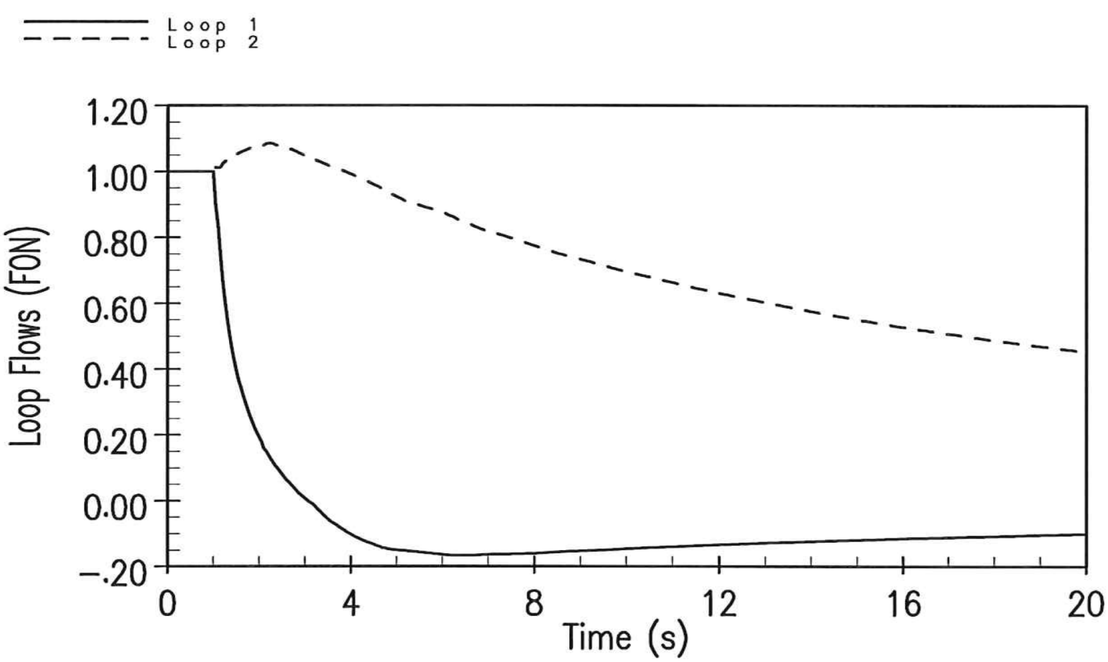
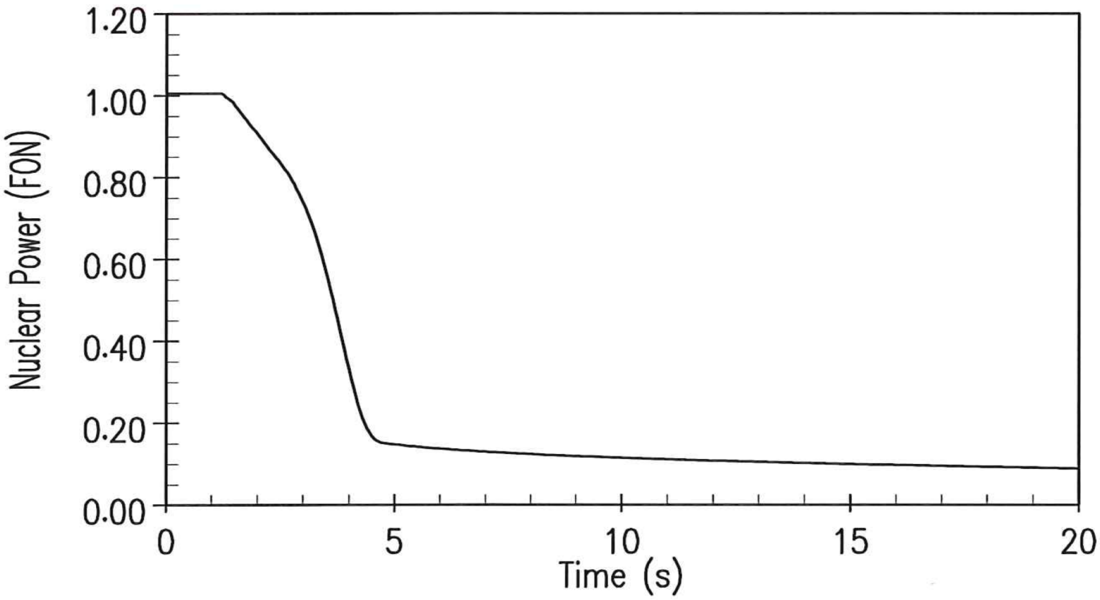


Figure 14.1.8-3 RCP LOCKED ROTOR

Sheet 2 of 3



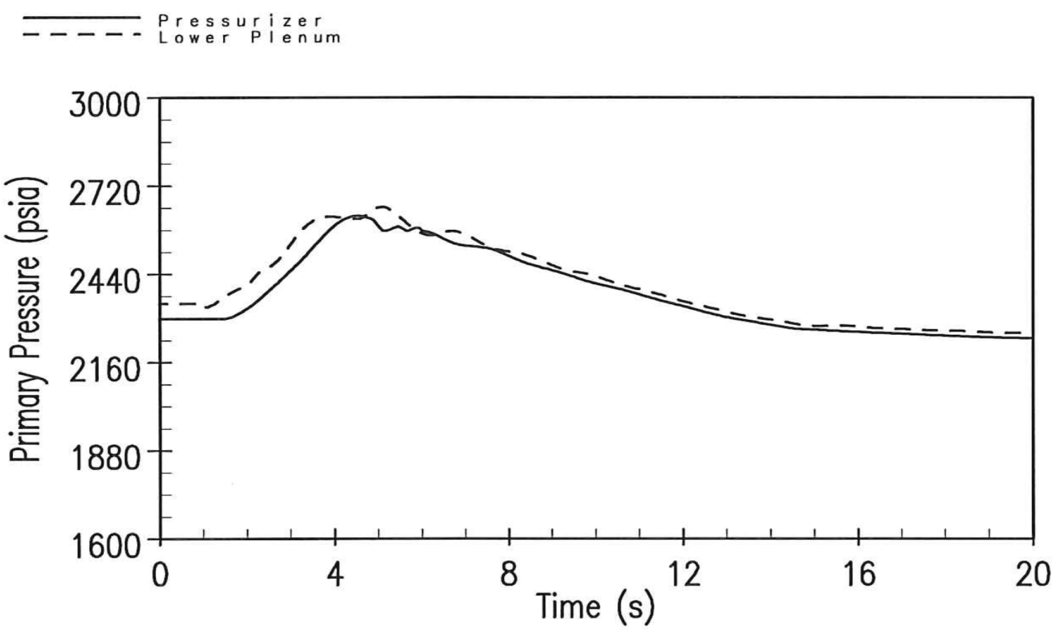
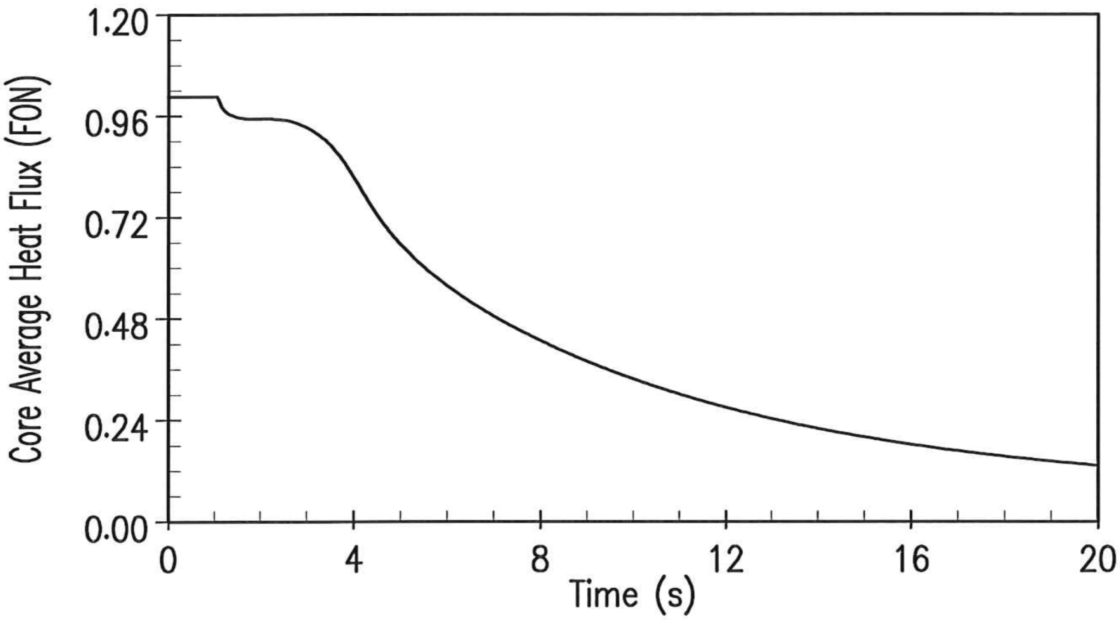
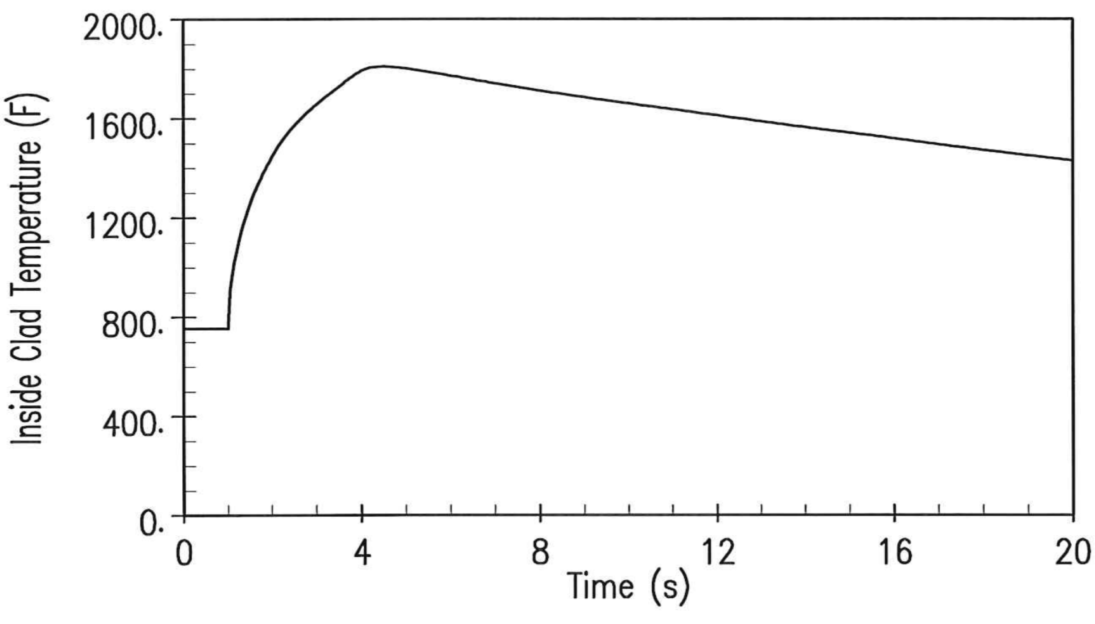


Figure 14.1.8-3 RCP LOCKED ROTOR

Sheet 3 of 3





14.1.9 LOSS OF EXTERNAL ELECTRICAL LOAD (EPU Conditions)

The plant is able to accept a 50% loss of electrical load over 15 seconds while operating at full power or a complete loss of load while operating below the P-9 setpoint without actuating a reactor trip. The automatic steam bypass system (Section 10.1) is able to accommodate this load rejection by reducing the transient imposed upon the reactor coolant system. The reactor power is reduced to the new equilibrium power level at a rate consistent with the capability of the rod control system. Should the reactor suffer a complete loss of load from full power, the reactor protection system would automatically actuate a reactor trip.

The most likely source of a complete loss of load on the nuclear steam supply system is a trip of the turbine-generator. In this case, there is a direct reactor trip signal derived from either the turbine autostop oil pressure or a closure of the turbine stop valves, provided the reactor is operating above the P-9 interlock setpoint. Reactor temperature and pressure do not increase significantly if the steam bypass system and pressurizer pressure control system are functioning properly. However, the plant behavior is evaluated for a complete loss of load from full power without a direct reactor trip, primarily to show the adequacy of the pressure relieving devices and also to show that no core damage occurs. The reactor coolant system and steam system pressure relieving capacities are designed to ensure the safety of the plant without requiring the automatic rod control, pressurizer pressure control, and/or steam bypass control systems.

Method of Analysis

The total loss of load transients are analyzed by employing the detailed digital computer program RETRAN (Reference 2). The program simulates the neutron kinetics, reactor coolant system, pressurizer, pressurizer relief and safety valves, pressurizer spray, steam generator, and steam generator safety valves.

The program computes pertinent plant variables, including temperatures, pressures, and power level.

In this analysis, the behavior of the unit is evaluated for a complete loss of steam load from full power without direct reactor trip, primarily to show the adequacy of the pressure-relieving devices and also to demonstrate core protection margins.

Plant characteristics and initial conditions are discussed in Section 14.0.

Initial Operating Conditions - The initial core power, reactor coolant temperature, and reactor coolant pressure are assumed at the most limiting nominal values. The DNBR calculations are performed using the Revised Thermal Design Procedure (Reference 1), in which the uncertainties in the initial conditions are included in the DNBR limit value. For the peak RCS and SG pressure calculations, uncertainties of 0.6%, 50 psi, and 6.4°F are applied in the most limiting direction to the initial core power, reactor coolant pressure, and reactor coolant temperature.

Moderator and Doppler Coefficients of Reactivity - The loss of load accident is analyzed with minimum reactivity feedback. These cases assume a moderator temperature coefficient of 0 pcm/°F and the least negative Doppler coefficient.

The loss of load event results in a primary system heatup and therefore is conservatively analyzed with minimum reactivity feedback. Maximum feedback cases are no longer analyzed since they are non-limiting with respect to DNB and peak RCS and steam generator pressure.

Reactor Control - From the standpoint of the maximum pressures attained, it is conservative to assume that the reactor is in manual control.

Steam Release - No credit is taken for the operation of the steam dump system or steam generator power-operated relief valves. The steam generator pressure rises to the safety valve setpoint, where steam release through safety valves limits secondary steam pressure at the setpoint value. Main Steam Safety Valve performance is described in Table 14.1.9-2.

Pressurizer Spray and Power-Operated Relief Valves - Three cases are analyzed:

a. For the DNB case, full credit is taken for the effect of pressurizer spray and power-operated relief valves in reducing or limiting the coolant pressure. Maximum steam generator tube plugging (10%) is assumed.

b. For the RCS overpressure case, no credit is taken for the effect of pressurizer spray and power-operated relief valves in reducing or limiting the coolant pressure. Safety valves are operable. Maximum steam generator tube plugging (10%) is assumed.

c. For SG overpressure case, full credit is taken for the effect of pressurizer spray and power-operated relief valves in reducing or limiting the primary coolant pressure, thereby delaying the time to reactor trip. Minimum steam generator tube plugging (0%) is assumed.

Feedwater Flow - Main feedwater flow to the steam generators is assumed to be lost at the time of loss of external electrical load. Reactor trip is actuated by the first reactor protection system trip setpoint reached, with no credit taken for the direct reactor trip on turbine trip.

Results

The transient responses for a total loss of load from full power operation are shown for three cases for minimum reactivity feedback illustrated in Figure 14.1.9-1 through Figure 14.1.9-3.

Figure 14.1.9-1 shows the transient response for the total loss of steam load (DNB case) with minimum reactivity feedback, maximum steam generator tube plugging (10%), and assuming full credit for the pressurizer spray and pressurizer power-operated relief valves. No credit is taken for the steam dump. The reactor is tripped by the high pressurizer pressure signal. The minimum departure from nucleate boiling ratio is well above the limit value. The pressurizer safety valves are actuated at a conservatively low setpoint.

Figure 14.1.9-2 shows the total loss of load accident (RCS overpressure case), assuming the plant to be initially operating at full power with maximum steam generator tube plugging (10%), and no credit taken for the pressurizer spray, pressurizer power-operated relief valves, or steam dump. The reactor is tripped on the high pressurizer pressure signal. In this case, the pressurizer safety valves are actuated. The peak RCS pressure of 2739.6 psia for Unit 1 and 2741.9 psia for Unit 2 occurs in the reactor vessel lower plenum.

Figure 14.1.9-3 shows the total loss of load accident (SG overpressure case), assuming the plant to be initially operating at full power with minimum steam generator tube plugging (0%), and assuming full credit for the pressurizer spray and pressurizer power-operated relief valves. No credit is taken for the steam dump. The reactor is tripped on the Overtemperature ΔT signal. The pressurizer safety valves are modeled with a conservatively low setpoint, but do not actuate.

The calculated sequence of events for these three cases is shown in Table 14.1.9-1.

Conclusions

Results of the analyses show that the plant design is such that a total loss of external electrical load without a direct or immediate reactor trip presents no hazard to the integrity of the reactor coolant system or the main steam system. Pressure-relieving devices incorporated in the two systems are adequate to limit the maximum pressures within the design limits.

The integrity of the core is maintained by operation of the reactor protection system; i.e., the departure from nucleate boiling ratio is maintained above the limit value.

References

1. Friedland, A. J., Ray S., "Revised Thermal Design Procedure," WCAP- 11397-P-A (Proprietary), WCAP-11397-A (Non-Proprietary), April 1989.

2. Huegel, D. S., et. al., "RETRAN-02 Modeling and Qualification for Westinghouse Pressurized Water Reactor Non-LOCA Safety Analyses," WCAP-14882-P-A (Proprietary), WCAP-15234-A (Non-Proprietary), April 1999.

3. Deleted.

4. Deleted.

5. Deleted.

Table 14.1.9-1 TIME SEQUENCE OF EVENTS FOR LOSS OF EXTERNAL ELECTRICAL LOAD

Case	Event	Time of Each Event (Seconds) Unit 1	Unit 2
a. With pressurizer control (DNB case)	Loss of electrical load	0	0
	Initiation of release from SG safety valves	10.2	9.6
	High pressurizer pressure reactor trip reached	11.7	11.4
	Rod begins to drop	12.7	12.4
	Minimum departure from nucleate boiling ratio occurs	14.1	13.7
b. Without pressurizer control (RCS overpressure case)	Loss of electrical load	0	0
	High pressurizer pressure reactor trip point reached	6.0	5.9
	Rods begin to drop	7.0	6.9
	Peak RCS pressure occurs	9.2	9.0
	Initiation of release from SG safety valves	10.6	8.3
c. With pressurizer control (SG overpressure case)	Loss of electrical load	0	0
	Initiation of release from SG safety valves	6.5	5.8
	Overtemperature ΔT reactor trip signal initiated	12.3	12.4
	Rods begin to drop	14.3	14.4
	Peak SG pressure occurs	18.3	18.0

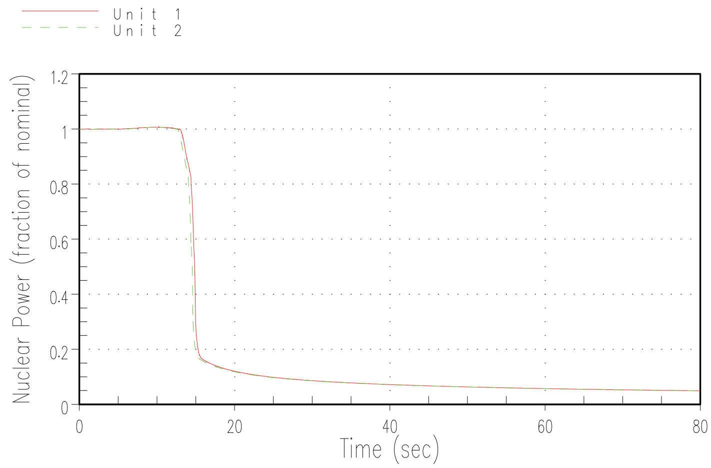
Table 14.1.9-2 MSSV CHARACTERISTICS

Parameter	Bank 1	Bank 2	Bank 3	Bank 4
Nominal set pressure (psig)	1085	1100	1105	1105
Lift pressure (psia)	1166.4	1181.9	1187.0	1187.0
Full-open pressure (psia)	1171.4	1186.9	1192.0	1192.0

Table 14.1.9-2 Notes

1. The lift pressure is the nominal set pressure, plus 3% allowance for setpoint tolerance (3% of the nominal set pressure), plus the appropriate allowance for the frictional pressure drop between the main steamline and the valve at full MSSV relief conditions, plus atmospheric pressure (14.7 psi).
2. The full-open pressure is the lift pressure, plus 5 psia for valve accumulation.
3. The MSSV relief rate, which is based on a Moody choked flow model for saturated steam discharge versus steam pressure, is assumed to be a linear function of the pressure between the lift pressure and the full-open pressure.
4. The values listed above for the lift pressure and full-open pressure reflect the main steamline pressure. However, since the safety valves are actually located downstream of the SG, the pressure at the valve is only the same as that in the main steamline when the first safety valve opens. Once relief flow is established, a frictional pressure drop will exist between the main steamline and the valves (assumed to be 34.2 psi at full relief flow) and the steam pressure at the safety valve will actually be less than the values listed above. Thus, the appropriate allowance for the frictional pressure drop has been conservatively included in the values listed above for the lift pressure and full-open pressure.

Figure 14.1.9-1 LOSS OF ELECTRICAL LOAD WITH PRESSURE CONTROL (DNB Case)
Sheet 1 of 3



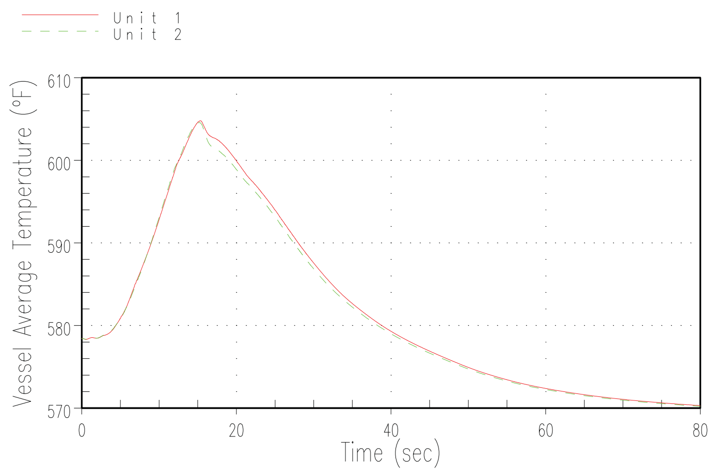
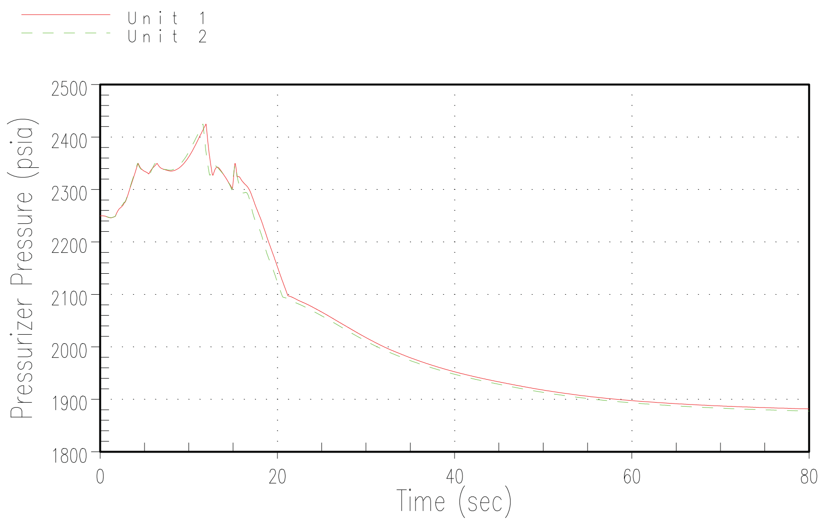


Figure 14.1.9-1 LOSS OF ELECTRICAL LOAD WITH PRESSURE CONTROL (DNB Case)
Sheet 2 of 3



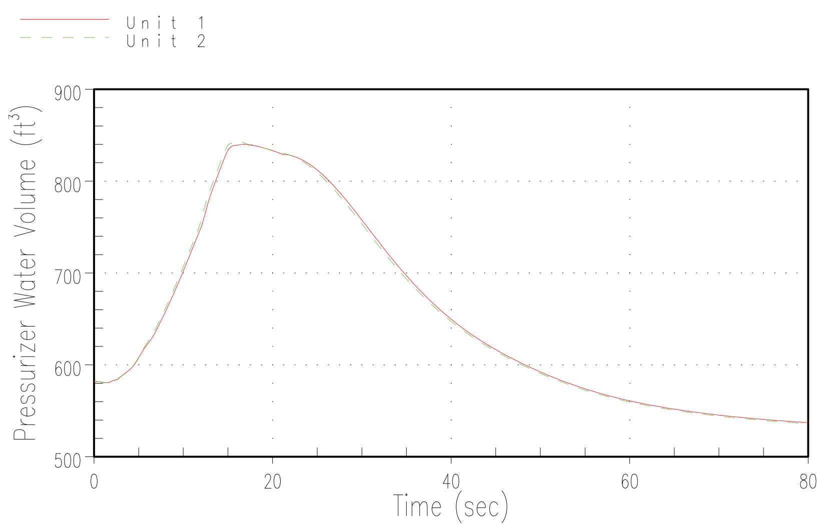
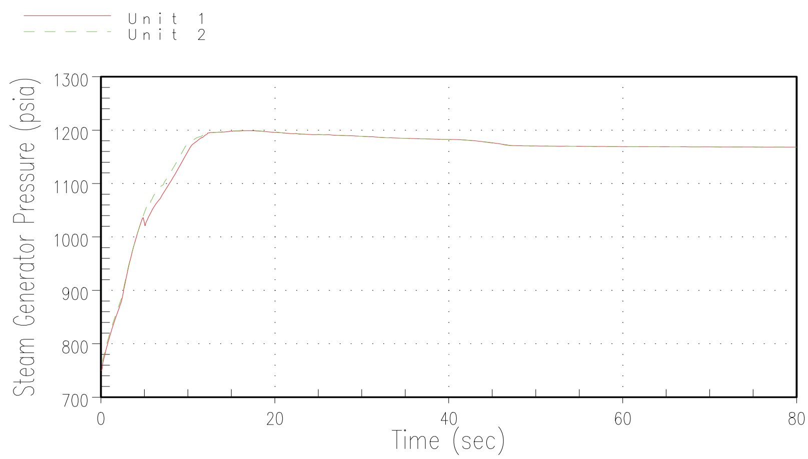


Figure 14.1.9-1 LOSS OF ELECTRICAL LOAD WITH PRESSURE CONTROL (DNB Case)
Sheet 3 of 3



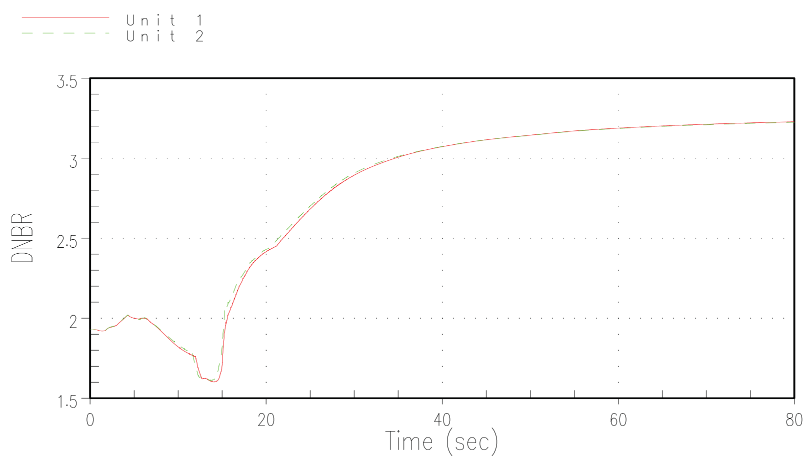
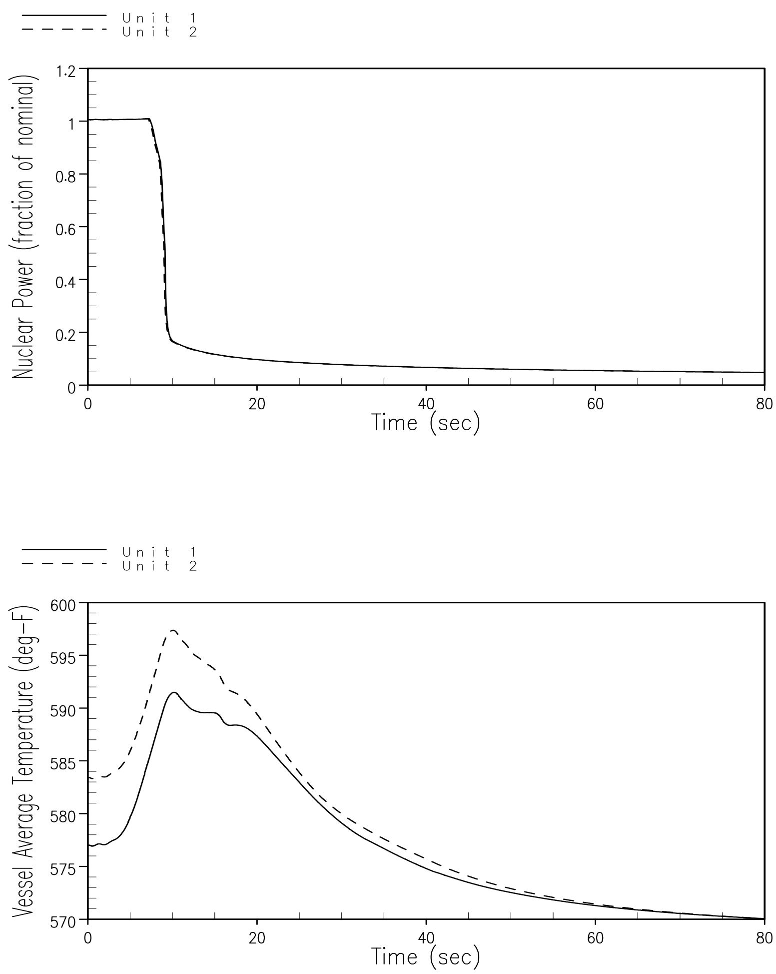


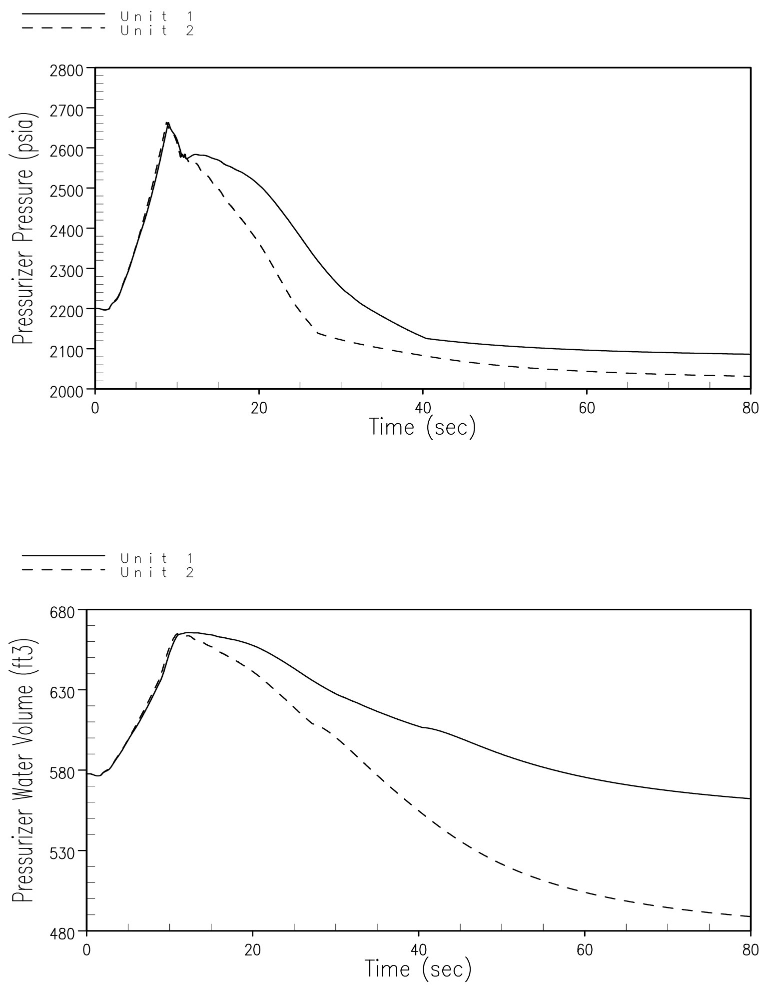
Figure 14.1.9-2 LOSS OF ELECTRICAL LOAD WITHOUT PRESSURE CONTROL
(RCS Overpressure Case)
Sheet 1 of 3



Point Beach Nuclear Plant
Units 1 and 2

Loss of Electrical Load
Without Pressure Control
(RCS Overpressure Case)
Figure 14.1.9-2
(Sheet 1 of 3)

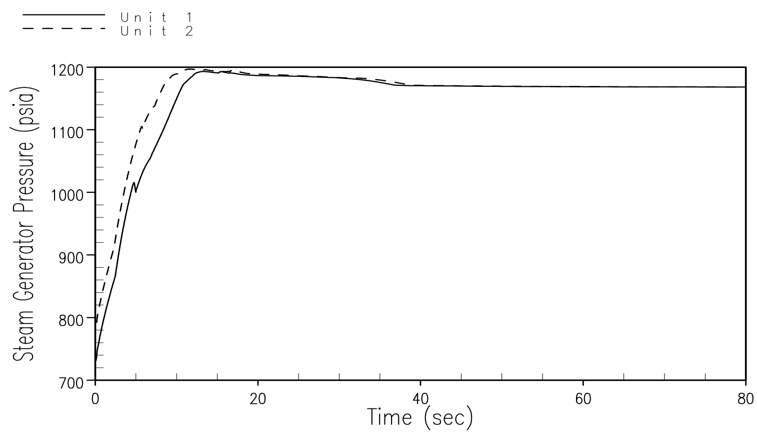
Figure 14.1.9-2 LOSS OF ELECTRICAL LOAD WITHOUT PRESSURE CONTROL
(RCS Overpressure Case)
Sheet 2 of 3



Point Beach Nuclear Plant
Units 1 and 2

Loss of Electrical Load
Without Pressure Control
(RCS Overpressure Case)
Figure 14.1.9-2
(Sheet 2 of 3)

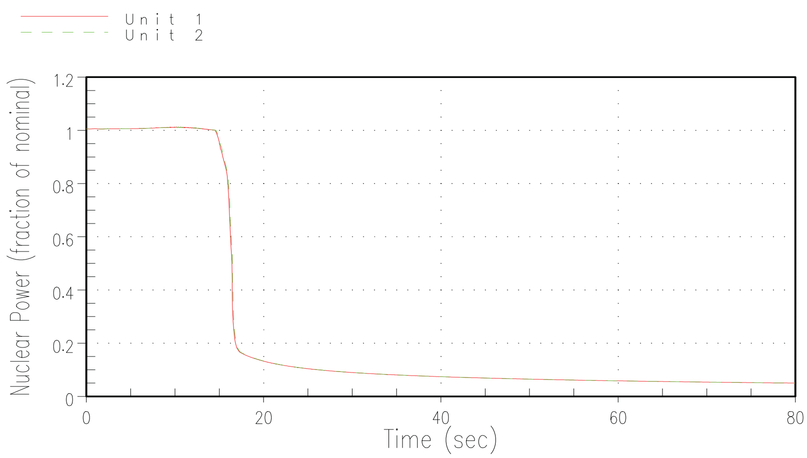
Figure 14.1.9-2 LOSS OF ELECTRICAL LOAD WITHOUT PRESSURE CONTROL
(RCS Overpressure Case)
Sheet 3 of 3



Point Beach Nuclear Plant
Units 1 and 2

Loss of Electrical Load
Without Pressure Control
(RCS Overpressure Case)
Figure 14.1.9-2
(Sheet 3 of 3)

Figure 14.1.9-3 LOSS OF ELECTRICAL LOAD WITH PRESSURE CONTROL
(SG Overpressure Case)
Sheet 1 of 3



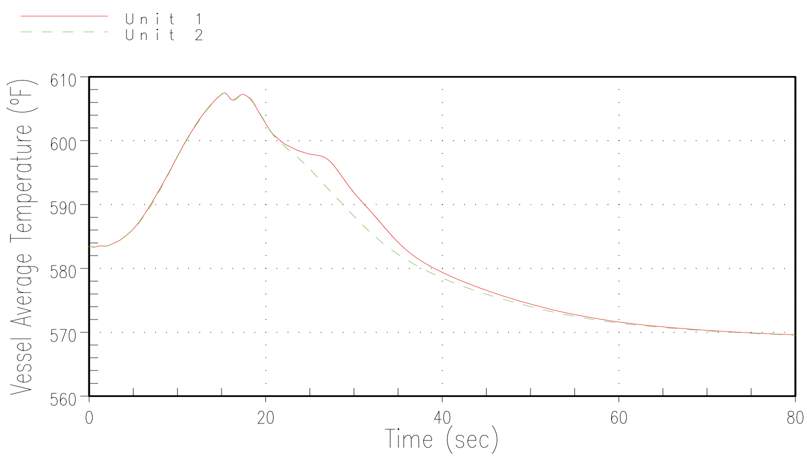
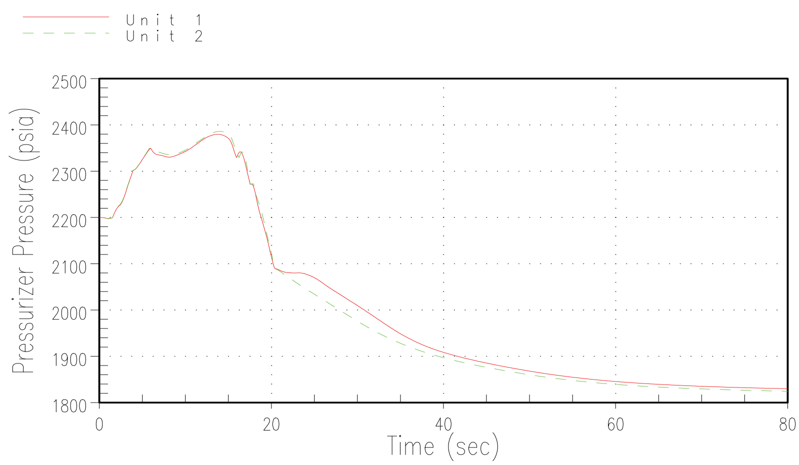


Figure 14.1.9-3 LOSS OF ELECTRICAL LOAD WITH PRESSURE CONTROL
(SG Overpressure Case)

Sheet 2 of 3



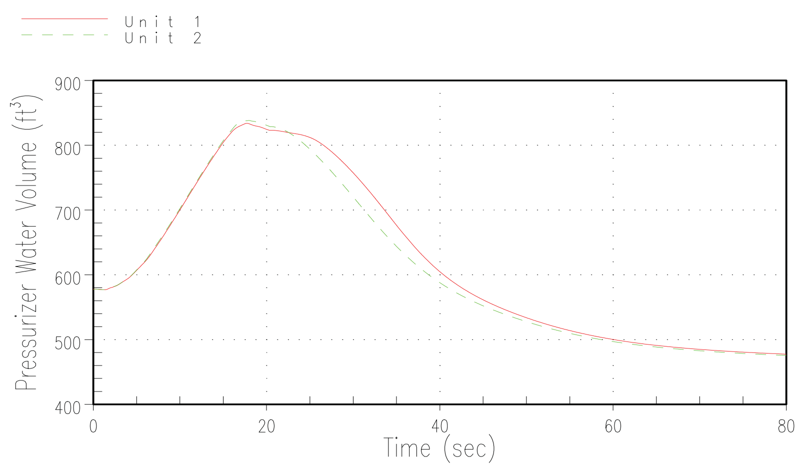
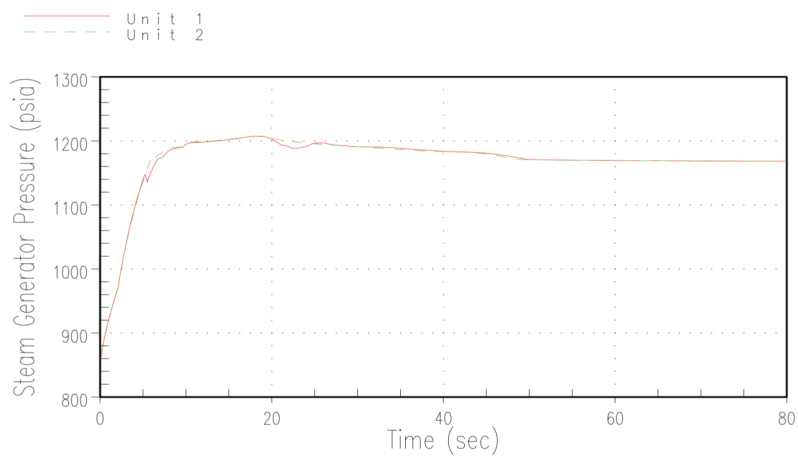


Figure 14.1.9-3 LOSS OF ELECTRICAL LOAD WITH PRESSURE CONTROL
(SG Overpressure Case)
Sheet 3 of 3



14.1.10 LOSS OF NORMAL FEEDWATER

A loss of normal feedwater (from a pipe break, pump failure, or valve malfunction) results in a reduction in capability of the secondary system to remove the heat generated in the reactor core. If the reactor is not tripped during this accident primary plant damage could possibly result from a sudden loss of heat sink. If an alternate supply of feedwater were not supplied to the plant, residual heat following reactor trip would heat the primary system water to the point where water relief from the pressurizer occurs, and significant loss of water from the reactor coolant system could conceivably lead to core damage. The following provides the protection in the event a loss of normal feedwater (LONF) occurs:

1. Reactor trip on low-low water level in either steam generator.

2. Reactor trip on steam flow-feedwater flow mismatch coincident with low water level in either steam generator.

3. A motor-driven and a steam driven auxiliary feedwater pump (275 gpm each) which are automatically started on any of the following:

   - Low-low water level in either steam generator.
   - Loss of voltage on both 4.16 kv buses supplying the main feedwater pump motors.
   - Trip or shutdown of both feedwater pumps or closure of either a feedwater isolation valve or a feedwater regulating valve in both main feedwater lines. These signals are processed through AMSAC at power levels above 40% (Reference Section 7.4).
   - Automatic or manual safety injection. In conjunction with a loss of AC the MDAFW pump start is sequenced a nominal 32.5 seconds after EDG breaker closure.

The motor driven auxiliary feedwater pumps is supplied by an emergency diesel generator if a loss of offsite power occurs. The turbine-driven pump utilizes steam from the secondary systems and exhausts the steam to the atmosphere. The auxiliary feedwater pumps take suction directly from the condensate storage tank (CST) for delivery to the steam generators, or from the Service Water System should the CST not be available. See Section 10.2.3 and Section 7.4.3 for a description of the automatic switchover of the AFW suction supply to Service Water.

The above protection provides considerable backup in equipment and control logic to ensure that reactor trip and automatic auxiliary feedwater flow will occur following any loss of normal feedwater including that caused by loss of AC power.

Method of Analysis

A detailed analysis using the RETRAN code (Reference 2) is performed in order to obtain the plant transient following a loss of normal feedwater. The simulation describes the plant thermal kinetics, RCS including the natural circulation, pressurizer, steam generators, and feedwater system. The digital program computes pertinent variables, including the steam generator level, pressurizer water level, and reactor coolant average temperature.

The following assumptions were made:

1. The plant is initially operating at 100.6% of 1806 MWt.

2. Core residual heat generation is based on the 1979 version of ANS-5.1 (Reference 1) plus two standard deviations for uncertainty. ANSI/ ANS-5.1-1979 is a conservative representation of the decay heat release rates.

3. The initiating signal for the reactor trip is a low-low steam generator level. No credit is taken for the reactor trip due to a steam flow/feed flow mismatch coincident with a low steam generator level.

4. Both steam generators are affected equally, and both reach their low-low level trip setpoints simultaneously. This assumption conservatively minimizes the secondary heat sink available at the time of the reactor trip.

5. The auxiliary feedwater system provides only 275 gpm of flow split to two steam generators. No credit is taken for AFW flow from the turbine driven pump.

6. AFW flow of 275gpm is delivered to the steam generator(s) starting 30 seconds after the initiating signal (low-low steam generator level trip). From 30 to 60 seconds the AFW flow is ramped from 0% to 80% of total flow: from 60 to 120 seconds AFW flow is ramped from 80% to 100% of total flow: beyond 120 seconds 100 % of total AFW flow is maintained.

7. The assumed steam generator models are 44F (Unit 1) and Delta-47 (Unit 2).

8. The pressurizer sprays, function to produce the maximum peak pressurizer water volume. The backup heaters are assumed to be unavailable on high pressurizer level deviation signal and the PORVs are assumed to be inoperable. Cases with the PORVs operable were found to be less limiting.

9. Secondary system steam relief is through the self-actuated safety valves.

<u>Results</u>

The calculated sequence of events for this event is listed in Table 14.1.10-1. Figure 14.1.10-1 and Figure 14.1.10-2 show the plant parameters following a loss of normal feedwater accident with the assumptions listed above for Units 1 and 2. Low-low level signal in either steam generator initiates the reactor trip. The reactor trip then initiates the turbine trip. Following the reactor and turbine trip from full load, the water level in the steam generators falls due to the reduction of steam generator void fraction and because steam flow through the safety valves continues to dissipate the stored and generated heat.

Upon the initiation of the low-low level signal, one auxiliary feedwater pumps is automatically started. The pumps will start to supply auxiliary feedwater to both steam generators within 30 seconds, reducing the rate of water level decrease.

The capacity of the auxiliary feedwater system is such that the water level in the steam generators does not recede below the lowest level at which sufficient heat transfer area is available to dissipate core residual heat without water relief from the RCS relief or safety valves. From Figure 14.1.10-1 and Figure 14.1.10-2 it can be seen that at no time is there water relief from the pressurizer.

Conclusion

The loss of normal feedwater does not result in any adverse condition in the core, because it does not result in water relief from the pressurizer relief or safety valves.

References

1. "American National Standard for Decay Heat Power in Light Water Reactors," ANSI/ ANS-5.1 - 1979, August 1979.

2. Huegel, D. S., et. al., "RETRAN-02 Modeling and Qualification for Westinghouse Pressurized Water Reactor Non-LOCA Safety Analyses," WCAP-14882-P-A (Proprietary), WCAP-15234-A (Non-Proprietary), April 1999.

3. Westinghouse CN-TA-08-79, Rev 1, Point Beach Unit 1 and 2 Loss of Normal Feedwater/ Loss of AC Power (LONF/LOAC) Analysis for the EPU Program, Approved February 26, 2009.

4. NRC Safety Evaluation, PBNP Units 1 and 2 - Issuance of License Amendments Regarding Extended Power Uprate, May 3, 2011.

5. NRC Safety Evaluation, "Point Beach Nuclear Plant Units 1 and 2-Issuance of License Amendments Re: Auxiliary Feedwater System Modification," dated March 25, 2011.

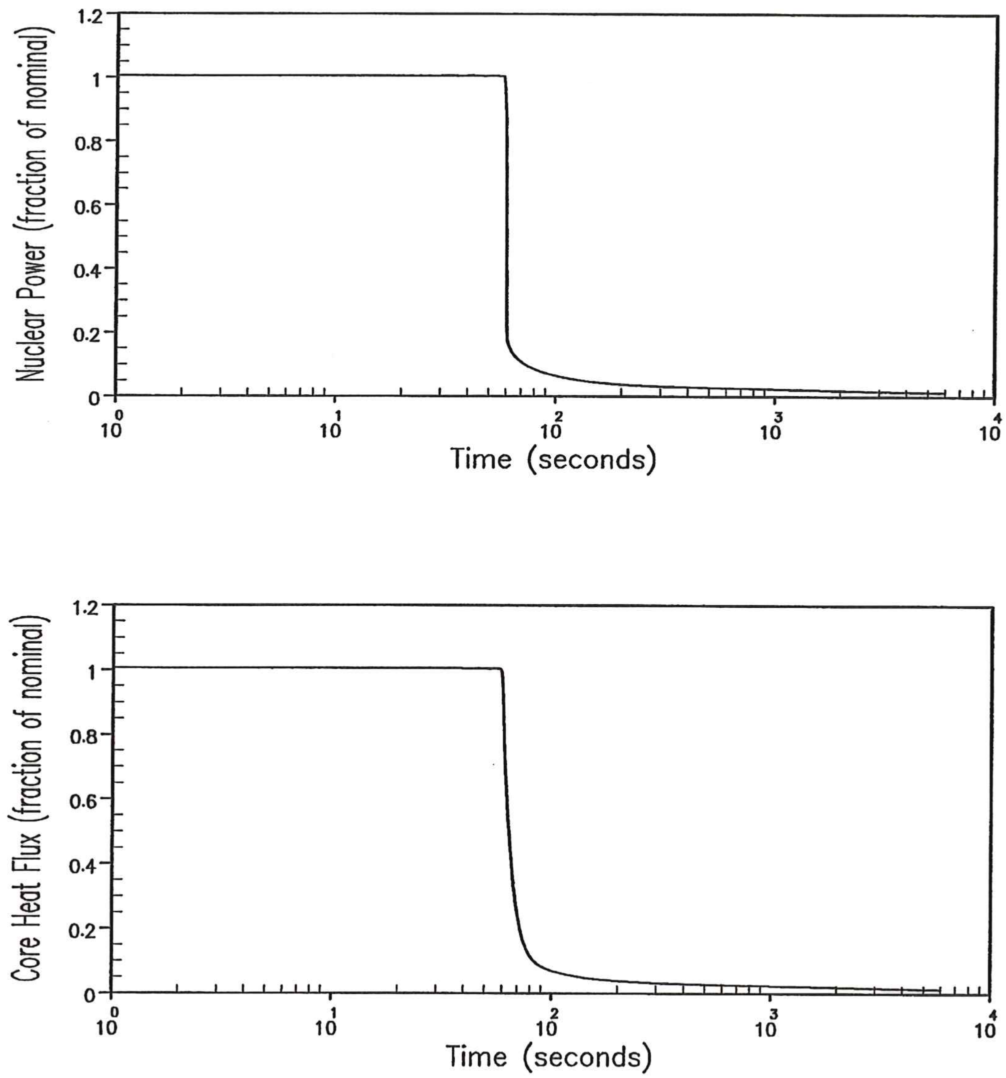
6. Letter NRC 2011-0086, NextEra Energy to NRC, Clarification/Comments on the NRC Safety Evaluation Report, Amendment Nos. 238 (Unit 1) and 242 (Unit 2), Auxiliary Feedwater System Modification, September 16, 2011.

7. NRC Letter to NextEra Energy, Point Beach Nuclear Plant, Units 1 and 2-NRC Staff Response to Clarification/Comments Related to the Safety Evaluation Report Associated with the Auxiliary Feedwater System Modification License Amendment, December 6, 2011.

Table 14.1.10-1 TIME SEQUENCE OF EVENTS FOR LOSS OF NORMAL FEEDWATER FLOW INCIDENTS

Event	Time of Each Event (Seconds) Unit 1	Unit 2
Main feedwater flow stops	20	20
Low-Low steam generator water level trip actuated	56.0	54.4
Rods begin to drop	58.0	56.4
AFW flow to each loop begins	86.0	84.4
80% of full AFW flow reached	116.0	114.4
100% of full AFW flow reached	176.0	174.4
Peak water level in pressurizer occurs	1410	1378
Core decay heat decreases to auxiliary feedwater heat removal capacity	~1414	~1392

Figure 14.1.10-1 UNIT 1 (MODEL 44F SG) LOSS OF NORMAL FEEDWATER
Sheet 1 of 6

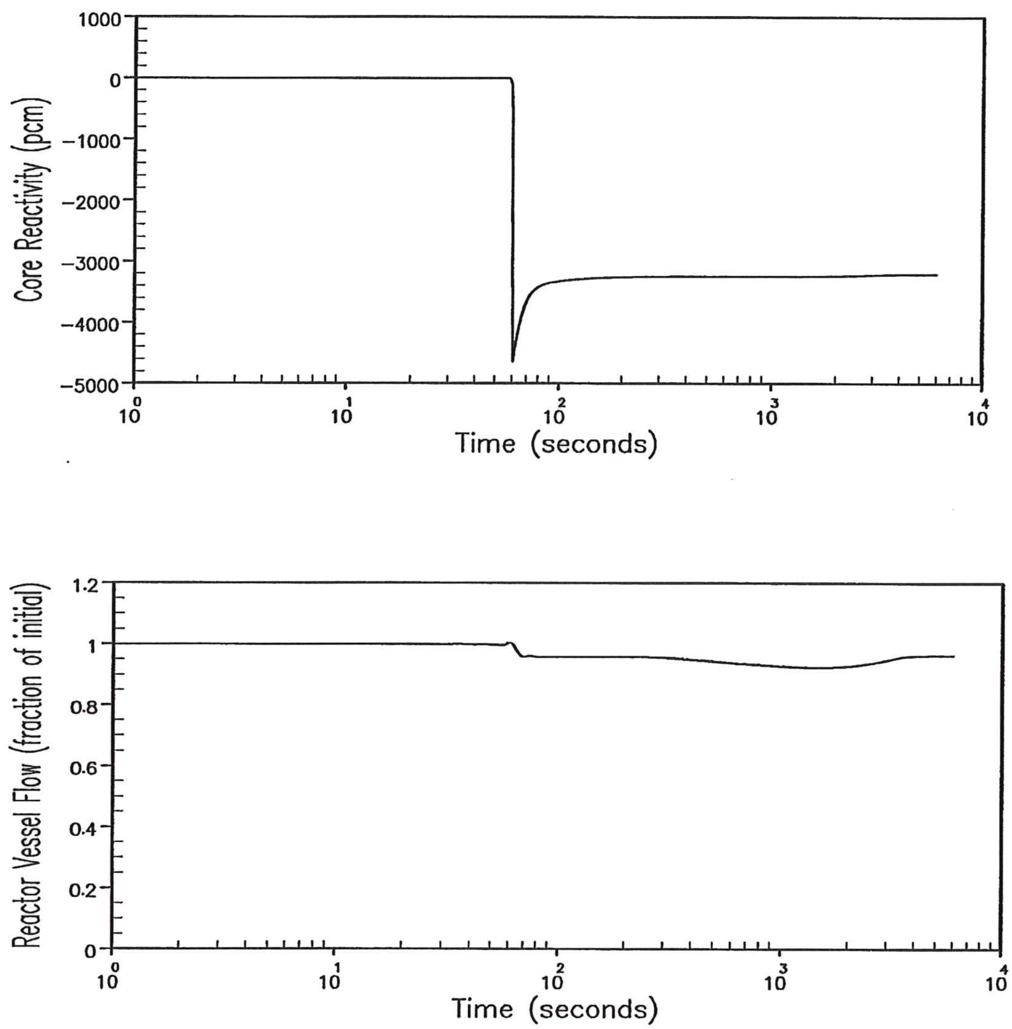


Point Beach Nuclear Plant
Units 1 and 2

Unit 1 (Model 44F SG)
Loss of Normal Feedwater

Figure 14.1.10-1 (sheet 1 of 6)

Figure 14.1.10-1 UNIT 1 (MODEL 44F SG) LOSS OF NORMAL FEEDWATER
Sheet 2 of 6

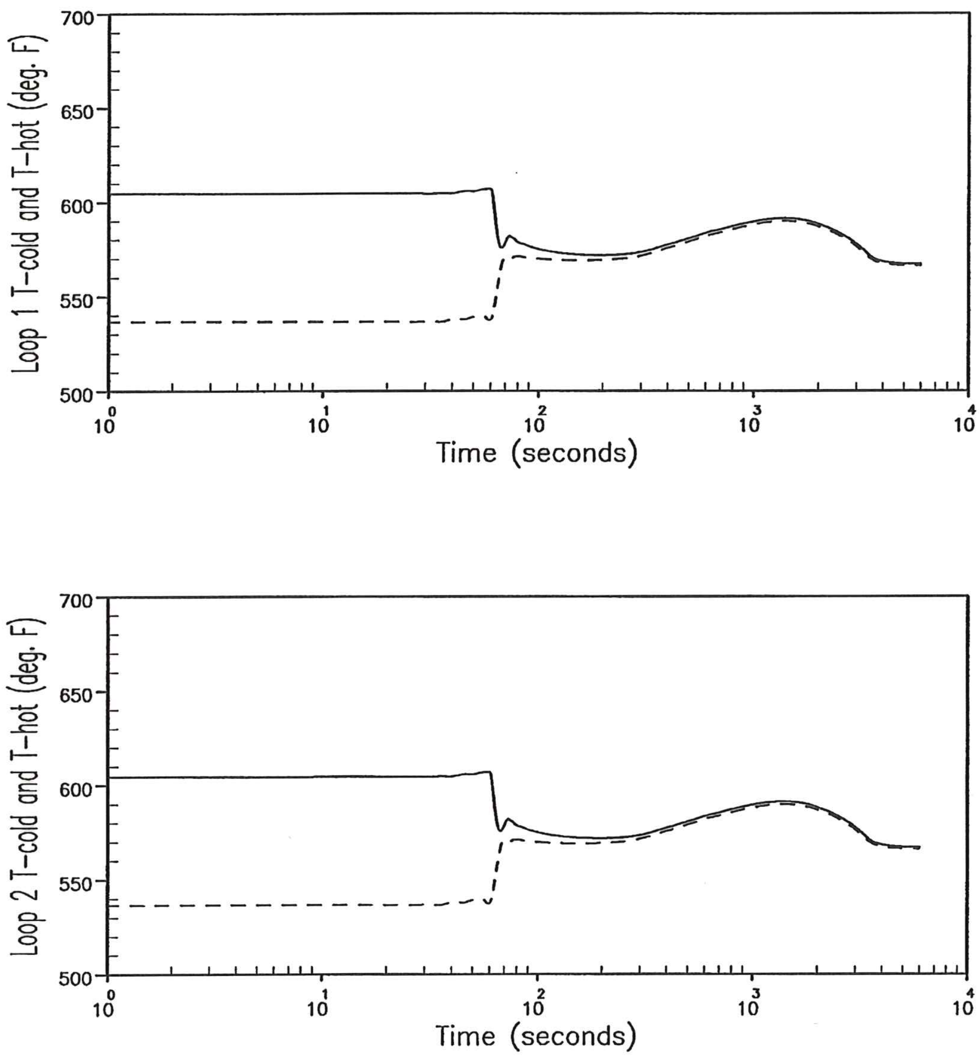


Point Beach Nuclear Plant
Units 1 and 2

Unit 1 (Model 44F SG)
Loss of Normal Feedwater

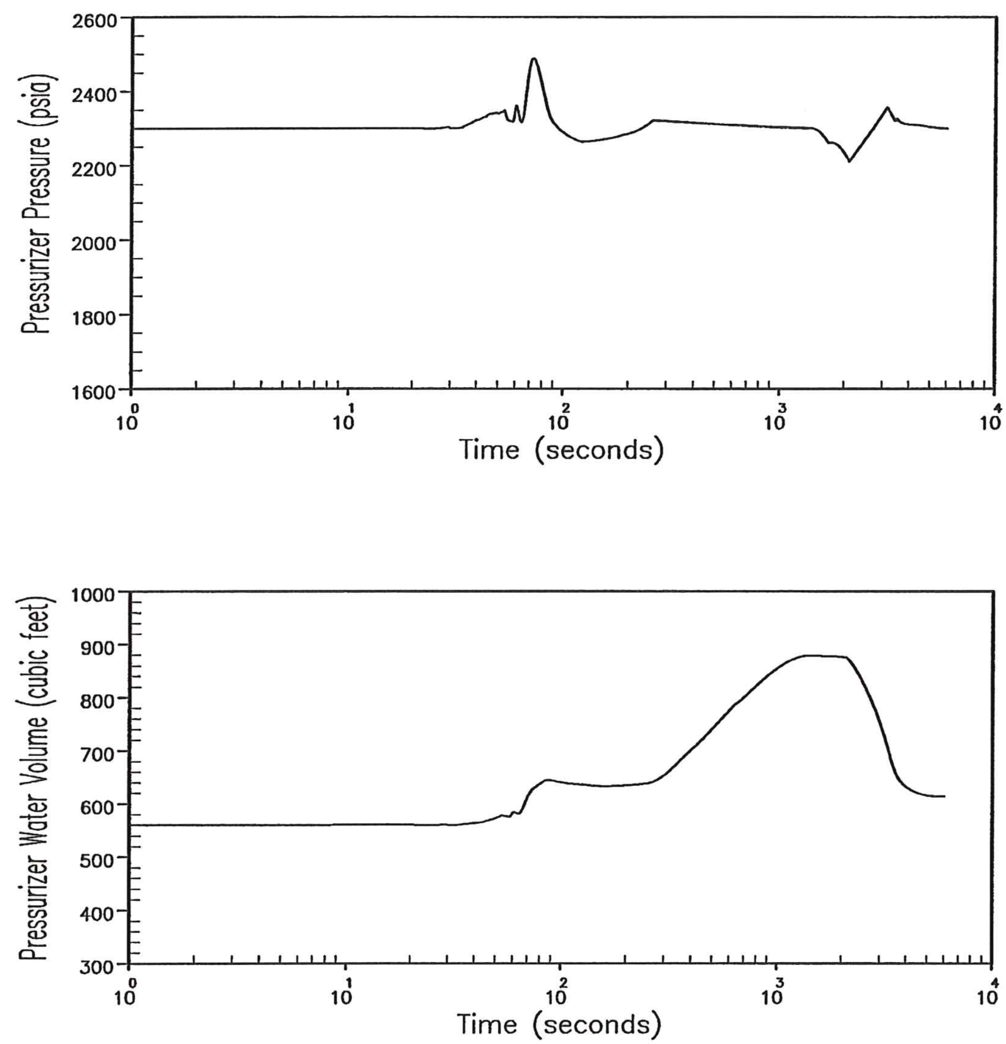
Figure 14.1.10-1 (sheet 2 of 6)

Figure 14.1.10-1 UNIT 1 (MODEL 44F SG) LOSS OF NORMAL FEEDWATER
Sheet 3 of 6



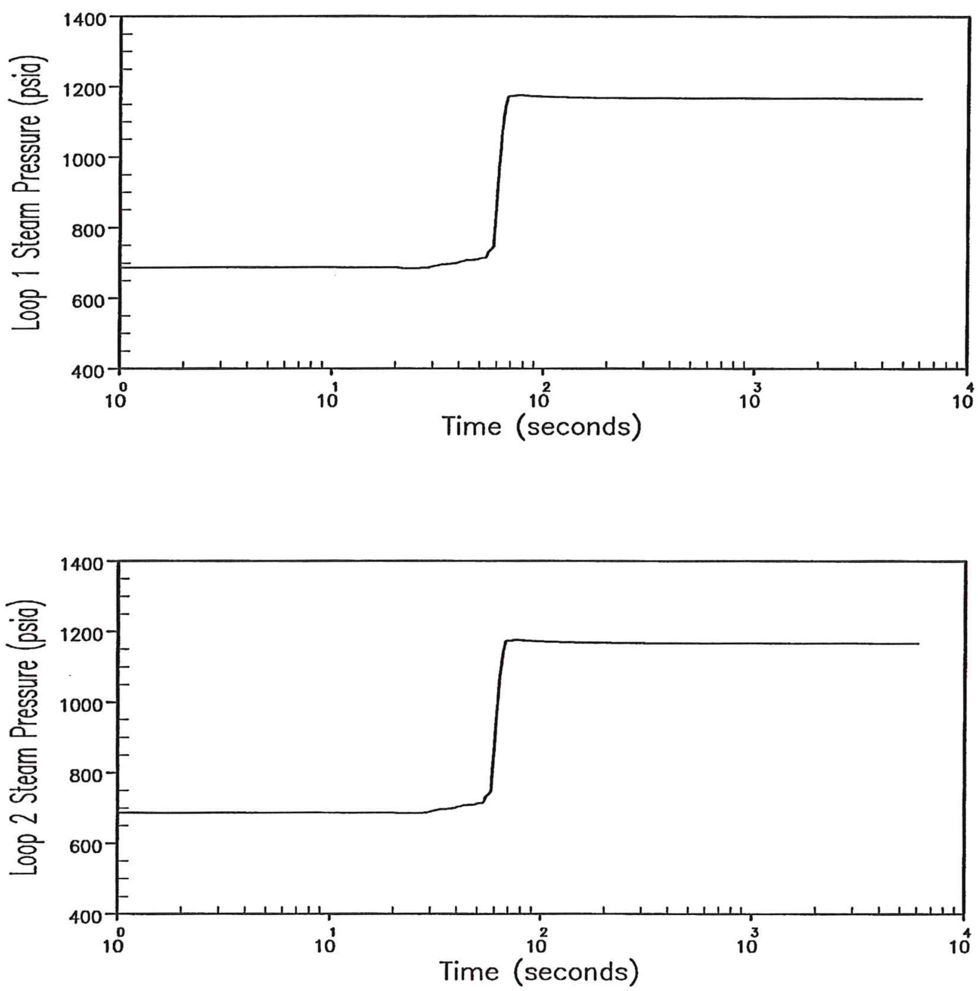
	Point Beach Nuclear Plant Units 1 and 2
	Unit 1 (Model 44F SG) Loss of Normal Feedwater **Figure 14.1.10-1 (sheet 3 of 6)**

Figure 14.1.10-1 UNIT 1 (MODEL 44F SG) LOSS OF NORMAL FEEDWATER
Sheet 4 of 6



	Point Beach Nuclear Plant Units 1 and 2
	Unit 1 (Model 44F SG) Loss of Normal Feedwater **Figure 14.1.10-1 (sheet 4 of 6)**

Figure 14.1.10-1 UNIT 1 (MODEL 44F SG) LOSS OF NORMAL FEEDWATER
Sheet 5 of 6



Point Beach Nuclear Plant
Units 1 and 2

Unit 1 (Model 44F SG)
Loss of Normal Feedwater

Figure 14.1.10-1 (sheet 5 of 6)

Figure 14.1.10-1 UNIT 1 (MODEL 44F SG) LOSS OF NORMAL FEEDWATER
Sheet 6 of 6

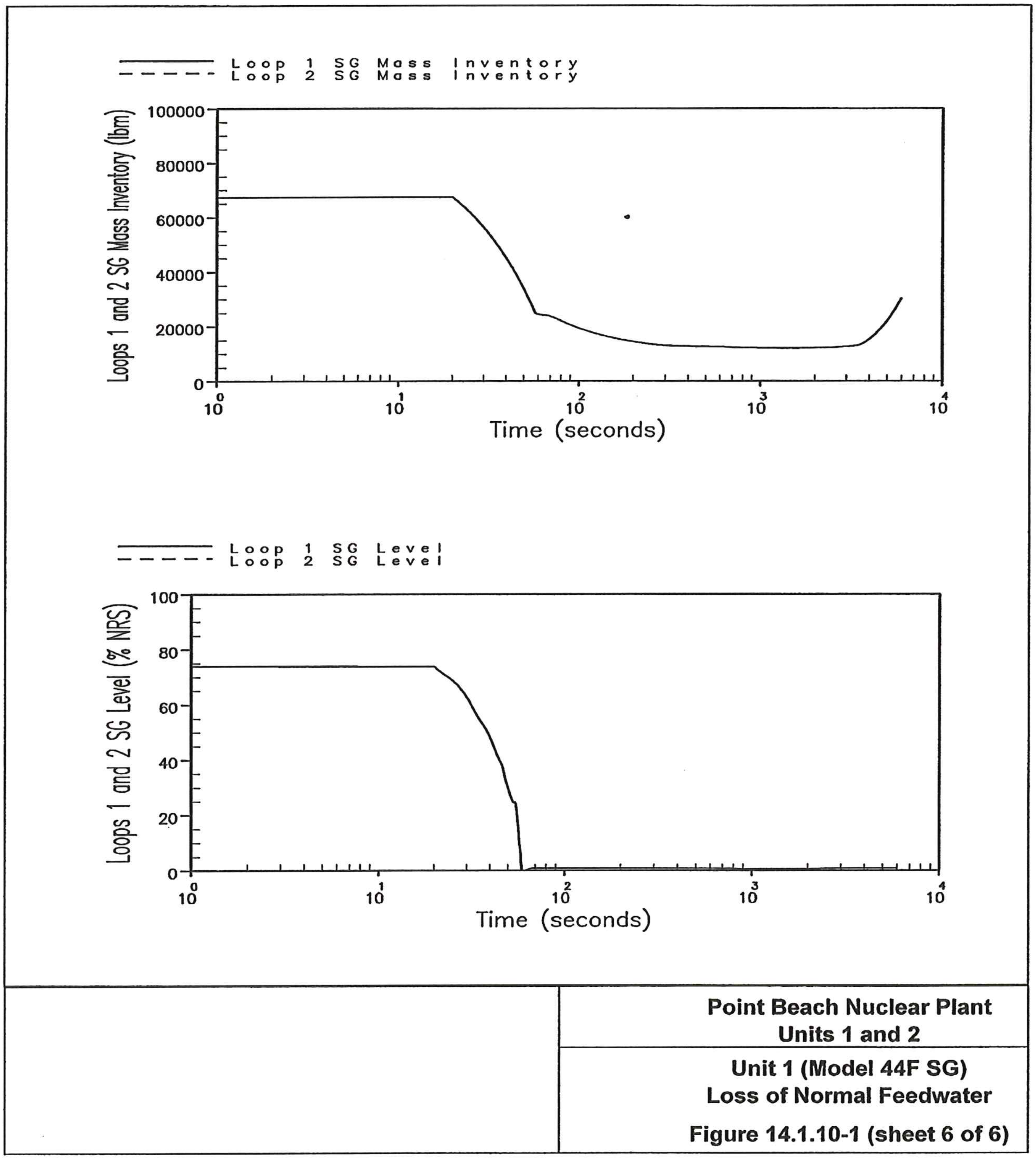
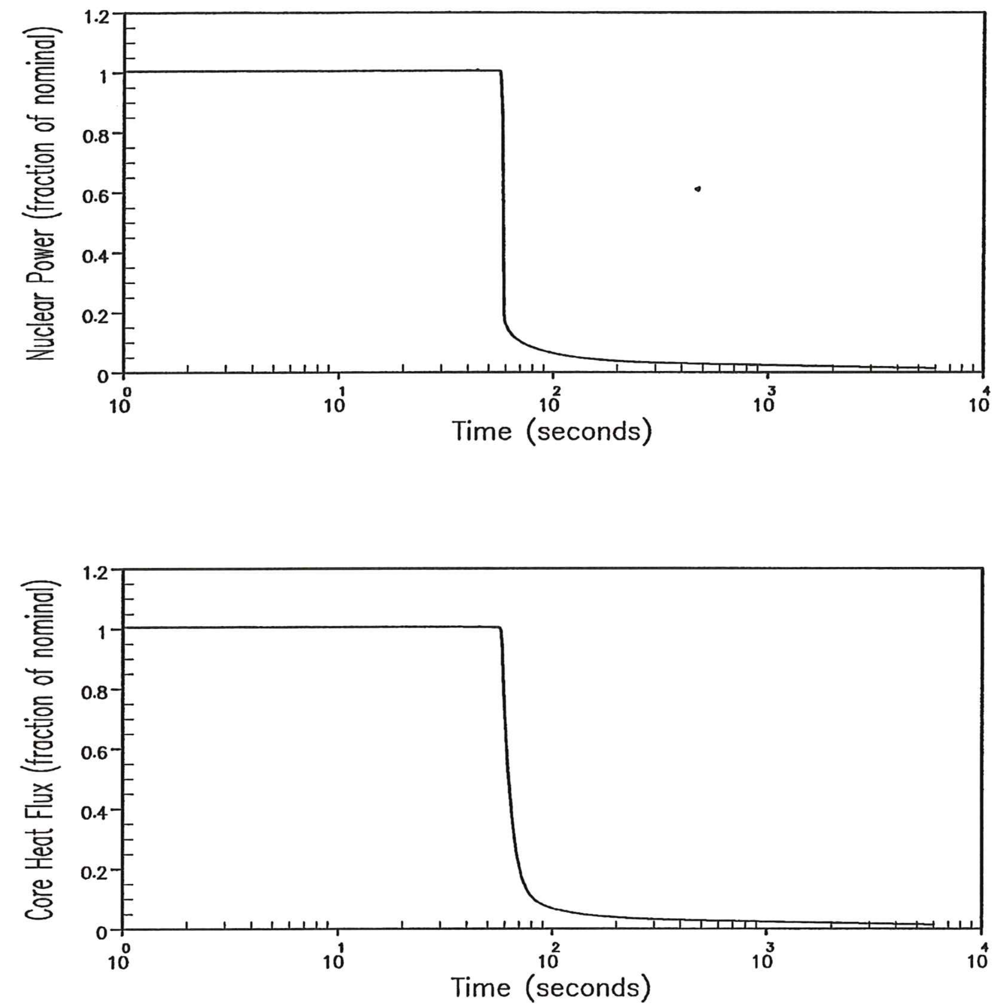


Figure 14.1.10-2 UNIT 2 (Delta - 47 SG) LOSS OF NORMAL FEEDWATER
Sheet 1 of 6

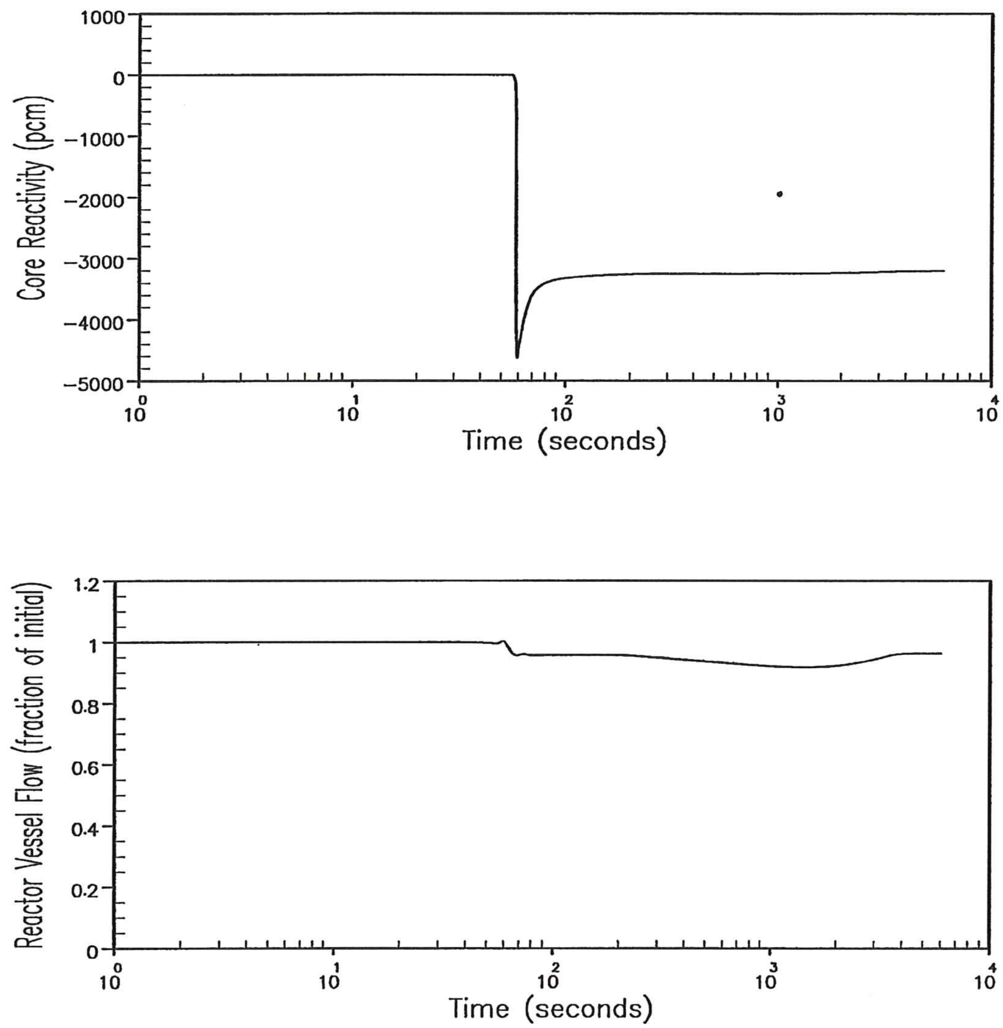


**Point Beach Nuclear Plant
Units 1 and 2**

**Unit 2 (Delta-47 SG)
Loss of Normal Feedwater**

Figure 14.1.10-2 (sheet 1 of 6)

Figure 14.1.10-2 UNIT 2 (Delta - 47 SG) LOSS OF NORMAL FEEDWATER
Sheet 2 of 6

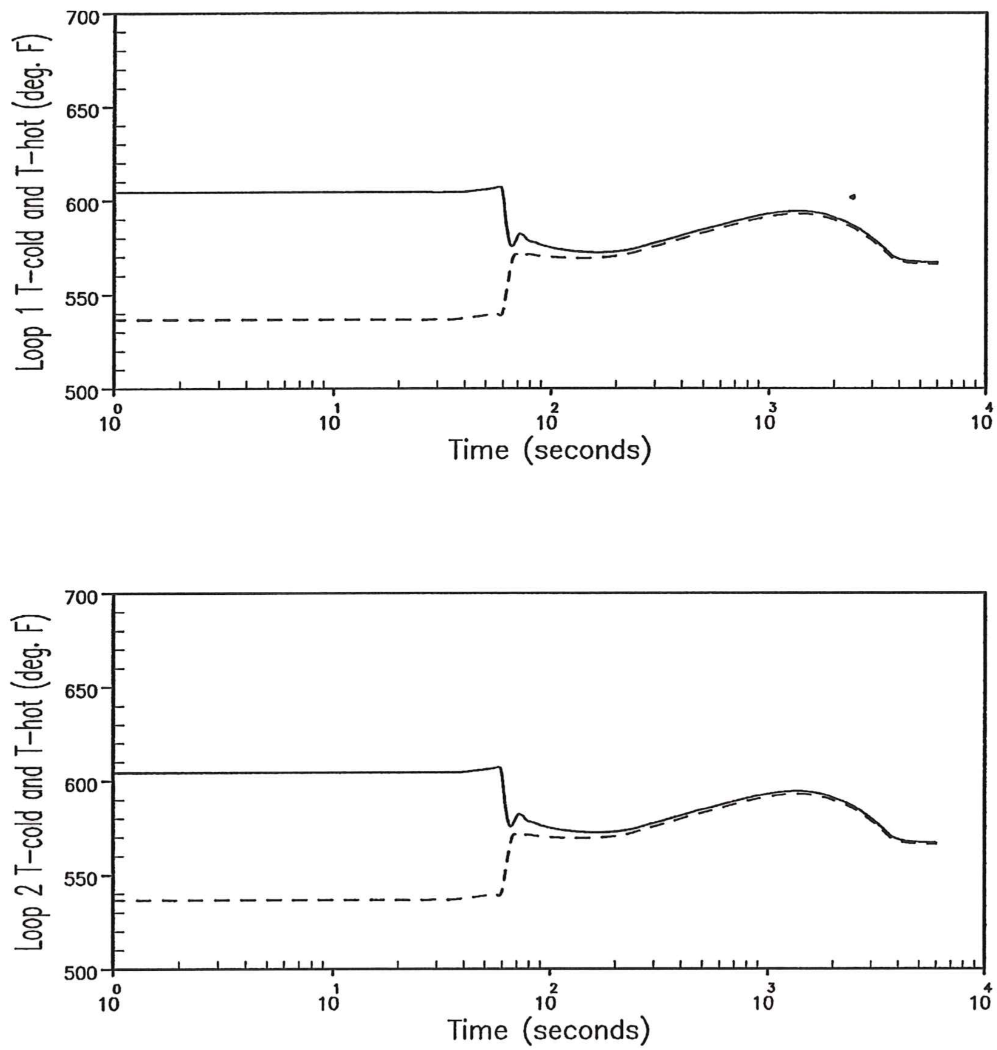


Point Beach Nuclear Plant
Units 1 and 2

Unit 2 (Delta-47 SG)
Loss of Normal Feedwater

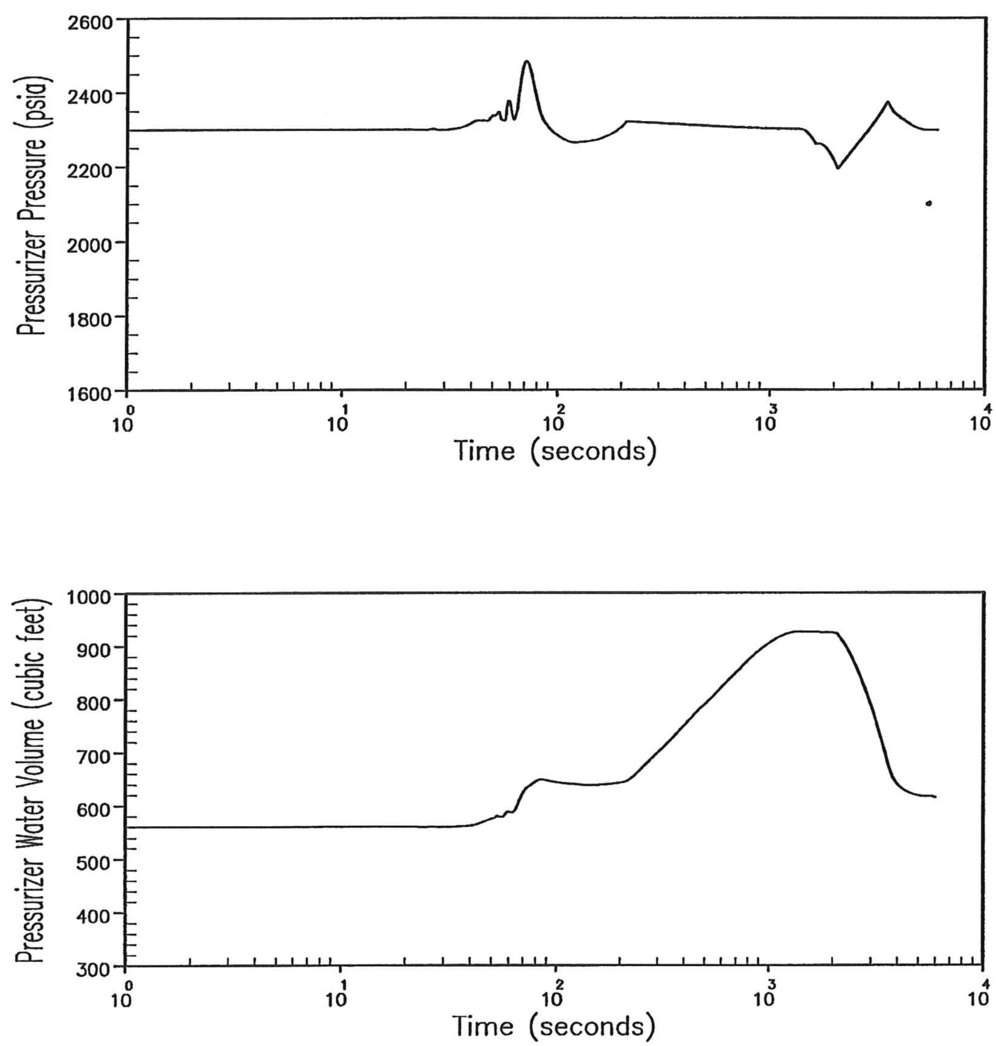
Figure 14.1.10-2 (sheet 2 of 6)

Figure 14.1.10-2 UNIT 2 (Delta - 47 SG) LOSS OF NORMAL FEEDWATER
Sheet 3 of 6



	Point Beach Nuclear Plant **Units 1 and 2**
	Unit 2 (Delta-47 SG) **Loss of Normal Feedwater** **Figure 14.1.10-2 (sheet 3 of 6)**

Figure 14.1.10-2 UNIT 2 (Delta - 47 SG) LOSS OF NORMAL FEEDWATER
Sheet 4 of 6

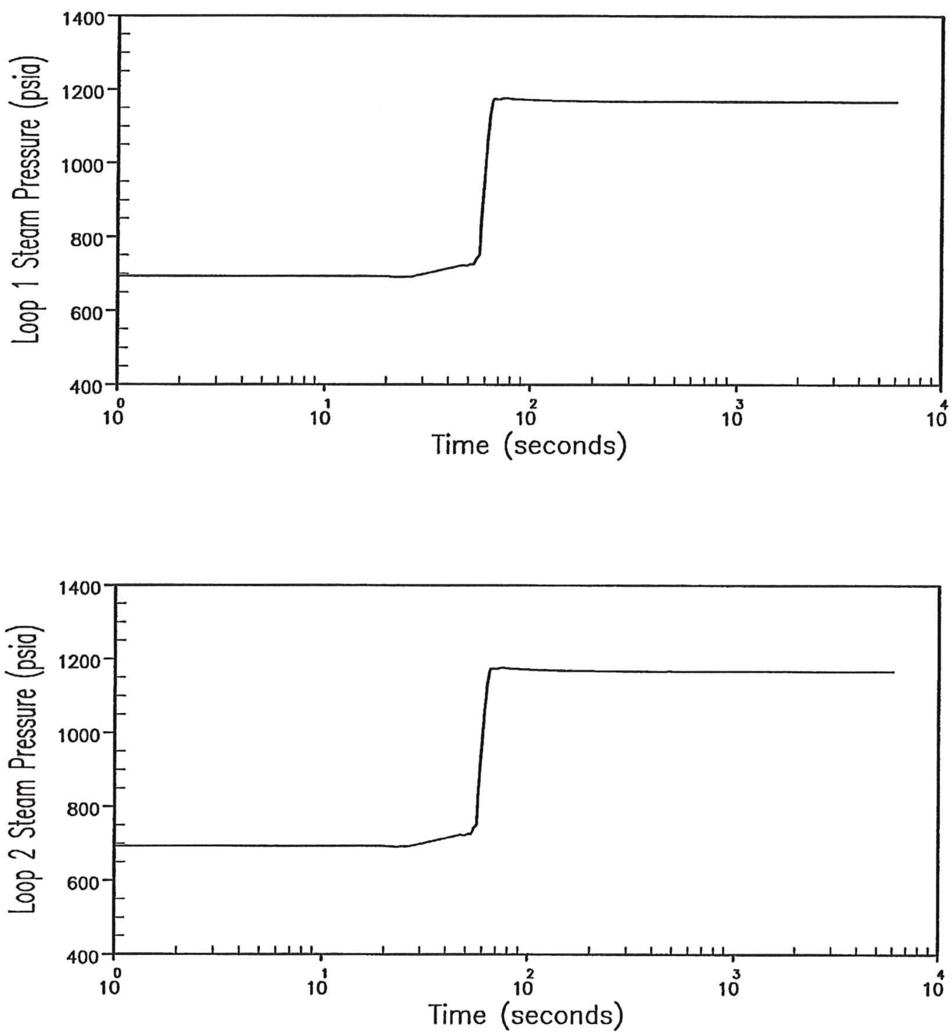


Point Beach Nuclear Plant
Units 1 and 2

Unit 2 (Delta-47 SG)
Loss of Normal Feedwater

Figure 14.1.10-2 (sheet 4 of 6)

Figure 14.1.10-2 UNIT 2 (Delta - 47 SG) LOSS OF NORMAL FEEDWATER
Sheet 5 of 6

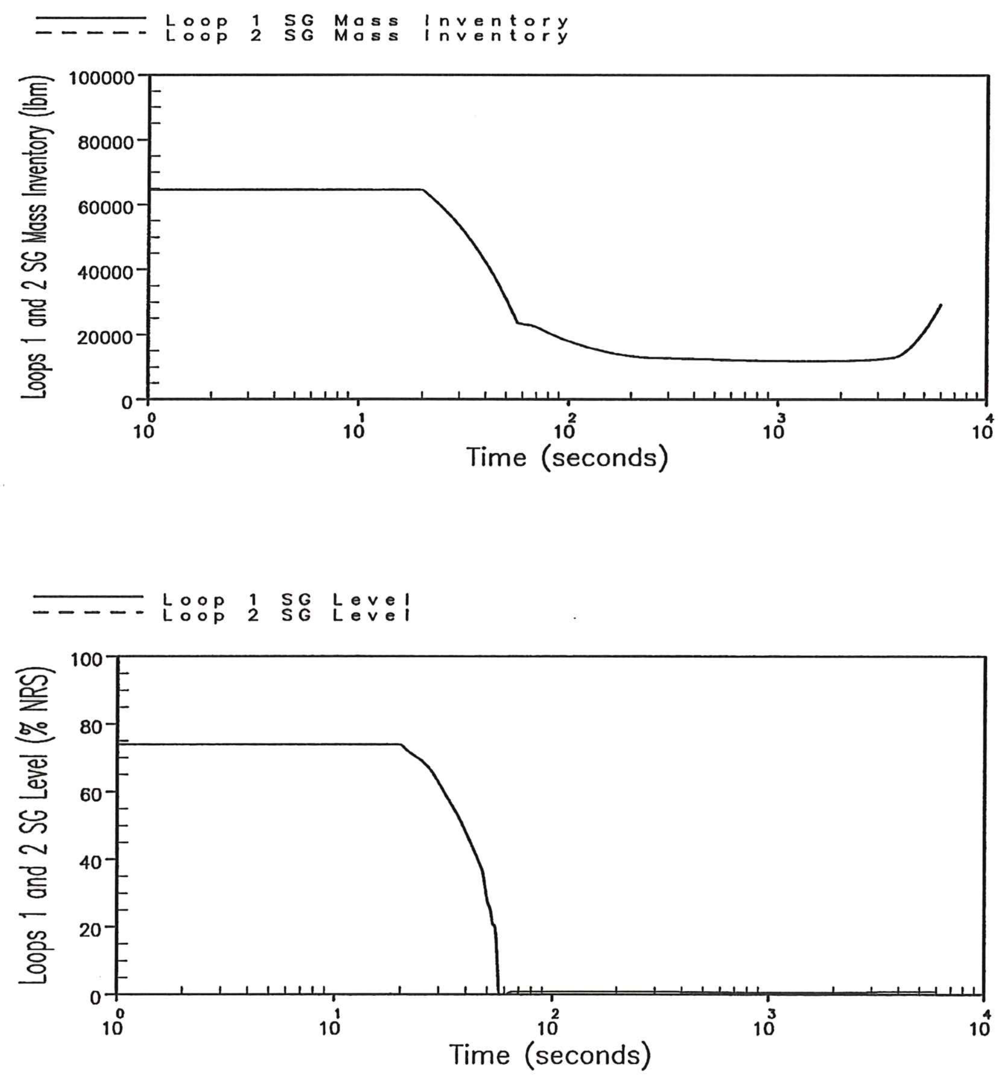


Point Beach Nuclear Plant
Units 1 and 2

Unit 2 (Delta-47 SG)
Loss of Normal Feedwater

Figure 14.1.10-2 (sheet 5 of 6)

Figure 14.1.10-2 UNIT 2 (Delta - 47 SG) LOSS OF NORMAL FEEDWATER
Sheet 6 of 6



Point Beach Nuclear Plant
Units 1 and 2

Unit 2 (Delta-47 SG)
Loss of Normal Feedwater

Figure 14.1.10-2 (sheet 6 of 6)

14.1.11 LOSS OF ALL AC POWER TO STATION AUXILIARIES

For the Point Beach EPU, the LONF (FSAR 14.1.10) refers to the loss of normal feedwater cases with offsite power available and the Loss of Offsite Power (LOOP) refers to the loss of normal feedwater cases with loss of offsite power. LOAC refers to the transient which is initiated by a loss of AC power. The LOAC cases are bounded by the LOOP cases, therefore the LOOP results are presented in this FSAR section as bounding results for the LOAC event.

In the unlikely event of a complete loss of all non-emergency AC power; the turbine will be tripped and there will be a loss of power to the station auxiliaries. The sequence below is described for the unit following a turbine trip:

1. Plant vital instruments are supplied by the emergency power sources.

2. As the steam system pressure subsequently increases, the steam generator power operated relief valves (also referred to as the atmospheric dump valves) are automatically opened to the atmosphere. Steam bypass to the condenser is not available because of loss of the circulating water pumps.

3. As the steam flow rate through the power operated relief valves may not be sufficient, the steam generator self-actuated safety valves may temporarily lift to augment the steam flow until the rate of heat dissipation is sufficient to carry away the sensible heat of the fuel and coolant above no-load temperature plus the residual heat produced in the reactor.

4. As the no-load temperature is reached, the steam generator power operated relief valves are used to dissipate the residual heat and to maintain the plant at the hot shutdown condition.

The steam turbine driven and motor driven auxiliary feedwater pumps are automatically started by the loss of AC power on the buses that supply power to the Main Feedwater Pumps. The turbine utilizes steam from the secondary system to drive the feedwater pump to deliver makeup water to the steam generators. The turbine driver exhausts the secondary steam to the atmosphere. The motor driven auxiliary feedwater pump is supplied by power from an emergency diesel generator. The pumps take suction directly from the condensate storage tanks (CSTs) for delivery to the steam generators, or from the Service Water System should the CSTs not be available. See Section 10.2.3 and Section 7.4.3 for a description of the automatic switchover of the AFW suction supply to Service Water. The auxiliary feedwater system insures feedwater supply of at least 275 gpm upon the loss of power to the station auxiliaries, since the steam turbine driven auxiliary feedwater pump and the motor driven auxiliary feedwater pumps have a minimum capacity of 275 gpm each.

Method of Analysis

A detailed analysis using the RETRAN code (Reference 2) is performed in order to obtain the plant transient following a loss of all AC power to the station auxiliaries. The simulation describes the plant thermal kinetics, RCS including the natural circulation, pressurizer, steam generators, and feedwater system. The digital program computes pertinent variables, including the steam generator level, pressurizer water level, and reactor coolant average temperature.

The following assumptions are made:

1. The plant is initially operating at 100.6% of 1806 MWt.

2. Core residual heat generation is based on the 1979 version of ANS-5.1 (Reference 1) plus two standard deviations for uncertainty. ANSI/ANS-5.1 - 1979 is a conservative representation of the decay heat release rates.

3. The initiating signal is a low-low steam generator level. This assumption conservatively disregards that a loss of AC power to the station auxiliaries would result in an immediate reactor trip due to loss of voltage to the 4.16kV busses.

4. Both steam generators are affected equally, and both reach their low-low level trip setpoints simultaneously. This assumption conservatively minimizes the secondary heat sink available at the time of the reactor trip.

5. The auxiliary feedwater system provides 275 gpm of flow split equally to two steam generators.

6. AFW flow of 275 gpm is delivered to the steam generator(s) starting at 60 seconds after the initiating signal (low-low steam generator level trip). From 60 to 90 seconds the AFW flow is ramped from 0% to 80% of total flow: from 90 to 150 seconds AFW flow is ramped from 80% to 100% of total flow: beyond 150 seconds 100 % of total AFW flow is maintained.

7. The assumed steam generator models are 44F (Unit 1) and Delta-47 (Unit 2).

8. Secondary system steam relief is through the self-actuated safety valves.

9. The pressurizer sprays are assumed to function as designed which maximizes the peak pressurizer water volume. The backup heaters are assumed to be unavailable on high pressurizer level deviation signal and the PORVs are assumed to be inoperable for the Unit 1 limiting case and operable for the Unit 2 limiting case.

The remaining assumptions used in the analysis are similar to the loss of normal feedwater (14.1.10) except that power is assumed to be lost to the reactor coolant pumps at the time of reactor trip plus an appropriate delay time (2 sec. for reactor trip and 2 sec. for loss of power for a total of 4 sec.).

Results

The calculated sequence of events for this accident is listed in Table 14.1.11-1. The transient response of the RCS following a loss of AC power is shown in Figure 14.1.11-1 and Figure 14.1.11-2.

The first few seconds after the loss of power to the reactor coolant pumps will closely resemble the simulation of the loss of reactor coolant flow event (14.1.8), where core damage due to rapidly increasing core temperatures is prevented by promptly tripping the reactor. After the reactor trip, stored and residual decay heat must be removed to prevent damage to either the RCS or the core.

The results of the analysis show that the natural circulation flow available is sufficient to provide adequate core decay heat removal following reactor trip and RCP coastdown. An inadvertent actuation of the shut down seal (SDS) on a rotating pump shaft will not have any measurable impact on RCP coastdown or on the pump's capability to provide sufficient cooling flow to the reactor core.

Conclusion

The loss of AC power to the station auxiliaries does not cause any adverse condition in the core, since it does not result in water relief from the pressurizer relief or safety valves.

References

1. "American National Standard for Decay Heat Power in Light Water Reactors," ANSI/ANS-5.1-1979, August 1979.

2. Huegel, D. S., et. al., "RETRAN-02 Modeling and Qualification for Westinghouse Pressurized Water Reactor Non-LOCA Safety Analyses," WCAP-14882-P-A (Proprietary), WCAP-15234-A (Non-Proprietary), April 1999.

3. Westinghouse Calculation Note CN-TA-08-79, Rev 1, Point Beach Unit 1 and 2 Loss of Normal Feedwater/Loss of AC Power (LONF/LOAC) Analysis for the EPU Program, Approved February 26, 2009.

4. NRC Safety Evaluation, PBNP Units 1 and 2 - Issuance of License Amendments Regarding Extended Power Uprate, May 3, 2011.

5. NRC Safety Evaluation, "Point Beach Nuclear Plant Units 1 and 2-Issuance of License Amendments Re: Auxiliary Feedwater System Modification," dated March 25, 2011.

6. Not Used

7. Not Used

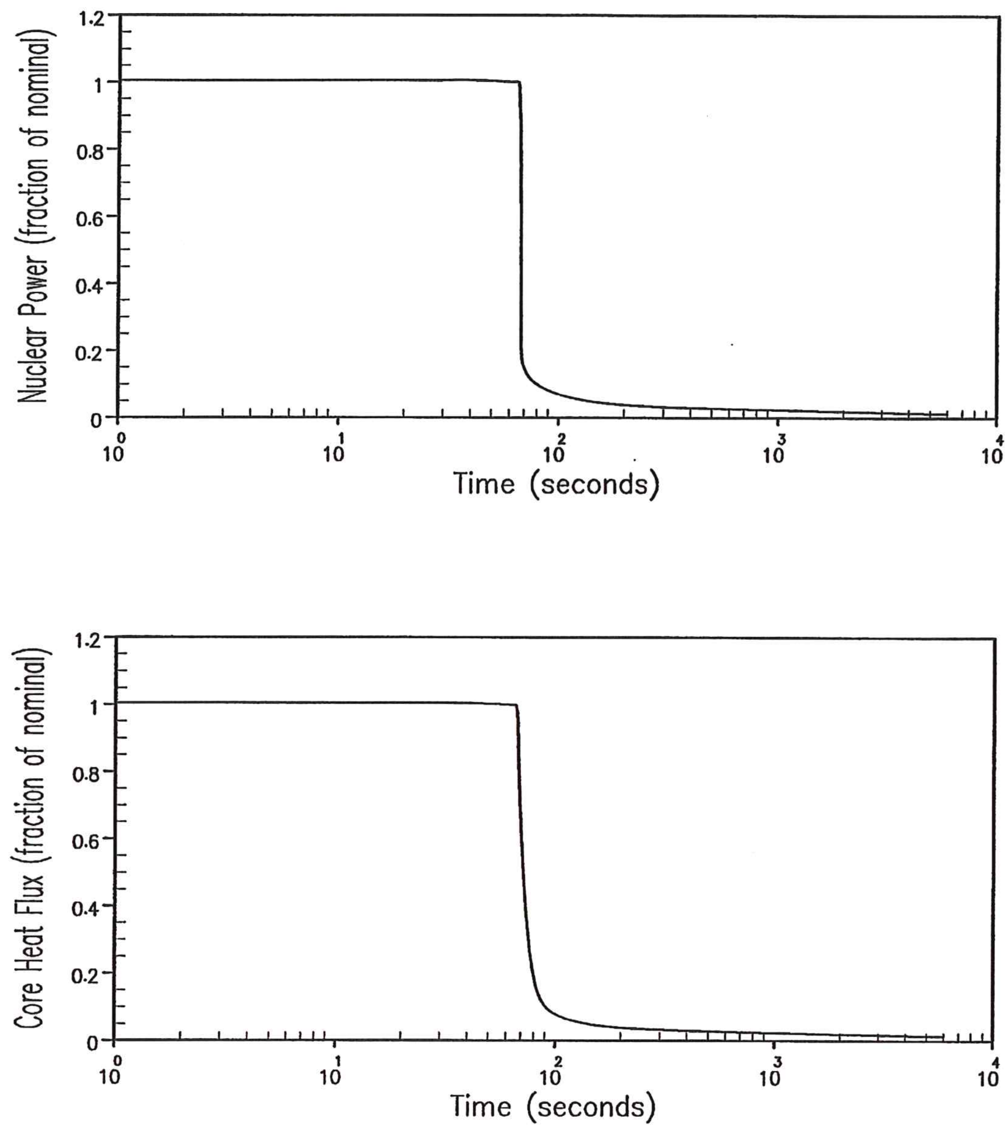
8. Letter WEP-14-64, Westinghouse to NextEra Energy, Point Beach RCP SDS Final Documentation Deliverable, October 9, 2014.

Table 14.1.11-1 TIME SEQUENCE OF EVENTS FOR LOSS OF OFFSITE POWER INCIDENTS*

	Time of Each Event (Seconds)	
Event	Unit 1	Unit 2
Main feedwater flow stops	20	20
Low-Low steam generator water level trip	63.5	55.0
Rods begin to drop	65.5	57.0
Reactor coolant pumps begin to coastdown	67.5	59.0
AFW flow to each loop begins	123.5	115.0
80% of full AFW flow reached	153.5	145.0
100% of full AFW flow reached	213.5	205.0
Peak water level in pressurizer occurs	285	776
Core decay heat decreases to auxiliary feedwater heat removal capacity	~844	~790

* Nonemergency AC power to station auxiliaries is lost at the times shown above for the start of RCP coastdown.

Figure 14.1.11-1 UNIT 1 (MODEL 44F SG) LOSS OF AC POWER
Sheet 1 of 6

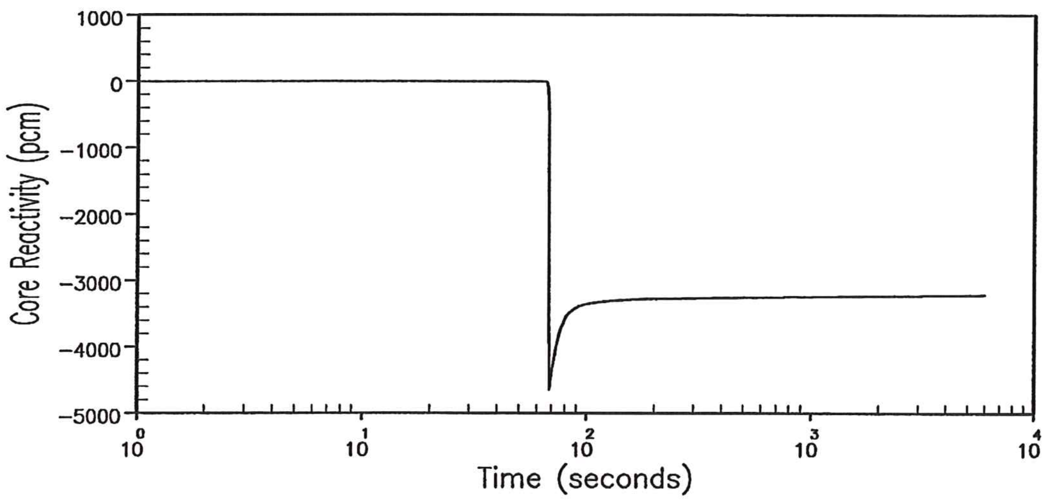


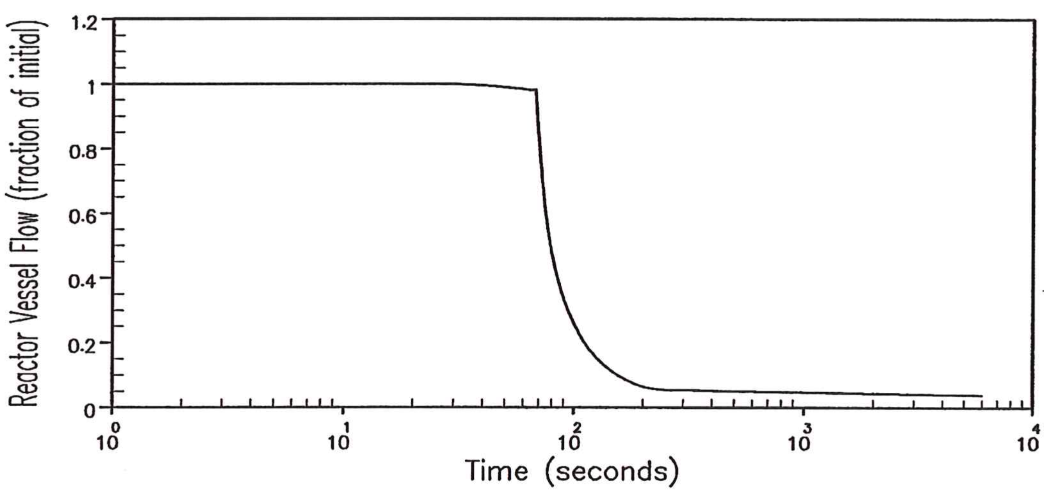
Point Beach Nuclear Plant
Units 1 and 2

Unit 1 (Model 44F SG)
Loss of AC Power

Figure 14.1.11-1 (sheet 1 of 6)

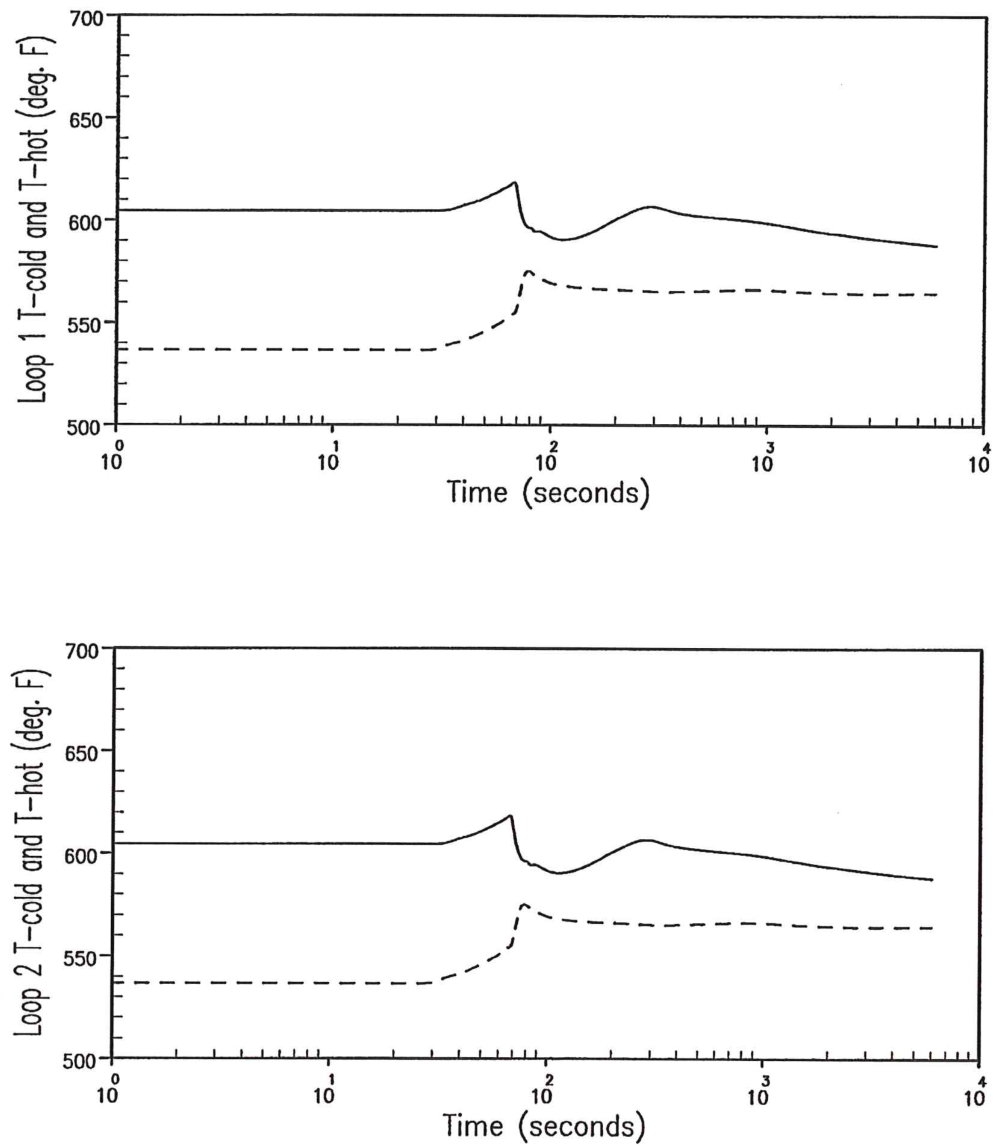
Figure 14.1.11-1 UNIT 1 (MODEL 44F SG) LOSS OF AC POWER
Sheet 2 of 6





	Point Beach Nuclear Plant Units 1 and 2
	Unit 1 (Model 44F SG) Loss of AC Power **Figure 14.1.11-1 (sheet 2 of 6)**

Figure 14.1.11-1 UNIT 1 (MODEL 44F SG) LOSS OF AC POWER
Sheet 3 of 6

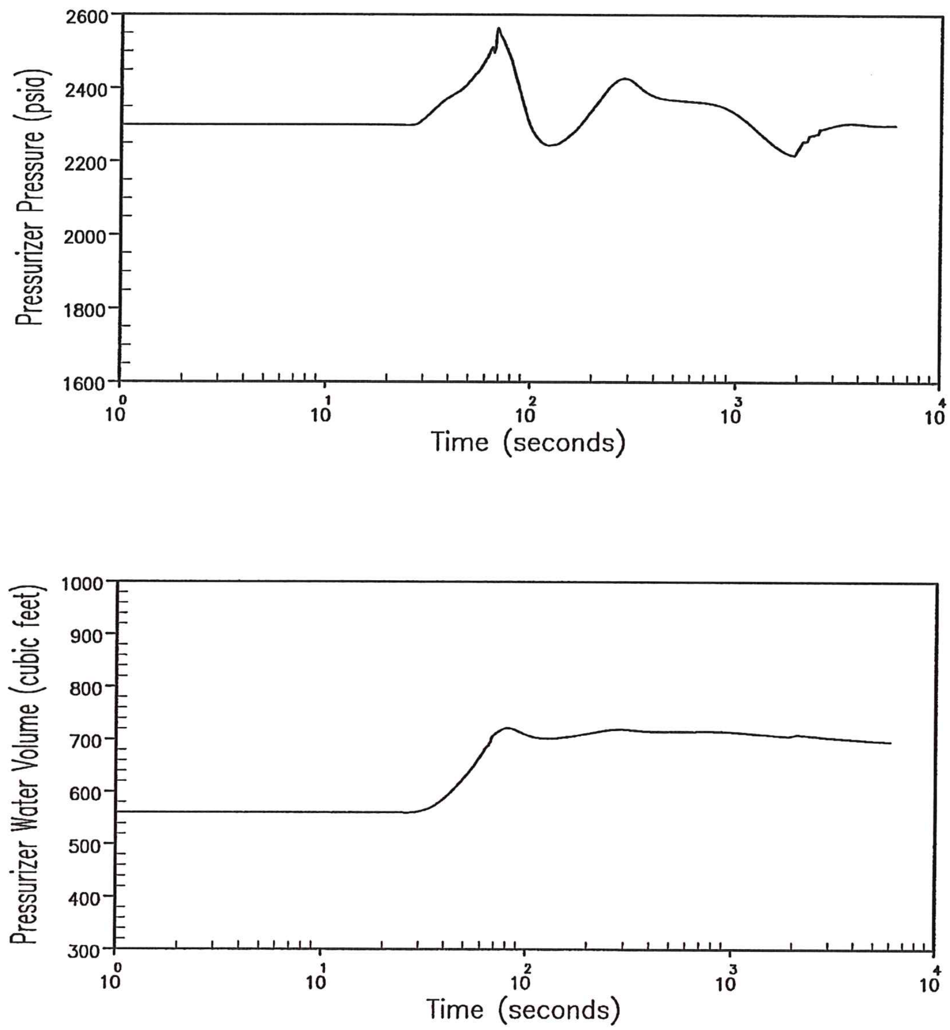


Point Beach Nuclear Plant
Units 1 and 2

Unit 1 (Model 44F SG)
Loss of AC Power

Figure 14.1.11-1 (sheet 3 of 6)

Figure 14.1.11-1 UNIT 1 (MODEL 44F SG) LOSS OF AC POWER
Sheet 4 of 6

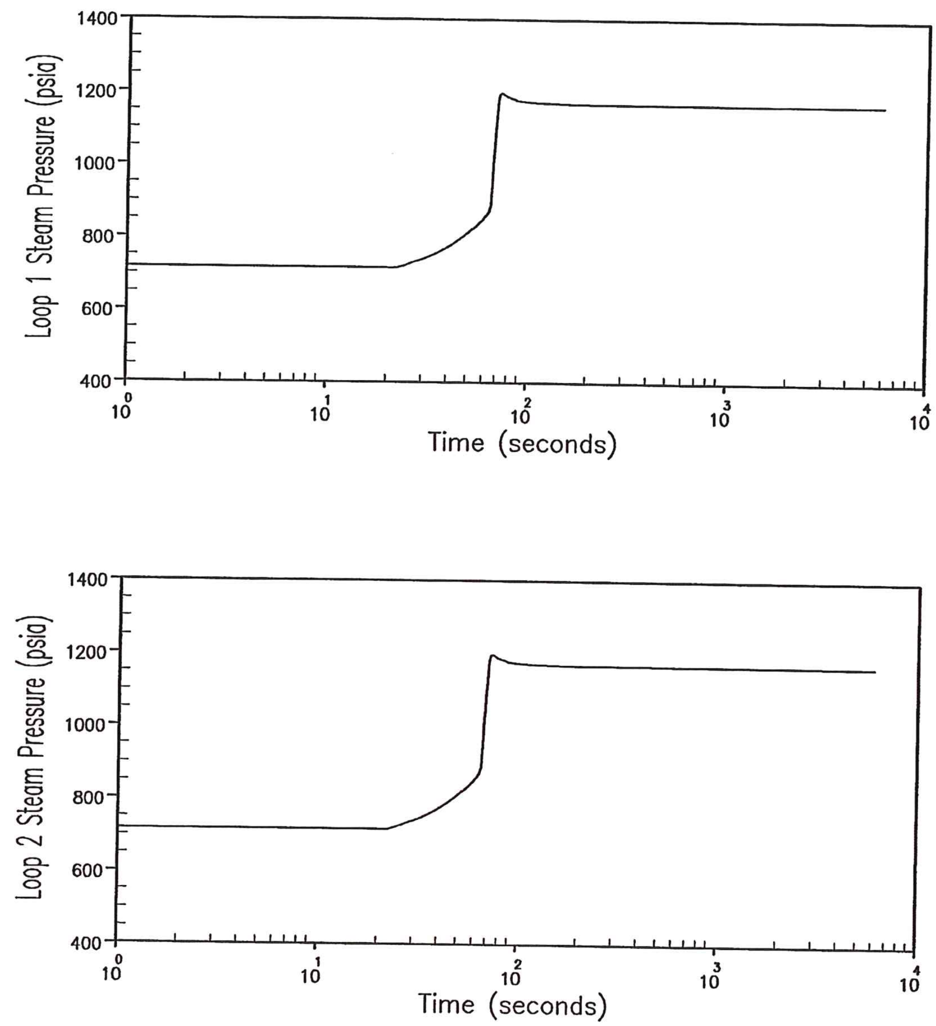


Point Beach Nuclear Plant
Units 1 and 2

Unit 1 (Model 44F SG)
Loss of AC Power

Figure 14.1.11-1 (sheet 4 of 6)

Figure 14.1.11-1 UNIT 1 (MODEL 44F SG) LOSS OF AC POWER
Sheet 5 of 6



Point Beach Nuclear Plant
Units 1 and 2

Unit 1 (Model 44F SG)
Loss of AC Power

Figure 14.1.11-1 (sheet 5 of 6)

Figure 14.1.11-1 UNIT 1 (MODEL 44F SG) LOSS OF AC POWER
Sheet 6 of 6

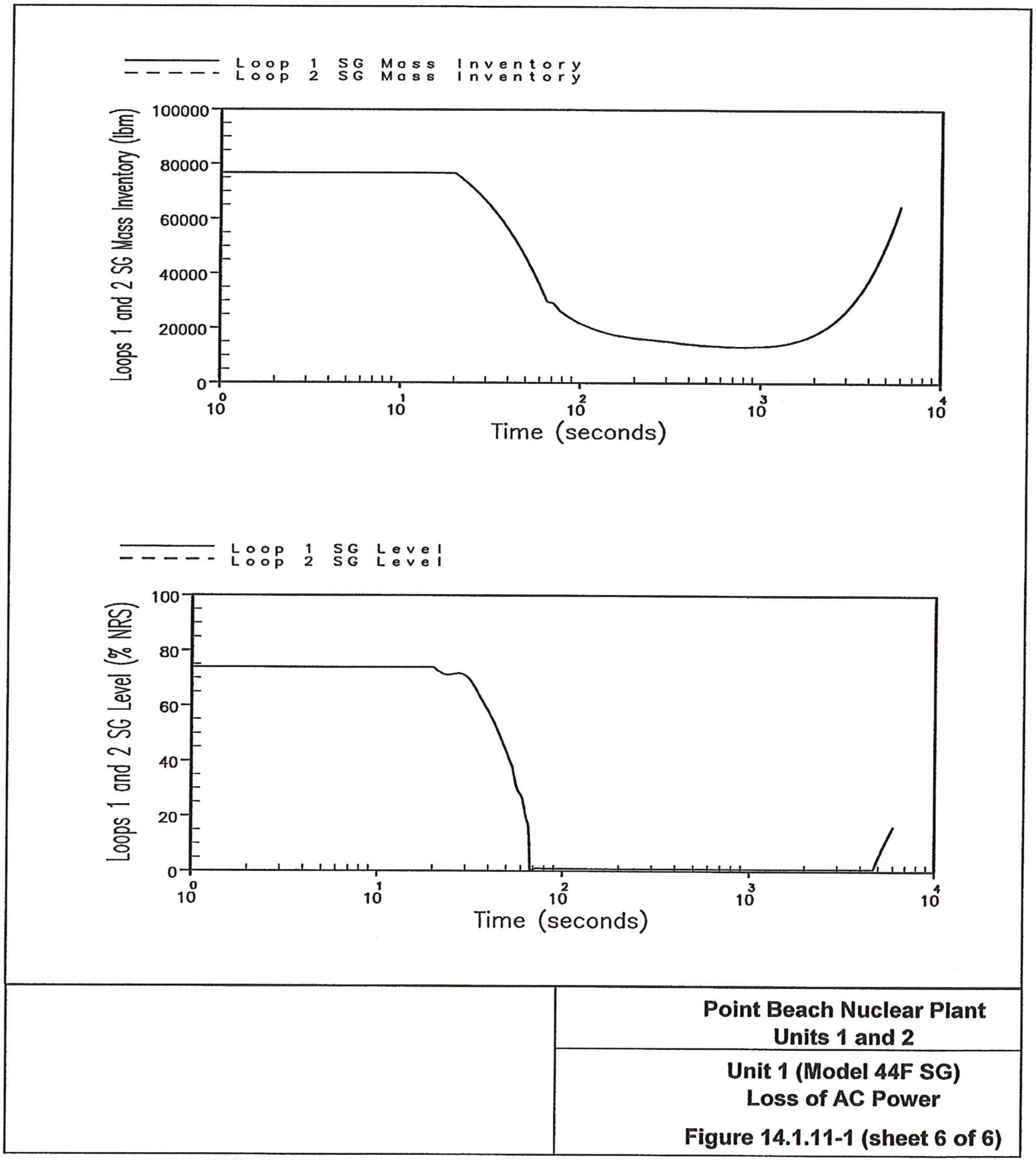
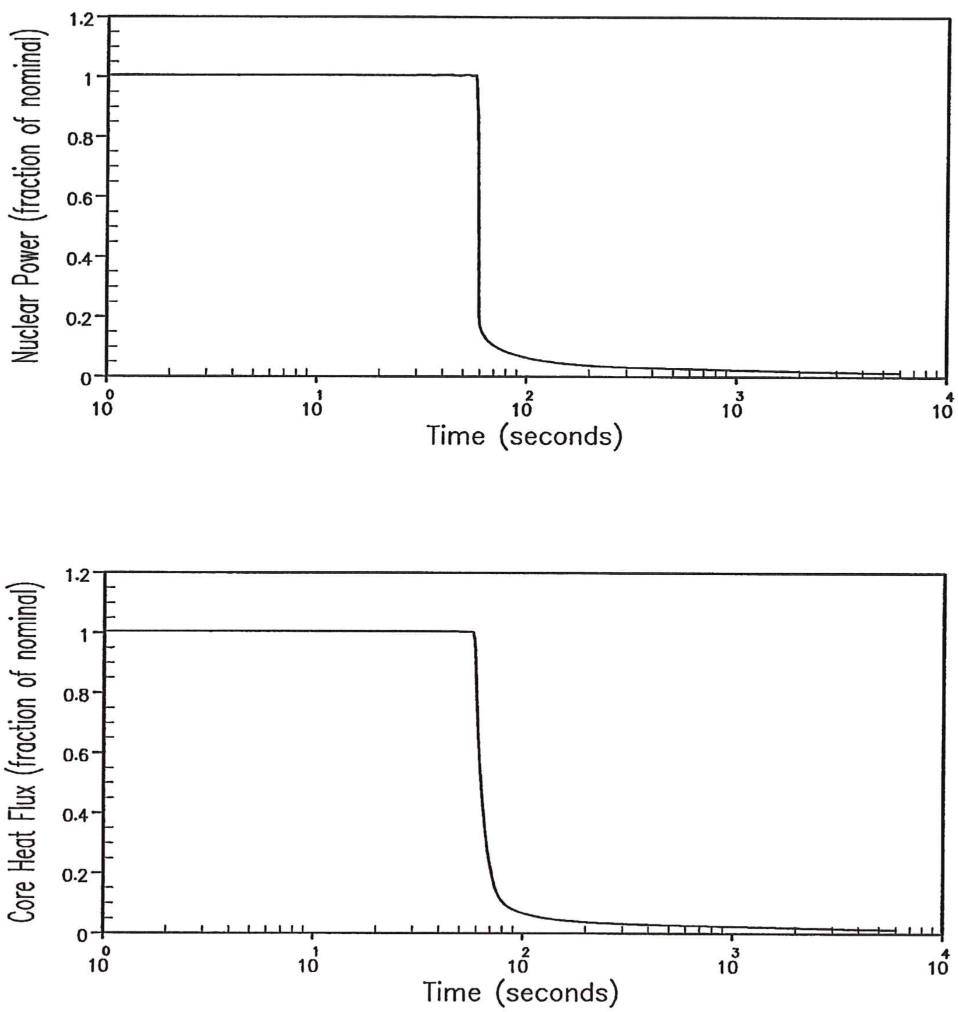


Figure 14.1.11-2 UNIT 2 (DELTA - 47 SG) LOSS OF AC POWER
Sheet 1 of 6

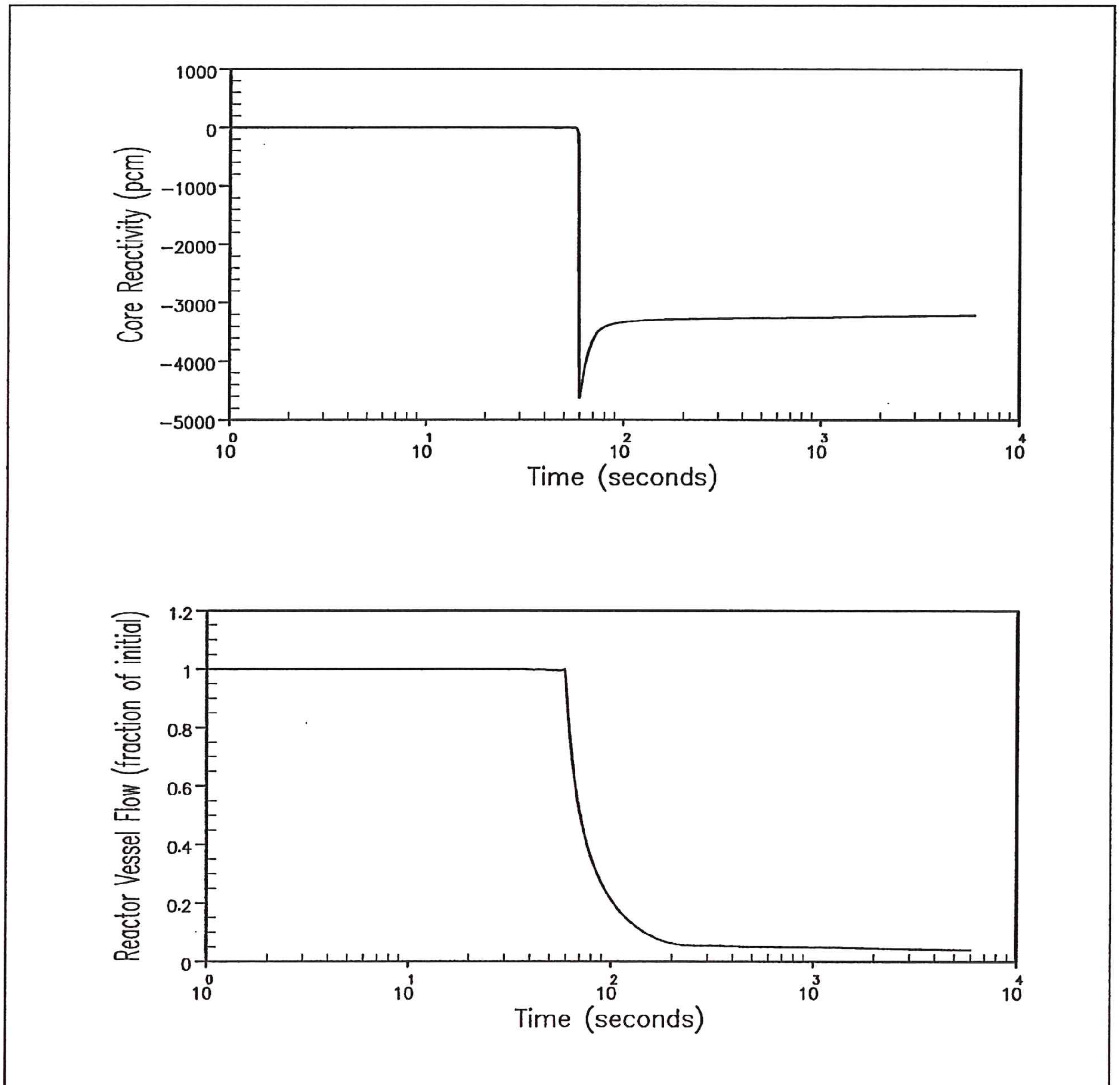


Point Beach Nuclear Plant
Units 1 and 2

Unit 2 (Delta-47 SG)
Loss of AC Power

Figure 14.1.11-2 (sheet 1 of 6)

Figure 14.1.11-2 UNIT 2 (DELTA - 47 SG) LOSS OF AC POWER
Sheet 2 of 6

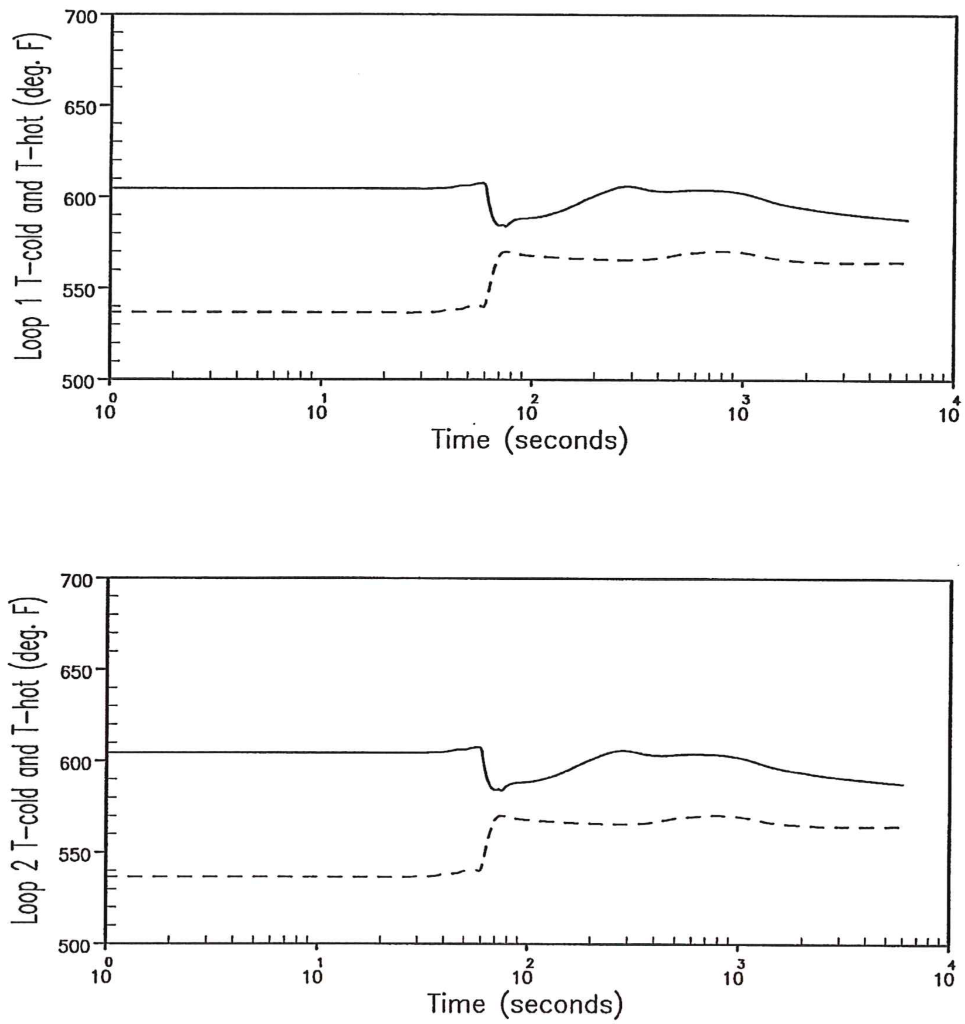


Point Beach Nuclear Plant
Units 1 and 2

Unit 2 (Delta-47 SG)
Loss of AC Power

Figure 14.1.11-2 (sheet 2 of 6)

Figure 14.1.11-2 UNIT 2 (DELTA - 47 SG) LOSS OF AC POWER
Sheet 3 of 6



Point Beach Nuclear Plant
Units 1 and 2

Unit 2 (Delta-47 SG)
Loss of AC Power

Figure 14.1.11-2 (sheet 3 of 6)

Figure 14.1.11-2 UNIT 2 (DELTA - 47 SG) LOSS OF AC POWER
Sheet 4 of 6

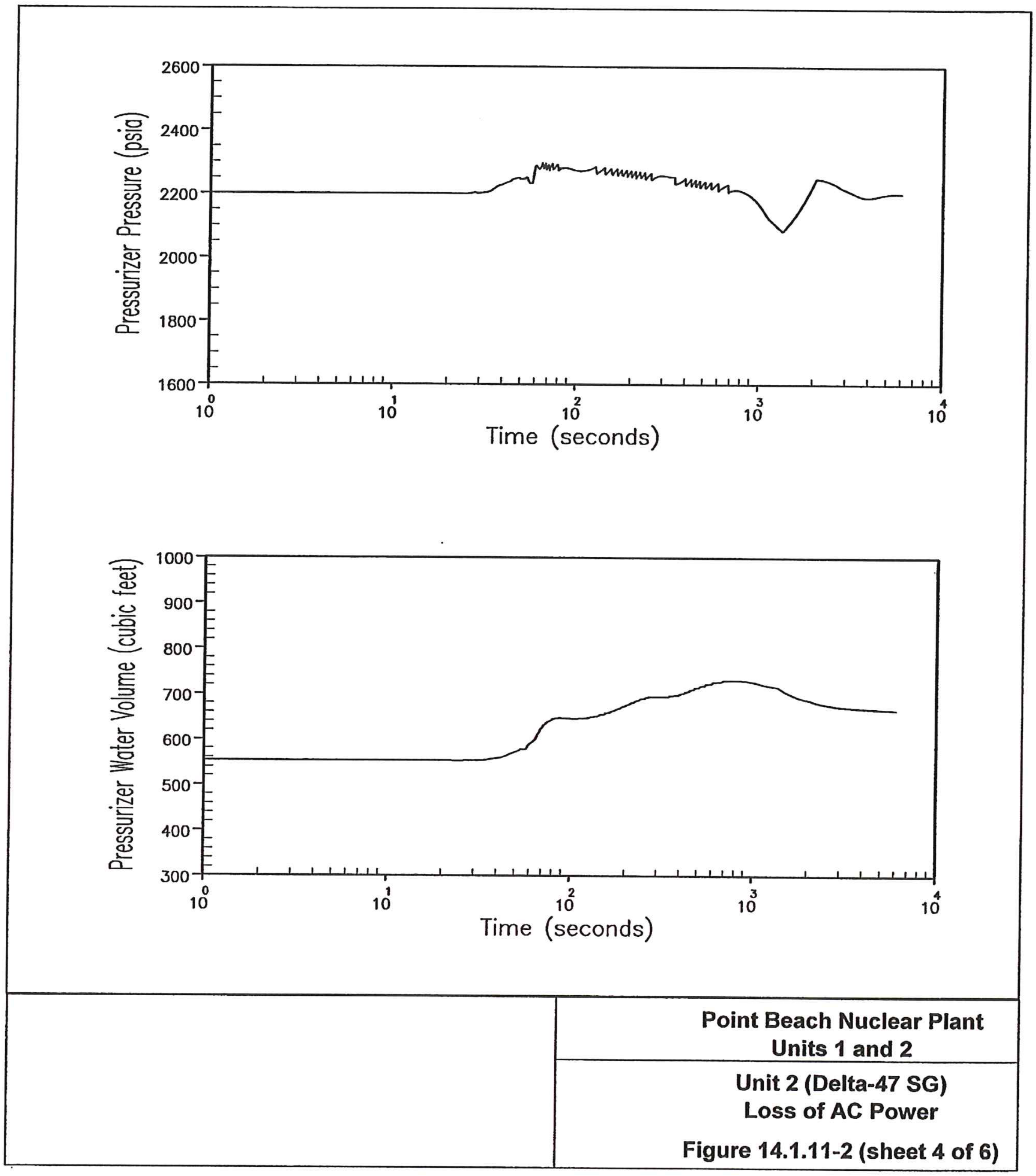
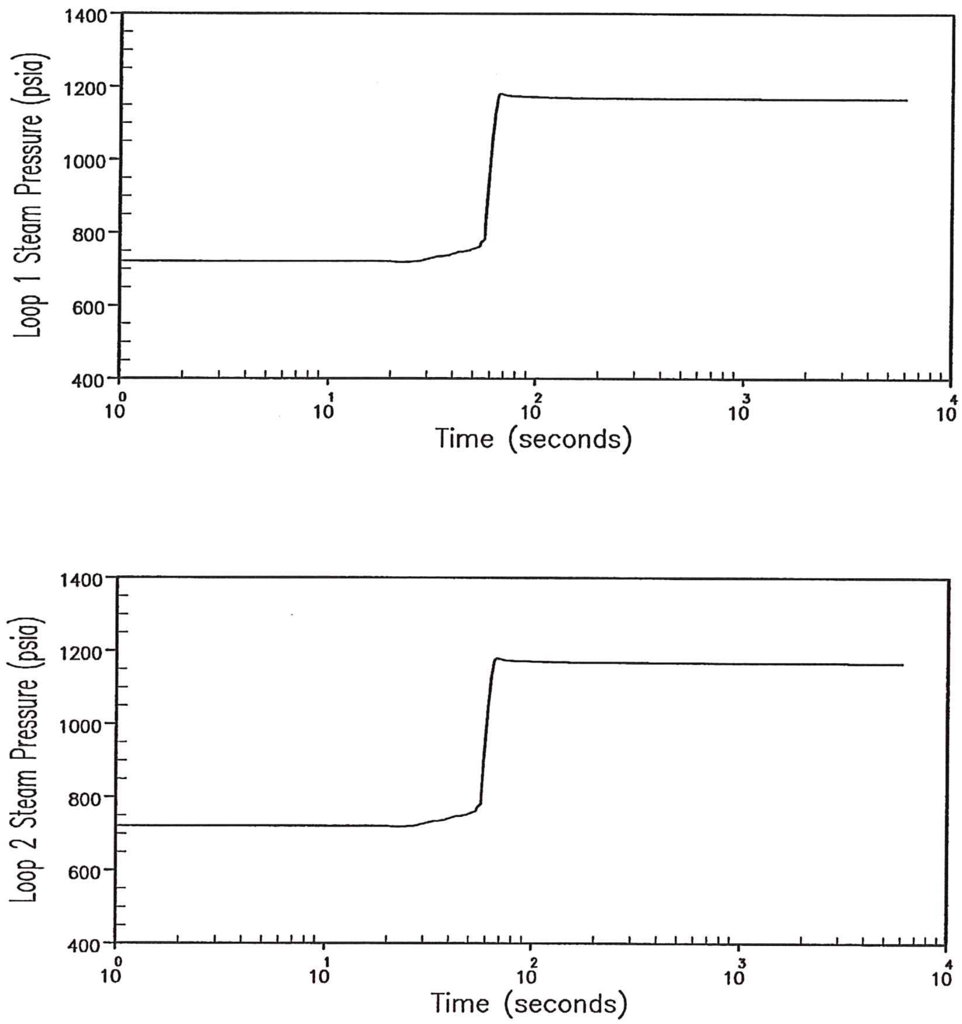


Figure 14.1.11-2 UNIT 2 (DELTA - 47 SG) LOSS OF AC POWER
Sheet 5 of 6

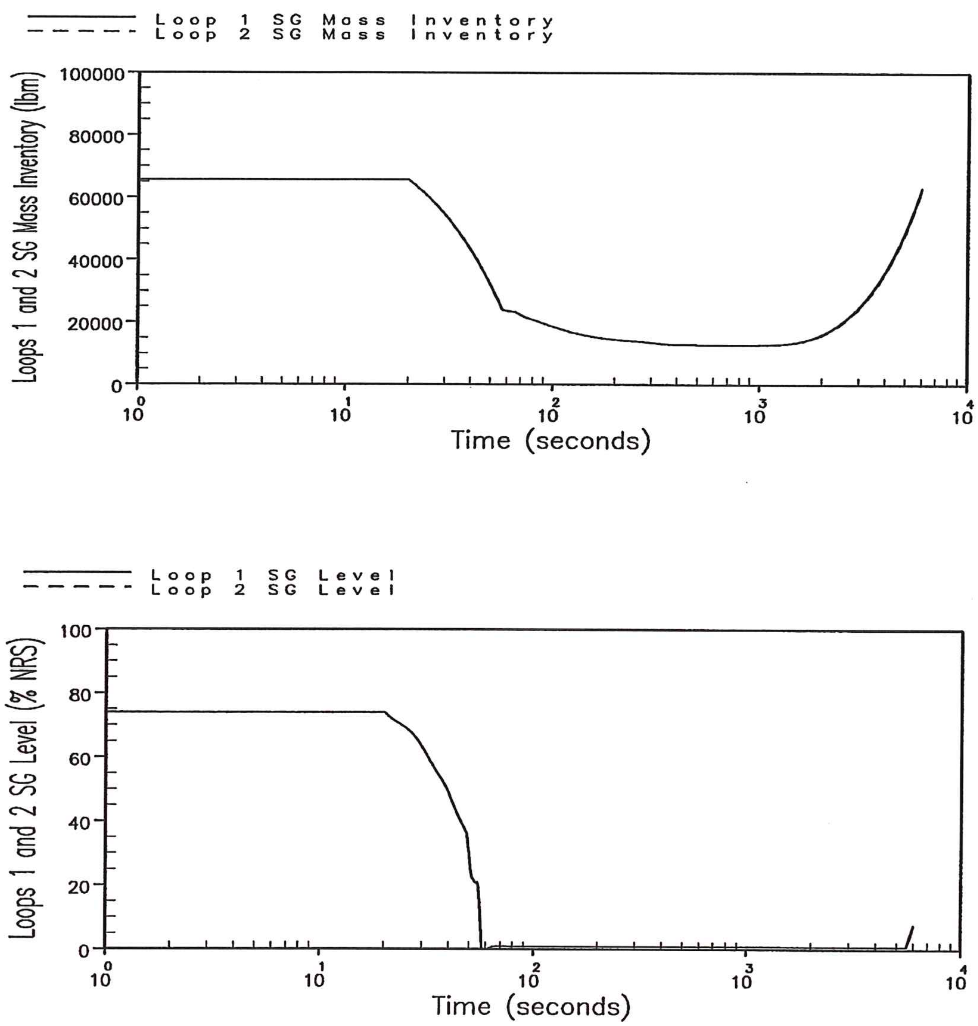


Point Beach Nuclear Plant
Units 1 and 2

Unit 2 (Delta-47 SG)
Loss of AC Power

Figure 14.1.11-2 (sheet 5 of 6)

Figure 14.1.11-2 UNIT 2 (DELTA - 47 SG) LOSS OF AC POWER
Sheet 6 of 6



Point Beach Nuclear Plant
Units 1 and 2

Unit 2 (Delta-47 SG)
Loss of AC Power

Figure 14.1.11-2 (sheet 6 of 6)

14.1.12 LIKELIHOOD OF TURBINE-GENERATOR UNIT OVERSPEED

The present advanced state of the art of rotor forging and inspection techniques guarantees practically defect-free turbine rotors. Due to the redundancy and reliability of the turbine control protection system and of the steam system, the probability of occurrence of a unit over-speeding above the design value, i.e., 132%, is very remote.

A description and operation of the electro-hydraulic governing system is located in Section 10.1. WCAP-7525-L (Reference 2) contains a description of the additional overspeed protection system and a reliability analysis demonstrating that the likelihood of exceeding the maximum design speed (i.e., 132% of rated) is practically zero. Also included are the bases of the maximum design, the characteristics of the missiles that could be generated between rated and the maximum design speed, and an analysis of the plant's capability to withstand such a missile.

Besides the provisions in the design of the turbine control and protection system during plant operation, turbine stop and governor valves will be exercised on a periodic basis to further preclude the possibility of a valve stem sticking. In addition, the turbine is periodically tested to verify the tripping speed. The remaining tripping devices are periodically checked and oil samples are analyzed.

The latest turbine overspeed analysis (Reference 16) found that based on the configuration and maintenance interval of the overspeed protection system at Point Beach, the probability of turbine missile ejection remains below the NRC acceptance criteria with extended turbine stop and governor valves, and protection system surveillance test frequency. The test frequencies for each protective systems are extended based on the recommendations from the latest analysis. The test frequencies are documented in TRM 3.7.6.

Consequences Of Turbine-Generator Unit Overspeeding (Historical Information)

Prior to the original licensing of Point Beach Nuclear Plant (PBNP), the analysis on the consequences of turbine overspeed indicated there would be only a low energy missile generated external to the low pressure turbine casing. The basic assumptions used in the analysis that led to this conclusion were deemed reasonable, at the time, by all parties involved. However, because of the potential serious consequences of external missiles, Westinghouse initiated a series of model tests to substantiate these assumptions.

The tests involved bursting of simulated low pressure turbine discs within various stationary steel cylinders modeled to approximate blade rings, inner cylinders and the outer casing. The most significant test findings were: (1) penetration occurs mostly by local punching with little bending or stretching of stationary steel; (2) a disc fragment can wedge a path between two blade rings if a blade ring is not directly opposite the rim of the disc. In either case, the stationary steel has less energy absorbing capability than originally expected, and as such, the energy required to penetrate is minimized.

As a result of these test series, new criteria were evolved for predicting the missile containing ability of the low pressure turbine structures. The previous calculations were redone using these new criteria and the results show the original position of only a low energy missile generated external to the turbine casing in the event of a turbine overspeed could no longer be maintained for original type rotor designs using shrunk-on blade discs.

Rupture of a low pressure turbine disk at or below design speed was postulated for design purposes, even though this failure is shown to have a very low probability because of design conservatism and original quality control. As a result of the updated missile generation studies, PBNP installed the independent overspeed protection system (IOPS) and the crossover steam dump system in both units. IOPS was designed and installed to be single failure proof to meet NRC commitments (Reference 12).

Since the original plant licensing, the bases for the consideration of the consequences of turbine-generator overspeeding have been modified. In a letter to Mr. James A. Martin, Westinghouse Electric Corporation Generation Technology Systems Division, dated February 2, 1987, the Nuclear Regulatory Commission (NRC) staff presented its views on precluding turbine missiles and consequential damage to safety-related structures, systems and components. The staff established that utilizing testing and inspection to maintain an initial small value of the probability of a turbine failure resulting in the ejection of fragments through the turbine casing simplifies and improves procedures for evaluation of turbine missile risks and ensures that the public health and safety are maintained. The staff provided Wisconsin Electric with the generic turbine failure guidelines for total turbine missile generation probabilities to be used for determining frequencies for turbine disc ultrasonic inspections and maintenance and testing schedules for turbine control and overspeed protection systems.

In response to the NRC guidance letter, Westinghouse prepared a report, Reference 3, for the Turbine Valve Test Frequency Evaluation Subgroup (which included Wisconsin Electric Power Company) of the Westinghouse Owners Group. That report provided a detailed probabilistic basis for extending the testing intervals of turbine valves. In performing the study, Westinghouse considered many variations of turbine stop valves and trip systems. As discussed on Page 5-2 of Reference 3, the availability of redundant overspeed protection systems, such as described in Reference 2, was not credited in the analyses because only eight of the nineteen units in the subgroup had one of these systems. The NRC approved the methodology developed in Reference 3 in the supplement to a safety evaluation dated February 7, 1989 for Northern States Power, which was the lead utility for the annual turbine valve testing. In another letter to the chairman of the turbine testing subgroup dated November 2, 1989, the NRC staff provided its generic conclusions regarding license amendment requests for changes in surveillance intervals for turbine valve tests and the applicability of Reference 3 to support these requests.

Subsequently, based on Reference 3, issuance of License Amendments 129 and 133 (Reference 4) dated October 16, 1991, for Units 1 and 2 respectively revised the turbine stop and governor valve testing from a monthly to an annual interval. They also required a commitment to work with the turbine vendor to maintain a turbine valve data base for the purpose of tracking changes in valve component failure rates, to accumulate and review valve failure rate information at least every three years to determine if the testing frequency requires modification, and to review the turbine valve test frequency anytime that major changes to the turbine system are made or a significant upward trend in turbine valve failure rate is identified.

In keeping with the Wisconsin Electric commitment to work with the turbine vendor, two reports (Reference 5 & Reference 6) were generated. These reports specified the appropriate turbine valve test intervals for PBNP. These reports recommended quarterly test, not annual. In September 2000, the WOG finalized the evaluation of BB-95/96 turbine valve failures. This report (Reference 10) concluded that the turbine valve testing frequency be quarterly and that the testing include checking the integrity of the stop valves in addition to freedom of movement and position verification. A more recent report (Reference 14 and Reference 15) recommends the maximum interval for turbine valve testing to be six months.

Unit 1 and Unit 2 each have had the original shrunk on blade disc design low pressure turbine rotors replaced with ruggedized monoblock rotors with integrally forged blade discs and complete low pressure turbine internal stream path. The replacements were done in 1997 (Unit 1) and 1998-1999 (Unit 2). Replacing the original design Low Pressure turbine rotors with ruggedized monoblock rotors with integrally forged blade discs significantly reduces concerns associated with missile generation associated with a turbine overspeed. Monoblock rotor construction with integrally forged blade discs are not susceptible to the same failure modes as the old rotors which use the shrunk-on discs.

The effect of the new rotors on turbine generator train overspeed is both positive and negative. Because of the increased efficiency of the new steam path, residual steam is allowed to perform more work towards increasing the overspeed of the unit during a trip. This effect is offset however, by the increased inertia of the new rotors with a net reduction in turbine overspeed for any given trip scenario. This effect is explained more fully in the PBNP overspeed analysis report (Reference 8) prepared by Westinghouse. Another overspeed evaluation (Reference 11) was performed by Siemens to support Extended Power Uprate (EPU). These reports provide the basis for the overspeed requirements contained in Technical Requirements Manual (TRM) 3.7.6. TRM 3.7.6 describes the operability requirements for the turbine mechanical overspeed trip system, the IOPS, and the crossover steam dump system for reactor power operation above 1518.5 MWt.

The missile generation report (Reference 9) developed by Westinghouse in 1984 and submitted to the NRC, examined the probability of various failure modes for their fully integral nuclear low pressure turbine rotors. Conclusions from this report state that the likelihood of missile generation from all mechanisms for the replacement monoblock rotors is significantly reduced. A condensed version of that report (Reference 13) was prepared and sent to PBNP in 1996 for the low pressure turbine replacements. Ductile bursting of the new rotors will not occur until the speed reaches greater than 177% rated speed. Based on the latest missile generation reports and the overspeed protection requirements and testing contained in TRM 3.7.6, the probability of missile generation for the PBNP turbine-generators is below the NRC safety criteria.

<u>References</u>

1. "History of the Special ASTM Task Force on Large Turbine and Generator Rotors," R. M. Curran, ASTM Annual Meeting, 1965, Purdue University.

2. WCAP-7525-L, (Proprietary), "Likelihood and Consequences of Turbine Overspeed at the Point Beach Nuclear Plant," J. N. Fox, June 1970.

3. WCAP-11525, (Proprietary), "Probabilistic Evaluation of Reduction in Turbine Valve Test Frequency," June 1987.

4. Robert B. Samworth, NRC, to James J. Zach, Amendment Nos. 129 and 133 to Facility Operating License Nos. DPR-24 and DPR-27, dated October 16, 1991.

5. WOG-TVTF-93-17, “Westinghouse Owners Group, TVTF Subgroup, Final Report, Update of BB-95/96 Turbine Valve Failure Rates and Effect of Destructive Overspeed Probabilities,” August 6, 1993.

6. WOG-TVTF-93-24, “Westinghouse Owners Group, TVTF Evaluation for Point Beach Units 1 & 2,” December 17, 1993.

7. Technical Requirements Manual TLCO 3.7.6, Turbine Overspeed Protection.

8. “Overspeed Analysis for Wisconsin Electric Power Company Point Beach 1 & 2 with New LP Rotors and with Uprated Conditions”, Westinghouse Electric Corporation Technical Report TR-98022, (Proprietary), dated March 6, 1998.

9. WSTG-4-NP, (Proprietary), Analysis of the Probability of the Generation of Missiles from Fully Integral Nuclear Low Pressure Rotors. Submitted to Nuclear Regulatory Commission in October, 1984.

10. “Final Update and Evaluation of BB95/96 Turbine Valve Failure Database”, Westinghouse Owners Group report MUHP 7002/8002 dated September 2000.

11. Siemens EC 08109, “FPL Point Beach 1 & 2 Missile Analysis Report, Overspeed Setpoints, and Overspeed Analysis,” (Confidential) dated July 25, 2008.

12. “Turbine Overspeed Protection & Crossover Steam Dump Operability”, Design Basis Document Discussion Paper dated August 1994.

13. “Results of the Analysis of the Probability of the Generation of Missiles from Fully Integral Nuclear Low Pressure Rotors”, (Proprietary), CT-27151, dated September 12, 1996.

14. WCAP-16054-P, (Proprietary), “Probabilistic Analysis of Reduction in Turbine Valve Test Frequency for Nuclear Plants with Siemens-Westinghouse BB-95/96 Turbines,” dated April 2003

15. Westinghouse Electric Company WEP-11-81, “Evaluation of the Continued Applicability of WCAP- 16054-P to the Modified Point Beach Units 1 and 2 Turbine Control Valves - Final Report,” (Proprietary) dated December 14, 2011.

16. MPR Associates, INC 0292-0077-CALC-001, "Effect of Extending Test Intervals of Turbine OPS Components on Point Beach OPS Reliability" dated May 15, 2020.

14.2 STANDBY SAFETY FEATURES ANALYSIS

Adequate provisions have been included in the design of the plant and its standby engineered safety features to limit potential exposure of the public for situations which have a very low probability of occurrence, but which could conceivably involve uncontrolled releases of radioactive materials to the environment. The situations which have been considered are:

1. Fuel Handling Accidents
2. Accidental Release of Waste Liquid
3. Accidental Release of Waste Gases
4. Rupture of a Steam Generator Tube
5. Rupture of a Steam Pipe
6. Rupture of a Control Rod Drive Mechanism Housing - Rod Cluster Control Assembly (RCCA) Ejection

14.2.1 FUEL HANDLING ACCIDENT

The following handling accidents are evaluated to ensure that no hazards are created:

1. A fuel assembly becomes stuck inside reactor vessel.
2. A fuel assembly or control rod cluster is dropped onto the floor of the reactor cavity or spent fuel pool.
3. A fuel assembly becomes stuck in the penetration valve.
4. A fuel assembly becomes stuck in the transfer carriage or the carriage becomes stuck.

The possibility of a fuel handling incident is very remote because of the many administrative controls and physical limitations imposed on fuel handling operations. All refueling operations are conducted in accordance with prescribed procedures under direct surveillance of a supervisor technically trained in nuclear safety. Also, before any refueling operations begin, verification of complete rod cluster control assembly insertion is obtained by tripping the rods to obtain indication of rod drop and disengagement from the control rod drive mechanisms. Boron concentration in the coolant is raised to the refueling concentration and verified by sampling. Refueling boron concentration is sufficient to maintain the clean, cold, fully loaded core subcritical with all rod cluster assemblies withdrawn. The refueling cavity is filled with water meeting the same boric acid specifications. As the vessel head is raised, a visual check is made to verify that the drive shafts are free in the mechanism housing.

After the vessel head is removed, the rod cluster control drive shafts are removed from their respective assemblies using the containment fuel handling crane and the shaft unlatching tool. A load cell is used to indicate that the drive shaft is free of the control cluster as the lifting force is applied.

The fuel handling manipulators and hoists are designed so that fuel cannot be raised above a position which provides adequate shield water depth for the safety of operating personnel. This safety feature applies to handling facilities in both the containment and in the spent fuel pool area. In the spent fuel pool, the design of storage racks and manipulation facilities is such that:

> Fuel at rest is positioned by positive restraints in an eversafe, always subcritical, geometrical array, with no credit for boric acid in the water.

Fuel can be manipulated only one assembly at a time.

Violation of procedures by placing one fuel assembly in juxtaposition with any group of assemblies in racks will not result in criticality.

Adequate cooling of fuel during underwater handling is provided by convective heat transfer to the surrounding water. The fuel assembly is immersed continuously while in the refueling cavity or spent fuel pool.

Even if a spent fuel assembly becomes stuck in the transfer tube, natural convection will maintain adequate cooling. The fuel handling equipment is described in detail in Section 9.0.

Two Nuclear Instrumentation System source range channels are continuously in operation and provide warning of any approach to criticality during refueling operations. This instrumentation provides a continuous audible signal in the containment, and would annunciate a local horn and a horn and light in the plant control room if the count rate increased above a preset low level.

Refueling boron concentration is sufficient to maintain the clean, cold, fully loaded core subcritical by at least 5% $\Delta \rho$ with all rod cluster control assemblies inserted. At this boron concentration, the core would also be more than 2% $\Delta \rho$ subcritical with all control rods withdrawn. The refueling cavity is filled with water meeting the same boric acid specifications.

All these safety features make the probability of a fuel handling incident very low. Nevertheless, it is possible that a fuel assembly could be dropped during the handling operations. Therefore, this incident is analyzed both from the standpoint of radiation exposure and accidental criticality.

Special precautions are taken in all fuel handling operations to minimize the possibility of damage to fuel assemblies during transport to and from the spent fuel pool and during installation in the reactor. All handling operations on irradiated fuel are conducted under water. The handling tools used in the fuel handling operations are conservatively designed and the associated devices are of a fail-safe design.

In the fuel storage area, the fuel assemblies are spaced in a pattern which prevents any possibility of a criticality accident. In addition, the design is such that only one fuel assembly can be handled at a given time.

The motions of the cranes which move the fuel assemblies are limited to a relatively low maximum speed. Caution is exercised during fuel handling to prevent the fuel assembly from striking another fuel assembly or structures in the containment or fuel storage building. The fuel handling equipment suspends the fuel assembly in the vertical position during fuel movements, except when the fuel is moved through the transport tube.

The design of the fuel assembly is such that the fuel rods are restrained by grid clips which provide a total restraining force of approximately 60 lb. on each fuel rod. If the fuel rods are in contact with the bottom plate of the fuel assembly, any force transmitted to the fuel rods is limited due to the restraining force of the grid clips. The force transmitted to the fuel rods during fuel handling is not sufficient to breach the fuel rod cladding. If the fuel rods are not in contact with the bottom plate of the assembly, the rods would have to slide against the 60 lb. friction force. This would absorb the shock and thus limit the force on the individual fuel rods. After the reactor is shut down, the fuel rods contract during the subsequent cooldown and would not be in contact with the bottom plate of the assembly. Considerable deformation would have to occur before the rod would make contact with the top plate and apply any appreciable load on the fuel rod. Based on the above, it is felt that it is unlikely that any damage would occur to the individual fuel rods during handling. If one assembly is lowered on top of another, no damage to the fuel rods would occur that would breach the integrity of the cladding.

If during handling the fuel assembly strikes against a flat surface, the loads would be distributed across the fuel assemblies and grid clips and essentially no damage would be expected in any fuel rods. If the fuel assembly were to strike a sharp object, it is possible that the sharp object might damage the fuel rods with which it comes in contact, but breaching of the cladding is not expected.

The refueling operation experience that has been obtained with Westinghouse reactors has verified the expectation that no fuel cladding integrity failures occur during any fuel handling operations.

Rupture of all fuel elements in a withdrawn assembly is assumed as a conservative limit for evaluating the environmental consequences of a fuel handling incident. The remaining fuel assemblies are so protected by the storage rack structure that no lateral bending loads would be expected.

Radiological Consequences of a Fuel Handling Accident (FHA)

This section describes the assumptions and analyses performed to determine the potential offsite and control room radiological consequences for the postulated design basis fuel handling accident based on an Alternative Source Term (AST) in accordance with Regulatory Guide 1.183 (Reference 1). The analyses were performed such that the results are bounding for an accident occurring inside either containment or the spent fuel pool.

Input Parameters and Assumptions: The following assumptions were used in the analyses of the offsite and control room radiological consequences:

1. The reactor was assumed to have been operating at 1811 MWt prior to shutdown.

2. The reactor has been sub-critical for a minimum of 65 hours when the fuel handling accident occurs.

3. The fuel handling accident is assumed to result in damage to all of the fuel rods in the equivalent of one fuel assembly to the extent that all their gap activity is released.

4. The fission product gap inventories used are 12% for I-131, 30% for Kr-85, and 10% for all other noble gas and iodine nuclides. These values are higher than those in Table 3 to Reference 1. The gap fractions have been increased to reflect the fact that some nuclear fuel assemblies exceed the criteria of RG 1.183, Table 3, footnote 11. As a conservative approach, the gap fractions are those from RG 1.25 (Reference 6) with the value for I-131 increased by 20%, consistent with the recommendation in NUREG/CR-5009 (Reference 7).

5. The fission product inventory for the average fuel assembly at 65 hours after shutdown is provided in Table 14.2.1-1.

6. To account for differences in core power distribution across the core, the averaged fission product inventory in the dropped assembly is conservatively multiplied by a radial peaking factor of 1.7.

7. Consistent with the guidance of Reference 1, the iodine species in the pool is 99.85% elemental and 0.15% organic.

8. Consistent with the guidance of Reference 1, the effective decontamination factor (DF) used for iodine is 200 which accounts for scrubbing of the iodine as it evolves through the pool water. Applicability of this assumption is predicated on a minimum water level of 23 ft above the top of the reactor vessel flange and over the top of the assemblies in the spent fuel pool during movement of irradiated fuel assemblies. No DF is applied to the noble gas releases (i.e., no retention of the noble gases available for release) and an infinite DF is applied to the particulate radionuclides (i.e., the cesium and rubidium).

9. The activity released from the pool is assumed to be released from the containment refueling cavity or the spent fuel pool to the outside atmosphere over a two-hour period.

10. No credit is taken for removal of iodine by containment or spent fuel pool building ventilation systems' filters nor is credit taken for isolation of release paths. In addition, no credit is taken for the containment equipment hatch placement or closure nor is credit taken for having personnel air lock doors capable of closure.

11. The exclusion area boundary (EAB) and low population zone (LPZ) atmospheric dispersion factors values are found in Table 14.2.1-2.

12. The control room atmospheric dispersion factor is based on a release from the Unit 2 containment building purge stack. This release point results in a bounding analysis because the assumptions and parameters used to model the activity released due to a FHA inside either containment are identical to those for a FHA in the spent fuel pool. The control room atmospheric dispersion factor was developed using ARCON96 (Reference 5). The control room atmospheric dispersion factor value is found in Table 14.2.1-2. The meteorological data set used to develop the control room atmospheric dispersion factor was collected at the site from September 2000 to September 2005.

13. Breathing rates assumed are consistent with Reference 1 and are listed in Table 14.2.1-2.

14. The total effective dose equivalent (TEDE) doses are determined at each location. The TEDE is equivalent to the committed effective dose equivalent (CEDE) from inhalation and the deep dose equivalent (DDE) from external exposure. Effective dose equivalent (EDE) is used in lieu of DDE in determining the contribution of external dose to the TEDE consistent with Reference 1. The dose conversion factors (DCFs) used in determining the CEDE dose are from the EPA Federal Guidance Report No. 11 (Reference 2). The dose conversion factors used in determining the EDE dose are from the EPA Federal Guidance Report No. 12 (Reference 3).

15. The site-boundary (also called the exclusion area boundary (EAB)) dose is calculated for the worst two-hour period and the low population zone (LPZ) dose is calculated for the release duration, that is two-hours for FHA. The control room personnel dose is calculated for 30 days.

16. The control room HVAC system is assumed to be initially operating in normal MODE, whereby fresh air is being brought into the control room unfiltered at a rate of 2000 cfm. It is conservatively assumed that the emergency HVAC MODE is entered 10 minutes after event initiation based on the area monitor inside the control room reaching its alarm set-point. The emergency HVAC MODE is assumed to provide 2500 cfm of filtered outside air with 1955 cfm filtered recirculation.

17. Parameters used in the control room personnel dose calculations are provided in Table 14.2.1-2. These parameters include the normal operation flow rates, the post-accident operation flow rates, unfiltered inleakage rate, control room volume, filter efficiencies, and the control room operator breathing rates.

Acceptance Criteria

The EAB and LPZ dose Standard Review Plan (SRP) 15.0.1 (Reference 4) acceptance criteria for a fuel handling accident is 6.3 rem TEDE, which is approximately 25% of the 10 CFR 50.67 limit of 25 rem. The control room personnel dose acceptance criterion is 5 rem TEDE per 10 CFR 50.67.

Results and Conclusions

The offsite and control room personnel doses due to a design basis FHA are presented below. These doses are within the acceptance criteria of SRP 15.0.1 and the dose limits of 10 CFR 50.67.

Location	Acceptance Criteria (rem)	TEDE (rem)
Exclusion Area Boundary	6.3	2.7
Low Population Zone	6.3	0.2
Control Room	5	4.3

14.2.1.1 References:

1. USNRC, Regulatory Guide 1.183, "Alternative Radiological Source Terms for Evaluating Design Basis Accidents at Nuclear Power Reactors," July 2000.

2. US EPA, "Limiting values of Radionuclide Intake and Air Concentration and Dose Conversion Factors for Inhalation Submersion, and Ingestion," Federal Guidance Report No. 11, September 1988.

3. US EPA, "External Exposure to Radionuclides in Air, Water, and Soil," Federal Guidance Report No. 12, September 1993.

4. Standard Review Plan (SRP) Section 15.0.1, "Radiological Consequence Analyses Using Alternative Source Terms," July 2000.

5. J. V. Ramsdell, Jr. and C. A. Simonen, "Atmospheric Relative Concentrations in Building Wakes," NUREG/CR-6331, Revision 1, May 1997.

6. USNRC, Regulatory Guide 1.25, “Assumptions Used for Evaluating the Potential Radiological Consequences of a Fuel Handling Accident in the Fuel Handling and Storage Facility for Boiling and Pressurized Water Reactors,” March 1972.

7. NUREG/CR-5009, “Assessment of the Use of Extended Burnup Fuel in Light Water Power Reactors,” February 1988.

8. Calculation CN-CRA-08-14, “EC 12732 Point Beach - Fuel Handling Accident Doses for the EPU,” dated May 11, 2011.

Table 14.2.1-1 ACTIVITY IN AN AVERAGE FUEL ASSEMBLY AT 65 HOURS POST SHUTDOWN

Nuclide	Activity (Ci)
I-130	2.29E+02
I-131	3.43E+05
I-132	3.50E+05
I-133	1.03E+05
I-135	8.76E+02
Kr-85m	4.89E+00
Kr-85	5.07E+03
Kr-87	9.34E-11
Kr-88	3.84E-02
Xe-131m	4.52E+03
Xe-133m	1.65E+04
Xe-133	6.95E+05
Xe-135m	1.43E+02
Xe-135	1.45E+04

Note: Neither the gap fractions nor the radial peaking factor have been applied to these values.

Table 14.2.1-2 ASSUMPTIONS USED FOR THE FHA DOSE ANALYSIS

Parameter	Value
Core Power Level (1800 MWt x 1.006)	1811 MWt
Radial Peaking Factor	1.7
Number of Damaged Assemblies	1 assembly
Fission Product Decay Period	65 hr
Gap Fractions	
I-131	12% of activity
Kr-85	30% of activity
Other Iodine and Noble Gas	10% of activity
Water Level (minimum for reactor cavity or pool)	23 ft [a]
Overall Pool Iodine Decontamination Factor	200
Noble Gas Decontamination Factor	1
Particulate Decontamination Factor	Infinite
Filter Efficiency	No filtration
Isolation of Release	No isolation
Atmospheric Dispersion Factors (χ/Q)	
Exclusion Boundary Area	5.0E-04 sec/m^3
Low Population Zone	3.0E-05 sec/m^3
Control Room, Limiting Case – Unit 2 Purge Stack	6.94E-03 sec/m^3
Breathing Rate	3.5E-04 m^3/sec
Control Room HVAC Parameters	
Normal MODE Ventilation Flow Rates	
Filtered Makeup Flow Rate	0 cfm
Filtered Recirculation Flow Rate	0 cfm
Unfiltered Makeup Flow Rate	2000 cfm
Unfiltered Inleakage Flow Rate	300 cfm
Emergency MODE Ventilation Flow Rates	
Filtered Makeup Flow Rate	2500 cfm
Filtered Recirculation Flow Rate	1955 cfm
Unfiltered Makeup Flow Rate	0 cfm
Unfiltered Inleakage Flow Rate	300 cfm
Filter Efficiencies	
Elemental	95%
Organic	95%
Particulate	99%
Control Room Isolation Actuation Signal/Timing	
Area Monitor High Set-point	2 mrem/hr
Timing of High Radiation Signal	<10 min
Occupancy Factors	
0-24 hours	1.0
1 – 4 days	0.6
4 – 30 days	0.4

a. Measured from reactor vessel flange for reactor cavity or top of fuel assemblies for spent fuel pool.

14.2.2 ACCIDENTAL RELEASE-RECYCLE OR WASTE LIQUID

Section 14.2.2 relocated to Section 11.1.5

14.2.3 ACCIDENTAL RELEASE-WASTE GAS

Section 14.2.3 relocated to Section 11.2.5

14.2.4 STEAM GENERATOR TUBE RUPTURE

General

A complete single tube break adjacent to the tube sheet in a steam generator is examined. Since the reactor coolant pressure is greater than the steam generator shell side pressure, the contaminated reactor coolant discharges into the secondary system.

The activity release is limited by operator action to limit the primary to secondary fluid leakage and terminate the releases from the affected steam generator to the atmosphere.

Steam Release Analysis

A mass and energy balance is used to calculate the primary-to-secondary break flow and steam generator steam releases resulting from a steam generator tube rupture accident. The analysis provides conservatively high mass transfers for use in the radiological consequences analysis. The analysis incorporates and supports the following assumptions:

- Core power of 1800 MWt.
- Vessel average temperature range between 558°F to 577°F.
- 0-percent or 10-percent steam generator tube plugging levels.
- Steam generator models 44F or Delta 47 in use at Unit 1 and Unit 2, respectively.
- The ruptured steam generator pressure is maintained at the lowest steam generator safety valve re-seat pressure of 930 psia (which includes 12.6-percent blowdown and 3-percent uncertainty)
- Maximum safety injection flow rates result in an equilibrium break flow rate of approximately 54 lbm/sec.
- Consistent with the vintage of Point Beach Units 1 and 2, no single failures are modeled in the analysis.

For the purpose of this analysis, it is assumed that when reactor trip occurs station normal power is lost. The reactor coolant pumps will then coast down and the condenser circulating water pumps will stop. On-site emergency power is available from the diesel generators to supply the necessary engineered safeguards equipment.

Core decay heat is then removed by natural circulation of reactor coolant to the steam generators. The atmospheric steam relief valves will open automatically to relieve high pressure in the steam generators. Steam dump to the condenser is isolated when condenser vacuum is lost. During this time, secondary safety valves may also lift.

Main steam safety valves open to restore primary system temperature to the hot shutdown value. They are designed to blowdown to 12.6% below the setpoint pressure to remove decay heat while maintaining the hot shutdown (hot standby per Technical Specification definitions) system pressure. With no operator action, the main steam safety valves would maintain the primary system temperature between approximately 535 and 557°F.

The safety injection system borates the reactor coolant system within several minutes and will eventually refill the reactor coolant system and pressurize it to a pressure at which the injection flow is balanced by discharge through the broken tube. Initially, the water level in the unaffected steam generator will decrease because the auxiliary feedwater supply will not match the steam relief needed to reduce the reactor coolant system to no-load temperature. When the steam dump is reduced to balance decay heat, the auxiliary feedwater supply exceeds decay heat requirements and the liquid level in the unaffected steam generator will increase. Because of the discharge from the reactor coolant system, the rate of increase in liquid level is greatest in the ruptured steam generator.

Up to this point, automatic actions will ensure safe shutdown of the reactor. Automatic actuation of safety injection will ensure that the core will not be damaged, and thus limit radioactivity releases to the level of the concentrations in the reactor coolant.

AFW flow will be initiated 60 seconds after the low-low SG water level setpoint is reached. Full AFW flow (i.e, 100 percent flow) at a minimum of 275 gpm will be obtained within 150 seconds to one SG, or split equally between two SGs.

For a SGTR, after the initial transient, the operator would isolate the affected steam generator, and perform a limited cooldown to assure subcooling margin by providing AFW to the intact SG. After realignment by the operator, up to 230 gpm could be delivered to the intact SG. (Reference 8). The safety injection system will maintain reactor coolant system pressure and pressurizer level, compensating for losses due to discharge in reaching pressure equilibrium between the reactor coolant system and the now isolated ruptured steam generator and for contraction losses during the remainder of cooldown. After cooldown, RCS depressurization would be performed to restore reactor coolant inventory, and subsequently the safety injection flow would be terminated to stop the primary-to-secondary break flow.

The analysis assumes that break flow to the ruptured steam generator is terminated 30 minutes following accident initiation. Steam releases from the ruptured steam generator are terminated when primary and secondary pressures are equalized at 30 minutes. Steam releases from the intact steam generator continue until the residual heat removal system takes over decay heat removal.

A fraction of the break flow flashes directly into steam upon entering the secondary side of the ruptured steam generator. The pre- and post-trip flashing fractions are conservatively calculated assuming the break flow is at the hot leg temperature. The flashing fractions are calculated to be 0.22 prior to reactor trip and 0.13 following reactor trip.

After the primary-to-secondary break flow has been terminated, the RCS would be cooled down to cold shutdown conditions. The cooldown is initiated by manually controlling the steam relief on the unaffected steam generator. During the cooldown, no further activity is discharged from the isolated steam generator.

The above assumptions lead to a conservative upper bound of 124,500 pounds for the total amount of reactor coolant transferred to the ruptured steam generator including 18,110 pounds of flashed primary coolant transferred to the ruptured steam generator. The assumptions also result in the release of 88,100 pounds of steam from the ruptured steam generator.

Because the licensing basis analysis described above is quite conservative it does not require operators to demonstrate the ability to terminate break flow within 30 minutes from the start of the event. It is recognized that the operators may not be able to terminate break flow within

30 minutes for all postulated steam generator tube rupture events. The operator actions applicable to the SGTR dose and margin-to-overfill analyses are specified below under the section for operator actions.

Margin to Overfill (MTO) Analysis)

Demonstration that the ruptured steam generator does not overfill during the accident has been performed by utilizing an NRC-approved thermal hydraulic analysis code. Reference 1 includes the NRC's approval of the LOFTTR2 computer code that has been used for the overfill analysis. This code simulates the plant response, and models specific operator actions. Thus, a more realistic representation of the break flow during the accident is obtained. The auxiliary feedwater flow is assumed to be maximum with a minimum delay time after reaching the low-low SG water level. Critical operator actions included in the LOFTTR2 simulation include: isolation of auxiliary feedwater flow to the ruptured steam generator (based on level indications), isolation of the ruptured steam generator, cooldown of the RCS by dumping steam from the intact steam generator, depressurizing the RCS, and terminating safety injection flow to terminate break flow.

Consistent with the vintage of Point Beach Units 1 and 2 and the licensing basis analysis, no single failures are modeled in the margin to overfill analysis. Instead, the following items from the unaffected unit are credited to mitigate the tube rupture event: (1) control-grade instrument air (IA), which is supplied from a shared system; and (2) in the event of a dual-unit LOOP, operator actions by the crew of the shared unit to restore power supply to the shared IA system. The ADV operator and the IA system are assumed to operate despite being non-safety related because both of the ADVs are required by Technical Specifications to be operable, and at least one IA compressor can be powered by an EDG, which would assure, with diversity, that IA is available to operate the ADV.

With the exception of the single failure assumption, the analysis is performed following the guidance in Reference 1. Conservative deviations from the Reference 1 method were taken to address the issues raised by NSAL-07-11 (Reference 2). The analysis demonstrates that following the complete severance of a steam generator tube break flow is terminated approximately 44 minutes after initiation of the tube rupture and that overfill of the ruptured steam generator does not occur.

Operator Actions for SGTR Dose and MTO Analyses

The operator actions used in the dose and MTO analyses are the following as documented in Reference 5:

- Isolate the ruptured SG within 6 minutes.
- Initiate RCS cooldown within 17 minutes after the ruptured SG is isolated.
- Initiate RCS depressurization within 3 minutes following the completion of cooldown.
- Secure ECCS within 2 minutes following the completion of depressurization.

Although not a direct operator action, the limiting SGTR analysis demonstrates that the SG tube break flow is terminated approximately 44 minutes after initiation of the tube rupture by crediting the above operator actions.

Radiological Consequences of a Steam Generator Tube Rupture Accident

The analysis of the SGTR radiological consequences uses the analytical methods and assumptions outlined in the RG 1.183 (Reference 3).

The quantity of radioactivity released to the environment due to a SGTR depends upon primary and secondary coolant activity, iodine spiking effects, primary-to-secondary break flow, break flow flashing, attenuation of activity carried by the flashed portion of the break flow, partitioning of iodine between the liquid and steam phases, moisture carryover, the mass of fluid released from the generators and liquid-vapor partitioning in the turbine condenser hot well. All of these parameters were conservatively evaluated for a design basis double ended rupture of a single tube

The concentrations of iodines and noble gasses in the RCS at the time the accident occurs are based on 520 µCi/gm of DE Xe-133 and the Technical Specification limit of 0.5 µCi/gm of dose equivalent (DE) I-131. The alkali metal concentration in the RCS is based on the fuel defect level that corresponds to 0.5 µCi/gm DE I-131. The iodine activity concentration of the secondary coolant at the time the accident occurs is assumed to be equivalent to the Technical Specification limit of 0.1 µCi/gm of DE I-131. The alkali metal activity concentration of the secondary coolant at the time the accident occurs is assumed to correspond to 0.1 µCi/gm of DE I-131. The equilibrium nuclide concentrations are presented in Table 14.1.8-4. In addition, two iodine spikes are considered.

Pre-accident Spike - A reactor transient has occurred prior to the event and has raised the primary coolant iodine concentration to a conservative value of 60 µCi/gm DE I-131.

Accident Initiated Spike - The primary coolant iodine concentration is initially at the Technical Specification limit of 0.5 µCi/gm DE I-131. Following the primary system depressurization and reactor trip associated with the event, an iodine spike is initiated in the primary system. The spike increases the iodine appearance rate from the fuel to the coolant to a value 335 times greater than the release rate corresponding to the initial primary system iodine concentration. The duration of the spike is 8 hours

Offsite power is assumed to be lost at reactor trip. Prior to reactor trip, activity is released through the condenser air ejector exhaust and a partition factor of 0.01 for iodines and alkali metals is assumed for this release path. Although the air ejector exhausts through the auxiliary building vent stack to the environment, the atmospheric dispersion factors associated with the Unit 2 safety valves is used to determine the concentration of this release path at the control room intake. After reactor trip and loss of offsite power, flow to the condenser is isolated.

An iodine partition factor of 0.01 (curies iodine/gm steam) / (curies iodine/gm water) and a particulate retention factor of 0.0025 are applied to both SGs based on full power moisture carryover.

The iodine and alkali metal transport model used in this analysis accounts for break flow flashing, steaming and partitioning. The model assumes that a fraction of the activity carried by the break flow becomes airborne immediately due to flashing and atomization. All of the iodine and alkali metal in the flashed break flow is assumed to be transferred out of the steam generator. Droplet removal by the dryers is conservatively neglected. The time dependent iodine and alkali metal removal efficiency for scrubbing of steam bubbles as they rise from the rupture site to the water surface was not calculated and was conservatively neglected. The fraction of primary coolant iodine that is not assumed to become airborne immediately mixes with the secondary water, and is assumed to become airborne at a rate proportional to the steaming rate.

Since there is no penalty taken for tube uncovery and scrubbing is not credited, the assumed location of the tube rupture is not significant for the radiological analysis. The thermal and hydraulic analysis has conservatively addressed the issue of the location of the tube rupture in the calculations of break flow rate and flashing fraction.

All noble gases in the break flow and primary-to-secondary leakage are assumed to be transferred instantly out of the steam generator to the atmosphere.

The integrated tube rupture break flow, flashed break flow, and integrated atmospheric steam releases are summarized in Table 14.2.4-2 for the different time intervals considered in the analysis. The time intervals considered are: from event initiation until reactor trip, reactor trip to 30 minutes, 30 minutes to 2 hours, 2 hours to 8 hours, 8 hours to 24 hours, and 24 hours to 30 hours. The plant cooldown to RHR operating conditions is assumed to be accomplished within 30 hours after initiation of the SGTR and steam releases are terminated at this time.

A total primary-to-secondary leak rate of 2000 gm/min is assumed to exist prior to the SGTR. The leak is assumed to be distributed with 1000 gm/min to the intact steam generator and 1000 gm/min to the ruptured steam generator. The leakage to the intact steam generator is assumed to persist for the duration of the accident.

Dose conversion factors, offsite atmospheric dispersion factors and breathing rates are provided in Table 14.1.8-3.

The control room HVAC begins in normal mode. Actuation of the emergency mode is conservatively assumed to occur when the SI/containment isolation actuation setpoint is reached at 220 seconds. Control room models are provided in Table 14.1.8-6.

Acceptance Criteria

The standard Review Plan (SRP) 15.0.1 (Reference 4) offsite dose acceptance criterion for a SGTR with pre-accident iodine spike is the 10 CFR 50.67 limit of 25 rem TEDE and the acceptance criterion for a SGTR with an accident initiated iodine spike is 2.5 rem TEDE, which is 10% of the 10 CFR 50.67 limit of 25 rem TEDE. The control room personnel dose acceptance criterion is 5 rem TEDE per 10 CFR 50.67.

Results and Conclusions

The results of the offsite and control room dose analyses are provided in Table 14.2.4-1, and indicate that the acceptance criteria are met. The exclusion area boundary doses reported are for the worst 2 hour period, determined to be from 0 to 2 hours.

Multiple Tube Ruptures

A much larger dose, e.g., TEDE dose of 25 rem at the exclusion radius, can only result from the rupture of sufficient steam generator tubes to cause fuel cladding failure.

Operating experience with steam generators of the type used in this plant has not shown significant numbers of single gross and immediate tube failures. Small leaks in a single tube which caused erosion type damage to adjacent tubes have been reported, but did not cause a rupture of the adjacent tubes. Thus, if a single tube failure were postulated, it is probable that adjacent tubes would not be damaged but any adjacent failure would be an erosion-caused leak rather than a sudden gross failure.

To perform a rigorous analysis of the flow dynamics of blowdown through multiple tube ruptures, one must understand and define mathematically the physical configuration of the ruptures. Because no reasonable mechanism exists for the multiple ruptures, it is instead just as meaningful to analyze the consequences of a pipe rupture, equivalent in terms of discharge rate to various multiples of the single tube discharge rate.

Such an analysis reveals that the core cooling system will prevent clad damage for break discharge rates equal to or smaller than that resulting from a broken pipe between 4 inches and 6 inches in diameter. The discharge rates which bracket the onset of cladding damage correspond to 18 and 40 times the discharge from a single severed steam generator tube. Actually, the ratio would be much larger owing to the fact that the discharge from a tube failure will be limited by the back pressure in the steam generator. Ultimately, the tube discharge would terminate when the reactor coolant system and the steam generator reached pressure equilibrium. The operator can initiate cooldown through the unaffected steam generator.

These conclusions are based on single-failure mode performances of the core cooling system. The core does not become uncovered by the calculated quiet level in those cases where cladding damage is found to be prevented.

The incredibility of multiple simultaneous tube failures is supported by the following reasoning:

1. At the maximum operating internal pressure the tube wall sees only about 1530 psi compared with a calculated bursting pressure in excess of 11,100 psi based on ultimate strength at design temperature.

2. The above margin applies to the longitudinal failure modes, induced by hoop stress. This failure mode is the least likely to cause propagation of failure tube-to-tube. An additional factor of two applies to ultimate pressure strength in the axial direction tending to resist double-ended failure (total factor of 14.6).

3. Failures induced by fretting, corrosion, erosion, or fatigue are of such a nature as to produce tell-tale leakage in substantial quantity while ample metal remains to prevent severance of the tube (a small fraction of the original tube wall section) as indicated by the margin derived in 2 above. Thus, any incipient failures that would develop to the point of severe leakage requiring a shutdown for plugging or repair, in accordance with Technical Specifications, would happen long before the large safety margin in pressure strength is lost.

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2. Nuclear Safety Advisory Letter, NSAL-07-11, “Decay Heat Assumption in Steam Generator Tube Rupture Margin -to-Overfill Analysis Methodology,” November 15, 2007.

3. USNRC Regulatory Guide 1.183, “Alternate Radiological Source Terms for Evaluating Design Basis Accidents at Nuclear Power Reactors,” July, 2000.

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6. NRC Safety Evaluation, “Point Beach Nuclear Plant Units 1 and 2-Issuance of License Amendments Re: Auxiliary Feedwater System Modification,” dated March 25, 2011.

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10. CN-CRA-08-35, Rev 1, “Point Beach Units 1 & 2 Steam Generator Tube Rupture Doses for the Extended Power Uprate.”

11. CN-CRA-08-40, Rev 0, “Supplemental Steam Generator Tube Rupture (SGTR) Thermal Hydraulic Input to Dose Analysis for Point Beach Units 1 and 2 (WEP/WIS) to Support the Extended Power Uprate.”

12. CN-CRA-08-47, Rev 1, “Supplemental Steam Generator Tube Rupture (SGTR) Margin to Overfill Analysis for Point Beach Units 1 and 2 (WEP/WIS) to Support the Extended Power Uprate.”

Table 14.2.4-1 STEAM GENERATOR TUBE RUPTURE ACCIDENT DOSES

A. With Pre-Accident Iodine Spike

0 - 2 hr Dose at Site Boundary	0 - 30 hr Dose at LPZ	0 - 30 day Dose in CR
2.0 rem TEDE	0.2 rem TEDE	1.9 rem TEDE

B. With Accident-Initiated Iodine Spike

0 - 2 hr Dose at Site Boundary	0 - 30 hr Dose at LPZ	0-30 day Dose in CR
0.6 rem TEDE	0.1 rem TEDE	0.5 rem TEDE

Table 14.2.4-2 MASS TRANSFER USED FOR SGTR DOSE ANALYSES

Ruptured Steam Generator		
Pre-trip Break Flow	21,300 lbm	(0-220 sec)
Post-trip Break Flow	103,200 lbm	(0-220 sec)-30 min)
Pre-trip Flashed Break flow	4,690 lbm	(0-220 sec)
Post-trip Break Flow	13,420 lbm	(0-220 sec-30 min)
Steam Release	1,130 lbm/sec	(0-220 sec)
	88,100 lbm	(0-220 sec-30 min)
Intact Steam Generator		
Primary-to-Secondary Leakage	1000 gm/min	
Steam Release	1,130 lbm/sec	(0-220 sec)
	257,700 lbm	(0-220 sec-2hr)
	584,000lbm	(2-8 hr)
	866,000 lbm	(8-24 hr)
	54,100 lbm/hr	(>24 hr)

14.2.5 RUPTURE OF A STEAM PIPE

A. Core Power and Reactor Coolant System Transient

A rupture of a steam pipe is assumed to include any accident which results in an uncontrolled steam release from a steam generator. The release can occur due to a break in a pipe line or due to a valve malfunction. The steam release results in an initial increase in steam flow which decreases during the accident as the steam pressure falls. The energy removal from the Reactor Coolant System causes a reduction of coolant temperature and pressure. With a negative moderator temperature coefficient, the cool down results in a reduction of core shutdown margin. If the most reactive control rod is assumed stuck in its fully withdrawn position, there is a possibility that the core will become critical and return to power even with the remaining control rods inserted. A return to power following a steam pipe rupture is a potential problem only because of the high hot channel factors which may exist when the most reactive rod is assumed stuck in its fully withdrawn position. Assuming the most pessimistic combination of circumstances which could lead to power generation following a steam line break, the core is ultimately shut down by the boric acid in the Safety Injection System.

The analysis of a steam pipe rupture is performed to demonstrate that with a stuck rod and minimum engineered safety features, the core remains in place and essentially intact so as not to impair effective cooling of the core.

Although DNB and possible cladding perforation (no cladding melting or zirconium-water reaction) following a steam pipe rupture are not necessarily unacceptable, the following analysis, in fact, shows that the DNB design basis is met for any rupture assuming the most reactive rod stuck in its fully withdrawn position. The following functions provide the necessary protection against a steam pipe rupture:

1. Safety Injection System actuation on:

   a. Two out of three pressurizer low pressure signals.

   b. Two out of three low pressure signals in any steam line.

   c. Two out of three high containment pressure signals.

2. The overpower reactor trips (neutron flux and ΔT) and the reactor trip occurring upon actuation of the Safety Injection System.

3. Redundant isolation of the main feedwater lines. Sustained high feedwater flow would cause additional cooldown, thus, in addition to the normal control action which will close the main feedwater valves, any safety injection signal will rapidly close all feedwater control valves and the feedwater isolation valves.

4. Closure of the fast acting steam line isolation valves (designed to close in less than 5 seconds upon receipt of a CLOSE signal) on:

   a. One out of the two high steam flow signals in that steam line in coincidence with any safety injection signal. (Dual set points are provided, with the lower set point used in coincidence with two out of four indications of low reactor coolant average temperature.)

   b. Two out of three high - high containment pressure signals.

Each steam line has a fast closing isolation valve and a check valve. These four valves prevent blowdown of more than one steam generator for any break location even if one valve fails to close. For example, for a break upstream of the isolation valve in one line, closure of either the check valve in that line or the isolation valve in the other line will prevent blowdown of the other steam generator.

Steam flow is measured by monitoring dynamic head in nozzles inside the steam pipes. The nozzles (16 in. I.D. vs. a pipe diameter of 28 in. I.D.) are located inside the containment near the steam generator. The Unit 1 and Unit 2 steam generators contain a steam nozzle flow limiting device which is designed to limit the steam generator depressurization rate by restricting the steam flow during any postulated steam line break accident.

Method of Analysis (Reference 11)

The analysis of the steam pipe rupture has been performed to determine:

1. The core heat flux and reactor coolant system temperature and pressure resulting from the cooldown following the steam line break. The RETRAN code (Reference 12) has been used.

2. The conservatism of the core reactivity feedback model used in (1) above was confirmed with a detailed core analysis using the ANC code (Reference 13). ANC also calculates the core peaking factors used in the DNB analysis and the maximum fuel linear heat generation rate (kW/ft) to confirm that no fuel centerline melting is predicted for the steam line break transient.

3. The thermal and hydraulic behavior of the core following a steam line break. A detailed thermal and hydraulic digital computer code, VIPRE (Reference 14), has been used to determine if DNB occurs for the core conditions computed in (1) and (2) above.

4. The offsite consequences of the steam line break accident which include consideration of the additional secondary loop activity resulting from a steam generator tube leak prior to the accident.

5. The onsite consequences (e.g., control room habitability). These analyses are described in general terms in this section.

The following assumptions are made:

1. A 2.0% shutdown reactivity from the rods at no load conditions. This is the end of life design value including design margins with the most reactive rod stuck in its fully withdrawn position. Operation of the RCCA banks is restricted in accordance with the Technical Specifications such that the main steam line break analysis remains bounding.

2. The negative moderator temperature coefficient corresponding to the end of life core with all but the most reactive rod inserted. The variation of the coefficient with temperature and pressure has been included. In computing the power generation following a steam line break, the local reactivity feedback from the high neutron flux in the region of the core near the stuck control rod has been included in the overall reactivity balance. The local reactivity

feedback is composed of Doppler reactivity from the high fuel temperatures near the stuck control rod and moderator feedback from the high water enthalpy near the stuck rod. For the cases analyzed where steam generation occurs in the high flux regions of the core the effect of void formation on the reactivity has been included. The effect of power generation in the core on overall reactivity is a function of the core temperature, pressure, and flow and thus is different for each case studied. The analysis assumes end of life core conditions with all rods in except the most reactive rod which is assumed stuck in its fully withdrawn position.

3. Minimum capability for injection of boric acid solution corresponding to the most restrictive single failure in the safety injection system. The emergency core cooling system consists of three systems: 1) the passive accumulators, 2) the low head safety injection (residual heat removal) system, and 3) the high head safety injection system. Both the accumulators and the high head safety injection are modeled for the steam line break accident analysis. The boric acid solution of the high head safety injection is 2700 ppm and no credit is taken for boron in the accumulators.

   The modeling of the safety injection system in RETRAN is described in Reference 12. The flow corresponds to that delivered by one safety injection pump delivering its full flow to both RCS cold legs. The accumulators are modeled to begin injection when the cold leg pressure drops to 694.7 psia.

   For cases where offsite power is available, the sequence of events in the safety injection system is the following: After the generation of the safety injection signal (appropriate delays for instrumentation, logic, and signal transport included), the appropriate valves begin to operate and the high head safety injection pump starts. Ten seconds later, the valves are assumed to be in their final position and the pump is assumed to be at full speed. When the RCS pressure falls below the SI pump shutoff pressure net injection flow begins and the volume containing unborated water is swept into the core before the borated water reaches the core. This delay, described above, is included in the modeling.

   In cases where offsite power is not available, maximum delay times are considered to account for SI signal processing (2 seconds), sequencer plus uncertainty (1 second), diesel generator start to full speed (15 seconds), and SI pump start to full speed (10 seconds), for a total delay of 28 seconds assumed in the analysis.

4. In computing the steam flow during a steam line rupture, the Moody Curve (Reference 15) for f(L/D) = 0 is used.

5. Power peaking factors corresponding to one stuck RCCA and nonuniform core inlet coolant temperatures are determined at end of core life. The coldest core inlet temperatures are assumed to occur in the sector with the stuck RCCA. The power peaking factors account for the effect of the local void in the region of the stuck RCCA during the return to power phase following the steam line break. This void in conjunction with the large negative moderator coefficient partially offsets the effect of the stuck RCCA. The power peaking factors depend upon the core power, temperature, pressure, and flow, and thus are different for each case studied.

6. Since both the Unit 1 and Unit 2 steam generators are equipped with integral flow restrictors with a 1.388 ft^2 throat area, any rupture with a break greater than this size, regardless of the location, would have the same effect on the reactor as a 1.388 ft^2 break. The following two cases have been considered in determining the core power and RCS transients for each unit.

    a. Complete severance of a pipe with the plant initially at no-load conditions, with offsite power available. Full reactor coolant flow is maintained.

    b. Complete severance of a pipe with the plant initially at no-load conditions, with offsite power unavailable. Loss of offsite power results in reactor coolant pump coastdown.

    The cases above assume initial hot shutdown conditions with the rods inserted (except for one stuck rod) at time zero. Should the reactor be just critical or operating at power at the time of a steam line break, the reactor will be tripped by the normal overpower protection system when the power level reaches a trip point.

    Following a trip at power, the reactor coolant system contains more stored energy than at no load, the average coolant temperature is higher than at no load and there is appreciable energy stored in the fuel. Thus, the additional stored energy is removed via the cooldown caused by the steam line break before the no load conditions of reactor coolant system temperature and shutdown margin assumed in the analyses are reached. After the additional stored energy has been removed, the cooldown and reactivity insertions proceed in the same manner as in the analyses which assume no load conditions at time zero.

7. Perfect moisture separation in the steam generator is assumed. This assumption leads to conservative results since considerable water would be expected to be discharged from the steam generator. Water entrainment in the steam reduces the steam generator inventory, thereby reducing the magnitude of the temperature decrease (cooldown) in the core.

8. To maximize the primary to secondary heat transfer rate, zero (0 percent) steam generator tube plugging is assumed.

9. All main and auxiliary feedwater pumps are assumed to be operating at full capacity when the rupture occurs. This assumption maximizes the cooldown. The main feedwater temperature at no-load conditions is assumed to be 35°F. A conservatively high auxiliary feedwater flow rate of 1200 gpm at a minimum temperature of 35°F is assumed to be delivered to the affected steam generator. Main feedwater is isolated following the SI signal; however, auxiliary feedwater continues for the duration of the transient.

10. The effect of heat transferred from thick metal in the RCS and the steam generators is not included in the cases analyzed. The heat transferred from these sources would be a net benefit since it would slow the cooldown of the RCS.

<u>Results</u>

The results presented are a conservative indication of the events which would occur assuming a steam line rupture. The worst case assumes that <u>all</u> of the following occur simultaneously.

1. Minimum shutdown reactivity margin.

2. The most negative moderator temperature coefficient for the rodded core at end of life.

3. The rod having the most reactivity stuck in its fully withdrawn position.

4. One safety injection pump fails to function as designed.

Rupture of a Steam Line at Zero Power Analysis

As described above, two cases were analyzed for each unit from zero power initial conditions. A time sequence of events for all cases analyzed is provided in Table 14.2.5-2. The peak heat flux and time of occurrence are also shown on the table for each case analyzed (Reference 11).

The limiting steam line rupture for each unit is the case in which offsite power is assumed to be available. The transient plots in Figure 14.2.5-1 show the limiting Unit 1 plant response following a main steam pipe rupture from zero power initial conditions with offsite power available. Figure 14.2.5-2 shows the plant response for the Unit 1 case with offsite power not available. Loss of offsite power results in a coastdown of the reactor coolant pumps and reduced core flow. This causes the core power to increase at a slower rate and reach a lower peak value. The Unit 2 transient plots are very similar to Unit 1, and thus are not presented.

The results of the major rupture of a main steam pipe event analysis confirm that the DNB and fuel centerline melt design bases are met for both units. The calculated minimum DNBR is above the applicable limit value of 1.45 (the W-3 DNB correlation limit with pressure less than 1000 psia). The calculated peak linear heat generation rate is less than the limit value of 22.54 kW/ft corresponding to fuel centerline melting. Primary and secondary pressure limits are not challenged because primary and secondary pressures decrease from their initial values during the transient. Therefore, this event does not adversely affect the core or the RCS, and all applicable acceptance criteria are met.

Rupture of a Steam Line at Full Power Analysis

To ensure safe shutdown during MODE 1 operation, the steam line rupture event was analyzed at hot full power conditions. For this analysis, initial conditions of core power and pressurizer pressure were assumed to be at their nominal values consistent with steady-state full power operation. RCS coolant temperature was assumed to be at its nominal, steady-state, full-power value plus a small temperature bias. Uncertainties in the initial conditions of these parameters are considered in the DNBR limit rather than explicitly modeled in the transient calculations, consistent with the application of the Revised Thermal Design Procedure (RTDP) methodology. Steam generator water level was assumed to be at its nominal value. Minimum measured reactor coolant flow was modeled according to the RTDP methodology. Zero steam generator tube plugging was assumed to maximize the primary-to-secondary heat transfer, which results in a more severe RCS cooldown transient.

For breaks outside containment, the overpower ΔT and Low Steam Line Pressure – Safety Injection protection functions are relied upon to provide the necessary protection to mitigate the event. For breaks inside containment, protection is provided by the Hi-1 Containment Pressure – Safety Injection function. The results of separate containment pressure response analyses showed that the Hi-1 Containment Pressure – Safety Injection signal would be reached before overpower ΔT on all inside containment break cases. A delayed reactor trip for this event results in more limiting transient results. Based on this, the outside containment breaks, which rely on overpower ΔT and Low Steam Line Pressure – Safety Injection, are determined to be the most limiting scenario; therefore, it is this scenario that is explicitly modeled.

The most limiting full power case is typically the largest break that produces a reactor trip on overpower ΔT. Larger breaks result in a rapid reactor trip as a result of the Low Steam Line Pressure – Safety Injection signal, before core power increases significantly, and are therefore less limiting. Since PBNP has steam exit nozzle flow restrictors which limit the flow area to about 1.388 ft^2, the analysis modeled a spectrum of break sizes up to 1.4 ft^2. The analysis demonstrates that the most limiting break size is 0.61 ft^2 (Unit 1) and 0.63 ft^2 (Unit 2); reactor trip for both cases is on overpower ΔT.

The results of the full-power steam line rupture analysis demonstrate that the DNB design basis is met. In addition, the peak linear heat generation rate (expressed in kW/ft) does not exceed the fuel centerline melt limit. Since this event results in a decrease in both the primary and secondary side pressures, the maximum RCS and Main Steam System pressure criteria are not challenged.

B. Radiological Consequences (Reference 24)

The complete severance of a main steamline outside containment is assumed to occur. The affected SG will rapidly depressurize and release to the outside atmosphere the activity initially contained in the secondary coolant and the activity transferred from the primary coolant through SG tube leakage. A portion of the activity initially contained in the intact SG and a portion of the activity due to tube leakage is released to the atmosphere through either the atmospheric dump valves or the main steam safety valves. This section describes the assumptions and analyses performed to determine the amount of radioactivity released and the doses resulting from the release.

The analysis of the main steamline break radiological consequences uses the analytical methods and assumptions outlined in the RG 1.183 (Reference 9).

The concentrations of iodines and noble gasses in the RCS at the time the accident occurs are based on 520 μCi/gm of DE Xe-133 and the Technical Specification limit of 0.5 μCi/gm of dose equivalent (DE) I-131. The alkali metal concentration in the RCS is based on the fuel defect level that corresponds to 0.5 μCi/gm DE I-131. The iodine activity concentration of the secondary coolant at the time the accident occurs is assumed to be equivalent to the Technical Specification limit of 0.1 μCi/gm of DE I-131. The alkali metal activity concentration of the secondary coolant at the time the accident occurs is assumed to correspond to 0.1 μCi/gm of DEI-131. The equilibrium nuclide concentrations are presented in Table 14.1.8-4. In addition, two iodine spikes are considered.

Pre-accident Spike - A reactor transient has occurred prior to the event and has raised the primary coolant iodine concentration to a conservative value of 60 μCi/gm DE I-131.

Accident-Initiated Spike - The primary coolant iodine concentration is initially at the Technical Specification limit of 0.5 μCi/gm DE I-131. Following the primary system depressurization and reactor trip associated with the event, an iodine spike is initiated in the primary system. The spike increases the iodine appearance rate from the fuel to the coolant to a value 500 times greater than the release rate corresponding to the initial primary system iodine concentration. The duration of the spike is 4 hours.

The SG connected to the broken steam line is assumed to boil dry within the initial two minutes. The entire liquid inventory of this SG is assumed to be steamed off and all of the iodine and alkali metal activity initially in this SG is released to the environment. In addition, all activity carried over to the faulted SG by tube leaks is assumed to be released directly to the environment with no credit taken for retention in the SG.

A total primary-to-secondary leak rate of 2000 gm/min is assumed to exist prior to the steam line rupture. The leak is assumed to be distributed with 1000 gm/min to the intact steam generator and 1000 gm/min to the ruptured steam generator. The leakage is assumed to persist for the duration of the accident.

An iodine partition factor of 0.01 (curies iodine/gm steam) / (curies iodine/gm water) and a particulate retention factor of 0.0025 based on full power moisture carryover are applied to the intact SG.

All noble gas activity carried over to the secondary side through SG tube leakage is assumed to be immediately released to the outside atmosphere.

The plant cooldown to RHR operating conditions is assumed to be accomplished within 30 hours after initiation of the event and steam releases from the intact steam generator are terminated at this time. Within 60 hours after the accident the reactor coolant system has been cooled to below 212°F and there are no further steam releases to the atmosphere from the faulted steam generator.

Dose conversion factors, offsite atmospheric dispersion factors and breathing rates are provided in Table 14.1.8-3.

The control room HVAC begins in normal mode. In the event of a steamline break, the low steam line pressure SI setpoint will be reached shortly after event initiation. The SI/containment isolation signal or a radiation monitor signal cause the control room HVAC to switch from the normal operation mode to the post-accident mode of operation. The analysis conservatively did not credit the SI signal but relied on the ventilation system line radiation monitor signal for control room isolation. It was confirmed that the radiation monitor setpoint is reached within 15 seconds. The control room HVAC switches from normal operation to post-accident mode of operation at 75 seconds (15 seconds for radiation signal plus 60 second delay time). Control room models are provided in Table 14.1.8-6.

Acceptance Criteria

The Standard Review Plan (SRP) 15.0.1 (Reference 10) offsite dose acceptance criterion for a steamline break with a pre-accident iodine spike is the 10 CFR 50.67 limit of 25 rem TEDE and the acceptance criterion for a steamline break with an accident initiated iodine spike is 2.5 rem TEDE, which is 10% of the 10 CFR 50.67 limit of 25 rem TEDE. The control room personnel dose acceptance criterion is 5 rem TEDE per 10 CFR 50.67.

Results and Conclusions

The results of the offsite and control room dose analyses are provided in Table 14.2.5-1, and indicate that the acceptance criteria are met. The exclusion area boundary doses reported are for the worst 2 hour period, determined to be from 0 to 2 hours for the pre-accident iodine spike and from 3.9 to 5.9 hours for the accident initiated iodine spike.

C. Containment Response Analysis (Reference 5)

An analysis is performed to predict the pressure and temperature response of the containment atmosphere to a main steamline break inside of containment. The steamline break is postulated as a full double-ended rupture (DER) of the steamline immediately downstream of the steam generator integral flow restrictor. The blowdown from the faulted steam generator is limited by the 1.4 ft^2 integral flow restrictor. The steamline non-return valve limits the reverse break flow to the steam in the steamline between the break and the non-return valve.

A spectrum of cases was considered in this analysis. All cases were analyzed at EPU conditions with a full DER. The cases included variations in initial power level and the single failure. The case resulting in the highest containment pressure was a full DER initiated from 30% power with the feedwater isolation valve (FIV) postulated to fail open. The open FIV allows additional main feedwater to be pumped into the faulted steam generator until the feedwater regulator valve (FRV) closes. Furthermore the FRV is located upstream of the FIV, creating a larger unisolable feedline volume. Additional hot water in the feedline will flash and enter the faulted steam generator when the feedwater becomes saturated due to the depressurization of the system.

Method of Analysis

The analysis consists of the calculation of the mass and energy releases from the steamline break and the calculation of the containment pressure and temperature response. The methods and assumptions of these calculations are summarized below.

Mass and Energy Release Calculation

WCAP-8822, "Mass and Energy Releases Following a Steam Line Rupture" (Reference 2) forms the basis for the assumptions and models used in the calculation of the mass and energy releases resulting from a steamline rupture. The steamline break mass and energy releases are generated using the NRC-approved LOFTRAN code (Reference 1). The Westinghouse steamline break mass and energy release methodology using LOFTRAN was approved by the NRC and is documented in Supplement 2 to WCAP-8822 (Reference 3).

The major inputs and assumptions affecting the mass and energy releases to containment are summarized below.

- The NSSS power level is 1806 MWt. Cases are analyzed at 100.6%, 70%, 30% and hot zero power.

- The full power RCS average temperature is 583.4°F, which includes a +6.4°F uncertainty.

- The core nuclear power transient due to the cooldown following the steamline rupture is based on end-of-core life conditions with the most reactive control rod stuck out of the core. The credited shutdown margin is 2.0%Δk.

- Two sources of latent energy to the reactor coolant system are modeled: the reactor vessel and primary system thick metal, and the fluid inventory in the intact steam generator.

- Offsite power is assumed to remain available. The largest effect of this assumption is the continued operation of the reactor coolant pumps, which maintains a high heat transfer rate to the steam generators.

- Minimum flowrates are modeled from ECCS injection, to conservatively minimize the amount of boron that provides negative reactivity feedback. The flowrates correspond to a single train of ECCS. The hydraulic performance of the ECCS systems assumed in the transient and accident analysis is based on certified pump curves lowered uniformly to provide head margin for periodic pump testing. The flowrates are assured by the plant in-service testing acceptance criteria.

- A high initial steam generator mass is assumed. The initial level corresponds to 64% NRS + 10% uncertainty.

- The calculation of secondary side break flow is based on the Moody critical flow correlation with fL/D=0.

- The main feedwater modeling accounts for an increase from the initial flowrate due to the depressurization of the faulted steam generator and the opening of the FRV in response to the increased steam flow. Main feedwater pumped flow is terminated by the closure of the FIV or FRV (when the FIV is assumed to fail open).

- Feedline flashing occurs when saturated conditions are reached in the 225 ft^3 unisolable volume between the faulted steam generator and the FIV or 355 ft^3 unisolable volume between the faulted steam generator and the FRV (when the FIV is assumed to fail open).

- Maximum flowrates of auxiliary feedwater (AFW) were assumed, with the AFW start conservatively modeled at the time of the SI signal, with no delay. AFW is assumed to be manually re-aligned at 600 seconds to prevent further water addition to the faulted steam generator (See Results Section for additional discussion). Cases have been analyzed with a control failure that increases AFW flowrates; however, these cases have been shown to be non-limiting and do not require isolation within 600 seconds (Reference 5).

- The steam in the unisolable volume of 1650 ft^3 between the faulted steam generator and the steamline non-return check valve comprises the reverse flow from the break.

- The break effluent is assumed to be dry, saturated steam throughout most of the transient. However, when a large double-ended break first occurs, it is expected that there will be a significant quantity of liquid in the break effluent. A conservative amount of liquid entrainment is assumed to occur in the beginning of the steam generator blowdown phase of the accident. The break effluent is assumed to return to all vapor within the first 25 seconds.

- The containment backpressure is modeled within LOFTRAN at a conservatively low value of 14.7 psia.

- The time to tube uncovery was modeled in the same manner as was used in Reference 3 for "predicted tube uncovery" cases. This affects the total amount of heat transfer to the secondary side, and the possible generation of superheated steam.

Containment Response Calculation

The GOTHIC computer code (Reference 4, Reference 16 and Reference 17) is used to calculate the containment pressure and temperature transient response following the postulated steamline break accident inside containment.

The initial conditions (Table 14.2.5-3) are selected to maximize the containment pressure response. The initial pressure has a direct relationship on the peak containment pressure, and thus is maximized. The initial temperature is maximized because the steady-state temperature of the containment heat sinks are assumed to be the same as the containment air temperature. The higher initial heat sink temperature causes them to be less effective in removing heat. The initial humidity is conservative when it is assumed to be low, since this maximizes the amount of air initially in the containment.

Two trains of containment fan coolers (four coolers) and two trains of containment spray are credited in the limiting case because the FIV failure has already been modeled in the mass and energy release calculation. Cases were analyzed with a containment safeguards train single failure, but were shown to be non-limiting. Conservative values for containment fan cooler heat removal performance were used. A conservatively high temperature has been assumed as the temperature of the spray water. The containment spray pump flow rates are conservatively low. Pump performance is based on certified pump curves lowered uniformly to provide head margin for periodic pump testing. The required system flowrate is assured by the plant in-service testing acceptance criteria.

Finally, the heat transfer through, and heat storage in, interior and exterior walls of the containment structure are considered. Structural heat sinks, consisting of steel and concrete, are modeled as slabs having specific areas and layers of varying thickness. The initial temperature of the structural heat sinks is assumed to be the initial containment air temperature of 120°F.

Results

The containment pressure and containment temperature transients are shown in Figure 14.2.5-3 and Figure 14.2.5-4. The peak containment pressure of 58.08 psig is reached at 264.2 seconds, which is below the 60 psig containment design pressure. The peak containment air temperature of 283.6°F is also reached at 254.2 seconds, which is below the containment design temperature of 286°F (see FSAR Section 5.1).

Both containment pressure and temperature trend consistently downward after peaking. This is due to heat removal by both active systems and passive heat sinks exceeding heat introduction from the break. At 600 seconds, the rate of pressure and temperature drop increases when AFW flow is isolated to the faulted steam generator. It is apparent from Figure 14.2.5-3 and Figure 14.2.5-4 however, that the isolation of AFW at 600 seconds does not affect the peak containment pressure and temperature experienced earlier in the transient because both parameters are already decreasing before AFW isolation occurs. Therefore, while the manual isolation of AFW is an input assumed by the analysis, the results of the analysis show that the manual action at 600 seconds is not necessary to ensure that containment integrity is maintained.

Conclusions

A DNB analysis has been performed. It was found that all cases have a minimum DNBR greater than the limit value. The calculated peak linear heat generation rate is less than a value corresponding to fuel centerline melting.

The analysis has shown that the criteria stated in Section 14.2.5 are satisfied. Although DNB and possible cladding perforation following a steam pipe rupture are not necessarily unacceptable and not precluded by the criteria, the above analysis, in fact, shows that the DNB design basis is met as stated in Section 3.2.

No significant exposure to the public would result from a rupture of a steam pipe.

The containment pressure and temperature responses to a MSLB inside of containment remain below the containment design pressure and temperature.

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6. Deleted.

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22. Deleted.

23. Deleted.

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Table 14.2.5-1 MAIN STEAMLINE BREAK ACCIDENT DOSES

Site Boundary	Dose (Rem)
Accident-Induced Spike TEDE Dose (3.9 - 5.9 hr)	0.2
Pre-Accident Spike TEDE Dose (0 - 2 hr)	0.14
Low Population Zone (0 - 60 hr)	**Dose (Rem)**
Accident-Induced Spike TEDE Dose	0.08
Pre-Accident Spike TEDE Dose	0.03
Control Room (0 - 30 days)	**Dose (Rem)**
Accident-Induced Spike TEDE Dose	4.0
Pre-Accident Spike TEDE Dose	1.9

Table 14.2.5-2 RUPTURE OF A STEAM PIPE ANALYSIS ASSUMPTIONS AND SEQUENCE OF EVENTS

PBNP Unit Affected	Unit1	Unit 1	Unit 2	Unit 2
Steam Generator Model	44F	44F	Delta-47	Delta-47
Initial shutdown margin, %Δk	2.0	2.0	2.0	2.0
Offsite Power Available	Yes	No	Yes	No
Main steam line ruptures in loop 1, sec	0.0	0.0	0.0	0.0
High-High steam flow setpoint reached in loop 1, sec	0.01	0.01	0.01	0.01
High-high steam line flow setpoint reached in loop 2, sec	0.23	0.23	0.24	0.24
Low steam pressure SI setpoint reached in loop 1, steam line isolation logic satisfied in both loops, sec	1.5	1.5	1.4	1.4
RCPs begin to coastdown, sec	NA	3.0	NA	3.0
SI actuation occurs, sec	3.5	3.5	3.4	3.4
Steam line isolation completed in both loops, sec	8.5	8.5	8.4	8.4
SI pump starts, sec	3.5	19.5	3.4	19.4
Main feedwater isolation completed in both loops, sec	13.5	13.5	13.4	13.4
SI pump achieves full speed, sec	14.5	29.5	14.4	29.4
SI flow injection begins (cold leg pressure below SI pump shutoff pressure), sec	16.9	19.5	16.2	19.5
Criticality attained, sec	39.8	49.0	39.5	49.0
Accumulators begin to inject, sec	73.0	229.0	66.5	230.5
Boron reaches the core (> 1 ppm), sec	93.5	111.5	92.0	110.0
Time of maximum core heat flux, sec	112.5	115.3	108.8	264.8
Maximum core heat flux, fraction of nominal	0.2095	0.0332	0.2058	0.0360

Table 14.2.5-3 GOTHIC MODEL INPUTS MSLB CONTAINMENT RESPONSE ANALYSIS

Input	Value
RWST water temperature for containment sprays (°F)	100
Initial containment temperature (°F)	120
Initial containment pressure (psia)	16.7
Initial relative humidity (%)	20
Net free volume (ft^3)	1.0×10^6

Figure 14.2.5-1 RUPTURE OF A STEAM PIPE UNIT 1 WITH OFFSITE POWER
Sheet 1 of 6

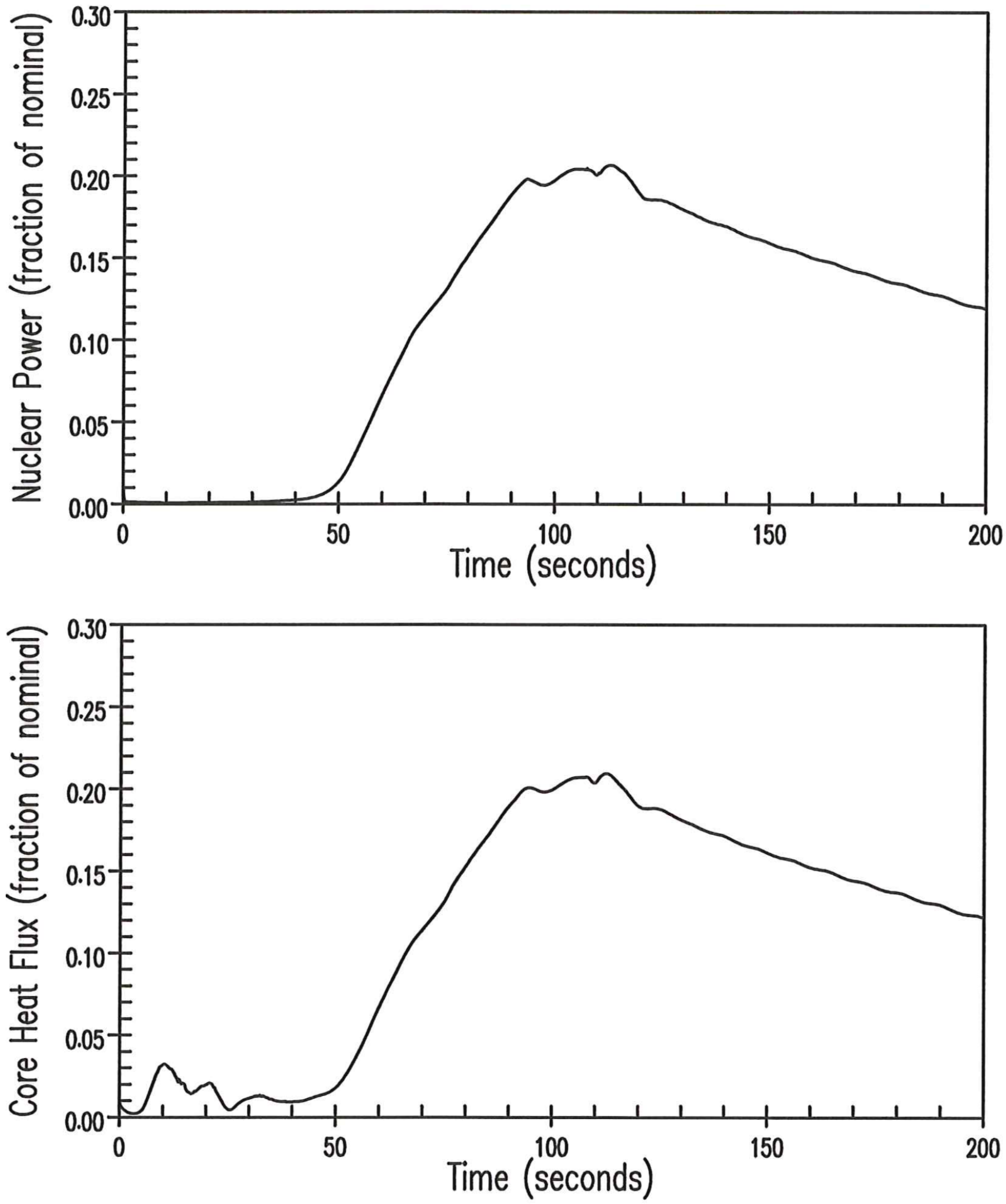
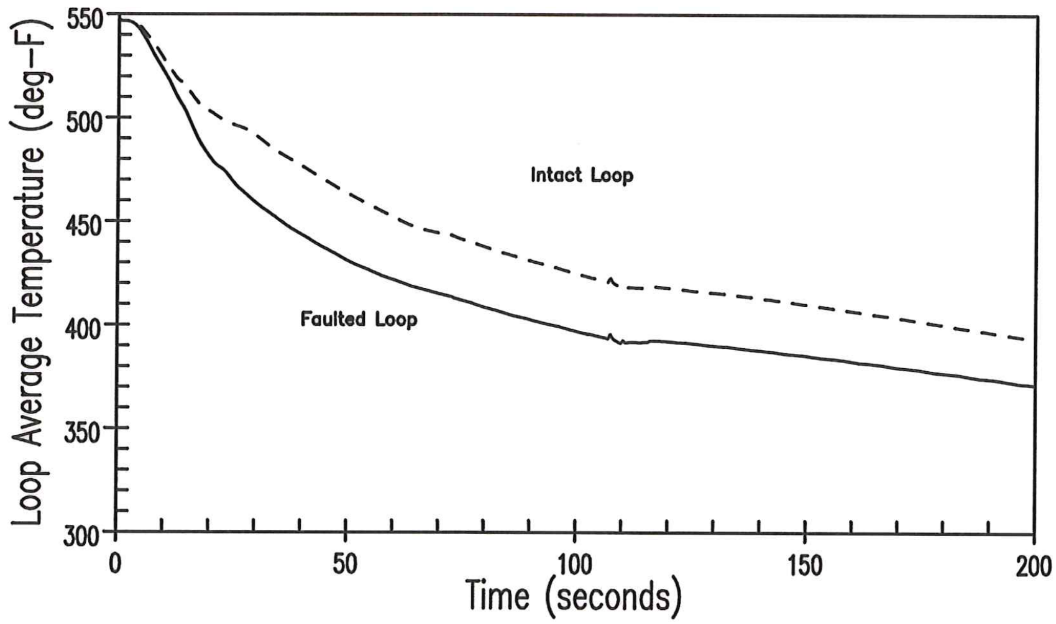


Figure 14.2.5-1 RUPTURE OF A STEAM PIPE UNIT 1 WITH OFFSITE POWER
Sheet 2 of 6



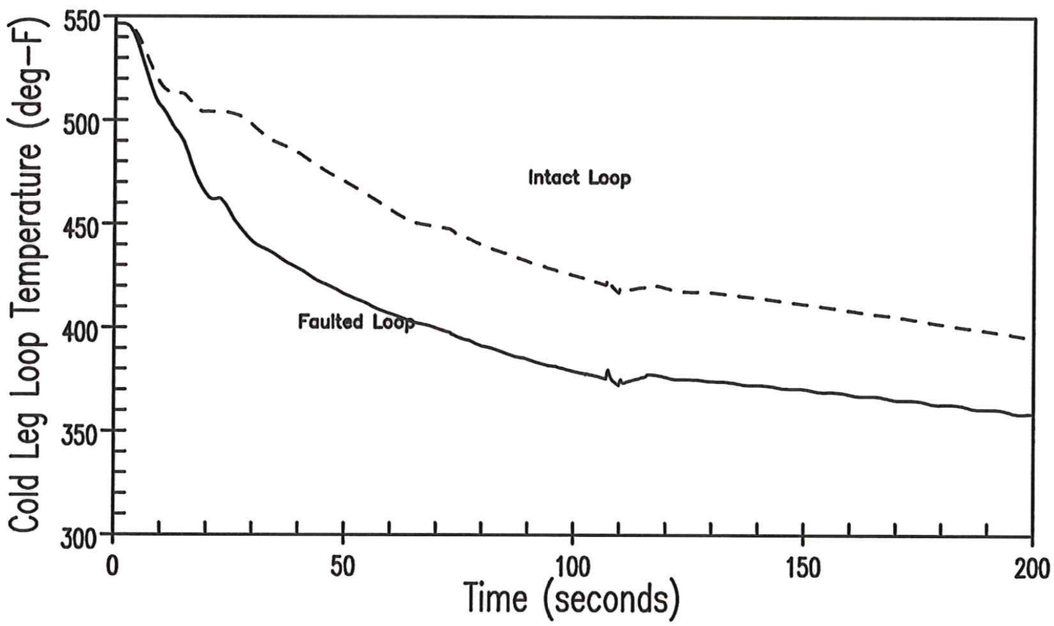
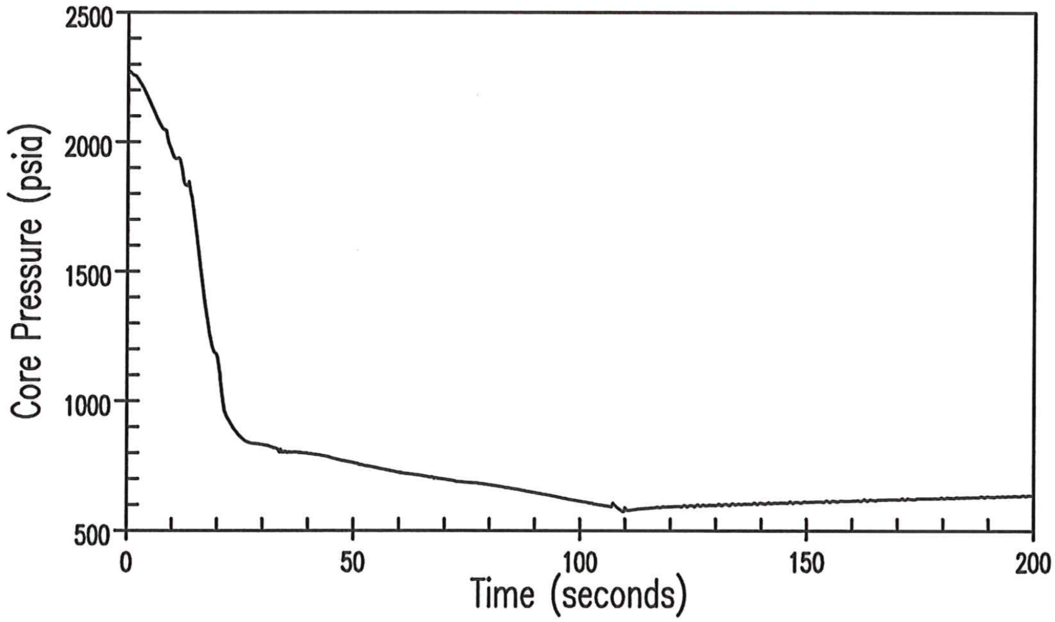
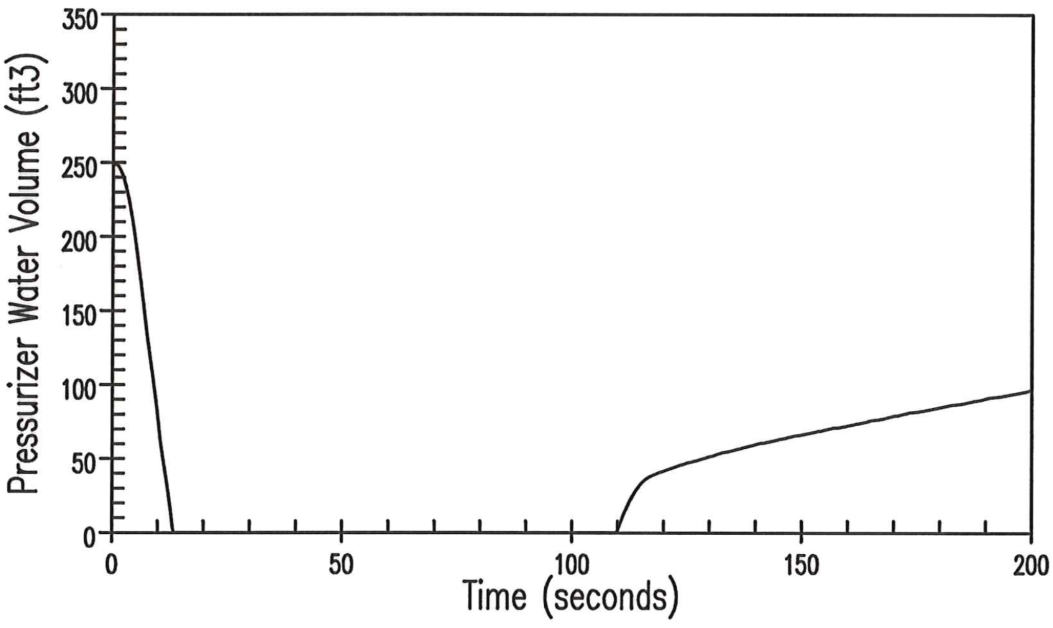


Figure 14.2.5-1 RUPTURE OF A STEAM PIPE UNIT 1 WITH OFFSITE POWER
Sheet 3 of 6





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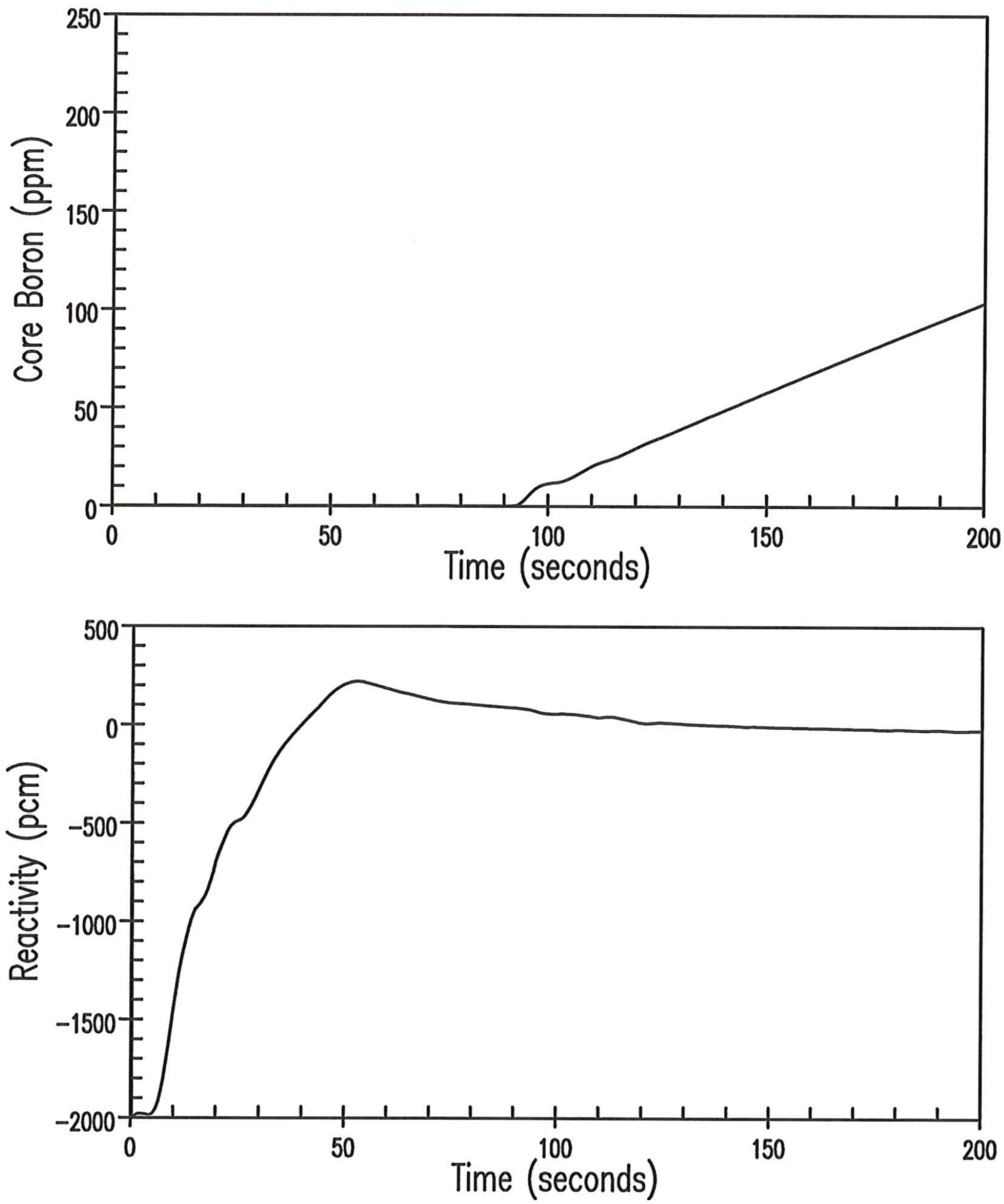
Sheet 4 of 6



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Sheet 5 of 6

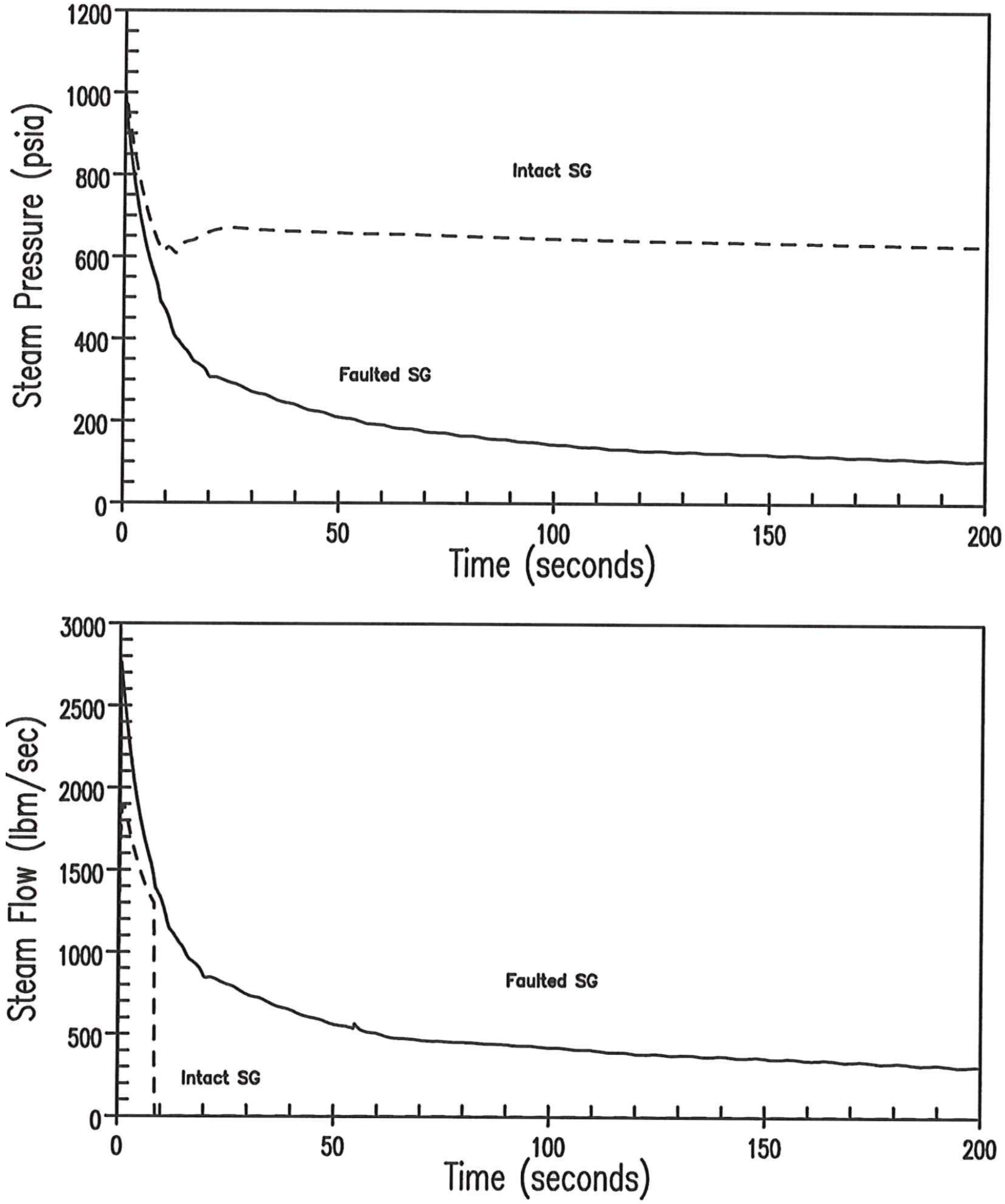


Figure 14.2.5-1 RUPTURE OF A STEAM PIPE UNIT 1 WITH OFFSITE POWER
Sheet 6 of 6

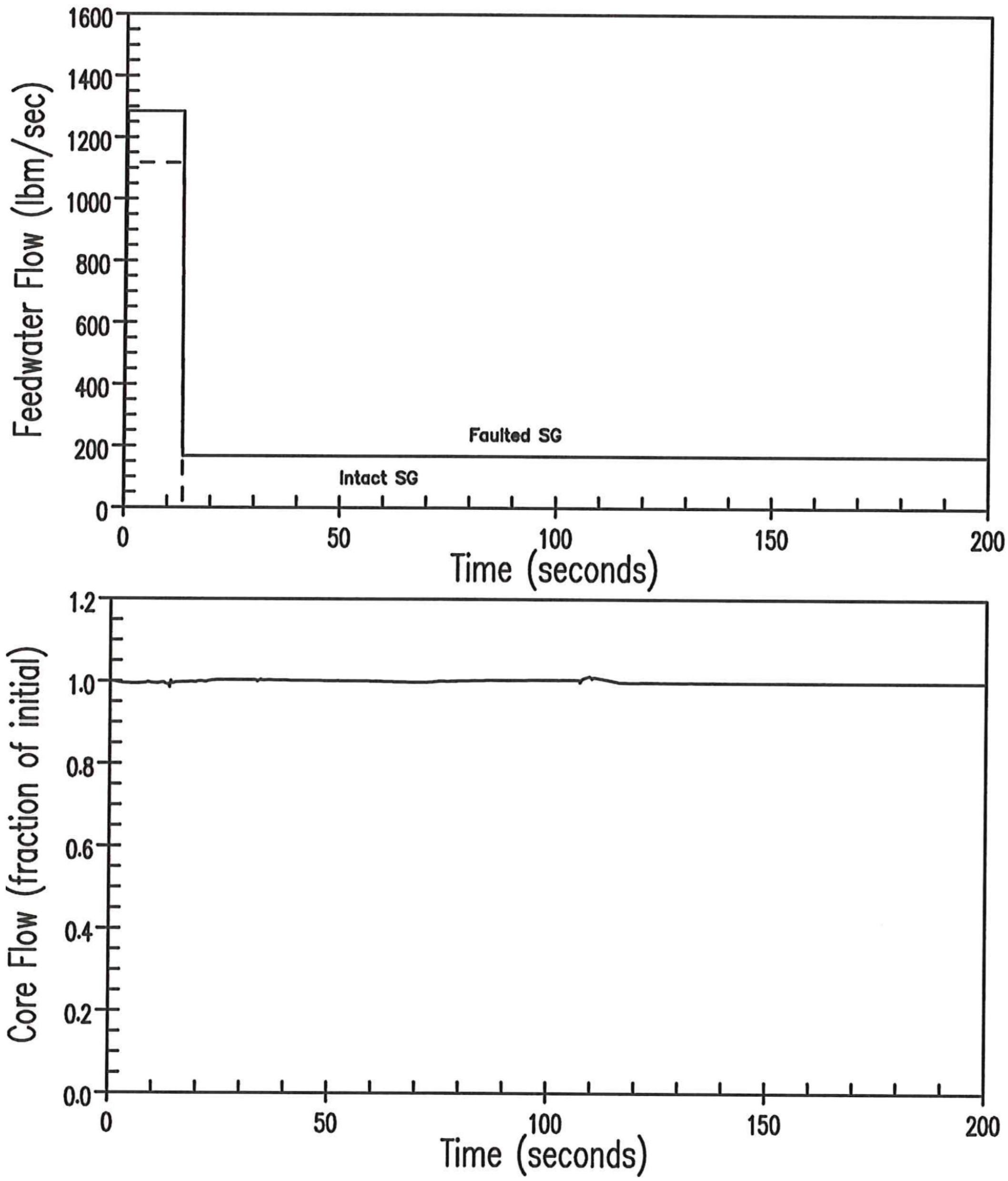


Figure 14.2.5-2 RUPTURE OF A STEAM PIPE UNIT 1 WITHOUT OFFSITE POWER
Sheet 1 of 6

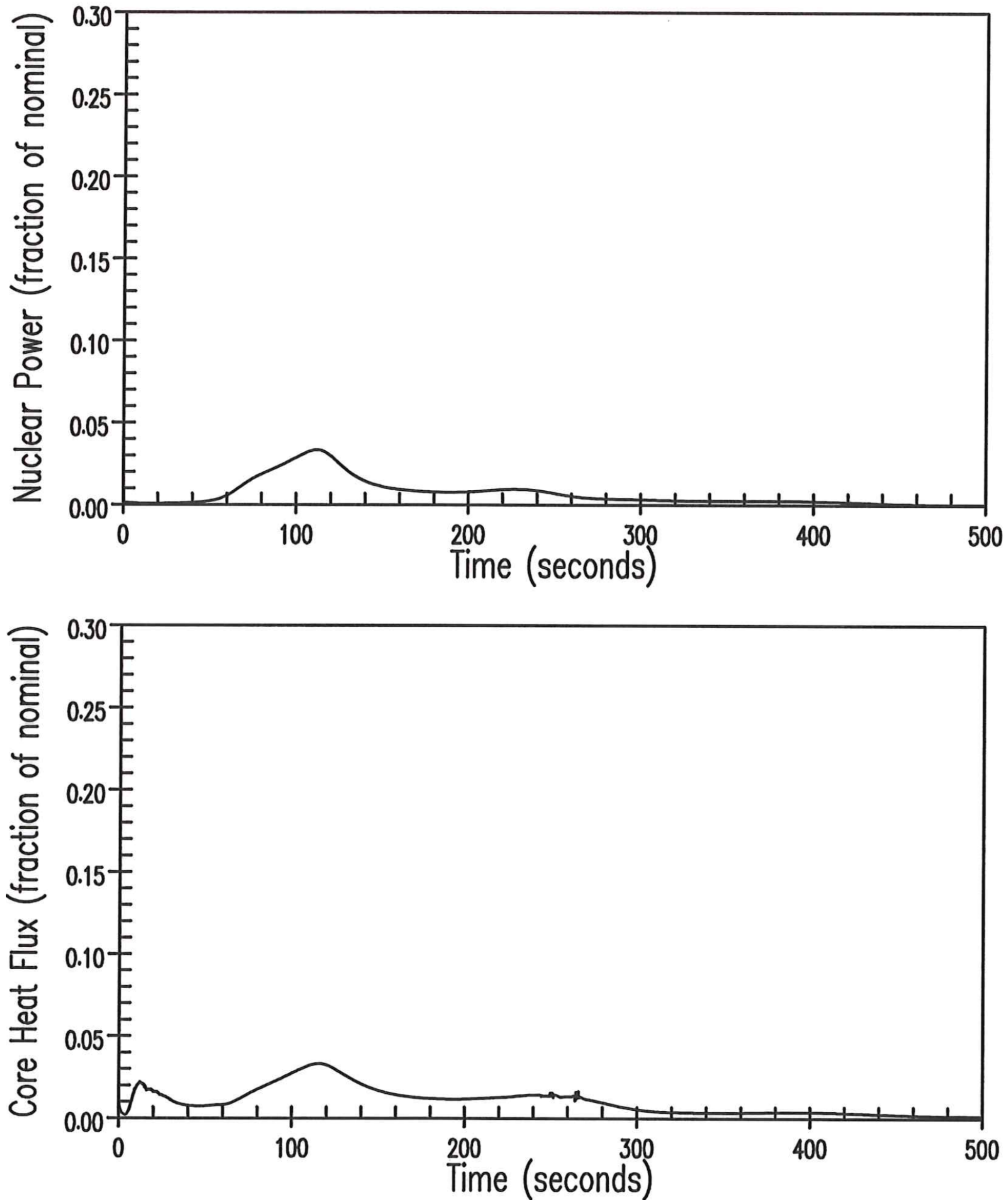
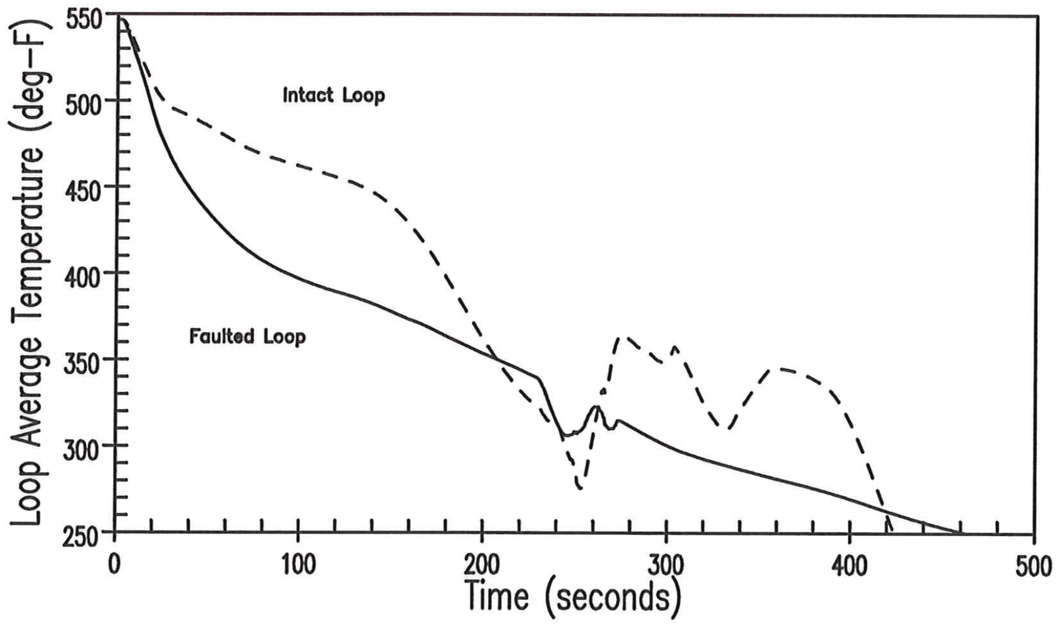


Figure 14.2.5-2 RUPTURE OF A STEAM PIPE UNIT 1 WITHOUT OFFSITE POWER
Sheet 2 of 6



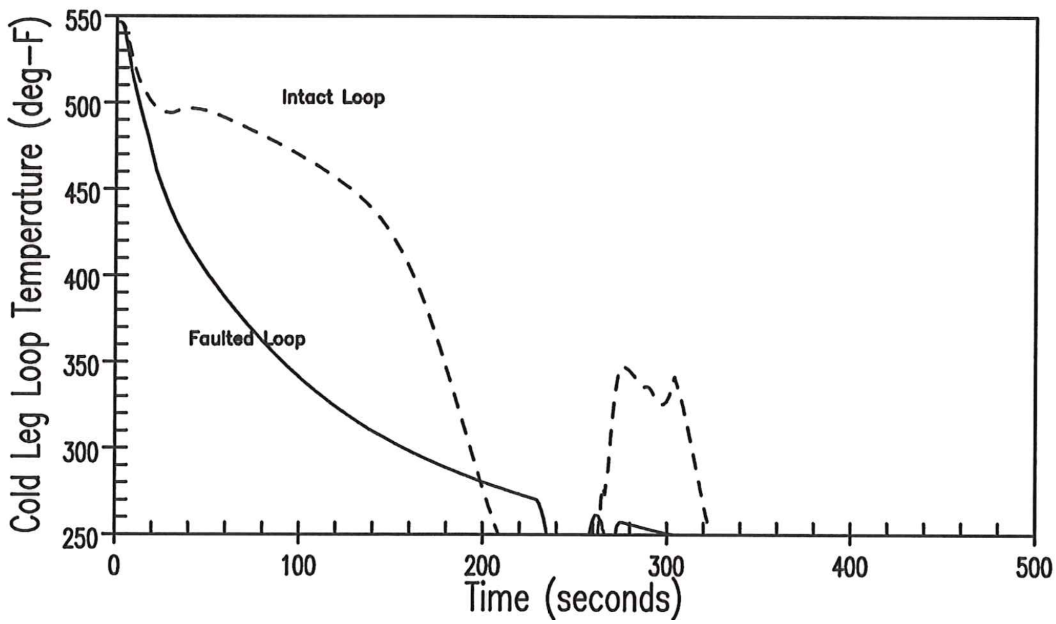
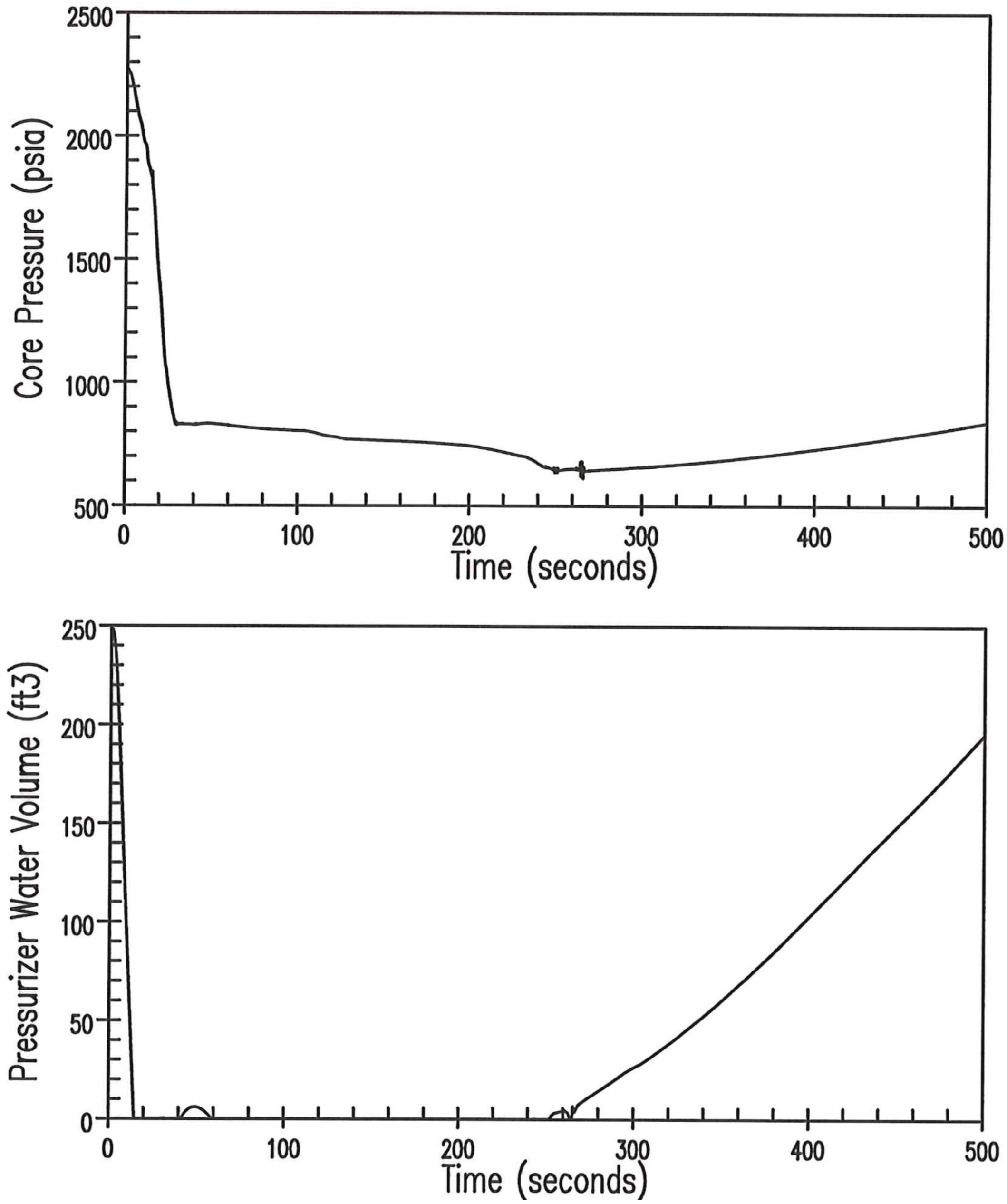


Figure 14.2.5-2 RUPTURE OF A STEAM PIPE UNIT 1 WITHOUT OFFSITE POWER
Sheet 3 of 6



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Sheet 4 of 6

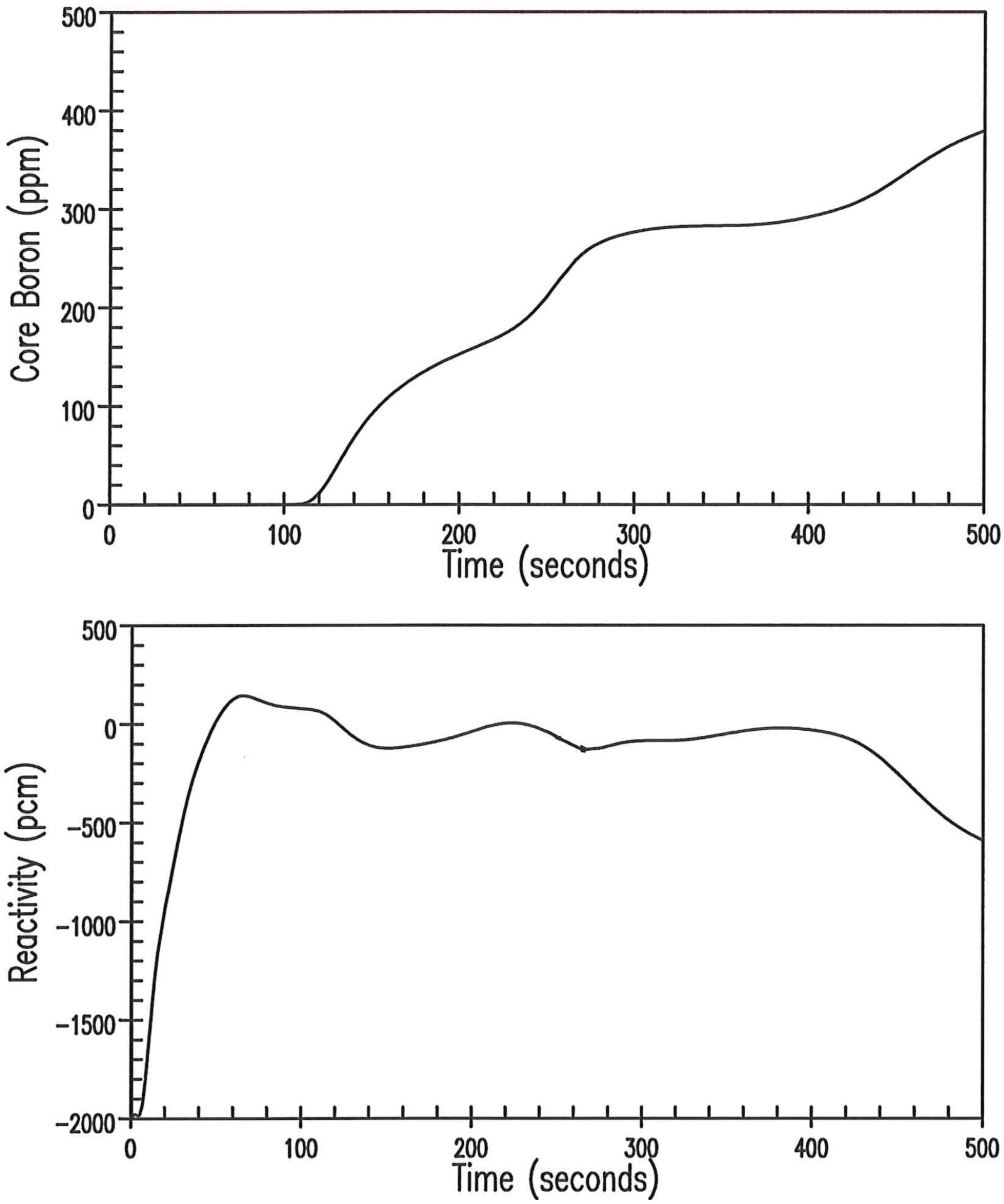


Figure 14.2.5-2 RUPTURE OF A STEAM PIPE UNIT 1 WITHOUT OFFSITE POWER
Sheet 5 of 6

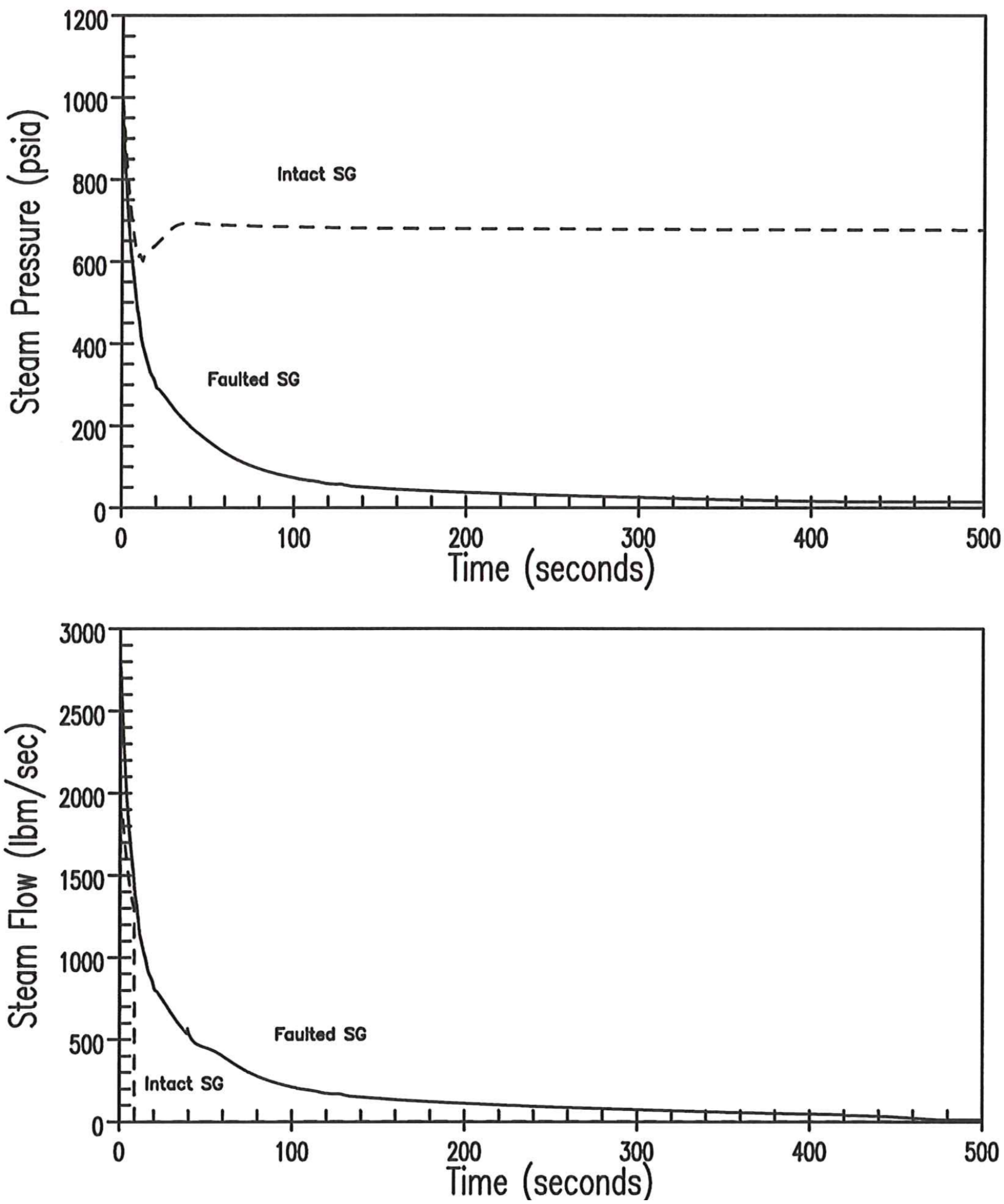


Figure 14.2.5-2 RUPTURE OF A STEAM PIPE UNIT 1 WITHOUT OFFSITE POWER
Sheet 6 of 6

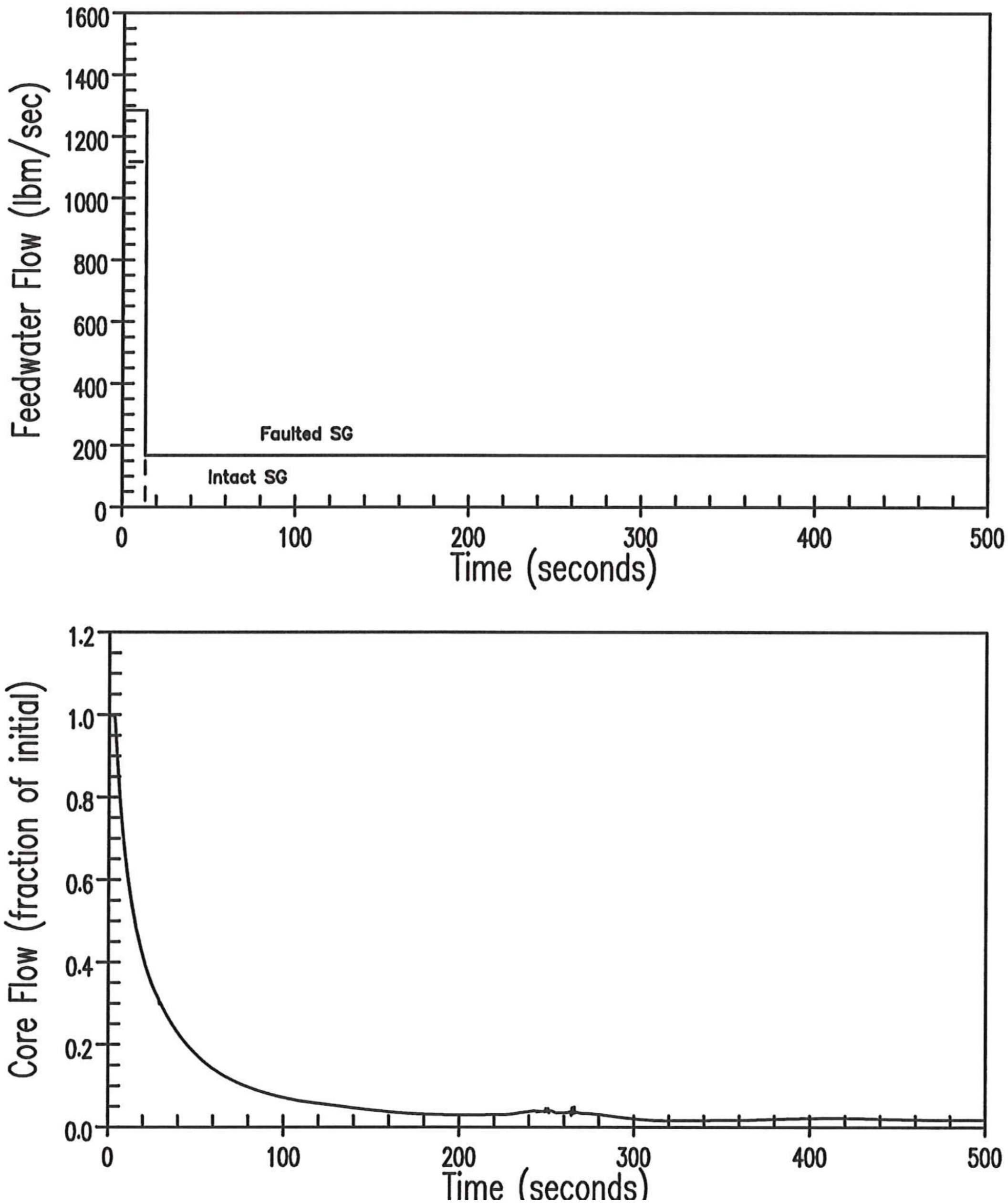


Figure 14.2.5-3 CONTAINMENT PRESSURE MSLB CONTAINMENT RESPONSE ANALYSIS

Containment pressure response for SLB Initiated at 30% Power with an FIV Failure

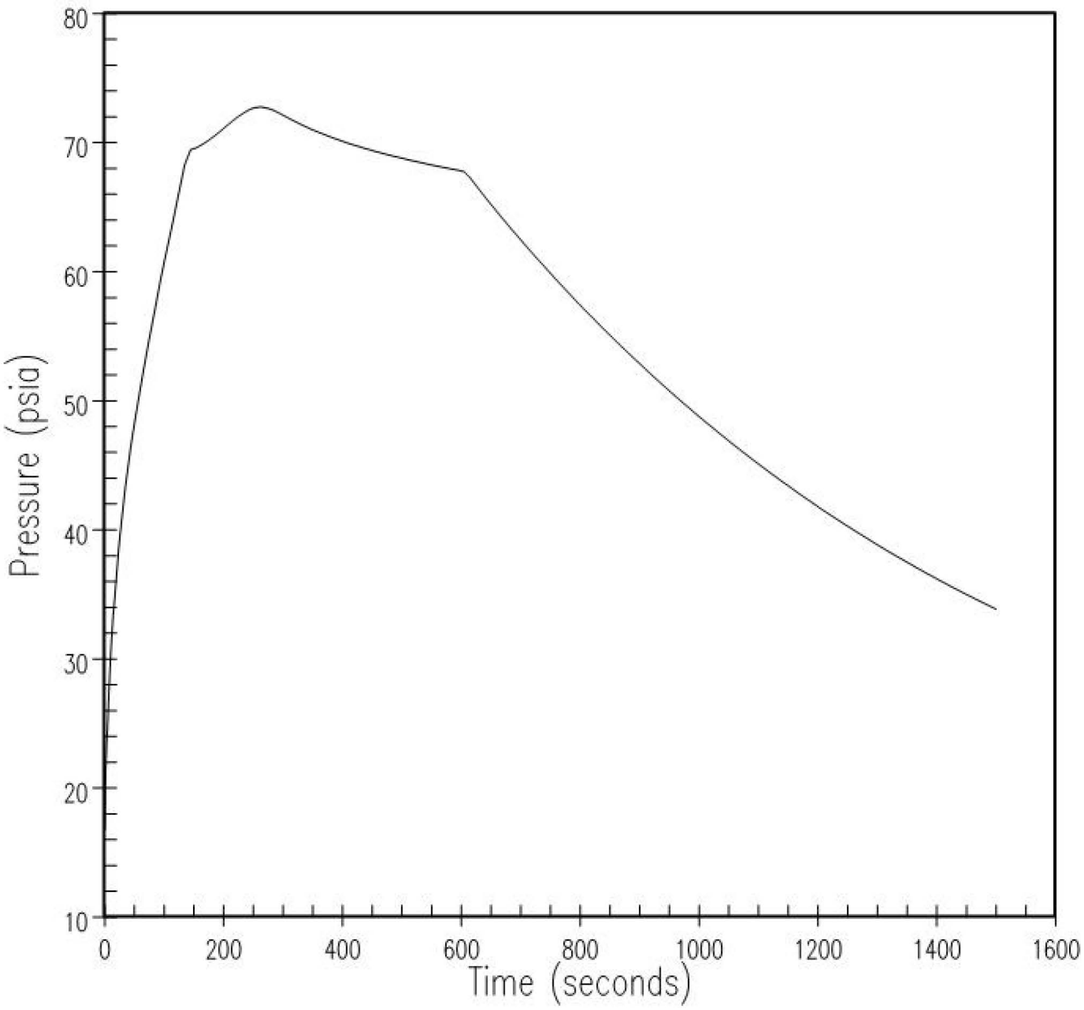
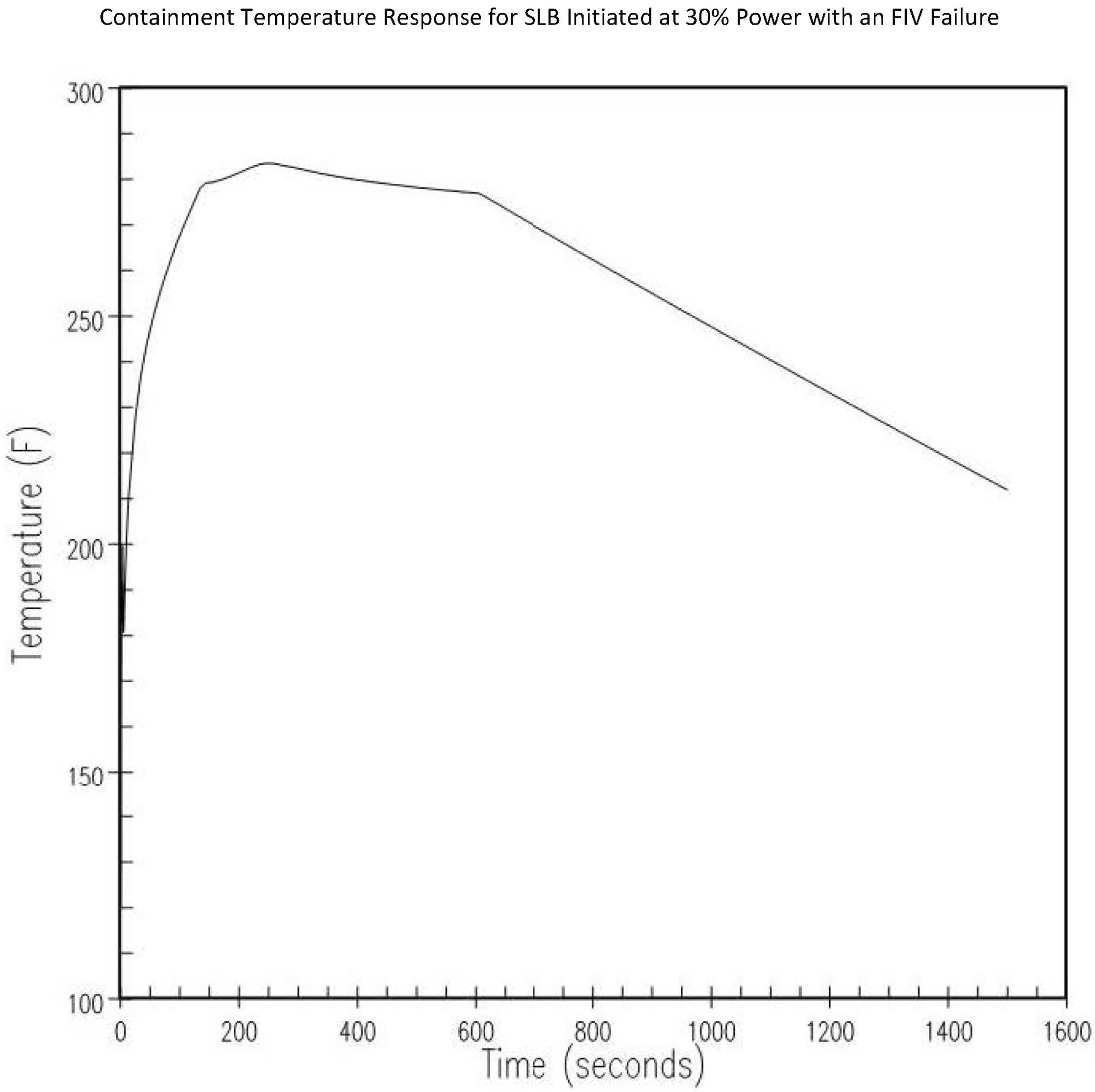


Figure 14.2.5-4 CONTAINMENT TEMPERATURE MSLB CONTAINMENT RESPONSE ANALYSIS



14.2.6 RUPTURE OF A CONTROL ROD MECHANISM HOUSING - RCCA EJECTION

In order for this accident to occur, a rupture of the control rod mechanism housing must be postulated, creating a full system pressure differential acting on the drive shaft. The resultant core thermal power excursion is limited by the Doppler reactivity effects of the increased fuel temperature and terminated by reactor trip actuated by high nuclear power signals.

A failure of a control rod mechanism housing sufficient to allow a control rod to be rapidly ejected from the core is not considered credible for the following reasons:

1. Each control rod drive mechanism housing is completely assembled and shop-tested at 3105 psig (nominal).

2. Stress levels in the mechanism are not affected by system transients at power, or by the thermal movement of the coolant loops. Moments induced by the design earthquake can be accepted within the allowable primary working stress range specified by the ASME code, Section III, for Class 1 components.

3. The latch mechanism housing and rod travel housing are Grade F316 stainless steel. This material exhibits excellent notch toughness at all temperatures that will be encountered. The joints between the latch mechanism housing and head adapter, and between the latch mechanism housing and rod travel housing, are fabricated with full penetration welds.

Nuclear Design

Even if a rupture of a RCCA drive mechanism housing is postulated, the operation of a plant utilizing chemical shim is such that the severity of an ejected RCCA is inherently limited. In general, the reactor is operated with the RCCA's inserted only far enough to permit load follow. Reactivity changes caused by core depletion and xenon transients are compensated by boron changes. Further, the location and grouping of control RCCA banks are selected during the nuclear design to lessen the severity of a RCCA ejection accident. Therefore, should a RCCA be ejected from its normal position during full power operation, only a minor reactivity excursion, at worst, could be expected to occur.

However, it may be occasionally desirable to operate with larger than normal insertions. For this reason, a rod insertion limit is defined as a function of power level. Operation with the RCCA's above this limit guarantees adequate shutdown capability and acceptable power distribution. The position of all RCCA's is continuously indicated in the control room. An alarm will occur if a bank of RCCA's approaches its insertion limit or if one RCCA deviates from its bank. Operating instructions require boration at the low-low alarm.

Reactor Protection

The reactor protection in the event of a rod ejection accident has been described in Reference 4. The protection for this accident is provided by high neutron flux trip (high and low setting). These protection functions are described in detail in Section 7.2 of the FSAR.

Effects on Adjacent Housings

Disregarding the remote possibility of the occurrence of a RCCA mechanism housing failure, investigations have shown that failure of a housing due to either longitudinal or circumferential cracking would not cause damage to adjacent housings. However, even if damage is postulated, it would not be expected to lead to a more severe transient, since RCCA's are inserted in the core in symmetric patterns, and control rods immediately adjacent to worst ejected rods are not in the core when the reactor is critical. Damage to an adjacent housing could, at worst, cause that RCCA not to fall on receiving a trip signal; however, this is already taken into account in the analysis by assuming a stuck rod adjacent to the ejected rod.

Limiting Criteria

This event is classified as an ANS Condition IV incident. Due to the extremely low probability of a RCCA ejection accident, some fuel damage could be considered an acceptable consequence.

Comprehensive studies, both of the threshold of fuel failure and of the threshold or significant conversion of the fuel thermal energy to mechanical energy, have been carried out as part of the SPERT project by the Idaho Nuclear Corporation. Extensive tests of UO_2 zirconium clad fuel rods representative of those in pressurized water reactor type cores have demonstrated failure thresholds in the range of 240 to 257 cal/gm. However, other rods of a slightly different design have exhibited failures as low as 225 cal/gm. These results differ significantly from the TREAT results, which indicated that this threshold decreases by about 10% with fuel burnup. The cladding failure mechanism appears to be melting for zero burnup rods and brittle fracture for irradiated rods. Also important is the conversion ratio of thermal to mechanical energy. This ratio becomes marginally detectable above 300 cal/gm for unirradiated rods and 200 cal/gm for irradiated rods; catastrophic failure (large fuel dispersal, large pressure rise) even for irradiated rods did not occur below 300 cal/gm.

In view of the above experimental results, criteria are applied to ensure that there is little or no possibility of fuel dispersal in the coolant, gross lattice distortion, or severe shock waves. These criteria are:

a. Average fuel pellet enthalpy at the hot spot below 200 cal/gm (360 Btu/lbm) for irradiated fuel. This bounds non-irradiated fuel which has a slightly higher enthalpy limit.

b. Peak reactor coolant pressure less than that which could cause stresses to exceed the faulted condition stress limits.

c. Fuel melting limited to less than the innermost ten percent of the fuel pellet at the hot spot, even if the average fuel pellet enthalpy is below the limits of criterion (a) above.

Method of Analysis

The calculation of the transient is performed in two stages, first an average core calculation and then a hot region calculation. The average core calculation is performed using spatial neutron kinetics methods to determine the average power generation with time including the various total core feedback effects, i.e., Doppler reactivity and moderator density reactivity. Enthalpy and temperature transients in the hot spot are determined by adding a multiple of the average core energy generation to the hotter rods and performing a transient heat-transfer calculation. The asymptotic power distribution calculated without feedback is pessimistically assumed to persist throughout the transient.

Average Core Analysis

The spatial kinetics computer code, TWINKLE (Reference 4 in Section 14.0), is used for the average core transient analysis. This code solves the two group neutron diffusion theory kinetic equation in one, two or three spatial dimensions (rectangular coordinates) for six delayed neutron groups and up to 8000 spatial points. The computer code includes a detailed multiregion, transient fuel-cladding-coolant heat transfer model for calculation of pointwise Doppler and moderator feedback effects. In this analysis, the code is used as a one dimensional axial kinetics code, since it allows a more realistic representation of the spatial effects of axial moderator feedback and RCCA movement. However, since the radial dimension is missing, it is still necessary to employ very conservative methods (described in the following) of calculating the ejected rod worth and hot channel factor. Further description of TWINKLE appears in Section 14.0.

Hot Spot Analysis

In the hot spot analysis, the initial heat flux is equal to the nominal times the design hot channel factor. During the transient, the heat flux hot channel factor is linearly increased to the transient value in 0.1 second, the time for full ejection of the rod. Therefore, the assumption is made that the hot spots before and after ejection are coincident. This is very conservative, since the peak after ejection will occur in or adjacent to the assembly with the ejected rod, and prior to ejection the power in this region will necessarily be depressed.

The hot spot analysis is performed using the detailed fuel-and cladding transient heat transfer computer code, FACTRAN (Reference 2 in Section 14.0). This computer code calculates the transient temperature distribution in a cross section of a metal clad UO_2 fuel rod, and the heat flux at the surface of the rod, using as input the nuclear power versus time and the local coolant conditions. The zirconium-water reaction is explicitly represented, and all material properties are represented as functions of temperature. A conservative pellet radial power distribution is used within the fuel rod.

FACTRAN uses the Dittus-Boelter or Jens-Lottes correlation to determine the film heat transfer before DNB, and the Bishop-Sandburg-Tong (BST) correlation to determine the film boiling coefficient after DNB. The BST correlation is conservatively used assuming zero bulk fluid quality. The DNB ratio is not calculated, instead the code is forced into DNB by specifying a conservative DNB heat flux. The gap heat transfer coefficient can be calculated by the code; however, it is adjusted in order to force the full power steady-state temperature distribution to agree with the fuel heat transfer design codes. Further description of FACTRAN appears in Section 14.0.

System Overpressure Analysis

Because safety limits for fuel damage specified earlier are not exceeded, there is little likelihood of fuel dispersal into the coolant. The pressure surge may therefore be calculated on the basis of conventional heat transfer from the fuel and prompt heat generation in the coolant. The pressure surge is calculated by first performing the fuel heat transfer calculation to determine the average and hot spot heat flux versus time. Using this heat flux data, a THINC (Section 3.2) calculation is conducted to determine the volume surge. Finally, the volume surge is simulated in a plant transient computer code. This code calculates the pressure transient taking into account fluid transport in the reactor coolant system and heat transfer to the steam generators. No credit is taken for the pressure reduction caused by the assumed failure of the control rod pressure housing.

Calculation of Basic Parameters

Input parameters for the analysis are conservatively selected on the basis of values calculated for this type of core. The more important parameters are discussed below. Table 14.2.6-1 presents the parameters used in this analysis.

Ejected Rod Worths and Hot Channel Factors

The values for ejected rod worths and hot channel factors are calculated using either three dimensional static methods or by a synthesis method employing one dimensional and two dimensional calculations. Standard nuclear design codes are used in the analysis. No credit is taken for the flux flattening effects of reactivity feedback. The calculation is performed for the maximum allowed bank insertion at a given power level, as determined by the rod insertion limits. Adverse xenon distributions are considered in the calculation.

Appropriate margins are added to the ejected rod worth and hot channel factors to account for any calculational uncertainties, including an allowance for nuclear power peaking due to densification.

Power distributions before and after ejection for a "worst case" can be found in Reference 4. During plant startup physics testing, ejected rod worths and power distributions are measured in the zero and full power rodded configurations and compared to values used in the analysis. Rod worth measurement may be eliminated from the startup testing program provided that cycle specific checklist items for alternate testing method are met (Reference 9). It has been found that the ejected rod worth and power peaking factors are consistently overpredicted in the analysis.

Reactivity Feedback Weighting Factors

The largest temperature rises, and hence the largest reactivity feedbacks occur in channels where the power is higher than average. Since the weight of a region is dependent on flux, these regions have high weights. This means that the reactivity feedback is larger than that indicated by a simple channel analysis. Physics calculations have been carried out for temperature changes with a flat temperature distribution, and with a large number of axial and radial temperature distributions. Reactivity changes have been compared and effective weighting factors determined. These weighting factors take the form of multipliers which when applied to single channel feedbacks correct them to effective whole core feedbacks for the appropriate flux shape. In this analysis, since a one dimensional (axial) spatial kinetics method is employed, axial weighting is not necessary if the initial condition is made to match the ejected rod configuration. In addition, no weighting is applied to the moderator feedback. A conservative radial weighting factor is applied to the transient fuel temperature to obtain an effective fuel temperature as a function of time accounting for the missing spatial dimension. These weighting factors have also been shown to be conservative compared to three dimensional analysis (Reference 4).

Moderator and Doppler Coefficient

The critical boron concentrations at the beginning of life and end of life are adjusted in the nuclear core in order to obtain moderator density coefficient curves which are conservative compared to actual design conditions for the plant. As discussed above, no weighting factor is applied to these results.

The Doppler reactivity defect is determined as a function of power level using a one dimensional steady-state computer code with a Doppler weighting factor of 1.0. The Doppler defect used is given in Table 14.2.6-1. The Doppler weighting factor will increase under accident conditions, as discussed above.

Delayed Neutron Fraction, β_{eff}

Calculations of the effective delayed neutron fraction (β_{eff}) typically yield values no less than 0.70% at beginning of life and 0.50% at end of life for the first cycle. The accident is sensitive to β if the ejected rod worth is equal to or greater than β as in zero power transients. In order to allow for reload cycles, pessimistic estimates of β of 0.49% at beginning of cycle and 0.43% at end of cycle were used in the analysis.

Trip Reactivity Insertion

The trip reactivity insertion assumed is given in Table 14.2.6-1 and includes the effect of one stuck RCCA. These values are reduced by the ejected rod reactivity. The shutdown reactivity has been simulated by dropping a rod of the required worth into the core. The start of rod motion occurs 0.5 second after the high neutron flux trip point is reached. This delay is assumed to consist of 0.2 second for the instrument channel to produce a signal, 0.15 second for the trip breaker to open and 0.15 second for the coil to release the rods. A curve of trip rod insertion versus time is used which assumes that insertion to the dashpot does not occur until 2.2 seconds after the start of fall. The choice of such a conservative insertion rate means that there is over one second after the trip point is reached before significant shutdown reactivity is inserted into the core. This is a particularly important conservatism for hot full power accidents.

Reactor Protection

Reactor protection for a rod ejection is provided by high neutron flux trip (high and low setting). These protection functions are part of the reactor trip system. No single failure of the reactor trip system will negate the protection functions required for the rod ejection accident, or adversely affect the consequences of the accident.

Results

Cases are presented for both beginning and end of life at zero and full power.

1. Beginning of Cycle, Full Power

   Control bank D is assumed to be inserted to its insertion limit. The worst ejected rod worth and hot channel factor are conservatively calculated to be 400 pcm and 4.2 respectively. The peak hot spot cladding average temperature is 2158°F. The peak hot spot fuel center temperature reaches melting, which is conservatively assumed to be 4900°F. However, melting is restricted to less than 10% of the pellet.

2. Beginning of Cycle, Zero Power

   For this condition, control bank D is assumed to be fully inserted and banks B and C are at their insertion limits. The worst ejected rod is located in control bank D and has a worth of 790 pcm and a hot channel factor of 11.0. The peak hot spot cladding average temperature reaches 2687°F, the fuel center temperature is 3975°F.

3. End of Cycle, Full Power

Control bank D is assumed to be inserted to its insertion limit. The ejected rod worth and hot channel factors are conservatively calculated to be 420 pcm and 5.69 respectively. This results in a peak cladding average temperature of 2169°F. The peak hot spot fuel temperature reaches melting, conservatively assumed to be 4800°F. However, melting is restricted to less than 10% of the pellet.

4. End of Cycle, Zero Power

The ejected rod worth and hot channel factor for this case are obtained assuming control bank D to be fully inserted and banks C and B at their insertion limit. The results are 930 pcm and 18.0, respectively. The peak cladding average and fuel center temperatures are 2916°F and 4021°F, respectively.

A summary of the cases presented above is given in Table 14.2.6-1. The nuclear power and hot spot fuel and cladding temperature transients are presented in Figure 14.2.6-1 through Figure 14.2.6-4.

For all cases, reactor trip occurs very early in the transient, after which the nuclear power excursion is terminated. As discussed previously, the reactor will remain subcritical following reactor trip.

The ejection of an RCCA constitutes a break in the reactor coolant system, located in the reactor pressure vessel head. The effects and consequences of loss of coolant accidents are discussed in Section 14.3. Following the RCCA ejection, the operator would follow the same emergency instructions as for any other loss of coolant accident to recover from the event.

Rods-in-DNB

It is assumed that fission products are released from the gaps of all rods entering DNB. In all cases considered, less than 10% of the rods entered DNB based on a detailed three-dimensional THINC analysis.

Pressure Surge

A detailed calculation of the pressure surge for an ejection worth of one dollar at beginning of life, hot full power, indicates that the peak pressure does not exceed that which would cause stress to exceed the faulted condition stress limits. Since the severity of the present analysis does not exceed the “worst case” analysis, the accident for this plant will not result in an excessive pressure rise or further damage to the reactor coolant system.

Lattice Deformations

A large temperature gradient will exist in the region of the hot spot. Since the fuel rods are free to move in the vertical direction, differential expansion between separate rods cannot produce distortion. However, the temperature gradients across individual rods may produce a differential expansion tending to bow the midpoint of the rods toward the hotter side of the rod. Calculations have indicated that this bowing would result in a negative reactivity effect at the hot spot since

Westinghouse cores are undermoderated, and bowing will tend to increase the undermoderation at the hot spot. Since the 14 x 14 fuel design is also undermoderated, the same effect would be observed. In practice, no significant bowing is anticipated, since the structural rigidity of the core is more than sufficient to withstand the forces produced. Boiling in the hot spot region would produce a net flow away from that region. However, the heat from the fuel is released to the water relatively slowly, and it is considered inconceivable that crossflow will be sufficient to produce significant lattice forces. Even if massive and rapid boiling, sufficient to distort the lattice, is hypothetically postulated, the large void fraction in the hot spot region would produce a reduction in this ratio at the hot spot. The net effect would therefore be a negative feedback. It can be concluded that no conceivable mechanism exists for a net positive feedback resulting from lattice deformation. In fact, a small negative feedback may result. The effect is conservatively ignored in the analysis.

Conclusions

Conservative analyses indicate that the described fuel and cladding limits are not exceeded. It is concluded that there is no danger of sudden fuel dispersal into the coolant. Since the peak pressure does not exceed that which would cause stresses to exceed the faulted condition stress limits, it is concluded that there is no danger of further consequential damage to the reactor coolant system. The analyses have demonstrated that the number of fuel rods entering DNB is limited to less than 10% of the fuel rods in the core.

Radiological Consequences of a Rod Ejection Accident

This section presents an evaluation of the offsite consequences of a control rod ejection (CRE) accident. The analysis of the CRE radiological consequences uses the analytical methods and assumptions outlined in the RG 1.183 (Reference 7).

Following the accident, two release paths contribute to the total radiological consequences of the accident. The first is the leakage of radioactivity from the containment atmosphere to the environment and the second is the leakage of radioactivity from the secondary system through the steam generator relief valves. The radioactivity in the containment atmosphere is due to the radioactivity in the primary system coolant that has spilled out of the primary system into the containment through the hole in the reactor head created by the rod ejection. The radioactivity in the secondary system is due to the radioactivity in the primary system coolant that has leaked into the secondary system prior to the accident and also to the radioactivity that is transported to the secondary system by the primary system coolant that leaks through the steam generator tubes during the accident. Steam is released from the steam generator for heat removal purposes because condenser cooling is lost due to the assumed coincident loss of offsite power during the accident.

The major assumptions and parameters used in the CRE dose analysis are itemized in Table 14.2.6-2. Other assumptions for this dose analysis are presented in Table 14.1.8-3 and Table 14.1.8-6.

The concentrations of iodines and noble gasses in the RCS at the time the accident occurs are assumed to be 0.5 μCi/gm of dose equivalent (DE) I-131 and 520 μCi/gm of DE Xe-133. The alkali metal concentration in the RCS is based on the fuel defect level that corresponds to 0.5 μCi/gm DE I-131. The iodine activity concentration of the secondary coolant at the time the accident occurs is assumed to be equivalent to the Technical Specification limit of 0.1 μCi/gm of DE I-131. The alkali metal activity concentration of the secondary coolant at the time the accident occurs is assumed to correspond to 0.1 μCi/gm of DE I-131. The equilibrium nuclide concentrations are presented in Table 14.1.8-4.

Core Release Model

The core activity is presented in Table 14.1.8-4. The quantity of radioactivity released from the reactor core either to the primary system or to the containment atmosphere during the accident was conservatively calculated using the following assumptions:

1. Ten percent of the fuel rods in the reactor core are assumed to suffer sufficient damage (DNB), as a result of the CRE, such that all of their gap activity is released to the RCS. Ten percent of the core iodine and noble gases and twelve percent of the core alkali metals are assumed to be in the fuel clad gap.

2. One quarter of one percent (0.25%) of the fuel in the reactor core suffers fuel melt. The fraction of melted fuel activity released to containment or the RCS is 100% for noble gases and 50% for iodines and alkali metals. The fuel melt fraction was determined using the following assumptions:

   a. Fifty percent of the fuel rods experiencing clad damage may also experience fuel melting at the centerline of the fuel rod

   b. Centerline fuel melting is limited to the inner 10% of the fuel

   c. Melting occurs over fifty percent of the axial length of the fuel rod

3. The activity releases from the damaged/melted fuel reflect the maximum radial peaking factor of 1.7.

Containment Release Pathway

The model for this release pathway assumes that all of the radioactivity initially present in the primary system and the radioactivity introduced by the fuel rod cladding failures and the melted fuel is instantaneously and homogeneously mixed throughout the net free volume of the containment atmosphere at the time of the accident. No credit is taken for plate out onto containment surfaces or for containment spray operation, which would remove airborne particulates and elemental iodine. The only removal processes considered are sedimentation of particulates, radioactive decay and leakage.

The containment is assumed to leak at the design leak rate of 0.2 weight percent per day for the first 24 hours of the accident and then to leak at half that rate (0.1 weight percent per day) for the remainder of the 30 day period following the accident considered in the analysis.

Primary-to-Secondary Leakage Release Pathway

When determining doses due to the primary-to-secondary SG tube leakage, all the iodine, alkali metals and noble gas activity (from prior to the accident and resulting from the accident) is assumed to be in the primary coolant (and not in the containment). An accident-induced primary-to-secondary leak rate of 1000 gm/min per SG is assumed. Although the primary-to-secondary pressure differential drops throughout the event, the constant flow rate is conservatively maintained. The primary-to-secondary tube leakage continues until the RCS pressure drops below the secondary pressure. A conservative time of 0.556 hours was used for this analysis. Steam releases from the SGs are conservatively assumed to continue for 30 hours.

An iodine partition factor in the SGs of 0.01 (curies iodine/gm steam) / (curies iodine/gm water) and a particulate retention factor of 0.0025 are used. All noble gas activity, transferred to the secondary side of the SG through SG tube leakage, is assumed to be directly released to the outside atmosphere.

Acceptance Criteria

The Standard Review Plan (SRP) 15.0.1 (Reference 8) offsite dose acceptance criterion for a CRE accident is 6.3 rem TEDE, which is approximately 25% of the 10 CFR 50.67 limit of 25 rem TEDE. The control room personnel dose acceptance criterion is 5 rem TEDE per 10 CFR 50.67.

Results and Conclusions

The results of the offsite and control room dose analyses are provided in Table 14.2.6-3, and indicate that the acceptance criteria are met. The exclusion area boundary doses reported are for the worst 2 hour period, determined to be from 0 to 2 hours.

References

1. Tong, "Post DNB Heat Transfer," WCAP 7247

2. Redfield, J.A., "CHIC-KIN -- A Fortran Program for Intermediate and Fast Transients in a Water Moderated Reactor," WAPD-TM-479, January, 1965

3. Barry, R. F., "The Revised LEOPARD Code - A Spectrum Dependent Non Spatial Depletion Program," WCAP-2759 (1965)

4. "Power Distribution Control of Westinghouse PWR" WCAP 7208 (1968)

5. Conway and Hein, Journal of Nuclear Materials (15.1), 1965

6. Ogard & Leary, "High Temperature Heat Content and Heat Capacity of Uranium Dioxide - Plutonium Dioxide Solid Solutions," LA-DC-8620

7. USNRC, Regulatory Guide 1.183, "Alternative Radiological Source Terms for Evaluating Design Basis Accidents at Nuclear Power Reactors," July 2000.

8. Standard Review Plan (SRP) Section 15.0.1, "Radiological Consequence Analyses Using Alternative Source Terms," July 2000.

9. PWROG-20039-P, Revision 0, Framatome Doc. 51-9322763-000, "Conditional Rod Worth Measurement Elimination," December 2020.

Table 14.2.6-1 PARAMETERS USED IN THE ANALYSIS OF THE ROD CLUSTER CONTROL ASSEMBLY EJECTION ACCIDENT

Parameters	BOL-HZP	BOL-HFP	EOL-HZP	EOL-HFP
Initial core power level, percent of 1800 MWt	0%	102%	0%	102%
Ejected rod worth, pcm	790	400	930	420
Delayed neutron fraction	0.0049	0.0049	0.0043	0.0043
Doppler reactivity defect (absolute value), pcm	1000	1000	1000	1000
Doppler feedback reactivity weighting	2.008	1.139	2.704	1.316
Trip reactivity, percent ΔK	2.0	4.0	2.0	4.0
F_q before rod ejection	N/A	2.6	N/A	2.6
F_q after rod ejection	11.0	4.2	18.0	5.69
Number of operational pumps	1	2	1	2
Maximum fuel pellet average temperature, °F	3554	4021	3682	4043
Maximum fuel center temperature, °F	3975	>4900	4021	>4800
Maximum cladding average temperature, °F	2687	2158	2916	2169
Maximum fuel stored energy, cal/gm	151.5	175.6	158.1	176.7
Maximum fuel melt, %	nil	6.3	nil	9.8

Table 14.2.6-2 ASSUMPTIONS USED FOR CONTROL ROD EJECTION ACCIDENT ANALYSIS

PARAMETER	VALUE
Initial Power	1811 MWt
Fraction of Fuel Rods in Core Assumed to Fail	10% of Core
Fraction of Fuel Rods in Core Assumed to Melt	0.25% of Core
Gap Fractions	
Iodines and Noble Gases	0.10
Alkali Metals	0.12
Fraction of Activity Released from Melted Fuel	
lodines and Alkali Metals	0.5
Noble Gases	1.0
Radial Peaking Factor	1.7
RCS Activity Prior to Accident	
Iodine	0.5 µCi/gm of DE I-131
Noble Gas	520 µCi/gm of DE Xe-133
Alkali Metals	Corresponds to 0.5 µCi/gm of DE I-131
Secondary Coolant Activity Prior to Accident	
Iodine	0.1 µCi/gm of DE I-131
Alkali Metals	Corresponds to 0.1 µCi/gm of DE I-131
Containment Leak Rate	
0 - 24 hours	0.2 weight %/day
> 24 hours	0.1 weight %/day
Iodine Chemical Form in Containment	
Elemental	4.85%
Organic	0.15%
Particulate	95%
Spray Removal in Containment	Not Credited
Sedimentation Removal Credit	
Iodines	Not credited
Alkali Metals	0.1 hr^{-1}
Total SG Tube Leak Rate	
0 - 0.556 hours	2000 gm/min
> 0.556 hours	0.0 gm/min
Steam Release to Environment	
0 - 2 hours	8.063E5 gm/min
2 - 14 hours	4.530E5 gm/min
14 - 30 hours	2.651E5 gm/min
SG Iodine Partition Factor	0.01
SG Alkali Metal Retention Factor	0.0025
Iodine Species Released to the Atmosphere from SGs	
Elemental	97%
Organic	3%

Table 14.2.6-3 DOSES DUE TO THE RADIOACTIVITY RELEASED DURING THE CONTROL ROD EJECTION ACCIDENT

Site Boundary (0 - 2 hr)	2.3 rem TEDE
Low Population Zone (0 - 30 days)	0.8 rem TEDE
Control Room (0 - 30 days)	2.9 rem TEDE

Figure 14.2.6-1 RCCA EJECTION TRANSIENT BEGINNING OF LIFE ZERO POWER

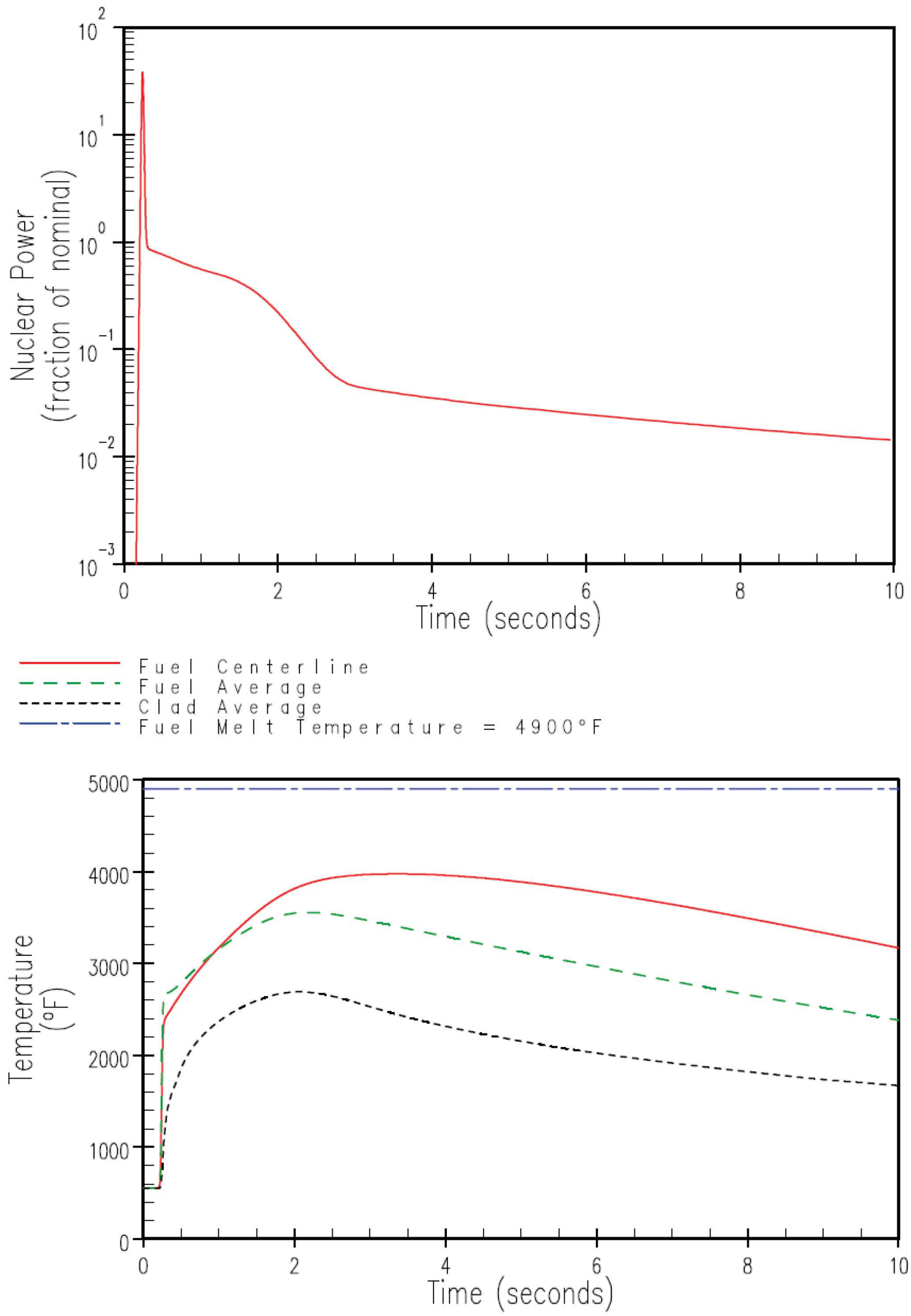


Figure 14.2.6-2 RCCA EJECTION TRANSIENT BEGINNING OF LIFE FULL POWER

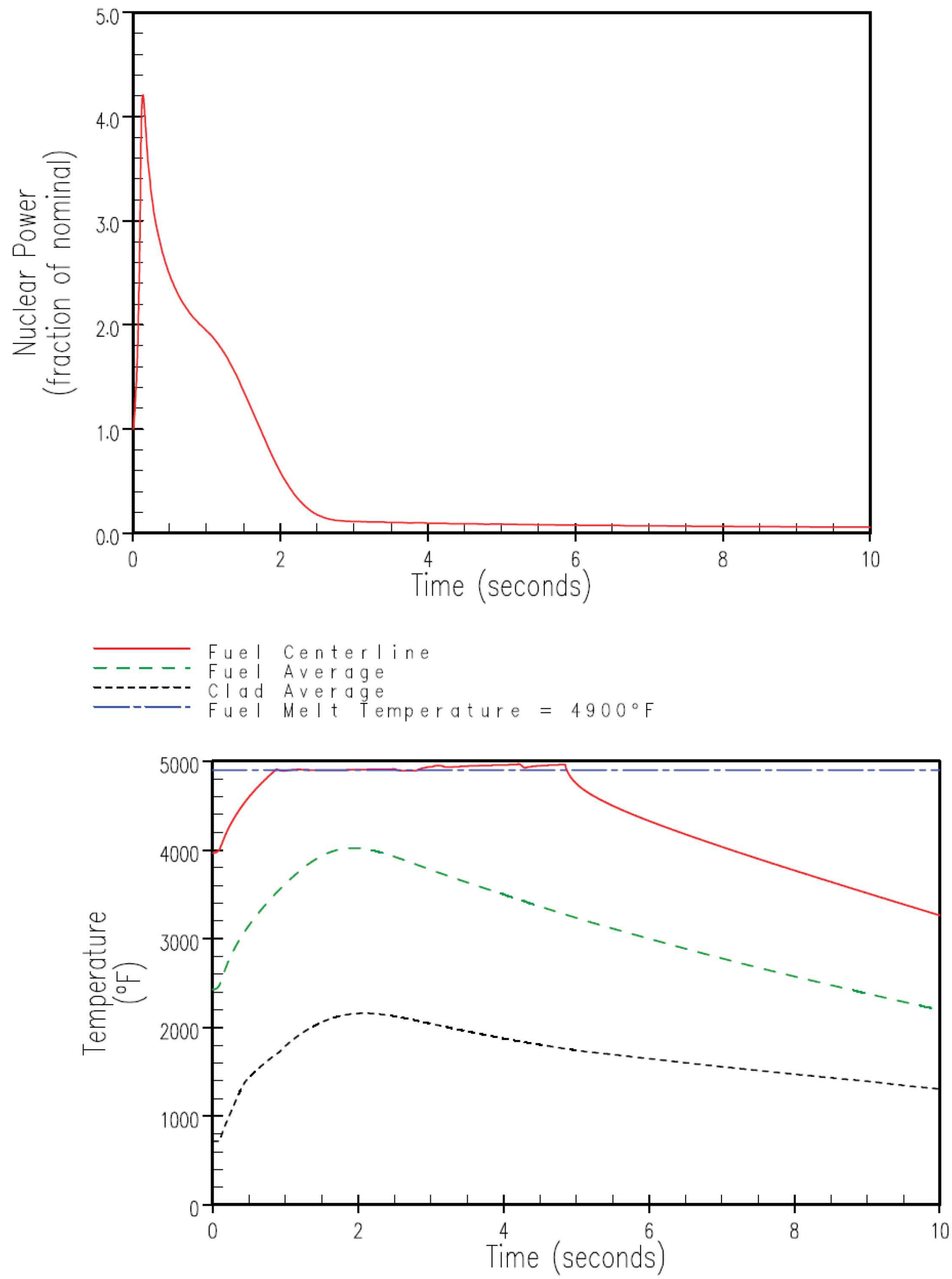


Figure 14.2.6-3 RCCA EJECTION TRANSIENT END OF LIFE ZERO POWER

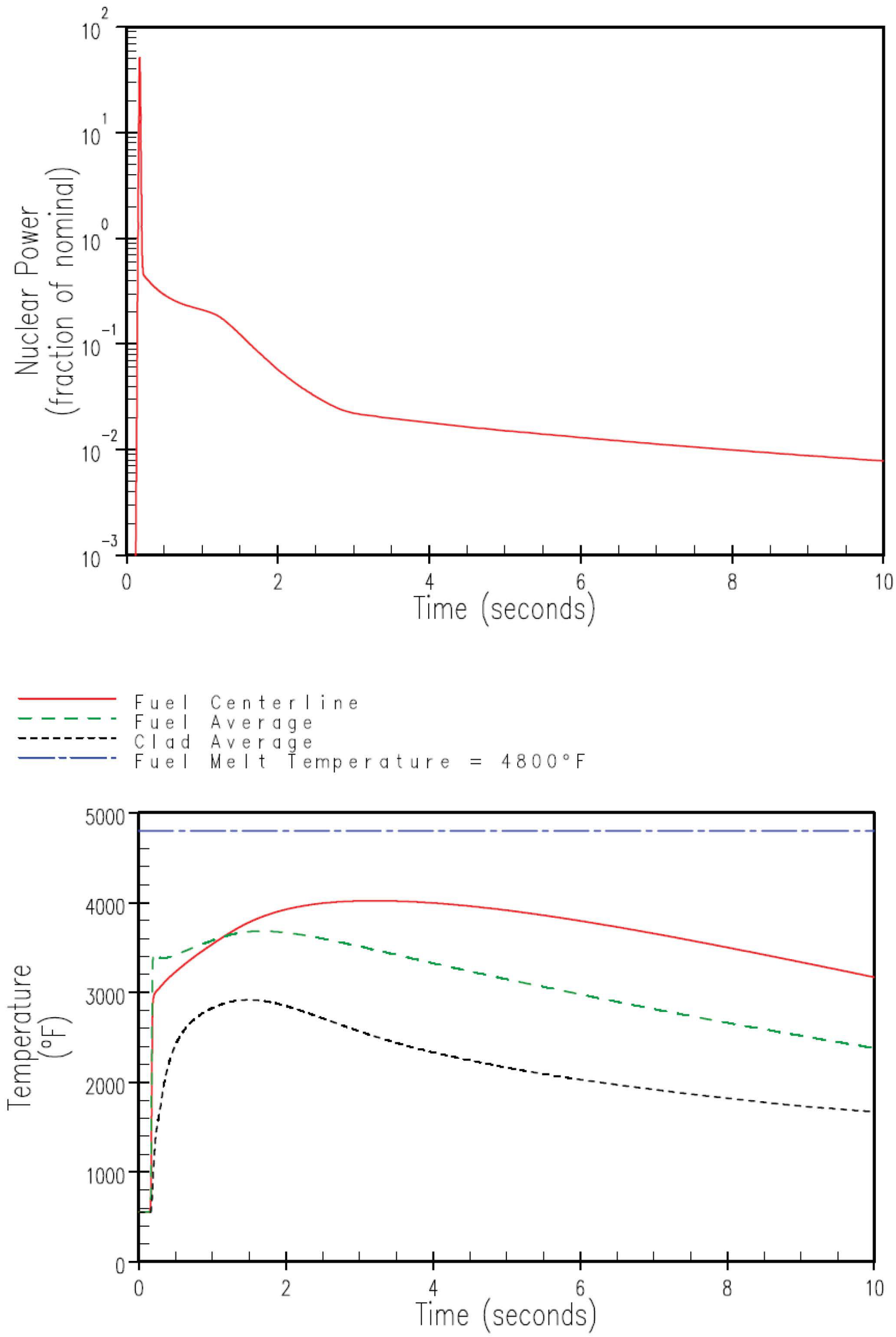
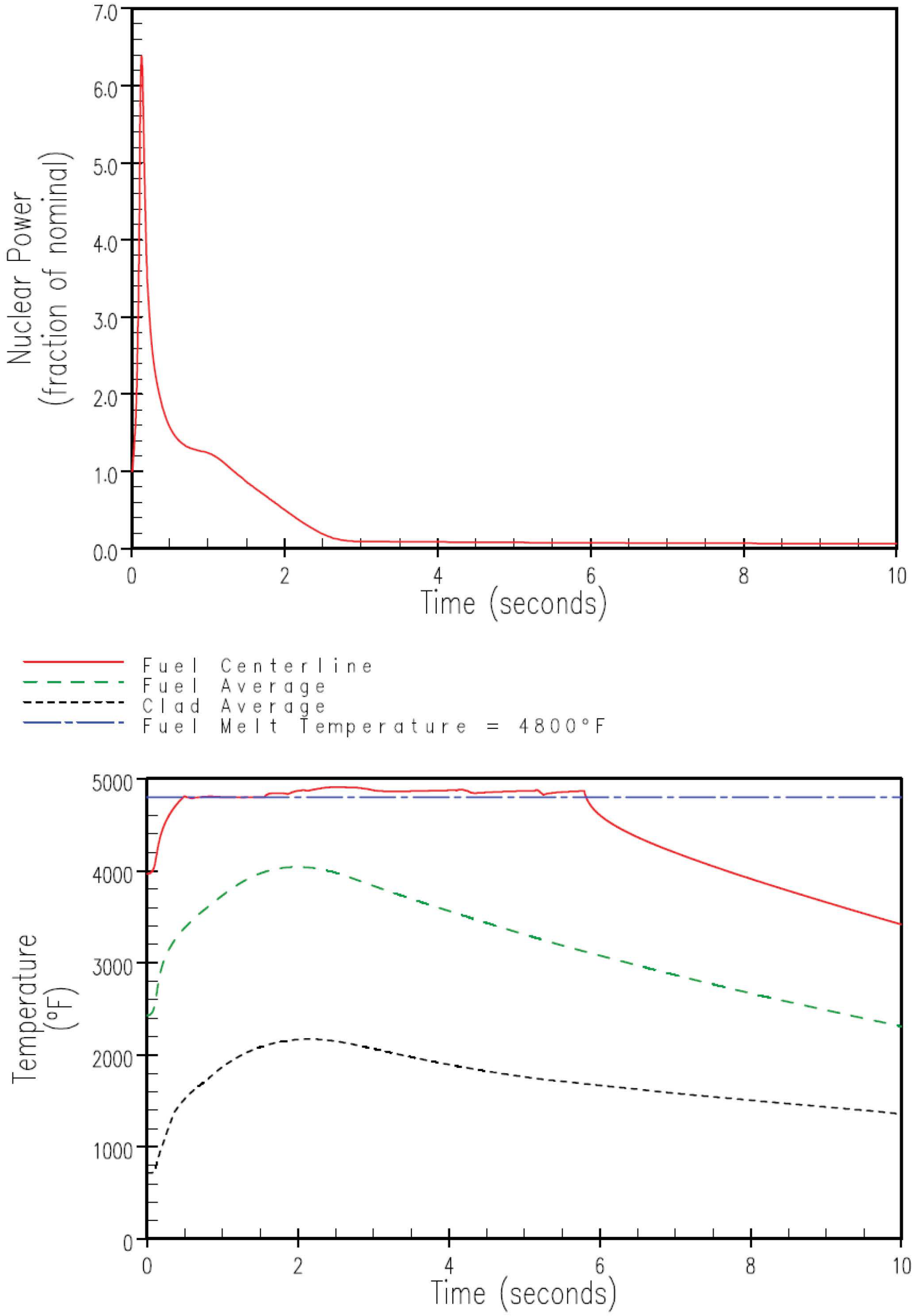


Figure 14.2.6-4 RCCA EJECTION TRANSIENT END OF LIFE FULL POWER



14.2.7 INADVERTENT OPENING OF A STEAM GENERATOR (SG) RELIEF OR SAFETY VALVE

The inadvertent opening of a steam generator (SG) relief or safety valve event is classified as an anticipated operational Occurrence (AOO) and considered to be an American Nuclear Society (ANS) Condition II event. The cooldown effects and transient results from an inadvertent opening of a SG relief or safety valve have been shown to be less severe than those for a hot zero power hypothetical steam line break (i.e., the double-ended rupture) (Reference 1 and Reference 2). The latter event, analyzed in the FSAR Section 14.2.5, is considered to be an ANS Condition IV event. The peak heat flux in the case of inadvertent opening of a SG relief or safety valve would be much less than that of the double-ended steam line break event due to the lower steam release rate.

The steam line break event is also analyzed in the FSAR Section 14.2.5 from hot full power conditions for a range of break sizes up to 1.4 ft^2, which would bound the inadvertent opening of a SG relief or safety valve.

The inadvertent opening of a SG relief or safety valve event is thus bounded by the limiting hot full power and hot zero power steam line break events described in the FSAR Section 14.2.5. Since the steam line break events in the FSAR Section 14.2.5 are analyzed to the same A00 acceptance criteria, the inadvertent opening of a SG relief or safety valve event is not explicitly analyzed for PBNP. The limiting steam line break accident described in FSAR Section 14.2.5, Rupture of A Steam Pipe, demonstrates that the DNBR and kW/ft limits are met.

Conclusions

The inadvertent opening of a steam generator relief or safety valve is less severe than that of a steam line break event (see Section 14.2.5). Based on results presented in [1], the applicable acceptance criteria for the inadvertent opening of a steam generator relief or safety valve have been met.

REFERENCES

1. NRC Safety Evaluation, PBNP Units 1 and 2 - Issuance of License Amendments Regarding Extended Power Uprate, May 3, 2011.

2. WCAP-12602, “Report for the Reduction of SI System Boron Concentration,” September 1990.

1.

14.3 PRIMARY SYSTEM PIPE RUPTURES

14.3.1 SMALL BREAK LOSS-OF-COOLANT ACCIDENT ANALYSIS

Identification of Causes and Accident Description

A loss of coolant accident is defined as a rupture of the reactor coolant system piping or of any line connected to the system up to the first closed valve. Ruptures of small cross section will cause loss of the coolant at a rate which can be accommodated by the charging pumps which would maintain an operational water level in the pressurizer permitting the operator to execute an orderly shutdown. A moderate quantity of coolant containing such radioactive impurities as would normally be present in the coolant, would be released to the containment.

The maximum break size for which the normal makeup system can maintain the pressurizer level is obtained by comparing the calculated flow from the reactor coolant system through the postulated break against the charging pump makeup flow at normal reactor coolant system pressure, i.e., 2250 psia. A makeup flow rate from two charging pumps is typically adequate to maintain pressurizer level long enough for the operator to respond without activating the ECCS for a break through a 3/8 inch diameter hole.

Should a larger break occur, depressurization of the reactor coolant system causes fluid to flow to the reactor coolant system from the pressurizer resulting in a pressure and level decrease in the pressurizer. Reactor trip occurs when the pressurizer low pressure trip setpoint is reached. The consequences of the accident are limited in two ways:

1. Reactor trip and borated water injection complement void formation in causing rapid reduction of nuclear power to a residual level corresponding to the delayed fission and fission product decay.

2. Injection of borated water ensures sufficient flooding of the core to prevent excessive cladding temperatures.

Before the break occurs, the plant is in an equilibrium condition, i.e., the heat generated in the core is being removed via the secondary system. During blowdown, heat from decay, hot internals and the vessel continues to be transferred to the reactor coolant system. The heat transfer between the reactor coolant system and the secondary system may be in either direction depending on the relative temperatures. In the case of continued heat addition to the secondary, system pressure increases and steam dumping may occur. The safety injection signal stops normal feedwater flow by closing the main feedwater line isolation valves and initiates emergency feedwater flow by starting Auxiliary Feedwater (AFW) pumps. Although the AFW System may be initiated during the Small Break LOCA, the event has been analyzed with no credit for auxiliary feedwater. The designated motor-driven and turbine-driven AFW pumps would automatically start as a result of a Safety Injection signal and may start as a result of 4.16KV bus undervoltage or steam generator low-low levels in both steam generators of the accident unit. However, the event was analyzed without AFW due to asymmetries and limit the modeling required to address all possible combinations and time-delays of AFW System configurations. The secondary flow aids in the reduction of reactor coolant system pressure. When the RCS depressurizes to 695 psia, the accumulators begin to inject water into the reactor coolant loops. The reactor coolant pumps are assumed to be tripped at the initiation of the accident and effects of pump coastdown are included in the blowdown analyses.

Analysis of Effects and Consequences - Method of Analysis

For small breaks less than 1.0 ft^2 the NOTRUMP Evaluation Model (Reference 1, Reference 2 and Reference 4) is employed to calculate the transient depressurization of the reactor coolant system as well as to describe the mass and enthalpy of flow through the break and the subsequent rod heat-up.

Small Break LOCA Analysis Using NOTRUMP

The NOTRUMP and LOCTA-IV (Reference 1 and Reference 3) computer codes are used in the analysis of loss-of-coolant accidents due to small breaks in the Reactor Coolant System. The NOTRUMP computer code is a one-dimensional general network code consisting of a number of advanced features. Among these features are the calculation of thermal non-equilibrium in all fluid volumes, flow regime-dependent drift flux calculations with counter-current flow limitations, mixture level tracking logic in multiple-stacked fluid nodes, and regime-dependent heat transfer correlations. Safety injection into the broken loop is modeled along with the COSI condensation model (Reference 4). The NOTRUMP small break LOCA emergency core cooling system (ECCS) evaluation model was developed to determine the RCS response to design basis small break LOCAs and to address the NRC concerns expressed in NUREG-0611, "Generic Evaluation of Feedwater Transients and Small Break Loss-of-Coolant Accidents in Westinghouse Designed Operating Plants."

The reactor coolant system is nodalized into volumes interconnected by flowpaths. Both the broken and intact loops are modeled explicitly. The transient behavior of the system is determined from the governing conservation equations of mass, energy, and momentum applied throughout the system. A detailed description of NOTRUMP is given in Reference 1, Reference 2 and Reference 4.

The use of NOTRUMP in the analysis involves, among other things, the representation of the reactor core as heated control volumes with the associated bubble rise model to permit a transient mixture height calculation. The multi-node capability of the program enables an explicit and detailed spatial representation of various system components. In particular, it enables a proper calculation of the behavior of the loop seal during a loss-of-coolant transient.

Peak cladding temperature analyses are performed with the LOCTA IV code. Input for the code is obtained from the NOTRUMP calculations which determine the RCS pressure, fuel rod power history, steam flow past the uncovered part of the core, core inlet enthalpy, and mixture height history.

Table 14.3.1-1 lists important input parameters and initial conditions used in the analysis. Major assumptions included a total peaking factor of 2.60, $F_{\Delta H}$ of 1.68, 10% steam generator tube plugging, thermal design flow of 89,000 gpm/loop and 100.6% of a core thermal power of 1800 MWt. Note: The Small Break LOCA analysis was performed with ZIRLO® cladding. However, Reference 7 concluded that the LOCA ZIRLO models are acceptable for application to Optimized ZIRLO™ cladding in the Small Break analysis, and that no additional calculations are necessary for evaluating the use of Optimized ZIRLO™ cladding provided that plant specific ZIRLO claculations were previously performed.

Safety injection flow rate to the reactor coolant system as a function of the system pressure is used as part of the input. The safety injection (SI) system is assumed to be delivering to the RCS 28 seconds after the generation of a safety injection signal. For this analysis, the ECCS delivery considers flow which is depicted in Figure 14.3.1-2 through Figure 14.3.1-3A as a function of RCS pressure; these figures represent injection flow from the HHSI and LHSI pumps based on Reference 5. The SI flows are assured by the plant in-service testing acceptance criteria. The 28 second delay includes time required for diesel startup and loading of the safety injection pumps onto the emergency buses. Also minimum Emergency Core Cooling System capability and operability has been assumed in these analyses.

The data used to generate Figure 14.3.1-1 through Figure 14.3.1-3A are provided in Table 14.3.1-2A through Table 14.3.1-2C, respectively.

Table 14.3.1-2A provides the broken and intact loop high head safety injection (HHSI) flows used for breaks less than the accumulator line inner diameter (8.75-inches). The faulted loop "Spills to RCS Pressure" when the assumed backpressure is the reactor coolant system, (RCS). Since the HHSI injects into the accumulator line, and the fault size is less than the inner diameter of the accumulator line, both the broken and intact loop HHSI flows inject ("spill") to RCS pressure.

Conversely, Table 14.3.1-2B provides the broken and intact loop HHSI flows for breaks greater than or equal to the accumulator line inner diameter. For these break cases, the faulted loop HHSI flow will inject ("spill") directly into containment. While the faulted loop does spill to containment pressure, the spilling rate for these breaks is a function of RCS pressure due to the communicating intact loop HHSI branch line.

Table 14.3.1-2C provides the low head safety injection (LHSI) flows. Since the LHSI injects directly into the upper plenum, and no fault is assumed on this line, these flows always inject to RCS pressure.

The reactor scram time is equal to the reactor trip signal time plus 4.2 seconds for signal transmission and rod insertion. During this period, the reactor is conservatively assumed to operate at 100.6% of 1800 MWt.

Figure 14.3.1-1 presents the axial power shape utilized to perform the small break analysis presented here. This power shape was chosen because it provides a conservative distribution of power versus core height by maximizing the local power in the upper regions of the reactor core, while minimizing the power in the lower regions of the core. This is limiting for small break analysis because of the uncovery process. As the core uncovers, the cladding in the upper elevation of the core heats up and is sensitive to the linear power at that elevation. The cladding temperatures in the lower elevations of the core, below the two phase mixture height, remains low reducing the amount of mixture level swell, thus providing a deeper core uncovery. The peak cladding temperatures occur above 10 ft.

Results of Small Break Analysis

This section presents results of the Point Beach Units 1 and 2 break spectrum. The analysis techniques for this evaluation allow for the Point Beach Units to operate at nominal vessel average temperatures ranging from 558.0°F to 577.0°F, at a pressure of 2250 psia ± 50 psi. The Units 1 and 2 time sequence of events is summarized in Table 14.3.1-3A and

Table 14.3.1-3B. The rod heatup information is summarized in Table 14.3.1-4A and Table 14.3.1-4B. The depressurization transient for the limiting 3-inch breaks are shown in Figure 14.3.1-4 and Figure 14.3.1-14 for Units 1 and 2 , respectively. The extent to which the core is uncovered for the limiting breaks are shown in Figure 14.3.1-5 and Figure 14.3.1-15 for Units 1 and 2 , respectively.

During the early part of the small break LOCA transient positive core flow is maintained by the reactor coolant pump coastdown, overcoming any potential for the cold leg break to induce negative flow or flow stagnation in the core. The resultant heat transfer cools the fuel rod and cladding to very near the coolant temperatures as long as the core remains covered by a two phase mixture.

The maximum hot rod peak cladding temperatures calculated during the transient are 1049 and 1103°F for Units 1 and 2 , respectively. The limiting hot rod peak cladding temperature transients are shown in Figure 14.3.1-12 and Figure 14.3.1-22 for Units 1 and 2 , respectively. The calculated PCT may vary for each core reload analysis and is limited by federal regulations (10 CFR 50.46) to a maximum temperature of 2200°F for this event. The vapor mass flow rate for the limiting breaks is shown in Figure 14.3.1-8 and Figure 14.3.1-18. When the mixture level drops below the top of the core, the steam flow computed in NOTRUMP provides cooling to the upper portion of the core. The cladding surface heat transfer coefficients for this phase of the transient are given in Figure 14.3.1-10 and Figure 14.3.1-20. The fluid temperature at the PCT elevation are shown in Figure 14.3.1-11 and Figure 14.3.1-21.

Additional Break Sizes

Additional break sizes were analyzed to identify the limiting break size, including 1.5, 2, 4, 6, and 8.75 inch breaks. Figure 14.3.1-24 through Figure 14.3.1-65 show the RCS Pressure, Core Mixture Level, Core Exit Vapor Temperature, Peak Cladding Temperature, and Maximum Local Oxidation for each break size. The 6 and 8.75 inch breaks do not have rod heat up data since there was no core uncovery for those break sizes.

Conclusions

Analyses presented in this section show that the emergency core cooling system, together with accumulators, provide sufficient core flooding to keep the calculated peak cladding temperatures below required limits of 10 CFR 50.46. Hence, adequate protection is afforded by the emergency core cooling system in the event of a small break loss-of-coolant accident.

References

1. Lee, N., et. al., “Westinghouse Small Break ECCS Evaluation Model Using the NOTRUMP Code,” WCAP-10054-P-A (Proprietary) and WCAP-10081-A (Non-Proprietary), August 1985.

2. Meyer, P. E., “NOTRUMP, A Nodal Transient Small Break and General Network Code,” WCAP-10079-P-A (Proprietary) and WCAP-10080-A (Non-Proprietary), August 1985.

3. Bordelon, F. M., et. al., “LOCTA-IV Program: Loss-of-Coolant Transient Analysis,” WCAP-8301 (Proprietary), WCAP-8305 (Non-Proprietary), June 1974.

4. Thompson, C.M., et. al., "Addendum to the Westinghouse Small Break ECCS Evaluation Model Using the NOTRUMP Code: Safety Injection into the Broken Loop and COSI Condensation Model," WCAP-10054-P-A, Addendum 2, Revision 1 (Proprietary), July 1997.

5. Calculation 2006-0021-000-A, "ECCS System Accident Analysis Flow Inputs," dated April 5, 2008.

6. Calculation CN-LIS-08-15 Revision 1, "Point Beach Units 1 and 2 (WEP/WIS) Extended Power Uprate (EPU) Small Break Loca (SBLOCA) Analysis," dated September 23, 2008.

7. WCAP-12610-P-A and CENPD-404-P-A Addendum 1-A, "Optimized ZIRLO™, July 2006.

Table 14.3.1-1 INPUT ASSUMPTIONS USED IN THE SMALL BREAK ANALYSIS

Input Parameters Used in the Small Break LOCA Analysis

100% Licensed Core Power	1800 MWt
Calorimetric Uncertainty	0.6%
Peak Hot Rod Linear Power	17.689 kW/ft
Fuel Type	14x14, 422V+ with ZIRLO® Cladding [2]
Total Core Peaking Factor, F_Q	2.6
Hot Channel Enthalpy Rise Factor, $F_{\Delta H}$	1.68
Hot Assembly Peaking factor, P_{HA}	1.62
Thermal Design Flow	89,000 gpm/loop
Nominal Vessel Average Temperature Range	558 - 577°F
Reactor Coolant Pressure (including uncertainties)	2300 psia
Accumulator Water Volume	1118 ft^3
Accumulator Gas Pressure (minimum, including uncertainties)	695 psia
Minimum AFW Flow Rate per Steam Generator	(1)
Steam Pressure	705 psia (Unit 1) / 726 psia (Unit 2)
Steam Generator Tube Plugging Level	10%

(1) Since asymmetric AFW flow is not modeled in the standard NOTRUMP evaluation model, the AFW flow is assumed to be 0 gpm.

(2) Optimized ZIRLO™ fuel cladding has been evaluated as an acceptable fuel cladding.

Table 14.3.1-2A HHSI FLOWS WITH THE FAULTED LOOP SPILLING TO RCS PRESSURE

High Head Safety Injection (HHSI) Flows vs. Pressure, Minimum Safeguards, Spill to RCS Pressure (Breaks < 8.75 in. diameter)

Pressure (psia)	Spilled Flow (lbm/s)	Injected Flow (lbm/s)
14.7	65.79	60.40
114.7	63.49	58.29
214.7	61.13	56.12
314.7	58.47	53.68
414.7	55.73	51.16
514.7	52.86	48.52
614.7	49.76	45.67
714.7	46.54	42.72
814.7	43.14	39.60
914.7	39.59	36.33
1014.7	35.38	32.46
1114.7	30.70	28.16
1214.7	25.22	23.10
1314.7	18.32	16.74
1364.7	13.53	12.29

Table 14.3.1-2B HHSI FLOWS WITH THE FAULTED LOOP SPILLING TO CONTAINMENT PRESSURE

High Head Safety Injection (HHSI) Flows vs. Pressure, Minimum Safeguards, Spill to 0 psig Containment Pressure (Breaks ≥ 8.75 in. diameter)

Pressure (psia)	Spilled Flow (lbm/s)	Injected Flow (lbm/s)
14.7	71.09	65.46
114.7	72.75	61.48
214.7	74.45	57.31
314.7	76.10	52.79
414.7	77.81	48.00
514.7	79.61	42.87
614.7	81.53	37.32
714.7	83.56	31.16
814.7	85.78	24.17
914.7	88.33	15.96
934.7	88.90	14.10

Table 14.3.1-2C LHSI FLOWS INJECTING TO RCS PRESSURE

Low Head Safety Injection (LHSI) Flows vs. Pressure, Minimum Safeguards, Upper Plenum Injection

Pressure (psia)	**Injecting Flow (lbm/s)**
14.7	235.2
24.7	224.8
34.7	214.2
44.7	202.8
54.7	190.8
64.7	178.3
74.7	164.9
84.7	150.7
94.7	133.3
104.7	113.9
114.7	90.9
134.7	0.0

Note:

RHR cut-in pressure is reached only for the 6- and 8.75-inch cases during the RWST injection phase.

Table 14.3.1-3A TIME SEQUENCE OF EVENTS FOR UNIT 1

NOTRUMP Transient Results for Unit 1

Event (sec)	**1.5-inch**	**2-inch**	**3-inch**	**4-inch**	**6-inch**	**8.75-inch**
Break Initiated	0	0	0	0	0	0
Reactor Trip Signal	153.7	76.1	31.3	19.0	8.5	8.7
Safety Injection Signal	153.7	76.1	31.3	19.0	8.5	8.7
Safety Injection Begins (1)	176.7	99.1	54.3	42.0	31.5	31.7
Loop Seal Clearing Occurs (2)	1037	590	230	125	28	27
Core Uncovery	4115	1130	442	433	N/A(3)	N/A(3)
Accumulator Injection Begins	N/A	3697	690	385	156	154
Core Recovery	5649	2256	1142	450	N/A(3)	N/A(3)
RWST Low Level	2320	2269	2173	2133	1956	1880

(1) Safety Injection is assumed to begin 23.0 s after the Safety Injection Signal (a 5 second SI delay increase was evaluated qualitatively).

(2) Loop seal clearing is assumed to occur when the steam flow through the loop seal in the broken loop is sustained above 1 lbm/s and mixture level is at or below the loop seal elevation. Only the broken loop is allowed to clear for break sizes less than 6-inches in diameter. For the 6- and 8.75-inch breaks, the loop seal in the broken loop clears prior to the intact loop.

(3) There is no core uncovery for the 6- and 8.75-inch breaks.

Table 14.3.1-3B TIME SEQUENCE OF EVENTS FOR UNIT 2

NOTRUMP Transient Results for Unit 2

Event (sec)	**1.5-inch**	**2-inch**	**3-inch**	**4-inch**	**6-inch**	**8.75-inch**
Break Initiated	0	0	0	0	0	0
Reactor Trip Signal	150.6	75.5	31.0	11.8	8.4	8.5
Safety Injection Signal	150.6	75.5	31.0	11.8	8.4	8.5
Safety Injection Begins (1)	173.6	98.5	54.0	34.8	31.4	31.5
Loop Seal Clearing Occurs (2)	1083	553	237	129	28	28
Core Uncovery	4258	1175	335	355	N/A(3)	N/A(3)
Accumulator Injection Begins	N/A	3705	685	366	164	158
Core Recovery	5654	2288	1183	490	N/A(3)	N/A(3)
RWST Low Level	2032	2270	2173	2131	1957	1883

(1) Safety Injection is assumed to begin 23.0 s after the Safety Injection Signal (a 5 second SI delay increase was evaluated qualitatively).

(2) Loop seal clearing is assumed to occur when the steam flow through the loop seal in the broken loop is sustained above 1 lbm/s and mixture level is at or below the loop seal elevation. Only the broken loop is allowed to clear for break sizes less than 6-inches in diameter. For the 6- and 8.75-inch breaks, the loop seal in the broken loop clears prior to the intact loop.

(3) There is no core uncovery for the 6- and 8.75-inch breaks.

Table 14.3.1-4A SBLOCTA BOL RESULTS FOR UNIT 1

Beginning of Life (BOL) Rod Heatup Results for Unit 1

Results	1.5-inch	2-inch	3-inch	4-inch	6-inch	8.75-inch
PCT, °F	678	958	1049	532		
PCT Time, sec	4887	1516	769	445		
PCT Elevation, ft	11.75	10.75	10.75	11.75		
Burst Time[1], sec	N/A	N/A	N/A	N/A		
Burst Elevation[1], ft					N/A[2]	N/A[2]
Maximum Local Transient ZrO_2, %	0.00	0.01	0.01	0.00		
Maximum Local Transient ZrO_2 Elevation, %	11.75	10.75	10.75	11.75		
Average ZrO_2, %	0.00	0.00	0.00	0.00		

(1) Neither the hot rod nor the hot assembly average rod burst during the SBLOCTA calculations.

(2) The core either does not uncover or only uncovers for a very short time; therefore, SBLOCTA calculations are not warranted for 6- and 8.75-inch breaks.

Table 14.3.1-4B SBLOCTA BOL RESULTS FOR UNIT 2

Beginning of Life (BOL) Rod Heatup Results for Unit 2

Results	**1.5-inch**	**2-inch**	**3-inch**	**4-inch**	**6-inch**	**8.75-inch**
PCT, °F	669	955	1103	803		
PCT Time, sec	4943	1530	758	442		
PCT Elevation, ft	11.75	10.75	10.75	11.00		
Burst Time(1), sec	N/A	N/A	N/A	N/A		
Burst Elevation(1), ft					N/A(2)	N/A(2)
Maximum Local Transient ZrO_2, %	0.00	0.01	0.02	0.00		
Maximum Local Transient ZrO_2 Elevation, %	11.75	10.75	10.75	11.00		
Average ZrO_2, %	0.00	0.00	0.00	0.00		

(1) Neither the hot rod nor the hot assembly average rod burst during the SBLOCTA calculations.

(2) The core either does not uncover or only uncovers for a very short time; therefore, SBLOCTA calculations are not warranted for 6- and 8.75-inch breaks.

Figure 14.3.1-1 HOT ROD AXIAL POWER DISTRIBUTION

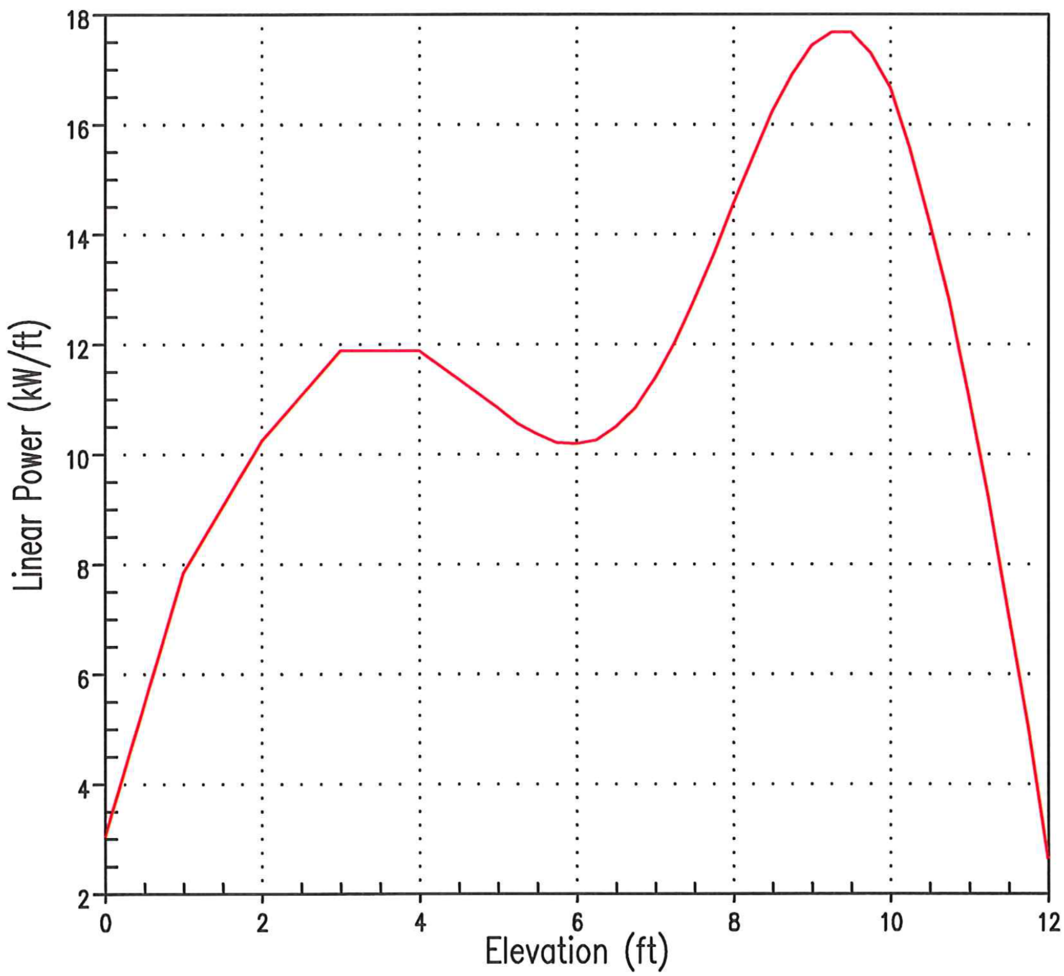


Figure 14.3.1-2 PUMPED HHSI SAFETY INJECTION FLOW RATE FAULTED LOOP SPILLING TO RCS PRESSURE

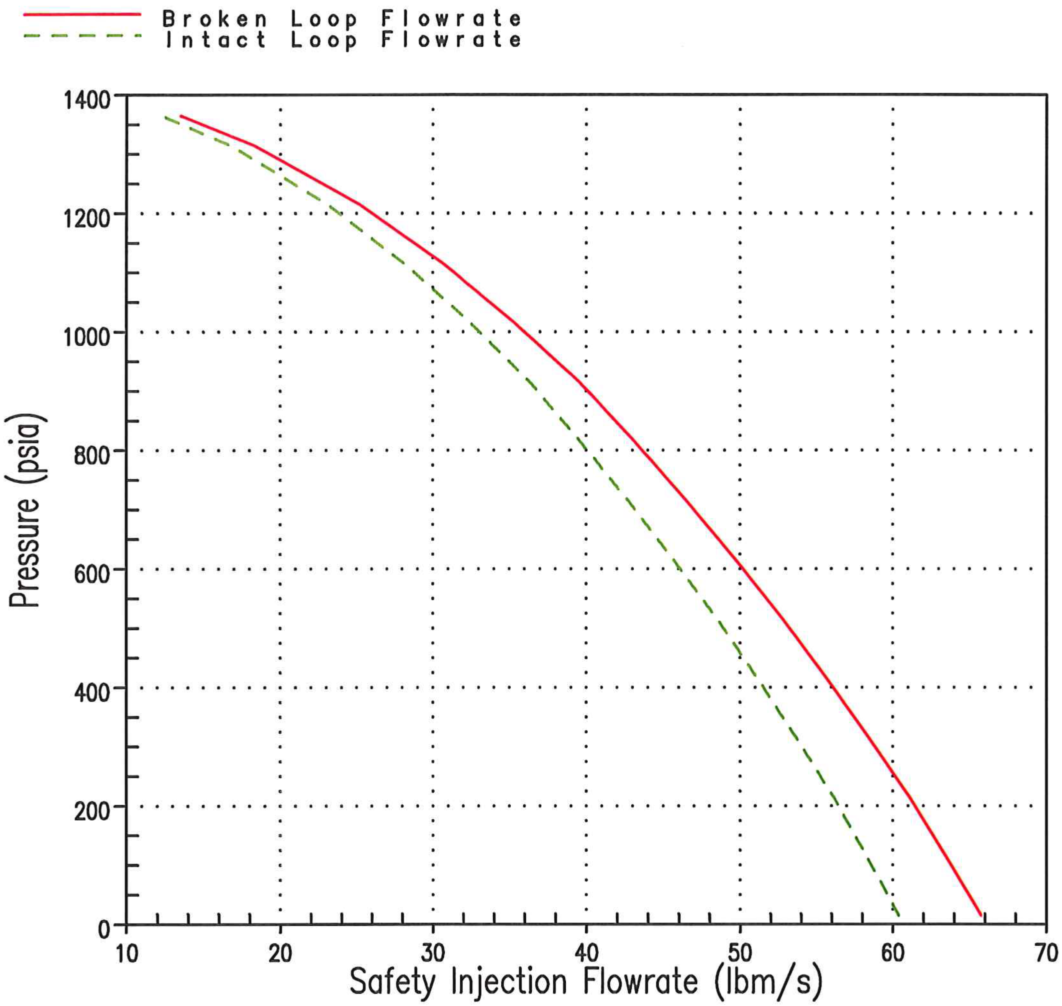


Figure 14.3.1-3 PUMPED HHSI SAFETY INJECTION FLOW RATE FAULTED LOOP SPILLING TO CONTAINMENT PRESSURE

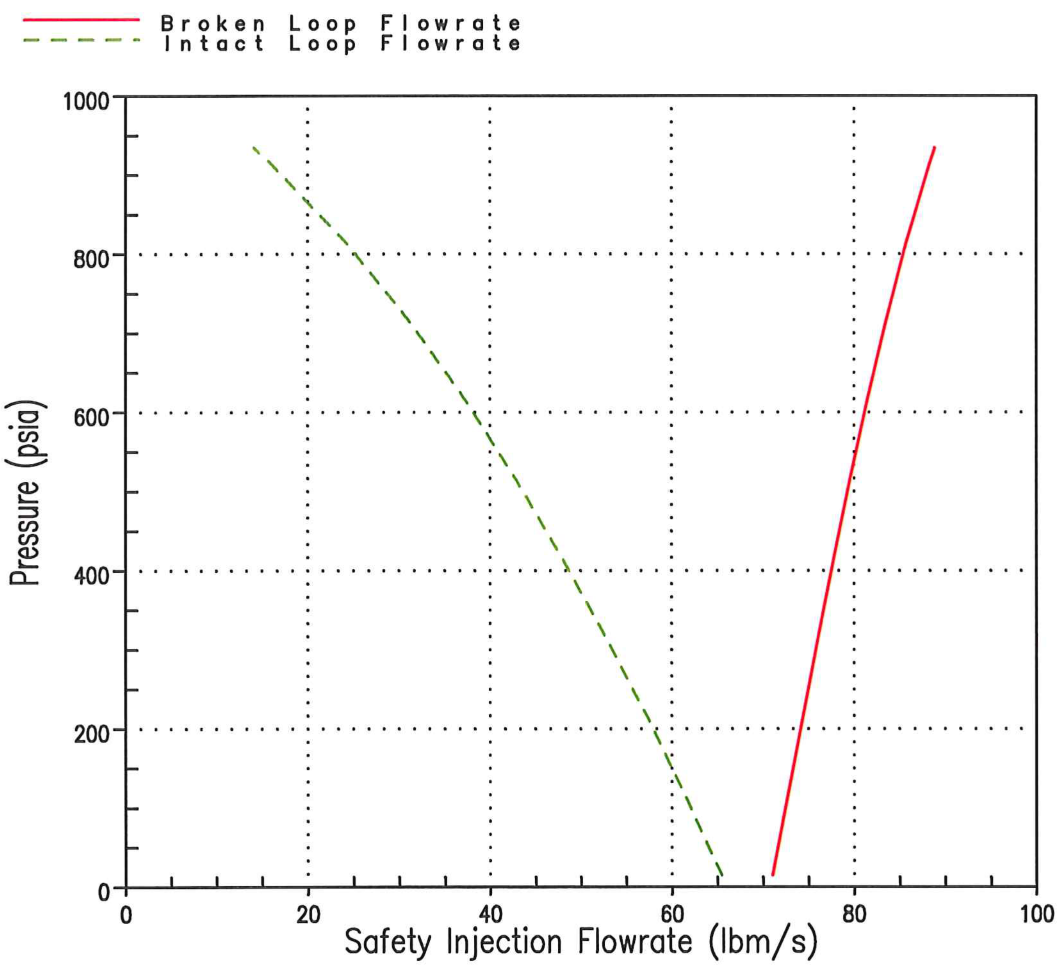


Figure 14.3.1-3A PUMPED LHSI SAFETY INJECTION FLOW RATE UPPER PLENUM INJECTION

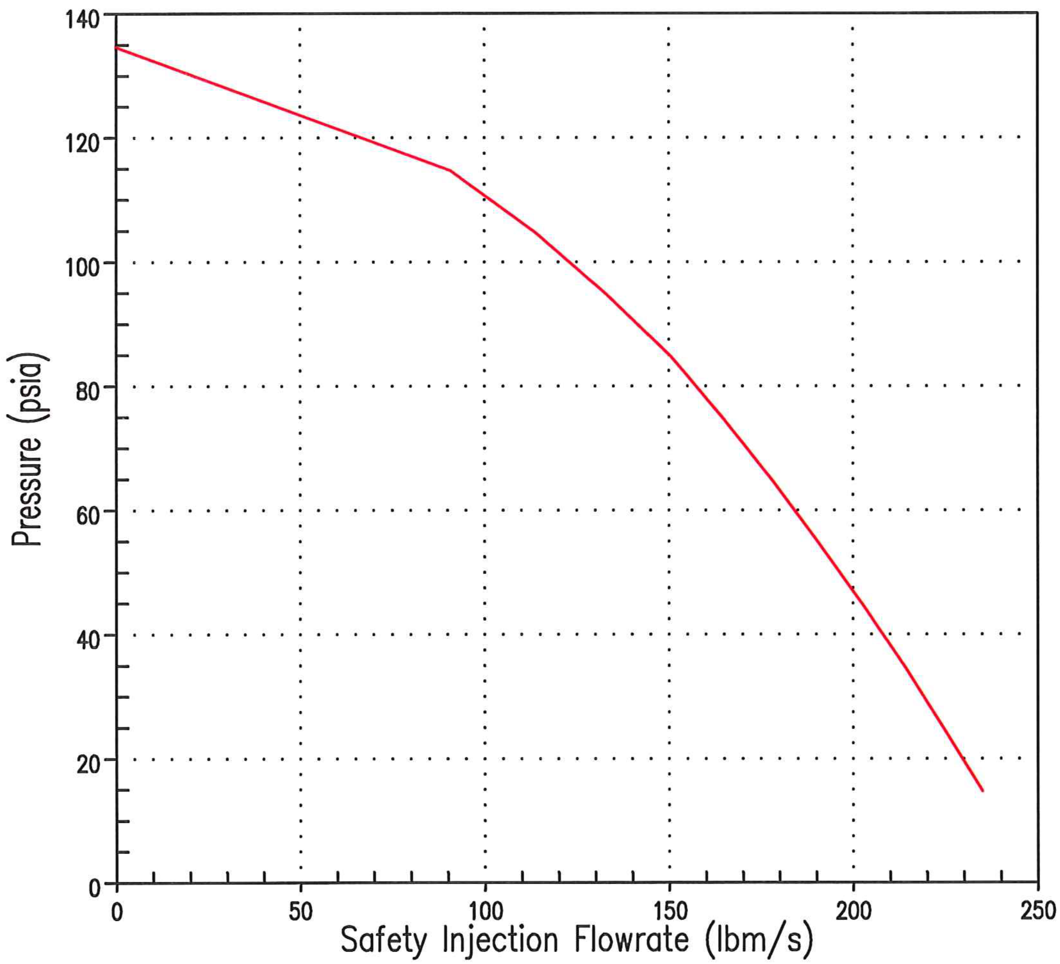


Figure 14.3.1-4 REACTOR COOLANT SYSTEM PRESSURE - 3 INCH BREAK
POINT BEACH UNIT 1

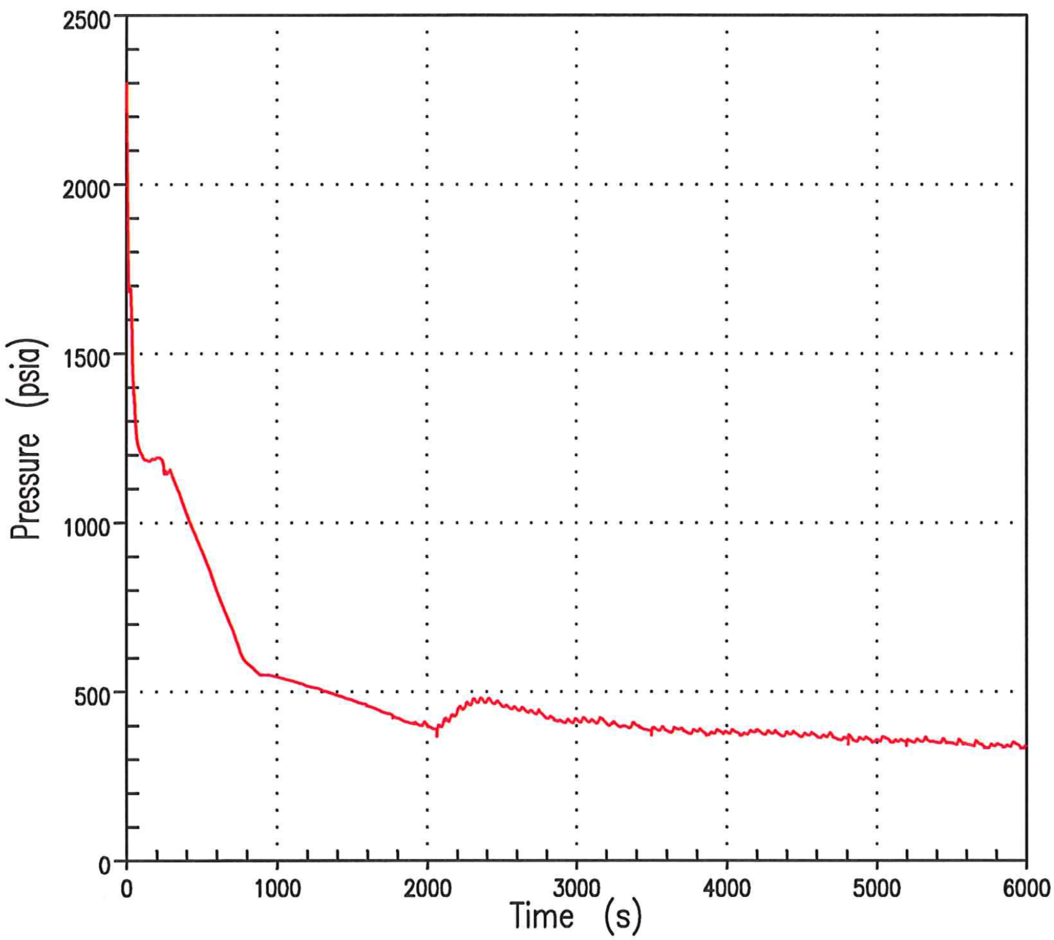


Figure 14.3.1-5 CORE MIXTURE LEVEL AND TOP OF CORE - 3 INCH BREAK
POINT BEACH UNIT 1

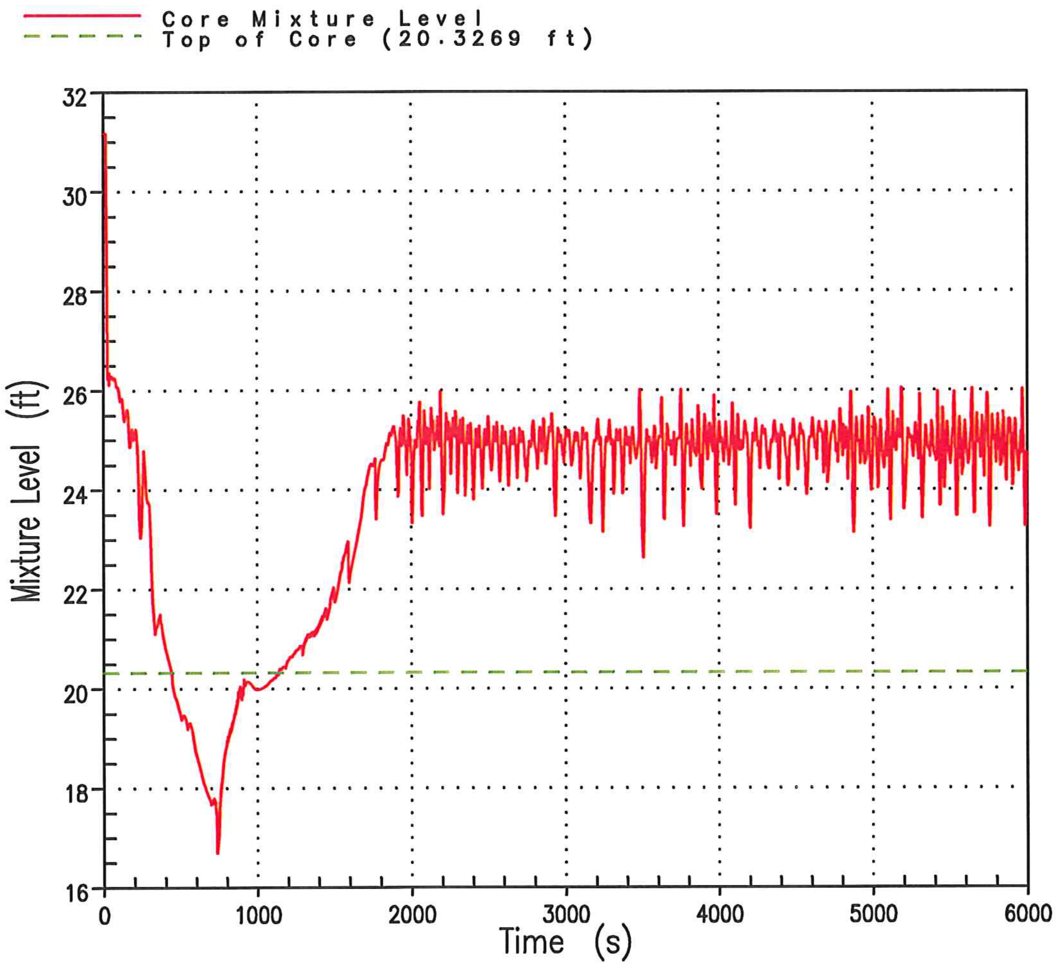


Figure 14.3.1-6 TOTAL REACTOR COOLANT SYSTEM MASS - 3 INCH BREAK POINT BEACH UNIT 1

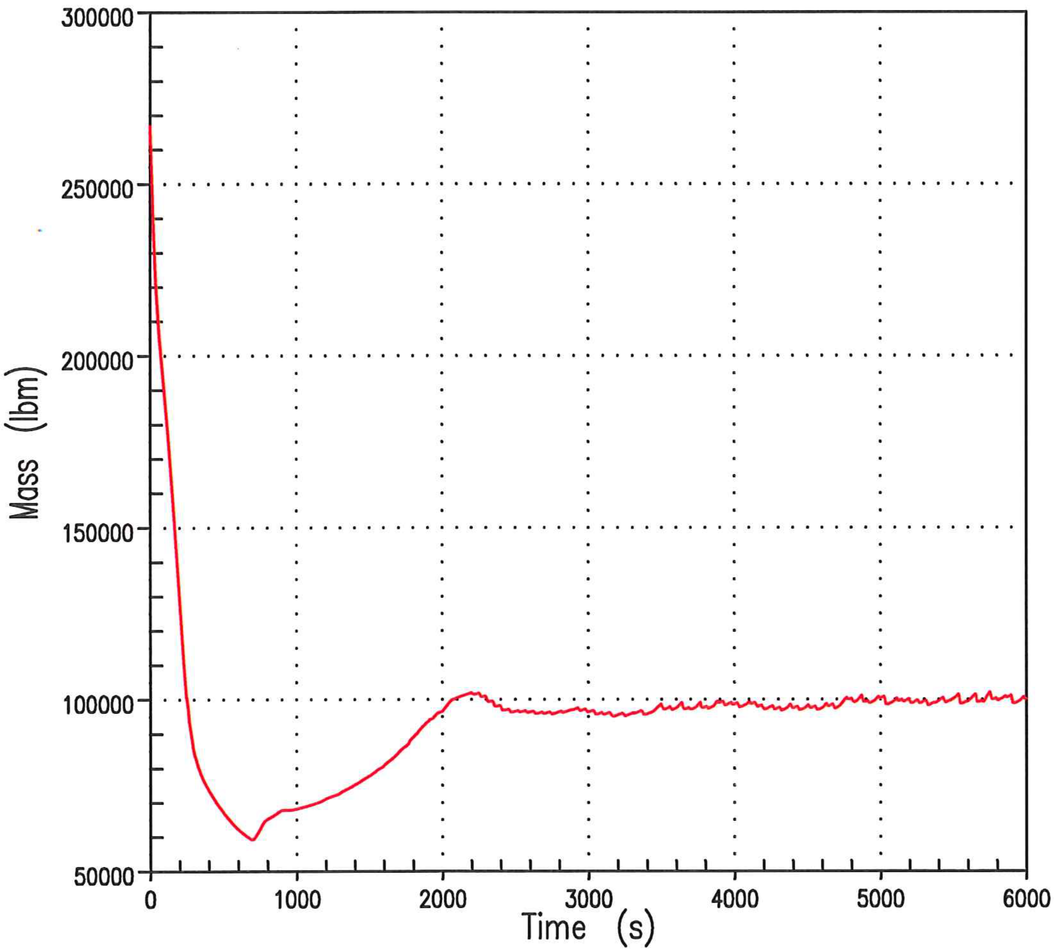


Figure 14.3.1-7 TOP CORE EXIT VAPOR TEMPERATURE - 3 INCH BREAK POINT BEACH UNIT 1

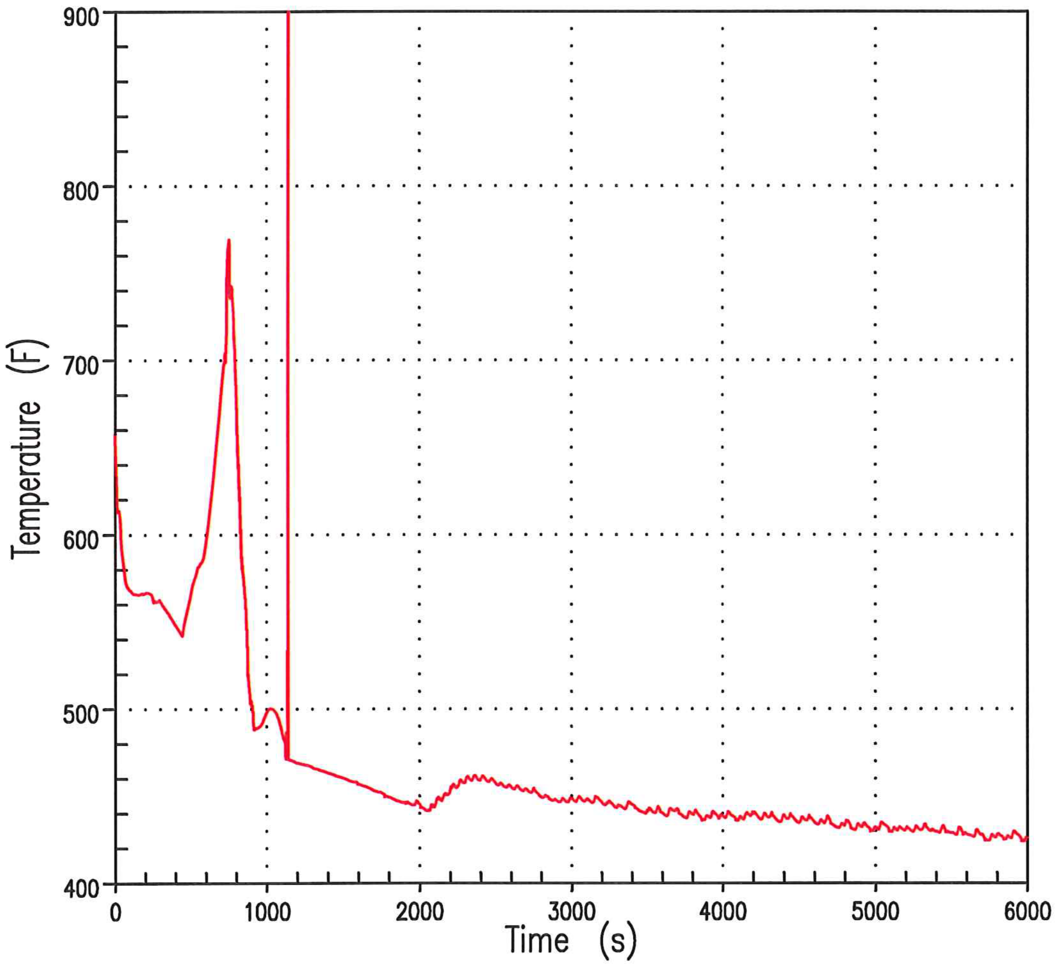


Figure 14.3.1-8 VAPOR MASS FLOW RATE OUT OF TOP OF CORE - 3 INCH BREAK POINT BEACH UNIT 1

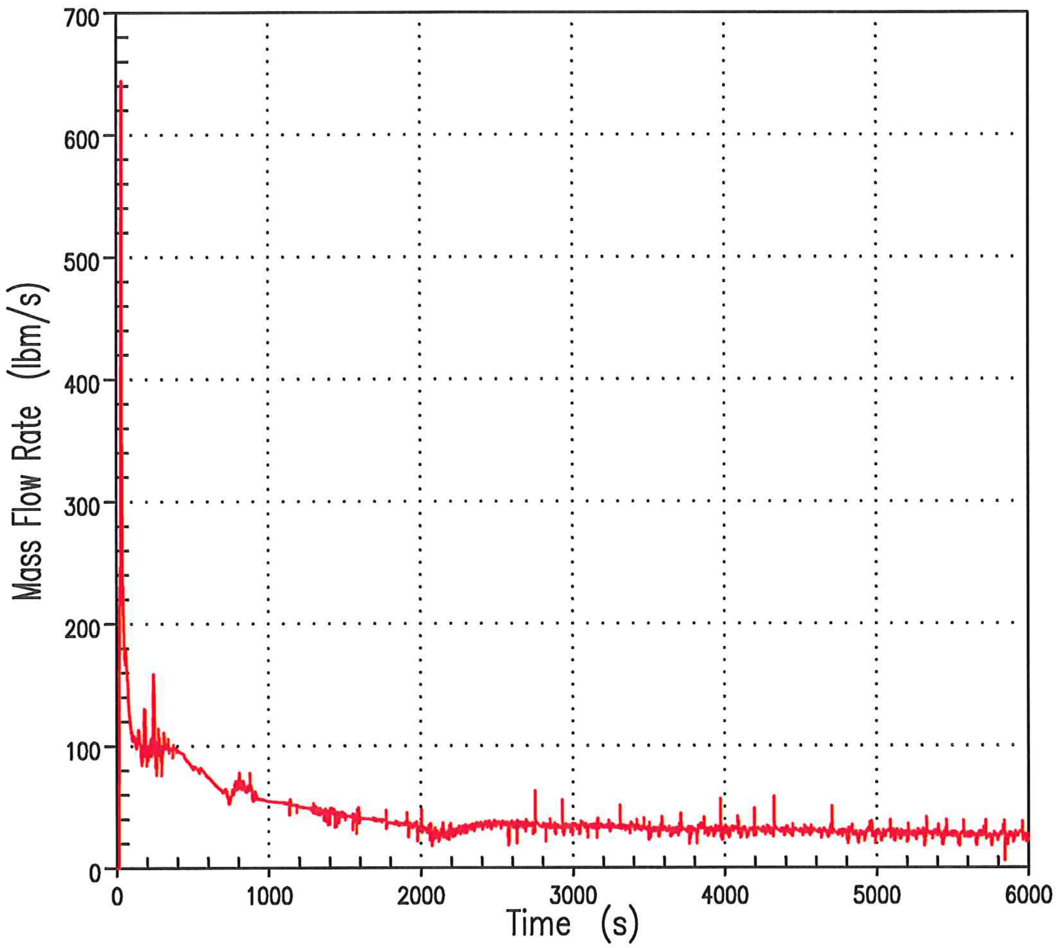


Figure 14.3.1-9 TOTAL BREAK FLOW AND SAFETY INJECTION FLOW - 3 INCH BREAK POINT BEACH UNIT 1

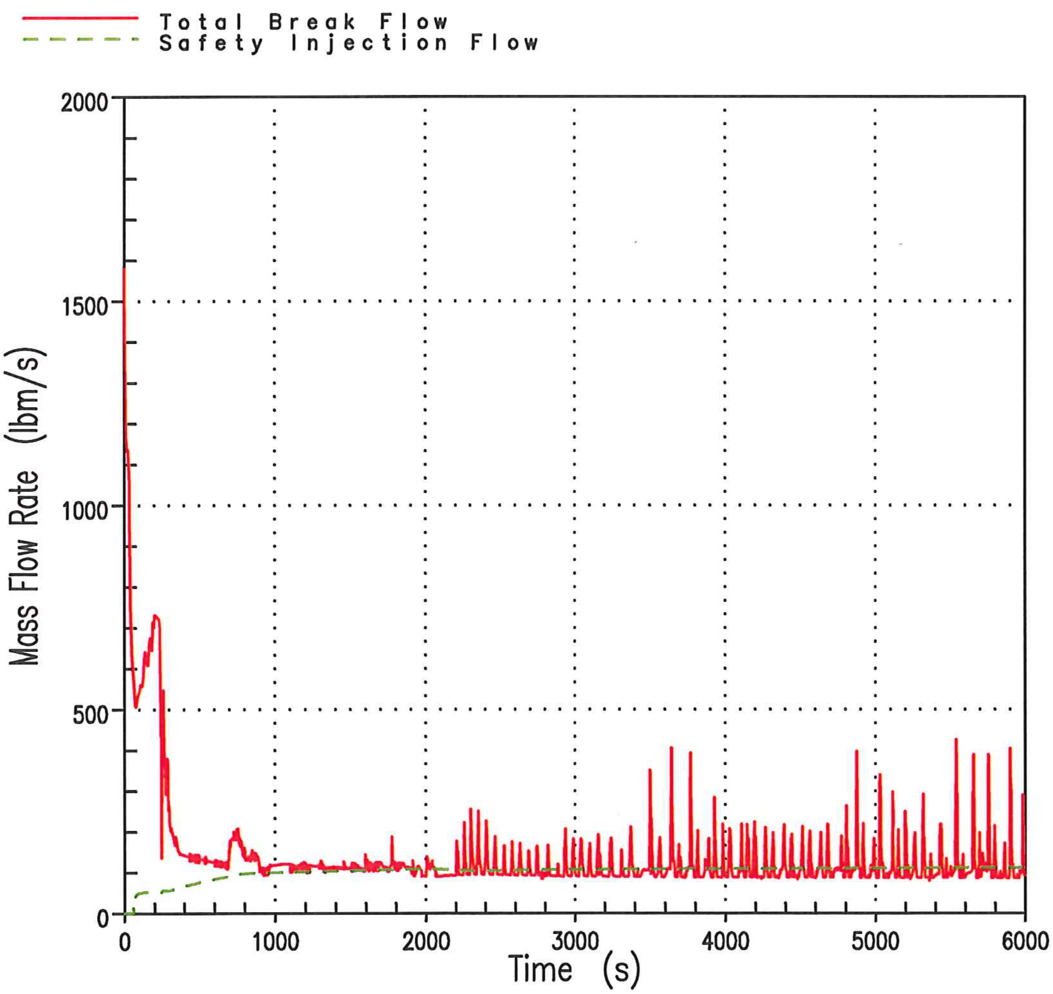


Figure 14.3.1-10 CLADDING SURFACE HEAT TRANSFER COEFFICIENT AT PCT ELEVATION - 3 INCH BREAK POINT BEACH UNIT 1

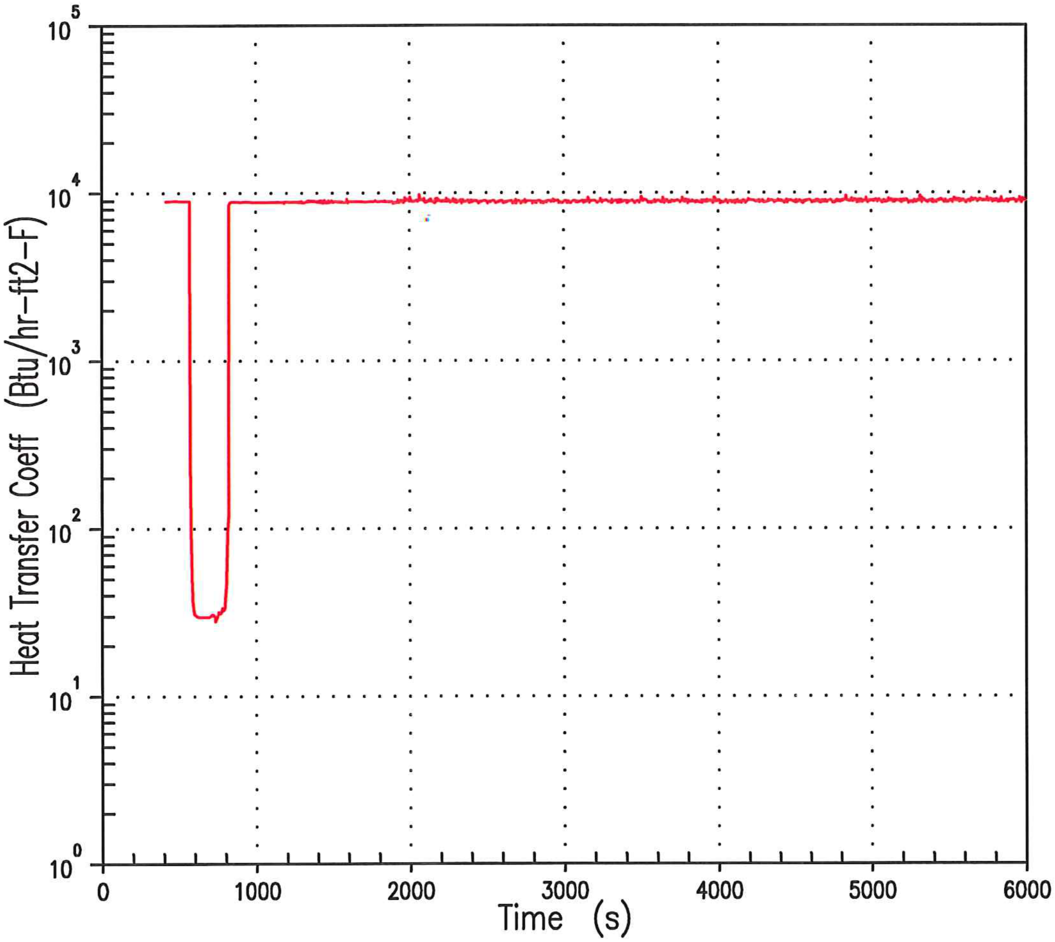


Figure 14.3.1-11 FLUID TEMPERATURE AT PCT ELEVATION - 3 INCH BREAK
POINT BEACH UNIT 1

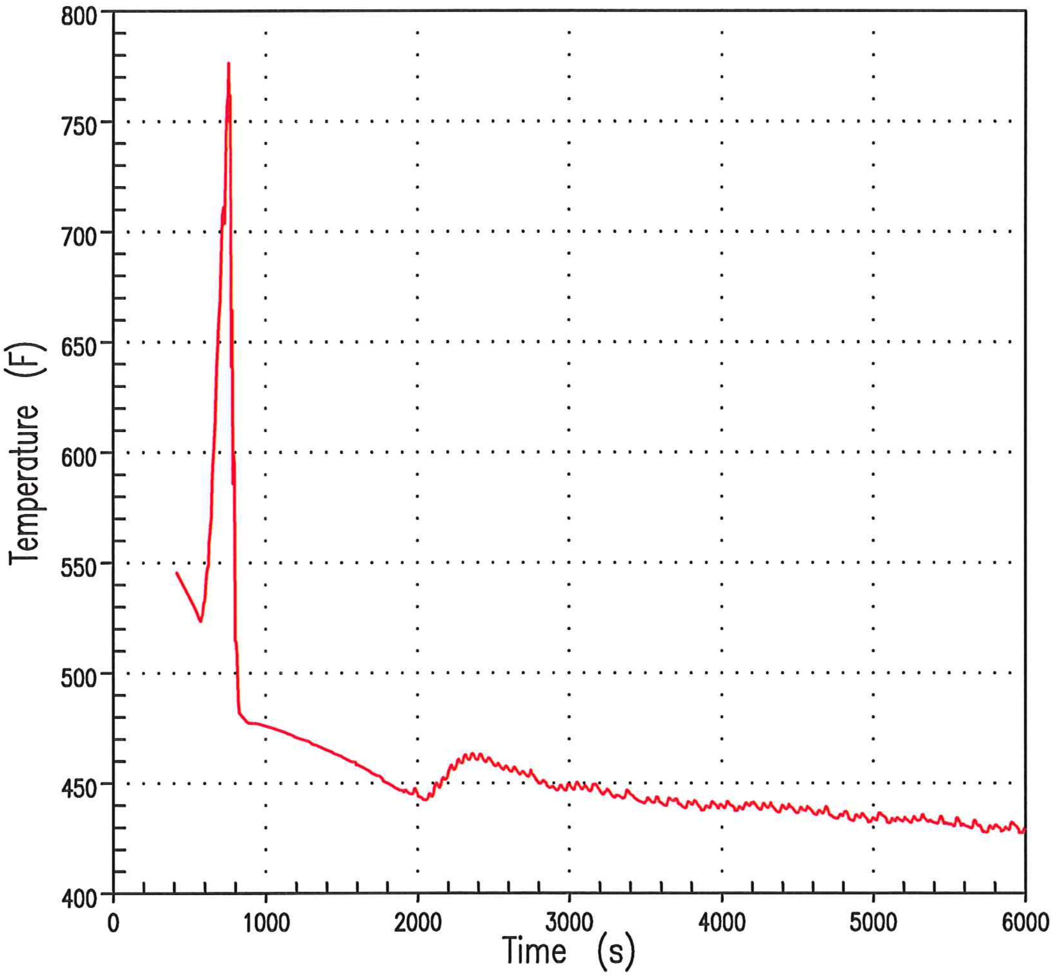


Figure 14.3.1-12 CLADDING TEMPERATURE TRANSIENT AT PCT ELEVATION - 3 INCH BREAK POINT BEACH UNIT 1

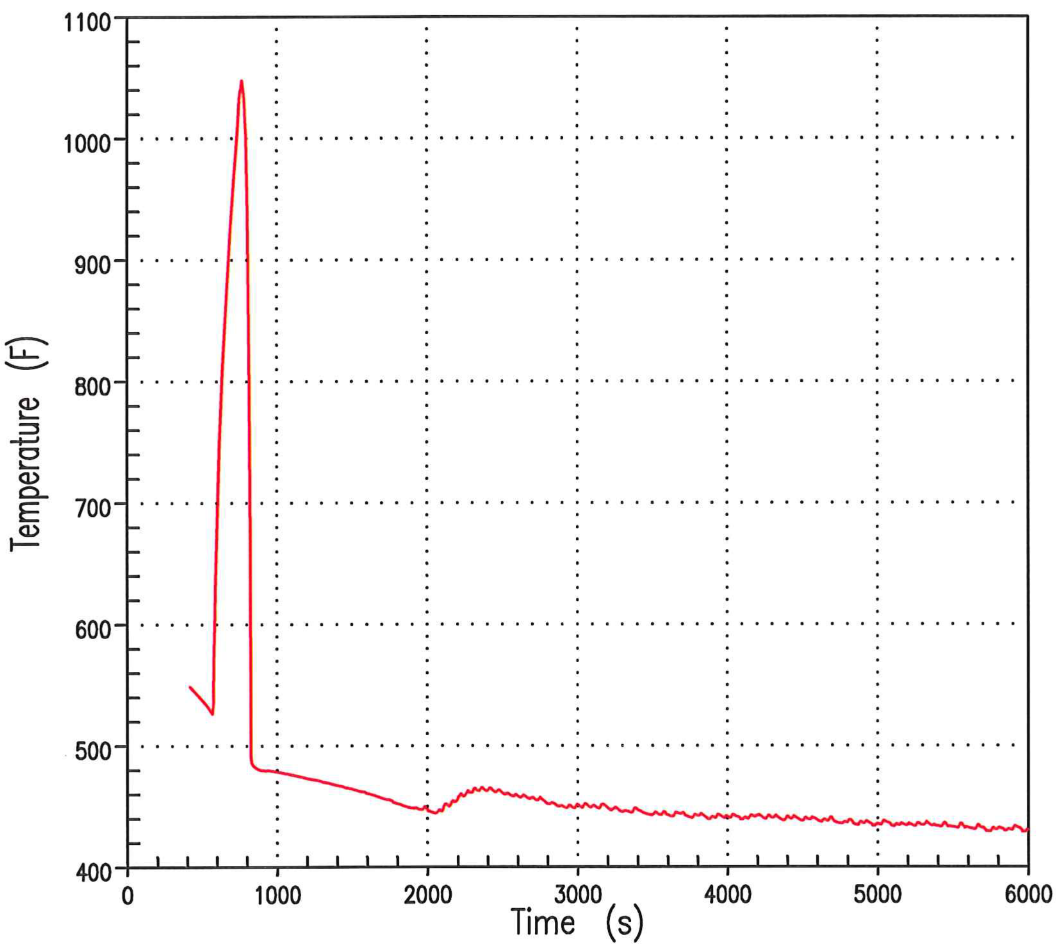


Figure 14.3.1-13 LOCAL ZRO2 THICKNESS AT MAXIMUM LOCAL ZRO2 ELEVATION - 3 INCH BREAK POINT BEACH UNIT 1

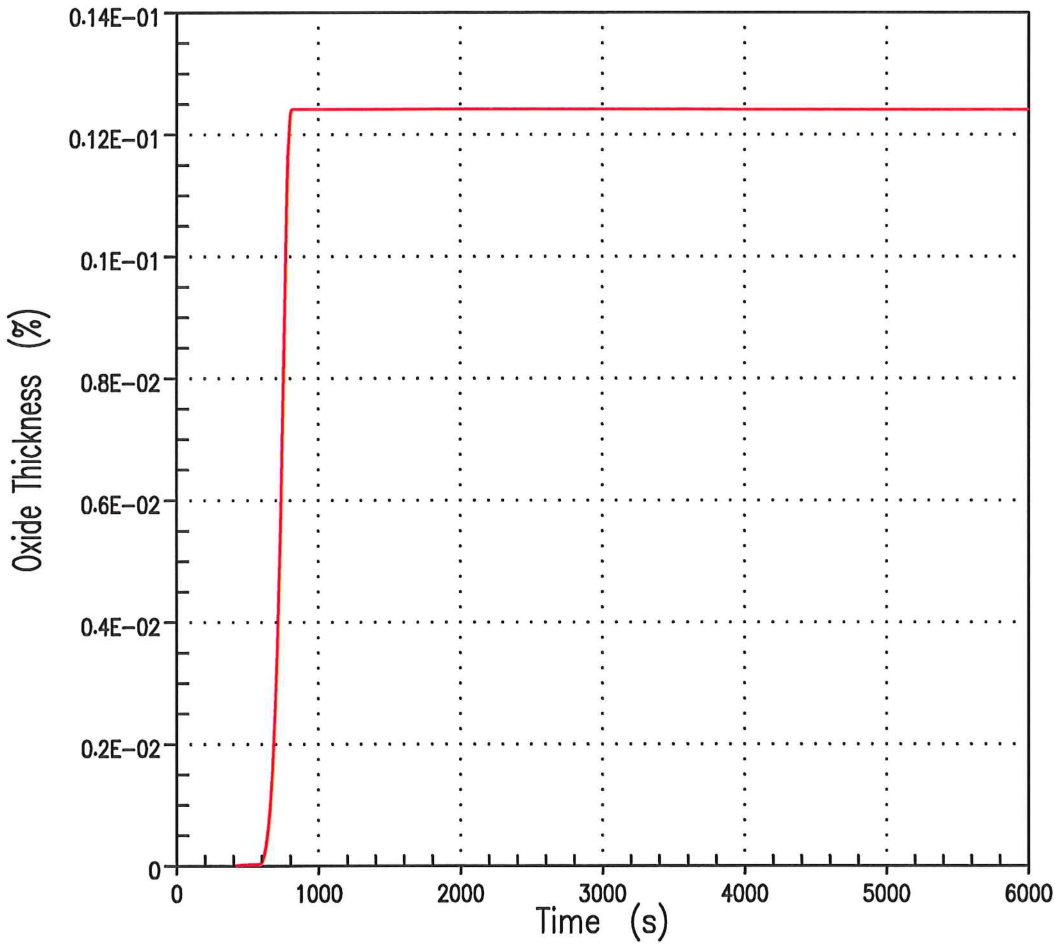


Figure 14.3.1-14 REACTOR COOLANT SYSTEM PRESSURE - 3 INCH BREAK
POINT BEACH UNIT 2

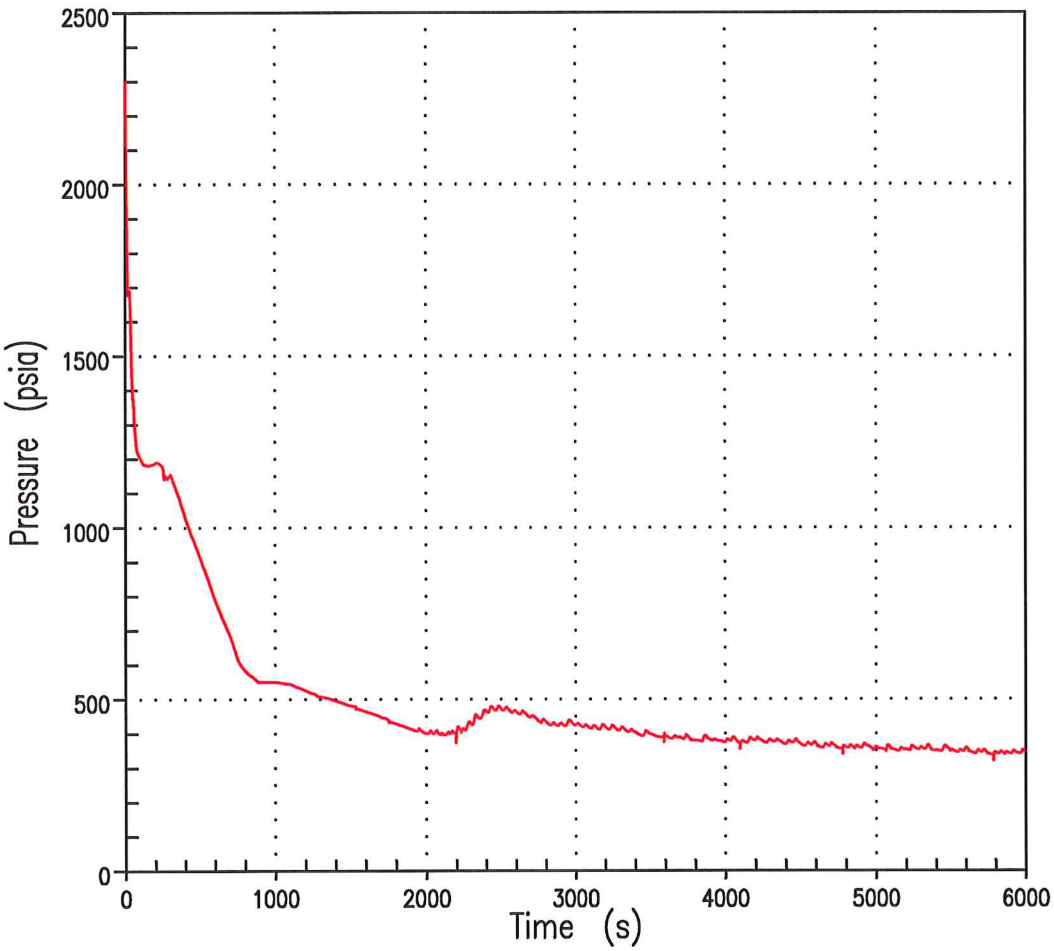


Figure 14.3.1-15 CORE MIXTURE LEVEL AND TOP OF CORE - 3 INCH BREAK
POINT BEACH UNIT 2

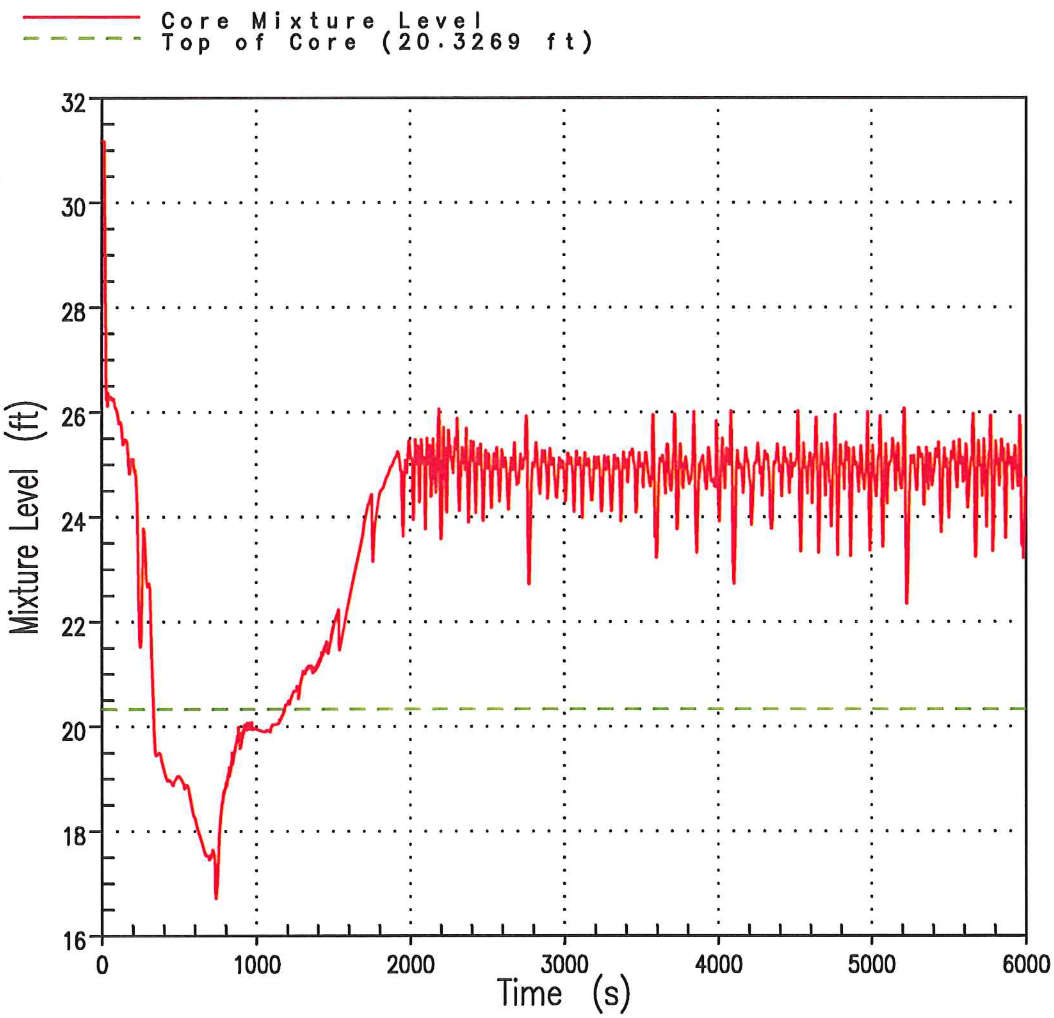


Figure 14.3.1-16 TOTAL REACTOR COOLANT SYSTEM MASS - 3 INCH BREAK
POINT BEACH UNIT 2

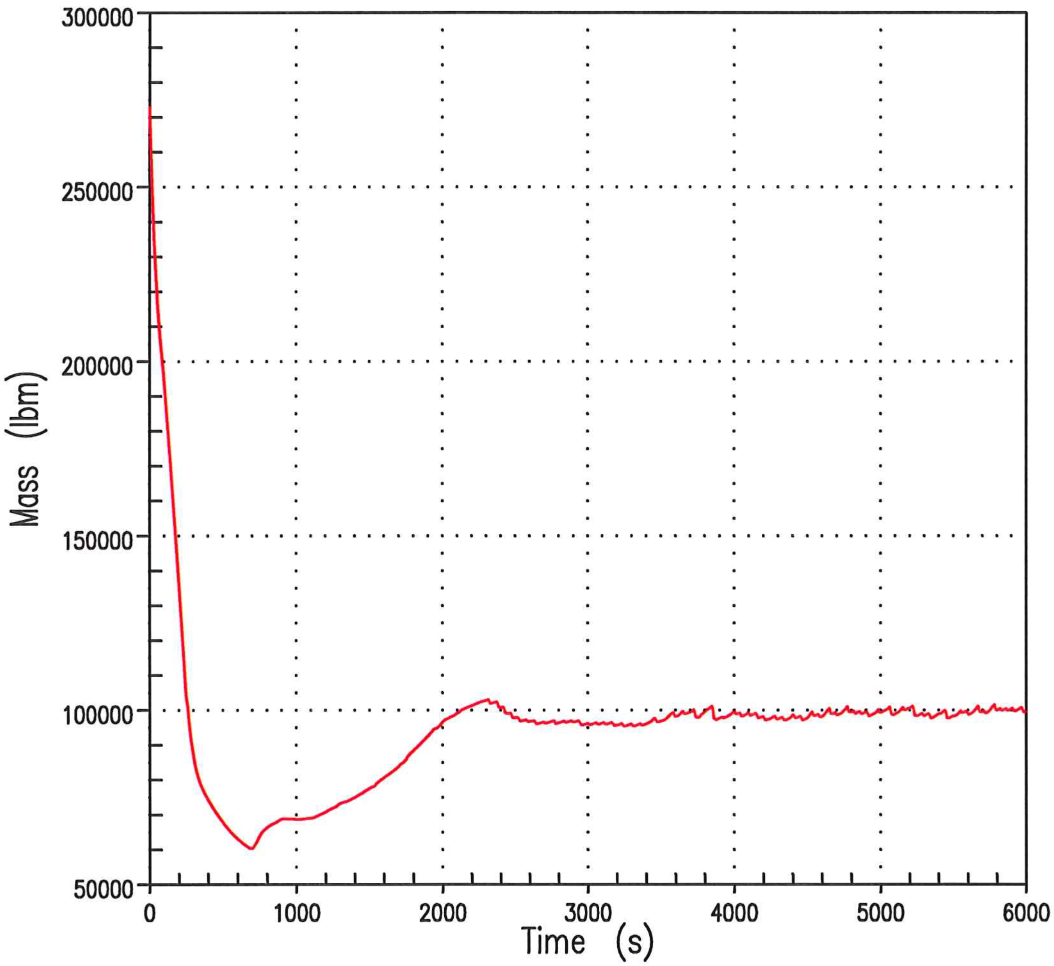


Figure 14.3.1-17 TOP CORE EXIT VAPOR TEMPERATURE - 3 INCH BREAK
POINT BEACH UNIT 2

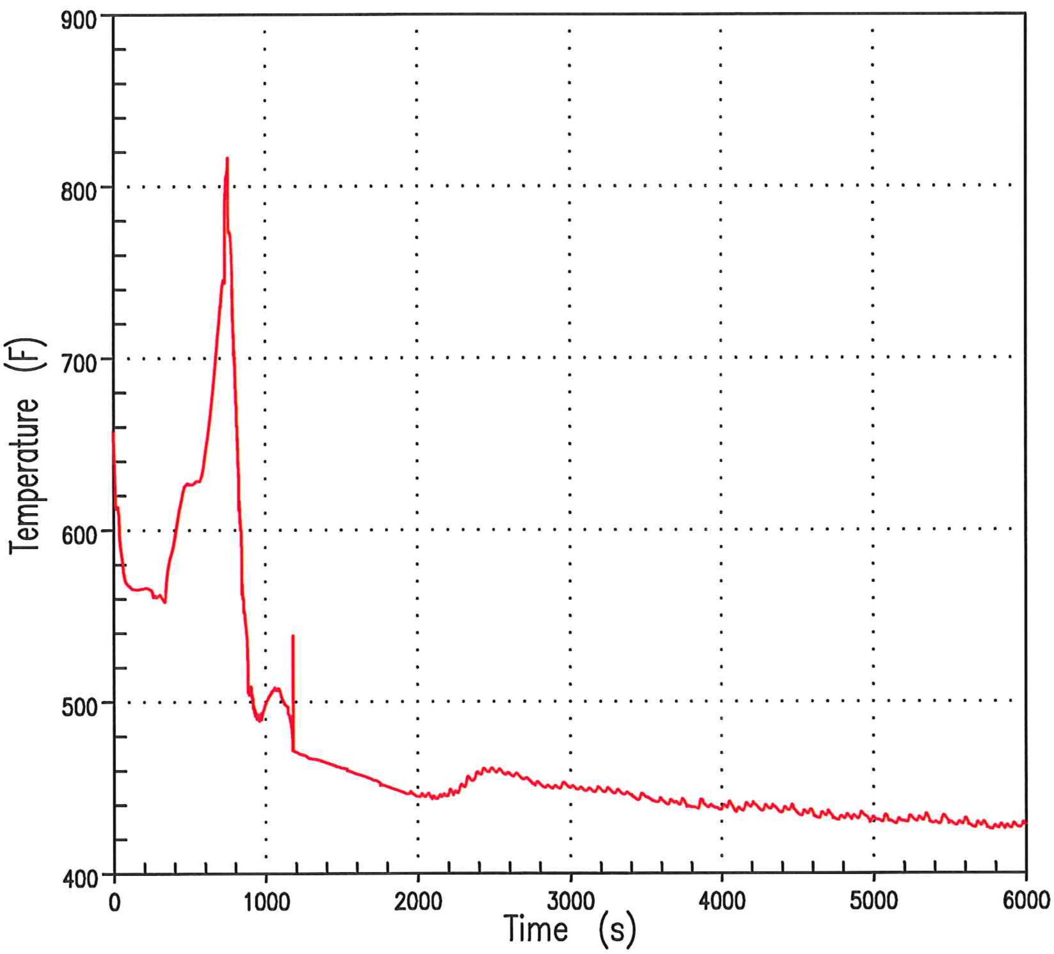


Figure 14.3.1-18 VAPOR MASS FLOW RATE OUT OF TOP OF CORE - 3 INCH BREAK
POINT BEACH UNIT 2

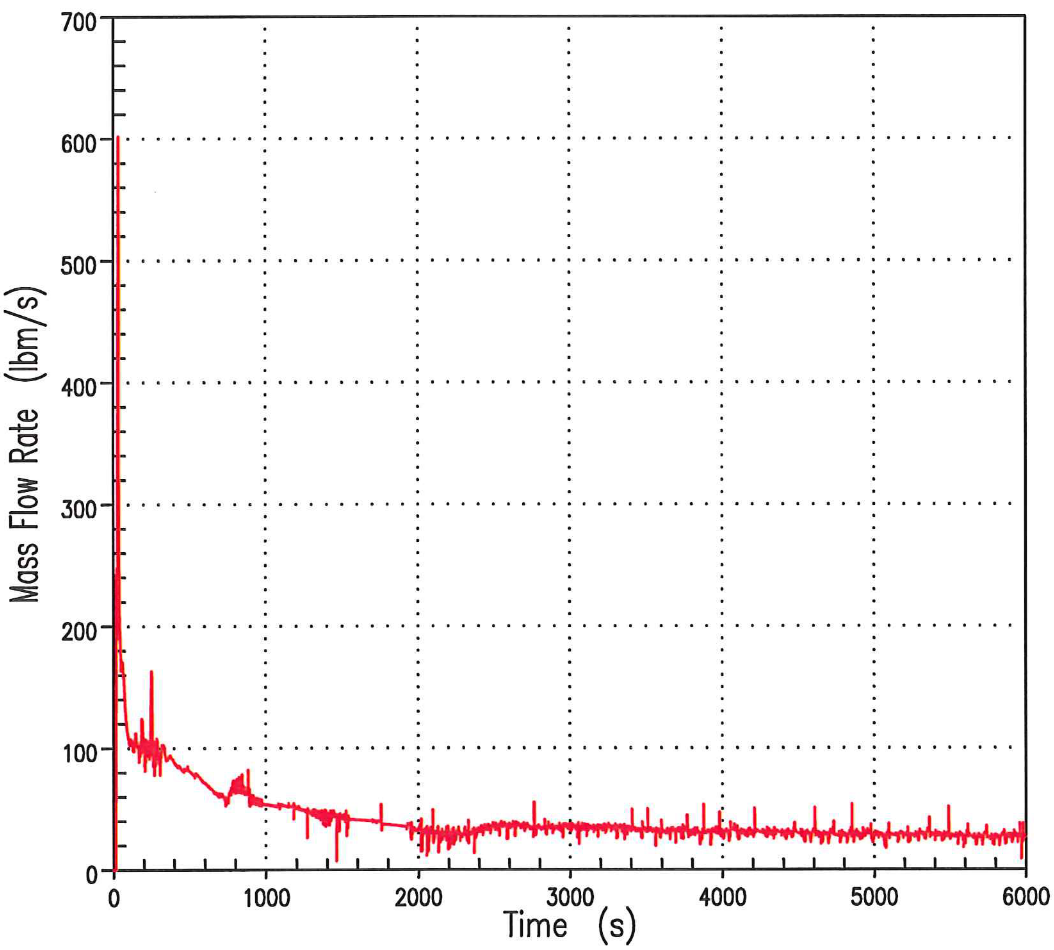


Figure 14.3.1-19 TOTAL BREAK FLOW AND SAFETY INJECTION FLOW - 3 INCH BREAK POINT BEACH UNIT 2

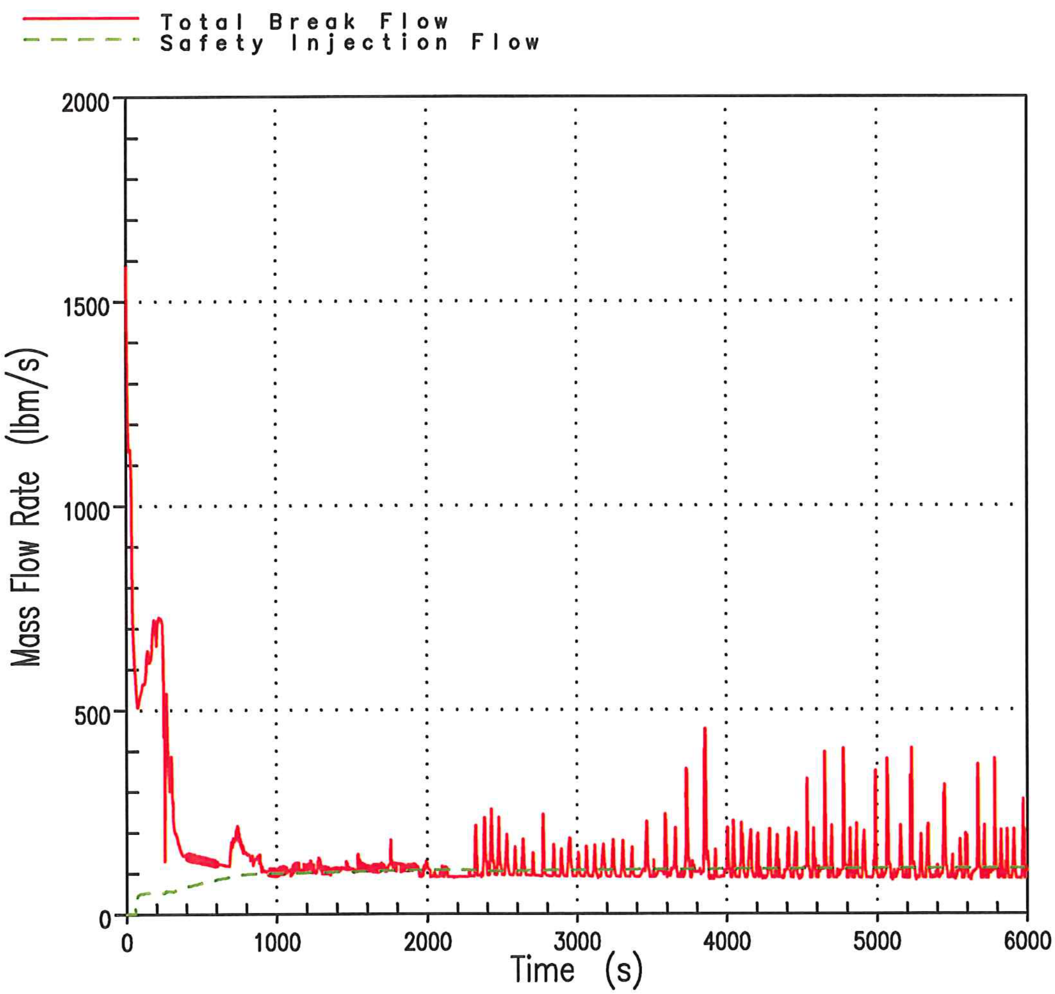


Figure 14.3.1-20 CLADDING SURFACE HEAT TRANSFER COEFFICIENT AT PCT ELEVATION - 3 INCH BREAK POINT BEACH UNIT 2

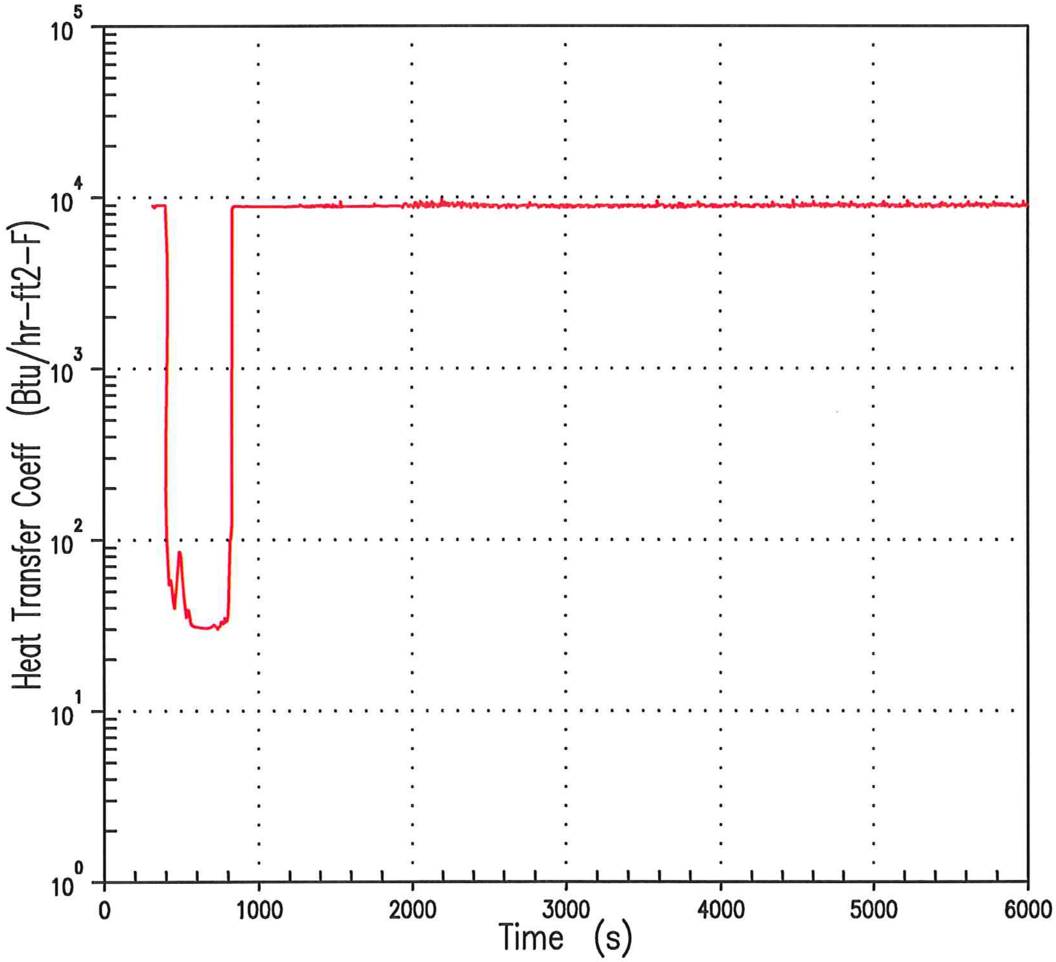


Figure 14.3.1-21 FLUID TEMPERATURE AT PCT ELEVATION - 3 INCH BREAK POINT BEACH UNIT 2

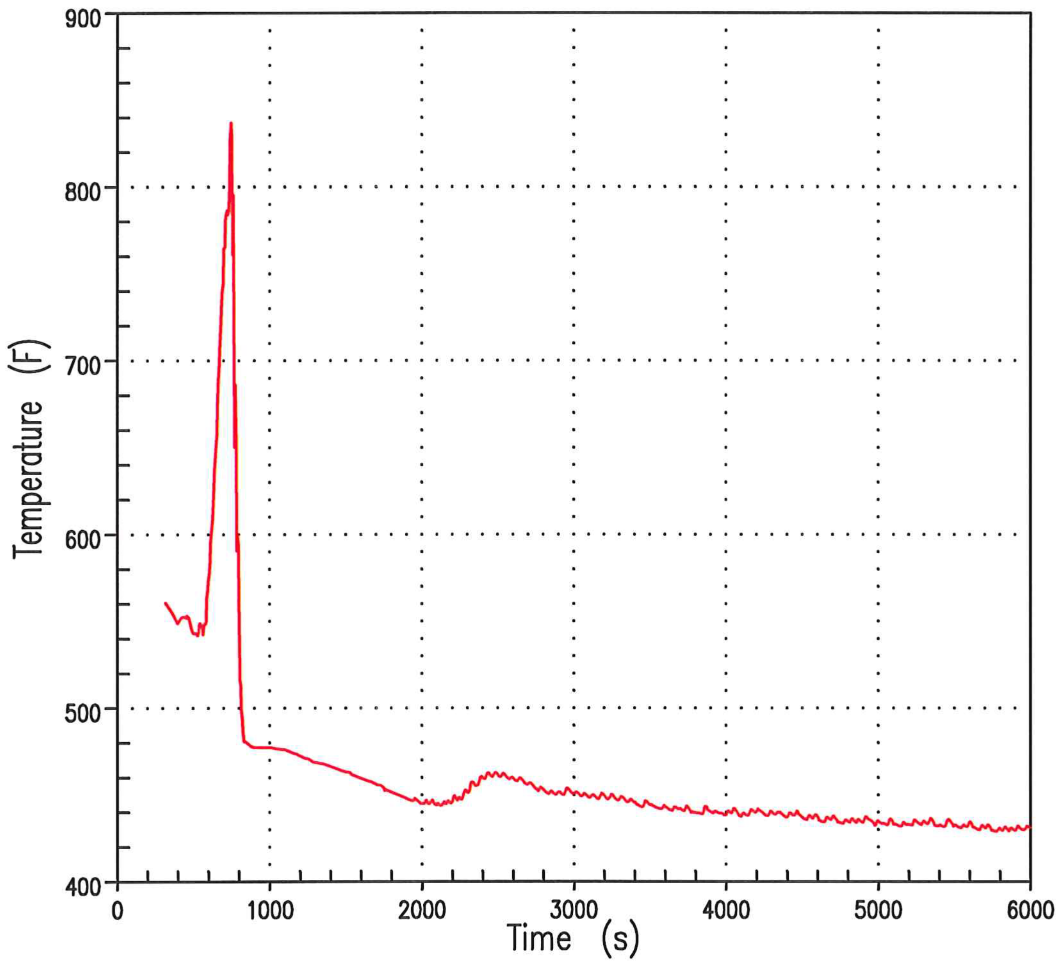


Figure 14.3.1-22 CLADDING TEMPERATURE TRANSIENT AT PCT ELEVATION - 3 INCH BREAK POINT BEACH UNIT 2

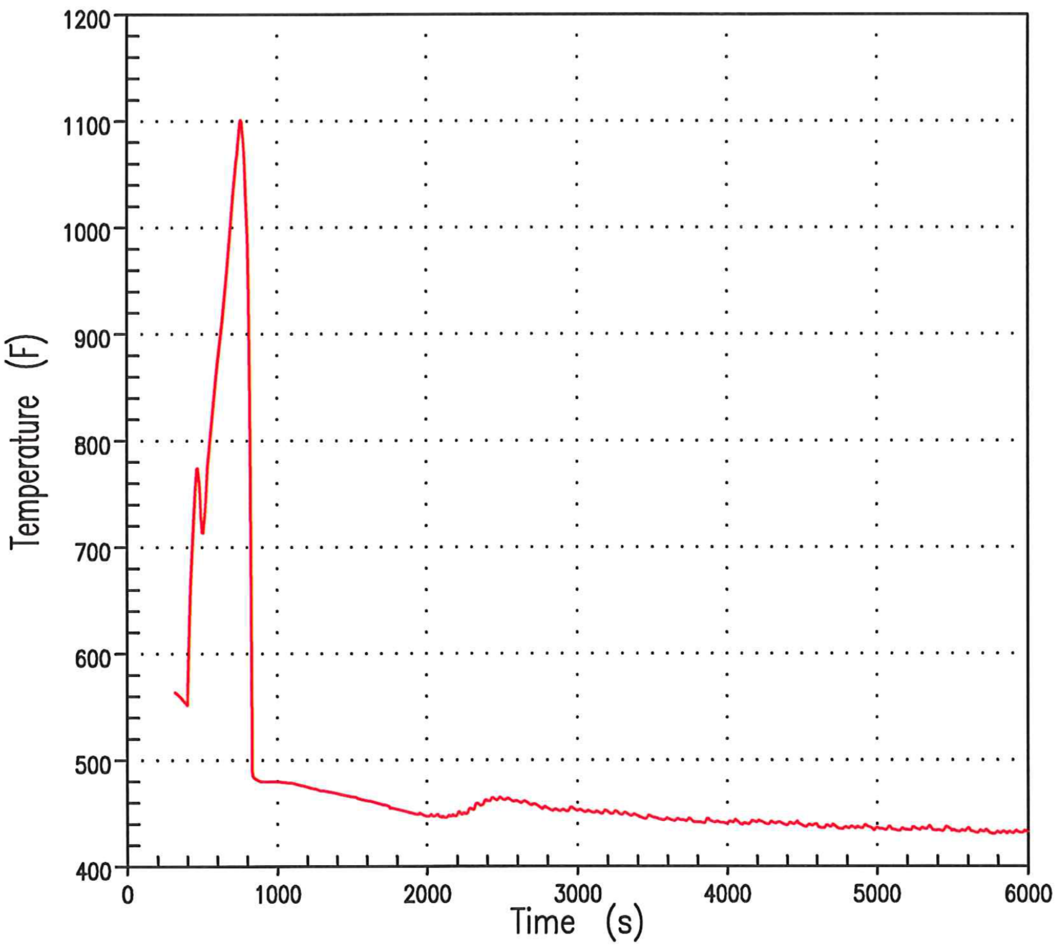


Figure 14.3.1-23 LOCAL ZR02 THICKNESS AT MAXIMUM LOCAL ZRO2 ELEVATION - 3 INCH BREAK POINT BEACH UNIT 2

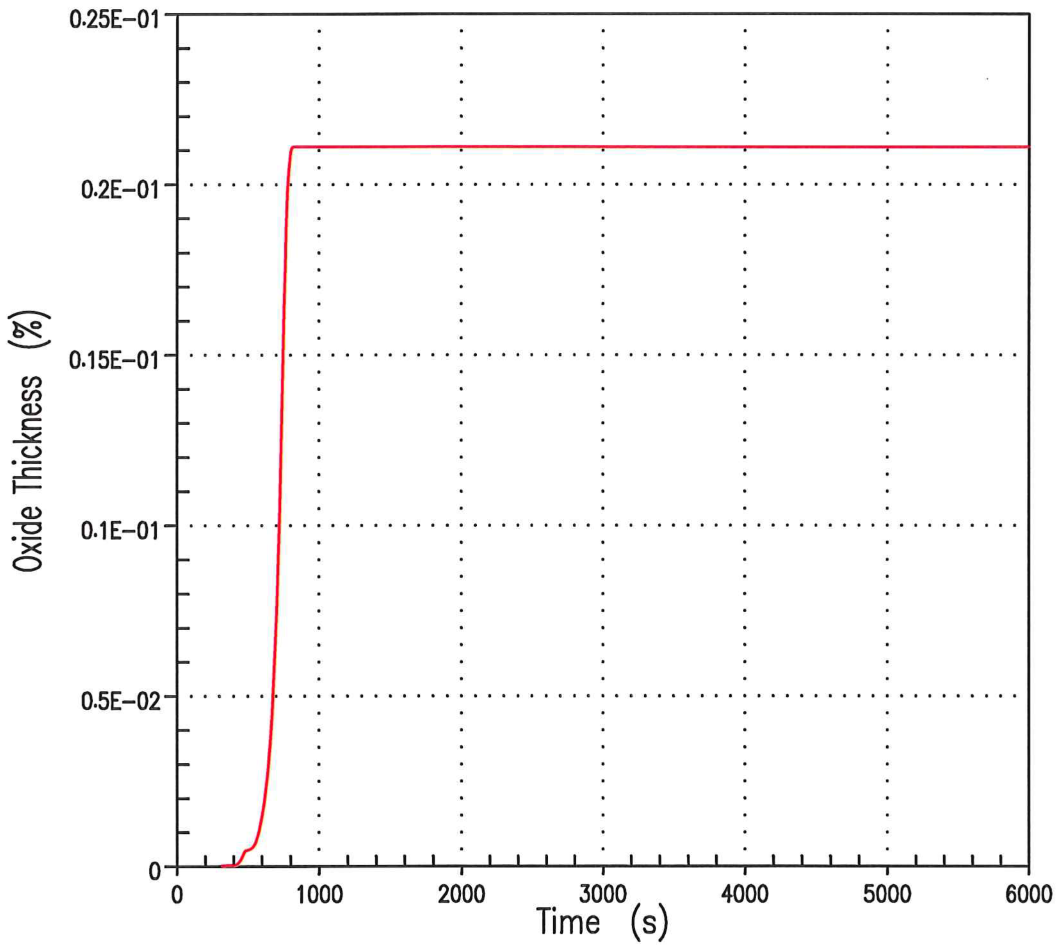


Figure 14.3.1-24 REACTOR COOLANT SYSTEM PRESSURE - 1.5 INCH BREAK
POINT BEACH UNIT 1

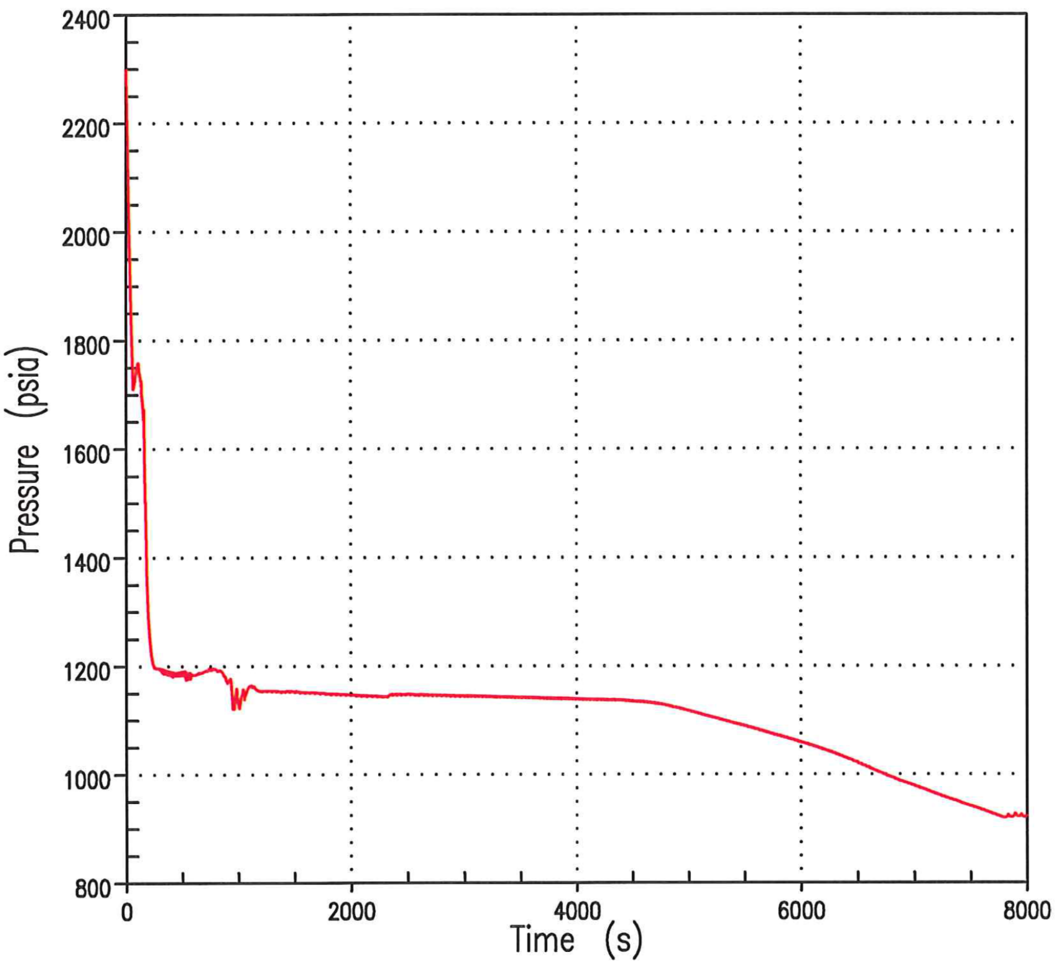


Figure 14.3.1-25 CORE MIXTURE LEVEL AND TOP OF CORE - 1.5 INCH BREAK
POINT BEACH UNIT 1

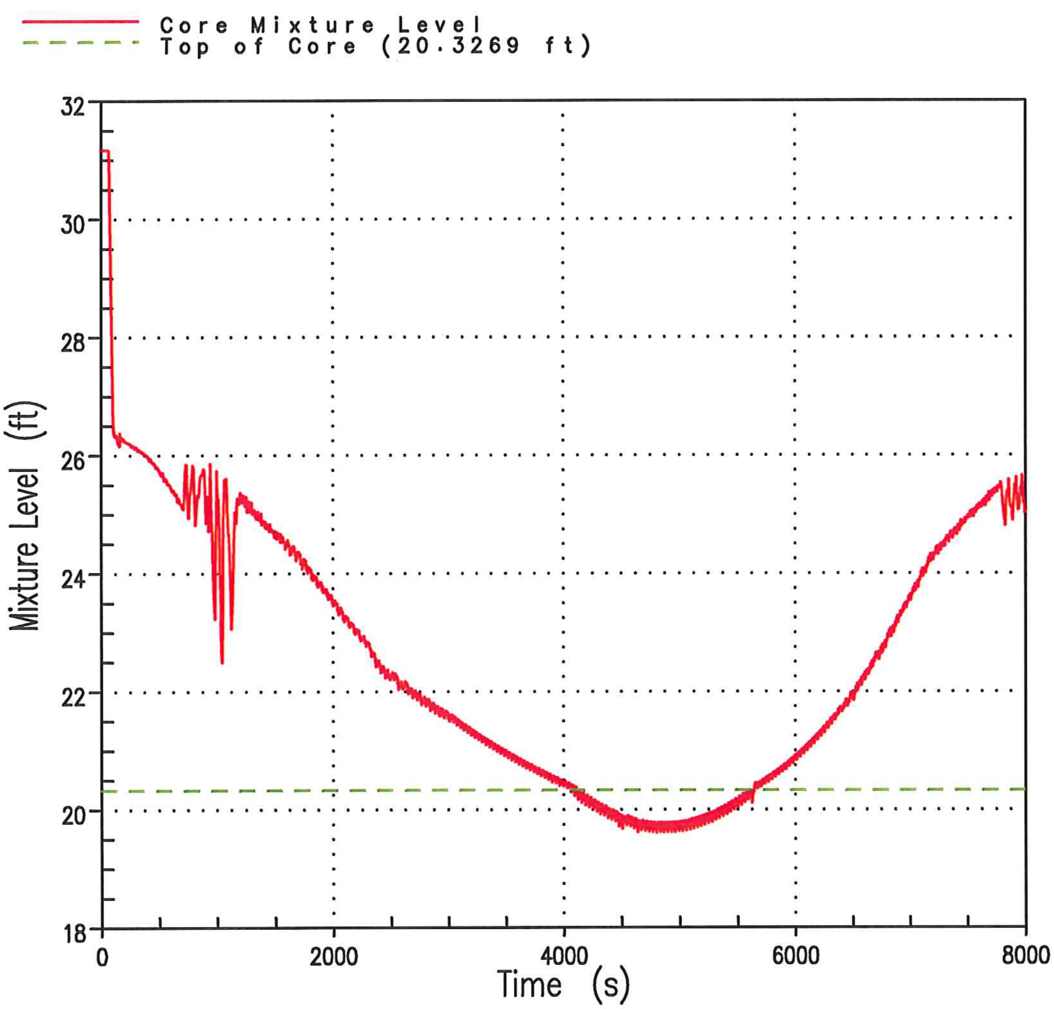


Figure 14.3.1-26 TOP CORE EXIT VAPOR TEMPERATURE - 1.5 INCH BREAK
POINT BEACH UNIT 1

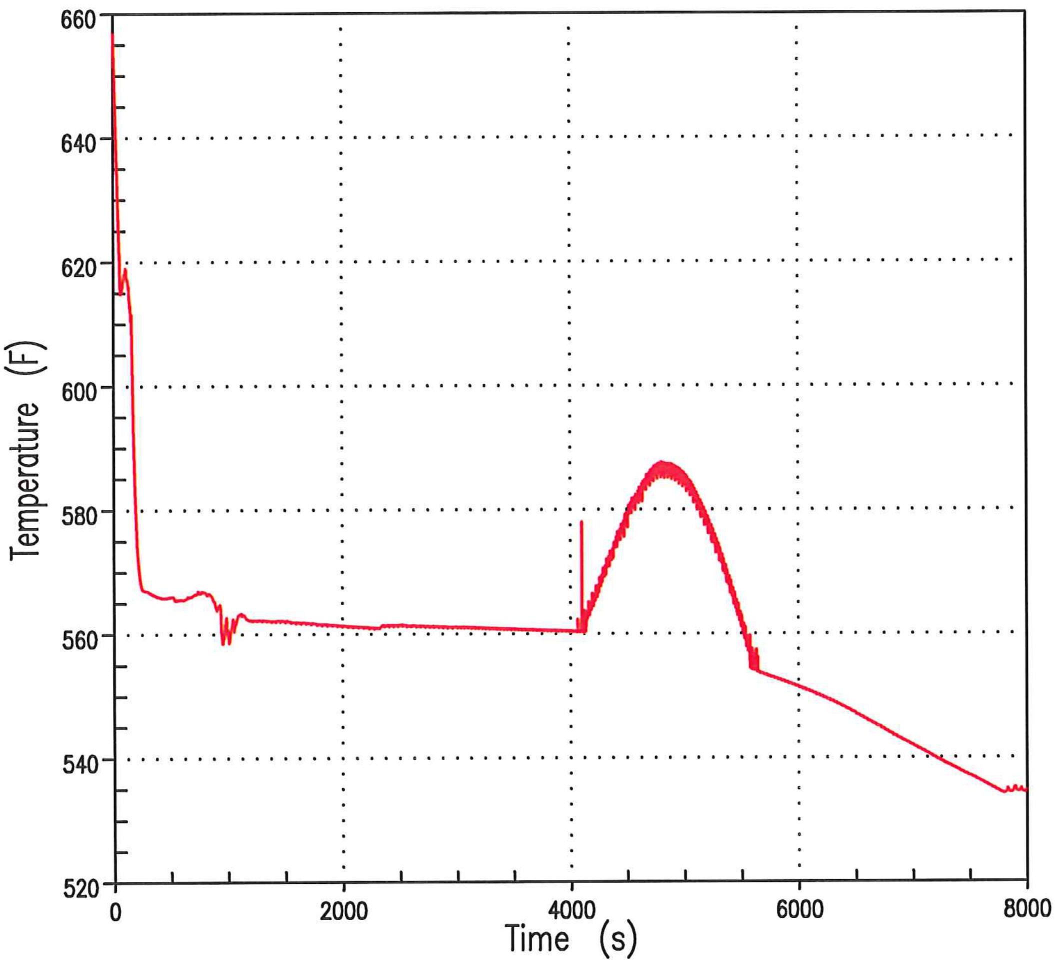


Figure 14.3.1-27 CLADDING TEMPERATURE TRANSIENT AT PCT ELEVATION - 1.5 INCH BREAK POINT BEACH UNIT 1

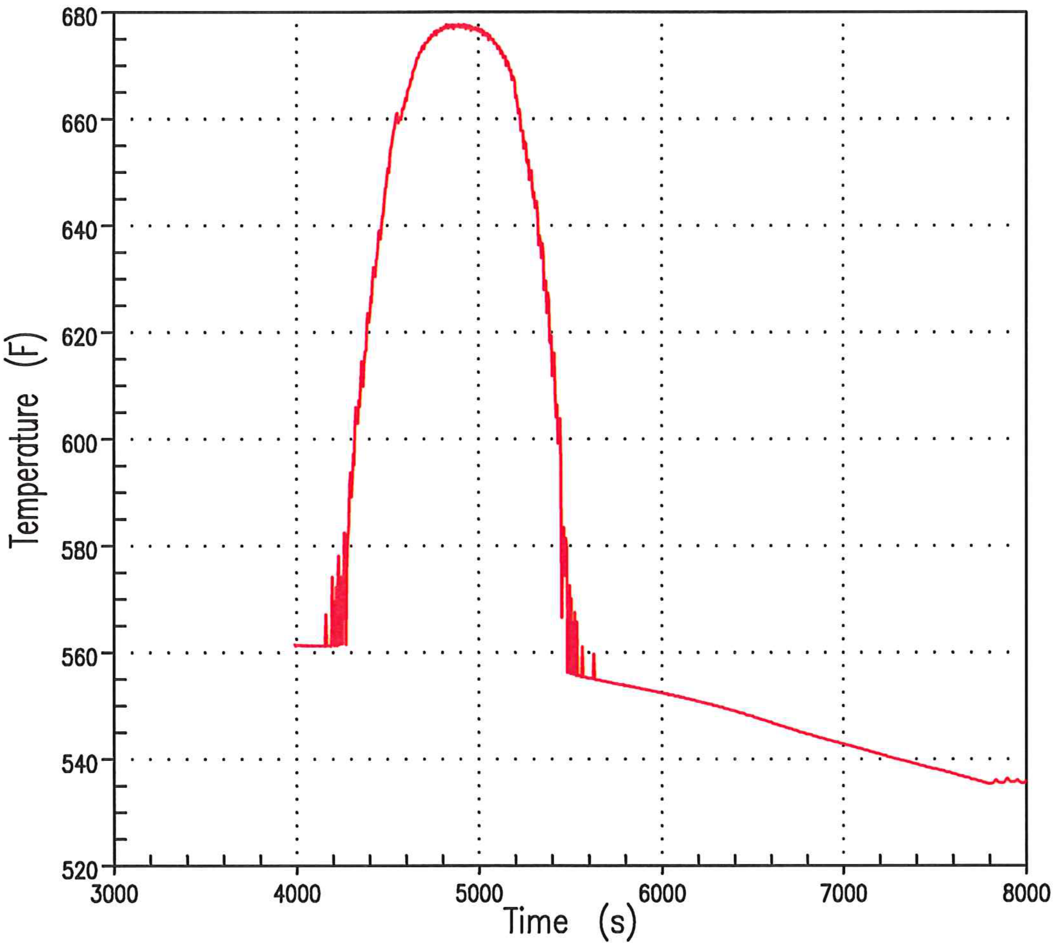


Figure 14.3.1-28 LOCAL ZRO2 THICKNESS AT MAXIMUM LOCAL ZRO2 ELEVATION - 1.5 INCH BREAK POINT BEACH UNIT 1

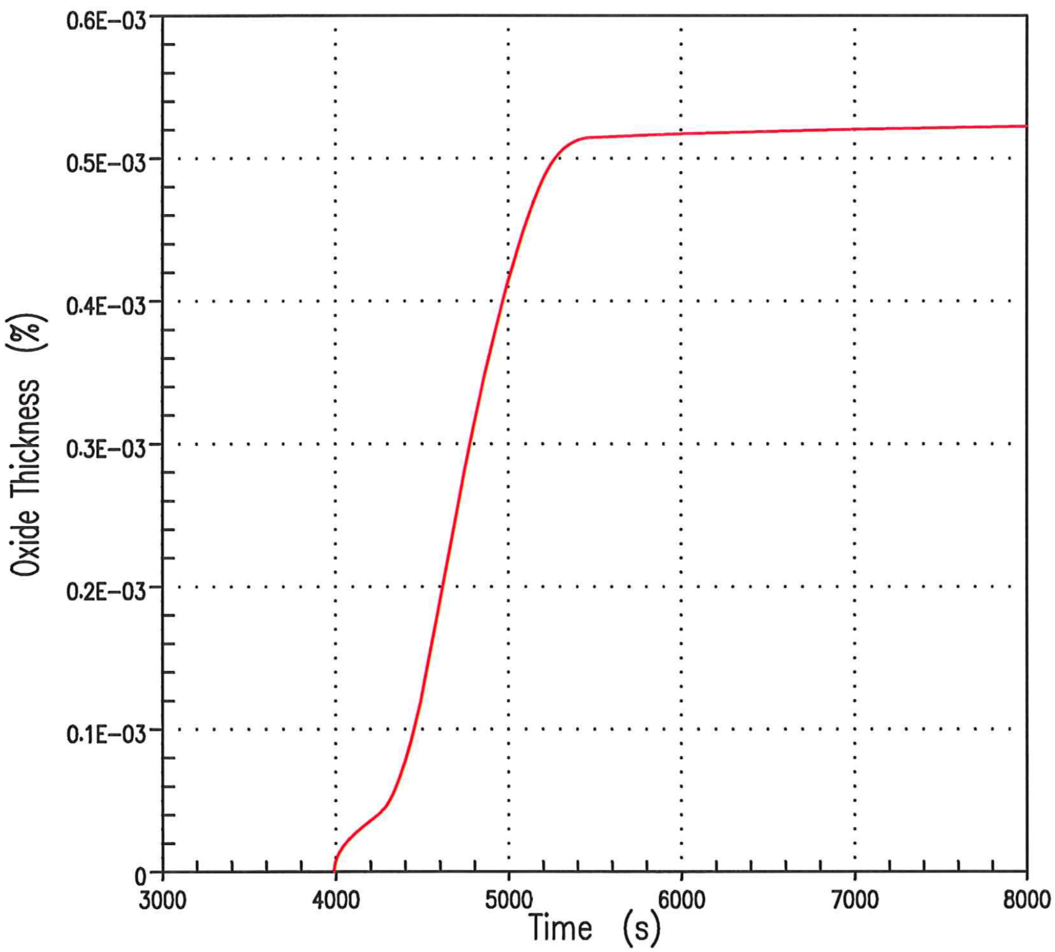


Figure 14.3.1-29 REACTOR COOLANT SYSTEM PRESSURE - 1.5 INCH BREAK
POINT BEACH UNIT 2

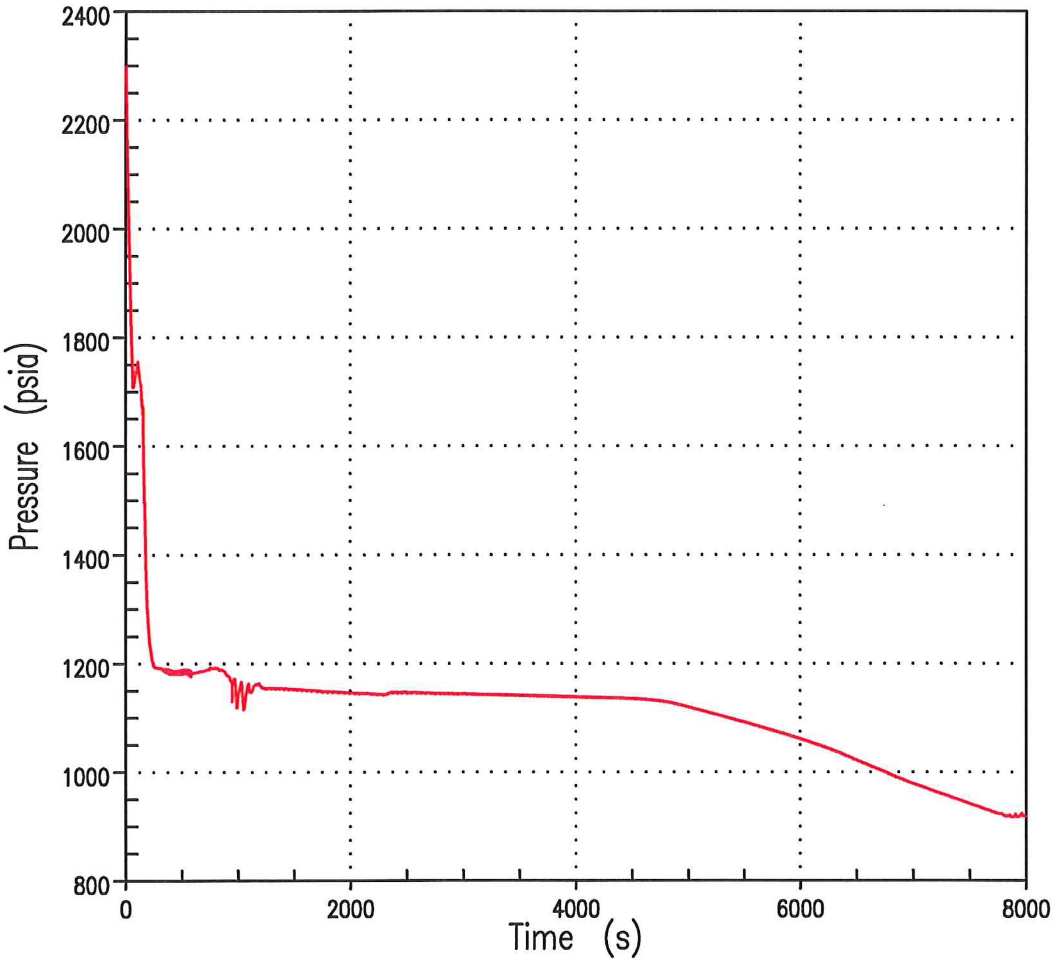


Figure 14.3.1-30 CORE MIXTURE LEVEL AND TOP OF CORE - 1.5 INCH BREAK
POINT BEACH UNIT 2

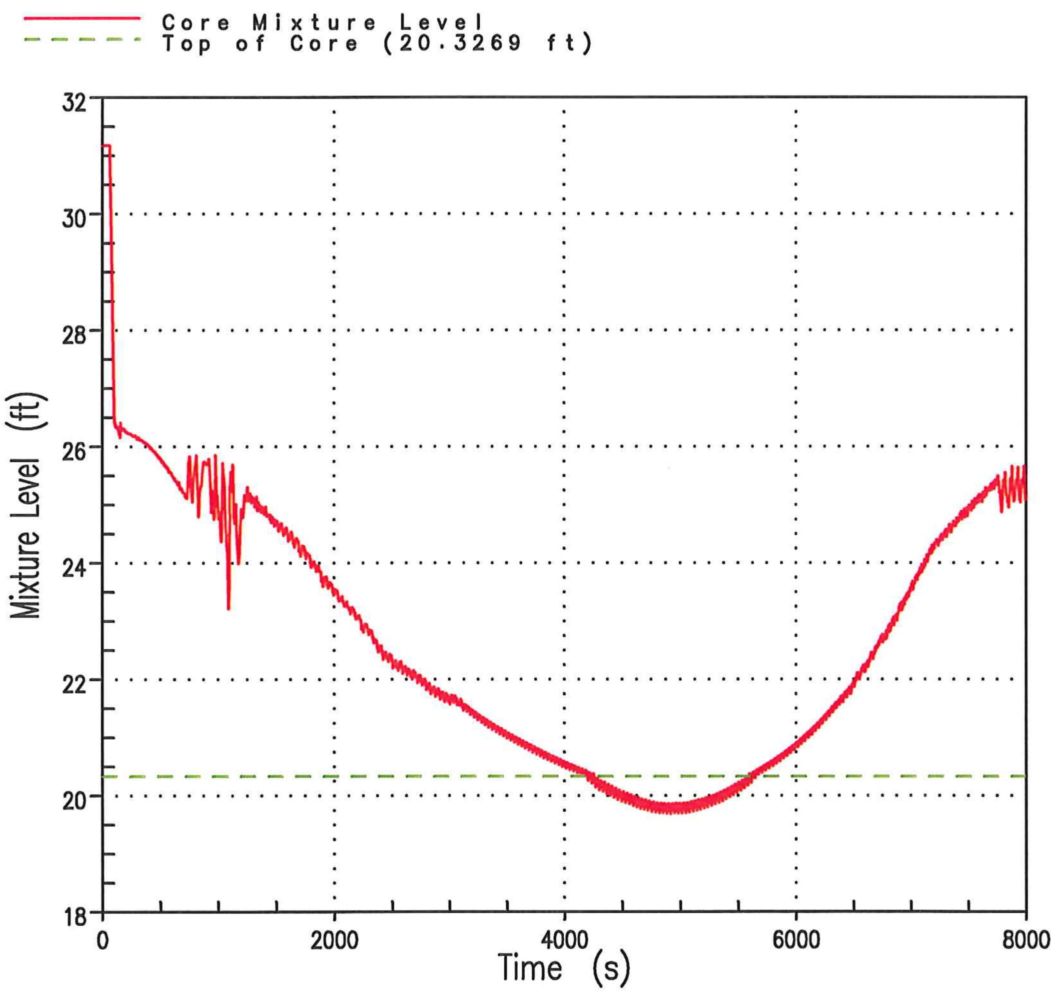


Figure 14.3.1-31 TOP CORE EXIT VAPOR TEMPERATURE - 1.5 INCH BREAK
POINT BEACH UNIT 2

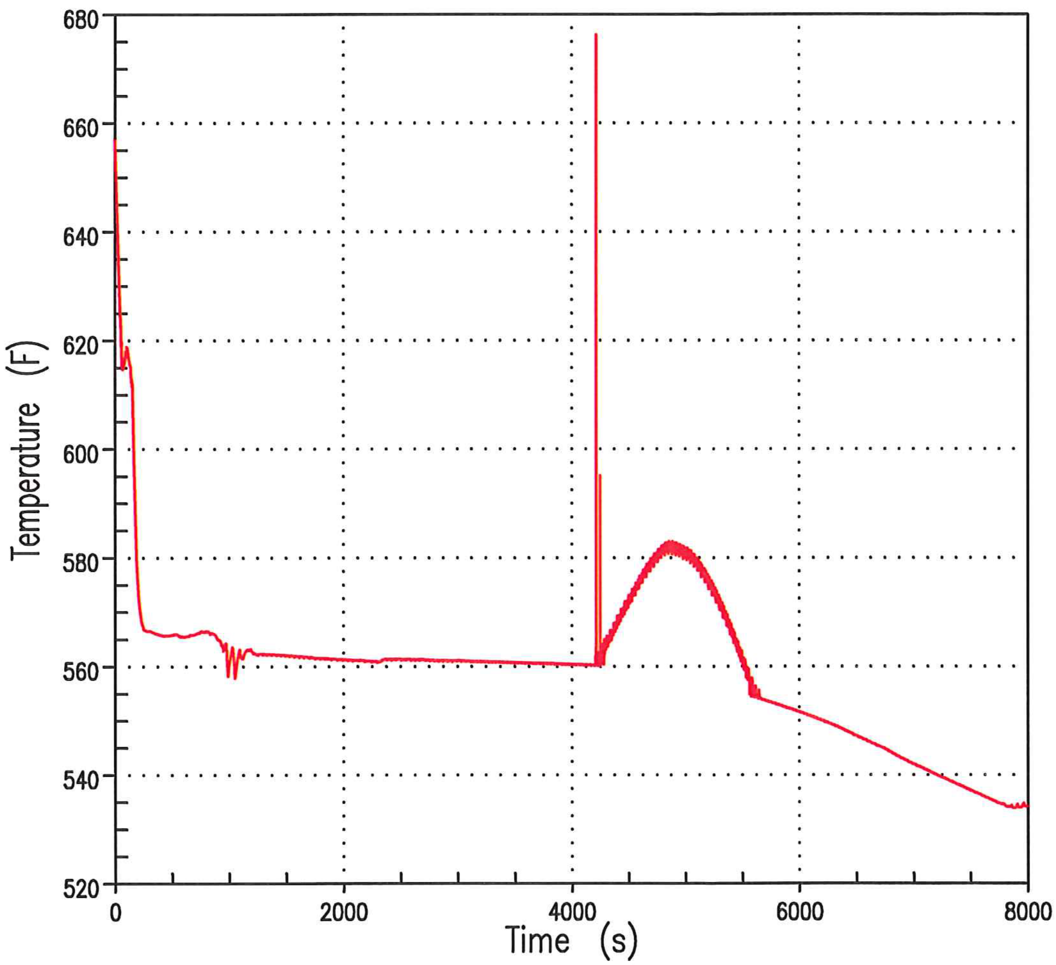


Figure 14.3.1-32 CLADDING TEMPERATURE TRANSIENT AT PCT ELEVATION - 1.5 INCH BREAK POINT BEACH UNIT 2

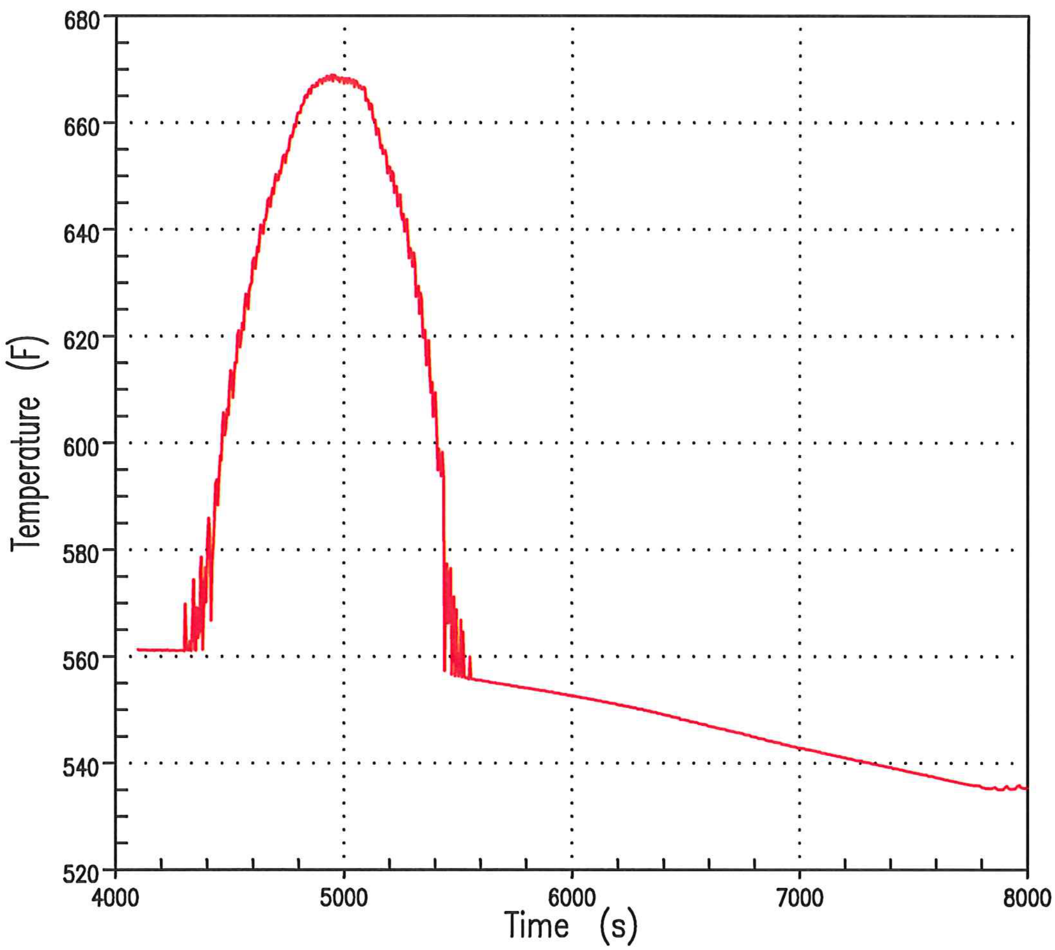


Figure 14.3.1-33 LOCAL ZRO2 THICKNESS AT MAXIMUM LOCAL ZRO2 ELEVATION - 1.5 INCH BREAK POINT BEACH UNIT 2

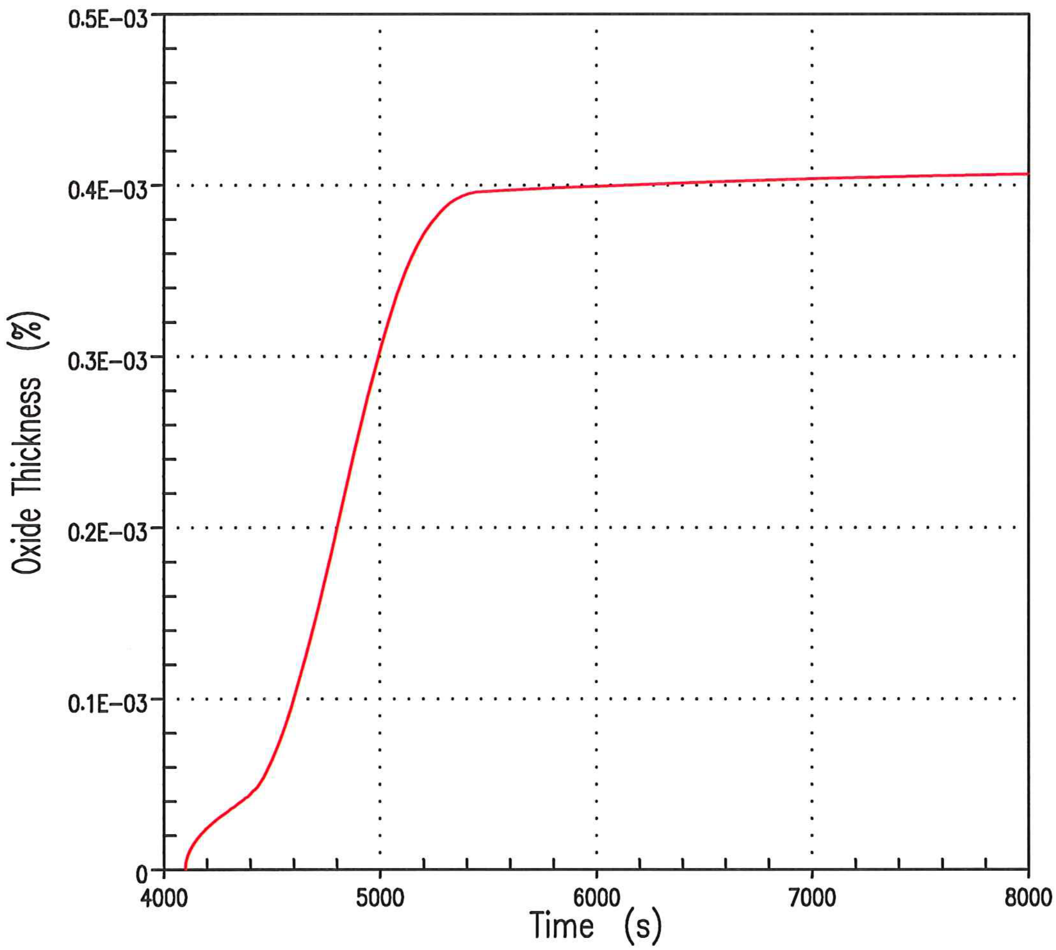


Figure 14.3.1-34 REACTOR COOLANT SYSTEM PRESSURE - 2 INCH BREAK
POINT BEACH UNIT 1

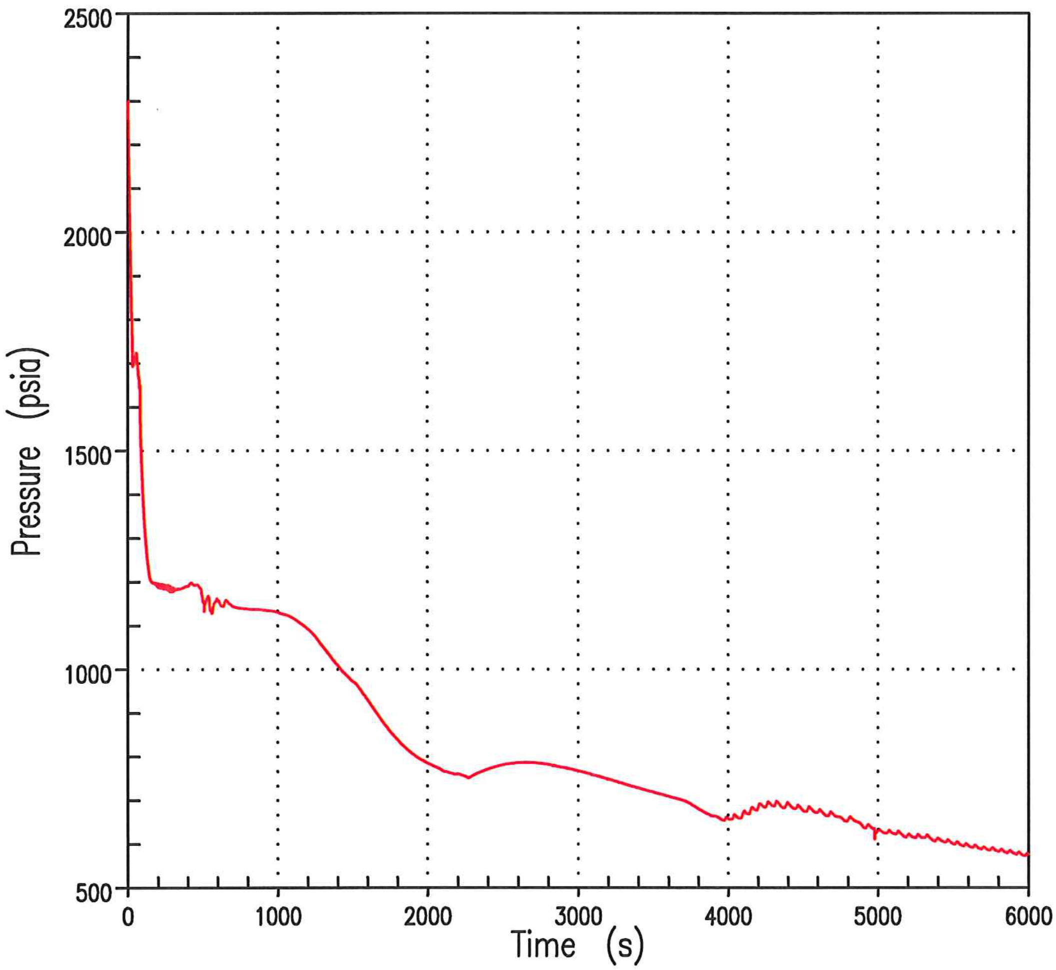


Figure 14.3.1-35 CORE MIXTURE LEVEL AND TOP OF CORE - 2 INCH BREAK
POINT BEACH UNIT 1

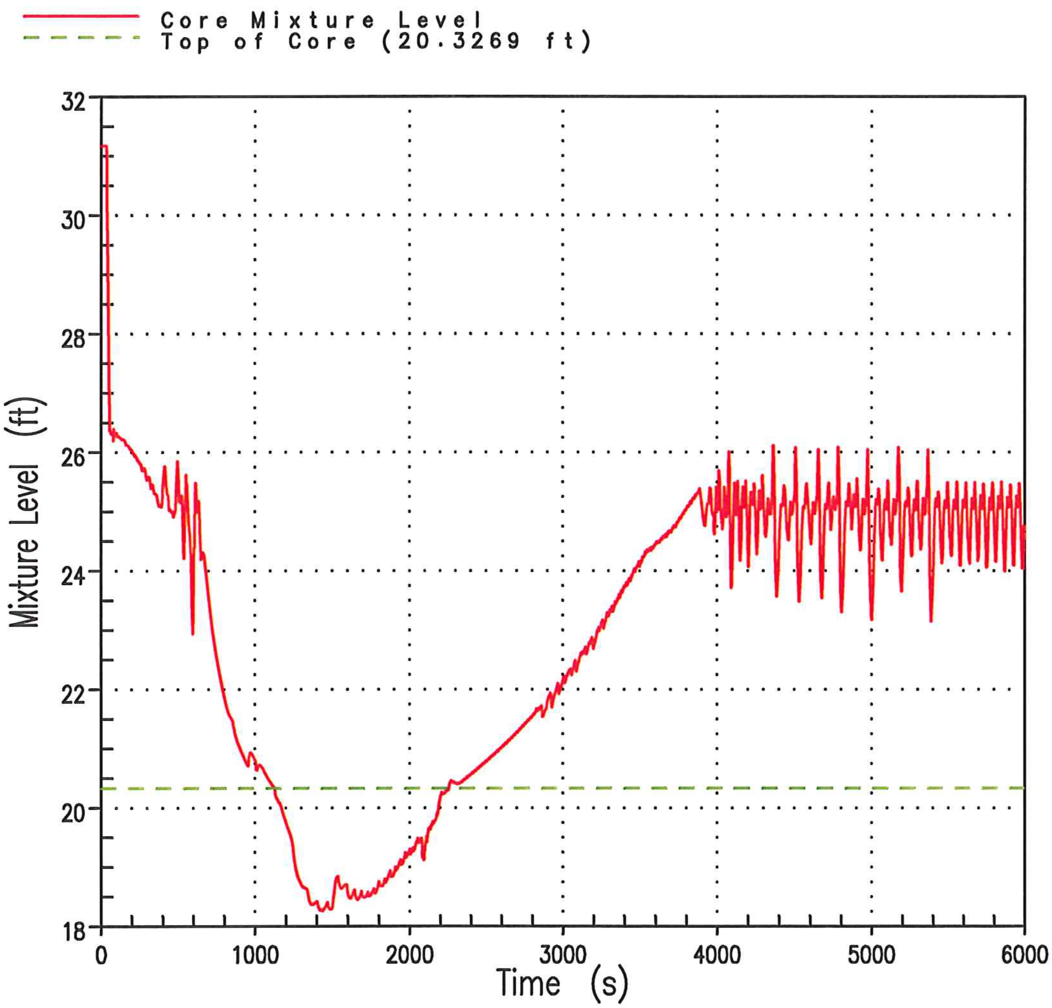


Figure 14.3.1-36 TOP CORE EXIT VAPOR TEMPERATURE - 2 INCH BREAK
POINT BEACH UNIT 1

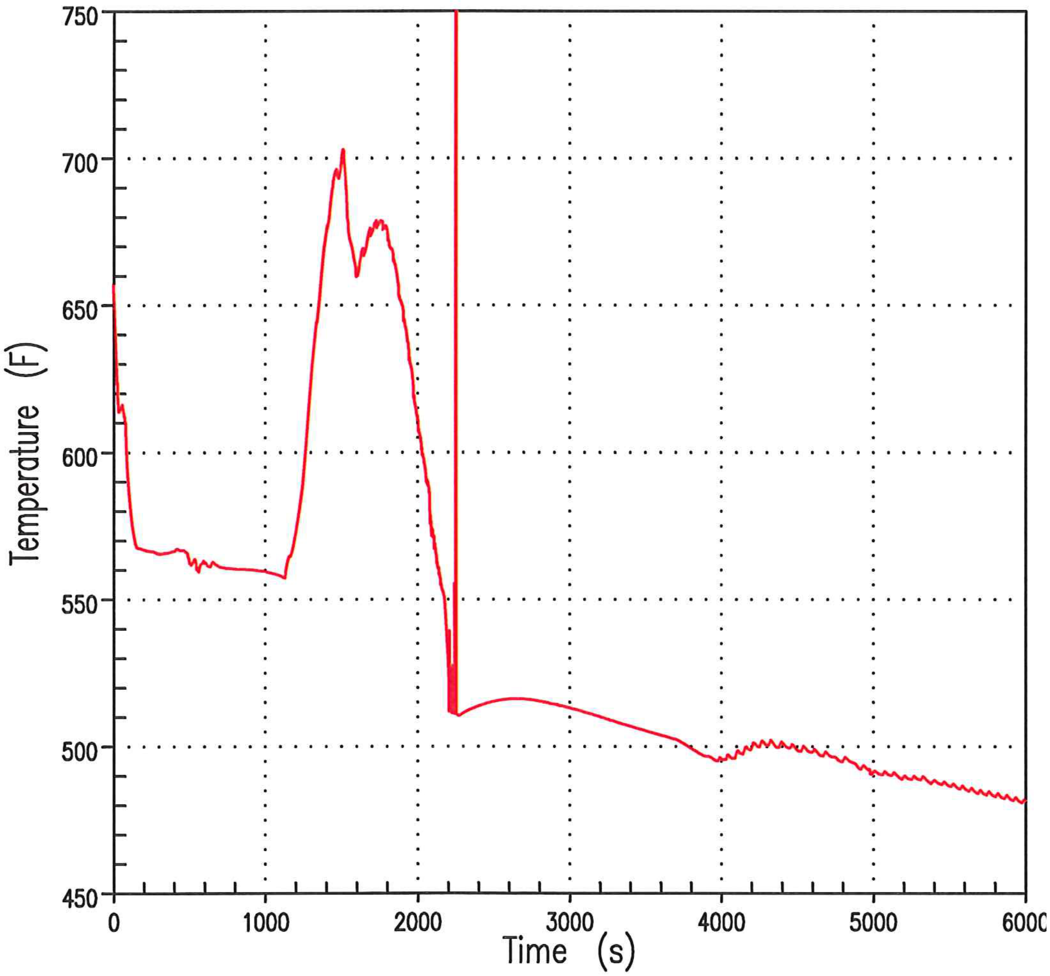


Figure 14.3.1-37 CLADDING TEMPERATURE TRANSIENT AT PCT ELEVATION - 2 INCH BREAK POINT BEACH UNIT 1

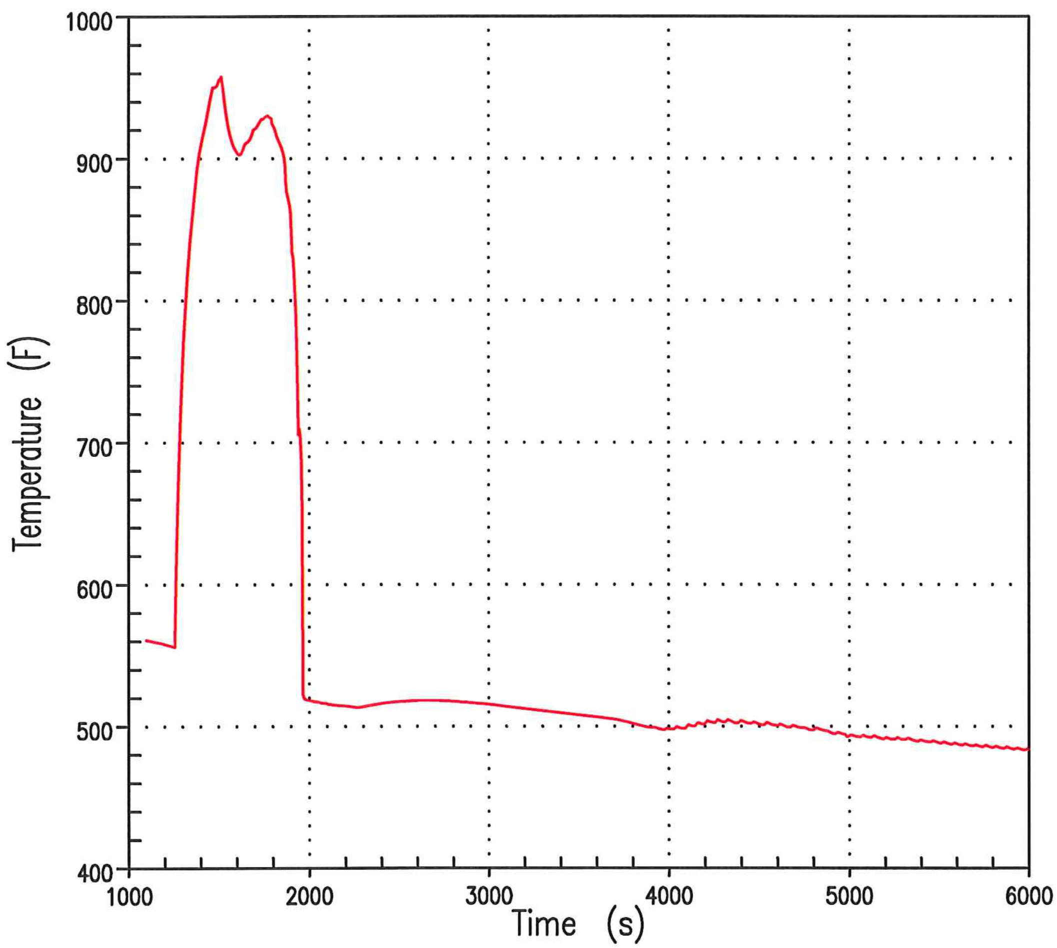


Figure 14.3.1-38 LOCAL ZRO2 THICKNESS AT MAXIMUM LOCAL ZRO2 ELEVATION - 2 INCH BREAK POINT BEACH UNIT 1

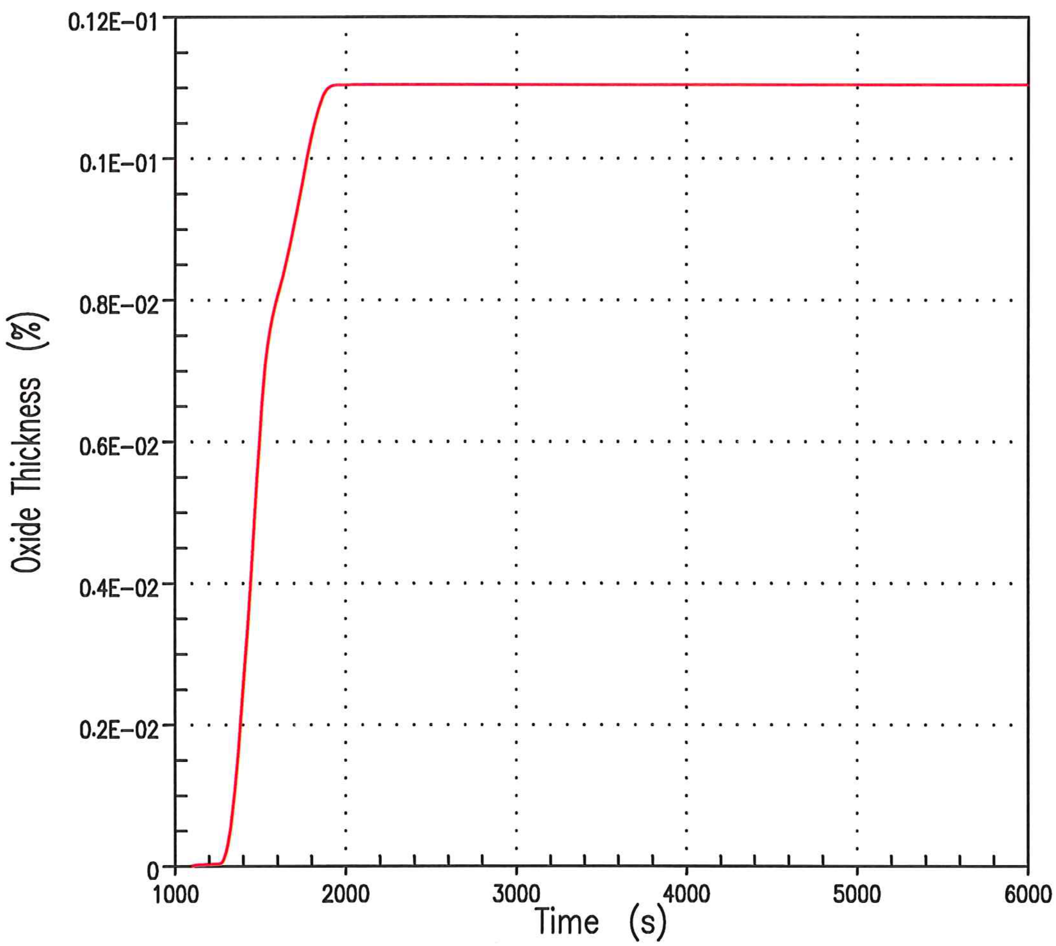


Figure 14.3.1-39 REACTOR COOLANT SYSTEM PRESSURE - 2 INCH BREAK
POINT BEACH UNIT 2

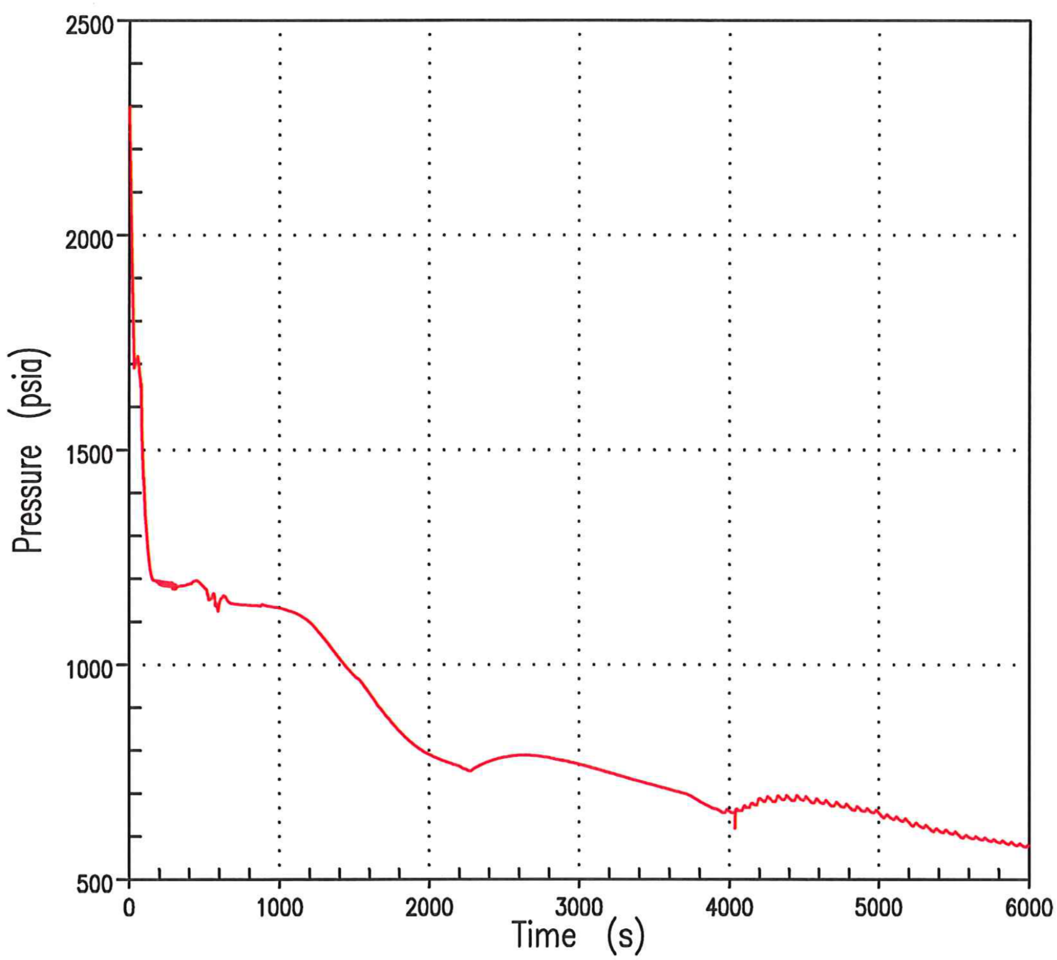


Figure 14.3.1-40 CORE MIXTURE LEVEL AND TOP OF CORE - 2 INCH BREAK POINT BEACH UNIT 2

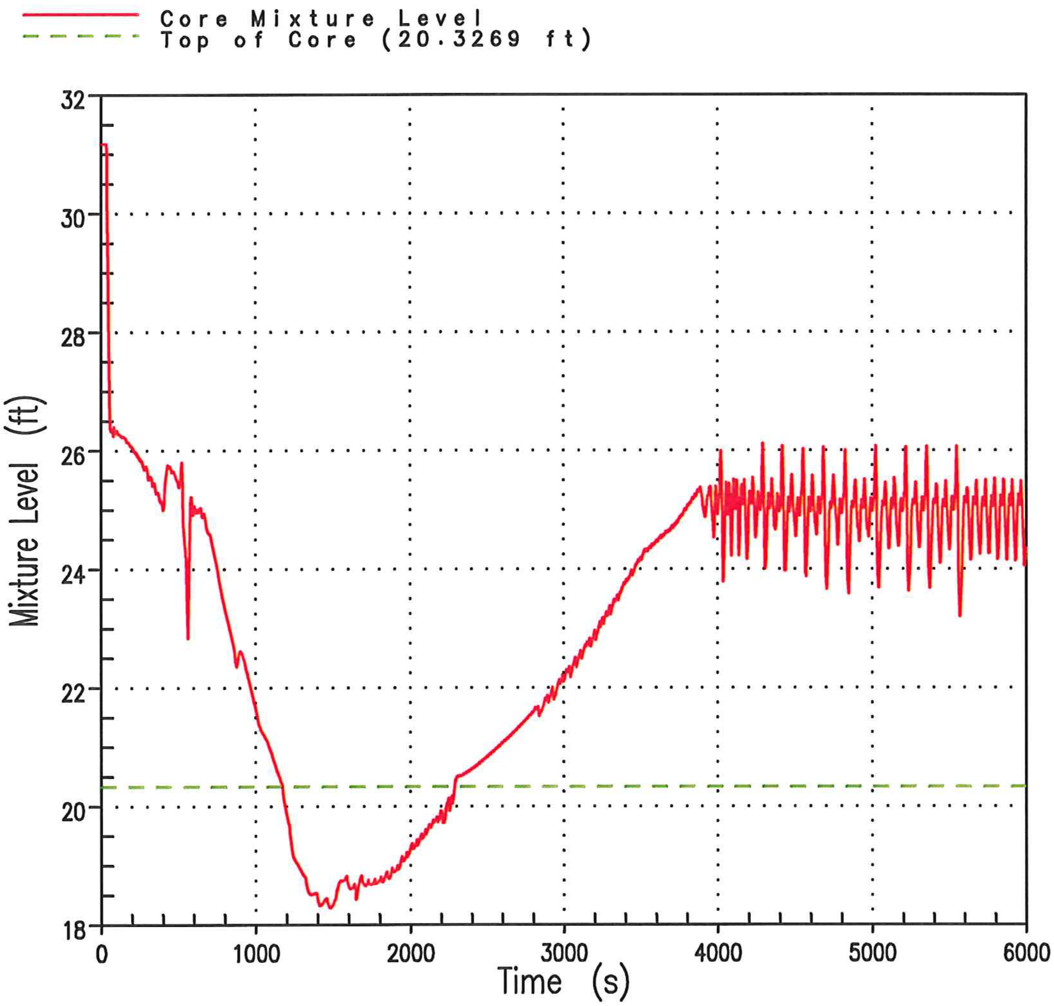


Figure 14.3.1-41 TOP CORE EXIT VAPOR TEMPERATURE - 2 INCH BREAK
POINT BEACH UNIT 2

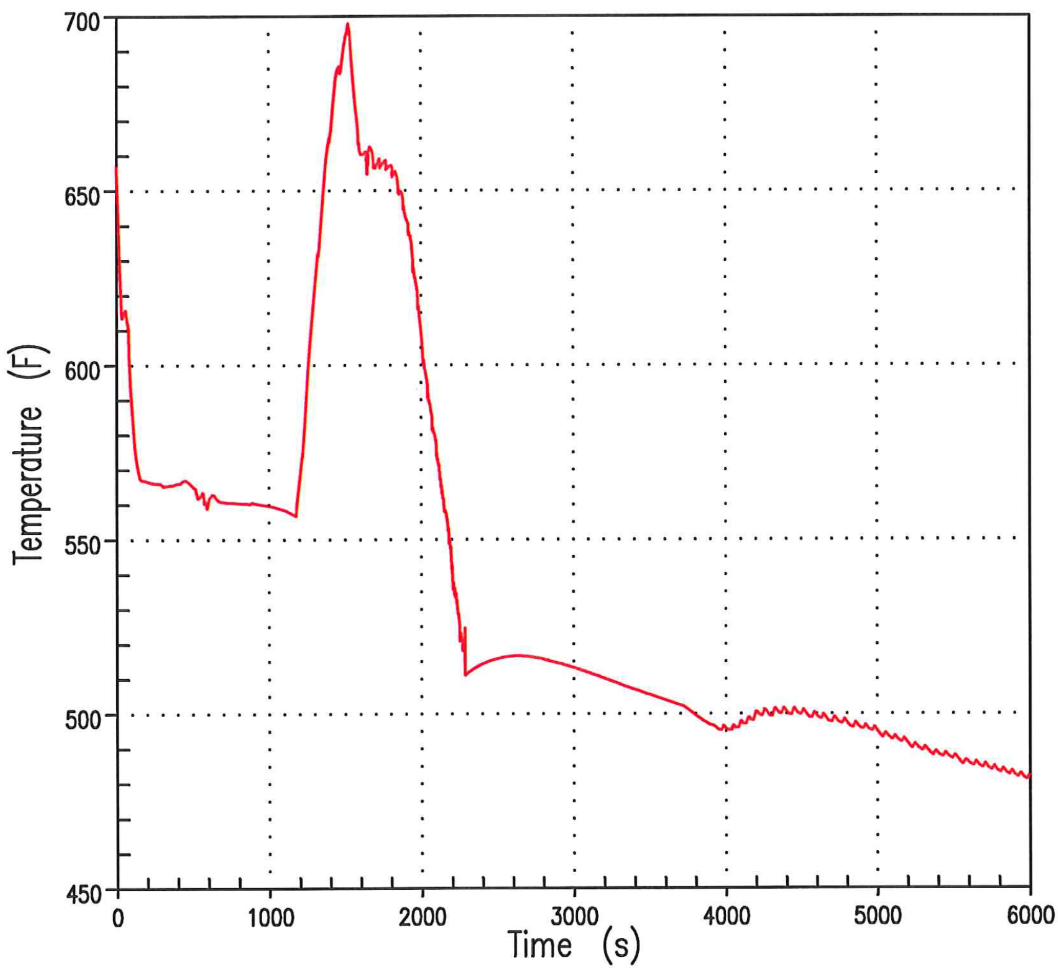


Figure 14.3.1-42 CLADDING TEMPERATURE TRANSIENT AT PCT ELEVATION - 2 INCH BREAK POINT BEACH UNIT 2

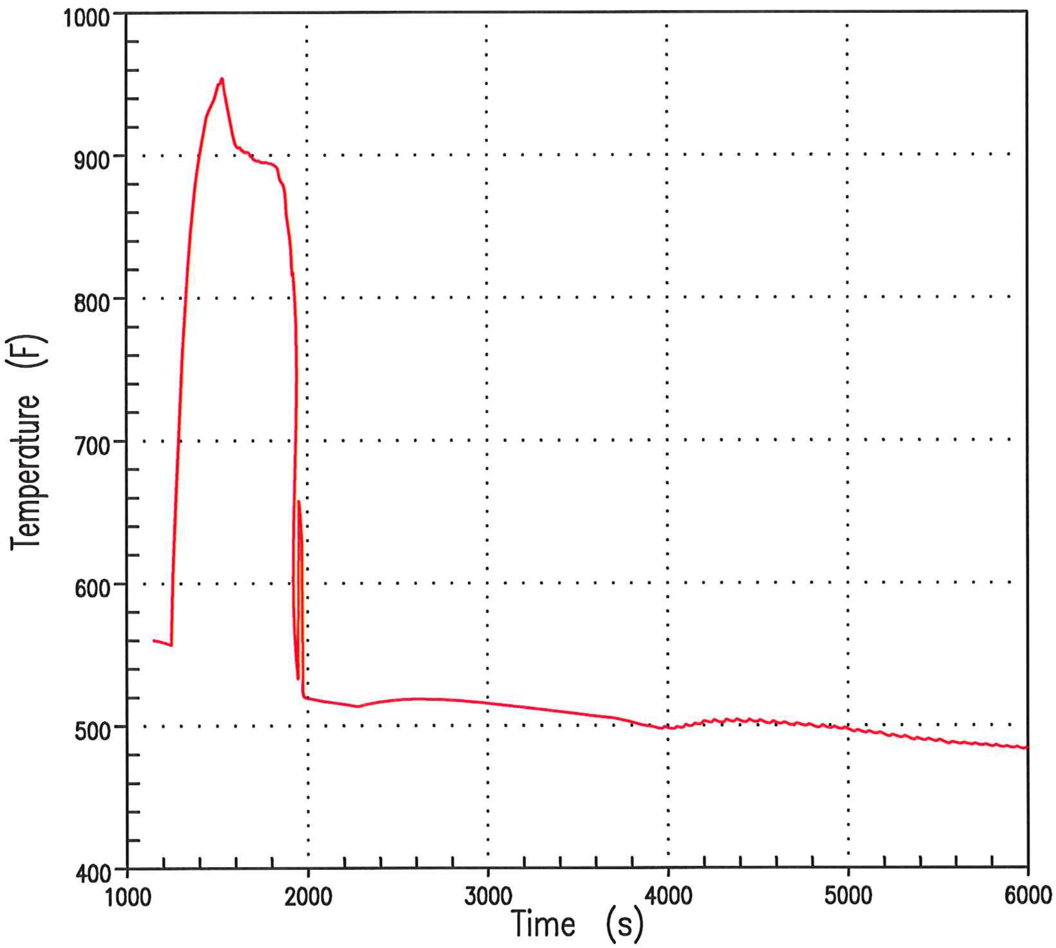


Figure 14.3.1-43 LOCAL ZRO2 THICKNESS AT MAXIMUM LOCAL ZRO2 ELEVATION - 2 INCH BREAK POINT BEACH UNIT 2

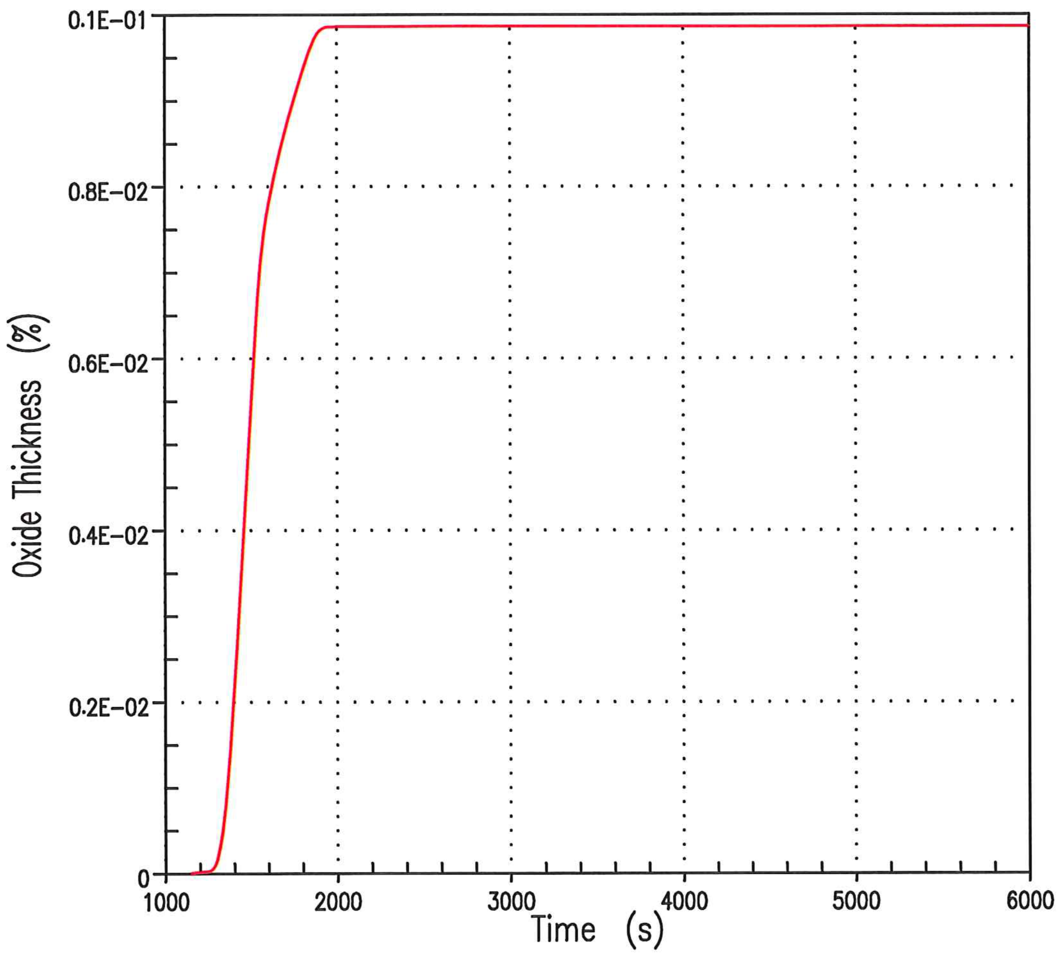


Figure 14.3.1-44 REACTOR COOLANT SYSTEM PRESSURE - 4 INCH BREAK
POINT BEACH UNIT 1

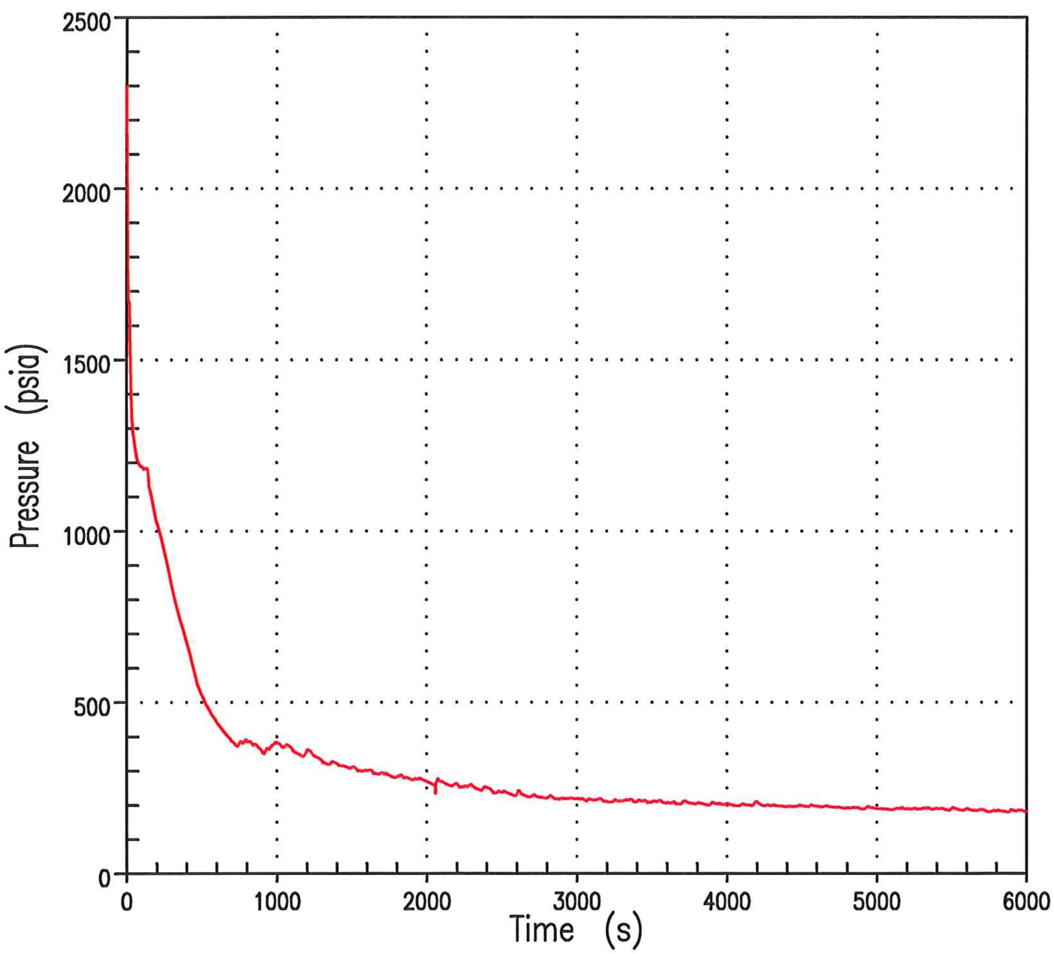


Figure 14.3.1-45 CORE MIXTURE LEVEL AND TOP OF CORE - 4 INCH BREAK
POINT BEACH UNIT 1

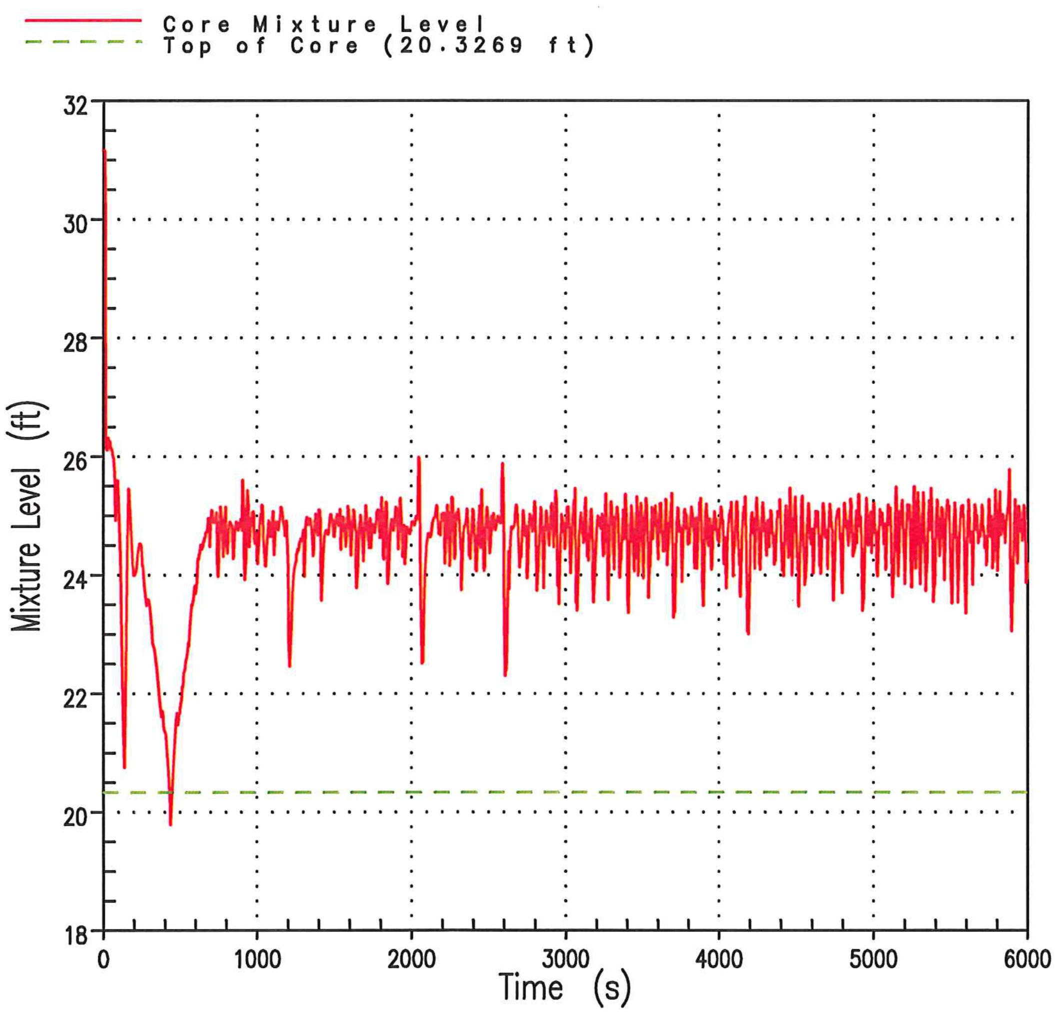


Figure 14.3.1-46 TOP CORE EXIT VAPOR TEMPERATURE - 4 INCH BREAK
POINT BEACH UNIT 1

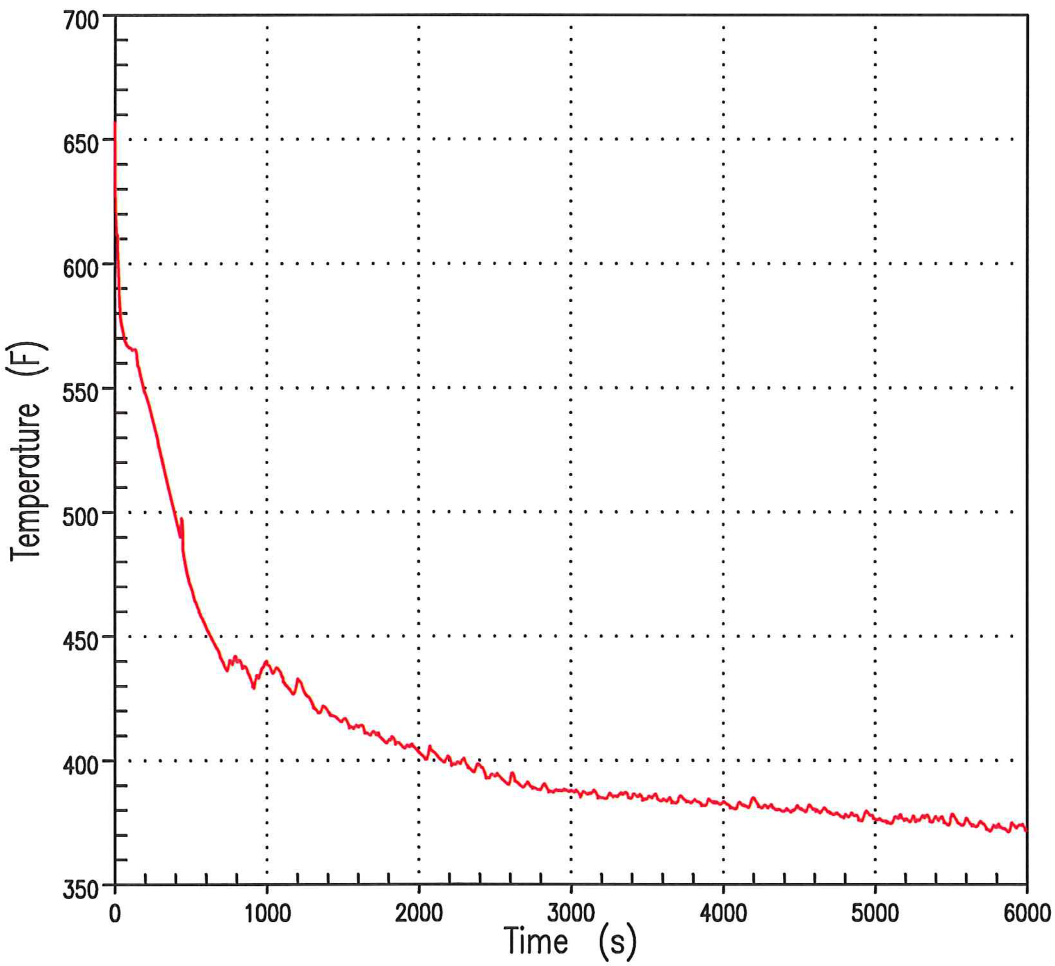


Figure 14.3.1-47 CLADDING TEMPERATURE TRANSIENT AT PCT ELEVATION - 4 INCH BREAK POINT BEACH UNIT 1

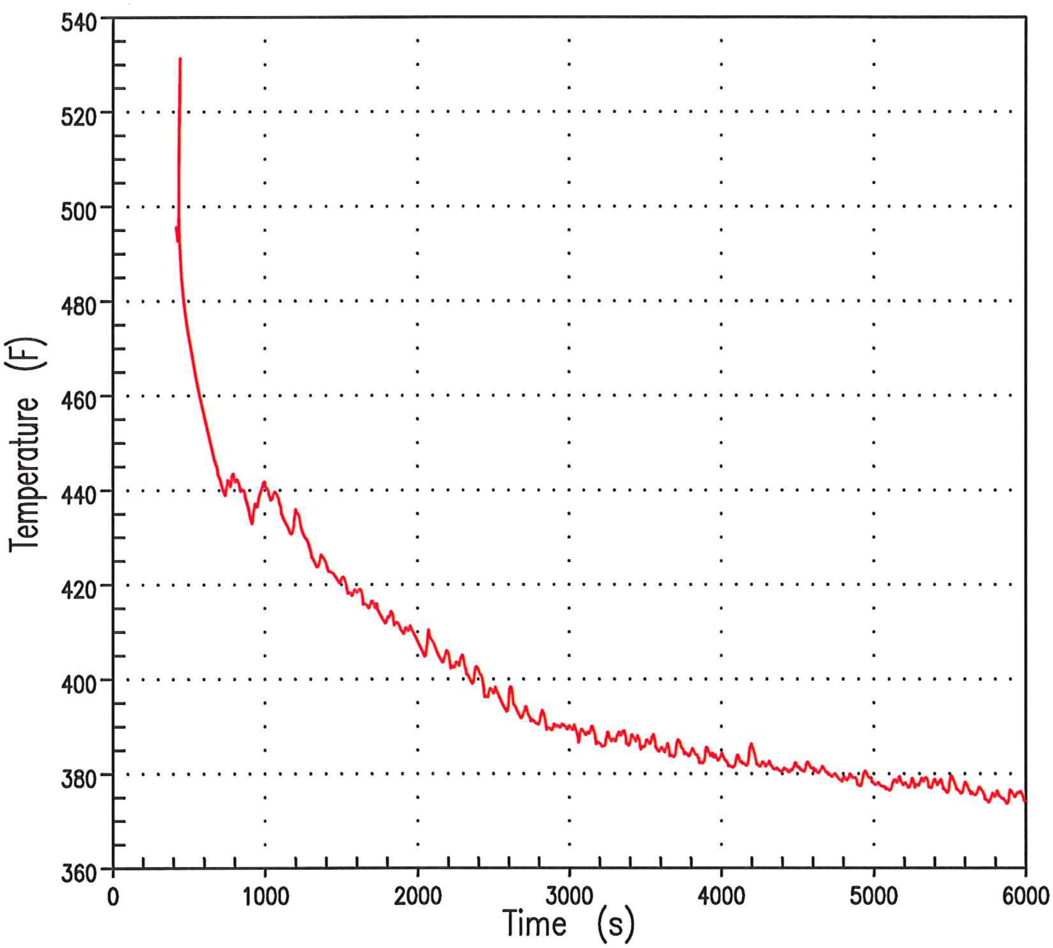


Figure 14.3.1-48 LOCAL ZRO2 THICKNESS AT MAXIMUM LOCAL ZRO2 ELEVATION - 4 INCH BREAK POINT BEACH UNIT 1

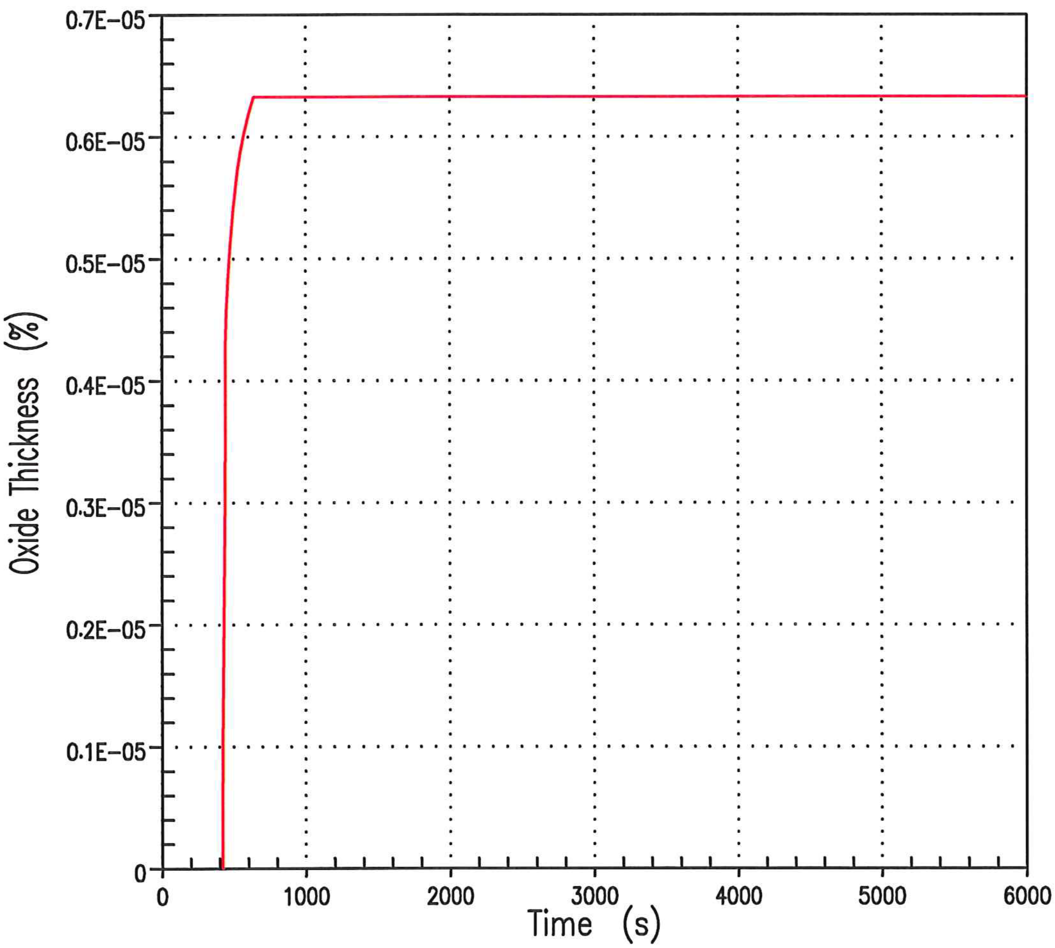


Figure 14.3.1-49 REACTOR COOLANT SYSTEM PRESSURE - 4 INCH BREAK
POINT BEACH UNIT 2

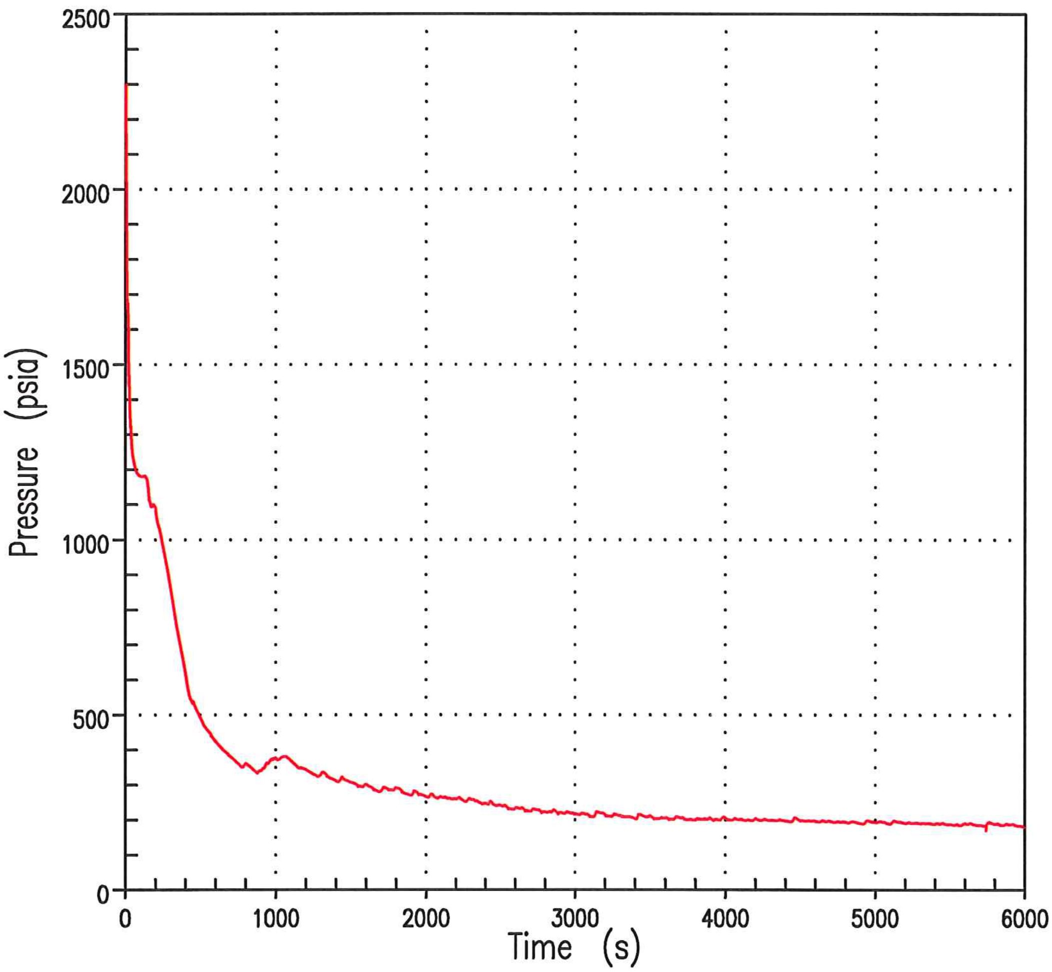


Figure 14.3.1-50 CORE MIXTURE LEVEL AND TOP OF CORE - 4 INCH BREAK
POINT BEACH UNIT 2

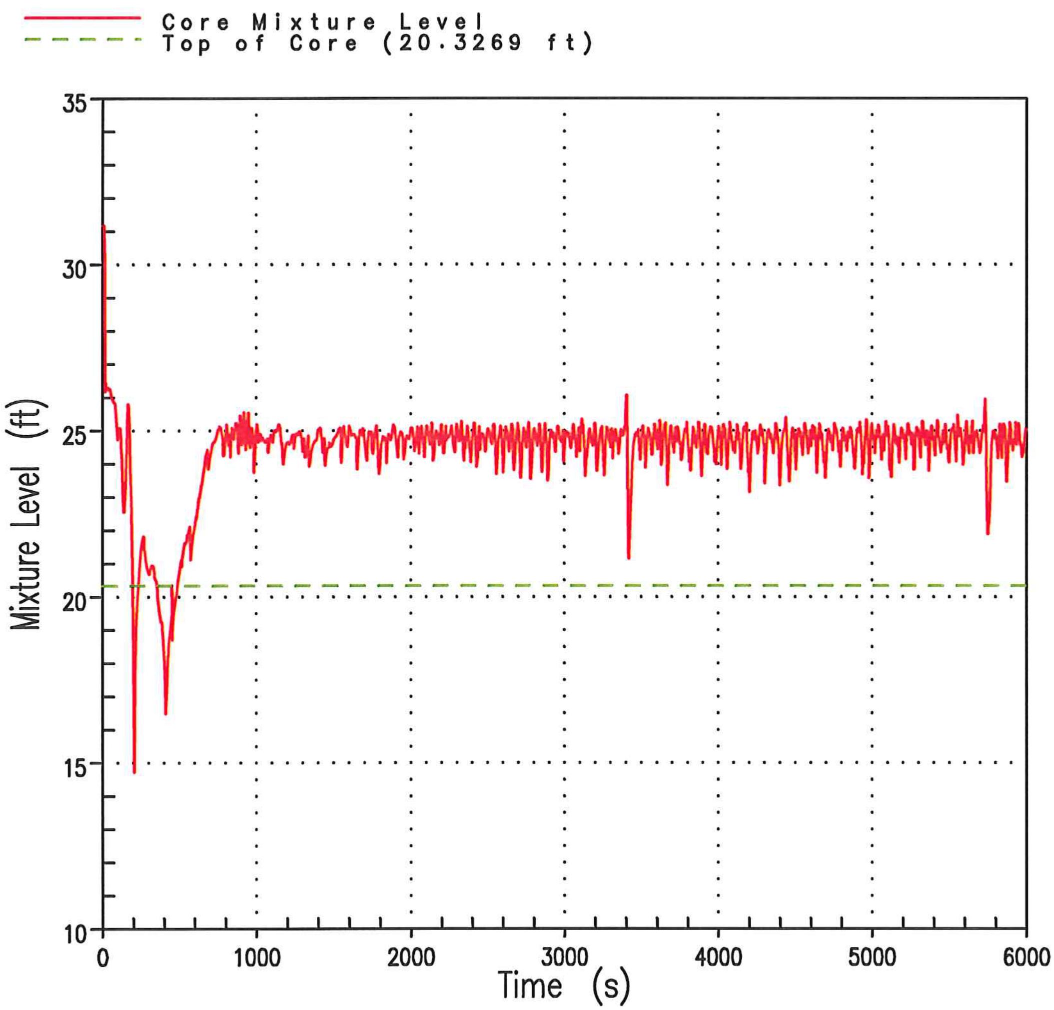


Figure 14.3.1-51 TOP CORE EXIT TEMPERATURE - 4 INCH BREAK POINT BEACH UNIT 2

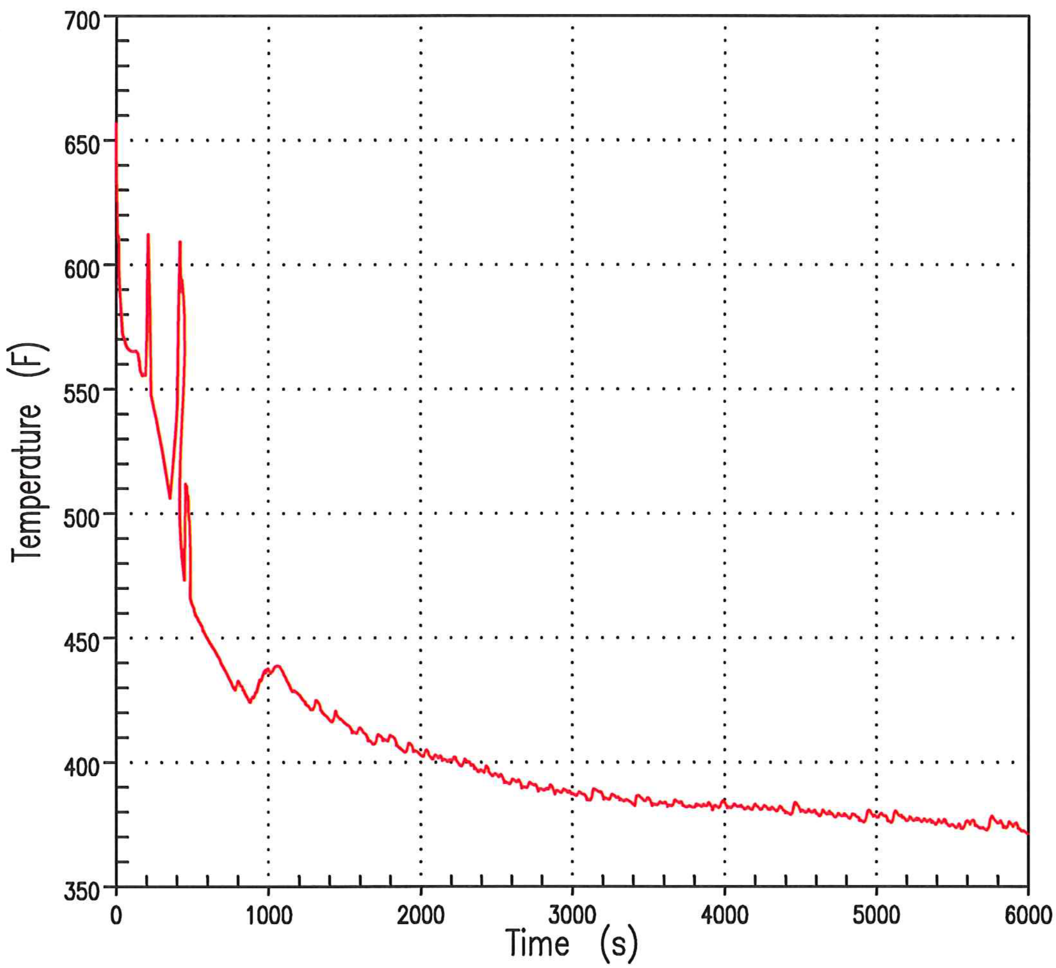


Figure 14.3.1-52 CLADDING TEMPERATURE TRANSIENT AT PCT ELEVATION - 4 INCH BREAK POINT BEACH UNIT 2

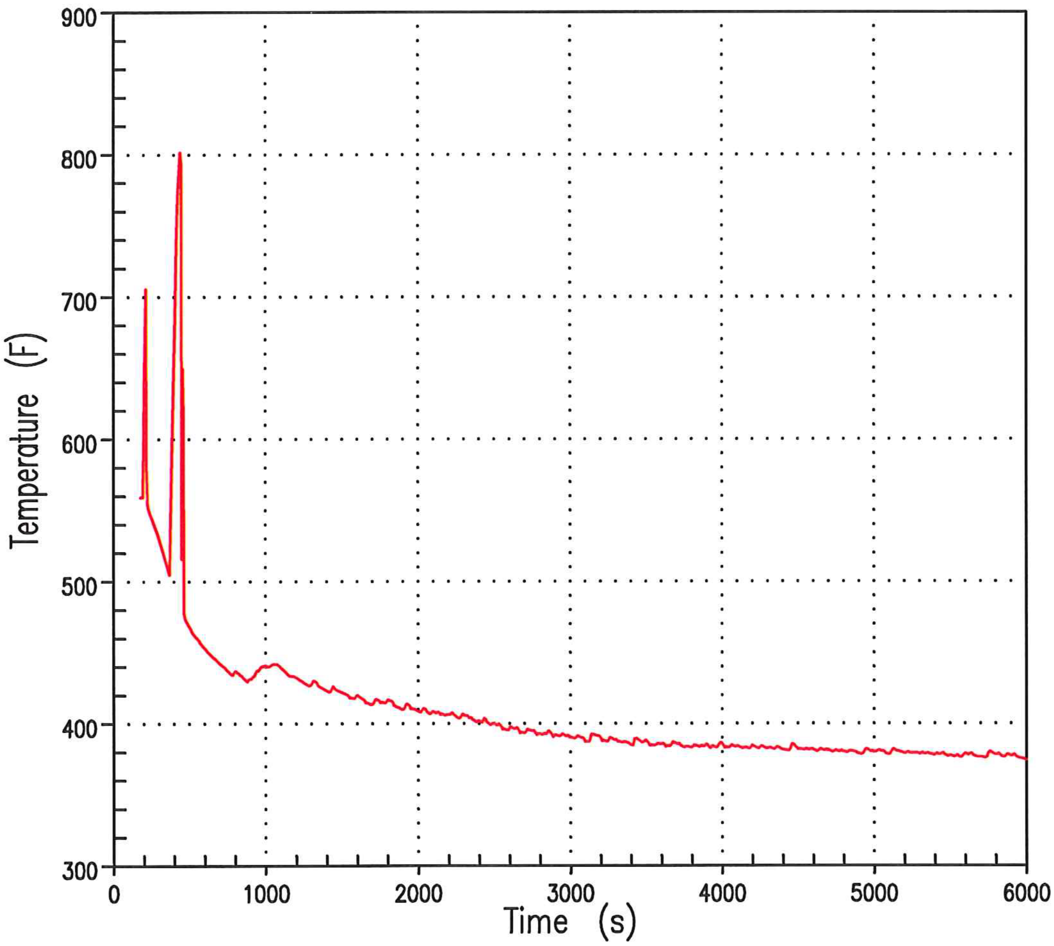


Figure 14.3.1-53 LOCAL ZRO2 THICKNESS AT MAXIMUM LOCAL ZRO2 ELEVATION - 4 INCH BREAK POINT BEACH UNIT 2

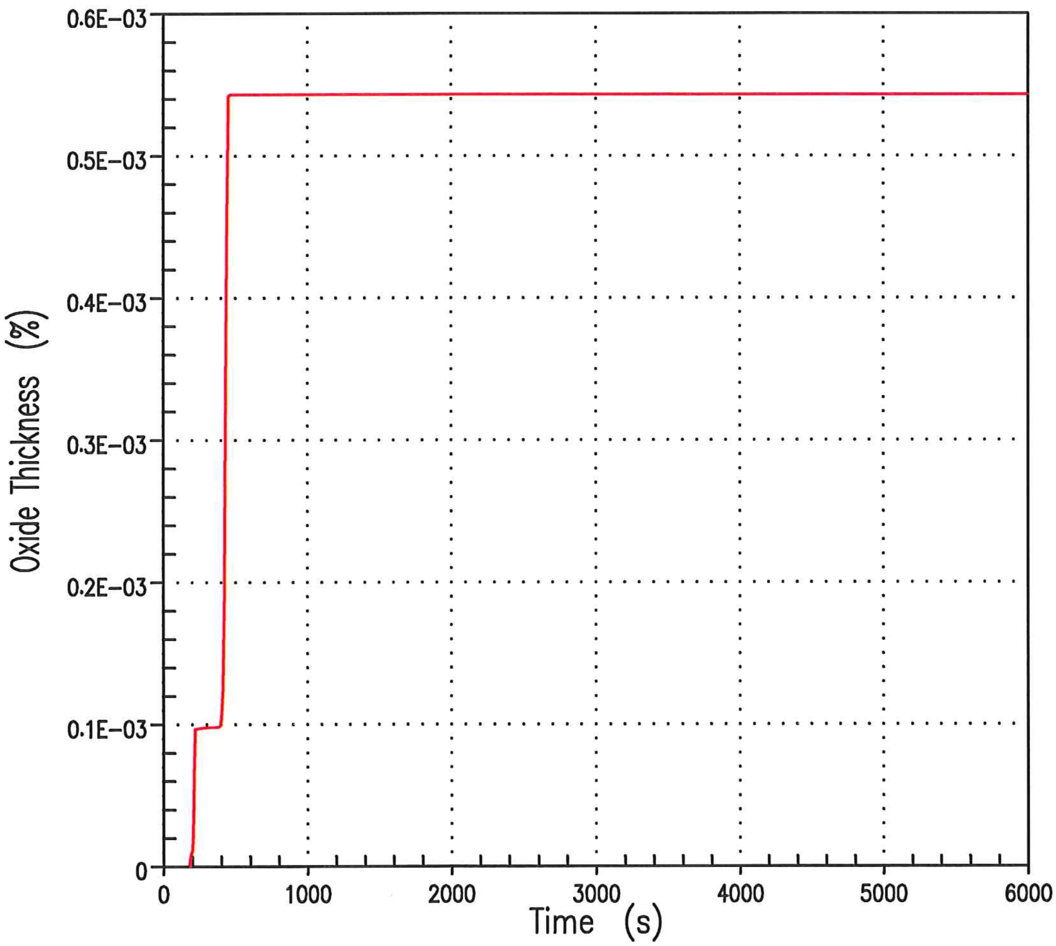


Figure 14.3.1-54 REACTOR COOLANT SYSTEM PRESSURE - 6 INCH BREAK
POINT BEACH UNIT 1

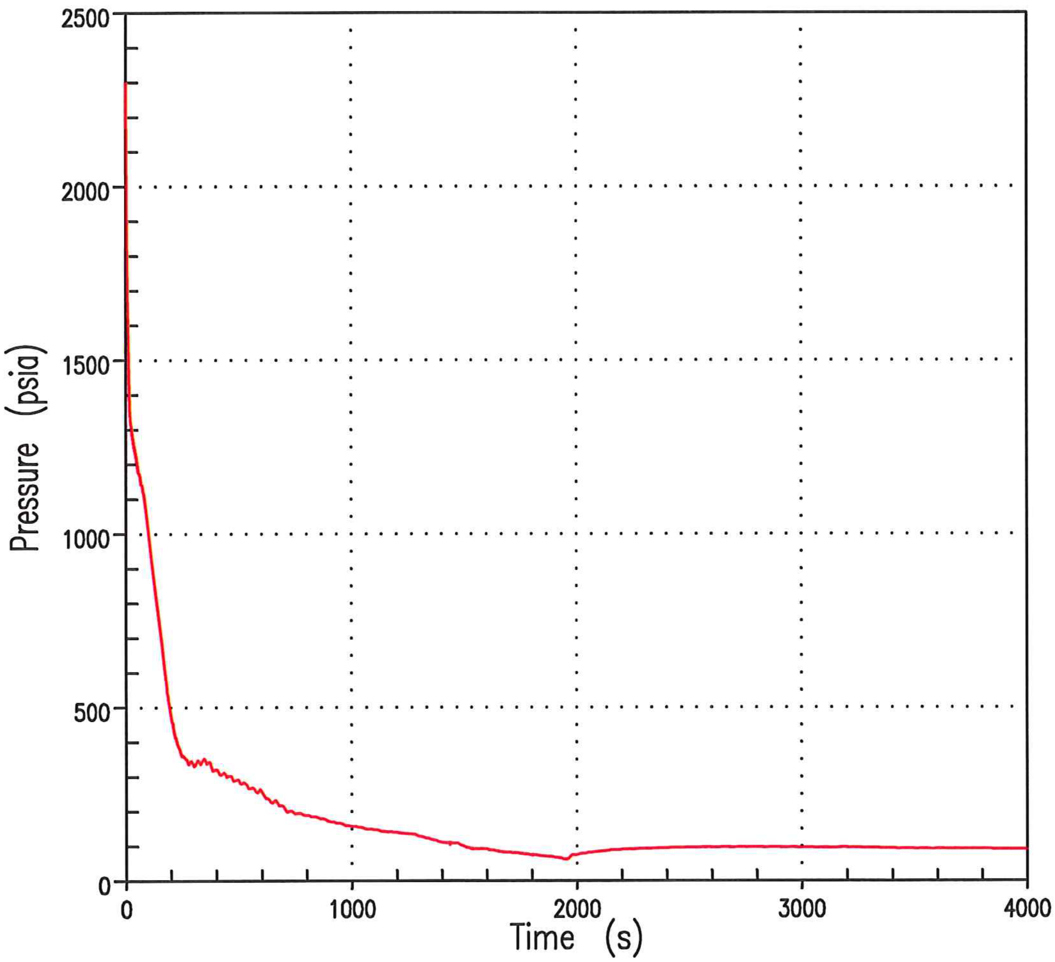


Figure 14.3.1-55 CORE MIXTURE LEVEL AND TOP OF CORE - 6 INCH BREAK
POINT BEACH UNIT 1

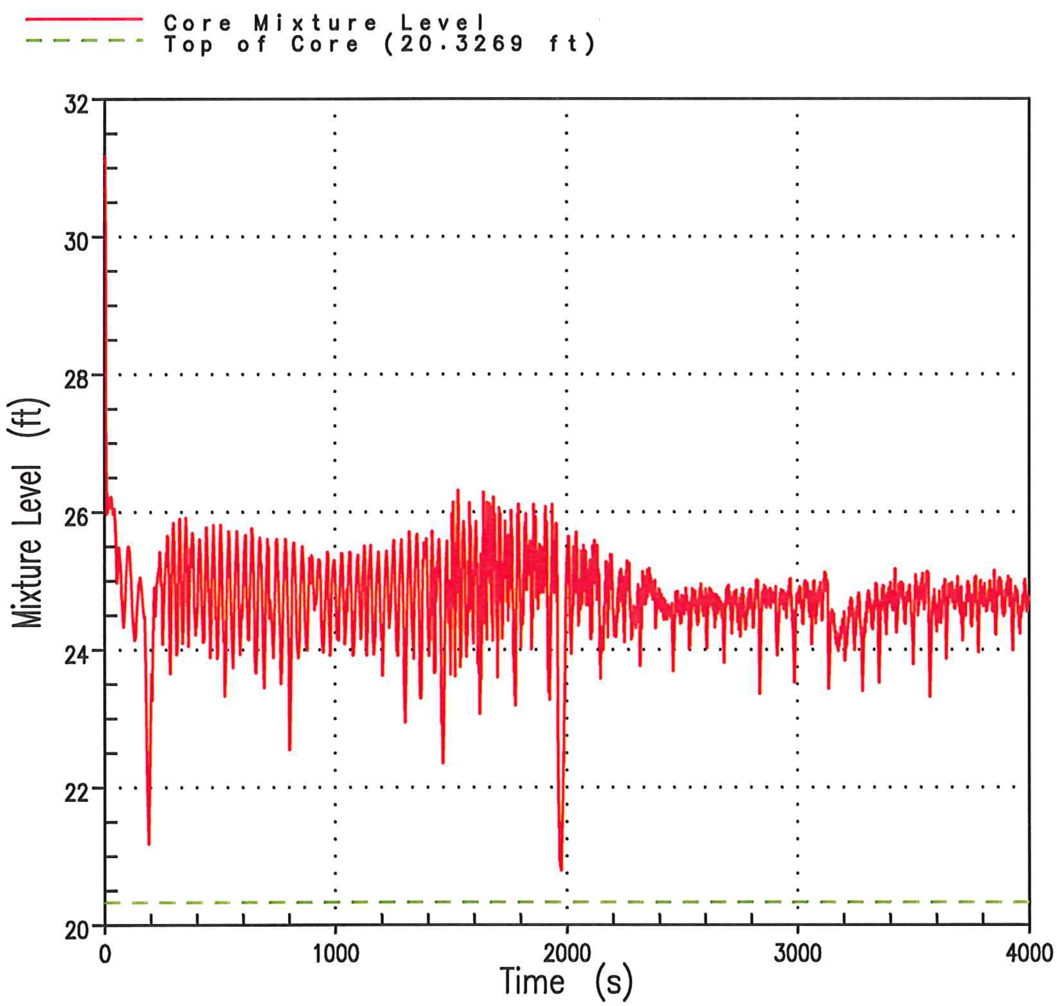


Figure 14.3.1-56 TOP CORE EXIT VAPOR TEMPERATURE - 6 INCH BREAK
POINT BEACH UNIT 1

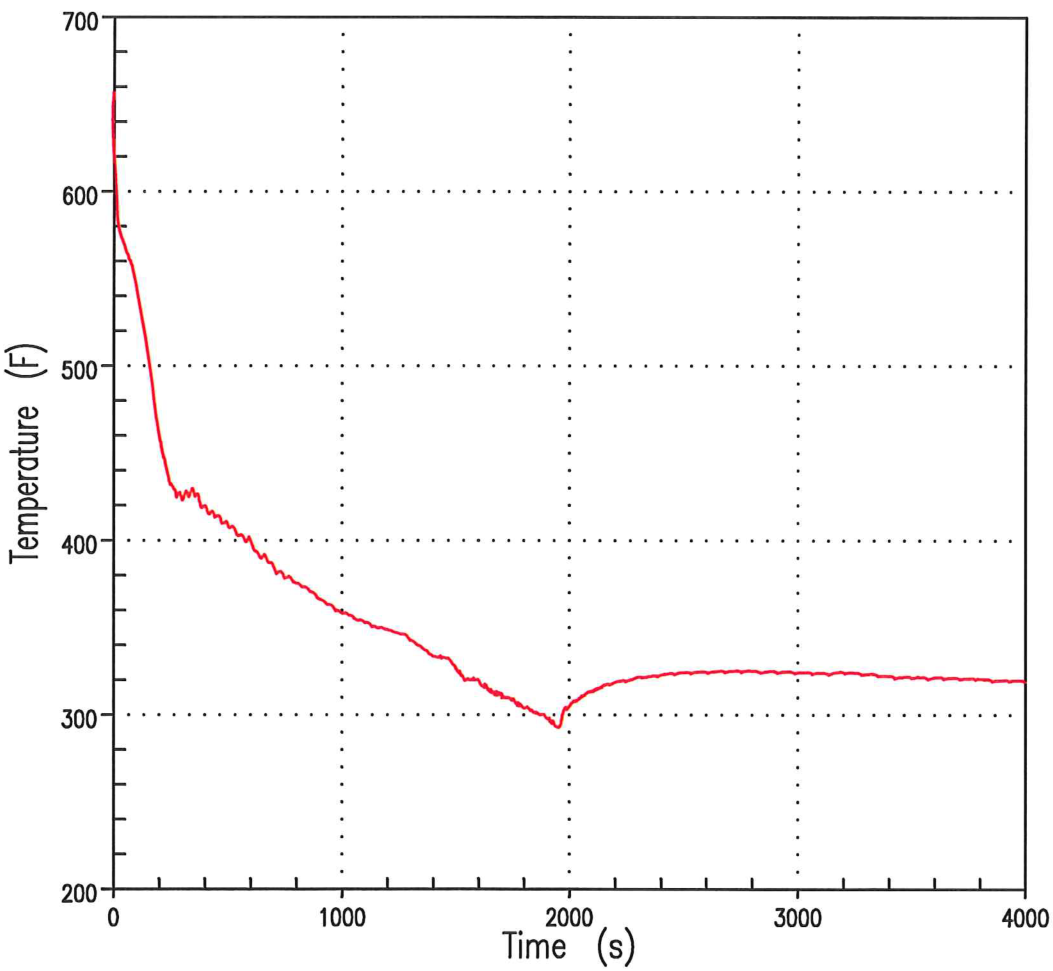


Figure 14.3.1-57 REACTOR COOLANT SYSTEM PRESSURE - 6 INCH BREAK
POINT BEACH UNIT 2

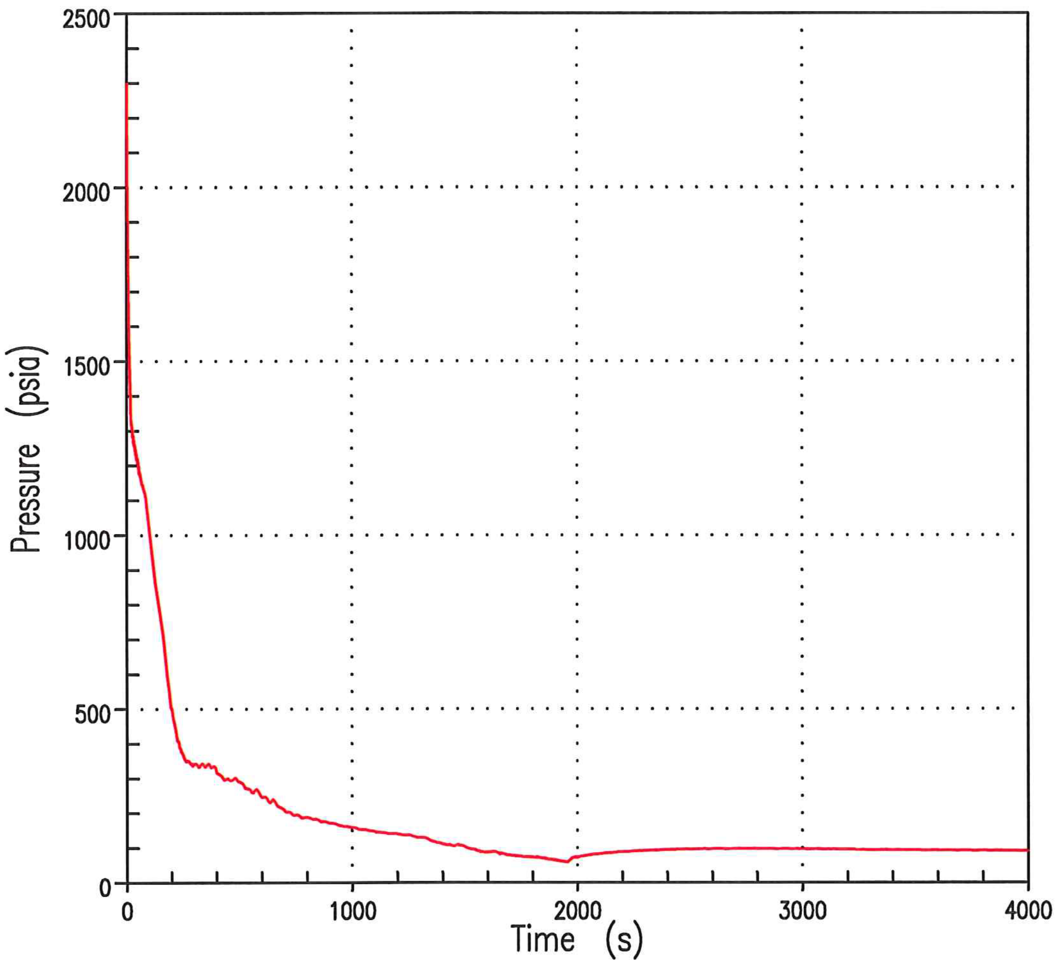


Figure 14.3.1-58 CORE MIXTURE LEVEL AND TOP OF CORE - 6 INCH BREAK
POINT BEACH UNIT 2

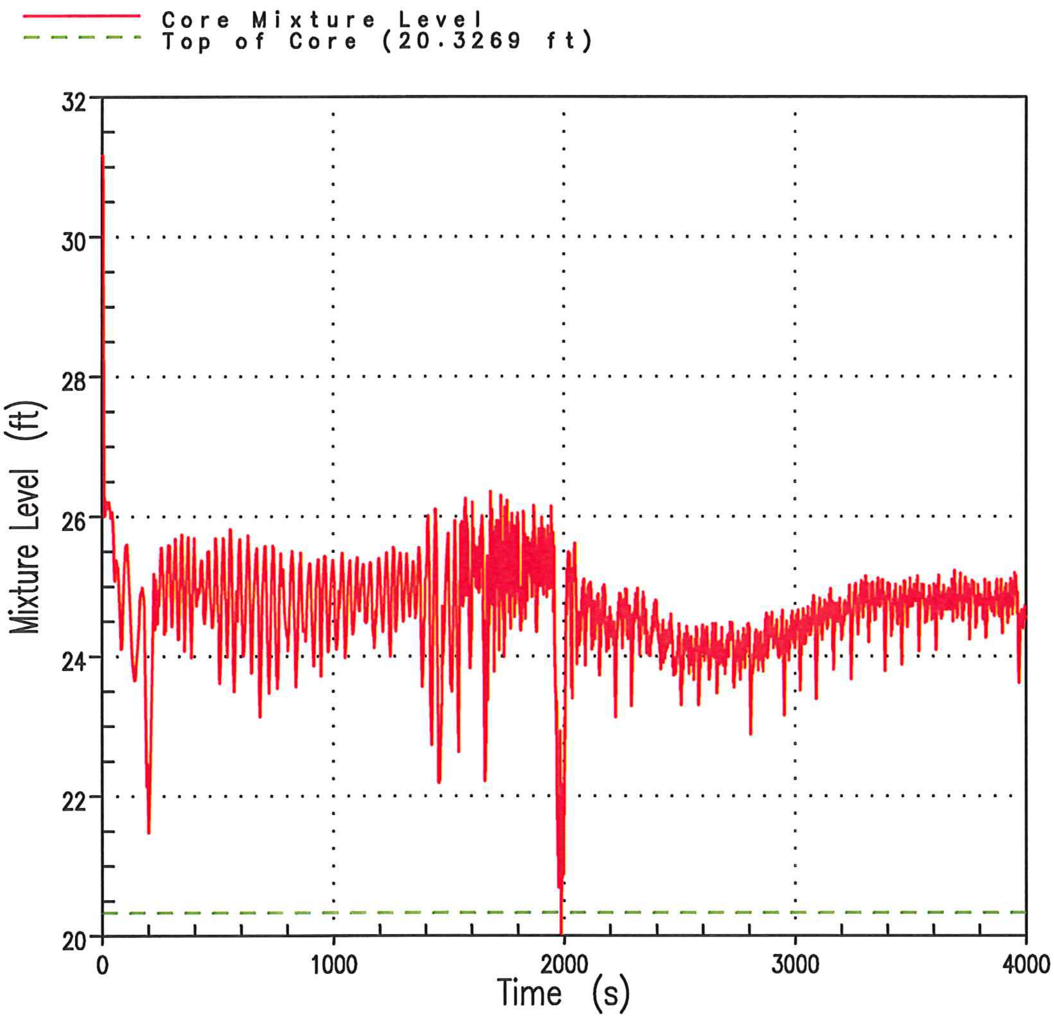


Figure 14.3.1-59 TOP CORE EXIT VAPOR TEMPERATURE - 6 INCH BREAK
POINT BEACH UNIT 2

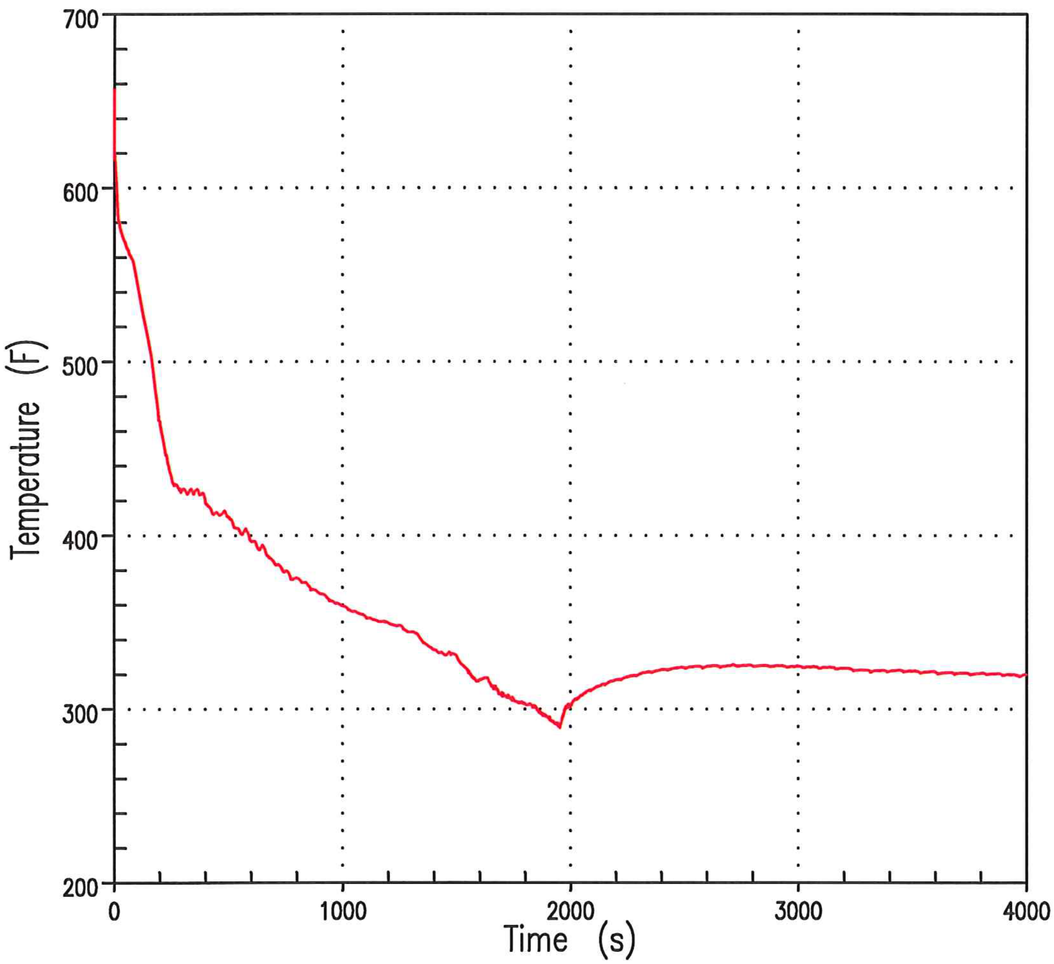


Figure 14.3.1-60 REACTOR COOLANT SYSTEM PRESSURE - 8.75 INCH BREAK
POINT BEACH UNIT 1

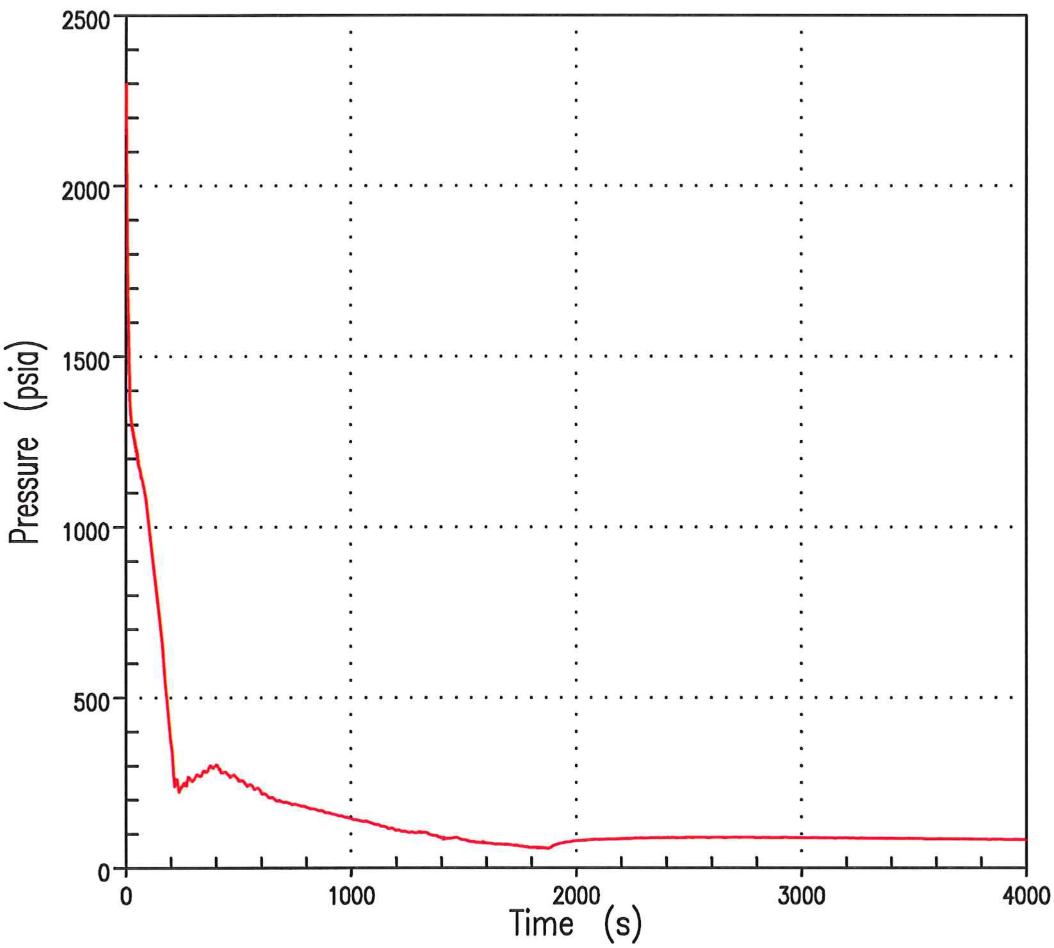


Figure 14.3.1-61 CORE MIXTURE LEVEL AND TOP OF CORE - 8.75 INCH BREAK
POINT BEACH UNIT 1

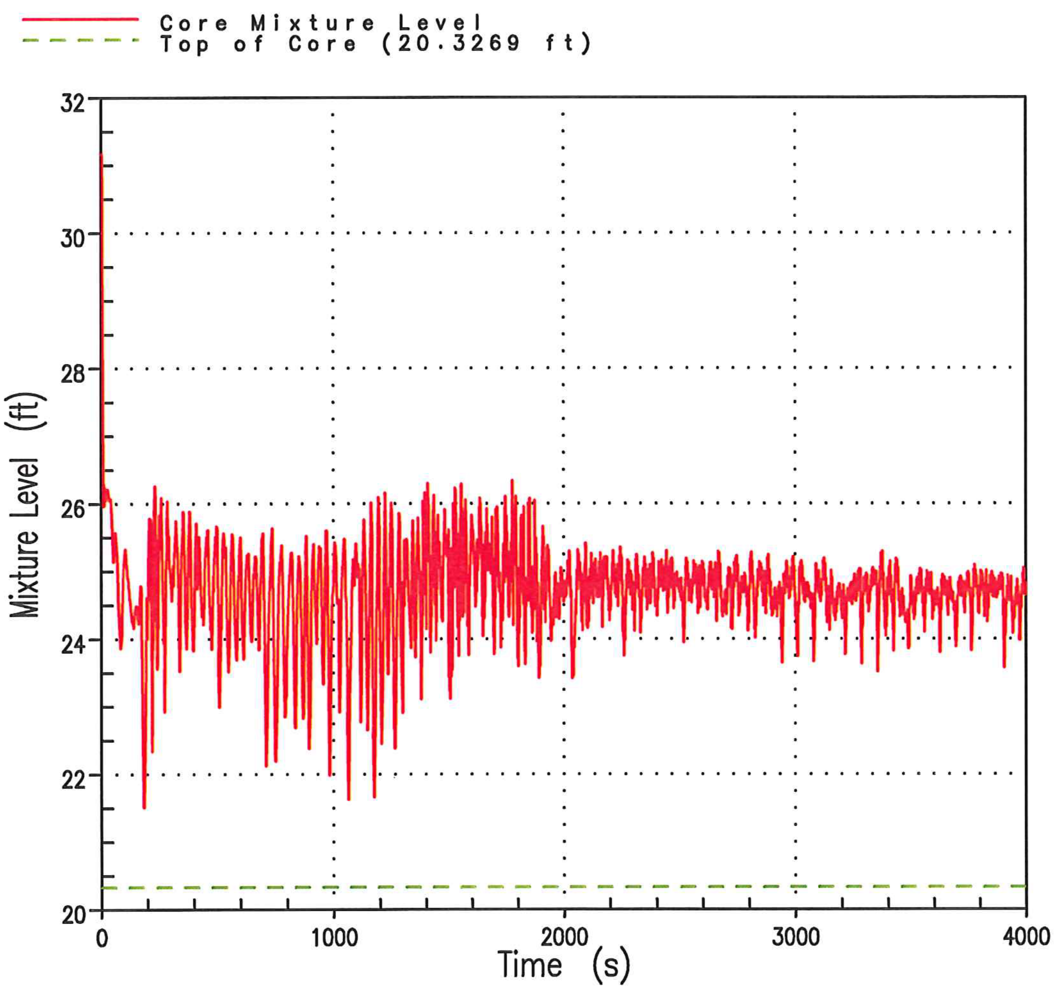


Figure 14.3.1-62 TOP CORE EXIT VAPOR TEMPERATURE - 8.75 INCH BREAK
POINT BEACH UNIT 1

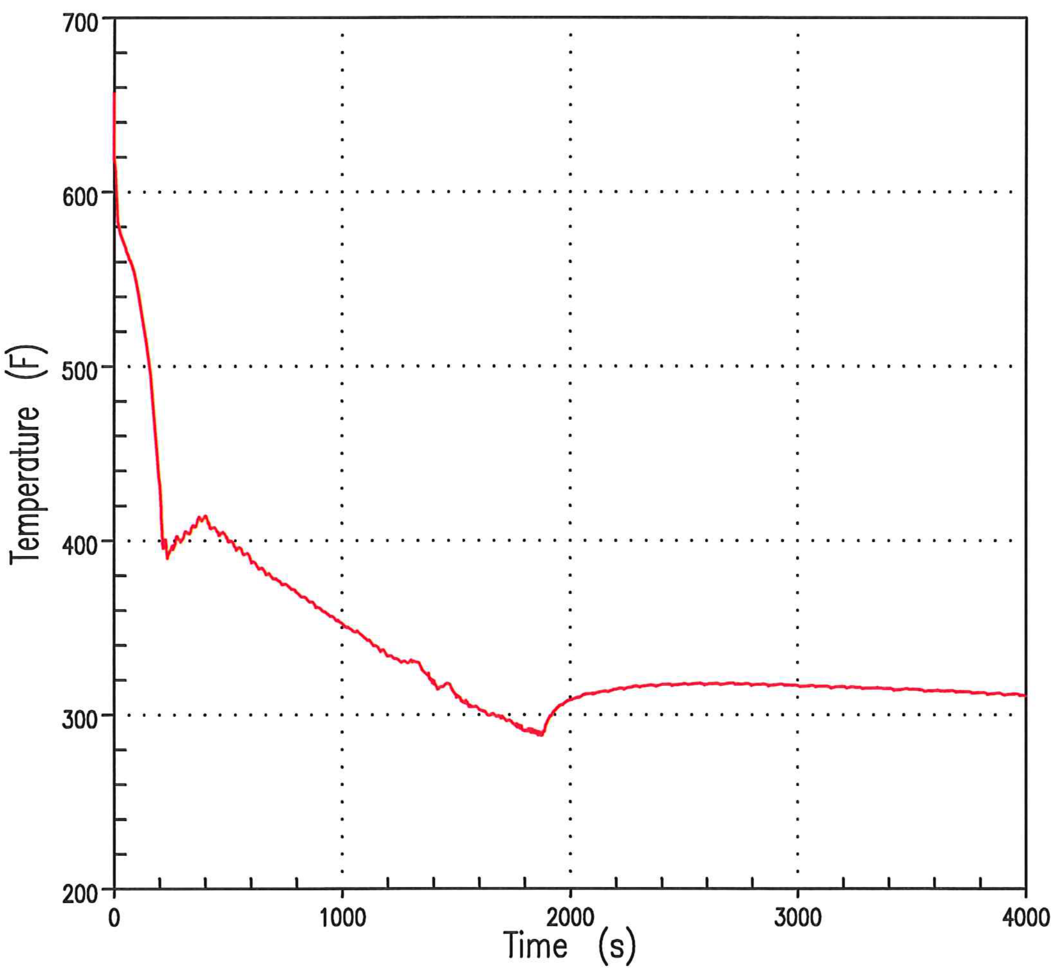


Figure 14.3.1-63 REACTOR COOLANT SYSTEM PRESSURE - 8.75 INCH BREAK
POINT BEACH UNIT 2

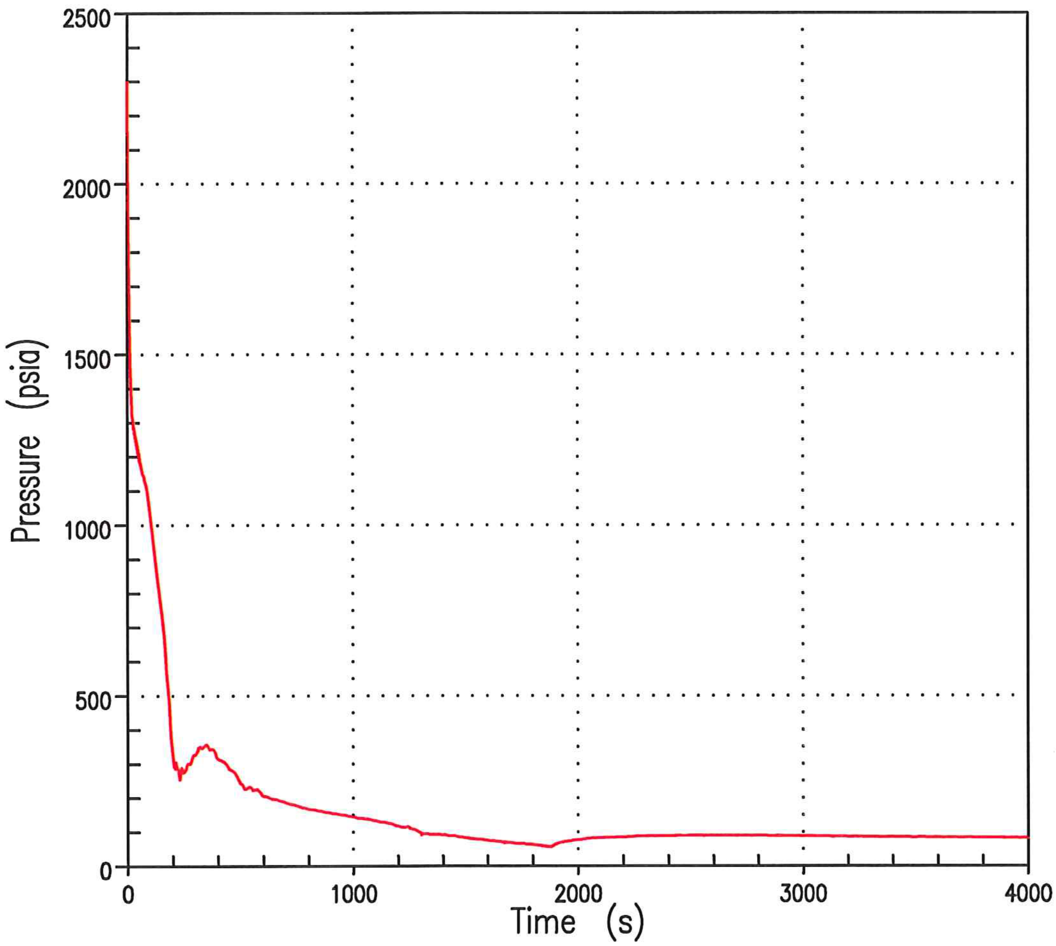


Figure 14.3.1-64 CORE MIXTURE LEVEL AND TOP OF CORE - 8.75 INCH BREAK
POINT BEACH UNIT 2

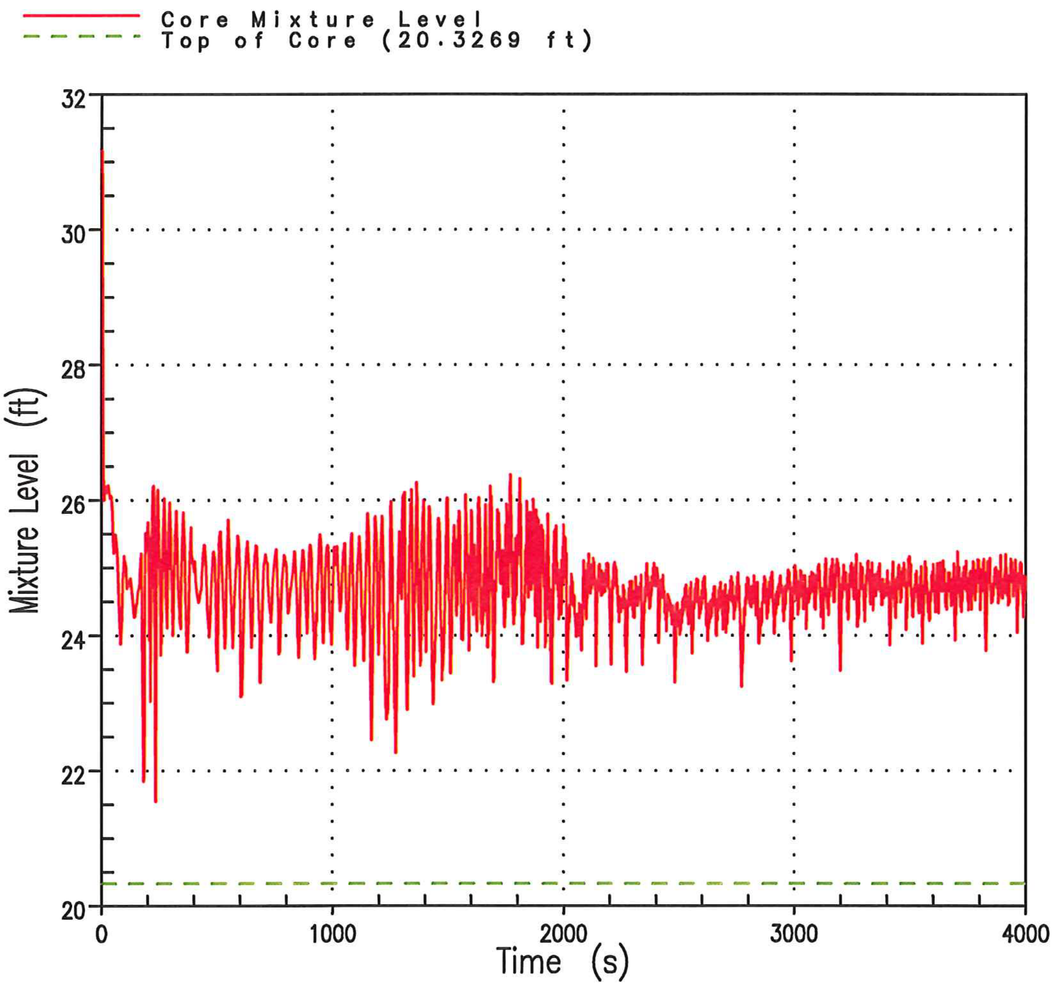
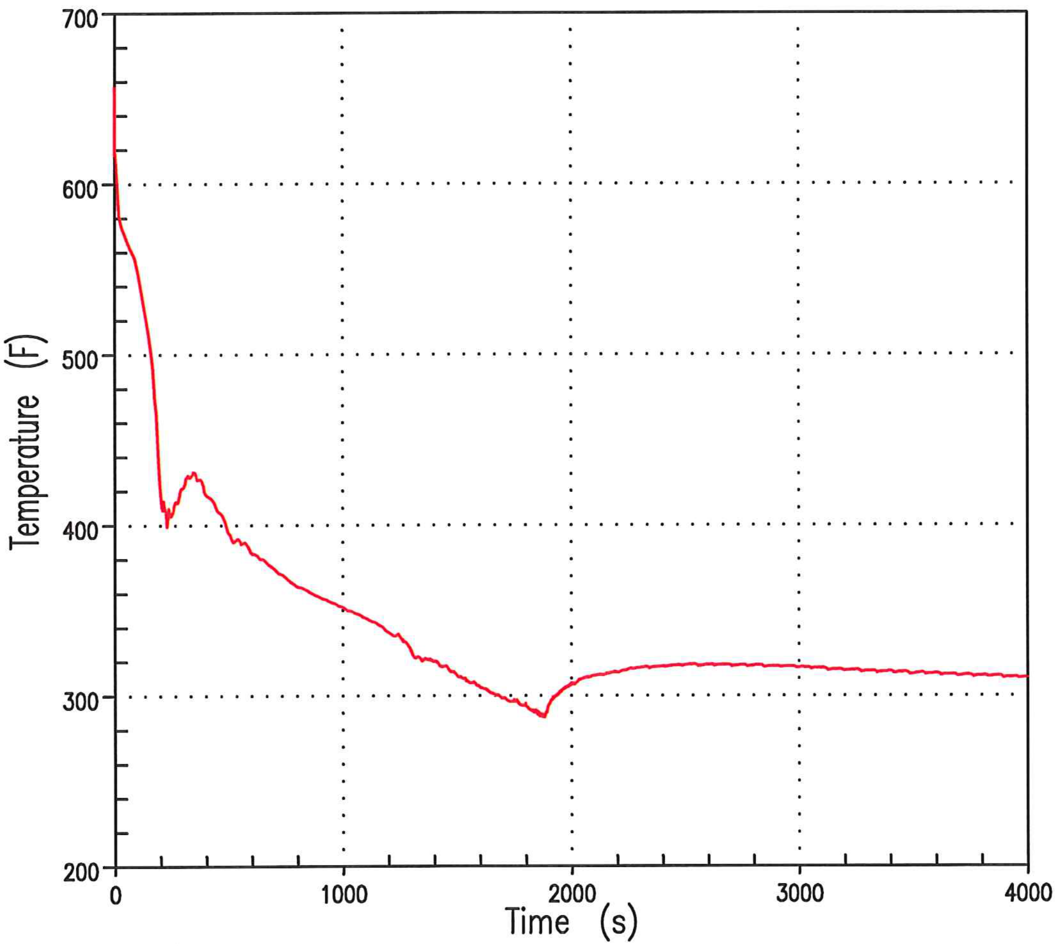


Figure 14.3.1-65 TOP CORE EXIT VAPOR TEMPERATURE - 8.75 INCH BREAK
POINT BEACH UNIT 2



14.3.2 LARGE BREAK LOSS-OF-COOLANT ACCIDENT ANALYSIS

14.3.2.1 Summary

When the Final Acceptance Criteria (FAC) governing the loss-of-coolant accident (LOCA) for Light Water Reactors was issued in Appendix K of 10 CFR 50.46, (Reference 1), both the Nuclear Regulatory Commission (NRC) and the industry recognized that the stipulations of Appendix K were highly conservative. That is, using the then accepted analysis methods, the performance of the Emergency Core Cooling System (ECCS) would be conservatively underestimated, resulting in predicted Peak Clad Temperatures (PCTs) much higher than expected. At that time, however, the degree of conservatism in the analysis could not be quantified. As a result, the NRC began a large-scale confirmatory research program with the following objectives:

1. Identify, through separate effects and integral effects experiments, the degree of conservatism in those models permitted in the Appendix K rule. In this fashion, those areas in which a purposely prescriptive approach was used in the Appendix K rule could be quantified with additional data so that a less prescriptive future approach might be allowed.

2. Develop improved thermal-hydraulic computer codes and models so that more accurate and realistic accident analysis calculations could be performed. The purpose of this research was to develop an accurate predictive capability so that the uncertainties in the ECCS performance and the degree of conservatism with respect to the Appendix K limits could be quantified.

Since that time, the NRC and the nuclear industry have sponsored reactor safety research programs directed at meeting the above two objectives. The overall results have quantified the conservatism in the Appendix K rule for LOCA analyses and confirmed that some relaxation of the rule can be made without a loss in safety to the public. It was also found that some plants were being restricted in operating flexibility by the overly conservative Appendix K requirements. In recognition of the Appendix K conservatism that was being quantified by the research programs, the NRC adopted an interim approach for evaluation methods. This interim approach is described in SECY-83-472, (Reference 2). The SECY-83-472 approach retained those features of Appendix K that were legal requirements, but permitted applicants to use best-estimate thermal-hydraulic models in their ECCS evaluation model. Thus, SECY-83-472 represented an important step in basing licensing decisions on realistic calculations, as opposed to those calculations prescribed by Appendix K.

In 1998, the NRC Staff amended the requirements of 10 CFR 50.46 and Appendix K, “ECCS Evaluation Models,” to permit the use of a realistic evaluation model to analyze the performance of the ECCS during a hypothetical LOCA. This decision was based on an improved understanding of LOCA thermal-hydraulic phenomena gained by extensive research programs. Under the amended rules, best-estimate thermal-hydraulic models may be used in place of models with Appendix K features. The rule change also requires, as part of the LOCA analysis, an assessment of the uncertainty of the best-estimate calculations. It further requires that this analysis uncertainty be included when comparing the results of the calculations to the prescribed acceptance criteria of 10 CFR 50.46. Further guidance for the use of best-estimate codes is provided in Regulatory Guide 1.157, (Reference 3).

To demonstrate use of the revised ECCS rule, the NRC and its consultants developed a method called the Code Scaling, Applicability, and Uncertainty (CSAU) evaluation methodology, NUREG/CR-5249, (Reference 4). This method outlined an approach for defining and qualifying a best-estimate thermal-hydraulic code and quantifying the uncertainties in a LOCA analysis.

A LOCA evaluation methodology for three- and four-loop Pressurized Water Reactor (PWR) plants based on the revised 10 CFR 50.46 rules was developed by Westinghouse with the support of EPRI and Consolidated Edison and has been approved by the NRC in WCAP-12945-P-A, (Reference 5). This methodology was later extended to Westinghouse two-loop plants equipped with upper plenum injection (UPI) as documented in WCAP-14449-P-A, (Reference 9).

More recently, Westinghouse developed an alternative uncertainty methodology called ASTRUM, which stands for Automated Statistical TReatment of Uncertainty Method as documented in WCAP-16009-P-A, (Reference 6). This method is still based on the Code Qualification Document (CQD) methodology and follows the steps in the CSAU methodology in NUREG/CR-5249. However, the uncertainty analysis (Element 3 in the CSAU) is replaced by a technique based on order statistics. The ASTRUM methodology replaces the response surface technique with a statistical sampling method where the uncertainty parameters are simultaneously sampled for each case. The ASTRUM methodology has received NRC approval for referencing in licensing calculations in WCAP-16009-P-A.

The three 10 CFR 50.46 criteria (peak clad temperature, maximum local oxidation, and core-wide oxidation) are satisfied by running a sufficient number of WCOBRA/TRAC calculations (sample size). In particular, the statistical theory predicts that 124 calculations are required to simultaneously bound the 95th percentile values of three parameters with a 95-percent confidence level.

This analysis is in accordance with the applicability limits and usage conditions defined in Section 13-3 of WCAP-16009-P-A, (Reference 6) as applicable to the ASTRUM methodology. Section 13-3 of WCAP-16009-P-A was found to acceptably disposition each of the identified conditions and limitations related to WCOBRA/TRAC and the CQD uncertainty approach per Section 4.0 of the ASTRUM Final Safety Evaluation Report appended to the topical report.

14.3.2.2 Method of Analysis

The methods used in the application of WCOBRA/TRAC to the large break LOCA with ASTRUM are described in WCAP-12945-P-A and WCAP-16009-P-A. A detailed assessment of the computer code WCOBRA/TRAC was made through comparisons to experimental data. These assessments were used to develop quantitative estimates of the code's ability to predict key physical phenomena in a PWR large break LOCA. Modeling of a PWR introduces additional uncertainties which are identified and quantified in the plant-specific analysis. WCOBRA/TRAC MOD7A was used for the execution of ASTRUM for Point Beach Units 1 and 2.

WCOBRA/TRAC combines two-fluid, three-field, multi-dimensional fluid equations used in the vessel with one-dimensional drift-flux equations used in the loops to allow a complete and detailed simulation of a PWR. This best-estimate computer code contains the following features:

1. Ability to model transient three-dimensional flows in different geometries inside the vessel

2. Ability to model thermal and mechanical non-equilibrium between phases

3. Ability to mechanistically represent interfacial heat, mass, and momentum transfer in different flow regimes

4. Ability to represent important reactor components such as fuel rods, steam generators, reactor coolant pumps, etc.

A typical calculation using WCOBRA/TRAC begins with the establishment of a steady-state, initial condition with all loops intact. The input parameters and initial conditions for this steady-state calculation are discussed in the next section.

Following the establishment of an acceptable steady-state condition, the transient calculation is initiated by introducing a break into one of the loops. The evolution of the transient through blowdown, refill, and reflood proceeds continuously, using the same computer code (WCOBRA/TRAC) and the same modeling assumptions. Containment pressure is modeled with the BREAK component using a time dependent pressure table. Containment pressure is calculated using the COCO code as described in WCAP-8327 (Proprietary) and WCAP-8326 (Non-Proprietary), (Reference 7) and mass and energy releases from the WCOBRA/TRAC calculation.

The final step of the best-estimate methodology, in which all uncertainties of the LOCA parameters are accounted for to estimate a PCT, Local Maximum Oxidation (LMO), and Core-Wide Oxidation (CWO) at 95- percent probability, is described in the following sections.

1) Plant Model Development:

In this step, a WCOBRA/TRAC model of the plant is developed. A high level of noding detail is used in order to provide an accurate simulation of the transient. However, specific guidelines are followed to ensure that the model is consistent with models used in the code validation. This results in a high level of consistency among plant models, except for specific areas dictated by hardware differences, such as in the upper plenum of the reactor vessel or the ECCS injection configuration.

2. Determination of Plant Operating Conditions:

In this step, the expected or desired operating range of the plant to which the analysis applies is established. The parameters considered are based on a “key LOCA parameters” list that was developed as part of the methodology. A set of these parameters, at mostly nominal values, is chosen for input as initial conditions to the plant model. A transient is run utilizing these parameters and is known as the “initial transient.” Next, several confirmatory runs are made, which vary a subset of the key LOCA parameters over their expected operating range in one-at-a-time sensitivities. Because certain parameters are not included in the uncertainty analysis, these parameters are set at their bounding condition. This analysis is commonly referred to as the confirmatory analysis. The most limiting input conditions, based on these confirmatory runs, are then combined into the model that will represent the limiting state for the plant, which is the starting point for the assessment of uncertainties.

3. Assessment of Uncertainty:

The ASTRUM methodology is based on order statistics. The technical basis of the order statistics is described in Section 11 of WCAP-16009-P-A, (Reference 6). The determination of the PCT uncertainty, LMO uncertainty, and CWO uncertainty relies on a statistical sampling technique. According to the statistical theory, 124 WCOBRA/TRAC calculations are necessary to assess against the three 10 CFR 50.46 criteria (PCT, LMO, CWO).

The uncertainty contributors are sampled randomly from their respective distributions for each of the WCOBRA/TRAC calculations. The list of uncertainty parameters, which are randomly sampled for each time in the cycle, break type (split or double-ended guillotine), and break size for the split break are also sampled as uncertainty contributors within the ASTRUM methodology.

Results from the 124 calculations are tallied by ranking the PCT from highest to lowest. A similar procedure is repeated for LMO and CWO. The highest rank of PCT, LMO, and CWO will bound 95 percent of their respective populations with 95 percent confidence level.

4. Plant Operating Range:

The plant operating range over which the uncertainty evaluation applies is defined. Depending on the results obtained in the above uncertainty evaluation, this range may be the desired range or may be narrower for some parameters to gain additional margin.

The Large Break LOCA analysis was performed with ZIRLO® cladding. However, Reference 17 concluded that the LOCA ZIRLO models are acceptable for application to Optimized ZIRLO™ cladding in the Large Break analysis, and that no additional calculations are necessary for evaluating the use of Optimized ZIRLO™ cladding provided that plant specific ZIRLO claculations were previously performed.

14.3.2.3 Analysis Assumptions

Two ASTRUM analyses were executed: one for Point Beach Unit 1 and one for Point Beach Unit 2. The expected PCT and its uncertainty developed are valid for a range of plant operating conditions. The range of variation of the operating parameters has been accounted for in the uncertainty evaluation. Table 14.3.2-1 summarizes the operating ranges as defined for the proposed operating conditions which are supported by the Best-Estimate LBLOCA analyses for Point Beach Units 1 and 2. If operation is maintained within these ranges, the LBLOCA results developed in this report using WCOBRA/TRAC are considered to be valid. Note that some of these parameters vary over their range during normal operation (accumulator temperature) and other ranges are fixed for a given operational condition (T_{avg}). Table 14.3.2-2, Table 14.3.2-3, and Table 14.3.2-4 summarize the LBLOCA containment data used for calculating containment pressure (for both units). Nominal values are used for containment initial temperature and pressure (Reference 12).

14.3.2.4 Design Basis Accident

The Point Beach Units 1 and 2 PCT-limiting transients are split break transients which analyze conditions that fall within those listed in Table 14.3.2-1. Traditionally, cold leg breaks have been limiting for large break LOCA. This location is the one where flow stagnation in the core appears most likely to occur.

The large break LOCA transient can be divided into convenient time periods in which specific phenomena occur, such as various hot assembly heatup and cooldown transients. For a typical large break, the blowdown period can be divided into the Critical Heat Flux (CHF) phase, the upward core flow phase, and the downward core flow phase. These are followed by the refill, reflood, and long-term cooling periods. Specific important transient phenomena and heat transfer regimes are discussed below, with the transient results shown in Figure 14.3.2-1 to Figure 14.3.2-14 for Unit 1 and Figure 14.3.2-15 to Figure 14.3.2-28 for Unit 2. The PCT-limiting case for each unit was chosen to show a conservative representation of the response to a large break LOCA.

1. Critical Heat Flux (CHF) Phase:

Immediately following the cold leg rupture, the break discharge rate is subcooled and high (Figure 14.3.2-2, Figure 14.3.2-3 for Unit 1 and Figure 14.3.2-16, Figure 14.3.2-17 for Unit 2). The regions of the RCS with the highest initial temperatures (core, upper plenum, upper head, and hot legs) begin to flash to steam, the core flow reverses and the fuel rods begin to go through departure from nucleate boiling (DNB). The fuel cladding rapidly heats up (Figure 14.3.2-1 for Unit 1 and Figure 14.3.2-15 for Unit 2) while the core power shuts down due to voiding in the core. This phase is terminated when the water in the lower plenum and downcomer begins to flash (Figure 14.3.2-7 and Figure 14.3.2-12 for Unit 1 and Figure 14.3.2-21 and Figure 14.3.2-26 for Unit 2, respectively). The mixture swells and intact loop pumps, still rotating in single-phase liquid, push this two-phase mixture into the core.

2. Upward Core Flow Phase:

Heat transfer is improved as the two-phase mixture is pushed into the core. This phase may be enhanced if the pumps are not degraded, or if the break discharge rate is low due to saturated fluid conditions at the break. If pump degradation is high or the break flow is large, the cooling effect due to upward flow may not be significant. Figure 14.3.2-4 (Unit 1) and Figure 14.3.2-18 (Unit 2) show the void fraction for one intact loop pump and the broken loop pump. Each figure shows that the intact loop remains in single-phase liquid flow for several seconds, resulting in enhanced upward core flow cooling. This phase ends as the lower plenum mass is depleted, the loop flow becomes two-phase, and the pump head degrades.

3. Downward Core Flow Phase:

The loop flow is pushed into the vessel by the intact loop pump and decreases as the pump flow becomes two-phase. The break flow begins to dominate and pulls flow down through the core, up the downcomer to the broken loop cold leg, and out the break. While liquid and entrained liquid flow provide core cooling, the top third of core vapor flow (Figure 14.3.2-5 for Unit 1 and Figure 14.3.2-19 for Unit 2) best illustrates this phase of core cooling. Once the system has depressurized to the accumulator pressure (Figure 14.3.2-6 for Unit 1 and Figure 14.3.2-20 for Unit 2), the accumulators begin to inject cold borated water into the intact cold legs (Figure 14.3.2-9 for Unit 1 and Figure 14.3.2-23 for Unit 2). During this period, due to steam upflow in the downcomer, a portion of the injected ECCS water is calculated to be bypassed around the downcomer and out the break. As the system pressure continues to fall, the break flow, and consequently the downward core flow, is reduced. The core begins to heat up as the system pressure approaches the containment pressure and the vessel begins to fill with ECCS water (Figure 14.3.2-8 for Unit 1 and Figure 14.3.2-22 for Unit 2).

4. Refill Period:

As the refill period begins, the core begins a period of heatup and the vessel begins to fill with ECCS water (Figure 14.3.2-9, Figure 14.3.2-10A and Figure 14.3.2-10B for Unit 1 and Figure 14.3.2-23, Figure 14.3.2-24A and Figure 14.3.2-24B for Unit 2). This period is characterized by a rapid increase in cladding temperatures at all elevations due to the lack of liquid and steam flow in the core region. This period continues until the lower plenum is filled and the bottom of the core begins to reflood and entrainment begins.

5. Reflood Period:

During the early reflood phase, the accumulators begin to empty and nitrogen enters the system. This forces water into the core, which then boils, causing system re-pressurization, and the lower core region begins to quench (Figure 14.3.2-11 for Unit 1 and Figure 14.3.2-25 for Unit 2). During this time, core cooling may increase due to vapor generation and liquid entrainment. During the reflood period, the core flow is oscillatory as cold water periodically rewets and quenches the hot fuel cladding, which generates steam and causes system re-pressurization. The steam and entrained water must pass through the vessel upper plenum, the hot legs, the steam generators, and the reactor coolant pumps before it is vented out of the break. This flow path resistance is overcome by the downcomer water elevation head, which provides the gravity driven reflood force. From the later stage of blowdown to the beginning of reflood, the accumulators rapidly discharge borated cooling water into the RCS, filling the lower plenum and contributing to the filling of the downcomer. The pumped ECCS water aids in the filling of the downcomer and subsequently supplies water to maintain a full downcomer and complete the reflood period. As the quench front progresses up the core, the PCT location moves higher into the top core region. As the vessel continues to fill, the PCT location is cooled and the early reflood period is terminated.

A second cladding heatup transient may occur due to boiling in the downcomer. The mixing of ECCS water with hot water and steam from the core, in addition to the continued heat transfer from the hot vessel and vessel metal, reduces the subcooling of ECCS water in the lower plenum and downcomer. The saturation temperature is dictated by the containment pressure. If the liquid temperature in the downcomer reaches saturation, subsequent heat transfer from the vessel and other structures will cause boiling and level swell in the downcomer. The downcomer liquid will spill out of the broken cold leg and reduce the driving head, which can reduce the reflood rate, causing a late reflood heatup at the upper core elevations. Figure 14.3.2-12 (Unit 1) and Figure 14.3.2-26 (Unit 2) show only a slight reduction in downcomer level and indicates that a late reflood heatup does not occur.

14.3.2.5 Post Analysis of Record Evaluations

In addition to the analyses presented in this section, evaluations and reanalyses may be performed as needed to address computer code errors and emergent issues, or to support plant changes. The issues or changes are evaluated, and the impact on the Peak Cladding Temperature (PCT) is determined. The resultant increase or decrease in PCT is applied to the analysis of record PCT. The PCT changes due to the evaluation model errors/changes are documented in the 10 CFR 50.46 reports. These PCT changes are not (or may not be) reflected in the PCT documented here. The impact on the analysis of record PCT due to the Thermal Conductivity Degradation (TCD) assessment is presented in Table 14.3.2-5 (Unit 1) and Table 14.3.2-7 (Unit 2) for the large break LOCA. The current PCT is demonstrated to be less than the 10 CFR 50.46(b) requirement of 2200°F.

In addition, 10 CFR 50.46 requires that licensees assess and report the effect of changes to or errors in the evaluation model used in the large break LOCA analysis. These reports constitute addenda to the analysis of record provided in the FSAR until the overall changes become significant as defined by 10 CFR 50.46. If the assessed changes or errors in the evaluation model result in significant changes in calculated PCT, a schedule for formal reanalysis or other action as needed to show compliance will be addressed in the report to the NRC.

Finally, the criteria of 10 CFR 50.46 requires that holders and users of the evaluation models establish a number of definitions and processes for assessing changes in the models or their use. Westinghouse, in consultation with the PWR Owner's Group (PWROG), has developed an approach for compliance with the reporting requirements. This approach is documented in WCAP-13451, (Reference 8). FPL Energy Point Beach provides the NRC with annual and 30-day reports, as applicable, for Point Beach Units 1 and 2. FPL Energy Point Beach intends to provide future reports required by 10 CFR 50.46 consistent with the approach described in WCAP-13451.

14.3.2.6 Conclusions

It must be demonstrated that there is a high level of probability that the limits set forth in 10 CFR 50.46 are met. The demonstration that these limits are met is as follows:

1. The limiting PCT corresponds to a bounding estimate of the 95th percentile PCT at the 95-percent confidence level. Since the resulting PCT for the limiting case is 1975°F for Unit 1 and 1810°F for Unit 2, the analyses confirm that 10 CFR 50.46 acceptance criterion (b)(1), i.e., "Peak Clad Temperature less than 2200°F", is demonstrated. The results are shown in Table 14.3.2-6 for Unit 1 and Table 14.3.2-8 for Unit 2. Impact on the analysis of record PCT due to 10 CFR 50.46 assessments is addressed in Table 14.3.2-5 (Unit 1) and Table 14.3.2-7 (Unit 2) as discussed in Section 14.3.2.5.

2. The maximum cladding oxidation corresponds to a bounding estimate of the 95th percentile Local Maximum Oxidation (LMO) at the 95-percent confidence level. Since the resulting LMO for the limiting case is 2.61 percent for Unit 1 and 2.57 percent for Unit 2, the analyses confirm that 10 CFR 50.46 acceptance criterion (b)(2), i.e., "Local Maximum Oxidation of the cladding less than 17 percent," is demonstrated. The results are shown in Table 14.3.2-6 for Unit 1 and Table 14.3.2-8 for Unit 2.

3. The limiting Core-Wide Oxidation (CWO) corresponds to a bounding estimate of the 95th percentile CWO at the 95-percent confidence level. The limiting Hot Assembly Rod (HAR) total maximum oxidation is 0.386 percent for Unit 1 and 0.154 percent for Unit 2. A detailed CWO calculation takes advantage of the core power census that includes many lower power assemblies. Because there is significant margin to the regulatory limit, the CWO value can be conservatively chosen as that calculated for the limiting HAR. A detailed CWO calculation is therefore not needed because the outcome will always be less than the HAR value. Since the resulting HAR is less than 1.0 percent, the analyses confirm that 10 CFR 50.46 acceptance criterion (b)(3), i.e., "Core-Wide Oxidation less than 1 percent," is demonstrated. The results are shown in Table 14.3.2-6 for Unit 1 and Table 14.3.2-8 for Unit 2.

4. 10 CFR 50.46 acceptance criterion (b)(4) requires that the calculated changes in core geometry are such that the core remains amenable to cooling. This criterion has historically been satisfied by adherence to criteria (b)(1) and (b)(2), and by assuring that fuel deformation due to combined LOCA and seismic loads is specifically addressed. It has been demonstrated that the PCT and maximum cladding oxidation limits remain in effect for Best-Estimate LOCA applications. The approved methodology in WCAP-12945-P-A specifies that effects of LOCA and seismic loads on core geometry do not need to be considered unless grid crushing extends beyond the peripheral assemblies. The actions, automatic or manual, that are currently in place at these plants to maintain long-term cooling remain unchanged with the application of the ASTRUM methodology as documented in WCAP-16009-P-A.

5. 10 CFR 50.46 acceptance criterion (b)(5) requires that long-term core cooling be provided following the successful initial operation of the ECCS. Long-term cooling is dependent on the demonstration of continued delivery of cooling water to the core. The actions, automatic or manual, that are currently in place at these plants to maintain long-term cooling remain unchanged with the application of the ASTRUM methodology as documented in WCAP-16009-P-A, (Reference 6).

Based on the ASTRUM Analyses results (Table 14.3.2-6 and Table 14.3.2-8), it is concluded that Point Beach Units 1 and 2 continue to maintain a margin of safety to the limits prescribed by 10 CFR 50.46.

14.3.2.7 References

1. 10 CFR 50.46, “Acceptance Criteria for Emergency Core Cooling Systems for Light Water Cooled Nuclear Power Reactors,” and 10 CFR 50 Appendix K, “ECCS Evaluation Models,” both dated January 4, 1974.

2. NRC Staff Report, “Emergency Core Cooling System Analysis Methods,” USNRC-SECY-83-472, November 1983.

3. USNRC Regulatory Guide 1.157, “Best-Estimate Calculations of Emergency Core Cooling System Performances,” May 1989.

4. NUREG/CR-5249, “Qualifying Reactor Safety Margins: Application of Code Scaling Applicability and Uncertainty (CSAU) Evaluation Methodology to a Large Break Loss-of-Coolant-Accident,” 1989.

5. WCAP 12945-P-A (Proprietary), Volume I, Revision 2, and Volumes II-V, Revision 1, “Westinghouse Code Qualification Document for Best Estimate Loss of Coolant Accident Analysis,” 1998.

6. WCAP-16009-P-A, “Realistic Large-Break LOCA Evaluation Methodology Using the Automated Statistical Treatment of Uncertainty Method (ASTRUM),” (Proprietary), January 2005.

7. WCAP-8327 (Proprietary) and WCAP-8326 (Non-Proprietary), “Containment Pressure Analysis Code (COCO),” July 1974.

8. WCAP-13451, "Westinghouse Methodology for Implementation of 10 CFR 50.46 Reporting," October 1992.

9. WCAP-14449-P-A, Revision 1, "Application of Best-Estimate Large-Break LOCA Methodology to Westinghouse PWRs with Upper Plenum Injection," 1999.

10. EC 12604, "Install Debris Interceptors - Unit 1," dated January 13, 2009

11. EC 14534, "GSI 191 Unit 1 Sump B Modifications."

12. Letter WEP-10-105, Westinghouse to NextEra Energy Resources, "Report Request: Technical Evaluation of Containment Internal Temperature Assumptions for LBLOCA Analysis," dated October 19, 2010.

13. NRC Safety Evaluation for License Amendments 235 and 239, "ASTRUM Implementation for Large Break LOCA Analysis," dated October 29, 2009.

14. Westinghouse CALC Note CN-LIS-08-91, "Point Beach Extended Power Uprate BELOCA ASTRUM Analysis: Units 1 and 2 (WEP/WIS) Uncertainty Analysis," dated September 29, 2008.

15. Letter NRC 2009-0027, FPL Energy to NRC, "Response to Request for Additional Information License Amendment Request 258, Incorporate Best Estimate Large Break Loss of Coolant Accident (LOCA) Analysis Using ASTRUM," dated March 4, 2009.

16. Letter NRC 2012-0038, NextEra Energy to NRC, "ECCS 30-Day Report for the Thermal Conductivity Degradation Impact on Point Beach Nuclear Plants Units 1 and 2 Large Break Loss of Coolant Accident Analysis with ASTRUM," dated May 30, 2012.

17. WCAP-12610-P-A and CENPD-404-P-A Addendum 1-A, "Optimized ZIRLO™, July 2006.

Table 14.3.2-1 PLANT OPERATING RANGE ANALYZED BY THE BEST-ESTIMATE LARGE BREAK LOCA ANALYSIS (Sheet 1 of 2)

Parameter		As-Analyzed Value or Range
1.0	Plant Physical Description	
	Dimensions	Nominal
	Pressurizer location	Assumed on Broken Loop
	Hot assembly location	Anywhere in core interior (1)
	Hot assembly type	14x14 422V+ fuel with ZIRLO ® (6) cladding, IFM
	Steam generator tube plugging level	≤10%
	Fuel assembly type	14x14 422V+ fuel with ZIRLO ® (6) cladding, IFM
	Steam generator type	U1: Model 44F U2: Model Delta-47
2.0	Plant Initial Operating Conditions	
	2.1 Reactor Power	
	Core power (5)	1811 MWt (100.6% of 1800 MWt)
	Peak heat flux hot channel factor (F_Q)	≤ 2.6
	Peak hot rod enthalpy rise hot channel factor ($F_{\Delta H}$)	≤ 1.68
	Hot assembly radial peaking factor ($\overline{P}_{HA}$)	$\leq 1.68/1.04$
	Hot assembly heat flux hot channel factor (F_{QHA})	$\leq 2.6/1.04$
	Axial power distribution (P_{BOT}, P_{MID})	U1: Figure 14.3.2-13 U2: Figure 14.3.2-27
	Low power region relative power (P_{LOW})	$0.2 \leq P_{LOW} \leq 0.6$
	Hot assembly burnup	≤ 75,000 MWD/MTU, lead rod (1)(3)
	MTC	≤ 0 at hot full power (HFP)
	Typical cycle average burnup	20,000 MWD/MTU
	Minimum core average burnup	≥ 10,000 MWD/MTU
	Maximum steady state depletion, F_Q	2.1
	2.2 Fluid Conditions	
	T_{AVG}	$558.0 - 6.4°F \leq T_{AVG} \leq 577.0 + 6.4°F$
	Pressurizer pressure	$2250 - 50$ psia $\leq P_{RCS} \leq 2250 + 50$ psia
	Loop flow	TDF ≥ 89,000 gpm/loop
	Upper head temperature	Function of T_{AVG}, Between T_{AVG} and T_{HOT}
	Pressurizer level	31% of span at Low T_{AVG} 50% of span at Hi T_{AVG}
	Accumulator temperature	60°F ≤ TACC ≤ 120°F
	Accumulator pressure	689.7 psia ≤ PACC ≤ 839.7 psia
	Accumulator liquid volume	1068 ft^3 ≤ VACC ≤ 1168 ft^3
	Accumulator fL/D (2)	7.056 +/- 20%
	Minimum accumulator boron	2600 ppm
3.0	Accident Boundary Conditions	
	Minimum safety injection flow	Table 14.3.2-9
	Safety injection temperature	32°F ≤ SI Temp ≤ 120°F

Table 14.3.2-1 PLANT OPERATING RANGE ANALYZED BY THE BEST-ESTIMATE LARGE BREAK LOCA ANALYSIS (Sheet 2 of 2)

	Safety injection delay [4]	High Head: 13 seconds (with no-LOOP) 28 seconds (with LOOP) Low Head: 23.7 seconds (with no-LOOP) 37 seconds (with LOOP)
	Containment modeling	See Table 14.3.2-2, Table 14.3.2-3, and Table 14.3.2-4
	Minimum containment pressure	See Table 14.3.2-2
	Containment spray initiation delay	See Table 14.3.2-2
	Recirculation spray initiation delay	See Table 14.3.2-2
	Single failure	Loss of one ECCS train

Notes:

1. 24 peripheral locations will not physically be lead power assembly.
2. Based on average L/D of 504.0
3. Please note that the fuel temperature and rod internal pressure data is only provided up to 62,000 MWD/MTU. In addition, the hot assembly/hot rod will not have a burnup this high in the ASTRUM analyses.
4. The BELOCA analysis originally modeled a High Head Safety Injection (HHSI) delay of 8 seconds with no-LOOP and 23 seconds with LOOP. However, the additional 5 second delay for HHSI was evaluated as negligible and thus the values of 13 and 28 seconds are reflected herein (See Page 82 of Reference 14).
5. It has been shown that LOCA analysis input values at 1811 MWt conservatively bound operation at lower power levels (Reference 13 and Reference 15).
6. Optimized ZIRLO™ fuel cladding has been evaluated as an acceptable fuel cladding.

Table 14.3.2-2 LARGE BREAK LOCA CONTAINMENT DATA USED FOR CALCULATION OF CONTAINMENT PRESSURE

Containment Net Free Volume	1,118,250 ft^3
Initial Conditions	
Initial containment pressure at full power operation	14.7 psia
Initial containment temperature at full power	90.0°F
Minimum RWST temperature	32.0°F
Minimum temperature outside containment	-25.0°F
Initial spray temperature	32.0°F
Spray System	
Number of containment spray pumps operating	2
Minimum post-accident spray system initiation delay	10 sec
Maximum spray system flow from all containment spray pumps	3900 gal/min
Fan Coolers	
Maximum number of containment fan coolers in operation	4
Minimum post-accident containment fan cooler initiation delay	0 sec
Fan Cooler Performance	See Table 14.3.2-3
Recirculation Spray	Not Modeled

Table 14.3.2-3 CONTAINMENT FAN COOLER HEAT REMOVAL RATE FOR ECCS CONTAINMENT BACKPRESSURE ANALYSIS

Containment Temperature (°F)	Heat Removal Rate for One Fan Cooler (Btu/sec)
120	3718
160	8893
190	14,953
210	19,425
220	21,558
240	25,539
260	29,047
270	30,725

Table 14.3.2-4 STRUCTURAL HEAT SINK DATA FOR ECCS CONTAINMENT BACKPRESSURE ANALYSIS (Sheet 1 of 4)

Heat Sink	Description(2)	Area (ft^2)	Material(1)	Thickness (inches)
1	Upper Dome	1,883.7	Paint Type 1	0.01404
			Carbon Steel	0.2496
			Gap	0.021
			Concrete	36
2	Middle Dome	6,917.0	Paint Type 1	0.01404
			Carbon Steel	0.2496
			Gap	0.021
			Concrete	36
3	Lower Dome	7,525.4	Paint Type 1	0.01404
			Carbon Steel	0.2496
			Gap	0.021
			Concrete	36
4	Upper Containment outer wall (above 66’)	19,876.0	Paint Type 1	0.015
			Carbon Steel	0.2496
			Gap	0.021
			Concrete	42
5	Middle Containment outer wall (21’ to 66’)	17,367.5	Paint Type 1	0.015
			Carbon Steel	0.2496
			Gap	0.021
			Concrete	42
6	Lower Containment outer wall (8’ to 21’)	4,874.2	Paint Type 1	0.015
			Carbon Steel	0.2496
			Gap	0.021
			Concrete	42
7	Reactor Cavity: Shield wall/Reactor Pit	1,983.2	Paint Type 2	0.039
			Concrete	12
8	Reactor Cavity: tunnel walls	304.2	Paint Type 2	0.039
			Concrete	12
9	Reactor Cavity: Keyway tower/shaft	1,310.4	Paint Type 2	0.039
			Concrete	12
10	Reactor Cavity: Floor slab	413.0	Paint Type 2	0.015
			Concrete	12

Table 14.3.2-4 STRUCTURAL HEAT SINK DATA FOR ECCS CONTAINMENT BACKPRESSURE ANALYSIS (Sheet 2 of 4)

Heat Sink	Description[2]	Area (ft^2)	Material[1]	Thickness (inches)
11	Pressurizer walls (inside 46' to 86')	2,371.6	Paint Type 2	0.039
			Concrete	15
12	Pressurizer floor slab	182.5	Paint Type 2	0.015
			Concrete	24
			Paint Type 2	0.039
13	Pressurizer missile shields	205.9	Paint Type 2	0.039
			Carbon Steel	0.5
			Gap	0.021
			Concrete	15
			Paint Type 1	0.039
14	Upper Containment interior walls	6,341.4	Paint Type 2	0.039
			Concrete	15
15	Upper Containment Floor/ Annular Compartment ceiling	5,076.6	Paint Type 2	0.015
			Concrete	4
16	Annular Compartment: Interior wall (46' to 66')	6,285.2	Paint Type 2	0.039
			Concrete	15
17	Annular Compartment: Interior wall (21' to 46')	9,667.7	Paint Type 2	0.039
			Concrete	15
18	Annular Compartment: laydown area high wall (21' to 66')	684.5	Paint Type 2	0.039
			Concrete	18
19	Annular Compartment 46' floor slab	4,579.4	Paint Type 2	0.015
			Concrete	4
20	Annular Compartment floor/Annular Sump ceiling (21')	4,998.2	Paint Type 2	0.015
			Concrete	4
21	Annular Sump: interior walls (8' to 21')	5,249.8	Paint Type 2	0.039
			Concrete	15
22	Annular Sump floor slab (8')	5,091.8	Paint Type 2	0.015
			Concrete	12
23	Loop A: walls	7,828.5	Paint Type 2	0.039
			Concrete	15
24	Loop A: floor slab	954.7	Paint Type 2	0.015
			Concrete	12

Table 14.3.2-4 STRUCTURAL HEAT SINK DATA FOR ECCS CONTAINMENT BACKPRESSURE ANALYSIS (Sheet 3 of 4)

Heat Sink	Description[2]	Area (ft^2)	Material[1]	Thickness (inches)
25	Loop A: missile shields	293.8	Paint Type 2	0.015
			Concrete	15
			Paint Type 2	0.039
26	Loop B: walls	9,461.8	Paint Type 2	0.039
			Concrete	15
27	Loop B: floor slab	929.0	Paint Type 2	0.015
			Concrete	12
28	Loop B: missile shields	243.4	Paint Type 2	0.015
			Concrete	15
			Paint Type 2	0.039
29	Loop B: sub-pressurizer compartment walls	334.6	Paint Type 2	0.039
			Concrete	15
30	Loop B: sub-pressurizer compartment floor	205.9	Paint Type 2	0.015
			Concrete	24
			Paint Type 2	0.039
31	Refueling cavity wall	5,488.5	Stainless Steel	0.1875
			Gap	0.021
			Concrete	18
			Paint Type 2	0.039
32	Refueling cavity floor/ Annular sump ceiling	627.1	Stainless Steel	0.1875
			Gap	0.021
			Concrete	36
			Paint Type 2	0.039
33	Misc. steel in reactor cavity compartment	780.8	Paint Type 1	0.013
			Carbon Steel	1.263
34	Misc. steel in the pressurizer compartment	1.3	Paint Type 1	0.013
			Carbon Steel	0.005
35	Misc. steel in the upper containment	5,906.5	Paint Type 1	0.013
			Carbon Steel	0.377
36	Misc. steel in the annular compartment	26,333.6	Paint Type 1	0.013
			Carbon Steel	0.396
37	Misc. steel in the annular sump compartment	7,795.5	Paint Type 1	0.013
			Carbon Steel	0.23

Table 14.3.2-4 STRUCTURAL HEAT SINK DATA FOR ECCS CONTAINMENT BACKPRESSURE ANALYSIS (Sheet 4 of 4)

Heat Sink	Description(2)	Area (ft^2)	Material(1)	Thickness (inches)
38	Misc. steel in the Loop A compartment	3,967.0	Paint Type 1	0.013
			Carbon Steel	0.372
39	Misc. steel in the Loop B compartment	3,967.0	Paint Type 1	0.013
			Carbon Steel	0.372
40	Misc. steel in the dome compartment	24,255.6	Paint Type 1	0.013
			Carbon Steel	0.148
41	Misc. steel in refueling cavity compartment	466.0	Paint Type 1	0.013
			Carbon Steel	1.475
42	1 CFC in upper containment compartment; unpainted copper	8,274.1	Copper	0.013
43	1 CFC in upper containment compartment	25.2	Stainless Steel	1.022
44	1 CFC in annular compartment	8,278.3	Copper	0.013
45	Unpainted stainless steel in Annular Compartment; 1 CFC	28.2	Stainless Steel	0.67
46	Polar crane and Rail grider in the upper containment	9,470.5	Paint Type 1	0.013
			Carbon Steel	0.906
47	A Reactor Coolant Pump in the Loop A compartment	667.5	Paint Type 1	0.0079
			Copper	2.583
48	B Reactor Coolant Pump in the Loop B compartment	667.5	Paint Type 1	0.0079
			Copper	2.583
49	Pressurizer Relief Tank Unpainted Stainless Steel	595.5	Stainless Steel	0.67

(1) Paint Type 1 is Amercote 66 top coating with a Dimecote 6 primer coating; Paint Type 2 is Phenoline 305 top coating with a Carboline 195 primer coating.

(2) Debris interceptors were installed in Unit 1 containment, and some were subsequently removed. This added a small amount of steel to the Unit 1 containment heat sink inventory not included in this table. See References 10 and 11.

Table 14.3.2-5 PEAK CLAD TEMPERATURE INCLUDING ALL PENALTIES AND BENEFITS, BEST-ESTIMATE LARGE BREAK LOCA (BE LBLOCA) UNIT 1

PCT for Analysis-of-Record (AOR)	1975°F
Impact due to Thermal Conductivity Degradation[1]	+151°F
BE LBLOCA PCT for Comparison to 10 CFR 50.46 Requirements	2126°F [2]

(1) Per Reference 16.

(2) The PCT changes due to the evaluation model errors/changes are documented in the 10 CFR 50.46 reports. These PCT changes are not (or may not be) reflected in the PCT documented here.

Table 14.3.2-6 UNIT 1 BEST-ESTIMATE LARGE BREAK LOCA RESULTS

10 CFR 50.46 Requirement	Value	Criteria
95/95 PCT[1] (°F)	1975	< 2,200
95/95 LMO[2] (%)	2.61	< 17
95/95 CWO[3] (%)	0.386	< 1

1. Peak Cladding Temperature
2. Local Maximum Oxidation
3. Core-Wide Oxidation

Table 14.3.2-7 PEAK CLAD TEMPERATURE INCLUDING ALL PENALTIES AND BENEFITS, BEST-ESTIMATE LARGE BREAK LOCA (BE LBLOCA) UNIT 2

PCT for Analysis-of-Record (AOR)	1810°F
Impact due to Thermal Conductivity Degradation[1]	+285°F
BE LBLOCA PCT for Comparison to 10 CFR 50.46 Requirements	2095°F [2]

(1) Per Reference 16.

(2) The PCT changes due to the evaluation model errors/changes are documented in the 10 CFR 50.46 reports. These PCT changes are not (or may not be) reflected in the PCT documented here.

Table 14.3.2-8 UNIT 2 BEST-ESTIMATE LARGE BREAK LOCA RESULTS

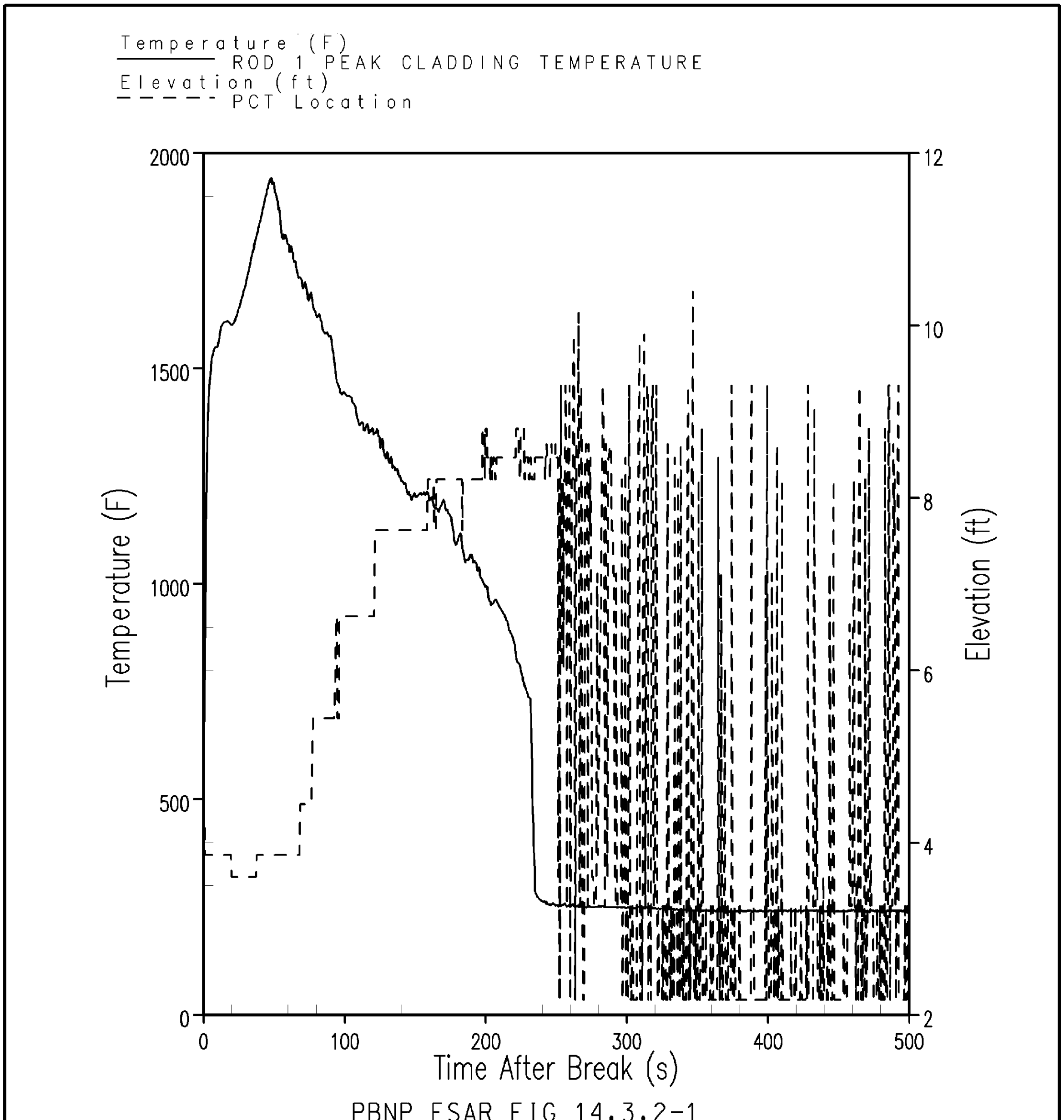
10 CFR 50.46 Requirement	Value	Criteria
95/95 PCT[1] (°F)	1810	< 2,200
95/95 LMO[2] (%)	2.57	< 17
95/95 CWO[3] (%)	0.154	< 1

1. Peak Clad Temperature
2. Local Maximum Oxidation
3. Core-Wide Oxidation

Table 14.3.2-9 INJECTED SAFETY INJECTION FLOW USED IN BEST-ESTIMATE LARGE-BREAK LOCA ANALYSIS FOR UNITS 1 AND 2

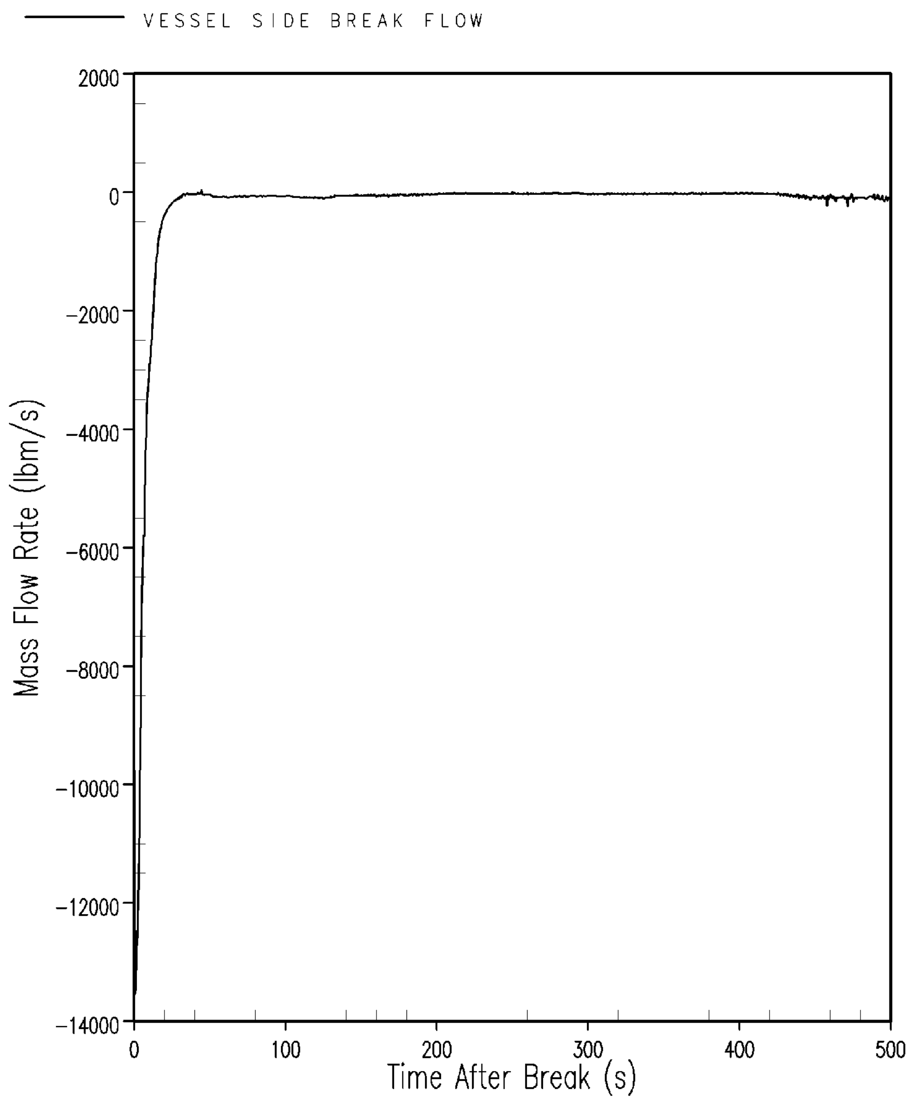
RCS Pressure (psia)	High Head Injected Flow (gpm)	Low Head Injected Flow (gpm)
14.7	439.5	1,693.5
24.7	439.5	1,618.9
34.7	439.5	1,542.1
44.7	439.5	1,460.4
54.7	439.5	1,374.1
64.7	439.5	1,283.7
74.7	439.5	1,187.6
84.7	439.5	1,084.8
94.7	439.5	959.8
104.7	439.5	819.8
114.7	415.5	654.6
214.7	390.5	0
314.7	364.2	0
414.7	336.6	0
514.7	306.0	0
614.7	273.1	0
714.7	237.4	0

Figure 14.3.2-1 UNIT 1 LIMITING PEAK CLAD TEMPERATURE CASE PCT AND PEAK CLAD TEMPERATURE LOCATION



00	07-09-10	INCORP. INTO PDS PER EC #15920	KJB	JLF	KJB
REV NO.	DATE	REVISION DESCRIPTION	DRAWN	CHK'D	APPRV'D

Figure 14.3.2-2 UNIT 1 LIMITING PEAK CLAD TEMPERATURE CASE VESSEL SIDE BREAK FLOW

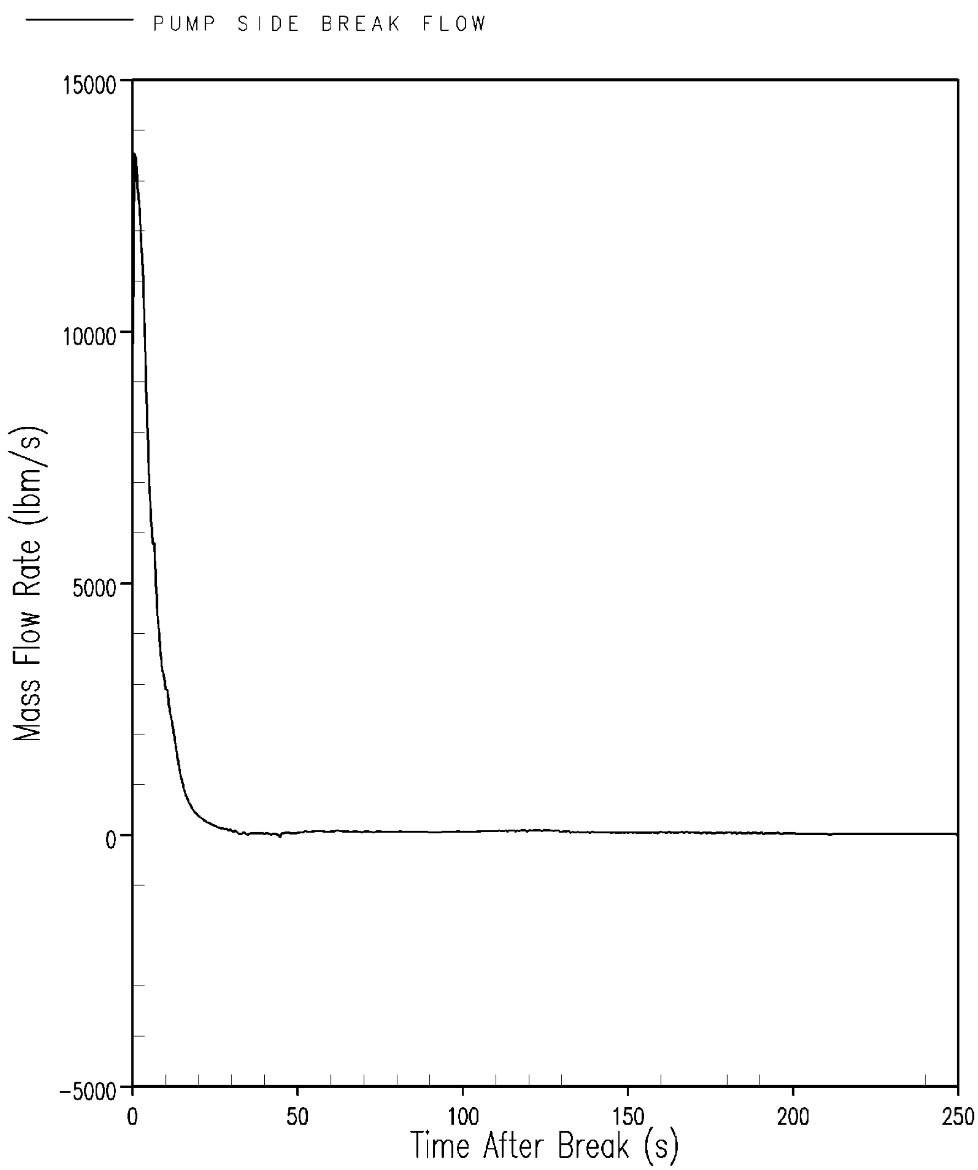


PBNP FSAR FIG 14.3.2-2

00	07-09-10	INCORP. INTO PDS PER EC #15920	KJB	JLF	KJB
REV NO.	DATE	REVISION DESCRIPTION	DRAWN	CHK'D	APPRV'D

UPDATE PRI: 2

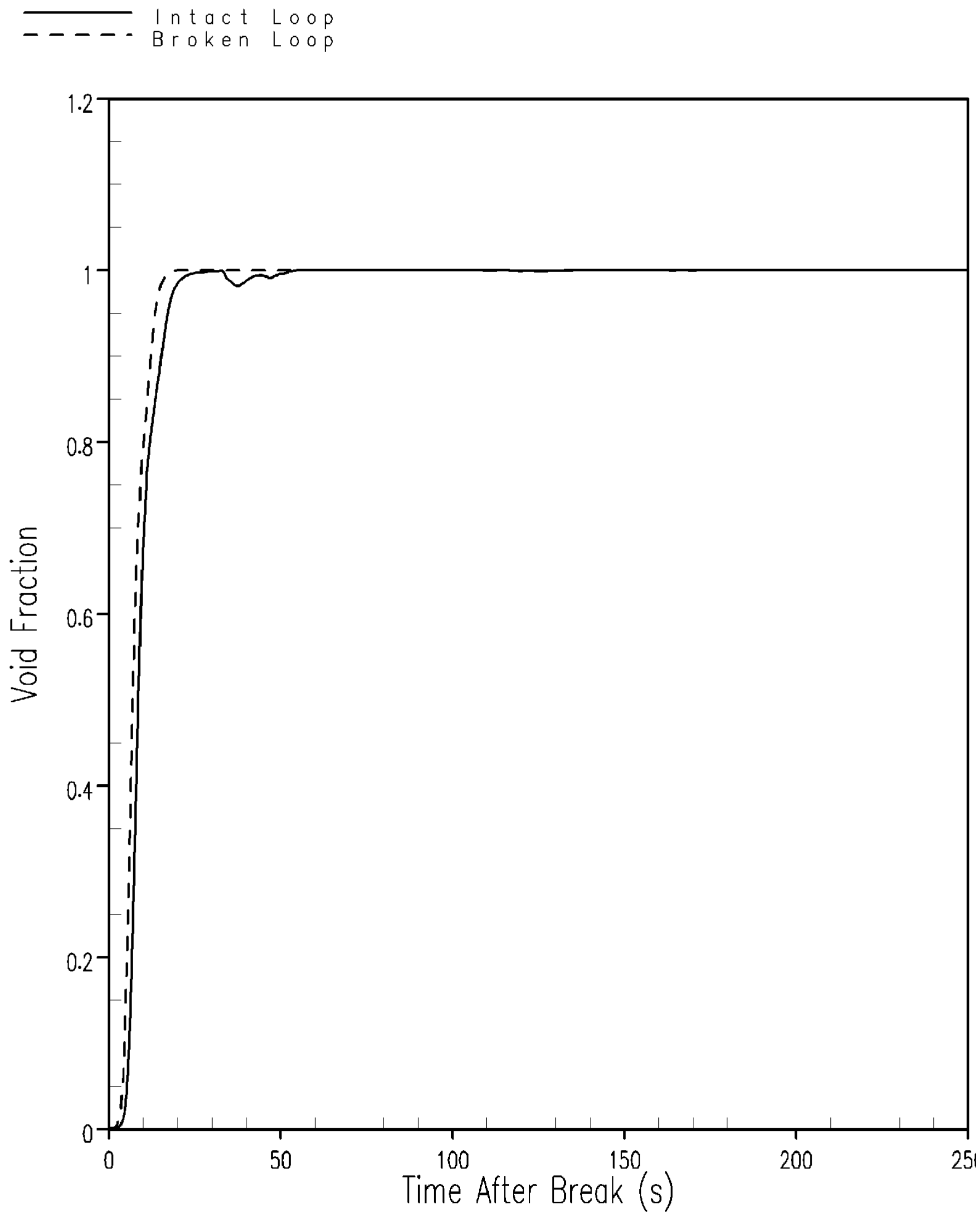
Figure 14.3.2-3 UNIT 1 LIMITING PEAK CLAD TEMPERATURE CASE PUMP SIDE BREAK FLOW



PBNP FSAR FIG 14.3.2-3

00	08-09-10	INCORP. INTO PDS PER EC # 15920	KJB	JLF	KJB
REV NO.	DATE	REVISION DESCRIPTION	DRAWN	CHK'D	APPRV'D

Figure 14.3.2-4 UNIT 1 LIMITING PEAK CLAD TEMPERATURE CASE BROKEN AND INTACT LOOP PUMP VOID FRACTION



PBNP FSAR FIG 14.3.2-4

00	08-09-10	INCORP. INTO PDS PER EC #15920	KJB	JLF	KJB
REV NO.	DATE	REVISION DESCRIPTION	DRAWN	CHK'D	APPRV'D

UPDATE PRI: 2

Figure 14.3.2-5 UNIT 1 LIMITING PEAK CLAD TEMPERATURE CASE HOT ASSEMBLY TOP THIRD OF CORE VAPOR FLOW

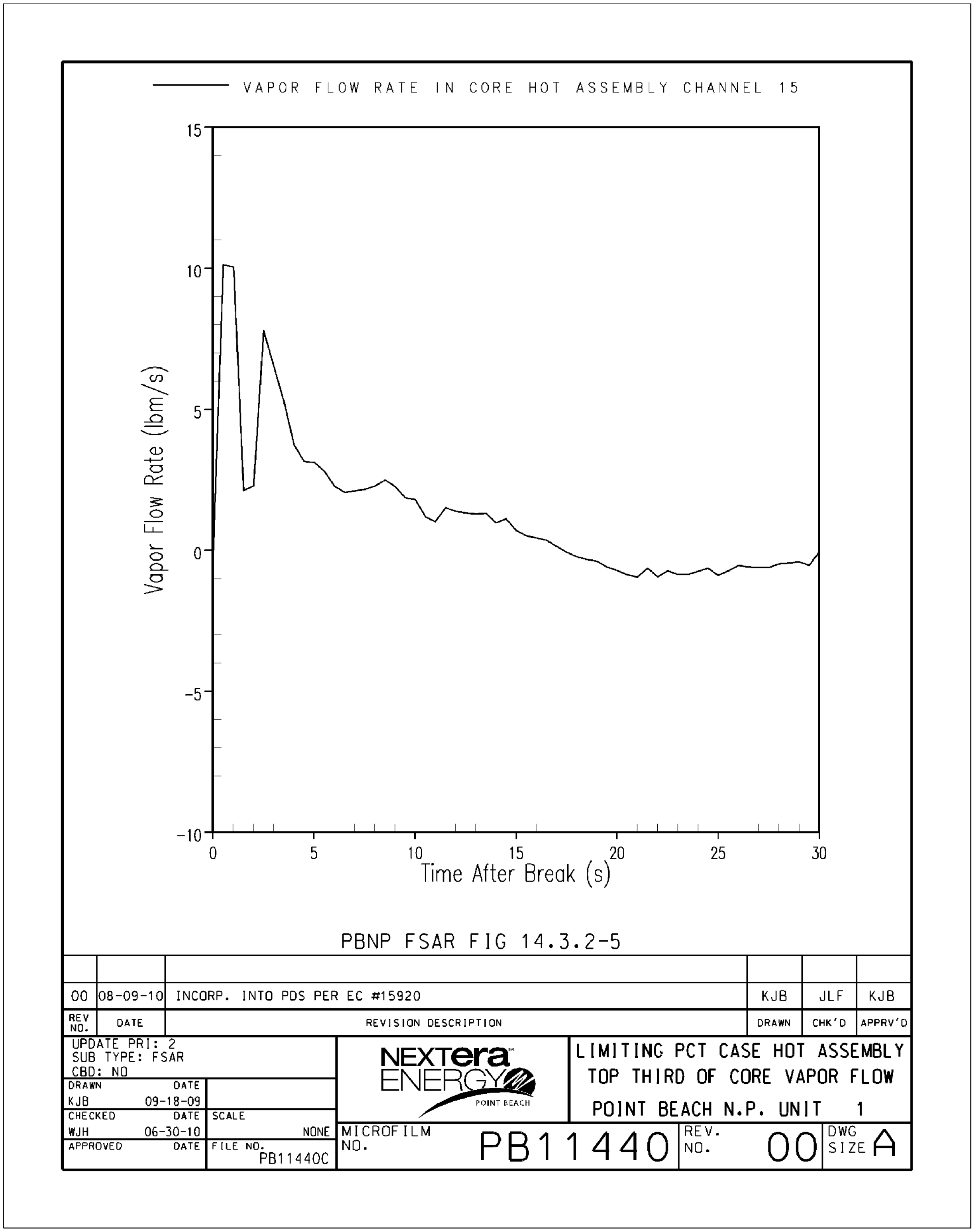


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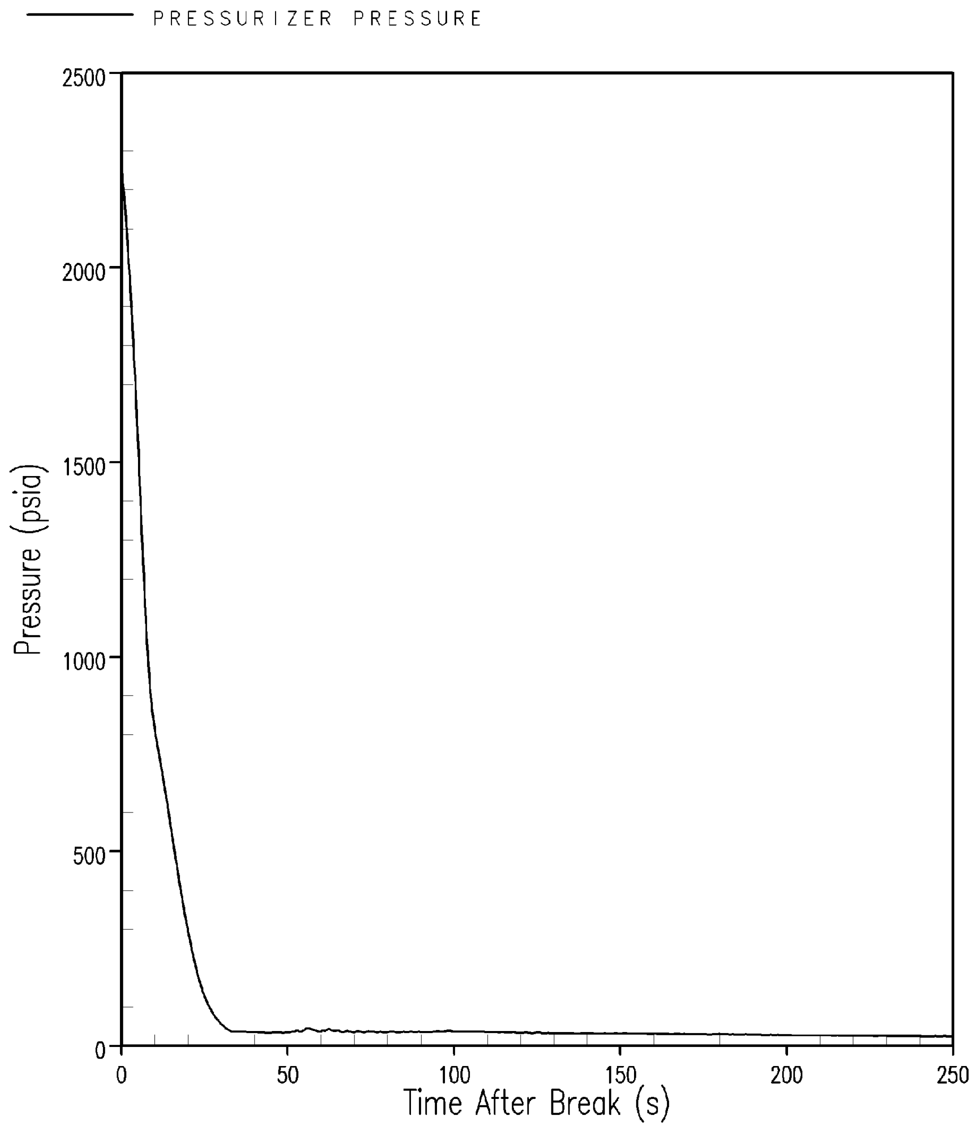
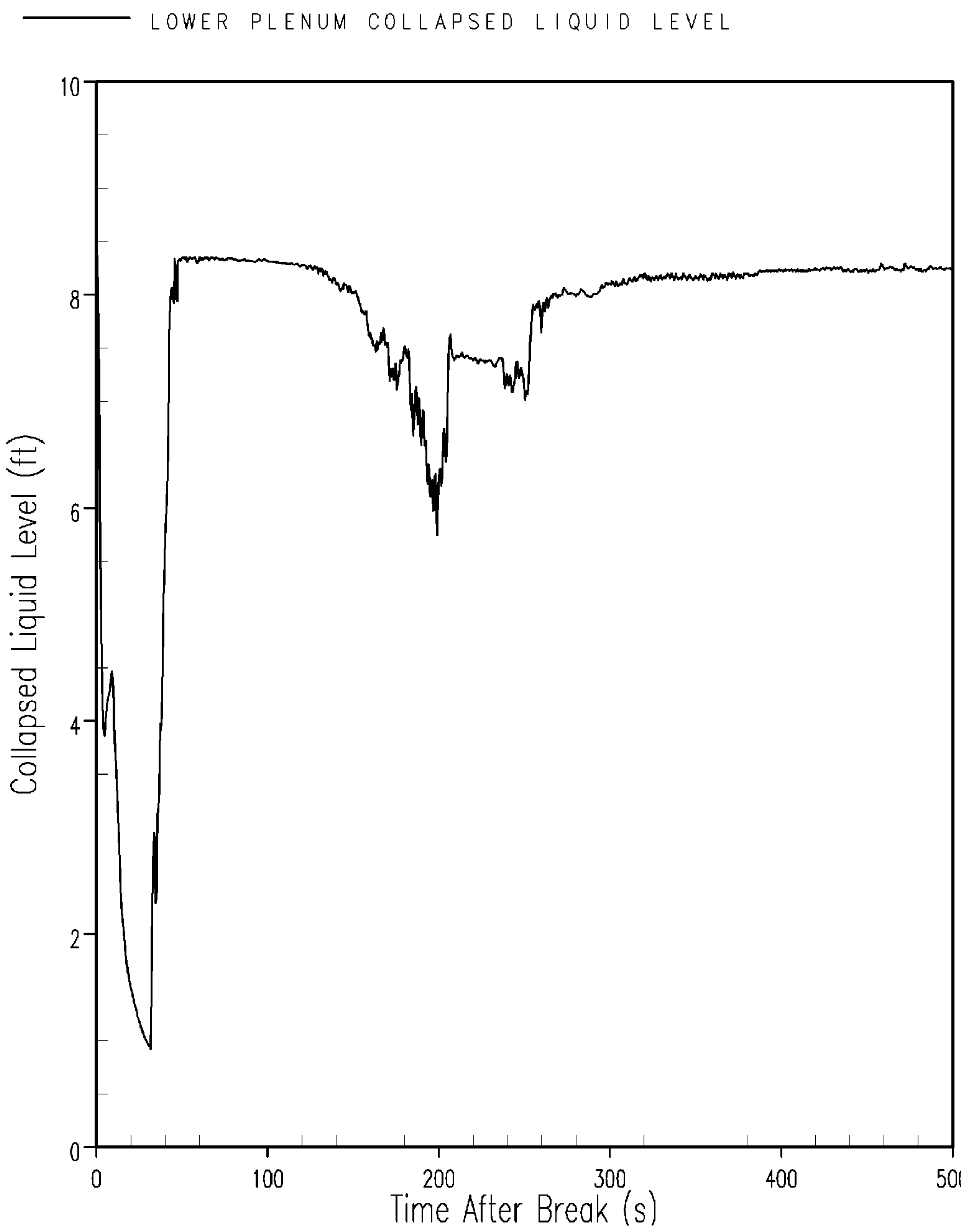
Figure 14.3.2-6 UNIT 1 LIMITING PEAK CLAD TEMPERATURE CASE PRESSURIZER PRESSURE



PBNP FSAR FIG 14.3.2-6

00	08-09-10	INCORP. INTO PDS PER EC #15920	KJB	JLF	KJB
REV NO.	DATE	REVISION DESCRIPTION	DRAWN	CHK'D	APPRV'D

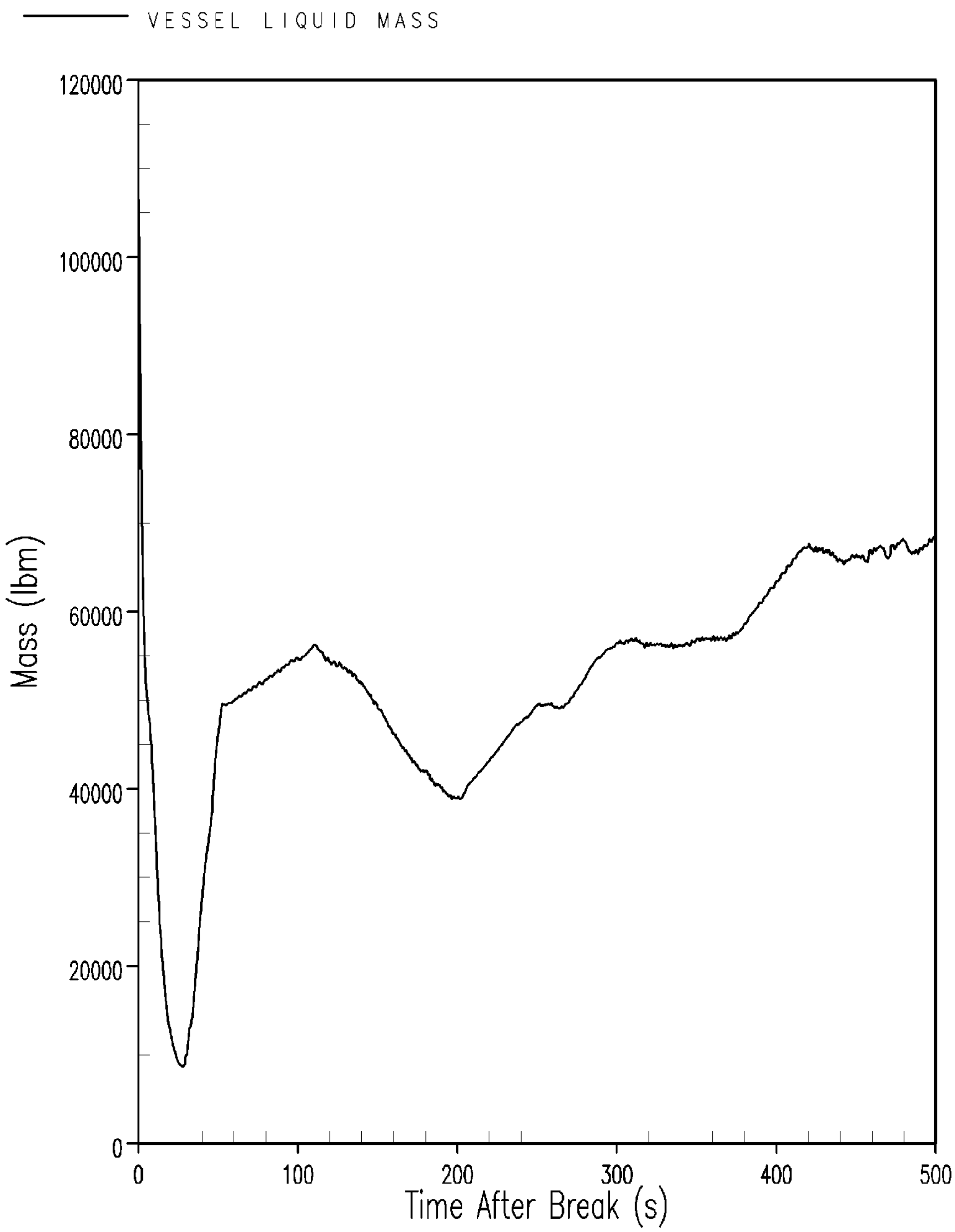
Figure 14.3.2-7 UNIT 1 LIMITING PEAK CLAD TEMPERATURE CASE LOWER PLENUM COLLAPSED LIQUID LEVEL



PBNP FSAR FIG 14.3.2-7

REV NO.	DATE	REVISION DESCRIPTION	DRAWN	CHK'D	APPRV'D
00	08-09-10	INCORP. INTO PDS PER EC #15920	KJB	JLF	KJB

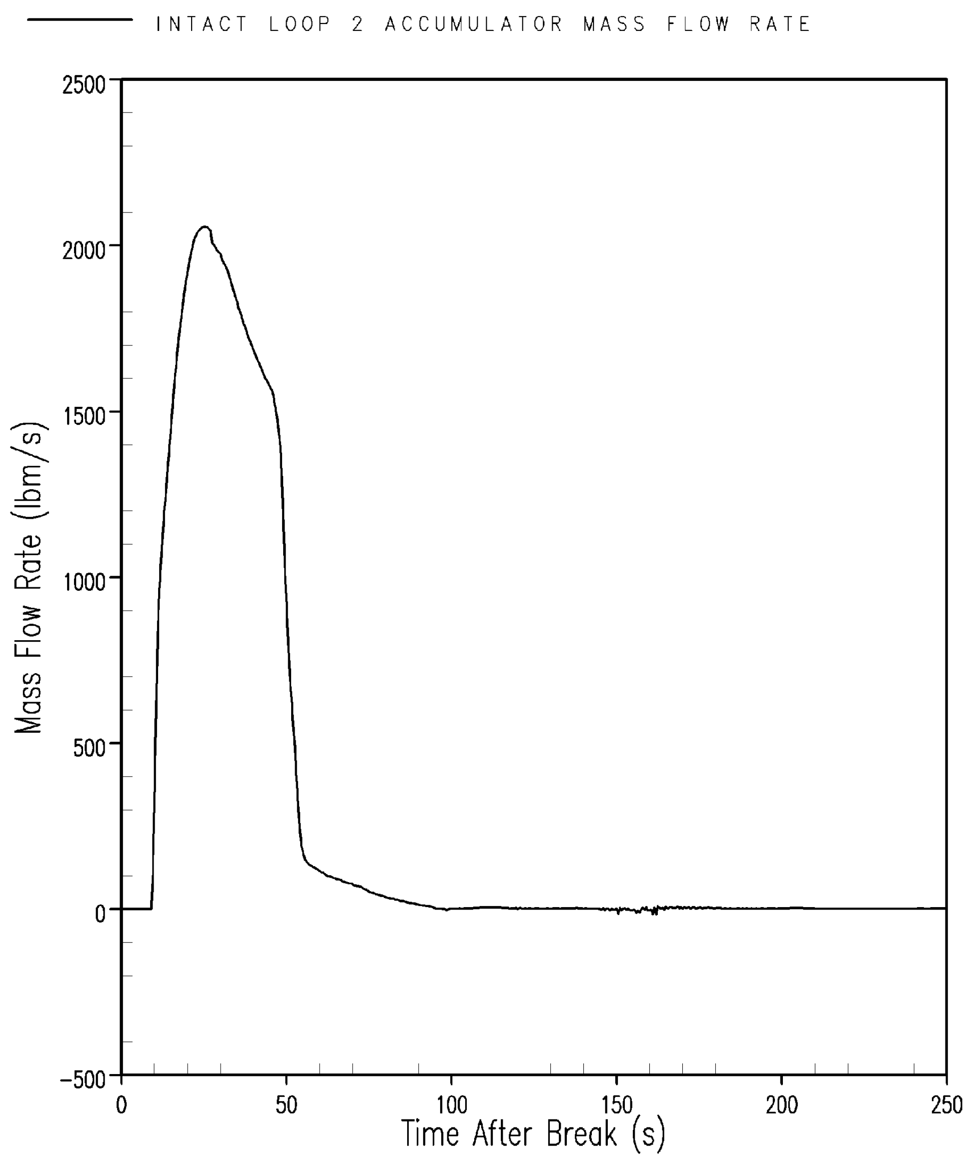
Figure 14.3.2-8 UNIT 1 LIMITING PEAK CLAD TEMPERATURE CASE VESSEL LIQUID MASS



PBNP FSAR FIG 14.3.2-8

REV NO.	DATE	REVISION DESCRIPTION	DRAWN	CHK'D	APPRV'D
00	08-09-10	INCORP. INTO PDS PER EC #15920	KJB	JLF	KJB

Figure 14.3.2-9 UNIT 1 LIMITING PEAK CLAD TEMPERATURE CASE LOOP 2 ACCUMULATOR FLOW



PBNP FSAR FIG 14.3.2-9

00	08-09-10	INCORP. INTO PDS PER EC #15920	KJB	JLF	KJB
REV NO.	DATE	REVISION DESCRIPTION	DRAWN	CHK'D	APPRV'D

Figure 14.3.2-10A UNIT 1 LIMITING PEAK CLAD TEMPERATURE CASE LOOP 2 HIGH HEAD SAFETY INJECTION FLOW

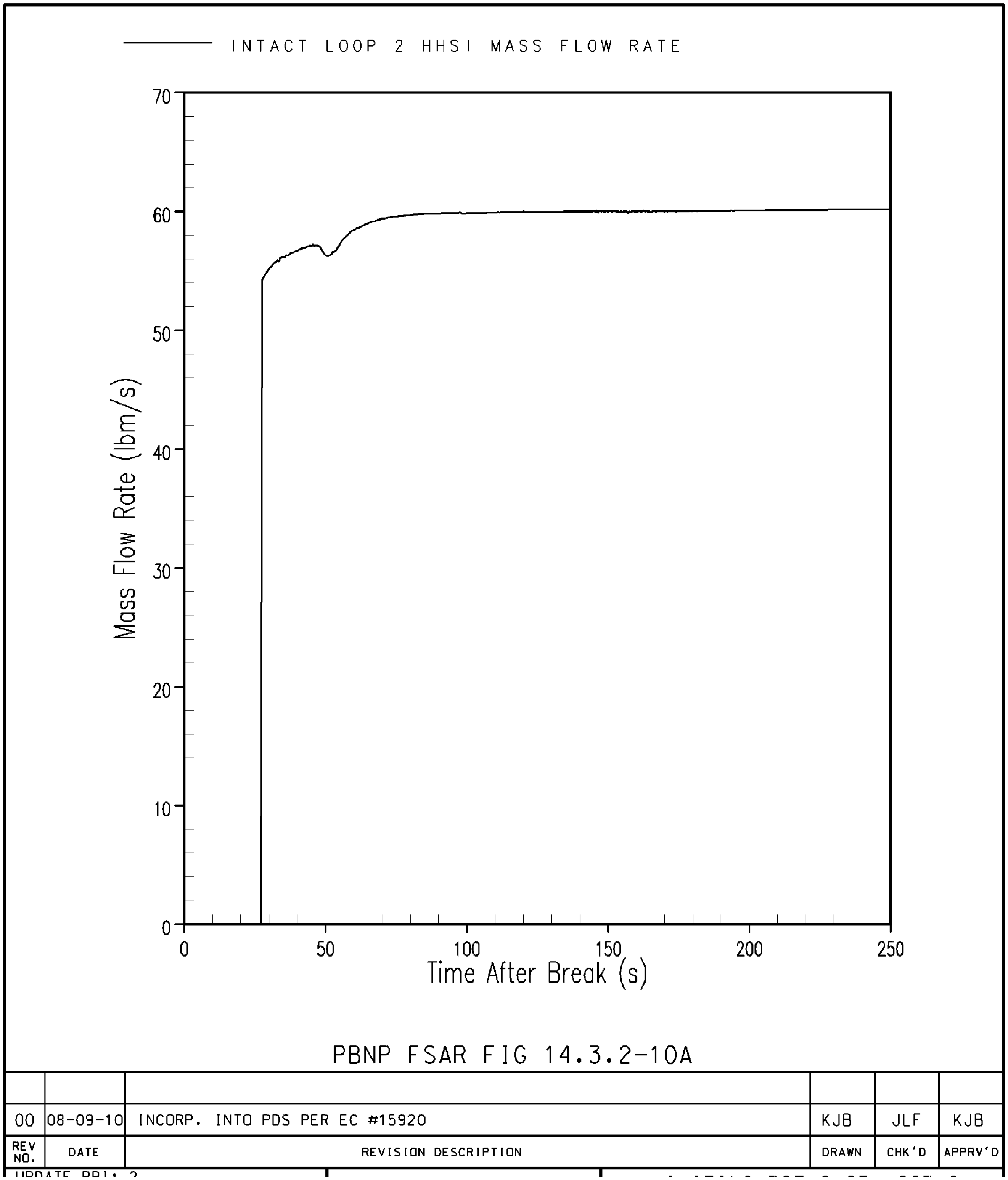
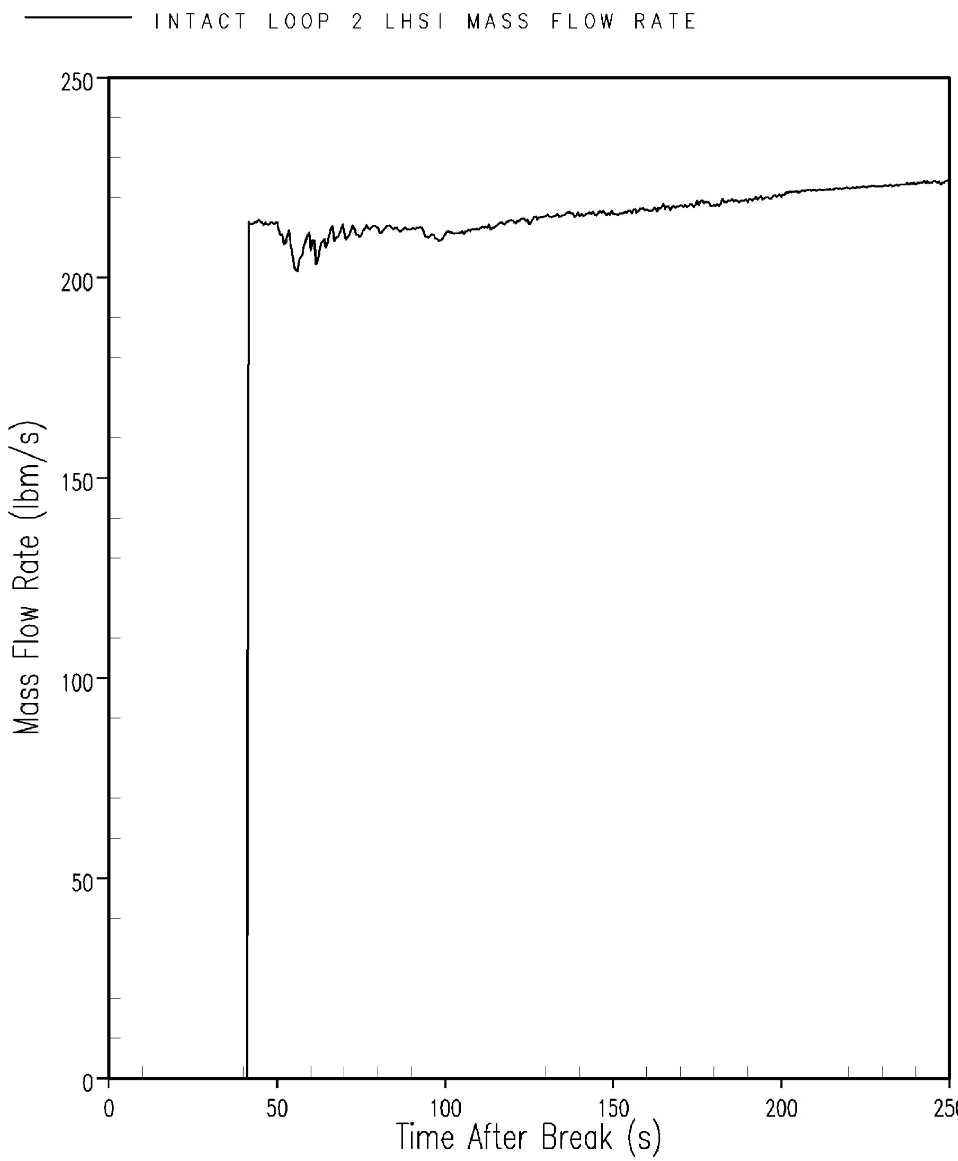


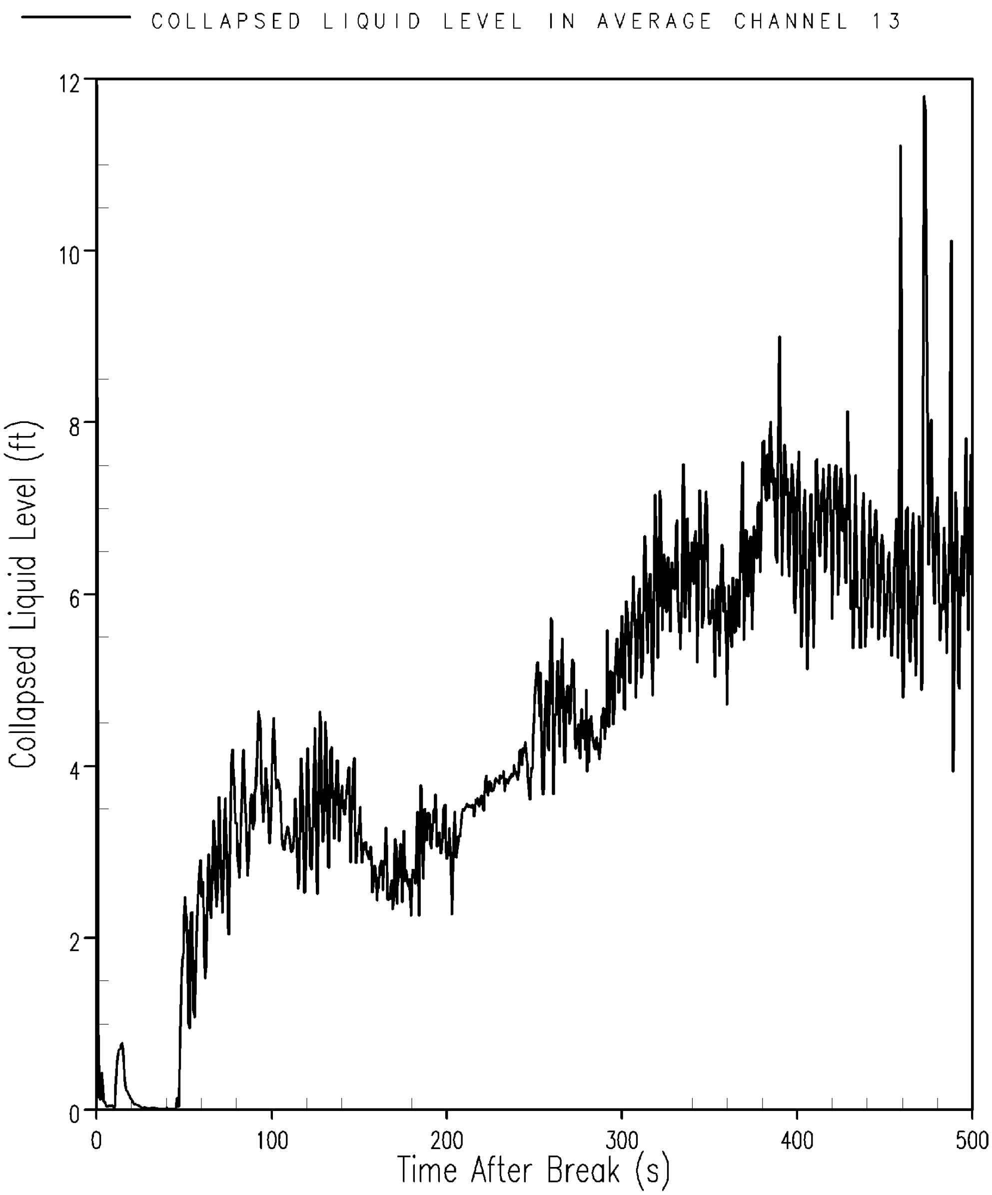
Figure 14.3.2-10B UNIT 1 LIMITING PEAK CLAD TEMPERATURE CASE LOOP 2 LOW HEAD SAFETY INJECTION FLOW



PBNP FSAR FIG 14.3.2-10B

00	08-09-10	INCORP. INTO PDS PER EC #15920	KJB	JLF	KJB
REV NO.	DATE	REVISION DESCRIPTION	DRAWN	CHK'D	APPRV'D

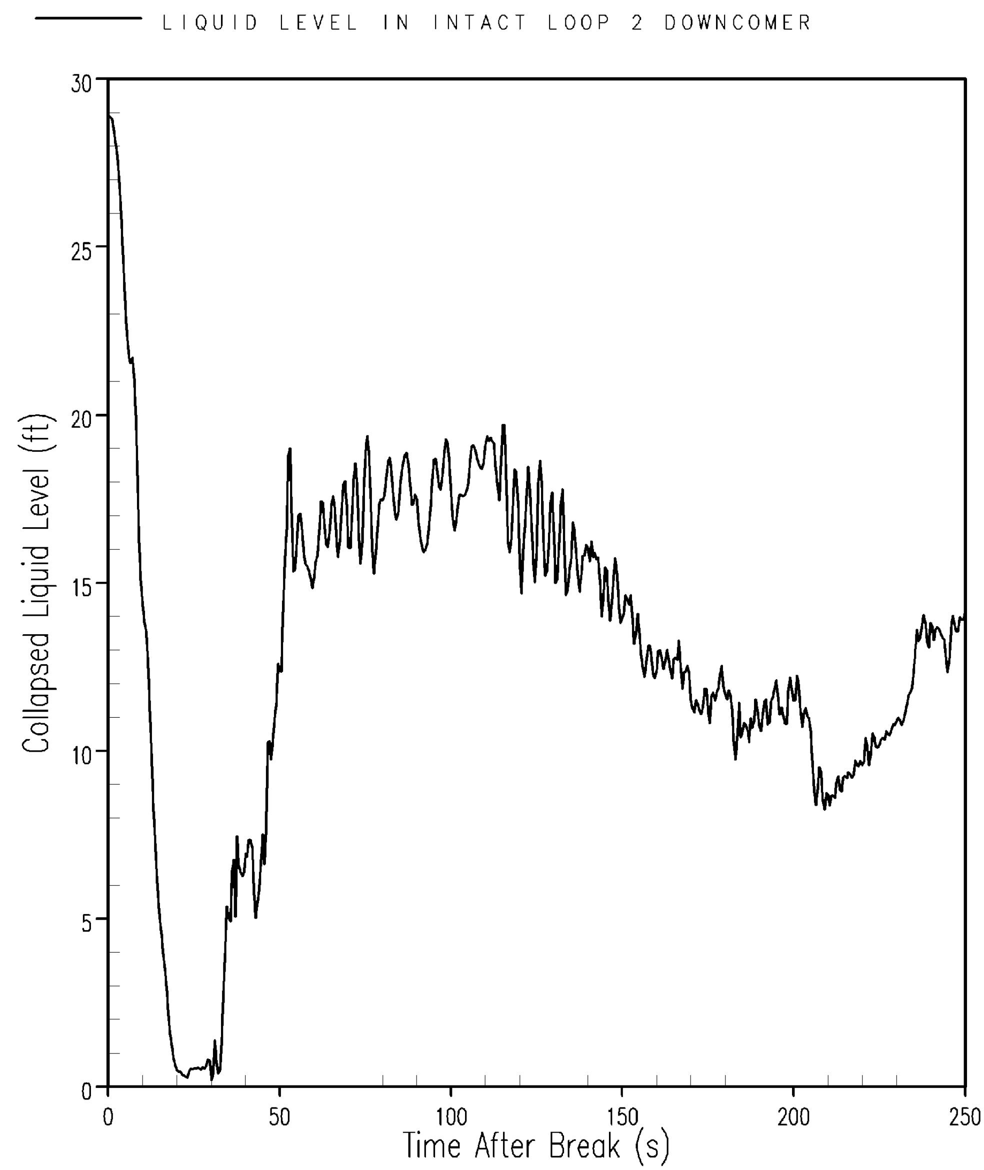
Figure 14.3.2-11 UNIT 1 LIMITING PEAK CLAD TEMPERATURE CASE CORE AVERAGE CHANNEL COLLAPSED LIQUID LEVEL



PBNP FSAR FIG 14.3.2-11

00	08-09-10	INCORP. INTO PDS PER EC #15920	KJB	JLF	KJB
REV NO.	DATE	REVISION DESCRIPTION	DRAWN	CHK'D	APPRV'D

Figure 14.3.2-12 UNIT 1 LIMITING PEAK CLAD TEMPERATURE CASE LOOP 2 DOWNCOMER COLLAPSED LIQUID LEVEL



PBNP FSAR FIG 14.3.2-12

REV NO.	DATE	REVISION DESCRIPTION	DRAWN	CHK'D	APPRV'D
00	08-09-10	INCORP. INTO PDS PER EC #15920	KJB	JLF	KJB

Figure 14.3.2-13 UNIT 1 BELOCA ANALYSIS AXIAL POWER SHAPE OPERATING SPACE ENVELOPE

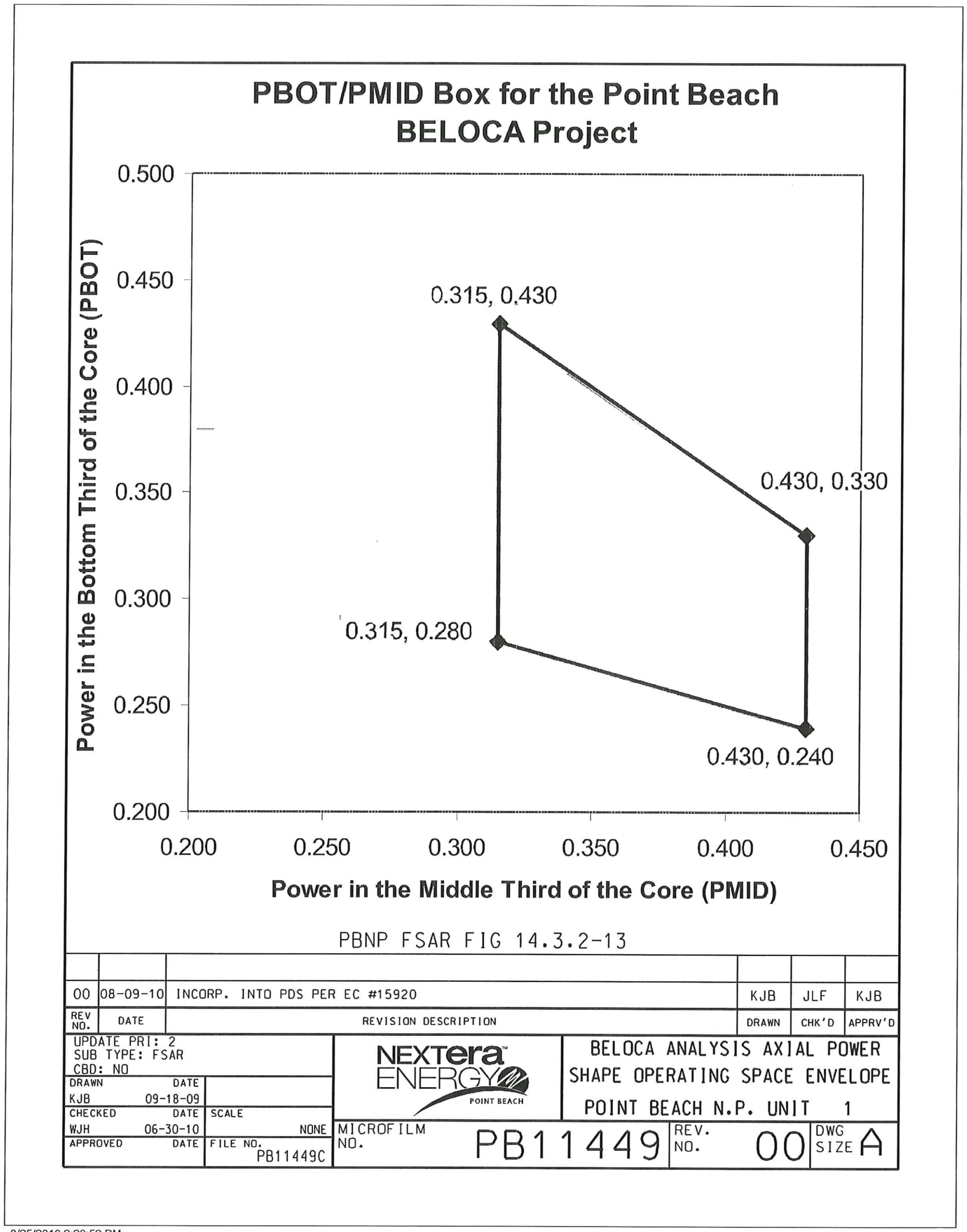


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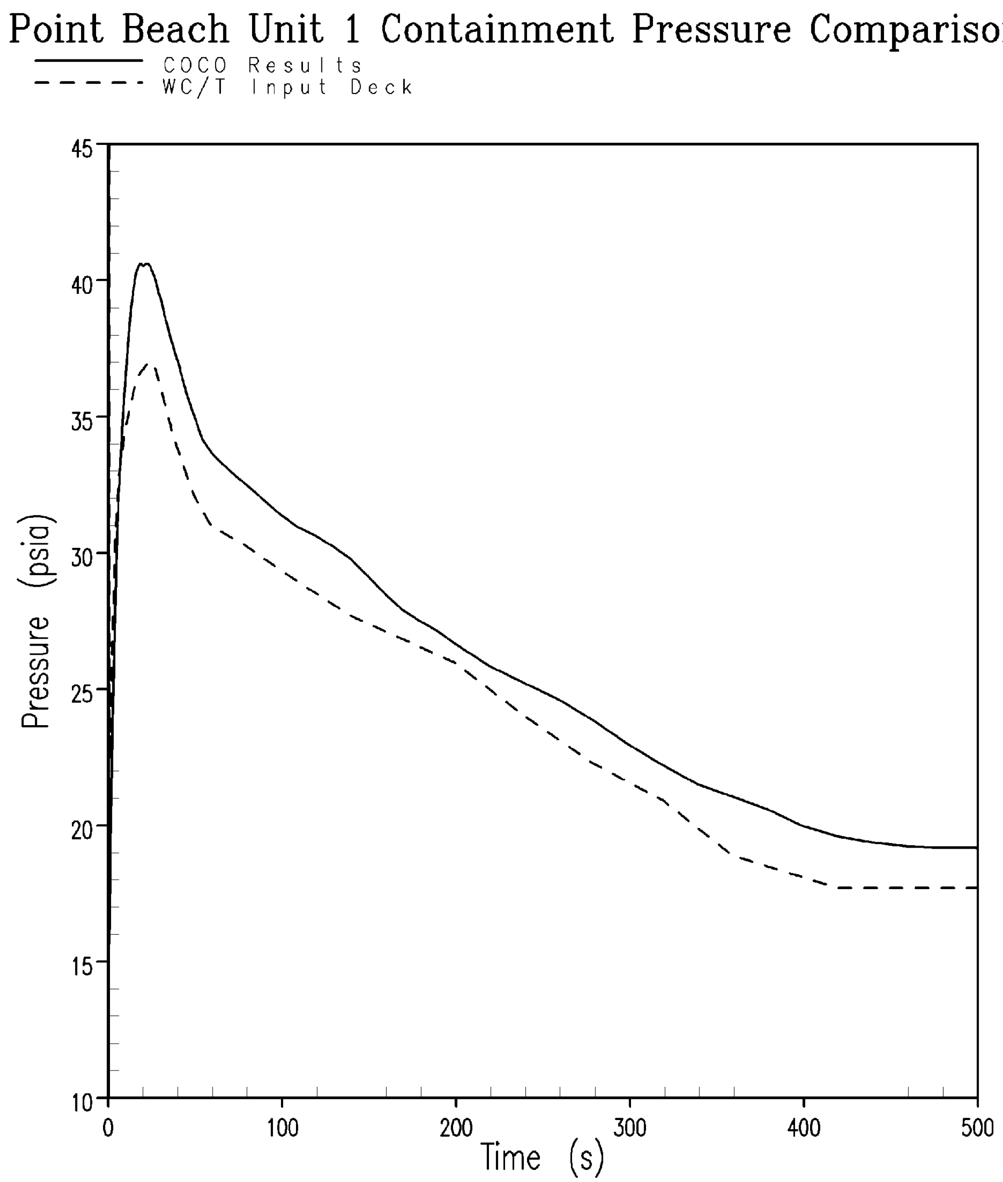
Figure 14.3.2-14 UNIT 1 LOWER BOUND CONTAINMENT PRESSURE



PBNP FSAR FIG 14.3.2-14

00	08-09-10	INCORP. INTO PDS PER EC #15920	KJB	JLF	KJB
REV NO.	DATE	REVISION DESCRIPTION	DRAWN	CHK'D	APPRV'D

Figure 14.3.2-15 UNIT 2 LIMITING PEAK CLAD TEMPERATURE CASE PEAK CLAD TEMPERATURE AND PEAK CLAD TEMPERATURE LOCATION

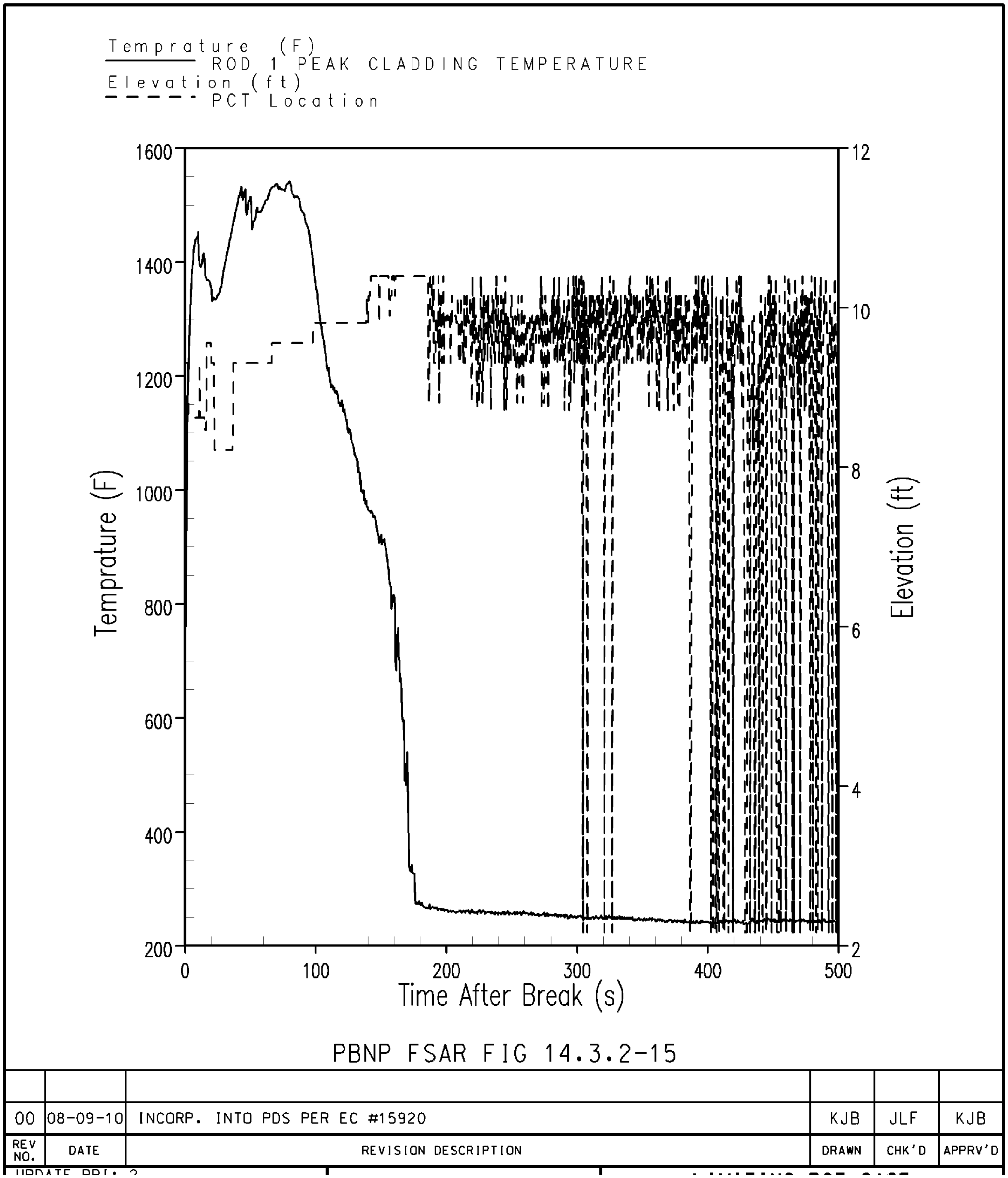


Figure 14.3.2-16 UNIT 2 LIMITING PEAK CLAD TEMPERATURE CASE VESSEL SIDE BREAK FLOW

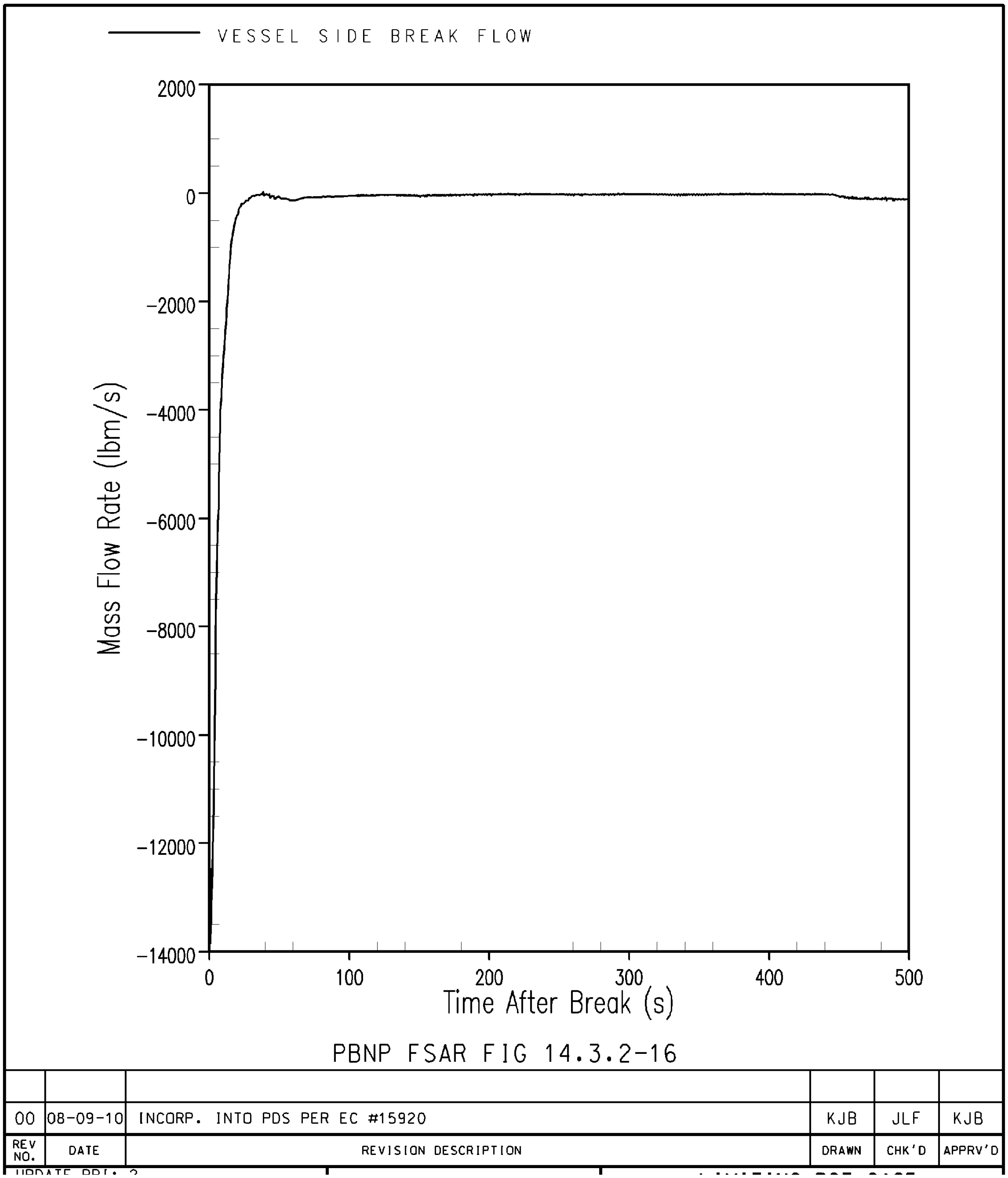


Figure 14.3.2-17 UNIT 2 LIMITING PEAK CLAD TEMPERATURE CASE PUMP SIDE BREAK FLOW

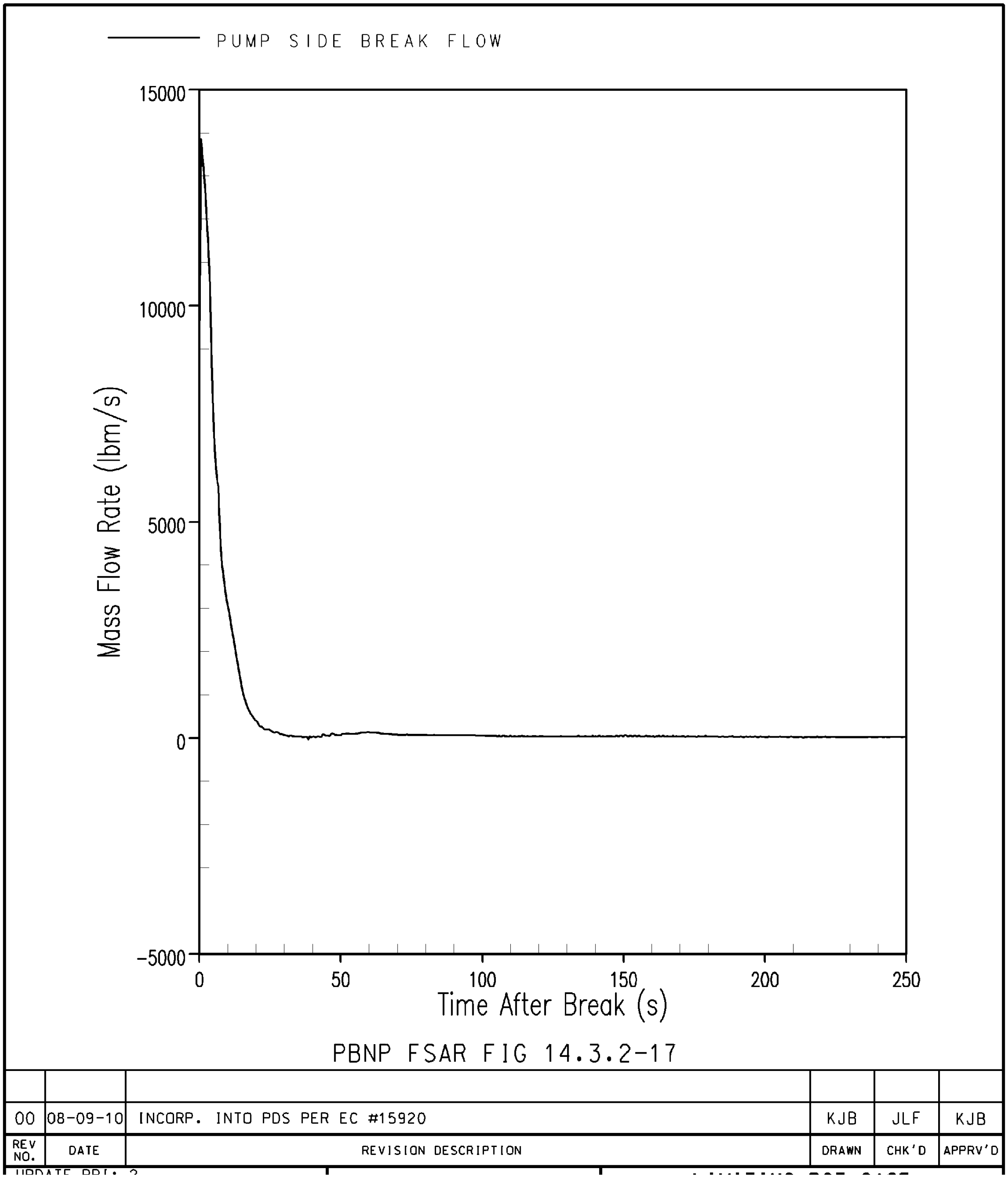
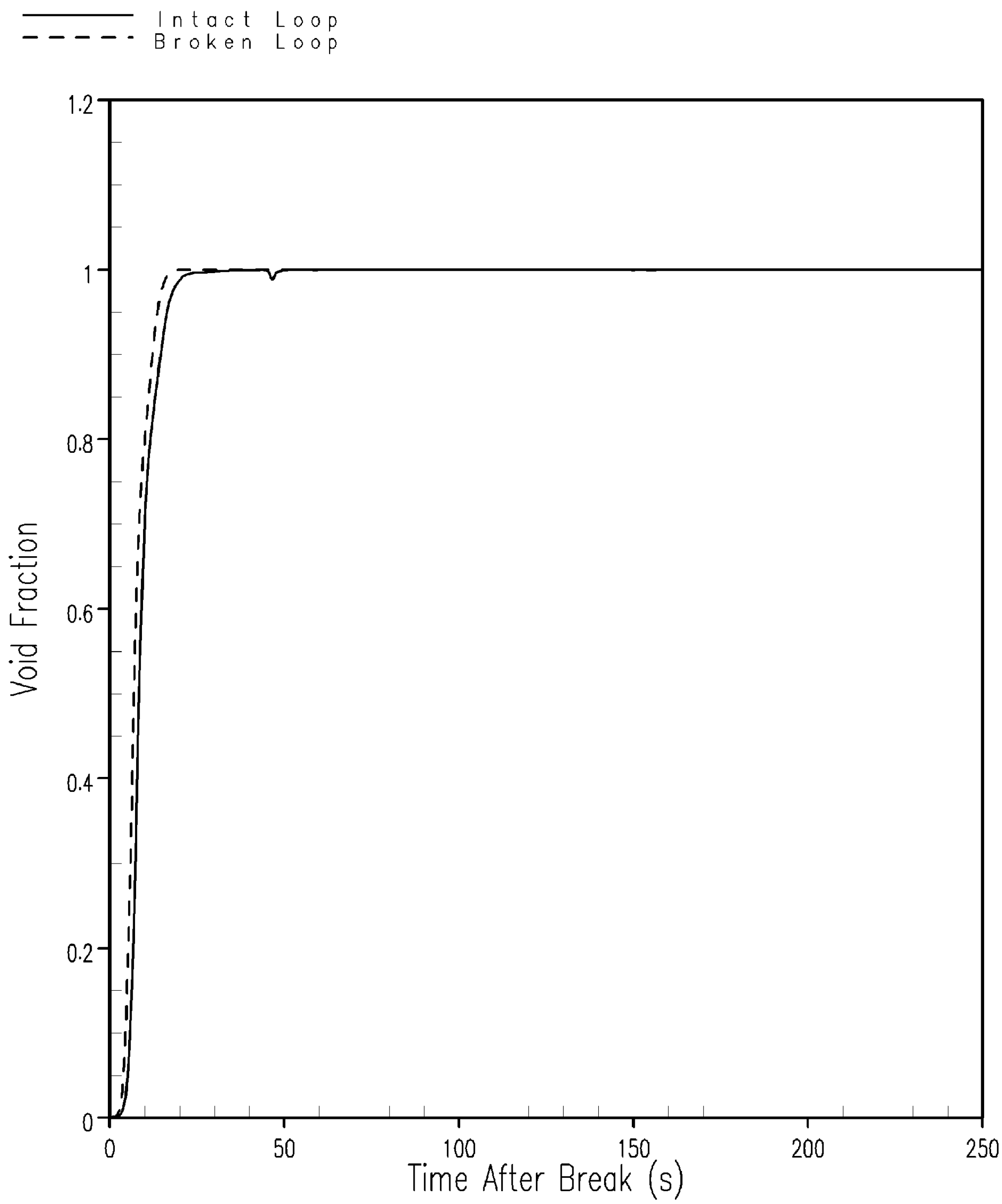


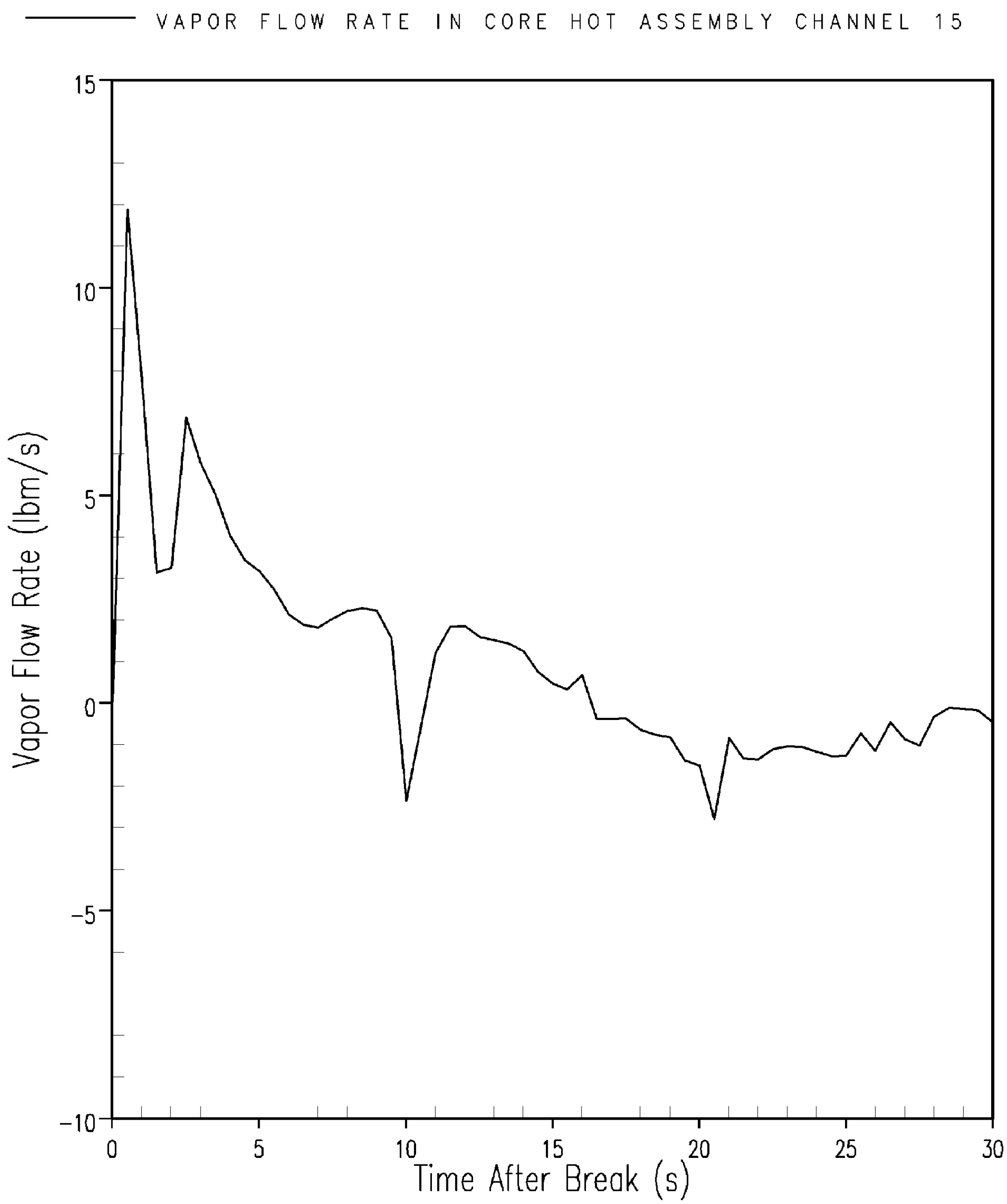
Figure 14.3.2-18 UNIT 2 LIMITING PEAK CLAD TEMPERATURE CASE BROKEN AND INTACT LOOP PUMP VOID FRACTION



PBNP FSAR FIG 14.3.2-18

REV NO.	DATE	REVISION DESCRIPTION	DRAWN	CHK'D	APPRV'D
00	08-09-10	INCORP. INTO PDS PER EC #15920	KJB	JLF	KJB

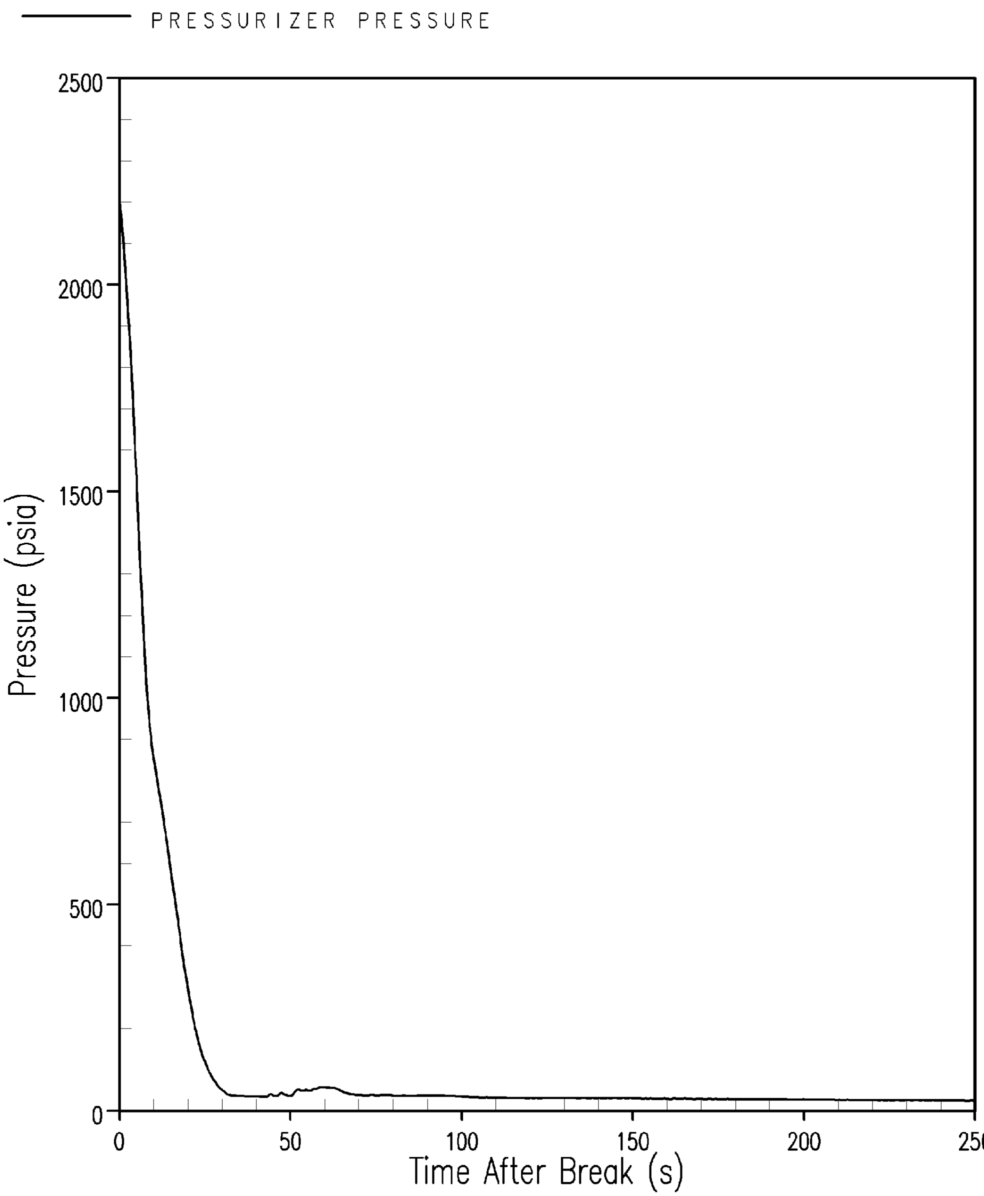
Figure 14.3.2-19 UNIT 2 LIMITING PEAK CLAD TEMPERATURE CASE HOT ASSEMBLY TOP THIRD OF CORE VAPOR FLOW



PBNP FSAR FIG 14.3.2-19

00	08-09-10	INCORP. INTO PDS PER EC #15920	KJB	JLF	KJB
REV NO.	DATE	REVISION DESCRIPTION	DRAWN	CHK'D	APPRV'D

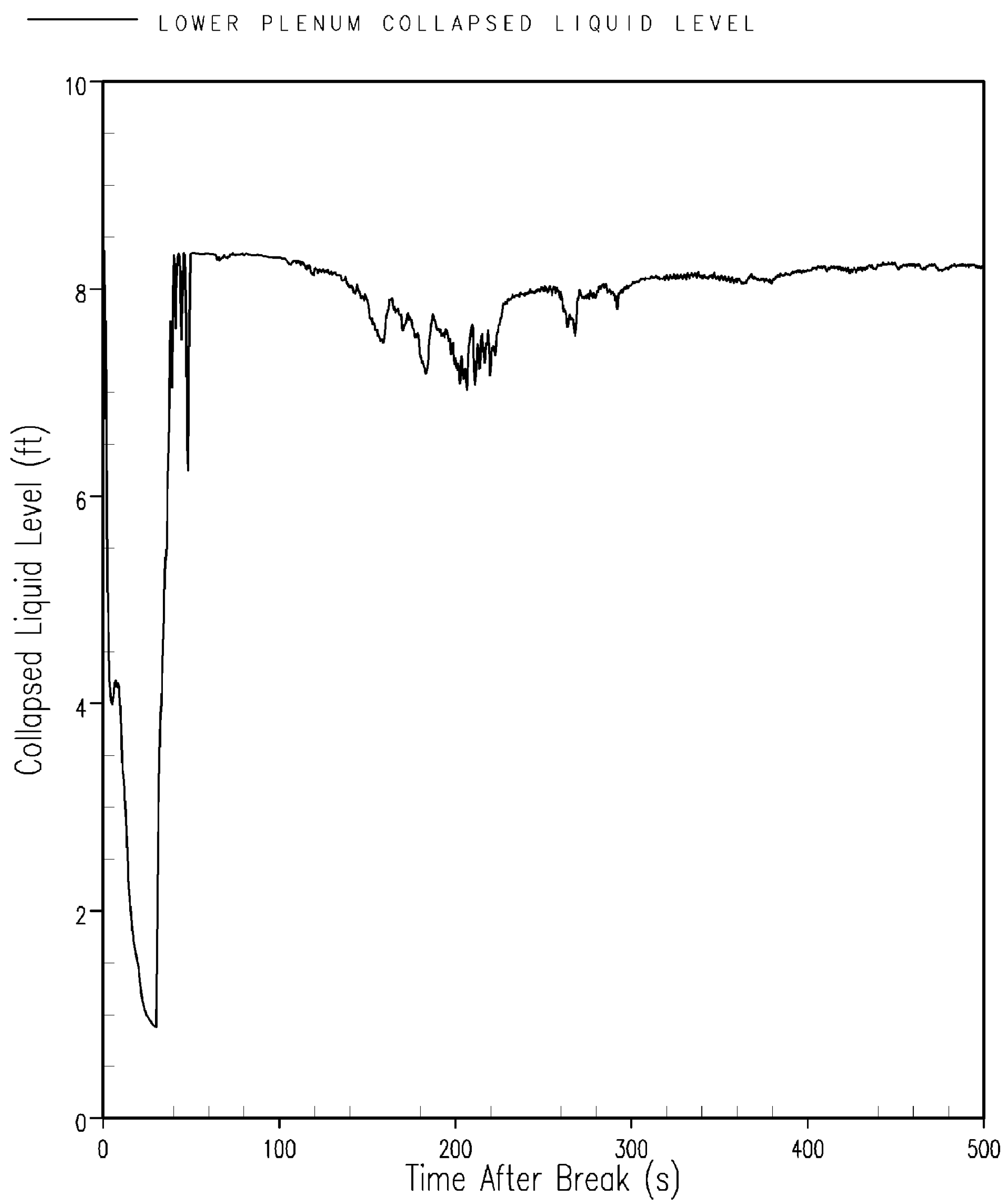
Figure 14.3.2-20 UNIT 2 LIMITING PEAK CLAD TEMPERATURE CASE PRESSURIZER PRESSURE



PBNP FSAR FIG 14.3.2-20

00	08-09-10	INCORP. INTO PDS PER EC #15920	KJB	JLF	KJB
REV NO.	DATE	REVISION DESCRIPTION	DRAWN	CHK'D	APPRV'D

Figure 14.3.2-21 UNIT 2 LIMITING PEAK CLAD TEMPERATURE CASE LOWER PLENUM COLLAPSED LIQUID LEVEL



PBNP FSAR FIG 14.3.2-21

00	08-09-10	INCORP. INTO PDS PER EC #15920	KJB	JLF	KJB
REV NO.	DATE	REVISION DESCRIPTION	DRAWN	CHK'D	APPRV'D

Figure 14.3.2-22 UNIT 2 LIMITING PEAK CLAD TEMPERATURE CASE VESSEL LIQUID MASS

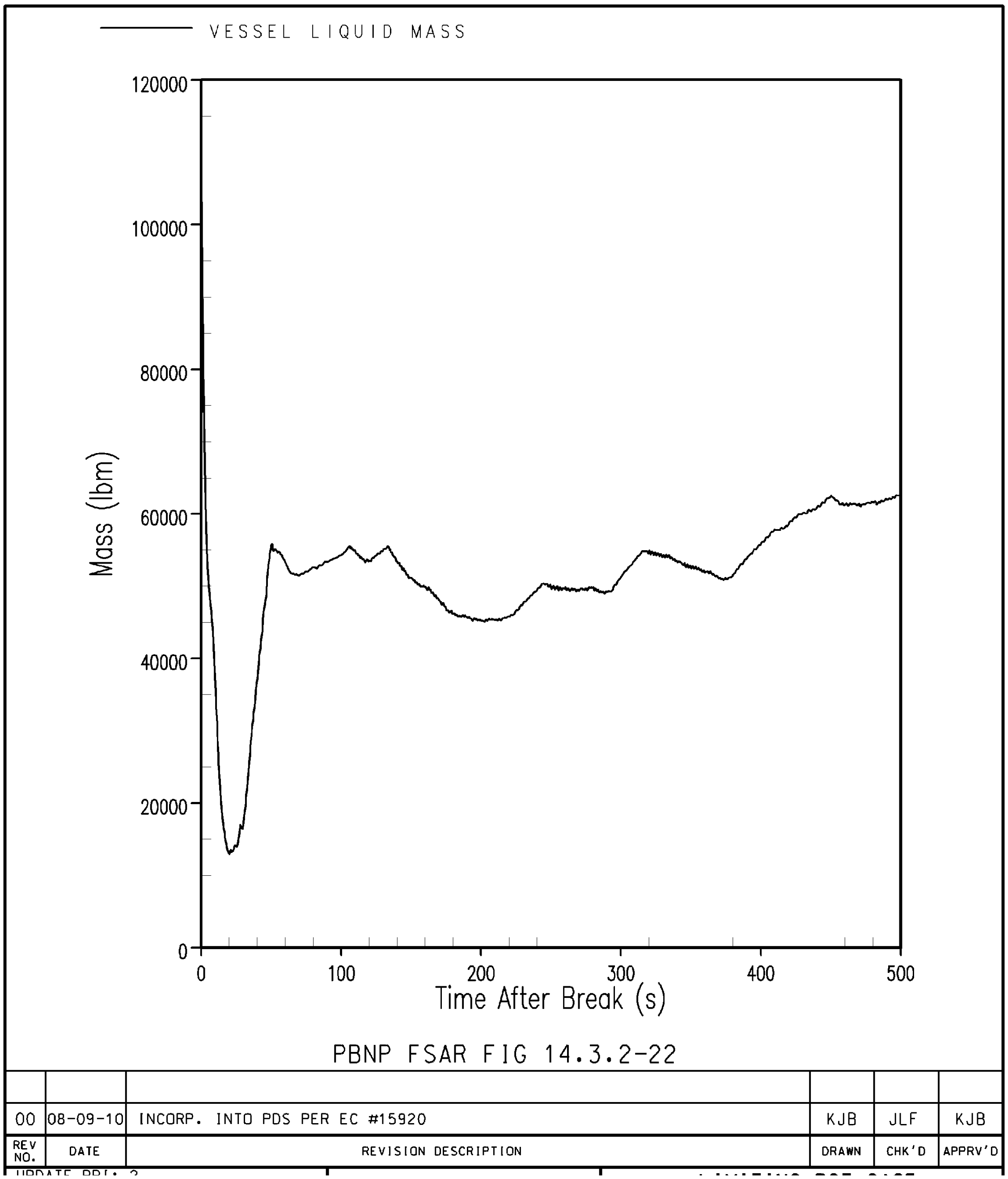
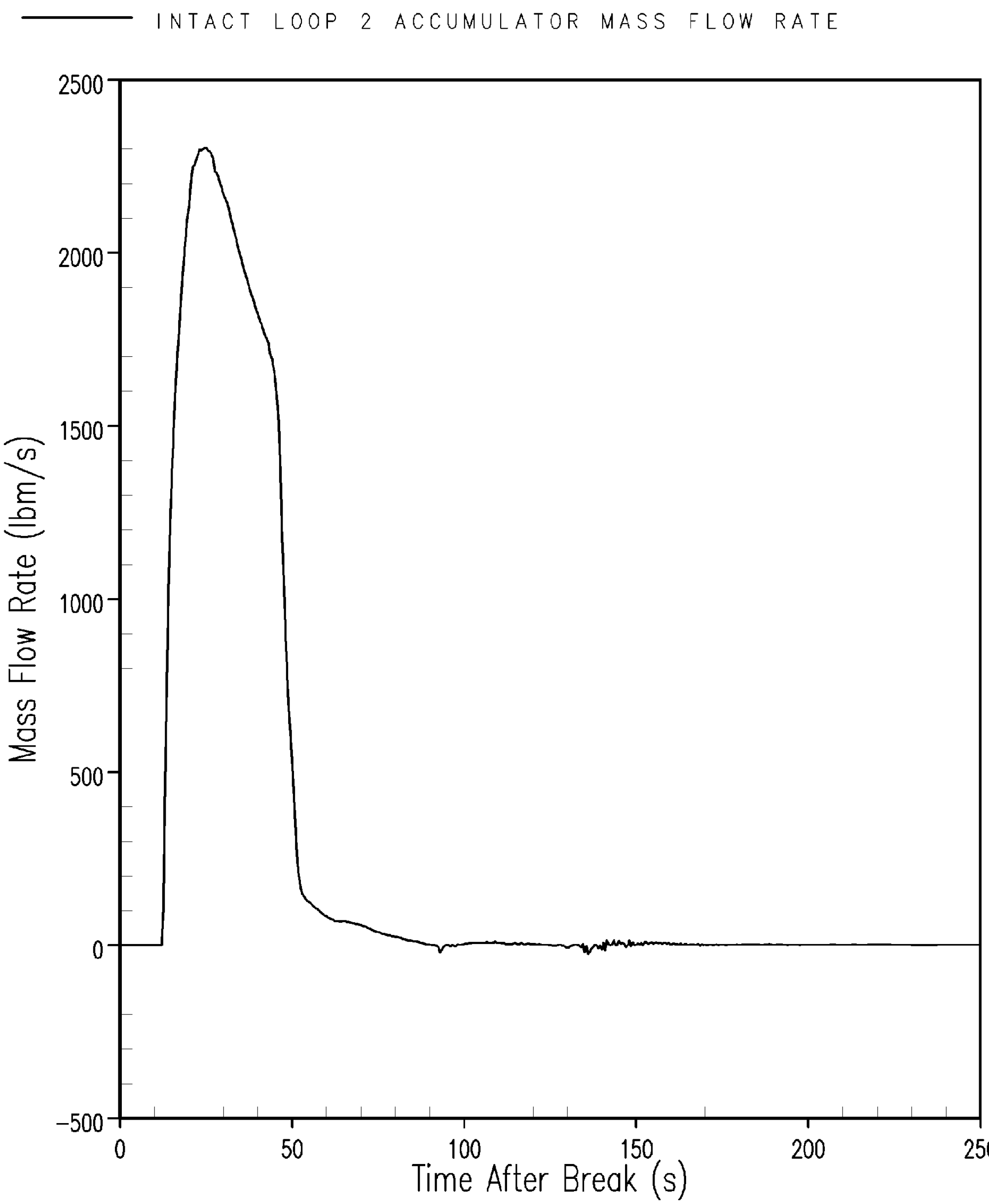


Figure 14.3.2-23 UNIT 2 LIMITING PEAK CLAD TEMPERATURE CASE LOOP 2 ACCUMULATOR FLOW



PBNP FSAR FIG 14.3.2-23

REV NO.	DATE	REVISION DESCRIPTION	DRAWN	CHK'D	APPRV'D
00	08-09-10	INCORP. INTO PDS PER EC #15920	KJB	JLF	KJB

Figure 14.3.2-24A UNIT 2 LIMITING PEAK CLAD TEMPERATURE CASE LOOP 2 HIGH HEAD SAFETY INJECTION FLOW

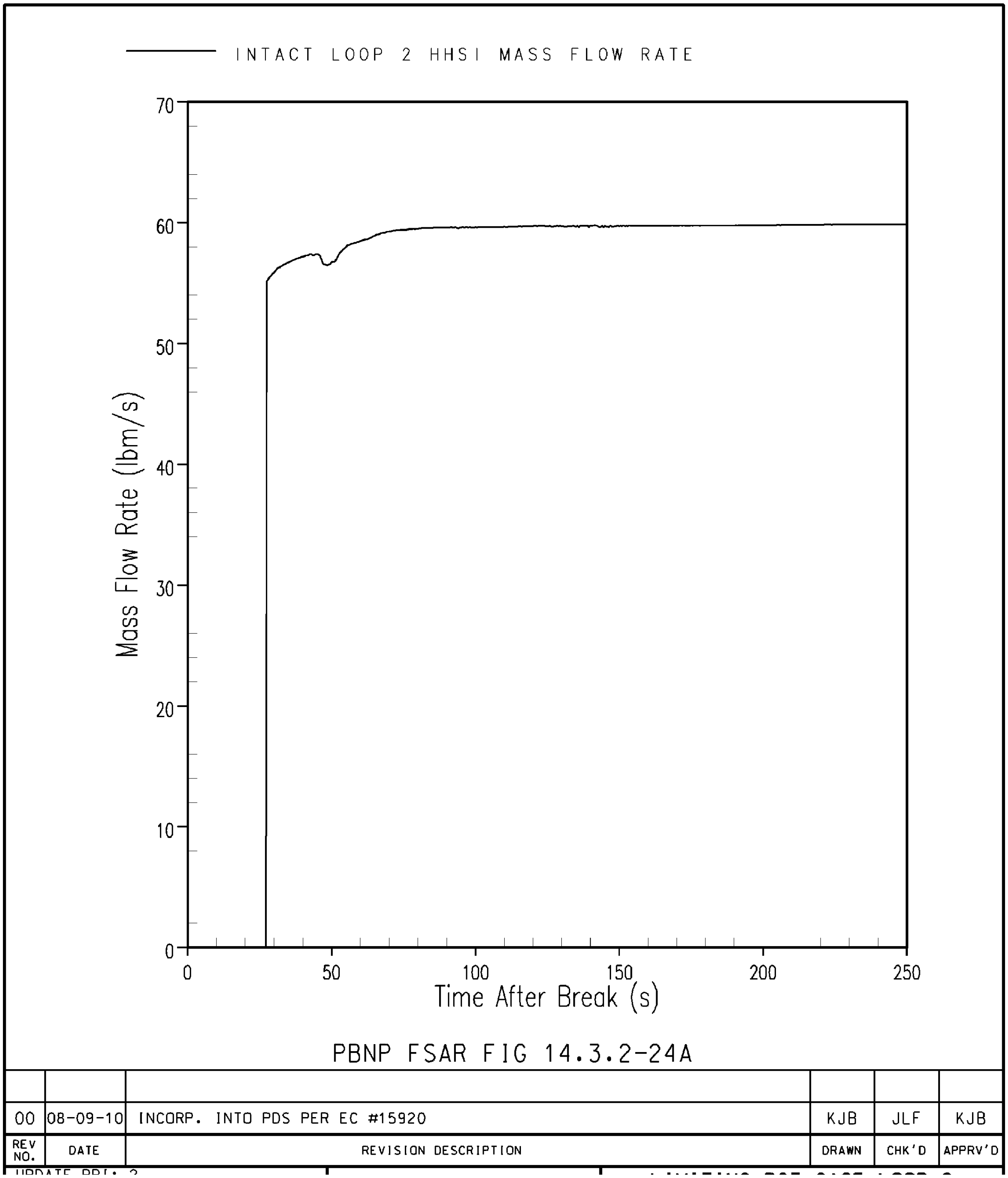
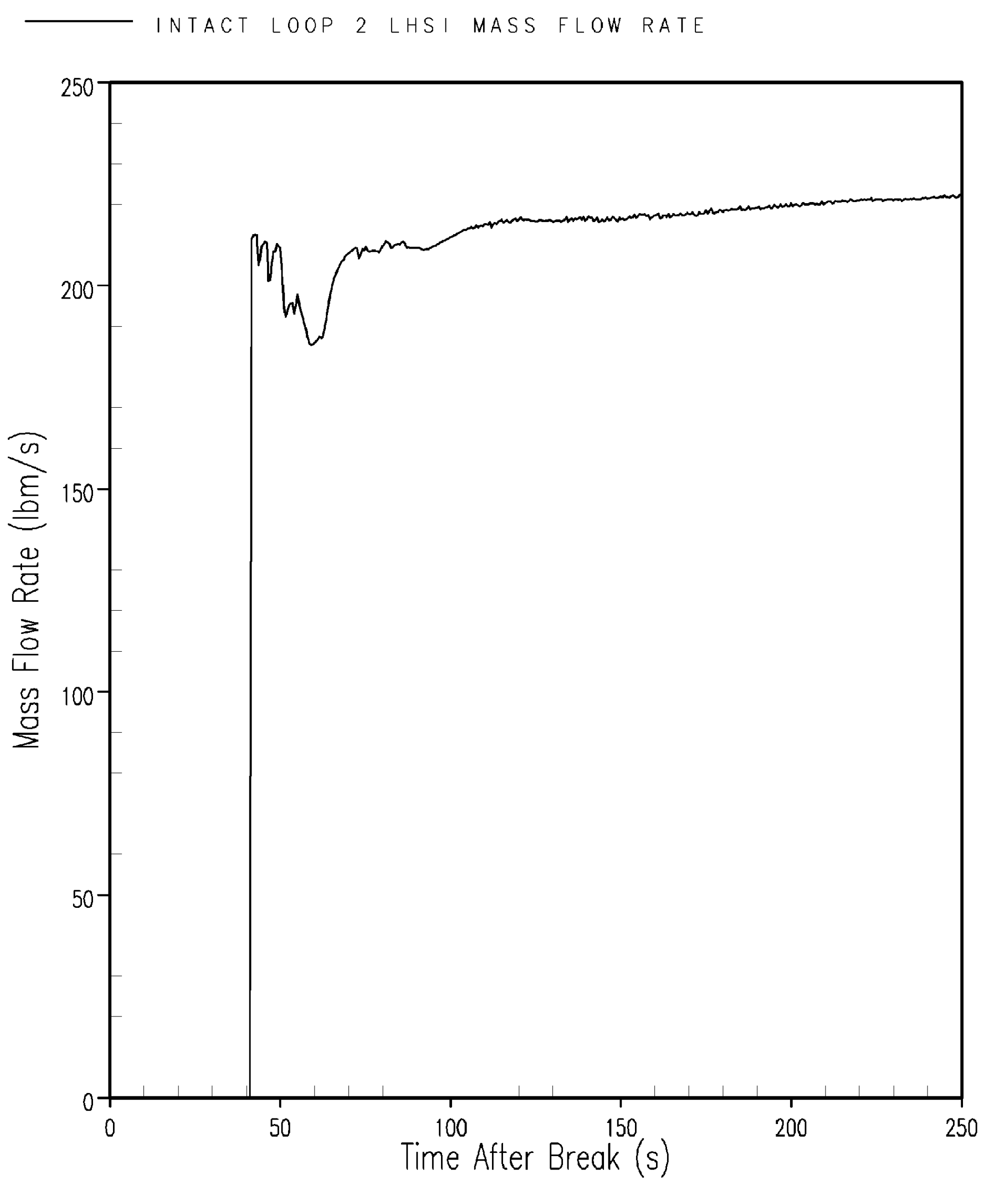


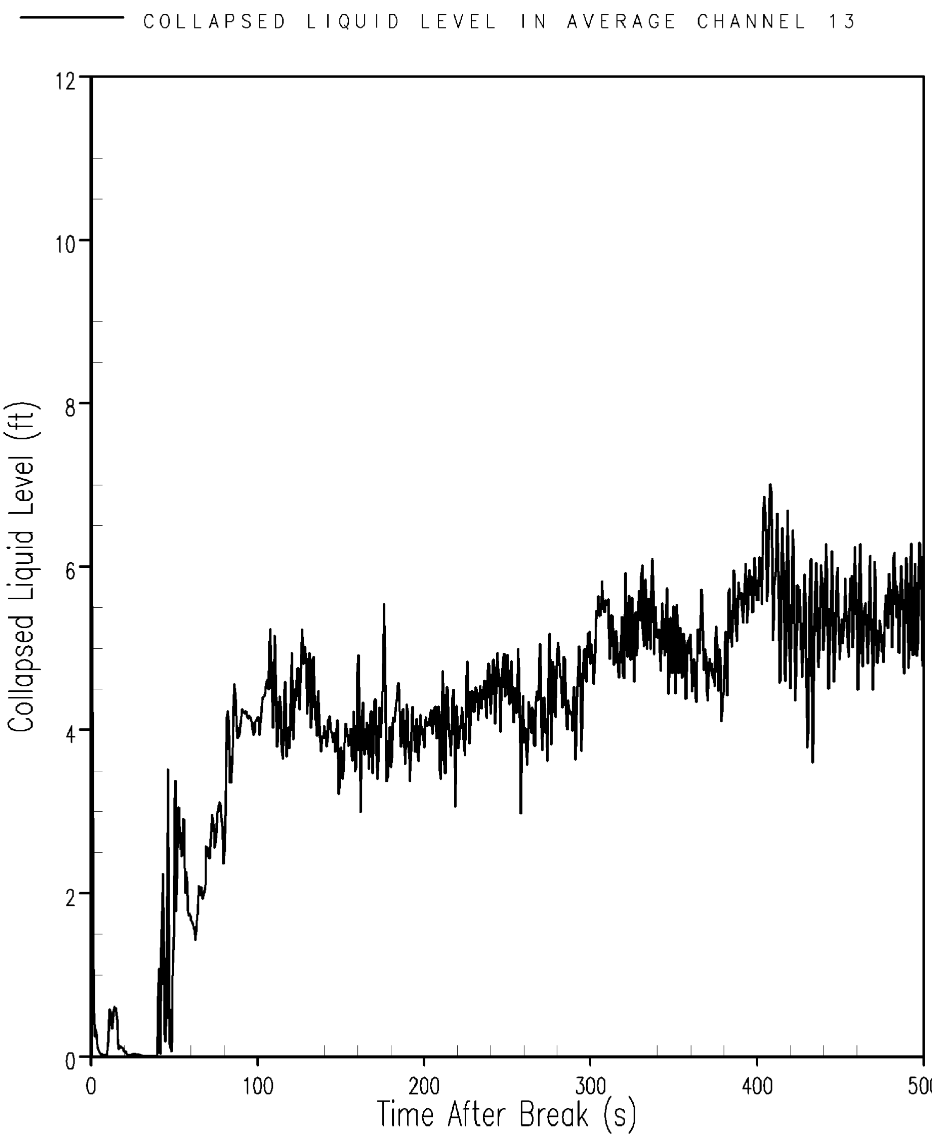
Figure 14.3.2-24B UNIT 2 LIMITING PEAK CLAD TEMPERATURE CASE LOOP 2 LOW HEAD SAFETY INJECTION FLOW



PBNP FSAR FIG 14.3.2-24B

REV NO.	DATE	REVISION DESCRIPTION	DRAWN	CHK'D	APPRV'D
00	08-09-10	INCORP. INTO PDS PER EC #15920	KJB	JLF	KJB

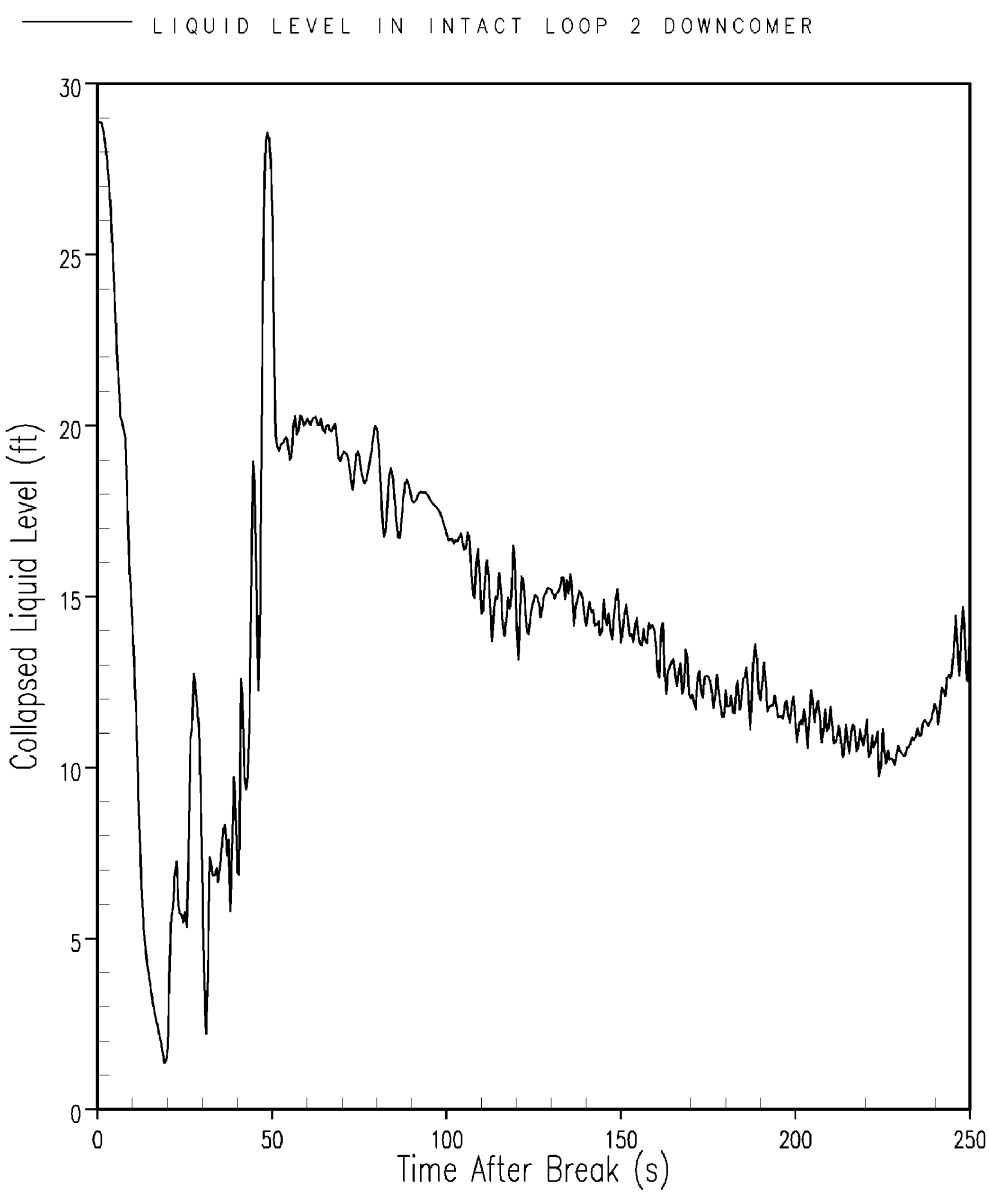
Figure 14.3.2-25 UNIT 2 LIMITING PEAK CLAD TEMPERATURE CASE CORE AVERAGE CHANNEL COLLAPSED LIQUID LEVEL



PBNP FSAR FIG 14.3.2-25

00	08-09-10	INCORP. INTO PDS PER EC #15920	KJB	JLF	KJB
REV NO.	DATE	REVISION DESCRIPTION	DRAWN	CHK'D	APPRV'D

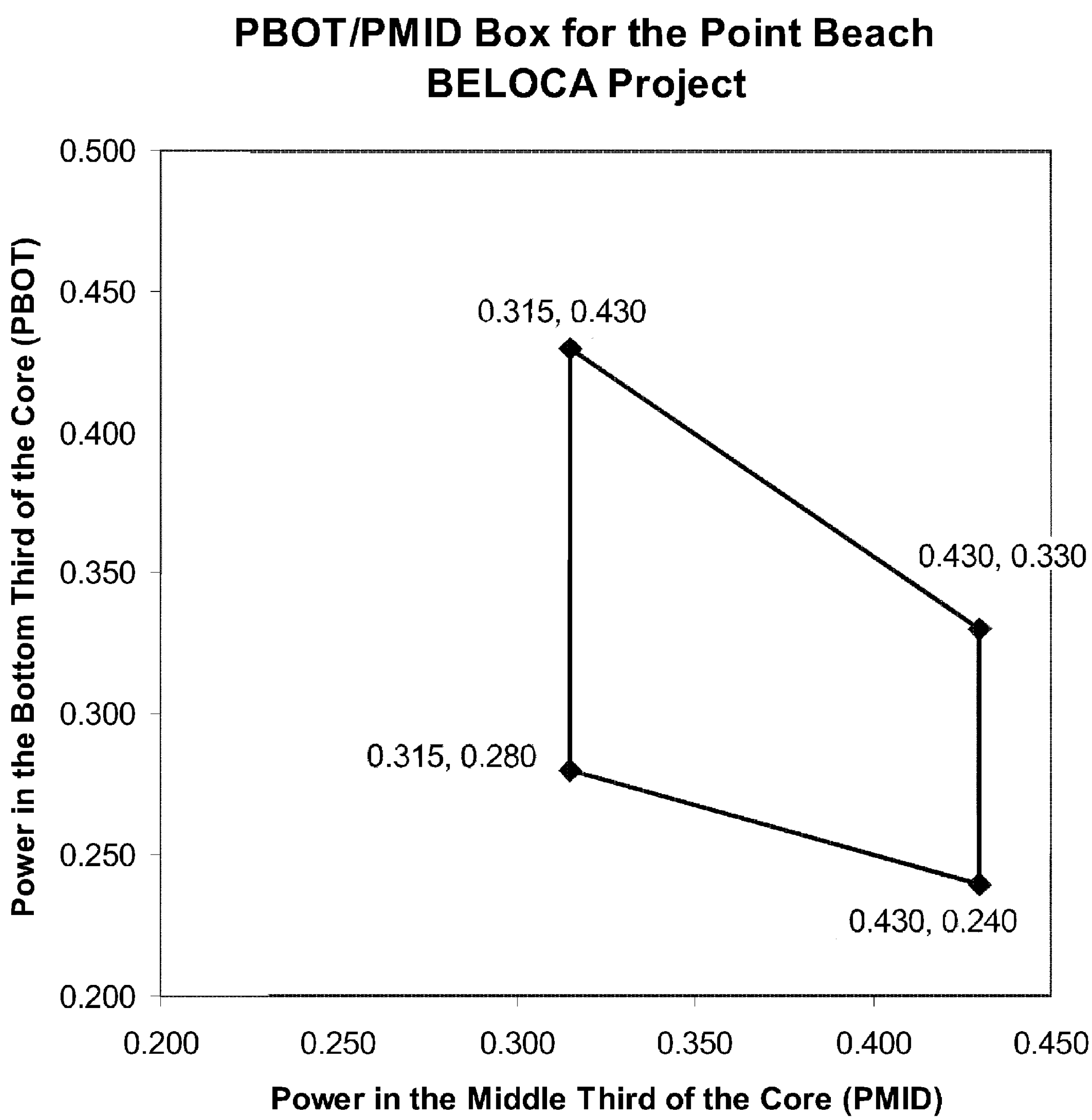
Figure 14.3.2-26 UNIT 2 LIMITING PEAK CLAD TEMPERATURE CASE LOOP 2 DOWNCOMER COLLAPSED LIQUID LEVEL



PBNP FSAR FIG 14.3.2-26

REV NO.	DATE	REVISION DESCRIPTION	DRAWN	CHK'D	APPRV'D
00	08-09-10	INCORP. INTO PDS PER EC #15920	KJB	JLF	KJB

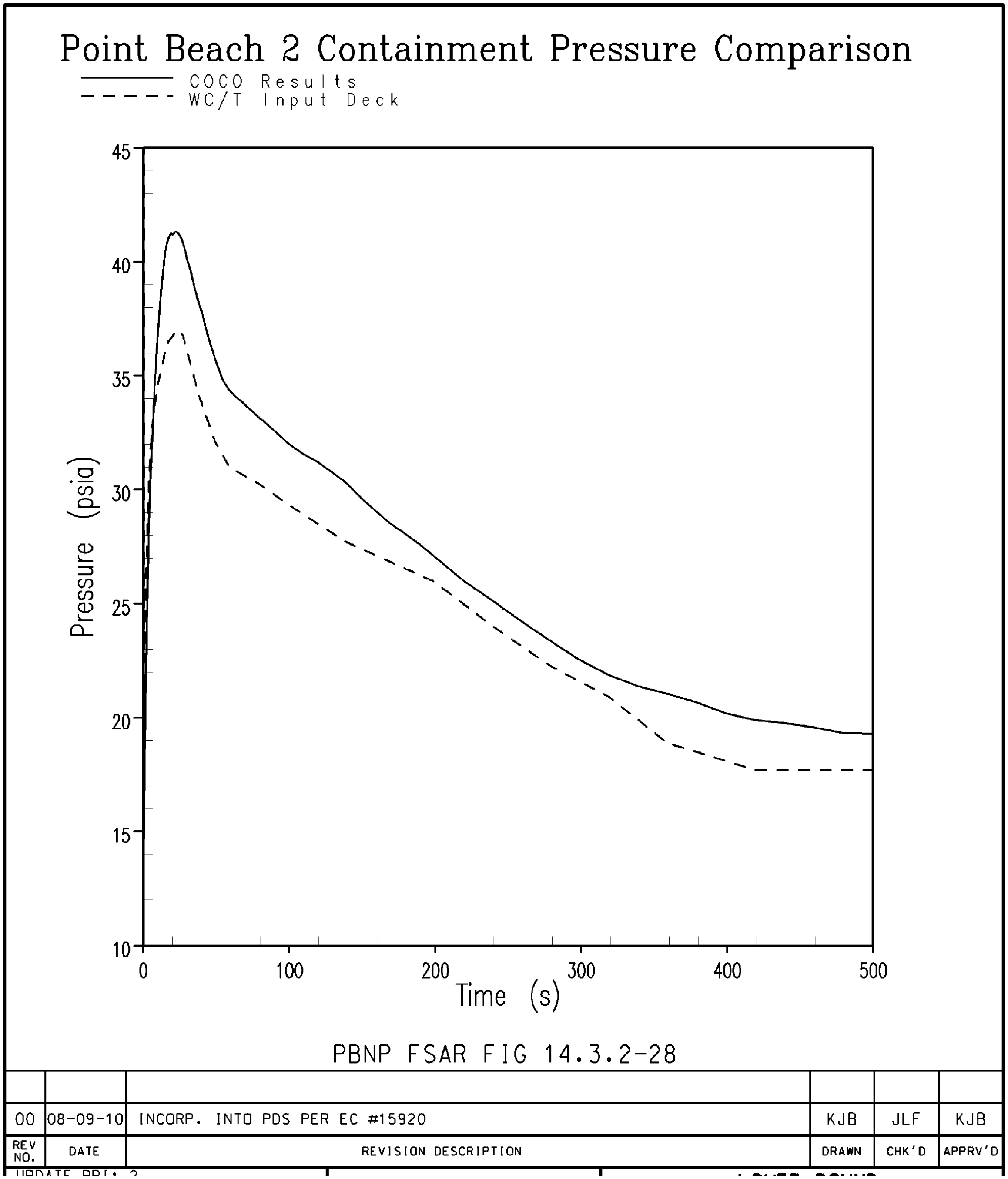
Figure 14.3.2-27 UNIT 2 BELOCA ANALYSIS AXIAL POWER SHAPE OPERATING SPACE ENVELOPE



PBNP FSAR FIG 14.3.2-27

00	08-09-10	INCORP. INTO PDS PER EC #15920	KJB	JLF	KJB
REV NO.	DATE	REVISION DESCRIPTION	DRAWN	CHK'D	APPRV'D

Figure 14.3.2-28 UNIT 2 LOWER BOUND CONTAINMENT PRESSURE



14.3.3 CORE AND INTERNALS INTEGRITY ANALYSIS

Internals Evaluation

The forces exerted on reactor internals and core, following a loss-of-coolant accident, are computed by employing the MULTIFLEX 3.0 (Reference 9) digital computer program developed for the space-time-dependent analysis of multi-loop PWR plants.

Design Criteria

The criteria for acceptability are that the core should be coolable and intact following a pipe rupture on the postulated 3" schedule 160 charging line (cold leg) or on the 6" schedule 120 capped line (hot leg) for extended power uprate (EPU) conditions. This implies that core cooling and adequate core shutdown must be assured. Consequently, the limitations established on the internals are concerned principally with the maximum allowable deflections and/or stability of the parts (Reference 7).

Critical Internals - Upper Barrel

The upper barrel deformation has the following limits:

> To assure reactor trip and to avoid disturbing the RCC guide structure, the barrel should not interfere with any guide tubes. This condition requires a stability check to assure that the barrel will not buckle under the accident loads.

Critical Internals - RCC Guide Tubes

The RCC guide tubes in the upper core support package have the following allowable limits. Tests were conducted on guide tubes to measure the insertion time versus guide tube deflection, with lateral forces simulating flow or inertia forces that the guide tubes are subjected to during a faulted event. The higher the lateral forces, the longer the insertion time. At a point, defined as the "allowable load," the guide tube would lose its function, and the control rods would no longer be able to insert. The allowable load for the guide tubes used at Point Beach Units 1 and 2 (i.e., 14x14 118-inch), derived from tests conducted on similar guide tubes, was established to be 15,500 pounds.

The maximum combined load during a safe-shutdown earthquake (SSE) and a loss-of-coolant accident (LOCA) event, as defined above, was calculated to be 14,580 pounds, which is less than the allowable load of 15,500 pounds. Therefore, control rod insertion for EPU conditions is not an issue (Reference 8).

Critical Internals - Fuel Assemblies

The limitations for this case are related to the stability of the thimbles at the upper end. During the accident, the fuel assembly will have a vertical displacement and could touch the upper package subjecting the components to dynamic stresses. The upper end of the thimbles shall not experience stresses above the buckling compressive stresses because any buckling of the upper end of the thimbles will distort the guide line and could affect the fall of the control rod.

Critical Internals - Upper Package

The maximum allowable local deformation of the upper core plate where a guide tube is located is 0.100 inch. This deformation will cause the plate to contact the guide tube since the clearance between plate and guide tube is 0.100 inch. This limit will prevent the guide tubes from being put in compression. In order to maintain the straightness of the guide tube, a maximum allowable total deflection of 1 inch for the upper support plate and deep beam has been established. The corresponding no loss of function deflection is above 2 inches.

Allowable Stress Criteria

The allowable stress criteria fall into two categories dependent upon the nature of the stress state: membrane or bending. A direct state of stress (Membrane) has a uniform stress distribution over the cross section. The allowable (Maximum) membrane or direct stress is taken to be equal to the stress corresponding to 0.2 of the uniform material strain or the yield strength, whichever is higher. For unirradiated 304 stainless steel at operating temperature, the stress corresponding to 20% of the uniform strain is:

$$(S_m)_{allowable} = 39500 \text{ psi}$$

For irradiated materials, the limit stress is higher. For a bending state of stress, the strain is linearly distributed over a cross section. The average strain value is, therefore, one half of the outer fiber strain where the stress is a maximum. Thus, by requiring the average strain to satisfy an allowable criterion similar to that for the direct state of stress, the outer fiber strain may be 0.4 times the uniform strain. The maximum allowable outer fiber bending stress is then taken to be equal to the stress corresponding to 40% of the uniform strain or the yield strength, whichever is higher. For unirradiated 304 stainless steel at operating temperature, we obtain from the stress strain curve:

$$(S_b)_{allowable} = 50{,}000 \text{ psi}$$

For combinations of membrane and bending stresses, the maximum allowable stress is taken to be equal to the stress corresponding to the maximum outer fiber strain not in excess of 40% uniform strain and average strain not in excess of 20% uniform strain.

Blowdown and Force Analysis - Blowdown Model

MULTIFLEX 3.0 (Reference 9) is a digital computer program for calculation of local fluid pressure, flow, and density transients that occur in the reactor primary coolant systems during a loss of coolant accident. This program applies to the subcooled, transition, and saturated two-phase blowdown regimes. This is in contrast to programs, such as WHAM (Reference 1), which are applicable only to the subcooled region and which, due to their method of solution, could not be extended into the region in which large changes in the sonic velocities and fluid densities take place.

MULTIFLEX 3.0 (Reference 9) is based on the method of characteristics wherein the resulting set of ordinary differential equations, obtained from the laws of conservation of mass, momentum, and energy, are solved numerically utilizing a fixed mesh in both space and time.

Although spatially one-dimensional conservation laws are employed, the code can be applied to describe 3-dimensional system geometries through the use of the equivalent piping networks. Such piping networks may contain any number of pipes or channels of various diameters, dead ends, branches (with up to six pipes connected to each branch), contractions, expansions, orifices, pumps, and free surfaces (such as in a pressurizer). All types of the system losses (such as friction, contraction, expansion, etc.) are considered.

Force Model

MULTIFLEX 3.0 (Reference 9) evaluates the pressure and velocity transients for a maximum of 2000 locations throughout the system. These pressure and velocity transients are made available to the programs LATFORC and FORCE 2 which utilize a detailed geometric description in evaluating the loadings on the reactor internals.

Each reactor component for which vertical force calculations are required is designated as an element and assigned an element number. Vertical forces acting upon each of the elements are calculated summing the effects of:

1. The pressure differential across the element
2. Flow stagnation on, and unrecovered orifice losses across the element
3. Friction losses along the element

Input to the code, in addition to the MULTIFLEX 3.0 (Reference 9) pressure and velocity transients, includes the effective area of each element on which acts the force due to the pressure differential across the element, a coefficient to account for flow stagnation and unrecovered orifice losses, and the total area of the element along which the shear forces act.

In addition to the vertical forces calculated by FORCE2, the horizontal forces on the vessel, core barrel, and thermal shield are calculated by LATFORC. The horizontal forces are calculated by summing the lateral force components around the vessel, core barrel and thermal shield, based on the pressure differential across each section, multiplied by the area of each section. This is done at ten different elevations. The total lateral force is calculated by summing the forces over the ten elevations.

Vertical Excitation - Structural Model and Method of Analysis

The response of reactor internals components due to an excitation produced by complete severance of a branch line pipe is analyzed. Assuming a pipe break occurs in a very short period of time, the rapid drop of pressure at the break produces a disturbance which propagates along the primary loop and excites the internal structure.

The internal structure is simulated by a multi-mass system connected with springs and dashpots representing the viscous damping due to structural and impact losses. The gaps between various components, as well as Coulomb type of friction, is also incorporated into the overall model. Since the fuel elements in the fuel assemblies are kept in position by friction forces originating from the preloaded fuel assembly grid fingers, any sliding that occurs between the fuel rods and assembly is considered as Coulomb type of friction. A series of mechanical models of local structures have been developed and analyzed so that certain basic nonlinear phenomena previously mentioned could be understood. Using the results of these models, a final eleven-mass model is adopted to represent the internals structure under vertical excitation. Figure 14.3.3-1 is a schematic representation of the internals structures. The eleven-mass model is shown in Figure 14.3.3-2. A comparison between Figure 14.3.3-1 and Figure 14.3.3-2 shows the parallel between the plant and the model. The modeling is conducted in such a way that uniform masses are lumped into easily identifiable discrete masses while elastic elements are represented by springs. A legend for the different masses is given in Table 14.3.3-1. The masses are readily recognized as Items W1 through W11. The core barrel and the lower package are easily discernible. The fuel assemblies have been segregated into two groups. The majority of the fuel mass, W4, is indirectly connected to the deep beam structure represented by mass W8. There is also a portion of the fuel mass, W6, which connects through the long columns to the top plate. The stiffness of the top plate panels is represented by K8. The hold down spring, K1, is bolted-up between the flange of the deep beam structure and the core barrel flange with the preload, Pl. After preloading the hold down spring, a clearance, G1, exists between the core barrel flange and the solid height of the hold down spring. Within the fuel assemblies, the fuel elements W4 and W6 are held in place by frictional contact with the grid spring fingers. Coulomb damping is provided in the analysis to represent this frictional restraint.

The analytical model is also provided with viscous terms to represent the structural damping of the elastic elements. The viscous dampers are represented by C1 through C11.

Restrictions are placed on the displacement amplitudes by specifying the free travel available to the dynamic masses. Available displacements are designated by symbols G1 through G8.

The displacements are tested during the solution of the problem to see if the available travel has been achieved. When the limit of travel has been attained, stops are engaged to arrest further motion of the dynamic masses. The stops of snubbers are designated by the symbols S1 through S11. Contact with the snubbers results in some damping of the motion of the model. The impact damping of the snubbers is represented by the devices D1 through D11.

During the assembly of the reactor, bolt-up of the closure head presets the spring loading of the core barrel and the spring loading on the fuel assemblies. Since the fuel assemblies in the model have been segregated into two groups, two preload values are provided in the analysis. Preload values P1, P3, and P5 represent the hold down spring preload on the core barrel and the top nozzle springs preload values on the fuel assemblies.

The formulation of the transient motion response problem and digital computer programming have been performed. The effects of an earthquake vertical excitation are also incorporated into the program.

In order to program the multi-mass system, the appropriate spring rates, weights, and forcing function for the various masses were determined. The spring rates and weights of the reactor components are calculated separately for each plant. The forcing functions for the masses are obtained from the FORCE2 program described in the previous section. It calculates the transient forces on reactor internals during blowdown using transient pressures and fluid velocities.

For the blowdown analysis the forcing functions are applied directly to the various internal masses.

For the earthquake analysis of the reactor internals, the forcing function, which is simulated earthquake response, is applied to the multi-mass system at the ground connections (the reactor vessel). Therefore, the external excitation is transmitted to the internals through the springs at the ground connections.

Results

Analysis was performed for a 1 millisecond opening time, and for hot leg and cold leg branch line breaks. The response of the structure to these excitations indicates that the vertical motion is irregular with peaks of very short duration. The deflections and motion of some of the reactor components are limited by the solid height of springs as is also the hold down spring located above the barrel flange.

The internals behave as a nonlinear system during the vertical oscillations produced by the blowdown forces. The nonlinearities are due to the Coulomb frictional forces between grids and rods, and to gaps between components causing discontinuities in force transmission. The frequency response is consequently a function not only of the exciting frequencies in the system, but also of the amplitude. Different break conditions excite different frequencies in the system. This situation can be seen clearly when the response under blowdown forces is compared with the one due to vertical seismic acceleration. Under seismic excitation, the system behaves almost linearly because component motion is not sufficient to cause closing of the various gaps in the structure or slippage in the fuel rods.

Under certain blowdown excitation conditions, the core moves upward, touches the core plate, and falls down on the lower structure causing oscillations in all the components. During the time that the oscillations occur and, depending on its initial position, the fuel rods slide on the fuel assembly. The response shows that the case could be represented as two large vibrating masses (the core and the barrel), and the rest of the system oscillates with respect to the barrel and the core. Damping effects have also been considered; it appears that the higher frequencies disappear rapidly after each impact of slippage.

The results of the computer program give not only the frequency response of the components, but also the maximum impact force and deflections. From these results, the stresses are computed using the standard “Strength of Material” formulas. The impact stresses are obtained in an analogous manner using the maximum forces seen by the various structures during impact.

Baffle Former Bolt Replacement (Unit 2 Only)

Point Beach Unit 2 was selected as a lead plant to collect information regarding a baffle former bolt cracking phenomena observed in some foreign nuclear power plants. All baffle former bolts were inspected and a select pattern of baffle former bolts were replaced using methodology presented WCAP-15133 “Determination of Acceptable Baffle-Barrel-Bolting for Point Beach Units 1 and 2”. This replacement also included one bolt in a “non-critical” location which was removed and not replaced. WCAP-15133 was based on an NRC accepted methodology presented in WCAP-15029 “Westinghouse Methodology for Evaluating the Acceptability of Baffle-Former-Barrel Bolting Distributions Under Faulted Load Conditions.” This methodology and its use were strictly limited to the baffle former bolt project (Reference 3 through Reference 6).

Aging Management Program

The Aging Management Program, Reactor Vessel Internals Program (FSAR Section 15.2.17) provides additional information for monitoring during the period of extended operation (NRC SE dated 12/2005, NUREG-1839).

References

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2. K. Takeuchi: "MULTIFLEX, A FORTRAN-IV Computer Program for Analyzing Thermal-Hydraulic-Structure System Dynamics," WCAP 8708-PA, WCAP 8709-A (Non-proprietary), September, 1977.

3. WCAP-15133 "Determination of Acceptable Baffle-Barrel-Bolting for Point Beach Units 1 and 2."

4. Westinghouse Engineering Letter NSD-E-MSI-99-036 "Evaluation of Case 132 and 132 no 722 Baffle Bolting Patterns," dated January 28, 1999.

5. WCAP-15029 "Westinghouse Methodology for Evaluating the acceptability of Baffle-Former-Barrel Bolting Distributions Under Faulted Load Conditions," by P.E. Schwirian, et. al., Westinghouse Electric Company, 1998.

6. NRC Safety Evaluation of Topical Report WCAP-15029 "Westinghouse Methodology for Evaluating the Acceptability of Baffle-Former-Barrel Bolting Distribution Under Faulted Load Conditions" (TAC NO. MA 1152)," dated November 10, 1998.

7. Westinghouse Calculation Note CN-RIDA-08-37, Rev. 2, "WEP/WIS (Point Beach Units 1 and 2) RPV System LOCA Analysis - EPU Program," November 20, 2008.

8. Westinghouse Calculation Note CN-RIDA-08-73, Rev. 0, "WEP/WIS (Point Beach Units 1 and 2) EPU - Guide Tube Control Rod Insertability," November 24, 2008.

9. K. Takeuchi: "MULTIFLEX 3.0, A FORTRAN-IV Computer Program for Analyzing Thermal-Hydraulic - Structural System Dynamics Advanced Beam Model," WCAP-9735 Rev. 2, WCAP-9736 (Non-proprietary) Rev. 1, February 1998.

Table 14.3.3-1 MULTI-MASS VIBRATIONAL MODEL-DEFINITION OF SYMBOLS

W1 - Core Barrel
W2 - Lower Package
W3 - Fuel Assemblies Major
W4 - Fuel Rods Major
W5 - Fuel Assemblies Minor
W6 - Fuel Rods Minor
W7 - Core Plate & Short Column
W8 - Deep Beam
W9 - Core Plate & Long Columns
W10 - Top Plate (Ctr.)
W11 - Core Barrel

K1 - Hold Down Spring
K2 - Lower Package Major
K3 - Top Nozzle Springs Major
K5 - Top Nozzle Springs Minor
K7 - Short Columns
K8 - Upper Core Plate
K9 - Long Columns
K10 - Top Plate
K11 - Core Barrel

Snubbers

S1 - Core Barrel Flange
S2 - Hold Down Spring
S3 - Top Nozzles Bars, Major
S4 - Pedestal Bars, Major
S5 - Top Nozzles Bars, Minor
S6 - Pedestal Bars, Minor
S7 - Top Nozzle Bumpers, Major
S8 - Top Nozzle Bumpers, Minor
S9 - Pedestals, Major
S10 - Pedestals, Minor
S11 - Deep Beam Flange

Impact Dampers

D1 - Barrel Flange
D2 - Hold Down Spring
D3 - Top Nozzle Bars, Major
D4 - Pedestal Bars, Major
D5 - Top Nozzle Bars, Minor
D6 - Pedestal Bars, Minor
D7 - Top Nozzles, Major
D8 - Top Nozzles, Minor
D9 - Pedestal, Major
D10 - Pedestal, Minor
D11 - Deep Beam Flange

Structural Dampers

C1 - Hold Down Springs
C2 - Lower Package
C3 - Top Nozzle, Major
C5 - Top Nozzle, Minor
C7 - Short Columns
C8 - Upper Core Plate
C9 - Long Columns
C10 - Top Plate
C11 - Core Barrel

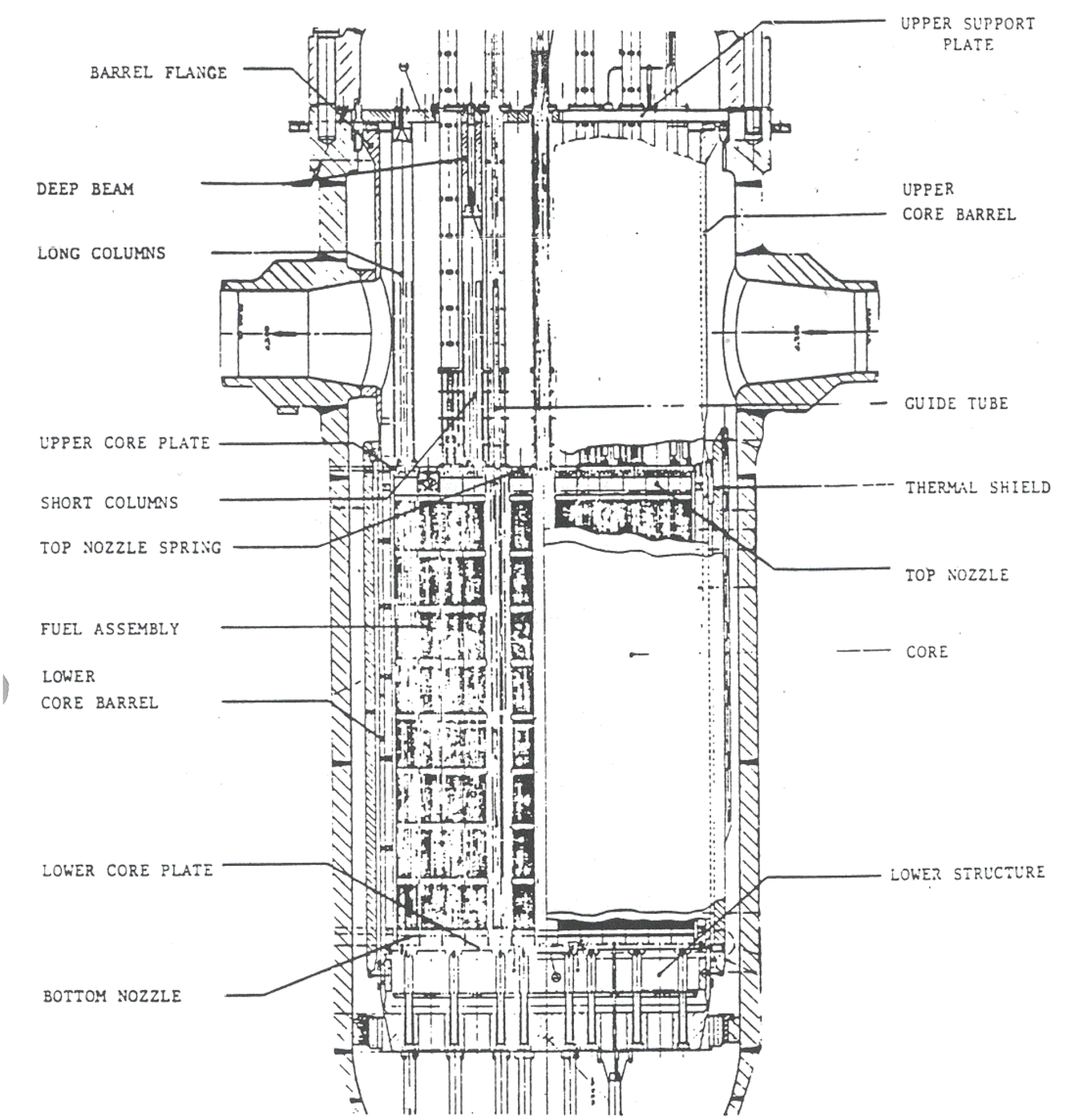
Clearances

G1 - Hold Down Spring
G3 - Fuel Rod Top, Major
G4 - Fuel Rod Bottom, Major
G5 - Fuel Rod Top, Minor
G6 - Fuel Rod Bottom, Minor
G7 - Fuel Assembly Major
G8 - Fuel Assembly Minor

Preloads

P1 - Hold Down Spring
P3 - Top Nozzle Springs Major
P5 - Top Nozzle Springs Minor

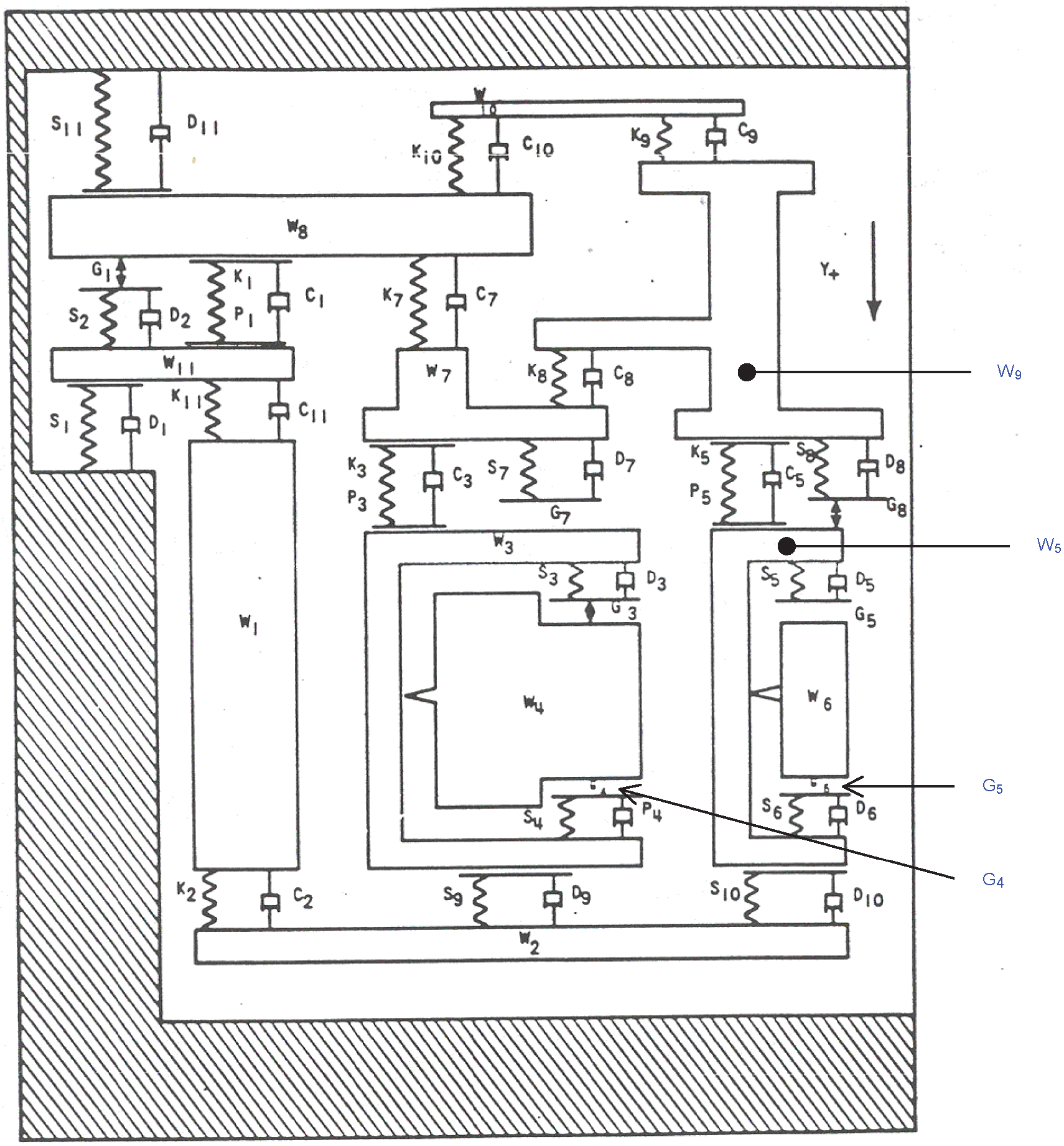
Figure 14.3.3-1 REACTOR VESSEL INTERNALS



REACTOR VESSEL INTERNALS

Figure 14.3.3-1

Figure 14.3.3-2 MULTI-MASS VIBRATIONAL MODEL



Multi-Mass Vibrational Model

Figure 14.3.3-2

14.3.4 LOCA M&E Release and Containment Response

14.3.4.1 Loss-of Coolant (LOCA) Mass and Energy Releases

The uncontrolled release of pressurized high-temperature reactor coolant, termed a loss-of-coolant accident (LOCA), will result in release of steam and water into the containment. This, in turn, will result in increases in the local subcompartment pressures, and an increase in the global containment pressure and temperature. Therefore, there are both long and short-term issues reviewed relative to a postulated LOCA that must be considered at the operating conditions for the Point Beach Units 1 and 2 EPU Program at a core power of 1,800 MWt (without uncertainty).

The long-term LOCA mass and energy (M&E) releases are analyzed and used as input to the containment integrity analysis [note that only the mass and energy releases up to 3,600 seconds will be utilized by GOTHIC for the containment integrity analysis (see Section 14.3.4.2)]. This demonstrates the acceptability of the containment safeguards systems to mitigate the consequences of a hypothetical large-break LOCA (LBLOCA). The containment safeguards systems must be capable of limiting the peak containment pressure to less than the design pressure and limiting the temperature excursion to less than the acceptance limits. For this program, Westinghouse generated the M&E releases using the March 1979 model, described in WCAP-10325-P-A (Reference 1) and associated support review documents (Reference 5 and Reference 7). The Nuclear Regulatory Commission (NRC) review and approval letter is included with WCAP-10325-P-A (Reference 1). Section 14.3.4.1.1 discusses the long-term LOCA M&E releases generated for this program. The results of this analysis were used in the containment integrity analysis.

The short-term LOCA-related M&E releases are used as input to the subcompartment analyses. These analyses are performed to ensure that the walls of a subcompartment can maintain their structural integrity during the short pressure pulse (generally less than 3 seconds) accompanying a high-energy line pipe rupture within that subcompartment. The subcompartments that are typically evaluated include the SG compartment, the reactor cavity region, and the pressurizer compartment. Point Beach Units 1 and 2 are approved for leak-before-break (LBB) (see Section 14.3.4.1.2) such that the only breaks that need to be evaluated are a 6 inch double-ended hot leg break and a 3 inch double-ended cold leg break. Any changes associated with the power uprate are typically offset by the LBB benefit of using the smaller Reactor Coolant System (RCS) nozzle breaks. The critical mass flux correlation utilized in the SATAN computer program (Reference 2) was used to conservatively estimate the impact of the changes in RCS temperatures on the short-term releases. The evaluation showed that the decrease in mass and energy releases associated with the smaller breaks more than offsets the potential penalties associated with increased releases associated with the EPU. Section 14.3.4.1.2 discusses the short-term evaluation conducted for this program.

14.3.4.1.1 Long-Term LOCA Mass and Energy Releases

The mass and energy release rates described in this section form the basis of further computations to evaluate the containment response (containment integrity peak pressure and the long-term containment temperature calculations) following the postulated accident to ensure that containment design margin is maintained. Discussed in this section are the long-term LOCA mass and energy releases for the hypothetical double-ended pump suction DEPS) rupture with minimum and maximum safeguards and the double-ended hot leg (DEHL) rupture break case mass and energy release which is limiting for the blowdown portion of the LOCA transient. These LOCA cases are used for the long-term containment integrity analyses in subsection 14.3.4.2 (Long-Term LOCA Containment Response).

14.3.4.1.1.1 Input Parameters and Assumptions

The mass and energy release analysis is sensitive to the characteristics of various plant systems, in addition to other key modeling assumptions. Where appropriate, bounding inputs are utilized and instrumentation uncertainties are included. For example, the RCS operating temperatures are chosen to bound the highest average coolant temperature range of all operating cases and a temperature uncertainty allowance of +6.4°F is then added. Nominal parameters are used in certain instances. For example, the RCS pressure in this analysis is based on a nominal value of 2,250 psia plus an uncertainty allowance (a conservatively high uncertainty of +50.0 psi was used).

All input parameters are chosen consistent with accepted analysis methodology. Some of the most critical items are the RCS initial conditions, core decay heat, safety injection (SI) flow, and primary and secondary metal mass and steam generator heat release modeling. Specific assumptions concerning each of these items are discussed in the following paragraphs. Table 14.3.4-1 through Table 14.3.4-4 present key data used in the analysis.

The core rated power of 1,811 MWt adjusted for calorimetric error (that is, 100.6% of 1,800 MWt) was used in the analysis. As previously noted, RCS operating temperatures were used to bound the highest average coolant temperature range as bounding analysis conditions. The use of higher temperatures is conservative because the initial fluid energy is based on coolant temperatures that are at the maximum levels attained in steady-state operation. Additionally, an allowance to account for instrument error and deadband is reflected in the initial RCS temperatures. The selection of 2,300 psia (2,250 psia nominal value + 50 psi uncertainty allowance) as the limiting pressure is considered to impact the blowdown phase results only, since this represents the initial pressure of the RCS. The RCS rapidly depressurizes from this value until the point at which it equilibrates with containment pressure.

The rate at which the RCS blows down is initially more severe at the higher RCS pressure. Additionally the RCS has a higher fluid density at the higher pressure (assuming a constant temperature) and subsequently has a higher RCS mass available for releases. Thus, 2,250 psia plus uncertainty was selected for the initial pressure as the limiting case for the long-term mass and energy release calculations.

Core stored energy is the amount of energy in the fuel rods above the local coolant temperature. The selection of the fuel design features for the long-term mass and energy release calculation are based on the need to conservatively maximize the energy stored in the fuel at the beginning of the postulated accident. The following fuel features are considered; 1) rod geometry, 2) rod power, and 3) limiting time in life (e.g., burn-up). Uncertainty is included in the core stored energy value to conservatively address the thermal fuel model, considering uncertainties, margin, and fuel densification. Core stored energy is addressed in the analysis as full power seconds (FPS). The core-stored energy that was selected for the Point Beach analysis was 5.25 FPS.

A 3-percent margin in the RCS volume (of which is composed of 1.6-percent allowance for thermal expansion and 1.4-percent allowance for uncertainty) was modeled. This assumption maximizes the initial RCS mass and energy fluid inventory.

A uniform steam generator tube plugging level of zero-percent was modeled. This assumption maximizes the reactor coolant volume and fluid release by virtue of consideration of the RCS fluid in all steam generator tubes. During the post-blowdown period, the steam generators are active heat sources, since significant energy remains in the secondary metal and secondary mass that has the potential to be transferred to the primary side. The zero-percent tube plugging assumption maximizes the heat transfer area and therefore, the transfer of secondary heat across the steam generator tubes. Additionally, this assumption reduces the reactor coolant loop resistance, which reduces the pressure drop (i.e., ΔP) upstream of the break for the pump suction breaks and increases break flow. Thus, the analysis very conservatively accounts for the effects related to steam generator tube plugging.

Secondary-to-primary heat transfer is maximized by assuming conservative coefficients of heat transfer (i.e., steam generator primary-to-secondary heat transfer and reactor coolant system metal heat transfer). Maximum secondary-to-primary heat transfer is ensured by maximizing the initial steam generator inventory based upon 100% power conditions, nominal level plus level uncertainty, and then increasing this by 10% to maximize the available energy. The 10% uncertainty is part of the licensed methodology in Reference 1.

Following a large-break LOCA blowdown inside containment, the safety injection system (SIS) actuates to reflood the RCS. Regarding safety injection flow, the mass and energy release analysis considered configurations, component failures, and offsite power assumptions to conservatively bound respective alignments. The first phase of the SIS operation is the passive accumulator injection. Two accumulators are assumed available to inject. In the LOCA mass and energy release analysis, when the RCS depressurizes below 834.7 psia [maximum accumulator gas cover pressure of 800 psig (814.7 psia) plus an allowance (adjustment) for pressure uncertainty of 20 psi], the accumulators begin to inject. The accumulator injection temperature was conservatively modeled high at 120°F. Relative to the active pumped emergency core cooling system (SI flow), the mass and energy release calculation considered configurations/failures, and offsite power assumptions to conservatively bound respective alignments. Both cases evaluated credited minimum safeguards consistent with the failure of a single train of power [one high head SI (HHSI) pump, and one low head SI (LHSI) pump; see Table 14.3.4-2]. In addition, the containment backpressure is assumed to be equal to the containment design pressure. This assumption was shown in WCAP-10325-P-A (Reference 1) to be conservative for the generation of mass and energy releases.

In summary, the following assumptions were employed to ensure that the mass and energy releases are conservatively calculated, thereby maximizing energy release to containment:

- Maximum expected operating temperature of the RCS (100-percent full-power operation)
- Allowance for RCS temperature uncertainty (+6.4°F)
- Analyzed Core power of 1,811 MWt
- Allowance for calorimetric error (0.6 percent of power)

- Conservative heat transfer coefficients (that is, steam generator primary/secondary heat transfer and RCS metal heat transfer)
- Allowance in core-stored energy for effect of fuel densification
- An allowance for RCS initial pressure uncertainty (+50psi)
- A total uncertainty for fuel temperature calculation based on a statistical combination of effects and dependent upon fuel type, power level, and burnup
- A maximum containment backpressure equal to the design pressure (74.7 psia)
- Steam Generator Tube Plugging (SGTP) level (0 percent uniform)
    - Maximizes reactor coolant volume and fluid release
    - Maximizes heat transfer area across the steam generator tubes
    - Reduces reactor coolant loop resistance, which reduces the ΔP upstream of the break for the pump suction breaks and increases break flow

Therefore, based on the previously discussed conditions and assumptions, an analysis for Point Beach Units 1 and 2 was performed for the release of mass and energy from the RCS in the event of a large break LOCA at 1,811 MWt core power.

Decay Heat Model

The American Nuclear Society (ANS) Standard 5.1 (Reference 4) was used in the LOCA mass and energy release model for the determination of decay heat energy. This standard was balloted by the Nuclear Power Plant Standards Committee (NUPPSCO) in October 1978 and subsequently approved. The official standard (Reference 4) was issued in August 1979. Table 14.3.4-4 lists the decay heat curve used in the Point Beach Units 1 and 2 mass and energy release analysis.

Significant assumptions in the generation of the decay heat curve for use in the LOCA mass and energy release analysis include the following:

- The decay heat sources considered are fission product decay and heavy element decay of U-239 and Np-239.
- The decay heat power from fissioning isotopes other than U-235 is assumed to be identical to that of U-235.
- The fission rate is constant over the operating history of maximum power level.
- The factor accounting for neutron capture in fission products has been taken from Table 10 of the ANS Standard 5.1 (Reference 4)
- The fuel has been assumed to be at full power for 10^8 seconds.
- The total recoverable energy associated with one fission has been assumed to be 200 MeV/fission.
- An uncertainty of two sigma (two times the standard deviation) has been applied to the fission product decay.

Based upon NRC staff review, (Safety Evaluation Report (SER) issued for the March 1979 evaluation model (Reference 1), use of the ANS Standard 5.1 (Reference 4) decay heat model was approved for the calculation of mass and energy releases to the containment following a LOCA.

Application of Single-Failure Criterion

An analysis of the effects of the single-failure criterion has been performed on the mass and energy release rates for each break analyzed. An inherent assumption in the generation of the mass and energy release is that offsite power is lost. This results in the actuation of the emergency diesel generators, which are required to power the emergency core cooling system (ECCS). Actuation of the emergency diesel generators results in a delay in the time to start both the ECCS and containment safeguards. A delay in the actuation of these accident mitigating components results in a higher containment pressure and temperature for the postulated LOCA. Since the M&E codes (Reference 1) are uncoupled from the containment pressure code (Reference 8, Reference 9, and Reference 12) an assumption on containment pressure is required in the Reference 2 M&E calculations. Maximum containment backpressure equal to the design pressure is modeled, which reduces the rate of safety injection, condensation of steam by the safety injection, and extends the reflood phase, which maximizes the steam release.

A single case to bound all possible single failures was analyzed. This case assumed minimum safeguards SI and containment spray flow based on the postulated failure of an EDG. This assumption results in the loss of one train of safeguards equipment. Therefore, the remaining ECCS was conservatively modeled as: one HHSI pump, one LHSI pump, and one containment spray pump. Earlier analyses had demonstrated that assuming two trains of ECCS and only one train of containment spray resulted in lower peak containment pressures and temperatures. Since the single EDG failure case had been demonstrated to be limiting, the single spray pump failure has not been updated or retained.

Acceptance Criteria

A large break loss-of-coolant accident is classified as an ANS Condition IV event, an infrequent fault. To satisfy the Nuclear Regulatory Commission acceptance criteria, the relevant requirements are as follows:

1. Point Beach Nuclear Plant (PBNP) FSAR Chapter 1.3 General Design Criteria; as it relates to General Design Criteria 10, 49, and 52, with the respect to containment design integrity and containment heat removal.
2. 10 CFR 50, Appendix K, paragraph I.A: as it relates to sources of energy during the LOCA, provides requirements to assure that all energy sources have been considered.

In order to meet these requirements, the following must be addressed.

1. Source of Energy
2. Break Size and Location
3. Calculation of Each Phase of the Accident
4. Single Failure Criteria

The mass and energy release flowrate table and related analysis information for Point Beach Units 1 and 2 are presented in Table 14.3.4-5 through Table 14.3.4-21.

14.3.4.1.1.2 Description of Analysis

This report section presents the long-term LOCA mass and energy releases generated for Point

Beach Units 1 and 2 at 1811 MWt core power. The evaluation model used for the long-term LOCA mass and energy release calculations is the March 1979 model described in Reference 1. This evaluation model has been reviewed and approved generically by the NRC. The approval letter is included with Reference 1. This LOCA mass and energy release methodology has been utilized and approved on the plant-specific dockets for other Westinghouse PWRs such as Catawba Units 1 and 2, Beaver Valley Unit 2, McGuire Units 1 and 2, Millstone Unit 3, Sequoyah Units 1 and 2, Surry Units 1 and 2, Indian Point Unit 2, and Indian Point Unit 3.

A description of the Reference 1 methodology is provided below.

14.3.4.1.1.3 LOCA Mass and Energy Release Phases

The containment system receives mass and energy releases following a postulated rupture in the RCS. These releases continue over a time period, which, for the LOCA mass and energy analysis, is typically divided into four phases:

- Blowdown~the period of time from accident initiation (when the reactor is at steady-state operation) to the time that the RCS and containment reach an equilibrium state.
- Refill - the period of time when the lower plenum is being filled by accumulator and emergency core cooling system (ECCS) water. At the end of blowdown, a large amount of water remains in the cold legs, downcorner, and lower plenum. To conservatively consider the refill period for the purpose of containment mass and energy releases, it is assumed that this water is instantaneously transferred to the lower plenum along with sufficient accumulator water to completely fill the lower plenum. This allows an uninterrupted release of mass and energy to containment. Thus, the refill period is conservatively neglected in the mass and energy release calculation.
- Reflood-begins when the water from the lower plenum enters the core and ends when the core is completely quenched.
- Post-reflood describes the period following the reflood phase. For the pump suction break, a two-phase mixture exits the core, passes through the hot legs, and superheated in the steam generators prior to exiting the break as steam. After the broken loop steam generator cools, the break flow becomes two phase.

14.3.4.1.1.4 Computer Codes

The Reference 1 mass and energy release evaluation model is comprised of mass and energy release versions of the following codes: SATAN-VI, WREFLOOD, FROTH, and EPITOME. These codes were used to calculate the long-term LOCA mass and energy releases for Point Beach.

SATAN-VI calculates blowdown, the first portion of the thermal-hydraulic transient for the RCS following break initiation, including pressure, enthalpy, density, mass and energy flowrates, and energy transfer between primary and secondary systems as a function of time.

The WREFLOOD code addresses the portion of the LOCA transient during the core reflood phase.

FROTH models the post-reflood portion of the transient. The FROTH code is used for the steam generator heat addition calculation from the broken and intact loop steam generators.

EPITOME continues the FROTH post-reflood portion of the transient from the time at which the secondary equilibrates to containment design pressure to the end of the transient.

14.3.4.1.1.5 Break Size and Location

Generic studies (Reference 2) have been performed to determine the effect of postulated break size on the LOCA mass and energy releases. The double-ended guillotine break has been found to be limiting due to larger mass flow rates during the blowdown phase of the transient. During the reflood and froth phases, the break size has little effect on the releases.

Three distinct locations in the reactor coolant system can be postulated for a pipe rupture for mass and energy release purposes:

- Hot leg (between vessel and steam generator)
- Cold leg (between pump and vessel)
- Pump suction (between steam generator and pump)

The break locations analyzed are the double-ended pump-suction (DEPS) rupture (10.48 ft^2) and the double-ended hot-leg (DEHL) rupture (9.17 ft^2). Break mass and energy releases have been calculated for blowdown, reflood, and post-reflood phases of the LOCA for the DEPS cases. For the DEHL case, the releases were calculated only for the blowdown. The following information provides a discussion on each break location.

The DEHL rupture has been shown in previous studies (Reference 1) to yield the highest blowdown mass and energy release rates. Although the core flooding rate would be the highest for this break location, the amount of energy released from the steam generator secondary is minimal because the bulk of the fluid that exits the core vents directly to containment bypassing the steam generators. As a result, the reflood mass and energy releases are reduced significantly as compared to either the pump-suction or cold-leg break locations where the core-exit mixture must pass through the steam generators before venting through the break. For the hot-leg break, generic studies (Reference 1, Section 3.3) have confirmed that there is no reflood peak, that is, from the end of the blowdown period, the containment pressure would continually decrease (Reference 1, Section 3.3). In addition, since none of the powered safety systems are assumed to be operational during the initial blowdown phase, the service water system has no impact on the DEHL break. Therefore, only the mass and energy releases for the hot-leg break (blowdown phase) are calculated and presented in this section of the report and no further evaluation is necessary.

The cold-leg break location has also been found in previous studies to be much less limiting in terms of the overall containment energy releases (Reference 1, Section 3.3). The cold-leg blowdown is faster than that of the pump-suction break, and more mass is released into the containment. However, the core heat transfer is greatly reduced, and this results in a considerably lower energy release into containment. The blowdown transient for the cold-leg is, in general less limiting than that for the pump suction break. During the reflood phase, the flooding rate is greatly reduced and the energy release rate into the containment is reduced. Therefore, the cold-leg break is bounded by other breaks and no further evaluation is necessary.

The pump-suction break combines the effects of the relatively high core flooding rate, as in the hot-leg break, and the addition of the stored energy in the steam generators. As a result, the pump-suction break yields the highest energy flow rates during the post-blowdown period by including all of the available energy of the RCS in calculating the releases to containment.

Therefore, only DEHL and DEPS case are analyzed for long-term LOCA containment integrity. LOCA mass and energy releases have been calculated for the blowdown, reflood and post-reflood phases for the DEPS cases. For the DEHL case, the releases were calculated only for the blowdown phase with this methodology.

14.3.4.1.1.6 Blowdown Mass and Energy Release Data

The SATAN-VI code is used for computing the blowdown transient. The code utilizes the control volume (element or nodal) approach with the capability for modeling a large variety of thermal fluid system configurations. The fluid properties are considered uniform and thermodynamic equilibrium is assumed in each element. A point kinetics model is used with weighted feedback effects. The major feedback effects include moderator density, moderator temperature, and Doppler broadening. A critical flow calculation for subcooled (modified Zaloudek), two-phase (Moody), or superheated break flow is incorporated into the analysis. The methodology for the use of this model is described in WCAP-10325-P-A (Reference 1).

Table 14.3.4-5 presents the calculated mass and energy release for the blowdown phase of the DEHL break. For the hot-leg break mass and energy release tables, break path 1 refers to the mass and energy exiting from the reactor vessel side of the break. Break path 2 refers to the mass and energy exiting from the steam generator side of the break. Table 14.3.4-6 and Table 14.3.4-7 present the mass and energy balance data for the DEHL case.

Table 14.3.4-8 presents the calculated mass and energy releases for the blowdown phase of the DEPS break location (applicable for both minimum and maximum safeguards break cases). For the pump-suction breaks, break path 1 in the mass and energy release tables refers to the mass and energy exiting from the steam generator side of the break. Break path 2 refers to the mass and energy exiting from the pump side of the break.

14.3.4.1.1.7 Reflood Mass and Energy Release Data

The WREFLOOD code is used for computing the reflood transient. The WREFLOOD code consists of two basic hydraulic models: one for the contents of the reactor vessel and one for the coolant loops. The two models are coupled through the interchange of the boundary conditions applied at the vessel outlet nozzles and at the top of the downcomer. Additional transient phenomena, such as pumped safety injection and accumulators, reactor coolant pump performance, and steam generator releases are included as auxiliary equations that interact with the basic models as required. The WREFLOOD code permits the capability to calculate variations during the core reflooding transient of basic parameters such as core flooding rate, core and downcomer water levels, fluid thermodynamic conditions (pressure, enthalpy, density) throughout the primary system, and mass flow rates through the primary system. The code permits hydraulic modeling of the two flow paths available for discharging steam and entrained water from the core to the break, that is, the path through the broken loop and the path through the unbroken loops.

A complete thermal equilibrium mixing condition for the steam and ECCS injection water during the reflood phase has been assumed for each loop receiving ECCS water. This is consistent with the usage and application of the WCAP-10325-P-A (Reference 1) mass and energy release evaluation model in recent analyses, for example, D. C. Cook Unit 1 Docket (Reference 5). Even though the WCAP-10325-P-A (Reference 1) model credits steam/water mixing only in the intact loop and not in the broken loop, the justification, applicability, and NRC approval for using the mixing model in the broken loop has been documented (Reference 5). Moreover, this assumption is supported by test data and is further discussed below.

The model assumes a complete mixing condition (that is, thermal equilibrium) for the steam/water interaction. The complete mixing process, however, is made up of two distinct physical processes. The first is a two-phase interaction with condensation of steam by cold ECCS water. The second is a single-phase mixing of condensate and ECCS water. Since the steam release is the most important influence to the containment pressure transient, the steam condensation part of the mixing process is the only part that must be considered. Any spillage directly heats only the sump.

The most applicable steam/water mixing test data have been reviewed for validation of the containment integrity reflood steam/water mixing model. This data was generated in 1/3-scale tests (Reference 6), which are the largest scale data available. Therefore, the test data most clearly simulates the flow regimes and gravitational effects that would occur in a PWR. These tests were designed specifically to study the steam/water interaction for PWR reflood conditions.

A group of 1/3-scale steam/water mixing tests discussed in Reference 6 corresponds directly to containment integrity reflood conditions. The injection flow rates for this group cover all phases and mixing conditions calculated during the reflood transient. The data from these tests were reviewed and discussed in detail in WCAP-10325-P-A (Reference 1). For all of these tests, the data clearly indicate the occurrence of very effective mixing with rapid steam condensation. The mixing model used in the containment integrity reflood calculation is, therefore, wholly supported by the 1/3-scale steam/water mixing data.

Additionally, the following justification is also noted. The post-blowdown limiting break for the containment integrity peak pressure analysis is the pump-suction double-ended rupture break. For this break, there are two flow paths available in the RCS by which mass and energy may be released to containment. One is through the outlet of the steam generator, the other via reverse flow through the RCP. Steam that is not condensed by ECCS injection in the intact RCS loops passes around the downcomer and through the broken-loop cold-leg and pump in venting to containment. This steam also encounters ECCS injection water as it passes through the broken-loop cold-leg, complete mixing occurs and a portion of it is condensed. It is this portion of steam that is condensed that is taken credit for in this analysis. This assumption is justified based upon the postulated break location, and the actual physical presence of the ECCS injection nozzle. A description of the test and test results are contained in WCAP-10325-P-A (Reference 1) and the operating license Amendment No. 126 for D. C. Cook (Reference 5).

Table 14.3.4-9 presents the calculated mass and energy releases for the reflood phase of the double-ended pump-suction rupture with minimum safeguards (i.e., the EDG failure) case.

The transient responses of the principal parameters during reflood are given in Table 14.3.4-11 for the DEPS.

14.3.4.1.1.8 Post-Reflood Mass and Energy Release Data

The FROTH code (Reference 1 and Reference 2) is used for computing the post-reflood transient. The FROTH code calculates the heat release rates resulting from a two-phase mixture present in the steam generator tubes. The mass and energy releases that occur during this phase are typically superheated (Reference 7) due to the depressurization and equilibration of the broken loop and intact loop steam generators. During this phase of the transient, the RCS has equilibrated with the containment pressure. However, the steam generators contain a secondary inventory at an enthalpy that is much higher than the primary side. Therefore, there is a significant amount of reverse heat transfer that occurs. Steam is produced in the core due to core decay heat. For a pump-suction break, a two-phase fluid exits the core, flows through the hot legs, and becomes superheated as it passes through the steam generator. Once the broken loop cools, the break flow becomes two-phase. During the FROTH calculation, ECCS injection is addressed for both the injection phase and the recirculation phase. The FROTH code calculation stops when the secondary side equilibrates to the saturation temperature (T_{sat}) at the containment design pressure. After this point, the EPITOME code completes the steam generator depressurization.

The methodology for the use of this model is described in WCAP-10325-P-A (Reference 1). The mass and energy release rates are calculated by the FROTH and EPITOME computer codes until the time of containment depressurization. After containment depressurization (14.7 psia), the mass and energy release available to containment is generated directly from core boil-off/decay heat.

Table 14.3.4-13 presents the two-phase post-reflood mass and energy release data for the pump suction double-ended break case.

14.3.4.1.1.9 Post-Reflood Mass and Energy Release Data-Steam Generator Equilibration and Depressurization

Steam generator equilibration and depressurization is the process by which secondary-side energy is removed from the steam generators in stages. The FROTH computer code calculates the heat removal from the secondary mass until the secondary temperature is the saturation temperature (T_{sat}) at the containment design pressure. After the FROTH calculations, the EPITOME code continues the FROTH calculation for steam generator cooldown removing steam generator secondary energy at different rates (that is, first- and second-stage rates). The first-stage rate is applied until the steam generator reaches the saturation temperature (T_{sat}) at the user specified intermediate equilibration pressure, when the secondary pressure is assumed to reach the actual containment pressure. Then the second-stage rate is used until the final depressurization, when the secondary reaches the reference temperature of T_{sat} at 14.7 psia, or 212°F. The heat removal of the broken loop and intact loop steam generators are calculated separately.

During the FROTH calculations, steam generator heat removal rates are calculated using the secondary side temperature, primary side temperature and a secondary side heat transfer coefficient determined using a modified McAdam's correlation. Steam generator energy is removed during the FROTH transient until the secondary side temperature reaches saturation temperature (Tsat) at the containment design pressure. The constant heat removal rate used during the first heat removal stage is based on the final heat removal rate calculated by FROTH. The steam generator energy available to be released during the first stage interval is determined by calculating the difference in secondary energy available at the containment design pressure and that at the (lower) user-specified intermediate equilibration pressure, assuming saturated conditions. The intermediate equilibrium pressures are chosen as discussed in Reference 1, Section 2.3 and 3.3. This energy is then divided by the first stage energy removal rate, resulting in an intermediate equilibration time. At this time, the rate of energy release drops substantially to the second stage rate. The second stage rate is determined as the fraction of the difference in secondary energy available between the intermediate equilibration and final depressurization at 212°F, and the time difference from the time of the intermediate equilibration to the user-specified time of the final depressurization at 212°F. With this methodology, all of the secondary energy remaining after the intermediate equilibration is conservatively assumed to be released by imposing a mandatory cooldown and subsequent depressurization down to atmospheric pressure at 3600 seconds; that is, 14.7 psia and at 212°F (the mass and energy balance tables have this point labeled as "Available Energy").

14.3.4.1.1.10 Post One-Hour mass and Energy Releases

The long-term post-one hour mass and energy releases (boil-off from core at the decay heating rate) are performed through user defined input functions in the GOTHIC code (Reference 8). This method of determining the long-term mass and energy releases is consistent with past application of Westinghouse methodology. See subsection 14.3.4.2.3 Boundary Conditions LOCA Mass and Energy Release for discussion of long-term mass and energy calculations.

14.3.4.1.1.11 Sources of Mass and Energy

The sources of mass considered in the LOCA mass and energy releases are given in Table 14.3.4-6 for the DEHL break case. The sources of mass for the DEPS break cases, i.e., minimum and maximum ECCS, respectively, are given in Table 14.3.4-15 and Table 14.3.4-16. These sources are:

- The RCS water
- Accumulator water (two accumulators injecting)
- Pumped injection water (SI)

The energy and inventories considered in the LOCA mass and energy release analysis are presented in Table 14.3.4-7 and Table 14.3.4-17 for the DEHL and DEPS cases, respectively. The energy sources are as follows:

- RCS water
- Accumulator water (two accumulators injecting)
- Pumped SI water
- Decay heat
- Core-stored energy
- RCS metal (includes the reactor vessel and internals, hot and cold leg piping, steam generator inlet and outlet plenums, and steam generator tubes)
- Steam generator metal (includes transition cone, shell, wrapper, and other internals)
- Steam generator secondary energy (includes fluid mass and steam mass)
- Secondary transfer of energy (feedwater into and steam out of the steam generator secondary)

The analysis used the following energy reference points:

Available energy:	212°F; 14.7 psia [energy available that could be released]
Total energy content:	32°F; 14.7 psia [total internal energy of the RCS]

The mass and energy inventories are presented at the following times, as appropriate:

- Time zero (initial conditions)
- End of blowdown time
- End of refill time
- End of reflood time
- Time of broken loop steam generator equilibration to pressure setpoint
- Time of intact loop steam generator equilibration to pressure setpoint
- Time of full depressurization (3600 seconds)

The energy release from the zirc-water reaction is considered as part of the WCAP-10325-P-A (Reference 1) methodology. Based on the way that the energy in the fuel is conservatively released to the vessel fluid, the fuel cladding temperature does not increase to the point where the metal-water reaction is significant. For the LOCA mass and energy calculation, the energy created by the metal-water reaction value is small and is not explicitly provided in the energy balance tables. The energy that is determined is part of the mass and energy releases, and is therefore already included in the LOCA mass and energy release.

The sequence of events for the LOCA transients is shown in Table 14.3.4-19 and Table 14.3.4-20 for the DEHL and DEPS cases, respectively.

14.3.4.1.1.12 Conclusions

The consideration of the various energy sources in the long-term mass and energy release analysis provides assurance that all available sources of energy have been included in this analysis. Thus, the review guidelines presented in SRP Section 6.2.1.3 (Reference 3) have been satisfied. The results of this analysis were available for use in the containment integrity analysis in a subsection of Section 14.3.4.2, Long-Term LOCA Containment Response.

14.3.4.1.2 Short-Term LOCA Mass and Energy Releases

An evaluation was performed to determine the effect of the Point Beach EPU program on the short-term LOCA-related M&E releases.

14.3.4.1.2.1 Accident Description

The short-term LOCA-related M&E releases are used as input to the subcompartment analyses. These analyses are performed to ensure that the walls of a subcompartment can maintain their structural integrity during the short pressure pulse (generally less than 3 seconds) accompanying a high-energy line pipe rupture within that subcompartment. The subcompartments that are typically evaluated include the SG compartment, the reactor cavity region, and the pressurizer compartment.

The magnitude of the pressure differential across the walls is a function of several parameters, which include the blowdown M&E release rates, the subcompartment volume, vent areas, and vent flow behavior. The blowdown M&E release rates are affected by the initial RCS temperature conditions.

Point Beach Units 1 and 2 were initially approved for Leak-Before-Break (LBB) via Reference 13. The pressurizer surge line was also eliminated from the structural design basis in Reference 14. Any changes associated with a major plant modification, such as a steam generator replacement or a power uprating, are typically offset by the LBB benefit of using the smaller RCS nozzle breaks. This demonstrates that the current licensing bases for the subcompartments would remain bounding for breaks postulated in the large, primary loop piping. All breaks larger than a 6 inch double-ended hot leg break and a 3 inch double-ended cold leg break have been eliminated by LBB. These specific breaks must be evaluated at the EPU conditions.

The critical mass flux correlation utilized in the SATAN-VI computer program (Reference 2) can be used to conservatively estimate the impact of the changes in RCS temperatures on the short-term releases. The following sections discuss the short-term evaluation conducted for this program.

14.3.4.1.2.2 Input Parameters and Assumptions

The short-term releases are linked directly to the critical mass flux, which increases with decreasing temperatures. The increase in mass flux is created by an increase in the differential pressure between the reservoir pressure and the saturation pressure at the RCS operating conditions. The critical mass flux is the maximum break flow per cross-sectional flow area based on a reservoir pressure and saturation temperature. The short-term LOCA releases would be expected to increase due to any reductions in RCS coolant temperature conditions.

It is noted that any changes in initial RCS inventory and SG liquid/steam mass and volume from the proposed parameters for the Point Beach Units I and 2 EPU Program have no effect on the releases because of the short duration of the postulated accident. The only change that needs to be addressed for this short-term LOCA M&E evaluation is the impact of the Point Beach Units 1 and 2 EPU Program on the RCS coolant temperatures.

Short-term releases are controlled by local pressures and temperatures, so the lower temperatures from the Point Beach Units 1 and 2 EPU Program operating conditions are more limiting. The hot leg temperature, cold leg temperature, RCS pressure, and system uncertainties for the EPU program can be found in Table 14.3.4-22.

14.3.4.1.2.3 Results

The short-term LOCA-related analyses for Point Beach Units 1 and 2 have been reviewed to assess the effects associated with the EPU Program. Based on the application of LBB methods, the only breaks that need to be evaluated are a 6 inch double-ended hot leg break and a 3 inch double-ended cold leg break. The decrease in mass and energy releases associated with the smaller breaks more than offsets the potential penalties associated with increased releases associated with the EPU. Additionally, releases have been provided for the smaller breaks at the EPU conditions in Table 14.3.4-23.

14.3.4.2 Long-Term LOCA Containment Response

The purpose of the LOCA containment integrity analysis performed for Point Beach Units 1 and 2 at 1811 MWt core power (includes uncertainty) is to analyze the bounding peak pressure and temperature of a design basis LOCA event inside containment and to demonstrate the ability of the containment heat removal system to mitigate the accident. The impacts of LOCA mass and energy releases on the containment pressure and temperature are assessed to ensure that the containment pressure and temperature remain below their respective design limits.

The Point Beach LOCA containment response analysis considered a spectrum of cases as discussed in Section 14.3.4.1.1, Long-Term LOCA Mass and Energy Releases. The cases address break locations, and postulated single failure (minimum and maximum safeguards). The limiting cases that address the containment peak pressure cases are presented here.

Calculation of the containment response following a postulated LOCA was analyzed by use of the digital computer code GOTHIC version 7.2a. The GOTHIC technical manual (Reference 8) provides a description of the governing equations, constitutive models, and solution methods in the solver. The GOTHIC qualifications report (Reference 9) provides a comparison of the solver results with both analytical solutions and experimental data.

The GOTHIC containment modeling for Point Beach is consistent with the recent NRC approved Ginna evaluation model (Reference 11). The latest code version is used to take advantage of the diffusion layer model (DLM) heat transfer option. This heat transfer option was approved by the NRC (Reference 11) for use in Ginna containment analyses with the condition that mist be excluded from what was earlier termed as the mist diffusion layer model (MDLM). The GOTHIC containment modeling for Point Beach has followed the conditions of acceptance placed on Ginna. The Point Beach containment volume is similar because both Point Beach and Ginna are 2-loop plants. The differences in GOTHIC code versions are documented in Appendix A of the GOTHIC User Manual Release Notes (Reference 12). Version 7.2a is used consistent with the restrictions identified in Reference 11; none of the user-controlled enhancements added to Version 7.2a were implemented in the Point Beach containment model.

The Point Beach GOTHIC containment evaluation model for the LOCA events consisted of one volume. Additional boundary conditions, volumes, flow paths, and components are used to model accumulator nitrogen release and sump recirculation. Injection of accumulator nitrogen during a LOCA event is modeled by a boundary condition. The recirculation system model uses GOTHIC component models for the RHR and component cooling water (CCW) heat exchangers and the CCW pumps. Recirculation flow from the sump is modeled using a boundary condition.

14.3.4.2.1 Accident Description

A break in the primary RCS piping causes a loss-of-coolant, which results in a rapid release of mass and energy to the containment atmosphere. Typically, the blowdown phase for the large LOCA event is over in less than 30 seconds. This large and rapid release of high-energy, two-phase fluid causes a rapid increase in the containment pressure, which initiates safety injection and containment spray.

The RCS accumulators begin to refill the lower plenum and downcomer of the reactor vessel with water after the end of blowdown. The reflood phase begins after the vessel fluid level reaches the bottom of the fuel. During this phase, the core is quenched with water from both the accumulators and pumped SI. The quenching process creates a large amount of steam and entrained water that is released to containment through the break. This two-phase mixture would have to pass through the steam generators and also absorb energy from the secondary side coolant if the break were located in the cold-leg or pump-suction piping.

The LOCA mass and energy release decreases with time as the system cools. Core decay heat is removed by nucleate boiling after the reflood phase is complete. The core fluid level is maintained by pumping water back into the vessel by the SI system from either the RWST or the containment sump. The containment heat removal systems continue to condense steam and slowly reduce the containment pressure and temperature over time.

14.3.4.2.2 Input Parameters, Assumptions, and Acceptance Criteria

An analysis of containment response to the rupture of the RCS must start with knowledge of the initial conditions in the containment. The pressure, temperature, and humidity of the containment atmosphere prior to the postulated accident are specified in the analysis as shown in Table 14.3.4-24.

Also, values for the initial temperature of the service water (SW) and refueling water storage tank (RWST) are assumed, along with containment spray (CS) pump flowrate and containment fan cooler (CFC) heat removal performance. All of these values are chosen conservatively, as shown in Table 14.3.4-24. Long term sump recirculation is addressed via Residual Heat Removal System (RHR) heat exchanger performance. The primary function of the RHR system is to remove heat from the core by way of Emergency Core Cooling System (ECCS). Table 14.3.4-24 provides the RHR system parameters assumed in the analysis.

Design Basis Accident

A series of cases was performed for the LOCA containment response. Section 14.3.4.1.1 documented the M&E releases for the minimum and maximum safeguards cases for a DEPS break and the releases from the blowdown of a DEHL break.

For the maximum safeguards DEPS case a failure of a containment spray pump was assumed as the single failure, which leaves available as active heat removal systems: one containment spray pump and four CFCs. Table 14.3.4-25 provides the CFC performance per unit versus containment saturation temperature and Table 14.3.4-26 provides the performance data for one spray pump in operation. Note: For the maximum safeguards case a limiting assumption was made concerning the modeling of the recirculation system, i.e., heat exchangers. The minimum safeguards data was conservatively used to model the RHR heat exchangers, i.e., one RHR heat exchanger (Hx) was credited for residual heat removal. Emergency safeguards equipment data is given in Table 14.3.4-24.)

The minimum safeguards case was based upon a diesel train failure (which leaves available as active heat removal systems one containment spray pump and 2 CFCs). Due to the duration of the DEHL transient (i.e. blowdown only), no containment safeguards equipment is modeled.

The calculations for all of the DEPS cases were performed for 2.6 million seconds (approximately 30 days). The DEHL cases were terminated soon after the end of the blowdown. The sequence of events for each of these cases is shown in Table 14.3.4-19 through Table 14.3.4-20.

Modeling Assumptions

The following are the major assumptions made in the analysis.

- The mass and energy released to the containment are descriped in Section 14.3.4.1.1 for LOCA.
- Homogeneous mixing is assumed. The steam-air mixture and the water phases each have uniform properties. More specifically, thermal equilibrium between the air and the steam is assumed. However, this does not imply thermal equilibrium between the steam-air mixture and the water phase.
- Air is taken as an ideal gas, while compressed water and steam tables are employed for water and steam thermodynamic properties.
- For the blowdown portion of the LOCA analysis, the discharge flow separates into steam and water phases at the breakpoint. The saturated water phase is at the total containment pressure, while the steam phase is at the partial pressure of the steam in the containment. For the post blowdown portion of the LOCA analysis, steam and water releases are input separately.
- The saturation temperature at the partial pressure of the steam is used for heat transfer to the heat sinks and the fan coolers.
- The containment fan coolers are activated by a containment high pressure SI signal.

Acceptance Criteria

The containment response for design-basis containment integrity is an ANS Condition IV event, an infrequent fault. The relevant requirements to satisfy Nuclear Regulatory Commission acceptance criteria as follows.

- General Design Criteria (GDC) 10 and GDC 49 from the PBNP FSAR Table 1.3-1: In order to satisfy the requirements of GDC 10 and 49, the peak calculated containment pressure should be less than the containment design pressure of 60 psig (74.7 psia)

- PBNP FSAR Table 1.3-1, GDC 52: In order to satisfy the requirements of GDC 52, the calculated pressure at 24 hours should be less than 50% of the peak calculated value. (This is related to the criteria for doses at 24 hours.)

14.3.4.2.3 Description of the LOCA GOTHIC Containment Model

Noding Structure

The Point Beach GOTHIC containment evaluation model for the LOCA events consisted of one volume. Additional boundary conditions, volumes, flow paths, and components are used to model accumulator nitrogen release and sump recirculation. Injection of accumulator nitrogen during a LOCA event is modeled by a boundary condition. The recirculation system model uses GOTHIC component models for the RHR and component cooling water (CCW) heat exchangers and the CCW pumps. Recirculation flow from the sump is modeled using a boundary condition.

Volume Input

GOTHIC requires the volume, height, diameter, and elevation input values for each node. The containment is modeled as a single control volume in the containment model. The minimum free volume of 1,000,000 ft^3 was used.

Initial Conditions

The containment initial conditions for containment integrity cases are:

Pressure: 16.7 psia

Relative humidity: 20%

Temperature: 120°F

Flow Paths

Flow boundary conditions linked to functions that define the M&E releases model the LOCA break flow to the containment. The boundary conditions are connected to the containment control volume via flow paths. The injection spray is modeled as a boundary condition connected to the containment control volume via a flow path.

The flow rates through the flow paths are specified by boundary conditions, so the purpose of the flow path is to direct the flow to the proper control volume. The flow path input is mostly arbitrary. Standard values are used for the area, hydraulic diameter, friction length, and inertia length of the flow path. Since this is a single volume lumped-parameter model, the elevation of the break flow paths is arbitrarily set to 1 foot and the elevation of the spray flow paths is arbitrarily set to 50 feet above the containment floor.

Heat Sinks

The structural heat sinks in the containment are modeled as GOTHIC thermal conductors. The heat sink geometry data are based on conservatively low surface areas and are summarized in Table 14.3.4-27.

A thin air gap is assumed to exist between the steel and concrete for steel-jacketed heat sinks. A gap conductivity of 0.0174 Btu/hr-ft-°F is assumed between steel and concrete.

The thermophysical properties for the heat sink materials are summarized in Table 14.3.4-28.

Heat and Mass Transfer Correlations

GOTHIC has several heat transfer coefficient options that can be used for containment analyses. For the Point Beach GOTHIC model, the direct heat transfer coefficient set is used with the DLM mass transfer correlation for the heat sinks inside containment. This heat transfer methodology was reviewed and approved for use in the Ginna containment design basis accident analyses (Reference 11). The DLM correlation does not require the user to specify a revaporization input value.

The direct heat transfer coefficient set is used for the heat sinks representing floors, ceilings, and walls. The submerged conductors are essentially insulated from the vapor after the pool develops. Insulated surfaces are modeled with no heat loss (0.0 Btu/hr-ft^2-°F).

Containment Fan Coolers

The reactor containment fan coolers (CFCs) are another means of heat removal. Each CFC has a fan which draws in the containment atmosphere from the upper volume of the containment via a return air riser. The steam/air mixture is routed through the enclosed CFC unit, past service water cooling coils. The fan then discharges the air through ducting containing a check damper. The discharged air is directed at the lower containment volume. The CFCs are modeled in GOTHIC as a cooler/heater component in the containment volume. They are initiated by the containment high pressure safety injection signal at 6 psig (20.7 psia), with a time delay of 84 seconds. The heat removal rate for one CFC is defined by a function in GOTHIC. Mulitpliers are used to define the amount of operational CFCs (2 for minimum safeguards, 4 for maximum safeguards). See Table 14.3.4-25 for the CFC heat removal capability assumed for the containment response analyses.

Sump Recirculation

A sump recirculation model consisting of simplified RHR system and CCW system models was included in the Point Beach containment model to calculate the long-term LOCA containment pressure and temperature response. The RHR heat exchanger cools the water from the containment sump. The RHR system injects the cooled water into the RCS to cool the core. The RHR heat exchanger is cooled with CCW water and service water provides the ultimate heat sink cooling the CCW heat exchangers.

Boundary Conditions

LOCA Mass and Energy Release

The LOCA mass and energy release methodology generates the releases from both sides of the break (or two flow paths: M&E exiting from the vessel side of the break; and M&E exiting from the steam generator side of the break - as defined for a double-ended hot leg break). The LOCA transient M&E releases are calculated as separate flow paths (for the first 3,600 seconds) and input to the GOTHIC containment model via flow boundary conditions. The flow boundary conditions are linked to functions that define the mass break flow and the enthalpy of the break flow. The break mass and enthalpy are input to the containment model as external functions defined by control variables. The M&E releases from the boundary conditions are analyzed for Point Beach out to 3,600 seconds; that is, the time at which all energy in the primary heat structures and steam generator secondary system is released/depressurized to atmospheric pressure (14.7 psia and 212°F). The LOCA M&E release rates are generated using the Westinghouse M&E methodology (Reference 1).

During blowdown, the liquid portion of the break flow is released as drops with an assumed diameter of 100 microns (0.00394 inch). This is consistent with the methodology approved for Ginna (Reference 11) and is based on data presented in Reference 10. After blowdown, the liquid release is assumed to be a continuous pour into the sump.

The long-term, post 3,600 second, mass and release (boil-off from the core at the decay heating rate) calculations are performed through user defined functions by GOTHIC. These input functions are used to incorporate the sump water cooling in the long term and are consistent with the Westinghouse methodology previously approved by the NRC. After primary system and secondary system energy have been released (depressurized to atmospheric pressure, (14.7 psia and 212°F), the M&E release to the containment is assumed to be from long-term steaming of decay heat. A flow boundary condition is defined to provide the long-term boil-off M&E release to containment. The mass flow rate and enthalpy of the flow is calculated using GOTHIC control variables.

The American Nuclear Society (ANS) Standard 5.1 (Reference 4) decay heat model (2δ uncertainty) is used to calculate the long-term boil-off from the core. All the decay heat is assumed to produce steam from the recirculated ECCS water. The remainder of the ECCS water is returned to the sump region of the containment control volume. These assumptions are consistent with the long-term M&E methodology documented in Reference 1.

Containment Spray System

Containment spray is modeled with one boundary condition for the injection phase and two coupled boundary conditions for the recirculation phase. Point Beach has two trains of containment safeguards available, with one spray pump per train. An inherent assumption in the LOCA containment analysis is that offsite power is lost with the pipe rupture. Injection sprays are modeled with one operational train for both the minimum and maximum safeguards cases due to this assumption combined with a limiting single failure.

Injection spray actuation is modeled on the containment Hi-Hi pressure setpoint (44.7 psia). The sprays begin injecting 100°F water after a specified 70-second delay. The containment spray flow varies according to containment pressure and can be found in Table 14.3.4-26. The spray flow rate is modeled in GOTHIC as a control variable. The injection spray switches over to recirculation spray after a specified 1,200-second (i.e. 20 minutes) delay. Recirculation spray is modeled to terminate per Table 14.3.4-24.

Accumulator Nitrogen Gas Modeling

The accumulator nitrogen gas release is modeled with a flow boundary condition in the LOCA containment model. The nitrogen release rate was conservatively calculated by maximizing the mass available to be injected. The nitrogen gas release rate was used as input for the GOTHIC function, as a specified rate over a fixed time period. Nitrogen gas is released at a rate of 244.32 lbm/second; beginning at 40.73 seconds (average accumulator tank water volume empty time) and ending at 60.64 seconds.

14.3.4.2.4 LOCA Containment Integrity Results (Reference 22)

The containment pressure and steam temperature profiles from each of the LOCA cases are shown in Figure 14.3.4-1 through Figure 14.3.4-4. The results of the DEHL break are shown in Figure 14.3.4-1 and Figure 14.3.4-2. The results of the DEPS break cases are shown in Figure 14.3.4-3 through Figure 14.3.4-4.

LOCA Containment Response Transient Description: Double Ended Hot Leg Break

This analysis assumes a loss-of-offsite power coincident with a double-ended rupture of the RCS piping between the reactor vessel outlet nozzle and the steam generator inlet (i.e., a break in the RCS hot leg).

The postulated RCS break results in a rapid release of mass and energy to the containment with a resulting rapid rise in both the containment pressure and temperature. As the containment pressure rises, the RCS rapidly depressurizes which results in the generation of a compensated pressurizer pressure reactor trip at 0.311 seconds and a low pressurizer pressure SI setpoint at 3.8 seconds. The containment pressure continues to rise rapidly in response to the release of mass and energy until the end of blowdown at 15.4 seconds, with the pressure reaching a value of 70.00 psia at 16.56 seconds. The peak containment temperature of 279.8°F also occurs coincident with the peak pressure. The end of blowdown marks a time when the initial inventory in the RCS has been exhausted and a process of filling the RCS downcomer in preparation for reflood has begun. Since the reflood for a hot leg break is very fast due to the low resistance to steam venting posed by the broken hot leg, the hot leg break mass and energy relies transients are terminated shortly after blowdown. Table 14.3.4-19 provides the transient sequence of events for the DEHL transient.

LOCA Containment Response Transient Description: Double Ended Pump Suction Break

This analysis assumes a loss-of-offsite power coincidence with a double-ended rupture of the RCS piping between the steam generator outlet and the RCS pump inlet (suction). The associated single failure assumption is the failure of a diesel to start, resulting in one train of ECCS and containment safeguards equipment being available. This combination results in a minimum set of safeguards being available. Further, loss of offsite power delays the actuation times of the safeguards equipment due to the required diesel startup time after receipt of the safety injection signal.

The postulated RCS break results in a rapid release of mass and energy to the containment with a resulting rapid rise in both the containment pressure and temperature. As the containment pressure rises, the RCS rapidly depressurizes which results in the generation of a compensated pressurizer pressure reactor trip at 0.418 seconds and a low pressurizerpressure SI setpoint at 4.1 seconds. The containment pressure continues to rise rapidly in response to the release of mass and energy until the end of the blowdown phase at 13.2 seconds.

The end of the blowdown phase marks a time when the initial inventory in the RCS has been exhausted and a slow process of filling the RCS downcomer in preparation for reflood has begun. Since the mass and energy release during this period is low, pressure decreases slightly and then increases in response to the reflood mass and energy release out to a second peak occurring at approximately 70 seconds. The turn around in containment pressure at 60 seconds is a result of the accumulator nitrogen cover gas flow ending at 60.73 seconds, initiation of the sprays at 72.73 seconds, and initiation of the containment fan coolers (CFCs) at 84.24 seconds. Reflood continues at a reduced flooding rate due to the buildup of mass in the RCS core which offsets the downcomer head. This reductions in flooding rate and the continued action of the CFCs and spray leads to a slowly decreasing pressure out to the end of reflood, which occurs at 207.4 seconds.

At this juncture, by design of the Reference 1 model, energy removal from the SG secondaries begins at a high rate, resulting in a rapid rise in containment pressure from the end of reflood out to approximately 800 seconds when energy has been removed from the SG in the faulted loop, bringing the SG in the faulted loop secondary pressure down to the containment design pressure of 74.7 psia. The result of the SG secondary energy release is a peak containment pressure of 71.08 psia and a peak containment temperature of 285.7°F at 1,007 seconds, the third major peak for this transient. This is the highest peak containment pressure and temperature of the two cases analyzed. After this event, the mass and energy released is reduced due to so much energy removal from the SGs having been accomplished and pressure slowly decreases out to the recirculation switchover time of 3,398.34 seconds.

At this time, the ECCS is realigned for recirculation resulting in an increase in the SI temperature due to delivery from the hot sump. At 6,000 seconds the injection sprays are terminated which results in a slight increase in pressure until the recirculation sprays are initiated at 7,200 seconds. The pressure once again decreases until the recirculation sprays are terminated at 14,400 seconds. After a slight increase in pressure, the containment pressure continues to decrease due to lower decay heat, SG energy release and continued CFC cooling. This trend continues to the end of the transient at 2.6E+06 seconds. Table 14.3.4-20 presents sequence of events for the DEPS.

Steam Generator Tube Material Properties Evaluation

An evaluation was performed to determine the effect of correcting the steam generator tube material properties on the LOCA containment peak pressure (NSAL-14-2). The steam generator tube properties were corrected from stainless steel to Inconel 690® in the LOCA mass and energy release calculation which was updated to include the drift model and break flow with inertia model originally approved in Reference 1. The combination of these changes determined that the current results remain limiting and no further changes to the results are applied.

14.3.4.2.5 Conclusion

The LOCA containment response analyses have been performed as part of the transition Point Beach Units 1 and 2 EPU. The analyses included long-term pressure and temperature profiles for each case. As illustrated in the results found in Section 14.3.4.2.4, all cases resulted in a peak containment pressure that was less than 60 psig (74.7 psia). In addition, all long-term cases were well below 50% of the peak value within 24 hours. Based on the results, all applicable criteria for Point Beach have been met.

14.3.4.2.6 REFERENCES

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2. WCAP-8264-P-A (Proprietary), Rev. 1, and WCAP-8312-A (Non-Proprietary), Rev. 2, Westinghouse Mass and Energy Release Data for Containment Design, August 1975.

3. U. S. Nuclear Regulatory Commission, Office of Nuclear Reactor Regulation, NUREG-0800, Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants, LWR Edition, Section 6.2.1, "Containment Function Design," Revision 3, March 2007.

4. ANSI/ANS-5.1 1979, American National Standard for Decay Heat Power in Light Water Reactors, August 29, 1979.

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15. NRC Safety Evaluation, PBNP Units 1 and 2-Issuance of License Amendments Regarding Extended Power Uprate, dated May 3, 2011.

16. NRC Safety Evaluation, PBNP Units 1 and 2-Issuance of License Amendments Regarding use of Alternate Source Term, dated April 14, 2011.

17. Westinghouse Calculation CN-CRA-08-6, LOCA Mass and Energy Release and Containment Response Analysis for the EPU Program, Revision 1, Approved December 29, 2008.

18. Westinghouse Calculation CN-CRA-08-6, LOCA Mass and Energy Release and Containment Response Analysis for the EPU Program, Revision 1-A, Approved June 29, 2011, Revision 1-B, Approved December 21, 2012, Revision 1-C, Approved March 15, 2013.

19. Westinghouse Memo to Harv Hanneman, WEP-08-4, Transmittal of Short-Term LOCA Mass and Energy Release Evaluation for the Point Beach Extended Power Uprate, dated January 9, 2008.

20. NRC 2011-0025, NEXTera Energy to the NRC, License Amendment Request 261, Extended Power Uprate, Request for Additional Information, dated February 25, 2011.

21. SCR 2013-0188-01, “Reduction of CFC Heat Removal Requirement,” dated November 21, 2013.

22. CN-CRA-12-26 Revision 2, “Point Beach Units 1 and 2 LOCA Containment Response Analysis”, August 3, 2017.

Table 14.3.4-1 System Parameters Initial Conditions

Parameters	Value
Core Thermal Power (1) MWt)	1,811.0
Reactor coolant System Flow Rate, per Loop (lbm/sec)	18,777.8
Vessel Outlet Temperature$^{(2)}$ (°F)	617.5
Core Inlet Temperature$^{(2)}$ (°F)	549.3
Vessel Baffle-Barrel Configuration	Upflow
Initial SG Steam Pressure (psia)	833
SG Design (Unit 1/Unit 2)	Model 44F/Δ47
SGTP (%)	0
Initial SG Secondary-Side Mass$^{(3)}$ (lbm)	105,704.5
Assumed Maximum Containment Backpressure (psia)	74.7
Accumulator • Water volume (ft^3) (per accumulator)$^{(4)}$ • N_2cover Gas Pressure$^{(5)}$ (psia) • Temperature (°F)	 1,100.0 834.7 120.0
SI Start Time (sec) [total time form beginning of event, which includes the maximum delay from reaching the setpoint]	40.8 (DEHL) 41.1 (DEPS)
Notes: (1) Includes allowance for calorimetric error (+0.6 percent of power). (2) Analysis value includes an additional +6.4°F allowance for instrument error and dead band. (3) SG secondary-side mass includes appropriate uncertainty and/or allowance. (4) Does not include accumulator line volume. (5) N_2 cover gas pressure includes uncertainty of +20 psi.	

Table 14.3.4-2 SAFETY INJECTION FLOW

RCS Pressure (psia)	Total Flow (lbm/sec)
Injection Mode (reflood phase)	
14.7	363.2
34.7	341.2
54.7	316.6
74.7	290.1
94.7	257.6
114.7	214.3
Injection Mode (post-reflood phase)	
74.7	290.1
Recirculation Mode	
14.7	270.9

Table 14.3.4-3 DELETED

Table 14.3.4-4 LOCA MASS AND ENERGY RELEASE ANALYSIS - CORE DECAY HEAT FRACTION

Time (sec)	Core Decay Heat Fraction of Full Power
10	0.053876
15	0.050401
20	0.048018
40	0.042401
60	0.039244
80	0.037065
100	0.035466
150	0.032724
200	0.030936
400	0.027078
600	0.024931
800	0.023389
1,000	0.022156
1,500	0.019921
2,000	0.018315
4,000	0.014781
6,000	0.013040
8,000	0.012000
10,000	0.011262
15,000	0.010097
20,000	0.009350
40,000	0.007778
60,000	0.006958
80,000	0.006424
100,000	0.006021
150,000	0.005323
200,000	0.004847
400,000	0.003770
600,000	0.003201
800,000	0.002834
1,000,000	0.002580
10,000,000	0.000808

Table 14.3.4-5 DEHL BREAK BLOWDOWN M&E RELEASE
Sheet 1 of 3

Time Seconds	Break Path No. 1(1) Mass lbm/sec	Break Path No. 1(1) Energy Thousand Btu/sec	Break Path No. 2(2) Mass lbm/sec	Break Path No. 2(2) Energy Thousand Btu/sec
0.0	0.0	0.0	0.0	0.0
0.0	43846.0	27887.8	43844.6	27886.0
0.0	45581.8	28990.5	45315.1	28815.3
0.1	36937.2	23746.7	26048.1	16529.1
0.2	34526.8	22145.0	22870.3	14419.6
0.3	33548.1	21468.3	20426.7	12701.9
0.4	32138.3	20561.1	19205.4	11746.6
0.5	31497.7	20152.1	18437.8	11098.0
0.6	31251.8	20008.9	17870.3	10605.8
0.7	30559.2	19615.8	17445.7	10227.6
0.8	30255.5	19507.5	17112.7	9927.4
0.9	29722.9	19281.0	16818.4	9668.5
1.0	28825.9	18816.3	16637.3	9488.7
1.1	27937.2	18363.2	16499.4	9344.2
1.2	27095.1	17943.8	16452.1	9259.3
1.3	26227.4	17508.9	16474.0	9218.7
1.4	25293.2	17020.8	16531.7	9203.2
1.5	24241.7	16443.5	16614.5	9205.2
1.6	23187.9	15850.7	16712.8	9220.1
1.7	22189.7	15293.5	16812.6	9240.2
1.8	21280.9	14810.1	16906.4	9261.4
1.9	20414.5	14373.2	16990.2	9281.4
2.0	19458.1	13889.5	17051.6	9293.6
2.1	18654.4	13424.7	17087.6	9296.0
2.2	18100.5	13036.7	17092.8	9285.3
2.3	17763.3	12712.1	17071.0	9263.0
2.4	17554.4	12445.7	17023.3	9229.4
2.5	17377.5	12209.2	16950.0	9184.5
2.6	17194.2	11991.8	16851.1	9127.9
2.7	17009.2	11794.5	16728.3	9060.1
2.8	16880.6	11659.4	16576.5	8978.2
2.9	16776.8	11553.0	16390.4	8879.2
3.0	16708.5	11462.7	16182.1	8769.3
3.1	16691.4	11387.9	15948.8	8647.2
3.2	16720.9	11331.1	15695.8	8515.4
3.3	16769.4	11281.7	15407.8	8365.6
3.4	16818.8	11235.7	15072.6	8190.8
3.5	16854.5	11187.2	14690.4	7991.2
3.6	16867.1	11132.8	14278.3	7776.0

Table 14.3.4-5 DEHL BREAK BLOWDOWN M&E RELEASE
Sheet 2 of 3

Time Seconds	Break Path No. 1(1) Mass lbm/sec	Break Path No. 1(1) Energy Thousand Btu/sec	Break Path No. 2(2) Mass lbm/sec	Break Path No. 2(2) Energy Thousand Btu/sec
3.7	16859.7	11074.5	13861.8	7559.1
3.8	16829.5	11014.7	13443.0	7342.3
3.9	16737.2	10940.6	13044.9	7137.8
4.0	16613.0	10854.6	12659.7	6941.6
4.2	16358.5	10681.3	11903.2	6556.3
4.4	16106.2	10498.4	11121.9	6156.0
4.6	15872.8	10313.0	10357.0	5762.7
4.8	15653.1	10131.8	9667.2	5408.2
5.0	15430.3	9948.9	9061.8	5098.0
5.2	15197.8	9759.0	8532.1	4827.4
5.4	14962.9	9565.8	8074.3	4594.0
5.6	14729.0	9368.6	7663.1	4384.8
5.8	11491.4	7978.5	7283.5	4191.9
6.0	11092.1	7701.1	6911.9	4002.6
6.2	10674.3	7471.3	6542.8	3815.8
6.4	10230.5	7182.4	6179.3	3634.6
6.6	9830.2	6927.1	5823.5	3460.7
6.8	9417.5	6700.2	5478.9	3295.3
7.0	9035.7	6451.6	5150.1	3139.7
7.2	8662.6	6184.8	4838.3	2992.9
7.4	8123.5	5895.9	4548.2	2855.8
7.6	7769.5	5656.3	4282.9	2728.6
7.8	7292.9	5355.2	4057.0	2619.8
8.0	6806.4	5107.8	3867.0	2523.4
8.2	6269.9	4842.3	3672.8	2416.2
8.4	5753.8	4577.2	3481.8	2314.1
8.6	5267.8	4319.2	3289.8	2218.8
8.8	4802.4	4073.9	3092.6	2126.9
9.0	4343.4	3833.5	2893.3	2037.3
9.2	3908.2	3607.1	2698.7	1952.7
9.4	3471.4	3391.9	2511.2	1874.0
9.6	3035.9	3180.8	2330.3	1800.6
9.8	2619.6	2887.8	2157.0	1732.4
10.0	2390.1	2676.6	1991.2	1668.5
10.2	2270.9	2494.4	1832.8	1607.2
10.4	2144.4	2341.2	1683.6	1549.6
10.6	1980.7	2193.2	1545.1	1501.6
10.8	1811.0	2060.4	1423.7	1459.8
11.0	1662.9	1934.8	1314.6	1417.7

Table 14.3.4-5 DEHL BREAK BLOWDOWN M&E RELEASE
Sheet 3 of 3

Time Seconds	Break Path No. 1[1] Mass lbm/sec	Break Path No. 1[1] Energy Thousand Btu/sec	Break Path No. 2[2] Mass lbm/sec	Break Path No. 2[2] Energy Thousand Btu/sec
11.2	1521.2	1804.9	1222.2	1378.7
11.4	1407.7	1692.4	1142.4	1324.7
11.4	1407.4	1692.0	1142.2	1324.5
11.4	1407.0	1691.6	1141.9	1324.3
11.4	1406.7	1691.3	1141.7	1324.2
11.4	1406.3	1690.9	1141.5	1324.0
11.4	1406.0	1690.5	1141.2	1323.8
11.4	1405.6	1690.1	1141.0	1323.7
11.4	1405.2	1689.7	1140.8	1323.5
11.6	1286.2	1558.7	1066.9	1265.9
11.8	1179.4	1443.7	961.0	1164.6
12.0	1060.0	1306.1	825.5	1014.6
12.2	916.1	1134.1	663.5	820.0
12.4	800.1	995.3	565.4	700.9
12.6	686.5	858.0	515.0	640.5
12.8	508.6	635.5	579.8	721.9
13.0	452.9	565.6	650.5	808.9
13.2	356.9	447.3	708.3	878.2
13.4	267.8	336.2	756.1	932.0
13.6	171.0	214.4	795.4	973.3
13.8	63.7	79.0	810.7	986.3
14.0	0.0	0.0	782.4	956.9
14.2	0.0	0.0	667.3	822.6
14.4	0.0	0.0	513.0	636.0
14.6	0.0	0.0	492.8	612.5
14.8	61.4	78.6	415.9	516.8
15.0	54.7	70.3	289.1	360.2
15.2	0.0	0.0	161.0	201.7
15.4	0.0	0.0	0.0	0.0

Notes:
1. Path 1: M&E exiting from the reactor vessel side of the break.
2. Path 2: M&E exiting from the steam generator side of the break.

Table 14.3.4-6 DEHL BREAK MASS BALANCE

Time (Seconds)		0.00	15.40	15.40+ε
		Mass (thousand lbm)		
Initial	In RCS and ACC	414.12	414.12	414.12
Added Mass	Pumped Injection	0	0	0
	Total Added	0	0	0
Total Available		414.12	414.12	414.12
Distribution	Reactor Coolant	272.88	51.57	68.81
	Accumulator	141.24	102.64	85.10
	Total Contents	414.12	153.91	153.91
Effluent	Break Flow	0	260.20	260.20
	ECCS Spill	0	0	0
	Total Effluent	0	260.20	260.20
Total Accountable		414.12	414.11	414.11

Note: +ε is used to indicate that the column represents the bottom of core recovery conditions that occurs instantaneously after blowdown.

Table 14.3.4-7 DEHL BREAK ENERGY BALANCE

Time (Seconds)		0.00	15.40	15.40+ε
		Energy (million Btu)		
InitialEnergy	In RCS, ACC, S GEN	432.19	432.19	432.19
Added Energy	Pumped Injection	0	0	0
	Decay Heat	0	2.91	2.91
	Heat from Secondary	0	13.04	13.04
	Total Added	0	15.96	15.96
Total Available		432.19	448.15	448.15
Distribution	Reactor Coolant	160.52	12.44	13.74
	Accumulator	12.73	9.25	7.95
	Core Stored	15.37	6.69	6.69
	Primary Metal	85.83	80.53	80.53
	Secondary Metal	43.54	42.14	42.14
	Steam Generator	114.21	125.80	125.80
	Total Contents	432.19	276.84	276.84
Effluent	Break Flow	0	170.82	170.82
	ECCS Spill	0	0	0
	Total Effluent	0	170.82	170.82
Total Accountable		432.19	447.66	447.66

Note: +ε is used to indicate that the column represents the bottom of core recovery conditions that occurs instantaneously after blowdown.

Table 14.3.4-8 DEPS BREAK BLOWDOWN M&E RELEASE
Sheet 1 of 3

Time Seconds	Break Path No. 1(1) Mass lbm/sec	Break Path No. 1(1) Energy Thousand Btu/sec	Break Path No. 2(2) Mass lbm/sec	Break Path No. 2(2) Energy Thousand Btu/sec
0.0	0.0	0.0	0.0	0.0
0.0	78894.0	42750.2	40705.8	22023.7
0.1	40724.8	22122.5	19870.4	10738.6
0.2	43133.1	25260.2	21792.8	11787.4
0.3	46398.1	25670.1	23269.5	12594.3
0.4	46379.4	25977.9	23648.7	12805.2
0.5	44127.4	25038.8	23196.0	12564.7
0.6	44661.9	25648.2	22624.4	12261.2
0.7	44352.4	25740.4	22179.8	12026.5
0.8	43212.9	25312.9	21896.2	11877.8
0.9	41893.4	24757.8	21658.3	11752.2
1.0	40609.1	24205.0	21395.7	11611.5
1.1	39333.7	23636.3	21091.7	11447.2
1.2	38065.0	23051.2	20756.6	11265.1
1.3	36798.2	22448.3	20388.1	11064.3
1.4	35479.7	21799.4	19991.7	10847.6
1.5	34051.2	21077.3	19612.3	10640.8
1.6	32698.9	20414.6	19310.0	10476.3
1.7	31635.6	19955.5	19028.6	10323.4
1.8	30622.2	19550.9	18711.2	10150.7
1.9	29432.6	19048.8	18365.8	9962.4
20.	27828.6	18297.9	18011.3	9769.4
2.1	23134.9	15447.2	17649.8	9572.6
2.2	19735.2	13443.4	17274.0	9368.1
2.3	17245.1	11959.5	16925.5	9179.3
2.4	15332.8	10777.2	16706.4	9062.3
2.5	14094.3	10004.0	16477.1	8939.4
2.6	13337.5	9529.6	15926.1	8640.6
2.7	12801.1	9186.6	15489.6	8405.5
2.8	12300.7	8865.8	15136.6	8216.5
2.9	11859.0	8601.9	14892.8	8087.8
3.0	11439.2	8368.8	14682.8	7977.5
3.1	11067.4	8177.5	14470.9	7865.9
3.2	10716.0	7999.1	14279.4	7765.6
3.3	10393.6	7836.4	14091.1	7667.1
3.4	10103.4	7694.3	14352.7	7817.7
3.5	9843.3	7569.4	14447.3	7873.3
3.6	9602.5	7451.6	14409.5	7856.4

Table 14.3.4-8 DEPS BREAK BLOWDOWN M&E RELEASE
Sheet 2 of 3

Time Seconds	Break Path No. 1(1) Mass lbm/sec	Break Path No. 1(1) Energy Thousand Btu/sec	Break Path No. 2(2) Mass lbm/sec	Break Path No. 2(2) Energy Thousand Btu/sec
3.7	9382.9	7341.4	14426.8	7870.2
3.8	9187.2	7241.2	14399.9	7859.5
3.9	9013.0	7147.4	14327.3	7823.4
4.0	8857.1	7056.5	14252.8	7786.2
4.2	8591.0	6880.9	14009.0	7658.6
4.4	8355.1	6691.6	13646.3	7466.5
4.6	8153.9	6491.1	13277.5	7273.7
4.8	7977.3	6276.3	12844.1	7047.2
5.0	7860.7	6083.4	14256.6	6847.3
5.2	7746.9	5889.1	11990.9	6603.8
5.4	7563.7	5677.8	11564.9	6383.3
5.6	7332.2	5438.9	11167.0	6164.8
5.8	7146.1	5218.4	10891.9	5982.2
6.0	7037.1	5041.3	10743.9	5847.2
6.2	7205.4	5047.0	10662.2	5738.7
6.4	7421.1	5125.4	10741.3	5719.0
6.6	7160.8	5132.1	10562.9	5575.6
6.8	6358.7	4820.2	10408.9	5444.6
7.0	5857.6	4517.7	10127.4	5255.7
7.2	5633.3	4325.4	9669.3	4976.4
7.4	5466.7	4176.4	9125.9	4655.0
7.6	5296.0	4042.2	8629.5	4365.1
7.8	5114.4	3916.7	8272.3	4157.3
8.0	4927.4	3795.8	7886.1	3941.6
8.2	4742.0	3684.4	7530.5	3741.3
8.4	4512.6	3569.6	7078.4	3485.7
8.6	4248.7	3436.5	6688.0	3247.7
8.8	4019.3	3319.2	6376.9	3042.9
9.0	3806.3	3210.2	6080.7	2845.4
9.2	3607.5	3113.6	5809.7	2663.9
9.4	3410.3	3029.9	5559.4	2498.5
9.6	3217.7	2956.3	5376.6	2370.1
9.8	3014.0	2883.3	5153.4	2230.2
10.0	2804.5	2820.6	4889.2	2078.2
10.2	2577.2	2758.3	4610.2	1924.7
10.4	2305.1	2654.5	4303.9	1765.5
10.6	1957.4	2392.5	3865.3	1557.8
10.8	1663.6	2057.8	3440.3	1356.6

Table 14.3.4-8 DEPS BREAK BLOWDOWN M&E RELEASE
Sheet 3 of 3

Time Seconds	Break Path No. 1[1] Mass lbm/sec	Break Path No. 1[1] Energy Thousand Btu/sec	Break Path No. 2[2] Mass lbm/sec	Break Path No. 2[2] Energy Thousand Btu/sec
11.0	1448.5	1798.8	3211.0	1222.3
11.2	1268.2	1578.9	3071.7	1116.1
11.4	1069.5	1335.1	2961.9	1028.9
11.6	894.3	1118.3	2797.3	936.0
11.8	740.1	926.5	2535.5	823.4
12.0	600.6	752.8	2196.3	697.3
12.2	480.7	603.0	1869.5	583.3
12.4	370.1	464.6	1489.0	458.1
12.6	253.7	318.8	1033.2	314.3
12.8	140.1	176.3	531.6	160.7
13.0	25.4	32.1	54.0	16.3
13.2	0.0	0.0	0.0	0.0

Notes: 1. Path 1: M&E exiting from the steam generator side of the break.
2. Path 2: M&E exiting from the broken loop reactor coolant pump side of the break.

Table 14.3.4-9 DEPS BREAK REFLOOD M&E RELEASE
Sheet 1 of 5

Time Seconds	Break Path No. 1(1) Mass lbm/sec	Break Path No. 1(1) Energy Thousand Btu/sec	Break Path No. 2 Flow(2) Mass lbm/sec	Break Path No. 2 Flow(2) Energy Thousand Btu/sec
13.2	0.0	0.0	0.0	0.0
13.7	0.0	0.0	0.0	0.0
13.8	0.0	0.0	0.0	0.0
14.0	0.0	0.0	0.0	0.0
14.1	0.0	0.0	0.0	0.0
14.11	0.0	0.0	0.0	0.0
14.2	82.9	97.9	0.0	0.0
14.3	27.4	32.4	0.0	0.0
14.4	20.8	24.5	0.0	0.0
14.6	25.8	30.5	0.0	0.0
14.7	34.6	40.9	0.0	0.0
14.8	41.8	49.4	0.0	0.0
14.9	48.6	57.5	0.0	0.0
15.0	55.2	65.2	0.0	0.0
15.1	61.4	72.6	0.0	0.0
15.2	67.4	79.7	0.0	0.0
15.21	68.8	81.4	0.0	0.0
15.3	72.4	85.5	0.0	0.0
15.4	76.9	90.8	0.0	0.0
15.5	81.2	95.9	0.0	0.0
15.6	85.3	100.8	0.0	0.0
15.7	89.3	105.5	0.0	0.0
15.8	93.1	110.0	0.0	0.0
15.9	96.8	114.4	0.0	0.0
16.0	100.4	118.7	0.0	0.0
16.1	103.9	122.8	0.0	0.0
16.2	107.3	126.9	0.0	0.0
16.3	110.6	130.8	0.0	0.0
17.3	139.9	165.4	0.0	0.0
18.3	164.3	194.3	0.0	0.0
18.9	265.0	313.7	2208.0	266.8
19.4	317.3	375.8	2920.0	353.2
20.4	326.4	386.7	2979.0	365.6
21.4	322.4	381.9	2935.5	361.6
22.4	318.1	376.8	2887.5	357.0
22.9	315.9	374.2	2863.1	354.6
23.4	313.8	371.7	2838.5	352.2
24.4	309.6	366.7	2789.7	347.4

Table 14.3.4-9 DEPS BREAK REFLOOD M&E RELEASE
Sheet 2 of 5

Time Seconds	Break Path No. 1(1) Mass lbm/sec	Break Path No. 1(1) Energy Thousand Btu/sec	Break Path No. 2 Flow(2) Mass lbm/sec	Break Path No. 2 Flow(2) Energy Thousand Btu/sec
25.4	305.5	361.8	2741.7	342.7
26.4	301.5	357.1	2694.8	338.1
27.4	297.7	352.6	2649.2	333.5
27.8	296.2	350.8	2631.3	331.8
28.4	294.1	348.2	2604.9	329.1
29.4	290.6	344.1	2562.0	324.9
30.4	287.2	340.1	2520.4	320.7
31.4	284.0	336.3	2480.1	316.7
32.4	280.9	332.6	2441.1	312.8
33.4	278.0	329.1	2403.2	309.1
34.4	275.2	325.8	2366.5	305.4
35.4	272.4	322.5	2330.9	301.8
36.4	269.8	319.4	2296.4	298.4
37.4	267.3	316.4	2262.8	295.0
38.4	264.8	313.5	2230.2	291.7
39.3	262.7	310.9	2201.6	288.8
39.4	223.5	264.5	921.5	170.0
40.4	188.7	223.2	970.9	164.3
41.4	198.8	235.2	1226.4	183.3
42.4	193.7	229.2	205.0	81.4
43.4	223.2	264.1	213.7	94.0
44.4	218.8	258.8	212.3	92.1
45.4	214.3	253.5	210.8	90.3
46.4	209.6	248.0	209.4	88.4
47.4	206.3	242.8	208.0	86.6
48.4	200.9	237.7	206.6	84.9
49.4	196.6	232.6	205.3	83.2
50.4	192.3	227.4	203.9	81.5
51.4	187.9	222.3	202.6	79.8
52.4	183.6	217.2	201.3	78.1
53.4	179.3	212.1	199.9	76.4
53.9	177.2	209.6	199.3	75.6
54.4	175.1	207.0	198.7	74.8
55.4	170.8	202.0	197.4	73.2
56.4	166.6	197.0	196.1	71.6
57.4	162.4	192.0	194.9	70.0
58.4	158.2	187.0	193.7	68.4
59.4	154.0	182.1	192.5	66.9
60.4	149.9	177.3	191.3	65.4

Table 14.3.4-9 DEPS BREAK REFLOOD M&E RELEASE
Sheet 3 of 5

Time Seconds	Break Path No. 1(1) Mass lbm/sec	Break Path No. 1(1) Energy Thousand Btu/sec	Break Path No. 2 Flow(2) Mass lbm/sec	Break Path No. 2 Flow(2) Energy Thousand Btu/sec
61.4	145.8	172.4	190.1	64.0
62.4	141.8	167.6	189.0	62.5
63.4	137.8	162.9	187.9	61.1
64.4	133.8	158.2	186.8	59.8
65.4	130.0	153.6	185.7	58.4
66.4	126.1	149.1	184.7	57.2
67.4	122.3	144.6	183.7	55.9
68.4	118.6	140.2	182.7	54.7
69.4	115.0	135.9	181.8	53.5
70.4	111.4	131.7	180.9	52.3
71.4	107.9	127.6	180.0	51.2
72.4	104.5	123.5	179.1	50.2
72.8	103.2	121.9	178.8	49.8
73.4	101.6	120.0	178.2	49.1
74.4	100.1	118.3	177.4	48.1
76.4	97.2	114.9	175.7	46.1
78.4	94.5	111.7	174.1	44.2
80.4	91.9	108.6	172.6	42.4
82.4	89.4	105.6	171.1	40.6
84.4	87.0	102.8	169.7	39.0
86.4	84.8	100.2	168.3	37.4
88.4	82.6	97.7	167.1	35.9
90.4	80.6	95.3	165.8	34.4
92.4	78.8	93.1	164.7	33.1
94.4	77.0	91.0	163.6	31.8
96.4	75.4	89.1	162.6	30.6
98.4	73.8	87.2	161.6	29.4
99.0	73.4	86.7	161.3	29.1
100.4	72.4	85.6	160.7	28.3
102.4	71.1	84.0	159.8	27.3
104.4	69.6	82.6	159.0	26.4
106.4	68.7	81.2	158.3	25.5
108.4	67.7	80.0	157.6	24.7
110.4	66.8	78.9	157.0	23.9
112.4	65.9	77.9	156.4	23.2
114.4	65.1	77.0	155.8	22.6
116.4	64.4	76.1	155.3	22.0
118.4	63.8	75.4	154.9	21.5
120.4	63.2	74.7	154.4	21.0

Table 14.3.4-9 DEPS BREAK REFLOOD M&E RELEASE
Sheet 4 of 5

Time Seconds	Break Path No. 1(1) Mass lbm/sec	Break Path No. 1(1) Energy Thousand Btu/sec	Break Path No. 2 Flow(2) Mass lbm/sec	Break Path No. 2 Flow(2) Energy Thousand Btu/sec
122.4	62.7	74.1	154.1	20.5
124.4	62.2	73.5	153.7	20.1
126.4	61.8	73.0	153.4	19.7
128.4	61.5	72.6	153.1	19.3
130.4	61.1	72.2	152.8	19.0
132.0	60.9	72.0	152.6	18.8
132.4	60.9	71.9	152.6	18.7
134.4	60.6	71.6	152.3	18.5
136.4	60.4	71.4	152.1	18.2
138.4	60.2	71.2	152.0	18.0
140.4	60.1	71.0	151.8	17.8
142.4	60.0	70.9	151.7	17.7
144.4	59.9	70.7	151.5	17.5
146.4	59.8	70.6	151.4	17.4
148.4	59.7	70.6	151.3	17.2
150.4	59.7	70.5	151.2	17.1
152.4	59.7	70.5	151.1	17.0
154.4	59.6	70.5	151.0	16.9
156.4	59.6	70.5	151.0	16.9
158.4	59.6	70.5	150.9	16.8
160.4	59.7	70.5	150.9	16.7
162.4	59.7	70.5	150.8	16.7
164.4	59.7	70.6	150.8	16.6
166.4	59.8	70.6	150.8	16.6
168.4	59.8	70.7	150.7	16.6
168.9	59.8	70.7	150.7	16.5
170.4	59.9	70.8	150.7	16.5
172.4	60.0	709.	150.7	16.5
174.4	60.0	70.9	150.7	16.5
176.4	60.1	71.0	150.6	16.5
178.4	60.2	71.1	150.6	16.5
180.4	60.3	71.2	150.6	16.4
182.4	60.4	71.3	150.6	16.4
184.4	60.5	71.5	150.6	16.4
186.4	60.6	71.6	150.6	16.4
188.4	60.7	71.7	150.6	16.4
190.4	60.8	71.8	150.6	16.5
192.4	60.9	71.9	150.6	16.5
194.4	61.0	72.0	150.6	16.5

Table 14.3.4-9 DEPS BREAK REFLOOD M&E RELEASE
Sheet 5 of 5

Time Seconds	Break Path No. 1[1] Mass lbm/sec	Break Path No. 1[1] Energy Thousand Btu/sec	Break Path No. 2 Flow[2] Mass lbm/sec	Break Path No. 2 Flow[2] Energy Thousand Btu/sec
196.4	61.1	72.2	150.7	16.5
198.4	61.2	72.3	150.7	16.5
200.4	61.3	72.4	150.7	16.5
202.4	61.4	72.5	150.7	16.5
204.4	61.5	72.7	150.7	16.5
206.4	61.6	72.8	150.7	16.6
207.4	61.7	72.9	150.7	16.6

Notes: 1. Path 1: M&E exiting from the steam generator side of the break.
2. Path 2: M&E exiting from the broken loop reactor coolant pump side of the break.

Table 14.3.4-10 DELETED

Table 14.3.4-11 DEPS - SAFETY INJECTION PRINCIPAL PARAMETERS DURING REFLOOD
Sheet 1 of 3

Time sec	Temp °F	Flooding Rate in/sec	Carry-over Fraction	Core Height ft	Downcomer Height ft	Flow Fraction	Total (Pounds mass per second)	Injector Accumulator (Pounds mass per second)	SI Spill (Pounds mass per second)	Enthalpy Btu/lbm
13.2	152	0	0	0	0	0.5	0	0	0	0
14	150.8	24.8	0	0.77	1.49	0	4306.8	4306.8	0	90.1
14.1	150.5	25.817	0	0.98	1.45	0	4295	4295	0	90.1
14.11	150.4	25.712	0	1.09	1.42	0	4283.2	4283.2	0	90.1
14.6	150.2	3.115	0.156	1.37	2.46	0.39	4227.2	4227.2	0	90.1
15.2	150.4	3.17	0.289	1.5	4.42	0.544	4155.6	4155.6	0	90.1
15.21	150.4	3.164	0.294	1.5	4.5	0.546	4153	4153	0	90.1
15.9	150.7	3.087	0.4	1.61	6.69	0.579	4082.2	4082.2	0	90.1
18.9	152.2	4.473	0.622	2	15.67	0.709	3758	3758	0	90.1
19.4	152.4	4.936	0.641	2.07	15.82	0.747	3701.2	3701.2	0	90.1
20.4	153	4.805	0.669	2.21	15.83	0.746	3613.9	3613.9	0	90.1
22.9	154.6	4.461	0.702	2.51	15.83	0.743	3436.5	3436.5	0	90.1
27.8	158	4.108	0.724	3	15.83	0.735	3147.3	3147.3	0	90.1
33.4	162.3	3.863	0.732	3.51	15.83	0.726	2881.7	2881.7	0	90.1
39.3	167	3.678	0.735	4	15.83	0.717	2652.6	2652.6	0	90.1

Table 14.3.4-11 DEPS - SAFETY INJECTION PRINCIPAL PARAMETERS DURING REFLOOD
Sheet 2 of 3

Time sec	Temp °F	Flooding Rate in/sec	Carry-over Fraction	Core Height ft	Downcomer Height ft	Flow Fraction	Total	Injector Accumulator	SI Spill	Enthalpy Btu/lbm
							(Pounds mass per second)			
40.4	167.8	2.967	0.724	4.08	15.83	0.648	1311.4	1311.4	0	90.1
41.4	168.6	3.065	0.726	4.15	15.83	0.66	1578.6	1291.1	0	86.08
42.4	169.4	3.137	0.724	4.22	15.81	0.673	289.1	0	0	68
43.4	170.2	3.304	0.732	4.29	15.53	0.681	285.2	0	0	68
46.4	172.9	3.127	0.73	4.51	14.73	0.677	285.9	0	0	68
53.9	180.2	2.71	0.725	5.01	13.04	0.665	287.5	0	0	68
63.4	190.4	2.212	0.715	5.55	11.49	0.642	289.1	0	0	68
72.8	200.4	1.782	0.705	6	10.54	0.605	290.2	0	0	68
86.4	213.9	1.496	0.698	6.55	9.84	0.599	290.2	0	0	68
99	224	1.311	0.693	7	9.58	0.596	290.2	0	0	68
116.4	235.2	1.157	0.69	7.55	9.64	0.595	290.2	0	0	68
132	243.6	1.091	0.69	8	9.9	0.597	290.2	0	0	68
150.4	252.2	1.058	0.693	8.51	10.35	0.601	290.2	0	0	68
168.9	259.7	1.048	0.698	9	10.84	0.604	290.1	0	0	68
180.4	264	1.047	0.701	9.3	11.16	0.607	290.1	0	0	68

Table 14.3.4-11 DEPS - SAFETY INJECTION PRINCIPAL PARAMETERS DURING REFLOOD
Sheet 3 of 3

Time sec	Temp °F	Flooding Rate in/sec	Carry-over Fraction	Core Height ft	Downcomer Height ft	Flow Fraction	Total	Injector Accumulator	SI Spill	Enthalpy Btu/lbm
							(Pounds mass per second)			
188.4	266.8	1.048	0.703	9.51	11.38	0.608	290.1	0	0	68
207.4	272.8	1.051	0.709	10	11.91	0.611	290.1	0	0	68

Table 14.3.4-12 DELETED

Table 14.3.4-13 DEPS BREAK POST-REFLOOD M&E RELEASE
Sheet 1 of 4

Time Seconds	Break Path No. 1(1) Mass lbm/sec	Break Path No. 1(1) Energy Thousand Btu/sec	Break Path No. 2 Flow(2) Mass lbm/sec	Break Path No. 2 Flow(2) Energy Thousand Btu/sec
207.5	115.8	147.1	177.5	47.3
212.5	115.4	146.7	177.4	47.3
217.5	115.1	146.2	177.2	47.3
222.5	114.8	145.8	177.1	47.2
227.5	114.5	146.8	177.0	46.9
232.5	115.2	146.4	176.8	46.9
237.5	114.8	145.9	176.7	46.9
242.5	114.5	145.5	176.6	46.8
147.5	114.2	145.1	176.4	46.8
252.5	114.9	146.0	176.3	46.5
257.5	114.6	145.6	176.2	46.5
262.5	114.2	145.1	176.0	46.4
267.5	113.9	144.7	176.3	46.4
272.5	113.5	144.2	176.7	46.4
277.5	114.2	145.2	175.9	46.1
282.5	113.9	144.7	176.3	46.0
287.5	113.5	144.2	176.7	46.0
292.5	113.1	143.8	177.0	46.0
297.5	112.8	143.3	177.4	46.0
302.5	113.5	144.2	176.7	45.7
307.5	113.1	143.7	177.1	45.6
312.5	112.7	143.2	177.4	45.6
317.5	112.3	142.8	177.8	45.6
322.5	112.0	142.3	178.2	45.6
327.5	112.6	143.1	177.5	45.3
332.5	112.3	142.7	177.9	45.3
337.5	111.9	142.2	178.3	45.2
342.5	111.5	141.7	178.7	45.2
347.5	112.1	142.5	178.0	44.9
352.5	111.7	142.0	178.4	44.9
357.5	111.3	141.5	178.8	44.9
362.5	110.9	141.0	179.2	44.9
367.5	111.6	141.8	179.6	44.6
372.5	111.2	141.3	179.0	44.6
377.5	110.8	140.7	179.4	45.8
382.5	110.3	140.2	179.8	45.8
387.5	110.9	141.0	179.2	45.5
392.5	110.5	140.4	179.6	45.5
397.5	110.1	139.9	180.1	45.5

Table 14.3.4-13 DEPS BREAK POST-REFLOOD M&E RELEASE
Sheet 2 of 4

Time Seconds	Break Path No. 1(1) Mass lbm/sec	Break Path No. 1(1) Energy Thousand Btu/sec	Break Path No. 2 Flow(2) Mass lbm/sec	Break Path No. 2 Flow(2) Energy Thousand Btu/sec
402.5	109.7	139.4	180.5	45.5
407.5	110.4	140.2	179.8	45.1
412.5	110.0	139.8	180.2	45.1
417.5	109.6	139.3	180.5	45.1
422.5	110.3	140.1	179.9	44.8
427.5	109.9	139.6	180.3	44.7
432.5	109.5	139.2	180.6	44.7
437.5	109.1	138.7	181.0	44.7
442.5	109.7	139.4	180.4	44.4
447.5	109.3	139.0	180.8	44.4
452.5	109.0	138.5	181.2	44.3
457.5	109.5	139.2	180.6	44.0
462.5	109.1	138.7	181.0	44.0
467.5	108.7	138.2	181.4	45.2
472.5	109.3	138.8	180.9	44.9
477.5	108.8	138.3	181.3	44.9
482.5	108.4	137.8	181.7	44.9
487.5	108.9	138.4	181.2	44.6
492.5	108.5	137.9	181.7	44.6
497.5	108.1	137.3	182.1	44.5
502.5	108.5	137.9	181.6	44.3
507.5	108.1	137.4	182.1	44.2
512.5	108.5	137.9	181.6	44.0
517.5	108.1	137.3	182.1	43.9
522.5	107.6	136.8	182.5	43.9
527.5	108.0	137.3	182.1	43.7
532.5	107.6	136.7	182.6	44.8
537.5	107.9	137.2	182.2	44.6
542.5	107.5	136.6	182.7	44.6
547.5	107.8	137.0	182.3	44.3
552.5	107.3	136.4	182.9	44.3
557.5	107.6	136.8	182.5	44.0
562.5	107.1	136.1	183.1	44.0
567.5	107.4	136.5	182.8	43.8
572.5	106.8	135.8	183.3	43.8
577.5	107.1	136.1	183.0	43.5
582.5	106.5	135.4	183.6	43.5
587.5	106.8	135.7	183.4	43.3
592.5	107.0	136.0	183.2	44.2

Table 14.3.4-13 DEPS BREAK POST-REFLOOD M&E RELEASE
Sheet 3 of 4

Time Seconds	Break Path No. 1(1) Mass lbm/sec	Break Path No. 1(1) Energy Thousand Btu/sec	Break Path No. 2 Flow(2) Mass lbm/sec	Break Path No. 2 Flow(2) Energy Thousand Btu/sec
597.5	106.4	135.2	183.8	44.2
602.5	106.6	135.4	183.6	44.0
607.5	106.7	135.7	183.4	43.8
612.5	106.1	134.9	184.0	43.8
617.5	106.3	135.0	183.9	43.6
622.5	106.4	135.2	183.8	43.4
627.5	106.5	135.3	183.7	43.2
632.5	106.5	135.3	183.6	43.0
637.5	105.8	134.4	184.4	44.1
642.5	105.8	134.5	184.4	44.0
647.5	105.8	134.4	184.4	43.8
652.5	105.7	134.3	184.4	43.6
657.5	105.6	134.2	184.5	43.4
662.5	105.5	134.1	184.7	43.3
667.5	105.3	133.9	184.8	43.2
672.5	105.8	134.5	184.3	42.8
677.5	105.6	134.1	184.6	43.8
682.5	105.3	133.8	184.9	43.7
687.5	105.6	134.2	184.6	43.4
692.5	105.2	133.6	185.0	43.3
697.5	105.3	133.8	184.8	43.1
702.5	105.4	133.9	184.8	42.9
707.5	105.4	133.9	184.8	42.7
712.5	105.3	133.8	184.9	43.5
717.5	105.1	133.6	185.1	43.4
722.5	104.8	133.2	185.4	43.3
727.5	104.9	133.3	185.2	43.0
732.5	104.9	133.3	185.3	42.8
737.5	104.7	133.0	185.5	42.6
742.5	104.8	133.1	185.4	43.4
747.5	104.6	132.9	185.6	43.3
752.5	104.6	132.9	185.6	43.0
757.5	104.2	132.4	186.0	42.9
762.5	104.2	132.4	186.0	42.7
767.5	104.3	132.5	185.9	43.4
772.5	104.2	132.4	186.0	43.2
777.5	104.1	132.2	186.1	43.0
782.5	103.9	132.0	186.3	42.8
787.5	103.6	131.7	186.5	42.6

Table 14.3.4-13 DEPS BREAK POST-REFLOOD M&E RELEASE
Sheet 4 of 4

Time Seconds	Break Path No. 1[1] Mass lbm/sec	Break Path No. 1[1] Energy Thousand Btu/sec	Break Path No. 2 Flow[2] Mass lbm/sec	Break Path No. 2 Flow[2] Energy Thousand Btu/sec
792.5	103.2	131.2	186.9	43.5
1006.1	103.2	131.2	186.9	43.5
1006.2	49.0	61.1	241.2	57.2
1007.5	49.0	61.1	241.2	57.2
1298.9	49.0	61.1	241.2	57.2
1299.0	45.9	52.8	244.3	18.7
3395.0	37.1	42.6	253.1	20.3
3395.1	37.1	42.6	233.8	40.6
3600.0	36.4	41.9	234.5	40.7

Notes: 1. Path 1: M&E exiting from the steam generator side of the break.
2. Path 2: M&E exiting from the broken loop reactor coolant pump side of the break.

Table 14.3.4-14 DELETED

Table 14.3.4-15 DEPS BREAK MASS BALANCE

	Time (Seconds)	.00	13.20	13.20+ε	207.40	1006.25	1298.87	3600.00
				Mass (Thousand lbm)				
Initial Mass	In RCS and Accumulator	414.12	414.12	414.12	414.12	414.12	414.12	414.12
Added Mass	Pumped Injection	0	0	0	48.19	279.95	364.86	1028.61
	Total Added	0	0	0	48.19	279.95	364.86	1028.61
*** Total Available ***		414.12	414.12	414.12	462.30	694.07	778.97	1442.73
Distribution	Reactor Coolant	272.88	18.13	42.74	71.08	71.08	71.08	71.08
	Accumulator	141.24	114.79	90.18	0	0	0	0
	Total Contents	414.12	132.92	132.92	71.08	71.08	71.08	71.08
Effluent	Break Flow	0	281.19	281.19	385.22	617.08	701.98	1365.73
	ECCS Spill	0	0	0	0	0	0	0
	Total Effluent	0	281.19	281.19	385.22	617.08	701.98	1365.73
*** Total Accountable ***		414.12	414.11	414.11	456.31	688.17	773.06	1436.82

Note: +ε is used to indicate that the column represents the bottom of core recovery conditions which occurs instantaneously after blowdown.

Table 14.3.4-16 DELETED

Table 14.3.4-17 DEPS BREAK ENERGY BALANCE

	Time (Seconds)	0.00	13.20	13.20+ε	207.40	1006.25	1298.87	3600.00
		Energy (Thousand Btu)						
Initial Energy	In RCS, Accumulators and Steam Generators	432.19	432.19	432.19	432.19	432.19	432.19	432.19
Added Energy	Pumped Injection	0	0	0	3.28	19.04	24.81	74.39
	Decay Heat	0	2.51	2.51	14.66	49.58	60.37	129.67
	Heat from Secondary	0	11.57	11.57	11.57	11.57	11.57	11.57
	Total Added	0	14.08	14.08	29.51	80.18	96.75	215.63
*** Total Available ***		432.19	446.27	446.27	461.70	512.38	528.94	647.82
Distribution	Reactor Coolant	160.52	5.03	7.25	19.19	19.19	19.19	19.19
	Accumulator	12.73	10.34	8.13	0	0	0	0
	Core Stored	15.37	9.47	9.47	2.77	2.63	2.54	1.81
	Primary Metal	85.83	82.17	82.17	68.99	41.71	38.46	27.37
	Secondary Metal	43.54	43.13	43.13	40.88	25.02	22.46	15.95
	Steam Generator	114.21	126.83	126.83	118.71	68.83	61.85	43.45
	Total Contents	432.19	276.97	276.97	250.55	157.38	144.50	107.78
Effluent	Break Flow	0	168.98	168.98	206.21	350.06	385.15	542.94
	ECCS Spill	0	0	0	0	0	0	0
	Total Effluent	0	168.98	168.98	206.21	350.06	385.15	542.94
*** Total Accountable ***		432.19	445.96	445.96	456.76	507.44	529.65	650.72

Note: +ε is used to indicate that the column represents the bottom of core recovery conditions which occurs instantaneously after blowdown.

Table 14.3.4-18 DELETED

Table 14.3.4-19 DOUBLE-ENDED HOT LEG BREAK SEQUENCE OF EVENTS

Time (sec)	Event Description
0.0	Break Occurs and Loss of Offsite Power is Assumed
0.311	Compensated Pressurizer Pressure for Reactor Trip (1968.7 psia) Reached and Turbine Trip Occurs
3.8	Low-Pressurizer Pressure Safety Injection (SI) Setpoint (1663 psia) Reached - Feedwater Isolation Signal
4.99	Broken Loop Accumulator Begins Injecting Water
5.03	Intact Loop Accumulator Begins Injecting Water
16.56	Peak Temperature Occurs (279.8°F)
16.56	Peak Pressure Occurs (70.00 psia)
15.4	End of Blowdown Phase
15.4	Feedwater Isolation Valves Closed
50.0	Transient Modeling Terminated

Table 14.3.4-20 DOUBLE-ENDED PUMP SUCTION BREAK SEQUENCE OF EVENTS
Sheet 1 of 2

Time (sec)	Event Description
0	Break Occurs and Loss of Offsite Power is Assumed
0.24	Containment High Pressure Safety Injection Actuation Pressure Setpoint (20.7 psia; Analysis Value) Reached. (CFCs Actuated)
0.418	Compensated Pressurizer Pressure for Reactor Trip (1,968.7 psia) Reached and Turbine Trip Occurs
2.73	Containment Spray Actuation Pressure Setpoint (44.7 psia; Analysis Value) Reached
4.1	Low Pressurizer Pressure SI Setpoint (1,663 psia) Reached (Safety Injection Begins coincident with Low Pressurizer Pressure SI Setpoint)
5.29	Broken Loop Accumulator Begins Injecting Water
5.40	Intact Loop Accumulator Begins Injecting Water
13.2	End of Blowdown Phase
13.2	Accumulator Mass Adjustment for Refill Period
13.2	Feedwater Isolation Valves Closed
39.25	Broken Loop Acculumator Water Injection Ends
41.1	Pumped Safety Injection Begins (Included 37 Second Diesel Delay)
42.2	Intact Loop Accumulator Water Injection Ends
72.73	Containment Spray Pump (RWST) Begins
84.24	CFCs Begin Heat Removal (Includes 84 Second Delay)
207.4	End of Reflood for Minimum Safeguards Case
797.5	M&E Release Assumption: Broken Loop Steam Generator (SG) Equilibration When the Secondary Temperature is at Saturation (T_{SAT}) at Containment Design Pressure of 74.7 psia
1,006.25	M&E Release Assumption: Broken Loop SG Equilibration at Containment Pressure of 60.7 psia
873.9	Containment Peak Temperature Occurs (285.7°F)
873.9	Containment Peak Pressure Occurs (71.08 psia)
1,127.65	M&E Release Assumption: Intact Loop SG Equilibration When the Secondary Temperature is at Saturation (T_{SAT}) at Containment Design Pressure of 74.7 psia

Table 14.3.4-20 DOUBLE-ENDED PUMP SUCTION BREAK SEQUENCE OF EVENTS
Sheet 2 of 2

1,298.87	M&E Release Assumption: Intact Loop SG Equilibration at Containment Pressure of 54.7 psia
3,398.34	Switchover to Recirculation Begins
6,000	Injection Sprays Terminated
7,200	Recirculation Sprays Initiated (Injection Spray Termination Plus 1,200 Second Delay)
14,400	Recirculation Spray Terminated
2.6E+6	Transient Modeling Terminated

Table 14.3.4-21 DELETED

Table 14.3.4-22 RCS CONDITIONS FOR SHORT-TERM MASS AND ENERGY RELEASES

Minimum RCS Vessel Outlet Temperature	529.9°F
Minimum RCS Vessel / Core Inlet Temperature	525.0°F
Allowance for RCS Temperature Uncertainty	-6.4°F
Nominal RCS Pressure	2,250.0 psia
Allowance for RCS Pressure Uncertainty	+50.0 psia

Table 14.3.4-23 SHORT-TERM LOCA M&E RELEASES

Time (Sec)	Flow (lbm/sec)	Enthalpy (Btu/lbm)
Double-Ended Hot Leg 6” Break		
0.0	0.0	0.0
0.001	9615.02	598.04
3.0	9615.02	598.04
Double-Ended Cold Leg 3” Break		
0.0	0.0	0.0
0.001	2952.76	510.29
3.0	2952.76	510.29

Table 14.3.4-24 CONTAINMENT INTEGRITY LOCA ANALYSIS PARAMETERS
Sheet 1 of 2

Parameter	Value
Service Water Temperature (°F)	85
Refueling Water Storage Tank / Containment Injection Spray Water Temperature (°F)	100
Initial Containment Temperature (°F)	120
Initial Containment Pressure (psia)	16.7
Initial Relative Humidity (%)	20
Containment Net Free Volume (ft^3)	1,000,000
Reactor Containment Fan Coolers	
Total CFCs Available	4
Analysis Maximum Safeguards	4
Analysis Minimum Safeguards (with Diesel Failure)	2
Containment High Pressure Setpoint (psig)	6.0
Delay Time (sec) - Without Offsite Power	 84.0
Air Flow Rate through Cooler (ft^3/min/CFC)	33,500
Containment Fan Cooler Heat Removal as a Function of Containment Saturation Temperature and Component Cooling Water Heat Exchanger Primary Side Outlet Temperature	See Table 14.3.4-25
Containment Spray Pumps	
Total CSPs Available	1
Analysis Minimum Safeguards (with Diesel Failure)	1
Containment Spray Pump Flow Rate (gpm/pump) Injection Phase Recirculation Phase	See Table 14.3.4-26 900
Containment Hi-Hi Pressure Setpoint (psig)	30.0
Spray Delay Time (Sec) Without Offsite Power (1 spray pump)	 70

Table 14.3.4-24 CONTAINMENT INTEGRITY LOCA ANALYSIS PARAMETERS
Sheet 2 of 2

Parameter	**Value**
Containment Spray Termination time (sum of injection and recirculation phase including 1,200 second delay time) (sec) -Minimum Safeguards -Maximum Safeguards	 14,400.0 11,400.0
ECCS Recirculation	
ECCS Recirculation Switchover (sec) -Minimum Safeguards -Maximum Safeguards (after SI setpoint is reached)	 3,395.0 1,646.0
Residual Heat Removal System	
RHR Heat Exchangers(1)	
Modeled in analysis	1
Flows - Tube Side and Shell Side (gpm) -Tube Side -Shellside (component cooling water)	 1,951.0 2,780.0
Component Cooling Water Heat Exchangers	
Modeled in analysis	1
Flows - Shell Side and Tube Side (gpm) -Shellside -Tubeside (service water)	 2,895.0 2,700.0
CCW Misc. Heat Loads (MBtu/hr)	2.0
Notes: (1) Modeled with 10% tube plugging	

Table 14.3.4-25 CONTAINMENT FAN COOLER PERFORMANCE

Containment Temperature (°F)	Heat Removal Rate [Btu/sec] Per Reactor Containment Fan Cooler
120	839.25
160	2,070.5
190	3,799.25
210	5,390
220	5,830
230	6,167.75
240	6,508.75
260	7,184.25
270	7,516

Table 14.3.4-26 CONTAINMENT SPRAY PERFORMANCE

Containment Pressure (psig)	1 Pump (gpm)
0	1324.0
10	1287.2
20	1250.3
30	1206.9
40	1162.5
50	1117.0
60	1070.7

Table 14.3.4-27 CONTAINMENT STRUCUTRAL HEAT SINK INPUT Sheet 1 of 7

GOTHIC Heat Sink Description	Area (ft^2)	Material	Thickness (inches)
Upper Dome	1610	Paint type 1	0.01404
		Carbon Steel	0.2496
		Gap	0.021
		Concrete	36
Middle Dome	5912	Paint Type 1	0.01404
		Carbon Steel	0.2496
		Gap	0.021
		Concrete	36
Lower Dome	6432	Paint Type 1	0.01404
		Carbon Steel	0.2496
		Gap	0.021
		Concrete	36
Upper Containment outter wall (above 66')	16988	Paint Type 1	0.015
		Carbon Steel	0.2496
		Gap	0.021
		Concrete	42
Middle Containment outter wall (21' to 66')	14844	Paint Type 1	0.015
		Carbon Steel	0.2496
		Gap	0.021
		Concrete	42

Table 14.3.4-27 CONTAINMENT STRUCUTRAL HEAT SINK INPUT Sheet 2 of 7

GOTHIC Heat Sink Description	Area (ft^2)	Material	Thickness (inches)
Lower Containment outer wall (8' top 21')	4166	Paint Type 1	0.015
		Carbon Steel	0.2496
		Gap	0.021
		Concrete	42
Rx Cavity: Shield wall / Rx Pit	1695	Paint Type 2	0.039
		Concrete	12
Rx Cavity: tunnel walls	260	Paint type 2	0.039
		Concrete	12
Rx Cavity: Keyway tower / shaft	1120	Paint Type 2	0.039
		Concrete	12
Rx Cavity: Floor slab	353	Paint Type 2	0.015
		Concrete	12
Pzr walls (inside 46'-86')	2027	Paint Type 2	0.039
		Concrete	15
Pzr floor slab	156	Paint Type 2	0.015
		Concrete	24
		Paint Type 2	0.039
Pzr missile shields	176	Paint Type 2	0.039
		Carbon Steel	0.5
		Gap	0.021
		Concrete	15

Table 14.3.4-27 CONTAINMENT STRUCUTRAL HEAT SINK INPUT Sheet 3 of 7

GOTHIC Heat Sink Description	**Area** (ft^2)	**Material**	**Thickness** (inches)
		Paint Type 1	0.039
Upper Ctmt interior walls	5420	Paint Type 2	0.039
		Concrete	15
Upper Ctmt floor / Annular Cmpt ceiling	4339	Paint Type 2	0.015
		Concrete	4
Annular Cmpt: Interior wall (46’ to 66’)	5372	Paint Type 2	0.039
		Concrete	15
Annular Cmpt: Interior wall (21’ to 46’)	8263	Paint Type 2	0.039
		Concrete	15
Annular Cmpt: lay-down area high wall (21’ to 66’)	585	Paint Type 2	0.039
		Concrete	18
Annular Cmpt 46’ floor slab	3914	Paint Type 2	0.015
		Concrete	4
Annular Cmpt floor / Annular Sump ceiling (21’)	4272	Paint Type 2	0.015
		Concrete	4
Annular Sump: interior walls (8’ to 21’)	4487	Paint type 2	0.039
		Concrete	15

Table 14.3.4-27 CONTAINMENT STRUCUTRAL HEAT SINK INPUT Sheet 4 of 7

GOTHIC Heat Sink Description	Area (ft^2)	Material	Thickness (inches)
Annular Sump floor slab (8')	4352	Paint Type 2	0.015
		Concrete	12
Loop A: walls	6691	Paint Type 2	0.039
		Concrete	15
Loop A: floor slab	816	Paint Type 2	0.015
		Concrete	12
Loop A: missile shields	251.1	Paint Type 2	0.015
		Concrete	15
		Paint Type 2	0.039
Loop B: walls	8087	Paint Type 2	0.039
		Concrete	15
Loop B: floor slab	794	Paint Type 2	0.015
		Concrete	12
Loop B: missile shields	208	Paint Type 2	0.015
		Concrete	15
		Paint Type 2	0.039
Loop B: sub-pzr cmpt walls	286	Paint Type 2	0.039
		Concrete	15
Loop B: sub-pzr cmpt floor	176	Paint Type 2	0.015
		Concrete	24
		Paint Type 2	0.039

Table 14.3.4-27 CONTAINMENT STRUCUTRAL HEAT SINK INPUT Sheet 5 of 7

GOTHIC Heat Sink Description	Area (ft^2)	Material	Thickness (inches)
Refueling cavity wall	4691	Stainless Steel	0.1875
		Gap	0.021
		Concrete	18
		Paint Type 2	0.039
Refueling cavity floor / Annular sump ceiling	536	Stainless Steel	0.1875
		Gap	0.021
		Concrete	36
		Paint Type 2	0.039
Misc. steel in reactor cavity compartment	667.36	Paint Type 1	0.0130
		Carbon Steel	1.2630
Misc. steel in the pressurizer compartment	1.08	Paint Type 1	0.0130
		Carbon Steel	0.0050
Misc. steel in the upper containment	5048.27	Paint Type 1	0.0130
		Carbon Steel	0.3770
Misc. steel in the annular compartment	22507.34	Paint Type 1	0.0130
		Carbon Steel	0.3960
Misc. steel in the annular sump compartment	6662.86	Paint Type 1	0.0130

Table 14.3.4-27 CONTAINMENT STRUCUTRAL HEAT SINK INPUT Sheet 6 of 7

GOTHIC Heat Sink Description	Area (ft^2)	Material	Thickness (inches)
		Carbon Steel	0.2300
Misc. steel in the Loop A compartment	3390.63	Paint Type 1	0.0130
		Carbon Steel	0.3720
Misc. steel in the Loop B compartment	3390.63	Paint Type 1	0.0130
		Carbon Steel	0.3720
Misc. steel in the dome compartment	20731.29	Paint Type 1	0.0130
		Carbon Steel	0.1480
Misc. steel in refueling cavity compartment	398.26	Paint Type 1	0.0130
		Carbon Steel	1.4750
1 CFC in upper containment compartment; unpainted copper	7071.89	Copper	0.0130
1 CFC in upper containment compartment	21.53	Stainless Steel	1.0220
1 CFC in annular compartment	7075.48	Copper	0.0130
Unpainted stainless steel in Annular Compartment; 1 CFC	24.08	Stainless Steel	0.6700
Polar crane & rail girder in the upper containment	8094.46	Paint Type 1	0.0130

Table 14.3.4-27 CONTAINMENT STRUCUTRAL HEAT SINK INPUT Sheet 7 of 7

GOTHIC Heat Sink Description	**Area (ft^2)**	**Material**	**Thickness (inches)**
		Carbon Steel	0.9060
A RCP in the Loop A compartment	570.49	Paint Type 1	0.0079
		Copper	2.583
A RCP in the Loop B compartment	570.49	Paint Type 1	0.0079
		Copper	2.583
PRT Unpainted SS	509	Stainless Steel	0.6700

Table 14.3.4-28 MATERIAL PROPERTIES FOR CONTAINMENT STRUCUTRAL HEAT SINKS

Material Type	**Density**	**Thermal Conductivity**	**Specific Heat**
	lbm/ft^3	Btu/hr-ft-°F	**Btu/lbm-°F**
Concrete	144	0.81	0.2
Stainless Steel	488	9.4	0.123
Carbon Steel	490	26	0.115
Copper (pure)	557.69	231.7	0.092
Gap (air)	0.06	0.0174	0.241
Amercote 66 top coating / Dimecote 6 primer coating (Paint Type 1)	1	0.25	21.7
Phenoline 305 top coating / Carboline 195 primer coating (Paint Type 2)	1	0.187	37.8

Table 14.3.4-29 SUMMARY OF PEAK CONTAINMENT PRESSURE AND TEMPERATURES

Case	Peak Pressure (psia)	Time (sec)	Peak Temp (°F)	Time (sec)	Pressure @ 24 hours (psia)
DEHL	70.39	14.51	280.3	14.51	-
DEPS MINSI	69.98	1,007	283.7	1,007	23.7
DEPS MAXSI	68.01	12.51	280.7	730.8	20.7
Limit	74.7		286.0		

Figure 14.3.4-1 CONTAINMENT PRESSURE - DOUBLE-ENDED HOT-LEG BREAK

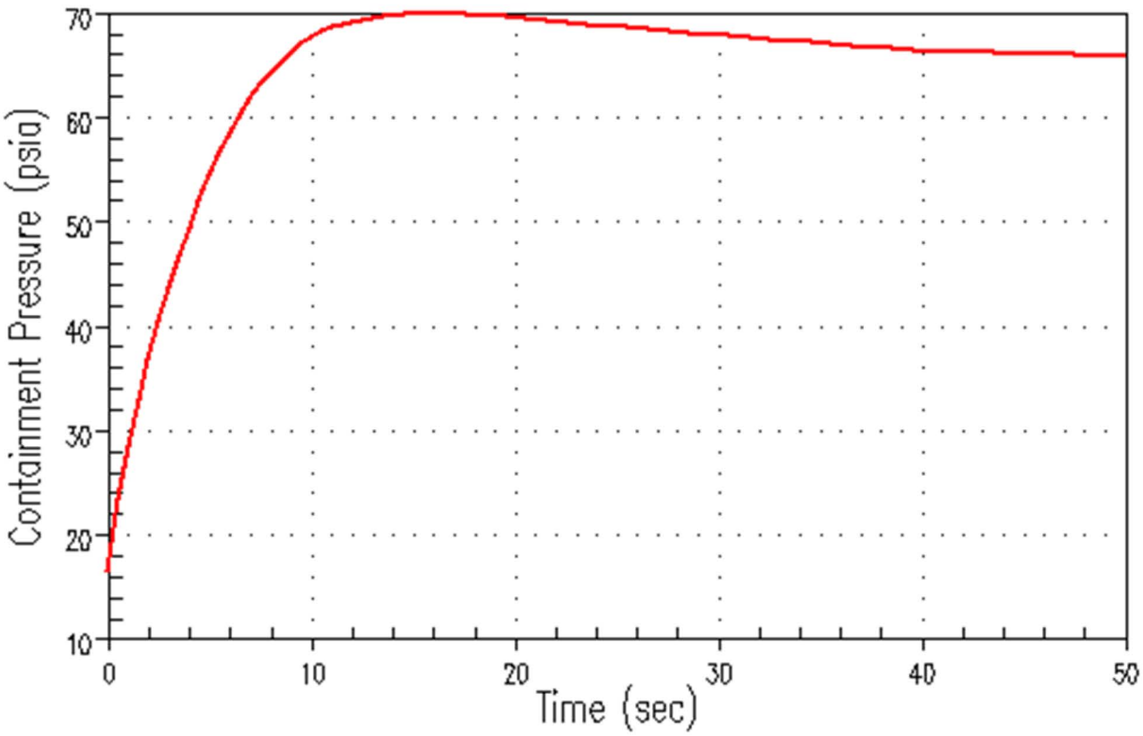


Figure 14.3.4-2 CONTAINMENT TEMPERATURE - DOUBLE-ENDED HOT-LEG BREAK

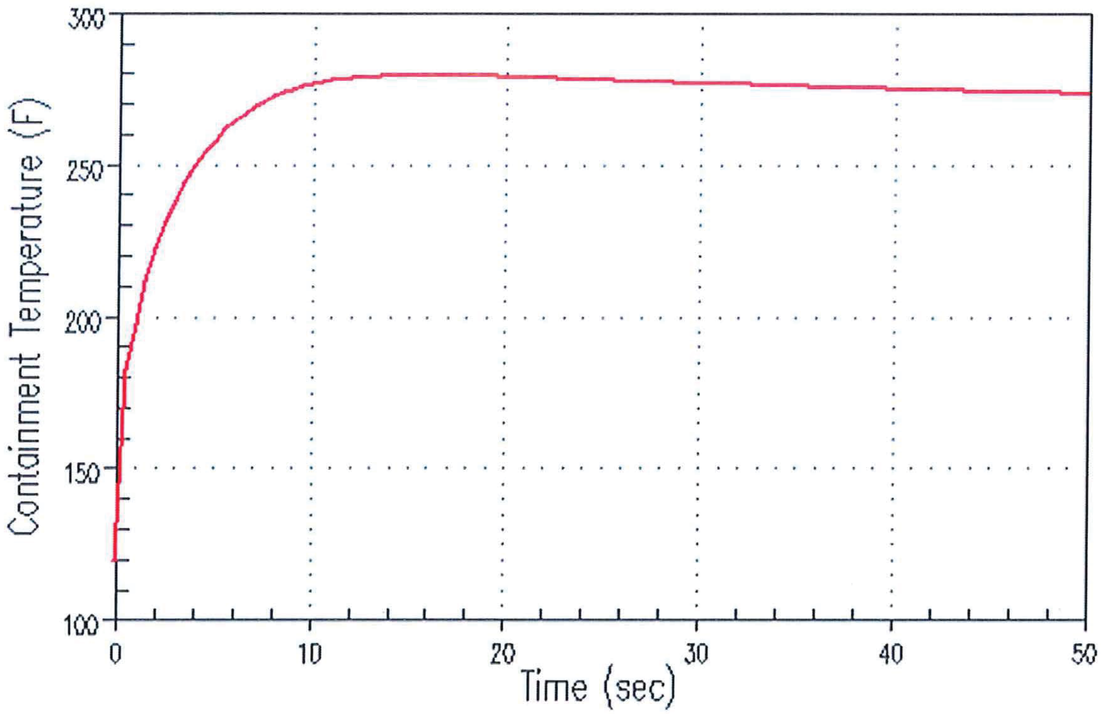


Figure 14.3.4-3 CONTAINMENT PRESSURE - DOUBLE-ENDED PUMP SUCTION BREAK

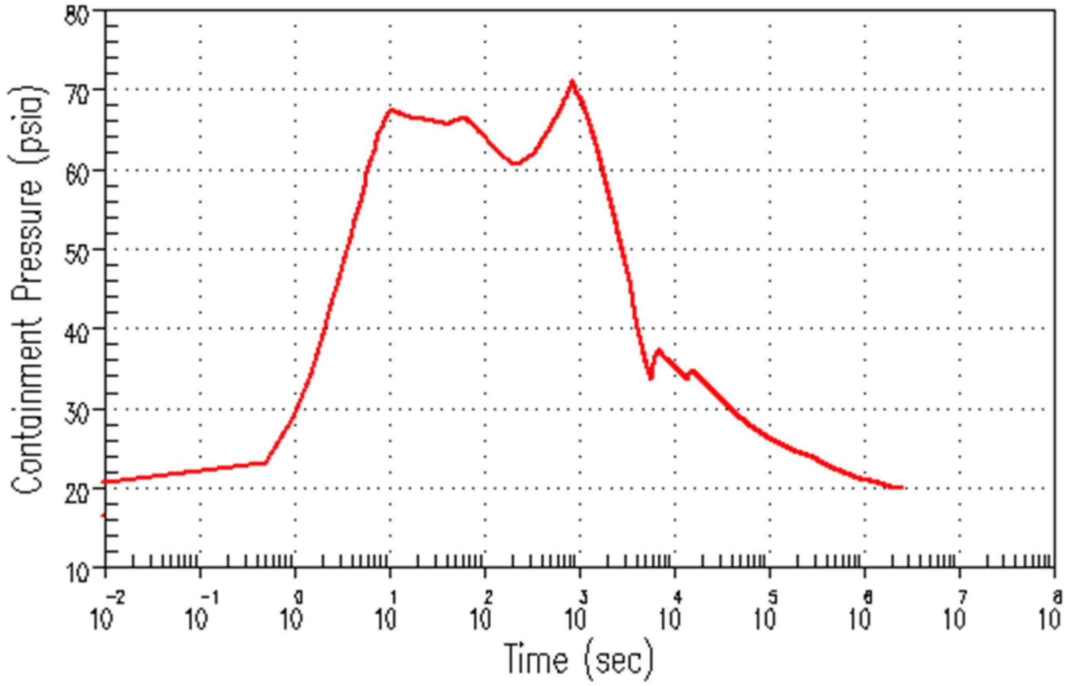


Figure 14.3.4-4 CONTAINMENT TEMPERATURE - DOUBLE-ENDED PUMP SUCTION BREAK

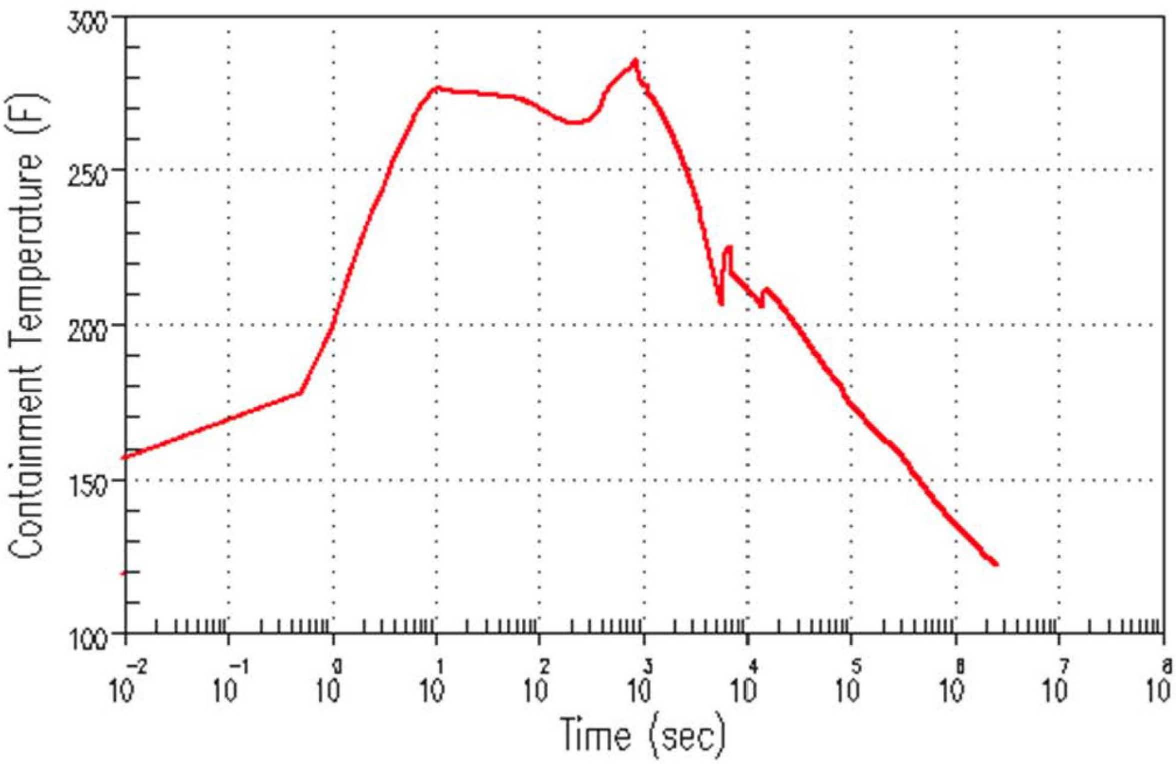


Figure 14.3.4-5 DELETED

Figure 14.3.4-6 DELETED

14.3.5 RADIOLOGICAL CONSEQUENCES OF LOSS-OF-COOLANT ACCIDENT

The results of analyses presented in this section demonstrate that the amounts of radioactivity released to the environment in the event of a loss-of-coolant accident result in calculated offsite radiological doses that do not exceed the limits specified in 10 CFR 50.67. The calculated doses are summarized in Table 14.3.5-6.

Basic Events and Release Fractions

There are two release pathways considered in this analysis: (1) radioactivity which enters containment from the reactor core and is released due to containment leakage, and (2) radioactivity which is released to the environment via ECCS equipment leakage.

The event causing the postulated releases is a double-ended rupture of a reactor coolant pipe, with subsequent blowdown, as described in Section 14.3.4. As demonstrated by the analysis in Section 14.3.2, the emergency core cooling system, using emergency power, keeps cladding temperatures well below melting and limits zirconium - water reactions to an insignificant level, assuring that the core remains intact and in place. As a result of the increase in cladding temperature and the rapid depressurization of the core, however, some cladding failure may occur in the hottest regions of the core. For analysis purposes, the entire core is assumed to fail. The release of activity from the core occurs over a 1.8 hour interval. The gap release phase occurs in the first half hour and the release from the melted fuel occurs over the next 1.3 hours. A wide spectrum of nuclides is taken into consideration. Table 14.3.5-1 lists the nuclides being considered for the LOCA with core melt.

Containment Vessel Inventory and Release Rate

Consistent with Regulatory Guide 1.183 (Reference 4), 95 percent of the radioiodine released to the containment is assumed to be cesium iodide (CsI), 4.85 percent is elemental iodine, and 0.15 percent is organic iodide. This includes releases from the gap and the fuel pellets. With the exception of elemental and organic iodine and noble gases, fission products are assumed to be in particulate form.

For the containment leakage analysis, all activity released from the fuel is assumed to be in the containment atmosphere until removed by sprays, sedimentation, radioactive decay or leakage from the containment.

The containment building is modeled as two discrete volumes: sprayed and unsprayed. The volumes are conservatively assumed to be mixed only by the containment fan coolers and all activity is assumed to be released into the unsprayed volume. The containment volume is 1.0E6 ft^3 with a sprayed fraction of 58.2 percent of the total (5.82E5 ft^3).

The containment is assumed to leak at the design leak rate of 0.2 weight percent per day for the first 24 hours of the accident and then to leak at half that rate (0.1 weight percent per day) for the remainder of the 30 day period following the accident considered in the analysis.

Removal of Activity from the Containment Atmosphere

The reduction of activity available for release to the environment depends on the chemical form. The removal of elemental iodine from the containment atmosphere is accomplished only by containment sprays and radioactive decay. The removal of particulates from the containment atmosphere is accomplished by containment sprays, sedimentation and radioactive decay. The noble gases and the organic iodine are subject to removal only by radioactive decay.

One train of the containment spray system is assumed to operate in the injection mode following the LOCA. When the RWST drains to a predetermined level, the operators switch to recirculation of the sump liquid to provide a source to the sprays. The minimum injection spray duration until the level is reached is 40 minutes. The switchover is assumed to take 20 minutes. During these 20 minutes, the analysis does not credit any spray removal in the containment. The analysis assumed that the recirculation sprays operate for a 2-hour duration.

Containment Spray Removal of Elemental Iodine

The Standard Review Plan (SRP) Section 6.5.2 (Reference 5) identifies a methodology for the determination of spray removal of elemental iodine independent of the use of spray additive. The upper limit of the removal coefficient was specified as 20 hr-1 for this model. For PBNP the calculated elemental spray removal coefficients were higher than the upper limit of 20 hr-1, therefore the upper limit of 20 hr-1 was conservatively used. When sprays are operating in the recirculation phase the elemental removal coefficient is reduced to 9.20 hr-1 to address the loading of the recirculating solution with elemental iodine.

Removal of elemental iodine from the containment atmosphere is assumed to be terminated when the airborne inventory drops to 0.5 percent of the total elemental iodine released to the containment (this is a decontamination factor or DF of 200). With the RG 1.183 source term methodology, this is considered as being 0.5 percent of the total inventory of elemental iodine that is released to the containment atmosphere over the duration of gap and in-vessel release phases. In the analysis, this occurs at 2.71 hours.

Containment Spray Removal of Particulates

Particulate spray removal is determined using the model described in SRP Section 6.5.2 (Reference 5). For PBNP the calculated particulate spray removal coefficient is 4.42 hr-1 during injection and 3.72 hr-1 during recirculation. Following the model in SRP Section 6.5.2, these coefficients are applied until the time when the inventory in the containment is reduced to 2 percent of its original amount (DF of 50), at which time they are reduced by a factor of 10. With the RG 1.183 source term methodology, this is considered as being 2 percent of the total inventory of particulate iodine that is released to the containment atmosphere over the duration of gap and in-vessel release phases. In the analysis, the DF of 50 is not achieved prior to the termination of containment sprays.

Sedimentation Removal of Particulates

During spray operation, credit is taken for sedimentation removal of particulates in the unsprayed region. After sprays are terminated (and during the 20 minute switchover from injection to recirculation when sprays are not credited), credit for sedimentation is taken in both the sprayed and unsprayed regions. For the analysis, the sedimentation removal coefficient is conservatively assumed to be 0.1 hr-1. It is also conservatively assumed that sedimentation removal does not continue beyond a DF of 1000. A DF of 1000 is reached at 38.11 hours.

ECCS Equipment Iodine Inventory and Leakage Rate

When Emergency Core Cooling System (ECCS) recirculation is established following the LOCA, leakage is assumed to occur from ECCS equipment located outside containment. It is also assumed that all of the iodine released from the core is in the sump water being recirculated. Hence, the ECCS equipment leakage results in the release of a significant amount of iodine activity to the outside environment. For this activity release path, no credit is taken for plateout of elemental iodine on containment surfaces or for iodine removal by the atmosphere filtration system in the primary auxiliary building (PAB). The iodine release from this path is conservatively assumed to be 97% elemental and 3% organic.

Only iodine is released through this pathway since the noble gases are not assumed to dissolve in the sump and particulates would remain in the water of the ECCS leakage. It is assumed that the iodine is instantaneously and homogeneously mixed in the primary containment sump water at the time of release from the core. In the calculation of the dose resulting from ECCS leakage recirculation is conservatively initiated at 0 minutes. The leakage continues for the 30 day period following the accident considered in the analysis.

There are two pathways considered for the ECCS recirculation leakage. One is the leakage directly into the PAB and the other is back-leakage into the refueling water storage tank (RWST).

The total ECCS recirculation leakage modeled in the analysis is 800 cc/min. (Consistent with RG 1.183 guidance this includes a factor of two increase over the postulated leak rates based on the historical data for ECCS leakage collected from the PBNP Leakage Reduction and Preventive Maintenance Program). Of the 800 cc/min total ECCS recirculation leakage, 300 cc/min (See Table 14.3.5-5 for clarification) is assumed to leak into the PAB, and 500 cc/min (See Table 14.3.5-5 for clarification) is assumed to leak back to the RWST.

Leakage to the PAB

The analysis models a total ECCS recirculation leakage into the PAB of 300 cc/min (See Table 14.3.5-5 for clarification). Instead of applying a 10% iodine airborne fraction as discussed in RG 1.183, the analysis applies iodine airborne fractions based on the calculated flashing fraction of ECCS recirculation leakage. The flashing fractions are developed using the calculated sump temperature and the constant enthalpy flashing fraction equation provided in RG 1.183. The maximum flashing fraction is calculated for several time intervals and a bounding airborne fraction is selected for use in the analysis. Once the sump temperature is less than 212°F, a constant airborne fraction of 2% is maintained for the duration of the event. The iodine airborne fractions are modeled as listed in Table 14.3.5-5.

Leakage to the RWST

ECCS back-leakage to the RWST is assumed at a rate of 500 cc/min (See Table 14.3.5-5 for clarification). The iodine in the sump solution is assumed to all be in nonvolatile iodide or iodate form. However, when the solution leaks into the RWST, the iodine will be in an acidic solution such that there is the possibility of conversion of iodine compounds to form elemental iodine. The amount of iodine that will convert to the elemental form is dependent both on the concentration of iodine in the solution and the pH of the solution. The initial boron concentration in the RWST is conservatively assumed to be 3500 ppm. The initial pH of the RWST solution is determined to be approximately 4.5. The RWST water pH and iodine concentration are determined as a function of time. Figure 3.1 of NUREG-5950 (Reference 6) is used to determine the amount of iodine becoming elemental based on the pH and iodine concentration of the RWST solution. With an RWST pH of 4.5 and low iodine concentration, the fraction of conversion to elemental iodine is 2%. By 300 hours, the RWST liquid pH will exceed 5.0 and the indicated conversion to elemental iodine is essentially zero; however, the fraction is conservatively assumed to be 1% for the remainder of the accident duration.

Elemental iodine is volatile and will partition between the liquid and the air in the RWST gas space. The partition coefficient for elemental iodine is determined to be 45.4 using a relationship to solution temperature from NUREG-5950 (Reference 6). This is modeled by the transfer of a portion of the flow to the RWST liquid and a portion to the RWST gas space. The modeling of the air flow out of the RWST is based on a diurnal heating and cooling cycle. This model ignores the effect of the large heat sink provided by the mass of water in the tank that would tend to moderate the effects of the heating and cooling from atmospheric temperature variations. Temperature swings for the RWST are assumed to be the Technical Specification limits and do not result in pressurization of the RWST. No credit is assumed for evaporation. The transfer from the RWST gas space to the environment is calculated to be 2.71 cfm based on displacement by the in-leakage and air expansion from the heating/cooling cycle.

Meteorological Data

Five years of hourly onsite meteorological data collected between September 2000 and September 2005 were used to generate new CR air intake atmospheric dispersion factors (χ/Q values) for the Alternate Source term (AST) license amendment request (LAR). Wind speed and wind direction were measured at the 45 and 10 meter levels and the atmospheric stability categorization was based on temperature difference measurements between these two levels. The measurements were primarily from the primary tower located about 40 meters inland of the Lake Michigan shoreline.

The NRC reviewed available information relative to the onsite meteorological measurements program, the 2000 through 2005 meteorological data measured at the PBNP site, and the ARCON96 meteorological data input files provided to them. Based on this review, the NRC staff concluded that the data provides an acceptable basis for making estimates of atmospheric dispersion for the DBA control room dose assessments associated with the AST LAR.

Control Room Atmospheric Dispersion Factors

Releases from the following locations to the control room air intake were postulated:

Auxiliary Building Vent
Drumming Area Vent
Spent Fuel Pool
Unit 1 and Unit 2 Containment Wall
Unit 1 and Unit 2 Containment Facade
Unit 1 “A and Unit 1” B Main Steam Safety Valves (MSSVs)
Unit 2 “A” and Unit 2 “B” MSSVs
Units 1 and 2 Purge Stacks
Units 1 and 2 Refueling Water Storage Tanks (RWSTs)

χ/Q values were generated using the ARCON96 computer code and guidance provided in RG 1.194. All sources were modeled as ground level releases based upon guidance provided in RG 1.194. The shortest horizontal distance between each release location and the control room intake was input as the distance between the release and receptor locations. Releases from the Containment wall were modeled as diffuse sources. All other releases were modeled as point sources.

All potential release scenarios for the DBAs associated with the AST LAR were considered, including those due to single failures. The resultant χ/Q values were compared and the χ/Q values associated with releases from the Unit 2 containment wall, Auxiliary Building Vent and Unit 2 RWST were found to be limiting for the LOCA:

Subsequently a loss-of-coolant accident (LOCA) control room dose analysis was performed without credit for the Primary Auxiliary Building Ventilation System (VNPAB). This included a revision to the control room χ/Q values for the assessment considering Emergency Core Cooling System (ECCS) leakage to the Primary Auxiliary Building (PAB), by taking no credit for the VNPAB, i.e., χ/Q values were calculated for a postulated release from the PBNP Unit 2 facade roof instead of the PAB vent stack. χ/Q values are listed in Table 14.3.5-2.

Offsite Atmospheric Dispersion Factors

The EAB and EPZ χ/Q values listed in Table 14.3.5-2 did not require any changes due to the AST LAR. These χ/Q values were generated based upon guidance in RG 1.145, “Atmospheric Dispersion Models for Potential Accident Consequence Assessments at Nuclear Power Plants,” using onsite data collected from 1991 through 1993. These χ/Q values were assessed against χ/Q values calculated using the PAVAN atmospheric dispersion computer code (NUREG/CR-2858, “PAVAN: An Atmospheric Dispersion Program for Evaluating Design Basis Accidental Releases of Radiological Materials from Nuclear Power Stations”) and the onsite meteorological data collected between September 2000 and September 2005 and found to be conservative.

Control Room Doses

Control room modeling assumptions related to the calculation of control room dose from activity that enters the control room are described in Table 14.3.5-3.

The dose contribution in the CR due to direct shine from the external cloud and from contained sources is 0.32 rem. The external cloud contribution includes containment leakage, ECCS leakage, and RWST back-leakage. The contained sources include shine from the containment structure and the control room charcoal and HEPA ventilation filters. The analysis takes credit for control room walls and ceiling and shielding modifications to the control room envelope done per Engineering Change (EC) 11691 (258119) (Reference 3). The analysis assumed an operator located 5 feet from the control room east window (Reference 9).

Computer code SW-QADCGGP was used to calculate the direct shine dose to an operator in the control room from the airborne source inside containment, external plume source, and the control room charcoal and HEPA filter sources. SW-QADCGGP is a Shaw S&W version of the industry standard point-kernel radiation shielding computer code QAD-CGGP (Reference 2). Stone & Webster computer program PERC 2 was used to calculate the radiation source term in post-LOCA containment atmosphere, in the external plume passing the control room due to containment and ECCS leakage, and in the control room emergency filters due to containment and ECCS leakage.

Results and Conclusions

The major assumptions and parameters used in the LOCA dose analysis are itemized in Table 14.3.5-1 through Table 14.3.5-5.

The results of the offsite and control room dose analyses are provided in Table 14.3.5-6, and indicate that the acceptance criteria are met (Reference 8, Reference 9 and Reference 13). The exclusion area boundary doses reported are for the worst 2 hour period, determined to be from 0.5 to 2.5 hours.

Technical Support Center (TSC)

The TSC is required to meet the same post-accident radiological habitability criteria as the control room, i.e. less than 5 rem TEDE. Calculations confirm that the 30-day post-accident doses for the TSC following extended power uprate using alternate source term methodology is less than 5 rem TEDE (Reference 11 and Reference 12).

REFERENCES

1. Eckerman, Keith F., Wolbarst, Anthony B., and Richardson, Allan C.B., Limiting Values of Radionuclide Intake and Air Concentration and Dose Conversion Factors for Inhalation, Submersion, and Ingestion, Federal Guidance Report Number 11, EPA-520/1-88-020, September 1988.

2. QAD-CGGP, "A Combinatorial Geometry Version of QAD-P5A, A Point Kernel Code System for Neutron and Gamma-Ray Shielding Calculations Using the GP Buildup Factor."

3. Engineering Change EC 11691 (258119), Revision 3, “Addition of Control Room Shielding,” July 12, 2011.

4. USNRC, Regulatory Guide 1.183, “Alternative Radiological Source Terms for Evaluating Design Basis Accidents at Nuclear Power Reactors,” July 2000.

5. NUREG-0800 Standard Review Plan, Section 6.5.2 entitled “Containment Spray as a Fission Product Cleanup System,” Revision 4, March 2007.

6. NUREG/CR-5950, “Iodine Evolution and pH Control,” E. C. Beahm, et al, December 1992.

7. K. F. Eckerman and J. C. Ryman, “External Exposure to Radionuclides in Air, Water, and Soil,” Federal Guidance Report 12, EPA-402-R-93-081, 1993.

8. Calculation CN-CRA-08-21, Revision 1, Point Beach LOCA Doses for the Extended Power Uprate, Approved April 22, 2011.

9. Calculation 129187-M-0105, Revision 1, Control Room Direct Shine Dose Due to a Loss of Coolant Accident Following Extended Power Uprate and Using Alternative Source Term Methodology, Approved April 28, 2011.

10. NRC Safety Evaluation, PBNP Units 1 and 2-Issuance of License Amendments Regarding use of Alternate Source Term, dated April 14, 2011.

11. CN-CRA-10-53, Revision 1, Point Beach TSC Doses for LOCA and SLB, approved April 22, 2011.

12. Calculation 129187-M-0112, Revision 1, Technical Support Center Direct Shine Dose due to a Loss-of-Coolant Accident Following Extended Power Uprate and using Alternative Source Term Methodology, approved May 18, 2011.

13. SCR 2011-0275, Revise FSAR 14.3.5, Radiological Consequences of a LOCA for EPU per AR 1688483.

Table 14.3.5-1 CORE ACTIVITIES[1]

Core Total Nuclide Activities at Shutdown

Isotope	Activity (Ci)	Isotope	Activity (Ci)
GROUP 1 - Noble Gases		GROUP 6 - Barium	
Kr-85	6.15E+05	Ba-139	9.42E+07
Kr-85m	1.36E+07	Ba-140	9.05E+07
Kr-87	2.68E+07		
Kr-88	3.60E+07	GROUP 7 - Noble Metals	
Xe-131m	5.55E+05	Ru-103	7.79E+07
Xe-133	1.02E+08	Ru-105	5.42E+07
Xe-133m	3.21E+06	Ru-106	2.54E+07
Xe-135	2.17E+07	Rh-105	5.08E+07
Xe-135m	2.20E+07	Te-99m	8.47E+07
Xe-138	9.05E+07	Mo-99	9.62E+07
GROUP 2 - Halogens		GROUP 8 - Cerium	
I-130	1.05E+06	Ce-141	8.52E+07
I-131	5.10E+07	Ce-143	8.03E+07
I-132	7.47E+07	Ce-144	6.72E+07
I-133	1.06E+08	Pu-238	1.33E+05
I-134	1.19E+08	Pu-239	1.45E+04
I-135	1.01E+08	Pu-240	2.25E+04
		Pu-241	5.73E+06
GROUP 3 - Alkali Metals (Rb / Cs)		Np-239	9.65E+08
Rb-86	9.95E+04		
Cs-134	9.52E+06	GROUP 9 - Lanthanides	
Cs-136	2.14E+06	Y-90	5.01E+06
Cs-137	6.27E+06	Y-91	6.56E+07
Cs-138	9.89E+07	Y-92	6.82E+07
		Y-93	7.67E+07
GROUP 4 - Tellurium		Nb-95	8.87E+07
Te-127	4.54E+06	Zr-95	8.76E+07
Te-127m	7.48E+05	Zr-97	8.80E+07
Te-129	1.33E+07	La-140	9.69E+07
Te-129m	2.52E+06	La-142	8.25E+07
Te-131m	9.95E+06	Pr-143	7.75E+07
Te-132	7.30E+07	Nd-147	3.33E+07
Sb-127	4.63E+06	Am-241	6.16E+03
Sb-129	1.42E+07	Cm-242	1.70E+06
		Cm-244	1.58E+05
GROUP 5 - Strontium			
Sr-89	5.03E+07		
Sr-90	4.80E+06		
Sr-91	6.30E+07		
Sr-92	6.73E+07		

1. These core activities are based on a core power level of 1811 MWt.

Table 14.3.5-2 DOSE CONVERSION FACTORS, BREATHING RATES, AND ATMOSPHERIC DISPERSION FACTORS

Exclusion Area Boundary[1]

Time (hr)	Breathing Rate (m^3/sec)	Atmospheric Dispersion Factor (X/Q sec/m^3)
0-720	3.5E-4	5.0E-4

Low Population Zone

Time (hr)	Breathing Rate (m^3/sec)	Atmospheric Dispersion Factor (X/Q sec/m^3)
0-8	3.5E-4	3.0E-5
8-24	1.8E-4	1.6E-5
24-96	2.3E-4	4.2E-6
96-720	2.3E-4	8.6E-7

Control Room2

Time (hr)	Containment Leakage Atmospheric Dispersion Factor (X/Q sec/m^3)	ECCS Leakage (PAB) Atmospheric Dispersion Factor (X/Q sec/m^3)	ECCS Leakage (RWST) Atmospheric Dispersion Factor (X/Q sec/m^3)
0 - 2 hr	1.39E-3	6.78E-3	9.89E-3
2 - 8 hr	9.80E-4	5.03E-3	7.98E-3
8 - 24 hr	3.84E-4	1.72E-3	2.88E-3
24 - 96 hr	3.46E-4	1.60E-3	2.75E-3
96 - 720 hr	3.02E-4	1.34E-3	2.35E-3

1 The breathing rate and atmospheric dispersion factors for the exclusion area boundary are held constant at the initial value for all time intervals to determine the limiting 2-hour period.

2 The control room breathing rate is assumed constant at 3.5E-4 for 0-720 hours and VNPAB is assumed out of service.

Table 14.3.5-2A COMMITTED EFFECTIVE DOSE EQUIVALENT DOSE CONVERSION FACTORS (Page 1 of 2)

Committed Effective Dose Equivalent Dose Conversion Factors (Reference 1)

Isotope	DCF (Sv/Bq)	Isotope	DCF (Sv/Bq)
I-130	7.14E-10	Cs-134	1.25E-08
I-131	8.89E-09	Cs-136	1.98E-09
I-132	1.03E-10	Cs-137	8.63E-09
I-133	1.58E-09	Cs-138	2.74E-11
I-134	3.55E-11	Rb-86	1.79E-09
I-135	3.32E-10	Ru-103	2.42E-09
Kr-85m	N/A	Ru-105	1.23E-10
Kr-85	N/A	Ru-106	1.29E-07
Kr-87	N/A	Rh-105	2.58E-10
Kr-88	N/A	Mo-99	1.07E-09
Xe-131m	N/A	Tc-99m	8.80E-12
Xe-133m	N/A	Y-90	2.28E-09
Xe-133	N/A	Y-91	1.32E-08
Xe-135m	N/A	Y-92	2.11E-10
Xe-135	N/A	Y-93	5.82E-10
Xe-138	N/A	Nb-95	1.57E-09
Te-127	8.60E-11	Zr-95	6.39E-09
Te-127m	5.81E-09	Zr-97	1.17E-09
Te-129m	6.47E-09	La-140	1.31E-09
Te-129	2.42E-11	La-142	6.84E-11
Te-131m	1.73E-09	Nd-147	1.85E-09
Te-132	2.55E-09	Pr-143	2.19E-09
Sb-127	1.63E-09	Am-241	1.20E-04
Sb-129	1.74E-10	Cm-242	4.67E-06
Ce-141	2.42E-09	Cm-244	6.70E-05
Ce-143	9.16E-10	Sr-89	1.12E-08

Table 14.3.5-2A COMMITTED EFFECTIVE DOSE EQUIVALENT DOSE CONVERSION FACTORS (Page 2 of 2)

Committed Effective Dose Equivalent Dose Conversion Factors (Reference 1)

Isotope	DCF (Sv/Bq)	Isotope	DCF (Sv/Bq)
Ce-144	1.01E-07	Sr-90	3.51E-07
Pu-238	1.06E-04	Sr-91	4.49E-10
Pu-239	1.16E-04	Sr-92	2.18E-10
Pu-240	1.16E-04	Ba-139	4.64E-11
Pu-241	2.23E-06	Ba-140	1.01E-09
Np-239	6.78E-10		

Table 14.3.5-2B EFFECTIVE DOSE EQUIVALENT DOSE CONVERSION FACTORS
(Page 1 of 2)

Effective Dose Equivalent Dose Conversion Factors (Reference 7)

Isotope	DCF (Sv m3/Bq sec)	Isotope	DCF (Sv m3/Bq sec)
I-130	1.04E-13	Cs-134	7.57E-14
I-131	1.82E-14	Cs-136	1.06E-13
I-132	1.12E-13	Cs-137	2.88E-14
I-133	2.94E-14	Cs-138	1.21E-13
I-134	1.30E-13	Rb-86	4.81E-15
I-135	7.98E-14	Ru-103	2.25E-14
Kr-85m	7.48E-15	Ru-105	3.81E-14
Kr-85	1.19E-16	Ru-106	0.0
Kr-87	4.12E-14	Rh-105	3.72E-15
Kr-88	1.02E-13	Mo-99	7.28E-15
Xe-131m	3.89E-16	Tc-99m	5.89E-15
Xe-133m	1.37E-15	Y-90	1.90E-16
Xe-133	1.56E-15	Y-91	2.60E-16
Xe-135m	2.04E-14	Y-92	1.30E-14
Xe-135	1.19E-14	Y-93	4.80E-15
Xe-138	5.77E-14	Nb-95	3.74E-14
Te-127	2.42E-16	Zr-95	3.60E-14
Te-127m	1.47E-16	Zr-97	9.02E-15
Te-129m	1.55E-15	La-140	1.17E-13
Te-129	2.75E-15	La-142	1.44E-13
Te-131m	7.01E-14	Nd-147	6.19E-15
Te-132	1.03E-14	Pr-143	2.10E-17
Sb-127	3.33E-14	Am-241	8.18E-16
Sb-129	7.14E-14	Cm-242	5.69E-18
Ce-141	3.43E-15	Cm-244	4.91E-18
Ce-143	1.29E-14	Sr-89	7.73E-17

Table 14.3.5-2B COMMITTED EFFECTIVE DOSE EQUIVALENT DOSE CONVERSION FACTORS (Page 2 of 2)

Committed Effective Dose Equivalent Dose Conversion Factors (Reference 7)

Isotope	DCF (Sv/Bq)	Isotope	DCF (Sv/Bq)
Ce-144	8.53E-16	Sr-90	7.53E-18
Pu-238	4.88E-18	Sr-91	3.45E-14
Pu-239	4.24E-18	Sr-92	6.79E-14
Pu-240	4.75E-18	Ba-139	2.17E-15
Pu-241	7.25E-20	Ba-140	8.58E-15
Np-239	7.69E-15		

Table 14.3.5-3 CONTROL ROOM PARAMETERS

Volume	65,243 ft^3
Unfiltered Inleakage	200 cfm
Normal Ventilation Flow Rates VNCR (Mode 1)	
Filtered Makeup Flow Rate	0 cfm
Filtered Recirculation Flow Rate	0 cfm
Unfiltered Makeup Flow Rate	2000 cfm
Emergency Mode Flow Rates VNCR (Mode 5)	
Filtered Makeup Flow Rate	2500 cfm
Filtered Recirculation Flow Rate	1955 cfm
Unfiltered Makeup Flow Rate	0 cfm
Filter Efficiency	
Elemental	95%
Organic (Methyl)	95%
Particulate	99%
Occupancy Factors	
0 - 24 hours	1.0
24 - 96 hours	0.6
4 - 30 days	0.4
Assumed time following SI signal to switch from normal to emergency filtration mode.	60 seconds

Table 14.3.5-4 ASSUMPTIONS USED FOR LARGE BREAK LOCA DOSE ANALYSIS CONTAINMENT LEAKAGE

Core Power (including uncertainties)	1811 MWt	
Core Activity	See Table 14.3.5-1	
Activity release fractions	Gap	Core
Nobel gases	0.05	0.95
Iodines	0.05	0.35
Alkali Metals	0.05	0.25
Tellurium	0.	0.05
Strontium, Barium	0.	0.02
Nobel Metals	0.	0.0025
Cerium	0.	0.0005
Lanthanides	0.	0.0002
Iodine chemical form in containment		
Elemental	4.85%	
Organic (methyl)	0.15%	
Particulate (cesium iodide)	95%	
Containment net free volume	1.0E6 ft^3	
Containment sprayed volume	5.82E5 ft^3	
Fan Coolers		
Number in operation	2	
Flow rate (per unit)	33,500 cfm	
Containment leak rates		
0 - 24 hours	0.2 weight %/day	
> 24 hours	0.1 weight %/day	
Spray operation		
Time to initiate injection sprays	90 seconds	
Time that injection sprays are terminated	40 minutes	
Delay time for switchover to recirculation sprays	20 minutes	
Recirculation spray duration	2 hours	
Spray flow rates		
Injection	1,070 gpm	
Recirculation	900 gpm	
Spray fall height	65.58 ft	
Containment Spray Removal Coefficients		
Spray elemental iodine removal		
Injection	20 hr-1	
Recirculation	9.20 hr-1	
Spray particulate removal*		
Injection	4.42 hr-1	
Recirculation	3.72 hr-1	
Sedimentation particulate removal (Unsprayed region: from start of event, Sprayed region: when sprays are not assumed to be operating)	0.1 hr-1	
Containment Spray DF		
Elemental	200	
Particulate	1000	

* These coefficients are applicable until the time when the inventory in the containment is reduced to 2-percent of its original amount (DF of 50) at which time they would be reduced by a factor of 10.

Table 14.3.5-5 ASSUMPTIONS USED FOR LARGE BREAK LOCA DOSE ANALYSIS ECCS EQUIPMENT LEAKAGE

Core Power	1811 MWt	
Core Activity	See Table 14.3.5-1	
Activity release fractions	Gap	Core
Iodines	0.05	0.35
Containment Sump Volume	2.43E+05 gal	
RWST Minimum Water Volume	25,500 gal	
RWST Maximum Air Volume	270,000 gal	
RWST Minimum Temperature	40°F	
RWST Maximum Temperature	100°F	
Time to Initiate ECCS Recirculation	0 min	
ECCS Leak Rate		
PAB Leak Rate	300 cc/min (see * below for measurements)	
RWST Leak Rate	500 cc/min (see * below for measurements)	
ECCS Leakage to PAB Iodine Airborne fraction	Time (sec)	Airborne Fraction
	0 - 2700	7%
	2700 - 3600	5%
	3600 - 4500	4%
	4500 - 6300	3%
	> 6300	2%
Transfer from the RWST gas space to the environment	2.71 cfm	
Iodine chemical from released to atmosphere		
Elemental	97%	
Organic (methyl)	3%	
Particulate (cesium iodide)	0%	

* The LOCA dose analysis performed with the above leakage values remains applicable for any combination of PAB leakage and RWST leakage as long as the PAB measured leakage does not exceed 150 cc/min and the total measured PAB plus RWST leakage does not exceed 400 cc/min. This is based on the impact of the PAB leakage on the dose being significantly more than that of the RWST leakage.

Table 14.3.5-6 LARGE BREAK OFFSITE AND CONTROL ROOM DOSES

	Dose (Rem TEDE)	Dose Limits (Rem TEDE)
Exclusion Area Boundary (0.5 - 2.5 hours)	14.0	25.0
Low Population Zone (0 - 30 days)	1.4	25.0
Control Room (0 - 30 days)		
All Pathways (excluded shine)	4.4	
Shine	0.32	
Total Dose	4.72	5.0

14.3.6 REACTOR VESSEL HEAD DROP EVENT

PBNP committed to incorporate an analysis of the Reactor Vessel Head (RVH) drop into the PBNP FSAR by letter NRC 2005-0094, dated July 24, 2005 (Reference 2). The analyses presented in this section demonstrate that a limiting postulated RVH drop will not result in rupture of the RCS and associated pressure boundaries, that the core will remain covered, and core cooling remains available.

To resolve questions pertaining to a postulated RVH drop event initiated as a result of the Unit 2 reactor head replacement in 2005, analyses were performed and submitted for NRC review and approval. The analyses performed included two structural analyses that evaluated the effect of the impact on the impact load path through the reactor vessel, RCS piping, and the reactor vessel supporting structures. Included were radiological analyses predicated on an assumption that the impact would result in a clad gap release, and a presumptive failure of the bottom mounted instrumentation (BMI) conduits located beneath the reactor vessel. Reference 1 is the Safety Evaluation (SE) documenting NRC acceptance of those analyses and is applicable to both units.

Subsequent analyses performed in accordance with later approved NRC methods, and utilizing the previously performed structural analyses, found that the BMI conduits would remain intact, and that the previous presumption of a clad gap release was not necessary. The maintaining of core cooling capability with normal decay heat removal, and the removal of the assumed clad gap release permitted the elimination of most of the additional regulatory commitments associated with the Reactor Vessel Head Drop Event (Reference 1 and Reference 2). Reference 7 is the Safety Evaluation (SE) documenting NRC acceptance of the analyses demonstrating that the BMI conduits would remain intact, and is applicable to both units.

14.3.6.1 Initiating Event Occurrences

While the potential causes of an RVH drop event are not specified in the NRC safety evaluations or the supporting submittals, such an event can be postulated to occur from mechanical failure of the crane hoist mechanism, cable failure, or RVH lift rig failure. The main hoist of each polar crane is equipped with two independent upper travel limit switches to prevent the possibility of a “two-blocking” incident. The two independent upper travel limit devices are of different design and are activated by independent mechanical means. These devices independently de-energize either the hoist drive motor or the main power supply. Since the upper travel limit switches on the containment polar cranes are independent, are tested, and operational restrictions limit upward travel, it was established in Reference 1 that the potential for an RVH drop event due to “two-blocking” (i.e., exceeding the physical upper travel limits of the crane) is negligible. See FSAR Appendix A.3 for additional discussion on “two-blocking.”

14.3.6.2 Event Frequency Classification

The initiating event in this assessment is the drop of the RVH while it is suspended over the reactor vessel. The RVH is assumed to fall onto the reactor vessel flange, resulting in damage to the reactor vessel support structure.

NUREG-1774, “A Survey of Crane Operating Experience at U.S. Nuclear Power Plants from 1968 through 2002,” (Reference 3) was written to address NRC Candidate Generic Issue 186, "Potential Risk and Consequences of Heavy Load Drops in Nuclear Power Plants." Crane operating history from 1968 through 2002 was reviewed as part of this report to provide a risk assessment associated with lifts of Very Heavy Loads (VHL). The risk analysis included in NUREG-1774 considers VHL lifts for any crane at any operating nuclear station. The analysis considers a postulated drop of load at any point during the movement of a load from the initial lift until set-down.

The probabilistic analysis contained within NUREG-1774 is primarily concerned with the probability of a VHL drop at an operating commercial nuclear power plant. A VHL is defined as any load over 30 tons. The generic probability for any VHL drop is given as 5.6E-5 per lift. This value is based upon three (3) drops per 54,000 VHL lifts.

Reference 1 established that a postulated RVH drop meets the frequency classification of an infrequent incident (i.e., an incident that may occur during the lifetime of the plant).

14.3.6.3 Sequence of Events

The analyzed event is a concentric drop of the RVH onto the reactor vessel flange from a height of 26.4 feet. This was determined to impart the maximum credible impact loads on the reactor vessel and supporting structures. The resultant impact displaces the reactor vessel downward. Downward movement of the vessel creates the potential for damage to piping and tubing directly or indirectly connected to the reactor vessel, thereby creating a potential for a decrease in reactor coolant inventory.

Upon impact with the vessel flange, the kinetic energy of the vessel head is partially dissipated and partially transferred to both the head (rebound) and the vessel through an elastic/plastic collision. The impact forces, if high enough, can lead to yielding of the vessel supporting structures and/or attached piping.

After the head and vessel have come to rest, decay heat removal can be maintained by one or both RHR trains. Damage to the point of rupture or shearing of other connected piping, including the main RCS loops, pressurizer surge line, core deluge lines, accumulator dump lines, normal charging, BMI conduits, and cold leg SI Lines, etc. are not expected.

14.3.6.4 Plant Characteristics Considered in the Safety Evaluation

To demonstrate the capability of the reactor vessel, RCS, and supporting systems and structures to sustain a postulated RVH drop event, two complementary inelastic structure and piping system analyses were performed (Reference 5 and Reference 6). A RVH drop is postulated to occur during refueling when the head is manipulated above the reactor vessel. The RVH is assumed to fall concentrically onto the reactor vessel. Established administrative controls limit the maximum RVH drop height to 26.4 feet. This drop height has been utilized in the analyses discussed below. Both analyses were performed prior to NRC issuance of (but consistent with) Reference 8 which established approved methods for analyses of postulated RVH drop events.

The Sargent & Lundy (S&L) analysis (Reference 5) evaluated the reactor vessel and vessel support behaviors using a finite element model. The Westinghouse analysis (Reference 6) evaluated the plastic deformation that may occur to connected RCS piping based on specified bounding reactor vessel displacements.

S&L Finite Element Analysis

This analysis considers a flat vertical impact of the new RVH, using weights of 200,000 lbs for Unit 1 and 194,000 lbs for Unit 2, dropping from a height of 26.4 feet onto the reactor vessel flange. This analysis also includes an evaluation of the structural integrity of supporting elements in the load path, and predicts the vertical downward displacement of the reactor vessel.

The load path consists of the reactor vessel, reactor vessel supports at the four RCS nozzles and two brackets under the RHR core deluge nozzles, the support girder box frame, and the six pipe columns and their supports, which rest on the concrete foundation. The reactor coolant system (RCS) piping provides additional stiffness to the reactor vessel nozzles under vertical impact loading, and also transfers a portion of the impact load to the steam generator (SG) and the reactor coolant pump (RCP) support structures under a postulated RVH scenario. The concrete and embedded reinforcing bar located between the support girder and the concrete foundation under the support columns is not considered to provide any vertical support, even if the predicted deflection of the vessel could result in contacting the concrete.

The analysis models used are static analysis models for stiffness calculations of various components and substructures, and a dynamic impact model. The finite element analyses are performed using the ANSYS computer code.

The static analysis models include:

(1) A detailed model of reactor vessel flange and reactor vessel shell below the flange, including a nozzle resting on a supporting shoe.

(2) A similar detailed model of reactor vessel flange and reactor vessel shell below the flange with a support bracket resting on a supporting shoe.

(3) A detailed model of the hexagonal girder box frame supported by six pipe columns at the vertices.

(4) Piping models for the RCS hot legs and cold legs.

These models are used to construct static load-displacement diagrams for all steel components that are within the impact load path. Static vertical displacement is applied to the components uniformly and a reaction force is calculated to construct the force-displacement diagram of the affected components. In the static analysis, non-linear material properties are modeled with a strength increase factor of 10 percent to account for the strain rate effects due to the dynamic impact. The large deformation analysis option was selected to account for potential buckling and yielding in the structural components along the impact load path.

The results of the static analysis are used as part of the input for dynamic analysis. In calculating the stiffness of RCS hot leg or cold leg, two bounding cases are analyzed:

1) A fixed boundary condition is used at either the SG location or the RCP location.
2) A pinned boundary condition is used at the SG location or the RCP location.

In both cases, the pipe axial movement is released to account for the potential horizontal movement of the SG or the RCP.

The dynamic impact model consists of a two-mass model with springs and dash-pot in a vertical configuration. The top mass represents the falling head, and the bottom mass represents the target reactor vessel model supported by various springs, which represent the stiffness of the nozzle/bracket support, the girder box frame/column supports, and the RCS piping.

In the dynamic impact analysis, an impact damping of 5% of the critical damping is used. This assumption is judged to be reasonable for this application in consideration of:

1) energy loss due to plastic damage at the impact surface between the RVH and the reactor vessel flange;
2) energy loss due to imparted damage to six lateral supports for the hexagonal girder box frame; and,
3) energy loss due to local damage to the liner and concrete crushing at the top of the six support columns.

Results of the dynamic transient analysis for Unit 2 indicate that the maximum dynamic downward displacement of the reactor vessel is 2.72 and 3.20 inches for cases 1 and 2 respectively. These displacements are both less than the 3.375" necessary before the hexagonal girder box frame would come into contact with the concrete "shelf", and this is consistent with the assumption that the concrete shelf does not provide any resistance to downward motion.

Using the limiting downward displacement of 3.2", the maximum Von Mises stress in the nozzle due to membrane plus bending is less than the ASME Boiler and Pressure Vessel Code, Section III, Appendix F allowable stresses for membrane stress intensity of 0.7 S_u. Similarly, the Von Mises stress in the reactor vessel support brackets is also less than 0.7 S_u.

The S&L analysis also evaluated the maximum impact load on the column foundation, and the capability of the concrete shelf to provide lateral support for the stability of the support columns (i.e. to limit buckling) located within the shelf and found the results acceptable.

Westinghouse Plastic Analysis of RCS Loop Piping

The evaluation consisted of a plastic analysis of the PBNP reactor coolant loop piping for a downward vertical displacement of the reactor vessel nozzles. Two displacements were analyzed: (1) a 4-inch displacement, which bounds the displacement calculated by the S&L model, and (2) a 6.5-inch displacement, which represents the maximum possible displacement of the reactor vessel nozzles before the RCS piping comes in contact with the biological shield wall.

The results of the analysis were compared to the criteria specified in the 1998 Edition of ASME Code, Section III, Appendix F, Paragraph F-1340. The criteria allow for large RCS loop piping deformations, with the intent that violations of the RCS pressure boundary do not occur.

The analysis uses an ANSYS finite element model of the hot and cold legs. The hot and cold legs are fixed at both ends (the reactor vessel nozzles and the SG or RCP nozzles). Each leg was modeled as a straight run of piping with one elbow. The hot and cold leg material properties were represented by a piece-wise linear stress-strain curve. Two sets of material properties were used to represent the upper and lower bound properties of the piping and elbow materials.

The results of the analysis indicate that the maximum calculated stress intensity in the hot and cold leg piping is within the ASME Code, Section III, Appendix F limit of 0.7 S_u for general primary membrane stress for the 4-inch reactor vessel nozzle displacement. Since the 4 inch reactor vessel nozzle displacement bounds the maximum calculated vessel displacement predicted from the S&L model, there is reasonable assurance that the pressure boundary integrity of the RCS loop piping will be maintained in the event of a postulated RVH drop.

The results also indicate that the 0.7 S_u limit is exceeded for the cold leg for a 6.5-inch vessel nozzle displacement. The maximum stress intensity was calculated in the cold leg elbow. While the calculated stress intensity exceeds the ASME Code general primary membrane stress intensity limit, it is concluded that loss of the RCS piping pressure boundary integrity would not be expected even if the vessel nozzle displaced 6.5 inches. This is because the maximum calculated stress intensity is still well below the material ultimate strength.

Analysis of Reactor Vessel Deflection

Based on the Sargent & Lundy FEA provided in Reference 5 and the Westinghouse analysis provided in Reference 6, the following bounding conditions apply:

Following the postulated RVH drop, using a conservatively estimated RVH weight of 200,000 lbs (Unit 1), the reactor vessel deflection would not exceed 3.36 inches. This calculated deflection is slightly greater than the Unit 2 calculated vessel deflection due to the conservative weight assumed and slight dimensional differences between units. RCS piping remains intact following the postulated reactor vessel deflection.

The impact of the postulated reactor vessel deflection on the attached RCS piping was assessed. This assessment was performed by Westinghouse and is documented in Reference 6. Westinghouse performed an analysis for a 4-inch deflection, which bounds the projected reactor vessel deflection. The results of the analysis show that stress values are less than the more restrictive criteria of 0.7 S_u specified in ASME Section III Appendix F. In addition, a second case to analyze a deflection value of 6.5 inches, which is equivalent to the gap that exists between the RCS piping and the shield wall, was conducted. The results of this analysis yielded stress values of greater than 0.7 S_u but did not predict failure of the RCS piping.

The combined results of the Sargent & Lundy and the Westinghouse analyses show that the damage from a RVH drop would not result in a loss of decay heat removal. Based on these results, it was concluded that adequate reactor core cooling and makeup capability would be maintained following the expected deflection of the reactor vessel from a postulated RVH drop.

Piping attached to the reactor coolant system (RCS) was not modeled or specifically analyzed for deflection and stress values as a result of the vessel deflection from a RVH drop. Based on the ability to analyze and demonstrate RCS piping acceptability for a bounding deflection of 4 inches, it was determined that the attached piping would also be acceptable. This conclusion was based upon the fact that all connections to the RCS piping are outside of the biological shield wall; thus, the deflection would be much less than the total deflection of the RCS piping. In addition, the attached piping is of smaller diameter and is more flexible. The main connections to the RCS, credited for maintaining core cooling and makeup following a RVH drop, are the residual heat removal (RHR) lines, cold leg safety injection (SI) injection lines and charging. The RHR suction and return lines are 10-inch lines; the cold leg SI flow path is through the 10-inch SI accumulator injection line connected to the RCS.

Charging and auxiliary charging are connected through a 3-inch and 2-inch line to the RCS. The 10-inch connections are the closest connections of concern to the reactor vessel, with one exception, and would therefore experience the greatest relative deflection. The only exception is that the Unit 1 Auxiliary Charging line is 10 inches closer to the reactor vessel than the corresponding Safety Injection line on the "B" cold leg. Since the Auxiliary Charging line is a 2-inch line with greater flexibility than the 10-inch SI line, the focus was on addressing the SI lines. For Unit 1, the ratio of the distance from the reactor vessel to the steam generators or reactor coolant pumps would yield a deflection of approximately 20 percent, or less, of the total vessel deflection. For a vessel deflection of 3.36 inches, the deflection at the connection would be approximately 0.67 inches.

In Unit 1, the shortest horizontal piping run from the 10-inch connections at the cold legs to the first vertical support (which is a spring hanger), is greater than 6 feet. The shortest vertical run is approximately 10 feet (on the opposite cold leg). Both connections have horizontal offsets that decrease their stiffness in the vertical direction. The shortest horizontal run to an anchor is greater than 14 feet with an intervening vertical loop.

The RHR return line connects to the SI accumulator injection line over 22 linear feet from the B loop cold leg connection. The condition is very similar for the RHR suction line connection to the A hot leg. The distance to the closest anchor is greater than 13 feet with an intervening vertical loop containing an additional 30 feet of piping.

In each case, the total linear distance between anchors for the attached piping is greater than the worst RCS piping case, and that case was shown to be acceptable for a deflection of 4 inches. Based on this, the added flexibility of smaller diameter piping and an equivalent deflection of approximately 0.67 inches, it was determined that a detailed analysis of the connected piping was not necessary.

Additionally, the integrity of the two 6-inch core deluge lines was evaluated based on comparing the section properties and applicable pipe spans to the RCS piping. This comparison, coupled with the fact that the core deluge lines are more flexible than the RCS piping, leads to the conclusion that the integrity of the core deluge lines are bounded by the assessment for the RCS piping.

Bottom-Mounted Instrument (BMI) Tubes

Reference 9 analyzed the stresses in the BMI conduits that result from the maximum downward displacement of the reactor vessel. The analysis was performed in accordance with the NRC approved guidance of Reference 10, and concluded that 0.7 S_u would not be exceeded in any of the BMI conduits. Therefore, no loss of integrity of the BMI conduits is expected, and the RCS inventory would be retained.

Conclusion

In the event of a worst case postulated RVH drop, the RCS pressure boundary remains intact, the core remains covered, and core cooling remains available. There would be no loss of RCS inventory, and no release of fission products from the reactor core. As such, no extraordinary measures are necessary to mitigate the consequences of a postulated RVH drop. Administrative controls limit the height of a reactor vessel head lift, ensuring that any real drop is bounded by the analyses of record.

14.3.6.5 References

1. NRC Safety Evaluation, Point Beach Nuclear Plant, Units 1 and 2 - Issuance of Amendment Re: Incorporation of Reactor Vessel Head Drop Accident Analysis Into the Final Safety Analysis Report," September 23, 2005, as revised by NRC letter "Point Beach Nuclear Plant, Units 1 and 2 - Revision to Safety Evaluation for Amendment Nos. 220 and 226 (TAC Nos. MC7650 and MC7651," dated January 12, 2006.

2. Point Beach Letter from D. L. Koehl to NRC, "Request for Review of Heavy Load Analysis," NRC 2005-0094, July 24, 2005.

3. NUREG-1774, "A Survey of Crane Operating Experience at U.S. Nuclear Power Plants from 1968 through 2002," July 2003.

4. NRC Regulatory Guide 1.70, "Standard Format and Content of Safety Analysis Reports for Nuclear Power Plants," Revision 3.

5. Sargent & Lundy Calculation 2005-06760, Rev. 3, "Analysis of Postulated Reactor Head Load Drop Onto the Reactor Vessel Flange," July 22, 2005.

6. Westinghouse Calculation Note CN-RCDA-05-68 Rev. 2, "Plastic Analysis of Point Beach Reactor Cooling Piping for Reactor Vessel Head Drop," July 21, 2005.

7. NRC Safety Evaluation, Point Beach Nuclear Plant, Units 1 and 2 - "Issuance of License Amendment Related to the Revision to the Reactor Vessel Head Drop Methodology (TAC Nos. ME4006 and ME4007)" dated June 1, 2011.

8. NRC Regulatory Issue Summary (RIS) 2008-28, "Endorsement of Nuclear Energy Institute Guidance for Reactor Vessel Head Heavy Load Lifts," dated December 1, 2008.

9. Calculation CN-MRCDA-08-51 Revision 1, "Point Beach Units 1 and 2 Evaluation of Bottom Mounted Instrumentation (BMI) Conduits for a Postulated Closure Head Assembly Drop Event," dated January 4, 2010.

10. Nuclear Energy Institute (NEI) 08-05, "Industry Initiative on Control of Heavy Loads," Revision 0, issued July 2008.

CHAPTER 15 TABLE OF CONTENTS

15.0 AGING MANAGEMENT PROGRAMS and TIME LIMITED AGING ANALYSIS

This Section has been selected for the location of Aging Management Program and Time Limited Aging Analysis related information. Section 15.1 provides an overview of the Quality Assurance Program requirements for aging management. Section 15.2 contains a summary description of the programs for managing the effects of aging during the period of extended operation. Time-limited aging analyses (TLAA) supporting activity summaries are contained in Section 15.3. Section 15.4 contains a summary of the evaluation of TLAAs for the period of extended operation. (NUREG-1839, Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, Docket Nos. 50-266 and 50-301, December 1, 2005).

15.1 PROGRAMS THAT MANAGE THE EFFECTS OF AGING AND GENERIC QUALITY ASSURANCE PROGRAM REQUIREMENTS

This section provides summaries of the programs and activities credited for managing the effects of aging. These aging management programs may not exist as discrete programs at PBNP. In many cases they exist as a compilation of various implementing documents that, when taken as a whole, satisfy the intent of NUREG-1800 and/or NUREG-1801 elements.

The Quality Assurance Topical Report implements the requirements of 10 CFR 50, Appendix B, and is consistent with the summary in Appendix A.2 of NUREG-1800, “Standard Review Plan for the Review of License Renewal Applications for Nuclear Power Plants,” published July 2001. The elements of corrective action, confirmation process, and administrative controls in the Quality Assurance Program are applicable to both safety-related and nonsafety related systems, structures and components that are subject to an aging management review. Generically, these three elements are applicable as follows:

Corrective Actions

Corrective actions are implemented in accordance with the requirements of 10 CFR 50, Appendix B, “Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants,” and the Quality Assurance Topical Report.

Confirmation Process

The confirmation process is part of the corrective action program, which is implemented in accordance with the requirements of 10 CFR 50, Appendix B and the Quality Assurance Topical Report.

Administrative Controls

Aging management programs are implemented through various plant documents. These implementing documents are subject to administrative controls, including a formal review and approval process, in accordance with the requirements of 10 CFR 50, Appendix B, and the Quality Assurance Topical Report.

15.2 AGING MANAGEMENT PROGRAM DESCRIPTIONS

The description of the PBNP Aging Management Programs are consistent with their status as configured to apply to the period of extended operation.

15.2.1 ASME SECTION XI, SUBSECTIONS IWB, IWC, AND IWD ISI PROGRAM

ASME Section XI, Subsections IWB, IWC and IWD Inservice Inspection (ISI) Program inspections are performed to identify and correct degradation in Class 1, 2 and 3 piping, components and their integral attachments. The program includes periodic visual, surface, and/or volumetric examinations and leakage tests of Class 1, 2 and 3 pressure-retaining components, and their integral attachments, including welds, pump casings, valve bodies, and pressure-retaining bolting. These components and their integral attachments are identified in ASME Section XI, “Rules for Inservice Inspection of Nuclear Power Plant Components,” or commitments requiring augmented inservice inspections, and are within the scope of license renewal. This program will use the edition and addenda of ASME Section XI required by 10 CFR 50.55a, as reviewed and approved by the NRC staff for aging management under 10 CFR 54. Alternatives to these requirements that are aging management related will be submitted to the NRC in accordance with 10 CFR 50.55a prior to implementation.

15.2.2 ASME SECTION XI, SUBSECTIONS IWE AND IWL ISI PROGRAM

The ASME Section XI, Subsections IWE and IWL Inservice Inspection Program manages aging of (a) steel liners of concrete containments and their integral attachments; containment hatches and airlocks; seals, gaskets and moisture barriers; and pressure-retaining bolting, and (b) reinforced concrete containments and unbonded post-tensioning systems. The primary inspection methods employed are visual examinations with limited supplemental volumetric and surface examinations, as necessary. Tendon anchorages and wires are visually examined. Tendon wires are tested to verify that minimum mechanical property requirements are met. Tendon corrosion protection medium is analyzed for alkalinity, water content and soluble ion concentrations. Pre-stressing forces are measured in sample tendons. Measured tendon lift-off forces are compared to predicted tendon forces calculated in accordance with Regulatory Guide 1.35.1. This program will use the edition and addenda of ASME Section XI required by 10 CFR 50.55a, as reviewed and approved by the NRC staff for aging management under 10 CFR 54. Alternatives to these requirements that are aging management related will be submitted to the NRC in accordance with 10 CFR 50.55a prior to implementation.

This program manages aging effects for:

1. Carbon steel and miscellaneous polymeric materials and components that provide containment pressure boundary/leak-tight barrier function and are tested/inspected in accordance with 10 CFR 50, Appendix J and/or ASME Section XI, Subsection IWE,

2. Containment tendons, and

3. Concrete, which is inspected in accordance with ASME Section XI, Subsection IWL.

15.2.3 ASME SECTION XI, SUBSECTION IWF ISI PROGRAM

The ASME Section XI, Subsection IWF Inservice Inspection Program manages aging effects for Class 1, 2 and 3 component supports. The primary inspection method employed is visual examination. Criteria for acceptance and corrective action are in accordance with ASME Section XI, Subsection IWF. Degradation that potentially compromises the function or load capacity of the support, including bolting, is identified for evaluation. Supports requiring corrective action are re-examined during the next inspection period. This program will use the edition and addenda of ASME Section XI required by 10 CFR 50.55a, as reviewed and approved by the NRC staff for aging management under 10 CFR 54. Alternatives to these requirements that are aging management related will be submitted to the NRC in accordance with 10 CFR 50.55a prior to implementation.

15.2.4 BOLTING INTEGRITY PROGRAM

The Bolting Integrity Program manages the aging effects associated with bolting through the performance of periodic inspections. The program also includes repair/replacement controls for ASME Section XI related bolting and generic guidance regarding material selection, thread lubrication and assembly of bolted joints. The program considers the guidelines delineated in NUREG-1339 for a bolting integrity program, EPRI NP-5769 (Reference 1) (with the exceptions noted in NUREG-1339) for safety related bolting, and EPRI TR-104213 (Reference 2) for non-safety related bolting. The Bolting Integrity Program credits seven separate aging management programs for the inspection of bolting. The seven aging management programs are: (1) ASME Section XI, Subsections IWB, IWC and IWD Inservice Inspection Program, (2) ASME Section XI, Subsections IWE and IWL Inservice Inspection Program, (3) ASME Section XI, Subsection IWF Inservice Inspection Program, (4) Systems Monitoring Program, (5) Structures Monitoring Program, (6) Reactor Vessel Internals Program, and (7) the Periodic Surveillance and Preventive Maintenance Program.

15.2.5 BORAFLEX MONITORING PROGRAM

The Boraflex Monitoring Program has been discontinued since Boraflex is no longer credited in the spent fuel pool criticality analysis. (Reference 4)

15.2.6 BORIC ACID CORROSION PROGRAM

The Boric Acid Corrosion Program manages aging effects for structures and components as a result of borated water leakage. The program requires periodic visual inspection of systems that contain borated water for evidence of leakage or accumulations of dried boric acid. It includes provisions for (a) determination of the principal location or source of the leakage, (b) examination requirements and procedures for locating small leaks, and (c) evaluations and/or corrective actions to ensure that boric acid leakage does not lead to degradation of the leakage source as well as other SSC exposed to the leakage, including mechanical, structural, and electrical items such as bolts, fasteners, piping, cables, cable trays, electrical connectors, etc., which could cause the loss of intended function(s). This program complies with PBNP's response to NRC GL 88-05.

15.2.7 BURIED SERVICES MONITORING PROGRAM

The Buried Services Monitoring Program manages aging effects on the external surfaces of buried carbon steel, low-alloy steel and cast iron components (e.g., tanks, piping) that are within the scope of license renewal in the Service Water, Fuel Oil, and Fire Protections Systems. This program includes (a) preventive measures to mitigate degradation (e.g., external coatings/ wrappings), (b) visual inspections of external surfaces of buried components for evidence of coating/wrapping damage and (c) visual inspections and/or hardness testing of external surfaces of buried components for evidence of degradation, if the coating/wrapping is damaged or the pipe is uncoated/unwrapped, to manage the effects of aging. The periodicity of these inspections will be based on plant operating experience and opportunities for inspection such as scheduled maintenance work. In addition, a susceptible location in the Fire Protection System (i.e., uncoated/unwrapped piping) will be scheduled to be inspected once prior to the period of extended operation and at least every 10 years during the period of extended operation. The intent of these scheduled inspections is to ensure that buried components within the Fire Protection System are periodically inspected. Therefore, if an opportunity for inspection occurs prior to the scheduled inspection, the inspection of opportunity can be credited for satisfying the scheduled inspection.

15.2.8 CABLE CONDITION MONITORING PROGRAM

The Cable Condition Monitoring Program manages aging of conductor insulation materials on cables and connectors, and other electrical insulation materials that are installed in adverse localized environments caused by heat, radiation, or moisture. The scope of this program includes accessible non-EQ electrical cables and connections, including control and instrumentation circuit cables, non-EQ electrical cables used in nuclear instrumentation circuits, and inaccessible non-EQ medium-voltage cables within the scope of license renewal. The program requires (a) visual inspection of a representative sample of accessible electrical cables and connections in adverse localized environments once every 10 years for evidence of jacket surface degradation, (b) testing of nuclear instrumentation circuits once every 10 years to detect a significant reduction in cable insulation resistance, and (c) testing of a representative sample of in-scope, medium-voltage cables not designed for submergence subject to significant moisture and significant voltage once every 10 years to detect deterioration of insulation.

15.2.9 CLOSED-CYCLE COOLING WATER SYSTEM SURVEILLANCE PROGRAM

The Closed-Cycle Cooling Water System Surveillance Program manages aging effects in closed cycle cooling water systems that are not subject to significant sources of contamination, in which water chemistry is controlled and heat is not directly rejected to the ultimate heat sink. The program includes (a) maintenance of system corrosion inhibitor concentrations to minimize degradation, and (b) periodic or one-time surveillance testing and inspections to evaluate system and component performance. Inspection methods may include visual, ultrasonic (UT) and eddy current (ECT) testing.

15.2.10 FIRE PROTECTION PROGRAM

The Fire Protection Program includes (a) fire barrier inspections, (b) electric and diesel-driven fire pump tests, (c) periodic inspection and testing of the halon fire suppression system, and (d) periodic maintenance, testing, and inspection of water-based fire protection systems. Periodic visual inspections of fire barrier penetration seals, fire dampers, fire barrier walls, ceilings and floors, and periodic visual inspections and functional tests of fire-rated doors are performed to ensure that functionality and operability is maintained. Periodic testing of the electric and diesel-driven fire pumps ensures that an adequate flow of firewater is supplied and that there is no degradation of diesel fuel supply lines. Periodic maintenance, testing and inspection activities of water-based fire protection systems provides reasonable assurance that fire water systems are capable of performing their intended function. Inspection and testing is performed in accordance with the nuclear insurance carrier's fire protection system testing requirements and generally follows the guidance of applicable NFPA Codes and Standards, as described in the Fire Protection Program Design Document (FPPDD).

15.2.11 FLOW-ACCELERATED CORROSION PROGRAM

The Flow Accelerated Corrosion Program manages aging effects due to flow-accelerated corrosion on the internal surfaces of carbon or low alloy steel piping, elbows, reducers, expanders, and valve bodies which contain high energy fluids (both single phase and two phase). The program implements the EPRI guidelines in NSAC-202L (Reference 3) for an effective FAC program and includes (a) an analysis using a predictive code such as CHECWORKS to determine critical locations, (b) baseline inspections to determine the extent of thinning at these locations, (c) follow-up inspections to confirm the predictions, and (d) repairing or replacing components, as necessary.

15.2.12 FUEL OIL CHEMISTRY CONTROL PROGRAM

The Fuel Oil Chemistry Control Program mitigates and manages aging effects on the internal surfaces of fuel oil storage tanks and associated components in systems that contain fuel oil. The program includes (a) surveillance and monitoring procedures for maintaining fuel oil quality by controlling contaminants in accordance with applicable ASTM Standards, (b) periodic draining of water from fuel oil tanks, (c) periodic or conditional visual inspection of internal surfaces or wall thickness measurements (e.g., by UT) from external surfaces of fuel oil tanks, and (d) one-time inspections of a representative sample of components in systems that contain fuel oil.

15.2.13 ONE-TIME INSPECTION PROGRAM

The One-Time Inspection Program addresses potentially long incubation periods for certain aging effects and provides a means of verifying that an aging effect is either not occurring or progressing so slowly as to have negligible effect on the intended function of the structure or component. Hence, the One-Time Inspection Program provides measures for verifying an aging management program is not needed, verifying the effectiveness of an existing program, or determining that degradation is occurring which will require evaluation and corrective action.

The program elements include (a) determination of appropriate inspection sample size, (b) identification of inspection locations, (c) selection of examination technique, with acceptance criteria, and (d) evaluation of results to determine the need for additional inspections or other corrective actions. The inspection sample includes locations where the most severe aging effect(s) would be expected to occur. Inspection methods may include visual (or remote visual), surface or volumetric examinations, or other established NDE techniques.

This program is used for the following:

- To verify the effectiveness of water chemistry control for managing the effects of aging in stagnant or low-flow portions of piping, or occluded areas of components, exposed to a treated water environment.
- To manage the aging effects of loss of material due to galvanic corrosion and selective leaching.
- To verify that in areas not managed by a chemistry control program the aging effects are occurring so slowly that the intended function will be unaffected through the period of extended operation.
- To verify the effectiveness of fuel oil chemistry control for managing the effects of aging of various components in systems that contain fuel oil.
- To verify aging effects are not occurring in various components (e.g., reactor vessel internals hold-down spring, letdown orifices, steam traps, downstream piping near the RHR pumps' mini-flow recirculation orifices, and miscellaneous heat exchangers).

15.2.14 OPEN-CYCLE COOLING (SERVICE) WATER SYSTEM SURVEILLANCE PROGRAM

The Open-Cycle Cooling (Service) Water System Surveillance Program manages aging effects caused by exposure of internal surfaces of metallic components in water systems (e.g., piping, valves, heat exchangers) to raw, untreated (e.g., service) water. The aging effects are managed through (a) surveillance and control of biofouling, (b) verification of heat transfer by testing, and (c) routine inspection and maintenance program activities to ensure that aging effects do not impair component intended function. Inspection methods include visual, ultrasonic (UT), eddy current (ECT), and Tangential Radiography. This program complies with the licensee's response to NRC Generic Letter 89-13 and subsequent commitment changes.

15.2.15 PERIODIC SURVEILLANCE AND PREVENTIVE MAINTENANCE PROGRAM

The Periodic Surveillance and Preventive Maintenance Program manages aging effects for certain SSCs within the scope of license renewal. The program provides for inspection, examination, or testing of selected structures and components, including fasteners, for evidence of age-related degradation on a specified frequency based on operating experience or other requirements (e.g., Technical Specification or Code requirements). Additionally, the program provides for replacement of certain components on a specified frequency based on operating experience. The Periodic Surveillance and Preventive Maintenance Program is also used to verify the effectiveness of other aging management programs.

15.2.16 REACTOR COOLANT SYSTEM ALLOY 600 INSPECTION PROGRAM

The Reactor Coolant System Alloy 600 Inspection Program manages crack initiation and growth due to PWSCC of RCS pressure boundary and non-pressure boundary nickel-based alloy components (e.g., Alloy 600/690 reactor vessel/head penetration nozzles, Inconel 82/182, 82/152, and 52/152 weld joints). The program includes (a) PWSCC susceptibility assessment using industry models to identify susceptible components, (b) monitoring and control of reactor coolant chemistry to mitigate PWSCC, (c) inservice inspections (ISI) of reactor vessel/head penetrations and RCS pressure boundary welds in accordance with ASME Section XI, Subsection IWB, Table IWB 2500-1, and (d) augmented inspections or preemptive repair/replacement of susceptible components or welds. The program is based on the guidance provided in Electric Power Research Institute (EPRI) MRP-126 "Generic Guidance for Alloy 600 Management." (Reference 5)

15.2.17 REACTOR VESSEL INTERNALS PROGRAM

The Reactor Vessel Internals Program manages the aging effects for reactor vessel internals (RVI). The program provides for (a) Inservice Inspection (ISI) in accordance with ASME Section XI requirements, including examinations performed during the 10-year ISI examination; (b) An evaluation that will identify leading locations with respect to IASCC and irradiation embrittlement, appropriate non-destructive examination techniques, and an examination schedule for these locations; (c) Baffle-former/barrel-former bolt evaluation that will determine the acceptability of the current arrangement or if ultrasonic examination and/or replacement of these bolts is necessary; (d) For cast austenitic stainless steel components subject to neutron fluence in excess of 1E17 n/cm^2 or determined to be susceptible to thermal embrittlement, an augmented inspection of components experiencing significant tensile stress (>5 ksi); (e) Evaluation of the significance of void swelling; (f) monitoring and control of reactor coolant water chemistry in accordance with the Water Chemistry Control Program to mitigate SCC or IASCC; (g) Participation in industry initiatives that will generate additional data on aging mechanisms relevant to RVI and develop appropriate inspection techniques to permit detection and characterization of features of interest; and (h) One-time inspection of the internals hold-down spring for evidence of stress relaxation. (Reference 6)

The description above provides a historical discussion of the program.

The RVI Inspection Program is based upon the guidance provided in the latest NRC accepted revision of EPRI MRP-227, "EPRI Materials Reliability Program, Pressurized Water Reactor Internals Inspection and Evaluation Guidelines." (Reference 6, Reference 7) The RVI Inspection Program is a living program that will be revised as necessary in response to ongoing joint industry efforts aimed at further understanding the aging effects of the RV Internals.

15.2.18 REACTOR VESSEL SURVEILLANCE PROGRAM

The Reactor Vessel Surveillance Program manages the aging effect reduction of fracture toughness due to neutron embrittlement of the low alloy steel reactor vessels. Monitoring methods will be in accordance with 10 CFR 50, Appendix H. This program includes (a) capsule insertion, withdrawal and materials testing/evaluation, (including upper shelf energy and RTNDT determinations), (b) fluence and uncertainty calculations, (c) monitoring of Effective Full Power Years (EFPY), (d) development of pressure-temperature limitations, (e) determination of low-temperature overpressure protection (LTOP) set points, and (f) implementation of a flux reduction program and other options, as necessary, allowed by 10 CFR 50.61(b) for the Unit 2 intermediate-to-lower shell girth weld. The program ensures the reactor vessel materials (a) meet the fracture toughness requirements of 10 CFR 50, Appendix G, and (b) have adequate margins against brittle fracture caused by Pressurized Thermal Shock (PTS) in accordance with 10 CFR 50.61.

15.2.19 STEAM GENERATOR INTEGRITY PROGRAM

The Steam Generator Integrity Program incorporates the guidance of NEI 97-06 and maintains the integrity of the steam generators, including tubes, tube plugs or other tube repairs, and various secondary-side internal components. The program manages aging effects through a balance of prevention, inspection, evaluation, repair, and leakage monitoring measures. Component degradation is mitigated by controlling primary and secondary water chemistry. Eddy current testing is used to detect steam generator tube flaws and degradation. Visual inspections are performed to identify degradation of various secondary-side steam generator internal components.

15.2.20 STRUCTURES MONITORING PROGRAM

The Structures Monitoring Program manages the aging effects associated with steel (including fasteners), concrete (including masonry block and grout), earthen berms, and elastomers. The environments include below grade and fluid exposed material, outdoor weather, and indoor air. The program includes all safety related buildings, structures within the containment, other buildings within the scope of license renewal, crane bridge and trolley structures, and component supports (including HELB structures, panels, etc.) within the scope of license renewal. The program provides for periodic visual inspections and examination of accessible surfaces of the structures and components and identifies the aging effects that impact the materials of construction. The program also visually examines normally inaccessible below grade concrete when it is exposed by excavation (i.e., inspections of opportunity) for signs of degradation.

15.2.21 SYSTEMS MONITORING PROGRAM

The Systems Monitoring Program manages aging effects on the external surfaces of piping, tanks and other components and equipment within the scope of license renewal. These aging effects are managed through visual inspection and monitoring of normally accessible external surfaces for leakage and evidence of material degradation.

15.2.22 TANK INTERNAL INSPECTION PROGRAM

The Tank Internal Inspection Program manages aging effects on the (a) internal surfaces of carbon steel tanks, and (b) inaccessible external surfaces of carbon steel tanks (i.e., tank bottoms) where wall thickness measurements may be taken from inside the tank to detect external degradation (e.g., using ultrasonic techniques)

This program provides for periodic inspections to confirm that aging effects will not impair tank intended functions. Tank wall thinning of internal surfaces may be detected by direct visual inspection from inside the tank or indirectly by UT wall thickness measurements from outside the tank. Tank wall thinning of external surfaces that are inaccessible (e.g., bottom of tanks that sit directly on the ground or other support structures) will be detected by UT wall thickness measurements from inside the tank.

15.2.23 THIMBLE TUBE INSPECTION PROGRAM

The Thimble Tube Inspection Program manages aging effects for incore instrument thimble tubes. This program requires periodic eddy current testing of thimble tubes and contains criteria for determining sample size, inspection frequency, flaw evaluation, and corrective action, in accordance with NRC Bulletin 88-09.

15.2.24 WATER CHEMISTRY CONTROL PROGRAM

The Water Chemistry Control Program manages aging effects by controlling the internal environment of systems and components. Primary borated and secondary water systems are included in the scope of the program. The program is based on EPRI PWR Primary Water Chemistry Guidelines and EPRI PWR Secondary Water Chemistry Guidelines. Guideline revisions are evaluated for applicability to PBNP and program implementing documents are revised as necessary. The aging effects are managed by controlling concentrations of known detrimental chemical species such as halogens, sulfates and dissolved oxygen below the levels known to cause degradation. The program includes specifications for chemical species, sampling and analysis frequencies, and corrective actions for control of water chemistry. For low-flow or stagnant portions of a system, a one-time inspection of selected components at susceptible locations provides verification of the effectiveness of the Water Chemistry Control Program. No verification inspections are required for intermediate and high flow regions.

15.2.25 REFERENCES

1. EPRI NP-5769, “Degradation and Failure of Bolting in Nuclear Power Plants,” dated April 1988. (Volume I and Volume II)

2. EPRI TR-104213, “Bolted Joint Maintenance & Applications Guide,” dated December 1995.

3. EPRI Nuclear Safety Analysis Center NSAC 202L, “Recommendations for an Effective Flow Accelerated Corrosion Program.”

4. NRC Safety Evaluation, “Point Beach Nuclear Plant, Units 1 and 2 - Issuance of Amendments Re: Spent Fuel Pool Storage Criticality Control,” dated March 5, 2010.

5. NRC Safety Evaluation, Point Beach Nuclear Plant, Units 1 and 2 -Alloy 600 Program License Renewal Commitment Submittal, dated October 6, 2009.

6. Point Beach Nuclear Plant, Units 1 and 2, Staff Assessment of Reactor Vessel Internals Inspection Plan Based on MRP-227-A (TAC NOS. ME8235 and ME8236), dated March 30, 2015.

7. EPRI MRP-227, "EPRI Materials Reliability Program, Pressurized Water Reactor Internals Inspection and Evaluation Guidelines," latest NRC-approved revision.

15.3 TIME LIMITED AGING ANALYSIS SUPPORTING ACTIVITIES

Environmental Qualification Program

The EQ Program manages component thermal, radiation and cyclical aging, as applicable, through the use of aging evaluations based on 10 CFR 50.49(f) qualification methods. As required by 10 CFR 50.49, EQ components not qualified for the current license term are to be refurbished, replaced, or have their qualification extended prior to reaching the aging limits established in the evaluation. Aging evaluations for EQ components that specify a qualification of at least 40 years are considered TLAA for license renewal. The EQ Program ensures that these EQ components are maintained within the bounds of their qualification bases.

Fatigue Monitoring Program

The Fatigue Monitoring Program is a confirmatory program that monitors loading cycles due to thermal and pressure transients and cumulative fatigue usage for selected reactor coolant system and other component locations. The program provides an analytical basis for confirming that the actual number of cycles does not exceed the number of cycles used in the design analysis, and the cumulative fatigue usage will be maintained below the allowable limit during the period of extended operation.

The impact of the effects of reactor coolant environment on component fatigue life has been evaluated for a sample of critical components, including the seven component locations selected in NUREG/CR-6260. Appropriate environmental fatigue factors were calculated using the formulae from NUREG/CR-6583 for carbon and low-alloy steels and NUREG/CR-5704 for austenitic stainless steels. These critical component locations were determined to be acceptable for the period of extended operation, including the effects of reactor coolant environment. The acceptability of these critical component locations, including the effects of reactor coolant environment, will continue to be confirmed by the Fatigue Monitoring Program.

15.4 EVALUATION OF TIME-LIMITED AGING ANALYSES

As part of a License Renewal Application, 10 CFR 54.21(c) requires that an evaluation of time-limited aging analyses (TLAAs) for the period of extended operation be provided. The following TLAAs have been identified and evaluated to meet this requirement. These discussions are numbered and inserted into the FSAR sections where these subjects are covered.

During the Extended Power Uprate Project the TLAAs were evaluated for operation at 1800 megawatts thermal (Reference 17). References to evaluations at lower power levels completed as part of the License Renewal Program were retained for their historical perspective.

15.4.1 REACTOR VESSEL IRRADIATION EMBRITTLEMENT

The PBNP Units 1 and 2 reactor vessels are described in Chapter 3.0 and Chapter 4.0. Time-limited aging analyses (TLAAs) applicable to the reactor vessels are:

- Pressurized thermal shock
- Upper-shelf energy
- Pressure-temperature limits

The Reactor Vessel Surveillance Program manages reactor vessel irradiation embrittlement utilizing subprograms to monitor, calculate, and evaluate the time-dependent parameters used in the aging analyses for pressurized thermal shock, upper-shelf energy and pressure-temperature limit curves to ensure continuing vessel integrity through the period of extended operation.

Reactor Vessel Pressurized Thermal Shock

The requirements in 10 CFR 50.61 provide rules for protection against pressurized thermal shock events for pressurized water reactors. Licensees are required to perform an assessment of the projected values of the maximum nil ductility reference temperature (RT_{PTS}) whenever a significant change occurs in projected values of RT_{PTS}, or upon request for a change in the expiration date for the operation of the facility.

The calculated RT_{PTS} values at the end of life extension for the PBNP Units 1 and 2 reactor vessels are less than the 10 CFR 50.61(b)(2) screening criteria of 270°F for intermediate and lower shells and 300°F for the circumferential welds. Initially, the Unit 2 RPV intermediate to lower shell circumferential weld exceeded the screening criteria established in 10 CFR 50.61 (300°F) during the period of extended operation.

Amendment Nos. 250 and 254 (Reference 16) allow the use of an alternate fracture toughness evaluation methodology for determining RCS pressure and temperature limits. BAW-2308, Revision 1-A and 2-A, “Initial RT_{NDT} of Linde 80 Weld Materials,” provides an alternative estimation of the initial nil-ductility reference temperature (RT_{NDT}) of Linde 80 weld materials. With this “Master Curve” methodology, the Unit 2 intermediate-to-lower shell circumferential weld does not exceed the PTS screening criteria at End-of-Life-Extended (EOLE).

Reactor Vessel Upper-Shelf Energy

The requirements on reactor vessel Charpy upper-shelf energy (USE) are included in 10 CFR 50, Appendix G. Specifically, 10 CFR 50, Appendix G requires licensees to submit an analysis at least 3 years prior to the time that the upper-shelf energy of any reactor vessel material is predicted to drop below 50 ft-lb, as measured by Charpy V-notch specimen testing.

The Charpy USE for the limiting welds will be less than 50 ft-lbs based on RG 1.99, Revision 2, at 53 effective full power years (EFPY). Therefore, in order to demonstrate that sufficient margins of safety against fracture remain to satisfy the requirements of Appendix G to 10 CFR Part 50, a fracture mechanics evaluation was performed to examine the PBNP USE values in the limiting weld. The evaluation examined the USE values for end of license extension (EOLE) conditions. The PBNP fracture mechanics evaluation used the J-R ratio methodology, which demonstrates the acceptability of J-R values in satisfying the USE requirement by examining J-R ratios, which are defined as the ratio of the lower bound J-R value divided by the applied J. If this ratio is greater than or equal to one, the acceptance criteria are met. This methodology is described in B&W Owners Reactor Vessel Working Group reports BAW-2192PA, "Low Upper-Shelf Toughness Fracture Mechanics Analysis of Reactor Vessels of B&W Owners Reactor Vessel Working Group for Level A & B Service Loads," and BAW-2178-PA, "Low Upper-Shelf Toughness Fracture Mechanics Analysis of Reactor Vessels of B&W Owners Reactor Vessel Working Group for Level C & D Service Loads," both dated April 1994. The NRC staff reviewed and approved both reports for referencing in licensing applications in separate letters dated March 29, 1994.

Additional equivalent margins analyses were performed for the PBNP RPVs to address the following EOLE (53 EFPY) conditions: the uprated power condition of 1678 megawatts thermal (MWt) without hafnium suppression assemblies; current power conditions of 1540 MWt without hafnium suppression assemblies; and current power conditions of 1540 MWt with hafnium suppression assemblies. The 2008 fluence projections (Reference 9) were used to define EOLE vessel fluences at 1800 MWt. An equivalent margins analysis compared the EPU fluence values with the fluence values used in BAW-2467P, Revision 1 (Reference 10). This analysis demonstrated that the analysis in BAW-2467P, Revision 1, remains applicable for the projected EPU fluence values to the end of the period of extended operation (Reference 20). The NRC reviewed and accepted the BAW-2467P, Revision 1, analysis in the Safety Evaluation Report transmitted by NRC letter dated May 10, 2007 (Reference 11).

The commitment related to the PPSAs for Unit 2 from NUREG-1839 (Reference 12, Appendix A, Commitment #46) "Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plants Units 1 and 2," no longer applies due to Amendment Nos. 250 and 254 (Reference 16). These amendments allow the use of BAW-2308, Revision 1-A and 2-A, "Initial RT_{NDT} of Linde 80 Weld Materials" as an alternate fracture toughness evaluation methodology for determining RCS pressure and temperature limits. With the "Master Curve" methodology, the calculated RT_{PTS} values at the end of life extension for the Unit 2 reactor vessel intermediate-to-lower shell circumferential weld is less than the 10 CFR 50.61(b)(2) screening criteria of 300°F, without crediting PPSAs.

The analysis associated with upper-shelf energy has been projected to the end of the period of extended operation in accordance with the requirements of 10 CFR 54.21(c)(1)(ii).

Reactor Vessel Pressure/Temperature Limits

The requirements in 10 CFR 50, Appendix G, ensure that heatup and cooldown of the reactor pressure vessel are accomplished within established pressure-temperature limits. These limits specify the maximum allowable pressure as a function of reactor coolant temperature. As the reactor pressure vessel becomes embrittled and its fracture toughness is reduced, the allowable pressure is reduced.

Operation of the Reactor Coolant System is also limited by the net positive suction head curves for the reactor coolant pumps. These curves specify the minimum pressure required to operate the reactor coolant pumps. Therefore, in order to heatup and cooldown, the reactor coolant temperature and pressure must be maintained within an operating window established between the Appendix G pressure-temperature limits and the reactor coolant pumps net positive suction head curves.

To address the period of extended operation, the end of license extension projected fluences, and the RPV material properties were used to determine the limiting materials, and calculate pressure-temperature limits for heatup and cooldown. The Point Beach Unit 1 and 2 heatup and cooldown pressure-temperature limit curves were generated using adjusted reference temperature (ART) values that bound both units (Reference 21). The term of applicability for the pressure-temperature curves is 50 EFPY under uprated conditions (1800 MWt) (Reference 16).

The analysis associated with reactor vessel pressure-temperature limit curves has been projected to the end of the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(ii).

15.4.2 FATIGUE

The thermal and mechanical fatigue analyses of plant mechanical components have been identified as time limited aging analyses for the Point Beach Nuclear Plant. Specific components have been designed and analyzed considering transient cycle assumptions identified in vendor specifications and the PBNP FSAR.

In conjunction with revising the NSSS design transients for the Unit 2 Replacement Steam Generator Project (SGRP), and the Extended Power Uprate Project, the NSSS design transients were also evaluated for acceptability for a 60-year operating period. The number of NSSS transients actually experienced by the two units was identified. Based on historical transient occurrences, and current plant operational practices, the number of future NSSS transients was forecasted for a 60-year operating period. With few exceptions, the anticipated number of transients for a 60-year operating period was far less than the original design number of transients for a 40-year operating period.

The exceptions noted above comprise a set of pressure test transients that were included in some of the NSSS component equipment specifications. The pressure test transients forecasted for a 60-year operating period exceeded the original design number of transients for a 40-year operating period. The NSSS design transient set was revised to include an increased number of pressure test transients, sufficient for a 60-year operating period.

In addition, the NSSS transient set was also revised to increase the number of steady-state random RCS pressure and temperature fluctuations to ensure adequate margin existed for a 60-year operating period. The revised set of NSSS design transients were used in performing the detailed engineering evaluations in support of the Extended Power Uprate Project (Reference 17).

Experience has shown, however, that actual plant operation is often very conservative with respect to the design transients. The use of actual operating history and transient monitoring data acquired by the FatiguePro Automatic Cycle Counting and Fatigue Monitoring System installed at Point Beach (Fatigue Monitoring Program) will allow quantification of the conservatism in the existing fatigue analysis and demonstrate that the design fatigue analyses will bound the extended period of operation. The PBNP Fatigue Monitoring Program is considered a confirmatory program.

ASME Boiler and Pressure Vessel Code, Section III, Class 1 Components

The PBNP Reactor Vessels, CRDMs, Steam Generators, and Pressurizers were designed, constructed and analyzed to the requirements of their original equipment specifications, and Section III of the ASME Code. The PBNP Reactor Vessels Internals and Reactor Coolant Pumps were designed, constructed and analyzed to the requirements of their original equipment specifications, and the intent of Section III of the ASME Code.

The fatigue calculations were reanalyzed for the above noted components at Extended Power Uprate conditions using the revised transient set for a 60-year operating period. The structural evaluations concluded that all components analyzed for fatigue are within the allowable limits for a 60-year operating period, with the exception of the Unit 1 Steam Generator inspection port bolts. The structural evaluation identifies a replacement interval of 12 years for the inspection port bolts.

In addition to the original ASME CLB analysis, a plant-specific insurge/outsurge fatigue analysis was performed for the extended license period. The analysis demonstrated acceptable structural integrity for the affected pressurizer locations to the end of license extension.

With the exception of the Unit 1 steam generator inspection port bolting, the analyses associated with verifying the structural integrity of the PBNP ASME III Class 1 components have been projected to the end of the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(ii).

The Periodic Surveillance and Preventive Maintenance Program will provide reasonable assurance that the Unit 1 SG inspection port bolt replacement is adequately managed for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(iii).

Pressurizer Surge Line Structural Integrity

Detailed fatigue analyses of the pressurizer surge lines were performed in response to NRC Bulletin 88-11, “Pressurizer Surge Line Thermal Stratification.” The analyses were performed in accordance with the requirements of Section III of the ASME Code. The methodology and results are presented in WCAP-13509, “Structural Evaluation of the Point Beach Units 1 & 2 Pressurizer Surge Lines, Considering the Effects of Thermal Stratification.”

Subsequently, the PBNP-specific surge line fatigue analysis was re-evaluated considering the operational conditions associated with the Extended Power Uprate and a 60-year operating period. The transient sets were reviewed for the new conditions. The majority of the transients defined for original power levels for 40 years were found to be bounding for EPU conditions for 60 years. Some of the feedwater transients required minor revision due to a change in feedwater temperatures associated with the proposed power uprate. The impact of the changes in the revised RCS conditions, thermal design transients, and the 60-year life were factored into determining the ASME stress levels and allowables for the surge line.

The results of the evaluation for the pressurizer surge line stratification showed that the EPU conditions changed the fatigue usage factors at the location of the highest usage factor by a negligible amount. The calculated change in the loadings on the pressurizer nozzle due to stratification for the EPU conditions was not considered significant. The results of the original evaluation for the surge line, WCAP-13509, remain unchanged for the 60-year operating period.

The analysis associated with verifying the structural integrity of the pressurizer surge line piping has been evaluated and determined to remain valid for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(i).

Spray Header Piping Structural Integrity

Piping connections to the RCS were evaluated in response to NRC Bulletin 88-08 (including Supplements 1 through 3) “Thermal Stresses in Piping Connected to Reactor Coolant Systems.” Two unisolable piping connections were identified that had the potential to be subjected to thermal stratification or temperature oscillations. These lines are the auxiliary charging connection, and auxiliary spray connection. These lines were subject to temperature monitoring to identify and quantify thermal stratification. No thermal stratification was noted on the auxiliary charging lines. Thermal stratification was noted on one of the auxiliary spray lines, where it ties into the spray header.

To evaluate the effect of thermal stratification on the pressurizer spray line header, including the auxiliary spray line connection, fatigue analyses were performed for each unit's applicable piping system. The analyses were based on actual piping surface temperature data obtained during a 153-day period (including one startup) of direct temperature monitoring on the Unit 2 piping. The Unit 2 data was considered applicable and bounding for both units since it experienced more stratification, and the line configuration was similar. The piping transient set was developed by expanding the measured piping thermal behavior to equate to a 60-year operating period. The analyses showed that the Cumulative Usage Factors (CUFs) in the subject piping were acceptable.

The analysis associated with verifying the structural integrity of the pressurizer auxiliary spray line, and spray header, have been projected to the end of the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(ii). An additional evaluation determined that all ASME Code stress limits remain satisfied for all proposed EPU conditions (Reference 20).

USAS B31.1 Piping Structural Integrity

In general, piping and associated pressure boundary components at PBNP were originally designed to the requirements of USAS B31.1, USA Standard Code for Pressure Piping. The B31.1 Code requirements assume a stress range reduction factor to provide conservatism in the piping design to account for the effects of thermal fatigue due to thermal cycling during operation. This reduction factor is 1.0 provided that the number of anticipated cycles is limited to 7000 equivalent full temperature cycles. This represents a condition where a piping system would have to be cycled approximately once every 3 days over the extended plant life of 60 years. Considering this limit, a review of the piping and associated pressure boundary components was performed to identify those systems that operate at elevated temperature and to establish their cyclic operating practices. Under current plant operating practices, piping is generally only occasionally subject to cyclic operation. Typically, piping is subject to continuous steady state operation and operating temperatures only vary during plant heatup and cooldown, during plant transients or during periodic testing. It is therefore very unlikely, for any piping system subject to thermal fatigue, that the actual number of thermal cycles would approach the assumed B31.1 limit of 7000 during the period of extended operation except for the Primary Sampling System lines. Establishing sample flow from the RCS results in thermal transients and cyclic stresses whenever the RCS is above ambient temperatures. The hot leg sample line receives the highest number of thermal cycles of all PBNP piping. An evaluation of the number of thermal cycles that the hot leg sample line would be expected to experience over a 60 year period of operation was performed in PBNP License Renewal Technical Report, LR-TR 516. The Technical Report demonstrates that the PBNP hot leg sample line will not exceed 7000 thermal cycles over a 60 year operating period. Thus, no PBNP piping is expected to exceed 7000 thermal cycles over a 60 year operating period, and thus remain within the bounds of their original design code.

The analyses associated with USAS B31.1 piping fatigue have been evaluated and determined to remain valid for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(i). The USAS B31.1 Code does not require a fatigue evaluation of the Reactor Coolant Loop piping system for proposed EPU conditions (Reference 17 and Reference 20).

Environmental Effects on Fatigue

As a part of the industry effort to address environmental effects for operating nuclear power plants during the current 40-year licensing term, Idaho National Engineering Laboratories (INEL) evaluated, in NUREG/CR-6260 (Reference 4), fatigue-sensitive component locations at plants designed by all four U. S. nuclear steam supply system vendors. The pressurized water reactor calculations, especially the early-vintage Westinghouse calculations, are directly relevant to PBNP. In addition, the transient cycles considered in the evaluation match or bound the PBNP design.

The fatigue-sensitive component locations chosen in NUREG/CR-6260 for the early-vintage Westinghouse plant were:

1. The reactor vessel shell and lower head
2. The reactor vessel inlet and outlet nozzles
3. The pressurizer surge line (including the pressurizer and hot leg nozzles)
4. The Reactor Coolant System piping charging system nozzle
5. The Reactor Coolant System piping safety injection nozzle
6. The Residual Heat Removal System Class 1 piping.

In addition to the NUREG/CR-6260 locations, the PBNP pressurizers were evaluated for the effects of coolant environment on fatigue, including insurge/outsurge transients, in accordance with Applicant Action Item 3.3.1.1 1 of the pressurizer Generic Technical Report WCAP-14574-A.

Environmental fatigue evaluations were performed for the NUREG/CR-6260 component locations, and the pressurizers using the Fen methodology contained in NUREG/CR-6583 for carbon/low alloy steel material and NUREG/CR-5704 for stainless steel material.

The effects of reactor coolant environment on component fatigue life during the period of extended operation have been evaluated at PBNP. The evaluation includes the seven component locations identified in NUREG/CR-6260, and the Pressurizer. Appropriate environmental fatigue factors have been applied to either the components design cumulative fatigue usage factor, or the components forecasted cumulative fatigue usage factor, based on actual operational transient monitoring by the EPRI FatiguePro software. The evaluations result in acceptable environmentally adjusted cumulative fatigue usage factors at EOLE for all of the component locations considered. Environmental effects on fatigue during EPU conditions were evaluated and found to be bounded by existing evaluations (Reference 17).

The Fatigue Monitoring Program is a confirmatory program that monitors loading cycles due to thermal and pressure transients for selected critical components. The program provides an analytical basis for confirming that the number of cycles established by the analysis of record will not be exceeded before the end of the period of extended operation.

Containment Liner Plate and Penetrations Fatigue Analysis

The interior surface of each Containment is lined with welded steel plate to provide an essentially leak tight barrier. Design criteria are applied to the liner to assure that the specified allowed leak rate is not exceeded under the design basis accident conditions. The fatigue loads as described in FSAR Section 5.1, were considered in the design of the liner plates and are considered time limited aging analyses for the purposes of license renewal. Each of these has been evaluated for the period of extended operation.

The number of thermal cycles due to annual outdoor temperature variations was increased from 40 to 60 for the extended period of operation. The effect of this increase is insignificant in comparison to the assumed 500 thermal cycles due to Containment interior temperature varying during heatup and cooldown of the Reactor Coolant System. The 500 thermal cycles includes a margin of 300 thermal cycles above the 200 Reactor Coolant System allowable design heatup and cooldown cycles, which is sufficient margin to accommodate the additional 20 cycles of annual outdoor temperature variation. Therefore, this loading condition is considered valid for the period of extended operation as it is enveloped by the evaluation for 500 thermal cycles.

The assumed 500 thermal cycles was evaluated based on the more limiting heatup and cooldown design cycles (transients) for the Reactor Coolant System. The Reactor Coolant

System was designed to withstand 200 heatup and cooldown thermal cycles. The evaluation determined that the originally projected number of maximum Reactor Coolant System design cycles is conservative enough to envelop the projected cycles for the extended period of operation. Therefore, the original containment liner plate fatigue analysis for 500 heatup and cooldown cycles is considered valid for the period of extended operation.

The assumed value of one for thermal cycling due to the maximum hypothetical accident remains valid. No maximum hypothetical accident has occurred and none is expected, therefore, this assumption is considered valid for the period of extended operation.

The design of the containment penetrations has been reviewed. The design meets the general requirements of the 1965 Edition of ASME Boiler and Pressure Vessel Code, Section III. The main steam piping, feedwater piping, blowdown piping, and letdown piping are the only piping penetrating the containment wall and liner plate that contribute significant thermal loading on the liner plate. The projected number of actual operating cycles for these piping systems through 60 years of operation was determined to be less than the original design limits.

The analyses associated with the containment liner plate and penetrations have been evaluated and determined to remain valid for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(i).

Crane Load Cycle Limit

The Containment Polar Cranes, Auxiliary Building Crane, and Turbine Hall Crane are included within the scope of license renewal and NUREG-0612.

The load cycle limit for PBNP cranes was identified as a time-limiting-aging analysis.

All PBNP cranes were designed and constructed to meet the requirements of Specification 61 of the Electric Overhead Crane Institute (EOCI-61).

NUREG-0612 required that the design of heavy load overhead handling systems meet the intent of Crane Manufactures Association of America, Inc. (CMAA) Specification No. 70. Per Guideline 7, NUREG-0612, Section 5.1.1(7), the design of the PBNP cranes listed above was evaluated in relation to the applicable criteria and guidelines of Chapter 2-1 of ANSI B30.2-1976, “Overhead and Gantry Cranes,” and of CMAA-70, “Specifications for Electric Overhead Traveling Cranes.” The PBNP cranes listed above substantially meet the criteria of CMAA-70 “Specifications for Electric Overhead Traveling Cranes,” as noted in the NRC NUREG-0612 safety evaluation. Cranes designed in accordance with CMAA-70 Class “A” service are designed for 20,000 to 200,000 load cycles.

The PBNP containment polar cranes and the turbine hall crane are used primarily during refueling outages. The PBNP auxiliary building crane is primarily used in support of material receipt (fuel and consumables), spent fuel cask transfers, and radwaste cask transfers. Occasionally, these cranes make lifts at or near their rated capacity. However, the majority of the crane lifts are substantially less than their rated capacity. Based on conservative usage assumptions, the above listed PBNP cranes are expected to make 50,000 partial load lifts over a 60-year operating period. This is significantly less than the CMAA-70 design cycle limit for Class “A” service cranes.

The specifications for the noted traveling cranes at PBNP included rated overload cycle limits of roughly two 125 percent rated load lifts per year, and three 150 percent rated load lifts in the cranes' lifetimes. With the exception of the containment polar cranes, no lifts in excess of the rated load have been made. Each containment polar crane was used to support its respective units steam generator replacement project. These lifts incorporating the containment polar cranes were specifically analyzed engineered lifts incorporating temporary replacement trolleys, bridge strengthening, and temporary center poles to ensure that the original design capabilities of the cranes were not degraded. Thus, since the major cranes are not used to make routine over rated load lifts, and special one-time over rated load maintenance lifts are addressed as specific engineered lifts, the original specified cycle limits for over rated load lifts will not be exceeded during the extended operating period.

Since the number of operating load cycles for the cranes will be fewer than the design cycles, the crane design will remain valid for the period of extended operation, in accordance with the requirements of 10 CFR 54.21(c)(1)(i).

15.4.3 FRACTURE MECHANICS ANALYSIS

Reactor Coolant Pump Flywheel Analysis

During normal operation, the reactor coolant pump flywheel possesses sufficient kinetic energy to potentially produce high-energy missiles in the unlikely event of failure. Conditions that may result in overspeed of the reactor coolant pump increase both the potential for failure and the kinetic energy. The aging effect of concern is fatigue crack initiation in the flywheel bore keyway.

An evaluation of the probability of failure over the extended period of operation was performed in WCAP-14535-A, Topical Report on Reactor Coolant Pump Flywheel Inspection Elimination, for all operating Westinghouse plants and certain Babcock and Wilcox plants. It demonstrates that the flywheel design has a high structural reliability with a very high flaw tolerance and negligible flaw crack extension over a 60-year service life. The NRC reviewed and approved the evaluation (WCAP-14535-A) for application with certain conditions and limitations (Reference 1). PBNP verified the RCP flywheel material and invoked this analysis as the basis for reducing the frequency of performing RCP flywheel inspections (Reference 2).

WCAP-15666-A, Revision 1, “Extension of Reactor Coolant Pump Motor Flywheel Examination,” October 2003, builds on the arguments in WCAP-14535-A and provides additional rationale, including a risk assessment of all credible flywheel speeds. WCAP-15666-A concludes that the change in risk is below Regulatory Guide 1.174 CDF and LERF acceptable guidelines.

The NRC approved the use of this Topical Report in NRC SER, “Safety Evaluation of Topical Report WCAP-15666, Extension of Reactor Coolant Pump Motor Flywheel Examination,” May 5, 2003. The NRC SER has been incorporated into the “A” revision of the WCAP. This analysis was used as a basis for a revision of TS 5.5.6 which increased the flywheel inspection interval from 10 years to 20 years.

The above analyses associated with the structural integrity of the reactor coolant pump flywheel have been evaluated and determined to remain valid for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(i).

The Extended Power Uprate does not affect system pressures for the systems inside containment such that additional missiles could be generated. The EPU will not result in any system configuration changes inside containment that would impact any existing missile barrier considerations. As such, the existing missile protection measures inside containment remain effective for EPU conditions. (Reference 17)

Reactor Coolant Pump Casing Analysis (ASME Code Case N-481 Analysis)

The ASME Section XI Code, up to and including the 1998 Edition, required a volumetric inspection of the RCP casing welds, and a visual inspection of the pressure boundary components. In lieu of performing the required Section XI internal visual and volumetric inspections of RCP Cast Austenitic Stainless Steel (CASS) casings, a fracture mechanics analysis, supplemented by visual examinations, per the requirements of ASME Code, Case N-481 was performed for the original operating period of 40 years. This analysis is contained in the generic industry WCAP-13045, “Compliance to ASME Code Case N-481 of the Primary Loop Pump Casings of Westinghouse Type Nuclear Steam Supply Systems,” and PBNP-specific WCAP-14705, “A Demonstration of Applicability of ASME Code Case N-481 to the Primary Loop Pump Casings of the Point Beach Units 1 and 2.” These analyses incorporated the effects of thermal embrittlement, and demonstrated compliance with Code Case N-481 requirements for the original 40-year operating license period.

The current ASME Section XI Code applicable for PBNP does not require pump casing weld volumetric or routine internal visual examinations. Thus, the fracture mechanics analysis is not necessary for the extended period of operation in support of applying Code Case N-481 to eliminate casing volumetric examinations. However, the Generic Technical Report (GTR) for Class 1 Piping and Associated Pressure Boundary Components, WCAP-14575-A, “License Renewal Evaluation: Aging Management Evaluation for Class 1 Piping and Associated Pressure Boundary Components,” identifies that a fracture mechanics analysis performed for the extended operating period is an acceptable means of managing thermal aging of CASS. Thus, the Code Case N-481 integrity analysis was evaluated throughout the extended period of operation.

Westinghouse performed an evaluation of the Code Case N-481 integrity analysis to identify if it is acceptable for the extended operating period. The results of the evaluation show that the ASME Code Case N-481 integrity analysis conclusions, documented in WCAP-13045 and WCAP-14705 for the PBNP Units 1 and 2 RCP casings remain valid for the 60-year licensed operating period. An additional evaluation confirmed that the Analysis of Record remain bounding and applicable for EPU conditions (Reference 20).

The Reactor Coolant Pump Integrity Analysis has been projected to the end of the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(ii).

Reactor Coolant System Main Loop Piping Leak-Before-Break Analysis

In response to Unresolved Safety Issue (USI) A-2 (Asymmetric Blowdown Loads on the Reactor Coolant System), Westinghouse performed a generic Leak-Before-Break (LBB) analysis, which was applicable to PBNP. The LBB analysis was performed to show that any potential leaks that develop in the Reactor Coolant System loop piping can be detected by plant monitoring systems before a postulated crack causing the leak would grow to unstable proportions during the 40-year plant life. The NRC reviewed and approved the generic Westinghouse LBB evaluation in NRC Generic Letter 84-04, "Safety Evaluation of Westinghouse Topical Reports Dealing with Elimination of Postulated Pipe Breaks in PWR Main Loops." By letter (Reference 3) dated May 6, 1986, the NRC acknowledged that PBNP was bounded by the generic Westinghouse LBB analysis and met the additional criteria identified in NRC Generic Letter 84-04.

A plant-specific LBB analysis for the PBNP Units 1 and 2 primary coolant loop piping was subsequently performed by Westinghouse in 1996, and subsequently revised in 2002 and 2003. The results of the current PBNP LBB analysis are documented in WCAP-14439, Revision 2, "Technical Justification for Eliminating Large Primary Loop Pipe Rupture as the Structural Design Basis for the Point Beach Nuclear Plant Units 1 and 2 for the Power Uprate and License Renewal Program." The report demonstrates compliance with LBB technology for the PBNP RCS piping based on plant-specific analysis, using the methodology and criteria of Standard Review Plan Section 3.6.3. The revised LBB analysis incorporates analysis parameters associated with power uprate conditions of up to 10.4 percent reactor power, and a 60-year operating period. This revision documents the plant specific reactor coolant system main loop piping geometry, loading, and material properties used in the fracture mechanics evaluation. Since the primary loop piping systems include cast stainless steel fittings, end of life (60-year) fracture toughness, considering the effects of thermal aging, was determined for each heat of material.

Based on loading, pipe geometry, and fracture toughness considerations, enveloping critical locations were determined at which leak-before-break crack stability evaluations were made. Through wall flaw sizes were found which would cause a leak at a rate of ten times the leakage detection system capability of the plant. Large margins for such flaw sizes were demonstrated against flaw instability. Finally, using the plant specific transients and cycles, fatigue crack growth for the 60 years was shown to be acceptable for the primary loop piping. All the recommended LBB margins (margin on leak rate, margin on flaw size, and margin on loads) were satisfied.

The Reactor Coolant System Main Loop Piping Leak-Before-Break Analysis has been projected to the end of the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(ii). This analysis was also reevaluated to address Extended Power Uprate conditions (Reference 18).

In addition a flaw tolerance analysis (Reference 5) was completed for the (CASS) elbows in the main reactor coolant piping system for Point Beach Units 1 and 2. The conclusion of that analysis was that even with the thermal aging in the susceptible reactor coolant loop CASS piping material for Point Beach Units 1 and 2, the susceptible piping locations have been shown to be tolerant of large flaws for the period of extended operation and operation at EPU conditions.

Pressurizer Surge Line Piping Leak-Before-Break Analysis

Leak-Before-Break (LBB) analysis for the Unit 1 and 2 pressurizer surge line piping was performed in 1998. The results of the analysis are documented in WCAP-15065. The report demonstrates compliance with LBB technology for the PBNP pressurizer surge line piping based on plant specific analysis. Westinghouse revised WCAP-15065 to include the NRC SER approving the LBB analysis for the PBNP Units 1 and 2 pressurizer surge line piping in 2001. This revision is documented in WCAP-15065-P-A, Revision 1, "Technical Justification for Eliminating Pressurizer Surge Line Rupture as the Structural Design Basis for the Point Beach Units 1 and 2 Nuclear Plants." The pressurizer surge line LBB analysis incorporates analysis parameters associated with original licensed power conditions, and a 40-year operating period. The LBB analysis includes the effects of thermal stratification, as evaluated for the PBNP surge lines in WCAP-13509, "Structural Evaluation of the Point Beach Units 1 and 2 Pressurizer Surge Lines, Considering the Effects of Thermal Stratification." WCAP-15065-P-A documents the plant-specific pressurizer surge line piping geometry, loading and material properties used in the fracture mechanics evaluation. It should be noted that the pressurizer surge line piping does not include cast stainless steel fittings.

The analysis is consistent with the criteria specified in NUREG-1061 Volume 3, utilizing the modified limit load method as specified in draft Standard Review Plan, Section 3.6.3. Based on loading, pipe geometry, and fracture toughness considerations, enveloping critical locations were determined at which leak-before-break crack stability evaluations were made. Through wall flaw sizes were found which would cause a leak at a rate of ten times the leakage detection system capability of the plant. Large margins for such flaw sizes were demonstrated against flaw instability. Finally, using the plant specific transients and cycles, fatigue crack growth for the 40 years was shown to be acceptable for the pressurizer surge line piping. All the recommended LBB margins (margin on leak rate, margin on flaw size, and margin on loads) were satisfied.

The pressurizer surge line LBB analysis was further evaluated to determine the impact of Extended Power Uprate conditions, and a 60-year operating period. The changes in the NSSS design conditions due to power uprate (Reference 18) did not result in any changes to the piping loads used in the analysis. There are no cast pipe fittings contained in the piping system, therefore thermal aging is not an issue for the extended operating period.

Thermal aging of the SS weld material was considered with saturated conditions (fully aged), and thus is valid for the extended period of operation. The transients and cycles for the 60 year operating period are the same as the transients and cycles used in the 40 year operating period analysis. The impacts of changes in NSSS design conditions, and the 60 year operating period were determined to be negligible. The conclusions of the original LBB analysis, contained in WCAP-15065-P-A, remained unchanged.

The pressurizer surge line LBB analysis has been evaluated and determined to remain valid for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(i).

Class 1 Accumulator Injection Line Piping Leak-Before-Break Analysis

Leak-Before-Break (LBB) analysis for the PBNP Unit's 1 and 2 accumulator injection line piping was performed in 1998. The scope of the analysis for the accumulator injection lines also includes the residual heat removal (RHR) return line. The results of the analysis are documented in WCAP-15107. The report demonstrates compliance with LBB technology for the PBNP accumulator injection line piping based on plant specific analysis. Westinghouse revised WCAP-15107 to include the NRC SER approving the LBB analysis for the PBNP Units 1 and 2 accumulator injection line piping in 2001. This revision is documented in WCAP-15107-P-A, Revision 1, "Technical Justification for Eliminating Accumulator Lines Rupture as the Structural Design Basis for the Point Beach Units 1 and 2 Nuclear Plants." The accumulator injection line LBB analysis incorporates analysis parameters associated with original licensed power conditions, and a 40-year operating period. WCAP-15107-P-A documents the plant specific accumulator injection line piping geometry, loading, and material properties used in the fracture mechanics evaluation. It should be noted that the accumulator injection line piping does not include cast stainless steel fittings.

The analysis is consistent with the criteria specified in NUREG-1061 Volume 3, utilizing the modified limit load method as specified in draft Standard Review Plan, Section 3.6.3. Based on loading, pipe geometry, and fracture toughness considerations, enveloping critical locations were determined at which leak-before-break crack stability evaluations were made. Through wall flaw sizes were found which would cause a leak at a rate of ten times the leakage detection system capability of the plant. Large margins for such flaw sizes were demonstrated against flaw instability. Finally, using the plant-specific transients and cycles, fatigue crack growth for the 40 years was shown to be acceptable for the accumulator injection line piping. All the recommended LBB margins (margin on leak rate, margin on flaw size, and margin on loads) were satisfied.

The accumulator injection line LBB analysis was further evaluated to determine the impact of Extended Power Uprate conditions (Reference 18), and a 60-year operating period. The changes in the NSSS design conditions due to power uprate did not result in any changes to the piping loads used in the analysis. There are no cast piping fittings contained in the piping system, therefore thermal aging is not an issue for the extended operating period. Thermal aging of the SS weld material was considered with saturated conditions (fully aged), and thus is valid for the extended period of operation. The transients and cycles for the 60-year operating period are the same as the transients and cycles used in the 40-year operating period analysis. The impacts of changes in NSSS design conditions, and the 60-year operating period were determined to be negligible. The conclusions of the original LBB analysis, contained in WCAP-15107-P-A, remained unchanged.

The accumulator injection line LBB analysis has been evaluated and determined to remain valid for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(i).

Class 1 RHR Line Piping Leak-Before-Break Analysis

Leak-Before-Break (LBB) analysis for the PBNP Unit's 1 and 2 residual heat removal (RHR) suction line piping was performed in 1998. The results of the analysis are documented in WCAP-15105. The report demonstrates compliance with LBB technology for the PBNP RHR line piping based on plant specific analysis. Westinghouse revised WCAP-15105 to include the

NRC SER approving the LBB analysis for the PBNP Units 1 and 2 RHR line piping in 2001. This revision is documented in WCAP-15105-P-A, Revision 1, "Technical Justification for Eliminating Residual Heat removal (RHR) Lines Rupture as the Structural Design Basis for the Point Beach Units 1 and 2 Nuclear Plants." The RHR line LBB analysis includes the effects of thermal stratification. The RHR line LBB analysis incorporates analysis parameters associated with original licensed power conditions, and a 40-year operating period. WCAP-15105-P-A documents the plant specific RHR line piping geometry, loading, and material properties used in the fracture mechanics evaluation. It should be noted that the RHR line piping does not include cast stainless steel fittings.

The analysis is consistent with the criteria specified in NUREG-1061 Volume 3, utilizing the modified limit load method as specified in draft Standard Review Plan, Section 3.6.3. Based on loading, pipe geometry and fracture toughness considerations, enveloping critical locations were determined at which leak-before-break crack stability evaluations were made. Through wall flaw sizes were found which would cause a leak at a rate of ten times the leakage detection system capability of the plant. Large margins for such flaw sizes were demonstrated against flaw instability. Finally, using the plant specific transients and cycles, fatigue crack growth for the 40 years was shown to be acceptable for the RHR line piping. All the recommended LBB margins (margin on leak rate, margin on flaw size, and margin on loads) were satisfied.

The RHR line LBB analysis was further evaluated to determine the impact of Extended Power Uprate conditions (Reference 18), and a 60-year operating period. The changes in the NSSS design conditions due to power uprate did not result in any changes to the piping loads used in the analysis. There are no cast piping fittings contained in the piping system, therefore thermal aging is not an issue for the extended operating period. Thermal aging of the SS weld material was considered with saturated conditions (fully aged), and thus is valid for the extended period of operation. The transients and cycles for the 60-year operating period are the same as the transients and cycles used in the 40-year operating period analysis. The impacts of changes in NSSS design conditions, and the 60-year operating period were determined to be negligible. The conclusions of the original LBB analysis, contained in WCAP-15105-P-A, remained unchanged.

The RHR line LBB analysis has been evaluated and determined to remain valid for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(i).

Reactor Vessel Head Penetration Analysis

The RPV heads were replaced during each unit's respective refueling outage in 2005. All analyses associated with the new RPV heads have been evaluated for operation through EOLE in accordance with 10 CFR 54.21(c)(1)(i). An additional evaluation confirmed that the Analysis of Record remains bounding and applicable for EPU conditions (Reference 20).

15.4.4 LOSS OF PRELOAD

Containment Tendon Loss of Prestress Analysis

The PBNP Units 1 and 2 containment buildings are post-tensioned, reinforced concrete structures composed of vertical cylinder walls and a shallow dome, supported on a conventional reinforced concrete base slab. The cylinder walls and dome are provided with tendons.

The prestress of containment tendons decreases over time as a result of seating of anchorage losses, elastic shortening of concrete, creep of concrete, shrinkage of concrete, relaxation of prestressing steel, and friction losses. New upper limit curves, and lower limit curves, of prestressing forces have been established for all tendons through the period of extended operation. The predicted final effective preload at the end of 60 years exceeds the minimum required preload for all containment tendons. Consequently, the post-tensioning system will continue to perform its intended function throughout the period of extended operation.

The analyses associated with containment tendon loss of prestress have been projected to the end of the period of extended operation, in accordance with the requirements of 10 CFR 54.21(c)(1)(ii).

15.4.5 NEUTRON ABSORBER

Spent Fuel Pool Storage Rack Boraflex

The Boraflex Monitoring Program has been discontinued as a result of an NRC approved criticality analysis (Reference 13) that does not credit the presence of Boraflex in the spent fuel pool.

15.4.6 ENVIRONMENTAL QUALIFICATION OF ELECTRICAL EQUIPMENT

The NRC has established nuclear plant EQ requirements in 10 CFR 50, Appendix A, Criterion 4, “Environmental and Dynamic Effects Design Bases,” and 10 CFR 50.49. 10 CFR 50.49 specifically requires that an EQ program be established to demonstrate that certain electrical components located in harsh plant environments (that is, those areas of the plant that could be subject to the harsh environmental effects of a loss of coolant accident (LOCA), high energy line break (HELB), or post-LOCA radiation) are qualified to perform their safety function in those harsh environments after the effects of inservice aging. 10 CFR 50.49 requires that the effects of significant aging mechanisms be addressed as part of EQ.

The EQ Program meets the requirements of 10 CFR 50.49 for the applicable electrical components important to safety. 10 CFR 50.49 defines the scope of components to be included, requires the preparation and maintenance of a list of in-scope components, and requires the preparation and maintenance of a qualification file that includes component performance specifications, electrical characteristics and the environmental conditions to which the components could be subjected. 10 CFR 50.49(e)(5) contains provisions for aging that require, in part, consideration of all significant types of aging degradation that can affect component functional capability. 10 CFR 50.49(e) also requires replacement or refurbishment of components qualified for less than the current license term prior to the end of designated life, unless additional life is established through ongoing qualification. 10 CFR 50.49(f) establishes four methods of demonstrating qualification for aging and accident conditions.

10 CFR 50.49(k) and (l) permit different qualification criteria to apply based on plant and component vintage.

The license renewal rule, 10 CFR 54, requires that for each structure and component subject to an Aging Management Review (AMR), the licensee shall demonstrate that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the current licensing basis for the period of extended operation. The EQ Program manages component thermal, radiation and cyclical aging, as applicable, through the use of aging evaluations based on 10 CFR 50.49(f) qualification methods. As required by 10 CFR 50.49, EQ components not qualified for the current license term are to be refurbished, replaced, or have their qualification extended prior to reaching the aging limits established in the evaluation.

Aging evaluations for EQ components that specify a qualification of at least 40 years are considered time-limited aging analyses (TLAA) for license renewal. The PBNP EQ Program ensures that these EQ components are maintained within the bounds of their qualification bases.

EQ equipment is identified and tabulated in the Master List of Electrical Equipment to be Environmentally Qualified (EQML). This list references the Equipment Qualification Summary Sheets (EQSS), which contain pertinent information that establishes qualified life and applicable environmental parameters.

The EQ Program has been demonstrated to be capable of programmatically managing the qualified lives of the components falling within the scope of the program for license renewal. Based upon a review of the existing program and operating experience, the effective implementation of the EQ Program will provide reasonable assurance that (a) the aging effects will be managed, and (b) EQ components will continue to perform their intended function(s) consistent with the current licensing basis for the period of extended operation.
Therefore, the EQ Program will be an acceptable aging management program for license renewal under 10 CFR 54.21(c)(1)(iii) during the period of extended operation.

The effect of the Extended Power Uprate on environmental conditions inside and outside containment on the qualification of electrical equipment was evaluated. Electrical equipment will continue to meet the relevant requirements of 10 CFR 50.49 following implementation of EPU. (Reference 17)

15.4.7 UNIT 1 PRESSURIZER FLAW EVALUATION

Results of Analysis

The fracture mechanics analysis presented in Calculation PBCH-14Q-301, shows that the current flaw identified during the Unit 1 fall 2005 outage in the Pressurizer upper shell-to-upper head weld is acceptable per the criteria of ASME Section XI, IWB-3612. The calculated maximum stress intensity factor for the observed flaw is 27.99 ksi-inch, as compared to the allowable value of 63.25 ksi-inch, which includes required safety margins as noted in Section 2 of this calculation. In fact, the flaw could grow to more than twice the current size and remain acceptable.

The fatigue growth calculation demonstrates that over more than 200 cycles from 0 to 30 ksi, the resulting flaw growth is insignificant compared to the current size of the flaw. Therefore, growth of the flaw to an unacceptable size over the remaining life of the plant (assumed 60-year operating license) is not predicted.

Degradation Mechanisms

The observed flaw is a subsurface flaw that is remote from any surface (either the wetted inside surface or the air outside surface). Such a flaw is therefore not a result of chemistry-driven mechanisms such as stress corrosion cracking or corrosion. Furthermore, the original fatigue analysis summarized that at this general location in the pressurizer, the cumulative fatigue usage factor over the life of the plant is less than 1.0, so flaw initiation by a fatigue mechanism is not plausible. ASME Section III limits fatigue usage over the life of the plant to less than 1.0, to limit fatigue damage such that fatigue cracks will not initiate. These factors lead to the conclusion that the observed flaw is in fact an artifact of original fabrication, and not to an active degradation mechanism. The evaluation of the hypothetical flaw growth by a fatigue mechanism is, therefore, conservative.

Conclusions and Discussions

Based on the results of the evaluation presented in this calculation package, the indication found during the inservice inspection of the pressurizer welds are acceptable and meet the requirement of ASME Code, Section XI, IWB-3610.

The indication area is about 0.5 in^2. The area of the upper shell to head weld is about 1164 in^2, assuming an inside radius of 42 inches, and a wall thickness of 4.41 inches. The area reduction is less than 0.043% of the original area. This area reduction will have no significant affect on the hoop stress in the weld. Thus, the pressurizer stress analysis based on ASME Boiler and Pressure Vessel Code Section III in Reference 6 is not affected. Therefore, the requirement of IWB-3610 (d) (2) is satisfied.

The post EPU power uprate loading/stresses and conditions remain the same or continue to be conservatively bounded by the assumptions and design input in Reference 6 (Reference 19).

15.4.8 UNIT 1 STEAM GENERATOR B FLAW EVALUATION

Results Of Analysis

The fracture mechanics analysis of a discovered flaw in the Unit 1 Steam Generator B transition cone weld presented in Calculation PBCH-14Q-302 Revision 3, shows that the bounding flaw is acceptable per the criteria of ASME Section XI, IWB-3612. The calculated maximum stress intensity factor for the observed flaw is 42 ksi-inch, as compared to the allowable value of 63.25 ksi-inch, which includes required safety margins as noted in Section 2 of this calculation. In fact, this flaw could grow to slightly more than twice the current size and remain acceptable. All actual flaws are smaller than this assumed bounding flaw.

The fatigue growth calculation demonstrates that over more than 3900 cycles from 0 to 64.7 ksi, the resulting flaw growth of the assumed bounding flaw remains below the allowable flaw size. Most transients experienced by the component are much less severe than this transient, and would lead to negligible growth. Therefore, growth of the flaw to an unacceptable size over the remaining life of the plant (assumed 60-year operating license) is not predicted.

The bounding flaw analyzed in this calculation is much more severe than are any of the flaws in this weld that were accepted under the Acceptance Standards of IWC-3510. Therefore, although fracture mechanics evaluation of such acceptable flaws is not required, the fracture mechanics analysis in this calculation could conservatively be applied to such flaws, if necessary.

Degradation Mechanisms

The observed flaws are subsurface flaws that are remote from any surface (either the wetted inside surface or the air outside surface). Such a flaw is therefore not a result of chemistry-driven mechanisms such as stress corrosion cracking or corrosion. These factors lead to the conclusion that the observed flaws are in fact artifacts of original fabrication, and not due to an active degradation mechanism. The evaluation of the hypothetical flaw growth by a fatigue mechanism is therefore conservative.

Conclusions And Discussions

Based on the results of the evaluation presented in this calculation package, the indications found during the inservice inspection of the Steam Generator B transition cone weld are acceptable and meet the requirement of ASME Code, Section XI, IWB-3610.

The total of all indication areas is about 9.2 in^2. The area of the steam generator weld is about 2012 in^2, assuming a circumference of 524 inches, and a wall thickness of 3.84 inches. The transverse area reduction is less than 0.5% of the original area. This area reduction will have no significant affect on the hoop stress in the weld. Thus, the steam generator stress analysis based on ASME Boiler and Pressure Vessel Code Section III is not affected. Therefore, the requirement of IWB-3610 (d) (2) is satisfied.

The post EPU power uprate loading/stresses and conditions remain the same or continue to be conservatively bounded by the assumptions and design input in Reference 7 (Reference 19).

15.4.9 UNIT 1 STEAM GENERATOR A FLAW EVALUATION

Results of Analysis

The fracture mechanics analysis of a discovered flaw in the Unit 1 Steam Generator A transition cone weld presented in Calculation PBCH-14Q-303 Revision 1, shows that flaw 19 is acceptable per the criteria of ASME Section XI, IWB-3612. The calculated maximum stress intensity factor for the observed flaw is 40 ksi-inch, as compared to the allowable value of 63.25 ksi-inch, which includes required safety margins (10) as noted in Section 2 of this calculation.

The fatigue growth calculation demonstrates that over more than 4800 cycles from 0 to 64.7 ksi, the resulting flaw growth of the flaw remains below the allowable flaw size. Most transients experienced by the component are much less severe than this transient, and would lead to negligible growth. Therefore, growth of the flaw to an unacceptable size over the remaining life of the plant (assumed 60-year operating license) is not predicted.

The flaw analyzed in this calculation is more severe than are any of the flaws in this weld that were accepted under the Acceptance Standards of IWC-3510. Therefore, although fracture mechanics evaluation of such acceptable flaws is not required, the fracture mechanics analysis in this calculation could conservatively be applied to such flaws, if necessary.

Degradation Mechanisms

The observed flaws are subsurface flaws that are remote from any surface (either the wetted inside surface or the air outside surface). Such a flaw is therefore not a result of chemistry-driven mechanisms such as stress corrosion cracking or corrosion. These factors lead to the conclusion that the observed flaws are in fact artifacts of original fabrication, and not due to an active degradation mechanism. The evaluation of the hypothetical flaw growth by a fatigue mechanism is therefore conservative.

Conclusions And Discussions

Based on the results of the evaluation presented in this calculation package, the indications found during the inservice inspection of the Steam Generator A transition cone weld are acceptable and meet the requirement of ASME Code, Section XI, IWB-3610.

The total of all indication areas is about 5.06 in^2. The area of the steam generator weld is about 1928 in^2, assuming a circumference of 524 inches (Reference 3), and a wall thickness of 3.68 inches. The transverse area reduction is less than 0.26% of the original area. This area reduction will have no significant affect on the hoop stress in the weld. Thus, the steam generator stress analysis based on ASME Boiler and Pressure Vessel Code Section III is not affected. Therefore, the requirement of IWB-3610 (d) (2) is satisfied.

The post EPU power uprate loading/stresses and conditions remain the same or continue to be conservatively bounded by the assumptions and design input in Reference 8 (Reference 19).

15.4.10 FLAW TOLERANCE EVALUATION FOR SUSCEPTIBLE CASS REACTOR COOLANT PIPING COMPONENTS IN POINT BEACH UNITS 1 AND 2

The susceptible piping locations in the reactor coolant loop piping system of Point Beach Nuclear Plant Units 1 and 2 were evaluated in accordance with the evaluation procedures and acceptance criteria in Paragraph IWB-3640 of ASME Section XI code. The reactor coolant loop A376 TP316 piping material is not susceptible to thermal aging, but some of the A351 CF8M piping elbow material is susceptible due to the δ-ferrite content level. The maximum acceptable flaw size for a range of flaw shapes for the susceptible CASS piping locations in the hot leg, crossover leg and cold leg are shown in Figures 6-1 to 6-6 of the report. The limiting flaw sizes for a given aspect ratio (R/a) are those shown in Figure 6-1 of the report for longitudinal flaws in the hot leg. From Figure 6-1 of the report, the maximum acceptable initial flaw depth is about 28% through-wall for a flaw with an aspect ratio of 6. Considering the hot leg wall thickness of

2.5 inch, a longitudinal flaw of 0.70 inch in depth and 4.2 inches in length would remain acceptable in accordance with the acceptance criteria of IWB- 3640 for the next 30 years, which represents the remaining plant life for both Point Beach Units 1 and 2 (assumed 60-year operating license). The acceptable initial flaw depths for circumferential flaws and flaws in the crossover leg and cold leg are larger as shown in Table 6-1 of the report. In addition, this maximum acceptable initial flaw depth is deeper than the recommended postulated flaw depth shown in Table L-3210-1 in Article L-3000 of the Code. Therefore, even with thermal aging in the susceptible reactor coolant loop CASS piping material for Point Beach Units 1 and 2, the susceptible piping locations have been shown to be tolerant of large flaws.

The flaw tolerance evaluation of CASS piping material at EPU conditions did not find any significant impact due to thermal aging. (Reference 5)

15.4.11 UNIT 1 REACTOR VESSEL INLET NOZZLE FLAW EVALUATION

Results of Analysis

Phased array ultrasonic examinations of the reactor vessel inlet nozzle-to-pipe weld (RC-32-MRCL-AIII-03) resulted in an American Society of Mechanical Engineers (ASME) Section XI Code rejectable indication in the "A" loop. The weld is a dissimilar metal weld (between the cast stainless elbow and carbon steel nozzle using stainless steel filler material). The indication was recorded 18 inches from top dead center (TDC) and 2.1 inches from the weld centerline on the nozzle side of the weld in the nozzle forging, and approximately 0.9 inches from the buttering. The indication is volumetric in nature (e.g., slag inclusion) and the indication orientation is predominantly circumferential in nature.

Due to inability to meet the ASME Section XI, Appendix VIII, Supplement 10 (dissimilar metal weld) required 0.125 inch root mean square (RMS) acceptance criterion, the flaw was evaluated in accordance with Performance Demonstration Initiative (PDI) policy (PDI 03-01) as allowed by an approved PBNP relief request (RR-21). In addition, because there were no procedurally demonstrated techniques for determining that indications close to the inside surface are, in fact, sub-surface; the indication was treated as surface-connected during the ASME Section XI evaluation(s).

Degradation Mechanisms

Based on current findings, it is considered that this indication or group of indications is most likely to be embedded fabrication flaws; however, it is being evaluated as a surface-connected flaw due to the proximity to the inside surface. The location is actually near to the buttering of the nozzle, and also near to the clad-to-base metal interface.

Conclusions And Discussions

The Section XI Flaw Evaluation of Indication Recorded on RC-32-MRCL-AIII-03 of the Point Beach Unit 1 Inlet Nozzle to Pipe Weld presented in Technical Note LTR-PAFM-10-50-NP shows the flaw is acceptable per Section XI, paragraph IWB-3600. Based on the results of the evaluation presented in the technical note, the indication was found to be acceptable for further service without repair for the remainder of the life of Unit 1, including the period of renewed operation (Reference 14) and operation at EPU conditions (Reference 15). The LBB analysis described in FSAR 15.4.3 remain valid.

15.4.12 REFERENCES

1. NRC Letter, "Acceptance for referencing of Topical Report WCAP-14535-A, "Topical report on Reactor Coolant Pump Flywheel Inspection Elimination," dated September 12, 1996.

2. NMC Letter to NRC, NRC 2001-059, "Reactor Coolant Pump Flywheel Inspection Interval Change Point Beach Nuclear Plant, Units 1 and 2," dated September 17, 2001.

3. NRC Letter to WE, "Docket Nos. 50-266 and 50-301," "Exemption from the Requirements of 10 CFR 50 Appendix A, General Design Criterion 4," dated May 6, 1986.

4. NUREG/CR-6260 (INEL-95/0045), "Application of NUREG/CR-5999 Interim Fatigue Curves to Selected Nuclear Power Plant Components," U.S. Nuclear Regulatory Commission, March 1995.

5. Westinghouse Report LTR-PAFM-05-58, Revision 1. "Flaw Tolerance Evaluation for Susceptible CASS Reactor Coolant Piping Components in Point Beach Units 1 and 2," dated June 2011.

6. Structural Integrity Associates, Inc. Calculation PBCH-14Q-301 Revision 0, Point Beach Unit 1, "Pressurizer Flaw Evaluation," October 2005.

7. Structural Integrity Associates, Inc. Calculation PBCH-14Q-302, Revision 3, Point Beach Unit 1, "Steam Generator B Flaw Evaluation," November 2005.

8. Structural Integrity Associates, Inc. Calculation PBCH-14Q-303, Revision 1, Point Beach Unit 1, "Steam Generator A Flaw Evaluation," November 2005.

9. Westinghouse Report, CN-REA-08-39, "Neutron Fluence Exposure Evaluations for the Point Beach Units 1 and 2 EPU," December 2008.

10. AREVA Document BAW-2467P, Revision 1, "Low Upper-Shelf Toughness Fracture Mechanics Analysis of Reactor Vessel of Point Beach Units 1 and 2 for Extended Life through 53 Effective Full Power Years," dated October 2004 (Incorporated by reference).

11. NRC Safety Evaluation Related to Amendment Nos. 227/232 to Renewed Facility Operating License Nos. DPR-24 and DPR-27, "Issuance of Amendments Regarding Review of Reactor Vessel Fracture Mechanics Analysis," dated May 10, 2007.

12. NRC Safety Evaluation, NUREG-1839 "Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2," dated December 2005

13. NRC Safety Evaluation, "Point Beach Nuclear Plant, Units 1 and 2 - Issuance of Amendments Re: Spent Fuel Pool Storage Criticality Control," dated March 5, 2010.

14. NEXTERA Energy letter NRC, NRC 2010-0050, "Unit 1 Refueling 32 Analytical Evaluation Report for the Reactor Vessel Point Beach Nuclear Plant," dated April 13, 2010.

15. Westinghouse Report LTR-PAFM-10-50-NP, Revision 1, "Section XI Flaw Evaluation of Indication Recorded on RC-32-MRCL-AIII-03 of the Point Beach Unit 1 Inlet Nozzle to Pipe Weld," dated June, 2011.

16. NRC Safety Evaluation, "Point Beach Nuclear Plant, Units 1 and 2 - Issuance of Amendment (Nos. 250 and 254) Regarding Change to Technical Specification 5.6.5, Reactor Coolant System (RCS) Pressure and Temperature Limits Report (PTLR) (TAC Nos. MF0532 and MF0533)," dated June 30, 2014.

17. FPL Energy letter to NRC, NRC 2009-0030, "License Amendment Request 261 Extended Power Uprate," dated April 7, 2009.

18. NRC Safety Evaluation, "Issuance of License Amendment Regarding Extended Power Uprate (TAC Nos. ME1044 and ME1045)," dated May 3, 2011.

19. Structural Integrity Associates, Inc. letter to NextEra Energy, "Reconciliation of Pressurizer and Steam Generator Flaw Evaluation Calculations to Incorporate Extended Power Uprate Conditions," dated September 8, 2011.

20. WCAP-16983-P, Revision 0, "Point Beach Units 1 and 2 Extended Power Uprate (EPU) Engineering Report," (Proprietary) dated September 2009.

21. WCAP-16669-NP, Revision 1 "Point Beach Units 1 and 2 Heatup and Cooldown Limit Curves for Normal Operation dated January 2009.

15.5 EXEMPTIONS

The requirements of 10 CFR 54.21(c) stipulate that the application for a renewed license should include a list of plant-specific exemptions granted pursuant to 10 CFR 50.12 and that are based on time-limited aging analyses, as defined in 10 CFR 54.3. Each active 10 CFR 50.12 exemption has been reviewed to determine whether the exemption is based on a time-limited aging analysis. No existing TLAA related exemptions were identified.

APPENDIX A TABLE OF CONTENTS

A.1 STATION BLACKOUT (SBO)

A.1.1 STATION BLACKOUT OVERVIEW

Station Blackout is defined as the complete loss of alternating current electric power to the essential and nonessential switchgear buses in a nuclear power plant (i.e., loss of offsite electric power system concurrent with a turbine trip and the unavailability of the onsite emergency AC power system). A Station Blackout does not involve the loss of available AC power to buses fed by station batteries through inverters. The event is considered to be terminated upon the restoration of power to the essential switchgear buses from any source, including the alternate AC source which has been qualified as an acceptable coping mechanism. A concurrent single failure or design basis accident need not be assumed during a station blackout event (Reference 2 and Reference 18).

The requirements for Station Blackout are established in 10 CFR 50.63 (Reference 1), which was formally issued in 1988. Guidance for compliance with the regulatory requirements is presented in NUMARC 87-00, Revision 0 (Reference 2) and Regulatory Guide 1.155 (Reference 3). The NRC has not endorsed Revision 1 to NUMARC 87-00, but has accepted specific supplements to NUMARC 87-00 Rev. 0, as described in Appendix K of NUMARC 87-00 Rev. 1 (Reference 2).

The station blackout regulation requires determination of the coping duration category based on criteria provided in Reference 2 and Reference 3. The “required coping duration” is defined as the time between the onset of station blackout and the restoration of off-site AC power to safe shutdown buses. “Coping duration category” is a quantification of the relative risk of a particular facility to the occurrence of a station blackout (loss of all onsite and offsite AC power).

The determination of the required coping duration category is based on several factors, such as the plant design and the probability of severe weather conditions in the area. Once the required coping duration category has been established, the design approach to coping with the station blackout event is demonstrated. This design approach may choose to take credit for either an available alternate AC power source or opt for an AC power-independent design. The plant systems must have the necessary capacity and capability to ensure the core is cooled and containment integrity is maintained for the required station blackout coping duration.

The coping duration categories are 2, 4, 8, or 16 hours, as determined from Table 3-8 of Reference 2. The intent of the regulation is for all domestic nuclear plant sites to fall in either the 2-hour or the 4-hour coping duration category, and then select either the “Alternate AC” or “AC-Independent” coping methodology for their specific plant. The NRC bases for coping duration category objectives are described in Section 2.3.2 of Reference 2. The major contributor to overall station blackout risk is the likelihood of losing off-site power and the duration of power unavailability. The stated objective of the NRC is to reduce the core damage frequency due to station blackout to approximately 10^{-5} per year for the average site. This objective is accomplished by requiring either a four hour coping capability or use of an Alternate AC (AAC) source.

PBNP's original response to the SBO rule concluded that the required coping duration category was 8 hours and used the Gas Turbine Generator (GTG) G-05 as the sole Alternate AC (ACC) source to power the safe shutdown loads of both blacked out units. Because the GTG cannot be shown to be available within 10 minutes of the onset of station blackout, a one hour coping assessment was performed as required by Section 7.1.2 of Reference 2. (Reference 4 and Reference 8)

The coping duration category was subsequently revised to 4 hours based on a change in the extremely severe weather (ESW) group classification as discussed in Section A.1.2. With the addition of the G-03 and G-04 EDGs, the SBO minimum redundancy requirements of emergency AC (EAC) power supplies for normal safe shutdown of both units is exceeded and utilization of an EDG as an AAC source is allowed. By definition, a unit with an available EAC power supply is not blacked out. However, any EDG credited as an AAC source must be capable of handling the safe shutdown loads in both the blacked out and non-blacked out units (Reference 2). The PBNP EDGs meet this requirement. Therefore, the present coping methodology utilizes the Gas Turbine Generator (GTG) G-05 or an Emergency Diesel Generator (EDG) from the non-blacked out unit as Alternate AC (ACC) sources. An EDG will start, accelerate to rated frequency and voltage, and can be connected to an EAC bus in either unit within ten minutes of SBO initiation. The GTG will be manually started, accelerate to rated frequency and voltage, and be available to power the safe shutdown loads within one hour of SBO initiation (Reference 6, Reference 15). Since PBNP continues to use the GTG as one of the ACC sources, and it cannot be shown to be available within 10 minutes, the one hour coping assessment has been retained and is described in Section A.1.3.

A.1.2 STATION BLACKOUT COPING DURATION CATEGORY DETERMINATION

The potential for long duration loss of off-site power (LOOP) events can have a significant impact on station blackout risk and required coping duration. Long duration LOOP events are typically associated with grid failures due to severe weather conditions or unique transmission system features. Shorter duration LOOP events tend to be associated with plant specific switchyard features. Per Reference 1, the required coping duration shall be based on the following factors:

1. The redundancy of the emergency standby power system
2. The reliability of each of the emergency power sources
3. The expected frequency of a loss of offsite power
4. The probable time required to restore offsite power

Offsite Power Design Characteristic Group

The regulatory guidance (Reference 2, Tables 3-5a and 3-6a; Reference 3, Table 4) has established three basic groups (P1, P2, and P3) for categorizing the design of the preferred offsite power system. A category of P3 is assigned to those plants with a frequency of grid-related loss of offsite power events greater than once in 20 site-years, which is limited to St. Lucie, Turkey Point and Indian Point (Reference 2).

Since PBNP is not included among the three noted plant sites, further evaluation of several factors is necessary to establish the Offsite Power Design Characteristic Group. The applicable group is defined based on combinations of the following three factors:

- extremely severe weather
- severe weather
- offsite power system independence

Extremely Severe Weather (ESW Group)

The estimated frequency of loss of offsite power due to extremely severe weather is determined by the annual expectation of storms at the site with wind velocities equal to or greater than 125 mph. These events are normally associated with the occurrence of hurricanes where high windspeeds may cause widespread transmission system unavailability for extended periods. Since electrical distribution systems are not designed for such conditions, it is assumed the occurrence of such windspeeds will directly result in the loss of offsite power.

The estimated frequency may be determined based on either site-specific data or on data from local weather stations. Table 3-2 of Reference 2 summarizes site-specific National Oceanic Atmospheric Administration (NOAA) data for the estimated frequency of occurrence of extremely severe weather. As published in this table, PBNP has an event frequency of 0.0036, and therefore was categorized in ESW Group 4 (Reference 4). Subsequent review determined the NOAA data for extremely severe weather was overly conservative for PBNP, and that an ESW event frequency supporting an ESW Group 2 category was justified (Reference 5). This departure from the NUMARC 87-00 criteria was reviewed and approved by the NRC (Reference 6).

Severe Weather (SW Group)

Table 6 of Reference 3 and Part 3.2.1.C of Reference 2 define the severe weather factor based on the frequency of a loss of offsite power due to severe weather. The severe weather considered includes snow, tornadoes, high winds, and storms with salt spray. These are related by the equation:

$$\text{frequency} = 1.3 \text{ x } 10^{-4} \text{ x } h_1 + b \text{ x } h_2 + 0.012 \text{ x } h_3 + c \text{ x } h_4$$

The variables in this equation are defined for PBNP in Reference 2, Section 3.2.1.C:

h_1 = annual expectation of snowfall for site, in inches; this is 42.0 inches for PBNP

h_2 =annual expectation of tornadoes with windspeeds greater than or equal to 113 miles per hour, in events per square mile; this is 0.000035 for PBNP

h_3 =annual expectation of storms with wind velocities between 75 and 124 mph; this is 0.1 for PBNP

h_4 =annual expectation of storms with significant salt spray for the site; this is 0.0 for PBNP.

b =72.3; the PBNP offsite power system design connects four 345 kV transmission circuits to the plant switchyard via a single right-of-way.

c =0; the PBNP site is not considered vulnerable to the effects of salt spray.

These factors, when combined in the severe weather frequency equation, yield an estimated frequency of loss of offsite power due to severe weather of 0.0092. This places PBNP in SW Group 2.

Independence of the Offsite Power System (I Group)

Reference 3, Table 5, defines the offsite power system independence factor, and Reference 2 Section 3.2.1.D simplifies the determination:

If: (a) all offsite power sources are connected to the safe shutdown buses through one switchyard or through multiple electrically connected switchyards, and (b1) the normal power source is from the main generator and there are no automatic and one or more manual transfers of all safe shutdown buses to the preferred or alternate offsite power sources, or (b2) there is one automatic and no manual transfers of the safe shutdown buses to one preferred or one alternate offsite power source, the site falls in the I-3 group. Otherwise, the site is assigned to the I-1/2 group.

The I-1/2 group is characterized by features associated with greater independence and redundancy of sources, and a more desirable transfer scheme. I-3 sites have simpler, less desirable offsite power systems and switchyard capabilities.

Condition a: The PBNP offsite power system consists of four (4) 345 kV transmission circuits, connected via a single right-of-way, to a single switchyard which serves both PBNP units. On this basis, the answer to Condition A is considered to be “YES” for the PBNP site.

Condition b1 and b2: The PBNP auxiliary power distribution system provides offsite power connections to the safety-buses of each unit via the high voltage station auxiliary transformers and the low voltage station auxiliary transformers. This normal supply of power to the safety-related buses is derived from offsite power sources. Upon loss of the preferred offsite power source to the safety-related buses of one unit, the buses will be powered from the preferred power source of the other unit. On this basis, the answers to both Condition b(1) and b(2) are considered to be “NO”, and the PBNP site is classified in the I-1/2 Group.

Offsite AC Power Design Characteristic Group Determination

The combination of the ESW, SW and I factors results in an Offsite Power Design Characteristic Group of P1 for PBNP, based on Reference 3, Table 4.

Emergency AC Power Configuration Group

Regulatory guidance defines four Emergency AC (EAC) Power Configuration groups (A, B, C, and D) based on the availability and redundancy of the emergency power supplies. Reference 2 Section 3.2.2 clarifies the EAC groups, basing it on the number of EAC power supplies required to handle the safe shutdown loads and on the number of additional EAC power supplies available. The PBNP EAC power configuration group is C, based on the following:

PBNP is a two-unit site with four shared Emergency Diesel Generators (EDGs) and one gas turbine generator (GTG). The two Train A EDGs are identical components with a 2000 hour rated output of 2850 kW at 4.16 kV. The two Train B EDGs are identical components with a 2000 hour rated output of 2848 kW at 4.16 kV. All four EDGs are available to support the safe shutdown equipment of either PBNP unit, and a single EDG can supply adequate power to the safe shutdown loads in both units. The GTG has a rating of 23.10 MVA at an output voltage of 13.8 kV, and can supply adequate power to the safe shutdown loads in both units.

Therefore, because only one EDG is necessary to operate safe shutdown equipment for both units following a loss of offsite power, the EAC power configuration group at PBNP is "C", as a 1 out of 2 EDG, dedicated, or 1 out of 3 EDGs, shared configuration per Table 3-7 of Reference 2. Additionally, the PBNP SBO licensing basis permits the use of either the GTG or an EDG as the AAC source.

Target Standby Diesel Generator Reliability

The reliability of the EAC power sources has a key role in the quantification of risk due to SBO. A target value for reliability was therefore made a factor in establishing the required SBO coping duration. The EDG target reliability was selected to be 0.975 based on the original EAC configuration group determination of "D" (i.e., prior to the installation of G-03 and G-04) and the reliability data that existed at the time of the initial SBO evaluation. (Reference 4) These reliability computations utilized the NRC-recommended methodology of EPRI Report NSAC-108 (Reference 7)

Because PBNP offsite power design group is P1, and EAC configuration is C, the target EDG reliability value may be 0.950 or 0.975 per Table 2 of Reference 3. PBNP has retained the reliability target value of 0.975 (Reference 15). PBNP has implemented an EDG reliability program which is based on the methodology of EPRI Report NSAC-108 and conforms to the guidance of RG 1.155, Position 1.2 (Reference 8 and Reference 15).

Coping Duration Category Determination Summary

The previous determinations are summarized below:

Offsite AC Power Design Characteristic Group	=P1
Emergency AC Power Configuration Group	=C
Target Standby Diesel Generator Reliability	=0.975

In accordance with Table 3-8 of Reference 2 and Table 2 of Reference 3, the group determinations listed above result in a coping duration category for PBNP of four hours.

A.1.3 STATION BLACKOUT COPING ANALYSES

Condensate Inventory for Decay Heat Removal

This analysis ensures that PBNP has sufficient condensate inventory to support the decay heat removal function for the SBO event duration. Section 7.2.1 of Reference 2 provides a simplified calculation approach to determine the required condensate volume. This analysis is satisfied by demonstrating that Technical Specification volume requirements envelop the volume estimated by the Reference 2 methodology.

At a core power of 1800 MWt, 14,000 gallons of condensate water are required for the one hour SBO event duration based on the methodology of Reference 2. However in order to maintain the same margin set by the NRC in Reference 8 for subsequent switchover to the long-term AFW water supply, the minimum CST usable volume is set at 15,410 gallons. This volume is bounded by the Technical Specification CST volume requirements which includes additional margin to account for suction piping losses, vortex prevention, pump NPSH requirements, unusable tank volume, and instrument uncertainty. Therefore, PBNP has sufficient condensate inventory for the SBO event duration, including time to transfer to the long-term source after the one-hour period, Reference 16, Reference 17, Reference 22.

Safety-Related Battery Capacity

This coping analysis assures the plant has adequate battery capacity to support required safe shutdown loads for the SBO event duration. Reference 2, Section 7.2.2 suggests the minimum battery capacity be four hours for plants using the AC-independent coping position and one hour for plants utilizing the Alternate AC power source position. The analysis should consider the factors in IEEE Standard 485, including lowest expected electrolyte temperatures and appropriate load duty cycles. Load shedding, if required, shall commence no sooner than 30 minutes after the SBO event initiation.

The evaluation of PBNP battery capacity is based on design analyses which verify sufficient capacity to support all safety related DC loads on all four DC channels (D05, D06, D105 and D106) for a minimum of one hour. No load shedding is required to meet this requirement (Reference 9). This determination was reviewed and accepted by the NRC (Reference 11).

Compressed Air

This analysis demonstrates that air operated valves required for decay heat removal can be operated as required for the defined coping duration. Section 7.2.3 of Reference 2, requests identification of all required valves and the availability of backup air supplies or manual operation capability. At PBNP, no safety-related air operated valves are required to cope with a SBO event for one hour (Reference 4, Reference 8).

Effects of Loss of Ventilation

This analysis ensures the room temperatures in areas containing equipment required to mitigate a SBO event do not increase to values impacting operability following loss of forced ventilation. Reasonable assurance of equipment operability is based on calculated maximum room temperatures less than or equal to 120 °F (Reference 12). The PBNP analyses evaluated the loss of ventilation effects in key plant areas, as summarized below.

Containment Building

The containment building analysis was based on generic analyses performed for Westinghouse Owners Group Emergency Response Guidelines. Based on engineering review and judgment, the containment building temperature would not reach levels which would impair equipment operability (Reference 12). The NRC found this analysis to be acceptable (Reference 8).

Instrument Inverter Rooms

The instrument inverter DY-03 and DY-04 rooms were evaluated as they have the smallest volume of the PBNP inverter rooms and thus would experience the fastest heatup. The results of room temperature analyses showed a maximum room temperature ≤ 120°F, which was considered acceptable for equipment operability (Reference 12). The NRC found this analysis to be acceptable (Reference 8).

Cable Spreading Room

The cable spreading room was evaluated utilizing the room temperature analysis method described above. This analysis showed a maximum room temperature ≤ 120°F, which was considered acceptable for equipment operability (Reference 12). The NRC found this analysis to be acceptable (Reference 8).

Auxiliary Feedwater Pump Room

The Auxiliary Feedwater Pump room was evaluated utilizing the room temperature analysis method described above. This analysis showed a maximum room temperature ≤ 120°F, which was considered acceptable for equipment operability (Reference 12). The NRC found this analysis to be acceptable (Reference 8).

Control Room

The Control Room was evaluated utilizing the room temperature analysis method described above. This analysis showed a maximum room temperature of 128 °F with all tiles for the suspended ceiling in place and ≤ 120°F with some of the ceiling tiles removed. The latter analysis was considered acceptable for equipment operability, and the control room ceiling was permanently modified to remove some of the suspended ceiling tiles (Reference 12). However, the NRC did not find this analysis to be acceptable, and requested additional information and justification of the analysis results (Reference 8). Additional analyses were performed which confirmed the original results (Reference 13). The NRC found the commitment to perform the confirmatory analyses and permanently modify the control room ceiling to be acceptable (Reference 11).

Computer Room

The Computer Room was evaluated utilizing the room temperature analysis method described above. This analysis showed a maximum room temperature of 174 °F with all tiles for the suspended ceiling in place and ≤ 120°F with some of the ceiling tiles removed. The latter analysis was considered acceptable for equipment operability, and the computer room ceiling was permanently modified to remove some of the suspended ceiling tiles (Reference 12). However, the NRC did not find this analysis to be acceptable, and requested additional information and justification of the analysis results (Reference 8). Additional analyses were performed at a higher initial room temperature which confirmed the viability of the ceiling tile removal modification (Reference 13). The NRC found the commitment to perform the confirmatory analyses and permanently modify the computer room ceiling to be acceptable (Reference 11).

Containment Isolation

One of the key safety functions identified in Reference 1 is containment integrity. In addressing this item, the containment isolation valves were reviewed to verify that valves which must be capable of being closed or that must be operated under station blackout conditions can be positioned, with indication, independent of the blacked-out unit's safety-related power supplies. Based on assessment guidelines provided in Section 7.2.5 of Reference 2, the following isolation valve types may be excluded from consideration as valves of concern:

1. Valves normally locked closed during operation
2. Valves that fail closed on a loss of power
3. Check valves
4. Valves in non-radioactive, closed loop systems not expected to be breached in an SBO (except lines which communicate directly with the containment atmosphere)
5. Valves of less than 3-inch nominal diameter.

Based on these exclusion criteria, there are five penetrations for each PBNP unit for which indication and control would be lost during a SBO event. Four of the five penetrations are associated with motor-operated valves in the component cooling water system. Manual isolation capability for these four valves provides adequate containment isolation. The remaining penetration is associated with the chemical and volume control system, and includes an automatic air-operated valve inside of containment. This valve would close on the loss of power, and the penetration can also be manually isolated (Reference 4). The NRC found the containment isolation analysis to be acceptable (Reference 8).

Reactor Coolant Inventory

The maximum reactor coolant pump (RCP) seal leakage rate of 25 gpm per RCP, assuming a complete loss of cooling, has been evaluated, as recommended by the guidance of Reference 2. The total RCP leakage plus the miscellaneous Technical Specification leakage of 10 gpm results in a total primary system leakage rate of 60 gpm. The conclusion is that the RCS inventory would be reduced by RCP seal leakage, but adequate initial RCS inventory is available for the one hour necessary to bring the AAC power source on line (Reference 4 and Reference 8).

The Extended Power Uprate (EPU) revisited the subject of reactor coolant inventory during an SBO event, and found that because EPU would not affect the leakage rates or initial pressurizer level, the reactor coolant inventory during an SBO would continue to be acceptable (Reference 23 and Reference 24).

A.1.4 ALTERNATE AC SOURCE

The original PBNP emergency power system configuration consisted of two EDGs shared between the two PBNP units. This design resulted in an EAC Power Configuration Group of “D”, based on one EDG required of two EDGs shared between the two PBNP units (Reference 4). This configuration prompted the use of gas turbine generator (GTG) G-05 as the AAC source, with commitments to maintain the target GTG reliability at or above 0.95, and to be able to start and load the GTG within 1 hour of a postulated SBO event (Reference 8).

The new EDG installation in 1991-1996 resulted in an EAC Power Configuration Group of “C”, based on either one of two EDGs in a dedicated unit configuration or one of three EDGs in a shared unit configuration (after discounting the EDG considered to be the AAC source). This design change also permitted adoption of a SBO coping strategy still utilizing GTG G-05 as the AAC source, and also utilizing one EDG in the non-blacked out unit as an AAC source in addition to or in lieu of G-05 (Reference 5, and Reference 6). The GTG or an EDG are normally available to support the safe shutdown equipment of either PBNP unit, and either power source can supply power sufficient to achieve safe shutdown in both units. The GTG and each EDG are thus considered fully capable AAC sources per Appendix B of Reference 2; i.e., with sufficient capacity and capability to operate necessary systems for the required 4-hour coping duration.

The EDGs can be connected to the EAC power buses of either unit in a SBO within 10 minutes (Reference 6 , Reference 14). Therefore per Section 3.2.5 of Reference 3, no coping analysis was required for using the EDGs as AAC sources (Reference 6).

A.1.5 PROCEDURES AND TRAINING

The PBNP plant currently has Emergency Operating Procedures (EOPs) addressing the loss of all AC power, including:

ECA 0.0, Loss of All AC Power
ECA 0.1, Loss of All AC Power Recovery Without SI Required
ECA 0.2, Loss of All AC Power Recovery With SI Required

These procedures were developed from the Westinghouse Owners Group Emergency Response Guidelines, which have been reviewed and approved by the NRC. The ECA 0.0 procedure directs operators to restore power to the safety-related buses by EDG restart, offsite power reconnection, gas turbine generator G-05 start or opposite unit safety-related bus crosstie. The ECA 0.1 and 0.2 procedures provide guidance for recovery from the station blackout condition once AC power has been restored. The SBO recovery guidelines were implemented prior to promulgation of the Station Blackout Rule, and thus additional operator training was not necessary (Reference 4). The NRC considered the procedures to be acceptable, and appropriate training is implemented for any EAC power source configuration changes (Reference 8 and Reference 9).

As part of the G-05 reliability program, testing in a manner similar with that as would be required during a SBO event is performed on at least a quarterly basis. The testing includes starting and running G-05 with its support systems powered by the auxiliary power diesel generator G-501. The testing synchronizes G-05 to the grid and includes operation for at least 1 hour at a load which envelopes the SBO requirements (Reference 11, Reference 13, Reference 19, Reference 20, and Reference 21).

A.1.6 QUALITY ASSURANCE PROGRAM

The PBNP SBO position utilizes equipment to cope with the postulated SBO event which was not previously covered by plant quality assurance (QA) programs. The plant equipment originally classified as safety-related and required for SBO coping is covered by a 10 CFR 50 Appendix B quality assurance program which meets or exceeds the guidelines of Appendix A of Reference 3. Non-safety-related components credited for coping in the PBNP SBO position have been assigned an Augmented Quality (AQ) classification which incorporates the QA program attributes (Reference 9). The NRC found the commitment to include non-safety-related components credited for SBO coping in the AQ program to be acceptable (Reference 11).

A.1.7 REFERENCES

1. 10 CFR 50.63, “Loss of All Alternating Current Power.”

2. NUMARC Document 87-00, “Guidelines and Technical Bases for NUMARC Initiatives Addressing Station Blackout at Light Water Reactors,” Revision 0; November 1987, Revision 1; August, 1991.

3. NRC Regulatory Guide 1.155, “Station Blackout,” Revision 1; August 1988.

4. VPNPD-89-216, NRC-89-043, WEPCo Letter to NRC, “Response to 10 CFR 50.63, TAC. Nos. 68586 and 68587, Loss of All Alternating Current Power, Point Beach Nuclear Plant, Units 1 and 2,” April 17, 1989.

5. NPL 94-0353, WEPCo Letter to NRC, “Supplement to 10 CFR 50.63, TAC. Nos. 68586 and 68587, Loss of All Alternating Current Power, Point Beach Nuclear Plant, Units 1 and 2,”September 22, 1994.

6. NRC Letter to WEPCo, TAC Nos. M90613 and M90614 “Station Blackout Modification, Point Beach Nuclear Plant, Units 1 and 2 ” October 16, 1995.

7. EPRI Report NSAC-108, “The Reliability of Emergency Diesel Generators at U.S. Nuclear Power Plants,” September 1986.

8. NRC Letter to WEPCo, TAC Nos. 68586 and 68587, “Safety Evaluation of the Point Beach Response to the Station Blackout Rule,” October 3, 1990.

9. VPNPD-90-459, NRC-90-110, WEPCo Letter to NRC, “10 CFR 50.63, TAC. Nos. 68586 and 68587, Loss of All Alternating Current Power, Point Beach Nuclear Plant, Units 1 and 2,” November 8, 1990.

10. Not used

11. NRC Letter to WEPCo, TAC 68586, “Supplemental Safety Evaluation of Response to Station Blackout Rule,” March 22, 1991.

12. VPNPD-90-148, NRC-90-030, WEPCo Letter to NRC, TAC. Nos. 68586 and 68587, “Supplement to 10 CFR 50.63, Loss of All Alternating Current Power, Point Beach Nuclear Plant, Units 1 and 2,” March 30, 1990.

13. VPNPD-93-182, NRC-93-112, WEPCo Letter to NRC, TAC. Nos. 68586 and 68587, “Supplement to 10 CFR 50.63, Loss of All Alternating Current Power, Point Beach Nuclear Plant, Units 1 and 2,” October 12, 1993.

14. NPM 2003-0795, Revision 1 to Memo NPM 2003-0646, Time-Critical Operator Actions, November 7, 2003.

15. NPL 95-0284, WEPCo Letter to NRC, TAC. Nos. M90613 and M90614, “Supplement to 10 CFR 50.63, Loss of All Alternating Current Power, Point Beach Nuclear Plant, Units 1 and 2,” June 14, 1995.

16. Calculation CN-SEE-111-08-3, Revision 0, “Point Beach 1 & 2 Minimum Condensate Storage Tank Volume for EPU Program,” November 12, 2008.

17. NRC Safety Evaluation "Point Beach Nuclear Plant (PBNP), Units 1 and 2 - Issuance Of License Amendments Regarding Extended Power Uprate (TAC Nos. ME1044 and ME1045)," dated May 3, 2011.

18. Code of Federal Regulations, Title 10, Section 50.2, "Definitions."

19. VPNPD-89-511, NRC-89-114, WEPCo Letter to NRC, "Supplement to 10 CFR 50.63, TAC. Nos. 68586 and 68587, Loss of All Alternating Current Power, Point Beach Nuclear Plant, Units 1 and 2," September 26, 1989.

20. VPNPD-93-058, "Supplement to 10 CFR 50.63, TAC Nos. 68586 and 68587 Loss Of All Alternating Current Power Point Beach Nuclear Plants, Units 1 and 2," March 5, 1993.

21. NRC Letter to WEPCo, Use of Point Beach Nuclear Plant Gas Turbine Generator (G-05) as an Alternate Ac Power Source; 10 CFR 50.63, TAC Nos. M84420 and M84421, "Loss Of All Alternating Current Power," August 12, 1993.

22. NRC Safety Evaluation, "Point Beach Nuclear Plant (PBNP), Units 1 and 2 -Issuance Of License Amendments Re: Auxiliary Feedwater System Modification (TAC Nos. Me1081 and Me1082)," dated March 25, 2011.

23. FPL Energy Letter to NRC, NRC 2009-0030, "License Amendment Request 261 Extended Power Uprate," dated April 7, 2009.

24. NRC Safety Evaluation, "Issuance of License Amendments Regarding Extended Power Uprate," dated May 3, 2011.

A.2 HIGH ENERGY PIPE FAILURE OUTSIDE CONTAINMENT

A.2.1 INTRODUCTION AND EVALUATION CRITERIA

The High Energy Line Break (HELB) program was initiated with the Atomic energy Commission (AEC) letter to Wisconsin Electric Power (WEP) dated December 19,1972 (Mr. Giambusso to Mr. Quale) (Reference 1 and Reference 2). In that letter, the commission stated that the consequences of postulated pipe failures outside of the containment structure, including the rupture of a main steam or feedwater line, need to be adequately documented and analyzed. The NRC's original acceptance of the PBNP response is contained in Reference 3. As part of the Extended Power Uprate (EPU) project, PNBP submitted several updated aspects of the HELB analysis. The changes were evaluated and accepted by the NRC in Reference 5.

The following specific criteria are applicable to the point Beach HELB analyses:

a. The definition of high energy piping systems are systems which have a combined pressure and temperature rating which exceeds a service temperature of 200°F or greater and a design pressure above 275 psig.

b. Normally depressurized lines which are pressurized only for infrequent periodic testing under controlled diagnostic conditions are not considered in the HELB analyses.

c. Coincident or compounded accidents, including natural events, are not considered in the HELB analysis unless the compound accident can be directly caused by the HELB.

d. Pipe motion and jet forces resulting from breaks shall not impair the ability to safely shut down the reactor or impair the ability to cool the reactor core. Safe shutdown is defined as Hot shutdown (MODE 4) for the HELB analyses.

e. Critical leakage cracks are located and oriented to cause worst effects.

A.2.2 DESCRIPTION OF HIGH ENERGY SYSTEMS

A.2.2.1 High energy piping systems are defined as those which have a service temperature of 200°F or greater and a design pressure above 275 psig (Reference 2). The Plant operational conditions under which the definition applies include normal reactor operation and anticipated operational occurrences. Piping systems 1" nominal pipe size and smaller are excluded from HELB review. The piping systems which fall under the definition listed above as determined in Reference 6 are:

a.Main steam

b.Main feedwater

c.Chemical and volume control system (CVCS) letdown

d.Steam generator blowdown

e.Condensate

f.Heater drain tank pump discharge

g.Turbine extraction steam

h. Feedwater heater and MSR vents and drains

A.2.3 DESCRIPTION OF BREAK AND CRACK LOCATIONS

Introduction

The HELB program requires the identification and application of specific criteria which define where a large break or a leakage crack must be postulated in each high energy system outside containment. This section describes those criteria and how they are applied at PBNP.

Locations of Required Postulated Large Breaks in High Energy Lines

a. For high energy systems that do not have a documented dynamic pipe stress analysis, NRC Generic Letter 87-11 (Reference 4) requires that a large break must be postulated at the piping welds to each fitting, valve, or welded attachment. Thus, for these high energy lines without documented dynamic pipe stress analyses, a large break is postulated to occur in every room or compartment through which the line is routed. The specific large break is postulated to occur at the most restrictive or most bounding location within each room or compartment. Calculation PBNP-994-21-06 (Reference 13) specifies the locations where each of these large breaks is postulated to occur. The high energy systems that fall into this category for large break locations are:

   Chemical and volume control system (CVCS) letdown
   Steam generator blowdown
   Condensate
   Heater drain tank pump discharge
   Turbine extraction steam
   Feedwater heater and MSR vents and drains

b. For high energy systems that have a documented dynamic pipe stress analysis, specific methodologies are used for Point Beach, as described in Section A.2.5. The methods described are summarized in Reference 13 and the tables and data contained therein document therein document the specific locations of postulated large breaks for these lines. The high energy lines which fall into this category are:

   Main Steam
   Main Feedwater

Size and Orientation of Large Breaks

The methods to determine the size and orientation of each large break are described in Section A.2.5. The results of those analyses are presented in Reference 13.

Required Postulated Leakage Cracks in High Energy Lines

Where high energy pipes are routed in the vicinity of structures and systems necessary for safe shutdown of the plant, a leakage crack in the piping system is postulated at the most adverse location possible with respect to the affected equipment. The location of the postulated cracks is provided in Reference 13. The methods of determining the size and orientation of the leakage cracks are described in Section A.2.5.

A.2.4 DESCRIPTION OF NEEDED EQUIPMENT

The December 19, 1972 AEC letter and its enclosure (Reference 1), as clarified in January 1973 (Reference 2), required the identification of those systems and components required to detect and mitigate HELB events and to maintain the plant in a safe shutdown condition and to maintain the ability to cool the reactor core. The equipment needed in the postulated HELB events is listed in Reference 19.

A.2.5 METHODOLOGIES FOR LOCATIONS, SIZE AND ORIENTATION OF BREAKS

Methodology for Postulating Large Breaks Locations in Lines with Dynamic Stress Analyses

As discussed in Section A.2.3, PBNP applies specific requirements to determine the location of required postulated large breaks in high energy lines for which a dynamic stress analysis has been performed. The methodologies described in Generic Letter 87-11 (Reference 4) were applied in Reference 7, Reference 8, Reference 9, Reference 10, Reference 11, Reference 12 to identify applicable stresses.

Point Beach reconciled the piping to the ASME 1977 B&PB Code, Section III, Subsection NC, including the Winter 1978 Addenda (Reference 21). Code Equations 9 and 10 from Reference 21 including stress intensification factors are identical to those utilized in the pipe stress analysis.

The piping systems identified in Section A.2.3 above were designed to the USAS AB31.1-1967 Power Piping Code (Reference 20). For purposes of HELB evaluation, the piping was evaluated against the criteria identified for ASME Section III Code Class 2 and 3. There are no ASME Section III Code Class 1 piping systems outside containment at Point Beach. Thus, a large break is postulated to occur at any location that meets any one of the following criteria:

a. Any terminal end

b. Any intermediate location where the circumferential or longitudinal stresses derived on an elastically calculated basis under the loadings associated with an operating basis earthquake (OBE) seismic event and operational plant conditions exceed 0.8 $(1.2S_h + S_A)$. S_h is the allowable stress limit at the operating temperature, and S_A is the allowable stress range for thermal expansion as found in Reference 20.

c. Any intermediate location where the thermal expansion stress term exceeds 0.8 S_A.

Methodology for Determining Size and Orientation of Postulated Large Breaks

Longitudinal breaks in main piping runs or branch runs were examined for pipes of 4" nominal pipe diameter and larger. A longitudinal break is parallel to the pipe axis and oriented at any point around the pipe circumference. The break area is equal to the effective cross-sectional flow area upstream of the break location with the length of the break equivalent to twice the inside pipe diameter. Dynamic forces resulting from such breaks are assumed to cause lateral pipe movements in the direction normal to the pipe axis.

Circumferential breaks were considered in piping runs and branch runs for pipes of less than a 4" nominal diameter. A circumferential break is perpendicular to the pipe axis, and the break area is equivalent to the cross-sectional flow area of the ruptured pipe. Dynamic forces resulting from such breaks are assumed to separate the piping axially and cause whipping in any direction normal to the pipe axis.

Methodology for Determining Size and Orientation of Postulated Leakage Cracks

A leakage crack is defined as a single open crack with a length equal to 1/2 the pipe diameter and a width equal to 1/2 the pipe wall thickness. The orientation of the leakage crack can be in any direction along the pipe at the most adverse location in terms of needed equipment or structures.

A.2.6 METHODOLOGY FOR CALCULATING MASS AND ENERGY RELEASE

This section describes the methodology for calculating mass and energy releases for compartment temperature and pressures. The mass and energy releases used for jet impingement and pipe whip are discussed in Section A.2.8 and Section A.2.9 respectively.

Calculation of mass and energy (M&E) releases from a break or crack are accomplished by running multiple cases to assure that all scenarios are bounded. This assures that the most conservative results are attained, with a trade-off between maximizing break enthalpy and maximizing mass release. Thus, the following two methods are used for temperature limiting cases and pressure limiting cases.

a. For temperature limiting cases throughout most of the Primary Auxiliary Building, Facades and Turbine Hall, the analyses are contained in Reference 28 using the computer code LOFTRAN. The most conservative plant condition is full power at Extended Power Uprate (EPU) conditions. The calculation includes the effects of core thermal power, energy from main feedwater and auxiliary feedwater additions, engineered safeguards systems, sensible heat stored in the RCS and steam generator metal mass and tubing, and reverse steam generator heat transfer. The evaluation methodology maximizes the superheat of the releases.

b. For pressure limiting cases throughout most of the Primary Auxiliary Building, the Facades, and the Turbine Hall, the analyses are found in Reference 14. The most conservative plant condition is hot zero power. These analyses use the Extended Henry-Fauske critical flow model for sub-cooled liquid conditions and the Moody critical flow model for saturated steam conditions.

c. For the CCW Heat Exchanger Room, all pressure and temperature limiting cases are documented in Reference 29 using the RELAP 5 computer code model. The methodology calculates mass and energy using the Moody critical flow model per ANSI/ANS 56.10-1982. The postulated HELB consists of a circumferential guillotine pipe rupture with the two ends completely offset. The flows from each end are comprised of a transient flow followed by a steady state flow which is determined independently. For the transient flow, fictional losses are conservatively neglected. For steady state flow, line losses downsteam of the source to the break are considered.

d. For temperature limiting cases for the Steam Generator Blowdown line in the lower portions of the Facade and for the CVCS Letdown line, the analyses are found in Calculation 2012-0012 (Reference 15).

A.2.7 METHODOLOGY FOR COMPARTMENT PRESSURE AND TEMPERATURE

Calculations of pressure and temperature responses of compartments within the PAB, Facades, and Turbine Hall were performed using the GOTHIC computer code. The buildings, the internal compartments and the net free volumes within them are modeled in a GOTHIC base case, which is based on detailed plant walkdowns and measurements. The heat absorbing slabs considered in the model are also based on plant walkdowns and measurements. All barriers between compartments (wall, floors, ceilings, doors, etc.) are defined in the GOTHIC model. The model for these calculations is found in Reference 15.

The pressure and temperature response calculations are performed by considering the locations of postulated breaks and leakage crack within the plant compartments. The bounding cases are run using the mass and energy releases associated with the limiting break or leakage cracks for the various compartments. Initial conditions for the evaluations include the following:

a. The assumed initial temperature of the volume in each compartment is contained in Reference 17.

b. The assumed initial pressure of each volume is 14.375 psia.

c. The assumed initial relative humidity of each volume is 37 percent. This is based on the minimum value of humidity ratio and maximum outside temperature of 95°F.

The calculations of compartment pressures and temperatures are documented in Reference 17.

A.2.8 METHODOLOGY FOR JET IMPINGEMENT

Jet Thrust Forces

Jet thrust forces that accompany a pipe break are both steady state and time dependent in nature. The steady state forces are due to the blowdown of fluid from some system stagnation pressure, P_o. The time dependent forces are due to the propagation of pressure disturbances in the fluid immediately following pipe break. Both types of forces must be considered in calculating pipe break.

Steady State Thrust Calculation

The generalized steady state thrust equation as developed by Shapiro (Reference 22) is:

$$F = \frac{\dot{m}}{g_c} V_e + (P_e - P_a) A_e \tag{1}$$

Where: $\dot{m}$ = fluid mass flow rate (lb_m/sec)
V_e = fluid exit velocity (ft/sec)
g_c = gravitational constant ($lb_m ft/lb_f\, sec^2$)
P_e = fluid exit pressure (PSF)
P_a = ambient pressure (PSF)
A_e = exit area (ft^2)

A convenient non-dimensional thrust can be defined by dividing through by P_o and A_e obtaining:

$$F/P_o A_e = \frac{\dot{m} V_e}{P_o A_e g_c} + \frac{(P_e - P_a)}{P_o} \tag{2}$$

One dimensional continuity, $\dot{m}$ = ρV and the definition, G = $\dot{m}$/A, can be used with (2) to obtain the following alternate expressions:

$$F/P_o A_e = \frac{G V_e}{P_o g_c} + \frac{(P_e - P_a)}{P_o} \tag{3}$$

and: $$F/P_o A_e = \frac{G^2 A_e}{\rho_e g_c P_o} + \frac{(P_e - P_a)}{P_o}$$

Where: ρ_e is exit mass density (lb_m/ft^3).

Four blowdown situations are considered for rupture of steam and water lines. They are:

a. Blowdown of steam from superheated conditions

b. Blowdown of a steam-water mixture

c. Blowdown of cold water

d. Blowdown of water with flashing from subcooled water conditions.

Superheated Steam

Superheated steam is usually treated as an ideal gas with the gas constant, R, equal to 85.75 ft. lb_f/ lb_m °R and the ratio of specific heats γ, equal to 1.3 (Reference 23). If the flow is further considered isentropic, the thrust parameter becomes (Reference 23):

$$F/P_oA_e = 1.26 - \frac{P_a}{P_o} \quad (4)$$

Friction effects can be considered by assuming the flow process follows the Fanno line as described by Shapiro. (Reference 22) The Fanno analysis predicts thrust parameter will be a function of the pipe friction parameter fL/D, as shown in Figure A.2-8. For the case of fL/D = 0 the Fanno analysis reduces to the inviscid flow case (equation (4)). Flow restrictions will tend to decrease flow rates and can be included using Figure A.2-9 - Figure A.2-11.

Steam Water Mixtures

An equilibrium, two-phase flow model has been developed by Moody (Reference 24) which can be used to predict blowdown of mixtures of steam and water. Moody provides plots of G_{max} as a function of stagnation conditions for friction parameters between 0 and 100. He also provides a plot which can be used to determine exit conditions. For frictionless flows (fL/D = 0), Moody's model gives approximately the same results as (4):

$$F/P_oA_e = \frac{P_a}{P_o} \quad (5)$$

Fauske (Reference 25) has proposed a second model which includes non-equilibrium effects. He compares his model with equilibrium models and concludes that for low steam qualities (x < 2%) and short pipes equilibrium models may not be conservative estimate of thrust for short pipes and low steam qualities. Again, Figure A.2-9 - Figure A.2-11 can be used to include flow restriction effects.

Cold Water Flow

Blowdown of cold water can be treated as flow of an incompressible fluid ($\rho = \rho_o$). For inviscid flow the exit pressure becomes the ambient pressure, P_a and the exit velocity becomes:

$$V_e = \sqrt{\frac{2(P_o - P_a)g_c}{\rho_o}} \tag{6}$$

The thrust parameter is then (Reference 23):

$$F/P_oA_e = 2 - \frac{2P_a}{P_o} \tag{7}$$

Friction effects can be included using the approximate expression:

$$F/P_oA_e = \frac{2}{\left(f\frac{L}{D} + 1\right)} \tag{8}$$

Subcooled Water Flow

Subcooled water blowdown is characterized by flashing of the fluid near the pipe exit. This flashing tends to cause lower thrust levels than those predicted using non-flashing incompressible flow theory. The non-equilibrium model developed by Fauske (Reference 25) is applicable in the subcooled region and can be used to predict subcooled water blowdown. The cold water thrust equation (7) can be used to obtain a quick conservative estimate of subcooled thrust.

Unsteady Flow Thrust

Definition of the unsteady thrust requires an examination of the interaction between the propagation of pressure disturbances and the initiation of blowdown. An approximation can be made by assuming the thrust to be defined by:

$$F/P_oA_e = 1.0 \tag{9}$$

over the period, $0 \le t \le t_1$

Where: $t_1 = 2L / C$ (10)

and: L = length of pipe from break to pressure vessel
= length of pipe from break to flow restriction
C = sonic velocity
= 1600 ft/sec from steam
= 4000 ft/sec for water

For $t > t_1$ thrust is equal to the steady state value.

Fluid Jet Impingement Forces

In the event of a pipe break, the fluid flowing through the pipe emerges out as a jet impinging at nearby structures or equipment. Various blowdown situations are described herein. On emerging from the break point, the jet undergoes free rapid expansion to the ambient pressure at relatively short distance - a few diameters of break area. For this asymptotic distance, momentum, and shear interactions with jet environment can reasonably be neglected. As such, applying forward momentum conservation, the total jet force, F_j, is constant throughout its travel; and, therefore as assumed by Moody (Reference 23).

$$F_j = F \tag{11}$$

where, F is the total thrust force defined in Equation (1). Methods of calculating F are also given there. For the purpose of this report, it is further assumed that F_j remains constant for all distances beyond the asymptotic area. This assumption is conservative. Therefore, the jet pressure at any location along the axis of the jet is given by:

$$P_j(x) = F/A_j(x) \tag{12}$$

where A_j (x) is the expanded jet area at location x along the jet axis. See Figure A.2-8 for system geometry.

Moody (Reference 23) as developed a simple analytical model for estimating the asymptotic jet area for steam, saturated water, and steam/water blowdown situation. Evaluations of LOFT (Reference 26) experimental results tend to indicate that for subcooled water and steam blowdown situations, the jet area expands uniformly at half angle of about 15°, where as steam/water blowdown expands much more rapidly because of large scale water flashing. Results of Moody's analytical analysis agree, at least qualitatively, with LOFT results. In addition, Moody's analytical analysis predicts results of other experiments, as discussed in Reference 23.

In this report, an empirical approach has been adopted combining Moody's analytical model with the uniform half angle approach, as shown in Figure A.2-8. The half angle is conservatively assumed to be $\phi = 10°$.

According to this empirical mode, the distance of jet travel is divided into 3 regions. Region 1 extends to the asymptotic area, at which point jet expansion area is calculated according to Moody's method; in Region 2, jet area remains constant; then in Region 3, the jet expands at half angle $\phi = 10°$. For subcooled water blowdown, this model assumes half angle approach, ϕ 10°, uniformly in all the three regions, since Moody's model is not well applicable for this case.

To follow Moody, extent of region 1 is taken as;

$$x_i = 5D_e \tag{13}$$

and the jet area at location x_1 is given by the equation:

$$\begin{aligned} A_j(x_1) &= \pi \cdot R_{j1}{}^2 \\ &= (A_e G)^2 v_1 / g_c F_j \end{aligned} \tag{14}$$

Where:

D_e = Equivalent diameter of pipe break area
A_e = Pipe break area
R_{j1} = Radius of the expanded jet at location x1. R_j1 is constant in Region 2.
F_j = F, thrust force (Eq. 11)
v_1 = Specific volume. v_1 is calculated as described in Reference 23

Other terms in Eq. 14 are described in 1. Region 2 extends to the location x_2 given by:

$$A_j(x_1) = A_j(x), x = x_2 \tag{15}$$

where A_j (x) is the jet area in Region 3 and is calculated by any one of the following equations;

1. Guillotine break:

$$A_j(x) = A_e\left(1 + \frac{2x}{D_e}\tan\phi\right)^2 \tag{16}$$

where $\phi = 10°$ is the half angle of jet expansion

2. Longitudinal (slot) break;

$$A_j(x) = A_e\left(1 + \frac{2x}{l}\tan\phi\right)\left(1 + \frac{2x}{w}\tan\phi\right) \tag{17}$$

where 1 and w are slot dimensions.

3. Circumferential crack:

$$A_j(x) = A_e\left(1 + \frac{2x}{w}\tan\phi\right)\left(1 + \frac{2x}{l}[1 + 2\tan\phi]\right) \tag{18}$$

In Region 1, additional conservative assumption is made that the jet area increases uniformly from A_e at x = 0, to A_j (x_1) at $x = x_1$, or:

$$A_j(x) = A_e\left[1 + \frac{X}{X_i}\left[\frac{R_{j1}}{R_e} - 1\right]\right]2, for 0 \le x \le x_1 \qquad (19)$$

where $R_e = D_e/2 = A_e/\pi$, and R_{j1} is given by Eq. 14.

Impingement Loads on Targets

Once the jet area A_j is calculated by the method described above, the jet pressure is readily calculated according to Eq. 12, i.e.:

$$P_j = F_j / A_j \qquad (20)$$

and the jet impingement load on the target is given by;

$$F_T = P_j \cdot A_{te} \qquad (21)$$

where A_{te} is the effective target area. Calculation of A_{te} for various geometries is outlined below:

1. Flat Surface

If the target with physical area A_t cancels all the fluid momentum in the jet, then;

$$A_{te} = A_t$$

For the case where target is oriented at angle θ with respect to the jet axis and there is no flow reversal:

$$A_{te} = A_t \sin\theta$$

2. Pipe Surface

Let: D_P = Diameter of pipe, and D_j = Diameter of jet impinging on pipe = $\sqrt{\frac{4A_j}{\pi}}$

Then, for $D_P < D_j$:

$$A_{te} = CA_j$$

where C is pipe curvature factor and $C = 2/\pi$ for $D_p < D_j$;

$$A_{te} = C \cdot A_t$$

where $A_t = D_P \cdot D_j$ (conservative approximation)

3. Deflecting Surface

Effective target surface area, A_{te}, for the targets which deflect the jet rather than totally cancel the fluid momentum in the jet, is calculated as described by Moody (Reference 23)

A.2.9 METHODOLOGY FOR PIPE WHIP

The maximum operating pressure (P) used in the calculations is 900 psig and the maximum temperature, 534°F. The maximum jet thrust (F) for a steam line is equal to 1.26 PA, where A equals the flow area of the pipe. Here the maximum jet thrust is equal to 8.4 kips. Assuming no strain hardening, the hinge moment for the 3 inch Schedule 40 piping is:

$$M_h = 1.28 T_y S_m$$

Where:

T_y = Minimum yield strength at 534°F for A106-GR. B

= 27.5 KSI

S_m = Section modulus

= 1.724 in^3

M_h = 60,700 in-obs

A ruptured pipe will then whip if the cantilevered length of pipe (L_h) normal to the direction of thrust is greater than:

$$L_h = \frac{M_h}{f} = 7.25 \text{ inches}$$

Jet Impingement Forces

Equipment	Jet Force	Local Pressure
Boric Acid Tank	8.4 Kips	14.5 psig
Component Cooling Heat Exchanger	8.4 Kips	14.5 psig
Component Cooling Surge Tank	-----------	2.5 psig

A.2.10 REFERENCES

1. ”General Information Required for Consideration of the Effects of a Piping System Break Outside of containment”, AEC, December 19, 1972.

2. Errata Sheet for “General Information Required for Consideration of the Effects of a Piping System Break Outside of Containment”, AEC, January 24, 1973.

3. “Safety Evaluation Report-High Energy Line Failure Outside of Containment, Point Beach Nuclear Plant Units 1 and 2”, NRC, Dated May 7, 1976.

4. NRC Generic Letter 87-11, “Relaxation in Arbitrary Pipe Rupture Requirements”, June 19,1987.

5. “Point Beach Nuclear Plant Units 1 and 2 - Issuance of License Amendments Regarding Extended Power Uprate (TAC NOS. ME 1044 AND ME 1045), NRC, May 3,2011.

6. Calculation PNBP-994-21-02, Rev.0, High Energy System Selection.

7. Calculation PBNP-994-21-05-P01, Rev.1, Unit 1 Main Steam.

8. Calculation PBNP-994-21-05-P02, Rev.1, Unit 2 Main Steam.

9. Calculation PBNP-994-21-05-P03, Rev.2, Unit 1 Main Feedwater.

10. Calculation PBNP-994-21-05-P04, Rev.2, Unit 2 Main Feedwater.

11. Calculation PBNP-994-21-05-P05, Rev. 1, Unit 1 Steam Supply to AFWPT.

12. Calculation PBNP-994-21-05-P06, Rev.1, Unit 2 Steam Supply to AFWPT.

13. Calculation PBNP-994-21-06, Rev.2, Break and Crack Size/Location Selection.

14. Calculation PBNP-994-21-07, Rev.0, Mass and Energy Releases.

15. Calculation 2012-0012, “HELB GOTHIC Base Model.”

16. Not Used.

17. Calculation 2012-0013, “HELB GOTHIC Analysis.”

18. Not Used.

19. Calculation PBNP-994-21-15, Rev.2, Required Equipment List.

20. USAS B31.1-1967, “Power Piping Code”.

21. ASME B&PV Code, Section III, 1977 with Winter 1978 Addenda.

22. Shapiro, A.H., “The Dynamics and Thermodynamics of Compressible Fluid Flow, “Vol.1, Ronald Press, New Your, New York, 1953.

23. Moody, F.J., "Prediction of Blowdown forces and Jet Thrusts," ASME Publication, June, 1969.

24. Moody, F.J., "Maximum Two Phase Vessel Blowdown form Pipes," G.E. Report APED-4827, 65 APE 11, April 20, 1965.

25. Fauske, Hans K. and Henry, Robert E., "The Two Phase Critical Flow of One-component Mixtures in Nozzles, Orifices, and Short Tubes," ASME Transactions, Journal of Heat Transfer, May 1971.

26. Loft Test, IDO-17242, Idaho Nuclear Corporation, 1968.

27. Not Used.

28. Westinghouse Letter WEP-08-174, "Transmittal of Steamline Break Mass/Energy Releases Outside Containment for the Point Beach Extended Power Uprate Program," December 29, 2008.

29. Point Beach Calculation 2008-12355, Rev.0 "Mass and Energy Calculation for High Energy Line Break in 3" Steam Line within CCW HX Room".

Table A.2-1 JET IMPINGEMENT FORCES ON CABLE SPREADING ROOM WALLS

1. Slot break jet impingement forces on cable-spreading room door and wall from:

   a. 24 in. main steam line nearest wall

(1) Aimed directly at wall -	pressure	83.5 psi
	area	41 ft.^{2}
(2) Aimed towards the door -	pressure	11.51 psi
	area	304.0 ft.^{2}

   b. 24 in. main steam line farthest from wall

(1) Aim to impinge on wall or door -	pressure	20.74 psi
	area	164.5 ft.^{2}

2. Slot break jet impingement forces on cable-spreading room door and wall:

   a. 24 in. turbine bypass line nearest wall

(1) Aimed directly at wall -	pressure	83.5 psi
	area	41 ft.^{2}
(2) Aimed towards the door -	pressure	49.3 psi
	area	68.8 ft.^{2}

   b. 24 in. turbine bypass line farthest from wall:

	pressure	42.41 psi
	area	79.6 ft.^{2}

Table A.2-2 JET IMPINGEMENT FORCES (VARIOUS LOCATIONS)

1. Critical crack jet impingement forces on barrier and non-vital switchgear from:

24 in. main steam line nearest switchgear

(1)	On barrier -	pressure	7.25 psi
		area	6.5 $ft.^2$
(2)	On switchgear 1A01 -	pressure	1.23 psi
		area	36.6 $ft.^2$
(3)	On switchgear 1A02 -	pressure	1.13 psi
		area	53.0 $ft.^2$

2. Critical crack jet impingement forces on the corner control room window from:

24 in. main steam line -	pressure	.258 psi

3. Critical crack jet impingement on concrete block wall between electrical equipment room and main steam pipe chase from:

30 in. main steam line -	pressure	71.4 psi

4. Critical crack jet impingement forces on boric acid tanks from:

3 in. main steam line to auxiliary feed pump -	pressure	0.44 psi
	area	3.36 $ft.^2$

5. Critical crack jet impingement forces on component cooling heat exchangers from:

3 in. main steam line to auxiliary feed pump -	pressure	0.04 psi
	area	34.6 $ft.^2$

Table A.2-3 MASS AND ENERGY USED IN JET IMPINGEMENT AND PIPE WHIP

Assuming Stop Valve Closure on Signal:

T (sec)	Mass Flow (lbm/sec)	Enthalpy (BTU/lbm)	STM Quality
$T_0 = 0$	5,630	1,190	100
$T_1 = 1.85$ or 3.3*	12,670	708	
$T_2 = 1.85$ or 3.5*	19,700	570	4
$T_3 = 7.55$**	19,700	570	4

* 1.85 sec is shortest time until entrainment - assumes only mass from break to SG plus ½ SG steam mass. 3.3 sec. includes decompression of SG, all piping upstream and down, and total steam mass of SG.

** Assumes 6 sec. valve closure time plus 1.55 sec. for piping blowdown.

(1)Data transmitted from Westinghouse via telecon R. Henderson/J. Kendall on April 25, 1973.

Table A.2-4 LIST OF CREDITED PROTECTION FEATURES FOR JET IMPINGEMENT AND PIPE WHIP

FSAR FIGURE No.	DESCRIPTION
Figure A.2-1	Cable Spreading Room Wall Barrier
Figure A.2-2	Non-Vital Switchgear Room Wall Barrier
Figure A.2-3	Control room Window Impingement
Figure A.2-4	Restraint R1 Aux. Steam Supply to Waste Disposal (Valve 1MOV-2020)
Figure A.2-5	Restraint R2 Aux. Steam Supply to Waste Disposal (Valve 1MOV-2020)
Figure A.2-6	Restraint R3 Aux. Steam Supply to Waste Disposal (Valve 2MOV-2020)
Figure A.2-7	Restraint R4 Aux. Steam Supply to Waste Disposal (Valve 2MOV-2020)

Figure A.2-1 CABLE SPREADING ROOM WALL BARRIER

Sheet 1 of 3

[redacted]

Figure A.2-1 CABLE SPREADING ROOM WALL BARRIER
Sheet 2 of 3

[redacted]

Figure A.2-1 CABLE SPREADING ROOM WALL BARRIER

Sheet 3 of 3

[redacted]

Figure A.2-2 NON-VITAL SWITCHGEAR ROOM WALL BARRIER

[redacted]

Figure A.2-3 CONTROL ROOM WINDOW IMPINGEMENT

[redacted]

Figure A.2-4 RESTRAINT R1

[redacted]

Figure A.2-5 RESTRAINT R2

[redacted]

Figure A.2-6 RESTRAINT R3

[redacted]

Figure A.2-7 RESTRAINT R4

[redacted]

Figure A.2-8 PIPE BREAK SCHEMATIC

[redacted]

Figure A.2-9 GUILLOTINE

[redacted]

Figure A.2-10 SLOT - LONGITUDINAL

[redacted]

Figure A.2-11 CIRCUMFERENTIAL CRACK

[redacted]

A.3 CONTROL OF HEAVY LOADS

A.3.1 OVERVIEW

NUREG-0612 (Reference 1) established guidelines to ensure that the probability and consequences of dropping a heavy load on irradiated fuel or equipment required to achieve safe shutdown and continue decay heat removal are acceptably small. Reference 2 and Reference 4 required licensees to submit information detailing how they met or intended to meet the requirements of NUREG-0612.

Reference 2 established a six-month response for "Phase I" submittals, and a nine-month response for "Phase II" submittals. Reference 4 corrected minor errors in Reference 2.

"Phase I" required compliance with Section 5.1.1 of NUREG-0612. The intent was to ensure that all load handling systems at nuclear power plants are designed and operated so their probability of failure is appropriately small for the critical tasks in which they are employed. Phase I consisted of seven general items:

- Defined Safe Load Paths for heavy load handling over or in the vicinity of irradiated fuel or safe shutdown equipment,
- Procedures for heavy load handling over or in the vicinity of irradiated fuel or safe shutdown equipment,
- Training and qualifications for crane operators,
- Design, testing, and inspection of special lifting devices,
- Installation and use of other lifting devices,
- Inspection, testing, and maintenance of overhead cranes, and
- Design standards for overhead cranes

Reference 5 is the Technical Evaluation Report (TER) that accepted the Point Beach responses for Phase I.

"Phase II" required compliance with Section 5.1.2 through 5.1.6 of NUREG-0612 to ensure that, for load handling systems used in areas where their failure might result in significant consequences, either:

1. The cranes and associated lifting devices satisfy the single failure proof criteria, or
2. Conservative evaluations of load handling accidents indicate that the potential consequences of any load drop are acceptably small.

Reference 6 concluded that the risks associated with damage to safe shutdown systems are relatively small because:

1. nearly all load paths avoid this equipment
2. most equipment is protected by an intervening floor
3. of the general independence between crane failure probability and safety-related systems which has been observed
4. redundancy of components.

Reference 6 also stated that the single most important example of the heavy load concern is the loads handled over the open reactor vessel during refueling (such as the reactor vessel head). It also stated that precautions have been and are being taken such that no accidents have occurred. Reference 6 concluded that the objective identified in Section 5.1 of NUREG-0612 for providing "maximum practical defense, in depth" is satisfied by Phase I compliance and that the Phase II analysis did not indicate the need to require further generic action at that time."

Bulletin 96-02 (Reference 15) alerted licensees to the importance of complying with existing regulatory guidelines associated with the control and handling of heavy loads in all MODES other than cold shutdown, refueling, and de-fueled. It further reminded licensees of their responsibilities for ensuring that heavy load activities carried out under their license are performed safely and within the requirements of Title 10 of the Code of Federal Regulations.

The bulletin further required a review of plans and capabilities for handling heavy loads in accordance with NUREG-0612 (Phase I), and Generic Letter 85-11. Reference 16 reported the results of this review for Point Beach to the NRC. Specific representations of that response are included where applicable in the following sections. In Reference 17, the NRC acknowledged receipt of the Bulletin 96-02 response, accepted it, and closed the NRC review of the matter at Point Beach.

In response to specific questions regarding measures that were or would be in place for the final lift of the original Unit 2 reactor vessel head from the vessel to remove fuel, specific one-time commitments and representations were made by Reference 18. Additional supplemental information pertaining to the risk of a reactor vessel head drop was not specific to the one-time lift.

The following sections summarize the PBNP licensing basis for control of heavy loads.

A.3.2 NUREG-0612 PHASE I REQUIREMENTS AND COMMITMENTS

(Reference 5 unless otherwise noted)

Safe Load Paths

The following cranes are cited as needing to comply with NUREG-0612:

Containment Polar Crane (both units)
Auxiliary Building Main Crane
Turbine Building Main Crane
Circulating Water Pumphouse Monorails (N-S and E-W)*
Reactor Pressure Vessel Head Monorails*
Containment Buttress Jib Cranes*
Main Shop Crane*
Jib Crane Over Core Instrumentation Seal Tables*

*Reference 7 and Reference 9 justified removal of these cranes from the scope of NUREG-0612 based on the separation and redundancy of safety-related equipment that could be impacted by a dropped load. However, in Reference 12 it was affirmed that these cranes either met the provisions of NUREG-0612 Section 5.1.1, or would by the completion of the next refueling outage. In the final TER (Reference 5), these cranes are cited as being in scope, but that Safe Load Paths were established only for the other four cranes (Containment Polar, Turbine Hall, and Primary Auxiliary Building cranes).

Use of Safe Load Paths are therefore required for the Containment Polar, Turbine Building and Primary Auxiliary Building Cranes when handling heavy loads (defined as 1750 lbs or greater). Use of a second individual with duties defined by procedure to ensure that the crane operator follows approved Safe Load Paths was deemed an acceptable alternative to permanently marking the Safe Load Paths. In addition, approval by the onsite Safety Review Committee (variously termed Manager's Supervisory Staff or MSS, and Plant Operations Review Committee or PORC, over the life of the plant) of deviations from established Safe Load Paths was found to meet the intent of the guideline.

Various plant modifications, which were installed after the final TER (Reference 5) was issued, led to the establishment of additional Safe Load Paths.

The plant was modified to install two additional emergency diesel generators. As part of the installation, safety related cabling was relocated to beneath the floor of the Unit 2 Turbine Hall truck bay. This was under an existing Safe Load Path. The relocation was reviewed for conformance to NUREG-0612 and found to be acceptable (Reference 24).

To protect buried SSCs that are needed for safe shutdown, a Safe Load Path was established in the east yard area for mobile cranes.

The Unit 1 and Unit 2 Steam Generator Blowdown Heat Exchanger Cranes were installed by Reference 22 and Reference 23 and Safe Load Paths established.

Load Handling Procedures

Load specific procedures meeting the requirements of NUREG-0612 5.1.1(2) are required for the following lifts:

1. Spent Fuel Shipping Cask
2. Resin Cask
3. Reactor Vessel Head
4. Reactor Vessel Internals

Generic procedures incorporating the requirements of NUREG-0612 5.1.1(2) are acceptable for all other lifts.

Crane Operator Training

All crane operators shall be trained, qualified, and conduct themselves in accordance with ANSI B30.2-1976, Chapter 2-3 (“Qualifications for and Conduct of Operators”) with the following approved exceptions:

1. The warning bell will be actuated only as required to advise personnel of crane movement, rather than continuously during crane motion.

2. The main line disconnect switch will not be left open. Use of main or local disconnect switches allow the crane to be deenergized for servicing.
3. The cranes will not be deenergized for normal maintenance since some maintenance requires that the power be on. Alternative safety practices will be used when servicing cranes.
4. Crane controls will not be tested at the beginning of each shift. They will be tested at the beginning of each lifting operation.
5. Medical examinations will include eye examinations to meet the requirements of ANSI B30.2-1976 Sections 2-3.1.2b, 1 and 2.

Special Lifting Devices

The special lifting devices identified in scope are:

1. Reactor Head Lifting Device
2. Upper Internals Lifting Device
3. Reactor Coolant Pump Motor Lifting Device
4. Spent Fuel Transfer Casks and Lifting Devices
5. Not Used
6. Not Used
7. Reactor Vessel 8 Stud Carrier Assembly

The following discussions for design, fabrication and testing and inspection are only applicable to the special lifting devices for the Reactor Head, Upper Internals and RCP Motor. Information on the Spent Fuel Transfer Casks and Lifting Devices can be found in the respective Final Safety Analysis Reports and 10 CFR 72.212 and Certificate of Compliance Evaluation Reports for each Dry Fuel Storage Cask System.

Design

These special lifting devices generally meet the criteria of ANSI N14.6-1978. Specific approved exceptions are taken for:

- Dynamic loads are considered minimal (due to low crane speeds) and have been disregarded,
- Load stress design safety factors less than the Code-required 3 or 5 for the following components of the internals lift rig:
  - Adaptor pin
  - Lift lug pin
  - Side lug pin
  - Sling leg pin

To justify these exceptions, Reference 14 contained extensive design margin analyses, diagrams, and detailed NDE requirements for the special lifting devices.

Fabrication

While a formal quality assurance program was not used in the fabrication of the special lifting devices, a completed review of the manufacturing process (including material selection, welders, welding procedures, and conformance to drawing requirements) was found to be an acceptable alternative.

Testing, Inspection, and Continued Compliance

Annual 150% load testing was waived due to impracticality (internals and head lift rigs) or substantial design margins (reactor pump motor lift rig).

Refueling interval visual inspections and 10-year NDE inspections (Reference 5 and Reference 26) of critical welds was approved in lieu of annual visual inspections. In the event of major maintenance or application of substantial stresses, it was agreed that lifting the designated loads a short distance for 10 minutes, and visually inspecting critical welds of concern was acceptable.

Lifting Devices (Not Specifically Designed)

All other lifting devices shall be designed, fabricated, and proof-tested per the requirements of ANSI B30.9-1971 and NUREG-0612 Section 5.1.1(5) with the following exceptions:

- Slings used in the Turbine Building south of column line 10 and north of column line 13,
- Slings used in the transport of the turbine rotors
- Rather than inspections on a regular basis per Section 9-2.8.1 of ANSI B30.9-1971, inspections may be performed prior to each use.
- Any existing slings that do not meet the requirements of ANSI B30.9-1971 are to be retired. Until retired, such slings are to be derated by a factor of two.

Inspection, Testing And Maintenance Of Cranes

In-scope cranes are inspected, tested, and maintained in accordance with Chapter 2-2 of ANSI B30.2-1976 with the exception of the containment polar cranes. It is not practical to meet the frequencies of ANSI B30.2 for periodic inspection and tests of these limited use cranes. Therefore, these cranes are given an initial inspection in accordance with OSHA requirements prior to use. The major annual inspection, fulfilling the requirements of Chapter 2-2 is performed prior to use in refueling outages.

At the time of the original submittal, refueling outages were every 12 months. Extension of the inspection interval to 18 months coinciding with a longer fuel cycle is consistent with Section 5.1.1(6) of NUREG-0612.

Crane Design

NUREG-0612 Section 5.1.1(7) requires that in scope cranes be designed in accordance with ANSI B30.2-1976, “Overhead and Gantry Cranes”, and CMAA-70, “Specifications for Electric Overhead Traveling Cranes.”

The in scope cranes at Point Beach were designed to EOCI-61, which was later superseded by CMAA-70. Reference 5 contains a reconciliation of 18 specific design criteria that differ between the Code of Construction and those endorsed by NUREG-0612.

It was also committed that the primary auxiliary building crane would be upgraded to meet the single failure proof requirements of Section 5.1.6 and Appendix C of NUREG-0612 (Reference 3).

Interim Protection Measures

In addition to the general requirements delineated above, six interim measures were required to be implemented. Four of these interim measures were encompassed by the Safe Load Paths, Load Handling Procedures, Crane Operator Training, and Crane Inspection, Testing, and Maintenance items discussed above. The two additional items were:

- A revision of the "Refueling and Spent Fuel Assembly Storage" Technical Specification to prohibit movement of heavy loads over and in the spent fuel pool until such time as a single-failure-proof crane was installed, and
- A special review for Heavy Loads Over the Core. Implementation of interim safe load paths, training, maintenance practices, etc. Acceptable completion of this activity was documented in Reference 5.

Reference 3 approved the removal of the Technical Specification restrictions on the movement of heavy loads over the spent fuel pool following completion of modifications to make the primary auxiliary building crane single failure proof.

Phase II Submittals

Phase II implementation of NUREG-0612 was to ensure that all heavy loads that could cause damage to irradiated fuel or safe shutdown equipment due to a load drop would either:

1. Be handled by cranes and lifting devices that satisfy single-failure-proof criteria, or
2. Be analyzed to demonstrate that the consequences of such a load drop would be acceptably small

To be successful, an analysis performed under the second option was required to meet four criteria. Based on calculations assuming an accidental dropping of a postulated heavy load,

I. Releases of radioactive material must produce doses that are equal to or less than 25% of the 10 CFR 100 limits, and

II Damage to fuel and fuel storage racks must not result in a configuration of the fuel such that k_{eff} is larger than 0.95, and

III Damage to the reactor vessel or spent fuel pool is limited so as not to result in water leakage that could uncover the fuel. Makeup water to overcome the leakage must be from a borated source of sufficient concentration if the water being lost is borated, and

IV Damage to redundant or dual safe shutdown equipment will be limited so as not to result in loss of required safe shutdown functions.

Reference 7 transmitted the initial responses to Phase II, and was later supplemented by Reference 8. These responses delineated the cranes capable of carrying loads which could, if dropped, land or fall into the spent fuel pool, on or in the reactor vessel, and/or on equipment necessary to maintain safe shutdown conditions, continued decay heat removal, or spent fuel pool cooling.

Only the primary auxiliary building crane and the containment polar cranes met the criteria for inclusion in the scope of this section of NUREG-0612. Since it was shown that the remaining plant cranes are incapable of impacting redundant or dual safe shutdown equipment from a single heavy load drop event, they were screened out of the requirement to be analyzed to Criterion IV (Reference 7).

A.3.3 AUXILIARY BUILDING CRANE

It was committed that the primary auxiliary building crane would be modified to make it single failure proof (Reference 7). Further commitments to communicate Design Rated Loads (DRL) and Maximum Critical Loads (MCL), etc. were deferred pending selection of a supplier of the modifications. A DRL and MCL of 100 tons were communicated in Reference 11, and was later increased to 125 tons by Reference 13. The commitment to upgrade the crane was part of the basis for Phase I, and was re-iterated in the commitments for Phase II.

The PAB superstructure has been analyzed for the capability of the structure to support and hold the crane with its full rated lift load of 125 tons plus a roof snow load and a concurrent seismic (OBE or SSE) event or a lift of 125 tons plus a roof snow load and design wind loads (Reference 21).

A.3.4 CONTAINMENT POLAR CRANE

A reactor vessel head drop analysis was initiated to determine the consequences of such an event. Reference 8 indicated that the initial analysis (limited to assessing the potential damage to the RCS, and not addressing the potential dose consequences) concluded that severe damage to the safety injection lines and primary loop piping could occur.

Consideration of boron concentration, the maximum permissible K_{eff}, and the potential for positive reactivity addition from a heavy load drop was limited to times when the Programmed and Remote (PaR) inspection device was being handled above a fueled core. This was because procedural controls limit the handling of heavy loads above an exposed core to the PaR device, the upper internals, and the reactor head. Due a combination of geometry and handling precautions for the latter two objects, it is not possible for them to contact fuel assemblies in the core in a way that could credibly cause core geometry changes. Therefore, movement of the PaR device over a core containing fuel assemblies is not allowed (Reference 19).

Subsequent developments prompted the creation of a new type of accident analysis for Point Beach: The Reactor Vessel Head Drop. The details of this analysis are located in FSAR Section 14.3.6. PBNP committed to incorporate the PBNP method of NUREG-0612

Phase 1 compliance into the PBNP FSAR by letter NRC 2005-0094, dated July 24, 2005. (Reference 19)

Reactor Vessel Head Lift

The integrated replacement reactor vessel heads at PBNP involve low headroom lifts. Therefore, measures to specifically minimize the potential for "two-blocking," as defined in NUREG-0612, have been developed. These measures include testing of controls and limit switches and operational restrictions when the load is near its maximum lift height.

NUREG-0612 defines a "two-blocking" event as the act of continued hoisting to the extent that the upper head block and the load block are brought into contact, and, unless additional measures are taken to prevent further movement of the load block, excessive loads will be created in the rope reeving system, with the potential for rope failure and dropping of the load. Of particular applicability to industry-standard handling systems is the potential for the wire rope supporting the load block to be cut or overloaded. This is of special concern with low headroom lifts where the load block is deliberately raised near the upper block in order for the load to clear obstructions. From this position, a stuck relay or operator error, combined with failure of the upper limit switch, could cause a load drop before corrective measures, such as removing power to the crane, could be implemented.

The main hoist of each polar crane is equipped with two independent upper travel limit switches to prevent the possibility of a "two-blocking" incident. The two independent upper travel limit devices are of different design and are activated by independent mechanical means. These devices independently de-energize either the hoist drive motor or the main power supply.

The first limit switch that would be activated is a gear-actuated travel limit. This limit switch is activated by the rotation of the main hoist drum. It is set to actuate prior to a potential "two-blocking" incident. This limit switch de-energizes the hoist drive motor and prevents further movement in the upward direction.

A second counterweight-activated limit switch would be relied upon if the geared limit switch fails. This limit switch would be activated by the physical contact of the lower block with a counterweight connected to the limit switch. The initial contact of the lower block with the counterweight will occur approximately six inches prior to the close of the limit switch. The actual close of the limit switch will occur sufficiently prior to "two-blocking." The limit switch circuit will de-energize the main power supply and consequently apply the hoist braking system.

The independent limit switches are set to ensure that sufficient margin exists between the actuation of these switches and physical contact of the upper and lower blocks. The counterweight-activated limit switch is functionally tested in accordance with maintenance procedures, prior to use if the crane has been idle greater than six months. The gear-actuated upper limit switch is tested daily when the containment crane is in use in accordance with maintenance procedures. Polar crane controls are also checked in accordance with procedures. These checks include initial checks following installation of the radio controls, as well as daily checks when the crane is in use. In addition, prior to lifting the RVH, procedures require a pre-lift inspection to be performed that includes a functional check of the main hoist gear-actuated upper limit switch.

The evolution to move the reactor head from the vessel to the storage stand involves lifting the head vertically, directly above the vessel, to an elevation that permits clearance of the 66-foot elevation interferences. The head is then moved horizontally from above the vessel to a location directly above the storage stand and finally lowered onto the stand. The movement from the stand to the vessel is a reverse of the above movements. The movement of the RVH is controlled by Safe Load Path (SLP) procedures. The SLP provides a path that minimizes crane manipulations and movement while the head is over the vessel.

The head is lifted straight up to the height needed to clear containment 66-foot elevation before any bridge or trolley moves are made. The PBNP refueling cavity design does not have adequate room to allow the head to be moved to a position that completely clears the reactor vessel once the head is above the guide studs. When the head is replaced it is again lifted to a height necessary to clear the containment 66-foot elevation and then moved directly above the vessel, using crane reference marks and then lowered onto the vessel. This sequence minimizes crane manipulations and thus the potential for a crane failure or human performance induced failure.

The integrated RVH assembly has an overall height that is taller than the original RVH assembly. To move the head between the storage stand and the vessel, the bottom flange of the head needs to clear the 66-foot elevation and other physical obstructions attached to the 66-foot elevation, which results in a lift height of 26.4 feet. The installed polar crane main hook has a maximum lift height, as determined by the physical design and limit switch settings. Based on the maximum physical hook elevation prior to "two-blocking" and the replacement head assembly height, the maximum height of the bottom flange of the replacement head is approximately the 69-foot, 5-inch plant elevation (without limit switch settings). The inclusion of the main hook limit switch settings results in a maximum height of the bottom flange of the replacement head at approximately the 67.5-foot plant elevation.

Operational restrictions will be included in procedures height of the bottom of the RVH flange to the 67-foot elevation to prevent actuation of the upper travel limit switches. The restriction will maintain adequate margin below the actuation setpoint of the first upper travel limit switch. This limit is maintained by using physical references and visual level checks during the lift.

The two independent limit switch designs, combined with the testing and operational restriction of the lift height, provide assurance that a “two-blocking” incident potential is minimal.

A.3.5 REFERENCES

1. NUREG-0612, “Control of Heavy Loads at Nuclear Power Plants,” July 1980.

2. NRC Letter, “Control of Heavy Loads,” December 22, 1980.

3. NRC Safety Evaluation, “NUREG-0612 Control of Heavy Loads,” September 3, 1985.

4. NRC Generic Letter 81-07, “Control of Heavy Loads,” February 3, 1981.

5. TER-C5506-382/383, “Control of Heavy Loads at Point Beach Nuclear Plant, Units 1 and 2,” March 2, 1984 (incorporated into NRC Safety Evaluation March 27, 1984).

6. NRC Generic Letter 85-11, Completion of Phase II of "Control of Heavy Loads at Nuclear Power Plants" NUREG-0612", June 28, 1985.

7. WEPCo Letter to NRC, "NUREG-0612 - Control of Heavy Loads at Nuclear Power Plants Transmittal of Nine-Month Response and Updated Six-Month Response Information," January 11, 1982.

8. WEPCo Letter to NRC, "Submittal of Outstanding Response Items NUREG-0612 - Control of Heavy Loads," November 22, 1982.

9. WEPCo Letter to NRC, "Submittal of Additional Information in Response to Draft Technical Evaluation Report NUREG-0612, Control of Heavy Loads," June 30, 1982.

10. Not Used.

11. WEPCo Letter to NRC, "Submittal of Outstanding Information NUREG-0612, Control of Heavy Loads," September 16, 1982.

12. WEPCo Letter to NRC, "Submittal of Additional Information in Response to Draft Technical Evaluation Report NUREG-0612, Control of Heavy Loads," September 28, 1983.

13. WEPCo Letter to NRC, "Transmittal of Additional Information NUREG-0612 - Control of Heavy Loads," February 15, 1983.

14. WEPCo Letter to NRC, "Transmittal of Additional Information NUREG-0612-Control of Heavy Loads," July 23, 1982.

15. NRC Bulletin 96-02, "Movement of Heavy Loads Over Spent Fuel, Over Fuel In the Reactor Core, or Over Safety-Related Equipment," April 11, 1996.

16. WEPCo Letter to NRC, "Response to NRC Bulletin 96-02, Movement of Heavy Loads Over Spent Fuel, Over Fuel in the Reactor Core, or Over Safety-Related Equipment," May 9, 1996.

17. NRC Letter to WEPCo, "Completion of Licensing Action for NRC Bulletin 96-02, Movement of Heavy Loads Over Spent Fuel, Over Fuel in the Reactor Core, or Over Safety-Related Equipment," April 16, 1998.

18. NRC 2005-0050A, NMC Letter to NRC, "Response to Request for Additional Information, Revision 1 NUREG-0612, Control of Heavy Loads Reactor Vessel Head Drop Analysis," April 20, 2005.

19. NRC 2005-0094, NMC Letter to NRC, "Request for Review of Heavy Load Analysis," July 24, 2005.

20. "Point Beach Nuclear Plants, Units 1 and 2 - Issuance of Amendment Re: Incorporation of Reactor Vessel Head Drop Accident Analysis into the Final Safety Analysis Report," September 23, 2005.

21. Automated Engineering Services Corp. Calculation PBNP-305336-S01, Rev. 1, "Structural Analysis of Central PAB with Crane Load of 125 Tons," dated April 3, 2006.

22. Engineering Change EC 12268, Modification to Leave the Crane Runway for the SGBD Heat Exchanger Replacement in Place, Closed April 7, 2009.

23. Engineering Change EC 13249, U2 SGBD HX Handling Equipment, Closed August 3, 2010.

24. SCR 2010-0204, "Heavy Load Handling considerations for Installation of Vital Cabling Beneath U2 Turbine Hall Truck Bay," September 29, 2010.

25. SCR 2012-0005, "Establish a Safe Load Path for Mobile Cranes in the East Yard Area," January 25, 2012.

26. Engineering Change EC 296374, Use of Acoustic Emission Technology as an Alternate Method for NDE of Special Lifting Devices.

A.4 (DELETED)

A.5 SEISMIC DESIGN ANALYSIS

A.5.1 SEISMIC DESIGN CLASSIFICATIONS

All equipment and structures are classified as Class I, and Class II, or Class III as recommended in:

1. TID-7024, "Nuclear Reactors and Earthquakes" August, 1963 and,
2. G. W. Housner, "Design of Nuclear Power Reactors Against Earthquakes," Proceedings of the Second World Conference on Earthquake Engineering, Vol. I, Japan 1960, Pg. 133, 134, and 137.

Class I

Those structures and components including instruments and controls whose failure might cause or increase the severity of a loss-of-coolant accident or result in an uncontrolled release of excessive amounts of radioactivity. Also, those structures and components vital to safe shutdown and isolation of the reactor.

Class II

Those structures and components which are important to reactor operation but not essential to safe shutdown and isolation of the reactor and whose failure could not result in the release of substantial amounts of radioactivity.

Class III

Those structures and components which are not directly related to reactor operation or containment.

When required to maintain a system's safety related functions, the interface between a Class I system and lower Class system is at a normally closed valve, a valve which is capable of remote operation from the control room, or a valve which is capable of self actuation.

Non-Seismic SSC over Seismic SSC (Also known as Seismic II/I or Seismic 2/1)

Class III systems and equipment including pipe are generally not designed to withstand any seismic loads. However, for the "Generic Letter 87-02 Unresolved Safety Issue (USI) A-46" effort, the seismic adequacy of certain PBNP equipment, including the potential interaction between class III and Class I structures, systems and components (SSC), was evaluated (Reference 19). Modifications were made to resolve seismic concerns identified by the review. Subsequent to the Generic Letter 87-02/USI A-46 seismic review effort, Class III structures, systems and components in the power block are now reviewed for earthquake loads if the potential for interaction with safety related SSCs exists. Class III SSC that could interact with Class I SSC are typically identified as Seismic II/I or Seismic 2/1.

All components, systems, and structures classified as Class I are designed in accordance with the following criteria:

1. Primary steady state stresses, when combined with the seismic stresses resulting from a response spectrum normalized to a maximum ground acceleration of 0.04g in the vertical direction and 0.06g in the horizontal direction simultaneously, are maintained within the allowable stress limits accepted as good practice and, where applicable, set forth in the appropriate design standards, e.g., ASME Boiler and Pressure Vessel Code, USAS B31.1 Code for Pressure Piping, ACI 318 Building Code Requirements for Reinforced Concrete, and AISC Specifications for the Design and Erection of Structural Steel for Buildings.

2. Primary steady state stresses when combined with the seismic stress resulting from a response spectrum normalized to a maximum ground acceleration of 0.08g acting in the vertical direction and 0.12g acting in the horizontal direction simultaneously, are limited so that the function of the component, system or structure shall not be impaired as to prevent a safe and orderly shutdown of the plant.

All Class II components are designed on the basis of a static analysis for a maximum acceleration of 0.04g acting in the vertical direction and 0.06g acting in the horizontal direction simultaneously.

The spectrum response curves for the equipment inside the building are generated by the time history technique of seismic analysis. The sample earthquake utilized is that recorded at Olympia, Washington N80E on April 13, 1949. The originally recorded earthquake is scaled to that of .06g. Essentially, the curves are generated by applying the recorded earthquake to a single degree of freedom system, for which the values for damping and natural frequency are varied. Some averaging of the curves is provided to smooth out the erratic response of the earthquake's random behavior. At the high frequency end of the curve, the acceleration levels converge to the peak input value at the location inside the building. Table A.5-2 gives the damping factors used in the design of components and structures. The 2% and 5% damping values given in the table for the containment structure include the soil-structure interaction damping.

The design of Class I Nuclear Steam Supply System Equipment and Supports employs one of three approaches to the problem. The first utilizes the "response spectrum" approach and modal analysis of the dynamic loads imparted by the earthquake. The supports are provided in accordance with actual system response to the earthquake. The second approach provides adequate supports to remove the piping system from the "resonance range."

The third method of analysis applied to Class I Nuclear Steam Supply Equipment and Supports proceeds as follows. A conservative analysis is accomplished by assuming that the natural period of vibration of the structure or components lies at the peak of the floor response spectrum, and that the corresponding response acceleration is used for the analysis at the appropriate damping value. Independent of the method adopted, the following applies:

1. Stresses and deflections resulting from the combined influence of normal loads and the seismic loads due to the design earthquake (ground accelerations of 0.04g acting in the vertical and 0.06g acting in the horizontal direction simultaneously) are calculated and checked against the limits imposed by the design standard.

2. Stresses and deflections resulting from the combined influence of normal loads and the seismic loads due to the assumed hypothetical earthquake (ground accelerations of 0.08g acting in the vertical and 0.12g acting in the horizontal direction simultaneously) are calculated and checked to verify that deflections do not cause loss of function and that stresses do not produce rupture.

For mechanical components of Engineered Safeguards Systems, analysis will be performed on a worst plant basis to determine the response in the frequency range of interest. Modifications will be made as necessary considering potential for resonance responses. The component will then be analyzed using seismic loads as obtained from building response calculations to show that stresses and deflections are within allowable limits and will not result in loss of function.

The seismic design of Class I piping systems in the nuclear plant employed one of three methods: (1) the main steam line in the containment and several other piping systems were treated using the response spectrum techniques coupled with a multidegree of freedom modal analysis including the effect of modal participation factors. The piping seismic restraints were designed in accordance with the dynamic response of the system. (2) Some of the piping systems were provided with adequate restraints to remove the fundamental frequency of the system from the "resonance range." Where the piping system can be assumed rigid with respect to the building, the maximum accelerations and displacements at the attachment points to the building, as determined from the building analysis, are used for design. (3) The major portion of the Class I piping seismic restraints are designed so as to withstand the peak accelerations determined from floor response spectra.

NOTE: The following describes the original method used to seismically qualify Class I equipment. Additional verification of the seismic adequacy of plant mechanical and electrical equipment was performed as discussed in Section A.5.6, Verification of Seismic Adequacy of Equipment per Generic Letter 87-02.

Class I equipment, including heat exchangers, pumps, tanks, valves, motors, and electrical equipment components, are analyzed in one of four methods depending on the relative rigidity of the equipment being analyzed. (1) Equipment which is rigid and rigidly attached to its support structure is analyzed for a g loading equal to the peak acceleration of the supporting structure at the appropriate elevation. (2) Equipment, which is not rigid and therefore potential for response to the support motion exists, is analyzed for the spectral peak of the floor response curve for appropriate damping values. (3) In some instances non-rigid equipment is analyzed using a multidegree of freedom modal analysis including the effect of modal participation factors and mode shapes together with the spectral motions of the floor response spectrum defined at the support of the equipment. The inertial forces, moments, and stresses are determined in each mode. The final seismic stress is determined by summation of individual modal stresses on a square-root-sum-of-the-squares basis. (4) Type testing of selected electrical equipment has been conducted to demonstrate seismic design adequacy as described in WCAP 7397-L. For the analysis of equipment to resist the vertical seismic component, 2/3 of the ground response spectrum curves for the design or hypothetical earthquake are used to determine the acceleration appropriate to the vertical frequency.

Class I equipment, which is located at or below ground level, e.g., pumps and emergency diesel generators (DG), is analyzed using the Housner ground response spectrum defined for the Point Beach site in the FSAR and repeated in Figure A.5-1 and Figure A.5-2. The “g-values” were obtained from the response curves for the appropriate damping values as defined in Table A.5-2.

Engineered Safeguards tanks, e.g., Spray Additive (CS) and Refueling Water Storage (SI), are analyzed for at least ground acceleration of 0.06g in any direction horizontally and 0.04g vertically occurring simultaneously, and in conjunction with other loads, without exceeding allowable stresses. Hydrodynamic analyses of these tanks have been performed using the methods described in Chapter 6 of “U.S. Atomic Energy Commission - TID 7024”.

Heat exchangers associated with the Engineered Safeguards Systems have been analyzed to determine the response in the frequency range of interest to show that stresses and deflections are within allowable limits. The method of dynamic analysis uses a proprietary computer code called WESDYN. This code uses as input; inertia values, member sectional properties, elastic characteristics, support and restraint data characteristics, and the appropriate seismic response spectrum. Both horizontal and vertical components of the seismic response spectrum are applied simultaneously. The modal participation factors are combined with the mode shapes and the appropriate seismic response spectra to give the structural response for each mode. The internal forces and moments are computed for each mode from which the modal stresses are determined. The stresses are then summed using the root mean square method.

Some Class I ventilation fans are mounted on elastomer shock isolation pads with flexible characteristics in the longitudinal, transverse, and vertical directions. The manufacturer supplied the pads' frequency relationships. The spectral acceleration was obtained using the frequency, appropriate damping value, and proper floor response spectrum.

The procedure for determining base shear for the design earthquake acceleration for a Class II item is the same as the procedure used for a Class I item.

A.5.2 SEISMIC CLASSIFICATION OF STRUCTURES AND EQUIPMENT

Particular structure and equipment classifications are given below:

Buildings and Structures	Seismic Class
Containment, including all penetrations and airlocks, the concrete shield, the liner, and the interior structures	I
Containment dome truss structures	III (See Note 1)
Spent fuel pool	I
Control room	I
Diesel generator room	I
Pumphouse (to the extent that water is always available to the service water pumps)	I

Buildings and Structures	Seismic Class
Auxiliary building (except for steel superstructure)	I
Emergency Diesel Generator Building (except stairway enclosure) (Reference 16 and Reference 17)	I
Turbine structure (Reference 4, Reference 5 and Section 10.2.5)	III
Buildings containing conventional facilities, auxiliary building superstructure, and diesel generator building stairway enclosure (See Section 10.2.5)	III
Steam Generator Storage Bldg. (Reference 1)	III

Equipment, Piping, and Supports	Seismic Class
Reactor Control and Protection System including miscellaneous relay racks (Reference 2) (except main feedwater flow transmitters, which are Class III)	I
Radiation Monitoring System	III
ATWS circuit isolation devices (Reference 3)	III
Process Instrumentation and Controls	I
Reactor	I
Vessel and its supports Vessel internals Fuel assemblies RCC assemblies and drive mechanisms Supporting and positioning members In-core instrumentation structure	
Reactor Coolant System	I
Piping and valves containing full system pressure (including safety & relief valves) Steam generators Pressurizer Reactor coolant pumps RCP Oil Collection Supporting and positioning members Reactor Coolant Gas Vent System (Reference 7 & Reference 8) LTOP System (Reference 6)	

Equipment, Piping, and Supports	Seismic Class
Engineered Safety Features	I
Safety Injection System (including safety injection and residual heat removal pumps (ACS), refueling water storage tank, accumulator tanks, residual heat exchangers (ACS), and primary connecting piping and valving)	
Containment Spray System (including spray pumps, spray headers, spray additive tank and primary connecting piping and valving)	
Containment Ventilation System (including fans, coolers, ducts and valves) (Containment Air Sampling System is an ESF but is not Seismic Class I.)	
Main Steam supply to TDAFWPs (Reference 9)	I
Auxiliary Building Ventilation System	III (See Section 9.5)
VNCR - CREFS Subsystem	I (See Section A.5.6.3)
CREFS Backup Filtration System	I (See Section A.5.6.3)
Condensate Storage tanks	III
Pressurizer relief tank	II
Residual heat removal loop	I
PAB Battery and Electrical Equipment Room Ventilating System	I
Component cooling loop	I
Sampling System	II
Spent Fuel Storage Racks (Reference 10)	I
Spent fuel pool cooling loop	I
Spent fuel pool purification loop	I
Fuel transfer tube	I

Equipment, Piping, and Supports	Seismic Class
Emergency Power Supply System	I
Diesel generators, associated fuel oil storage tanks and fuel oil transfer system DC power supply system Power distribution lines to equipment, transformers, switchgear supplying the engineered safety features Control panel boards Motor control centers	
Control Equipment, facilities and lines necessary for the above Class I items	I
The control air supply from the accumulators for pressurizer PORV's (Reference 11)	I
Waste Disposal System	I
Waste holdup tank Sump tank Gas decay tanks Reactor coolant drain tank Waste gas compressor package Waste evaporator Waste evaporator feed pump Sump tank pumps Interconnecting waste gas piping	
Waste Disposal System All elements not listed as Class I (including Blowdown Evaporator)	III
Containment crane	I
Manipulator and other cranes	III
Conventional equipment, tanks and piping, other than Class I and II	III
Service Water pumps and piping, including service water for fire protection of Class I components where required	I
Main Feedwater equipment that isolates the supply of Main Feedwater to the Steam Generators (Reference 12)	III
Fire protection pumps and piping except as noted above	III

Equipment, Piping, and Supports	Seismic Class
Auxiliary Feedwater System (except for Condensate Storage Tanks and some interconnected branch piping) (standby Steam Generator feedpumps and associated components are seismic class I for system pressure boundary integrity.) (Reference 5, Reference 13, Reference 14, and Reference 15)	I
The Chemical and Volume Control System is Class I except:	
Boric Acid Storage Tank	II
Batching tank	II
Evaporator condensate demineralizers	II
Condensate filter	II
Monitor tanks	II
Monitor tank pumps	II
Deborating demineralizers	II
Concentrates holding tank	II
Concentrates holding tank transfer pumps	II
Chemical mixing tank	III
Resin fill tank	III

Note 1:
The containment dome truss structures were originally construction aids with the function to support the containment dome liner and concrete during construction. In the as-left configuration, the truss structures are classified as Seismic Class III structures, as no qualifications or assessments exist for the truss structures to support a higher classification; however the truss structures maintain functions which include providing support to Seismic Class I systems/components and preventing Seismic II/I interaction. Refer to Section A.5.10, for further detail.

A.5.3 CLASS I DESIGN CRITERIA FOR VESSELS AND PIPING

All components of the reactor coolant system and associated systems are designed to the standards of the applicable ASME Code or USAS Code. The loading conditions which are employed in the design of Class I components of these systems, i.e., vessels, piping, supports, vessel internals and other applicable components, are given in Table A.5-3.
This table also indicates the stress limits which are used in the design of the listed equipment for the various loading conditions.

To be able to perform their function, i.e., allow core shutdown and cooling, the reactor vessel internals must satisfy deformation limits presented in Table A.5-1 as well as the stress limits shown in Section 14.3.3. For this reason the reactor vessel internals are treated separately. The load conditions used in reactor coolant system component design also include a case assuming simultaneous occurrence of a hypothetical earthquake and design basis accident. This is the case of a hypothetical earthquake occurring during the steady-state portion of the design base accident. The analysis shows that RCS integrity would not be further compromised by this occurrence.

<u>Piping, Vessels, and Supports</u>

The reasoning for selection of the load conditions and stress limits given in Table A.5-3 is as follows. For the design earthquake, the Class I components are designed to be capable of continued safe operation, i.e., for the condition of normal loads and design earthquake loading.

In the case of the assumed hypothetical earthquake, it is only necessary to ensure that critical components do not lose their capability to perform their safety function, i.e., shut the plant down and maintain it in a safe condition. This capability is ensured by maintaining the stress limits as shown in Table A.5-3. No rupture of a Class I pipe can be caused by the occurrence of the assumed hypothetical earthquake.

Careful design and thorough quality control during manufacture and construction and periodic inspection during plant life, ensures that the independent occurrence of a reactor coolant pipe rupture is extremely remote. If it is assumed that a reactor coolant pipe ruptures, the stresses in the unbroken legs will be equal to or less than those allowed per loading condition 4 of Table A.5-3.

For the extremely remote events represented by the hypothetical earthquake, or the design basis accident, or the hypothetical earthquake in combination with the steady state portion of the design basis accident, the design of Class I piping and components is checked for no loss of function, i.e., contain fluid and allow fluid flow. This is assured by limiting the various stress combinations within the limit curves as presented in WCAP 5890, Revision 1, as modified by Note 1 of this Section. This minimum margin of safety between the design stress limit and the expected collapse condition is that for the case of pure tension and is defined as:

$$\frac{S_{ultimate} - S_{design}}{S_{design}}$$

In the more practical cases of design, piping and vessels will always experience some combination of tension and bending. For these combinations of loads the margin of safety is larger than that for pure tension, as shown by the limit curves contained in WCAP-5890, Revision 1. Therefore, it is conservative to base the margin of safety on pure tension.

<u>Reactor Vessel Internals - Design Criteria for Normal Operation</u>

The internals and core are designed for normal operation conditions and subjected to loads of mechanical, hydraulic, and thermal origin. The loading of the structure due to the design earthquake as well as the operational transients is considered as an upset condition.

The stress criteria of ASME Section III, which are used as a guide in the design of the internals and core with exception of those fabrication techniques and materials which are not covered by the Code such as the fuel rod cladding including the operating earthquake, are based on a limit design theory with the assumption that the material behavior is perfectly plastic with no strain-hardening. The criteria are chosen so that the structure has a sufficient margin against the limit load for primary stresses and that shakedown to elastic behavior is assured for secondary stresses.

Section 14.3.3 lists the stress criteria for the core and internals integrity analysis in the case of primary system pipe rupture. The limitations established on the internals are concerned principally with the maximum allowable deflections and/or stability of the parts. For the blowdown accident the assumption of a perfectly plastic material with yield stress equal to the initial yield stress of the actual material at temperature is too conservative. Therefore, for this case we are in agreement with the NRC developed stress criteria, which are based on the same limit analysis concept as the criteria of Section III, but take credit for the strain hardening capabilities of the materials. The allowable stress values given in Section 14.3.3 are based on the actual stress-strain curve of 304 SS at 600°F.

The members are designed under the basic principles of: (1) maintaining distortions within acceptable limits, (2) keeping the stress levels within acceptable limits, and (3) prevention of fatigue failures.

To study the seismic response of the reactor internals, a dynamic, elastic study is performed as follows. The maximum stresses are obtained by combining the contributions from the horizontal and vertical earthquakes by adding components. These stresses are then superimposed on the normal operating stresses. The following paragraphs describe the horizontal and vertical contributions for the standard 2-loop, 12 ft. core, reactor internals.

Horizontal Earthquake Model and Procedure

The reactor building with the reactor vessel support, the reactor vessel, and the reactor internals are included in this analysis. The mathematical model of the building, attached to ground, is similar to that used to evaluate the building structure. The reactor internals are mathematically modeled by beams, concentrated masses, and linear springs.

All masses, water, and metal are included on the mathematical model. All beam elements have the component weight or mass distributed uniformly, e.g., the fuel assembly mass and barrel mass. Additionally, wherever components are attached somewhat uniformly their mass is included as an additional uniform mass, e.g., baffles and formers acting on the core barrel. The water near and about the beam elements is also included as a distributed mass. Horizontal components are considered as concentrated mass acting on the barrel. This concentrated mass also includes components attached to the horizontal members since this is the media through which the reaction is transmitted. The water near and about these separated components is considered as being additive at these concentrated mass points.

The concentrated masses attached to the barrel represent the following; (1) the upper core support structure, including the upper vessel head and one-half the upper internals; (2) the upper core plate, including the thermal shield and the other half of the upper internals; (3) the lower core plate, including one-half of the lower core support columns; (4) the lower one-half of the thermal shield; and (5) the lower core support, including the lower instrumentation and the remaining half of the lower core support columns.

The modulus of elasticity is chosen at its hot value for the three major materials found in the vessel, internals, and fuel assemblies. In considering shear deformation, the appropriate cross-sectional area is selected along with a value of Poisson's ratio. The fuel assembly moment of inertia is derived from experimental results by static and dynamic tests performed on fuel assembly models. These tests provide stiffness values for use in this analysis.

Modal analysis, plus the response spectrum method (Note 2) is used in this analysis. Natural frequencies and normal modes are obtained by the use of a transfer matrix method.

The maximum deflection, acceleration, is determined at each particular point by summing the absolute values obtained for all modes. Shear forces and bending moments are determined, and the earthquake stresses are calculated.

Analytical Model for Vertical Earthquake Model and Procedure

The reactor internals are modeled as a single degree of freedom system for vertical earthquake analysis using all the spring constants from the ground to the core.

Spent Fuel Storage

The spent fuel storage pool is constructed of reinforced concrete and is Class I seismic design. The entire interior basin face and transfer canal is lined with stainless steel plate. The spent fuel storage racks are designed in accordance with Regulatory Guide 1.29, Revision 2 as seismic Class I components. The structural analysis of the racks has considered all the loads and the load combinations specified in the NRC Standard Review Plan. The honeycomb steel structure of the rack not only provides a smooth all welded stainless steel box structure to preclude damage during normal and abnormal load conditions, but also provides an additional margin of safety in the form of internal structural damping created by the large areas of load bearing surface between boxes with array.

Design Criteria for Abnormal Operation

The abnormal design condition assumes blowdown effects due to a reactor coolant pipe double-ended break. For this condition, the criteria for acceptability are that the reactor be capable of safe shutdown and that the engineered safety features are able to operate as designed. Consequently, the limitations established on the internals for these types of loads are concerned principally with the maximum allowable deflections. The deflection criteria for critical structures under abnormal operation are presented in Table A.5-1.

Reactor Vessel

The criteria for movement of the reactor vessel, under the worst combination of loads, i.e., normal plus the assumed hypothetical earthquake or normal plus reactor coolant pipe rupture loads, assures that the movement of the reactor vessel will not exceed the clearance between the reactor coolant piping and the surrounding concrete nor cause stresses in excess of the levels set forth in Table A.5-3.

The relative motions between reactor coolant system components are controlled by the structures which are used to support the reactor vessel, the steam generators, the pressurizer and the reactor coolant pumps, and will result in stress levels as set forth in Table A.5-3.

The relative motions between components will be controlled to within Table A.5-1 limits by the stiffness of the supporting structure. Where provisions for thermal growth are necessary, snubbers will be provided to serve as limit stops under seismic and pipe rupture loading.

ANALYSIS NOTES

Note 1

1. Use material data to develop stress-strain curves. Typical stress-strain curves of Type 304 Stainless Steel, Inconel 600, and SA 302B low alloy steel at 600° F have been generated from tests using graphs of applied load versus cross-head displacement as automatically plotted by the recorder of the tensile test apparatus. The scale and sensitivity of the test apparatus recorder assure accurate measurement of the uniform strain.

   For materials other than these three, stress-strain curves have been developed by conservative use of pertinent available material data (i.e., lowest values of uniform strain and initial strain hardening). When the available data was not sufficient to develop a reliable stress-strain curve, three standard ASTM tensile tests of the material in question were performed at design temperature. These data were conservatively applied in developing a stress-strain curve as described above.

2. Normalize the ordinate (stress) of the stress-strain curves to the measured yield strength.

3. Use 20% of uniform strain as defined on the curve developed under Item 1 as the allowed membrane strain.

4. Establish the normalized stress ratio at 20% of uniform strain on the normalized stress ratio-strain curves developed under Item 2.

5. Establish the value of the membrane stress limit. Multiply the normalized stress ratio in Item 4 by the applicable code yield strength at the design temperature to get the membrane stress limit. As an alternate, the actual physical properties as determined from standard ASTM tensile tests on specimens from the same heats were used to determine the membrane stress limit. If such an approach was adopted, sufficient documentation was provided to support the actual material properties used.

   Develop limit curves for the combination of local membrane and bending stresses.

Note 2

Shock and Vibration Handbook, edited by Harris and Crede, Volume 3, Chapter 50, "Vibration of Structures Induced by Seismic Waves", by George W. Housner.

A.5.4 SEISMIC DESIGN OF CLASS I STRUCTURES

Introduction

The following supplementary information is provided in support of the seismic design of structures and equipment for the Point Beach Nuclear Plant.

a. With reference to FSAR Figure 5.1-14, the sum of the lumped masses representing the containment structure (designated WT) is 39,000,000 lbs. The sum of the weights of the interior concrete and equipment shown as dashed circles is 22,000,000 lbs, of which the steam generators contribute about 1,500,000 lbs.

Higher modes (more than two) have been checked and found to be insignificant. Absolute values of the forces are added instead of the RMS (as in Section 5.1.2.4) when the RMS at the ground is smaller than the actual ground acceleration.

b. The following is a description of a sample calculation demonstrating the method used in determining the seismic response of a Class I building for the purpose of restraining piping.

The results of the seismic analysis conducted on the Point Beach Nuclear Power Plant for the control room building are presented herewith. This same procedure has been utilized for the purpose of providing a seismic design of other structural systems and Class I equipment.

The control room building is enclosed in the turbine building but is considered as an independent structure, since no fixed connections exist between the two buildings. Essentially the structure consists of exterior and interior concrete shear walls in both N-S and E-W direction connected by lighter concrete slabs. For the purpose of the seismic analysis a mathematical model is constructed consisting of lumped masses and stiffness coefficients. A brief sketch of the building and a superimposed outline of the model is shown on Figure A.5-3 and Figure A.5-8.

The control room building is subjected analytically to a horizontal ground acceleration of 0.06g (g = unit acceleration of gravity) for the design earthquake and a horizontal ground acceleration of 0.12g for the hypothetical earthquake. The results of the analysis are discussed in the form of internal forces and geometric behavior. The methods utilized are presented with a discussion of how the seismic analysis is conducted.

Results

A summary of the mass model values is shown in Figure A.5-8 and Figure A.5-9.

The results of analyzing the model for natural frequencies and mode shapes are presented in Figure A.5-10. The mode shapes are plotted and labeled to show how the structure vibrates at its various natural frequencies. Damping values of the various materials are also presented in this analysis.

The result of the seismic analysis due to the design earthquake are presented in Figure A.5-4 through Figure A.5-7 showing internal forces and geometric behavior. For the hypothetical earthquake, all values have to be increased by a factor of 2.0.

This analysis is provided for the E-W direction. However, the building acts not as much as a flexible structure but as a rigid body interacting with the soil. The analysis performed on the N-S direction provided results identical to the E-W. On this basis the analysis applies to both directions.

Method Of Analysis

The methods used in conducting the seismic analysis consist essentially of five steps. The first step involves the formulation of a mathematical model. The natural frequencies and mode shapes of the model are determined during the second step. Appropriate damping values are selected in the third step upon evaluation of the materials and mode shapes. The fourth step is the appropriate description of the earthquake. The response of the structure to the earthquake is determined in the fifth step.

The mathematical model of the structure is constructed in terms of lumped masses and stiffness coefficients. At appropriate locations within the building, points are chosen to lump the weights of the structure. Between these locations, properties are calculated for moments of inertia, cross-sectional areas, effective shear areas, and lengths (Figure A.5-8 and Figure A.5-9). Appropriate properties are obtained for the soil upon which the building rests. These properties are utilized to obtain soil stiffness coefficients. The properties of the model are utilized in an IBM computer program, STRESS, along with the unit loads to obtain the flexibility coefficients of the building at the mass locations.

The natural frequencies and mode shapes of the structure are obtained by Bechtel computer program, CE617 (Bechtel proprietary program). This program utilizes the flexibility coefficients and lumped weights of the model. The flexibility coefficients are formulated into a matrix and inverted to form a stiffness matrix. The program then uses the technique of diagonalization by successive rotations to obtain the natural frequencies and mode shapes. The results are shown in Figure A.5-10.

Damping values for the structural system are selected based upon evaluation of the materials and mode shapes. Appropriate damping values of individual materials are presented in Table A.5-2. Evaluation of the mode shapes makes possible the selection of damping values to be associated with each mode. Both first and second mode indicate mainly activity due to the elasticity of the underlying soil. First mode shows the soil to be contributing to a translating effect and only a little rocking of the building. The second mode indicated also translation but the amount of rocking is considerably larger. For both modes flexure of structure is negligible.

Due to this strong effect from soil elasticity and the relatively small flexibility of the structure, no proportional combining of damping values are necessary. In determining the response of the building to the earthquake the spectrum response technique is utilized. For this technique the earthquake is described by a spectrum response curve as shown in Figure A.5-1 and Figure A.5-2. Curves are provided for both the design and hypothetical earthquake. From the curves, acceleration levels are determined as associated with the natural frequency and damping value of each mode. These acceleration levels are shown on Figure A.5-10. The standard spectrum response technique uses these values to determine inertial forces, shears, moments, and displacements per mode. These results are then combined on the basis of the sum of the absolute values to obtain the structural response. The process is accomplished by a Bechtel computer program CE641 (Bechtel proprietary program).

A.5.5 SEISMIC DESIGN OF SERVICE WATER PIPING

(The scope of this section applies only to the service water piping in the “Pump House” extending from the discharge of the service water pumps to the point where the piping leaves the pump house building.)

A static “g” load analysis was performed in each of the two horizontal directions as well as in the vertical direction. The direction for one horizontal loading is taken normal to the axis of the most slender piping profile and the other direction is taken along that axis. In this load analysis, no restraint credit is taken for sliding supports.

For the Class I system, the boundaries of the piping system model used in the seismic analysis extends well beyond the stress analysis boundaries set by the first normally closed valve. This is done to provide confidence that the loading influence of the non-essential piping outside of (but attached to) the critical Class I portion of the system model is adequately accounted for.

At a given point, the largest stress due to one horizontal seismic loading is combined with the stress due to the vertical seismic loading to obtain the total seismic stress. All stresses include stress intensification factors as recommended by USAS B31.1.0-1967.

The static "g" factor used in the before mentioned loading analysis was obtained from the ground response spectra for the Hypothetical Basis Earthquake (0.12g) between 0.5% and 1.0% critical damping as follows:

1. The use of the ground response spectra is justified because the "Pump House" is a very rigid low profile structure. The ground response is essentially transmitted to the building contents without amplification.

2. From the before mentioned response spectra, the peak acceleration between 0.5% and 1.0% of critical damping is 0.5g. The peak acceleration occurs at a period of about 0.2 seconds.

3. The unrestrained piping system has calculated vibrational periods of approximately T=.23 seconds and T=.13 seconds. Since both of these periods are near the peak of the response curve described in sub paragraph (2), the static analysis was based on an acceleration of 0.5g. This is a conservative practice whereby any restraints that are imposed to satisfy stress requirements tend to stiffen the system so that the acceleration imposed in service will be less than the 0.5g designed for.

4. The longitudinal stress at a cross section are calculated per Paragraph 102.3.2 (d) of USAS B31.1.0-1967. The stresses are combined as follows:

   $$\sigma = S_p + S_{ew} + S_{ee}$$

   Where S_{ee} is the larger of:

   $$S_{ee} = S_{e1} + 2/3S_{e2} \text{ or } S_{e3} + 2/3S_{e2}$$

   Where:

   S_P = Longitudinal stress due to internal pressure

   S_{ew} = Longitudinal stress due to dead load weight

   S_{e1} & S_{e3} = Longitudinal stress due to the horizontal seismic loading

   S_{e2} = Longitudinal stress due to the vertical seismic loading

   For the design earthquake (.06g), the values for S_{e1} , S_{e2} , and S_{e3} are taken as one half of the values used for the Hypothetical Earthquake.

The stresses calculated per the before mentioned procedure for both the Hypothetical Earthquake and Design Earthquake have been compared with the FSAR criteria and all conditions have been satisfied.

NOTE: Seismic response spectra have been developed for the Pump House. In lieu of the above static "g" load analysis, seismic analysis may be performed using the Response Spectrum Methodology, see Section A.5.7.

A.5.6 VERIFICATION OF SEISMIC ADEQUACY OF EQUIPMENT PER NRC GENERIC LETTER 87-02

A.5.6.1 Evaluation of Existing Plant Equipment

Seismic adequacy evaluation of then-existing plant equipment necessary to bring the plant to, and maintain it in, a safe shutdown condition during the first 72 hours following a safe shutdown earthquake (SSE) was performed in response to Generic Letter (GL) 87-02, "Verification of Seismic Adequacy of Mechanical and Electrical Equipment in Operating Reactors, Unresolved Safety Issue (USI) A-46." This was done using the SQUG "Generic Implementation Procedure (GIP) for Verification of Nuclear Plant Equipment," Revision 2. For these evaluations, safe shutdown was defined as the reactor subcritical with a minimum shutdown margin between 1% and 2.77% and the reactor coolant average temperature at or greater than 540°F. Documentation of the methodology used, equipment evaluated and the results of these evaluations are contained in Reference 18 and Reference 19 is the NRC SE of the USI A-46 implementation program.

A.5.6.2 Seismic Design and Verification of Modified, New and Replacement Equipment

Modified, new, or replacement equipment classified as Seismic Class I may be seismically designed and verified (after installation) for seismic adequacy using seismic experience data in accordance with a methodology developed by the Seismic Qualification Utility Group and approved by the NRC as documented in both of the following:

1. Seismic Qualification Utility Group (SQUG), GENERIC IMPLEMENTATION PROCEDURE (GIP) FOR SEISMIC VERIFICATION OF NUCLEAR PLANT EQUIPMENT, Revision 2, Corrected February 14, 1992; as modified by

2. U. S. Nuclear Regulatory Commission, "SUPPLEMENT NO. 1 TO GENERIC LETTER (GL) 87-02 THAT TRANSMITS SUPPLEMENTAL SAFETY EVALUATION REPORT NO. 2 (SSER No. 2) ON SQUG GENERIC IMPLEMENTATION PROCEDURE, REVISION 2, AS CORRECTED ON FEBRUARY 14, 1992 (GIP-2)," May 22, 1992.

The scope of equipment to which the SQUG Methodology above may be applied includes certain classes of active mechanical and electrical equipment as specified in the SQUG GIP, electrical relays, cable trays and conduit, heat exchangers, and tanks (modification of existing tanks only). As stated in SSER-2, "For new installations and newly designed anchorages in modifications or replacements, the GIP-2 criteria and procedures may also be applied, except that the factor of safety currently recommended for new nuclear power plants in determining the allowable anchorage loads shall be met."

A.5.6.3 Control Room Emergency Filtration System (CREFS)

CREFS has two parts: 1 – a portion of existing Control Room Ventilation (VNCR) and 2 - the CREFS Backup Filtration System. These two subsystems do perform a safety function and are required to meet Quality Related (QR) requirements.

VNCR - CREFS Subsystem

The AST SE (NRC Safety Evaluation, Reference 20) allows application of seismic experience data evaluations for AST only. Use of seismic experience data for Ventilation or HVAC other than AST will require NRC approval – see Reference 20, Section 2.4.2.2.

Existing, new and replacement (non-like-for-like) equipment, except as noted below in CREFS Backup Filtration System, can be qualified using one or more of the following:

1. Seismic experience data as provided for in the SQUG GIP,
    a. See FSAR Section A.5.6.1 for existing equipment and
    b. See FSAR Section A.5.6.2 for modified, new or replacement equipment,
2. EPRI Topical Report 1014608, “Seismic Evaluation Guidelines for HVAC Duct and Damper Systems, Revision to 1007896” dated December 2006, or
3. Full seismic I qualification.

CREFS Backup Filtration System

As stated in Reference 20, the CREFS Backup Filtration units along with associated ductwork and bubble tight dampers are to be installed and supported to Class I requirements, as defined in FSAR Appendix A.5. Since the CREFS Backup Filtration subsystem was added c. 2011, the supports and ductwork did not exist prior to implementation of AST. The supports were designed to meet both OBE and SSE requirements. Supports and bubble tight dampers are not qualified by use of seismic experience data. Modifications and repairs to the CREFS Backup Filtration subsystem are to be designed and installed to Class I requirements. Modifications and repairs cannot use seismic experience data as a means of seismic qualification.

A.5.7 SEISMIC ANALYSIS OF PIPING SYSTEMS

Piping may be generally classified according to the dynamic response of the system. Systems are considered rigid if they are supported and restrained in such a manner so as to cause the first mode of vibration to occur in the rigid range of the response spectrum curve. All other piping is considered flexible.

The rigid range of the response spectrum curve is defined as that portion in which there is no significant change in spectral acceleration with increasing frequencies. If piping is supported and restrained so that the first mode of vibration occurs in this range, it is classified as rigid.

Rigid piping systems are analyzed with static equivalent loads corresponding to the acceleration in the rigid range of the response spectrum curves for the applicable floor elevations. Both horizontal and vertical static equivalent loads are applied to the rigid piping systems. The amplitude of the component for the horizontal and vertical direction are combined on an absolute sum basis. The larger of the combined N-S and vertical or E-W and vertical components are used in the stress computations. The stresses are then computed in accordance with "ASME Boiler and Pressure Vessel Code Section III-Nuclear Power Plant Components, 1971," hereafter referred to as ASME Section III. The rigid range is dependent on site seismicity and building response and as such will be determined on a case basis. The rigid range typically begins between 20 to 33 cps.

Piping that cannot be classified as rigid by the method defined above is assumed to be flexible and the analytical technique must incorporate consideration of pipe natural frequencies in addition to the fundamental frequency.

The dynamic analysis of flexible piping systems is performed using the response spectrum method. A flexible piping system is idealized as a mathematical model consisting of lumped masses connected by massless elastic members. The lumped masses are carefully located so as to adequately represent the dynamic and elastic properties of the piping system. The three-dimensional stiffness matrix of the mathematical model is determined by the direct stiffness method. Axial, shear, flexural, and torsional deformations of each member are included. For curved members, a decreased stiffness is used in accordance with ASME Section III. The mass matrix is also calculated.

After the stiffness and mass matrix of the mathematical model are calculated, the natural frequencies of piping system and corresponding mode shapes are determined using the following equation:

$$(\underline{K} - W_n^2 \underline{M})\underline{\phi}_n = \underline{0}$$

Where:

$\underline{K}$ = stiffness matrix
W_n = natural circular frequency for the nth mode
$\underline{M}$ = mass matrix
$\underline{\phi}_n$ = mode shape matrix for the nth mode
$\underline{0}$ = zero matrix

The Given's or the Jacobi method is used in the solution of the above equation. The mode shapes are normalized as follows:

$$\underline{\phi}_n{}^t \underline{M} \underline{\phi}_n = 1$$

A generalized mass matrix is calculated, and should correspond to:

$$\underline{\phi}^t \underline{M} \underline{\phi} = \underline{I}$$

Where:

$\underline{\phi}$ = matrix of mode shapes

$\underline{\phi}^t$ = transpose of $\underline{\phi}$
$\underline{I}$ = identity matrix.

The response spectrum method is then used to find the maximum response of each mode:

$$\underline{Y}_n(t)_{max} = \frac{\underline{\phi}_n^t \underline{M}\underline{D}S_{an}}{W_n^2 M_n}$$

Where:

S_{an} = spectral acceleration value for the nth mode
$\underline{D}$ = earthquake vector matrix, used to introduce earthquake direction to the response analysis
$\underline{\phi}_n{}^t$ = transpose of the nth mode shape
M_n = generalized mass of the nth mode; equals one by Equation
$\underline{Y}_n$ = generalized coordinate matrix for the nth mode.

Using the maximum generalized coordinate for each mode, the maximum displacements associated with each mode are calculate.

$$\underline{V}_n = \phi \underline{Y}_n(t)_{max}$$

The square root of the sum of the squares method is used to combine the modal responses:

$$V_i = \sqrt{V_{i1}^2 + V_{i2}^2 + \dots V_{in}^2}$$

Where:

V_i = displacement at ith due to the response of n modes
V_{in} = displacement at ith point due to nth mode.

Once the appropriate displacements have been determined for each mass and each mode, the effective inertia forces for each mode are computed:

$$\underline{Q}_n = \underline{K}\underline{V}_n$$

Where:

$\underline{Q}_n$ = effective inertia force matrix due to nth mode
$\underline{V}_n$ = displacement matrix due to nth mode.

The effective acceleration for each mode is calculated:

$$\underline{a}_n = \underline{M}^{-1}\underline{Q}_n$$

Where:

$\underline{a}_n$ = effective acceleration matrix due to n^{th} mode
$\underline{M}^{-1}$ = the inverse of mass matrix.

After the effective inertia forces have been determined, the internal forces and moments for each mode are also calculated:

$$\underline{S}_n = \underline{b}\underline{Q}_n$$

Where:

$\underline{S}_n$ = internal force and moment matrix due to the nth mode
$\underline{b}$ = force transformation matrix
The effective inertia forces, the effective accelerations, and the internal forces and moments are combined with the square root of the sum of the squares method. For each piping system, the analysis is performed three times; once for horizontal excitation in the N-S direction, once for the E-W direction, and once for vertical excitation. Each horizontal analysis is combined with vertical analysis. The basis of combination is the square root of the sum of the squares. The maximum internal force or moment, restraining forces or moments, effective inertia force, effective acceleration, or displacement is the larger number as obtained from either of the horizontal (combined with vertical) analyses. The stresses are then computed from the internal forces and moments and are combined with other loadings (e.g., weight pressure and thermal).

A.5.8 MASONRY WALL DESIGN

NRC Bulletin No. 80-11, "Masonry Wall Design," required identifying all masonry walls in the plant which are in proximity to or have attachments from safety-related piping or equipment such that wall failure could affect a safety related system. The Bulletin also required a reevaluation of the design adequacy of these walls to determine whether they will perform their intended function under all postulated loads and load combinations.

In response to Bulletin 80-11, masonry walls that could affect safety related equipment were identified and re-evaluated using criteria submitted to the NRC by Wisconsin Electric letter dated August 14, 1981. The criteria is enclosed with the letter as Appendix B, Criteria For the Reevaluation of Concrete Masonry Walls For the Point Beach Nuclear Plant, Revision 1, August 15, 1981. The NRC accepted use of these criteria in Safety Evaluation Report, "Masonry Wall Design," transmitted to Wisconsin Electric by letter dated May 11, 1982. These criteria remain applicable to future modifications affecting masonry walls whose failure could affect a safety-related system.

A.5.9 SEISMIC ANALYSIS OF THE DIESEL GENERATOR BUILDING (DGB)

The mathematical model of the DGB consisted of several stick elements representing the reinforced concrete shear walls with nodes at each floor level. Each of these nodes was connected by rigid links, representing the rigid diaphragm action of the floor slab. The soil-structure interaction was accounted for by using six soil springs (three translations and three rotations in a Cartesian system), attached to the rigid foundation mat. The Housner horizontal design spectra with a peak ground acceleration of 0.06g for an operating basis earthquake and 0.12g for a safe shutdown earthquake were used as ground input motions. The vertical component of ground acceleration was 2/3 of the magnitude of the horizontal component. The responses (deflections, moments, shears, etc.) of the building were obtained through the response spectrum method using one set of soil spring values.

Response spectra curves for equipment located in the DGB were obtained through time history analysis. The analysis started with the design earthquake time histories input at the bottom of the mathematic model of the DGB. The time histories for the three directions of motion (two horizontal and one vertical), at each floor were then obtained as a result of the analysis. By applying these floor time histories to a single-degree-of-freedom oscillator, response spectra curves were obtained for each of the floors of the DGB. (Reference 16 and Reference 17)

A.5.10 STRUCTURAL QUALIFICATION OF THE CONTAINMENT DOME CONSTRUCTION TRUSS STRUCTURES

The containment dome construction truss structures were initially erected during site construction to support the containment dome liner steel during the initial 8 in. pour of the containment dome concrete (Section 5.6.1.2). The truss structures were subsequently lowered away from the dome liner approximately 3 in., when the initial 8 in. of concrete reached design strength, but prior to placing the balance of the dome concrete. The truss structures have remained in the lowered position since construction within each respective containment building and are used to provide support for:

- the containment spray piping ring headers (including a portion of upstream piping),
- a portion of the containment air recirculation cooling system (VNCC) ductwork,
- the post-accident containment ventilation (PACV) piping,
- and miscellaneous lighting and associated conduits.

The design functions of the truss structures in the post-construction configuration include:

- Maintaining sufficient structural integrity to preclude seismic interaction with Seismic Class I SSCs located adjacent to (i.e., containment liner and building) and below the truss structures before, during, and after a design basis accident or event.
- Providing support without impeding the design functions of the attached Seismic Class I systems:
    - Containment spray piping
    - Containment air recirculation cooling system (VNCC) ductwork.
- Providing support to non-seismic equipment (PACV piping, lighting and associated conduit) to preclude seismic interaction with Seismic Class I SSCs.

The original containment dome construction truss structures functioned as a construction aid, and had no seismic classification specified in the FSAR. In the as-left configuration, the truss structures were documented as having been evaluated to demonstrate that the trusses and attached piping would not collapse from applied loading due to the maximum earthquake (Reference 35). The truss structures in the original as-left configuration were implicitly classified as Seismic Class III structures (since no assessments, documentation, or evaluations existed to support higher seismic classification). The design functions, as listed above, of the truss structures included providing support to Seismic Class I SSCs.

In the post construction configuration with the attached supported systems, the truss structures and the attached containment spray ring headers did not meet the code of record acceptance limits as required per Section A.5.1, Seismic Design Classifications.

The containment dome construction truss structures were evaluated (Reference 30) for seismic loading (without any applied pipe support loads) to determine the stiffness and seismic amplification of the containment response spectra at the El. 105 ft. for evaluation of the containment spray piping. A revision to the truss structural analysis (Reference 30) was not performed to incorporate all applied loading (pipe support loads, ductwork, etc.) for all postulated loading scenarios (design basis accident and event loads).

To address the attached equipment loading on the truss structures, a structural analysis was pursued. Initial assessment of the truss structures to evaluate for the applied piping and seismic loads determined that the as-built configuration of the truss was not consistent with the as-designed and previously analyzed truss. The as-found configuration was analyzed and determined to result in stresses that were nonconforming to the original code of record (AISC 6th Ed.) (Reference 36). Subsequent walkdowns and follow-on reviews of photos of the truss structures identified that, in addition to the as-built discrepancies, the clearance between the trusses and the containment liner at certain locations around the containment circumference were postulated to result in contact between the trusses and the containment liner due to thermal expansion during a design basis accident or truss deflection from applied seismic loads during a design basis event. The potential contact load would result in code (see Section 5.1.2.2, Mechanical Design Bases) nonconformances for the containment liner/structure. Additionally, field walkdowns identified that the anchor bolts for the truss structure bearing housings at several truss locations were positioned at or near the end of the slotted hole. The as-found configuration would limit thermal movement of the truss structures during a design basis accident, leading to additional stresses that did not conform to the design code of record. The legacy nonconformances were identified in both Units 1 and 2. Modifications (Reference 31) (Reference 32) were completed to relocate the anchor bolts centered within the slotted hole of the bearing housing to permit free thermal growth of the truss.

To address the nonconformance to site design basis guidelines and codes of record, a risk-informed license amendment request (LAR) was submitted (Reference 21). The basis of the LAR was a risk-informed evaluation (Reference 33) that was performed to determine the risk associated with acceptance of the trusses in the as-built configuration for Unit 2, and an as-modified configuration for Unit 1 (see discussion below), considering the occurrence of a seismic or thermal event (Reference 21).

To support the risk-informed evaluation, a series of engineering calculations were performed to identify the limiting truss members and the associated fragility values for the truss structures for both applied design basis thermal and seismic loading. The structural calculations served a secondary function of demonstrating that the truss structures maintained structural integrity before, during, and after applied loading from a design basis accident or event. The engineering calculations used alternate evaluation methods and acceptance criteria, as the evaluated structures/components did not meet the original design criteria. The alternate evaluation methods and acceptance criteria, which are different than the original codes of record, formed the basis to support the risk evaluation, and upon regulatory approval, became the codes and guidelines to be used for current and future evaluation of the truss structures.

The following guidance and criteria are applicable to the evaluation of the trusses (Reference 28):

- The ground seismic input is the site specific ground motion response spectra (GMRS) as documented in Reference 34.
- In-structure seismic response spectra are determined through soil-structure interaction (SSI) analysis. Ground motion time histories shall meet Section 2.4 of ASCE/SEI 43-05 with the limitations identified in NUREG/CR-6926.
    - Soil damping is as determined as part of the SSI analysis.
    - Damping for the truss structures is 7%.
    - Damping for the containment spray piping attached to the truss structures is 4%.
    - Damping for the containment structure is 5%.
- AISC N690-1994(R2004), American National Standard Specification for the Design, Fabrication, and Erection of Steel Safety-Related Structures for Nuclear Facilities, is used as the code for evaluating the truss structural components, using the increased allowable stresses for dead load and seismic load combinations and dead load and thermal load combinations.
    - For truss members of the upper and/or lower chord that do not meet the limits of AISC N690-1994(R2004), the maximum permissible strain is limited to 1.5% for combined axial and flexure or flexure only.
- The allowable contact load on the containment liner is based on guidance in ASME B&PV Code, Section III, Division 1, 1983, Appendix F:
    - The allowable load under seismic or design basis accident loads is the minimum of the load that develops a maximum primary stress intensity of 0.9Su (ultimate strength) and 2/3 of the maximum sustainable load.
    - Liner integrity for applied cyclic loading is assessed by comparing the accumulation in strains and the change in strains between cycles, in combination with the fatigue curve from Figure 1-9.1 of ASME Boiler and Pressure Vessel Code, Section III, 1983.
    - Localized exceedance of permissible concrete strain truss contact points, with an allowable limit of 0.003 in/in per ACI 318-63.
    - The concrete compressive strength is based on the compressive strength from test data as permitted in ACI 318-63.

Note: The above criteria are limited in application to the truss structures and adjacent or supported equipment near the truss structures which was used to resolve the nonconformances addressed in Reference 21.

All of the equipment supported by the truss structures, such as the containment spray piping, PACV piping, associated pipe supports, VNCC ductwork, lighting, and associated conduits shall use the design code of record for evaluation.

The above criteria was used to calculate the seismic fragility and a thermal probability of failure for the trusses and attached components for use in the probabilistic risk assessment (Reference 33), based on which the trusses were accepted. The analyses evaluated Unit 1 assuming completion of a modification to trim the truss structures at six designated locations to increase clearance between the trusses and the containment liner, and evaluated Unit 2 in the as-found/post-construction condition with no modifications pending. Moving forward, future evaluations/modifications for the trusses and/or attached components shall follow the above criteria.

To meet the new acceptance criteria (Reference 21), the following modification (Reference 23) was completed:

- A modification to the Unit 1 truss structures to improve clearances between the construction trusses and the containment liner at six truss locations.

Containment spray pipe support SI-301R-1-H202 was identified as requiring modification to the U-bolt size (diameter) based on original support drawings. As part of the work order to implement the truss modification (Reference 23) it was determined the as-installed U-bolt was larger than noted on the support drawings and acceptable without modification (Reference 37).

The clearance modification to Unit 1 results in stress reduction and a configuration bounded by the Unit 2 thermal fragility analysis. The supporting calculations demonstrated that following completion of the Unit 1 truss modification, structural integrity, i.e., the ability to support carried loads and not interfere with supported equipment functions, was maintained in both Units with adequate margin.

The risk informed resolution of the nonconformances included implementation of new thermal and seismic limits to initiate assessment of the construction trusses, equipment supported by the trusses, and the containment/containment liner, as necessary, for any event exceeding the specified limits. Any event reaching or exceeding the specified limit(s) requires Unit shutdown and inspection and/or analysis to ensure the affected structures/components can withstand a subsequent design basis accident without adversely impacting the SSCs' design function(s).

THERMAL LIMIT	VALUE
Unit 1 maximum containment atmospheric temperature	227°F (Reference 26)
Unit 2 maximum containment atmospheric temperature	236°F (Reference 26)

SEISMIC LIMIT	VALUE
Horizontal peak ground acceleration	0.05g (Reference 27)
Vertical peak ground acceleration	0.04g (Reference 27)

The risk-informed resolution of the code nonconformances was approved by License Amendment Nos. 263 to Renewed Facility Operating License No. DPR-24 and 266 to Renewed Facility Operating License No. DPR-27 dated March 26, 2019 (Reference 22). The truss structures continue to remain classified as Seismic Class III structures as no assessments, documentation, or evaluations have been developed to support higher seismic classification as the required input necessary for higher seismic qualification does not exist and cannot be replicated (i.e., material test reports, weld inspection, weld procedures and qualifications, final as-built dimension validation, etc.). The truss structures' design functions remain unchanged following the resolution of the nonconformances, which includes continuing to provide support to Seismic Class I SSCs.

A.5.11 REFERENCES

1. NRC Safety Evaluation dated September 30, 1983, Amendment No. 75 to Facility Operating License No. DPR-24.

2. WE Letter to NRC, VPNPD-91-112, "Status Update Electrical Distribution System Functional Inspection Point Beach Nuclear Plant Units 1 and 2," dated March 28, 1991.

3. NRC Safety Evaluation Dated September 17, 1986, "Safety Evaluation of Topical Report (WCAP-10858)," "AMSAC Generic Design Package."

4. WE Letter to NRC, "Additional Response To NRC Generic Letter 81-14," Point Beach Nuclear Plant, Units 1 and 2, dated May 4, 1982.

5. NRC Letter, Status Report and Technical Evaluation Report, "Seismic Qualification Of The Auxiliary Feedwater System," Point Beach Nuclear Plant Units 1 and 2, dated January 16, 1985.

6. NRC Safety Evaluation, Amendment Nos. 45/50 to Facility Operating License Nos. DPR-24 and DPR-27 for the Point Beach Nuclear Plant, Units 1 and 2, "Low Temperature Overpressure Mitigating Systems," dated May 20, 1980.

7. NRC Letter, "NUREG-0737 Item II.B.l, Reactor Coolant System Vents - Point Beach Nuclear Plant Units 1 And 2," dated September 22, 1983.

8. WE Letter to NRC, "Reactor Coolant System Gas Vent System Point Beach Nuclear Plant, Units 1 and 2," dated June 18, 1982.

9. NRC Safety Evaluation, Addendum No. 5 to the Safety Evaluation in the Matter of Point Beach Nuclear Plant Units 1 and 2, dated November 2, 1971.

10. NRC Safety Evaluation, Amendment Nos. 35/41 to Facility Operating License Nos. DPR-24 and DPR-27 for the Point Beach Nuclear Plant, Units 1 and 2, "Modification of The Spent Fuel Storage Pool," dated April 4, 1979.

11. WE Letter to NRC, "Reactor Vessel Overpressurization," Point Beach Nuclear Plant, Units 1 and 2, dated December 20, 1976.

12. NRC Safety Evaluation, "Main Steam Line Break with Continued Feedwater Addition," Point Beach Nuclear Plant, Units 1 and 2, dated October 8, 1982.

13. WE Letter to NRC, "Final Resolution of Generic Letter 81-14 Seismic Qualification of Auxiliary Feedwater System," Point Beach Nuclear Plant, Units 1 And 2, dated April 26, 1985.

14. NRC Safety Evaluation, "Seismic Qualification of the Auxiliary Feedwater System," Point Beach Nuclear Plant Units 1 And 2, dated September 16, 1986.

15. WE Letter to NRC, "Seismic Qualification of the Auxiliary Feedwater System," Point Beach Nuclear Plant Units 1 and 2, dated December 15, 1982.

16. VPNPD-93-171, “Design Summary for the Installation of Two additional Emergency Diesel Generators - Point Beach Nuclear Plants, Unit 1 and 2,” dated September 24, 1993 and attached Report REP-0026, “PBNP Diesel Project Design Submittal,” Revision 0, dated September 21, 1993.

17. NRC Safety Evaluation 94-003, “Emergency Diesel Generator Addition Project, Point Beach Nuclear Plant,” October 24, 1994.

18. US NRC Generic Letter 87-02, USI A-46 Resolution, Seismic Evaluation Report, Revision 1, dated January 1996.

19. NRC SE, “Response to Supplement No. 1 to Generic Letter 87-02 for the Point Beach Nuclear Plant, Units 1 and 2,” dated July 7, 1998.

20. US NRC SE, “Amendment No. 240 to Renewed Facility Operating License No. DPR-24 and Amendment No. 244 to Renewed Facility Operating License No. DPR-27, NextEra Energy Point Beach, LLC, Point Beach Nuclear Plant, Units 1 and 2, Docket Nos. 50-266 and 50-301,” dated April 14, 2011.

21. License Amendment Request 278, Risk-Informed Approach to Resolve Construction Truss Design Code Non-conformances, dated March 31, 2017.

22. US NRC Safety Evaluation, "Amendment No. 263 to Renewed Facility Operating License No. DPR-24 and Amendment No. 266 to Renewed Facility Operating License No. DPR-27, NextEra Energy Point Beach, LLC, Point Beach Nuclear Plant, Units 1 and 2, Docket Nos. 50-266 and 50-301," dated March 26, 2019 (ML18345A110).

23. EC 291725, Modification to Unit 1 Containment Dome Truss to Increase Available Horizontal Liner Gap; includes SI-301R-1-H202 modification.

24. US NRC Safety Evaluation, "Amendment No. 267 to Renewed Facility Operating License No. DPR-24, NextEra Energy Point Beach, LLC, Point Beach Nuclear Plant, Unit 1, Docket No. 50-266," dated September 25, 2020 (ML20241A058).

25. Not Used.

26. Calculation 11Q0060-C-036, Thermal Evaluation of Units 1 and 2 Containment Dome Trusses for Lesser Events.

27. Calculation 11Q0060-C-037, Seismic Evaluation of Units 1 and 2 Containment Dome Trusses for Lesser Events.

28. Calculation 11Q0060-RPT-002, Methodology and Criteria to Determine the Strength Capacity of the Point Beach Nuclear Plant Containment Dome Trusses and Attached/ Adjacent Components in Support of a Risk-Informed License Amendment Request.

29. Not Used.

30. Calculation 6904-15-TR, Calculation for Adequacy of Containment Dome Construction Truss.

31. EC 281440, U1C Dome Truss Bearing Box Bolted Connection Work.

32. EC 281403, U2C Dome Truss Bearing Box Bolted Connection Work.

33. Probabilistic Risk Assessment Evaluation PBN-BFJR-17-019, Rev. 1, Point Beach Units 1 & 2 Construction Truss PRA Evaluation.

34. Correspondence NRC 2014-0024, Dated March 31, 2014, Subj. NextEra Energy Point Beach, LLC, Seismic Hazard and Screening Report (CEUS Sites), Response NRC Request for Information Pursuant to 10 CFR 50.54(f) Regarding Recommendation 2.1 of the Near-Term Task Force Review of Insights from the Fukushima Dai-ichi Accident.

35. Correspondence PBB-W-3162, Dated July 15, 1970, Subj. Containment Dome Trusses Seismic Analysis.

36. AR 01750123, Unit 1 & 2 Containment Dome Truss Analysis Preliminary Results.

37. AR 02425033, As-Found Support U-Bolt Larger Than Shown on Support Drawing.

Table A.5-1 INTERNALS DEFLECTIONS UNDER ABNORMAL OPERATION (INCHES)

	Calculated Deflection (Preliminary)	Allowable Limit	No Loss-of-Function Limit
Upper Barrel expansion/compression (to assume sufficient inlet flow area/and to prevent the barrel from touching any guide tube to avoid disturbing the RCC guide structure).	0.072	3	6
Upper Package axial deflection (to maintain the control rod guide structure geometry).	0.005	1	2
RCC Guide Tube cross section distortion (to avoid interference between the RCC elements and the guides.)	0	0.035	0.072
RCC Guide Tube deflection as a beam (to be consistent with conditions under which ability to trip has been tested).	0.2	1.0	1.5
Fuel Assembly Thimbles cross section distortion (to avoid interference between the control rods and the guides).	0	0.035	0.072

Table A.5-2 DAMPING FACTORS

Type of Condition and Structure	Design Earthquake	Hypothetical Earthquake
Welded Steel Plate Assemblies	1%	2%
Welded Steel Framed Structures	2%	2%
Bolted Steel Framed Structures	2.5%	5%
Interior Concrete Equip. Supports	2%	2%
Reinforced Concrete Structures on Soil	5%	7.5%
Prestressed Concrete Containment Structure on Piles	2%	5%
Vital Piping Systems*	0.5%	0.5%
Soil Damping	5%	5%
Verification of Electrical and Mechanical Equipment and Anchorage**		5%
Verification of Vertical Welded Steel Tanks**		4%

* For the Unit 1 main steam line outside of containment, with a support configuration that includes energy absorbers, the damping factors range from 0.5% - 4.3% for the design earthquake, and from 0.5% - 17% for the hypothetical earthquake. For the Unit 2 main steam line outside of containment, with a support configuration that includes energy absorbers, the damping factors range from 0.5% - 3.6% for the design earthquake, and from 0.5% - 20% for the hypothetical earthquake.

** Refer to Section A.5.6

Table A.5-3 LOADING CONDITIONS AND STRESS LIMITS
Sheet 1 of 6

This table reflects the License Bases as historically docketed with the NRC in the referenced documents. The contents of this table do not preclude the appropriate use of later Codes and Standards as approved by the NRC in 10 CFR 50.55a and as permitted without prior NRC approval under the conditions of 10 CFR 50.59. For the design Code used for specific systems, structures, or components, see the applicable section of the FSAR.

Definitions[1, 2]

1. Normal Conditions: Any condition in the course of system start-up, operation in the design power range, and system shutdown, in the absence of Upset, Emergency, or Faulted Conditions.

2. Upset Conditions: Any deviations from Normal Conditions anticipated to occur often enough that design should include a capability to withstand the conditions without operational impairment. The Upset Conditions include those transients which result from any single operator error or control malfunction, transients caused by a fault in a system component requiring its isolation from the system, transients due to loss of load or power, and any system upset not resulting in a forced outage. The estimated duration of an Upset Condition shall be included in the Design Specifications -- The Upset Conditions include the effect of the specified earthquake for which the system must remain operational or must regain its operational status.

3. Emergency Conditions: Any deviations from normal conditions which require shutdown for correction of the conditions or repair of damage in the system. The conditions have a low probability of occurrence but are included to provide assurance that no gross loss of structural integrity will result as a concomitant effect of any damage developed in the system. The total number of postulated occurrences for such events shall not exceed twenty-five (25).

4. Faulted Conditions: Those combinations of conditions associated with extremely low probability postulated events whose consequences are such that the integrity and operability of the nuclear energy system may be impaired to the extent where considerations of public health and safety are involved. Such considerations require compliance with safety criteria as may be specified by jurisdictional authorities. Among the Faulted Conditions may be a specified earthquake for which safe shutdown is required.

1. Summer 1968 Addenda to the ASME B&PV Code, Section III.
2. 3rd Amendment to the License Application, dated 11 February 1970.

Table A.5-3 LOADING CONDITIONS AND STRESS LIMITS
Sheet 2 of 6

PRESSURE VESSELS[2]

	Loading Conditions	Stress Intensity Limits	Note
1.	Normal Conditions	(a) $P_m \leq S_m$	
		(b) P_m (or P_L) + $P_B \leq 1.5S_m$	1
		(c) P_m (or P_L) + $P_B + Q \leq 3.0S_m$	2
2.	Upset Conditions (Normal + OBE)	(a) $P_m \leq S_m$	
		(b) P_m (or P_L) + $P_B \leq 1.5S_m$	1
		(c) P_m (or P_L) + $P_B + Q \leq 3.0S_m$	2
3.	Emergency Conditions	(a) $P_m \leq 1.2S_m$ or $P_m \leq S_y$, whichever is larger	
		(b) P_m (or P_L) + $P_B \leq 1.5 * 1.2S_m$ OR	3
		P_m (or P_L) + $P_B \leq 1.5\ S_y$, whichever is larger	3
4.	Faulted Conditions[3] (Normal + DBE, Normal + DBA, Normal + DBE + DBA')	(a) $P_m \leq 1.2S_m$	4, 5
		(b) $P_L + P_B \leq 1.2 * 1.5S_m$	
		(c) $P_L + P_B + Q \leq (1.8+1.5)\ S_m$	

3. The stress intensity limits originally listed cited the "Design Limit Curves of WCAP-5890, Rev. 1…". The equations listed are the bases for the curves taken from the same document. The use of the curves (and these equations) was contingent on incorporating changes that were pending to WCAP-5890 in Revision 2. Those changes are discussed in detail in Note 1 of Appendix A as documented in the 3rd Amendment to the License Application, dated 11 February 1970.

Table A.5-3 LOADING CONDITIONS AND STRESS LIMITS
Sheet 3 of 6

where:

P_m	=	primary general membrane stress intensity
P_L	=	primary local membrane stress intensity
P_B	=	primary bending stress intensity
Q	=	Secondary stress intensity
S_m	=	stress intensity value from ASME B&PV Code, Section, III, Nuclear Vessels.
S_y	=	minimum specified material yield strength

DBE[4]	=	Hypothetical Earthquake
OBE	=	Design Earthquake
DBA	=	Design Basis Accident
DBA'	=	Steady-state Portion of Design Basis Accident

4. Also termed "SSE" for "Safe Shutdown Earthquake."

Table A.5-3 LOADING CONDITIONS AND STRESS LIMITS
Sheet 4 of 6

PRESSURE PIPING[2]

	Loading Conditions	Stress Limits	Note
1.	Normal Conditions	$P \leq S$	
2.	Upset Conditions	$P \leq 1.2S$	
3.	Emergency Conditions	$P \leq 1.2S$	
4.	Faulted Conditions[3]	$P_m \leq 1.2S$ $P_L + P_B \leq 1.2 * 1.5S$[5]	4

where:

P = Principal Stress
S = allowable stress from USAS B31.1, Code for Power Piping

5. The effective multiplier for this equation was increased to 2.4S on a case-by-case bases when evaluating existing piping in response to IEB 79-14 by letter NPC-27869 "Further Response to Bulletin 79-14" dated 9 June 1980.

Table A.5-3 LOADING CONDITIONS AND STRESS LIMITS
Sheet 5 of 6

EQUIPMENT SUPPORTS[2]

	Loading Conditions	Stress Limits
1.	Normal Conditions	Within working limits
2.	Upset Conditions	Within working limits
3.	Emergency Conditions	Within material yield strength after load redistribution*
4.	Faulted Conditions	Within material yield strength after load redistribution*

* Higher stress values can be adopted if a plastic instability analysis of the support and supported component/system is performed.

Material	F (y) (KSI)	Stress Limits	F (B) (KSI)	F (T) (KSI)	F (V) (KSI)
ASTM - A36	36	Working Yield	24 32.4	22 32.4	14.5 19.4
ASTM - A514 ASTM - A517	100	Working Yield	66 90	60 90	40 54
ASTM - A490	125	Working Yield	82.5 112.5	75 112.5	32 67.5

Working stress limits correspond to loading conditions 1 & 2.
Yield stress limits correspond to loading conditions 3 & 4.

F (y) = Yield Stress
F (B) = Bending Stress
F (T) = Tensile Stress
F (V) = Shear Stress

Table A.5-3 LOADING CONDITIONS AND STRESS LIMITS
Sheet 6 of 6

NOTES FOR TABLE Table A.5-3

NOTE: 1 The limits on local membrane stress intensity ($P_L \leq 1.5S_m$) and primary membrane plus primary bending stress intensity (P_m(or P_L) $+P_b \leq 1.5S_m$) need not be satisfied at a specific location if it can be shown by means of limit analysis or by tests that the specified loadings do not exceed 2/3 of the lower bound collapse load as per paragraph N-417.6(b) of the ASME B&PV Code, Section III, Nuclear Vessels.

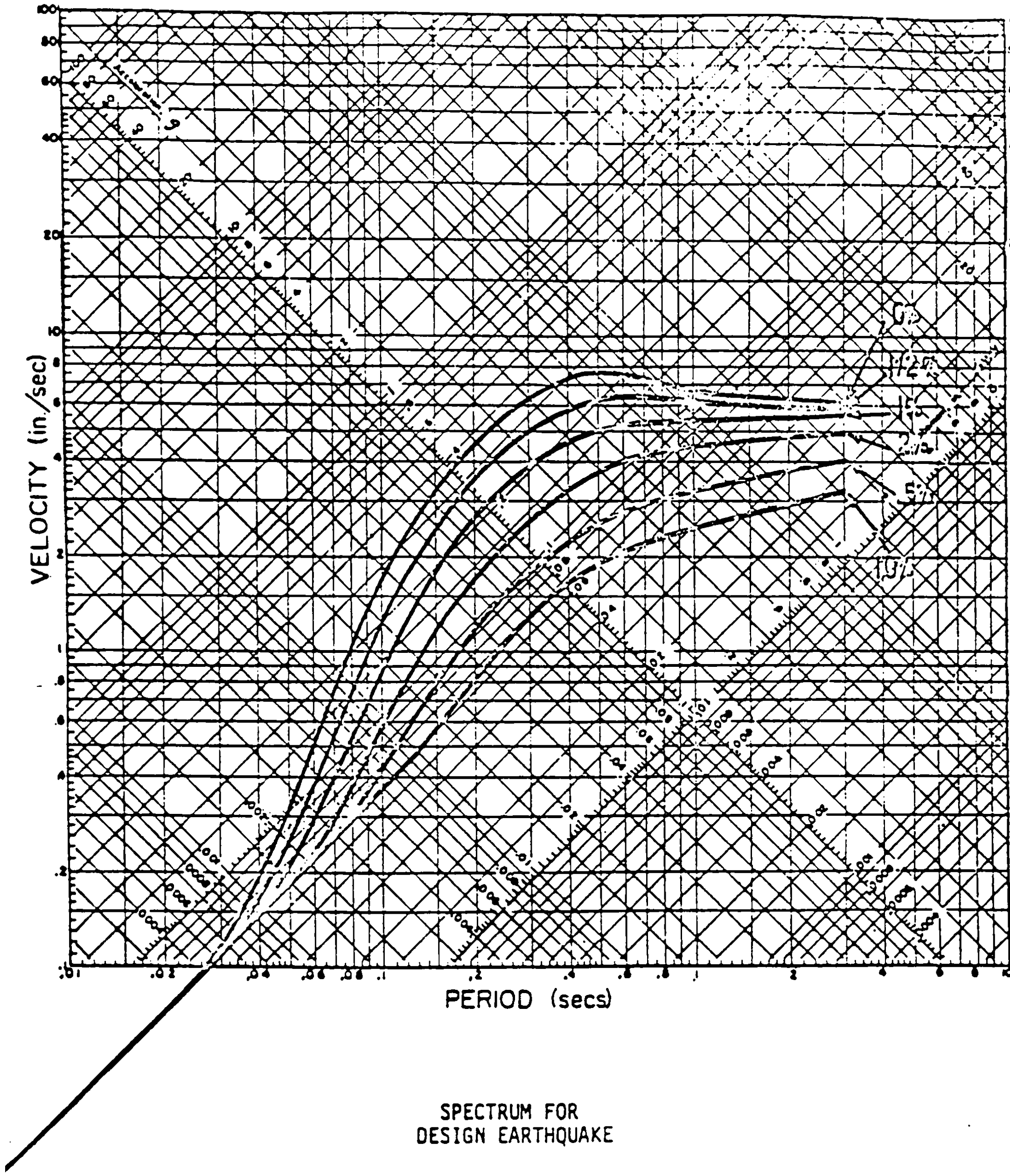
NOTE: 2 In lieu of satisfying the specific requirements for the local membrane ($P_L \leq 1.5S_m$) or the primary plus secondary stress intensity ($P_L + P_b + Q \leq 3S_m$) at a specific location, the structural action may be calculated on a plastic basis and the design will be considered to be acceptable if shakedown occurs, as opposed to continuing deformation, and if the deformations which occur prior to shakedown do not exceed specified limits, as per paragraph N-417.6(a)(2) of the ASME B&PV Code, Section III, Nuclear Vessels.

NOTE: 3 The limits on local membrane stress intensity ($P_L \leq 1.5S_m$) and primary membrane plus primary bending stress intensity (P_m (or P_L) $+ P_b \leq 1.5S_m$) need not be satisfied at a specific location if it can be shown by means of limit analysis or by test that the specified loadings do not exceed 120% of 2/3 of the lower bound collapse load, as per paragraph N-417.10(c) of the ASME Boiler and Pressure Vessel Code, Section III, Nuclear Vessels.

NOTE: 4 As an alternate to the design limit curves which represent a pseudo plastic instability analysis, a plastic instability analysis may be performed in some specific cases considering the actual strain-hardening characteristics of the material, but with the yield strength adjusted to correspond to the tabulated value at the appropriate temperature in Table N-424 or N-425, as per paragraph N-417.11c of the ASME B&PV Code, Section III, Nuclear Vessels. These specific cases will be justified on an individual basis.

NOTE: 5 The Faulted Condition load condition for the replacement reactor vessel closure heads and CRDM pressure housings consists of Normal + SRSS (DBE + DBA), where SRSS refers to the square-root-of-the sum-of-squares load condition methodology.

Figure A.5-1 EARTHQUAKE RESPONSE SPECTRUM - .06g



SPECTRUM FOR
DESIGN EARTHQUAKE

Figure A.5-2 EARTHQUAKE RESPONSE SPECTRUM - 0.12g

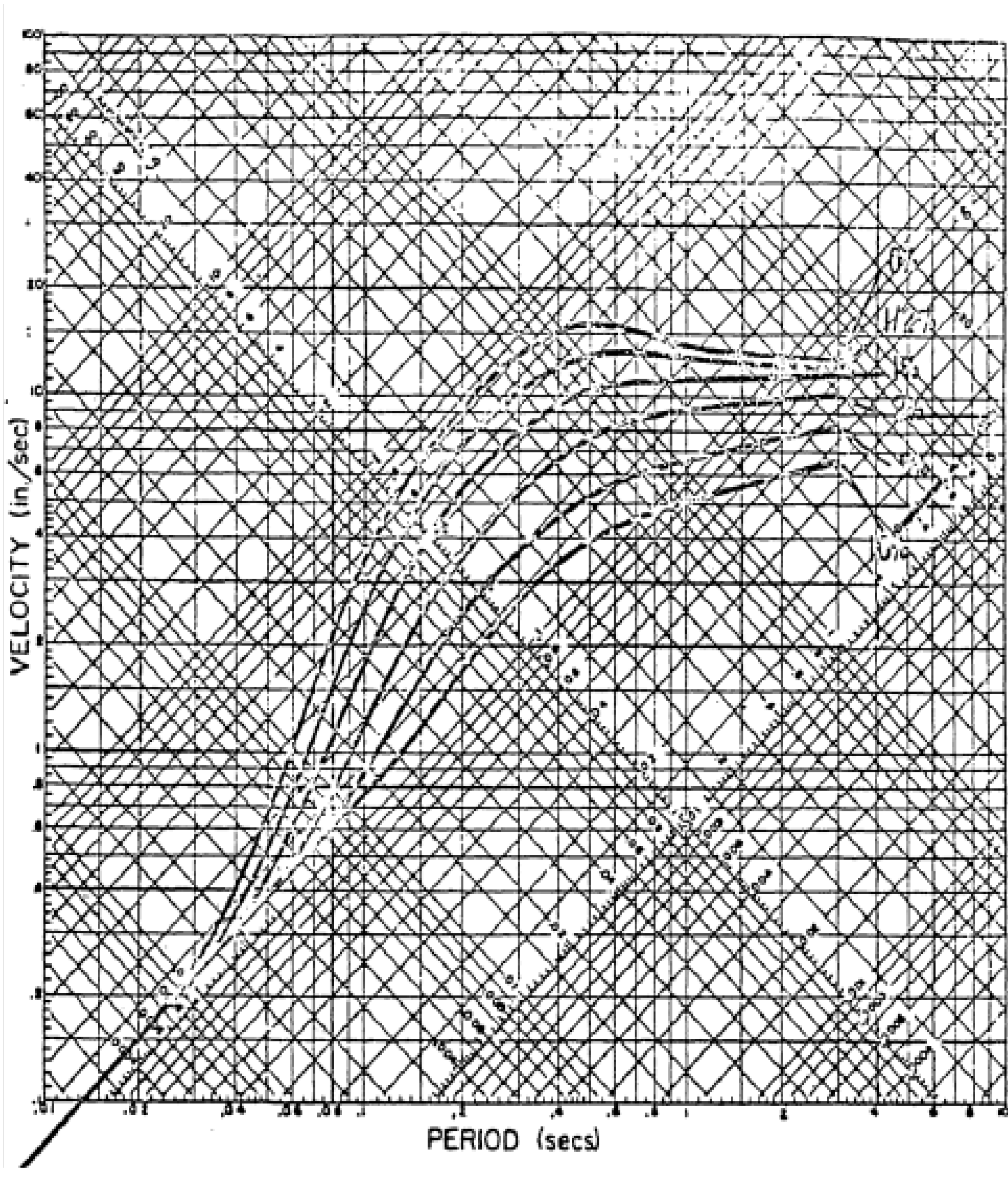


Figure A.5-3 CONTROL ROOM BUILDING SECTION, N-S DIRECTION

[redacted]

Figure A.5-4 CONTROL ROOM BUILDING BENDING MOMENT - HEIGHT

[redacted]

Figure A.5-5 CONTROL ROOM BUILDING SHEAR - HEIGHT

[redacted]

Figure A.5-6 CONTROL ROOM BUILDING - ACCELERATION ENVELOPE

[redacted]

Figure A.5-7 CONTROL ROOM BUILDING - DISPLACEMENT ENVELOPE

[redacted]

Figure A.5-8 CONTROL ROOM - MODEL FOR STRESS

[redacted]

Figure A.5-9 CONTROL ROOM - PROPERTIES OF LUMP MASSES AND CONNECTING MEMBERS

Mass #	Weight Kips	Member #	Shear Area Ft^2	Total Area Ft^2	I_2 $Ft^4 \times 10^3$
1	3726.0				
		1	427.50	921.20	820.2
2	4700.0				
		2	237.0	362.25	326.2
3	2742.0				
		3	223.20	341.70	323.3
4	1670.0				
		4	210.75	468.15	343.5
5	1331.0				

Figure A.5-10 CONTROL ROOM BUILDING - MODE SHAPES AND FREQUENCIES

[redacted]

A.6 SHARED SYSTEMS ANALYSIS

Certain components of plant systems are shared by the two units as stated in Section 1.2.9. The purpose of this Appendix is to present a failure analysis of shared components (Table A.6-1) to demonstrate that the following GDC is met:

> Sharing of Systems
> Reactor facilities may share systems or components if it can be shown that such sharing will not result in undue risk to the health and safety of the public. (GDC 4)

In addition to listing shared components by system, Table A.6-1 also includes the corresponding equipment functions which are shared between the two units, each unit's condition that places the maximum demand on the shared system/component, and the ability of the shared system to tolerate the failure of any single active component without loss of the shared function.

Table A.6-1 SHARED SYSTEMS ANALYSIS

Shared System	Shared Components	Shared Fuction	Quantity Provided	Explanation	Conditions of Maximum Demand on the System	Quantity req'd for Maximum Demand	Able to tolerate the single failure of an active component
Chemical and Volume Control System	Boric Acid Storage Tanks	Storage of boric acid for refueling and emergency shutdown	3	Three tanks are provided such that all the boric acid required during the operating cycles of both units may be stored in them. Depending on boron concentration, either one or two tanks are required to shutdown a unit to cold xenon-free concentration, and assuming the most reactive rod fully withdrawn	Simultaneous shutdown of both units	1	No (See Note 1)
	Batching Tank	Makeup of fresh concentrated boric acid solution	1	One tank is provided for the two units. It is used infrequently after initial boration.	N/A	N/A	N/A
	Holdup Tanks	Storage of dilute boric acid prior to recycle processing	3	Three tanks are provided to handle the rejected chemical shim solution from all expected operating and start-up transients for two unit plant operation.	N/A	N/A	N/A
	Recirculation Pump	Handling of tank inventory	1	Serves the common hold up tanks infrequently	N/A	N/A	N/A
	Gas Stripper Feed Pumps	Pumping of chemical shim solution to gas stripper/boric acid evaporator processing train	2	Two pumps are provided each with sufficient capacity to supply both processing trains simultaneously. One pump serves as a spare to the other.	N/A	N/A	N/A
	Evaporator Feed Ion Exchangers	Remove cesium and lithium activity from boric acid to be processed for reuse.	4	Four vessels are provided. Two vessels in series have sufficient capacity to supply both processing trains simultaneously. Two resin beds serve as a spare to the other two.	N/A	N/A	N/A

Table A.6-1 SHARED SYSTEMS ANALYSIS

Shared System	Shared Components	Shared Fuction	Quantity Provided	Explanation	Conditions of Maximum Demand on the System	Quantity req'd for Maximum Demand	Able to tolerate the single failure of an active component
	Gas Stripper Boric Acid Evaporator Train	Processing used chemical shim solution to produce clean, re-usable reactor makeup water and concentrated boric acid solution.	2	Two processing trains serve as common equipment for the two units. One train serves as a spare to the other although both may be operated simultaneously.	N/A	N/A	N/A
	Monitor Tanks	Reservoirs for processed water for analysis prior to storage in reactor makeup water tank.	4	Four tanks are provided to permit continuous operation of each evaporator train and so that one may be filling while the other is examined and emptied in each train.	N/A	N/A	N/A

Table A.6-1 SHARED SYSTEMS ANALYSIS

Shared System	Shared Components	Shared Fuction	Quantity Provided	Explanation	Conditions of Maximum Demand on the System	Quantity req'd for Maximum Demand	Able to tolerate the single failure of an active component
	Monitor Tank Pumps	Pump water from the monitor tanks to the reactor makeup water tank	2	Two pumps are provided, each with adequate capacity to handle both units. One pump serves as a spare to the other.	N/A	N/A	N/A
	Evaporator Condensate Demineralizers	Remove trace amounts of boric acid from processed water	3	Three demineralizers are provided each with sufficient capacity to serve both units. Thus adequate spare capacity is provided.	N/A	N/A	N/A
	Reactor Makeup Water Tank	Storage of clean makeup water	1	One tank is provided which is adequately sized to serve both units.	N/A	N/A	N/A
	Reactor Makeup Water Tank Pumps	Supply miscellaneous reactor makeup	2	Two pumps are provided, each with sufficient capacity to serve needs of the two units. One pump serves as a spare to the other.	N/A	N/A	N/A
	Concentrates Holding Tank	Storage of boric acid evaporator bottoms for sampling	1	One tank holds the production of concentrates from one batch of evaporator operation.	N/A	N/A	N/A
	Concentrates Holding tank Transfer Pumps	Discharge of boric acid solution from concentrates holding tank.	2	Two pumps provided to service the common concentrates holding tank.	N/A	N/A	N/A

Table A.6-1 SHARED SYSTEMS ANALYSIS

Shared System	Shared Components	Shared Fuction	Quantity Provided	Explanation	Conditions of Maximum Demand on the System	Quantity req'd for Maximum Demand	Able to tolerate the single failure of an active component
Auxiliary Coolant System	Component Cooling Heat Exchangers	Intermediate heat exchanger between service water and component cooling water.	4	Four exchangers are provided to serve both units. Normally one exchanger will provide adequate cooling for each unit. Two exchangers serve as spare units. The spare exchangers may be utilized to speed the shutdown of either unit as required. See Note 4	Simultaneous initiation of shutdown cooling at RHR cut-in conditions (350°F) on both units	2	yes
	Component Cooling Water Pumps	Circulate component cooling water for miscellaneous services in both units.	4	Four pumps are provided to serve both units. Normally one pump will provide adequate circulation to cool each unit, with the other pump assigned to that unit serving as a standby spare. The spare pumps may be used to speed the shutdown of either unit as required.	Simultaneous initiation of shutdown cooling at RHR cut-in conditions (350°F) on both units	2	yes
	Spent Fuel Pool Pumps	Recirculation of spent fuel pool water	2	Two pumps are provided to service the common spent fuel pool.	See Note 2	2	N/A
	Spent Fuel Pool Demineralizer	Purification of the spent fuel pool water and refueling water	1	One demineralizer is provided. It is operated intermittently and may be bypassed when the resin is replaced.	See Note 2	N/A	N/A

Table A.6-1 SHARED SYSTEMS ANALYSIS

Shared System	Shared Components	Shared Fuction	Quantity Provided	Explanation	Conditions of Maximum Demand on the System	Quantity req'd for Maximum Demand	Able to tolerate the single failure of an active component
	Spent Fuel Pool Filter	Purification of the spent fuel pool water and refueling water	1	One filter is provided. The purification loop is by-passed when the cartridge is replaced.	See Note 2	N/A	N/A
	Spent Fuel Pool Heat Exchanger	Cooling Spent Fuel Pool Water	2	Sufficient capacity is provided to maintain reasonable pool temperatures	See Note 2	2	N/A
	Refueling Water Circulating Pump	Circulation of refueling water if required for purification	1	One pump provides in frequent purification service for both refueling water tanks.	N/A	N/A	N/A
Fuel Handling System	Spent Fuel Storage Pool	Storage of spent fuel elements from refueling until shipment	1	A common area is provided with adequate rack storage space to meet the requirements of two units.	See Note 2	N/A	N/A
	New Fuel Storage	Storage of new fuel elements from delivery until loading into the reactors.	1	A common area with new fuel storage rack is provided with adequate space to serve both units.	N/A	N/A	N/A
	Decontamination Area	Easily cleaned area for decontamination of equipment.	1	A common area is provided with adequate space to serve both units.	N/A	N/A	N/A
	Spent Fuel Pool Bridge	Transfer of fuel elements between storage and fuel transfer system.	1	A common bridge is provided serving the common spent fuel pool.	N/A	N/A	N/A

Table A.6-1 SHARED SYSTEMS ANALYSIS

Shared System	Shared Components	Shared Fuction	Quantity Provided	Explanation	Conditions of Maximum Demand on the System	Quantity req'd for Maximum Demand	Able to tolerate the single failure of an active component
Service Water System	Pumphouse and Headers	Environment for service water pumping equipment.	1	A common pumphouse is provided for the service water pumping equipment.	The recirculation phase of the post-LOCA condition in one unit with normal power operation in the second unit.		See Service Water Pumps
	Service Water Pumps	Provide cooling water for various common and Unit specific loads as described in Section 9.6.	6	Six service water pumps are provided to supply water to the dual, common loop piped system for the two units. Normally, pumps will supply both units; the additional pumps provide increased capacity when required and serve as spares.	The recirculation phase of the post-LOCA condition in one unit with normal power operation in the second unit.	3	yes
Electrical System	Diesel Generators	Supply emergency power in the event of a loss of the AC power supply.	4	Four Diesel generators are supplied as common to both units. Each has adequate capacity to safely control a LOCA in one unit and a concurrent trip of the second unit to the hot shutdown condition (See Note 3).	LOCA in one unit with concurrent trip of the second unit (to the hot shutdown condition) when all AC power supply is simultaneously lost.	1	yes
	Gas Turbine	Supply power during a blackout and certain fire scenarios	1	One gas turbine unit is supplied in the event of a blackout, to supply spinning reserve and for peaking purposes.	N/A	N/A	N/A

Waste Disposal	A common waste disposal system is used for the two units. Each containment structure has its own reactor coolant drain tank, and containment sump, and each is serviced by two reactor coolant drain tank pumps. All other waste disposal equipment is sized to adequately serve two units and the common auxiliary and service buildings. This shared equipment includes:			The Waste Disposal System serves no emergency function.
	Laundry and Hot Shower Tank Chemical Drain Tank Sump Tank Waste Hold-up Tank	Waste Gas Compressors Waste Evaporator Train Drumming Station Gas Analyzer	Boric Acid Evaporator Letdown Gas Stripper Cryogenic System Waste Condensate Tanks	Waste Distillate Tanks Blowdown Evaporator (abandoned) Gas Decay Tanks Gas Manifolds Filtration/Demineralization System

1 Boric acid injection affords backup reactivity shutdown capability, independent of control rod cluster which normally serve this function in the short term situation. Normally, boric acid injection is only used either to supplement rod control for xenon decay or for reactor cooldown. At the lower allowed acid concentrations, one full storage tank will not be sufficient to achieve the required shut down margin. Additional boric acid solution from a second tank will be required. However, sufficient storage exists in all three tanks to support shutdown of both units.

2 Operation of the Spent Fuel Handling System is only required when nuclear fuel is to be moved underwater. The spent fuel pool cooling system is designed for a heat load greater than that generated by a complete core offload with about 1381 assemblies already in the pool.

3 See Section 8.0.

4 License condition for amendment 178 requires that each unit will utilize only one CCW heat exchanger until such time that analyses are completed and the SW system is reconfigured as necessary to allow operation of one or both units with two heat exchangers in service.

A.7 PLANT FLOODING

The Point Beach Site selection is inherently resistant to external flooding risks as discussed in Section 2.5 "Hydrology." The plant design and equipment layout provide additional protection from postulated internal and external flooding sources. This Appendix provides information on affected systems, critical equipment heights and protective strategies for addressing internal and external plant flooding.

A.7.1 AFFECTED SYSTEMS AND PROTECTION METHODS

Systems and components that must be protected from external flooding were specified in the original plant Safety Evaluation Report (SER) (Reference 6) as "critical plant components."

The Point Beach internal flooding basis was initiated by a 1972 Atomic Energy Commission (AEC) communication and specifies that no failure of a non-Category I (seismic) component can result in a flooding condition that could adversely affect equipment needed to get the plant to safe shutdown or to limit the consequences of an accident (Reference 1) (Reference 3) (Reference 5).

Protection Methods

Acceptable methods for providing flood protection for plant systems and equipment are diverse. The basic strategies include:

Equipment Height:
- If the elevation of the potentially vulnerable equipment exceeds the design basis flood level for the affected room, then adequate protection exists. (Reference 5) (Reference 6)

Topography
- Lake bottom contour, construction of the bank, and distance from shore can be credited for mitigating the effects of wave run-up events. Property slope can be credited for mitigating the effects of precipitation events and for providing a relief path for internal flooding.

Barriers:
- Interior or exterior barriers that protect vulnerable equipment from the effects of flooding can be used to provide adequate protection from flooding from internal (Reference 3) or external sources. The use of sandbags is an acceptable option to provide for the protection of plant equipment from internal or external flood sources at Point Beach (Reference 7) (Reference 8).

Separation:
- Separation and redundancy of trains or equipment is sufficient if both trains, or redundant equipment, cannot be impacted by the same flooding event. This provides acceptable protection from internal flood sources only (Reference 3) (Reference 9).

Operator Actions:
- Operator actions as specified in plant procedures can be credited in response to both internal and external flooding sources (Reference 2) (Reference 4) (Reference 5) (Reference 7) (Reference 8).

Detection:
- Water level alarms can be credited if they process an alarm to the Control Room and are redundant (Reference 3) (Reference 13).

Relief Paths:
- Passages or piping and other openings may be credited as a relief path if they are designed for the safe shutdown earthquake (SSE), including seismically induced wave action of water inside the affected compartment during the SSE (Reference 3).

A.7.2 EXTERNAL FLOODING

The bounding external flooding event can be either a storm surge or a maximum precipitation event. The site topography and hydrology, as discussed in Section 2.5, both serve to minimize potential flooding vulnerability.

Flooding Conveyance Paths

The site topography provides sufficient drainage capacity and conveyance to the lake to address potential impacts from a design basis precipitation event (see FSAR Section 2.5.2 "Lake Levels and Flooding").

Wave Runup Event

The site layout, consisting of the intake structure and rip-rap bank topography, are credited in the flooding evaluations, which demonstrate that the calculated flood level is bounded by the license basis flood level of +9.0 feet. Protection to +9.0 feet is provided by procedurally driven installation of temporary barriers at entrances to the CWPH and Turbine Building during elevated lake level. When lake level exceeds administratively controlled limits, both units are brought to cold shutdown and barriers are installed. The Circulating Water, Condensate and Feedwater Systems are secured prior to installation of barriers at the Turbine Building doors/flood dampers in order to eliminate the major sources of internal flooding while the Turbine Building relief paths are blocked.

[redacted], even if the entry doors are not credited with holding back external flooding. The flood relief dampers in the floor [redacted] have been demonstrated to be sufficient to keep flood water below the elevation of the potentially vulnerable components (Reference 10).

The turbine building, which is the structure next closest to the lake, is more than 100 feet from the top of the bank. The combination of this distance and the shoreline riprap mitigate flooding from the lake.

Maximum Precipitation Event

Description of this event is in Section 2.5. Reference 14 lists the design features credited for mitigating external plant flooding.

Underground Conduits and Trenches

The external manhole and cable trenches are designed to remove water through a cascade system utilizing a combination of gravity drains and pumps. The manholes are monitored through the Facilities Monitoring Program and the Cable Condition Monitoring Program.

A.7.3 INTERNAL FLOODING

Design Basis Flood Level

Design Basis Flood Levels for internal flooding sources are based upon protecting safety-related or safe shutdown equipment (Reference 1), (Reference 3), (Reference 5), (Reference 12), and (Reference 14) and are therefore unique to each room and the associated limiting flood source. Timelines for system/operator response are based on a mass/flow balance that determines equilibrium flood levels (Reference 10).

The consequences of a single failure of any non-Category I (Seismic) SSC that has the potential to cause flooding have been evaluated for all areas where such a failure could have an impact on safe shutdown equipment (Reference 10).

Loss of Offsite Power (LOOP)

A loss of offsite power (LOOP) is assumed to occur during internal flood events unless the LOOP results in a less limiting consequence (Reference 3). Design features that rely on electric power to operate (such as sump pumps) can only be credited for flood protection if they can be powered by site emergency power sources.

Internal Flooding Sources

The Point Beach internal flooding license basis as established by the Safety Evaluation Report (SER) dated November 20, 1975 did not require Category I (Seismic) SSCs to be postulated as internal flooding sources (Reference 1) (Reference 5). In addition, components which can withstand a SSE are not postulated as flood sources.

Reference 10 has demonstrated that, under both normal operating conditions and while the internal flood drain paths are blocked by the External Wave Run up Flood Mitigation Strategy, there is sufficient time available to eliminate the source of internal flooding prior to impacting safety related/safe shutdown equipment.

Internal flooding from a failure of the fire protection piping in the G03/G04 Emergency Diesel Generator Building is a through-wall leakage crack, sized in accordance with Branch Technical Position (BTP) MEB 3-1, “Postulated Rupture Locations in Fluid System Piping Inside and Outside Containment” (Reference 11).

Reference 14 lists the applicable rooms, the flood sources, and the design features credited for mitigation of plant internal flooding.

REFERENCES

1. AEC letter to WE, Request for Review of Non-Category I (Seismic) Systems as Possible Flood Sources, dated September 26, 1972.

2. WE letter to NRC, Flooding Resulting from Non-Category I Failure Point Beach Nuclear Plant - Units 1 and 2, dated February 20, 1973.

3. AEC letter to WE, Supplemental Request for Flooding Analysis of Non-Category I System Sources, dated December 10, 1974.

4. WE letter to NRC, Flooding Resulting from Non-Category I Failure Point Beach Nuclear Plant - Units 1 and 2, dated February 17, 1975.

5. NRC letter to WE, Safety Evaluation Regarding the Potential for Flooding from Postulated Ruptures of Non-Category I (Seismic) Systems, dated November 20, 1975 and associated Safety Evaluation.

6. NRC Safety Evaluation dated July 15, 1970.

7. NUREG/CR-4458 Section 3.4.2 “External Flood Vulnerability.”

8. Original Plant FFDSAR.

9. NUREG/CR-4458 section 3.3.2 “Internal Flooding Vulnerability.”

10. Calculation 2014-0007, “Allowable Flood Levels.”

11. VPNPD-93-171, “Design Summary for the Installation of Two additional Emergency Diesel Generators - Point Beach Nuclear Plants, Unit 1 and 2," dated September 24, 1993 and attached Report REP-0026, "PBNP Diesel Project Design Submittal,” Revision 0, dated September 21, 1993.

12. NRC Letter to WE, Seismic Qualification of the Auxiliary Feedwater System at Point Beach Nuclear Plant, Units 1 and 2, dated September 16, 1986.

13. EC 282055, “High Condenser Pit and Lake Level Alarm Inputs.”

14. NP 8.4.17, “PBNP Flooding Program.”

APPENDIX B TABLE OF CONTENTS

B.2 DESIGN PARAMETERS AND PLANT COMPARISONS

The design parameters of the Point Beach Nuclear Plant were initially provided in a comparison with H. B. Robinson, Indian Point 2, and Ginna Station. This comparison provided an informational reference of similar aspects of similar plants constructed during the same time period to demonstrate that the technology employed at Point Beach was proven in multiple applications.

The design parameters listed were considered valid at the time of license issuance, and have been retained for historical context in the following Table B.2-1 and paragraphs. Note: The information provided is not currently reflective of the PBNP design specifications, and therefore should not be used as the basis of any Safety Evaluation without prior verification against current information provided elsewhere in the FSAR.

In 2003 a measurement uncertainty recapture power uprate was performed increasing the rated thermal power level to 1540 MWt. The tables of this section have not been updated since this Appendix is historical.

Design Highlights

The design of each Point Beach unit is based upon proven concepts which have been developed and successfully applied in the construction of pressurized water reactor systems. In subsequent paragraphs, a few of the design features are listed which represent slight variation or extrapolations from units presently operating such as San Onofre and Connecticut-Yankee.

POWER LEVEL - The license application power level of 1518.5 MWt is smaller than the capability of the Prairie Island plant and larger than the capability of the Ginna plant. This level is a reasonable increase over power levels of pressurized water reactors now operating.

REACTOR COOLANT LOOPS - The Reactor Coolant System for each Point Beach unit consists of two loops, the same as the Prairie Island and Ginna Units.

PEAK SPECIFIC POWER - Based on the design hot channel factors, operation at a primary heat output of 1518.5 MWt corresponds to a peak specific power of 16.0 kw/ft. This design rating is slightly lower than that licensed in Ginna (16.5 kw/ft) as well as that of Prairie Island (17.4 kw/ft). The maximum overpower condition is 17.9 kw/ft (112%) compared to 19.6 kw/ft (118%) for Prairie Island and 18.5 kw/ft for Ginna.

FUEL ASSEMBLY DESIGN - The fuel assembly design incorporates the rod cluster control concept in a canless assembly utilizing a spring clip grid to provide support for the 14 x 14 array of fuel rods. This concept incorporates the advantages of the Yankee canless fuel assembly and the Saxton spring clip grid with the rod cluster control scheme. Extensive out-of-pile tests have been performed on this concept and operating experience is available from the San Onofre and Connecticut-Yankee plants.

ENGINEERED SAFETY FEATURES - The engineered safety features provided are similar to those provided for the Connecticut-Yankee plant, augmented by borated water injection accumulators. There is a safety injection system of the Connecticut-Yankee type which can be operated from emergency on-site diesel power. The system design is such that it can be tested while the plant is at power. There is air recirculation cooling for post-loss-of-coolant conditions which utilizes the normal ventilation fans. A containment spray system provides cool, chemically-treated, borated water spray into the containment atmosphere for additional cooling capacity, and provides a means of rapidly reducing the concentration of airborne halogen fission products in the containment atmosphere.

EMERGENCY POWER - In addition to the multiple ties to outside sources for emergency power, four diesel generator units are provided as backup power supplies for the case of loss of all outside power. Each generator is capable of operating sufficient safety injection and containment cooling equipment to ensure an acceptable post-loss-of-coolant pressure transient in the affected unit, and safe shutdown of the other unit.

NET LOAD REJECTION - Each of the Point Beach units is designed to accept loss of 50% of external load without a reactor or turbine trip. This is accomplished by an automatic control system which dumps steam to the condenser and atmosphere as a short term supplemental load to provide time for the reactor control system to reduce the reactor output without exceeding acceptable core and coolant conditions. No unique or unproven features are required in the reactor control system to accomplish this.

Table B.2-1 COMPARISON OF DESIGN PARAMETERS
(See General Note)

Thermal and Hydraulic Parameters	PBNP U1/U2 Final Report	Robinson 2 Final Report	Indian Point 2 Final Report	R.E. Ginna Final Report	Reference Line No.
Total Primary Heat Output, MWt	1518.5	2200	2758	1300	1
Total Core Heat Output, Btu/hr	$5181x10^6$	$7479x10^6$	$9413x10^6$	$4437x10^6$	2
Heat Generated in Fuel,%	97.4	97.4	97.4	97.4	3
Maximum Thermal Overpower	12%	12%	12%	12%	4
System Pressure, Nominal, psia	2250	2250	2250	2250	5
System Pressure, Minimum Steady State, psia	2220	2220	2220	2220	6
Hot Channel Factors					
Heat Flux, F_q	2.32	3.23	3.23	3.38	7
Enthalpy Rise, $F_{\Delta H}$	1.60	1.77	1.77	1.77	8
DNB Ratio at Nominal Conditions	2.11	1.81	2.00	2.15	9
Minimum DNBR for Design Transients	1.30	1.30	1.30	1.30	10
Coolant Flow					
Total Flow Rate, lb/hr	$66.7x10^6$	$101.5x10^6$	$136.3x10^6$	$67.3x10^6$	11
Effective Flow Rate for Heat Transfer, lb/hr	$63.6x10^6$	$97.0x10^6$	$130x10^6$	$64.3x10^6$	12
Effective Flow Area for Heat Transfer, ft^2	27.0	41.8	51.4	27.0	13
Average Velocity Along Fuel Rods, ft/sec	15.0	14.3	15.4	14.7	14

Table B.2-1 COMPARISON OF DESIGN PARAMETERS

(See General Note)

Thermal and Hydraulic Parameters	PBNP U1/U2 Final Report	Robinson 2 Final Report	Indian Point 2 Final Report	R.E. Ginna Final Report	Reference Line No.
Average Mass Velocity, lb/hr-ft^2	$2.37x10^6$	$2.32x10^6$	$2.53x10^6$	$2.38x10^6$	15
Coolant Temperatures, °F					
Nominal Inlet, °F	552.5	546.2	543	551.9	16
Maximum Inlet Due to Instrumentation					
Error and Deadband, °F	556.5	550.2	547	555.9	17
Average Rise in Vessel, °F	57.6	55.9	53.0	49.5	18
Average Rise in Core, °F	60.0	58.3	55.5	52	19
Average in Core, °F	582.5	575.4	571.0	578.0	20
Average in Vessel, °F	581.3	574.2	569.5	577.0	21
Nominal Outlet of Hot Channel, °F	642.9	642	633.5	634.0	22
Average Film Coefficient, Btu/hr-ft^2-F	5600	5400	5790	5590	23
Average Film Temperature Difference, °F	31.0	31.8	30.3	26.9	24
Heat Transfer at 100% Power					
Active Heat Transfer Surface Area, ft^2	28,715	42,460	52,200	28,715	25
Average Heat Flux, Btu/hr-ft^2	175,800	171,600	175,600	150,500	26
Maximum Heat Flux, Btu/hr-ft^2	491,000	554,200	567,300	508,700	27
Average Thermal Output, kw/ft	5.7	5.5	5.7	4.88	28
Maximum Thermal Output, kw/ft	16.0	17.9	18.4	16.52	29

Table B.2-1 COMPARISON OF DESIGN PARAMETERS
(See General Note)

Thermal and Hydraulic Parameters	PBNP U1/U2 Final Report	Robinson 2 Final Report	Indian Point 2 Final Report	R.E. Ginna Final Report	Reference Line No.
Maximum Clad Surface Temperature at					
Nominal Pressure, °F	657	657	657	657	30
Fuel Central Temperature, °F					
Maximum at 100% Power	3750	4030	4090	3880	31
Maximum at Overpower	4000	4300	4380	4100	32
Thermal Output, kw/ft at Maximum Overpower	17.9	20.0	20.6	18.5	33

<u>CORE MECHANICAL DESIGN PARAMETERS</u>

Fuel Assemblies					
Design	RCC Canless 14x14	RCC Canless 15x15	RCC Canless 15x15	RCC Canless 14x14	34
Rod Pitch, in.	0.556	0.563	0.563	0.556	35
Overall Dimensions, in.	7.763x7.763	8.426x8.426	8.426x8.426	7.763x7.763	36
Fuel Assemblies					
Fuel Weight (as UO_2), pounds	118,729	176,200	216,000	120,782	37
Total Weight, pounds	154,519	226,200	276,000	152,895	38
Number of Grids per Assembly	7	7	9	9	39

Table B.2-1 COMPARISON OF DESIGN PARAMETERS
(See General Note)

Thermal and Hydraulic Parameters	PBNP U1/U2 Final Report	Robinson 2 Final Report	Indian Point 2 Final Report	R.E. Ginna Final Report	Reference Line No.
Fuel Rods					
Number	21,659	32,028	39,372	21,659	40
Outside Diameter, in.	0.422	0.422	0.422	0.422	41
Diametral Gap, in.	0.0065	0.0065	0.0065	0.0065	42
Clad Thickness, in.	0.0243	0.0243	0.0243	0.0243	43
Clad Material	Zircaloy	Zircaloy	Zircaloy	Zircaloy	44
Fuel Pellets					
Material	UO_2 Sintered	UO_2 Sintered	UO_2 Sintered	UO_2 Sintered	45
Density (% of Theoretical)	Unit 1 94-92-91 Unit 2 94-93-92	94-92-91	94-92-91	94-92-91-93	46
Diameter, in.	0.3669	0.3669	0.3669	0.3669	47
Length, in.	0.6000	0.6000	0.6000	0.6000	48
Rod Cluster Control Assemblies					
Neutron Absorber	5% Cd-15% In-80% Ag.	5% Cd-15% In-80% Ag.	5% Cd-15% In-80% Ag.	5% Cd-15% In-80% Ag.	49

Table B.2-1 COMPARISON OF DESIGN PARAMETERS
(See General Note)

Thermal and Hydraulic Parameters	PBNP U1/U2 Final Report	Robinson 2 Final Report	Indian Point 2 Final Report	R.E. Ginna Final Report	Reference Line No.
Cladding Material	Type 304 SS-Cold Wrkd.	Type 304 SS-Cold Wrkd.	Type 304 SS-Cold Wrkd.	Type 304 SS-Cold Wrkd.	50
Rod Cluster Control Assemblies					
Clad Thickness, in.	0.019	0.019	0.019	0.019	51
Number of Clusters	33	53	53	29	52
Number of Control Rods per Cluster	16	20	20	16	53
Core Structure					
Core Barrel I.D./O.D., in.	109.0/112.5	133.875/ 137.875	148.0/152.5	109.0/112.5	54
Thermal Shield I.D./O.D., in.	115.3/122.5		158.5/164.0	115.3/122.5	55
<u>Structural Characteristics</u>					
Fuel Weight (as UO2), lbs.	118,729	176,200	216,000	120,130	56
Clad Weight, lbs.	24,260	36,300	44,600	22,440	57
Core Diameter, in. (Equivalent)	96.5	119.5	132.5	96.5	58
Core Height, in. (Active Fuel)	144	144	144	144	59

Table B.2-1 COMPARISON OF DESIGN PARAMETERS
(See General Note)

Thermal and Hydraulic Parameters	PBNP U1/U2 Final Report	Robinson 2 Final Report	Indian Point 2 Final Report	R.E. Ginna Final Report	Reference Line No.
Reflector Thickness and Composition					
Top - Water plus Steel, in.	10	10	10	10	60
Bottom - Water plus Steel, in.	10	10	10	10	61
Side - Water plus Steel, in.	15	15	15	15	62
H_20/U, (Cold Volume Ratio)	4.20	4.18	4.18	4.08	63
Number of Fuel Assemblies	121	157	193	121	64
UO2 Rods per Assembly	179	204	204	179	65
<u>Performance Characteristics</u>					
Loading Technique	3 region, non-uniform	3 region, non-uniform	3 region, non-uniform	3 region, non-uniform	66
Fuel Discharge Burnup, MWD/MTU					
Average First Cycle	15,100	14,500	14,200	~14,900	67
Equilibrium Region Average	33,000	33,000	24,700	~24,400	68
Feed Enrichments, w/o					
Region 1	2.27	1.85	2.2	2.44	69
Region 2	3.03	2.55	2.7	2.78	70
Region 3	3.40	3.10	3.2	3.48	71
Equilibrium	3.40	3.10			

Table B.2-1 COMPARISON OF DESIGN PARAMETERS
(See General Note)

Thermal and Hydraulic Parameters	PBNP U1/U2 Final Report	Robinson 2 Final Report	Indian Point 2 Final Report	R.E. Ginna Final Report	Reference Line No.
<u>Control Characteristics</u>					
Effective Multiplication (Beginning of Life)					
Cold, No Power, Clean	1.211	1.180	1.257	1.188	72
Hot, No Power, Clean	1.167	1.38	1.999	1.137	73
Hot, Fuel Power, Xe and Sm Equilibrium	1.113	1.077	1.152	1.080	74
Rod Cluster Control Assemblies					
Material	5% Cd-15% In-80% Ag.	5% Cd-15% In-80% Ag.	5% Cd-15% In-80% Ag.	5% Cd-15% In-80% Ag.	75
Number of RCC Assemblies	37	53	53	33	76
Number of Absorbers per RCC Assembly	16	20	20	16	77
Total Rod Worth	See Table 3.2.1-3	See Table 3.2.1-3	See Table 3.2.1-3	6.8%	78
Boron Concentrations					
To shut reactor down with no rods inserted,					
clean (k_{eff} = .99) Cold/hot	1598 ppm/ 1676 ppm	1250 ppm/ 1210 ppm	1480 ppm/ 1370 ppm	1160 ppm/ 820 ppm	79
To control at power with no rods inserted,					
clean/equilibrium xenon and samarium	1465 ppm/ 1007 ppm	1000 ppm/920 ppm	1200 ppm/ 780 ppm	1310 ppm/ 890 ppm	80

Table B.2-1 COMPARISON OF DESIGN PARAMETERS
(See General Note)

Thermal and Hydraulic Parameters	PBNP U1/U2 Final Report	Robinson 2 Final Report	Indian Point 2 Final Report	R.E. Ginna Final Report	Reference Line No.
Boron Worth, Hot	1% δk/k/130 ppm	7.3 δk/k	1% δk/k/89 ppm	1% δk/k/120 ppm	81
Boron Worth, Cold	1% δk/k/98 ppm	5.6 δk/k	1% δk/k/72 ppm	1% δk/k/90 ppm	82
Kinetic Characteristics					
Moderator Temperature Coefficient (δk/k/°F)	$+0.3\text{x}10^{-4}$ to $-3.5\text{x}10^{-4}$	$+0.3\text{x}10^{-4}$ to $-3.5\text{x}10^{-4}$	$-0.3\text{x}10^{-4}$ to $-3.0\text{x}10^{-4}$	$+0.5\text{x}10^{-4}$ to $-3.5\text{x}10^{-4}$	83
Moderator Pressure Coefficient (δk/k/psi)	$-0.3\text{x}10^{-6}$ to $3.5\text{x}10^{-6}$	$-0.3\text{x}10^{-6}$ to $3.5\text{x}10^{-6}$	$+0.3\text{x}10^{-6}$ to $+3.0\text{x}10^{-6}$	$-0.5\text{x}10^{-6}$ to $3.5\text{x}10^{-6}$	84
Moderator Void Coefficient	-0.10 to -0.30	$+0.5\text{x}10^{-3}$ to $-2.5\text{x}10^{-3}$	+0.03 to -0.30	-0.10 to -0.30	85
	δk/k/g/cm^3	δk/k/% void	δk/k/g/cm^{-3}	δk/k/g/cm^3	
Doppler Coefficient (δk/k/°F)	$-1\text{x}10^{-5}$ to $-1.6\text{x}10^{-5}$	$-1\text{x}10^{-5}$ to $-1.6\text{x}10^{-5}$	$-1.1\text{x}10^{-5}$ to $+1.8\text{x}10^{-5}$	$-1.1\text{x}10^{-5}$ to $1.8\text{x}10^{-5}$	86

Table B.2-1 COMPARISON OF DESIGN PARAMETERS
(See General Note)

Thermal and Hydraulic Parameters	PBNP U1/U2 Final Report	Robinson 2 Final Report	Indian Point 2 Final Report	R.E. Ginna Final Report	Reference Line No.
REACTOR COOLANT SYSTEM - CODE REQUIREMENTS					
Reactor Vessel	ASME III Class A	ASME III Class A	ASME III Class A	ASME III Class A	87
Steam Generator					
Tube Side	ASME III Class A	ASME III Class A	ASME III Class A	ASME III Class A	88
Shell Side	ASME III Class C*	ASME III Class C*	ASME III Class C*	ASME III Class C*	89
Pressurizer	ASME III Class A	ASME III Class A	ASME III Class A	ASME III Class A	90
Pressurizer Relief Tank	ASME III Class C	ASME III Class C	ASME III Class C	ASME III Class C	91
Pressurizer Safety Valves	ASME III	ASME III	ASME III	ASME III	92
Reactor Coolant Piping	USAS B31.1	USAS B31.1	USAS B31.1	USAS B31.1	93

*The shell side of the steam generator conforms to the requirements for Class A vessels and is so stamped as permitted under the rules of Section III.

PRINCIPAL DESIGN PARAMETERS OF THE REACTOR COOLANT SYSTEM					
Reactor Primary Heat Output, MWt	1518.5	2200	2758	1300	94

Table B.2-1 COMPARISON OF DESIGN PARAMETERS
(See General Note)

Thermal and Hydraulic Parameters	PBNP U1/U2 Final Report	Robinson 2 Final Report	Indian Point 2 Final Report	R.E. Ginna Final Report	Reference Line No.
Reactor Primary Heat Output, Btu/hr	$5181x10^6$	$7508x10^6$	$9413x10^6$	$4437x10^6$	95
Operating Pressure, psig	2235	2235	2235	2235	96
Reactor Inlet Temperature	552.5	546.2	543	551.9	97
Reactor Outlet Temperature	610.1	602.1	596.0	601.4	98
Number of Loops	2	3	4	2	99
Design Pressure, psig	2485	2485	2485	2485	100
Design Temperature, ^oF	650	650	650	650	101
Hydrostatic Test Pressure (Cold), psig	3110	3110	3110	3110	102
Coolant Volume, including pressurizer, cu. ft.	6450	9088	12,600	6245	103
Total Reactor Flow, gpm	178,000	268,500	358,800	180,000	104
Material	SA-302 Grade B, low alloy steel, internally clad with austenitic SS	SA-302 Grade B, low alloy steel, internally clad with austenitic SS	SA-302 Grade B, low alloy steel, internally clad with austenitic SS	SA-302 Grade B, low alloy steel, internally clad with austenitic SS	105
Design Pressure, psig	2485	2485	2485	2485	106
Design Temperature, ^oF	650	650	650	650	107
Operating Pressure, psig	2235	2235	2235	2235	108

Table B.2-1 COMPARISON OF DESIGN PARAMETERS
(See General Note)

Thermal and Hydraulic Parameters	PBNP U1/U2 Final Report	Robinson 2 Final Report	Indian Point 2 Final Report	R.E. Ginna Final Report	Reference Line No.
Inside Diameter of Shell, in.	132	155.5	173	132	109
Outside Diameter Across Nozzles, in.	224-1/16	236	262-7/16	219-5/16	110
Overall Height of Vessel & Enclosure Head, ft-in.	39-0	41-6	43' 9-11/16"	39' 1-5/16"	111
Minimum Clad Thickness, in.	5/32	5/32	5/32	5/32	112
PRINCIPAL DESIGN PARAMETERS OF THE STEAM GENERATORS					
Number of Units	2	3	4	2	113
Type	Vertical U-tube with interal-moisture separator	Vertical U-tube with integral-moisture separator	Vertical U-tube with integral-moisture separator	Vertical U-tube with integral-moisture separator	114
Tube Material	Inconel	Inconel	Inconel	Inconel	115
Shell Material	Carbon Steel	Carbon Steel	Carbon Steel	Carbon Steel	116
Tube Side Design Pressure, psig	2485	2485	2485	2485	117
Tube Side Design Temperature, ^oF	650	650	650	650	118
Tube Side Design Flow, lb/hr	$33.35x10^6$	$33.93x10^6$	$34.07x10^6$	$33.63x10^6$	119
Shell Side Design Pressure, psig	1085	1085	1085	1085	120
Shell Side Design Temperature, ^oF	556	556	556	556	121

Table B.2-1 COMPARISON OF DESIGN PARAMETERS
(See General Note)

Thermal and Hydraulic Parameters	PBNP U1/U2 Final Report	Robinson 2 Final Report	Indian Point 2 Final Report	R.E. Ginna Final Report	Reference Line No.
Operating Pressure, Tube Side, Nominal, psig	2235	2235	2235	2235	122
Operating Pressure, Shell Side, Maximum, psi	1020	1020	1015.3	1020	123
Maximum Moisture at Outlet at Full Load, %	1/4	1/4	1/4	1/4	124
Hydrostatic Test Pressure, Tube Side (Cold), psig	3110	3110	3110	3110	125
<u>PRINCIPAL DESIGN PARAMETERS OF THE REACTOR COOLANT PUMPS</u>					
Number of Units	2	3	4	2	126
Type	Vertical, single stage radial flow with bottom suction & horiz. disch.	Vertical, single stage radial flow with bottom suction & horiz. disch.	Vertical, single stage radial flow with bottom suction & horiz. disch.	Vertical, single stage radial flow with bottom suction & horiz. disch.	127
Design Pressure, psig	2485	2485	2485	2485	128
Design Temperature, ^oF	650	650	650	650	129
Operating Pressure, Nominal, psig	2235	2235	2235	2235	130
Suction Temperature, ^oF	551.5	546.5	556	551.9	131
Design Capacity, gpm	89,000	88,500	90,000	90,000	132
Design Head, ft.	259	261	252	252	133
Hydrostatic Test Pressure (Cold), psig	3110	3110	3110	3110	134

Table B.2-1 COMPARISON OF DESIGN PARAMETERS
(See General Note)

Thermal and Hydraulic Parameters	PBNP U1/U2 Final Report	Robinson 2 Final Report	Indian Point 2 Final Report	R.E. Ginna Final Report	Reference Line No.
Motor Type	AC induc. single speed air cooled	AC induc. single speed air cooled	AC induc. single speed air cooled	AC induc. single speed air cooled	135
Motor Rating (Nameplate)	6000 HP	6000 HP	6000 HP	5500 HP	136
Material	Austenitic SS	Austenitic SS	Austenitic SS	Austenitic SS	137
Hot Leg - I.D., in.	29	29	29	29	138
Cold Leg - I.D., in.	27-1/2	27-1/2	27-1/2	27-1/2	139
Between Pump and Steam Generator - I.D., in.	31	31	31	31	140
Design Pressure, psig	2485	2485	2485	2485	141

B.3 INITIAL PLANT DESIGN

Research and development (as defined in Section 50.2 of the Commission's regulations) was conducted regarding core design details and parameters, analytical methods for kinetics calculations, thermal shock and its effects on reactor vessel integrity, the safety injection (emergency core cooling) system, xenon stability and related control systems, containment spray additive effectiveness, and capability of reactor internals to resist blowdown forces.

Core Design

The nuclear design, including fuel configuration and enrichments, control rod pattern and worths, reactivity coefficients, and boron requirements are presented in Section 3.2 and the thermal-hydraulics design parameters are also in Section 3.2. Section 3.2 presents the fuel, fuel rod, fuel assembly, and control rod mechanical design. The core design incorporates fixed burnable poison rods (Reference 1) in the initial loading and, when necessary, in subsequent core reloads to ensure a negative moderator reactivity temperature coefficient at operating temperature. This improves reactor stability and lessens the consequences of a rod ejection or loss-of-coolant accident. The mechanical design is presented in Section 3.2.

Development Of Analytical Methods For Reactivity Transients From Rod Ejection Accidents

A control rod ejection accident is not considered credible since it would require the fracture of a control rod mechanism housing. Nevertheless, the reactivity and associated pressure and temperature transients for this accident have been analyzed. Rod ejection analyses for this plant were performed using the CHIC-KIN code(Reference 2), which uses a point reactor kinetics model and a single channel fuel and coolant description. The rod ejection analysis results are given in Section 14.2.6 of this report, together with a brief description of the CHIC-KIN code. These analyses show that the temperature and pressure transients associated with a rod ejection accident do not cause any consequential damage to the reactor coolant system. The consequences of a rod ejection accident are now lessened because the moderator coefficient of reactivity is always negative at operating conditions. In addition, the effects of rod ejection are inherently limited in this reactor, in which boric acid chemical shim is employed, since full-length control rods need only to be inserted sufficiently to handle load changes.

The initial cores contain fixed burnable poison rods. These, by allowing a reduction in the chemical shim concentration, ensure that the moderator coefficient of reactivity is always negative at operating temperature. The burnable poison rods, contain borosilicate glass. Critical experiments were conducted at the Westinghouse Reactor Evaluation Center using rods containing 12.8 w/o boron and Zircaloy clad UO_2 fuel rods, 2.27% enriched. These values are also typical of this plant's initial core. The experiments showed that standard analytical methods can be used to calculate the reactivity worth of the burnable poison rods. The design basis and critical experiments are described in Reference 1. In-core testing completed in the Saxton reactor showed satisfactory performance of these rods.

Safety Injection System (SI) Design

The design of the safety injection system includes nitrogen-pressurized accumulators to inject borated water into the reactor coolant system to rapidly and reliably reflood the core following a loss-of-coolant accident. Additional analyses have been performed to demonstrate that the accumulators, in conjunction with other components of the emergency core cooling system, can adequately cool the core for any pipe rupture. These analyses are presented in Section 14.3. The computer code, FLASH-R, used for the blowdown phase of the loss-of-coolant accident was modified to take into account the accumulator injection.

Research and development work has also been performed on the integrity of Zircaloy-clad fuel under conditions simulating those during a loss-of-coolant accident. Under the conservatively elevated temperatures predicted for the fuel rods during loss-of-coolant accident, the clad may burst due to a combination of fuel rod internal gas pressure and the reduction of clad strength with temperature. Burst cladding could block flow channels in the core, so that core cooling by the safety injection system would be insufficient to prevent fuel rod melting. Rod burst experiments have, therefore, been conducted on Zircaloy rods. The results of single-rod tests have been presented to the AEC in WCAP-7379-L Volume I (Westinghouse Proprietary) and Volume II. The results of multi-rod tests have been reported to the AEC in WCAP-7495-L.

Systems For Reactor Control During Xenon Instabilities

Extensive analytical work has been performed on reactor core stability(Reference 3, Reference 4, and Reference 5). These indicated that a core of this size may be unstable against axial power redistribution, but is nominally stable against transverse (denoted X-Y) power oscillations. The plant was, therefore, provided with instrumentation and control equipment which would allow the operator to detect and suppress the axial power oscillations.

The original plant design provided for part-length control rods to control axial power oscillations which could result from the potential of power spatial redistribution caused by instabilities in local xenon concentration. Initial plant operations established that part-length control rods were not necessary for control of axial power oscillation. The part-length control rods at Point Beach Nuclear Plant Units 1 and 2 were subsequently removed.

Control information for axial power oscillation suppression is obtained from four long ion chambers, each divided into an upper and lower section mounted vertically outside the core. Both calculation and experimental measurements at SENA, San Onofre, and Haddam Neck have shown that this out-of-core instrumentation represents in-core power distribution adequately for power distribution control(Reference 5).

The control strategy is based on the difference in output between the top and bottom sections of the long ion chambers. If the operator allows axial power imbalance to exceed operating limits, various levels of protection are invoked automatically. These include generation of alarms, turbine power cutback, blocking of control rod withdrawal, and reactor trip. This capability is described in Section 7.0.

Containment Spray Additive For Iodine Removal

Initially, sodium thiosulphate, $Na_2S_2O_3$, was proposed as the iodine removal additive to the boric acid containment spray, but an evaluation program led to the selection of sodium hydroxide, NaOH. The results of the evaluation program are detailed in Reference 6 and are summarized briefly below:

1. Chemical Characteristics

   The $Na_2S_2O_3$ solution was found to be oxidized by air at the post-accident temperatures in containment. NaOH was not unstable in this way.

2. Iodine Removal Characteristics

   The removal efficiency of the NaOH solution (at pH not less than 9.5) was comparable to that of the $Na_2S_2O_3$ solution.

3. Materials Compatibility

   Corrosion rates of copper and copper-alloy heat exchanger tubing were reduced by more than an order of magnitude compared with high pH $Na_2S_2O_3$ solution and were acceptably low (<0.01 mils/month at 100^0F) for the application. These tests showed that pitting or local corrosion did not occur.

4. Radiolysis

   The NaOH solution was radiolytically stable, and liberates significantly less net hydrogen than the unstable $Na_2S_2O_3$ solution.

Therefore, further testing has centered on the use of NaOH as the spray additive leading to the development of a technical basis for its inclusion in the plant engineered safety features as a means of "fixing" absorbed iodine, enhancing the natural rate of deposition of I_2, and thus lowering the calculated off-site thyroid dose resulting from a postulated release of fission products to the containment atmosphere.

Section 6 gives a further discussion of iodine removal by the containment spray system.

Blowdown Capability Of Reactor Internals

The forces exerted on reactor internals and the core following a loss-of-coolant accident are computed by employing the BLODWN-2 digital computer program developed for the space-time-dependent analysis of multi-loop PWR plants. This program and the models used are discussed in Section 14.3.3.

Reactor Vessel Thermal Shock

Research was performed prior to and following the issuance of the Point Beach Operating Licenses to determine the effect of the addition of cold water from the accumulators to the reactor pressure vessel. This research considered three failure modes: the ductile failure mode, the fatigue yielding mode and the brittle failure mode. Analysis of the ductile and fatigue modes determined that reactor vessel integrity is maintained following addition of the accumulator water. Extensive analysis of the brittle failure mode demonstrated adequate reactor vessel fracture toughness to prevent brittle failure for a period of several years of plant operation.

Subsequently, but before the end of the analyzed period, the NRC issued 10 CFR 50.61, "Fracture Toughness Requirements for Protection Against Pressurized Thermal Shock Events." 10 CFR 50.61 contains "screening criteria" for material fracture toughness, such that, if the materials of construction of the reactor vessel for a nuclear power plant maintain fracture toughness in compliance with the screening criteria, the functional integrity of the reactor vessel is ensured. It has been demonstrated that Point Beach Units 1 and 2 have adequate fracture toughness to be in compliance with the screening criteria of 10 CFR 50.61 through the end of their Operating Licenses. Therefore, brittle failure of the Point Beach reactor vessels is not a credible failure mode.

Identification Of Contractors

The Licensee engaged or approved the engagement of the contractors identified below in connection with the design and construction of the Point Beach Nuclear Plant. However, irrespective of the contractual arrangements discussed below, Wisconsin Electric Power Company is the sole holder of the operating licenses and, as the Licensee, is responsible for the design, construction, and operation of the Point Beach Nuclear Plant.

Point Beach Nuclear Plant was designed and built by Westinghouse Electric Corporation as prime contractor for the Licensee. Westinghouse contracted to provide a complete, safe, and operable nuclear power unit ready for commercial service. The project was directed by Westinghouse from the offices of its Atomic Power Divisions in Pittsburgh, Pennsylvania, and by Westinghouse representatives at the plant site during construction and plant startup. Westinghouse engaged the engineering firm of Bechtel Corporation, San Francisco, California, to provide the design of the structures and non-nuclear portions of the plant and to prepare specifications for the purchase and construction thereof. The Licensee reviewed the designs and specifications prepared by Westinghouse and Bechtel to assure that the general plant arrangements, equipment, and operating provisions were satisfactory.

The plant was constructed under the general direction of Westinghouse through Bechtel as the general contractor who was responsible for the management of all site construction activities and who either performed or subcontracted the work of construction and equipment erection.

NUS Corporation, Washington, D.C., was engaged as consultants on general site studies and meteorology. The firm of Murray and Trettel, Inc. assisted on meteorology. The firm of Dames and Moore, Chicago, Illinois, was engaged as consultants on earth science and geology. The engineering firm of Sargent and Lundy, Chicago, Illinois, was engaged to design cooling water facilities.

In addition, specialists in environmental sciences have participated in developing information concerning the Point Beach site. Harza Engineering Company of Chicago, Illinois, provided assistance in hydrology and the firm of John A. Blume and Associates of San Francisco, California, provided assistance is assessing the seismic history of the sites and establishing the ground accelerations associated with the design earthquake.

Stone and Webster Engineering Corporation of Boston, Massachusetts, provided assistance in system planning and site studies.

The Licensee had qualified representatives at the site throughout construction and, with their own personnel and consultants, inspected major components and construction installations. The Licensee's initial operating force performed acceptance testing of all structures and equipment.

REFERENCES

1. Wood, P. M., Baller, E. A., et al, "Use of Burnable Poison Rods in Westinghouse Pressurized Water Reactors," WCAP-7113 (October 1967).

2. Redfield, V. A., "CHIC-KIN... A Fortran Program for Intermediate and Fast Transients in a Water Moderated Reactor," WAPD-TM-479 (January 1, 1965).

3. Poncelet, C. G. and Christie, A. M., "Xenon Induced Spatial Instabilities in Large Pressurized Water Reactors," WCAP-3680-20 (March 1968).

4. McGaugh, J. D., "The Effect of Xenon Spatial Variations and the Moderator Coefficient on Core Stability," WCAP-2983 (August 1968).

5. Westinghouse Proprietary Report, "Power Distribution Control in Westinghouse PWR's," WCAP-7208 (October 1968).

6. Westinghouse Confidential Report, "Investigation of Chemical Additives for Reactor Containment Sprays," WCAP-7153 (March 1968).

7. Westinghouse Customer Report, "Fracture Mechanics Evaluation of the Wisconsin Electric Power Company and Wisconsin Michigan Power Company Point Beach Nuclear Plant Unit 2 Reactor Vessel," WCAP-8737 (February 1977).

8. Westinghouse Customer Report, "Fracture Mechanics Evaluation of the Wisconsin Electric Power Company and Wisconsin Michigan Power Company Point Beach Nuclear Plant Unit 1 Reactor Vessel," WCAP-8742 (February 1977).

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C.1 PURPOSE OF CHEMICAL ADDITION TO CONTAINMENT SPRAY

The containment spray system in this pressurized water reactor facility is one of the engineered safety features which is employed inside the containment to reduce the pressure and temperature of the atmosphere following a loss of coolant accident. The flow rate and inlet subcooling of the spray are sufficient to provide thermal capacity for condensing steam produced by dissipation of heat in the reactor and its associated systems. Minimum operability of these systems with on site power and under a single component failure contingency will prevent pressurization of containment above the design pressure with substantial margin.

The spray system also serves as a removal mechanism for fission products postulated to be dispersed in the containment atmosphere. The source term used for the LOCA dose analysis assumes major core degradation and is defined in Regulatory Guide 1.183 as being a release of gap activity (noble gases, iodines, and alkali metal nuclides) over a half-hour period followed by a core melt that releases additional activity in those three nuclide groups plus additional nuclides over a 1.3 hour duration. The iodine activity is assumed to be primarily in the particulate form (cesium iodide) with small fractions of the iodine in the elemental and organic forms. Nuclides other than the iodines and noble gases are all modeled as being in the particulate form. The sprays are effective at removing elemental iodine and particulates from the containment atmosphere but the organic iodine and the noble gases are not subject to removal by the sprays.

The chemistry of the spray solution is modified by adding NaOH, raising the pH to within the acceptable range of 7.0 to 10.5. The minimum pH in the containment sump needed to keep iodine in the iodate form is 7.0. A pH of greater than 7.0 assures the iodine removed by the spray is retained in the sump. The maximum pH is based on equipment qualification considerations and is set at 10.5 (Reference 1).

TECHNICAL BASIS FOR IODINE REMOVAL FACTOR

1. ELEMENTAL IODINE REMOVAL

The elemental iodine spray removal coefficient was calculated using the mathematical model given in SRP 6.5.2, Rev. 4 (Reference 2). An actual value of >20 hr^{-1} was calculated during injection; however, as directed in SRP 6.5.2, Rev. 4, the removal coefficient was limited to 20 hr^{-1} in the LOCA radiological analysis.

The removal rate constant was determined as follows:

$$\lambda_S = \frac{6(K_g)(T)(F)}{(V)(D)}$$

Where:

	λ_S	=	Spray Removal Constant, hr^{-1}
	K_g	=	Gas Phase Mass Transfer Coefficient, ft/min
	T	=	Time of Fall of the Spray Drops, min

F = Volume Flow Rate of Sprays, ft^3/hr

V = Containment Sprayed Volume, ft^3

D = Mass Mean Diameter of the Spray Drops, ft

Gas Phase Mass Transfer Coefficient:

K_g = 3 m/min = 9.84 ft/min (the minimum observed Kg, BNL-Technical Report A-3788, dated 8/12/86, p A-18, 21.)

Time of Fall of the Spray Drops:

T = 0.0893 min (calculated for injection based on spray flow rate, fall height, containment temperature and pressure.)

Volume of Flow Rate of Sprays:

F = 1,070 gpm (0.1337 ft^3/gal)(60 min/hr) = 8583 ft^3/hr

Containment Sprayed Volume:

V = 582,000 ft^3

Although SRP 6.5.2 states that the containment free volume is to be used, the spray removal coefficients have been calculated based only on the sprayed containment volume. In the dose calculations these removal coefficients only apply to activity while it is in the sprayed region of containment. This applies to both the elemental and particulate iodine removal coefficients.

Mass Mean Diameter of the Spray Drops:

D = 3.609E-3 ft (calculated for injection based on spray flow rate, fall height, containment temperature and pressure.)

$$\lambda_S = \frac{6(9.84 ft/min)(0.0893 min)(8583)ft^3/hr)}{(582,000 ft^3)(3.609\text{E}-3\text{ ft})} = 21.5 hr^{-1}$$

Recirculation spray has a flow rate of 900 gpm (7220 ft^3/hr), an associated fall time of 0.0899 minutes, and a drop diameter of 3.56E-3 ft., resulting in a calculated removal coefficient of 18.4/hr. This is conservatively reduced to 9.2/hr. for use in the analysis to address loading of the recirculating solution with elemental iodine.

2. PARTICULATE IODINE REMOVAL

The particulate iodine spray removal coefficient was calculated using the mathematical model given in SRP 6.5.2, Rev. 4 . The removal rate constant was determined as follows:

$$\lambda_p = \frac{3(h)(F)(E)}{2(V)(D)}$$

Where: λ_p = Spray Removal Constant hr^{-1}

h = Drop Fall Height, ft

F = Volume of Flow Rate of Sprays, ft^3/hr

V = Containment Sprayed Volume, ft^3

E/D = Ratio of a Dimensionless Collection Efficiency E to the Average Drop Diameter D.

Spray Drop Fall Height:

h = 131.58 - 66.0 = 65.58 ft The fall height is defined as the distance from the operating deck to the lowest spray ring header.

Volume Flow Rate of Sprays for injection:

F = 1,070 gpm (0.1337 ft^3/gal)(60 min/hr) = 8583 ft^3/hr

Containment Sprayed Volume:

V = 582,000 ft^3

E/D ratio: These values were taken from SRP 6.5.2

E/D = 10 m^{-1} for $M_o/M_t \leq 50$ used to calculate λ_{p-1}

E/D = 1 m^{-1} for $M_o/M_t > 50$ used to calculate λ_{p-2}

Where Mo/Mt is the ratio of the initial aerosol mass to the aerosol mass at time t

$$\lambda_{p-1} = \frac{3(65.58ft)(8583ft^3/hr)(10m^{-1})(0.3048m/ft)}{2(582,000ft^3)} = 4.42hr^{-1}$$

$$\lambda_{p-2} = 0.1 \times 4.42hr^{-1} = 0.442hr^{-1}$$

Recirculation spray has a flow rate of 900 gpm (7220 ft^3/hr), resulting in calculated removal coefficients of 3.72/hr and 0.372/hr.

3. ELEMENTAL IODINE DECONTAMINATION FACTOR

The maximum achievable elemental iodine decontamination factor (DF) for the containment atmosphere achieved by the containment spray system was calculated using the mathematical model from SRP 6.5.2, Rev. 4. The elemental iodine DF for the containment atmosphere is determined by the following equation:

$$DF = 1 + [V_S/(V_C - V_S)](PC)$$

Where: DF = decontamination factor

V_S = volume of liquid in containment sump and sump overflow, ft^3

PC = partition coefficient for iodine in water

V_C = containment net free volume, ft^3

Volume of Liquid in Containment Sump and Sump Overflow = 243,000 gal = 3.25 E4 ft^3

Containment Net Free Volume

V_C = 1.0E6 ft^3

Partition Coefficient for Iodine in Water

PC = 10,000

Figure 33 from NUREG/CR 2900, "Predicted Rates of Formation of Iodine Hydrolysis Species at pH Levels, Concentrations, and Temperatures Anticipated in LWR Accidents," which shows partition coefficient for different pH solutions as a function of time (the PC increases with time) for water at 100°C was used to determine the appropriate partition coefficient. Using a pH of 7.0, the partition coefficient is 2000 at 100 seconds (0.0278 hr), and even higher as time continues. From these values, a partition coefficient of 10,000 would be a conservative value to use since the spray will be used for at least 60 minutes.

$$DF = 1 + \frac{(3.25E4)(1.0E4)}{(1.0E6 - 3.25E4)} = 337$$

The effectiveness of the spray in removing elemental iodine is presumed to end when the maximum elemental iodine DF is reached. As specified by SRP 6.5.2 the analysis limits the DF to a value of 200.

REFERENCES

1. Point Beach Calculation 2000-0036, "pH of Post LOCA Sump and Containment Spray," Revision 2, July 31, 2007.

2. NUREG-0800 Standard Review Plan, Section 6.5.2 "Containment Spray as a Fission Product Cleanup System, Revision 4, March 2007.

3. NRC Safety Evaluation "Issuance of License Amendments Regarding Use of Alternate Source Term," April 14, 2011.

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D DIESEL GENERATOR PROJECT

D.1 INTRODUCTION

Emergency Diesel Generators G-03 and G-04 and related auxiliary equipment were installed via Modification 91-116. The scope of the modification included the construction of the building to house the new EDGS, installation of new B train 4.16kV switchgear 1-A06 and 2-A06, 480 VAC motor control centers (MCC)1-B40 and 2-B40, and DC distribution panels D-28 and D-40, installation of new A train 480 VAC MCCs 1-B30 and 2-B30, installation of a new fuel oil supply system for both trains of EDGs, and the related underground piping, ducts, and cabling linking the equipment in the Diesel Generator Building (DGB) to the equipment in the Control Building.

A project design summary was submitted to the NRC for review (Reference 1, Reference 2, and Reference 3). The design summary included a list of the various codes and standards used in the project. The design summary submittal also included an evaluation of design conformance to the applicable sections of NUREG-0800, "Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants, LWR Edition" and the various 10 CFR 50, Appendix A General Design Criteria, Regulatory Guides and other standards referenced therein. The NRC formally approved the project design in a Safety Evaluation Report dated October 24, 1994 (Reference 4).

Design criteria applicable to structures, systems, or components installed under Modification 91-116 may differ from that used in the original plant construction. This appendix supplements related design information provided elsewhere in the FSAR and is specific to SSC installed under Modification 91-116.

D.2 DIESEL GENERATOR BUILDING (DGB)

The diesel generator building is a two-story reinforced concrete structure. The structure is 110 feet long, 71 feet wide, and 52 feet high. The structure consists of reinforced concrete shear walls in the vertical direction and slabs in the horizontal direction. There are no masonry walls in the building. There is no high energy piping in the building. The building is designed as a Seismic Category I structure. The stairway structure attached to the building is Seismic Class III. All systems and components within the DGB designed as safety-related are designed and qualified as Seismic Class I. All systems and components not designated as safety-related are designed to ensure that a safe shutdown earthquake would not cause any structural failure resulting in damage to safety related systems or components.

Design Loads and Load Combinations

Dead loads, live loads, flood loads, construction loads, snow/rain loads, wind loads, tornado loads, earthquake loads, temperature loads, and pipe reaction loads have been considered in the design of the building.

Dead loads include the weight of framing, roofs, floors, walls, partitions, platforms and all permanent equipment. Minimum live loads of 100 psf, 250 psf, and 200 psf were specified for platforms and gratings, ground floor, and all other floors, respectively. The probable maximum precipitation and wave runup flood elevations were determined to have no detrimental effect on the DGB. All applicable construction loads were considered. A 30 psf snow load and 65 psf rain load were applied on the horizontal projected roof area. A l00-year recurrence wind of 108 mph was applied to the building. A lateral force caused by a funnel of tornado wind having a peripheral tangential velocity of 300 mph and a forward progress of 60 mph was applied to the building. Temperature loads were considered but were not used in the design, because they were not large enough to make a difference in the final design. Pipe reaction loads were based on the most critical transient or steady-state condition resulting from normal conditions, upset conditions, emergency conditions, and faulted conditions. The load combinations considered for the design of the DGB were in conformance with the Standard Review Plan 3.8.4, Other Seismic Category I Structures, Revision 1, July 1981.

Design Codes for the Diesel Generator Building

The reinforced concrete structure of the DGB was designed in accordance with the ACI-318-89, "Building Code Requirements for Reinforced Concrete." The steel work inside the DGB was in accordance with the AISC, "Manual of Steel Construction," 9th Edition, 1989.

Anchorage

The design of expansion anchors for piping in the DGB meets the requirements of NRC IEB-79-02, "Pipe Support Base Plate Designs Using Concrete Expansion Anchor Bolts." The design of pre-cast anchorage for large supports uses a 45° stress cone. This is the same methodology used in the original plant design calculations. The anchorage criteria developed by the Seismic Qualification Utility Group (SQUG) was used to qualify USI A-46 related anchors.

D.3 CABLE AND RACEWAY DESIGN

1. Cable and raceway separation and segregation within the DGB conforms to the requirements of IEEE 384-1992 except for the requirements of physical separation distances between Class 1E and non-Class 1E circuits within control switchboards.

2. Cable and raceway interconnections between the DGB and the existing plant facilities including all duct runs and other raceway systems excluding cables and raceways routed within existing plant facilities are separated and segregated in accordance with the requirements of IEEE 384-1992.

3. Safety-related (Class 1E) cables are segregated into two distinct Train B divisions, one for EDG G-03 (and its auxiliaries) serving Unit 1, and one for EDG G-04 (and its auxiliaries) serving Unit 2. Safety-related (Class 1E) cables are segregated into two distinct Train A divisions for power and control of the G-01 and G-02 Fuel Oil Transfer Pumps.

4. Cables designated as non-safety-related (non-Class 1E) are segregated from the safety-related cables by routing them in raceways which only contain nonsafety-related cables.

5. Instrument cables do not share raceways with power or control cables.

6. Cable and wire used to interconnect equipment are certified by the manufacturer as passing an approved flame test which meets the intent of IEEE 383-1974. This requirement does not apply to wire internal to factory assembled devices or pieces of equipment (such as the internal wiring of a computer display terminal). Custom assembled equipment such as control boards or switchgear assemblies were specified with flame resistant wiring which meets the intent of IEEE 383-1974.

7. All Class 1E insulated cable have copper conductors, are properly sized to the required ampacity and voltage drop, and are qualified in accordance with IEEE 383-1974.

D.4 VENTILATION SYSTEM

The DGB ventilation systems are designed to provide a suitable environment for the operation of the EDGs, and their associated auxiliary components during all modes of plant operation, including accident conditions. The ventilation system consists of safety-related, and non-safety related portions or subsystems. The non-safety related subsystem provides EDG room heating and cooling when the EDG is not in operation. During EDG operation, the safety-related ventilation subsystem operates to maintain temperatures within the required personnel and equipment limits. Safety related heaters maintain the temperature in the fuel oil transfer pump and day tank rooms above the fuel oil cloud point.

During EDG standby modes, one exhaust fan may run continuously during the cooling season to maintain room temperatures below 105°F. Unit electric heaters are provided to maintain a minimum temperature of 50°F during the heating season. Each EDG room has two thermostatically controlled exhaust fans to maintain the rooms below 120°F during EDG operation. Air is admitted to the room via gravity dampers, which are protected from missiles.

D.5 COMBUSTION AIR INTAKE AND EXHAUST SYSTEM

Each G-03 and G-04 engine has an independent intake and exhaust system to supply fresh air to the engine for combustion and to dispose of the engine exhaust to atmosphere. Intake air for each EDG engine is taken from the outside, no less than 20 feet above grade and away from the exhaust line discharge. Intake air is drawn through an oil bath air intake filter, an intake silencer, and a turbocharger compressor. Exhaust gases are discharged from the cylinders through the turbocharger and exhaust silencer to the atmosphere.

Separation of the exhaust system from the air intake system substantially reduces the possibility of contamination of the intake air with exhaust gases. Interaction of the combustion air intake with other plant related exhaust, fires, or failure of onsite gas storage vessels are precluded by elevation differences between the air intake and these potential sources.

The diesel generator intake and exhaust system is designed as a safety-related system. The design and operation of the G-03 and G-04 EDG engine intake and exhaust system conforms with the guidance as described in the SRP Section 9.5.8, Emergency Diesel Engine Combustion Air Intake and Exhaust System, Revision 2, July 1981.

D.6 ENGINE COOLING SYSTEM

The G-03 and G-04 engines are each provided with an independent closed glycol (coolant) cooling system which cools the engine jacket, cylinder block, aftercooler, and the lube oil cooler. The system is provided with two engine-driven pumps, an expansion tank, a coolant-to-air heat exchanger (radiator), a drain tank, and a three-way thermostatic valve. In addition, the cooling system is provided with a preheating circuit to facilitate quick startup of the diesel engine. The preheating circuit contains an electric immersion heater.

In standby, coolant heated by the thermostatically controlled immersion heater circulates through the lube oil cooler and engine by thermosyphon action to warm the engine. During EDG operation, the coolant temperature is maintained at design temperature by a 3-way thermostatic valve which will either direct flow to, or bypass the radiator.

With the exception of the coolant drain tank and its associated transfer pump and piping, expansion tank fill, overflow, vent beyond the first isolation valve, and drain line valve, the EDG engine cooling system is designed as a safety related, Seismic Class I system.

The design and operation of G-03 and G-04 EDG engine cooling system conforms with the guidance as described in the SRP Section 9.5.5, Emergency Diesel Engine Cooling Water System, Revision 2, July 1981.

D.7 STARTING AIR SYSTEM

G-03 and G-04 each have an independent air starting system, consisting of a diesel-driven air compressor, a motor-driven air compressor, an after cooler, a wet air receiver, an air dryer, and two banks of air receivers. With the exception of the portion from the air compressors, up to the inlet side of the check valve downstream of the air dryer, the system is designed as a safety-related Seismic Class I system.

The design and operation of the starting air system for G-03 and G-04 conforms with the guidance as described in the SRP Section 9.5.6, Emergency Diesel Engine Starting System, Revision 2, July 1981.

D.8 LUBE OIL SYSTEM

An individual lubricating oil system is provided for each of the G-03 and G-04 engines. The system is a combination of four separate subsystems which are the main lubricating system, piston cooling system, scavenging oil system, and auxiliary lube oil system. Each system has its own pump or pumps. The main lubricating, piston cooling, and scavenging oil pumps are driven from the accessory gear train of the engine. The main lubricating oil pump and piston cooling oil pump, although individual pumps, are both contained within a single housing and are driven from a common shaft.

The main lubricating oil system supplies oil under pressure to the various moving parts of the engine. The piston cooling system supplies oil for piston cooling and lubrication of the piston pin bearing surface. During operation, oil is drawn from the sump through a strainer by the scavenging oil pump and discharged through a main oil filter, to the lube oil cooler and then into the main lube oil strainer housing to supply the main lubricating oil pump and piston cooling oil pump.

The auxiliary lube oil system which provides the capability of automatic fast starting consists of two AC motor driven pumps. One is the soakback pump, which prelubes the turbocharger bearings so that the bearings are fully lubricated when the engine receives an automatic start requiring rated speed and application of rated load within a matter of seconds. It also removes residual heat from the turbocharger bearing area upon shutdown of the engine. The other pump will circulate warm oil through the oil system and keep the engine in a constant state of readiness for an immediate start.

With the exception of the auxiliary lube oil system and the lube oil tank fill line, the lube oil system is designed as a safety-related and Seismic Class I.

The design and operation of the lube oil system for G-03 and G-04 conforms with the guidance as described in the SRP Section 9.5.7, Emergency Diesel Engine Lubrication System, Revision 2, July 1981.

D.9 FUEL OIL SYSTEM

The design and operation of the fuel oil storage and transfer system conforms with the guidance as described in the SRP Section 9.5.4, Emergency Diesel Engine Fuel Oil Storage and Transfer System, Revision 2, July 1981.

D.10 REFERENCES

1. VPNPD-93-171, “Design Summary for the Installation of Two additional Emergency Diesel Generators - Point Beach Nuclear Plants, Unit 1 and 2,” dated September 24, 1993 and attached Report REP-0026, “PBNP Diesel Project Design Submittal,” Revision 0, dated September 21, 1993.

2. VPNPD-94-057, “Technical Specification Change Request 166,” dated May 26, 1994 and attached portions of Report REP-0026, “PBNP Diesel Project Design Submittal,” Revision 1, dated May 24, 1994.

3. NPL 94-0264, “Addendum to Technical Specification Change Request 166,” dated July, 1994 and attached portion of Report REP-0026, “PBNP Diesel Project Design Submittal,” Revision 2, dated June 22, 1994.

4. NRC Safety Evaluation 94-0030, “Emergency Diesel Generator Addition Project, Point Beach Nuclear Plant,” October 24, 1994.

5. 10 CFR 50.59 Screening SCR 2013-0213, “FSAR Sect 2.5 PMP Flood,” Revision 1, January 28, 2014.

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I.1 10 CFR 50, APPENDIX I EVALUATION OF RADIOACTIVE RELEASES FROM POINT BEACH NUCLEAR PLANT

I.1 INTRODUCTION

Appendix I to 10 CFR Part 50 of the Nuclear Regulatory Commission (NRC) regulations, published in May, 1975, sets forth numerical guidelines for design objectives and limiting conditions for operation to maintain releases of radioactive materials from light water reactors "as low as is reasonably achievable." Section V.B of Appendix I requires the holders of permits or licenses for operation of light water reactors to submit information necessary to evaluate the means employed to meet the objectives of Appendix I. This appendix contains information for the evaluation in response to guidelines provided by the Commission in February, 1976.

Radioactive waste system and related systems are described in the FSAR, Section 9.0 and Section 11.0. In the initial plant design provisions were made for processing of all radioactive liquid and gaseous wastes prior to release via monitored pathways to the environment. Brief descriptions of the various systems and operation are as follows.

I.1.1 LIQUID RADIOACTIVE WASTE SYSTEM (See Note 1)

All liquid radioactive wastes from controlled areas of the plant are collected in the liquid radioactive waste system waste holdup tank. These wastes are then processed by evaporation, as a minimum, and are released to the circulating water discharge on a batch basis. Each batch is analyzed prior to release. Filtration and demineralization equipment is available for further processing prior to release. Liquids are normally not recycled from this system.

I.1.2 GASEOUS RADIOACTIVE WASTE SYSTEM (See Note 1)

Initial plant design incorporated a compressed gas decay tank system supplying cover gas for tanks containing un-degassed reactor coolant. Cover gas (primarily nitrogen) displaced by filling tanks and gas from chemical and volume control system gas strippers is compressed and stored in gas decay tanks. This gas is reused as cover gas when tanks are drained by processing or transfer of liquids. Periodically, gas must be released. The release is on a batch basis following a minimum decay time specified by Technical Specifications. Each batch is analyzed prior to release.

I.1.3 SECONDARY SYSTEM WASTES (See Note 1)

Turbine building drains from both Units 1 and 2 are collected and routed to the effluent sump. Potable Water System Reverse Osmosis unit concentrate discharge and filter backwash are drained into the plant effluent sump. The façade sumps are normally pumped to the effluent sump. Sanitary wastes from the plant are routed to the plant sewage treatment system, which also discharges to the effluent sump. The effluent sump is pumped to the retention pond. The retention pond overflow effluent is normally released to a pathway subject to monitoring via radiation monitor RE-230 to the circulating water system. Capability for further processing of these wastes is not provided.

Initial plant design incorporated a flash tank for pressure reduction and cooling of the steam generator blowdown for each unit. The vent from each flash tank is routed to a plant ventilation exhaust. Liquid from the flash tank is routed to the circulating water discharge. Provisions are also included for routing this liquid to the boric acid evaporators in the chemical and volume control system during periods of operation with significant primary-to-secondary leakage. Processed liquids are normally not recycled from this system.

I.1.4 CHEMICAL AND VOLUME CONTROL SYSTEM (See Note 1)

The chemical and volume control system (CVCS) holdup tanks are shared between Units 1 and 2 and collect reactor coolant letdown for boron control and miscellaneous other reactor coolant drains. These liquids are then processed by ion exchange, gas stripping, filtration, and evaporation in the boron recovery portion of the CVCS. Boric acid evaporator condensate is collected and monitored on a batch basis prior to recycle to the reactor makeup water storage tank or release to the circulating water discharge. Concentrated boric acid is sent to the boric acid storage tanks or is solidified in cement and shipped offsite for burial. Evaporator condensate from this system is recycled as far as practicable for use as reactor makeup water.

I.1.5 PLANT VENTILATION AND FILTRATION SYSTEM (See Note 1)

Ventilation air from buildings normally containing radioactive materials and equipment is exhausted through HEPA and/or carbon adsorber equipment depending on the potential for significant releases. Turbine building ventilation is exhausted through roof exhausters with no treatment.

Containment ventilation systems include HEPA and carbon adsorber equipment in internal recirculation systems and purge systems.

I.1.6 PREVIOUS RADIOACTIVE WASTE SYSTEM MODIFICATIONS (See Note 1)

In 1971, Licensees completed conceptual designs of additional equipment to augment the initial plant systems and allow further reduction of radioactive releases from Point Beach Nuclear Plant. This additional equipment included treatment of air ejector offgas, larger evaporation equipment, gas stripping and decay processes, and cryogenic adsorption equipment for removal of long-lived noble gases from waste gas prior to release.

The additional evaporation equipment is used to process radioactive liquid waste and can be used to process steam generator blowdown from either unit. The capability for recycle of processed blowdown is also incorporated in these modifications. In addition, steam generator blowdown tank vent condensers are used to minimize potential gaseous releases.

Air ejector offgas from Units 1 and 2 passes through a delay duct for decay of short-lived isotopes and can be processed by a carbon adsorber prior to release.

Gas stripper equipment is used to maintain reactor coolant gas concentrations at low levels by stripping the letdown from each unit. Stripped gas from the gas strippers is sent to charcoal decay tanks shared by Units 1 and 2. Effluent from the charcoal decay tanks is normally recycled to Unit 1 and Unit 2 volume control tanks in the CVCS to minimize gaseous releases. If stripped gas is released, it can be processed for krypton removal in the cryogenic adsorption equipment prior to release. The adsorbed krypton is then stored in a gas decay tank.

I.1.7 SUBSEQUENT CHANGES TO THE WASTEWATER EFFLUENT SYSTEM

In 2002, conveyor type filters replaced the Retention Pond. A modification installed two filtration conveyors capable of processing 300 gpm each through a roll of paper media. These new filtration conveyers were installed to process the turbine hall sumps and the water treatment wastewell to provide assurance of compliance with the WPDES permit for total suspended solids. After the installation of the conveyers the turbine hall sump was rerouted to the conveyers and isolated as an input to the effluent sump. As part of the retirement of the retention pond, the wastewater stream from the plant effluent sump discharge was rerouted back into the plant and joined the common discharge piping downstream of the new filters, but upstream of RE-230, Wastewater effluent process monitor. The effluent sump was routed downstream of the filters because the inputs to the sump (sewage treatment plant effluent and potable water RO unit filter backwash and reject), meet the WPDES permit for solids without further treatment. The inputs into the effluent sump are routed past RE-230 prior to discharge.

A third filtration conveyer was installed to process the facade sump drains. The façade sumps were rerouted to a 30-gpm conveyor, and the filter media is checked for contamination prior to disposal. This limits the spread of contamination and will prevent cross contamination of normally clean systems.

The Retention Pond was subsequently capped and abandoned.

I.1.8 SUBSEQUENT CHANGES TO THE LIQUID RADIOACTIVE WASTE SYSTEM

A filtration/demineralization system has been added to the liquid radioactive waste system, and serves as the primar means of processing liquid radioactive waste. Wastes are processed and released to the circulating water discharge on a batch basis. Each batch is analyzed prior to release. If necessary, the processed liquid can be returned for reprocessing. The estimated liquid releases, based on use of the filtration/demineralization system, are listed in Table 11.1-3.

Note 1.Description reflects plant design information when the Appendix I evaluation was performed. See other FSAR sections as applicable for current system descriptions.

I.2 INFORMATION IN RESPONSE TO APPENDIX D OF DRAFT REGULATORY GUIDE 1.BB

The information in this section was provided in response to Draft Regulatory Guide 1.BB (Reference 1) and referenced the FSAR where appropriate. In many instances, plant operating data were used, rather than design data in the FSAR, because these data were representative of expected plant operation. Adjustments in the assumptions contained in Reference 1 also were included where appropriate to account for shared systems and structures at Point Beach Nuclear Plant.

The information and data provided in this response are part of the evaluation demonstrating compliance with 10 CFR 50, Appendix I governing design (dose) objectives for radioactive effluents. Updates or changes to individual parameters are not to be made in the remaining sections (i.e., 2.0 – 9.0) unless a complete re-evaluation is to be performed. However, design or procedural changes that impact the calculation results or conclusion of this evaluation are to be updated in the appropriate sections of the evaluation. PBNP effluents are controlled, quantified, and evaluated pursuant to the programs required by the PBNP Offsite Dose Calculation Manual.

I.2.1 GENERAL

a. Maximum core thermal power is 1518.5 MWt as stated in the FSAR, Table 3.2-1, and Operating Licenses DPR-24 and DPR-27.

b. 1) The total calculated mass of uranium and plutonium in an equilibrium core is as follows:

	Beginning Of Life	Middle Of Life	End Of Life
Uranium (as U), lbs.	105,409	104,816	104,093
Plutonium (as Pu), lbs.	425	583	711

These values are based on an average burnup of 9300 MWD/MTU and operation at approximately 80 percent capacity factor.

2) Reload fuel is enriched to 3.1 weight percent uranium U^{235}

3) There is no fissile plutonium in reload fuels at the present time.

c. 1) The assumed plant capacity factor is 80 percent.

2) The assumed fuel defect level is 0.12 percent. The fuel cladding is Zircaloy.

3) Concentrations of fission, corrosion, and activation products in the primary and secondary coolant are given in Table I.3-2 and Table I.3-3, respectively, and are based on calculational methods recommended by Reference 1.

d. The quantity of tritium released in liquid and gaseous effluents is 610 and 610 curies per year, respectively, as calculated according to Reference 1 assumptions. Tritium quantities released in liquid and gaseous effluents based on plant operating data are 859 and 110 curies per year, respectively.

I.2.2 PRIMARY SYSTEM

a. The total calculated mass of primary coolant in the system (excluding the pressurizer and purification system) is 247,600 pounds per unit at full power. This value is based on volumes given in the FSAR, Table 4.1-1 and Table 4.1-3, with operation at T_{avg} of 570°F and a pressure of 2250 psig.

b. The average primary coolant letdown rate to the purification system is 40 gallons per minute (19,800 pounds per hour) for each unit, based on information in the FSAR, Table 9.3-2.

c. The average flow rate through the cation demineralizers in the purification system is zero. Although initial design and operation included a cation demineralizer in series with a mixed bed demineralizer present plant operation normally utilizes only a single mixed bed demineralizer. Lithium control is accomplished with a mixed bed in H_3BO_3 form. This change was made necessary by the limited availability of lithium-7 hydroxide and lithium-7 form demineralizer resins.

d. The average flow rate to the CVCS holdup tanks is approximately 1.1 gallons per minute (564 pounds per hour) for each unit, based on plant operating data for 1974 and 1975.

I.2.3 SECONDARY SYSTEM

a. Each unit has two U-tube recirculating type steam generators. The carryover assumed in the evaluation is 0.20 percent for each steam generator based on plant measurements.

b. The steam flow is 6.62 x 10^6 pounds per hour (3.31 x 10^6 pounds per hour per steam generator) based on the FSAR, Table 4.1-4.

c. The mass of steam in each steam generator at full power is 5,230 pounds, based on the FSAR, Table 4.1-4, and steam conditions of 521°F and 821 psia.

d. The mass of liquid in each steam generator at full power is 80,240 pounds based on the FSAR, Table 4.1-4, and saturated conditions at 821 psia.

e. The total mass of coolant in the secondary system at full power is 197,600 pounds (excluding the steam generators and the condenser hotwells) based on calculations from plant measurements.

f. The primary to secondary leak rate assumed in the evaluation is 100 pounds per day for each unit.

g. Each steam generator is provided with a blowdown connection located above the tubesheet. The blowdown is presently routed to a blowdown flash tank in each unit through throttling valves. The discharge from the flash tank is pumped through a filter to the plant circulating water discharge. Each blowdown flash tank is provided with a vent condenser cooled by service water. Modifications to the present system were made to allow heat recovery and processing of blowdown by the filtration/demineralization system if required prior to release.

During operation with significant primary to secondary leakage, steam generator blowdown can be processed at a reduced rate by routing the affected steam generator(s) blowdown to the waste holdup tank and the filtration/demineralization system; which is shared by Units 1 and 2. The steam generator blowdown system is further discussed in the FSAR, Section 10.1 and Section 11.1.

Steam generator blowdown rates are normally on the order of 25 gallons per minute (12,500 pounds per hour) per steam generator. This is the average value used in the evaluation.

h. Point Beach Nuclear Plant does not have provisions for condensate polishing demineralizers.

I.2.4 LIQUID WASTE PROCESSING SYSTEMS

a. Information on sources of radioactive liquid wastes, flow rates, and expected radioactivity concentrations is provided in Table I.2-1. These values are based on recommendations of Reference 1, where appropriate, and on plant operating data. All liquid waste sources are calculated assuming plant operation for 365 days per year except for steam generator blowdown which is adjusted for an 80 percent capacity factor.

Since Point Beach Nuclear Plant is a two-unit plant with many shared systems and structures, it is not appropriate in all cases to double the values for a single unit as recommended by Reference 1. In addition, because of the sharing, releases cannot be directly attributed to either Unit 1 or Unit 2 in most cases. Therefore, the information presented in Table I.2-1 represents the total for Point Beach Nuclear Plant.

Values provided in Reference 1, Table B-17, are used and are doubled for the two-unit plant except for the following items:

1) Laboratory drains are not doubled since there is a single laboratory for two units with drains directed to the liquid waste system.

2) Detergent wastes are not doubled since there is a single laundry for two units.

3) In addition to turbine building floor drains, additional secondary system waste is generated by continuous chemical analyzers in the secondary system. These have been added in addition to the turbine building floor drains value in Reference 1.

4) Point Beach Nuclear Plant does not regenerate demineralizers in primary systems and no allowance is made for these wastes.

5) Evaporator condensate from the boric acid evaporators is recycled as reactor makeup water if the purity is within chemical specifications for makeup, however, releases from this source occur frequently. Table I.2-1 includes this source as a separate category.

Comparison of plant released for 1974 and 1975 with values derived from Table I.2-1 indicates good agreement. Table I.2-1 is therefore used in the evaluation of releases.

Capacities of tanks and processing equipment used in calculating holdup times and decontamination factors for each processing step are provided in Table I.2-2 and Figure I.2-1, respectively.

Calculated liquid source terms by isotope and waste category are provided in Table I.7-3. Calculated holdup times for each waste category are provided in Table I.2-3. Observed operational liquid releases are provided in Table I.7-6.

b. Piping and instrument diagrams for radioactive waste systems and related systems are shown in the FSAR, Figure 9.3-1 through Figure 9.3-5, Figure 10.1-1, Figure 11.1-1 through Figure 11.1-3, and Figure 11.2-1 through Figure 11.2-4. Process flow diagrams for the liquid waste system and the CVCS are presented in Figure I.2-1 and Figure I.2-2, respectively.

I.2.5 GASEOUS WASTE PROCESSING SYSTEM

a. The volume of gas stripped from the primary coolant is approximately 78,000 cubic feet per year for each unit based upon a primary coolant hydrogen concentration of 35 cc per kilogram at standard conditions, a normal letdown flow of 40 gallons per minute, and two cold shutdowns per year for each unit.

b. During normal operation, the primary coolant letdown flow for purification is continuously stripped, with stripped gas being routed to the gaseous radioactive waste processing system. The purified hydrogen from the charcoal decay tanks in the gaseous radioactive waste system is recycled to the volume control tanks as described in the FSAR, Section 11.2.

Prior to a refueling shutdown or a cold shutdown requiring opening of the primary system, the primary system is stripped of dissolved gases. Under these conditions, the purified gas is routed to the volume control tank of the other unit.

The gaseous radioactive waste system incorporates a closed cover gas system with pressurized storage tanks which are used to store gas displaced during filling of the tanks in the CVCS and from operation of the gas strippers in the boron recovery portion of the CVCS. When tanks are emptied by processing, the stored gas is then recycled to fill the tank space. Periodically, gas inventory requires release of a portion of the stored gas. Present operation of the system utilizes four gas decay tanks in the cover gas system. The fourth tank can be used for storage of krypton from the cryogenic absorption equipment.

Each of the four usable gas decay tanks in the cover gas system has a volume of 525 cubic feet and a maximum operating pressure of 105 psig at ambient temperature. The total volume released from the tank at maximum pressure is approximately 3750 cubic feet at standard conditions. Plant radioactive release records indicate average release rates ranging from 2 to 15 cfm during batch releases.

c. During normal operation, cover gas is routed between the CVCS holdup tanks and the gas decay tanks with small quantities of gas being produced from the gas strippers in the CVCS. The major source of gas is that produced by filling a CVCS holdup tank with letdown from the primary system during plant startup, load-follow operation, or boron dilution near the end of core life and from draining of the fuel transfer canal in the spent fuel pool. Normally, one gas decay tank is held in reserve to accommodate filling of one holdup tank. Releases are made as required to allow one gas decay tank to be held in reserve.

Minimum holdup time prior to release of a gas decay tank is 7 days as specified in Technical Specifications. Actual holdup times are significantly longer, based on plant experience on the order of one release per month.

Fill times for gas decay tanks are not predictable due to the variety of operating conditions which result in filling a tank and to the reuse of gas as cover gas. During letdown to the hold up tanks, the fill time is controlled by the maximum letdown rate of 80 gallons per minute. Under these conditions, the fill time is approximately 6 hours. During fuel transfer canal draining, the fill time is controlled by gas compressor capacity of 40 cubic feet per minute. Under these conditions, the fill time is approximately 1.5 hours.

Further discussion of the gaseous radioactive waste system is provided in the FSAR, Section 11.2.

d. HEPA filters are not provided downstream of the gas decay tanks.

e. Stripped gas from the continuously operating letdown gas strippers (one per unit) is routed to 3 charcoal decay tanks connected in series. These 3 tanks, common to both units, each contain approximately 1000 pounds of charcoal. Total volume of each tank is 46 cubic feet and normal operating pressure is 75 psig at ambient temperature. The dynamic absorption coefficients (K) for krypton and xenon are 77.7 and 1,386 cm^3/gm, respectively, at an operating pressure of 75 psig at 77°F. The dew point is 40°F. From Section 2.5.a, the operational flow rate is calculated at 0.37 cubic feet per minute at standard conditions for both units.

Stripped gas, mainly hydrogen, is normally routed from the charcoal decay tanks back to the reactor coolant system. Optional routing is to the cryogenic system for krypton removal or to the gas decay tanks in the cover gas system. An additional route to the auxiliary building vent exists but is not normally used.

f. Piping and instrumentation diagrams for the gaseous radioactive waste system are given in the FSAR, Figure 11.2-1, Figure 11.2-2, and Figure 11.2-3. A process flow diagram is presented in Figure I.2-3.

I.2.6 VENTILATION AND EXHAUST SYSTEMS

a. Areas of Point Beach Nuclear Plant which normally contain radioactive materials and which are provided with measures to reduce airborne radioactivity releases are shown in the FSAR, Figure 11.4-1 through Figure 11.4-8. Within these areas, the ventilation systems are designed so that flow is from areas of low potential for radioactive contamination to areas of higher potential. Piping and instrumentation diagrams for these ventilation systems are shown in Figure I.2-4 and Figure I.2-5. Areas of the plant which could contain low levels of radioactive contaminants with primary-to-secondary leakage, such as the turbine building, are not provided with HEPA or carbon adsorber equipment since releases from the areas are insignificant. A process flow diagram for all major ventilation systems is presented in Figure I.2-3. Ventilation and exhaust systems are as follows:

1) Containment Ventilation

Each containment is provided with a containment purge system, an internal cleanup system, and a purge vent which exhausts above the containment facade. Purge exhaust (12,500 cubic feet per minute) is through roughing filters, HEPA filters, and carbon adsorbers. The internal cleanup system (5,000 cubic feet per minute) is provided with roughing filters, HEPA filters and carbon adsorbers. The cleanup system is not necessarily operated prior to each purge and therefore no credit is taken in the evaluation of releases via containment ventilation.

Pressure buildup in the containment as a result of instrument air leakage is vented continuously at a rate of approximately 10 cubic feet per minute via the containment air monitor. This effluent is routed to the containment purge filters prior to release via the purge vent.

The gas stripper building ventilation is routed to the Unit 2 purge vent at flow rates varying from 400 to 12,000 cubic feet per minute, depending on building air temperature. Operational measurements indicate that only about 2 percent of the total plant noble gas release is via this pathway. Capability exists for routing this ventilation air through the Unit 2 containment purge filtration equipment.

2) Auxiliary Building Ventilation

The auxiliary building ventilation includes ventilation air from service building controlled areas and is exhausted through the auxiliary building and the drumming area vents located above the Unit 1 containment facade.

The drumming area vent receives ventilation air from the drumming station in the auxiliary building, general areas of the auxiliary building above elevation 46' and spent fuel pool areas. Roughing and HEPA filters are provided for this exhaust.

The auxiliary building vent exhausts air from the service building, chemistry laboratory, general areas of the auxiliary building and cubicles containing radioactive equipment. The chemistry laboratory exhausts to the auxiliary building vent through roughing filters, HEPA filters and carbon adsorbers. Service building ventilation and general areas and cubicles of the auxiliary building containing equipment with low potential for iodine releases are exhausted through roughing and HEPA filters. Areas of the auxiliary building with high potential for iodine releases are routed through roughing and HEPA filters to the auxiliary building vent with an optional route through carbon adsorbers and HEPA filters.

3) Turbine Building Ventilation

Units 1 and 2 share a combined turbine building. Outside air is provided at all levels of the building and is exhausted through 19 turbine building roof exhausters evenly spaced along the length of the turbine building roof.

4) Condenser Air Ejectors

Unit 1 and Unit 2 air ejectors discharge to a delay duct in the turbine building which provides a nominal one hour holdup prior to release via the auxiliary building vent. An optional route is through a carbon adsorber prior to the delay duct.

5) Radioactive Waste Gases

Releases of cover gas from gas decay tanks are directly to the auxiliary building vent at a controlled rate.

Stripped gas from the Unit 1 and Unit 2 gas strippers is normally routed through the charcoal decay tanks and back to the CVCS volume control tank for each unit. This gas may also be released directly to the auxiliary building vent. An optional route is to pass the charcoal decay tank effluent through cryogenic adsorption equipment prior to release. No credit for the cryogenic system is taken in calculating radioactive releases.

b. Decontamination factors of 10 for iodines through carbon adsorbers and 100 for particulates through HEPA filters are assumed for the evaluation, consistent with recommendations in Reference 1. All carbon adsorbers at Point Beach Nuclear Plant have a bed depth of 2 inches and a maximum face velocity of 40 feet per minute. Periodic testing of filtration equipment indicates decontamination factors at least equal to the above values. Credit is taken only for those filters which are normally in service.

c. Calculated gaseous release rates for Point Beach Nuclear Plant are provided in Table I.7 -1 and are based on methods recommended by Reference 1. Observed operational gaseous releases for 1974 and 1975 are presented in Table I.7-4 and Table I.7-5.

d. Release point descriptions are provided in Table I.2-4. The release vents are the highest points of the plant. Where a range is given, the lower flow is assumed for the evaluation.

Each containment has a net free volume of 1,065,000 cubic feet. The containments are continuously vented to the containment purge filters via the containment monitoring system at a rate of approximately 10 cubic feet per minute.

Periodic venting of containment through the purge outlet valves with the unit at power was allowed during early plant operation. This practice is no longer allowed by plant Technical Specifications. However, for the purposes of the evaluation and based on plant operation during 1974 and 1975, an average of 10 purges per year per unit is assumed during power operation and four purges per year per unit are assumed during shutdown. The average purge time is assumed to be 7 hours at a flow of 12,500 cubic feet per minute.

Since the containment cleanup system is not necessarily operated prior to each purge, no credit is taken for the system in evaluating releases from Point Beach Nuclear Plant.

I.2.7 REFERENCE

1. Draft Regulatory Guide 1.BB, "Calculation of Releases of Radioactive Materials in Liquid and Gaseous Effluents From Pressurized Water Reactors (PWR's)," Sept. 1975.

I.3 CALCULATED SOURCE TERMS AND RELEASES OF GASEOUS AND LIQUID EFFLUENTS

I.3.1 ORIGINAL APPENDIX I EVALUATION

The source terms (primary coolant and secondary side liquid and steam radioactivities) and the resulting radioactive releases (liquid and gaseous) are calculated using the basic assumptions and approaches recommended by NRC Draft Regulatory Guide 1.BB.

The procedures used in this evaluation provide essentially the same mathematical treatments as the PWR-GALE code used by the NRC staff. Values of plant parameters are based on Point Beach Nuclear Plant design and operating data.

The plant design and operating data, draft regulatory guide reference plant parameters, and applicable ranges are shown in Table I.3-1. Since the power level of 1518.5 MWt is outside the range given in Table I.3-1, the NRC references of plant coolant activities shown in Table B of Draft Regulatory Guide 1.BB have been adjusted. Table I.3-2 lists the resultant primary and secondary coolant radioactivity concentrations using these adjustment factors. Table I.3-3 lists the total primary and secondary liquid activities calculated in a similar manner.

I.3.2 IMPACT OF UPRATED POWER OPERATIONS

The impact of a 17.6% power uprate (1811 MWT, including a 0.6% instrument uncertainty) on the annual liquid and gaseous releases were estimated in Reference 1, using methodology and assumptions from NUREG-0017. The evaluation indicated an approximate 17.6% increase in the liquid effluent release concentrations compared to pre-uprate operations, as this activity is based on RCS activity possessing long half-lives (which increases in proportion to the power uprate percentage) and on waste volumes (which are essentially independent of power level within the applicability range on NUREG-0017). Tritium releases in liquid effluents increased proportionately to the power uprate.

Similarly for the gaseous releases, the impact of uprated power on Kr-85 and tritium is limited to the increase in power level, 17.6%, taking into consideration a 0.6% uncertainty in the power level. Isotopes with shorter half-lives have increases slightly greater than the uprate percentage, estimated at 18.1 %. The other component of gaseous releases (i.e., iodines and particulates via the building ventilation systems), although increased, have a negligible impact on dose to the public. This is because the iodines and particulates category includes tritium, which is the controlling dose contributor.

I.3.3 REFERENCE

1. Shaw Calculation 129187-M-0104, “Impact of EPU on Normal Operation Gaseous and Liquid Radioactive Effluent Releases,” dated March 26, 2009.

I.4. METEOROLOGY

I.4.1 METEOROLOGICAL PROGRAM AT POINT BEACH NUCLEAR PLANT

The meteorological monitoring program at Point Beach Nuclear Plant was conducted in accordance with requirements in existence at the plant licensing stage. The data used in this evaluation was obtained during the 4/19/67 through 4/18/69 period. The meteorological tower is located approximately 2,000 feet south of the nearest reactor containment. Wind speed and wind direction at the 150-foot level (approximate height of the containments) were monitored by Belfort Type M wind instruments. The wind data were recorded on the Belfort recorder located in a shelter adjacent to the base of the tower and were reduced by visual (equal area) methods.

Atmospheric stability classes were determined by calculating hourly values of wind range, defined as the difference in azimuth between the maximum and minimum wind direction values during each hour. Hourly wind range values were then divided by a factor of 6, and a σ_{Θ} versus Pasquill Stability Class relationship, now referenced in Regulatory Guide 1.23 (Reference 1), was applied to establish the stability class. Hourly average values of wind speed, wind direction, and atmospheric stability class were used to compute hourly X/Q and D/Q values.

Wind direction was recorded to the nearest degree. Wind speed was measured to the nearest mile per hour, while calms were determined by a calculational or computer threshold wind speed of 0.7 miles per hour and assigned to the last valid wind direction.

In order to calculate plume rise, ambient dry-bulb temperature is required. Since this parameter was not monitored at the site, monthly normals (1931-1960) at Kewaunee, Wisconsin (12 miles north) were used for each hour of the month considered.

a. Point Beach Meteorological Data

Table I.4-32 presents joint frequency distributions of wind speed and wind direction for each specific stability class, and all combined stability classes for the 4/19/67-4/18/69 onsite data period. Table I.4-33 presents similar distributions for each monthly period. A wind rose summary of Point Beach meteorology is presented in Table I.4-1.

b. Onsite Data Representativeness

Data obtained during the meteorological monitoring program at Point Beach Nuclear Plant is compared to that obtained from a program conducted at Haven, Wisconsin (approximately 30 miles south on the shore of Lake Michigan), during 1973 and 1974 as summarized in Table I.4-28. The latter program was designed in accordance with the guidance in Regulatory Guide 1.23. Table I.4-22, Table I.4-23, and Table I.4-24 provide a comparison of Haven and Point Beach data with that obtained at Milwaukee, Wisconsin, for concurrent and long-term periods.

National Weather Service data for General Mitchell Field, Milwaukee, Wisconsin, is presented in Table I.4-29 through Table I.4-31. The similarities between Point Beach and Haven are as expected since both sites are similar in surrounding terrain and both are located on the shore of Lake Michigan.

The following comparisons can be made from Table I.4-22, Table I.4-23, and Table I.4-24:

Comparison A - Point Beach (1967-1969) to Haven (1973-1974)

Comparison B - Milwaukee (1967-1969) to Milwaukee (1973-1974)

Comparison C - Milwaukee (1967-1969) to Milwaukee (1956-1975)

Comparison A shows the similarities between Point Beach data and Haven data. Comparison B shows the overall similarity of the meteorological conditions that occurred during the 4/19/67-1/18/69 period with those conditions occurring during the 6/1/73-5/31/74 period. Comparison C shows the long-term data representativeness with climatology, using the 1/1/56-12/31/75 Milwaukee data base. For the 1/1/65-12/31/75 period, only 3-hour observations were recorded by the National Weather Service, however, this has no significant bearing on the comparisons, since a large data sample is used.

Table I.4-22 shows stability class frequencies for the three sites and five data periods. Comparison A shows excellent similarity. The large preponderance of E, F, and G stabilities directly reflects the lake breeze phenomenon of undercutting cold air replacing warmer surface air, thus causing shallow pseudo-inversions. This is not present in the Milwaukee data, since the STAR (Reference 2) methodology is based on gross parameterization of incoming solar radiation and wind speed. “A” stabilities at this latitude are rare, since a solar angle of at least 60 degrees is required. Also, E, F and G stabilities can only occur at night. Thus, Milwaukee data cannot reflect the effect of the daytime lake breeze on the stability classifications. Comparison B shows good similarity in the overall meteorology for both the Point Beach and Haven data periods. Similarly, Comparison C indicates that both the 4/19/67-4/18/69, and the 6/1/73-5/31/74 periods are representative of the long-term climatology.

Table I.4-23 shows the frequency distribution of wind direction by quadrant (and offshore/onshore breakdown) for the three sites and five data periods. Comparison A shows small anomalies in the ESE-S and WNW-N sectors, while Comparison B shows minor differences in the NNE-E sectors. These anomalies reflect small synoptic-scale meteorological differences. For example, during the 4/19/67-4/18/69 period, Milwaukee had 22.0 percent WNW-N winds, while Haven had 27.2 percent. Those figures reflect the larger frequency of northerly component winds with an increase in latitude north from Milwaukee. Comparison C shows long-term representativeness of both the Point Beach and Haven data periods.

Table I.4-24 shows the average wind speed for each quadrant for the three sites and five data bases. Comparison A shows Point Beach somewhat windier than Haven, even though Comparison B indicates 6/1/73-5/31/74 to be the windier period. This is the result of the decreased friction of the earth's surface at the 150-foot Point Beach measurement, as opposed to the 10-meter Haven level, and the 20-foot Milwaukee level. Wind speed differences of this order can be found in year to year climatological variances. Comparison C shows overall similarity of both the Point Beach and Haven data periods with long-term climatology. Table I.4-22, Table I.4-23, and Table I.4-24 show general representativeness of the Point Beach data to long-term climatology data from Milwaukee. Table I.4-28 through Table I.4-32 present wind speed - wind direction point frequency distributions of the data used in the representativeness analysis.

It is concluded that the 4/19/67-4/18/69 Point Beach data are representative of the actual meteorology occurring at Point Beach, and also of the long-term climatology of the area. Since the present program produces representative meteorological data there is no basis for upgrading the program in accordance with Reference 1.

c. Wet Deposition

Table I.4-25 and Table I.4-27 present precipitation-wind frequency distributions and intensity frequency distributions for National Weather Service Stations in the vicinity of Point Beach.

The onsite data period is represented by Green Bay (Austin Straubel Field), while the long-term climatology precipitation wind rose is represented by Milwaukee data. Table I.4-27 shows that 90 percent of all precipitation falls at a rate of 0.09 inch/hour or less, and shows the lack of a well-defined rainy period within the growing and grazing season. Table I.4-25 shows the precipitation to be generally well distributed with wind direction and wind speed. Table I.4-26 shows that precipitation levels within a 50-mile vicinity of the site do not vary significantly. It is unlikely that significant wet deposition occurs near the Point Beach site. Thus, the D/Q analysis reflects dry deposition only.

d. Airflow Trajectory Regimes of Importance and Topography in the Vicinity of Point Beach

The Point Beach Nuclear Plant is situated near the shoreline of Lake Michigan in a relatively flat region of Wisconsin. Within a ten-mile radius of the plant, the scattered hills and knolls do not exceed 800 feet mean sea level (MSL) in any downwind sector. Plant grade is 606 feet MSL and major plant release points are at approximately 774 feet MSL. Based on the low relief of the surrounding terrain, airflow trajectory reversals caused by topographic obstacles are unlikely and, if they occur, are relatively insignificant. General topography within a 10-mile radius is shown in Figure I.4-1. Maximum topographic elevation vs. distance by sector is illustrated in Figure I.4-2.

Thunderstorm activity, squall lines and frontal passages are relatively infrequent in the vicinity of Point Beach, therefore, air flow reversals caused by their presence are minimal. These meteorological phenomena are generally short-lived and transitional and probably affect the overall local airflow less than one percent of the year. Based on the low frequency and short duration of these phenomena, as compared to an 8760-hour year, the overall effect on airflow reversals due to the phenomena are also relatively insignificant.

During the mid-spring to late-summer months (April through September), the lake is generally colder than the land. When the synoptic-scale meteorological conditions are weak and not very well established, a shallow flow from lake to land develops during the late morning to late afternoon hours. This airflow reversal phenomenon is called the “lake breeze.” The lake breeze, when well established, can penetrate as much as 25 miles inland. Conservatively assuming the lake breeze prevails six hours (1100LST - 1700LST) each day during the early spring through late summer (April through September) period, approximately 10 percent of the annual period would be subject to these conditions.

In order to conservatively account for airflow trajectory reversals with the Gaussian single-line trajectory model, the terrain correction factor, shown in Figure 2 of Regulatory Guide 1.111 (Reference 3) was applied to all X/Q and D/Q calculations. This factor assumes that the same air is advected four times over the same receptor location at distances of 1200 meters or less from the plant and approaches unity at greater distances. The terrain correction factor was conservatively applied to all occurrences, onshore or offshore winds, summer or winter, and day or night conditions. The application of Figure 2 terrain correction factors more than adequately compensates for the level of air trajectory reversals that would be experienced at PBNP.

I.4.2 DESCRIPTION OF X/Q AND D/Q MODELING PROCEDURES

In general, the methodology recommended by Reference 3 was used in the calculation of annual average and growing and grazing season average X/Q and D/Q values for the Point Beach site. Since there are a variety of release modes for the major release points, X/Q and D/Q must be evaluated for each operating condition. Six categories of release modes are defined and evaluated as follows:

Release Mode IA

This mode is the continuous exhaust of plant ventilation air through the auxiliary building vent. Since the exit velocity is high, this release is considered to be an elevated release subject to the constraints discussed in this section.

Release Mode IB

This mode is the periodic release of gas decay tank contents through the auxiliary building vent. The X/Q and D/Q values are evaluated for the gas decay tank release intervals and frequencies.

Release Mode IIA

This mode is the continuous release of 10 cubic feet per minute through each containment purge vent. Since exit velocities are negligible, the releases are considered ground level.

Release Model IIB

This mode is the periodic purge of containment through the containment purge vent. The exit velocities are high and the release is elevated. The X/Q and D/Q values are evaluated for the purge intervals and frequencies.

Release Mode IIC

This mode is the continuous release of gas stripper building ventilation through the Unit 2 containment purge vent. Exit velocities are variable and depend on building temperature; hence, the release is considered to be ground level.

Release Mode III

This mode is the continuous release of turbine building ventilation through the roof exhausters. The release is considered to be ground level.

A separate release mode was not defined for the drumming area vent, since the treatment assumed (HEPA) and the exit velocities and locations are essentially the same as that for the auxiliary building vent.

a. X/Q Model

The straight-line Gaussian diffusion model is used for X/Q calculations. Airflow reversals that are primarily caused by lake-breeze activity in the spring and summer months are conservatively accounted for by applying the correction factor (Ω(x)) presented in Figure 2 of Regulatory Guide 1.111. The following equation is utilized for annual average and grazing season average X/Q calculations:

$$\left[\frac{X}{Q}(x)\right]_{k1} = \frac{2.032}{N}\sum_{j=1}^{n1}\left[\frac{\Omega(x)}{x}\right]_{k}\left[\frac{E_t}{\bar{u}(\sigma_z^2(x)) + \frac{ch_b^2}{\pi}}\frac{1}{2}2 + \frac{(1-E_T)\exp-\frac{1}{2}\left(\frac{he(x)}{\sigma z}\right)^2}{\bar{U}\sigma_z(x)}\right] \quad (1)$$

The entrainment coefficient (E_T)is a function of the ratio of exit velocity (U_e) to wind speed (u) for conditionally elevated release points. For stacks that are at least twice the height of a nearby structure, $E_T = 0$. For vent released occurring below the level of a nearby structure, 100 percent downwash is conservatively assumed ($E_T = 1$). For vent releases occurring between 1 and 2 times the height of a nearby structure, a "conditionally elevated" release is assumed, and the entrainment coefficient is defined as follows:

$E_T = 0.0$ when $U_e/\hat{u} > 5.0$

$E_T = 0.30 - 0.06\,(U_e/\hat{u})$ when $1.5 < U_e/\hat{u} \leq 5.0$ (2)

$E_T = 2.58 - 1.58\,(U_e/\hat{u})$ when $1.0 < U_e/\hat{u} \leq 1.5$

$E_T = 1.0$ when $U_e/\hat{u} \leq 1.0$

The effective release height (h_e) is defined as:

$h_e(x) = h_r + \Delta h(x) - [h_t(x) + h_a]$ (3)

where Δh is the plume rise.

To calculate plume rise, let $S = \frac{g\,d\theta}{T\,dz}$ (4)

Then for A-D stabilities when x < 10 hr and for E-G stabilities when x < 2.4eq û/S$^{1/2}$, plume rise is given by:

$$\Delta h(x) = \frac{1.6}{\bar{u}}\left[\frac{gQH}{\pi C p_p T}^{1/3}(x)^{2/3}\right] \qquad (5)$$

For A-D stabilities, when x ≥ 10 h_r, plume rise is given by:

$$\Delta h(x) = \frac{1.6}{\bar{u}}\frac{gQH}{\pi C p_p T}^{1/3}(10h_r)^{2/3} \qquad (6)$$

For E-G stabilities when x ≥ 2.4 û/S$^{1/2}$, plume rise is given by:

$$\delta h(x) = 2.9\frac{gQH}{\pi C p_p T\bar{u}S}^{1/3} \qquad (7)$$

The topographic height ($h_t(x)$) is the actual height of the surface at the receptor point above plant grade. The aerodynamic downwash height correction (h_a) is defined by:

$$h_a = 3(1.5 - U_e/\bar{u})d \qquad (8)$$

For cases where entrainment occurs, credit is taken for vertical plume expansion in the wake behind the release point building.

b. D/Q Model

Deposition is calculated as follows:

$$\left[\frac{D}{Q}(x)\right]_{k1} = \left(\frac{\Omega(x)}{x}\right)_k\left(\frac{2\pi N}{16}\right)^{-1}\sum_{j=1}^{n_1}\left[n_1\left(\frac{\delta}{Q}\right)_{Gk}E_t + \frac{1}{n_t}\sum_{i=1}^{3}[1-(E_t)_i]n_{i1}\left(\frac{\delta}{Q}\right)_{ik}\right] \qquad (9)$$

Figure 7 of Reference 3 is used to determine ground release (entrained) relative deposition values, while Figures 8 through 10 of this Regulatory Guide are used to determine [d_i(x)]j values as a function of release height. Inspection of rainfall rate distributions at Austin Straubel Field in Green Bay, Wisconsin, for the 4/19/67-4/18/69 data period indicates that 90 percent of the hours with precipitation had totals of 0.09 inches or less. Therefore, it is unlikely that significant wet deposition occurs at the Point Beach site.

Dry deposition is calculated for elemental radioiodines and particulates only. The deposition rate for noble gases, tritium, carbon-14, and non-elemental radioiodines is too slow to allow accumulation at the distances considered in this evaluation. Although deposition and plume depletion occur simultaneously, the X/Q values are not reduced in order to remain conservative.

c. Methodology Employed For Intermittent Releases

The methodology employed in the calculation of intermittent release X/Q's and D/Q's is as follows and reflects current Site Analysis Branch practices:

1. One-hour sector-averaged X/Q values are calculated without terrain correction factors.
2. The 15% one-hour value is plotted at 1-hr. on log-log coordinates while the annual average value is plotted. At 8760 hours; a straight line is drawn, connecting the two points.
3. Log-log interpolation based on total ground intermittent release hours versus annual hours yields X/Q multiplier.
4. The multiplier is applied to annual average X/Q and D/Q values to obtain intermittent X/Q and D/Q values.

d. List of Symbols

1. Indices and Subscripts

i = index for elevated release stability group

j = index for number of hours

k = index for a particular receptor distance

l = index for a particular 22.5× sector

G = ground level

b = building

r = release

b = building

r = release

e = effective, exit

t = terrain

a = aerodynamic downwash

H = heat flux

P = pressure

2. Parameters

X/Q= relative concentration

D/Q= relative deposition rate

x = downwind (receptor) distance

$\Omega(x)$= terrain correction factor

N = total number of valid data hours

$\hat{u}$= average wind speed

h_b = building height

$h_e(x)$= effective release height

$\sigma_z(x)$= vertical diffusion coefficient

U_e = exit velocity

h_r = release height

$\Delta h(x)$= plume rise

h_t = topographic impaction height

h_a = aerodynamic downwash correction height adjustment

g = gravitational acceleration

Q_H = heat flux

Cp = specific heat at constant pressure

ρ = density of ambient air

T = ambient temperature

T_s = stack temperature

S = stability parameter

$d\Theta/dt$= lapse rate of potential temperature

d = inner stack diameter

δ = relative deposition

n = number of valid data hours within a given sector

I.4.3 CALCULATED X/Q AND D/Q VALUE FOR POINT BEACH NUCLEAR PLANT

Table I.4-2 presents the highest offsite sector D/Q and X/Q values at the site boundary, nearest milk cow, milk goat, meat animal, resident, and vegetable garden. The annual period is represented by the 4/19/67-4/18/69 data period, while the grazing and/or growing season is approximated by the combination of the 4/19/67-10/18/67 and 4/19/68-10/18/68 periods. Table I.4-4 through Table I.4-13 list the X/Q values for each of the above key receptors, the shoreline receptors (if any), the population distances to 50 miles, and selected distances out to three miles, since two of the six release modes are conditionally elevated. Table I.4-14 through Table I.4-21 presents D/Q values for the same receptors and locations. Because the three former onsite residences have either been demolished or abandoned, the annual and grazing season X/Q and D/Q values at these locations (WNW sector at 1250 meters, NNW sector at 1880 and 1980 meters) provided in Table I.4-3 are historical.

I.4.4 REFERENCES

1. Regulatory Guide 1.23, "Onsite Meteorological Programs," February 1972.

2. STAR is a computer program used by the National Climatic Center, Asheville, N.C., to determine the probability of simultaneous occurrences of a specified wind speed, direction and stability class. STAR uses hourly records of this data over a long period of time to establish a climatological frequency matrix of wind speed, direction and stability class for a given site.

3. Regulatory Guide 1.111, "Methods of Estimating Atmospheric Transport and Dispersion of Gaseous Effluents in Routine Releases from Light-Water-Cooled Reactors," March 1976.

I.5 HYDROLOGY

I.5.1 DESCRIPTION OF DISCHARGE

The two Point Beach discharge flumes are each designed to accommodate discharge flows of 390,000 gpm. There is one flume for each unit. They are of similar design, one being the mirror image of the other.

Each flume is constructed of two rows of interlocked sheet pile sections. The shoreline (west) ends of the flumes are attached to the east pumphouse wall, perpendicular to the shoreline. Unit 1 flume extends into Lake Michigan in a SSE direction at an angle of 60 degrees to the shoreline. Unit 2 flume extends at the same angle in a NNE direction. Each flume is 35 feet wide at the lake end, 17 feet wide at the pumphouse and is 228 feet long. The floor of each flume consists of tremie concrete approximately two feet thick. The bottom depth below mean water level varies between 19 feet and 17 feet-9 inches. The flumes are protected along their sides from wave and ice action by steel spreaders between the piling and rubble stone placed along the outside of each piling row.

The Unit 1 flume has a 35 foot by 19 foot platform on the lake end which had been open to the public for fishing.

I.5.2 HYDROLOGY MODEL

The mathematical model used to calculate the lake dilution factor for Point Beach Nuclear Plant is based on methods suggested by Draft Regulatory Guide 1.EE (Reference 1). The plane source solution of the model can be obtained by integration of a point source solution over the source dimensions. For a steady point source discharge into a large lake of constant depth (d), a known steady longshore current (u), and straight shoreline the solution of the transport equation is:

$$x = \frac{W}{2\pi u \sigma_y \sigma_z} f(\sigma_z, z, z_s, d) f(\sigma_y, y, y_s) \qquad (1)$$

$$f(\sigma_z, z, z_s, d) = \sum_{m=-\infty}^{\infty} \left\{ \exp - \left[\frac{(2md + z_s - z)^2}{2\sigma_z^2} \right] + \exp - \left[\frac{(2md - z_s - z)^2}{2\sigma_z^2} \right] \right\}$$

$$f(\sigma_y, y, y_s) = \exp - \left[\frac{(y_s - y)^2}{2\sigma_y^2} \right] + \exp - \left[\frac{(y_s + y)^2}{2\sigma_y^2} \right]$$

$$\sigma_y = \sqrt{\frac{2K_y X}{u}}, \quad \sigma_z = \sqrt{\frac{2K_z X}{u}}$$

Where:

x is the non-decaying concentration

K_y, K_z are the lateral and vertical turbulent diffusion coefficients

W is source strength

d is depth of the lake at the discharge point

X is distance in horizontal direction

h is the vertical depth of the discharge plume

In deriving Equation (1), it is assumed that:

(1) the discharge is located at the point (0, Y_s, Z_s), i.e., at the origin of the x-axis and a distance Y_s from the shoreline and Z_s beneath the water surface; and,

(2) the longitudinal diffusion and time dependence in the dissolved constituent transport equation are negligible.

The solution of a plane source can be obtained by integration of Equation (1) over the source dimensions. It is assumed that the plane source has a width of b (in the Y-axis) and a depth of h (in the Z-axis). Integrating f (σ_s, z, z_s, d) from z_s to z_s + h with respect to z_s gives:

$$\int_{z_s}^{z_s+h} f(\sigma_s, z, z_s, d)dz_S = \sigma_z\sqrt{\frac{\pi}{2}}\sum_{m=-\infty}^{\infty} -A$$

Where:

$$A = -erf\frac{(2md - z_s - z)}{\sqrt{2}\sigma_z} + erf\frac{(2md + z_s + h - z)}{\sqrt{2}\sigma_z} + erf\frac{(2md - z_s - z)}{\sqrt{2}\sigma_z} - erf\frac{(2md + -z_s - h - z)}{\sqrt{2}\sigma_z}$$

Integrating f(σ_y,y,y_s) from y_s to y_s + b with respect to y_s gives:

$$\int_{y_s}^{(y_s+b)} f(\sigma_y, y, y_s)dy_s = \sigma_y\sqrt{\frac{\pi}{2}}B \qquad (3)$$

Where:

$$B = -erf\frac{(y_s - y)}{\sqrt{2}\sigma_y} + erf\frac{(y_s + b - y)}{\sqrt{2}\sigma_y} - erf\frac{(y_s + y)}{\sqrt{2}\sigma_y} + erf\frac{(y_s + b + y)}{\sqrt{2}\sigma_y}$$

Therefore:

$$x = \frac{W}{2\pi u\sigma_y\sigma_z}\int_{z_s}^{z_s+h} f(\sigma_z, z, z_s, d)dz_s\int_{y_s}^{y_s+b} f(\sigma_y, y, y_s)dy_s$$

$$= \frac{W}{4u}\left(\sum_{m=-\infty}^{\infty} A\right)B \qquad (4)$$

Where W is source strength per unit area.

The dilution factor, DF, is given by: DF = W/(xQ) (5),

where Q is the volumetric discharge rate of the effluent.

I.5.3 INPUT DATA

Based on a paper by Paddock et. al. (Reference 2) the width of the plane source is estimated to be 1000 feet and the plane source is discharging 1000 feet offshore into a 0.4 feet per second current. The lateral and vertical mixing coefficients are 900 cm^2/sec (0.97 ft^2/sec) and 2 cm^2/sec (0.0022 ft^2/sec), respectively. (Reference 3) From Equations (4) and (5), the centerline dilution factor 12 miles downstream at the Two Rivers, Wisconsin potable water intake is approximately 10 for a discharge rate of 644 cubic feet per second.

Field observations of flow patterns at Point Beach show the presence of reversing currents. (Reference 3, Reference 4) As indicated in Reference 1, when the directional distribution of currents is approximately bimodal, long-term dilution factors would be about twice those calculated from Equation (4). It is also noted that the dilution calculated by the above model is for a far field. Additional dilution arising from initial mixing in the near field (an additional dilution factor of 5) is also applied. The total dilution factor at the nearest water intake at Two Rivers, Wisconsin, is then calculated to be 100.

I.5.4 REFERENCES

1. Draft Regulatory Guide 1.EE (Working Paper), Methods for Estimating Aquatic Dispersion of Liquid Effluents from Routine Reactor Releases for the purpose of Implementing Appendix I, February, 1976.

2. Paddock, R. A., Policastro, A. J., Dunn, W. E., and Kyser, J. M., "Application of Prominent Near-Field Models for Heated Surface Discharge to Prototype Field Data on Lake Michigan," Energy and Envir. Systems Div., Argonne National Laboratory, paper presented at U.S. - Japan Seminar on Engineering and Environmental Aspects of Waste Heat Disposal, April 15-19, 1974, Tokyo, Japan.

3. Point Beach Nuclear Plant, "Non-Radiological Environmental Surveillance Program," Wisconsin Electric Power Company and Wisconsin Michigan Power Company, Annual Report No. 1, September 1972 through November 1973.

4. Point Beach Nuclear Plant, "Non-Radiological Environmental Surveillance Program," Wisconsin Electric Power Company and Wisconsin Michigan Power Company, Annual Report Nos. 2 and 3, November 1973 through October 1975.

I.6 SUPPLEMENTAL INFORMATION

By Enclosures 1 and 2 to a letter dated February 17, 1976, the Nuclear Regulatory Commission requests that certain specific information be provided as part of the Appendix I evaluation. Requested information not provided elsewhere in the evaluation is presented in this section.

I.6.1 ENCLOSURE 1

"Guidance to Holders of Permits to Construct or Licenses to Operate Light-Water-Cooled Reactors for Which Application was Filed Prior to January 2, 1971, to Meet the Requirements of Appendix I to 10 CFR Part 50."

a. Radioactive source terms used in the evaluation are consistent with the parameters and methodology set forth in Regulatory Guide 1.BB to the extent practicable. Any deviations from the Reg. Guide are noted. Descriptions of the applicable plant parameters and source term are provided in Section I.2 and Section I.3, respectively.

b. Meteorological and Hydrological parameters used in the calculation of doses are consistent with Regulatory Guides 1.DD and 1.EE to the extent practicable. Meteorology and hydrology are discussed in further detail in Section I.4. and Section I.5, respectively.

c. Dose calculations are consistent with Regulatory Guide 1.109 to the extent practicable. Any deviations from Regulatory Guide 1.109 are noted in the detailed discussion presented in Section I.8.

d. Operational liquid effluent release data is presented on an annual basis for 1974 and 1975 in Table I.7-6. All liquid discharges are released through the discharge flumes via the circulating water system. Operational gaseous effluent release data is presented on an annual basis for 1974 and 1975 in Table I.7-4. Operational gaseous effluent release data is presented on a monthly basis for 1974 and 1975 by release point in Table I.7-5. A brief description of operating condition of each unit is noted for each month.

e. Information requested in Enclosure 2 is provided in Section 6.2.

f. Proposed Technical Specifications reflecting the requirements of Appendix I to 10 CFR Part 50 have been provided under separate cover.

I.6.2 ENCLOSURE 2

"Additional Information Needed from Holders of Permits or Licenses to Construct or Operate Light-Water-Cooled Reactors for Which Application was Filed Prior to January 2, 1971."

a. The information requested in Appendix D of Regulatory Guide 1.BB is provided as Section I.2.

b. Distances to the nearest site boundary are provided in Table I.6-1. Distances to the nearest residence and nearest vegetable garden are presented in Table I.6-2. Distances to the nearest milk cow, milk goat, and meat animal are given in Table I.6-3.

In deriving these distances, it is assumed that every residence (farm or non-farm) has the potential for having a vegetable garden. Since the land use in the vicinity of Point Beach Nuclear Plant is predominantly agricultural, the distance to the nearest milk or meat producing animal is assumed to be the distance to the nearest practicing farm having dwelling and a barn. However, it is assumed that land surrounding the site, owned by the Licensee and leased to local farmers, is unlikely to be used for pasture. Consistent with these assumptions, Figure I.6-1 shows the locations of all farms and non-farm residences out to a distance of 3 miles for each radial sector.

c. Based on considerations in Draft Regulatory Guide 1.DD, estimates of relative concentration (X/Q) and deposition (D/Q) appropriate for locations determined in item 2, above, are presented in Table I.4-4 through Table I.4-21.

d. A complete description of the meteorological program, data, models, and parameters is presented in Section 4.0.

e. Regulatory Guide 1.23 did not exist during the design and licensing stages of Point Beach Nuclear Plant. The meteorological program and data are discussed in detail in Section I.4.1.

f. Meteorological data for the Point Beach site, discussion of representativeness, and description of meteorological monitoring instrumentation is presented in Section I.4.. Since the present program produces representative meteorological data as discussed in Section I.4.1., there is no basis for upgrading the program in accordance with Regulatory Guide 1.23.

g. The lake breeze phenomenon is the only airflow trajectory regime of importance in the vicinity of Point Beach Nuclear Plant. A detailed discussion is presented in Section I.4.1.

h. A map showing detailed topographic features within a 10-mile radius of the plant is given in Figure I.4-1. Plots of maximum topographic elevation versus distance for each sector are given in Figure I.4-2.

i. Intermittent gaseous releases at Point Beach Nuclear Plant occur from containment purges and gas decay tank releases. A summary of containment purge experience from January 1, 1974, to February 29, 1976, is presented in Table I.6-4. Gas decay tank releases are summarized in Table I.6-5.

I.7 COMPARISONS OF REPORTED AND CALCULATED RELEASES OF RADIOACTIVITY

I.7.1 GASEOUS RELEASES

Calculated annual gaseous releases are provided in Table I.7 -1 and are based on the methods and assumptions in Draft Regulatory Guide 1.BB. Reported Point Beach Nuclear Plant gaseous releases are provided for 1974 and 1975 by month in Table I.7-5 and by year in Table I.7-4.

a. Noble Gases

The calculated annual release of noble gases for the two-unit plant is 690 Curies per year. Comparing this value to the reported annual average releases of 27,000 Curies per year indicates disagreement by a factor of approximately 40. This disagreement is believed to be caused by a combination of radiation monitoring system background interference and assumptions in the model recommended by Draft Regulatory Guide 1.BB for calculation of releases.

The major release point for reported noble gas releases at Point Beach Nuclear Plant is the auxiliary building vent. This release point is monitored by a scintillation detector in the vent stack. The recorded output of this monitor is used to calculate total noble gas releases for the vent. The detector is shielded so small increases in ambient external background radiation levels will not increase the reported noble gas releases. Internal stack contamination or large increases in background radiation may increase the reported amount. Plant practice has been to account for these background changes where the duration and effects can be quantified, however, this cannot be done in all instances. As a result, reported releases of noble gases are conservatively high. Also, as a backup, a SPING pallet continuously draws samples off the vent stack.

The model recommended by Draft Regulatory Guide 1.BB accounts for noble gas releases from system leakage only via the leakage of undegassed liquids. Plant experience indicates that small leaks can occur from systems containing radioactive gases, such as the cover gas system. The radioactivity of these gases may be several orders of magnitude higher on a per volume basis than the noble gas radioactivity of undegassed liquids; hence a very small gaseous leak can result in significant noble gas releases. Since the model does not consider this potential the releases predicted by the model may not be compared to our experiences. A "gaseous leak" term for the model would be difficult to quantify since in most cases the volumetric leak rates of gaseous systems are so small that measurement is impracticable. Nevertheless, some allowance should be made for gaseous leaks to avoid setting design or operating objectives based on a release model which may not include all normal operating occurrences.

The reported releases are conservatively high because of the inclusion of a portion of radiation monitor background in determining noble gas releases while the calculated releases based on the model may be low because of the inability of the model to account for small gaseous leaks. Further refinements in both areas should result in calculated releases approaching actual plant releases.

Reference to Table I.8-5 indicates that the dose based on calculated noble gas releases is approximately 0.03 millirems per year to the total body of an offsite individual. Adjusting this to the reported releases would result in a calculated dose on the order of 1 millirem per year. Both calculated doses are well within the design objective of 5 millirem per year.

b. Iodines

The calculated annual release of radioactive iodine for the plant is 0.3 Curies per year. This value compares favorably with reported iodine releases of 0.14 Curies per year on an annual average basis. The disagreement by a factor of 2 is not significant and may be the result of the lower fuel defect level during actual operation.

c. Particulates

The calculated annual release of particulate material for the plant is approximately 0.007 Curies per year while the reported releases for the plant are approximately 0.03 Curies per year on an annual average basis. The disagreement by a factor of approximately 4 arises primarily from higher than normal Cesium-138 during one month in the 1974 - 1975 period. Cesium-138 is a short-lived isotope not predicted by the model in Draft Regulatory Guide 1.BB. Cesium-138 is of negligible dose significance and the factor of 4 disagreement is not significant.

d. Tritium

Calculated tritium releases based on Draft Regulatory Guide 1.BB are 610 Curies per year via gaseous pathways compared to reported releases of 110 Curies per year on an annual average basis. The disagreement by a factor of 6 is due to the assumption in Draft Regulatory Guide 1.BB that half the tritium produced is released in gaseous effluents. The difference is not significant since the dose significance of tritium is small.

I.7.2 LIQUID RELEASES

a. Gross Radioactivity (excluding tritium)

Calculated annual liquid releases are provided in Table I.7-2 and Table I.7-3. Reported Point Beach Nuclear Plant releases for 1974 and 1975 are provided in Table I.7-6.

The calculated releases from Point Beach Nuclear Plant, excluding tritium and dissolved noble gases, are 3.2 Curies per year for the two unit plant, while the reported annual average is approximately 1 Curie per year for 1974 and 1975. The disagreement by approximately a factor of 3 is the result of the higher fuel defect assumptions and the 0.3 Curies for anticipated operational occurrences in the model recommended by Draft Regulatory Guide 1.BB.

I.8 CALCULATIONS OF DOSES TO MAN

I.8.1 DOSE MODELS - OFFSITE INDIVIDUALS

Doses are calculated using the dose models contained in Regulatory Guide 1.109 (Reference 1) in the evaluation of potential doses to individuals in the vicinity of Point Beach Nuclear Plant. Pathways not considered in Reference 1 or methods differing from Reference 1 are described in the dose models and assumptions presented below.

Included in this evaluation are dose assessments of three pathway categories: 1) pathways associated with releases of liquid effluents to Lake Michigan, 2) the direct exposure from releases of noble gases to the atmosphere, and 3) pathways associated with radioiodines, particulates, carbon-14, and tritium releases to the atmosphere.

1. Liquid Effluents

A condenser circulating water flow rate of 644 cubic feet per second (290,000 gallons per minute) for the release streams is used in the calculation of all doses due to liquid effluents and is based on plant operating records for 1974 and 1975. All usage factors are taken from Table A-2 of Reference 1 unless otherwise noted.

1. Swimming and Boating

For boating and swimming, the COHORT-II Monte Carlo Radiation Transport Code (Reference 2) has been used to calculate dose rates to boaters and swimmers. The gamma energy spectrum is based on the eighteen-group of the DLC-23/CASK library (Reference 3). The source radioactivity used for boating and swimming is the radioactivity in the discharge diluted by a factor of 5 to account for near-field dilution in the mixing zone.

The boating model assumes a disc source 50 feet in diameter with a thickness of 3 feet. Dose rates are calculated at points 1, 2, and 3 feet above the water to approximate the location of boaters. Attenuation by the boat is neglected.

The calculated dose rate is nearly constant at the three receptor points considered, indicating that the source model is essentially semi-infinite in this analysis. These dose rate levels are approximately half the submerged dose rates calculated for swimmers.

Usage factors for boating of 52 hours per year for teen and adult age groups and 29 hours per year for child are used as suggested by Reference 1.

The Monte Carlo program is used to calculate the dose rate for swimming. A cylindrical source 10 feet in diameter is enclosed in an annular mass of water 20 feet in diameter. The source region was limited to the 10 feet diameter cylinder. The 20 feet diameter outer cylinder is added to include backscattering into the source region in the Monte Carlo analysis. A receptor point 2 feet below the surface is used. The calculated submerged dose rate is approximately twice the dose rate above the surface of the water.

The swimming pathway is not considered in Reference 1. A usage factor of 100 hours per year is used for the adult and teen age groups. A usage factor of 56 hours per year is used for the child age group.

2. Ingestion of Potable Water

The Green Bay, Wisconsin, potable water intake is located in Lake Michigan approximately 13 miles north of the Point Beach site and the Two Rivers, Wisconsin, potable water intake is located approximately 12 miles south of the site. As part of intensive non-radiological environmental surveillance programs[4] the lake current characteristics have been determined in the vicinity of the site. These studies indicate highly variable lake current direction; therefore, dilution factors at both intakes were evaluated and found to be approximately equal. Since the Two Rivers, Wisconsin, intake is nearest the site, this intake is considered in the evaluation; however, calculated ingestion doses would also be applicable to any individual using Green Bay, Wisconsin, potable water.

The calculational methods for determining lake dilution factors are described in Section 5. A far-field dilution factor of 10 is calculated at the Two Rivers intake. Using a near-field dilution factor of 5 and a factor of 2 to account for variable current direction, the total dilution factor at the Two Rivers intake is 100. In addition to this dilution, a decay time of 44 hours is assumed (based on lake current measurements) and an additional 12 hours decay is assumed during transport of water through the purification plant. No credit is taken for removal of radioactivity by water treatment processes.

Ingestion of potable water is assumed to be 730 liters per year for adults and 510 liters per year for all other age groups.

3. Ingestion of Fish

For the maximum individual case, fish are assumed to be caught at the edge of the initial mixing zone. The appropriate mixing zone dilution factor is 5, as suggested by Reference 1. A holdup time of 24 hours between catching and eating fish is assumed. The consumption of fish is assumed to be 21, 16, and 6.9 kilograms per year for an adult, teen and child, respectively.

4. Shoreline Recreation

A point 1500 meters south is the closest point to the site at which this pathway exists. A decay time of 3.4 hours is assumed and a total dilution factor of 878 at the shoreline is calculated in accordance with the models presented in Section 5. Usage factors of 12, 67, and 14 hours per year are used for an adult, teen, and child, respectively. The shore width factor is assumed to be 0.

5. Ingestion of Invertebrates

Doses for ingestion of invertebrates are not calculated for Point Beach Nuclear Plant. There is no known fishery in the area for invertebrates.

6. Ingestion of Leafy Vegetables

For the maximum individual case, leafy vegetables are assumed to be irrigated from the potable water supply of the City of Two Rivers. The dilution factor is 100 and the consumption is 64, 42 and 26 kilograms per year for the adult, teen, and child, respectively. A holdup time of 24 hours is assumed between harvesting and eating leafy vegetables.

7. Ingestion of Stored Vegetables

For the maximum individual case, non-leafy stored vegetables are assumed to be irrigated from the Two Rivers potable water supply with a dilution factor of 100. The consumption is assumed to be 520, 630, and 520 kilograms per year for the adult, teen, and child, respectively. A holdup time of 60 days is assumed between harvesting and consumption.

8. Ingestion of Cow's Milk

For the maximum individual case, cow's milk is assumed to be produced at a farm which gets drinking and irrigation water from the potable water supply of the City of Two Rivers. A dilution factor of 100 is assumed. Consumption of cow's milk is assumed to be 310, 400, 330, and 330 liters per year for the adult, teen, child, and infant, respectively. A hold up time of 2 days is used between production and consumption.

9) Ingestion of Meat

Meat for the maximum individual is assumed to be produced from an animal at a farm which gets drinking and irrigation water from the potable water supply of Two Rivers. A dilution factor of 100 is assumed. The consumption is 110, 65, and 41 kilograms per year for the adult, teen, and child, respectively. A holdup time of 20 days is used between slaughter and consumption.

b. Gaseous Effluents

All dose pathways from gaseous releases are calculated using the methods and parameters described in Reference 1. The following pathways are considered:

1. Noble Gas Releases

The maximum individual is assumed to be at the nearest residence in the south-southwest direction at a distance of 1460 meters for total body and beta skin doses. For gamma and beta air doses, the maximum individual is assumed to be at the site boundary in the south direction at a distance of 1270 meters. Annual average X/Q values are used.

2. Inhalation

The maximum individual is assumed to be at the nearest residence at a distance of 1460 meters in the south-southwest direction. Annual average X/Q values are applied for this location. Breathing rates of 7300, 5100, 2700, and 1900 m^3/yr are assumed for the adult, teen, child, and infant, respectively.

3. Ingestion of Leafy Vegetables

For doses from ingestion of leafy vegetables, a garden is assumed to be at the nearest residence in the south-southwest direction at a distance of 1460 meters. Growing season X/Q's and deposition rates are applied based on a growing season of 6 months. Concentrations of tritium and carbon-14 in the vegetables are calculated using X/Q values as recommended in Reference 1. The consumption is assumed to be the same as for the liquid pathway.

4. Ingestion of Stored Vegetables

Stored vegetables are grown at the same location as leafy vegetables and use the same X/Q's and deposition rates. Consumption of stored vegetables is assumed to be the same as for the liquid pathway.

5. Ingestion of Cow's Milk

A cow is assumed to be at the site boundary in the SSE direction at a distance of 1300 meters. A six month grazing season is assumed. Growing season X/Q's and deposition rates are applied. Concentrations of tritium and carbon-14 in the vegetation which the animal consumes are calculated using X/Q values as recommended in Reference 1. The consumption of cow's milk is assumed to be the same as for the liquid pathway.

6. Ingestion of Goat's Milk

A milk goat is assumed to be at the same location as the milk cow. The X/Q's and deposition rates for the cow's milk pathway are used for this pathway. Consumption of goat's milk is assumed to be 310, 400, 330, and 330 liters per year for the adult, teen, child, and infant, respectively.

7. Ingestion of Meat

A meat animal is assumed to be at the same location as the milk cow. The X/Q's and deposition rates for the cow's milk pathway are used for this pathway. A six month grazing season is assumed. Consumption of meat is assumed to be the same as for the liquid pathways.

8. Standing on Contaminated Ground

The maximum individual is assumed to be in the south-southwest direction at a distance of 1460 meters. Annual deposition rates are applied for this location, and an occupancy and shielding factor of 0.7 is assumed.

I.8.2 DOSE MODELS - ONSITE INDIVIDUALS

Note: The following is historical because there are no longer any occupied residences within the site boundary.

Three occupied residences exist within the Point Beach Nuclear Plant site boundary which are owned by the Licensees and which are occupied only by families of plant employees. Since some (but not all) pathways exist for potential exposure of these individuals to releases from the plant, hypothetical doses have been calculated for onsite individuals in all age groups at the maximum location. No calculations are performed for ingestion of fresh or stored vegetables (liquid release pathway only), ingestion of cow or goat milk, and ingestion of meat since these pathways either cannot exist or are known not to exist for these individuals.

For the remainder of the potential pathways, the calculated doses are for individuals in the WNW sector at a distance of 1250 meters from the plant. Calculated doses for recreational activities such as fishing, swimming, and boating are identical to those for offsite individuals. Dose models for appropriate pathways are identical to those for offsite individuals except as modified by distance from release points.

I.8.3 CALCULATED DOSES

Calculated doses to offsite individuals are provided in Table I.8-1 through Table I.8-4 for radioiodine and particulates in gaseous effluents. Calculated doses to offsite individuals from liquid effluents are provided in Table I.8-6 through Table I.8-9. Calculated doses to offsite and onsite individuals from noble gas releases are provided in Table I.8-5.

Calculated doses to onsite individuals for radioiodine and particulates in gaseous releases are provided in Table I.8-10 through Table I.8-13. Calculated doses to onsite individuals from liquid effluents can be obtained from Table I.8-6 through Table I.8-9 by summing the fish ingestion, swimming, boating and shoreline pathways.

The replacement of the Retention Pond by the conveyor-type filtration units does not have an adverse effect upon the calculated doses. Only the path has changed, with the function of the Retention Pond as a settling basin replaced by active filtration through the new equipment.

I.8.4 REFERENCES

1. Regulatory Guide 1.109, "Calculation of Annual Doses to Man From Routine Releases of Reactor Effluents For The Purpose of Evaluating Compliance With 10 CFR Part 50, Appendix I," March, 1976, U. S. Nuclear Regulatory Commission, Washington, D.C.

2. L. Soffer and L. Clemons, Jr., "COHORT-II-A Monte Carlo General Purpose Shielding Computer Code," CCC-198, Union Carbide Corporation, April, 1971.

3. G. W. Morrison, E. A. Straker, and R. H. Obegaarden, "A Coupled Neutron and Gamma-Ray Multigroup Cross Section Library For Use In Shielding Calculations," Trans. American Nuclear Society, 15, 535, 1972.

4. Point Beach Nuclear Plant "Non-Radiological Environmental Surveillance Program," Wisconsin Electric Power Company and Wisconsin Michigan Power Company, Annual Reports 1, 2 and 3 covering the period from November, 1972 through October, 1975.

I.9 SUMMARY

Calculations of radioactive releases and potential doses to individuals have been performed in accordance with models in Nuclear Regulatory Commission Regulatory Guides. The potential doses are calculated for each pathway through which exposure might be realized for various individuals. These pathways are then combined, as appropriate, to estimate the potential dose to a hypothetical individual exposed to all pathways. A comparison of calculated doses with the design objectives is given in Table I.9-1 for offsite individuals and for onsite individuals. All calculated doses are within the design objectives and are as low as reasonably achievable.

I.9.1 GASEOUS RELEASES

Calculated gamma and beta air doses at the site boundary are 0.06 and 0.07 millirads per year, respectively, and are a small fraction of the design objectives of 10 and 20 millirads per year for gamma and beta dose rates.

Calculated total body and skin doses to an offsite individual are 0.03 and 0.06 millirems per year, respectively. These doses are a small fraction of the design objectives of 5 and 15 millirems per year to the total body and skin, respectively. Corresponding calculated doses to an onsite resident are 0.02 millirems per year total body, and 0.04 millirems per year to the skin. These calculated doses are also well within the design objectives.

The maximum calculated dose to any organ of an offsite individual from all pathways for radioiodine and particulates is 15 millirem per year to the thyroid and is equal to the design objective of 15 millirem per year. The maximum hypothetical individual for this case is an offsite infant residing at a distance of 1,460 meters in the south-southwest sector and ingesting 330 liters per year of goat's milk in addition to being exposed to radioactivity in air and on the ground. The calculated dose for the same infant ingesting an equivalent volume of cow's milk is 12 millirems per year. In either case, the design objective is met.

The calculated dose to any organ of an onsite resident is 0.82 millirems per year to the child thyroid. This calculated dose is well within the design objective of 15 millirems per year. Since all conservatively calculated doses from gaseous releases are within the design objectives it is concluded that gaseous waste processing systems and ventilation system filtration equipment at Point Beach Nuclear Plant will continue to maintain releases as low as reasonably achievable and further augmentation is not required.

I.9.2 LIQUID RELEASES

a. Calculated Doses

The highest calculated total body dose is 0.19 millirem per year for a hypothetical adult. Essentially all of this dose is calculated to be from eating fish living at the edge of the initial mixing zone in the surface plume near the plant. The calculated doses are well within the design objective of 5 millirem per year.

The highest calculated dose to any organ from liquid pathways is 0.26 millirem per year to the liver of an offsite teenage individual. The major portion of this dose is calculated to be from the same fish pathway as for the adult. This calculated dose is well within the design objective of 5 millirems per year.

b. Calculated Releases

Actual plant liquid releases for 1974 and 1975 average approximately 1 Curie per year and calculated releases are 3.2 Curies per year. These releases are well within the design objective of 5 Curies per year per reactor (10 Curies per year for the plant).

Because the doses and Curie releases via liquid pathways are much less than the design objectives there is no need to further augment liquid waste systems to continue to maintain releases as low as is reasonably achievable.

I.9.3 IMPACT OF UPRATED POWER OPERATIONS

Scaling techniques, based on NUREG-0017, Revision 1 methodology, were used to assess the impact of core power uprate on radioactive gaseous and liquid effluents at PBNP.

As described in Reference 1, the conservatively performed power uprate analysis used the plant core power operating history during the years 2002 to 2006, the reported liquid effluent and dose data during that period, NUREG-0017 equations and assumptions, and conservative methodology, to estimate the impact of operation at the analyzed uprate core power level of 1811 MWt on radioactive gaseous and liquid effluents, and normal operation off-site doses.

The licensed reactor core power level prior to 2003 was 1518.5 MWt. The core power was increased to 1540 MWt at the end of 2002. For the uprate condition, the system parameters used in the power uprate analysis reflected the flow rates and coolant masses at an analyzed core power level of 1811 MWt. For the pre-uprate condition, the evaluation used offsite doses based on an average 5 year set of organ and whole body doses calculated using data presented in the PBNP Annual Radioactive Effluent Release Reports for the years 2002 through 2006, taking into consideration the associated average annual core power level, extrapolated to 100 percent availability at the licensed power level.

Using the methodology and equations found in NUREG-0017, Revision 1, and based on a comparison of the change in power level and in plant coolant system parameters (e.g., reactor coolant mass, steam generator liquid mass, steam flow rate, reactor coolant letdown flow rate, flow rate to the cation demineralizer, letdown flow rate for boron control, steam generator blowdown flow rate, steam generator moisture carryover, etc.) for both pre-uprate and uprate conditions, the maximum potential percentage increase in coolant activity levels due to the uprate for each chemical group identified in NUREG-0017 was estimated.

To estimate an upper bound impact on off-site doses, the highest factor found for any chemical group pertinent to the release pathway was applied to the average doses previously determined as representative of operation at pre-uprate conditions. This approach was utilized to estimate the maximum potential increase in effluent doses due to the uprate, and demonstrate that the estimated off-site doses following the uprate, although increased, will continue to remain below the regulatory limits set by 10 CFR 50, Appendix I. Reference 1 shows that based on operating history, the maximum estimated dose due to gaseous liquid radwaste effluents following power uprate will continue to remain significantly below the annual design objectives for gaseous and liquid radwaste effluents set by 10 CFR 50 Appendix I.

It is noted that actual gaseous and liquid effluent isotopic release and dose information are provided in the PBNP Annual Radioactive Effluent Release Reports.

I.9.4 REFERENCE

1. Shaw Calculation 129187-M-0104, "Impact of EPU on Normal Operation Gaseous and Liquid Radioactive Effluent Releases," dated March 26, 2009.

Table I.2-1 SOURCES AND EXPECTED RADIOACTIVITY OF LIQUID WASTES AT POINT BEACH NUCLEAR PLANT

SOURCE	RATE (gal/day)	TOTAL [1] (gal/yr)	EXPECTED FRACTION [2] OF PRIMARY COOLANT RADIOACTIVITY	EXPECTED FRACTION TO BE RELEASED
Primary System Waste				
Containment Sumps	80	29,200	1.0	1.0
Auxiliary Building Drains	400	146,000	0.1	1.0
Laboratory Drains	400	146,000	0.002	1.0
Sampling Drains	70	25,550	1.0	1.0
Detergent Wastes	450	164,250	< 0.0001 Ci/yr	1.0
Miscellaneous	1,400	511,000	0.01	1.0
Anticipated Occurrences	-	4,000	0.30 Ci/yr	1.0
Total	2,800	1,026,000		
Secondary System Waste				
Turbine Building Floor Drains	14,400	5,250,000	Steam Condensate	1.0
Secondary System Sampling	5,000	1,820,000	Steam Condensate	1.0
Steam Generator Blowdown	144,000	42,050,000	0.1 x Steam Generator Blowdown	1.0
Total	163,400	49,120,000		
Other				
Letdown to CVCS Holdup Tanks	3,290	1,200,000	1.0	0.53

(1) Assumes 365 days per year for both Unit 1 and Unit 2 except for steam generator blowdown which is adjusted for 80 percent capacity factor.
(2) All fractions for primary system waste are related to degassed primary coolant concentrations and are prior to processing in radioactive liquid waste systems and related systems.

Table I.2-2 CAPACITIES USED IN CALCULATING HOLDUP TIMES FOR RADIOACTIVE LIQUIDS

WASTE SOURCE	COMPONENT	TOTAL PROCESS RATE OR VOLUME	RATE OR VOLUME USED
Primary System Waste	Waste Holdup Tank	21,000 gal.	8,400 gal.
	Waste Evaporator	35 gal./min.	35 gal./min.
	Waste Condensate Tanks	10,000 gal. each	8,000 gal.
	Waste Condensate Pumps	75 gal./min. each	150 gal./min.
Other			
Letdown to CVCS	Holdup Tanks	58,000 gal. each	69,600 (1)
Holdup Tanks	Boric Acid Evaporator	12.5 gal./min.	12.5 gal./min.
	Monitor Tanks	10,000 gal. each	8,000 gal.
	Monitor Tank Pumps	60 gal./min. each	120 gal./min.

(1) Based on sharing of three tanks by Units 1 and 2.

Table I.2-3 CALCULATED HOLDUP TIMES FOR COLLECTION, PROCESSING AND RELEASE

SOURCE	CALCULATED HOLDUP TIME (1) (Days)
Primary System	
Containment Sumps	3.2
Auxiliary Building Drains	3.2
Laboratory Drains	3.2
Sampling Drains	3.2
Detergent Wastes	3.2
Miscellaneous	3.2
Anticipated Operational Occurrences	Not Applicable
Secondary System	
Turbine Building Floor Drains	30
Secondary System Sampling	30
Steam Generator Blowdown	Negligible
Other	
Letdown to CVCS Holdup Tanks	46.2 (2)

(1) Calculated holdup times are based on methods recommended by Draft Regulatory Guide 1.BB.

(2) Based on sharing of three holdup tanks by Units 1 and 2.

Table I.2-4 POINT BEACH NUCLEAR PLANT RELEASE POINT DESCRIPTIONS

Sheet 1 of 3

Outside Design Temperature: -15°F (Winter) and 95°F (Summer)

1. UNIT 1 PURGE VENT

Diameter	= 36″
Flow	= 12,500 to 25,000 cfm for purging and 10 cfm for continuous venting.
Exit Velocity	= 20.1 to 40.2 miles per hour for purging.
Elevation	= 168′ 0″
Height	= 142′ 0″ above finished grade 26′ 0″
Location	= NE corner of Unit 1 facade
Facade Elevation	= 161′ 6″
Design Temperatures:	
Operating	= 105°F (Winter) and 105°F (Summer)
Shutdown	= 50°F (Winter) and 105°F (Summer)

Adjacent Structures:

N - Aux. Bldg. (el. 111′ 9″) and Unit 2 facade (el. 161′ 6″)

E - Service Bldg. and Turbine Bldg. (el. 111′ 9″)

S - None

W - None

2. UNIT 2 PURGE VENT

Diameter	= 36″
Flow	= 12,500 to 25,000 cfm for purging, 400 to 12,000 cfm for gas stripper bldg. ventilation, and 10 cfm for continuous venting.
Exit Velocity	= 20.1 to 40.2 miles per hour for purging and 0.6 to 19.3 miles per hour for gas stripper bldg. ventilation.
Elevation	= 168′ 0″
Height	= 142′ 0″ above finished grade 26′ 0″
Location	= SE corner of Unit 2 facade
Facade Elevation	= 161′ 6″
Design Temperatures:	
Operating	= 105°F (Winter) and 105°F (Summer)
Shutdown	= 50°F (Winter) and 105°F (Summer)

Adjacent Structures:

N - None

E - Service Bldg. and Turbine Bldg. (el. 111′ 9″)

S - Aux. Bldg. (el. 111′ 9″) and Unit 1 facade (el. 161′ 6″)

W - None

Table I.2-4 POINT BEACH NUCLEAR PLANT RELEASE POINT DESCRIPTIONS
Sheet 2 of 3

3. DRUMMING AREA VENT

Diameter	= 46″
Flow	= 43,100 cfm
Exit Velocity	= 42.4 miles per hour
Elevation	= 168′ 0″
Height	= 142′ 0″ above finished grade 26′ 0″
Location	= NW corner of Unit 1 facade
Facade Elevation	= 161′ 6″
Design Temperatures:	= 65°F (Winter) and 85°F (Summer)

Adjacent Structures:

N - Aux. Bldg. (el. 111′ 9″) and Unit 2 facade (el. 161′ 6″)

E - Service Bldg. and Turbine Bldg. (el. 111′ 9″)

S - None

W - None

4. AUXILIARY BUILDING VENT

Diameter	= 54″
Flow	= 61,400 cfm
Exit Velocity	= 43.9 miles per hour
Elevation	= 168′ 0″
Height	= 142′ 0″ above finished grade of 26′ 0″
Location	= SE corner of Unit 1 facade
Facade Elevation	= 161′ 6″
Design Temperatures:	= 65°F (Winter) and 85°F (Summer)

Adjacent Structures:

N - Aux. Bldg. (el. 111′ 9″) and Unit 2 facade (el. 161′ 6″)

E - Service Bldg. and Turbine Bldg. (el. 111′ 9″)

S - None

W - None

Table I.2-4 POINT BEACH NUCLEAR PLANT RELEASE POINT DESCRIPTIONS
Sheet 3 of 3

5. TURBINE BUILDING ROOF EXHAUSTERS (19)

Diameter	= NA		no credit taken for elevated
Flow	= 47,000 cfm each	--	release; ground release
Exit Velocity	= NA		assumed
Elevation	= Approximately 110′		(elevation of turbine building roof)
Height	= Approximately 84′ above finished grade of 26′ 0″		
Location	= Evenly spaced along a north-south line atop the turbine building		
Design Temperatures:	= 65°F (Winter) and 115°F (Summer)		

Adjacent Structures:

N - None

E - None

S - None

W - Facade Structures (el. 161′ 6″)

Table I.3-1 COMPARISONS WITH PARAMETERS USED TO DESCRIBE THE REFERENCE PRESSURIZED WATER REACTOR WITH U-TUBE STEAM GENERATORS

PARAMETER	SYMBOL	UNITS	NOMINAL VALUE	RANGE MAXIMUM	RANGE MINIMUM	PBNP VALUE
Thermal Power	P	MWt	3400	3800	3000	1518.5
Steam Flow Rate	FS	lbs/hr	1.5(7)	1.7(7)	1.3(7)	6.62(6)
Weight of water in reactor coolant system	SP	lbs	5.5(5)	6.0(5)	5.0(5)	2.75(5)
Weight of water in all steam generators	WS	lbs	4.5(5)	5.0(5)	4.0(5)	1.60(5)
Reactor coolant letdown flow (purification)	FD -	lbs/hr	3.7(4)	4.2(4)	3.2(4)	1.98(4)
Reactor coolant letdown flow (yearly average for boron control)	FB	lbs/hr	500	1000	250	564
Steam Generator blowdown flow (total)	FBD	lbs/hr				
Volatile			75,000	100,000	50,000	25,000
Fraction of radioactivity in blowdown stream which is not returned to the secondary coolant system	NBD	-	1.0	1.0	0.9	1.0
Flow through the purification system cation demineralizer	FA	lbs/hr	3700	7500	0.0	0.0
Ratio of condensate demin eralizer flow rate to the total steam flow rate	NC	-				
Volatile			0.65	0.75	0.55	0.0
Ratio of the total amount of noble gases routed to gaseous radwaste from the purification system to the total amount of noble gases routed from the primary coolant system to the purification system (not including the boron recovery system)	Y	-	0.0	0.01	0.0	0.0 Kr-85 1.0 All Others

Table I.3-2 POINT BEACH NUCLEAR PLANT CALCULATED SOURCE TERM CONCENTRATIONS (μCi/gm)
Sheet 1 of 3

Isotope	Reactor Coolant (μCi/gm)	Steam Generator Liquid (μCi/gm)	Steam Generator Steam (μCi/gm)
	NOBLE GASES		
Kr-83m	1.7E-02	0.0	1.1E-08
Kr-85m	7.2E-02	0.0	4.6E-08
Kr-85	5.9E-02	0.0	3.8E-08
Kr-87	5.2E-02	0.0	3.1E-08
Kr-88	1.5E-01	0.0	9.3E-08
Kr-89	4.9E-03	0.0	3.1E-09
Xe-131m	4.3E-03	0.0	2.7E-09
Xe-133m	3.2E-02	0.0	2.0E-08
Xe-133	1.3E+00	0.0	8.2E-07
Xe-135m	1.3E-02	0.0	7.9E-09
Xe-135	1.7E-01	0.0	1.1E-07
Xe-137	8.9E-03	0.0	5.6E-09
Xe-138	4.3E-02	0.0	2.6E-08
	HALOGENS		
Br-83	4.6E-03	2.2E-07	2.2E-09
Br-84	2.6E-03	2.5E-08	3.5E-10
Br-85	3.0E-04	5.6E-10	5.6E-12
I-130	1.9E-03	1.9E-07	1.9E-09
I-131	2.3E-01	2.7E-05	2.7E-07
I-132	9.6E-02	5.8E-06	5.8E-08
I-133	3.3E-01	3.8E-05	3.8E-07
I-134	4.6E-02	1.0E-06	1.0E-08
I-135	1.8E-01	1.4E-05	1.4E-07

Table I.3-2 POINT BEACH NUCLEAR PLANT CALCULATED SOURCE TERM CONCENTRATIONS (µCi/gm)
Sheet 2 of 3

CS, RB

Rb-86	7.6E-05	1.2E-08	1.2E-11
Rb-88	2.0E-01	1.7E-06	1.7E-09
Cs-134	2.2E-02	3.2E-06	3.2E-09
Cs-136	1.2E-02	1.8E-06	1.8E-09
Cs-137	1.6E-02	2.6E-06	2.6E-09

WATER ACTIVATION PRODUCTS

N-16	4.0E+01	2.8E-06	2.8E-06

TRITIUM

H-3	1.0E+00	1.0E-03	1.0E-03

OTHER NUCLIDES

Cr-51	1.6E-03	2.5E-07	2.5E-10
Mn-54	2.6E-04	5.6E-08	5.6E-11
Fe-55	1.3E-03	2.3E-07	2.3E-10
Fe-59	8.3E-04	1.7E-07	1.7E-10
Co-58	1.3E-02	2.3E-06	2.3E-09
Co-60	1.7E-03	2.5E-07	2.5E-10
Sr-89	2.9E-04	5.7E-08	5.7E-12
Sr-90	8.3E-06	1.1E-09	1.1E-12
Sr-91	5.9E-04	1.5E-08	1.5E-11
Y-90	1.4E-05	1.1E-09	1.1E-12
Y-91m	3.7E-04	8.5E-09	8.5E-12
Y-91	1.7E-03	2.5E-07	2.5E-10
Y-93	1.2E-01	5.9E-09	5.9E-12
Zr-95	5.0E-05	1.1E-08	1.1E-11
Nb-95	4.1E-05	1.1E-08	1.1E-11
Mo-99	3.8E-01	2.0E-05	2.0E-08

Table I.3-2 POINT BEACH NUCLEAR PLANT CALCULATED SOURCE TERM CONCENTRATIONS (µCi/gm)
Sheet 3 of 3

Tc-99m	3.5E-01	1.8E-05	1.8E-08
Ru-103	3.7E-05	5.7E-09	5.7E-12
Ru-106	8.3E-06	1.1E-09	1.1E-12
Rh-103m	4.4E-05	5.7E-09	5.7E-12
Rh-106	9.9E-06	1.1E-09	1.1E-09
Te-125m	2.4E-05	1.7E-09	1.7E-12
Te-127m	2.3E-04	2.8E-08	2.8E-11
Te-127	7.7E-04	8.8E-08	8.8E-11
Te-129m	1.2E-03	1.7E-07	1.7E-10
Te-129	1.6E-03	1.7E-07	1.7E-10
Te-131m	2.2E-03	2.9E-07	2.9E-10
Te-131	1.1E-03	5.6E-08	5.6E-11
Te-132	2.3E-02	2.9E-06	2.9E-09
Ba-137m	1.6E-02	2.5E-06	2.5E-09
Ba-140	1.8E-04	2.8E-08	2.8E-11
La-140	1.3E-04	2.0E-08	2.0E-11
Ce-141	5.8E-05	1.1E-08	1.1E-11
Ce-143	3.5E-05	2.9E-09	2.9E-12
Ce-144	2.7E-05	5.6E-09	5.6E-12
Pr-143	4.2E-05	5.7E-09	5.7E-12
Pr-144	3.3E-05	5.6E-09	5.6E-12
Np-239	1.0E-03	1.7E-07	1.7E-10

Table I.3-3 POINT BEACH NUCLEAR PLANT CALCULATED SOURCE TERM ACTIVITIES (Ci)

Sheet 1 of 3

Isotope	Reactor Coolant (Ci)	Steam Generators Liquid (Ci)
	NOBLE GASES	
Kr-83m	1.9E+00	0.0
Kr-85m	8.1E+00	0.0
Kr-85	6.7E+00	0.0
Kr-87	5.8E+00	0.0
Kr-88	1.7E+01	0.0
Kr-89	5.5E-01	0.0
Xe-131m	4.8E-01	0.0
Xe-133m	3.6E+00	0.0
Xe-133	1.5E+02	0.0
Xe-135m	1.4E+00	0.0
Xe-135	1.9E+01	0.0
Xe-137	1.0E+00	0.0
Xe-138	4.8E+00	0.0
	HALOGENS	
Br-83	5.2E-01	1.6E-05
Br-84	2.9E-01	2.5E-06
Br-85	3.3E-02	4.1E-08
I-130	2.1E-01	1.4E-05
I-131	2.5E+01	2.0E-03
I-132	1.1E+01	4.3E-04
I-133	3.8E+01	2.8E-03
I-134	5.2E+00	7.5E-05
I-135	2.0E+01	1.0E-03
	CS, RB	
Rb-86	8.6E-03	8.9E-07
Rb-88	2.2E+01	1.3E-04
Cs-134	2.5E+00	2.3E-04

Table I.3-3 POINT BEACH NUCLEAR PLANT CALCULATED SOURCE TERM ACTIVITIES (Ci)

Sheet 2 of 3

Isotope	Reactor Coolant (Ci)	Steam Generators Liquid (Ci)
	CS, RB	
Cs-136	1.3E+00	1.3E-04
Cs-137	1.8E+00	1.9E-04
	WATER ACTIVATION PRODUCTS	
N-16	4.5E+03	2.0E-04
	TRITIUM	
H-3	1.1E-02	7.3E-02
	OTHER NUCLIDES	
Cr-51	1.8E-01	1.9E-05
Mn-54	2.9E-02	4.1E-06
Fe-55	1.5E-01	1.6E-05
Fe-59	9.3E-02	1.2E-05
Co-58	1.5E+00	1.6E-04
Co-60	1.9E-01	1.9E-05
Sr-89	3.3E-02	4.1E-06
Sr-90	9.3E-04	8.2E-08
Sr-91	6.6E-02	1.1E-06
Y-90	1.6E-03	8.3E-08
Y-91m	4.2E-02	6.2E-07
Y-91	1.9E-01	1.9E-05
Y-93	1.3E-02	4.3E-07
Zr-95	5.6E-03	8.2E-07
Nb-95	4.7E-03	8.2E-07
Mo-99	4.3E+01	1.5E-03
Tc-99m	4.0E+01	1.3E-03
Ru-103	4.2E-03	4.1E-07

Table I.3-3 POINT BEACH NUCLEAR PLANT CALCULATED SOURCE TERM ACTIVITIES (Ci)

Sheet 3 of 3

Isotope	Reactor Coolant (Ci)	Steam Generators Liquid (Ci)
	OTHER NUCLIDES	
Ru-106	9.3E-04	8.2E-08
Rh-103m	5.0E-03	4.2E-07
Rh-106	1.1E-03	8.1E-08
Te-125m	2.7E-03	1.2E-07
Te-127m	2.6E-02	2.1E-06
Te-127	8.7E-02	6.4E-06
Te-129m	1.3E-01	1.2E-05
Te-129	1.8E-01	1.3E-05
Te-131m	2.4E-01	2.1E-05
Te-131	1.2E-01	4.1E-06
Te-132	2.6E+00	2.1E-04
Ba-137m	1.8E+00	1.8E-04
Ba-140	2.1E-02	2.1E-06
La-140	1.4E-02	1.5E-06
Ce-141	6.5E-03	8.2E-07
Ce-143	3.9E-03	2.1E-07
Ce-144	3.1E-03	4.1E-07
Pr-143	4.7E-03	4.1E-07
Pr-144	3.7E-03	4.1E-07
Np-239	1.1E-01	1.3E-05

Table I.4-1 POINT BEACH NUCLEAR PLANT ON-SITE WIND ROSE FOR 4/19/67 TO 4/18/69 (FREQUENCY PERCENT)

	WIND SPEED CLASSIFICATIONS (MPH)						
WINDS BLOWING FROM	1 - 3	4 - 7	8 - 12	13 - 18	19 - 24	25	TOTAL
N	0.56	1.42	2.93	3.16	1.11	0.66	9.84
NNE	0.31	0.85	1.89	1.77	0.94	0.72	6.49
NE	0.36	1.02	1.28	1.28	0.47	0.29	4.71
ENE	0.40	0.66	0.51	0.44	0.27	0.12	2.40
E	0.62	0.79	0.44	0.33	0.13	0.16	2.46
ESE	0.52	0.66	0.44	0.17	0.20	0.05	2.05
SE	0.51	1.02	0.81	0.61	0.31	0.27	3.52
SSE	0.37	0.83	1.37	0.82	0.57	0.25	4.21
S	0.48	1.25	2.63	2.13	1.04	0.53	8.06
SSW	0.40	1.30	4.27	4.45	1.73	0.39	12.54
SW	0.44	1.50	3.47	2.27	0.46	0.12	8.24
WSW	0.26	0.83	1.78	1.30	0.38	0.13	4.69
W	0.42	1.14	2.23	2.40	0.91	0.60	7.70
WNW	0.32	1.13	2.88	3.52	1.37	0.43	9.65
NW	0.29	1.05	2.72	2.47	0.45	0.15	7.13
NNW	0.19	0.76	2.12	1.60	0.59	0.14	5.40

Total Observations = 14,647

Percentage of Calms = 0.91

Table I.4-2 POINT BEACH NUCLEAR PLANT SUMMARY OF ANNUAL AND GRAZING SEASON X/Q's AND D/Q's FOR HIGHEST OFFSITE SECTORS

				Highest Sectors for Site Boundary & Animal Locations						Highest Sector for Nearest Resident & Vegetable Garden Location		
		Release Mode		S Sector (1,270m)			SSE Sector (1,300m)			SSW Sector (1,460m)		
	Location		Type		X/Q x 10^7	D/Q x 10^9		X/Q x 10^7	D/Q x 10^9		X/Q x 10^7	D/Q x 10^9
IA	Auxiliary Building Vent	Continuous	Conditionally elevated	A GS	4.01 2.75	13.3 6.78	A GS	3.11 2.08	20.1 11.7	A GS	2.86 3.57	5.90 7.08
IB	Auxiliary Building Vent	Intermittent (during gas decay tank releases	Conditionally elevated	A GS	9.43 7.34	31.3 18.1	A GS	9.36 8.44	60.5 47.5	A GS	8.05 9.00	16.6 17.8
IIA	Unit 1 and Unit 2 Purge Vent	Continuous 10 cfm Vent	Ground Level	A GS	60.7 51.9	47.9 34.1	A GS	19.5 13.1	24.6 14.7	A GS	23.9 28.0	21.8 26.3
IIB	Unit 1 and 2 Purge Vent	Intermittent (purge)	Conditionally elevated	A GS	27.0 22.1	47.6 33.2	A GS	16.7 12.4	50.0 37.9	A GS	19.1 20.7	29.1 30.1
IIC	Gas Stripper Building (through Unit 2 Purge Vent)	Continuous	Ground Level	A GS	60.7 51.9	47.9 34.1	A GS	19.5 13.1	24.6 14.7	A GS	23.9 28.0	21.8 26.3
III	Turbine Building Roof Exhausters	Continuous	Ground Level	A GS	70.4 60.8	47.9 34.1	A GS	21.0 14.1	24.6 14.7	A GS	26.6 31.4	21.8 26.3

Notes: A = Annual Average; GS = Grazing or Growing Season, X/Q in sec/m^3; D/Q in m^{-2}

Table I.4-3 * POINT BEACH NUCLEAR PLANT ANNUAL GROWING SEASON X/Q's AND D/Q's FOR ONSITE RESIDENTS

	Release Mode				WNW Sector (1,250 meters)			NNW Sector (1,880 meters)			NNW Sector (1,980 meters)	
	Location		Type		X/Q x 10^7	D/Q x 10^9		X/Q x 10^7	D/Q x 10^9		X/Q x 10^7	D/Q x 10^9
IA	Auxiliary Building Vent	Continuous	Conditionally elevated	A GS	0.732 0.857	3.91 5.37	A GS	1.49 1.89	3.90 4.31	A GS	1.40 1.78	3.39 3.75
IB	Auxiliary Building Vent	Intermittent (during gas decay tank releases	Conditionally elevated	A GS	4.05 4.31	21.7 27.2	A GS	6.55 7.45	17.1 17.0	A GS	6.25 7.11	15.1 15.0
IIA	Unit 1 and Unit 2 Purge Vent	Continuous 10 cfm Vent	Ground Level	A GS	28.6 36.3	11.0 14.1	A GS	9.59 13.1	7.28 9.18	A GS	8.52 11.6	6.37 8.04
IIB	Unit 1 and 2 Purge Vent	Intermittent (purge)	Conditionally elevated	A GS	11.9 12.8	23.9 28.8	A GS	9.82 10.7	15.7 15.6	A GS	9.19 10.1	14.0 14.0
IIC	Gas Stripper Building (through Unit 2 Purge Vent)	Continuous	Ground Level	A GS	28.6 36.3	11.0 14.1	A GS	9.59 13.1	7.28 9.18	A GS	8.52 11.6	6.37 8.04
III	Turbine Building Roof Exhausters	Continuous	Ground Level	A GS	32.4 40.9	11.0 14.1	A GS	10.6 14.6	7.28 9.18	A GS	9.38 12.9	6.37 8.07

Notes: A = Annual Average; GS = Growing Season, X/Q in sec/m^3; D/Q in m^{-2}

* This table is historical because onsite residences have either been demolished or abandoned.

Table I.4-4 POINT BEACH NUCLEAR PLANT AUXILIARY BUILDING VENT, CONTINUOUS ELEVATED RELEASE (IA)

DATA PERIOD: 4/19/67 - 4/18/69

X/Q (Sec/M^3) at Various Receptor Distances (M)

Downwind Sector	Shoreline Boundary	Site Boundary	Nearest Residence	Nearest Farm	805	1,700	1,980	2,415	2,800	3,200	3,600	4,025	4,830	5,635	7,245	12,070	24,140	40,235	56,330	72,425
Order	E-07	E-07	E-07	E-07	E-07	E-07	E-07	E-07	E-07	E-07	E-07	E-07	E-07	E-07	E-08	E-08	E-08	E-09	E-09	E-09
SSE	3.37	3.11	1.84	3.11	3.74	2.19	1.78	1.34	1.08	0.896	0.754	0.640	0.483	0.380	2.53	1.16	0.464	2.41	1.56	1.12
S	N/A	4.01	1.67	4.01	5.90	2.88	2.47	2.02	1.74	1.52	1.35	1.19	1.01	0.882	6.41	3.40	1.60	9.13	6.26	4.71
SSW	N/A	3.17	2.86	2.22	4.09	2.65	2.46	2.12	1.78	1.52	1.31	1.13	0.869	0.697	4.87	2.22	1.02	5.55	3.69	2.72
SW	N/A	2.43	2.16	2.39	2.61	2.15	2.16	1.95	1.70	1.47	1.30	1.14	0.791	0.582	3.62	1.67	0.818	4.35	2.86	2.09
WSW	N/A	1.12	0.922	1.12	1.14	0.974	0.980	0.901	0.746	0.755	0.693	0.638	0.504	0.411	2.46	1.18	0.589	3.19	2.12	1.56
W	N/A	0.885	0.844	0.885	1.06	0.907	0.902	0.841	0.834	0.815	0.784	0.740	0.581	0.473	2.64	1.49	0.765	4.06	2.67	1.95
WNW	N/A	0.676	0.775	0.768	0.691	0.715	0.884	0.766	0.805	0.819	0.830	0.817	0.585	0.443	3.56	1.77	0.922	4.98	3.30	2.43
NW	N/A	1.03	0.884	0.915	1.78	1.15	1.05	0.910	0.906	0.890	0.876	0.857	0.830	0.788	5.35	2.01	1.01	5.43	3.61	2.65
NNW	2.96	1.37	1.09	1.37	2.81	1.69	1.40	1.13	1.02	0.961	0.913	0.861	0.792	0.725	4.82	2.16	0.863	4.56	2.99	2.18
N	12.0	0.938	0.836	N/A	4.97	2.94	2.41	1.84	1.49	1.23	1.04	0.944	0.828	0.745	5.86	3.05	1.17	6.00	3.87	2.79
NNE	55.4	N/A	N/A	N/A	7.61	3.78	3.12	2.43	2.01	1.69	1.45	1.26	0.985	0.802	5.72	2.93	1.30	7.21	4.87	3.62
NE	47.7	N/A	N/A	N/A	4.22	1.81	1.52	1.23	1.06	0.924	0.820	0.732	0.605	0.513	3.90	2.22	1.09	6.40	4.45	3.38
ENE	23.3	N/A	N/A	N/A	2.58	1.27	1.06	0.831	0.696	0.593	0.515	0.450	0.360	0.298	2.18	1.17	0.547	3.11	2.13	1.60
E	45.2	N/A	N/A	N/A	5.06	2.17	1.75	1.34	1.10	0.921	0.791	0.685	0.542	0.446	3.25	1.75	0.815	4.64	3.18	2.39
ESE	29.7	N/A	N/A	N/A	7.92	3.44	2.67	1.93	1.51	1.22	1.01	0.848	0.637	0.502	3.44	1.67	0.706	3.82	2.54	1.87
SE	11.0	N/A	N/A	N/A	6.22	2.68	2.07	1.48	1.16	0.928	0.766	0.639	0.477	0.374	2.54	1.23	0.514	2.78	1.85	1.37

Table I.4-5 POINT BEACH NUCLEAR PLANT GROWING/GRAZING SEASON X/Q AUXILIARY BUILDING VENT, CONTINUOUS ELEVATED RELEASE (IA)

DATA PERIOD: 4/19/67-10/18/67
AND: 4/19/68-10/18/68

X/Q (Sec/M^3) at Various Receptor Distances (M)

Downwind Sector	Shoreline Boundary	Site Boundary	Nearest Residence	Nearest Farm	805	1,700	1,980	2,415	2,800	3,200	3,600	4,025	4,830	5,635	7,245	12,070	24,140	40,235	56,330	72,425
Order	E-07	E-07	E-07	E-07	E-07	E-07	E-07	E-07	E-07	E-07	E-07	E-07	E-07	E-07	E-08	E-08	E-08	E-09	E-09	E-09
SSE	2.55	2.08	1.23	2.08	2.38	1.47	1.19	0.893	0.716	0.591	0.495	0.419	0.314	0.246	1.62	0.736	0.296	1.55	1.01	0.731
S	N/A	2.75	1.19	2.75	4.20	1.98	1.71	1.41	1.23	1.08	0.968	0.862	0.750	0.672	5.00	2.77	1.37	7.95	5.52	4.19
SSW	N/A	3.90	3.57	2.83	4.75	3.35	3.14	2.71	2.28	1.94	1.68	1.44	1.11	0.885	6.15	2.77	1.27	6.86	4.56	3.35
SW	N/A	3.29	2.96	3.26	3.17	2.93	2.96	2.69	2.35	2.04	1.80	1.58	1.10	0.808	5.01	2.31	1.15	6.10	4.02	2.93
WSW	N/A	1.29	1.22	1.29	1.11	1.20	1.27	1.21	1.02	1.06	0.989	0.922	0.737	0.604	3.62	1.75	0.888	4.84	3.22	2.37
W	N/A	0.937	1.06	0.937	0.870	1.08	1.11	1.07	1.09	1.08	1.06	1.01	0.803	0.658	3.66	2.10	1.11	5.93	3.90	2.85
WNW	N/A	0.858	1.06	1.05	0.686	0.922	1.19	1.05	1.13	1.16	1.18	1.17	0.834	0.628	5.02	2.45	1.21	6.42	4.22	3.08
NW	N/A	1.24	1.13	1.13	1.83	1.34	1.26	1.12	1.15	1.16	1.17	1.17	1.18	1.15	7.84	2.91	1.50	8.15	5.43	4.01
NNW	3.57	1.74	1.43	1.74	3.38	2.12	1.78	1.45	1.34	1.28	1.24	1.19	1.12	1.04	6.96	3.13	1.25	6.60	4.33	3.16
N	13.6	1.21	1.09	N/A	6.10	3.72	3.06	2.34	1.91	1.58	1.34	1.22	1.08	0.981	7.86	4.21	1.63	8.43	5.46	3.95
NNE	67.8	N/A	N/A	N/A	9.46	4.95	4.11	3.22	2.67	2.26	1.94	1.68	1.32	1.08	7.74	3.99	1.78	9.93	6.72	5.00
NE	53.9	N/A	N/A	N/A	4.95	2.11	1.76	1.42	1.22	1.07	0.946	0.844	0.698	0.593	4.52	2.61	1.31	7.69	5.37	4.09
ENE	29.4	N/A	N/A	N/A	3.25	1.55	1.27	0.988	0.819	0.692	0.596	0.518	0.410	0.337	2.45	1.30	0.604	3.43	2.35	1.77
E	33.2	N/A	N/A	N/A	4.13	1.73	1.38	1.03	0.834	0.691	0.586	0.502	0.390	0.316	2.26	1.19	0.556	3.19	2.19	1.66
ESE	16.3	N/A	N/A	N/A	5.38	2.13	1.63	1.16	0.914	0.739	0.616	0.521	0.398	0.319	2.25	1.17	0.535	3.02	2.07	1.55
SE	6.53	N/A	N/A	N/A	4.25	1.71	1.30	0.928	0.722	0.579	0.478	0.399	0.298	0.234	1.59	0.778	0.335	1.84	1.24	0.924

Table I.4-6 POINT BEACH NUCLEAR PLANT ANNUAL AVERAGE X/Q
AUXILIARY BUILDING VENT, INTERMITTENT ELEVATED RELEASE (IB)

Data Period: 4/19/67-4/18/69

X/Q (sec/m^3) at Various Receptor Distances (m)

Downwind Sector Order	Shoreline Boundary E-07	Site Boundary E-07	Nearest Residence E-07	Nearest Farm E-07
SSE	9.83	9.36	6.61	9.36
S	N/A	9.43	5.25	9.43
SSW	N/A	8.41	8.05	7.58
SW	N/A	8.63	8.70	9.13
WSW	N/A	5.33	5.90	5.33
W	N/A	4.40	5.53	4.40
WNW	N/A	4.26	5.65	5.69
NW	N/A	5.40	5.14	5.10
NNW	11.56	6.15	5.46	6.15
N	30.07	3.61	3.53	N/A
NNE	106.	N/A	N/A	N/A
NE	129.	N/A	N/A	N/A
ENE	85.8	N/A	N/A	N/A
E	116.	N/A	N/A	N/A
ESE	63.4	N/A	N/A	N/A
SE	28.2	N/A	N/A	N/A

Table I.4-7 POINT BEACH NUCLEAR PLANT GROWING/GRAZING SEASON X/Q AUXILIARY BUILDING VENT, INTERMITTENT ELEVATED RELEASE (IB)

4/19/67-10/18/67 AND 4/19/68-10/18/68

X/Q at Various Receptor Distances

Downwind Sector Order	Shoreline Boundary E-07	Site Boundary E-07	Nearest Residence E-07	Nearest Farm E-07
SSE	8.86	8.44	5.93	8.44
S	N/A	7.34	4.64	7.34
SSW	N/A	9.21	9.00	8.77
SW	N/A	10.1	10.1	10.7
WSW	N/A	5.72	7.03	5.72
W	N/A	4.72	6.60	4.72
WNW	N/A	4.72	6.66	6.81
NW	N/A	5.92	5.99	5.69
NNW	12.62	6.98	6.25	6.98
N	31.7	4.14	4.08	N/A
NNE	116	N/A	N/A	N/A
NE	142	N/A	N/A	N/A
ENE	96.0	N/A	N/A	N/A
E	103	N/A	N/A	N/A
ESE	48.3	N/A	N/A	N/A
SE	22.5	N/A	N/A	N/A

Table I.4-8 POINT BEACH NUCLEAR PLANT ANNUAL AVERAGE X/Q'S, UNIT 1 OR UNIT 2 CONTAINMENT PURGE VENT, CONTINUOUS GROUND LEVEL RELEASE (IIA) AND GAS STRIPPER BUILDING VIA UNIT 2 CONTAINMENT PURGE VENT, CONTINUOUS GROUND LEVEL RELEASE (IIC)

DATA PERIOD: 4/19/67-10/18/67

X/Q (Sec/M^3) at Various Receptor Distances (M)

Downwind Sector	Shoreline Boundary	Site Boundary	Nearest Residence	Nearest Farm	805	1,700	1,980	2,415	2,800	3,200	3,600	4,025	4,830	5,635	7,245	12,070	24,140	40,235	56,330	72,425
Order	E-07	E-07	E-07	E-07	E-07	E-07	E-07	E-07	E-07	E-07	E-07	E-07	E-07	E-07	E-08	E-08	E-08	E-09	E-09	E-09
SSE	22.9	19.5	7.40	19.5	44.3	10.0	6.96	4.40	3.16	2.35	1.83	1.44	0.985	0.721	4.43	1.79	0.633	3.10	1.95	1.37
S	N/A	60.7	9.22	60.7	129.0	29.8	21.2	13.7	10.1	7.64	6.03	4.84	3.41	2.56	16.3	7.10	2.80	14.9	9.82	7.20
SSW	N/A	32.3	23.9	9.89	69.8	16.6	11.7	7.48	5.42	4.08	3.19	2.54	1.77	1.31	8.22	3.44	1.30	6.70	4.33	3.13
SW	N/A	15.7	8.45	11.7	51.7	12.0	8.45	5.41	3.92	2.95	2.31	1.84	1.28	0.947	5.94	2.49	0.941	4.85	3.14	2.27
WSW	N/A	17.5	5.02	17.5	41.1	9.43	6.63	4.24	3.08	2.32	1.81	1.44	1.00	0.745	4.68	1.97	0.749	3.87	2.51	1.82
W	N/A	20.5	5.97	20.5	46.2	10.7	7.50	4.81	3.49	2.63	2.06	1.64	1.14	0.846	5.31	2.24	0.851	4.40	2.85	2.06
WNW	N/A	14.9	7.21	6.55	58.1	13.5	9.50	6.11	4.44	3.35	2.62	2.09	1.46	1.08	6.83	2.90	1.11	5.74	3.73	2.71
NW	N/A	8.60	3.96	6.01	57.3	13.0	9.19	5.93	4.32	3.27	2.57	2.05	1.44	1.07	6.79	2.91	1.12	5.90	3.87	2.82
NNW	49.7	8.23	4.42	8.23	52.1	12.1	8.52	5.46	3.95	2.98	2.33	1.85	1.29	0.956	6.01	2.53	0.958	4.93	3.18	2.30
N	367.0	2.65	1.80	N/A	77.7	17.6	12.3	7.83	5.65	4.24	3.30	2.62	1.81	1.33	8.29	3.44	1.27	6.41	4.10	2.94
NNE	1,190.0	N/A	N/A	N/A	117.0	27.0	19.1	12.3	8.92	6.73	5.28	4.21	2.94	2.18	13.8	5.83	2.23	11.6	7.55	5.49
NE	1,540.0	N/A	N/A	N/A	108.0	24.9	17.7	11.4	8.36	6.34	5.00	4.00	2.81	2.10	13.4	5.79	2.26	12.0	7.87	5.76
ENE	796.0	N/A	N/A	N/A	57.6	13.1	9.27	5.97	4.35	3.29	2.58	2.06	1.44	1.07	6.77	2.89	1.11	5.81	3.80	2.77
E	1,150.	N/A	N/A	N/A	83.6	19.1	13.5	8.65	6.28	4.74	3.71	2.96	2.06	1.53	9.66	4.09	1.56	8.10	5.27	3.83
ESE	711.	N/A	N/A	N/A	77.7	17.2	12.0	7.64	5.52	4.14	3.23	2.56	1.77	1.31	8.17	3.42	1.27	6.48	4.18	3.01
SE	298.	N/A	N/A	N/A	62.6	13.7	9.60	6.12	4.42	3.32	2.59	2.06	1.42	1.05	6.57	2.76	1.03	5.29	3.42	2.48

Table I.4-9 POINT BEACH NUCLEAR PLANT GROWING/GRAZING SEASON X/Q'S, UNIT 1 OR UNIT 2 CONTAINMENT PURGE VENT, CONTINUOUS GROUND LEVEL RELEASE (IIA) AND GAS STRIPPER BUILDING VIA UNIT 2 CONTAINMENT PURGE VENT, CONTINUOUS GROUND LEVEL RELEASE (IIC)

DATA PERIOD: 4/19/67-10/18/67
AND 4/19/68-10/18/68

X/Q (Sec/M^3) at Various Receptor Distances (M)

Downwind Sector	Shoreline Boundary	Site Boundary	Nearest Residence	Nearest Farm	805	1,700	1,980	2,415	2,800	3,200	3,600	4,025	4,830	5,635	7,245	12,070	24,140	40,235	56,330	72,425
Order	E-07	E-07	E-07	E-07	E-07	E-07	E-07	E-07	E-07	E-07	E-07	E-07	E-07	E-07	E-08	E-08	E-08	E-09	E-09	E-09
SSE	15.4	13.1	4.95	13.1	29.9	6.70	4.66	2.94	2.11	1.57	1.22	0.959	0.655	0.479	2.94	1.19	0.420	2.06	1.29	0.911
S	N/A	51.9	7.96	51.9	112	25.4	18.1	11.8	8.68	6.61	5.23	4.21	2.98	2.24	14.4	6.36	2.54	13.6	9.07	6.69
SSW	N/A	37.8	28.0	11.6	81.8	19.4	13.7	8.82	6.40	4.83	3.78	3.02	2.10	1.56	9.82	4.13	1.57	8.14	5.28	3.82
SW	N/A	21.8	11.7	16.2	72.1	16.7	11.7	7.52	5.45	4.11	3.22	2.56	1.78	1.32	8.30	3.49	1.32	6.84	4.43	3.21
WSW	N/A	26.4	7.58	26.4	61.8	14.2	10.0	6.42	4.56	3.51	2.75	2.19	1.52	1.13	7.12	3.01	1.14	5.92	3.84	2.78
W	N/A	30.1	8.75	30.1	68.1	15.6	11.0	7.04	5.11	3.85	3.01	2.40	1.67	1.24	7.80	3.30	1.25	6.49	4.21	3.05
WNW	N/A	19.0	9.12	8.28	73.3	M	12.1	7.72	5.59	4.21	3.29	2.62	1.82	1.35	8.47	3.57	1.34	6.89	4.45	3.21
NW	N/A	12.3	5.71	8.66	82.8	18.6	13.2	8.54	6.24	4.73	3.72	2.98	2.09	1.56	9.95	4.30	1.68	8.87	5.84	4.28
NNW	68.0	11.3	6.06	11.3	71.4	M	11.6	7.48	5.43	4.09	3.20	2.55	1.78	1.32	8.33	3.53	1.35	6.99	4.54	3.30
N	513	3.68	2.50	N/A	108	24.2	17.0	10.8	7.81	5.86	4.57	3.63	2.51	1.85	11.6	4.82	1.79	9.09	5.84	4.20
NNE	1,630	N/A	N/A	N/A	161	37.1	26.2	16.8	12.2	9.24	7.24	5.77	4.03	2.99	18.9	8.00	3.06	15.9	10.4	7.52
NE	1,850	N/A	N/A	N/A	127	29.2	20.7	13.5	9.85	7.48	5.90	4.73	3.33	2.50	15.9	6.93	2.72	14.5	9.54	6.99
ENE	894	N/A	N/A	N/A	64.3	14.5	10.3	6.62	4.82	3.65	2.86	2.29	1.60	1.19	7.54	3.23	1.24	6.54	4.29	3.13
E	822	N/A	N/A	N/A	58.8	13.2	9.28	5.98	4.35	3.29	2.58	2.06	1.44	1.07	6.77	2.89	1.11	5.81	3.80	2.77
ESE	620	N/A	N/A	N/A	64.2	14.1	9.94	6.39	4.64	3.50	2.75	2.19	1.53	1.14	7.18	3.07	1.18	6.16	4.04	2.95
SE	206	N/A	N/A	N/A	41.8	9.11	6.38	4.08	2.95	2.22	1.74	1.38	0.961	0.713	4.48	1.91	0.722	3.74	2.44	1.77

Table I.4-10 POINT BEACH NUCLEAR PLANT ANNUAL AVERAGE X/Q'S, UNIT 1 OR UNIT 2 CONTAINMENT PURGE VENT, INTERMITTENT RELEASE (IIB)

4/19/67-4/18/69

X/Q (Sec/M^3) at Various Receptor Distances (M)

Downwind Sector	Shoreline Boundary	Site Boundary	Nearest Residence	Nearest Farm	805	2,415	4,025	5,635	7,245	12,070	24,140	40,235	56,330	72,425
Order	E-07	E-07	E-07	E-07	E-07	E-07	E-07	E-07	E-08	E-08	E-08	E-09	E-09	E-09
SSE	18.6	16.7	9.60	16.7	11.8	2.20	0.890	0.492	3.16	1.37	0.528	2.69	1.72	1.23
S	N/A	27.0	8.96	27.0	24.8	4.64	2.11	1.37	9.42	4.62	2.04	11.3	7.62	5.67
SSW	N/A	22.9	19.1	12.8	17.0	3.91	1.68	0.951	6.31	2.74	1.16	6.13	4.02	2.93
SW	N/A	17.3	13.7	15.9	11.4	3.25	1.49	0.744	4.57	2.00	0.890	4.64	3.03	2.20
WSW	N/A	13.5	8.90	13.5	5.41	1.68	0.911	0.538	3.20	1.44	0.662	3.51	2.31	1.68
W	N/A	12.0	8.74	12.0	4.54	1.66	1.08	0.629	3.51	1.79	0.829	4.32	2.81	2.04
WNW	N/A	8.75	8.86	8.69	3.72	1.63	1.29	0.663	5.00	2.32	1.08	5.67	3.71	2.70
NW	N/A	9.41	7.24	7.84	7.93	1.91	1.29	0.982	6.41	2.45	1.11	5.85	3.85	2.81
NNW	27.9	9.04	7.10	9.04	9.61	1.97	1.19	0.871	5.61	2.43	0.937	4.86	3.15	2.28
N	135	4.28	3.85	N/A	16.5	2.96	1.29	0.915	6.87	3.33	1.25	6.34	4.06	2.92
NNE	461	N/A	N/A	N/A	28.6	4.63	1.94	1.12	7.60	3.61	1.53	8.29	5.53	4.08
NE	533	N/A	N/A	N/A	17.5	2.99	1.38	0.850	6.01	3.09	1.41	7.94	5.41	4.05
ENE	323	N/A	N/A	N/A	9.71	1.72	0.765	0.459	3.18	1.57	0.690	3.81	2.57	1.91
E	494	N/A	N/A	N/A	18.3	2.87	1.23	0.729	5.00	2.44	1.06	5.79	3.88	2.87
ESE	283	N/A	N/A	N/A	21.0	3.10	1.21	0.676	4.47	2.07	0.846	4.48	2.95	2.15
SE	110	N/A	N/A	N/A	14.9	2.33	0.915	0.511	3.37	1.56	0.634	3.37	2.22	1.63

Table I.4-11 POINT BEACH NUCLEAR PLANT GROWING/GRAZING SEASON X/Q'S, UNIT 1 OR UNIT 2 CONTAINMENT PURGE VENT, INTERMITTENT RELEASE (IIB)

4/19/67-10/18/67 AND 4/19/68-10/18/68

X/Q (Sec/M^3) at Various Receptor Distances (M)

Downwind Sector	Shoreline Boundary	Site Boundary	Nearest Residence	Nearest Farm	805	2,415	4,025	5,635	7,245	12,070	24,140	40,235	56,330	72,425
Order	E-07	E-07	E-07	E-07	E-07	E-07	E-07	E-07	E-08	E-08	E-08	E-09	E-09	E-09
SSE	13.7	12.4	7.23	12.4	6.58	1.29	0.532	0.298	1.93	0.855	0.336	1.73	1.11	0.794
S	N/A	22.1	7.07	22.1	17.6	3.06	1.47	1.01	7.19	3.70	1.71	9.68	6.63	4.98
SSW	N/A	24.8	20.7	13.9	20.1	4.64	2.00	1.14	7.56	3.28	1.40	7.42	4.88	3.56
SW	N/A	19.4	15.4	17.9	14.1	4.28	2.02	1.01	6.18	2.72	1.24	6.49	4.24	3.08
WSW	N/A	14.1	10.5	14.1	5.53	2.22	1.30	0.781	4.63	2.11	0.993	5.29	3.49	2.55
W	N/A	11.5	9.64	11.5	4.16	2.00	1.45	0.870	4.79	2.53	1.21	6.34	4.14	3.01
WNW	N/A	9.63	10.0	9.83	4.25	2.07	1.66	0.850	6.29	2.90	1.29	6.76	4.40	3.19
NW	N/A	10.0	8.06	8.41	8.81	2.26	1.73	1.42	9.35	3.52	1.65	8.78	5.80	4.26
NNW	30.0	9.93	7.99	9.93	11.2	2.48	1.61	1.22	7.89	3.42	1.33	6.92	4.51	3.28
N	140	4.78	4.46	N/A	18.7	3.59	1.61	1.18	9.17	4.62	1.74	8.94	5.76	4.15
NNE	473	N/A	N/A	N/A	33.8	5.79	2.50	1.47	10.0	4.84	2.07	11.3	7.54	5.57
NE	562	N/A	N/A	N/A	19.5	3.17	1.49	0.932	6.67	3.50	1.63	9.27	6.36	4.79
ENE	355	N/A	N/A	N/A	11.1	1.84	0.811	0.485	3.36	1.67	0.734	4.08	2.76	2.06
E	422	N/A	N/A	N/A	13.2	1.91	0.795	0.464	3.18	1.57	0.694	3.86	2.61	1.95
ESE	202	N/A	N/A	N/A	11.9	1.76	0.726	0.426	2.92	1.46	0.642	3.56	2.41	1.80
SE	76.6	N/A	N/A	N/A	8.62	1.33	0.527	0.297	1.98	0.939	0.396	2.16	1.44	1.07

Table I.4-12 POINT BEACH NUCLEAR PLANT ANNUAL AVERAGE X/Q'S, TURBINE BUILDING ROOF EXHAUSTERS, CONTINUOUS GROUND LEVEL RELEASE (III)

DATA PERIOD: 4/19/67-10/18/68

X/Q (Sec/M^3) at Various Receptor Distances (M)

Downwind Sector	Shoreline Boundary	Site Boundary	Nearest Residence	Nearest Farm	805	1,700	1,980	2,415	2,800	3,200	3,600	4,025	4,830	5,635	7,245	12,070	24,140	40,235	56,330	72,425
Order	E-07	E-07	E-07	E-07	E-07	E-07	E-07	E-07	E-07	E-07	E-07	E-07	E-07	E-07	E-08	E-08	E-08	E-09	E-09	E-09
SSE	24.8	21.0	7.83	21.0	49.7	10.7	7.36	4.61	3.29	2.44	1.89	1.49	1.01	0.738	4.51	1.81	0.639	3.13	1.96	1.38
S	N/A	70.4	10.3	70.4	147	34.7	24.3	15.6	11.3	8.47	6.63	5.29	3.69	2.75	17.4	7.44	2.89	15.3	10.1	7.39
SSW	N/A	36.3	26.6	10.7	81.4	18.3	12.7	8.07	5.80	4.34	3.37	2.68	1.85	1.36	8.50	3.52	1.32	6.79	4.38	3.16
SW	N/A	17.5	9.27	13.0	59.3	13.3	9.27	5.87	4.21	3.15	2.45	1.94	1.34	0.990	6.17	2.56	0.959	4.93	3.19	2.30
WSW	N/A	19.7	5.49	19.7	46.9	10.5	7.31	4.63	3.32	2.48	1.93	1.53	1.06	0.782	4.88	2.03	0.765	3.94	2.55	1.85
W	N/A	23.1	6.55	23.1	52.9	11.9	8.28	5.24	3.76	2.82	2.19	1.74	1.20	0.887	5.54	2.31	0.870	4.48	2.90	2.10
WNW	N/A	16.8	7.94	7.19	66.5	15.2	10.6	6.70	4.82	3.61	2.81	2.23	1.54	1.14	7.14	2.99	1.13	5.86	3.80	2.76
NW	N/A	9.69	4.35	6.70	64.3	14.9	10.4	6.61	4.77	3.58	2.79	2.22	1.54	1.14	7.17	3.03	1.16	6.06	3.96	2.89
NNW	57.1	9.05	4.77	9.05	60.0	13.5	9.38	5.93	4.26	3.19	2.48	1.97	1.36	1.00	6.25	2.61	0.978	5.02	3.24	2.33
N	427	2.79	1.88	N/A	87.4	19.3	13.3	8.41	6.02	4.49	3.48	2.75	1.89	1.39	8.58	3.53	1.29	6.52	4.17	2.99
NNE	1,230	N/A	N/A	N/A	133	30.4	21.2	13.5	9.70	7.27	5.67	4.50	3.11	2.30	14.4	6.03	2.28	11.9	7.70	5.59
NE	1,560	N/A	N/A	N/A	122	28.8	20.1	12.9	9.29	6.98	5.46	4.35	3.03	2.25	14.2	6.05	2.33	12.3	8.07	5.90
ENE	813	N/A	N/A	N/A	64.7	14.9	10.4	6.63	4.77	3.58	2.79	2.22	1.54	1.14	7.13	3.01	1.14	5.96	3.89	2.83
E	1,180	N/A	N/A	N/A	94.4	21.5	15.0	9.50	6.84	5.12	3.99	3.17	2.19	1.62	10.1	4.23	1.60	8.29	5.38	3.91
ESE	773	N/A	N/A	N/A	86.1	19.0	13.2	8.30	5.95	4.43	3.44	2.72	1.87	1.38	8.52	3.53	1.30	6.63	4.27	3.08
SE	337	N/A	N/A	N/A	69.1	15.3	10.6	6.68	4.78	3.57	2.77	2.19	1.51	1.11	6.89	2.86	1.06	5.42	3.50	2.53

Table I.4-13 GROWING/GRAZING SEASON X/Q'S, TURBINE BUILDING ROOF EXHAUSTERS, CONTINUOUS GROUND LEVEL RELEASE (III)

DATA PERIOD: 4/19/67-10/18/67
AND: 4/19/68-10/18/68

X/Q (Sec/M^3) at Various Receptor Distances (M)

Downwind Sector	Shoreline Boundary	Site Boundary	Nearest Residence	Nearest Farm	805	1,700	1,980	2,415	2,800	3,200	3,600	4,025	4,830	5,635	7,245	12,070	24,140	40,235	56,330	72,425
Order	E-07	E-07	E-07	E-07	E-07	E-07	E-07	E-07	E-07	E-07	E-07	E-07	E-07	E-07	E-08	E-08	E-08	E-09	E-09	E-09
SSE	16.6	14.1	5.24	14.1	33.4	7.14	4.92	3.08	2.20	1.63	1.26	0.990	0.673	0.491	3.00	1.20	0.424	2.08	1.30	0.919
S	N/A	60.8	9.03	60.8	125	30.2	21.2	13.6	9.87	7.45	5.84	4.67	3.26	2.44	15.5	6.71	2.64	14.1	9.35	6.88
SSW	N/A	42.7	31.4	12.7	95.0	21.7	15.1	9.58	6.89	5.16	4.02	3.19	2.21	1.63	10.2	4.24	1.60	8.28	5.36	3.88
SW	N/A	24.4	12.9	18.1	82.4	18.6	12.9	8.19	5.88	4.40	3.43	2.72	1.87	1.39	8.64	3.59	1.35	6.96	4.51	3.26
WSW	N/A	29.7	8.32	29.7	70.7	15.9	11.1	7.01	5.04	3.77	2.94	2.33	1.61	1.19	7.43	3.11	1.17	6.04	3.91	2.83
W	N/A	33.9	9.61	33.9	77.6	17.5	12.2	7.70	5.53	4.14	3.22	2.56	1.76	1.30	8.14	3.40	1.28	6.62	4.29	3.11
WNW	N/A	21.1	9.93	8.99	84.7	19.0	13.2	8.37	6.01	4.49	3.49	2.77	1.91	1.41	8.80	3.66	1.37	7.01	4.51	3.25
NW	N/A	14.1	6.35	9.75	92.3	21.6	15.1	9.62	6.95	5.22	4.08	3.25	2.26	1.68	10.6	4.50	1.73	9.14	6.01	4.39
NNW	78.2	12.5	6.58	12.5	82.1	18.6	12.9	8.18	5.88	4.40	3.43	2.72	1.88	1.39	8.70	3.64	1.38	7.13	4.63	3.35
N	593	3.88	2.62	N/A	120	26.7	18.5	11.7	8.37	6.25	4.85	3.84	2.63	1.94	12.0	4.96	1.83	9.26	5.94	4.27
NNE	1,690	N/A	N/A	N/A	183	41.8	29.1	18.5	13.3	9.97	7.77	6.17	4.27	3.16	19.8	8.27	3.13	16.3	10.6	7.67
NE	1,870	N/A	N/A	N/A	144	34.0	23.8	15.2	11.0	8.29	6.49	5.18	3.60	2.68	17.0	7.26	2.82	14.9	9.80	7.17
ENE	914	N/A	N/A	N/A	71.7	16.6	11.6	7.38	5.32	3.99	3.12	2.48	1.72	1.27	7.97	3.37	1.28	6.72	4.40	3.21
E	846	N/A	N/A	N/A	65.4	15.0	10.5	6.65	4.79	3.59	2.80	2.23	1.54	1.14	7.15	3.02	1.14	5.97	3.90	2.84
ESE	658	N/A	N/A	N/A	70.7	16.1	11.2	7.12	5.12	3.83	2.99	2.37	1.64	1.21	7.60	3.20	1.21	6.35	4.15	3.03
SE	228	N/A	N/A	N/A	46.2	10.3	7.14	4.51	3.23	2.42	1.88	1.49	1.03	0.758	4.72	1.98	0.744	3.85	2.50	1.81

Table I.4-14 POINT BEACH NUCLEAR PLANT ANNUAL AVERAGE D/Q'S, AUXILIARY BUILDING VENT, CONTINUOUS ELEVATED RELEASE (IA)

DATA PERIOD: 4/19/67-10/18/68

D/Q (Sec/M^{-2}) at Various Receptor Distances (m)

Downwind Sector	Shoreline Boundary	Site Boundary	Nearest Residence	Nearest Farm	805	1,700	1,980	2,415	2,800	3,200	3,600	4,025	4,830	5,635	7,245	12,070	24,140	40,235	56,330	72,425
Order	E-09	E-09	E-09	E-09	E-09	E-09	E-09	E-09	E-09	E-09	E-09	E-10	E-10	E-10	E-10	E-10	E-11	E-11	E-11	E-12
SSE	24.0	20.1	6.95	20.1	46.9	9.85	6.48	3.80	2.58	1.84	1.37	10.4	6.78	4.81	2.89	1.12	3.61	1.45	0.758	4.63
S	N/A	13.3	1.48	13.3	29.4	6.10	4.04	2.40	1.65	1.19	0.905	7.13	5.12	4.19	3.48	2.12	9.36	3.80	1.89	11.0
SSW	N/A	8.07	5.90	2.12	18.7	3.88	2.57	1.53	1.05	0.760	0.580	4.58	3.30	2.72	2.28	1.40	6.23	2.53	1.25	7.27
SW	N/A	4.73	2.29	3.36	16.8	3.47	2.29	1.36	0.930	9.669	0.507	3.96	2.78	2.21	1.74	1.00	4.33	1.76	0.880	5.15
WSW	N/A	3.64	0.886	3.64	9.08	1.86	1.23	0.727	0.498	0.358	0.271	2.11	1.48	1.17	0.910	0.519	2.23	0.913	0.459	2.69
W	N/A	4.15	1.02	4.15	9.94	2.03	1.34	0.790	0.540	0.387	0.293	2.28	1.58	1.24	0.942	0.525	2.23	0.917	0.463	2.73
WNW	N/A	1.92	0.810	0.722	8.27	1.71	1.13	0.665	0.454	0.325	0.246	1.91	1.33	1.05	0.812	0.460	1.97	0.805	0.404	2.38
NW	N/A	1.71	0.672	1.11	13.5	2.80	1.85	1.09	0.747	0.536	0.405	3.16	2.20	1.73	1.33	0.753	3.21	1.31	0.657	3.85
NNW	23.6	3.26	1.55	3.26	24.6	5.15	3.39	1.99	1.36	0.968	0.725	5.57	3.73	2.76	1.86	0.887	3.41	1.38	0.700	4.16
N	153	1.57	1.00	N/A	69.5	14.7	9.64	5.66	3.84	2.73	2.03	15.5	10.1	7.15	4.29	1.67	5.37	2.14	1.12	6.80
NNE	219	N/A	N/A	N/A	63.6	13.4	8.82	5.20	3.54	2.53	1.90	14.6	9.91	7.47	5.25	2.65	10.5	4.24	2.13	12.6
NE	135	N/A	N/A	N/A	25.9	5.36	3.54	2.09	1.43	1.03	0.784	6.16	4.39	3.57	2.92	1.76	7.74	3.16	1.67	9.19
ENE	100	N/A	N/A	N/A	24.8	5.19	3.42	2.01	1.37	0.979	0.735	5.66	3.82	2.87	2.00	0.993	3.93	1.59	0.806	4.78
E	208	N/A	N/A	N/A	43.6	9.03	5.96	3.51	2.40	1.71	1.28	9.89	6.64	4.95	3.38	1.64	6.37	2.59	1.32	7.83
ESE	425	N/A	N/A	N/A	84.3	17.0	11.2	6.61	4.51	3.21	2.40	18.3	12.0	8.54	5.14	2.00	6.67	2.79	1.50	9.35
SE	229	N/A	N/A	N/A	63.5	12.6	8.30	4.90	3.34	2.39	1.79	13.7	8.94	6.36	3.82	1.48	4.96	2.12	1.16	7.29

Table I.4-15 POINT BEACH NUCLEAR PLANT GROWING/GRAZING SEASON D/Q'S, AUXILIARY BUILDING VENT, CONTINUOUS ELEVATED RELEASE (IA)

DATA PERIOD: 4/19/67-10/18/67
AND 4/19/68-10/18/68

D/Q (Sec/M^{-2}) at Various Receptor Distances (m)

Downwind Sector	Shoreline Boundary	Site Boundary	Nearest Residence	Nearest Farm	805	1,700	1,980	2,415	2,800	3,200	3,600	4,025	4,830	5,635	7,245	12,070	24,140	40,235	56,330	72,425
Order	E-09	E-09	E-09	E-09	E-09	E-09	E-09	E-09	E-09	E-09	E-09	E-10	E-10	E-10	E-10	E-10	E-11	E-11	E-11	E-12
SSE	14.1	11.7	4.06	11.7	27.7	5.76	3.79	2.22	1.51	1.07	0.801	6.10	3.98	2.83	1.71	0.668	2.19	0.891	0.470	2.88
S	N/A	6.78	0.766	6.78	15.2	3.11	2.06	1.23	0.849	0.618	0.476	3.81	2.87	2.49	2.28	1.51	6.95	2.84	1.41	8.16
SSW	N/A	9.65	7.08	2.53	22.2	4.65	3.08	1.82	1.25	0.903	0.688	5.43	3.92	3.23	2.73	1.69	7.50	3.04	1.51	8.74
SW	N/A	6.50	3.14	4.61	23.0	4.76	3.14	1.86	1.27	0.911	0.689	5.37	3.76	2.97	2.31	1.31	5.63	2.29	1.15	6.73
WSW	N/A	4.76	1.15	4.76	11.8	2.44	1.61	0.947	0.645	0.462	0.349	2.71	1.89	1.48	1.13	0.634	2.70	1.11	0.556	3.27
W	N/A	5.30	1.30	5.30	12.7	2.59	1.71	1.00	0.684	0.490	0.369	2.86	1.96	1.51	1.12	0.600	2.51	1.03	0.525	3.11
WNW	N/A	2.65	1.11	0.990	11.3	2.35	1.55	0.911	0.621	0.444	0.335	2.60	1.80	1.40	1.06	0.586	2.48	1.01	0.510	3.00
NW	N/A	1.94	0.762	1.26	15.5	3.19	2.10	1.24	0.847	0.608	0.460	3.59	2.52	2.01	1.58	0.916	3.97	1.63	0.817	4.80
NNW	26.2	3.60	1.71	3.60	27.3	5.69	3.75	2.21	1.50	1.07	0.806	6.21	4.20	3.17	2.23	1.12	4.48	1.82	0.923	5.47
N	194.	1.90	1.22	N/A	84.4	17.7	11.7	6.84	4.65	3.30	2.46	18.7	12.2	8.68	5.25	2.06	6.75	2.71	1.42	8.65
NNE	272.	N/A	N/A	N/A	80.4	16.9	11.1	6.56	4.47	3.20	2.40	18.5	12.5	9.45	6.67	3.38	13.5	5.44	2.74	16.2
NE	161.	N/A	N/A	N/A	29.8	6.11	4.04	2.39	1.74	1.18	0.895	7.03	5.02	4.07	3.34	2.01	8.87	3.63	1.81	10.6
ENE	122.	N/A	N/A	N/A	28.1	5.85	3.86	2.27	1.55	1.11	0.830	6.39	4.31	3.24	2.25	1.12	4.42	1.80	0.911	5.41
E	173.	N/A	N/A	N/A	32.6	6.68	4.41	2.60	1.77	1.27	0.951	7.32	4.91	3.65	2.47	1.18	4.59	1.88	0.967	5.79
ESE	298.	N/A	N/A	N/A	48.7	9.57	6.33	3.74	2.56	1.83	1.37	10.5	6.91	4.98	3.08	1.26	4.47	1.90	1.03	6.41
SE	151.	N/A	N/A	N/A	37.4	7.25	4.49	2.83	1.94	1.39	1.04	7.96	5.24	3.76	2.30	0.923	3.25	1.41	0.775	4.86

Table I.4-16 POINT BEACH NUCLEAR PLANT ANNUAL AVERAGE D/Q'S, AUXILIARY BUILDING VENT, INTERMITTENT ELEVATED RELEASE (IB)

4/19/67-10/18/68

D/Q (m^{-2}) at Various Receptor Distances (m)

Downwind Sector Order	Shoreline Boundary E-09	Site Boundary E-09	Nearest Residence E-09	Nearest Farm E-09
SSE	M	60.5	25.0	60.5
S	N/A	31.3	4.65	31.3
SSW	N/A	21.4	16.6	7.24
SW	N/A	16.8	9.22	12.8
WSW	N/A	17.3	5.67	17.3
W	N/A	20.6	6.69	20.6
WNW	N/A	12.1	5.91	5.35
NW	N/A	8.96	3.91	6.19
NNW	92.2	14.6	7.77	14.6
N	383	6.05	4.23	N/A
NNE	419	N/A	N/A	N/A
NE	364	N/A	N/A	N/A
ENE	368	N/A	N/A	N/A
E	534	N/A	N/A	N/A
ESE	907	N/A	N/A	N/A
SE	588	N/A	N/A	N/A

Table I.4-17 POINT BEACH NUCLEAR PLANT GROWING/GRAZING SEASON D/Q'S, AUXILIARY BUILDING VENT, INTERMITTENT ELEVATED RELEASE (IB)

4/19/67-10/18/67 AND 4/19/68-10/18/68

D/Q (m^{-2}) at Various Receptor Distances (m)

Downwind Sector Order	Shoreline Boundary E-09	Site Boundary E-09	Nearest Residence E-09	Nearest Farm E-09
SSE	M	47.5	19.6	47.5
S	N/A	18.1	2.98	18.1
SSW	N/A	22.2	17.8	7.84
SW	N/A	19.8	10.8	15.2
WSW	N/A	21.1	6.62	21.1
W	N/A	26.7	8.10	26.7
WNW	N/A	14.6	6.98	6.42
NW	N/A	9.26	4.04	6.34
NNW	92.6	14.5	7.47	14.5
N	452	6.51	4.57	N/A
NNE	464	N/A	N/A	N/A
NE	425	N/A	N/A	N/A
ENE	398	N/A	N/A	N/A
E	538	N/A	N/A	N/A
ESE	882	N/A	N/A	N/A
SE	521	N/A	N/A	N/A

Table I.4-18 POINT BEACH NUCLEAR PLANT ANNUAL AVERAGE D/Q'S, UNIT 1 OR UNIT 2 PURGE VENT, CONTINUOUS GROUND LEVEL RELEASE (IIA), GAS STRIPPER BUILDING VIA UNIT 2 PURGE VENT, CONTINUOUS GROUND LEVEL RELEASE (IIC), AND TURBINE BUILDING ROOF EXHAUSTERS, CONTINUOUS GROUND LEVEL RELEASE (III)

DATA PERIOD: 4/19/67-10/18/68

D/Q (Sec/M^{-2}) at Various Receptor Distances (m)

Downwind Sector	Shoreline Boundary	Site Boundary	Nearest Residence	Nearest Farm	805	1,700	1,980	2,415	2,800	3,200	3,600	4,025	4,830	5,635	7,245	12,070	24,140	40,235	56,330	72,425
Order	E-09	E-09	E-09	E-09	E-09	E-09	E-09	E-09	E-09	E-09	E-09	E-10	E-10	E-10	E-10	E-10	E-11	E-11	E-11	E-12
SSE	29.3	24.6	8.72	24.6	60.2	12.1	8.17	4.94	3.42	2.47	1.86	1.43	9.33	6.56	3.76	1.28	3.35	1.25	0.650	3.96
S	N/A	47.9	5.63	47.9	110	22.1	14.9	9.01	6.24	4.50	3.39	2.60	17.0	12.0	6.86	2.34	6.12	2.29	1.19	7.24
SSW	N/A	30.4	21.8	8.18	72.7	14.6	9.86	5.96	4.13	2.98	2.24	1.72	11.3	7.92	4.54	1.55	4.05	1.51	0.785	4.78
SW	N/A	14.1	7.10	10.2	52.4	10.5	7.10	4.29	2.97	2.15	1.62	1.24	8.11	5.71	3.27	1.11	2.92	1.09	0.566	3.45
WSW	N/A	10.7	2.69	10.7	27.2	5.47	3.69	2.23	1.54	1.11	0.839	0.644	4.21	2.97	1.70	0.579	1.51	0.567	0.294	1.79
W	N/A	11.3	2.89	11.3	27.6	5.55	3.74	2.26	1.57	1.13	0.851	0.653	4.27	3.01	1.72	0.587	1.54	0.575	0.298	1.82
WNW	N/A	5.43	2.39	2.15	24.2	4.86	3.28	1.98	1.37	0.991	0.746	0.573	3.75	2.64	1.51	0.514	1.35	0.504	0.261	1.59
NW	N/A	4.95	2.02	3.28	39.5	7.93	5.35	3.23	2.24	1.62	1.22	0.934	6.11	4.30	2.46	0.839	2.20	0.822	0.426	2.60
NNW	44.7	6.13	3.03	6.13	47.0	9.45	6.37	3.85	2.67	1.93	1.45	1.11	7.28	5.12	2.93	1.00	2.62	0.979	0.508	3.09
N	458	2.16	1.38	N/A	89.7	18.0	12.2	7.35	5.09	3.67	2.77	2.12	13.9	9.78	5.60	1.91	4.99	1.87	0.969	5.90
NNE	1,360	N/A	N/A	N/A	139	28.0	18.9	11.4	7.90	5.70	4.29	3.29	21.5	15.2	8.68	2.96	7.74	2.90	1.50	9.15
NE	1,160	N/A	N/A	N/A	91.8	18.5	12.4	7.52	5.21	3.76	2.83	2.17	14.2	10.0	5.72	1.95	5.11	1.91	0.991	6.04
ENE	665	N/A	N/A	N/A	52.5	10.5	7.11	4.30	2.98	2.15	1.62	1.24	8.12	5.72	3.27	1.12	2.92	1.09	0.566	3.45
E	1,090	N/A	N/A	N/A	86.3	17.4	11.7	7.07	4.90	3.53	2.66	2.04	13.4	9.41	5.38	1.84	4.80	1.80	0.932	5.68
ESE	973	N/A	N/A	N/A	107	21.6	14.6	8.80	6.09	4.40	3.31	2.54	16.6	11.7	6.70	2.28	5.98	2.24	1.16	7.07
SE	385	N/A	N/A	N/A	79.5	16.0	10.8	6.52	4.51	3.26	2.45	1.88	12.3	8.66	4.96	1.69	4.43	1.66	0.859	5.23

Table I.4-19 POINT BEACH NUCLEAR PLANT GROWING/GRAZING SEASON D/Q'S, UNIT 1 OR UNIT 2 PURGE VENT, CONTINUOUS GROUND LEVEL RELEASE (IIA), GAS STRIPPER BUILDING VIA UNIT 2 PURGE VENT, CONTINUOUS GROUND LEVEL RELEASE (IIC), AND TURBINE BUILDING ROOF EXHAUSTERS, CONTINUOUS GROUND LEVEL RELEASE (III)

DATA PERIOD: 4/19/67-10/18/67
AND 4/19/68-10/18/68

D/Q (Sec/M^{-2}) at Various Receptor Distances (m)

Downwind Sector	Shoreline Boundary	Site Boundary	Nearest Residence	Nearest Farm	805	1,700	1,980	2,415	2,800	3,200	3,600	4,025	4,830	5,635	7,245	12,070	24,140	40,235	56,330	72,425
Order	E-09	E-09	E-09	E-09	E-09	E-09	E-09	E-09	E-09	E-09	E-09	E-10	E-10	E-10	E-10	E-10	E-11	E-11	E-11	E-12
SSE	17.5	14.7	5.22	14.7	36.0	7.25	4.89	2.95	2.05	1.48	1.11	8.53	5.58	3.93	2.25	0.767	2.01	0.751	0.389	2.37
S	N/A	34.1	4.01	34.1	78.3	15.7	10.6	6.41	4.44	3.21	2.41	18.5	12.1	8.53	4.88	1.66	4.36	1.63	0.845	5.15
SSW	N/A	36.6	26.3	9.86	87.6	17.6	11.9	7.18	4.97	3.59	2.70	20.7	13.6	9.55	5.47	1.86	4.88	1.82	0.946	5.76
SW	N/A	18.6	9.32	13.4	68.8	13.8	9.32	5.64	3.90	2.82	2.12	16.3	10.6	7.49	4.29	1.46	3.83	1.43	0.743	4.53
WSW	N/A	13.1	3.31	13.1	33.4	6.72	4.53	2.74	1.90	1.37	1.03	7.91	5.18	3.64	2.09	0.711	1.86	0.696	0.361	2.20
W	N/A	13.0	3.33	13.0	31.8	6.39	4.31	2.60	1.80	1.30	0.980	7.52	4.92	3.46	1.98	0.676	1.77	0.662	0.343	2.09
WNW	N/A	6.95	3.06	2.75	31.0	6.22	4.20	2.54	1.76	1.27	0.955	7.33	4.79	3.37	1.93	0.658	1.72	0.645	0.334	2.04
NW	N/A	6.05	2.46	4.01	48.2	9.68	6.53	3.95	2.73	1.97	1.49	11.4	7.45	5.25	3.00	1.02	2.68	1.00	0.520	3.17
NNW	56.3	7.73	3.82	7.73	59.3	11.9	8.04	4.86	3.36	2.43	1.83	14.0	9.18	6.46	3.70	1.26	3.30	1.23	0.640	3.90
N	567	2.67	1.71	N/A	111	22.3	15.0	9.10	6.30	4.55	3.42	26.3	17.2	12.1	6.92	2.36	6.18	2.31	1.20	7.30
NNE	1,740	N/A	N/A	N/A	178	35.8	24.1	14.6	10.1	7.28	5.49	42.1	27.5	19.4	11.1	3.78	9.90	3.70	1.92	11.7
NE	1,330	N/A	N/A	N/A	105	21.1	14.2	8.61	5.96	4.30	3.24	24.9	16.3	11.5	6.56	2.24	5.85	2.19	1.13	6.91
ENE	748	N/A	N/A	N/A	59.0	11.9	8.00	4.84	3.35	2.42	1.82	14.0	9.14	5.43	3.68	1.26	3.28	1.23	0.637	3.88
E	794	N/A	N/A	N/A	62.6	12.6	8.48	5.13	3.55	2.56	1.93	14.8	9.69	6.82	3.90	1.33	3.48	1.30	0.676	4.12
ESE	612	N/A	N/A	N/A	67.5	13.6	9.16	5.53	3.83	2.77	2.08	16.0	10.5	7.36	4.21	1.44	3.76	1.41	0.729	4.44
SE	240	N/A	N/A	N/A	49.7	9.99	6.73	4.07	2.82	2.03	1.53	11.8	7.69	5.41	3.10	1.06	2.76	1.03	0.536	3.27

Table I.4-20 POINT BEACH NUCLEAR PLANT ANNUAL AVERAGE D/Q'S, UNIT 1 OR UNIT 2 CONTAINMENT PURGE VENT, INTERMITTENT RELEASE (IIB)

4/19/67-4/18/69

D/Q (Sec/M²) at Various Receptor Distances (m)

Downwind Sector	Shoreline Boundary	Site Boundary	Nearest Residence	Nearest Farm	805	2,415	4,025	5,635	7,245	12,070	24,140	40,235	56,330	72,425
Order	E-09	E-09	E-09	E-09	E-09	E-09	E-10	E-10	E-10	E-10	E-11	E-11	E-11	E-11
SSE	M	50.0	21.0	50.0	49.4	4.01	11.2	5.20	3.09	1.17	3.61	1.43	0.745	0.454
S	N/A	47.6	7.43	47.6	56.2	4.59	13.4	6.77	4.60	2.19	8.28	3.30	1.66	0.977
SSW	N/A	39.3	29.1	12.9	40.6	3.33	9.67	4.81	3.18	1.46	5.33	2.11	1.06	0.626
SW	N/A	22.7	12.8	17.4	29.1	2.36	6.82	3.39	2.25	1.03	3.83	1.53	0.773	0.458
WSW	N/A	23.0	7.33	23.0	15.2	1.23	3.53	1.75	1.16	0.533	1.98	0.797	0.404	0.241
W	N/A	23.9	7.18	23.9	14.3	1.14	3.28	1.65	1.12	0.535	2.06	0.834	0.425	0.253
WNW	N/A	11.9	5.98	5.39	11.8	0.951	2.73	1.39	0.956	0.468	1.83	0.739	0.374	0.221
NW	N/A	10.5	4.81	7.15	21.4	1.73	4.99	2.49	1.66	0.774	2.90	1.16	0.589	0.350
NNW	83.5	13.6	7.53	13.6	30.1	2.44	6.96	3.37	2.14	0.923	3.24	1.29	0.659	0.394
N	572	5.58	3.89	N/A	72.5	5.90	16.6	7.70	4.60	1.75	5.45	2.15	1.11	0.677
NNE	1,128	N/A	N/A	N/A	86.1	7.03	20.2	9.82	6.31	2.76	9.75	3.86	1.96	1.16
NE	851	N/A	N/A	N/A	39.5	3.21	9.38	4.91	3.51	1.80	7.21	2.90	1.46	0.856
ENE	700	N/A	N/A	N/A	29.8	2.42	6.94	3.42	2.25	1.03	3.78	1.51	0.769	0.457
E	1,221	N/A	N/A	N/A	55.7	4.51	12.9	6.27	3.99	1.71	5.98	2.39	1.22	0.730
ESE	1,228	N/A	N/A	N/A	89.1	7.12	20.2	9.40	5.59	2.11	6.5	2.65	1.40	0.864
SE	600	N/A	N/A	N/A	66.7	5.26	14.8	6.90	4.09	1.54	4.86	2.00	1.08	0.671

Table I.4-21 POINT BEACH NUCLEAR PLANT GROWING/GRAZING SEASON D/Q'S, UNIT 1 OR UNIT 2 CONTAINMENT PURGE VENT, INTERMITTENT ELEVATED RELEASE (IIB)

4/19/67-10/18/68 AND 4/19/68-10/18/69

D/Q (Sec/M^{-2}) at Various Receptor Distances (m)

Downwind Sector	Shoreline Boundary	Site Boundary	Nearest Residence	Nearest Farm	805	2,415	4,025	5,635	7,245	12,070	24,140	40,235	56,330	72,425
Order	E-09	E-09	E-09	E-09	E-09	E-09	E-10	E-10	E-10	E-10	E-11	E-11	E-11	E-11
SSE	M	37.9	15.9	37.9	28.9	2.33	6.51	3.02	1.81	0.691	2.19	0.877	0.461	0.282
S	N/A	33.2	5.02	33.2	32.4	2.64	7.80	4.12	2.98	1.55	6.24	2.51	1.26	0.736
SSW	N/A	40.4	30.1	13.2	45.7	3.75	10.9	5.48	3.70	1.74	6.54	2.60	1.30	0.766
SW	N/A	25.1	14.0	19.2	36.5	2.96	8.53	4.27	2.87	1.35	5.08	2.04	1.03	0.611
WSW	N/A	23.3	7.21	23.3	16.5	1.33	3.80	1.93	1.32	0.646	2.51	1.02	0.515	0.305
W	N/A	24.3	7.13	24.3	15.2	1.21	3.44	1.75	1.22	0.606	2.41	0.985	0.502	0.299
WNW	N/A	14.2	6.95	6.31	15.5	1.25	3.56	1.79	1.23	0.595	2.31	0.934	0.473	0.281
NW	N/A	10.1	4.58	6.83	22.6	1.82	5.26	2.69	1.88	0.935	3.69	1.49	0.755	0.447
NNW	86.5	13.6	7.43	13.6	33.9	2.74	7.85	3.87	2.54	1.16	4.27	1.71	0.871	0.519
N	617	6.03	4.27	N/A	87.7	7.11	19.9	9.27	5.57	2.15	6.81	2.70	1.41	0.856
NNE	1,088	N/A	N/A	N/A	104	8.47	24.2	11.9	7.77	3.49	12.7	5.05	2.55	15.2
NE	814	N/A	N/A	N/A	41.6	3.36	9.87	5.26	3.87	2.05	8.42	3.41	1.71	10.0
ENE	754	N/A	N/A	N/A	33.4	2.70	7.76	3.83	2.53	1.16	4.27	1.71	0.870	0.518
E	986	N/A	N/A	N/A	39.1	3.14	8.99	4.38	2.81	1.23	4.40	1.77	0.912	0.548
ESE	940	N/A	N/A	N/A	51.5	4.06	11.5	5.44	3.31	1.31	4.37	1.80	0.958	0.590
SE	465	N/A	N/A	N/A	39.3	3.04	8.61	4.04	2.44	0.949	3.17	1.34	0.726	0.452

Table I.4-22 POINT BEACH NUCLEAR PLANT PERCENTAGE FREQUENCY DISTRIBUTION OF PASQUILL STABILITY CLASS FOR POINT BEACH, HAVEN, AND MILWAUKEE

LOCATION	VALID DATA HOURS	DATA PERIOD	PASQUILL STABILITY CLASS FREQUENCY PERCENTAGE A	B	C	D	E	F	G
POINT BEACH [1]	14,647	4/19/67-4/18/69	0.87	1.37	9.39	35.02	34.55	11.67	7.13
HAVEN [2]	7,968	6/1/73 - 5/31/74	1.91	1.50	2.35	34.63	37.83	14.02	7.76
MILWAUKEE [3]	5,848 [4]	4/19/67 - 4/18/69	0.17	2.89	8.96	69.90	8.81	6.24	4.04
MILWAUKEE [3]	2,920 [4]	6/1/73 - 5/31/74	0.00	1.10	7.23	74.37	9.67	5.72	1.82
MILWAUKEE [3]	110,968 [4]	1/1/56 - 12/31/75	0.08	2.28	8.09	68.75	10.03	7.13	3.65

Notes:

1. Stability Class determined by wind range.
2. Stability Class determined by Regulatory Guide 1.23 ΔT Classifications.
3. Stability Class determined by the STAR Program of the National Weather Service.
4. Observations recorded every third hour from 1/1/65 - 12/31/75.

Table I.4-23 POINT BEACH NUCLEAR PLANT PERCENTAGE FREQUENCY DISTRIBUTION OF WIND DIRECTION FOR POINT BEACH, HAVEN, AND MILWAUKEE

WIND FREQUENCY PERCENTAGE BY QUADRANT

	VALID	DATA	ONSHORE		OFFSHORE		CALM AND
LOCATION	DATA HOURS	PERIOD	NNE - E	ESE - S	SSW - W	WNW - N	VARIABLE
POINT BEACH (1)	14,647	4/19/67-4/18/69	16.06	17.84	33.17	32.02	0.91
HAVEN (2)	7,968	6/1/73 - 5/31/74	16.97	21.99	33.36	27.18	0.50
MILWAUKEE (3)	5,848 (4)	4/19/67 - 4/18/69	17.93	21.84	35.51	22.00	2.72
MILWAUKEE (3)	2,920 (4)	6/1/73 - 5/31/74	14.69	23.01	34.45	25.86	1.99
MILWAUKEE (3)	110,968 (4)	1/1/56 - 12/31/75	17.54	22.17	34.23	24.12	1.94

Notes:

1. Monitored at the Point Beach Nuclear Plant.
2. Monitored at the Haven Site, according to Regulatory Guide 1.23 recommendations.
3. Observations taken at General Mitchell Field, a first-order National Weather Service Station.
4. Observations recorded every third hour from 1/1/65 - 12/31/75.

Table I.4-24 POINT BEACH NUCLEAR PLANT WIND SPEED BY QUADRANT FOR POINT BEACH, HAVEN, AND MILWAUKEE

			AVERAGE WIND SPEED BY QUADRANT (MPH)			
	VALID	DATA	ONSHORE		OFFSHORE	
LOCATION	DATA HOURS	PERIOD	NNE - E	ESE - S	SSW - W	WNW - N
POINT BEACH (1)	14,647	4/19/67- 4/18/69	12.3	11.7	12.5	12.8
HAVEN (2)	7,968	6/1/73 - 5/31/74	10.1	8.2	8.4	10.3
MILWAUKEE (3)	5,848 (4)	4/19/67 - 4/18/69	10.6	9.9	11.1	12.0
MILWAUKEE (3)	2,920 (4)	6/1/73 - 5/31/74	12.0	10.5	12.0	12.1
MILWAUKEE (3)	110,968 (4)	1/1/56 - 12/31/75	12.0	10.4	11.8	12.8

Notes:

1. Monitored at the Point Beach Nuclear Plant.
2. Monitored at the Haven Site, according to Regulatory Guide 1.23 recommendations.
3. Observations taken at General Mitchell Field, a first-order National Weather Service Station.
4. Observations recorded every third hour from 1/1/65 - 12/31/75.

Table I.4-25 POINT BEACH NUCLEAR PLANT WIND-PRECIPITATION (FREQUENCY PERCENT) SUMMARY FOR 1/1/56 - 12/31/75 AT MILWAUKEE

WINDS BLOWING FROM	PRECIPITATION OCCURING DURING WIND SPEED CLASSIFICATIONS (MPH) 1 - 3	4 - 7	8 - 12	13 - 18	19 - 24	> 25	TOTAL
N	.024	.087	.207	.393	.189	.199	1.020
NNE	.030	.128	.280	.441	.235	.117	1.231
NE	.026	.085	.169	.259	.102	.075	.716
ENE	.023	.041	.133	.180	.101	.035	.513
E	.032	.085	.147	.205	.059	.047	.575
ESE	.030	.091	.209	.229	.056	.021	.635
SE	.036	.099	.206	.223	.064	.033	.661
SSE	.043	.128	.268	.220	.054	.011	.724
S	.054	.174	.308	.256	.059	.011	.862
SSW	.033	.137	.257	.229	.060	.019	.735
SW	.030	.088	.176	.191	.054	.036	.575
WSW	.030	.096	.169	.200	.068	.041	.605
W	.038	.147	.225	.264	.091	.040	.805
WNW	.032	.138	.221	.320	.124	.030	.864
NW	.028	.078	.260	.296	.102	.030	.793
NNW	.028	.078	.260	.296	.102	.030	.793

TOTAL OBSERVATIONS = 110,960.
PRECIPITATION OCCURING DURING CALM WIND CONDITIONS = 0.086.

Table I.4-26 POINT BEACH NUCLEAR PLANT AVERAGE PRECIPITATION FOR WEATHER STATIONS IN THE VICINITY OF POINT BEACH NUCLEAR PLANT

STATION	DISTANCE FROM	PERIOD OF	AVERAGE PRECIPITATION (INCHES)											
LOCATION	PBNP (MILES)	RECORD	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
Manitowoc	13 SSW	1863 - 1960	1.58	1.54	2.09	2.65	2.98	3.49	3.22	3.08	3.24	2.48	2.20	1.69
Kewaunee	12 N	1913 - 1960	1.44	1.36	1.59	2.51	3.08	3.26	2.94	2.78	3.09	2.04	2.27	1.45
Brillion	27 WSW	1924 - 1960	1.35	1.40	1.66	2.40	2.90	3.61	2.63	3.11	3.25	1.96	2.06	1.20
Green Bay	32 NW	1931 - 1960	1.15	1.08	1.34	2.46	3.06	3.36	2.71	2.75	2.92	1.91	1.91	1.18
Two Rivers	9 SSW	1951 - 1960	0.99	1.29	1.79	3.01	3.12	2.66	4.29	3.04	2.49	2.58	1.97	1.42

Annual Average Precipitations:

Manitowoc 30.24 inches
Kewaunee 27.81 inches
Brillion 27.53 inches
Green Bay 25.83 inches
Two Rivers 28.65 inches

Table I.4-27 POINT BEACH NUCLEAR PLANT MONTHLY PRECIPITATION TOTALS AND INTENSITY FREQUNCY DISTRIBUTIONS AT GREEN BAY, WISCONSIN APRIL 19, 1967 THROUGH APRIL 18, 1969

DATA PERIOD	TOTAL PRECIPITATION (INCHES)	HOURLY PRECIPITATION INTENSITY FREQUENCY TRACE	.01-.09	.10-.19	.20-.49	.50-.99	1.00 +	HOURS WITH PRECIPITATION
4/19-4/30, 1967	0.27	46	10	0	0	0	0	56
5/1-5/31, 1967	2.45	36	37	8	0	0	0	81
6/1-6/30, 1967	8.47	46	62	12	4	3	1	128
7/1-7/31, 1967	1.96	23	11	5	0	1	0	40
8/1-8/31, 1967	2.43	32	22	7	2	0	0	63
9/1-9/30, 1967	0.46	21	20	0	0	0	0	41
10/1-10/31, 1967	4.71	63	78	9	2	0	0	152
11/1-11/30, 1967	1.66	86	42	4	0	0	0	132
12/1-12/31, 1967	1.17	105	37	2	0	0	0	144
1/1-1/31, 1968	0.94	151	45	0	0	0	0	196
2/1-2/29, 1968	0.45	126	32	0	0	0	0	158
3/1-3/31, 1968	0.97	49	22	1	1	0	0	73
4/1-4/30, 1968	4.84	69	61	12	5	0	0	147
5/1-5/31, 1968	3.10	80	44	7	3	0	0	134
6/1-6/30, 1968	6.97	51	68	11	8	1	0	139
7/1-7/31, 1968	2.00	18	16	7	2	0	0	43
8/1-8/31, 1968	2.66	29	16	3	3	1	0	52
9/1-9/30, 1968	3.31	54	37	3	5	0	0	99
10/1-10/31, 1968	1.01	35	21	3	0	0	0	59
11/1-11/30, 1968	1.01	97	50	0	0	0	0	147
12/1-12/31, 1968	2.69	165	108	0	0	0	0	273
1/1-1/31, 1969	2.60	130	86	1	0	0	0	217
2/1-2/28, 1969	0.04	64	4	0	0	0	0	68
3/1-3/31, 1969	1.04	84	40	2	0	0	0	126
4/1-4/18, 1969	2.06	24	44	3	0	0	0	71
Total	59.27	1,684	1,013	100	35	6	1	2,839
Percent of Total Hours		9.60	5.77	0.570	0.199	0.034	0.006	16.18

Table I.4-28 HAVEN JOINT FREQUENCY DISTRIBUTION ANNUAL SUMMARY 6/1/73 THROUGH 5/31/74

HAVEN SITE WIND - STABILITY SUMMARY STABILITY CLASS - A - METER WINDS, PERIOD 6/1/73 TO 5/31/74 NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	1	0	1	0	0	0	2
NNE	0	0	10	3	7	0	20
NE	0	0	4	13	3	0	20
ENE	0	1	1	7	0	0	9
E	0	3	7	0	0	0	10
ESE	0	3	6	0	0	0	9
SE	0	1	12	0	0	0	13
SSE	0	0	1	3	0	0	4
S	0	0	3	0	0	0	3
SSW	0	1	0	2	0	0	3
SW	0	0	4	4	0	0	8
WSW	0	0	5	6	2	0	13
W	0	1	1	5	1	0	8
WNW	0	0	5	4	5	2	16
NW	0	1	4	3	1	0	9
NNW	0	0	3	2	0	0	5
TOTAL	1	11	67	52	19	2	152

Number of calm hours	0
Number of variable directions	0
Total number of observations	152

Sheet 1 of 8

Table I.4-28 (CONTINUED)

HAVEN SITE WIND - STABILITY SUMMARY STABILITY CLASS - B - METER WINDS, PERIOD 6/1/73 TO 5/31/74, NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	0	1	1	3	2	0	7
NNE	0	0	2	1	3	0	6
NE	0	1	3	5	0	0	9
ENE	1	0	3	1	1	0	6
E	0	2	0	0	0	0	2
ESE	0	6	0	1	0	0	7
SE	1	1	2	1	0	0	5
SSE	0	0	5	0	0	0	5
S	0	2	0	1	0	0	3
SSW	0	1	2	0	0	0	3
SW	0	1	4	5	1	0	11
WSW	0	1	7	4	1	0	13
W	0	2	8	4	1	0	15
WNW	0	0	0	7	2	0	9
NW	0	0	4	3	0	0	7
NNW	0	3	4	4	0	0	11
TOTAL	2	21	45	40	11	0	119

Number of calm hours	0
Number of variable directions	0
Total number of observations	119

Sheet 2 of 8

Table I.4-28 (CONTINUED)

HAVEN SITE WIND - STABILITY SUMMARY STABILITY CLASS - C - METER WINDS, PERIOD 6/1/73 TO 5/31/74, NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	0	0	0	4	1	0	5
NNE	0	1	6	2	2	0	11
NE	0	3	6	7	3	2	21
ENE	0	3	5	1	1	0	10
E	0	1	6	2	0	0	9
ESE	0	5	3	1	0	0	9
SE	0	5	4	0	0	0	9
SSE	0	0	2	3	0	0	5
S	1	2	3	2	0	0	8
SSW	0	0	2	2	0	0	4
SW	0	0	6	5	2	0	13
WSW	1	2	5	5	2	0	15
W	0	3	5	11	2	0	21
WNW	0	1	5	12	6	0	24
NW	0	2	3	5	2	0	12
NNW	0	2	4	5	0	0	11
TOTAL	2	30	65	67	21	2	187

Number of calm hours	0
Number of variable directions	0
Total number of observations	187

Sheet 3 of 8

Table I.4-28 (CONTINUED)

HAVEN SITE WIND - STABILITY SUMMARY STABILITY CLASS - D - METER WINDS, PERIOD 6/1/73 TO 5/31/74, NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	6	28	41	49	14	6	144
NNE	1	16	57	51	22	3	150
NE	3	33	48	62	15	6	167
ENE	4	36	30	49	17	5	141
E	11	28	49	41	15	0	144
ESE	1	21	58	34	8	0	122
SE	2	39	75	32	3	0	151
SSE	0	30	86	16	0	0	132
S	7	28	58	24	1	0	118
SSW	2	51	68	31	4	0	156
SW	4	37	71	56	6	0	174
WSW	4	25	55	52	6	0	142
W	6	21	84	83	23	0	217
WNW	3	39	152	108	29	4	335
NW	4	38	103	82	13	0	240
NNW	6	27	99	83	8	0	223
TOTAL	64	497	1134	853	184	24	2756

Number of calm hours	2
Number of variable directions	2
Total number of observations	2760

Sheet 4 of 8

Table I.4-28 (CONTINUED)

HAVEN SITE WIND - STABILITY SUMMARY STABILITY CLASS - E - METER WINDS, PERIOD 6/1/73 TO 5/31/74, NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	15	53	61	37	1	1	168
NNE	10	52	74	38	2	2	178
NE	6	39	30	8	1	0	84
ENE	17	48	22	9	1	0	97
E	25	44	22	6	1	0	98
ESE	9	49	20	3	0	0	81
SE	11	54	55	25	0	0	145
SSE	23	80	111	39	4	0	257
S	31	124	93	20	3	0	271
SSW	29	117	72	25	2	0	245
SW	25	143	110	29	5	0	312
WSW	16	67	83	37	4	0	207
W	18	65	83	48	6	2	222
WNW	13	70	150	51	8	2	294
NW	8	59	89	30	0	0	186
NNW	7	33	83	32	4	0	159
TOTAL	263	1097	1158	437	42	7	3004

Number of calm hours	1
Number of variable directions	10
Total number of observations	3015

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Table I.4-28 (CONTINUED)

HAVEN SITE WIND - STABILITY SUMMARY STABILITY CLASS - F - METER WINDS, PERIOD 6/1/73 TO 5/31/74, NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	8	21	5	0	0	0	34
NNE	9	18	17	14	0	0	58
NE	3	15	7	0	0	0	25
ENE	5	6	1	0	0	0	12
E	4	13	3	0	0	0	20
ESE	2	11	1	0	0	0	14
SE	3	32	26	1	0	0	62
SSE	15	45	32	1	1	0	94
S	28	55	19	4	0	0	106
SSW	27	92	35	3	0	0	157
SW	21	74	32	0	0	0	127
WSW	12	57	28	1	0	0	98
W	10	70	37	4	0	0	121
WNW	9	31	44	2	0	0	86
NW	5	21	27	4	0	0	57
NNW	12	13	10	0	0	0	35
TOTAL	173	574	324	34	1	0	1106

Number of calm hours	7
Number of variable directions	4
Total number of observations	1117

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Table I.4-28 (CONTINUED)

HAVEN SITE WIND - STABILITY SUMMARY STABILITY CLASS - G - METER WINDS, PERIOD 6/1/73 TO 5/31/74, NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	9	5	3	0	0	0	17
NNE	8	5	4	0	0	0	17
NE	9	2	2	0	0	0	13
ENE	4	4	0	0	0	0	8
E	4	3	0	0	0	0	7
ESE	3	4	0	2	0	0	9
SE	8	16	10	0	0	0	34
SSE	11	22	17	0	0	0	50
S	12	12	1	1	0	0	26
SSW	9	26	15	0	0	0	50
SW	28	38	24	0	0	0	90
WSW	32	73	9	0	0	0	114
W	22	61	15	1	0	0	99
WNW	8	13	12	0	0	0	33
NW	11	5	2	0	0	0	18
NNW	4	11	4	0	0	0	19
TOTAL	182	300	118	4	0	0	604

Number of calm hours	5
Number of variable directions	9
Total number of observations	618

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Table I.4-28 (CONTINUED)

HAVEN SITE WIND - STABILITY SUMMARY STABILITY CLASS - ALL - METER WINDS, PERIOD 6/1/73 TO 5/31/74, NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	39	108	112	93	18	7	377
NNE	28	92	170	109	36	5	440
NE	21	93	100	95	22	8	339
ENE	31	98	62	67	20	5	283
E	44	94	87	49	16	0	290
ESE	15	99	88	41	8	0	251
SE	25	148	184	59	3	0	419
SSE	49	177	254	62	5	0	547
S	79	223	177	52	4	0	535
SSW	67	288	194	63	6	0	618
SW	78	293	251	99	14	0	735
WSW	65	225	192	105	15	0	602
W	56	223	233	156	33	2	703
WNW	33	154	368	184	50	8	797
NW	28	126	232	127	16	0	529
NNW	29	89	207	126	12	0	463
TOTAL	687	2530	2911	1487	278	35	7928

Number of calm hours	15
Number of variable directions	25
Total number of observations	7968

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Table I.4-29 MILWAUKEE JOINT FREQUENCY DISTRIBUTION ANNUAL SUMMARY 6/1/73 THROUGH 5/31/74

MILWAUKEE WIND - STABILITY SUMMARY

STABILITY CLASS - A - ANNUAL 6/1/73 TO 5/31/74
NUMBER OF HOURLY OBSERVATIONS

	WIND SPEED (MPH)						
WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	0	0	0	0	0	0	0
NNE	0	0	0	0	0	0	0
NE	0	0	0	0	0	0	0
ENE	0	0	0	0	0	0	0
E	0	0	0	0	0	0	0
ESE	0	0	0	0	0	0	0
SE	0	0	0	0	0	0	0
SSE	0	0	0	0	0	0	0
S	0	0	0	0	0	0	0
SSW	0	0	0	0	0	0	0
SW	0	0	0	0	0	0	0
WSW	0	0	0	0	0	0	0
W	0	0	0	0	0	0	0
WNW	0	0	0	0	0	0	0
NW	0	0	0	0	0	0	0
NNW	0	0	0	0	0	0	0
TOTAL	0	0	0	0	0	0	0

Number of calm hours 0

Total number of observations 0

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Table I.4-29 (CONTINUED)

MILWAUKEE WIND - STABILITY SUMMARY

STABILITY CLASS - B - ANNUAL 6/1/73 TO 5/31/74
NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	0	1	0	0	0	0	1
NNE	1	1	1	0	0	0	3
NE	0	1	3	0	0	0	4
ENE	0	0	0	0	0	0	0
E	1	0	3	0	0	0	4
ESE	0	1	1	0	0	0	2
SE	1	1	1	0	0	0	3
SSE	0	0	0	0	0	0	0
S	2	0	1	0	0	0	3
SSW	1	1	1	0	0	0	3
SW	1	0	1	0	0	0	2
WSW	0	1	2	0	0	0	3
W	1	1	1	0	0	0	3
WNW	0	0	1	0	0	0	1
NW	0	2	1	0	0	0	3
NNW	4	0	0	0	0	0	4
TOTAL	12	10	17	0	0	0	39

Number of calm hours 5

Total number of observations 44

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Table I.4-29 (CONTINUED)

MILWAUKEE WIND - STABILITY SUMMARY

STABILITY CLASS - C - ANNUAL 6/1/73 TO 5/31/74
NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	0	1	8	1	0	0	10
NNE	0	0	9	1	0	0	10
NE	0	2	3	0	0	0	5
ENE	0	1	3	0	0	0	4
E	0	3	8	0	0	0	11
ESE	0	0	8	3	0	0	11
SE	0	2	6	3	0	0	11
SSE	0	1	3	1	0	0	5
S	1	1	11	2	0	0	15
SSW	0	5	7	1	0	0	13
SW	1	3	10	0	0	0	14
WSW	3	6	10	2	0	0	21
W	1	7	19	4	0	0	31
WNW	1	2	10	0	0	0	13
NW	0	3	12	1	0	0	16
NNW	0	1	5	0	0	0	6
TOTAL	7	38	132	19	0	0	196

Number of calm hours 10

Total number of observations 206

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Table I.4-29 (CONTINUED)

MILWAUKEE WIND - STABILITY SUMMARY

STABILITY CLASS - D - ANNUAL 6/1/73 TO 5/31/74
NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	2	16	41	71	21	6	157
NNE	1	15	37	37	8	3	101
NE	1	5	33	31	6	1	77
ENE	0	5	21	31	8	1	66
E	0	8	37	49	7	1	102
ESE	1	7	37	44	5	0	94
SE	2	14	51	69	6	0	142
SSE	2	10	22	34	2	1	71
S	5	20	67	60	6	0	158
SSW	0	8	35	53	8	4	108
SW	1	10	47	97	26	6	187
WSW	2	14	46	108	28	4	202
W	3	17	63	96	19	0	198
WNW	2	16	68	96	20	1	203
NW	1	10	64	68	5	0	148
NNW	3	3	33	40	5	1	85
TOTAL	26	178	702	984	180	29	2099

Number of calm hours 12

Total number of observations 2111

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Table I.4-29 (CONTINUED)

MILWAUKEE WIND - STABILITY SUMMARY

STABILITY CLASS - E - ANNUAL 6/1/73 TO 5/31/74
NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	0	5	8	0	0	0	13
NNE	0	7	3	0	0	0	10
NE	0	3	3	0	0	0	6
ENE	0	3	1	0	0	0	4
E	0	2	4	0	0	0	6
ESE	0	2	0	0	0	0	2
SE	0	10	5	0	0	0	15
SSE	0	12	7	0	0	0	19
S	0	16	34	0	0	0	50
SSW	0	13	19	0	0	0	32
SW	0	7	34	0	0	0	41
WSW	0	7	25	0	0	0	32
W	0	8	37	0	0	0	45
WNW	0	7	33	0	0	0	40
NW	0	3	14	0	0	0	17
NNW	0	0	3	0	0	0	3
TOTAL	0	105	230	0	0	0	335

Number of calm hours	0
Total number of observations	335

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Table I.4-29 (CONTINUED)

MILWAUKEE WIND - STABILITY SUMMARY

STABILITY CLASS - F - ANNUAL 6/1/73 TO 5/31/74
NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	1	7	0	0	0	0	8
NNE	1	2	0	0	0	0	3
NE	0	4	0	0	0	0	4
ENE	0	2	0	0	0	0	2
E	1	4	0	0	0	0	5
ESE	2	3	0	0	0	0	5
SE	2	4	0	0	0	0	6
SSE	1	14	0	0	0	0	15
S	1	33	0	0	0	0	34
SSW	1	6	0	0	0	0	7
SW	1	10	0	0	0	0	11
WSW	0	12	0	0	0	0	12
W	1	25	0	0	0	0	26
WNW	2	12	0	0	0	0	14
NW	0	7	0	0	0	0	7
NNW	2	3	0	0	0	0	5
TOTAL	16	148	0	0	0	0	164

Number of calm hours 10

Total number of observations 174

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Table I.4-29 (CONTINUED)

MILWAUKEE WIND - STABILITY SUMMARY

STABILITY CLASS - G - ANNUAL 6/1/73 TO 5/31/74
NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	1	0	0	0	0	0	1
NNE	0	0	0	0	0	0	0
NE	1	0	0	0	0	0	1
ENE	0	0	0	0	0	0	0
E	1	0	0	0	0	0	1
ESE	1	0	0	0	0	0	1
SE	2	0	0	0	0	0	2
SSE	4	0	0	0	0	0	4
S	4	0	0	0	0	0	4
SSW	4	0	0	0	0	0	4
SW	2	0	0	0	0	0	2
WSW	5	0	0	0	0	0	5
W	4	0	0	0	0	0	4
WNW	0	0	0	0	0	0	0
NW	0	0	0	0	0	0	0
NNW	0	0	0	0	0	0	0
TOTAL	29	0	0	0	0	0	29

Number of calm hours 21

Total number of observations 50

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Table I.4-29 (CONTINUED)

MILWAUKEE WIND - STABILITY SUMMARY

STABILITY CLASS - ALL - ANNUAL 6/1/73 TO 5/31/74
NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	4	30	57	72	21	6	190
NNE	3	25	50	38	8	3	127
NE	2	15	42	31	6	1	97
ENE	0	11	25	31	8	1	76
E	3	17	52	49	7	1	129
ESE	4	13	46	47	5	0	115
SE	7	31	63	72	6	0	179
SSE	7	37	32	35	2	1	114
S	13	70	113	62	6	0	264
SSW	6	33	62	54	8	4	167
SW	6	30	92	97	26	6	257
WSW	10	40	83	110	28	4	275
W	10	58	120	100	19	0	307
WNW	5	37	112	96	20	1	271
NW	1	25	91	69	5	0	191
NNW	9	7	41	40	5	1	103
TOTAL	90	479	1081	1003	180	29	2862

Number of calm hours	58
Total number of observations	2920

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Table I.4-30 MILWAUKEE JOINT FREQUENCY DISTRIBUTION TWO-YEAR SUMMARY 4/19/67 THROUGH 4/18/69

MILWAUKEE WIND - STABILITY SUMMARY

STABILITY CLASS - A - ANNUAL 4/19/67 TO 4/18/69
NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	0	0	0	0	0	0	0
NNE	0	0	0	0	0	0	0
NE	0	1	0	0	0	0	1
ENE	0	2	0	0	0	0	2
E	0	1	0	0	0	0	1
ESE	0	0	0	0	0	0	0
SE	0	0	0	0	0	0	0
SSE	0	0	0	0	0	0	0
S	0	1	0	0	0	0	1
SSW	0	2	0	0	0	0	2
SW	0	0	0	0	0	0	0
WSW	0	0	0	0	0	0	0
W	0	1	0	0	0	0	1
WNW	0	0	0	0	0	0	0
NW	0	0	0	0	0	0	0
NNW	0	0	0	0	0	0	0
TOTAL	0	8	0	0	0	0	8

Number of calm hours 2

Total number of observations 10

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Table I.4-30 (CONTINUED)

MILWAUKEE WIND - STABILITY SUMMARY

STABILITY CLASS - B - ANNUAL 4/19/67 TO 4/18/69
NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	2	0	0	0	0	0	2
NNE	1	8	5	0	0	0	14
NE	5	5	10	0	0	0	20
ENE	1	2	1	0	0	0	4
E	0	17	22	0	0	0	39
ESE	3	2	8	0	0	0	13
SE	0	5	8	0	0	0	13
SSE	1	4	3	0	0	0	8
S	2	4	2	0	0	0	8
SSW	4	5	3	0	0	0	12
SW	0	1	3	0	0	0	4
WSW	0	1	1	0	0	0	2
W	4	9	6	0	0	0	19
WNW	0	1	2	0	0	0	3
NW	0	2	1	0	0	0	3
NNW	0	1	1	0	0	0	2
TOTAL	23	67	76	0	0	0	166

Number of calm hours	3
Total number of observations	169

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Table I.4-30 (CONTINUED)

MILWAUKEE WIND - STABILITY SUMMARY

STABILITY CLASS - C - ANNUAL 4/19/67 TO 4/18/69
NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	1	1	2	1	0	0	5
NNE	1	6	36	11	0	0	54
NE	0	2	25	1	0	0	28
ENE	0	1	16	1	0	0	18
E	3	11	29	3	0	0	46
ESE	1	3	24	3	0	0	31
SE	2	3	31	7	0	0	43
SSE	8	1	16	1	0	0	26
S	10	3	9	2	0	0	24
SSW	5	8	27	6	0	0	46
SW	1	4	12	2	0	0	19
WSW	2	2	17	2	0	0	23
W	8	12	36	6	0	0	62
WNW	1	5	17	1	0	0	24
NW	4	5	17	4	0	0	30
NNW	5	2	15	0	0	0	22
TOTAL	52	69	329	51	0	0	501

Number of calm hours 23

Total number of observations 524

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Table I.4-30 (CONTINUED)

MILWAUKEE WIND - STABILITY SUMMARY

STABILITY CLASS - D - ANNUAL 4/19/67 TO 4/18/69
NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	5	15	28	72	17	7	144
NNE	13	42	130	153	40	7	385
NE	5	26	49	36	2	0	118
ENE	0	9	21	20	1	0	51
E	5	35	59	64	2	0	165
ESE	5	17	32	21	0	0	75
SE	5	33	76	81	5	0	200
SSE	17	68	135	140	13	1	374
S	3	39	79	86	8	4	219
SSW	7	52	136	193	18	0	406
SW	2	35	81	110	15	7	250
WSW	6	8	55	64	20	4	157
W	14	83	163	275	69	5	609
WNW	2	31	62	158	24	3	280
NW	3	24	80	151	16	0	274
NNW	6	39	88	147	19	0	299
TOTAL	98	556	1274	1771	269	38	4006

Number of calm hours	23
Total number of observations	4029

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Table I.4-30 (CONTINUED)

MILWAUKEE WIND - STABILITY SUMMARY

STABILITY CLASS - E - ANNUAL 4/19/67 TO 4/18/69
NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	0	3	6	0	0	0	9
NNE	0	6	21	0	0	0	27
NE	0	2	6	0	0	0	8
ENE	0	0	4	0	0	0	4
E	0	4	5	0	0	0	9
ESE	0	1	1	0	0	0	2
SE	0	2	4	0	0	0	6
SSE	0	17	17	0	0	0	34
S	0	12	43	0	0	0	55
SSW	0	19	59	0	0	0	78
SW	0	7	31	0	0	0	38
WSW	0	6	21	0	0	0	27
W	0	15	82	0	0	0	97
WNW	0	8	42	0	0	0	50
NW	0	8	28	0	0	0	36
NNW	0	5	30	0	0	0	35
TOTAL	0	115	400	0	0	0	515

Number of calm hours	0
Total number of observations	515

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Table I.4-30 (CONTINUED)

MILWAUKEE WIND - STABILITY SUMMARY

STABILITY CLASS - F - ANNUAL 4/19/67 TO 4/18/69
NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	1	6	0	0	0	0	7
NNE	2	18	0	0	0	0	20
NE	2	4	0	0	0	0	6
ENE	1	3	0	0	0	0	4
E	1	7	0	0	0	0	8
ESE	0	1	0	0	0	0	1
SE	3	10	0	0	0	0	13
SSE	7	28	0	0	0	0	35
S	6	40	0	0	0	0	46
SSW	4	40	0	0	0	0	44
SW	2	15	0	0	0	0	17
WSW	0	19	0	0	0	0	19
W	5	72	0	0	0	0	77
WNW	1	20	0	0	0	0	21
NW	0	14	0	0	0	0	14
NNW	3	12	0	0	0	0	15
TOTAL	38	309	0	0	0	0	347

Number of calm hours 18

Total number of observations 365

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Table I.4-30 (CONTINUED)

MILWAUKEE WIND - STABILITY SUMMARY

STABILITY CLASS - G - ANNUAL 4/19/67 TO 4/18/69
NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	3	0	0	0	0	0	3
NNE	9	0	0	0	0	0	9
NE	1	0	0	0	0	0	1
ENE	1	0	0	0	0	0	1
E	6	0	0	0	0	0	6
ESE	4	0	0	0	0	0	4
SE	3	0	0	0	0	0	3
SSE	20	0	0	0	0	0	20
S	23	0	0	0	0	0	23
SSW	24	0	0	0	0	0	24
SW	14	0	0	0	0	0	14
WSW	12	0	0	0	0	0	12
W	18	0	0	0	0	0	18
WNW	3	0	0	0	0	0	3
NW	2	0	0	0	0	0	2
NNW	3	0	0	0	0	0	3
TOTAL	146	0	0	0	0	0	146

Number of calm hours	90
Total number of observations	236

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Table I.4-30 (CONTINUED)

MILWAUKEE WIND - STABILITY SUMMARY

STABILITY CLASS - ALL - ANNUAL 4/19/67 TO 4/18/69
NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	12	25	36	73	17	7	170
NNE	26	80	192	164	40	7	509
NE	13	40	90	37	2	0	182
ENE	3	17	42	21	1	0	84
E	15	75	115	67	2	0	274
ESE	13	24	65	24	0	0	126
SE	13	53	119	88	5	0	278
SSE	53	118	171	141	13	1	497
S	44	99	133	88	8	4	376
SSW	44	126	225	199	18	0	612
SW	19	62	127	112	15	7	342
WSW	20	36	94	66	20	4	240
W	49	192	287	281	69	5	883
WNW	7	65	123	159	24	3	381
NW	9	53	126	155	16	0	359
NNW	17	59	134	147	19	0	376
TOTAL	357	1124	2079	1822	269	38	5689

Number of calm hours	159
Total number of observations	5848

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Table I.4-31 MILWAUKEE JOINT FREQUENCY DISTRIBUTION TEN YEAR SUMMARY 1/1/56 THROUGH 12/31/75

MILWAUKEE WIND - STABILITY SUMMARY

STABILITY CLASS - A - ANNUAL 1/1/56 TO 12/31/75
NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	0	1	0	0	0	0	1
NNE	0	3	0	0	0	0	3
NE	1	9	0	0	0	0	10
ENE	1	5	0	0	0	0	6
E	2	11	0	0	0	0	13
ESE	2	7	0	0	0	0	9
SE	1	4	0	0	0	0	5
SSE	0	1	0	0	0	0	1
S	1	1	0	0	0	0	2
SSW	1	5	0	0	0	0	6
SW	0	4	0	0	0	0	4
WSW	0	5	0	0	0	0	5
W	1	6	0	0	0	0	7
WNW	1	0	0	0	0	0	1
NW	0	1	0	0	0	0	1
NNW	0	3	0	0	0	0	3
TOTAL	11	66	0	0	0	0	77

Number of calm hours 7

Total number of observations 84

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Table I.4-31 (CONTINUED)

MILWAUKEE WIND - STABILITY SUMMARY

STABILITY CLASS - B - ANNUAL 1/1/56 TO 12/31/75
NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	22	19	13	0	0	0	54
NNE	25	61	92	0	0	0	178
NE	38	75	155	0	0	0	268
ENE	30	89	88	0	0	0	207
E	30	118	186	0	0	0	334
ESE	19	70	171	0	0	0	260
SE	25	67	74	0	0	0	166
SSE	33	38	23	0	0	0	94
S	28	36	28	0	0	0	92
SSW	29	62	64	0	0	0	155
SW	31	44	54	0	0	0	129
WSW	23	50	57	0	0	0	130
W	39	75	61	0	0	0	175
WNW	25	32	45	0	0	0	102
NW	36	28	15	0	0	0	79
NNW	13	9	12	0	0	0	34
TOTAL	446	873	1138	0	0	0	2457

Number of calm hours 71

Total number of observations 2528

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Table I.4-31 (CONTINUED)

MILWAUKEE WIND - STABILITY SUMMARY

STABILITY CLASS - C - ANNUAL 1/1/56 TO 12/31/75
NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	34	42	105	12	0	0	193
NNE	38	76	441	95	0	0	650
NE	41	77	482	56	0	0	656
ENE	33	66	325	29	0	0	453
E	50	114	447	32	0	0	643
ESE	45	80	635	104	0	0	864
SE	73	62	460	100	0	0	695
SSE	103	59	184	28	0	0	374
S	90	108	210	29	0	0	437
SSW	69	94	365	49	0	0	577
SW	73	91	389	49	0	0	602
WSW	66	116	451	64	0	0	697
W	84	135	476	57	0	0	752
WNW	52	114	388	40	0	0	594
NW	53	72	193	31	0	0	349
NNW	37	46	113	6	0	0	202
TOTAL	941	1352	5664	781	0	0	8738

Number of calm hours 238

Total number of observations 8976

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Table I.4-31 (CONTINUED)

MILWAUKEE WIND - STABILITY SUMMARY

STABILITY CLASS - D - ANNUAL 1/1/56 TO 12/31/75
NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	82	355	937	1846	734	266	4220
NNE	106	601	1622	2803	980	413	6525
NE	103	470	944	1261	338	128	3244
ENE	54	280	665	738	257	78	2072
E	85	350	733	734	139	74	2115
ESE	90	440	948	1136	211	36	2861
SE	114	507	1423	1899	311	63	4317
SSE	125	595	1497	1381	227	35	3860
S	158	687	1836	2008	416	80	5185
SSW	94	628	2029	3260	781	235	7027
SW	87	452	1557	2770	737	276	5879
WSW	92	481	1461	2625	754	289	5702
W	148	723	1760	3079	832	215	6757
WNW	85	658	1675	3632	1107	289	7446
NW	72	392	1286	2374	642	116	4882
NNW	64	302	966	1859	510	132	3833
TOTAL	1559	7921	21339	33405	8976	2725	75925

Number of calm hours 360

Total number of observations 76285

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Table I.4-31 (CONTINUED)

MILWAUKEE WIND - STABILITY SUMMARY

STABILITY CLASS - E - ANNUAL 1/1/56 TO 12/31/75
NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	0	129	240	0	0	0	369
NNE	0	209	326	0	0	0	535
NE	0	99	149	0	0	0	248
ENE	0	55	67	0	0	0	122
E	0	66	53	0	0	0	119
ESE	0	97	62	0	0	0	159
SE	0	186	98	0	0	0	284
SSE	0	345	340	0	0	0	685
S	0	509	809	0	0	0	1318
SSW	0	335	1116	0	0	0	1451
SW	0	238	938	0	0	0	1176
WSW	0	228	814	0	0	0	1042
W	0	286	983	0	0	0	1269
WNW	0	201	1093	0	0	0	1294
NW	0	122	548	0	0	0	670
NNW	0	82	304	0	0	0	386
TOTAL	0	3187	7940	0	0	0	11127

Number of calm hours	0
Total number of observations	11127

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Table I.4-31 (CONTINUED)

MILWAUKEE WIND - STABILITY SUMMARY

STABILITY CLASS - F - ANNUAL 1/1/56 TO 12/31/75
NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	60	216	0	0	0	0	276
NNE	63	252	0	0	0	0	315
NE	47	136	0	0	0	0	183
ENE	33	65	0	0	0	0	98
E	55	84	0	0	0	0	139
ESE	59	102	0	0	0	0	161
SE	90	167	0	0	0	0	257
SSE	141	521	0	0	0	0	662
S	155	768	0	0	0	0	923
SSW	116	786	0	0	0	0	902
SW	96	527	0	0	0	0	623
WSW	83	600	0	0	0	0	683
W	96	931	0	0	0	0	1027
WNW	67	697	0	0	0	0	764
NW	54	304	0	0	0	0	358
NNW	46	161	0	0	0	0	207
TOTAL	1261	6317	0	0	0	0	7578

Number of calm hours	331
Total number of observations	7909

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Table I.4-31 (CONTINUED)

MILWAUKEE WIND - STABILITY SUMMARY

STABILITY CLASS - G - ANNUAL 1/1/56 TO 12/31/75
NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	115	0	0	0	0	0	115
NNE	121	0	0	0	0	0	121
NE	73	0	0	0	0	0	73
ENE	52	0	0	0	0	0	52
E	85	0	0	0	0	0	85
ESE	84	0	0	0	0	0	84
SE	172	0	0	0	0	0	172
SSE	289	0	0	0	0	0	289
S	384	0	0	0	0	0	384
SSW	325	0	0	0	0	0	325
SW	285	0	0	0	0	0	285
WSW	293	0	0	0	0	0	293
W	304	0	0	0	0	0	304
WNW	155	0	0	0	0	0	155
NW	91	0	0	0	0	0	91
NNW	83	0	0	0	0	0	83
TOTAL	2911	0	0	0	0	0	2911

Number of calm hours 1144

Total number of observations 4055

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Table I.4-31 (CONTINUED)

MILWAUKEE WIND - STABILITY SUMMARY

STABILITY CLASS - ALL - ANNUAL 1/1/56 TO 12/31/75
NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	313	762	1295	1858	734	266	5228
NNE	353	1202	2481	2898	980	413	8327
NE	303	866	1730	1317	338	128	4682
ENE	203	560	1145	767	257	78	3010
E	307	743	1419	766	139	74	3448
ESE	299	796	1816	1240	211	36	4398
SE	475	993	2055	1999	311	63	5896
SSE	691	1559	2044	1409	227	35	5965
S	816	2109	2883	2037	416	80	8341
SSW	634	1910	3574	3309	781	235	10443
SW	572	1356	2938	2819	737	276	8698
WSW	557	1480	2783	2689	754	289	8552
W	672	2156	3280	3136	832	215	10291
WNW	385	1702	3201	3672	1107	289	10356
NW	306	919	2042	2405	642	116	6430
NNW	243	603	1395	1865	510	132	4748
TOTAL	7129	19716	36081	34186	8976	2725	108813

Number of calm hours 2151

Total number of observations 110964

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Table I.4-32 POINT BEACH JOINT FREQUENCY DISTRIBUTION TWO-YEAR SUMMARY, 4/19/67 THROUGH 4/18/69

POINT BEACH WIND - STABILITY SUMMARY

STABILITY CLASS - A - 150 FT WINDS, PERIOD 4/19/67 TO 4/18/69
NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	3	2	1	0	0	0	6
NNE	3	0	0	0	0	0	3
NE	4	0	0	0	0	0	4
ENE	1	2	0	0	0	0	3
E	5	1	0	0	0	0	6
ESE	1	1	0	0	0	0	2
SE	6	2	0	0	0	0	8
SSE	1	1	2	0	0	0	4
S	6	0	0	0	0	0	6
SSW	2	2	3	1	0	0	8
SW	3	4	0	0	0	1	8
WSW	2	4	1	2	0	0	9
W	9	4	2	0	0	0	15
WNW	3	3	5	1	0	0	12
NW	4	4	6	0	0	1	15
NNW	2	4	0	0	0	0	6
TOTAL	55	34	20	4	0	2	115

Number of calm hours	12
Number of variable directions	0
Total number of observations	127

Sheet 1 of 8

Table I.4-32 (CONTINUED)

POINT BEACH WIND - STABILITY SUMMARY

STABILITY CLASS - B - 150 FT WINDS, PERIOD 4/19/67 TO 4/18/69
NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	3	2	0	0	0	0	5
NNE	0	0	0	0	0	0	0
NE	4	3	0	0	0	0	7
ENE	5	2	0	0	0	0	7
E	1	4	0	0	0	0	5
ESE	3	1	0	0	0	0	4
SE	3	1	0	0	0	0	4
SSE	9	2	3	0	0	0	14
S	2	3	6	1	0	0	12
SSW	5	2	5	0	0	0	12
SW	1	3	4	2	0	0	10
WSW	2	5	1	1	0	0	9
W	3	7	4	1	0	0	15
WNW	4	13	16	6	0	0	39
NW	2	12	15	7	1	0	37
NNW	1	3	3	1	0	0	8
TOTAL	48	63	57	19	1	0	188

Number of calm hours	12
Number of variable directions	0
Total number of observations	200

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Table I.4-32 (CONTINUED)

POINT BEACH WIND - STABILITY SUMMARY

STABILITY CLASS - C - 150 FT WINDS, PERIOD 4/19/67 TO 4/18/69
NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	5	7	5	5	1	0	23
NNE	3	4	0	1	1	1	10
NE	11	8	2	2	0	0	23
ENE	6	7	1	0	0	0	14
E	13	9	3	0	0	1	26
ESE	9	7	1	0	0	0	17
SE	6	9	3	0	0	1	19
SSE	5	9	8	4	1	1	28
S	9	17	42	12	3	4	87
SSW	1	14	29	3	2	3	52
SW	8	15	13	7	1	2	46
WSW	5	8	14	4	1	1	33
W	8	16	31	14	6	2	77
WNW	9	24	100	176	84	25	418
NW	8	45	135	158	40	15	401
NNW	6	16	32	20	5	1	80
TOTAL	112	215	419	406	145	57	1354

Number of calm hours	23
Number of variable directions	0
Total number of observations	1377

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Table I.4-32 (CONTINUED)

POINT BEACH WIND - STABILITY SUMMARY

STABILITY CLASS - D - 150 FT WINDS, PERIOD 4/19/67 TO 4/18/69
NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	12	30	65	99	21	11	238
NNE	18	33	42	23	14	5	135
NE	19	54	35	20	6	0	134
ENE	22	26	14	10	0	0	72
E	26	36	12	3	0	2	79
ESE	30	23	10	5	2	1	71
SE	28	31	22	25	10	3	119
SSE	15	43	72	55	50	28	263
S	22	81	226	265	142	74	810
SSW	10	57	203	229	143	39	681
SW	19	39	58	79	21	9	225
WSW	14	31	71	80	45	16	257
W	17	46	79	136	85	60	423
WNW	11	63	178	265	108	37	662
NW	13	48	175	148	20	6	410
NNW	8	60	179	177	76	20	520
TOTAL	284	701	1441	1619	743	311	5099

Number of calm hours	31
Number of variable directions	0
Total number of observations	5130

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Table I.4-32 (CONTINUED)

POINT BEACH WIND - STABILITY SUMMARY

STABILITY CLASS - E - 150 FT WINDS, PERIOD 4/19/67 TO 4/18/69
NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	23	81	201	195	87	57	644
NNE	16	64	169	165	92	95	601
NE	10	58	109	127	50	39	393
ENE	16	36	42	42	30	14	180
E	28	42	32	32	17	18	169
ESE	20	36	35	19	25	7	142
SE	18	43	47	46	33	36	223
SSE	11	43	70	49	32	7	212
S	17	53	88	33	6	0	197
SSW	19	51	254	367	106	15	812
SW	18	70	169	157	41	5	460
WSW	4	43	96	73	10	2	228
W	11	62	108	133	39	26	379
WNW	9	28	60	38	6	1	142
NW	7	21	38	24	5	0	95
NNW	11	20	80	32	6	0	149
TOTAL	238	751	1598	1532	585	322	5026

Number of calm hours	34
Number of variable directions	0
Total number of observations	5060

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Table I.4-32 (CONTINUED)

POINT BEACH WIND - STABILITY SUMMARY

STABILITY CLASS - F - 150 FT WINDS, PERIOD 4/19/67 TO 4/18/69
NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	12	44	107	118	48	27	356
NNE	6	18	49	51	24	5	153
NE	3	14	28	33	11	3	92
ENE	7	13	15	9	8	3	55
E	13	16	8	10	2	3	52
ESE	11	15	16	1	2	0	45
SE	3	32	28	17	2	0	82
SSE	9	17	26	9	1	0	62
S	9	21	15	0	1	0	46
SSW	11	30	83	39	2	0	165
SW	9	39	151	61	4	0	264
WSW	5	15	42	17	0	0	79
W	8	12	52	31	3	0	106
WNW	5	15	43	17	2	0	82
NW	8	11	17	10	0	0	46
NNW	0	7	6	3	0	0	16
TOTAL	119	319	686	426	110	41	1701

Number of calm hours	8
Number of variable directions	0
Total number of observations	1709

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Table I.4-32 (CONTINUED)

POINT BEACH WIND - STABILITY SUMMARY

STABILITY CLASS - G - 150 FT WINDS, PERIOD 4/19/67 TO 4/18/69
NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	24	42	50	46	5	1	168
NNE	0	6	17	19	7	0	49
NE	2	13	14	6	2	0	37
ENE	2	10	2	4	2	1	21
E	5	7	9	3	0	0	24
ESE	2	14	3	0	0	0	19
SE	10	31	18	32	0	0	61
SSE	4	7	20	3	0	0	34
S	5	8	8	1	0	0	22
SSW	10	35	48	13	0	0	106
SW	6	49	113	26	0	0	194
WSW	6	16	36	14	0	0	72
W	6	20	51	36	0	0	113
WNW	6	19	20	13	0	0	58
NW	0	13	12	15	0	0	40
NNW	0	2	10	1	0	0	13
TOTAL	88	292	431	202	16	2	1031

Number of calm hours	13
Number of variable directions	0
Total number of observations	1044

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Table I.4-32 (CONTINUED)

POINT BEACH WIND - STABILITY SUMMARY

STABILITY CLASS - ALL - 150 FT WINDS, PERIOD 4/19/67 TO 4/18/69
NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	82	208	429	463	162	96	1440
NNE	46	125	277	259	138	106	951
NE	53	150	188	188	69	42	690
ENE	59	96	74	65	40	18	352
E	91	115	64	48	19	24	361
ESE	76	97	65	25	29	8	300
SE	74	149	118	90	45	40	516
SSE	54	122	201	120	84	36	617
S	70	183	385	312	152	78	1180
SSW	58	191	625	652	253	57	1836
SW	64	218	508	332	67	17	1207
WSW	38	122	261	191	56	19	687
W	62	167	327	351	133	88	1128
WNW	47	165	422	516	200	63	1413
NW	42	154	398	362	66	22	1044
NNW	28	112	310	234	87	21	792
TOTAL	944	2375	4652	4208	1600	735	14514

Number of calm hours	133
Number of variable directions	0
Total number of observations	14647

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Table I.4-33 POINT BEACH JOINT FREQUENCY DISTRIBUTION BY MONTH FOR THE PERIOD 4/19/67 THROUGH 4/18/69

POINT BEACH WIND - STABILITY SUMMARY

STABILITY CLASS - A - 150 FT WINDS, (JAN) PERIOD 1/1/68 TO 1/31/69
NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	0	0	0	0	0	0	0
NNE	0	0	0	0	0	0	0
NE	0	0	0	0	0	0	0
ENE	0	0	0	0	0	0	0
E	0	0	0	0	0	0	0
ESE	0	0	0	0	0	0	0
SE	0	0	0	0	0	0	0
SSE	0	0	0	0	0	0	0
S	1	0	0	0	0	0	1
SSW	1	0	0	0	0	0	1
SW	0	0	0	0	0	0	0
WSW	0	0	0	0	0	0	0
W	2	0	1	0	0	0	3
WNW	0	0	1	0	0	0	1
NW	0	0	0	0	0	0	0
NNW	0	0	0	0	0	0	0
TOTAL	4	0	2	0	0	0	6

Number of calm hours	1
Number of variable directions	0
Total number of observations	7

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Table I.4-33 (CONTINUED)

POINT BEACH WIND - STABILITY SUMMARY

STABILITY CLASS - B - 150 FT WINDS, (JAN) PERIOD 1/1/68 TO 1/31/69
NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	0	0	0	0	0	0	0
NNE	0	0	0	0	0	0	0
NE	0	0	0	0	0	0	0
ENE	0	0	0	0	0	0	0
E	0	0	0	0	0	0	0
ESE	1	0	0	0	0	0	1
SE	0	0	0	0	0	0	0
SSE	0	0	0	0	0	0	0
S	0	0	0	0	0	0	0
SSW	0	0	0	0	0	0	0
SW	0	0	0	0	0	0	0
WSW	0	0	0	0	0	0	0
W	0	0	0	0	0	0	0
WNW	1	1	1	0	0	0	3
NW	0	0	0	0	0	0	0
NNW	0	0	0	0	0	0	0
TOTAL	2	1	1	0	0	0	4

Number of calm hours	0
Number of variable directions	0
Total number of observations	4

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Table I.4-33 (CONTINUED)

POINT BEACH WIND - STABILITY SUMMARY

STABILITY CLASS - C - 150 FT WINDS, (JAN) PERIOD 1/1/68 TO 1/31/69
NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	0	0	0	0	0	0	0
NNE	0	0	0	0	0	0	0
NE	0	0	0	0	0	0	0
ENE	0	0	0	0	0	0	0
E	0	0	0	0	0	0	0
ESE	0	0	0	0	0	0	0
SE	0	0	0	0	0	0	0
SSE	0	0	3	0	0	0	3
S	0	0	0	0	0	0	0
SSW	0	0	0	0	1	0	1
SW	0	1	0	0	0	0	1
WSW	1	0	0	0	0	0	1
W	1	0	1	0	0	0	2
WNW	2	2	8	13	11	1	37
NW	1	6	9	7	2	1	26
NNW	0	2	1	1	2	0	6
TOTAL	5	11	22	21	16	2	77

Number of calm hours	0
Number of variable directions	0
Total number of observations	77

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Table I.4-33 (CONTINUED)

POINT BEACH WIND - STABILITY SUMMARY

STABILITY CLASS - D - 150 FT WINDS, (JAN) PERIOD 1/1/68 TO 1/31/69
NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	2	6	1	11	7	0	27
NNE	2	1	0	0	1	4	8
NE	0	0	0	3	0	0	3
ENE	0	0	1	4	0	0	5
E	1	0	1	2	0	0	4
ESE	0	0	2	3	0	0	5
SE	1	0	1	12	5	1	20
SSE	0	3	7	10	18	15	53
S	0	0	26	27	10	6	69
SSW	0	1	2	11	8	7	29
SW	1	1	4	3	0	1	10
WSW	3	5	8	6	2	0	24
W	0	5	8	12	8	3	36
WNW	1	5	22	38	26	8	100
NW	1	7	31	32	7	1	79
NNW	1	12	10	18	7	1	49
TOTAL	13	46	124	192	99	47	521

Number of calm hours	0
Number of variable directions	0
Total number of observations	521

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Table I.4-33 (CONTINUED)

POINT BEACH WIND - STABILITY SUMMARY

STABILITY CLASS - E - 150 FT WINDS, (JAN) PERIOD 1/1/68 TO 1/31/69
NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	2	14	15	9	9	6	55
NNE	0	2	3	2	8	15	30
NE	1	1	1	8	6	1	18
ENE	0	0	1	10	11	1	23
E	1	1	1	5	0	0	8
ESE	1	1	4	2	1	0	9
SE	0	3	4	5	8	13	33
SSE	0	2	5	4	6	4	21
S	0	3	2	3	3	0	11
SSW	0	2	7	21	8	1	39
SW	2	4	14	16	5	0	41
WSW	0	1	8	7	1	0	17
W	3	13	15	18	13	11	73
WNW	0	1	5	5	5	1	17
NW	1	1	2	4	3	0	11
NNW	3	6	5	5	0	0	19
TOTAL	14	55	92	124	87	53	425

Number of calm hours	0
Number of variable directions	0
Total number of observations	425

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Table I.4-33 (CONTINUED)

POINT BEACH WIND - STABILITY SUMMARY

STABILITY CLASS - F - 150 FT WINDS, (JAN) PERIOD 1/1/68 TO 1/31/69
NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	0	5	3	3	1	0	12
NNE	1	3	1	5	1	0	11
NE	0	0	0	3	1	1	5
ENE	0	0	0	4	4	0	8
E	1	0	3	4	0	0	8
ESE	0	1	6	1	0	0	8
SE	0	0	3	1	0	0	4
SSE	2	0	1	0	0	0	3
S	1	1	0	0	0	0	2
SSW	0	2	1	0	0	0	3
SW	0	0	6	6	1	0	13
WSW	0	0	0	0	0	0	0
W	0	1	3	6	3	0	13
WNW	0	1	5	3	2	0	11
NW	0	2	1	0	0	0	3
NNW	0	0	0	0	0	0	0
TOTAL	5	16	33	36	13	1	104

Number of calm hours	1
Number of variable directions	0
Total number of observations	105

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Table I.4-33 (CONTINUED)

POINT BEACH WIND - STABILITY SUMMARY

STABILITY CLASS - G - 150 FT WINDS, (JAN) PERIOD 1/1/68 TO 1/31/69
NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	2	4	1	1	1	0	9
NNE	0	0	0	1	0	0	1
NE	0	0	0	0	0	0	0
ENE	0	2	0	0	0	0	2
E	0	0	3	0	0	0	3
ESE	0	0	1	0	0	0	1
SE	0	0	0	0	0	0	0
SSE	0	0	0	0	0	0	0
S	0	0	0	0	0	0	0
SSW	0	0	0	1	0	0	1
SW	0	0	2	1	0	0	3
WSW	0	1	0	0	0	0	1
W	0	0	3	1	0	0	4
WNW	0	1	1	1	0	0	3
NW	0	3	0	0	0	0	3
NNW	0	0	0	0	0	0	0
TOTAL	2	11	11	6	1	0	31

Number of calm hours	0
Number of variable directions	0
Total number of observations	31

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Table I.4-33 (CONTINUED)

POINT BEACH WIND - STABILITY SUMMARY

STABILITY CLASS - ALL - 150 FT WINDS, (JAN) PERIOD 1/1/68 TO 1/31/69
NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	6	29	20	24	18	6	103
NNE	3	6	4	8	10	19	50
NE	1	1	1	14	7	2	26
ENE	0	2	2	18	15	1	38
E	3	1	8	11	0	0	23
ESE	2	2	13	6	1	0	24
SE	1	3	8	18	13	14	57
SSE	2	5	16	14	24	19	80
S	2	4	28	30	13	6	83
SSW	1	5	10	33	17	8	74
SW	3	6	26	26	6	1	68
WSW	4	7	16	13	3	0	43
W	6	19	31	37	24	14	131
WNW	4	11	43	60	44	10	172
NW	3	19	43	43	12	2	122
NNW	4	20	16	24	9	1	74
TOTAL	45	140	285	379	216	103	1168

Number of calm hours	2
Number of variable directions	0
Total number of observations	1170

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Table I.4-33 (CONTINUED)

POINT BEACH WIND - STABILITY SUMMARY

STABILITY CLASS - A - 150 FT WINDS, (FEB) PERIOD 2/1/68 TO 2/28/69
NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	0	0	0	0	0	0	0
NNE	1	0	0	0	0	0	1
NE	0	0	0	0	0	0	0
ENE	0	0	0	0	0	0	0
E	0	0	0	0	0	0	0
ESE	0	0	0	0	0	0	0
SE	0	0	0	0	0	0	0
SSE	0	0	0	0	0	0	0
S	1	0	0	0	0	0	1
SSW	0	0	0	0	0	0	0
SW	0	0	0	0	0	0	0
WSW	1	0	0	0	0	0	1
W	0	0	0	0	0	0	0
WNW	0	0	0	0	0	0	0
NW	0	0	0	0	0	0	0
NNW	1	0	0	0	0	0	1
TOTAL	4	0	0	0	0	0	4

Number of calm hours	0
Number of variable directions	0
Total number of observations	4

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Table I.4-33 (CONTINUED)

POINT BEACH WIND - STABILITY SUMMARY

STABILITY CLASS - B - 150 FT WINDS, (FEB) PERIOD 2/1/68 TO 2/28/69
NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	0	0	0	0	0	0	0
NNE	0	0	0	0	0	0	0
NE	0	1	0	0	0	0	1
ENE	2	1	0	0	0	0	3
E	0	0	0	0	0	0	0
ESE	0	0	0	0	0	0	0
SE	0	0	0	0	0	0	0
SSE	0	0	0	0	0	0	0
S	0	0	0	0	0	0	0
SSW	0	0	0	0	0	0	0
SW	0	0	0	0	0	0	0
WSW	0	0	0	0	0	0	0
W	0	0	0	0	0	0	0
WNW	1	0	0	1	0	0	2
NW	0	1	0	0	0	0	1
NNW	0	0	0	0	0	0	0
TOTAL	3	3	0	1	0	0	7

Number of calm hours	2
Number of variable directions	0
Total number of observations	9

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Table I.4-33 (CONTINUED)

POINT BEACH WIND - STABILITY SUMMARY

STABILITY CLASS - C - 150 FT WINDS, (FEB) PERIOD 2/1/68 TO 2/28/69
NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	1	1	0	1	1	0	4
NNE	0	1	0	0	0	0	1
NE	0	0	0	0	0	0	0
ENE	2	0	1	0	0	0	3
E	0	0	0	0	0	0	0
ESE	0	0	0	0	0	0	0
SE	0	0	0	0	0	0	0
SSE	0	0	0	0	0	0	0
S	0	0	0	0	0	0	0
SSW	0	0	0	0	0	0	0
SW	0	0	0	0	0	0	0
WSW	0	0	0	0	0	0	0
W	2	0	0	0	1	0	3
WNW	1	5	12	33	20	1	72
NW	3	5	14	18	7	2	49
NNW	0	1	3	3	1	0	8
TOTAL	9	13	30	55	30	3	140

Number of calm hours	4
Number of variable directions	0
Total number of observations	144

Table I.4-33 (CONTINUED)

POINT BEACH WIND - STABILITY SUMMARY

STABILITY CLASS - D - 150 FT WINDS, (FEB) PERIOD 2/1/68 TO 2/28/69
NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	2	9	11	15	1	1	39
NNE	3	1	0	2	1	0	7
NE	0	4	0	0	0	0	4
ENE	0	1	4	0	0	0	5
E	0	0	0	1	0	0	1
ESE	1	1	0	1	0	0	3
SE	0	2	1	1	0	0	4
SSE	1	1	3	0	0	0	5
S	0	2	2	4	0	0	8
SSW	0	0	0	0	0	0	0
SW	1	1	2	1	1	0	6
WSW	0	2	1	1	3	0	7
W	6	0	5	13	6	1	31
WNW	4	11	24	41	31	4	115
NW	2	8	26	19	1	3	59
NNW	2	9	38	40	22	11	122
TOTAL	22	52	117	139	66	20	416

Number of calm hours	3
Number of variable directions	0
Total number of observations	419

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Table I.4-33 (CONTINUED)

POINT BEACH WIND - STABILITY SUMMARY

STABILITY CLASS - E - 150 FT WINDS, (FEB) PERIOD 2/1/68 TO 2/28/69
NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	7	10	14	33	11	10	85
NNE	3	4	3	19	7	1	37
NE	0	1	9	15	2	0	27
ENE	0	4	6	10	0	0	20
E	1	1	8	15	0	0	25
ESE	1	0	9	4	0	0	14
SE	2	2	3	0	0	0	7
SSE	0	1	0	0	0	0	1
S	1	1	2	0	0	0	4
SSW	2	0	0	0	1	3	6
SW	2	3	3	6	4	0	18
WSW	0	2	5	3	0	0	10
W	2	7	9	10	2	1	31
WNW	2	4	7	6	0	0	19
NW	3	3	4	4	0	0	14
NNW	0	2	12	6	4	0	24
TOTAL	26	45	94	131	31	15	342

Number of calm hours	6
Number of variable directions	0
Total number of observations	348

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Table I.4-33 (CONTINUED)

POINT BEACH WIND - STABILITY SUMMARY

STABILITY CLASS - F - 150 FT WINDS, (FEB) PERIOD 2/1/68 TO 2/28/69
NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	3	4	6	12	3	5	33
NNE	2	0	0	1	0	0	3
NE	0	0	2	2	0	0	4
ENE	0	0	2	2	0	0	4
E	1	0	2	2	0	0	5
ESE	0	0	1	0	0	0	1
SE	0	0	2	4	0	0	6
SSE	0	0	0	0	0	0	0
S	0	0	0	0	0	0	0
SSW	0	0	2	0	0	0	2
SW	2	1	4	0	0	0	7
WSW	1	2	1	0	0	0	4
W	3	2	2	4	0	0	11
WNW	0	0	2	1	0	0	3
NW	1	0	1	0	0	0	2
NNW	0	0	1	1	0	0	2
TOTAL	13	9	28	29	3	5	87

Number of calm hours	3
Number of variable directions	0
Total number of observations	90

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Table I.4-33 (CONTINUED)

POINT BEACH WIND - STABILITY SUMMARY

STABILITY CLASS - G - 150 FT WINDS, (FEB) PERIOD 2/1/68 TO 2/28/69
NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	2	0	2	0	0	0	4
NNE	0	0	0	0	0	0	0
NE	0	0	1	0	0	0	1
ENE	0	0	0	0	0	0	0
E	0	0	0	0	0	0	0
ESE	0	0	0	0	0	0	0
SE	0	0	0	0	0	0	0
SSE	0	0	0	0	0	0	0
S	0	0	0	0	0	0	0
SSW	2	0	0	0	0	0	2
SW	2	4	5	0	0	0	11
WSW	1	6	2	0	0	0	9
W	3	4	1	1	0	0	9
WNW	1	1	1	2	0	0	5
NW	0	1	0	1	0	0	2
NNW	0	0	0	0	0	0	0
TOTAL	11	16	12	4	0	0	43

Number of calm hours	4
Number of variable directions	0
Total number of observations	47

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Table I.4-33 (CONTINUED)

POINT BEACH WIND - STABILITY SUMMARY

STABILITY CLASS - ALL - 150 FT WINDS, (FEB) PERIOD 2/1/68 TO 2/28/69
NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	15	24	33	61	16	16	165
NNE	9	6	3	22	8	1	49
NE	0	6	12	17	2	0	37
ENE	4	6	13	12	0	0	35
E	2	1	10	18	0	0	31
ESE	2	1	10	5	0	0	18
SE	2	4	6	5	0	0	17
SSE	1	2	3	0	0	0	6
S	2	3	4	4	0	0	13
SSW	4	0	2	0	1	3	10
SW	7	9	14	7	5	0	42
WSW	3	12	9	4	3	0	31
W	16	13	17	28	9	2	85
WNW	9	21	46	84	51	5	216
NW	9	18	45	42	8	5	127
NNW	3	12	54	50	27	11	157
TOTAL	88	138	281	359	130	43	1039

Number of calm hours	22
Number of variable directions	0
Total number of observations	1061

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Table I.4-33 (CONTINUED)

POINT BEACH WIND - STABILITY SUMMARY

STABILITY CLASS - A - 150 FT WINDS, (MAR) PERIOD 3/1/68 TO 3/31/69
NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	0	0	0	0	0	0	0
NNE	0	0	0	0	0	0	0
NE	0	0	0	0	0	0	0
ENE	0	0	0	0	0	0	0
E	0	1	0	0	0	0	1
ESE	0	0	0	0	0	0	0
SE	0	0	0	0	0	0	0
SSE	0	0	0	0	0	0	0
S	0	0	0	0	0	0	0
SSW	1	0	0	0	0	0	1
SW	0	0	0	0	0	0	0
WSW	0	0	0	0	0	0	0
W	0	0	0	0	0	0	0
WNW	0	1	0	0	0	0	1
NW	1	2	0	0	0	0	3
NNW	0	3	0	0	0	0	3
TOTAL	2	7	0	0	0	0	9

Number of calm hours	0
Number of variable directions	0
Total number of observations	9

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Table I.4-33 (CONTINUED)

POINT BEACH WIND - STABILITY SUMMARY

STABILITY CLASS - B - 150 FT WINDS, (MAR) PERIOD 3/1/68 TO 3/31/69
NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	0	1	0	0	0	0	1
NNE	0	0	0	0	0	0	0
NE	0	0	0	0	0	0	0
ENE	0	0	0	0	0	0	0
E	0	0	0	0	0	0	0
ESE	0	0	0	0	0	0	0
SE	0	0	0	0	0	0	0
SSE	0	0	0	0	0	0	0
S	0	0	1	0	0	0	1
SSW	1	0	0	0	0	0	1
SW	0	0	1	0	0	0	1
WSW	0	0	0	0	0	0	0
W	0	1	1	0	0	0	2
WNW	1	4	2	1	0	0	8
NW	0	2	2	0	0	0	4
NNW	0	0	0	0	0	0	0
TOTAL	2	8	7	1	0	0	18

Number of calm hours	0
Number of variable directions	0
Total number of observations	18

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Table I.4-33 (CONTINUED)

POINT BEACH WIND - STABILITY SUMMARY

STABILITY CLASS - C - 150 FT WINDS, (MAR) PERIOD 3/1/68 TO 3/31/69
NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	1	1	0	1	0	0	3
NNE	0	0	0	0	0	0	0
NE	0	0	0	0	0	0	0
ENE	0	1	0	0	0	0	1
E	0	1	1	0	0	1	3
ESE	0	0	0	0	0	0	0
SE	1	0	0	0	0	0	1
SSE	0	0	0	0	0	0	0
S	0	0	0	0	0	0	0
SSW	0	0	2	0	0	0	2
SW	0	1	2	0	0	0	3
WSW	1	0	2	1	0	0	4
W	0	1	2	1	0	0	4
WNW	0	0	8	22	4	0	34
NW	0	2	11	11	1	0	25
NNW	1	1	2	2	0	1	7
TOTAL	4	8	30	38	5	2	87

Number of calm hours	0
Number of variable directions	0
Total number of observations	87

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Table I.4-33 (CONTINUED)

POINT BEACH WIND - STABILITY SUMMARY

STABILITY CLASS - D - 150 FT WINDS, (MAR) PERIOD 3/1/68 TO 3/31/69
NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	1	5	6	5	1	1	19
NNE	1	1	4	2	0	0	8
NE	0	1	4	0	0	0	5
ENE	0	0	0	0	0	0	0
E	0	1	1	0	0	0	2
ESE	0	0	0	0	1	0	1
SE	0	1	1	0	1	0	3
SSE	0	0	1	1	0	0	2
S	0	2	3	8	17	2	32
SSW	0	0	4	10	3	1	18
SW	0	2	9	8	0	0	19
WSW	1	0	6	3	1	0	11
W	0	1	8	11	2	0	22
WNW	0	6	6	24	4	0	40
NW	1	3	12	12	1	0	29
NNW	1	5	12	22	11	1	52
TOTAL	5	28	77	106	42	5	263

Number of calm hours	0
Number of variable directions	0
Total number of observations	263

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Table I.4-33 (CONTINUED)

POINT BEACH WIND - STABILITY SUMMARY

STABILITY CLASS - E - 150 FT WINDS, (MAR) PERIOD 3/1/68 TO 3/31/69
NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	3	12	29	12	12	17	85
NNE	0	6	10	16	8	14	54
NE	0	3	6	12	5	1	27
ENE	0	1	1	0	0	0	2
E	0	0	3	0	0	0	3
ESE	1	0	1	0	1	0	3
SE	0	0	0	0	0	0	0
SSE	0	1	0	0	0	0	1
S	0	2	1	0	1	0	4
SSW	0	1	7	13	7	1	29
SW	0	3	8	12	4	0	27
WSW	0	4	3	6	1	0	14
W	1	3	11	19	9	0	43
WNW	0	1	6	6	0	0	13
NW	0	2	1	5	0	0	8
NNW	0	1	7	3	1	0	12
TOTAL	5	40	94	104	49	33	325

Number of calm hours	0
Number of variable directions	0
Total number of observations	325

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Table I.4-33 (CONTINUED)

POINT BEACH WIND - STABILITY SUMMARY

STABILITY CLASS - F - 150 FT WINDS, (MAR) PERIOD 3/1/68 TO 3/31/69
NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	0	3	13	4	6	16	42
NNE	1	0	5	2	0	0	8
NE	0	0	1	1	0	0	2
ENE	0	0	0	0	0	0	0
E	0	0	0	0	0	0	0
ESE	0	0	1	0	0	0	1
SE	0	1	0	1	0	0	2
SSE	0	0	0	0	0	0	0
S	0	0	0	0	0	0	0
SSW	0	0	1	1	1	0	3
SW	0	0	4	3	0	0	7
WSW	0	2	4	1	0	0	7
W	0	1	4	1	0	0	6
WNW	0	0	3	1	0	0	4
NW	0	0	0	3	0	0	3
NNW	0	0	2	0	0	0	2
TOTAL	1	7	38	18	7	16	87

Number of calm hours	0
Number of variable directions	0
Total number of observations	87

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Table I.4-33 (CONTINUED)

POINT BEACH WIND - STABILITY SUMMARY

STABILITY CLASS - G - 150 FT WINDS, (MAR) PERIOD 3/1/68 TO 3/31/69
NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	0	2	2	0	0	1	5
NNE	0	0	0	0	0	0	0
NE	0	0	0	0	0	0	0
ENE	0	0	0	0	0	0	0
E	0	0	0	0	0	0	0
ESE	0	0	0	0	0	0	0
SE	0	0	1	0	0	0	1
SSE	0	0	0	0	0	0	0
S	0	0	0	0	0	0	0
SSW	0	0	0	0	0	0	0
SW	0	0	1	0	0	0	1
WSW	0	1	0	1	0	0	2
W	0	1	9	7	0	0	17
WNW	0	1	1	3	0	0	5
NW	0	1	0	4	0	0	5
NNW	0	1	1	1	0	0	3
TOTAL	0	7	15	16	0	1	39

Number of calm hours	0
Number of variable directions	0
Total number of observations	39

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Table I.4-33 (CONTINUED)

POINT BEACH WIND - STABILITY SUMMARY

STABILITY CLASS - ALL - 150 FT WINDS, (MAR) PERIOD 3/1/68 TO 3/31/69
NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	5	24	50	22	19	35	155
NNE	2	7	19	20	8	14	70
NE	0	4	11	13	5	1	34
ENE	0	2	1	0	0	0	3
E	0	3	5	0	0	1	9
ESE	1	0	2	0	2	0	5
SE	1	2	2	1	1	0	7
SSE	0	1	1	1	0	0	3
S	0	4	5	8	18	2	37
SSW	2	1	14	24	11	2	54
SW	0	6	25	23	4	0	58
WSW	2	7	15	12	2	0	38
W	1	8	35	39	11	0	94
WNW	1	13	26	57	8	0	105
NW	2	12	26	35	2	0	77
NNW	2	11	24	28	12	2	79
TOTAL	19	105	261	283	103	57	828

Number of calm hours	0
Number of variable directions	0
Total number of observations	828

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Table I.4-33 (CONTINUED)

POINT BEACH WIND - STABILITY SUMMARY

STABILITY CLASS - A - 150 FT WINDS, (APR) PERIOD 4/19/67 TO 4/18/69
NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	0	0	0	0	0	0	0
NNE	0	0	0	0	0	0	0
NE	0	0	0	0	0	0	0
ENE	0	1	0	0	0	0	1
E	1	0	0	0	0	0	1
ESE	0	1	0	0	0	0	1
SE	0	1	0	0	0	0	1
SSE	0	1	0	0	0	0	1
S	1	0	0	0	0	0	1
SSW	0	0	1	0	0	0	1
SW	0	0	0	0	0	0	0
WSW	0	0	0	0	0	0	0
W	1	0	0	0	0	0	1
WNW	0	0	0	0	0	0	0
NW	0	0	0	0	0	0	0
NNW	0	0	0	0	0	0	0
TOTAL	3	4	1	0	0	0	8

Number of calm hours	1
Number of variable directions	0
Total number of observations	9

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Table I.4-33 (CONTINUED)

POINT BEACH WIND - STABILITY SUMMARY

STABILITY CLASS - B - 150 FT WINDS, (APR) PERIOD 4/19/67 TO 4/18/69
NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	0	0	0	0	0	0	0
NNE	0	0	0	0	0	0	0
NE	0	0	0	0	0	0	0
ENE	1	0	0	0	0	0	1
E	1	1	0	0	0	0	2
ESE	0	0	0	0	0	0	0
SE	0	0	0	0	0	0	0
SSE	1	0	0	0	0	0	1
S	0	0	0	0	0	0	0
SSW	0	0	1	0	0	0	1
SW	0	0	0	0	0	0	0
WSW	0	1	0	0	0	0	1
W	0	1	1	0	0	0	2
WNW	0	0	0	0	0	0	0
NW	0	0	1	0	0	0	1
NNW	1	0	0	1	0	0	2
TOTAL	4	3	3	1	0	0	11

Number of calm hours	0
Number of variable directions	0
Total number of observations	11

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Table I.4-33 (CONTINUED)

POINT BEACH WIND - STABILITY SUMMARY

STABILITY CLASS - C - 150 FT WINDS, (APR) PERIOD 4/19/67 TO 4/18/69
NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	2	0	1	0	0	0	3
NNE	0	0	0	0	0	0	0
NE	1	3	0	0	0	0	4
ENE	0	1	0	0	0	0	1
E	2	4	0	0	0	0	6
ESE	4	3	0	0	0	0	7
SE	0	2	0	0	0	1	3
SSE	0	1	1	1	0	0	3
S	1	1	3	0	0	1	6
SSW	0	1	2	0	0	1	4
SW	1	1	1	0	0	0	3
WSW	0	2	0	0	0	0	2
W	0	2	4	1	0	0	7
WNW	0	1	4	10	6	0	21
NW	1	0	6	3	2	0	12
NNW	0	0	3	2	0	0	5
TOTAL	12	22	25	17	8	3	87

Number of calm hours	0
Number of variable directions	0
Total number of observations	87

Table I.4-33 (CONTINUED)

POINT BEACH WIND - STABILITY SUMMARY

STABILITY CLASS - D - 150 FT WINDS, (APR) PERIOD 4/19/67 TO 4/18/69
NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	0	0	1	7	0	0	8
NNE	1	4	5	1	0	0	11
NE	3	10	4	3	0	0	20
ENE	4	4	3	1	0	0	12
E	2	6	2	0	0	0	10
ESE	5	5	3	0	0	0	13
SE	8	3	4	0	1	0	16
SSE	2	6	6	7	2	2	25
S	0	15	20	23	17	17	92
SSW	0	12	24	28	23	1	88
SW	1	1	0	0	3	2	7
WSW	2	2	2	3	1	1	11
W	2	2	4	1	8	9	26
WNW	0	1	2	12	7	6	28
NW	0	1	0	4	1	0	6
NNW	1	0	4	0	0	0	5
TOTAL	31	72	84	90	63	38	378

Number of calm hours	3
Number of variable directions	0
Total number of observations	381

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Table I.4-33 (CONTINUED)

POINT BEACH WIND - STABILITY SUMMARY

STABILITY CLASS - E - 150 FT WINDS, (APR) PERIOD 4/19/67 TO 4/18/69
NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	0	5	10	6	4	1	26
NNE	4	3	21	34	12	29	103
NE	0	10	19	25	2	11	67
ENE	1	1	5	2	0	0	9
E	1	6	2	1	0	0	10
ESE	1	1	4	1	10	2	19
SE	1	8	5	3	2	3	22
SSE	2	6	6	0	0	0	14
S	0	8	14	5	0	0	27
SSW	0	5	22	49	32	0	108
SW	2	7	7	4	3	0	23
WSW	1	1	4	4	1	0	11
W	0	3	9	10	4	2	28
WNW	0	1	0	1	0	0	2
NW	0	0	1	1	0	0	2
NNW	0	1	2	0	0	0	3
TOTAL	13	66	131	146	70	48	474

Number of calm hours	1
Number of variable directions	0
Total number of observations	475

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Table I.4-33 (CONTINUED)

POINT BEACH WIND - STABILITY SUMMARY

STABILITY CLASS - F - 150 FT WINDS, (APR) PERIOD 4/19/67 TO 4/18/69
NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	0	2	1	6	2	0	11
NNE	0	1	2	11	2	0	16
NE	1	2	1	6	0	1	11
ENE	0	0	0	1	0	0	1
E	1	1	1	0	1	3	7
ESE	1	0	1	0	0	0	2
SE	0	2	1	0	0	0	3
SSE	0	4	2	1	0	0	7
S	0	1	5	0	0	0	6
SSW	1	5	13	7	0	0	26
SW	1	3	11	7	2	0	24
WSW	0	0	3	2	0	0	5
W	0	0	2	0	0	0	2
WNW	0	0	1	0	0	0	1
NW	1	0	1	0	0	0	2
NNW	0	0	0	0	0	0	0
TOTAL	6	21	45	41	7	4	124

Number of calm hours	0
Number of variable directions	0
Total number of observations	124

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Table I.4-33 (CONTINUED)

POINT BEACH WIND - STABILITY SUMMARY

STABILITY CLASS - G - 150 FT WINDS, (APR) PERIOD 4/19/67 TO 4/18/69
NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	1	3	19	27	2	0	52
NNE	0	0	0	0	0	0	0
NE	0	1	1	1	0	0	3
ENE	0	1	0	1	0	0	2
E	0	0	0	0	0	0	0
ESE	0	1	1	0	0	0	2
SE	0	1	0	1	0	0	2
SSE	0	0	0	0	0	0	0
S	0	0	1	0	0	0	1
SSW	1	2	9	0	0	0	12
SW	1	0	7	4	0	0	12
WSW	0	0	2	0	0	0	2
W	1	2	0	0	0	0	3
WNW	0	1	1	0	0	0	2
NW	0	0	0	0	0	0	0
NNW	0	0	1	0	0	0	1
TOTAL	4	12	42	34	2	0	94

Number of calm hours	0
Number of variable directions	0
Total number of observations	94

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Table I.4-33 (CONTINUED)

POINT BEACH WIND - STABILITY SUMMARY

STABILITY CLASS - ALL - 150 FT WINDS, (APR) PERIOD 4/19/67 TO 4/18/69
NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	3	10	32	46	8	1	100
NNE	5	8	28	46	14	29	130
NE	5	26	25	35	2	12	105
ENE	6	8	8	5	0	0	27
E	8	18	5	1	1	3	36
ESE	11	11	9	1	10	2	44
SE	9	17	10	4	3	4	47
SSE	5	18	15	9	2	2	51
S	2	25	43	28	17	18	133
SSW	2	25	72	84	55	2	240
SW	6	12	26	15	8	2	69
WSW	3	6	11	9	2	1	32
W	4	10	20	12	12	11	69
WNW	0	4	8	23	13	6	54
NW	2	1	9	8	3	0	23
NNW	2	1	10	3	0	0	16
TOTAL	73	200	331	329	150	93	1176

Number of calm hours	5
Number of variable directions	0
Total number of observations	1181

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Table I.4-33 (CONTINUED)

POINT BEACH WIND - STABILITY SUMMARY

STABILITY CLASS - A - 150 FT WINDS, (MAY) PERIOD 5/1/67 TO 5/31/68
NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	1	0	0	0	0	0	1
NNE	0	0	0	0	0	0	0
NE	1	0	0	0	0	0	1
ENE	0	1	0	0	0	0	1
E	0	0	0	0	0	0	0
ESE	0	0	0	0	0	0	0
SE	0	0	0	0	0	0	0
SSE	0	0	2	0	0	0	2
S	1	0	0	0	0	0	1
SSW	0	0	1	0	0	0	1
SW	0	0	0	0	0	0	0
WSW	1	0	0	0	0	0	1
W	1	0	0	0	0	0	1
WNW	0	0	3	0	0	0	3
NW	0	1	1	0	0	0	2
NNW	0	0	0	0	0	0	0
TOTAL	5	2	7	0	0	0	14

Number of calm hours	0
Number of variable directions	0
Total number of observations	14

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Table I.4-33 (CONTINUED)

POINT BEACH WIND - STABILITY SUMMARY

STABILITY CLASS - B - 150 FT WINDS, (MAY) PERIOD 5/1/67 TO 5/31/68
NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	1	0	0	0	0	0	1
NNE	0	0	0	0	0	0	0
NE	1	2	0	0	0	0	3
ENE	0	1	0	0	0	0	1
E	0	3	0	0	0	0	3
ESE	0	1	0	0	0	0	1
SE	0	0	0	0	0	0	0
SSE	0	0	2	0	0	0	2
S	0	0	0	1	0	0	1
SSW	0	0	0	0	0	0	0
SW	0	0	0	1	0	0	1
WSW	1	0	0	0	0	0	1
W	0	0	1	0	0	0	1
WNW	1	0	2	2	0	0	5
NW	0	0	3	1	0	0	4
NNW	0	0	1	0	0	0	1
TOTAL	4	7	9	5	0	0	25

Number of calm hours	0
Number of variable directions	0
Total number of observations	25

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Table I.4-33 (CONTINUED)

POINT BEACH WIND - STABILITY SUMMARY

STABILITY CLASS - C - 150 FT WINDS, (MAY) PERIOD 5/1/67 TO 5/31/68
NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	0	0	1	0	0	0	1
NNE	0	1	0	0	1	1	3
NE	3	2	1	1	0	0	7
ENE	1	5	0	0	0	0	6
E	3	0	1	0	0	0	4
ESE	2	1	1	0	0	0	4
SE	1	2	2	0	0	0	5
SSE	2	0	1	0	1	0	4
S	0	0	0	1	2	2	5
SSW	0	0	4	1	1	1	7
SW	0	1	0	2	1	0	4
WSW	0	0	1	2	1	0	4
W	0	0	0	5	0	1	6
WNW	0	2	7	10	7	7	33
NW	0	2	3	14	3	1	23
NNW	0	2	1	1	0	0	4
TOTAL	12	18	23	37	17	13	120

Number of calm hours	0
Number of variable directions	0
Total number of observations	120

Table I.4-33 (CONTINUED)

POINT BEACH WIND - STABILITY SUMMARY

STABILITY CLASS - D - 150 FT WINDS, (MAY) PERIOD 5/1/67 TO 5/31/68
NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	2	3	0	2	0	0	7
NNE	5	8	20	8	0	0	41
NE	4	22	19	5	0	0	50
ENE	6	7	5	1	0	0	19
E	5	11	1	0	0	0	17
ESE	5	7	2	1	0	0	15
SE	2	15	6	7	1	0	31
SSE	1	3	9	5	8	3	29
S	4	5	9	19	24	15	76
SSW	1	2	5	10	12	0	30
SW	0	1	2	3	5	2	13
WSW	0	1	0	9	2	0	12
W	0	2	3	12	5	3	25
WNW	0	0	7	8	6	4	25
NW	0	0	8	4	0	0	12
NNW	1	1	6	11	4	0	23
TOTAL	36	88	102	105	67	27	425

Number of calm hours	0
Number of variable directions	0
Total number of observations	425

Table I.4-33 (CONTINUED)

POINT BEACH WIND - STABILITY SUMMARY

STABILITY CLASS - E - 150 FT WINDS, (MAY) PERIOD 5/1/67 TO 5/31/68
NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	2	9	8	8	0	0	27
NNE	2	18	60	41	18	12	151
NE	0	17	27	41	18	5	108
ENE	5	9	11	9	8	1	43
E	4	6	5	1	6	0	22
ESE	0	5	7	3	7	0	22
SE	0	4	12	9	7	1	33
SSE	0	2	13	7	5	1	28
S	1	3	5	2	0	0	11
SSW	2	2	9	26	11	1	51
SW	1	1	8	5	1	1	17
WSW	0	3	2	5	1	0	11
W	0	3	6	8	2	1	20
WNW	0	1	2	3	0	0	6
NW	0	5	0	0	0	0	5
NNW	1	0	0	2	0	0	3
TOTAL	18	88	175	170	84	23	558

Number of calm hours	0
Number of variable directions	0
Total number of observations	558

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Table I.4-33 (CONTINUED)

POINT BEACH WIND - STABILITY SUMMARY

STABILITY CLASS - F - 150 FT WINDS, (MAY) PERIOD 5/1/67 TO 5/31/68
NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	1	2	5	1	0	0	9
NNE	0	2	3	9	7	1	22
NE	0	3	1	4	5	1	14
ENE	0	1	1	0	2	2	6
E	1	0	0	3	0	0	4
ESE	0	0	0	0	1	0	1
SE	0	0	5	1	0	0	6
SSE	0	0	2	0	0	0	2
S	0	2	1	0	0	0	3
SSW	0	3	7	5	1	0	16
SW	0	1	4	6	0	0	11
WSW	0	0	3	0	0	0	3
W	0	1	9	3	0	0	13
WNW	0	1	6	0	0	0	7
NW	0	2	2	0	0	0	4
NNW	0	2	0	1	0	0	3
TOTAL	2	20	49	33	16	4	124

Number of calm hours	0
Number of variable directions	0
Total number of observations	124

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Table I.4-33 (CONTINUED)

POINT BEACH WIND - STABILITY SUMMARY

STABILITY CLASS - G - 150 FT WINDS, (MAY) PERIOD 5/1/67 TO 5/31/68
NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	9	12	12	11	0	0	44
NNE	0	0	0	4	0	0	4
NE	0	3	0	1	0	0	4
ENE	0	1	0	0	1	1	3
E	0	2	2	3	0	0	7
ESE	1	0	0	0	0	0	1
SE	0	0	1	0	0	0	1
SSE	0	0	2	0	0	0	2
S	0	0	1	0	0	0	1
SSW	0	1	5	2	0	0	8
SW	0	1	9	7	0	0	17
WSW	0	0	1	3	0	0	4
W	0	0	1	6	0	0	7
WNW	0	3	0	0	0	0	3
NW	0	3	1	0	0	0	4
NNW	0	0	0	0	0	0	0
TOTAL	10	26	35	37	1	1	110

Number of calm hours	0
Number of variable directions	0
Total number of observations	110

Table I.4-33 (CONTINUED)

POINT BEACH WIND - STABILITY SUMMARY

STABILITY CLASS - ALL - 150 FT WINDS, (MAY) PERIOD 5/1/67 TO 5/31/68
NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	16	26	26	22	0	0	90
NNE	7	29	83	62	26	14	221
NE	9	49	48	52	23	6	187
ENE	12	25	17	10	11	4	79
E	13	22	9	7	6	0	57
ESE	8	14	10	4	8	0	44
SE	3	21	26	17	8	1	76
SSE	3	5	31	12	14	4	69
S	6	10	16	23	26	17	98
SSW	3	8	31	44	25	2	113
SW	1	5	23	24	7	3	63
WSW	2	4	7	19	4	0	36
W	1	6	20	34	7	5	73
WNW	1	7	27	23	13	11	82
NW	0	13	18	19	3	1	54
NNW	2	5	8	15	4	0	34
TOTAL	87	249	400	387	185	68	1376

Number of calm hours	0
Number of variable directions	0
Total number of observations	1376

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Table I.4-33 (CONTINUED)

POINT BEACH WIND - STABILITY SUMMARY

STABILITY CLASS - A - 150 FT WINDS, (JUN) PERIOD 6/1/67 TO 6/30/68
NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	0	0	0	0	0	0	0
NNE	1	0	0	0	0	0	1
NE	1	0	0	0	0	0	1
ENE	1	0	0	0	0	0	1
E	1	0	0	0	0	0	1
ESE	0	0	0	0	0	0	0
SE	3	0	0	0	0	0	3
SSE	0	0	0	0	0	0	0
S	1	0	0	0	0	0	1
SSW	0	1	0	0	0	0	1
SW	0	2	0	0	0	0	2
WSW	0	0	1	1	0	0	2
W	2	0	1	0	0	0	3
WNW	0	0	0	1	0	0	1
NW	2	1	0	0	0	1	4
NNW	0	0	0	0	0	0	0
TOTAL	12	4	2	2	0	1	21

Number of calm hours	0
Number of variable directions	0
Total number of observations	21

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Table I.4-33 (CONTINUED)

POINT BEACH WIND - STABILITY SUMMARY

STABILITY CLASS - B - 150 FT WINDS, (JUN) PERIOD 6/1/67 TO 6/30/68
NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	0	0	0	0	0	0	0
NNE	0	0	0	0	0	0	0
NE	1	0	0	0	0	0	1
ENE	1	0	0	0	0	0	1
E	0	0	0	0	0	0	0
ESE	0	0	0	0	0	0	0
SE	2	0	0	0	0	0	2
SSE	1	1	1	0	0	0	3
S	1	0	1	0	0	0	2
SSW	1	1	0	0	0	0	2
SW	0	1	0	0	0	0	1
WSW	1	1	0	0	0	0	2
W	0	0	0	0	0	0	0
WNW	0	1	5	1	0	0	7
NW	0	2	0	0	0	0	2
NNW	0	0	0	0	0	0	0
TOTAL	8	7	7	1	0	0	23

Number of calm hours	1
Number of variable directions	0
Total number of observations	24

Table I.4-33 (CONTINUED)

POINT BEACH WIND - STABILITY SUMMARY

STABILITY CLASS - B - 150 FT WINDS, (JUN) PERIOD 6/1/67 TO 6/30/68
NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	1	1	0	0	0	0	2
NNE	1	1	0	0	0	0	2
NE	3	0	0	0	0	0	3
ENE	2	0	0	0	0	0	2
E	2	1	1	0	0	0	4
ESE	0	1	0	0	0	0	1
SE	3	1	1	0	0	0	5
SSE	1	4	1	0	0	0	6
S	3	5	2	3	0	0	13
SSW	1	4	4	1	0	0	10
SW	0	2	1	1	0	2	6
WSW	1	1	1	0	0	0	3
W	1	1	2	2	0	0	6
WNW	1	3	7	4	2	1	18
NW	0	2	5	3	1	0	11
NNW	1	0	0	1	0	0	2
TOTAL	21	27	25	15	3	3	94

Number of calm hours	2
Number of variable directions	0
Total number of observations	96

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Table I.4-33 (CONTINUED)

POINT BEACH WIND - STABILITY SUMMARY

STABILITY CLASS - D - 150 FT WINDS, (JUN) PERIOD 6/1/67 TO 6/30/68
NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	0	1	2	1	0	0	4
NNE	3	3	7	1	2	0	16
NE	4	3	2	2	1	0	12
ENE	3	2	1	0	0	0	6
E	0	3	0	0	0	0	3
ESE	3	5	0	0	0	0	8
SE	1	2	2	0	0	0	5
SSE	3	5	6	1	0	0	15
S	5	11	15	16	5	1	53
SSW	1	20	32	25	7	3	88
SW	1	9	9	8	0	1	28
WSW	1	2	3	4	4	3	17
W	2	4	4	6	4	2	22
WNW	3	2	2	8	0	0	15
NW	0	3	5	1	0	0	9
NNW	0	3	8	3	8	1	23
TOTAL	30	78	98	76	31	11	324

Number of calm hours	1
Number of variable directions	0
Total number of observations	325

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Table I.4-33 (CONTINUED)

POINT BEACH WIND - STABILITY SUMMARY

STABILITY CLASS - E - 150 FT WINDS, (JUN) PERIOD 6/1/67 TO 6/30/68
NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	1	2	4	4	0	0	11
NNE	1	9	30	14	9	10	73
NE	1	5	13	5	1	7	32
ENE	2	5	2	0	1	0	10
E	4	2	1	0	0	0	7
ESE	4	2	3	1	0	0	10
SE	0	5	8	1	0	0	14
SSE	2	6	6	2	0	0	16
S	2	4	7	3	0	0	16
SSW	2	8	30	44	3	1	88
SW	2	5	18	18	1	0	44
WSW	1	4	8	4	3	0	20
W	1	3	2	3	0	0	9
WNW	2	0	4	2	0	0	8
NW	1	1	2	0	0	0	4
NNW	1	0	8	0	1	0	10
TOTAL	27	61	146	101	19	18	372

Number of calm hours	3
Number of variable directions	0
Total number of observations	375

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Table I.4-33 (CONTINUED)

POINT BEACH WIND - STABILITY SUMMARY

STABILITY CLASS - F - 150 FT WINDS, (JUN) PERIOD 6/1/67 TO 6/30/68
NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	1	6	6	4	0	0	17
NNE	1	4	17	12	7	4	45
NE	0	1	6	12	3	0	22
ENE	0	1	2	0	0	0	3
E	0	1	0	0	0	0	1
ESE	0	1	3	0	0	0	4
SE	0	3	3	0	0	0	6
SSE	2	3	3	0	0	0	8
S	0	0	1	0	0	0	1
SSW	1	3	3	6	0	0	13
SW	1	4	17	10	0	0	32
WSW	0	1	2	0	0	0	3
W	0	1	1	1	0	0	3
WNW	0	1	0	0	0	0	1
NW	0	0	0	0	0	0	0
NNW	0	0	0	0	0	0	0
TOTAL	6	30	64	45	10	4	159

Number of calm hours	0
Number of variable directions	0
Total number of observations	159

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Table I.4-33 (CONTINUED)

POINT BEACH WIND - STABILITY SUMMARY

STABILITY CLASS - G - 150 FT WINDS, (JUN) PERIOD 6/1/67 TO 6/30/68
NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	0	5	2	0	0	0	7
NNE	0	0	5	6	6	0	17
NE	0	3	4	4	2	0	13
ENE	1	0	0	0	0	0	1
E	0	0	1	0	0	0	1
ESE	0	5	0	0	0	0	5
SE	2	3	2	0	0	0	7
SSE	0	1	2	0	0	0	3
S	0	0	2	0	0	0	2
SSW	1	0	2	2	0	0	5
SW	0	2	4	5	0	0	11
WSW	1	0	2	0	0	0	3
W	0	0	2	0	0	0	2
WNW	0	1	0	0	0	0	1
NW	0	0	0	0	0	0	0
NNW	0	0	0	0	0	0	0
TOTAL	5	20	28	17	8	0	78

Number of calm hours	0
Number of variable directions	0
Total number of observations	78

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Table I.4-33 (CONTINUED)

POINT BEACH WIND - STABILITY SUMMARY

STABILITY CLASS - ALL - 150 FT WINDS, (JUN) PERIOD 6/1/67 TO 6/30/68
NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	3	15	14	9	0	0	41
NNE	7	17	59	33	24	14	154
NE	10	12	25	23	7	7	84
ENE	10	8	5	0	1	0	24
E	7	7	3	0	0	0	17
ESE	7	14	6	1	0	0	28
SE	11	14	16	1	0	0	42
SSE	9	20	19	3	0	0	51
S	12	20	28	22	5	1	88
SSW	7	37	71	78	10	4	207
SW	4	25	49	42	1	3	124
WSW	5	9	17	9	7	3	50
W	6	9	12	12	4	2	45
WNW	6	8	18	16	2	1	51
NW	3	9	12	4	1	1	30
NNW	2	3	16	4	9	1	35
TOTAL	109	227	370	257	71	37	1071

Number of calm hours	7
Number of variable directions	0
Total number of observations	1078

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Table I.4-33 (CONTINUED)

POINT BEACH WIND - STABILITY SUMMARY

STABILITY CLASS - A - 150 FT WINDS, (JUL) PERIOD 7/1/67 TO 7/31/68
NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	0	2	1	0	0	0	3
NNE	0	0	0	0	0	0	0
NE	1	0	0	0	0	0	1
ENE	0	0	0	0	0	0	0
E	2	0	0	0	0	0	2
ESE	0	0	0	0	0	0	0
SE	1	1	0	0	0	0	2
SSE	1	0	0	0	0	0	1
S	0	0	0	0	0	0	0
SSW	0	0	0	0	0	0	0
SW	2	1	0	0	0	1	4
WSW	0	2	0	0	0	0	2
W	0	1	0	0	0	0	1
WNW	0	1	0	0	0	0	1
NW	0	0	1	0	0	0	1
NNW	0	0	0	0	0	0	0
TOTAL	7	8	2	0	0	1	18

Number of calm hours	2
Number of variable directions	0
Total number of observations	20

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Table I.4-33 (CONTINUED)

POINT BEACH WIND - STABILITY SUMMARY

STABILITY CLASS - B - 150 FT WINDS, (JUL) PERIOD 7/1/67 TO 7/31/68
NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	1	0	0	0	0	0	1
NNE	0	0	0	0	0	0	0
NE	1	0	0	0	0	0	1
ENE	0	0	0	0	0	0	0
E	0	0	0	0	0	0	0
ESE	1	0	0	0	0	0	1
SE	0	0	0	0	0	0	0
SSE	3	0	0	0	0	0	3
S	0	0	3	0	0	0	3
SSW	0	0	1	0	0	0	1
SW	0	0	1	0	0	0	1
WSW	0	0	1	0	0	0	1
W	0	1	0	0	0	0	1
WNW	0	0	1	0	0	0	1
NW	0	1	4	3	0	0	8
NNW	0	0	0	0	0	0	0
TOTAL	6	2	11	3	0	0	22

Number of calm hours	3
Number of variable directions	0
Total number of observations	25

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Table I.4-33 (CONTINUED)

POINT BEACH WIND - STABILITY SUMMARY

STABILITY CLASS - C - 150 FT WINDS, (JUL) PERIOD 7/1/67 TO 7/31/68
NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	0	0	1	0	0	0	1
NNE	1	1	0	0	0	0	2
NE	1	0	1	0	0	0	2
ENE	0	0	0	0	0	0	0
E	0	1	0	0	0	0	1
ESE	0	0	0	0	0	0	0
SE	0	1	0	0	0	0	1
SSE	0	2	1	1	0	0	4
S	1	5	7	1	0	0	14
SSW	0	6	6	0	0	0	12
SW	1	5	3	0	0	0	9
WSW	1	1	4	1	0	0	7
W	0	1	4	3	1	0	9
WNW	0	0	10	9	2	0	21
NW	0	1	15	13	0	0	29
NNW	1	2	7	2	0	0	12
TOTAL	6	26	59	30	3	0	124

Number of calm hours	8
Number of variable directions	0
Total number of observations	132

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Table I.4-33 (CONTINUED)

POINT BEACH WIND - STABILITY SUMMARY

STABILITY CLASS - D - 150 FT WINDS, (JUL) PERIOD 7/1/67 TO 7/31/68
NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	1	1	3	0	1	0	6
NNE	0	6	0	0	0	0	6
NE	2	8	2	0	0	0	12
ENE	3	3	0	0	0	0	6
E	3	3	1	0	0	0	7
ESE	6	1	0	0	0	0	7
SE	7	2	0	0	0	0	9
SSE	3	6	12	0	0	0	21
S	5	13	23	11	5	2	59
SSW	3	7	40	41	9	1	101
SW	5	5	9	12	1	0	32
WSW	2	3	9	4	1	2	21
W	1	3	8	12	4	2	30
WNW	0	2	14	7	0	1	24
NW	2	0	8	0	0	0	10
NNW	1	4	24	12	0	0	41
TOTAL	44	67	153	99	21	8	392

Number of calm hours	8
Number of variable directions	0
Total number of observations	400

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Table I.4-33 (CONTINUED)

POINT BEACH WIND - STABILITY SUMMARY

STABILITY CLASS - E - 150 FT WINDS, (JUL) PERIOD 7/1/67 TO 7/31/68
NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	2	8	8	1	1	0	20
NNE	3	11	14	6	0	0	34
NE	4	11	3	2	0	0	20
ENE	1	4	0	0	0	0	5
E	3	5	2	0	0	0	10
ESE	1	5	0	0	0	0	6
SE	3	4	2	1	0	0	10
SSE	2	6	10	2	0	0	20
S	2	15	6	4	0	0	27
SSW	5	11	56	59	3	0	134
SW	3	13	19	8	0	0	43
WSW	1	4	11	8	0	0	24
W	0	5	8	7	0	0	20
WNW	2	1	6	4	0	0	13
NW	0	3	5	1	0	0	9
NNW	0	2	9	1	0	0	12
TOTAL	32	108	159	104	4	0	407

Number of calm hours	5
Number of variable directions	0
Total number of observations	412

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Table I.4-33 (CONTINUED)

POINT BEACH WIND - STABILITY SUMMARY

STABILITY CLASS - F - 150 FT WINDS, (JUL) PERIOD 7/1/67 TO 7/31/68
NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	3	4	10	5	0	0	22
NNE	1	5	8	2	3	0	19
NE	1	4	9	1	1	0	16
ENE	4	3	6	1	0	0	14
E	1	5	0	0	0	0	6
ESE	1	3	1	0	0	0	5
SE	1	7	3	1	0	0	12
SSE	1	2	6	0	0	0	9
S	2	2	2	0	0	0	6
SSW	0	6	17	8	0	0	31
SW	0	7	27	12	0	0	46
WSW	0	2	6	4	0	0	12
W	0	0	4	3	0	0	7
WNW	1	3	2	1	0	0	7
NW	0	2	1	1	0	0	4
NNW	0	1	0	1	0	0	2
TOTAL	16	56	102	40	4	0	218

Number of calm hours	1
Number of variable directions	0
Total number of observations	219

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Table I.4-33 (CONTINUED)

POINT BEACH WIND - STABILITY SUMMARY

STABILITY CLASS - G - 150 FT WINDS, (JUL) PERIOD 7/1/67 TO 7/31/68
NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	1	5	1	0	0	0	7
NNE	0	3	9	4	1	0	17
NE	0	6	7	0	0	0	13
ENE	1	4	2	3	1	0	11
E	0	2	2	0	0	0	4
ESE	0	4	1	0	0	0	5
SE	3	10	11	1	0	0	25
SSE	1	3	7	0	0	0	11
S	3	0	0	0	0	0	3
SSW	0	9	14	5	0	0	28
SW	0	4	22	5	0	0	31
WSW	0	1	5	1	0	0	7
W	0	2	5	1	0	0	8
WNW	2	5	0	1	0	0	8
NW	0	0	3	1	0	0	4
NNW	0	1	0	0	0	0	1
TOTAL	11	59	89	22	2	0	183

Number of calm hours	2
Number of variable directions	0
Total number of observations	185

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Table I.4-33 (CONTINUED)

POINT BEACH WIND - STABILITY SUMMARY

STABILITY CLASS - ALL - 150 FT WINDS, (JUL) PERIOD 7/1/67 TO 7/31/68
NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	8	20	24	6	2	0	60
NNE	5	26	31	12	4	0	78
NE	10	29	22	3	1	0	65
ENE	9	14	8	4	1	0	36
E	9	16	5	0	0	0	30
ESE	9	13	2	0	0	0	24
SE	15	25	16	3	0	0	59
SSE	11	19	36	3	0	0	69
S	13	35	41	16	5	2	112
SSW	8	39	134	113	12	1	307
SW	11	35	81	37	1	1	166
WSW	4	13	36	18	1	2	74
W	1	13	29	26	5	2	76
WNW	5	12	33	22	2	1	75
NW	2	7	37	19	0	0	65
NNW	2	10	40	16	0	0	68
TOTAL	122	326	575	298	34	9	1364

Number of calm hours	29
Number of variable directions	0
Total number of observations	1393

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Table I.4-33 (CONTINUED)

POINT BEACH WIND - STABILITY SUMMARY

STABILITY CLASS - A - 150 FT WINDS, (AUG) PERIOD 8/1/67 TO 8/31/68
NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	1	0	0	0	0	0	1
NNE	0	0	0	0	0	0	0
NE	0	0	0	0	0	0	0
ENE	0	0	0	0	0	0	0
E	0	0	0	0	0	0	0
ESE	0	0	0	0	0	0	0
SE	1	0	0	0	0	0	1
SSE	0	0	0	0	0	0	0
S	0	0	0	0	0	0	0
SSW	0	0	0	1	0	0	1
SW	0	1	0	0	0	0	1
WSW	0	1	0	1	0	0	2
W	1	1	0	0	0	0	2
WNW	1	0	0	0	0	0	1
NW	0	0	0	0	0	0	0
NNW	0	0	0	0	0	0	0
TOTAL	4	3	0	2	0	0	9

Number of calm hours	3
Number of variable directions	0
Total number of observations	12

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Table I.4-33 (CONTINUED)

POINT BEACH WIND - STABILITY SUMMARY

STABILITY CLASS - B - 150 FT WINDS, (AUG) PERIOD 8/1/67 TO 8/31/68
NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	0	0	0	0	0	0	0
NNE	0	0	0	0	0	0	0
NE	0	0	0	0	0	0	0
ENE	0	0	0	0	0	0	0
E	0	0	0	0	0	0	0
ESE	0	0	0	0	0	0	0
SE	0	1	0	0	0	0	1
SSE	2	1	0	0	0	0	3
S	0	1	1	0	0	0	2
SSW	1	0	2	0	0	0	3
SW	1	2	2	0	0	0	5
WSW	0	1	0	0	0	0	1
W	0	0	1	1	0	0	2
WNW	0	2	2	0	0	0	4
NW	0	0	3	1	0	0	4
NNW	0	2	1	0	0	0	3
TOTAL	4	10	12	2	0	0	28

Number of calm hours	2
Number of variable directions	0
Total number of observations	30

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Table I.4-33 (CONTINUED)

POINT BEACH WIND - STABILITY SUMMARY

STABILITY CLASS - C - 150 FT WINDS, (AUG) PERIOD 8/1/67 TO 8/31/68
NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	0	0	1	0	0	0	1
NNE	0	0	0	0	0	0	0
NE	1	2	0	1	0	0	4
ENE	0	0	0	0	0	0	0
E	0	1	0	0	0	0	1
ESE	1	2	0	0	0	0	3
SE	1	1	0	0	0	0	2
SSE	0	1	0	1	0	0	2
S	1	3	14	0	1	1	20
SSW	0	1	2	0	0	0	3
SW	0	1	1	1	0	0	3
WSW	0	0	5	0	0	1	6
W	2	2	4	0	1	0	9
WNW	1	1	9	8	1	0	20
NW	0	1	7	6	0	0	14
NNW	0	0	1	3	0	0	4
TOTAL	7	16	44	20	3	2	92

Number of calm hours	2
Number of variable directions	0
Total number of observations	94

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Table I.4-33 (CONTINUED)

POINT BEACH WIND - STABILITY SUMMARY

STABILITY CLASS - D - 150 FT WINDS, (AUG) PERIOD 8/1/67 TO 8/31/68
NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	0	1	6	6	1	0	14
NNE	0	3	2	0	0	1	6
NE	1	1	0	0	0	0	2
ENE	3	4	0	0	0	0	7
E	7	4	2	0	0	0	13
ESE	6	0	0	0	0	0	6
SE	4	2	1	0	0	0	7
SSE	0	7	10	7	0	0	24
S	2	7	33	21	1	0	64
SSW	2	4	27	34	6	0	73
SW	3	7	5	12	1	1	29
WSW	0	5	13	18	14	3	53
W	0	4	5	3	2	1	15
WNW	1	4	6	1	0	0	12
NW	2	3	7	7	0	0	19
NNW	0	3	13	4	1	0	21
TOTAL	31	59	130	113	26	6	365

Number of calm hours	2
Number of variable directions	0
Total number of observations	367

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Table I.4-33 (CONTINUED)

POINT BEACH WIND - STABILITY SUMMARY

STABILITY CLASS - E - 150 FT WINDS, (AUG) PERIOD 8/1/67 TO 8/31/68
NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	2	5	34	22	8	0	71
NNE	2	4	8	14	19	5	52
NE	1	6	21	4	0	0	32
ENE	2	9	12	1	0	0	24
E	6	14	7	0	0	0	27
ESE	4	14	0	0	0	0	18
SE	4	6	5	0	0	0	15
SSE	1	9	11	8	0	0	29
S	7	1	8	0	0	0	16
SSW	3	10	42	34	0	0	89
SW	1	11	28	14	1	0	55
WSW	0	3	17	17	0	0	37
W	0	4	7	5	0	0	16
WNW	1	2	2	0	0	0	5
NW	0	2	2	0	1	0	5
NNW	2	2	4	1	0	0	9
TOTAL	36	102	208	120	29	5	500

Number of calm hours	2
Number of variable directions	0
Total number of observations	502

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Table I.4-33 (CONTINUED)

POINT BEACH WIND - STABILITY SUMMARY

STABILITY CLASS - F - 150 FT WINDS, (AUG) PERIOD 8/1/67 TO 8/31/68
NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	1	5	25	25	8	0	64
NNE	0	2	6	5	1	0	14
NE	0	1	8	3	1	0	13
ENE	3	3	3	1	0	0	10
E	2	6	0	0	0	0	8
ESE	5	4	2	0	0	0	11
SE	1	7	6	0	0	0	14
SSE	2	2	4	1	0	0	9
S	4	4	0	0	0	0	8
SSW	3	3	17	5	0	0	28
SW	2	12	25	6	0	0	45
WSW	0	0	8	4	0	0	12
W	0	1	2	1	0	0	4
WNW	1	2	0	0	0	0	3
NW	1	1	4	1	0	0	7
NNW	0	0	0	0	0	0	0
TOTAL	25	53	110	52	10	0	250

Number of calm hours	0
Number of variable directions	0
Total number of observations	250

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Table I.4-33 (CONTINUED)

POINT BEACH WIND - STABILITY SUMMARY

STABILITY CLASS - G - 150 FT WINDS, (AUG) PERIOD 8/1/67 TO 8/31/68
NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	0	3	7	4	1	0	15
NNE	0	3	2	2	0	0	7
NE	1	0	1	0	0	0	2
ENE	0	0	0	0	0	0	0
E	1	2	0	0	0	0	3
ESE	1	2	0	0	0	0	3
SE	3	3	1	0	0	0	7
SSE	3	1	3	2	0	0	9
S	1	1	0	1	0	0	3
SSW	3	12	11	2	0	0	28
SW	1	15	24	1	0	0	41
WSW	1	3	6	6	0	0	16
W	1	3	4	7	0	0	15
WNW	1	4	2	1	0	0	8
NW	0	0	0	1	0	0	1
NNW	0	0	4	0	0	0	4
TOTAL	17	52	65	27	1	0	162

Number of calm hours	3
Number of variable directions	0
Total number of observations	165

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Table I.4-33 (CONTINUED)

POINT BEACH WIND - STABILITY SUMMARY

STABILITY CLASS - ALL - 150 FT WINDS, (AUG) PERIOD 8/1/67 TO 8/31/68
NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	4	14	73	57	18	0	166
NNE	2	12	18	21	20	6	79
NE	4	10	30	8	1	0	53
ENE	8	16	15	2	0	0	41
E	16	27	9	0	0	0	52
ESE	17	22	2	0	0	0	41
SE	14	20	13	0	0	0	47
SSE	8	21	28	19	0	0	76
S	15	17	56	22	2	1	113
SSW	12	30	101	76	6	0	225
SW	8	49	85	34	2	1	179
WSW	1	13	49	46	14	4	127
W	4	15	23	17	3	1	63
WNW	6	15	21	10	1	0	53
NW	3	7	23	16	1	0	50
NNW	2	7	23	8	1	0	41
TOTAL	124	295	569	336	69	13	1406

Number of calm hours	14
Number of variable directions	0
Total number of observations	1420

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Table I.4-33 (CONTINUED)

POINT BEACH WIND - STABILITY SUMMARY

STABILITY CLASS - A - 150 FT WINDS, (SEP) PERIOD 9/1/67 TO 9/30/68
NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	0	0	0	0	0	0	0
NNE	1	0	0	0	0	0	1
NE	0	0	0	0	0	0	0
ENE	0	0	0	0	0	0	0
E	0	0	0	0	0	0	0
ESE	0	0	0	0	0	0	0
SE	0	0	0	0	0	0	0
SSE	0	0	0	0	0	0	0
S	1	0	0	0	0	0	1
SSW	0	0	1	0	0	0	1
SW	0	0	0	0	0	0	0
WSW	0	0	0	0	0	0	0
W	0	1	0	0	0	0	1
WNW	1	1	0	0	0	0	2
NW	0	0	2	0	0	0	2
NNW	0	1	0	0	0	0	1
TOTAL	3	3	3	0	0	0	9

Number of calm hours	1
Number of variable directions	0
Total number of observations	10

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Table I.4-33 (CONTINUED)

POINT BEACH WIND - STABILITY SUMMARY

STABILITY CLASS - B - 150 FT WINDS, (SEP) PERIOD 9/1/67 TO 9/30/68
NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	0	1	0	0	0	0	1
NNE	0	0	0	0	0	0	0
NE	1	0	0	0	0	0	1
ENE	1	0	0	0	0	0	1
E	0	0	0	0	0	0	0
ESE	1	0	0	0	0	0	1
SE	1	0	0	0	0	0	1
SSE	1	0	0	0	0	0	1
S	1	2	0	0	0	0	3
SSW	1	0	0	0	0	0	1
SW	0	0	0	1	0	0	1
WSW	0	0	0	1	0	0	1
W	0	3	0	0	0	0	3
WNW	0	4	0	0	0	0	4
NW	1	2	2	0	0	0	5
NNW	0	0	0	0	0	0	0
TOTAL	8	12	2	2	0	0	24

Number of calm hours	2
Number of variable directions	0
Total number of observations	26

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Table I.4-33 (CONTINUED)

POINT BEACH WIND - STABILITY SUMMARY

STABILITY CLASS - C - 150 FT WINDS, (SEP) PERIOD 9/1/67 TO 9/30/68
NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	0	2	0	1	0	0	3
NNE	0	0	0	0	0	0	0
NE	0	1	0	0	0	0	1
ENE	1	0	0	0	0	0	1
E	4	1	0	0	0	0	5
ESE	2	0	0	0	0	0	2
SE	0	0	0	0	0	0	0
SSE	0	0	0	1	0	0	1
S	2	2	12	4	0	0	20
SSW	0	0	2	1	0	0	3
SW	3	0	3	0	0	0	6
WSW	0	0	0	0	0	0	0
W	0	4	4	0	0	0	8
WNW	0	2	8	17	4	0	31
NW	1	7	18	4	0	0	30
NNW	0	5	5	0	0	0	10
TOTAL	13	24	52	28	4	0	121

Number of calm hours	3
Number of variable directions	0
Total number of observations	124

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Table I.4-33 (CONTINUED)

POINT BEACH WIND - STABILITY SUMMARY

STABILITY CLASS - D - 150 FT WINDS, (SEP) PERIOD 9/1/67 TO 9/30/68
NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	1	0	4	14	2	0	21
NNE	3	2	3	9	10	0	27
NE	2	5	2	4	4	0	17
ENE	2	5	0	1	0	0	8
E	5	7	4	0	0	0	16
ESE	3	3	2	0	0	0	8
SE	2	3	0	1	0	0	6
SSE	2	6	9	7	6	0	30
S	3	16	56	49	11	1	136
SSW	0	4	40	14	10	1	69
SW	1	0	3	12	3	0	19
WSW	3	3	9	10	3	1	29
W	1	2	0	8	6	1	18
WNW	0	6	9	4	0	0	19
NW	0	7	15	0	0	0	22
NNW	0	6	9	10	1	0	26
TOTAL	28	75	165	143	56	4	471

Number of calm hours	6
Number of variable directions	0
Total number of observations	477

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Table I.4-33 (CONTINUED)

POINT BEACH WIND - STABILITY SUMMARY

STABILITY CLASS - E - 150 FT WINDS, (SEP) PERIOD 9/1/67 TO 9/30/68
NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	0	0	14	36	9	2	61
NNE	0	2	1	8	8	3	22
NE	1	1	0	0	3	0	5
ENE	4	2	2	1	0	0	9
E	5	7	0	1	0	0	13
ESE	5	8	2	0	0	0	15
SE	7	10	1	2	1	0	21
SSE	4	5	13	14	10	0	46
S	3	5	13	6	1	0	28
SSW	5	7	33	13	0	0	58
SW	4	9	21	5	3	0	42
WSW	0	6	15	4	0	0	25
W	0	5	6	7	0	0	18
WNW	1	4	3	0	0	0	8
NW	0	1	3	3	0	0	7
NNW	0	1	4	3	0	0	8
TOTAL	39	73	131	103	35	5	386

Number of calm hours	9
Number of variable directions	0
Total number of observations	395

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Table I.4-33 (CONTINUED)

POINT BEACH WIND - STABILITY SUMMARY

STABILITY CLASS - F - 150 FT WINDS, (SEP) PERIOD 9/1/67 TO 9/30/68
NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	2	4	4	19	1	0	30
NNE	0	0	2	0	0	0	2
NE	1	1	0	0	0	0	2
ENE	0	4	0	0	0	0	4
E	6	1	0	0	0	0	7
ESE	4	5	1	0	1	0	11
SE	1	7	4	8	2	0	22
SSE	2	5	4	3	1	0	15
S	2	5	1	0	0	0	8
SSW	5	5	5	0	0	0	15
SW	2	6	19	4	0	0	31
WSW	1	1	4	3	0	0	9
W	1	2	8	7	0	0	18
WNW	0	5	9	3	0	0	17
NW	1	1	1	3	0	0	6
NNW	0	0	1	0	0	0	1
TOTAL	28	52	63	50	5	0	198

Number of calm hours	2
Number of variable directions	0
Total number of observations	200

Table I.4-33 (CONTINUED)

POINT BEACH WIND - STABILITY SUMMARY

STABILITY CLASS - G - 150 FT WINDS, (SEP) PERIOD 9/1/67 TO 9/30/68
NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	2	3	0	0	0	0	5
NNE	0	0	0	0	0	0	0
NE	1	0	0	0	0	0	1
ENE	0	2	0	0	0	0	2
E	4	1	1	0	0	0	6
ESE	0	2	0	0	0	0	2
SE	1	10	1	0	0	0	12
SSE	0	2	2	0	0	0	4
S	1	4	1	0	0	0	6
SSW	2	9	2	0	0	0	13
SW	0	11	16	3	0	0	30
WSW	0	4	10	2	0	0	16
W	0	5	17	11	0	0	33
WNW	1	0	6	3	0	0	10
NW	0	0	0	3	0	0	3
NNW	0	0	0	0	0	0	0
TOTAL	12	53	56	22	0	0	143

Number of calm hours	2
Number of variable directions	0
Total number of observations	145

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Table I.4-33 (CONTINUED)

POINT BEACH WIND - STABILITY SUMMARY

STABILITY CLASS - ALL - 150 FT WINDS, (SEP) PERIOD 9/1/67 TO 9/30/68
NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	5	10	22	70	12	2	121
NNE	4	4	6	17	18	3	52
NE	6	8	2	4	7	0	27
ENE	8	13	2	2	0	0	25
E	24	17	5	1	0	0	47
ESE	15	18	5	0	1	0	39
SE	12	30	6	11	3	0	62
SSE	9	18	28	25	17	0	97
S	13	34	83	59	12	1	202
SSW	13	25	83	28	10	1	160
SW	10	26	62	25	6	0	129
WSW	4	14	38	20	3	1	80
W	2	22	35	33	6	1	99
WNW	3	22	35	27	4	0	91
NW	3	18	41	13	0	0	75
NNW	0	13	19	13	1	0	46
TOTAL	131	292	472	348	100	9	1352

Number of calm hours	25
Number of variable directions	0
Total number of observations	1377

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Table I.4-33 (CONTINUED)

POINT BEACH WIND - STABILITY SUMMARY

STABILITY CLASS - A - 150 FT WINDS, (OCT) PERIOD 10/1/67 TO 10/31/68
NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	0	0	0	0	0	0	0
NNE	0	0	0	0	0	0	0
NE	0	0	0	0	0	0	0
ENE	0	0	0	0	0	0	0
E	0	0	0	0	0	0	0
ESE	0	0	0	0	0	0	0
SE	1	0	0	0	0	0	1
SSE	0	0	0	0	0	0	0
S	0	0	0	0	0	0	0
SSW	0	1	0	0	0	0	1
SW	1	0	0	0	0	0	1
WSW	0	0	0	0	0	0	0
W	0	0	0	0	0	0	0
WNW	0	0	1	0	0	0	1
NW	1	0	2	0	0	0	3
NNW	1	0	0	0	0	0	1
TOTAL	4	1	3	0	0	0	8

Number of calm hours	0
Number of variable directions	0
Total number of observations	8

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Table I.4-33 (CONTINUED)

POINT BEACH WIND - STABILITY SUMMARY

STABILITY CLASS - B - 150 FT WINDS, (OCT) PERIOD 10/1/67 TO 10/31/68
NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	0	0	0	0	0	0	0
NNE	0	0	0	0	0	0	0
NE	0	0	0	0	0	0	0
ENE	0	0	0	0	0	0	0
E	0	0	0	0	0	0	0
ESE	0	0	0	0	0	0	0
SE	0	0	0	0	0	0	0
SSE	1	0	0	0	0	0	1
S	0	0	0	0	0	0	0
SSW	1	0	1	0	0	0	2
SW	0	0	0	0	0	0	0
WSW	0	0	0	0	0	0	0
W	2	0	0	0	0	0	2
WNW	0	0	3	1	0	0	4
NW	1	0	0	2	1	0	4
NNW	0	1	1	0	0	0	2
TOTAL	5	1	5	3	1	0	15

Number of calm hours	0
Number of variable directions	0
Total number of observations	15

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Table I.4-33 (CONTINUED)

POINT BEACH WIND - STABILITY SUMMARY

STABILITY CLASS - C - 150 FT WINDS, (OCT) PERIOD 10/1/67 TO 10/31/68
NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	0	0	1	0	0	0	1
NNE	0	0	0	0	0	0	0
NE	0	0	0	0	0	0	0
ENE	0	0	0	0	0	0	0
E	2	0	0	0	0	0	2
ESE	0	0	0	0	0	0	0
SE	0	0	0	0	0	0	0
SSE	1	0	0	0	0	1	2
S	1	0	3	3	0	0	7
SSW	0	2	6	0	0	0	8
SW	2	1	2	2	0	0	7
WSW	1	1	0	0	0	0	2
W	0	3	8	2	1	1	15
WNW	2	1	16	20	13	3	55
NW	0	6	16	13	2	0	37
NNW	1	1	4	3	0	0	9
TOTAL	10	15	56	43	16	5	145

Number of calm hours	2
Number of variable directions	0
Total number of observations	147

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Table I.4-33 (CONTINUED)

POINT BEACH WIND - STABILITY SUMMARY

STABILITY CLASS - D - 150 FT WINDS, (OCT) PERIOD 10/1/67 TO 10/31/68
NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	1	1	5	4	2	1	14
NNE	0	1	0	0	0	0	1
NE	1	0	0	3	1	0	5
ENE	0	0	0	3	0	0	3
E	1	0	0	0	0	0	1
ESE	1	0	0	0	0	0	1
SE	1	0	2	4	1	0	8
SSE	1	2	3	9	13	6	34
S	2	7	27	66	42	22	166
SSW	2	2	20	40	44	12	120
SW	0	4	6	7	4	0	21
WSW	2	1	4	14	7	0	28
W	1	7	13	30	20	19	90
WNW	1	8	35	22	8	3	77
NW	1	8	15	8	0	0	32
NNW	0	11	12	12	6	0	41
TOTAL	15	52	142	222	148	63	642

Number of calm hours	1
Number of variable directions	0
Total number of observations	643

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Table I.4-33 (CONTINUED)

POINT BEACH WIND - STABILITY SUMMARY

STABILITY CLASS - E - 150 FT WINDS, (OCT) PERIOD 10/1/67 TO 10/31/68
NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	0	3	17	18	7	8	53
NNE	1	1	18	6	0	0	26
NE	1	2	9	14	4	0	30
ENE	1	1	1	3	2	0	8
E	2	0	0	0	1	0	3
ESE	1	0	0	2	2	1	6
SE	0	1	0	8	5	2	16
SSE	0	3	3	7	7	0	20
S	0	8	23	8	1	0	40
SSW	0	1	27	75	26	2	131
SW	0	5	17	13	0	0	35
WSW	1	2	4	5	0	0	12
W	0	4	13	13	2	2	34
WNW	0	3	15	2	0	0	20
NW	1	0	11	0	0	0	12
NNW	1	1	12	4	0	0	18
TOTAL	9	35	170	178	57	15	464

Number of calm hours	2
Number of variable directions	0
Total number of observations	466

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Table I.4-33 (CONTINUED)

POINT BEACH WIND - STABILITY SUMMARY

STABILITY CLASS - F - 150 FT WINDS, (OCT) PERIOD 10/1/67 TO 10/31/68
NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	0	0	14	11	4	2	31
NNE	0	0	2	3	0	0	5
NE	0	2	0	1	0	0	3
ENE	0	1	1	0	0	0	2
E	0	2	0	0	0	0	2
ESE	0	1	0	0	0	0	1
SE	0	4	1	0	0	0	5
SSE	0	1	1	1	0	0	3
S	0	2	2	0	1	0	5
SSW	1	0	11	4	0	0	16
SW	0	3	12	2	0	0	17
WSW	2	2	6	2	0	0	12
W	0	0	10	2	0	0	12
WNW	0	0	7	2	0	0	9
NW	1	1	2	0	0	0	4
NNW	0	0	0	0	0	0	0
TOTAL	4	19	69	28	5	2	127

Number of calm hours	0
Number of variable directions	0
Total number of observations	127

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Table I.4-33 (CONTINUED)

POINT BEACH WIND - STABILITY SUMMARY

STABILITY CLASS - G - 150 FT WINDS, (OCT) PERIOD 10/1/67 TO 10/31/68
NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	3	4	0	1	0	0	8
NNE	0	0	1	2	0	0	3
NE	0	0	0	0	0	0	0
ENE	0	0	0	0	0	0	0
E	0	0	0	0	0	0	0
ESE	0	0	0	0	0	0	0
SE	1	3	0	0	0	0	4
SSE	0	0	1	1	0	0	2
S	0	2	1	0	0	0	3
SSW	1	2	4	0	0	0	7
SW	1	5	15	0	0	0	21
WSW	0	0	7	1	0	0	8
W	0	2	5	0	0	0	7
WNW	1	2	5	0	0	0	8
NW	0	3	2	0	0	0	5
NNW	0	0	0	0	0	0	0
TOTAL	7	23	41	5	0	0	76

Number of calm hours	2
Number of variable directions	0
Total number of observations	78

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Table I.4-33 (CONTINUED)

POINT BEACH WIND - STABILITY SUMMARY

STABILITY CLASS -ALL- 150 FT WINDS, (OCT) PERIOD 10/1/67 TO 10/31/68
NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	4	8	37	34	13	11	107
NNE	1	2	21	11	0	0	35
NE	2	4	9	18	5	0	38
ENE	1	2	2	6	2	0	13
E	5	2	0	0	1	0	8
ESE	2	1	0	2	2	1	8
SE	3	8	3	12	6	2	34
SSE	3	6	8	18	20	7	62
S	3	19	56	77	44	22	221
SSW	5	8	69	119	70	14	285
SW	4	18	52	24	4	0	102
WSW	6	6	21	22	7	0	62
W	3	16	49	47	23	22	160
WNW	4	14	82	47	21	6	174
NW	5	18	48	23	3	0	97
NNW	3	14	29	19	6	0	71
TOTAL	54	146	486	479	227	85	1477

Number of calm hours	7
Number of variable directions	0
Total number of observations	1484

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Table I.4-33 (CONTINUED)

POINT BEACH WIND - STABILITY SUMMARY

STABILITY CLASS - A - 150 FT WINDS, (NOV) PERIOD 11/1/67 TO 11/30/68
NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	1	0	0	0	0	0	1
NNE	0	0	0	0	0	0	0
NE	1	0	0	0	0	0	1
ENE	0	0	0	0	0	0	0
E	0	0	0	0	0	0	0
ESE	0	0	0	0	0	0	0
SE	0	0	0	0	0	0	0
SSE	0	0	0	0	0	0	0
S	0	0	0	0	0	0	0
SSW	0	0	0	0	0	0	0
SW	0	0	0	0	0	0	0
WSW	0	1	0	0	0	0	1
W	2	1	0	0	0	0	3
WNW	0	0	0	0	0	0	0
NW	0	0	0	0	0	0	0
NNW	0	0	0	0	0	0	0
TOTAL	4	2	0	0	0	0	6

Number of calm hours	4
Number of variable directions	0
Total number of observations	10

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Table I.4-33 (CONTINUED)

POINT BEACH WIND - STABILITY SUMMARY

STABILITY CLASS - B - 150 FT WINDS, (NOV) PERIOD 11/1/67 TO 11/30/68
NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	1	0	0	0	0	0	1
NNE	0	0	0	0	0	0	0
NE	0	0	0	0	0	0	0
ENE	0	0	0	0	0	0	0
E	0	0	0	0	0	0	0
ESE	0	0	0	0	0	0	0
SE	0	0	0	0	0	0	0
SSE	0	0	0	0	0	0	0
S	0	0	0	0	0	0	0
SSW	0	0	0	0	0	0	0
SW	0	0	0	0	0	0	0
WSW	0	1	0	0	0	0	1
W	1	1	0	0	0	0	2
WNW	0	0	0	0	0	0	0
NW	0	3	0	0	0	0	3
NNW	0	0	0	0	0	0	0
TOTAL	2	5	0	0	0	0	7

Number of calm hours	2
Number of variable directions	0
Total number of observations	9

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Table I.4-33 (CONTINUED)

POINT BEACH WIND - STABILITY SUMMARY

STABILITY CLASS - C - 150 FT WINDS, (NOV) PERIOD 11/1/67 TO 11/30/68
NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	0	2	0	1	0	0	3
NNE	1	0	0	1	0	0	2
NE	2	0	0	0	0	0	2
ENE	0	0	0	0	0	0	0
E	0	0	0	0	0	0	0
ESE	0	0	0	0	0	0	0
SE	0	0	0	0	0	0	0
SSE	0	1	1	0	0	0	2
S	0	1	0	0	0	0	1
SSW	0	0	0	0	0	0	0
SW	1	1	0	0	0	0	2
WSW	0	1	0	0	0	0	1
W	0	1	1	0	0	0	2
WNW	2	4	8	19	5	0	38
NW	2	8	26	27	13	0	76
NNW	2	0	5	1	1	0	9
TOTAL	10	19	41	49	19	0	138

Number of calm hours	2
Number of variable directions	0
Total number of observations	140

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Table I.4-33 (CONTINUED)

POINT BEACH WIND - STABILITY SUMMARY

STABILITY CLASS - D - 150 FT WINDS, (NOV) PERIOD 11/1/67 TO 11/30/68
NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	0	2	22	31	1	1	57
NNE	0	0	1	0	0	0	1
NE	2	0	1	0	0	0	3
ENE	1	0	0	0	0	0	1
E	2	1	0	0	0	2	5
ESE	0	1	1	0	1	0	3
SE	2	0	3	0	0	0	5
SSE	2	2	6	7	0	0	17
S	1	3	10	9	1	0	24
SSW	0	2	5	4	4	1	16
SW	4	5	5	10	1	0	25
WSW	0	4	8	6	4	0	22
W	4	9	9	14	14	8	58
WNW	1	16	36	53	15	6	127
NW	2	4	38	23	5	0	72
NNW	1	1	34	27	10	1	74
TOTAL	22	50	179	184	56	19	510

Number of calm hours	7
Number of variable directions	0
Total number of observations	517

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Table I.4-33 (CONTINUED)

POINT BEACH WIND - STABILITY SUMMARY

STABILITY CLASS - E - 150 FT WINDS, (NOV) PERIOD 11/1/67 TO 11/30/68
NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	0	9	29	45	21	0	104
NNE	0	1	0	5	3	2	11
NE	1	0	1	1	9	5	17
ENE	0	0	1	5	4	3	13
E	1	0	1	2	7	9	20
ESE	1	0	2	1	2	0	6
SE	1	0	3	5	2	0	11
SSE	0	1	2	3	0	0	6
S	1	2	7	0	0	0	10
SSW	0	4	16	21	0	1	42
SW	1	5	21	31	9	0	67
WSW	0	10	10	6	0	1	27
W	3	10	13	25	5	2	58
WNW	1	5	8	5	1	0	20
NW	0	1	6	4	0	0	11
NNW	0	3	14	3	0	0	20
TOTAL	10	51	134	162	63	23	443

Number of calm hours	6
Number of variable directions	0
Total number of observations	449

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Table I.4-33 (CONTINUED)

POINT BEACH WIND - STABILITY SUMMARY

STABILITY CLASS - F - 150 FT WINDS, (NOV) PERIOD 11/1/67 TO 11/30/68
NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	0	3	14	27	23	3	70
NNE	0	0	3	1	3	0	7
NE	0	0	0	0	0	0	0
ENE	0	0	0	0	0	0	0
E	0	0	2	0	0	0	2
ESE	0	0	0	0	0	0	0
SE	0	1	0	0	0	0	1
SSE	0	0	0	1	0	0	1
S	0	2	2	0	0	0	4
SSW	0	1	4	3	0	0	8
SW	0	1	20	2	1	0	24
WSW	1	5	3	0	0	0	9
W	4	1	3	2	0	0	10
WNW	3	0	3	2	0	0	8
NW	1	1	1	0	0	0	3
NNW	0	3	1	0	0	0	4
TOTAL	9	18	56	38	27	3	151

Number of calm hours	1
Number of variable directions	0
Total number of observations	152

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Table I.4-33 (CONTINUED)

POINT BEACH WIND - STABILITY SUMMARY

STABILITY CLASS - G - 150 FT WINDS, (NOV) PERIOD 11/1/67 TO 11/30/68
NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	2	1	2	2	1	0	8
NNE	0	0	0	0	0	0	0
NE	0	0	0	0	0	0	0
ENE	0	0	0	0	0	0	0
E	0	0	0	0	0	0	0
ESE	0	0	0	0	0	0	0
SE	0	1	0	0	0	0	1
SSE	0	0	0	0	0	0	0
S	0	0	0	0	0	0	0
SSW	0	0	0	1	0	0	1
SW	1	7	7	0	0	0	15
WSW	3	0	1	0	0	0	4
W	0	1	0	2	0	0	3
WNW	0	0	0	1	0	0	1
NW	0	0	2	0	0	0	2
NNW	0	0	0	0	0	0	0
TOTAL	6	10	12	6	1	0	35

Number of calm hours	0
Number of variable directions	0
Total number of observations	35

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Table I.4-33 (CONTINUED)

POINT BEACH WIND - STABILITY SUMMARY

STABILITY CLASS -ALL- 150 FT WINDS, (NOV) PERIOD 11/1/67 TO 11/30/68
NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	4	17	67	106	46	4	244
NNE	1	1	4	7	6	2	21
NE	6	0	2	1	9	5	23
ENE	1	0	1	5	4	3	14
E	3	1	3	2	7	11	27
ESE	1	1	3	1	3	0	9
SE	3	2	6	5	2	0	18
SSE	2	4	9	11	0	0	26
S	2	8	19	9	1	0	39
SSW	0	7	25	29	4	2	67
SW	7	19	53	43	11	0	133
WSW	4	22	22	12	4	1	65
W	14	24	26	43	19	10	136
WNW	7	25	55	80	21	6	194
NW	5	17	73	54	18	0	167
NNW	3	7	54	31	11	1	107
TOTAL	63	155	422	439	166	45	1290

Number of calm hours	22
Number of variable directions	0
Total number of observations	1312

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Table I.4-33 (CONTINUED)

POINT BEACH WIND - STABILITY SUMMARY

STABILITY CLASS - A - 150 FT WINDS, (DEC) PERIOD 12/1/67 TO 12/31/68
NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	0	0	0	0	0	0	0
NNE	0	0	0	0	0	0	0
NE	0	0	0	0	0	0	0
ENE	0	0	0	0	0	0	0
E	1	0	0	0	0	0	1
ESE	1	0	0	0	0	0	1
SE	0	0	0	0	0	0	0
SSE	0	0	0	0	0	0	0
S	0	0	0	0	0	0	0
SSW	0	0	0	0	0	0	0
SW	0	0	0	0	0	0	0
WSW	0	0	0	0	0	0	0
W	0	0	0	0	0	0	0
WNW	1	0	0	0	0	0	1
NW	0	0	0	0	0	0	0
NNW	0	0	0	0	0	0	0
TOTAL	3	0	0	0	0	0	3

Number of calm hours	0
Number of variable directions	0
Total number of observations	3

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Table I.4-33 (CONTINUED)

POINT BEACH WIND - STABILITY SUMMARY

STABILITY CLASS - B - 150 FT WINDS, (DEC) PERIOD 12/1/67 TO 12/31/68
NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	0	0	0	0	0	0	0
NNE	0	0	0	0	0	0	0
NE	0	0	0	0	0	0	0
ENE	0	0	0	0	0	0	0
E	0	0	0	0	0	0	0
ESE	0	0	0	0	0	0	0
SE	0	0	0	0	0	0	0
SSE	0	0	0	0	0	0	0
S	0	0	0	0	0	0	0
SSW	0	1	0	0	0	0	1
SW	0	0	0	0	0	0	0
WSW	0	1	0	0	0	0	1
W	0	0	0	0	0	0	0
WNW	0	1	0	0	0	0	1
NW	0	1	0	0	0	0	1
NNW	0	0	0	0	0	0	0
TOTAL	0	4	0	0	0	0	4

Number of calm hours	0
Number of variable directions	0
Total number of observations	4

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Table I.4-33 (CONTINUED)

POINT BEACH WIND - STABILITY SUMMARY

STABILITY CLASS - C - 150 FT WINDS, (DEC) PERIOD 12/1/67 TO 12/31/68
NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	0	0	0	1	0	0	1
NNE	0	0	0	0	0	0	0
NE	0	0	0	0	0	0	0
ENE	0	0	0	0	0	0	0
E	0	0	0	0	0	0	0
ESE	0	0	0	0	0	0	0
SE	0	2	0	0	0	0	2
SSE	1	0	0	0	0	0	1
S	0	0	1	0	0	0	1
SSW	0	0	1	0	0	1	2
SW	0	1	0	1	0	0	2
WSW	0	2	1	0	0	0	3
W	2	1	1	0	2	0	6
WNW	0	3	3	11	9	12	38
NW	0	5	5	39	9	11	69
NNW	0	2	0	1	1	0	4
TOTAL	3	16	12	53	21	24	129

Number of calm hours	0
Number of variable directions	0
Total number of observations	129

Table I.4-33 (CONTINUED)

POINT BEACH WIND - STABILITY SUMMARY

STABILITY CLASS - D - 150 FT WINDS, (DEC) PERIOD 12/1/67 TO 12/31/68
NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	2	1	4	3	5	7	22
NNE	0	3	0	0	0	0	3
NE	0	0	1	0	0	0	1
ENE	0	0	0	0	0	0	0
E	0	0	0	0	0	0	0
ESE	0	0	0	0	0	1	1
SE	0	1	1	0	1	2	5
SSE	0	2	0	1	3	2	8
S	0	0	2	12	9	8	31
SSW	1	3	4	12	17	12	49
SW	2	3	4	3	2	2	16
WSW	0	3	8	2	3	6	22
W	0	7	12	14	6	11	50
WNW	0	2	15	47	11	5	80
NW	2	4	10	38	5	2	61
NNW	0	5	9	18	6	5	43
TOTAL	7	34	70	150	68	63	392

Number of calm hours	0
Number of variable directions	0
Total number of observations	392

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Table I.4-33 (CONTINUED)

POINT BEACH WIND - STABILITY SUMMARY

STABILITY CLASS - E - 150 FT WINDS, (DEC) PERIOD 12/1/67 TO 12/31/68
NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	4	4	19	1	5	13	46
NNE	0	3	1	0	0	4	8
NE	0	1	0	0	0	9	10
ENE	0	0	0	1	4	9	14
E	0	0	2	7	3	9	21
ESE	0	0	3	5	2	4	14
SE	0	0	4	12	8	17	41
SSE	0	1	1	2	4	2	10
S	0	1	0	2	0	0	3
SSW	0	0	5	12	15	5	37
SW	0	4	5	25	10	4	48
WSW	0	3	9	4	3	1	20
W	1	2	9	8	2	7	29
WNW	0	5	2	4	0	0	11
NW	1	2	1	2	1	0	7
NNW	3	1	3	4	0	0	11
TOTAL	9	27	64	89	57	84	330

Number of calm hours	0
Number of variable directions	0
Total number of observations	330

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Table I.4-33 (CONTINUED)

POINT BEACH WIND - STABILITY SUMMARY

STABILITY CLASS - F - 150 FT WINDS, (DEC) PERIOD 12/1/67 TO 12/31/68
NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	1	6	6	1	0	1	15
NNE	0	1	0	0	0	0	1
NE	0	0	0	0	0	0	0
ENE	0	0	0	0	2	1	3
E	0	0	0	1	1	0	2
ESE	0	0	0	0	0	0	0
SE	0	0	0	1	0	0	1
SSE	0	0	3	2	0	0	5
S	0	2	1	0	0	0	3
SSW	0	2	2	0	0	0	4
SW	1	1	2	3	0	0	7
WSW	0	0	2	1	0	0	3
W	0	2	4	1	0	0	7
WNW	0	2	5	4	0	0	11
NW	2	1	3	2	0	0	8
NNW	0	1	1	0	0	0	2
TOTAL	4	18	29	16	3	2	72

Number of calm hours	0
Number of variable directions	0
Total number of observations	72

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Table I.4-33 (CONTINUED)

POINT BEACH WIND - STABILITY SUMMARY

STABILITY CLASS - G - 150 FT WINDS, (DEC) PERIOD 12/1/67 TO 12/31/68
NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	2	0	2	0	0	0	4
NNE	0	0	0	0	0	0	0
NE	0	0	0	0	0	0	0
ENE	0	0	0	0	0	0	0
E	0	0	0	0	0	0	0
ESE	0	0	0	0	0	0	0
SE	0	0	1	0	0	0	1
SSE	0	0	3	0	0	0	3
S	0	1	2	0	0	0	3
SSW	0	0	1	0	0	0	1
SW	0	0	1	0	0	0	1
WSW	0	0	0	0	0	0	0
W	1	0	4	0	0	0	5
WNW	0	0	3	1	0	0	4
NW	0	2	4	5	0	0	11
NNW	0	0	4	0	0	0	4
TOTAL	3	3	25	6	0	0	37

Number of calm hours	0
Number of variable directions	0
Total number of observations	37

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Table I.4-33 (CONTINUED)

POINT BEACH WIND - STABILITY SUMMARY

STABILITY CLASS -ALL- 150 FT WINDS, (DEC) PERIOD 12/1/67 TO 12/31/68
NUMBER OF HOURLY OBSERVATIONS

WIND SPEED (MPH)

WINDS FROM	1-3	4-7	8-12	13-18	19-24	25+	TOTAL
N	9	11	31	6	10	21	88
NNE	0	7	1	0	0	4	12
NE	0	1	1	0	0	9	11
ENE	0	0	0	1	6	10	17
E	1	0	2	8	4	9	24
ESE	1	0	3	5	2	5	16
SE	0	3	6	13	9	19	50
SSE	1	3	7	5	7	4	27
S	0	4	6	14	9	8	41
SSW	1	6	13	24	32	18	94
SW	3	9	12	32	12	6	74
WSW	0	9	20	7	6	7	49
W	4	12	30	23	10	18	97
WNW	1	13	28	67	20	17	146
NW	5	15	23	86	15	13	157
NNW	3	9	17	23	7	5	64
TOTAL	29	102	200	314	149	173	967

Number of calm hours	0
Number of variable directions	0
Total number of observations	967

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Table I.6-1 POINT BEACH NUCLEAR PLANT NEAREST SITE BOUNDARY (METERS)

N	-	Lake:	nearest shoreline	-	300 m;	nearest land	-	4000 m.
NNE	-	Lake:	nearest shoreline	-	200 m;	nearest land	-	>50 miles
NE	-	Lake:	nearest shoreline	-	170 m;	nearest land	-	>50 miles
ENE	-	Lake:	nearest shoreline	-	170 m;	nearest land	-	>50 miles
E	-	Lake:	nearest shoreline	-	170 m;	nearest land	-	>50 miles
ESE	-	Lake:	nearest shoreline	-	210 m;	nearest land	-	>50 miles
SE	-	Lake:	nearest shoreline	-	310 m;	nearest land	-	>50 miles
SSE	-	1300 m;	nearest shoreline	-	1220 m			
S	-	1270 m		-				
SSW	-	1290 m		-				
SW	-	1520 m		-				
WSW	-	1320 m		-				
W	-	1300 m		-				
WNW	-	1630 m		-				
NW	-	2040 m		-				
NNW	-	2010 m;	nearest shoreline	-	830 m;			

Note: The nearest shoreline access points for any individual are as follows, measured from the midpoint of a line connecting the containment centers:

a) Onsite north - at Unit 2 discharge flume, 170 m

b) Onsite south - at Unit 1 discharge flume, 170 m

c) Offsite north - at site boundary, 2010 m

d) Offsite south - at sire boundary, 1500 m

Table I.6-2 POINT BEACH NUCLEAR PLANT DISTANCE TO NEAREST RESIDENCE AND NEAREST VEGETABLE GARDEN IN SEARCH SECTOR[1]

Sector	Distance (meters)
N	4840
NNE	Lake
NE	Lake
ENE	Lake
E	Lake
ESE	Lake
SE	Lake
SSE	1930
S	2920
SSW	1460
SW	1980
WSW	2240
W	2190
WNW	1250 (onsite) [2]; 2240 (offsite)
NW	2920
NNW	1980, (onsite) [2]; 2660 (offsite)

Notes:

1. It is assumed that every residence (farm or non-farm) has the potential for having a vegetable garden. Distances are scaled from topographic maps and buildings were located by visual automobile survey. Accuracy is estimated to be within 100 meters.

2. There are 3 onsite residences leased to plant employees, one in the WNW sector and two in the NNW sector. Onsite residents are assumed to have vegetable gardens but do not have milk or meat producing animals. (These residences were later demolished or abandoned.)

Table I.6-3 POINT BEACH NUCLEAR PLANT DISTANCE TO NEAREST MILK COW, MEAT ANIMAL AND MILK GOAT IN EACH SECTOR[1]

Sector	Distance (meters)
N	none
NNE	Lake
NE	Lake
ENE	Lake
E	Lake
ESE	Lake
SE	Lake
SSE	1300 (site boundary)
S	1270 (site boundary)
SSW	2130
SW	1720
WSW	1320 (site boundary)
W	1300 (site boundary)
WNW	2340
NW	2400
NNW	2010 (site boundary)

Notes:

1. Since the PBNP area land use is predominantly agricultural, the distance to the nearest milk cow, milk goat, and meat animal is assumed to be the distance to the nearest practicing farm having a dwelling and a barn. However, it is assumed that land surrounding the site, owned by the Licensee and leased to local farmers, is unlikely to be used for pasture.

Table I.6-4 POINT BEACH NUCLEAR PLANT CONTAINMENT PURGE SUMMARY [1]
1/1/74 TO 2/29/76

Unit 1

Date	Condition	Start Time	Duration
3/5/74	At Power	0957	3 hrs.
4/14/74	Shutdown	0035	16 days
5/1/74	Shutdown	(Continued)	17 days
1/13/75	At Power	1615	3 hrs.
1/26/75	Shutdown	2310	5 days
2/28/75	Shutdown	1650	30 days
4/2/75	Shutdown	1830	2 days
5/21/75	At Power	1115	2 hrs.
6/6/75	At Power	0355	5 hrs.
6/11/75	At Power	0415	5 hrs.
6/12/75	At Power	0400	10 hrs.
6/28/75	Shutdown	0640	6 hrs.
8/13/75	At Power	2045	4 hrs.
9/26/75	At Power	0443	3 hrs.
9/17/75	At Power	2315	7 hrs.
9/17/75	At Power	0427	3 hrs.
11/20/75	Shutdown	1243	44 days
1/13/76	At Power	2135	3 hrs.
2/19/76	At Power	1040	22 hrs.
2/20/76	At Power	1150	7 hrs.

Table I.6-4 (CONTINUED)

POINT BEACH NUCLEAR PLANT CONTAINMENT PURGE SUMMARY [1]

1/1/74 TO 2/29/76

Unit 2

10/22/74	Shutdown	0935	50 days
2/21/75	Shutdown	0045	6 hrs.
4/19/75	Shutdown	0110	4 hrs.
5/10/75	Shutdown	0305	3 hrs.
7/20/75	Shutdown	0212	13 hrs.
8/13/75	Shutdown	0257	4 days
2/19/76	At Power	1545	22 hrs.
2/27/76	Shutdown	0307	23 days

Note:

1. Average purge duration at power (1/1/74 - 3/1/76) = 7 hours

Table I.6-5 POINT BEACH NUCLEAR PLANT GAS DECAY TANK RELEASES (1974-1975)

Date	GDT# [3]	Start	Stop	Time (min)	Ci	ft^3	%Kr-85 [1]
2/6/74	D	1736	1145	1089	28.15	3544	19.9%
2/18/74	B	0900	0007 [2]	743	10.89	3628	44.4%
10/22/74	C	1559	2220	261	4.23	3607	98.6%
1/26/75	B	0954	1410	256	24.52	3393	25.2%
2/8/75	C	1632	0450	738	11.19	3696	38.1%
3/29/75	B	1440	2215	455	6.19	3376	80.4%
4/18/75	D	0730	0815				
		1042	1820	503	3.28	2807	89.6%
5/12/75	C	1155	0355	240	3.62	3000	99.7%
5/29/75	B	1335	1505	90	14.50	200	33.9%
7/14/75	C	1150	2100	550	5.13	3393	64.1%
8/11/75	D	1605	1435	1350	2.54	3178	96.7%
9/9/75	C	1102	1115	12	0.154	173	97.0%
11/5/75	C	1628	1900	152	3.43	2357	100.0%
		1920	2055	95		857	
11/18/75	B	1845	0655	730	2.79	3625	97.8%

Notes:

1. Principally Xe-133 and Kr-85 with minor amounts of Xe-131 and Xe-133m
2. There were several start/stops during this period
3. Gas decay tank number

Table I.7 -1POINT BEACH NUCLEAR PLANT CALCULATED TOTAL ANNUAL GASEOUS RELEASES (Ci/yr)

	AUXILIARY BUILDING VENT*			UNIT 1 CONTAINMENT PURGE VENT		UNIT 2 CONTAINMENT PURGE VENT			TURBINE BUILDING ROOF EXHAUST	
Isotope	Auxiliary Building Ventilation	Gas Decay Tank Effluent	Unit 1 and Unit 2 Condenser Air Ejectors	Unit 1 Containment Purge	Unit 1 Continuous Containment Ventilation	Unit 2 Containment Purge	Unit 2 Continuous Containment Ventilation	Gas Stripper Building Ventilation	Turbine Building Ventilation	Total Annual Releases
Ar-41	-	-	-	2.5E+01	-	2.5E+01	-	-	-	5.0E+01
Kr-83m	7.2E-01	-	3.2E-01	5.4E-02	8.2E-03	5.4E-02	8.2E-03	2.3E-02	1.23-04	1.2E+00
Kr-85m	3.0E+00	-	1.6E+00	4.1E-01	8.4E-02	4.1E-01	8.4E-02	1.1E-01	5.0E-04	5.7E+00
Kr-85	2.6E+00	7.2E+01	1.6E+00	1.7E+01	2.5E+00	1.7E+01	2.5E+00	2.3E+00	4.2E-04	1.2E+02
Kr-87	2.2E+00	-	8.0E-01	1.3E-01	1.7E-02	1.3E-01	1.7E-02	6.6E-02	3.4E-04	3.4E+00
Kr-88	6.4E+00	-	3.1E+00	6.3E-01	1.1E-01	6.3E-01	1.1E-01	2.2E-01	1.0E-03	1.1E+01
Kr-89	2.0E-01	-	2.5E-07	9.8E-04	6.8E-05	9.8E-04	6.8E-05	4.0E-03	3.4E-05	2.1E-01
Xe-131m	1.8E-01	-	1.1E-01	7.3E-01	1.3E-01	7.3E-01	1.3E-01	4.0E-02	3.0E-05	2.1E+00
Xe-133m	1.4E+00	-	8.3E-01	1.6E+00	3.4E-01	1.6E+00	3.4E-01	1.2E-01	2.2E-04	6.2E+00
Xe-133	5.6E+01	3.1E+01	3.4E+01	1.4E+02	2.8E+01	1.4E+02	2.8E+01	9.2E+00	8.8E-03	4.7E+02
Xe-135m	5.6E-01	-	2.2E-02	1.0E-02	8.4E-04	1.0E-02	8.4E-04	1.2E-02	8.6E-05	6.2E-01
Xe-135	7.2E+00	-	4.3E+00	1.7E+00	4.0E-01	1.7E+00	4.0E-01	3.1E-01	1.2E-03	1.6E+01
Xe-137	3.8E-01	-	4.7E-06	2.1E-03	1.5E-04	2.1E-03	1.5E-04	7.7E-03	6.0E-05	3.9E-01
Xe-138	1.8E+00	-	6.1E-02	3.3E-02	2.7E-03	3.3E-02	2.7E-03	3.9E-02	2.8E-04	2.0E+00
I-131	7.4E-02	-	4.6E-02	3.1E-03	5.7E-04	3.1E-03	5.7E-04	-	3.0E-03	1.3E-01
I-133	1.0E-01	-	6.4E-02	4.9E-04	1.7E-04	6.9E-04	1.7E-04	-	4.2E-03	1.7E-01
Co-58	1.2E-03	-	-	7.5E-04	-	7.5E-04	-	-	-	2.7E-03
Co-60	5.4E-04	-	-	3.4E-04	-	3.4E-04	-	-	-	1.2E-03

Table I.7-1 (CONTINUED)
POINT BEACH NUCLEAR PLANT CALCULATED TOTAL ANNUAL GASEOUS RELEASES (Ci/yr)

	AUXILIARY BUILDING VENT*			UNIT 1 CONTAINMENT PURGE VENT		UNIT 2 CONTAINMENT PURGE VENT			TURBINE BUILDING ROOF EXHAUST	
Isotope	Auxiliary Building Ventilation	Gas Decay Tank Effluent	Unit 1 and Unit 2 Condenser Air Ejectors	Unit 1 Containment Purge	Unit 1 Continuous Containment Ventilation	Unit 2 Containment Purge	Unit 2 Continuous Containment Ventilation	Gas Stripper Building Ventilation	Turbine Building Ventilation	Total Annual Releases
Mn-54	3.6E-04	-	-	2.2E-04	-	2.2E-04	-	-	-	8.0E-04
Fe-59	1.2E-04	-	-	7.5E-05	-	7.5E-05	-	-	-	2.7E-04
Sr-89	2.6E-05	-	-	1.7E-05	-	1.7E-05	-	-	-	6.0E-05
Sr-90	4.0E-06	-	-	3.0E-06	-	3.0E-06	-	-	-	1.0E-05
Cs-134	3.6E-04	-	-	2.2E-04	-	2.2E-04	-	-	-	8.0E-04
Cs-137	6.0E-04	-	-	3.8E-04	-	3.8E-04	-	-	-	1.4E-03
C-14	1.6E+01	-	-	-	-	-	-	-	-	1.6E+01
H-3	7.7E+01	-	-	2.65E+02	-	2.65E+02	-	-	-	6.1E+02
Total Noble Gases	8.3E+01	1.0E+02	4.7E+01	1.9E+02	3.2E+01	1.9E+02	3.2E+01	1.2E+01	1.3E-02	6.9E+02
Total Iodines	1.7E-01	-	1.1E-01	3.8E-03	7.4E-04	3.8E-03	7.4E-04	-	7.2E-03	3.0E-01
Total Particulates	2.3E-03	-	-	2.0E-03	-	2.0E-03	-	-	-	7.2E-03

<*>.Unit 1 and 2 Auxiliary Building Ventilation Releases Include Drumming Area Vent Releases Since Exit Velocities and Locations are Essentially Identical.

Table I.7-2 POINT BEACH NUCLEAR PLANT TOTAL LIQUID RELEASES PER PALNT - CALCULATED(1)

Isotope	Radioactivity (μCi/gm)	Annual Release (Ci)
H-3	2.7E-03	6.1E+02
Kr-85		
Kr-85m		
Kr-87		
Xe-131m		
Xe-133		
Xe-133m		
Xe-135		
Xe-138		
I-130	6.6E-12	3.8E-03
I-131	9.4E-10	5.4E-01
I-132	2.0E-10	1.2E-01
I-133	1.3E-09	7.6E-01
I-134	3.5E-11	2.0E-02
I-135	4.9E-10	2.8E-01
Na-24		
Cr-51	8.7E-12	5.0E-03
Mn-54	2.0E-12	1.1E-03
Fe-55	8.0E-12	4.6E-03
Fe-59	5.9E-12	3.4E-03
Co-57		
Co-58	8.0E-11	4.6E-02
Co-60	8.7E-12	5.0E-03
Br-83	7.7E-12	4.4E-03
Br-84	1.2E-12	7.0E-04
Br-85	2.0E-14	1.1E-05
Rb-86	4.2E-13	2.4E-04
Rb-88	5.9E-11	3.4E-02

Sheet 1 of 3

Table I.7-2 (CONTINUED)
POINT BEACH NUCLEAR PLANT TOTAL LIQUID RELEASES
PER PALNT - CALCULATED(1)

Isotope	Radioactivity (µCi/gm)	Annual Release (Ci)
Sr-89	2.0E-12	1.1E-03
Sr-90	3.8E-14	2.2E-05
Sr-91	5.2E-13	3.0E-04
Y-90	3.8E-14	2.2E-05
Y-91m	3.0E-13	1.7E-04
Y-91	8.7E-12	5.0E-03
Y-93	2.1E-13	1.2E-04
Zr-95	3.8E-13	2.2E-04
Nb-95	3.8E-13	2.2E-04
Mo-99	7.0E-10	4.0E-01
Tc-99m	6.3E-10	3.6E-01
Ru-103	2.0E-13	1.1E-04
Ru-106	3.8E-14	2.2E-05
Rh-103m	2.0E-13	1.1E-04
Rh-106	3.8E-14	2.2E-05
Cd-109		
Ag-110m		
Sb-124		
Sb-125		
Te-125m	5.9E-14	3.4E-05
Te-127m	9.8E-13	5.6E-04
Te-127	3.1E-12	1.8E-03
Te-129m	5.9E-12	3.4E-03
Te-129	5.9E-12	3.4E-03
Te-131m	1.0E-11	5.8E-03
Te-131	2.0E-12	1.1E-03
Te-132	1.0E-10	5.8E-02
Cs-134	1.1E-10	6.4E-02

Sheet 2 of 3

Table I.7-2 (CONTINUED)
POINT BEACH NUCLEAR PLANT TOTAL LIQUID RELEASES
PER PALNT - CALCULATED[1]

Isotope	Radioactivity (μCi/gm)	Annual Release (Ci)
Cs-136	6.3E-11	3.6E-02
Cs-137	9.1E-11	5.2E-02
Cs-138		
Ba-137m	8.7E-11	5.0E-02
Ba-140	9.8E-13	5.6E-04
La-140	7.0E-13	4.0E-04
Ce-141	3.8E-13	2.2E-04
Ce-143	1.0E-13	5.8E-05
Ce-144	2.0E-13	1.1E-04
Pr-143	2.0E-13	1.1E-04
Pr-144	2.0E-13	1.1E-04
Bi-207		
Th-232		
Np-239	5.9E-12	3.4E-03
Total Calculated Release	5.0E-09	2.9E+00
Anticipated Operational Occurrences	5.2E-10	3.0E-01
Total (Excluding Tritium)	5.5E-09	3.2E+00

1. Isotope Releases of less than 1.E-10 curies/year are set to 0.0.
2. Anticipated operational occurrences 3.00E-01 curies are added to calculated releases and assumed to have the same isotopic distribution for dose calculations.

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Table I.7-3 POINT BEACH NUCLEAR PLANT CALCULATED ANNUAL RELEASES BY SOURCE (Ci/yr)

Isotope	Steam Generator Blowdown, Ea. Unit	Lab. Drains Per Plant	Sampling Drains Per Unit	Laundry and Shower Drains Per Plant	Containment Sump Drains Ea. Unit	Aux. Bldg. Floor Drains Per Plant	Misc. Waste Per Plant	Turb. Bldg. Floor Drains, Ea. Unit	Secondary Side Sampling Per Plant	Reactor Coolant Letdown Each Unit	Reactor Coolant Leakage Each Unit
Br-83	2.2E-03	4.5E-09	2.0E-07	0.0	2.3E-07	2.3E-07	7.8E-08	0.0	0.0	0.0	0.0
Br-84	3.5E-04	6.1E-12	2.5E-10	0.0	2.9E-10	2.9E-10	1.0E-10	0.0	0.0	0.0	0.0
Br-85	5.6E-06	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
I-130	1.9E-03	2.6E-08	1.2E-06	0.0	1.3E-06	1.3E-06	4.6E-07	0.0	0.0	1.0E-09	7.3E-10
I-131	2.7E-01	1.5E-05	6.2E-04	3.5E-08	7.3E-04	7.2E-04	2.5E-04	2.0E-04	3.0E-05	2.6E-04	1.8E-04
I-132	5.8E-02	1.3E-06	5.8E-05	0.0	6.6E-05	5.5E-05	2.3E-05	4.9E-08	7.5E-09	6.4E-07	4.5E-07
I-133	3.8E-01	7.7E-06	3.5E-04	0.0	4.0E-04	4.0E-04	1.4E-04	1.4E-13	2.6E-14	2.5E-06	1.8E-06
I-134	9.9E-03	1.8E-09	7.7E-08	0.0	8.8E-08	8.8E-08	3.0E-08	0.0	0.0	0.0	0.0
I-135	1.4E-01	1.1E-06	4.7E-04	0.0	5.4E-05	5.4E-05	1.9E-05	0.0	0.0	5.4E-10	3.8E-10
Rb-86	1.2E-04	5.2E-09	2.3E-07	0.0	2.6E-07	2.6E-07	9.1E-08	3.8E-08	5.9E-09	9.9E-08	1.3E-08
Rb-88	1.7E-02	2.5E-12	1.1E-10	0.0	1.3E-10	1.3E-10	4.4E-11	0.0	0.0	0.0	0.0
Cs-134	3.2E-02	1.6E-06	7.2E-05	8.7E-07	8.3E-05	8.3E-05	2.9E-05	3.0E-05	4.7E-06	6.4E-05	8.6E-06
Cs-136	1.8E-02	8.3E-07	3.5E-05	0.0	4.0E-05	4.0E-05	1.4E-05	3.5E-06	5.4E-07	1.1E-05	1.6E-06
Cs-137	2.6E-02	1.2E-06	5.3E-05	1.6E-06	6.1E-05	6.1E-05	2.1E-05	2.5E-05	3.9E-06	4.7E-05	6.5E-06
Cr-51	2.5E-03	1.1E-07	4.8E-06	0.0	5.5E-06	5.5E-06	1.9E-06	1.2E-06	1.8E-07	5.2E-07	3.7E-07
Mn-54	5.6E-04	1.9E-08	8.2E-07	6.8E-08	9.4E-07	9.4E-07	3.2E-07	5.1E-07	7.8E-08	1.5E-07	1.0E-07
Fe-55	2.3E-03	9.4E-08	4.2E-06	0.0	4.8E-06	4.8E-06	1.7E-06	2.3E-06	3.5E-07	7.6E-07	5.3E-07
Fe-59	1.7E-03	6.1E-08	2.6E-06	0.0	3.0E-06	3.0E-06	1.0E-06	1.1E-06	1.7E-07	3.3E-07	2.3E-07
Co-58	2.3E-02	9.4E-07	4.1E-05	2.6E-07	4.7E-05	4.7E-05	1.6E-05	1.7E-05	2.6E-06	5.8E-06	4.1E-06
Co-60	2.5E-03	1.3E-07	5.3E-06	6.0E-07	6.1E-06	6.1E-06	2.1E-06	2.5E-06	3.8E-07	9.9E-07	6.9E-07
Sr-89	5.7E-04	2.1E-08	9.1E-07	0.0	1.0E-06	1.0E-06	3.6E-07	3.7E-08	5.7E-09	1.2E-07	8.6E-08

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Table I.7-3 (CONTINUED) POINT BEACH NUCLEAR PLANT CALCULATED ANNUAL RELEASES BY SOURCE (Ci/yr)

Isotope	Steam Generator Blowdown, Ea. Unit	Lab. Drains Per Plant	Sampling Drains Per Unit	Laundry and Shower Drains Per Plant	Containment Sump Drains Ea. Unit	Aux. Bldg. Floor Drains Per Plant	Misc. Waste Per Plant	Turb. Bldg. Floor Drains, Ea. Unit	Secondary Side Sampling Per Plant	Reactor Coolant Letdown Each Unit	Reactor Coolant Leakage Each Unit
Sr-90	1.1E-05	6.1E-10	2.6E-08	0.0	3.0E-08	3.0E-08	1.1E-08	1.1E-08	1.7E-09	4.8E-09	3.4E-09
Sr-91	1.5E-04	6.1E-09	2.6E-07	0.0	3.0E-07	3.0E-07	1.0E-07	0.0	0.0	5.0E-12	3.5E-12
Y-90	1.1E-05	8.8E-10	3.8E-08	0.0	4.4E-08	4.4E-08	1.5E-09	1.1E-08	1.7E-09	5.0E-09	3.5E-09
Y-91m	8.4E-05	4.0E-09	1.8E-07	0.0	2.0E-07	2.0E-07	7.0E-08	0.0	0.0	3.4E-12	2.4E-12
Y-91	2.5E-03	1.2E-07	5.3E-06	0.0	6.1E-06	6.1E-06	2.1E-06	1.8E-06	2.7E-07	7.6E-07	5.3E-07
Y-93	5.8E-05	1.3E-09	5.8E-08	0.0	6.6E-08	6.6E-08	2.3E-08	0.0	0.0	1.7E-12	1.2E-12
Zr-95	1.1E-04	3.6E-09	1.6E-07	9.3E-08	1.8E-07	1.8E-07	6.3E-08	7.8E-08	1.2E-08	2.3E-08	1.6E-08
Nb-95	1.1E-04	3.0E-09	1.3E-07	1.3E-07	1.5E-07	1.5E-07	5.5E-08	9.8E-08	1.5E-08	2.4E-08	1.7E-08
Mo-99	2.0E-01	1.9E-05	8.2E-04	0.0	9.4E-04	9.4E-04	3.2E-04	9.8E-08	1.5E-08	7.6E-06	5.3E-06
Tc-99m	1.8E-01	1.8E-05	7.7E-04	0.0	8.8E-04	8.8E-04	3.0E-04	9.8E-08	1.5E-08	7.6E-06	5.3E-06
Ru-103	5.7E-05	2.6E-09	1.2E-07	9.3E-09	1.3E-07	1.3E-07	4.6E-08	3.3E-08	5.1E-09	1.4E-08	9.8E-09
Ru-106	1.1E-05	6.1E-10	2.6E-08	1.6E-07	3.0E-08	3.0E-08	1.0E-08	9.8E-09	1.5E-09	4.6E-09	3.2E-09
Rh-103m	5.7E-05	2.6E-09	1.2E-07	8.7E-09	1.3E-07	1.3E-07	4.6E-08	3.2E-08	5.0E-09	1.4E-08	9.8E-09
Rh-106	1.1E-05	6.1E-10	2.6E-08	1.6E-07	3.0E-08	3.0E-08	1.0E-08	9.8E-09	1.5E-09	4.6E-09	3.2E-09
Te-125m	1.7E-05	1.7E-09	7.7E-08	0.0	8.8E-08	8.8E-08	3.0E-08	1.2E-08	1.8E-09	1.0E-08	7.3E-09
Te-127m	2.8E-04	1.7E-08	7.2E-07	0.0	8.3E-07	8.3E-07	2.9E-07	2.3E-07	3.5E-08	1.2E-07	8.2E-08
Te-127	8.7E-04	2.2E-08	9.6E-07	0.0	1.1E-06	1.1E-06	3.8E-07	2.3E-07	3.5E-08	1.1E-07	7.8E-08
Te-129m	1.7E-03	8.3E-08	3.7E-06	0.0	4.2E-06	4.2E-06	1.5E-06	8.9E-07	1.4E-07	4.3E-07	3.0E-07
Te-129	1.7E-03	5.4E-08	2.4E-06	0.0	2.7E-06	2.7E-06	9.3E-07	5.7E-07	8.7E-08	2.7E-07	1.9E-07
Te-131m	2.9E-03	7.2E-08	3.1E-06	0.0	3.5E-06	3.5E-06	1.2E-06	1.7E-13	2.6E-14	6.4E-09	4.5E-09
Te-131	5.6E-04	1.3E-08	5.8E-07	0.0	6.6E-07	6.6E-07	2.3E-07	3.0E-14	4.7E-15	1.2E-09	8.2E-10

Sheet 2 of 3

Table I.7-3 (CONTINUED) POINT BEACH NUCLEAR PLANT CALCULATED ANNUAL RELEASES BY SOURCE (Ci/yr)

Isotope	Steam Generator Blowdown, Ea. Unit	Lab. Drains Per Plant	Sampling Drains Per Unit	Laundry and Shower Drains Per Plant	Containment Sump Drains Ea. Unit	Aux. Bldg. Floor Drains Per Plant	Misc. Waste Per Plant	Turb. Bldg. Floor Drains, Ea. Unit	Secondary Side Sampling Per Plant	Reactor Coolant Letdown Each Unit	Reactor Coolant Leakage Each Unit
Te-132	2.9E-02	1.2E-06	5.3E-05	0.0	6.1E-05	6.1E-05	2.1E-05	4.7E-08	7.2E-09	6.4E-07	4.5E-07
Ba-137m	2.5E-02	1.1E-06	4.8E-05	1.5E-06	5.5E-05	5.5E-05	1.9E-05	2.5E-05	3.8E-06	4.4E-05	6.1E-06
Ba-140	2.8E-04	1.2E-08	5.3E-07	0.0	6.1E-07	6.1E-07	2.1E-07	5.4E-08	8.3E-09	3.3E-08	5.7E-08
La-140	2.0E-04	1.1E-08	4.8E-07	0.0	5.4E-07	5.4E-07	1.9E-07	6.2E-08	9.5E-09	3.8E-08	2.7E-08
Ce-141	1.1E-04	4.1E-09	1.8E-07	0.0	2.0E-07	2.0E-07	7.0E-08	5.7E-08	8.7E-09	2.0E-08	1.4E-08
Ce-143	2.9E-05	1.2E-09	5.3E-08	0.0	6.1E-08	6.1E-08	2.1E-08	7.7E-15	1.2E-15	1.3E-10	9.4E-11
Ce-144	5.6E-05	2.0E-09	8.6E-08	3.3E-07	9.9E-08	9.9E-08	3.4E-08	5.1E-08	7.8E-09	1.5E-08	1.0E-08
Pr-143	5.7E-05	3.0E-09	1.3E-07	0.0	1.5E-07	1.5E-07	5.1E-08	1.3E-08	2.0E-09	8.7E-09	6.1E-09
Pr-144	5.6E-05	2.0E-09	8.6E-08	3.3E-07	9.9E-08	9.9E-08	3.4E-08	5.1E-08	7.8E-09	1.5E-08	1.0E-08
Np-239	1.7E-03	4.6E-08	2.0E-06	0.0	2.3E-06	2.3E-06	8.0E-07	2.5E-10	3.8E-11	1.5E-08	1.0E-08
Total	1.44E+00	6.99E-05	3.43E-03	6.15E-06	3.45E-03	3.45E-03	1.19E-03	3.13E-04	4.74E-05	4.56E-04	2.24E-04

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Table I.7-4 POINT BEACH NUCLEAR PLANT AIRBORNE RELEASES (1974-1975) (Ci/yr)

Isotope	1974	1975	Annual Average
H-3	4.28E+01	1.77E+02	1.10E+02
Ar-41	3.20E+01	4.16E+02	2.24E+02
Kr-85	2.31E+01	4.48E+01	3.40E+01
Kr-85m	3.74E+02	2.48E+03	1.43E+03
Kr-87	2.51E+02	1.79E+03	1.02E+03
Kr-88	5.42E+02	3.35E+03	1.95E+03
Xe-131m	4.10E+02	8.56E-01	2.05E+02
Xe-133	6.04E+03	1.99E+04	1.30E+04
Xe-133m	1.33E+02	3.18E+02	2.26E+02
Xe-135	1.30E+03	1.05E+04	5.90E+03
Xe-135m	3.22E+02	2.68E+03	1.50E+03
Xe-138	3.21E+02	2.97E+03	1.65E+03
I-131	5.31E-02	2.35E-02	3.83E-02
I-132	4.71E-08	1.52E-01	7.60E-02
I-133	3.84E-02	1.04E-02	2.44E-02
I-134	<MDA	8.76E-04	4.38E-04
I-135	<MDA	5.58E-04	2.79E-04
F-18	6.68E-06	<MDA	3.34E-06
Na-24	3.16E-05	5.47E-06	1.85E-05
Mn-54	<MDA	4.66E-05	2.33E-05
Co-57	<MDA	5.50E-07	2.75E-07
Co-58	3.79E-03	1.13E-03	2.46E-03
Co-60	1.50E-03	2.81E-03	2.16E-03
Rb-88	9.15E-04	4.95E-03	2.93E-03
Zr-95	<MDA	1.49E-10	7.50E-11
Nb-95	3.19E-04	1.69E-04	2.44E-04
Mo-99	<MDA	3.28E-03	1.64E-03
Ru-103	<MDA	2.73E-05	1.37E-05
Cd-109	<MDA	1.95E-08	9.75E-09
Cs-134	<MDA	4.08E-05	2.04E-05

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Table I.7-4 (CONTINUED)
POINT BEACH NUCLEAR PLANT AIRBORNE RELEASES (1974-1975) (Ci/yr)

Isotope	1974	1975	Annual Average
Cs-136	<MDA	7.00E-06	3.50E-06
Cs-137	2.32E-04	1.38E-03	8.06E-04
Cs-138	1.41E-04	3.55E-02	1.78E-02
Ce-141	<MDA	1.29E-05	6.45E-06
Ce-144	<MDA	1.11E-04	5.55E-05

SUMMARY OF AIRBORNE RELEASES:

	Tritium	Noble Gases	Iodines	Particulate
1974	4.28E+01	9.75E+03	9.15E-02	6.93E-03
1975	1.77E+02	4.43E+04	1.87E-01	4.95E-02
Average	1.10E+02	2.70E+04	1.39E-01	2.82E-02

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Table I.7-5 POINT BEACH NUCLEAR PLANT OBSERVED MONTHLY GASEOUS RELEASES BY RELEASE POINT

PBNP AIRBORNE RELEASE SUMMARY FOR JANUARY, 1974

Unit 1 - 2 Maintenance Shutdowns; 0.3 Day Total Outage

Unit 2 - No Shutdowns

Isotope	Unit 1 Air Ej.	Unit 2 Air Ej.	Aux. Bldg. Vent	Unit 1 Contain.	Unit 2 Contain.	Turb. Bldg.	Dr. Area Vent
H-3			8.14E-01	1.03E-02	1.20E-02		3.70E-01
F-18							
Ar-41			7.00E-01	1.10E-04	1.30E-03		
Kr-85			5.80E-01	4.70E-02	7.00E-03		
Kr-85m			6.05E+01	1.25E-01	1.40E-02		
Kr-87			3.72E+01	2.40E-02	7.00E-03		
Kr-88			8.72E+01	1.13E-01	5.70E-02		
Xe-131m							
Xe-133			6.15E+02	4.61E+00	6.25E+00		6.60E+01
Xe-133m			1.28E+01	8.30E-02	1.14E-01		
Xe-135			2.52E+02	9.33E-01	6.46E-01		
Xe-135m			3.95E+01	3.00E-03	1.00E-03		
Xe-138			5.70E+01	5.00E-03	1.00E-03		
I-131			1.40E-04	7.35E-10			
I-132							
I-133			4.70E-04				
I-134							
I-135							
Na-24					6.00E-09		
Mn-54							
Co-57							
Co-58							4.12E-04
Co-60			1.90E-06	2.20E-08			4.58E-05
Rb-88							
Zr-95							
Nb-95							
Mo-99							
Ru-103							
Ru-106							
Cd-109							
Cs-134							
Cs-136							
Cs-137							
Cs-138							
Ce-141							
Ce-144							

Sheet 1 of 24

Table I.7-5 (CONTINUED)- POINT BEACH NUCLEAR PLANT OBSERVED MONTHLY GASEOUS RELEASES BY RELEASE POINT

PBNP AIRBORNE RELEASE SUMMARY FOR FEBRUARY, 1974

Unit 1 - 0.2 Day Shutdown for Maintenance

Unit 2 - No Shutdowns

Isotope	Unit 1 Air Ej.	Unit 2 Air Ej.	Aux. Bldg. Vent	Unit 1 Contain.	Unit 2 Contain.	Turb. Bldg.	Dr. Area Vent
H-3			7.35E-01	1.48E-02	1.06E-02		3.41E-01
F-18							
Ar-41			2.00E+00		4.80E-05		
Kr-85			1.13E+01	6.10E-02			
Kr-85m			6.80E+01	1.31E-01	7.60E-04		
Kr-87			4.20E+01	2.60E-02	1.20E-04		
Kr-88			9.40E+01	1.14E-01	1.20E-03		
Xe-131m			1.37E+02	1.11E+00	7.70E-03		
Xe-133			8.21E+02	6.19E+00	6.40E-02		2.35E-01
Xe-133m			1.40E+01	1.05E-01	1.40E-03		
Xe-135			2.82E+02	9.97E-01	8.20E-03		
Xe-135m			4.80E+01	9.00E-03	1.60E-05		
Xe-138			6.30E+01	9.00E-03	1.60E-05		
I-131			2.90E-04				
I-132							
I-133			4.58E-03				
I-134							
I-135							
Na-24					6.00E-06		
Mn-54							
Co-57							
Co-58							2.34E-04
Co-60			5.61E-06				2.60E-05
Rb-88							
Zr-95							
Nb-95							
Mo-99							
Ru-103							
Ru-106							
Cd-109							
Cs-134							
Cs-136							
Cs-137							
Cs-138							
Ce-141							
Ce-144							

Sheet 2 of 24

Table I.7-5 (CONTINUED)- POINT BEACH NUCLEAR PLANT OBSERVED MONTHLY GASEOUS RELEASES BY RELEASE POINT

PBNP AIRBORNE RELEASE SUMMARY FOR MARCH, 1974

Unit 1 - No Shutdowns
Unit 2 - No Shutdowns

Isotope	Unit 1 Air Ej.	Unit 2 Air Ej.	Aux. Bldg. Vent	Unit 1 Contain.	Unit 2 Contain.	Turb. Bldg.	Dr. Area Vent
H-3			1.65E+00	5.09E-02	1.31E-02	4.32E+00	1.21E-01
F-18							
Ar-41			1.21E+00	3.60E-03	4.80E-05		
Kr-85			5.10E-01	1.20E-01	4.63E-04		
Kr-85m			4.55E+01	2.76E-01	8.68E-04		
Kr-87			3.06E+01	5.55E-02	1.54E-04		
Kr-88			6.60E+01	2.55E-01	7.17E-04		
Xe-131m			1.00E+02	2.59E+00	8.75E-03		
Xe-133			4.61E+02	1.05E+01	7.39E-02		
Xe-133m			8.40E+00	1.81E-01	1.25E-03		
Xe-135			2.13E+02	2.33E+00	1.03E-02		
Xe-135m			4.18E+01	9.80E-03	2.10E-05		
Xe-138			4.41E+01	1.84E-01	2.10E-05		
I-131			8.03E-04		1.82E-09		
I-132							
I-133			3.56E-03				
I-134							
I-135							
Na-24					8.00E-09		
Mn-54							
Co-57							
Co-58							8.51E-05
Co-60							9.46E-06
Rb-88			7.01E-04	9.88E-06			
Zr-95							
Nb-95							
Mo-99							
Ru-103							
Ru-106							
Cd-109							
Cs-134							
Cs-136							
Cs-137							
Cs-138			1.05E-04	4.30E-06			
Ce-141							
Ce-144							

Sheet 3 of 24

Table I.7-5 (CONTINUED)- POINT BEACH NUCLEAR PLANT OBSERVED MONTHLY GASEOUS RELEASES BY RELEASE POINT

PBNP AIRBORNE RELEASE SUMMARY FOR APRIL, 1974

Unit 1 - Commence First 24 Days of Refueling Outage
Unit 2 - No Shutdowns

Isotope	Unit 1 Air Ej.	Unit 2 Air Ej.	Aux. Bldg. Vent	Unit 1 Contain.	Unit 2 Contain.	Turb. Bldg.	Dr. Area Vent
H-3			1.65E+00	5.23E+00	1.50E-02	4.32E+00	2.11E-01
F-18							
Ar-41			6.20E-01	4.00E-04	1.00E-03		
Kr-85			3.10E-01	1.40E-02			
Kr-85m			2.09E+01	2.30E-02	4.90E-02		
Kr-87			1.60E+01	4.00E-03	6.00E-03		
Kr-88			3.14E+01	2.10E-02	4.90E-02		
Xe-131m			4.86E+01	4.48E+01	4.47E-01		
Xe-133			3.38E+02	4.27E+02	4.75E+00		3.35E-01
Xe-133m			6.20E+00	1.04E+01	7.20E-02		
Xe-135			1.13E+02	1.72E+00	6.51E-01		
Xe-135m			2.15E+01	1.00E-03	2.00E-03		
Xe-138			1.85E+01	2.00E-03	6.00E-03		
I-131			3.3E-02	1.50E-05	3.46E-09		1.59E-04
I-132							
I-133			5.56E-04				
I-134							
I-135							
Na-24					9.70E-09		
Mn-54							
Co-57							
Co-58				1.58E-06			1.80E-03
Co-60				1.78E-07			1.20E-04
Rb-88				1.98E-04			
Zr-95							
Nb-95							
Mo-99							
Ru-103							
Ru-106							
Cd-109							
Cs-134							
Cs-136							
Cs-137							
Cs-138				3.20E-05			
Ce-141							
Ce-144							

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Table I.7-5 (CONTINUED)- POINT BEACH NUCLEAR PLANT OBSERVED MONTHLY GASEOUS RELEASES BY RELEASE POINT

PBNP AIRBORNE RELEASE SUMMARY FOR MAY, 1974

Unit 1 - 26 Days of Refueling Outage; 5 Days Turbine Repair Outage

Unit 2 - No Shutdowns

Isotope	Unit 1 Air Ej.	Unit 2 Air Ej.	Aux. Bldg. Vent	Unit 1 Contain.	Unit 2 Contain.	Turb. Bldg.	Dr. Area Vent
H-3			5.92E-01	3.13E+00	1.64E-02	2.34E+00	2.14E-01
F-18					1.91E-09		
Ar-41			3.30E-01		1.00E-04		
Kr-85			4.20E-01		4.40E-03		
Kr-85m			3.22E+00		8.00E-04		
Kr-87			1.90E+00		1.00E-04		
Kr-88			3.92E+00		6.00E-04		
Xe-131m			1.80E+01		1.16E-02		
Xe-133			7.62E+01	3.16E+01	7.80E-02		
Xe-133m			1.25E+00		1.20E-03		
Xe-135			1.67E+01		8.00E-03		
Xe-135m			2.67E+00		1.00E-04		
Xe-138			1.39E+00		1.00E-04		
I-131			6.17E-04	4.39E-06	1.34E-10		5.95E-04
I-132							
I-133							
I-134							
I-135							
Na-24					6.53E-09		
Mn-54							
Co-57							
Co-58				2.50E-06			1.04E-04
Co-60				2.70E-07			6.80E-05
Rb-88				1.98E-04			
Zr-95							
Nb-95							
Mo-99							
Ru-103							
Ru-106							
Cd-109							
Cs-134							
Cs-136							
Cs-137			2.32E-04				
Cs-138							
Ce-141							
Ce-144							

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Table I.7-5 (CONTINUED)- POINT BEACH NUCLEAR PLANT OBSERVED MONTHLY GASEOUS RELEASES BY RELEASE POINT

PBNP AIRBORNE RELEASE SUMMARY FOR JUNE, 1974

Unit 1 - 7 Days Outage for Turbine Repair; 0.4 Day Outage for Turbine Balancing
Unit 2 - No Shutdowns

Isotope	Unit 1 Air Ej.	Unit 2 Air Ej.	Aux. Bldg. Vent	Unit 1 Contain.	Unit 2 Contain.	Turb. Bldg.	Dr. Area Vent
H-3			2.71E+00	3.00E-03	2.30E-02	1.10E-01	2.35E-01
F-18					1.39E-08		
Ar-41			4.21E+00	6.00E-03			
Kr-85			1.10E-01	1.33E-02			
Kr-85m			1.51E+01	4.52E-02	7.00E-04		
Kr-87			6.67E+00	5.30E-03	1.00E-04		
Kr-88			1.90E+01	3.73E-02	6.00E-04		
Xe-131m			4.32E+01	3.51E-01	5.11E-02		
Xe-133			1.64E+02	1.77E+00	7.78E-02		
Xe-133m			4.21E+00	4.52E-02	1.40E-03		
Xe-135			7.09E+01	3.81E-01	7.30E-03		
Xe-135m			1.90E+01	3.00E-03	1.00E-04		
Xe-138			4.91E+00	1.00E-03			
I-131			2.24E-03	1.90E-08	9.50E-11		1.41E-04
I-132							
I-133			1.96E-02				
I-134							
I-135							
Na-24					4.76E-08		
Mn-54							
Co-57							
Co-58			8.26E-04	7.10E-06			
Co-60			1.71E-03	7.70E-06			9.90E-05
Rb-88							
Zr-95							
Nb-95							
Mo-99							
Ru-103							
Ru-106							
Cd-109							
Cs-134							
Cs-136							
Cs-137							
Cs-138							
Ce-141							
Ce-144							

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Table I.7-5 (CONTINUED)- POINT BEACH NUCLEAR PLANT OBSERVED MONTHLY GASEOUS RELEASES BY RELEASE POINT

PBNP AIRBORNE RELEASE SUMMARY FOR JULY, 1974

Unit 1 - No Shutdowns
Unit 2 - 3.7 Day Outage for Maintenance

Isotope	Unit 1 Air Ej.	Unit 2 Air Ej.	Aux. Bldg. Vent	Unit 1 Contain.	Unit 2 Contain.	Turb. Bldg.	Dr. Area Vent
H-3			1.99E+00	4.83E-03	1.93E-02	6.10E-02	9.40E-02
F-18					1.76E-08		
Ar-41			1.70E+00	1.09E-01	4.00E-05		
Kr-85			1.10E-01	6.80E-03	1.00E-04		
Kr-85m			9.09E+00	1.38E-01	1.10E-03		
Kr-87			7.67E+00	2.73E-02	3.00E-04		
Kr-88			1.08E+01	1.09E-01	9.00E-04		
Xe-131m			1.51E+01	9.84E-01	2.70E-03		
Xe-133			1.76E+02	1.11E+01	9.08E-02		1.89E-01
Xe-133m			3.12E+00	1.78E-01	1.50E-03		
Xe-135			4.86E+01	1.34E+00	1.19E-02		
Xe-135m			7.67E+00	6.80E-03	6.00E-05		
Xe-138			4.26E+00	4.00E-03	4.00E-05		
I-131			6.22E-04	4.16E-09	1.21E-10		6.39E-05
I-132							
I-133			1.92E-03				
I-134							
I-135							
Na-24					6.03E-08		
Mn-54							
Co-57							
Co-58			6.80E-04	6.24E-09			
Co-60			6.80E-04				
Rb-88							
Zr-95							
Nb-95			2.99E-04				
Mo-99							
Ru-103							
Ru-106							
Cd-109							
Cs-134							
Cs-136							
Cs-137							
Cs-138							
Ce-141							
Ce-144							

Sheet 7 of 24

Table I.7-5 (CONTINUED)- POINT BEACH NUCLEAR PLANT OBSERVED MONTHLY GASEOUS RELEASES BY RELEASE POINT

PBNP AIRBORNE RELEASE SUMMARY FOR AUGUST, 1974

Unit 1 - 0.7 Day Outage for Testing & Maintenance
Unit 2 - No Shutdowns

Isotope	Unit 1 Air Ej.	Unit 2 Air Ej.	Aux. Bldg. Vent	Unit 1 Contain.	Unit 2 Contain.	Turb. Bldg.	Dr. Area Vent
H-3	3.44E-01		5.46E-01	6.04E-03	1.25E-02	8.67E-02	1.36E-01
F-18					5.68E-06		
Ar-41	1.66E-03		3.90E-01	5.20E-03	1.00E-04		
Kr-85							
Kr-85m	1.82E-01		4.26E+00	1.87E-01	1.20E-03		
Kr-87	1.77E-01		4.13E+00	5.37E-02	3.00E-04		
Kr-88	2.43E-01		5.68E+00	1.61E-01	8.00E-04		
Xe-131m							
Xe-133	3.62E+00		8.46E+01	1.49E+01	1.48E-01		1.73E+00
Xe-133m	6.08E-02		1.42E+00	2.30E-01	3.60E-03		
Xe-135	9.57E-01		2.23E+01	1.79E+00	1.47E-02		
Xe-135m	1.66E-01		3.88E+00	1.04E-02	1.00E-04		
Xe-138	1.11E-01		2.58E+00	6.90E-03	1.00E-04		
I-131			2.32E-04	7.73E-07	1.14E-08		2.80E-04
I-132							
I-133			8.84E-05				1.12E-04
I-134							
I-135							
Na-24					1.95E-05		
Mn-54							
Co-57							
Co-58			3.93E-05	4.45E-07			
Co-60			3.93E-05				1.56E-04
Rb-88							
Zr-95							
Nb-95			1.73E-05				
Mo-99							
Ru-103							
Ru-106							
Cd-109							
Cs-134							
Cs-136							
Cs-137							
Cs-138							
Ce-141							
Ce-144							

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Table I.7-5 (CONTINUED)- POINT BEACH NUCLEAR PLANT OBSERVED MONTHLY GASEOUS RELEASES BY RELEASE POINT

PBNP AIRBORNE RELEASE SUMMARY FOR SEPTEMBER, 1974

Unit 1 - No Shutdowns

Unit 2 - No Shutdowns

Isotope	Unit 1 Air Ej.	Unit 2 Air Ej.	Aux. Bldg. Vent	Unit 1 Contain.	Unit 2 Contain.	Turb. Bldg.	Dr. Area Vent
H-3			4.04E-01	5.28E-03		8.39E-02	3.66E-01
F-18					9.58E-07		
Ar-41			5.50E-01	1.30E-03	1.00E-04		
Kr-85							
Kr-85m			5.82E+00	3.43E-02	8.00E-04		
Kr-87			3.64E+00	6.30E-03	2.00E-04		
Kr-88			7.64E+00	2.86E-02	8.00E-04		
Xe-131m							
Xe-133			1.16E+02	2.77E+00	7.64E-02		
Xe-133m			4.36E+00	9.79E-02	1.20E-03		
Xe-135			3.64E+01	3.93E-01	8.50E-03		
Xe-135m			5.09E+00	1.70E-03	3.00E-05		
Xe-138			2.91E+00	1.00E-03	3.00E-05		
I-131			6.80E-05	4.20E-08	1.29E-09	4.91E-03	
I-132							
I-133			5.45E-09		4.14E-10		
I-134							
I-135							
Na-24					5.91E-06		
Mn-54							
Co-57							
Co-58			6.99E-06	1.48E-08			
Co-60			6.99E-06			1.56E-05	
Rb-88					5.38E-06		
Zr-95							
Nb-95			3.07E-06				
Mo-99							
Ru-103							
Ru-106							
Cd-109							
Cs-134							
Cs-136							
Cs-137							
Cs-138							
Ce-141							
Ce-144							

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Table I.7-5 (CONTINUED)- POINT BEACH NUCLEAR PLANT OBSERVED MONTHLY GASEOUS RELEASES BY RELEASE POINT

PBNP AIRBORNE RELEASE SUMMARY FOR OCTOBER, 1974

Unit 1 - 2 Day Outage for Testing & Maintenance
Unit 2 - Refueling & Maintenance Outage; 15 Days

Isotope	Unit 1 Air Ej.	Unit 2 Air Ej.	Aux. Bldg. Vent	Unit 1 Contain.	Unit 2 Contain.	Turb. Bldg.	Dr. Area Vent
H-3			5.06E-01	5.31E-03		1.64E-09	8.00E-02
F-18							
Ar-41	3.20E-03		1.53E+00	3.20E-03	3.70E-02		
Kr-85	4.60E-04		2.18E-01	4.20E-03			
Kr-85m	2.90E-02		1.38E+01	6.48E-02	1.85E-01		
Kr-87	1.86E-02		8.87E+00	1.21E-02	4.93E-02		
Kr-88	3.90E-02		1.86E+01	5.59E-02	1.63E-01		
Xe-131m							
Xe-133	5.00E-01		2.36E+02	4.53E+00	2.01E+01		4.79E-02
Xe-133m	7.87E-03		3.74E+00	6.48E-02	4.28E-01		
Xe-135	1.28E-01		6.10E+01	5.29E-01	1.93E+00		
Xe-135m	2.30E-02		1.09E+01	3.20E-03	9.21E-03		
Xe-138	1.80E-02		8.54E+00	2.60E-03	7.66E-03		
I-131			4.72E-03	2.16E-08	5.48E-07		1.58E-06
I-132					3.83E-09		
I-133			1.50E-03		2.72E-06		
I-134							
I-135							
Na-24							
Mn-54							
Co-57							
Co-58				3.19E-08			
Co-60							5.94E-06
Rb-88				1.98E-04			
Zr-95							
Nb-95							
Mo-99							
Ru-103							
Ru-106							
Cd-109							
Cs-134							
Cs-136							
Cs-137							
Cs-138							
Ce-141							
Ce-144							

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Table I.7-5 (CONTINUED)- POINT BEACH NUCLEAR PLANT OBSERVED MONTHLY GASEOUS RELEASES BY RELEASE POINT

PBNP AIRBORNE RELEASE SUMMARY FOR NOVEMBER, 1974

Unit 1 - 2.0 Day Outage for Chemistry Adjustment in Steam Generator

Unit 2 - Refueling & Maintenance Outage; Entire Month

Isotope	Unit 1 Air Ej.	Unit 2 Air Ej.	Aux. Bldg. Vent	Unit 1 Contain.	Unit 2 Contain.	Turb. Bldg.	Dr. Area Vent
H-3	2.44E-01		4.91E+00	5.21E-03		1.64E-09	1.97E+00
F-18							
Ar-41	2.90E-02		2.40E+00	8.90E-04	7.40E-02		
Kr-85							
Kr-85m	3.74E-01		3.13E+01	2.83E-02	3.70E-01		
Kr-87	2.93E-01		2.46E+01	6.50E-03	9.90E-02		
Kr-88	4.87E-01		4.08E+01	2.37E-02	3.26E-01		
Xe-131m							
Xe-133	5.86E+00		4.91E+02	1.82E+00	4.02E+01		4.02E-01
Xe-133m	3.82E-01		3.20E+01	1.08E-01	9.64E-01		
Xe-135	1.78E+00		1.49E+02	2.48E-01	3.86E+00		
Xe-135m	2.60E-01		2.18E+01	1.00E-03	1.80E-02		
Xe-138	2.20E-01		1.84E+01	1.00E-03	1.50E-02		
I-131			2.47E-04		1.07E-07		3.05E-05
I-132					4.33E-08		
I-133			1.94E-04				
I-134							
I-135							
Na-24							
Mn-54							
Co-57							
Co-58			1.50E-04	1.95E-08	8.56E-08		1.51E-05
Co-60					1.24E-07		
Rb-88							
Zr-95							
Nb-95							
Mo-99							
Ru-103							
Ru-106							
Cd-109							
Cs-134							
Cs-136							
Cs-137							
Cs-138							
Ce-141							
Ce-144							

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Table I.7-5 (CONTINUED)- POINT BEACH NUCLEAR PLANT OBSERVED MONTHLY GASEOUS RELEASES BY RELEASE POINT

PBNP AIRBORNE RELEASE SUMMARY FOR DECEMBER, 1974

Unit 1 - No Shutdowns

Unit 2 - 21 Day Outage for Refueling & Maintenance; 2 Shutdowns for Testing & Turbine Balancing (0.3 Day Additional Outage)

Isotope	Unit 1 Air Ej.	Unit 2 Air Ej.	Aux. Bldg. Vent	Unit 1 Contain.	Unit 2 Contain.	Turb. Bldg.	Dr. Area Vent
H-3	7.70E-01			5.31E-03	5.31E-04		9.77E-01
F-18							
Ar-41	3.90E-02		1.60E+01	1.50E-03	7.39E-02		
Kr-85	7.24E-03		3.00E+00	3.89E-03	6.85E-02		
Kr-85m	2.34E-01		9.41E+01	5.16E-02	1.99E-01		
Kr-87	1.6E-01		6.55E+01	1.04E-02	4.97E-01		
Kr-88	3.84E-01		1.54E+02	5.41E-02	1.83E-01		
Xe-131m							
Xe-133	4.45E+00		1.79E+03	4.07E+00	2.05E+01		6.02E-01
Xe-133m	6.08E-02		2.70E+01	5.50E-02	5.20E-01		
Xe-135	1.41E+00		5.68E+02	5.74E-01	2.07E+00		2.41E+00
Xe-135m	2.46E-01		9.90E+01	3.26E-03	1.00E-02		
Xe-138	2.36E-01		9.50E+01	3.51E-03	8.57E-03		
I-131			1.82E-03	1.92E-07	3.90E-06		1.82E-03
I-132							
I-133			5.73E-03	1.01E-08	2.29E-06		3.20E-06
I-134							
I-135							
Na-24							
Mn-54							
Co-57							
Co-58			1.27E-04	1.36E-06	3.36E-06		9.01E-05
Co-60					4.46E-06		8.32E-05
Rb-88							
Zr-95							
Nb-95							
Mo-99							
Ru-103							
Ru-106							
Cd-109							
Cs-134							
Cs-136							
Cs-137							
Cs-138							
Ce-141							
Ce-144							

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Table I.7-5 (CONTINUED)- POINT BEACH NUCLEAR PLANT OBSERVED MONTHLY GASEOUS RELEASES BY RELEASE POINT

PBNP AIRBORNE RELEASE SUMMARY FOR JANUARY, 1975

Unit 1 - 18 Day Outage for Sludge Lancing & Maintenance

Unit 2 - No Shutdowns

Isotope	Unit 1 Air Ej.	Unit 2 Air Ej.	Aux. Bldg. Vent	Unit 1 Contain.	Unit 2 Contain.	Turb. Bldg.	Dr. Area Vent
H-3	1.37E-01			2.84E-03			2.14E-01
F-18							
Ar-41	9.25E-03		4.24E+01	9.16E-03	3.04E-02		
Kr-85	8.93E-04		4.09E+00	5.19E-03	3.26E-02		
Kr-85m	4.73E-02		2.17E+02	5.13E-01	2.10E-02		
Kr-87	3.82E-02		1.75E+02	1.29E-01	3.73E-03		
Kr-88	7.45E-02		3.41E+02	5.50E-01	1.97E-02		
Xe-131m							
Xe-133	5.72E-01		2.62E+03	3.83E+01	2.06E+00		
Xe-133m	9.14E-03		4.19E+01	5.92E-03	5.11E-04		
Xe-135	2.73E-01		1.25E+03	5.75E+00	2.43E-01		
Xe-135m	5.21E-02		2.39E+02	2.25E+00	5.76E-02		
Xe-138	5.40E-02		2.47E+02	4.18E-02	1.21E-03		
I-131			6.91E-03	8.81E-06	2.16E-07		1.84E-04
I-132			4.61E-05		1.80E-08		
I-133			1.56E-03	6.66E-09	1.65E-07		
I-134					3.57E-08		
I-135					6.12E-08		
Na-24							
Mn-54							1.66E-05
Co-57							
Co-58			1.70E-04	4.25E-07	1.66E-08		2.56E-06
Co-60				6.74E-07	3.12E-08		7.12E-06
Rb-88							
Zr-95							
Nb-95							3.30E-06
Mo-99							
Ru-103							5.86E-06
Ru-106							
Cd-109							
Cs-134							
Cs-136							
Cs-137							
Cs-138							
Ce-141							
Ce-144							

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Table I.7-5 (CONTINUED)- POINT BEACH NUCLEAR PLANT OBSERVED MONTHLY GASEOUS RELEASES BY RELEASE POINT

PBNP AIRBORNE RELEASE SUMMARY FOR FEBRUARY, 1975

Unit 1 - 5 Day Shutdown for Steam Generator Tube Repair & CRD Maintenance
Unit 2 - 2 Shutdowns for Maintenance & Valve Lineup (Total 3.4 Day Outage)

Isotope	Unit 1 Air Ej.	Unit 2 Air Ej.	Aux. Bldg. Vent	Unit 1 Contain.	Unit 2 Contain.	Turb. Bldg.	Dr. Area Vent
H-3				8.33E-03	1.06E-01		
F-18							
Ar-41	2.04E-01		6.30E+01	3.70E-03	1.12E-01		
Kr-85							
Kr-85m	1.16E+00		3.56E+02	9.03E-02	9.86E-02		
Kr-87	7.64E-01		2.36E+02	2.18E-02	9.66E-02		
Kr-88	1.53E+00		4.56E+02	6.68E-02	8.07E-02		
Xe-131m							
Xe-133	9.74E+00		3.01E+03	2.58E+00	1.29E+01		2.67E+01
Xe-133m	1.80E-01		5.55E+01	6.60E-04	5.20E-03		
Xe-135	4.87E+00		1.50E+03	6.08E-01	8.04E-01		
Xe-135m	1.80E+00		3.33E+02	2.83E-01	3.01E-01		
Xe-138	1.53E+00		4.71E+02	7.27E-03	5.13E-03		
I-131			3.62E-03	3.58E-07	1.30E-05		1.47E-04
I-132			2.47E-05		4.10E-06		
I-133			1.41E-03	2.59E-07	1.05E-05		
I-134					1.30E-10		
I-135					1.19E-05		
Na-24					5.47E-06		
Mn-54							
Co-57							
Co-58				2.31E-08	9.02E-07		4.15E-06
Co-60					1.21E-06		1.15E-05
Rb-88							
Zr-95							
Nb-95							5.35E-06
Mo-99					1.75E-06		
Ru-103							9.50E-06
Ru-106							
Cd-109							
Cs-134					1.30E-10		
Cs-136							
Cs-137					1.16E-06		
Cs-138							
Ce-141							
Ce-144							

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Table I.7-5 (CONTINUED)- POINT BEACH NUCLEAR PLANT OBSERVED MONTHLY GASEOUS RELEASES BY RELEASE POINT

PBNP AIRBORNE RELEASE SUMMARY FOR MARCH, 1975

Unit 1 - Outage for Steam Generator Tube Repair & Maintenance Continued Through Entire Month

Unit 2 - No Shutdowns

Isotope	Unit 1 Air Ej.	Unit 2 Air Ej.	Aux. Bldg. Vent	Unit 1 Contain.	Unit 2 Contain.	Turb. Bldg.	Dr. Area Vent
H-3			2.34E-01	7.62E-03			
F-18							
Ar-41			4.93E+01	1.42E-02			
Kr-85							
Kr-85m			2.18E+01	2.03E-02			
Kr-87			1.16E+01	3.15E-03			
Kr-88			2.70E+01	1.62E-02			
Xe-131m							
Xe-133			7.97E+02	2.39E+00			5.46E+01
Xe-133m			7.68E+00	4.25E-04			
Xe-135			1.25E+02	1.91E-01			
Xe-135m			1.47E+02	5.10E-01			
Xe-138			1.71E+01	1.07E-03			
I-131			4.81E-03	1.51E-08			1.69E-03
I-132			1.50E-01				
I-133			2.53E-04	1.18E-09			
I-134							
I-135							
Na-24							
Mn-54							
Co-57							
Co-58			1.43E-04				1.37E-05
Co-60							
Rb-88							
Zr-95							
Nb-95				6.20E-09			7.16E-06
Mo-99							
Ru-103							
Ru-106							
Cd-109							
Cs-134							
Cs-136							
Cs-137				2.32E-09			
Cs-138							
Ce-141							
Ce-144			1.74E-05				

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Table I.7-5 (CONTINUED)- POINT BEACH NUCLEAR PLANT OBSERVED MONTHLY GASEOUS RELEASES BY RELEASE POINT

PBNP AIRBORNE RELEASE SUMMARY FOR APRIL, 1975

Unit 1 - 4 Day Outage for Steam Generator Tube Repair & CRD Maintenance
Unit 2 - 1.1 Day Outage for Chemistry Adjustment

Isotope	Unit 1 Air Ej.	Unit 2 Air Ej.	Aux. Bldg. Vent	Unit 1 Contain.	Unit 2 Contain.	Turb. Bldg.	Dr. Area Vent
H-3	4.96E+01	<MDA	4.76E-01	2.53E-03	7.61E-03		6.41E-04
F-18							
Ar-41	1.38E-02		1.34E+01	4.43E-03	3.32E-03		
Kr-85							
Kr-85m	2.19E-01		2.13E+02	3.32E-01	8.04E-03		
Kr-87	1.58E-01		1.54E+02	7.00E-02	1.59E-03		
Kr-88	2.90E-01		2.82E+02	2.84E-01	6.70E-03		
Xe-131m							
Xe-133	2.18E+00		2.13E+03	1.19E+01	1.48E+00		2.80E+00
Xe-133m	5.16E-02		5.03E+01	4.47E-03	2.77E-04		
Xe-135	1.12E+00		1.09E+03	3.12E+00	8.83E-02		
Xe-135m	1.82E-01		1.77E+02	1.03E+00	2.29E-02		
Xe-138	2.36E-01		2.30E+02	2.43E-02	4.75E-04		
I-131			6.80E-04	1.43E-09	1.14E-06		6.48E-05
I-132			6.41E-04		2.34E-07		
I-133			1.96E-05		2.79E-07		
I-134							
I-135							
Na-24							
Mn-54							
Co-57							
Co-58			3.82E-05	1.85E-07			
Co-60							
Rb-88							
Zr-95							
Nb-95					3.29E-05		
Mo-99							
Ru-103							1.19E-05
Ru-106							
Cd-109							
Cs-134							
Cs-136							
Cs-137					1.23E-05		
Cs-138							
Ce-141							1.15E-05
Ce-144			9.38E-05				

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Table I.7-5 (CONTINUED)- POINT BEACH NUCLEAR PLANT OBSERVED MONTHLY GASEOUS RELEASES BY RELEASE POINT

PBNP AIRBORNE RELEASE SUMMARY FOR MAY, 1975

Unit 1 - No Shutdown

Unit 2 - 2 Shutdowns for Maintenance; Total 3.4 Day Outage

Isotope	Unit 1 Air Ej.	Unit 2 Air Ej.	Aux. Bldg. Vent	Unit 1 Contain.	Unit 2 Contain.	Turb. Bldg.	Dr. Area Vent
H-3	<MDA		7.08E-01	2.38E-02	4.88E-02	1.38E-10	1.63E-01
F-18							
Ar-41	5.93E-03		8.44E+00	7.15E-03	3.35E-03		
Kr-85							
Kr-85m	2.11E-01		3.01E+02	1.21E+00	2.01E-02		
Kr-87	1.51E-01		2.15E+02	2.54E-01	2.87E-03		
Kr-88	2.83E-01		4.02E+02	1.05E+00	1.33E-02		
Xe-131m							
Xe-133	2.77E+00		3.95E+03	6.25E+01	2.13E+00		
Xe-133m	3.66E-02		5.21E+01	1.24E-02	3.74E-04		
Xe-135	1.04E+00		1.48E+03	1.10E+01	1.71E-01		
Xe-135m	2.42E-01		3.44E+02	5.16E+00	7.60E-02		
Xe-138	2.05E-01		2.92E+02	7.77E-02	1.61E-03		
I-131			3.52E-04		1.33E-08		2.96E-06
I-132							
I-133			1.81E-04				1.61E-05
I-134							
I-135							
Na-24							
Mn-54				3.62E-10			1.31E-05
Co-57							
Co-58				5.07E-10			1.41E-05
Co-60			1.80E-04				2.95E-05
Rb-88				2.48E-06			
Zr-95							
Nb-95				6.92E-10			4.98E-06
Mo-99							
Ru-103					1.82E-07		
Ru-106							
Cd-109					2.72E-09		
Cs-134							
Cs-136							
Cs-137							
Cs-138			1.87E-04				
Ce-141							
Ce-144							

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Table I.7-5 (CONTINUED)- POINT BEACH NUCLEAR PLANT OBSERVED MONTHLY GASEOUS RELEASES BY RELEASE POINT

PBNP AIRBORNE RELEASE SUMMARY FOR JUNE, 1975

Unit 1 - 1.2 Day Outage for Personnel, Licensing & Maintenance

Unit 2 - 0.7 Day Outage for Maintenance

Isotope	Unit 1 Air Ej.	Unit 2 Air Ej.	Aux. Bldg. Vent	Unit 1 Contain.	Unit 2 Contain.	Turb. Bldg.	Dr. Area Vent
H-3	4.14E-02	<MDA	7.32E-01	1.84E-02	3.17E-03	1.63E-09	1.43E-01
F-18							
Ar-41	2.03E-02		2.00E+01	1.16E-01	2.63E-03		
Kr-85							
Kr-85m	3.10E-01		3.06E+02	6.94E+02	9.30E-03		
Kr-87	2.68E-01		2.65E+02	1.77E+00	1.77E-03		
Kr-88	4.48E-01		4.42E+02	6.44E+00	7.85E-03		
Xe-131m							
Xe-133	2.94E+00		2.90E+03	2.44E+02	1.19E+00		1.04E+03
Xe-133m	4.55E-02		4.49E+01	5.76E-02	1.90E-04		1.38E+01
Xe-135	1.39E+00		1.37E+03	5.66E+01	9.58E-02		7.44E+00
Xe-135m	3.13E-01		3.09E+02	2.66E+01	2.10E-02		
Xe-138	4.85E-01		4.78E+02	7.41E-01	5.87E-04		
I-131			3.18E-04	3.72E-06			7.96E-06
I-132							
I-133			3.54E-04	2.31E-06			
I-134							
I-135							
Na-24							8.52E-07
Mn-54							
Co-57							
Co-58				7.20E-11			1.04E-06
Co-60			1.78E-05	3.94E-07			2.24E-06
Rb-88			3.94E-05	4.75E-03			
Zr-95					1.49E-10		
Nb-95				2.25E-08			3.21E-07
Mo-99							
Ru-103							
Ru-106							
Cd-109							
Cs-134							
Cs-136							
Cs-137							
Cs-138			1.83E-04				
Ce-141							
Ce-144							

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Table I.7-5 (CONTINUED)- POINT BEACH NUCLEAR PLANT OBSERVED MONTHLY GASEOUS RELEASES BY RELEASE POINT

PBNP AIRBORNE RELEASE SUMMARY FOR JULY, 1975

Unit 1 - No Shutdowns

Unit 2 - 1.8 Day Maintenance Outage

Isotope	Combined Air Ej.	Aux. Bldg. Vent	Unit 1 Contain.	Unit 2 Contain.	Turb. Bldg.	Dr. Area Vent	Gas. Str. Bldg.
H-3	2.88E-05	1.01E+00	7.79E-03	1.30E-02	1.54E-01	1.75E+01	
F-18							
Ar-41	1.49E-02	5.37E+01	4.01E-04	1.60E-03			6.26E-02
Kr-85							
Kr-85m	1.21E-01	3.33E+02	7.84E-03	7.16E-03			3.88E-01
Kr-87	6.10E-02	2.43E+02	1.71E-03	1.22E-03			2.83E-01
Kr-88	1.56E-01	4.67E+02	6.94E-03	5.81E-03			5.44E-01
Xe-131m							
Xe-133	3.06E-01	7.95E+02	4.89E-01	5.05E+00			9.27E-01
Xe-133m	5.56E-03	1.48E+01	2.13E-03	2.67E-02			1.73E-02
Xe-135	4.49E-01	1.15E+03	5.45E-02	7.26E-02		1.56E+01	1.34E+00
Xe-135m	1.17E-02	3.76E+02	4.67E-04	3.66E-04			4.38E-01
Xe-138	1.49E-02	3.48E+02	6.43E-04	5.07E-04			4.06E-01
I-131		2.15E-04	1.14E-10	2.20E-05		1.07E-05	
I-132							
I-133		1.67E-04		9.07E-05		1.20E-05	
I-134							
I-135							
Na-24							
Mn-54						1.49E-058	
Co-57							
Co-58						1.01E-05	
Co-60		2.57E-03	6.49E-07			3.28E-05	
Rb-88							
Zr-95							
Nb-95				9.84E-05		1.20E-05	
Mo-99		3.28E-03					
Ru-103							
Ru-106							
Cd-109							
Cs-134							
Cs-136							
Cs-137		1.23E-03				1.25E-05	
Cs-138							
Ce-141							
Ce-144							

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Table I.7-5 (CONTINUED)- POINT BEACH NUCLEAR PLANT OBSERVED MONTHLY GASEOUS RELEASES BY RELEASE POINT

PBNP AIRBORNE RELEASE SUMMARY FOR AUGUST, 1975

Unit 1 - No Shutdowns

Unit 2 - 8.2 Days Shutdown for S. G. Tube Plugging & Minor Maint.

Isotope	Combined Air Ej.	Aux. Bldg. Vent	Unit 1 Contain.	Unit 2 Contain.	Turb. Bldg.	Dr. Area Vent	Gas. Str. Bldg.
H-3	1.05E-05	9.07E-01	3.12E-02	3.63E-03	4.18E-02	1.81E-01	
F-18							
Ar-41	7.80E-03	1.97E+01	1.35E-02	1.33E-02			1.50E-01
Kr-85							
Kr-85m	8.52E-02	1.65E+02	3.21E-01	2.53E-02			1.25E+00
Kr-87	3.86E-02	1.20E+02	6.93E-02	4.94E-03			9.08E-01
Kr-88	1.05E-01	2.27E+02	2.90E-01	2.19E-02			1.72E+00
Xe-131m							
Xe-133	2.84E-01	4.56E+02	2.12E+01	3.68E+00			3.46E+00
Xe-133m	5.24E-03	8.51E+00	1.09E-01	6.01E-02			6.47E-02
Xe-135	3.23E-01	5.67E+02	2.25E+00	1.73E-01			4.30E+00
Xe-135m	4.36E-03	1.76E+02	1.74E-02	1.80E-03			1.34E+00
Xe-138	7.89E-03	2.25E+02	2.24E-02	1.28E-03			1.71E+00
I-131		6.48E-04		1.33E-06		7.18E-05	
I-132							
I-133		6.77E-04				1.61E-06	
I-134							
I-135							
Na-24							
Mn-54						1.12E-06	
Co-57							
Co-58		5.94E-08	1.23E-08	9.50E-08		6.38E-06	
Co-60			1.75E-09	8.58E-10		1.12E-05	
Rb-88							
Zr-95							
Nb-95							
Mo-99							
Ru-103							
Ru-106							
Cd-109							
Cs-134							
Cs-136							
Cs-137							
Cs-138		1.29E-06					
Ce-141							
Ce-144							

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Table I.7-5 (CONTINUED)- POINT BEACH NUCLEAR PLANT OBSERVED MONTHLY GASEOUS RELEASES BY RELEASE POINT

PBNP AIRBORNE RELEASE SUMMARY FOR SEPTEMBER, 1975

Unit 1 - No Shutdowns

Unit 2 - No Shutdowns

Isotope	Combined Air Ej.	Aux. Bldg. Vent	Unit 1 Contain.	Unit 2 Contain.	Turb. Bldg.	Dr. Area Vent	Gas. Str. Bldg.
H-3		9.15E-01	2.34E-02	1.98E-03		1.60E-01	
F-18							
Ar-41	2.42E-03	4.64E+01	2.95E-02	1.47E-02			2.08E-01
Kr-85							
Kr-85m	1.69E-02	2.46E+02	6.77E-01	1.28E-02			1.10E+00
Kr-87	7.99E-03	1.89E+02	1.50E-01	2.43E-03			8.46E-01
Kr-88	2.16E-02	3.52E+02	6.21E-01	1.09E-02			1.58E+00
Xe-131m							
Xe-133	6.35E-02	7.64E+02	2.41E+01	1.83E+00			3.42E+00
Xe-133m	1.46E-03	1.77E+01	1.93E-01	1.69E-02			7.92E-02
Xe-135	7.19E-02	9.44E+02	4.41E+00	1.04E-01			4.23E+00
Xe-135m	7.74E-04	2.59E+02	4.02E-02	6.16E-04			1.16E+00
Xe-138	1.33E-03	3.10E+02	5.49E-02	7.32E-04			1.39E+00
I-131		8.33E-04		5.15E-10		5.48E-05	
I-132							
I-133		8.03E-04		8.56E-10			
I-134							
I-135							
Na-24							
Mn-54							
Co-57							
Co-58			6.97E-07				
Co-60			5.29E-08				
Rb-88		1.61E-04					
Zr-95							
Nb-95							1.21E-06
Mo-99							
Ru-103							
Ru-106							
Cd-109				3.79E-09			
Cs-134							2.31E-06
Cs-136							
Cs-137							
Cs-138		2.12E-04					
Ce-141						1.10E-06	
Ce-144							

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Table I.7-5 (CONTINUED)- POINT BEACH NUCLEAR PLANT OBSERVED MONTHLY GASEOUS RELEASES BY RELEASE POINT

PBNP AIRBORNE RELEASE SUMMARY FOR OCTOBER, 1975

Unit 1 - No Shutdowns

Unit 2 - 1.1 Day Maintenance Outage

Isotope	Combined Air Ej.	Aux. Bldg. Vent	Unit 1 Contain.	Unit 2 Contain.	Turb. Bldg.	Dr. Area Vent	Gas. Str. Bldg.
H-3	2.28E-05	3.91E-01	1.74E-02	2.39E-03		3.21E-01	
F-18							
Ar-41	3.29E-01	2.57E+01	2.18E-04	8.21E-03			9.26E-01
Kr-85							
Kr-85m	2.53E+00	1.04E+02	4.34E-03	7.95E-03			3.75E+00
Kr-87	1.19E+00	7.73E+01	9.39E-04	1.48E-03			2.78E+00
Kr-88	3.14E+00	1.44E+02	3.89E-03	6.77E-03			5.17E+00
Xe-131m							
Xe-133	6.43E+00	2.04E+02	2.79E-01	1.43E+00			8.64E+00
Xe-133m	1.44E-01	6.12E+00	2.21E-03	1.86E-02			2.20E-01
Xe-135	9.34E+00	3.51E+02	3.17E-01	6.71E-02			1.26E+01
Xe-135m	1.40E-01	1.09E+02	2.55E-04	3.92E-04			3.93E+00
Xe-138	2.58E-01	1.43E+02	3.48E-04	4.91E-04			5.14E+00
I-131		7.75E-04	1.83E-10	8.23E-10		6.70E-06	
I-132							
I-133		8.06E-04		1.32E-09			
I-134							
I-135							
Na-24							
Mn-54							
Co-57							
Co-58							
Co-60		4.25E-06	4.45E-10				
Rb-88							
Zr-95							
Nb-95						2.89E-06	
Mo-99							
Ru-103							
Ru-106							
Cd-109				1.20E-08			
Cs-134						5.51E-07	
Cs-136							
Cs-137							
Cs-138		8.84E-05					
Ce-141						2.62E-07	
Ce-144							

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Table I.7-5 (CONTINUED)- POINT BEACH NUCLEAR PLANT OBSERVED MONTHLY GASEOUS RELEASES BY RELEASE POINT

PBNP AIRBORNE RELEASE SUMMARY FOR NOVEMBER, 1975*

Unit 1 - Refueling Shutdown; 15 Days

Unit 2 - 1.1 Day Maintenance Outage

Isotope	Combined Air Ej.	Aux. Bldg. Vent	Unit 1 Contain.	Unit 2 Contain.	Turb. Bldg.	Dr. Area Vent	Gas. Str. Bldg.
H-3	3.93E-05	6.26E-01	2.39E+00	6.20E-03	8.17E-02	1.07E+00	
F-18							
Ar-41	4.33E-03	1.65E+01	7.86E-02	9.21E-04			1.75E+01
Kr-85							
Kr-85m	2.34E-02	5.98E+01	5.70E-01	9.39E-04			6.35E+01
Kr-87	8.11E-03	4.18E+01	4.11E-01	1.65E-04			4.43E+01
Kr-88	2.71E-02	8.15E+01	7.78E-01	7.92E-04			8.64E+01
Xe-131m							
Xe-133	8.50E-02	1.65E+02	2.84E+00	1.68E-01		9.02E-01	1.75E+02
Xe-133m	8.71E-04	1.72E+00	4.99E-03	2.30E-03			1.83E+00
Xe-135	9.54E-02	2.11E+02	2.05E+00	7.54E-03			2.23E+02
Xe-135m	2.07E-04	6.31E+01	5.82E-01	4.85E-05			6.70E+01
Xe-138	5.30E-04	7.35E+01	7.51E-01	6.07E-05			7.80E+01
I-131		2.31E-06	2.21E-05	2.65E-08		9.81E-05	
I-132		2.45E-05					
I-133		1.10E-03				1.66E-05	
I-134							
I-135							
Na-24							
Mn-54							
Co-57							
Co-58						1.45E-06	
Co-60		3.18E-06	5.61E-10			7.54E-06	
Rb-88							
Zr-95							
Nb-95							
Mo-99							
Ru-103							
Ru-106							
Cd-109				1.05E-09			
Cs-134							
Cs-136							
Cs-137							
Cs-138		3.48E-02					
Ce-141							
Ce-144							

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Table I.7-5 (CONTINUED)- POINT BEACH NUCLEAR PLANT OBSERVED MONTHLY GASEOUS RELEASES BY RELEASE POINT

PBNP AIRBORNE RELEASE SUMMARY FOR DECEMBER, 1975

Unit 1 - Refueling Outage; Entire Month

Unit 2 - No Shutdowns

Isotope	Combined Air Ej.	Aux. Bldg. Vent	Unit 1 Contain.	Unit 2 Contain.	Turb. Bldg.	Dr. Area Vent	Gas. Str. Bldg.
H-3	1.96E-03		7.76E+00	1.43E-02	3.12E-01	3.02E+00	
F-18							
Ar-41	1.16E-04	3.70E+01		1.24E-03			3.12E-01
Kr-85	2.71E-05	4.27E+00		9.07E-02			3.59E-02
Kr-85m	8.16E-05	1.72E+01		1.10E-03			1.45E-01
Kr-87	3.15E-05	1.37E+01		1.93E-04			1.15E-01
Kr-88	9.19E-05	2.29E+01		9.29E-04			1.93E-01
Xe-131m							
Xe-133	1.59E-03	2.53E+02		2.07E-01			2.13E+00
Xe-133m	2.63E-05	4.24E+00		2.68E-03			3.57E-02
Xe-135	4.79E-04	8.67E+01		9.05E-03			7.31E-01
Xe-135m	3.86E-07	8.55E+00		5.36E-05			7.20E-02
Xe-138	3.19E-06	4.13E+01		9.16E-05			3.48E-01
I-131		1.22E-03	1.85E-05	2.22E-09		1.34E-04	
I-132							
I-133		2.96E-05					
I-134							
I-135							
Na-24							
Mn-54						5.08E-07	
Co-57							
Co-58						1.81E-06	
Co-60		5.94E-06	2.91E-06	5.88E-10		4.06E-06	
Rb-88							
Zr-95						4.47E-07	
Nb-95			7.06E-07	4.56E-10		3.92E-06	
Mo-99							
Ru-103			6.59E-07			1.33E-06	
Ru-106							
Cd-109							
Cs-134							
Cs-136							
Cs-137				4.56E-10			
Cs-138							
Ce-141							
Ce-144							

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Table I.7-6 POINT BEACH NUCLEAR PLANT LIQUID RELEASES (1974-1975) (Ci/yr)

Isotope	1974	1975	Annual Average
H3	8.33E+02	8.85E+02	8.59E+02
Kr-85	1.08E-03		5.40E-04
Kr-85m		3.72E-04	1.86E-04
Kr-87		6.00E-07	3.00E-07
Xe-131m	3.39E-04	1.69E-03	1.01E-03
Xe-133	2.01E-01	2.07E-01	2.04E-01
Xe-133m	3.36E-04	1.34E-03	8.38E-04
Xe-135	8.98E-03	1.01E-01	5.50E-02
Xe-138		3.10E-04	1.55E-04
I-131	1.82E-02	1.71E-01	9.46E-02
I-132	1.20E-03	1.29E-01	6.51E-02
I-133	2.87E-02	2.68E-01	1.48E-01
I-134		1.36E-01	6.80E-02
I-135	6.98E-03	2.71E-01	1.39E-01
Na-124		4.80E-03	2.40E-03
Cr-51		7.89E-02	3.95E-02
Mn-54	1.96E-05	1.47E-02	7.36E-03
Fe-55			
Fe-59		2.17E-03	1.09E-03
Co-57	2.32E-04	6.99E-02	3.51E-02
Co-58	1.02E-03	2.42E-01	1.22E-01
Co-60	2.12E-04	6.29E-02	3.16E-02
Br-83			
Br-84			
Br-85			
Rb-86			
Rb-88			
Sr-89	1.17E-03	7.13E-04	9.42E-04
Sr-90	1.46E-04	2.36E-03	1.25E-03
Sr-91			
Y-90			
Y-91m			
Y-91			
Y-93			
Zr-95	7.95E-05	1.31E-01	6.55E-02

Sheet 1 of 3

Table I.7-6 (CONTINUED)
POINT BEACH NUCLEAR PLANT LIQUID RELEASES (1974-1975) (Ci/yr)

Isotope	1974	1975	Annual Average
Nb-95	1.27E-04	1.87E-01	9.36E-02
Mo-99		1.75E-05	8.75E-06
Tc-99m			
Ru-103	5.40E-04	1.20E-01	6.03E-02
Ru-106	5.79E-04	1.02E-02	5.39E-03
Rh-103m			
Rh-106			
Cd-109		2.08E-03	1.04E-03
Ag-110m		3.12E-04	1.56E-04
Sb-124		6.35E-05	3.18E-05
Sb-125		2.47E-04	1.24E-04
Te-125m			
Te-127m			
Te-127			
Te-129m			
Te-129			
Te-131m			
Te-131			
Te-132		2.43E-04	1.22E-04
Cs-134	3.84E-02	1.79E-02	2.82E-02
Cs-136		7.99E-04	4.00E-04
Cs-137	9.82E-02	6.55E-02	8.19E-02
Cs-138		1.02E-01	5.10E-02
Ba-137m			
Ba-140		9.59E-02	4.80E-02
La-140		4.11E-02	2.06E-02
Ce-141		4.88E-02	2.44E-02
Ce-143			
Ce-144	8.00E-06	1.09E-01	5.45E-02
Pr-143			
Pr-144			
Bi-207		9.34E-05	4.67E-02
Th-232		9.72E-06	4.86E-02
Np-239			

Sheet 2 of 3

Table I.7-6 (CONTINUED)
POINT BEACH NUCLEAR PLANT LIQUID RELEASES (1974-1975) (Ci/yr)

Release Summary, Average Ci/yr:

Total Tritium	8.59E+02
Total Noble Gases	2.62E-01
Total Iodines	5.65E-01
Total Others	7.56E-01
Total Non-Tritium	1.39E+00

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Table I.7-7 POINT BEACH NUCLEAR PLANT PARAMETERS FOR RADIOACTIVE GASEOUS RELEASES

Unit 1 and 2 Containment Releases (applicable to each unit)	
Fraction/day of primary coolant noble gas activity released to containment	0.01
Fraction/day of primary coolant iodine activity released to the containment	0.00001
Iodine exhaust filter efficiency	90%
Particulate exhaust filter efficiency	99%
Purge exhaust ventilation rate (cfm)	12,500
Purge exhaust ventilation time (hrs)	7
Number of hot purges/year/unit	12
10 purges/year during operation	
2 purges/year during hot shutdown	
Number of cold purges/year/unit	2
Continuous ventilation exhaust	10
Containment free volume (ft^3)	$1.065 x 10^6$
Units 1 and 2 Auxiliary Building Releases	
Auxiliary building leakage of primary coolant (lb/day/unit)	160
Iodine partition factor for primary coolant leakage in the aux. bldg.	0.0075
No charcoal filters	
Auxiliary building HEPA filter efficiency	99%
Units 1 and 2 Turbine Building Releases	
Turbine building leakage (lb/hr/unit)	1700
Iodine partition coefficient for all iodines	1.0
No filters (charcoal or HEPA)	
Main Condenser Air Ejector	
Fraction of the iodine inventory in the primary coolant which is volatile	0.05
Primary-to-secondary leak rate (lb/day/unit)	100
Main condenser air ejector iodine partition factor	0.15
Units 1 and 2 air ejector effluents enter a decay duct which provides a 1.0 hour delay before release to the environment	
No filters (charcoal or HEPA)	

Sheet 1 of 2

Table I.7-7 (CONTINUED)
POINT BEACH NUCLEAR PLANT PARAMETERS FOR RADIOACTIVE GASEOUS RELEASES

Blowdown Flash Tanks

PBNP has blowdown flash tanks, however, liquid which flashes is all condensed; therefore, no iodines or noble gases are released through the plant vent from the blowdown flash tanks

Gas Decay Tank Effluents

3750 ft^3/month of gas decay tank effluent is released for 2 units

103 curies/yr are released from the gas decay tank in batched (70% Kr, 30% Xe-133)

Each release is intermittent and lasts for 250 minutes at a flow rate of 15 cfm

No filters (charcoal/HEPA)

Gas Stripper Building Releases

2% of the noble gases in the Appendix I analysis will be assumed to come from the gas stripper building

Gas stripper building ventilation (cfm)	400-12,000

No filters (charcoal or HEPA)

Sheet 2 of 2

Table I.8-1 POINT BEACH NUCLEAR PLANT ANNUAL DOSES TO MAXIMUM OFFSITE INDIVIDUAL IN ADULT GROUP FROM RADIOIODINE AND PARTICULATES IN GASEOUS EFFLUENTS

	ANNUAL DOSE (mrem/yr)							
Pathway and Location	Total Body	Skin	Bone	Liver	Thyroid	Kidney	Lung	GI Tract
Inhalation - SSW (1,460 m)	3.2E-02	-	2.6E-03	3.3E-02	5.58E-02	3.2E-02	3.3E-02	3.2E-02
Deposition on Ground - SSW (1,460 m)	3.3E-02	3.8E-02	3.3E-02	3.3E-02	3.3E-02	3.3E-02	3.3E-02	3.3E-02
Fresh Vegetables - SSW (1,460 m)	1.9E-02	-	2.6E-02	2.1E-02	6.7E-01	2.1E-02	1.7E-02	1.7E-02
Stored Vegetables - SSW (1,460 m)	1.5E-01	-	2.0E-01	1.5E-01	1.7E-01	1.4E-01	1.4E-01	1.4E-01
Cow's milk - SSE (1,300 m)	4.0E-02	-	4.9E-02	4.6E-02	1.7E+00	4.2E-02	3.2E-02	3.3E-02
Goat's milk - SSE (1,300 m)	6.9E-02	-	6.2E-02	8.0E-02	1.2E+00	6.3E-02	4.6E-02	4.5E-02
Meat - SSE (1,300 m)	1.6E-02	-	3.7E-02	1.6E-02	7.4E-02	1.5E-02	1.5E-02	1.6E-02
TOTAL OF ABOVE PATHWAYS WITH INGESTION OF COW'S MILK	2.9E-01	3.8E-02	3.5E-02	3.0E-01	2.7E+00	2.8E-01	2.7E-01	2.7E-01
TOTAL OF ABOVE PATHWAYS WITH INGESTION OF GOAT'S MILK	3.2E-01	3.8E-02	3.6E-01	3.3E-01	3.1E+00	3.0E-01	2.8E-01	2.8E-01

Table I.8-2 POINT BEACH NUCLEAR PLANT ANNUAL DOSES TO MAXIMUM OFFSITE INDIVIDUAL IN TEEN GROUP FROM RADIOIODINE AND PARTICULATES IN GASEOUS EFFLUENTS

	ANNUAL DOSE (mrem/yr)							
Pathway and Location	Total Body	Skin	Bone	Liver	Thyroid	Kidney	Lung	GI Tract
Inhalation - SSW (1,460 m)	1.8E-02	-	5.1E-04	1.9E-02	3.9E-02	2.3E-02	1.9E-02	1.8E-02
Deposition on Ground - SSW (1,460 m)	3.3E-02	3.8E-02	3.3E-02	3.3E-02	3.3E-02	3.3E-02	3.3E-02	3.3E-02
Fresh Vegetables - SSW (1,460 m)	1.2E-03	-	6.8E-03	1.4E-02	5.0E-01	1.4E-02	1.1E-02	1.1E-02
Stored Vegetables - SSW (1,460 m)	1.6E-01	-	8.3E-02	1.8E-01	2.0E-01	1.7E-01	1.6E-01	1.6E-01
Cow's milk - SSE (1,300 m)	4.8E-02	-	3.1E-02	6.2E-02	2.5E+00	5.5E-02	3.8E-02	3.8E-02
Goat's milk - SSE (1,300 m)	7.6E-02	-	5.3E-02	1.1E-01	3.1E+00	8.2E-02	5.6E-02	5.2E-02
Meat - SSE (1,300 m)	9.6E-03	-	6.3E-03	1.0E-02	5.1E-02	9.0E-03	9.2E-03	9.7E-03
TOTAL OF ABOVE PATHWAYS WITH INGESTION OF COW'S MILK	2.8E-01	3.8E-02	1.6E-01	3.2E-01	3.3E+00	3.0E-01	2.7E-01	2.7E-01
TOTAL OF ABOVE PATHWAYS WITH INGESTION OF GOAT'S MILK	3.1E-01	3.8E-02	1.8E-01	3.7E-01	3.9E+00	3.3E-01	2.9E-01	2.8E-01

Table I.8-3 POINT BEACH NUCLEAR PLANT ANNUAL DOSES TO MAXIMUM OFFSITE INDIVIDUAL IN CHILD GROUP FROM RADIOIODINE AND PARTICULATES IN GASEOUS EFFLUENTS

	ANNUAL DOSE (mrem/yr)							
Pathway and Location	Total Body	Skin	Bone	Liver	Thyroid	Kidney	Lung	GI Tract
Inhalation - SSW (1,460 m)	1.9E-02	-	8.0E-04	1.9E-02	4.6E-02	1.2E-02	1.9E-02	1.9E-02
Deposition on Ground - SSW (1,460 m)	3.3E-02	3.8E-02	3.3E-02	3.3E-02	3.3E-02	3.3E-02	3.3E-02	3.3E-02
Fresh Vegetables - SSW (1,460 m)	1.6E-02	-	1.2E-02	1.9E-02	7.5E-01	8.4E-03	1.5E-02	1.5E-02
Stored Vegetables - SSW (1,460 m)	3.0E-01	-	1.9E-01	3.4E-01	3.9E-01	1.4E-01	3.0E-01	3.0E-01
Cow's milk - SSE (1,300 m)	7.6E-02	-	7.3E-02	1.1E-01	5.0E+00	4.5E-02	7.2E-02	7.1E-02
Goat's milk - SSE (1,300 m)	1.1E-01	-	1.3E-01	2.0E-01	6.0E+00	6.8E-02	1.0E-01	9.3E-02
Meat - SSE (1,300 m)	1.5E-02	-	1.2E-02	1.6E-02	7.7E-02	5.6E-03	1.5E-02	1.5E-02
TOTAL OF ABOVE PATHWAYS WITH INGESTION OF COW'S MILK	4.6E-01	3.8E-02	3.2E-01	5.4E-01	6.3E+00	2.4E-01	4.5E-01	4.5E-01
TOTAL OF ABOVE PATHWAYS WITH INGESTION OF GOAT'S MILK	4.9E-01	3.8E-02	3.8E-01	6.3E-01	7.3E+00	2.7E-01	4.8E-01	4.8E-01

Table I.8-4 POINT BEACH NUCLEAR PLANT ANNUAL DOSES TO MAXIMUM OFFSITE INDIVIDUAL IN INFANT GROUP FROM RADIOIODINE AND PARTICULATES IN GASEOUS EFFLUENTS

	ANNUAL DOSE (mrem/yr)							
Pathway and Location	Total Body	Skin	Bone	Liver	Thyroid	Kidney	Lung	GI Tract
Inhalation - SSW (1,460 m)	2.0E-02	-	1.2E-03	2.1E-02	6.6E-02	8.5E-03	2.1E-02	2.0E-02
Deposition on Ground - SSW (1,460 m)	3.3E-02	3.8E-02	3.3E-02	3.3E-02	3.3E-02	3.3E-02	3.3E-02	3.3E-02
Fresh Vegetables - SSW (1,460 m)	-	-	-	-	-	-	-	-
Stored Vegetables - SSW (1,460 m)	-	-	-	-	-	-	-	-
Cow's milk - SSE (1,300 m)	1.5E-01	-	1.6E-01	2.3E-01	1.2E+01	4.5E-02	1.3E-01	1.3E-01
Goat's milk - SSE (1,300 m)	2.0E-01	-	2.6E-01	4.0E-01	1.5E+01	6.8E-02	1.8E-01	1.6E-01
Meat - SSE (1,300 m)	-	-	-	-	-	-	-	-
TOTAL OF ABOVE PATHWAYS WITH INGESTION OF COW'S MILK	2.0E-01	3.8E-02	1.9E-01	2.8E-01	1.2E+01	8.7E-02	1.8E-01	1.8E-01
TOTAL OF ABOVE PATHWAYS WITH INGESTION OF GOAT'S MILK	2.5E-01	3.8E-02	2.9E-01	4.5E-01	1.5E+01	1.1E-01	2.3E-01	2.1E-01

Table I.8-5 POINT BEACH NUCLEAR PLANT ANNUAL DOSES TO MAXIMUM INDIVIDUAL FROM NOBLE GASES IN GASEOUS EFFLUENTS

Individual	Total Body Dose (mrem/yr)	Skin Dose (mrem/yr)
Onsite (1250 m, WNW)	1.7E-02	3.6E-02
Offsite (1460 m, SSW)	2.7E-02	5.6E-02

Table I.8-6 POINT BEACH NUCLEAR PLANT ANNUAL DOSES TO MAXIMUM OFFSITE INDIVIDUAL IN ADULT AGE GROUP FROM LIQUID EFFLUENTS UNDER EQUILIBRIUM CONDITIONS

	ANNUAL DOSE (mrem/yr)							
Pathway and Location	Total Body	Skin	Bone	Liver	Thyroid	Kidney	Lung	GI Tract
Ingestion of potable water - (Two Rivers - 12 miles S)	3.1E-04	-	1.7E-04	3.9E-04	1.3E-02	3.0E-04	1.4E-04	2.2E-04
Ingestion of fish - (edge of initial mixing zone)	1.9E-01	-	1.3E-01	2.5E-01	1.3E-01	9.0E-02	2.8E-02	2.1E-02
Ingestion of fresh vegetables - (Two Rivers - 12 miles S)	1.4E-04	-	1.0E-04	1.9E-04	3.2E-03	8.9E-05	3.0E-05	4.0E-05
Ingestion of stored vegetables - (Two Rivers - 12 miles S)	1.0E-03	-	7.4E-04	1.4E-03	2.4E-04	5.2E-04	2.3E-04	1.8E-04
Ingestion of cow's milk (Two Rivers - 12 miles S)	8.7E-04	-	5.9E-04	1.1E-03	1.1E-02	4.7E-04	1.7E-04	1.0E-04
Ingestion of meat - (Two Rivers - 12 miles S)	5.6E-05	-	3.1E-05	7.0E-05	2.1E-04	4.2E-05	2.6E-05	4.4E-05
Swimming - (edge of initial mixing zone)	1.3E-04	1.3E-04	1.3E-04	1.3E-04	1.3E-04	1.3E-04	1.3E-04	1.3E-04
Boating - (edge of initial mixing zones)	4.4E-05	4.4E-05	4.4E-05	4.4E-05	4.4E-05	4.4E-05	4.4E-05	4.4E-05
Shoreline deposits - (1500 meters - South)	1.2E-06	1.4E-06	1.2E-06	1.2E-06	1.2E-06	1.2E-06	1.2E-06	1.2E-06
TOTAL OF ABOVE PATHWAYS	1.9E-01	1.8E-04	1.3E-01	2.5E-01	1.6E-01	9.0E-02	2.9E-02	2.2E-02

Table I.8-7 POINT BEACH NUCLEAR PLANT ANNUAL DOSES TO MAXIMUM OFFSITE INDIVIDUAL IN TEEN AGE GROUP FROM LIQUID EFFLUENTS UNDER EQUILIBRIUM CONDITIONS

	ANNUAL DOSE (mrem/yr)							
Pathway and Location	Total Body	Skin	Bone	Liver	Thyroid	Kidney	Lung	GI Tract
Ingestion of potable water - (Two Rivers - 12 miles S)	1.8E-04	-	1.4E-04	3.1E-04	1.0E-02	2.1E-04	8.8E-05	1.4E-04
Ingestion of fish - (edge of initial mixing zone)	1.1E-01	-	1.3E-01	2.5E-01	1.2E-01	6.9E-02	3.1E-02	1.5E-01
Ingestion of fresh vegetables - (Two Rivers - 12 miles S)	7.4E-05	-	8.9E-05	1.7E-04	2.4E-03	5.8E-05	2.4E-02	2.4E-05
Ingestion of stored vegetables - (Two Rivers - 12 miles S)	9.6E-04	-	1.2E-03	2.2E-03	3.1E-01	6.2E-04	3.5E-04	1.9E-04
Ingestion of cow's milk (Two Rivers - 12 miles S)	8.5E-04	-	1.0E-03	1.9E-03	1.8E-02	6.2E-04	2.8E-04	1.1E-04
Ingestion of meat - (Two Rivers - 12 miles S)	2.5E-05	-	2.3E-05	4.8E-05	1.4E-04	2.4E-05	1.5E-05	2.3E-05
Swimming - (edge of initial mixing zone)	1.3E-04	1.3E-04	1.3E-04	1.3E-04	1.3E-04	1.3E-04	1.3E-04	1.3E-04
Boating - (edge of initial mixing zones)	4.4E-05	4.4E-05	4.4E-05	4.4E-05	4.4E-05	4.4E-05	4.4E-05	4.4E-05
Shoreline deposits - (1500 meters - South)	6.8E-06	8.0E-06	6.8E-06	6.8E-06	6.8E-06	6.8E-06	6.8E-06	6.8E-06
TOTAL OF ABOVE PATHWAYS	1.1E-01	1.8E-04	1.3E-01	2.6E-01	1.5E-01	7.1E-02	3.3E-02	1.5E-01

Table I.8-8 POINT BEACH NUCLEAR PLANT ANNUAL DOSES TO MAXIMUM OFFSITE INDIVIDUAL IN CHILD AGE GROUP FROM LIQUID EFFLUENTS UNDER EQUILIBRIUM CONDITIONS

	ANNUAL DOSE (mrem/yr)							
Pathway and Location	Total Body	Skin	Bone	Liver	Thyroid	Kidney	Lung	GI Tract
Ingestion of potable water - (Two Rivers - 12 miles S)	2.1E-04	-	4.0E-04	6.1E-04	2.5E-02	2.1E-04	1.7E-04	2.0E-04
Ingestion of fish - (edge of initial mixing zone)	4.3E-02	-	1.7E-01	2.1E-01	1.3E-01	3.0E-02	2.4E-02	6.6E-03
Ingestion of fresh vegetables - (Two Rivers - 12 miles S)	4.3E-05	-	1.5E-04	2.0E-04	3.6E-03	3.6E-05	2.6E-05	1.8E-05
Ingestion of stored vegetables - (Two Rivers - 12 miles S)	7.8E-04	-	2.8E-03	3.5E-03	5.7E-04	5.2E-04	5.2E-04	2.0E-04
Ingestion of cow's milk (Two Rivers - 12 miles S)	6.5E-04	-	2.3E-03	3.1E-03	3.4E-02	5.1E-04	4.1E-04	1.3E-04
Ingestion of meat - (Two Rivers - 12 miles S)	2.2E-05	-	4.4E-05	6.5E-05	2.3E-04	1.7E-06	1.8E-05	2.1E-05
Swimming - (edge of initial mixing zone)	7.3E-05	7.3E-05	7.3E-05	7.3E-05	7.3E-05	7.3E-05	7.3E-05	7.3E-05
Boating - (edge of initial mixing zones)	2.4E-05	2.4E-05	2.4E-05	2.4E-05	2.4E-05	2.4E-05	2.4E-05	2.4E-05
Shoreline deposits - (1500 meters - South)	1.4E-06	1.7E-06	1.4E-06	1.4E-06	1.4E-06	1.4E-06	1.4E-06	1.4E-06
TOTAL OF ABOVE PATHWAYS	4.5E-02	9.9E-05	1.8E-01	2.1E-01	2.0E-01	3.1E-02	2.5E-02	1.1E-02

Table I.8-9 POINT BEACH NUCLEAR PLANT ANNUAL DOSES TO MAXIMUM OFFSITE INDIVIDUAL IN INFANT AGE GROUP FROM LIQUID EFFLUENTS UNDER EQUILIBRIUM CONDITIONS

	ANNUAL DOSE (mrem/yr)							
Pathway and Location	Total Body	Skin	Bone	Liver	Thyroid	Kidney	Lung	GI Tract
Ingestion of potable water - (Two Rivers - 12 miles S)	3.7E-04	-	8.1E-04	1.3E-03	6.1E-02	2.1E-04	2.9E-04	2.5E-04
Ingestion of fish - (edge of initial mixing zone)	-	-	-	-	-	-	-	-
Ingestion of fresh vegetables - (Two Rivers - 12 miles S)	-	-	-	-	-	-	-	-
Ingestion of stored vegetables - (Two Rivers - 12 miles S)	-	-	-	-	-	-	-	-
Ingestion of cow's milk (Two Rivers - 12 miles S)	7.7E-04	-	4.8E-03	6.9E-03	8.3E-02	5.1E-04	8.8E-04	1.7E-04
Ingestion of meat - (Two Rivers - 12 miles S)	-	-	-	-	-	-	-	-
Swimming - (edge of initial mixing zone)	-	-	-	-	-	-	-	-
Boating - (edge of initial mixing zones)	-	-	-	-	-	-	-	-
Shoreline deposits - (1500 meters - South)	-	-	-	-	-	-	-	-
TOTAL OF ABOVE PATHWAYS	1.1E-03	-	5.6E-03	8.2E-03	1.4E-01	7.2E-04	1.2E-03	4.2E-04

Table I.8-10 POINT BEACH NUCLEAR PLANT ANNUAL DOSES TO MAXIMUM ONSITE INDIVIDUAL IN ADULT GROUP FROM RADIOIODINE AND PARTICULATES IN GASEOUS EFFLUENTS

	ANNUAL DOSE (mrem/yr)							
Pathway and Location	Total Body	Skin	Bone	Liver	Thyroid	Kidney	Lung	GI Tract
Inhalation - WNW - 1250 m	2.0E-02	-	6.9E-04	2.0E-02	3.2E-02	2.0E-02	2.0E-02	2.0E-02
Deposition on ground - WNW - 1250 m	2.6E-02	3.1E-02	2.6E-02	2.6E-02	2.6E-02	2.6E-02	2.6E-02	2.6E-02
Fresh vegetables - WNW - 1250 m	1.1E-02	-	8.3E-03	1.2E-02	5.1E-01	1.2E-02	8.6E-03	9.5E-03
Stored vegetables - WNW - 1250 m	8.0E-02	-	5.7E-02	8.2E-02	9.3E-02	7.3E-02	7.0E-02	7.3E-02
TOTAL OF ABOVE PATHWAYS	1.4E-01	3.1E-02	9.2E-02	1.4E-01	6.6E-01	1.3E-01	1.2E-01	1.3E-01

Table I.8-11 POINT BEACH NUCLEAR PLANT ANNUAL DOSES TO MAXIMUM ONSITE INDIVIDUAL IN TEEN GROUP FROM RADIOIODINE AND PARTICULATES IN GASEOUS EFFLUENTS

	ANNUAL DOSE (mrem/yr)							
Pathway and Location	Total Body	Skin	Bone	Liver	Thyroid	Kidney	Lung	GI Tract
Inhalation - WNW - 1250 m	1.1E-02	-	1.6E-04	1.1E-02	2.1E-02	1.4E-02	1.1E-02	1.1E-02
Deposition on ground - WNW - 1250 m	2.6E-02	3.1E-02	2.6E-02	2.6E-02	2.6E-02	2.6E-02	2.6E-02	2.6E-02
Fresh vegetables - WNW - 1250 m	6.4E-03	-	3.43E-03	7.6E-03	3.8E-01	7.6E-03	4.9E-03	5.5E-03
Stored vegetables - WNW - 1250 m	8.2E-02	-	3.6E-02	9.3E-02	1.1E-01	8.8E-02	7.4E-02	7.6E-02
TOTAL OF ABOVE PATHWAYS	1.3E-01	3.1E-02	6.6E-02	1.4E-01	5.4E-01	1.4E-02	1.2E-01	1.2E-01

Table I.8-12 POINT BEACH NUCLEAR PLANT ANNUAL DOSES TO MAXIMUM ONSITE INDIVIDUAL IN CHILD GROUP FROM RADIOIODINE AND PARTICULATES IN GASEOUS EFFLUENTS

	ANNUAL DOSE (mrem/yr)							
Pathway and Location	Total Body	Skin	Bone	Liver	Thyroid	Kidney	Lung	GI Tract
Inhalation - WNW - 1250 m	1.1E-02	-	2.4E-04	1.1E-02	2.5E-02	7.3E-03	1.1E-02	1.1E-02
Deposition on ground - WNW - 1250 m	2.6E-02	3.1E-02	2.6E-02	2.6E-02	2.6E-02	2.6E-02	2.6E-02	2.6E-02
Fresh vegetables - WNW - 1250 m	7.0E-03	-	5.7E-03	9.9E-03	5.8E-01	4.8E-03	6.4E-03	6.7E-03
Stored vegetables - WNW - 1250 m	1.4E-01	-	7.9E-02	1.6E-01	1.9E-01	7.3E-02	1.3E-01	1.3E-01
TOTAL OF ABOVE PATHWAYS	1.8E-01	3.1E-02	1.1E-01	2.1E-01	8.2E-01	1.1E-01	1.7E-01	1.7E-01

Table I.8-13 POINT BEACH NUCLEAR PLANT ANNUAL DOSES TO MAXIMUM ONSITE INDIVIDUAL IN INFANT GROUP FROM RADIOIODINE AND PARTICULATES IN GASEOUS EFFLUENTS

	ANNUAL DOSE (mrem/yr)							
Pathway and Location	Total Body	Skin	Bone	Liver	Thyroid	Kidney	Lung	GI Tract
Inhalation - WNW - 1250 m	1.2E-02	-	3.6E-04	1.2E-02	3.5E-02	5.2E-03	1.2E-02	1.2E-02
Deposition on ground - WNW - 1250 m	2.6E-02	3.1E-02	2.6E-02	2.6E-02	2.6E-02	2.6E-02	2.6E-02	2.6E-02
Fresh vegetables - WNW - 1250 m	-	-	-	-	-	-	-	-
Stored vegetables - WNW - 1250 m	-	-	-	-	-	-	-	-
TOTAL OF ABOVE PATHWAYS	3.8E-02	3.1E-02	2.6E-02	3.8E-02	6.1E-02	3.1E-02	3.8E-02	3.8E-02

Table I.9-1 COMPARISON OF MAXIMUM CALCULATED DOSES FROM POINT BEACH NUCLEAR PLANT WITH DESIGN OBJECTIVES IN DOCKET RM-50-2[1]

		RM-50-2	Calculated Maximum Dose		
	Release	Design Objective	Individual	Organ	Dose
	Liquid Effluents				
1.	Total body	5 millirem/year	Adult	-	0.19 millirem/year
2.	Any organ	5 millirem/year	Teen	Liver	0.26 millirem/year
	Noble gases				
1.	Gamma Dose in Air[2]	10 millirads/year	-	-	0.06 millirads/year
2.	Beta Dose in Air[2]	20 millirads/year	-	-	0.07 millirads/year
3.	Total body	5 millirem/year	Any Any[3]	- -	0.03 millirem/year 0.02 millirem/year
4.	Skin	15 millirem/year	Any Any[3]	Skin Skin	0.06 millirem/year 0.04 millirem/year
	Radioiodine and Particulates in Gaseous Releases[4]				
1.	Any organ from all pathways	15 millirem/year	Infant Child[3]	Thyroid Thyroid	15.0 millirem/year 0.82 millirem/year

1. “Concluding Statement of Position of the Regulatory Staff,” Docket RM-50-2, February 20, 1974, U. S. Atomic Energy Commission, Washington, D.C.
2. Calculated at site boundary
3. Onsite resident
4. Carbon-14 and tritium have been added to this category.

Figure I.2-1 LIQUID WASTE SYSTEM PROCESS FLOW DIAGRAM

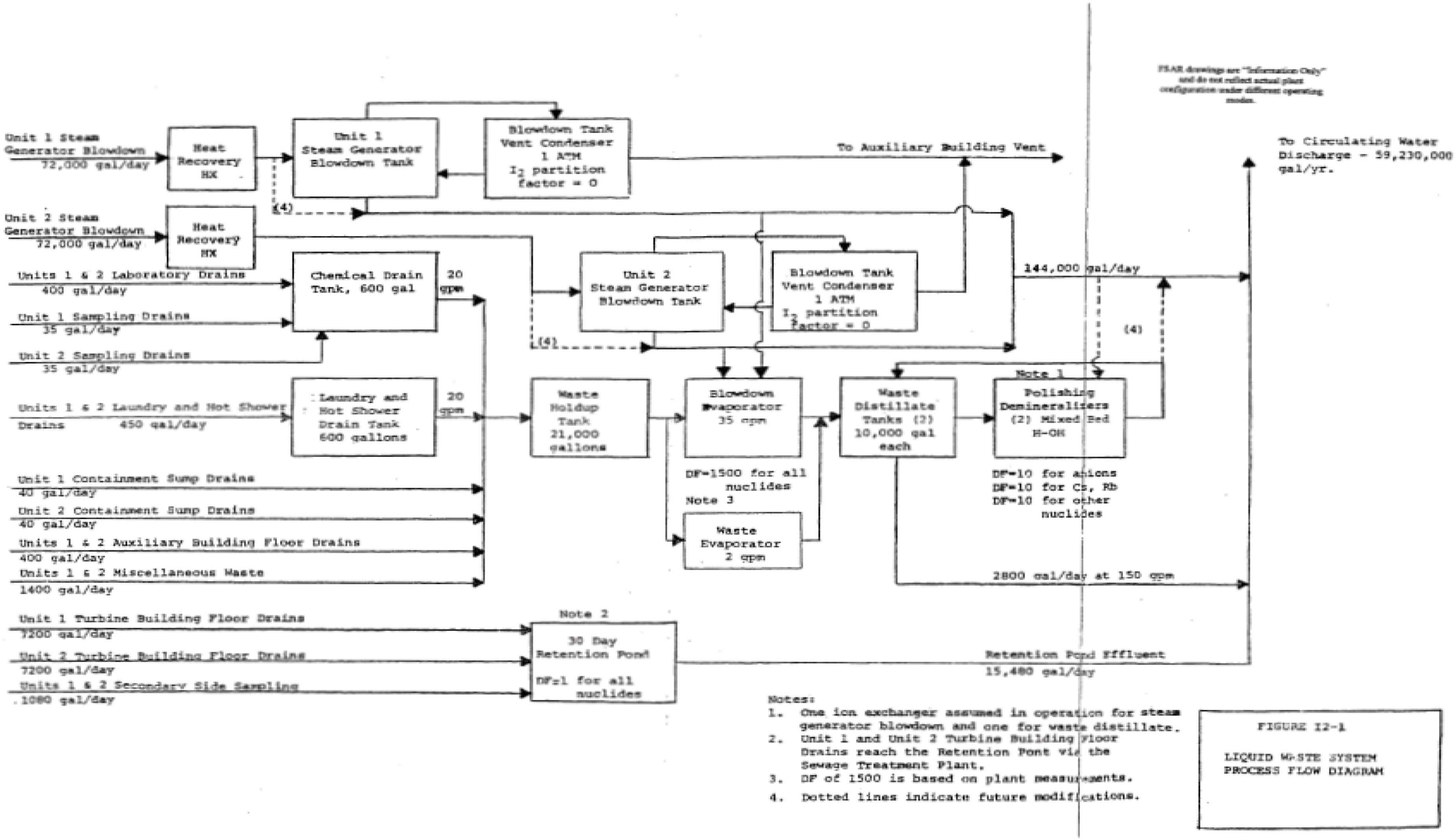


Figure I.2-2 CHEMICAL & VOLUME CONTROL SYSTEM PROCESS FLOW DIAGRAM

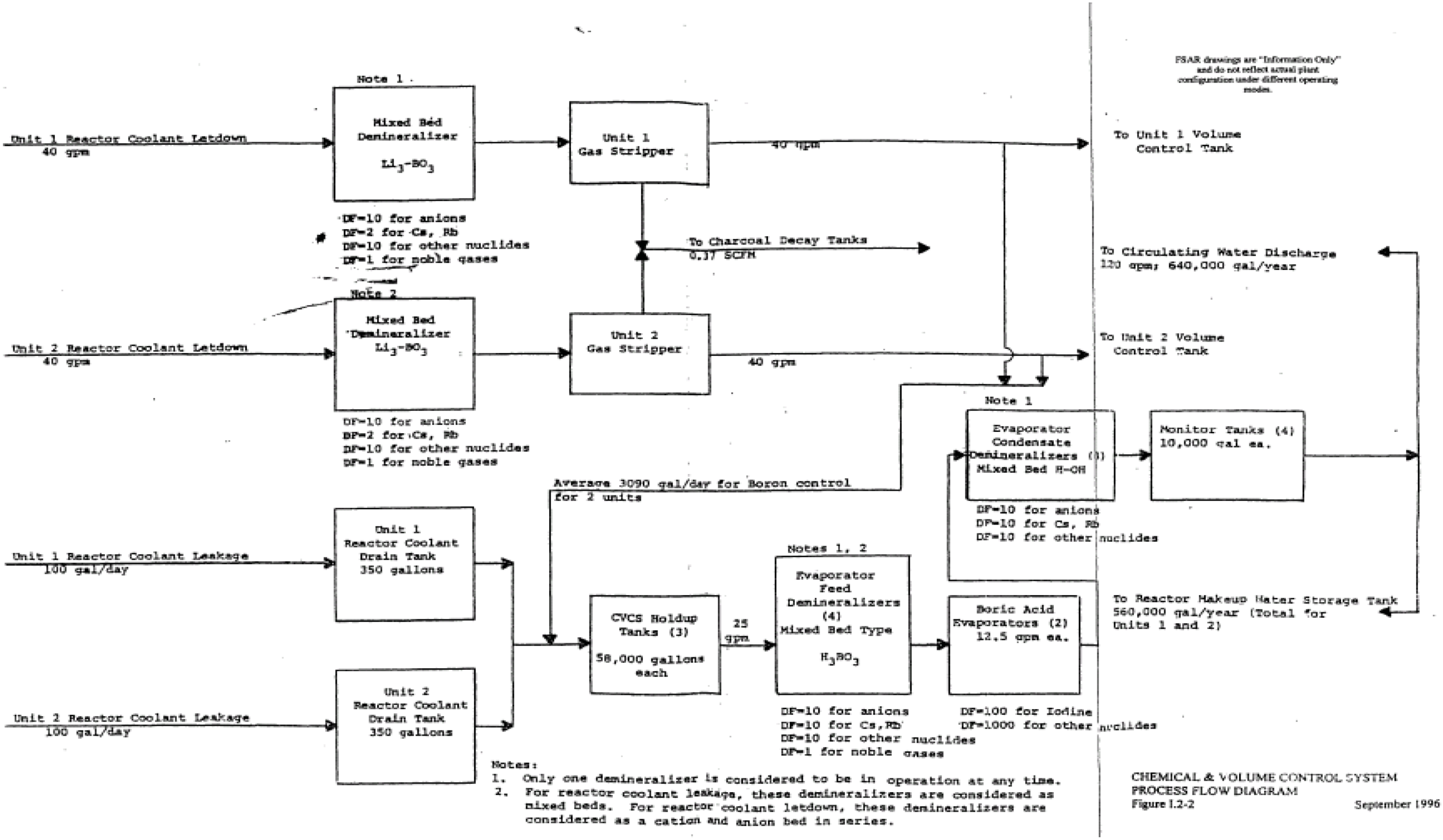


Figure I.2-3 VENTILATION AND GASEOUS WASTE PROCESS FLOW DIAGRAM

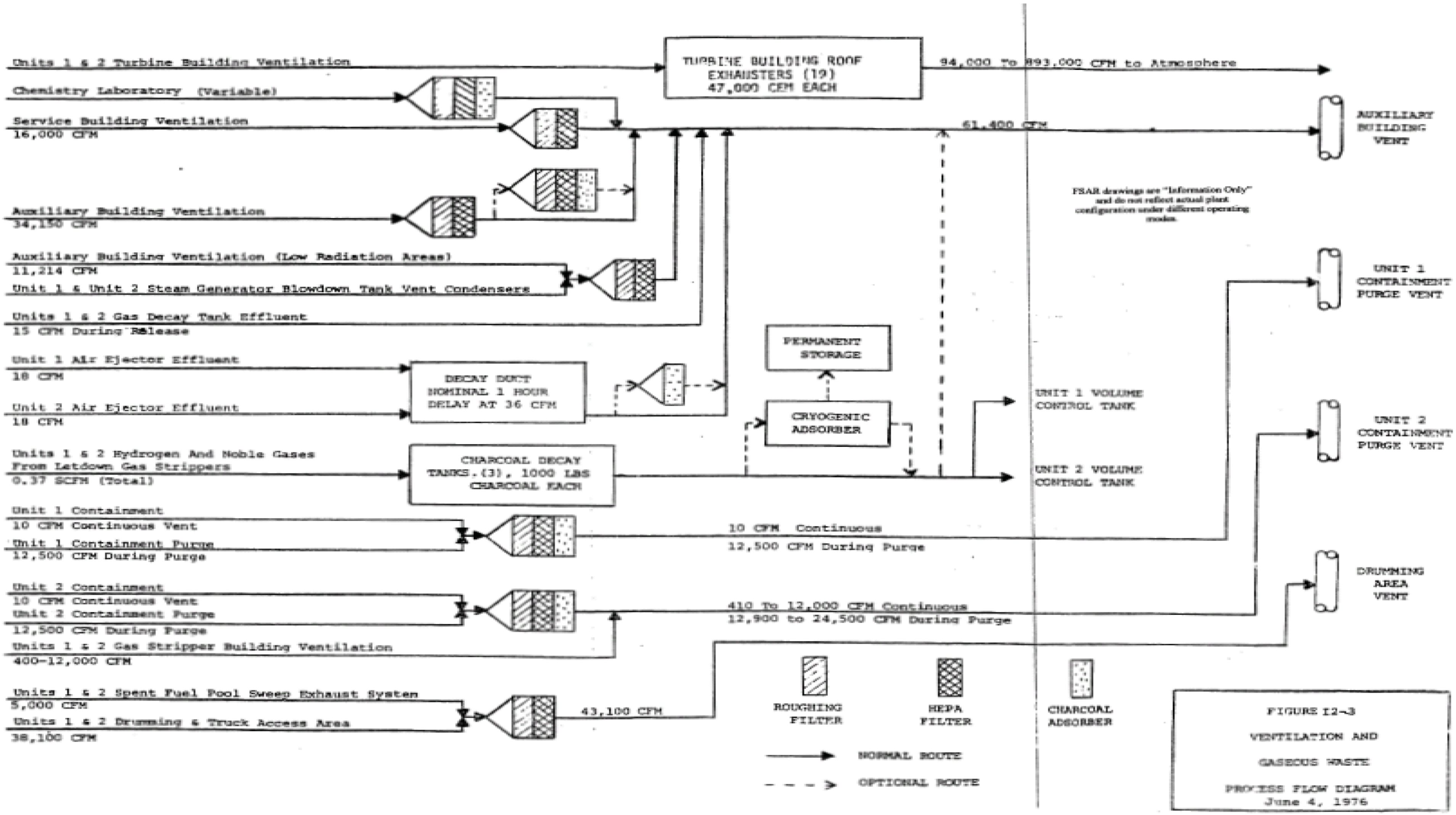


Figure I.2-4 PIPING & INSTRUMENT DIAGRAM HEATING & VENTILATION AIRFLOW

[redacted]

Figure I.2-5 PIPING & INSTRUMENT DIAGRAM HEATING & VENTILATION SYSTEMS

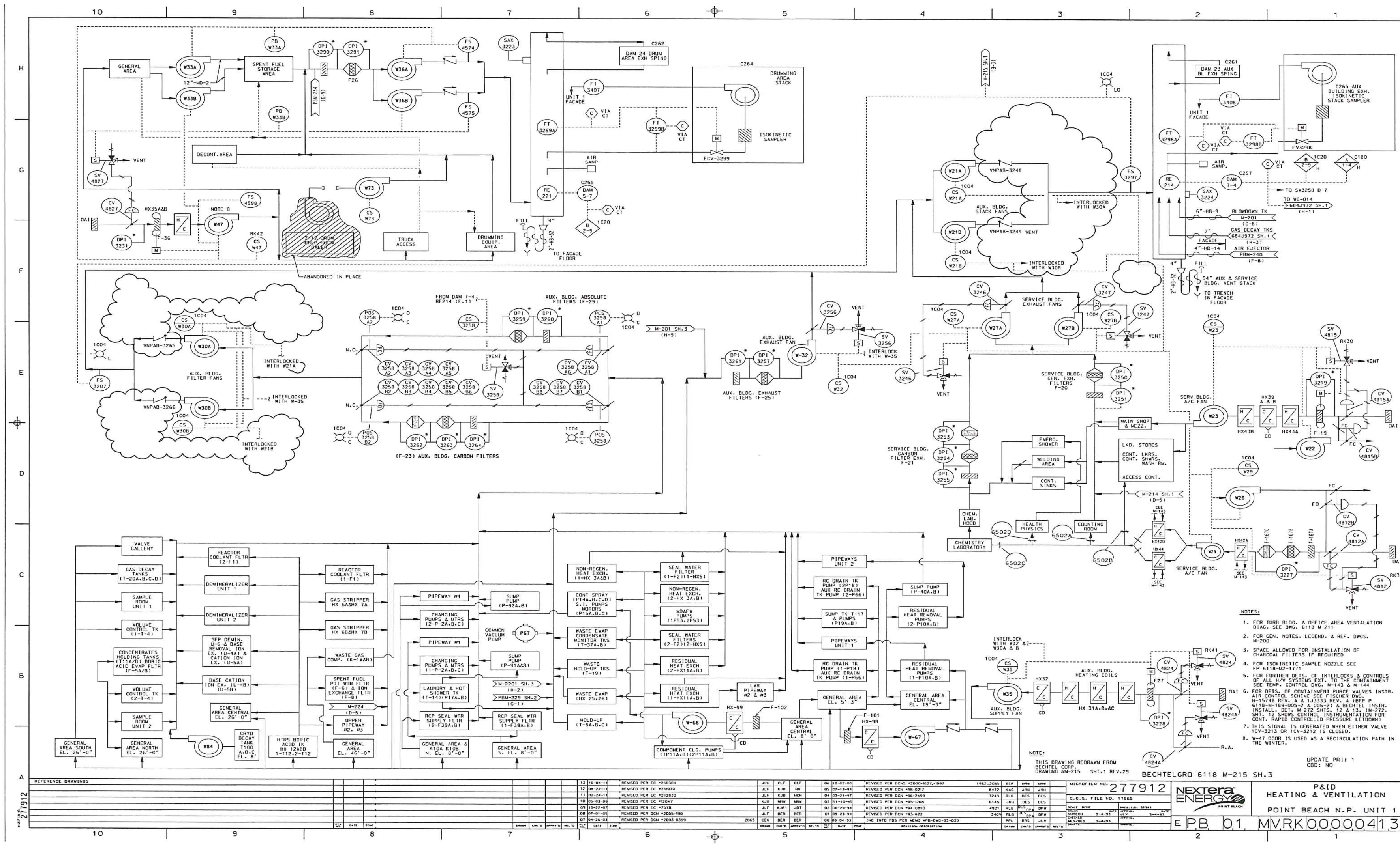


Figure I.4-1 GENERAL TOPOGRAPHY WITHIN 10-MILE RADIUS

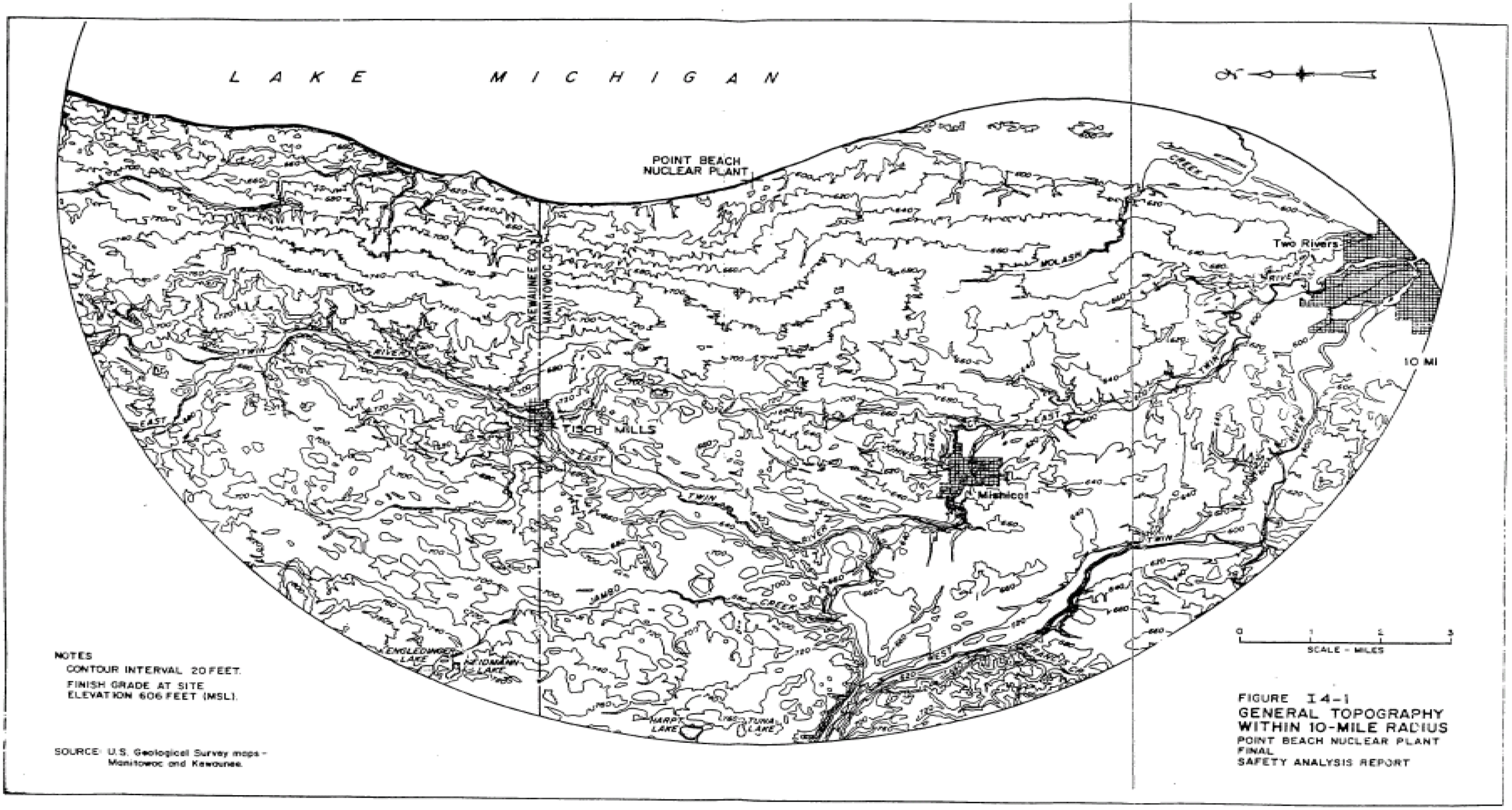


Figure I.4-2 MAXIMUM TOPOGRAPHIC ELEVATION VS DISTANCE BY SECTOR

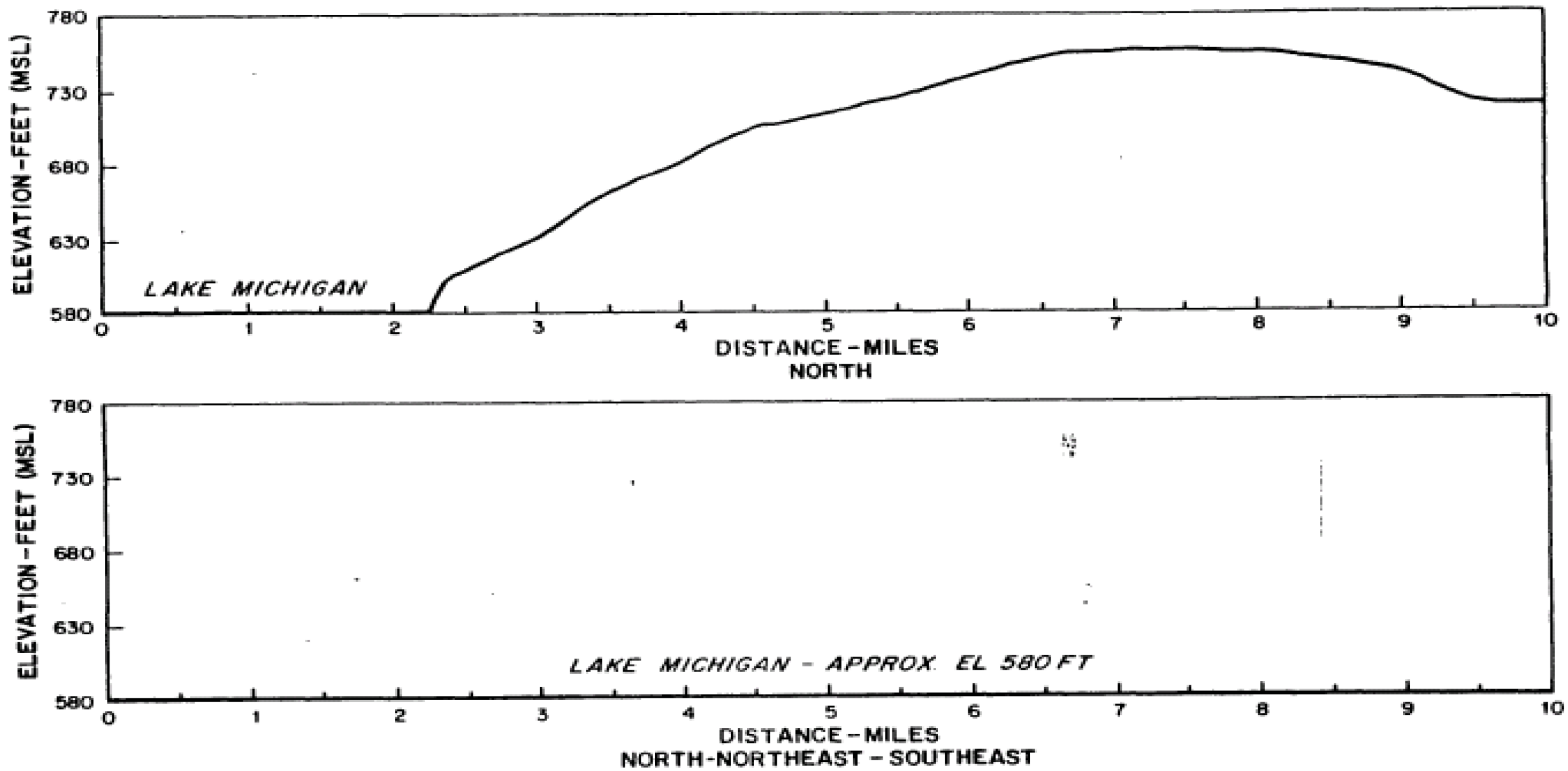


FIGURE I4-2 (P1 OF 6)
MAXIMUM TOPOGRAPHIC
ELEVATION VS DISTANCE BY SECTOR
POINT BEACH NUCLEAR PLANT
FINAL
SAFETY ANALYSIS REPORT

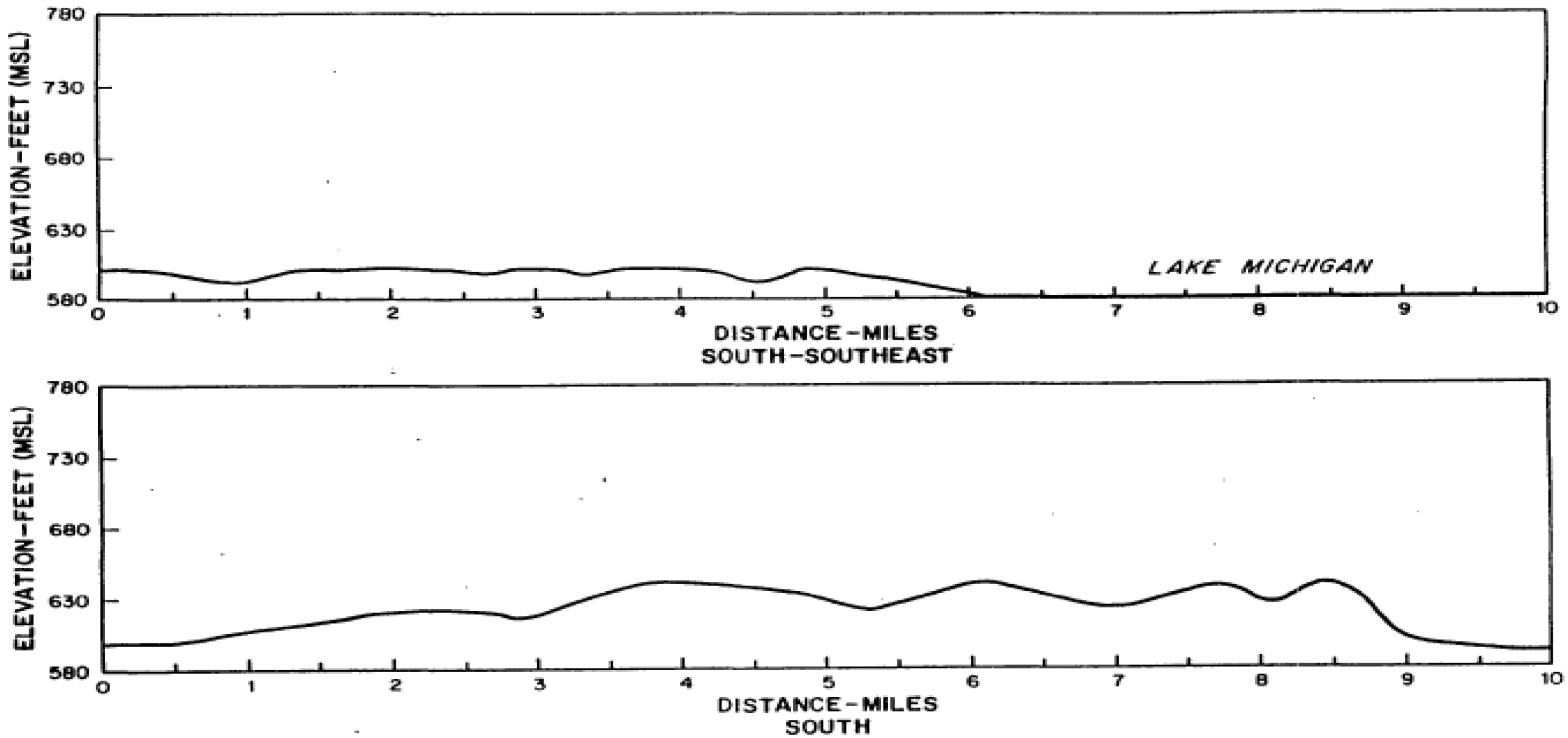


FIGURE I4-2 (P2 OF 6)
MAXIMUM TOPOGRAPHIC
ELEVATION VS DISTANCE BY SECTOR
POINT BEACH NUCLEAR PLANT
FINAL
SAFETY ANALYSIS REPORT

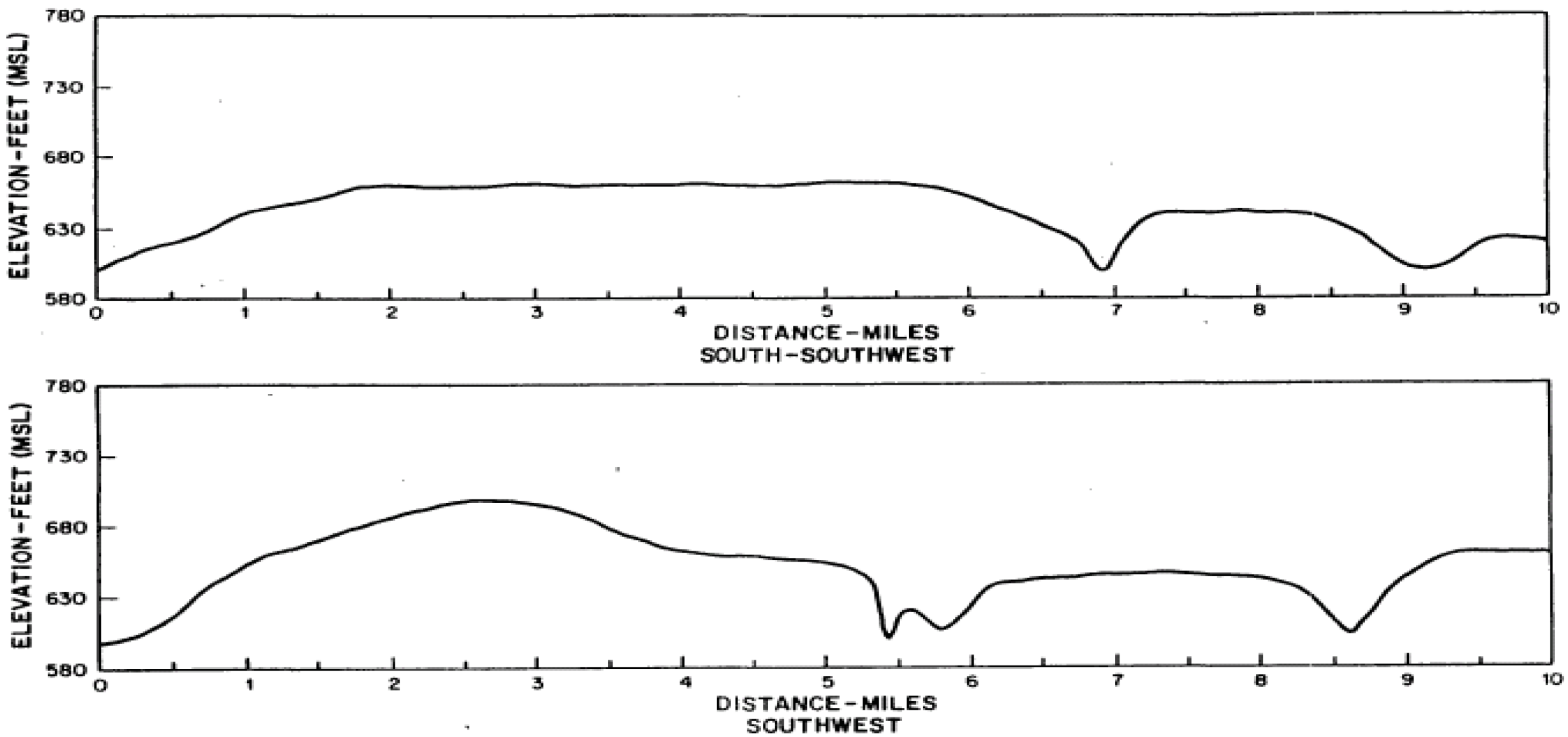


FIGURE I4-2 (P3 OF 6)
MAXIMUM TOPOGRAPHIC
ELEVATION VS DISTANCE BY SECTOR
POINT BEACH NUCLEAR PLANT
FINAL
SAFETY ANALYSIS REPORT

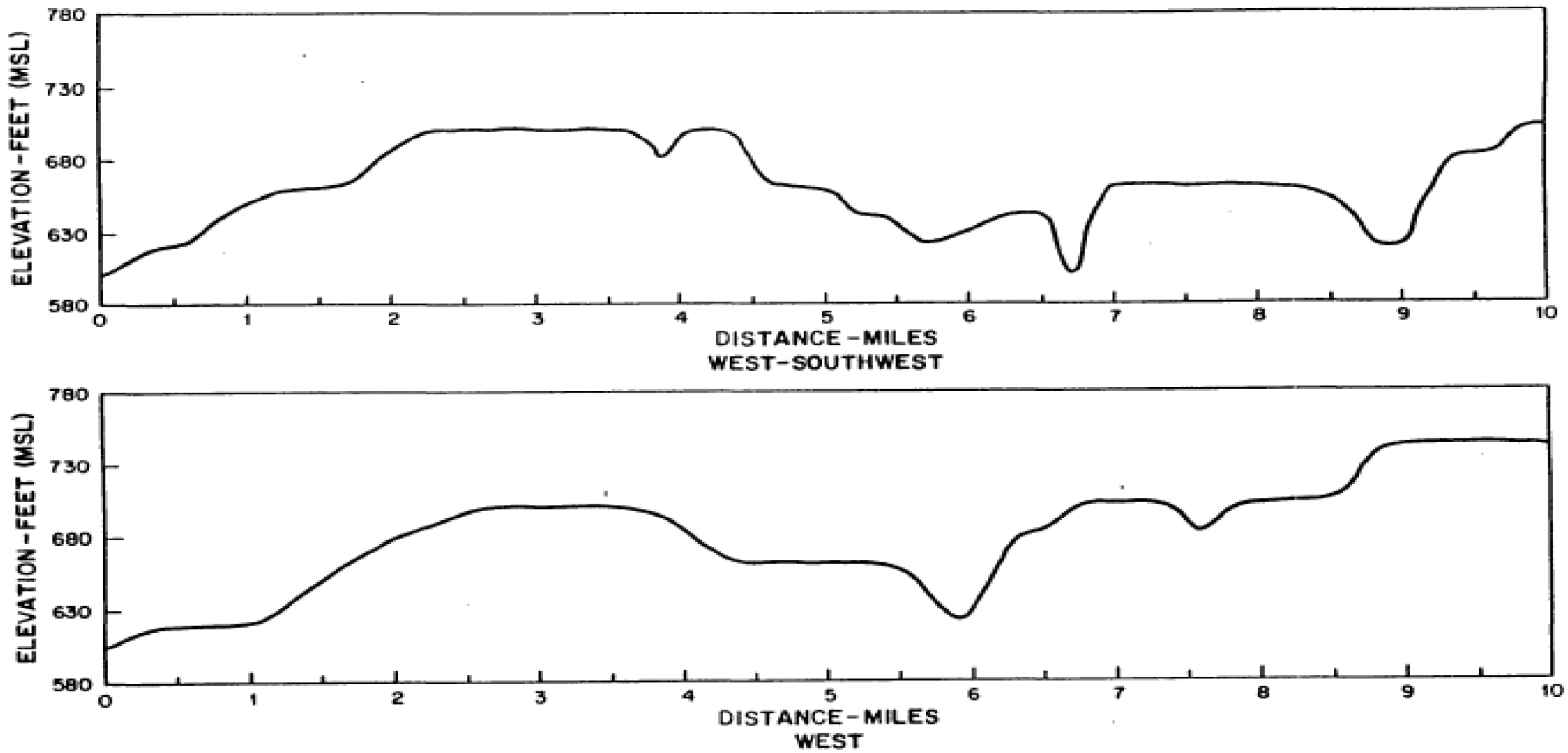


FIGURE I4-2 (P4 OF 6)
MAXIMUM TOPOGRAPHIC
ELEVATION VS DISTANCE BY SECTOR
POINT BEACH NUCLEAR PLANT
FINAL
SAFETY ANALYSIS REPORT

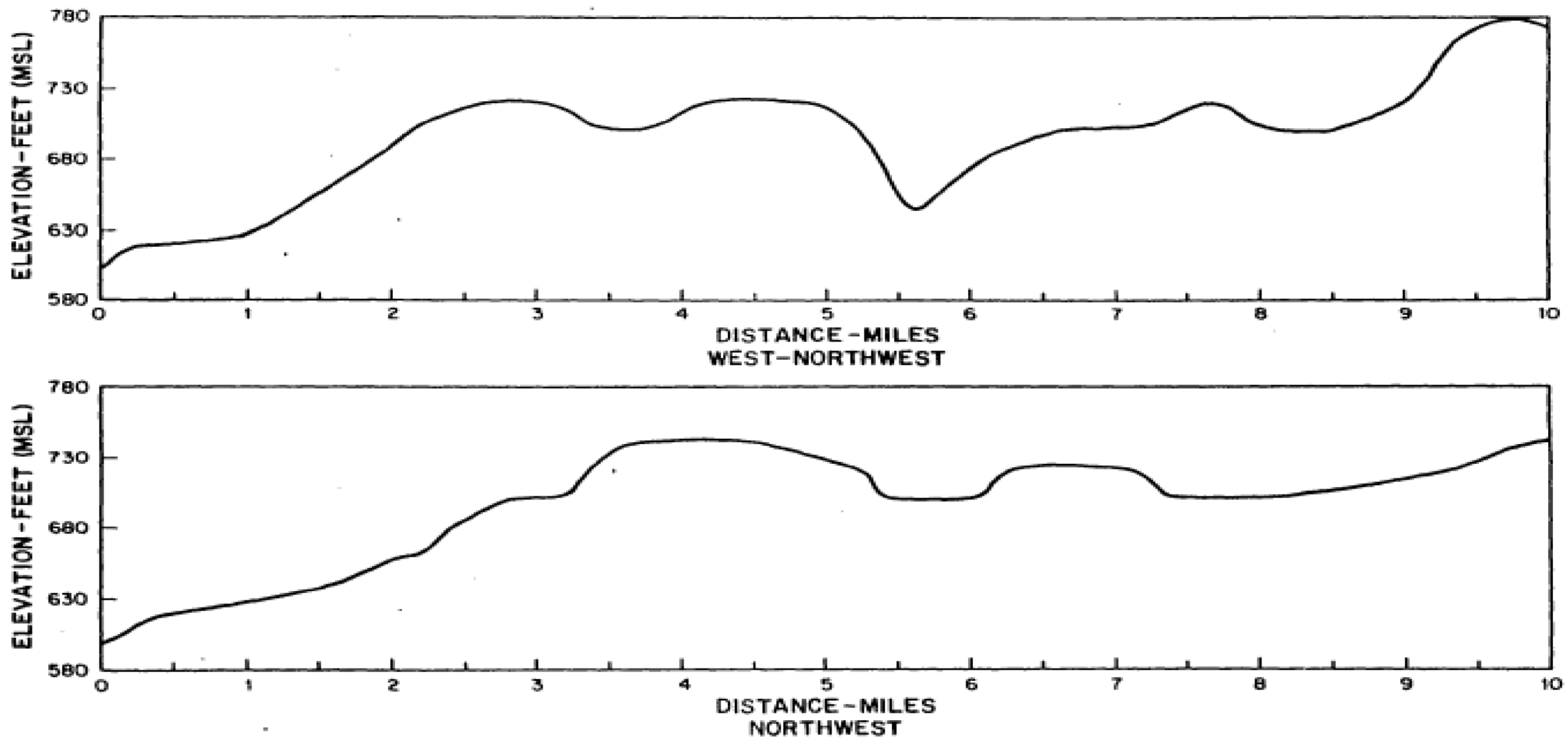


FIGURE I4-2 (P5 OF 6)
MAXIMUM TOPOGRAPHIC
ELEVATION VS DISTANCE BY SECTOR
POINT BEACH NUCLEAR PLANT
FINAL
SAFETY ANALYSIS REPORT

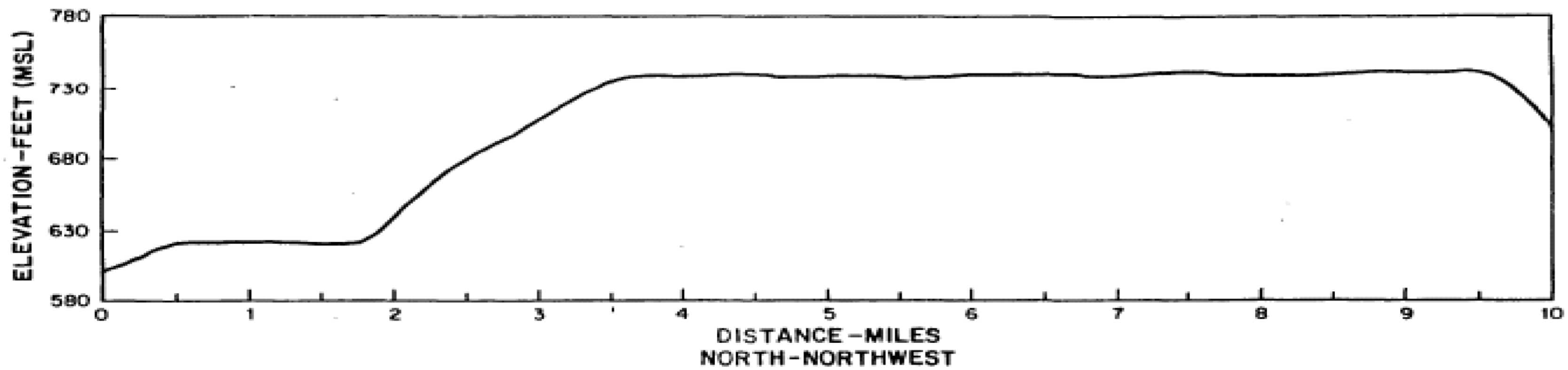
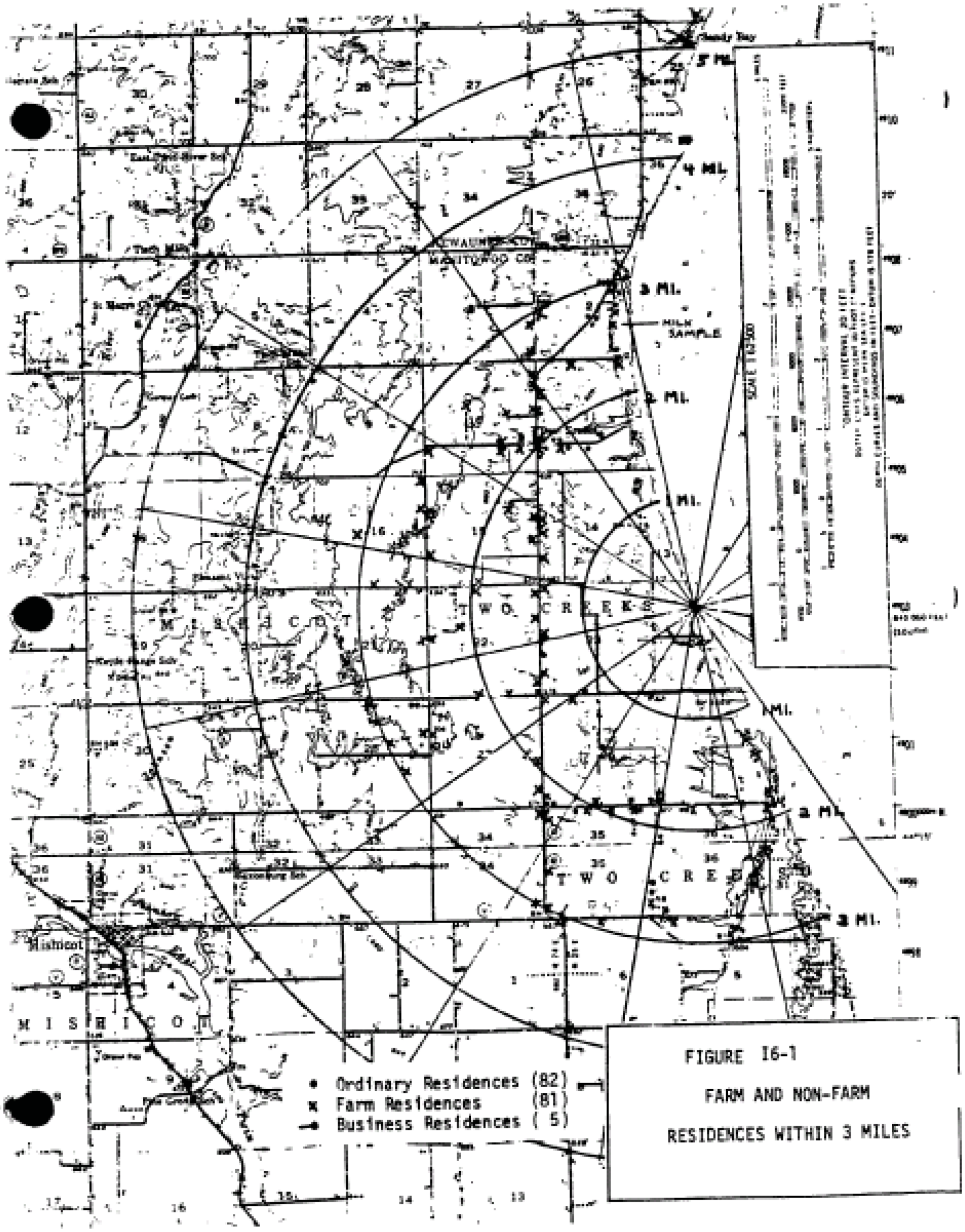


FIGURE I4-2 (P6 OF 6)
MAXIMUM TOPOGRAPHIC
ELEVATION VS DISTANCE BY SECTOR
POINT BEACH NUCLEAR PLANT
FINAL
SAFETY ANALYSIS REPORT

Figure I.6-1 FARM AND NON-FARM RESIDENCES WITHIN 3 MILES



T.1 TECHNICAL REQUIREMENTS MANUAL

The Technical Requirements Manual (TRM) is a licensee-controlled document that contains certain items removed from the Technical Specifications that do not meet the criteria of 10 CFR 50.36, Technical Specifications. The TRM is incorporated by reference into the FSAR and is therefore subject to the change control requirements of 10 CFR 50.59. Summaries of changes to the TRM are submitted to the NRC on a frequency consistent with 10 CFR 50.71(e) requirements.

ENCLOSURE 3

NEXTERA ENERGY POINT BEACH, LLC
POINT BEACH NUCLEAR PLANT, UNITS 1 AND 2

REPORT CONSISTENT WITH 10 CFR 54.37(b) ON HOW EFFECTS OF AGING OF NEWLY-IDENTIFIED STRUCTURES, SYSTEMS, OR COMPONENTS ARE MANAGED

This update follows the guidance regarding the appropriate level of detail for reports under 10 CFR 54.37(b) that is presented in Frequently Asked Questions (FAQs) About License Renewal Inspection Procedure (IP) 71003, "Post-Approval Site Inspection for License Renewal." This report provides summary information as required by 10 CFR 54.37(b) for the period between March 1, 2021 through September 1, 2022.

Regulatory Requirements and Guidance

10 CFR 54.37(b)

After the renewed license is issued, the FSAR update required by 10 CFR 50.71(e) must include any systems, structures, and components newly identified that would have been subject to an aging management review or evaluation of time-limited aging analysis in accordance with §54.21. This FSAR update must describe how the effects of aging will be managed such that the intended function(s) in §54.4(b) will be effectively maintained during the period of extended operation.

RIS 2007-16, Revision 1

Newly Identified Systems, Structures, and Components (SSCs)

The intent of 10 CFR 54.37(b) is to capture those SSCs that, if they had been identified at the time of the license renewal application, would have been subject to an aging management review or evaluation of TLAAs. In the context of 10 CFR 54.37(b), newly identified SSCs that should be included in the next FSAR update required by 10 CFR 50.71(e) are those SSCs that meet one of the two following conditions:

(1) *There is a change to the current licensing basis (CLB) that meets the following criteria:*

- *The change impacts SSCs that were not in scope for license renewal when the NRC approved the license renewal application.*

- *The SSCs would have been in the scope of license renewal based on the CLB change if 10 CFR 54.4(a) were applied to the SSCs.*

(2) *SSCs were installed in the plant at the time of the license renewal review that, in accordance with the CLB at the time, should have been included in the scope of license renewal per 10 CFR 54.4(a) but were not identified as in scope until after issuance of the renewed license.*

SSCs that are plant additions or modifications installed after the renewed license is issued are not subject to the provisions of 10 CFR 54.37(b).

Identification of SSCs under 10 CFR 54.37(b)

The language of 10 CFR 54.37(b) does not limit how or who finds newly identified SSCs. A licensee may identify SSCs that should be within the scope of its license renewal program at any time. The NRC staff may also discover newly identified SSCs. One way to identify these SSCs is through the LR-ISG process.

Newly Identified SSC

In 2022, using the guidance of RIS 2007-16, Rev. 1, PBNP staff reviewed changes to the plant that had taken place since the last 54.37(b) review of the Current Licensing Basis (March 2021). This review did not identify any additional components that that would be considered "newly identified" and subject to 10 CFR 54.37(b) reporting requirements.