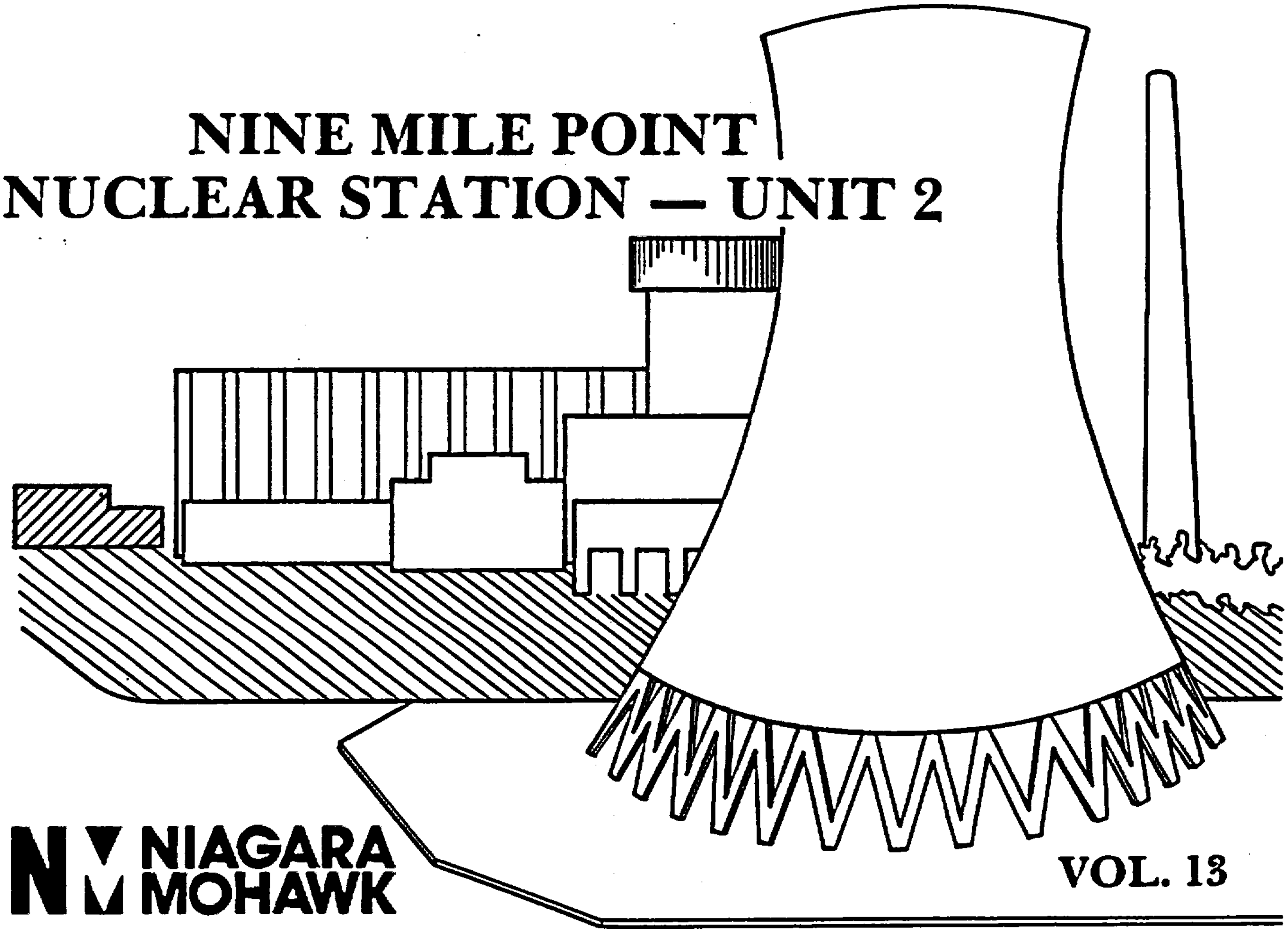
UPDATED SAFETY ANALYSIS REPORT

NINE MILE POINT NUCLEAR STATION — UNIT 2



NIAGARA MOHAWK

VOL. 13

CHAPTER 5

REACTOR COOLANT SYSTEM AND CONNECTED SYSTEMS

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REACTOR COOLANT SYSTEM AND CONNECTED SYSTEMS

5.1 SUMMARY DESCRIPTION

The reactor coolant system (RCS) includes those systems and components which contain or transport fluids coming from, or going to, the reactor core. These systems and the reactor vessel form the reactor coolant pressure boundary (RCPB). This chapter provides information regarding the RCS and pressure-containing appendages out to and including the outside isolation valves. The following group of components is defined as the RCPB.

The RCPB includes all pressure-containing components such as pressure vessels, piping, pumps, and valves, which are:

1. Part of the RCS, or

2. Connected to the RCS, up to and including any or all of the following:

   a. The outside containment isolation valve in piping which penetrates the primary reactor containment.

   b. The second of the two valves normally closed during normal reactor operation in system piping that does not penetrate the primary reactor containment.

   c. The RCS safety/relief valves (SRV).

Section 5.4 also discusses various subsystems closely allied to the RCPB.

The nuclear system pressure relief system protects the RCPB from damage due to overpressure. To protect against overpressure, SRVs are provided that can discharge steam from the nuclear system to the suppression pool. The pressure relief system also acts to automatically depressurize the nuclear system in the event of a loss-of-coolant accident (LOCA) in which the high pressure core spray (HPCS) system fails to maintain reactor vessel water level. Depressurization of the nuclear system allows the low pressure core cooling systems to supply enough cooling water to adequately cool the fuel.

Section 5.2.5 establishes the limits on nuclear system leakage inside the drywell so that appropriate action can be taken before the integrity of the nuclear system process barrier is impaired.

The reactor vessel and appurtenances are described in Section 5.3. Various loading combinations are considered in the vessel design. The vessel meets the requirements of applicable codes and criteria described in Sections 3.2, 5.2.1, and Appendix 5A. The possibility of brittle fracture is considered, and suitable design, material selection, material surveillance activity, and operational limits are established that avoid conditions where brittle fracture is possible.

The reactor recirculation system provides coolant flow through the core. Adjustment of the core coolant flow rate changes reactor power output, thus providing a means of following plant load demand without adjusting control rods. The recirculation system is designed to provide a slow coastdown of flow so that fuel thermal limits cannot be exceeded as a result of recirculation system malfunctions. The arrangement of the recirculation system routing is such that a piping failure cannot compromise the integrity of the floodable inner volume of the reactor vessel.

Venturi-type main steam line (MSL) flow restrictors are installed in each MSL inside the primary containment. The restrictors are designed to limit the loss of coolant resulting from a main steam line break (MSLB) outside the primary containment. The coolant loss is limited so that reactor vessel water level remains above the top of the core during the time required for the main steam isolation valves (MSIV) to close. This action protects the fuel barrier.

Two isolation valves are installed on each MSL, one located inside and the other located outside the primary containment. In the event that a MSLB occurs inside the containment, closure of the isolation valve outside the primary containment acts to seal the primary containment itself. The MSIVs automatically isolate the RCPB in the event a pipe break occurs downstream of the inside isolation valves. This action limits the loss of coolant and the release of radioactive materials from the nuclear system. Details of the MSIVs are given in Section 5.4.5.

The reactor core isolation cooling (RCIC) system provides makeup water to the core during a reactor shutdown in which feedwater flow is not available. The system is automatically initiated upon receipt of a low reactor water level signal or manually by the Operator. Water is pumped to the core by a steam turbine-driven pump.

The residual heat removal (RHR) system includes a number of pumps and heat exchangers that can be used to cool the nuclear system under a variety of situations. During normal shutdown and reactor servicing, the RHR system removes residual and decay heat. The RHR system allows decay heat to be removed whenever the main heat sink (main condenser) is not available (e.g., hot standby). One mode of RHR operation allows the removal of heat from the primary containment following a LOCA. Another operational mode of the RHR system is low-pressure coolant injection (LPCI). The LPCI mode of operation is part of the

3. Included with the SRV is an instruction manual provided to the customer. Within this manual will be recommended periodic maintenance programs as recommended by the manufacturer based upon his experience.

During the inservice (operational) phase, all main steam SRVs will be subject to the following tests and inspections in accordance with the IST program:

During every refueling outage, a sample of the installed valves will be tested for verification of set-pressures, opening and closing using the pneumatic power actuator, testing of all bolted closures, and testing of pneumatic actuator leakage. Valve sample size will be in accordance with the IST program plan.

After the preceding testing, the valves will undergo preventive maintenance in accordance with an approved procedure.

All disassembled valves will be inspected for wear, damage, and erosion. All gaskets, seals, and parts will be replaced as needed in accordance with inspection results. Valves will be relapped, as required, and lubricated. All disassembled valves will be retested, and appropriate adjustments will be made prior to use.

It is not feasible to test the SRV setpoints while the valves are in place. The valves are mounted on 1,500-lb primary service rating flanges. They can be removed for maintenance or bench checks and reinstalled during normal plant shutdowns. SRVs are tested and adjusted in accordance with the Code, 10CFR50.55a, Technical Specifications, and the IST program. The external surface and seating surface of all SRVs are 100-percent visually inspected when the valves are removed for maintenance or bench tests. Valve operability was verified during the preoperational test program as discussed in Chapter 14.

A discussion of SRV operability testing for two-phase flow, in accordance with NUREG-0737, is provided in Section 1.10, Task II.D.1.

5.2.3 Reactor Coolant Pressure Boundary Materials

5.2.3.1 Material Specifications

Table 5.2-5 lists the principal pressure-retaining components and materials and the appropriate material specifications for the RCPB components.

5.2.3.2 Compatibility with Reactor Coolant

5.2.3.2.1 PWR Chemistry of Reactor Coolant

Not applicable to boiling water reactors (BWRs).

5.2.3.2.2 BWR Chemistry of Reactor Coolant

Materials in the RCS are primarily austenitic stainless steel, carbon steel, and Zircaloy cladding. The reactor water chemistry limits are established to provide an environment favorable to these materials. Limits are placed on conductivity and chloride concentrations. Conductivity is limited because it can be continuously and reliably measured and gives an indication of abnormal conditions and the presence of unusual materials in the coolant. Chloride limits are specified to prevent stress corrosion cracking of stainless steel[2].

The water quality requirements are supported by General Electric Company (GE) stress corrosion test data summarized as follows:

1. Type 304 stainless steel specimens were exposed in a flowing loop operating at 537°F. The water contained 1.5 ppm chloride and 1.2 ppm oxygen at a pH of 7. Test specimens were bent beam strips stressed over their yield strength. After 2,100-hr exposure, no cracking or failures occurred.

2. Welded Type 304 stainless steel specimens were exposed in a refreshed autoclave operating at 550°F. The water contained 0.5 ppm chloride and 1.5 ppm oxygen at a pH of 7. Uniaxial tensile test specimens were stressed at 125 percent of their 550°F yield strength. No cracking or failures occurred at 15,000-hr exposure.

When conductivity is in its normal range, pH, chloride, and other impurities affecting conductivity are also within their normal range[2]. When conductivity becomes abnormal, chloride measurements are made to determine whether they are also out of their normal operating values. Conductivity may be high due to the presence of a neutral salt which does not have an effect on pH or chloride. In such a case, high conductivity alone is not a cause for shutdown. In some types of water-cooled reactors, conductivities are high because of the purposeful use of additives. In BWRs, however, where no additives are used and where near-neutral pH is maintained, conductivity provides a good and prompt measure of the quality of the reactor water. Significant changes in conductivity provide the Operator with a warning mechanism so he can investigate and remedy the condition before reactor water limits are reached. Methods available to the Operator for correcting the out-of-specification condition include operation of the RWCU system or placing the reactor in the cold shutdown condition. The major benefit of cold shutdown is to reduce the temperature-dependent corrosion rates and

For piping, in manual welds with the gas tungsten arc (GTAW) and shielded metal arc (SMAW) welding processes, the heat input was limited by weaving and welding technique restrictions. Nonweaving (stringer bead) techniques were used where possible. When required, weaving was controlled to meet the following bead width limits: for GTAW, the lesser of five times the filler wire diameter or 7/16 in; for SMAW, the lesser of 4 times the electrode core wire diameter or 5/8 in. For automatic welding, heat input was restricted to 50,000 joules/in. Interpass temperature was restricted to 350°F for all stainless steel welds. High heat welding processes such as block welding and electroslag welding were not permitted. All weld filler metal and castings were required by specification to have a minimum of 5-percent delta ferrite.

Whenever any wrought austenitic stainless steel was heated to temperatures over 800°F, by means other than welding or thermal cutting, the material was resolution heat treated. These controls were used to avoid severe sensitization and to comply with the intent of RG 1.44.

Process Controls to Minimize Exposure to Contaminants

Exposure to contaminants capable of causing stress corrosion cracking of austenitic stainless steel components was avoided by controlling cleaning and processing materials which contact the stainless steel during manufacture and construction. Special care is exercised to ensure removal of surface contaminants prior to any heating operations. Water quality for cleaning, rinsing, flushing, and testing was controlled and monitored. Suitable packaging and protection was provided for components to maintain cleanliness during shipping and storage. The degree of surface cleanliness obtained by these procedures meets the requirements of RG 1.44.

Cold-Worked Austenitic Stainless Steels

Austenitic stainless steels with a yield strength greater than 90,000 psi are not used.

5.2.3.4.2 Control of Welding

Avoidance of Hot Cracking

RG 1.31 describes an acceptable method of implementing requirements with regard to the control of welding when fabricating and joining austenitic stainless steel components and systems.

Written welding procedures that are approved by GE, other approved vendor, or NMPC are required for all primary pressure boundary welds. These procedures comply with the requirements of ASME Sections III and IX and applicable regulatory guides.

The areas where Unit 2 practices comply with RG 1.31 are as follows:

1. Verification of test results to 10CFR50 requirements for reporting (in accordance with ASME Code).

2. The minimum acceptable ferrite content of 5 percent (or 5 ferrite number [FN]) in undiluted weld pads and constitutional diagram evaluations.

3. Exemption of austenitic stainless steel cladding and Type 16Cr-8Ni-2Mo filler metal from ferrite control.

4. Measurements to be made prior to production welding on each heat and each lot of filler metal and/or flux combination.

Areas where some degree of variation occurred are as follows:

1. No maximum value was placed on ferrite content; however, RG 1.31 allows waivers in situations where the maximum may be exceeded.

2. Gauge Types for Measurement - The Unit 2 RPV requirements did not specify the type of magnetic measuring gauge, its calibration, or examination criteria to be used. Magnetic gauges were used. The type and calibration technique data may not be the same as required by RG 1.31.

3. Pad preparation technique for Unit 2 welds is in accordance with ASME Code SFA 5.9 in GE specifications which differ somewhat from AWS 5.4-74 techniques specified by RG 1.31. The ferrite variation due to these different techniques for pad deposition is not significant.

The variations that exist are considered minor in respect to accomplishing the basic purpose of RG 1.31. The specifications go beyond the regulatory guide requirements in that low carbon grades of filler metal were specified for improved corrosion resistance, and the need for a minimum ferrite content was recognized and actions implemented to assure its presence before RG 1.31 was published in any of its revisions. The main purpose of RG 1.31 was to provide added assurance by testing and documentation that the specified ferrite actually was present in the filler metal used in production. The procedures accomplished this even though there may have been slight differences in technique.

Electroslag Welds (Regulatory Guide 1.34)

Electroslag welding was not employed for RCPB components.

Welder Qualification for Areas of Limited Accessibility (Regulatory Guide 1.71)

RG 1.71 states that weld fabrication and repair for wrought low-alloy and high-alloy steels, or other materials such as static and centrifugal castings and bimetallic joints, should comply with fabrication requirements of ASME Sections III and IX. It also requires additional performance qualifications for welding in areas of limited access. All ASME Section III welds were fabricated in accordance with the requirements of ASME Sections III and IX. There are few restrictive welds involved in the fabrication of BWR components. Welder qualification for welds with the most restrictive access was accomplished by mockup welding. Mockups were examined by radiography or sectioning.

5.2.4 Inservice Inspection and Testing of Reactor Coolant Pressure Boundary

This section discusses the Unit 2 ISI program and IST program for ASME Class 1 components. The ISI program and the IST program were developed to meet the requirements of 10CFR50.55a and the inservice inspection and testing Codes.

5.2.4.1 System Boundary Subject to Inspection

The RPV, system piping, pumps, valves, and components within the RCPB defined as ASME Class 1 are designed and fabricated to permit compliance with ASME Section XI as required by 10CFR50.55a(b). The examination procedures required for ISI have been considered in the design of components, weld joint configurations, and system arrangement to assure access for inspection. Where required, access is provided for a volumetric and surface examination of pressure-retaining welds from the external surface. Periodic design reviews and onsite audits are performed throughout the design and erection phase to assure that these objectives are being met.

The ASME Class 1 components (including supports and pressure-retaining bolting) subject to inspection, according to the method specified in Table IWB-2500-1 of ASME Section XI, include the RPV and piping, pumps, and valves within the following systems. Where the system penetrates primary containment, the areas of examination on ASME Class 1 components, as defined in Table IWB-2500-1, will be extended up to and including the outside containment isolation valve.

1. Reactor pressure vessel.

2. Main steam lines.

3. Reactor feedwater lines.

4. Reactor recirculation lines.

5. RHR system lines.

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6. HPCS and LPCS lines.

7. RCIC system lines.

8. Standby liquid control/core ΔP line.

9. RWCU lines.

10. CRD housing.

11. RPV vent lines.

12. Reactor drain line.

5.2.4.2 Provisions for Access to the Reactor Coolant Pressure Boundary

5.2.4.2.1 Reactor Pressure Vessel

Access for examination of the RPV has been provided through provisions incorporated into the design of the vessel shield wall and vessel insulation as follows:

1. The shield wall and vessel insulation behind the shield wall are erected away from the RPV outside surface. Access ports are located at each RPV nozzle and at the base of the shield wall. The annular space between the RPV outside surface and insulation inside surface permits insertion of remotely-operated ultrasonic devices for examination of vessel longitudinal and circumferential welds. Access for insertion of the automated devices is provided at the base of the shield wall or through removable insulation panels at the top of the shield wall.

2. Access to the RPV circumferential, longitudinal, and nozzle-to-vessel welds above the shield wall is provided through use of removable insulation panels. Either manual or automated examination methods may be employed.

3. The vessel flange area and vessel closure head can be examined during normal refueling outages using manual ultrasonic methods. With the closure head removed, access is provided to the upper interior portion of the vessel by removal of the steam dryer and steam separator assemblies. Removal of these components also enables examination of the remaining internal RPV components utilizing remote visual techniques. The examination of the flange-to-vessel weld can be performed manually from the flange seal surface.

4. The closure head is dry stored during refueling. Removable insulation permits manual examination of all

welds on the vessel head from the outside surface. The nuts and washers are dry stored during refueling and may be examined at that time. All RPV studs are accessible for required examinations during refueling either in place or when removed.

5. Openings in the RPV support skirt provide access for manual or automated ultrasonic methods for examination of the RPV meridional and circumferential welds within the support skirt. Welds that are inaccessible will be identified in the ISI program plan.

Compliance with Regulatory Guide 1.150

The Unit 2 preservice examination is scheduled for 1985. Compliance with RG 1.150 will be discussed in the Unit 2 ISI program.

5.2.4.2.2 Pipe, Pumps, and Valves

Arrangements

Physical arrangement of pipe, pumps, and valves provides personnel access to weld locations. Working platforms are provided at areas to facilitate servicing of pumps and valves. Platforms and ladders are provided to gain access to piping welds including the pipe-to-vessel nozzle welds. Removable thermal insulation is provided on welds and components that require access for ISI.

Accessibility for Ultrasonic Examination

Welds are located to permit ultrasonic examination from at least one side, but where component geometries permit, access from both sides is provided. Consideration was given to weld joint configurations and surfaces during fabrication to permit thorough ultrasonic examinations.

5.2.4.3 Examination Techniques and Procedures

Examination techniques and procedures, including any special techniques and procedures, will be written in accordance with the requirements of Table IWB-2500-1 of ASME Section XI.

5.2.4.3.1 Equipment for In-service Inspection

Manual ultrasonic examination is planned for the preservice inspection and the subsequent in-service examination of the welds in the RPV top and bottom heads including the flange-to-vessel weld. Remote ultrasonic scanning will be used to examine the circumferential, longitudinal and nozzle-to-vessel welds on the balance of the vessel. The ISI program will delineate the equipment and methods used for ISI.

5.2.4.3.2 Coordination of Inspection Equipment with Access Provisions

Development of inspection equipment is followed closely to assure that ISI access provisions are adequate to permit their use.

5.2.4.3.3 Recording and Comparing Data

Manual data recording will be performed where manual examinations are performed. Electronic data recording and comparison analysis will be employed with automated examination equipment. Each ultrasonic transducer will be fed into an individual channel from which the key parameter of the reflectors will be recorded. The data to be recorded for both manual and automated methods will be in accordance with mandatory Appendix III of ASME Section XI.

5.2.4.4 Inspection Intervals

ISI intervals will be in accordance with Subarticle IWA-2400 in Section XI of the ASME Boiler and Pressure Vessel Code. Each interval is divided into inspection periods in accordance with Table IWB-2412-1 (Inspection Program B) in Section XI. The inservice schedule and inspections to be performed during each period and interval are defined in the ISI program plan.

5.2.4.5 Inservice Inspection Program Categories and Requirements

Examination categories and requirements are defined in the ISI program plan, and closely follow the categories and requirements specified in Table IWB-2500-1 of ASME Section XI.

5.2.4.6 Evaluation of Examination Results

Results of the preoperational examinations and subsequent inservice examinations will be evaluated in accordance with Article IWB-3000 of ASME Section XI.

5.2.4.7 System Leakage and Hydrostatic Pressure Tests

System leakage tests and hydrostatic tests will be performed as required in accordance with IWA-5000 and IWB-5000 of ASME Section XI, and the Inservice Pressure Testing (ISPT) program plan. The scheduling, conduct, and acceptance criteria for these tests are described in the ISPT program plan and its implementing documents. Visual examinations for evidence of leakage will be performed during these tests. Insulation and components need not be removed during the tests.

5.2.4.8 Inservice Inspection Commitment

All safety class components will be examined once prior to startup in accordance with the requirements in Technical

Specifications. This preservice inspection examination satisfied the requirements of ASME XI for the RPV and associated piping, pumps, and valves. The preservice examinations and tests were based on the ASME Boiler and Pressure Vessel Code, Section XI, 1980 Edition through the Winter 1980 Addenda, except for the extent of examination of ASME Class 2 piping of the RHR system, ECCS, and containment heat removal system. The extent of examination for these systems was based on ASME Section XI, 1974 Edition through Summer 1975 Addenda.

Portions of ANSI B31.1 upgraded piping ≥ 2 1/2 in in the main steam system extending from the outboard MSIVs up to and including the turbine stop valves, including branch connection lines ≥ 2 1/2 in up to the first isolation valve in the branch lines, were examined in accordance with ASME Section XI, 1980 Edition through Winter 1980 Addenda.

(See Section 3.9A.6 for the IST program for pumps and valves.) Subsequent ISIs will be performed in accordance with the requirements of 10CFR50.55a(g) as described in the ISI program.

Additionally, the ISI program for piping identified in Nuclear Regulatory Commission (NRC) Generic Letter (GL) 88-01 will be performed in accordance with the NRC staff positions on schedule, methods, personnel, and sample expansion included in this generic letter. GL 88-01 applies to all BWR piping made of austenitic stainless steel that is 4 in or larger in nominal diameter and contains reactor coolant at a temperature above 200°F during power operation, regardless of ASME Code classification.

5.2.5 RCPB and ECCS Leakage Detection System

5.2.5.1 Leakage Detection Methods

The nuclear boiler leak detection system (LDS) consists of temperature, pressure, level, flow, airborne gaseous and particulate fission product sensors, and process radiation sensors with associated instrumentation used to indicate and alarm leakage from the RCPB. The LDS in certain cases is used to initiate signals used for automatic closure of isolation valves to shut off leakage external to the containment. The system is assessed to be in conformance with RG 1.45. Those portions of the system which affect automatic isolation of leakage are designed to IEEE-279-1971 (refer to Table 3.2-1).

Abnormal leakage from the following systems within the containment and within the selected areas of the plant outside the primary containment is detected, indicated, alarmed and, in certain cases, isolated.

1. Main steam lines.

2. RWCU system.

3. RHR system.

4. RCIC system.

5. Feedwater system.

6. HPCS.

7. Coolant systems within the containment.

8. LPCS.

9. RPV.

10. Miscellaneous systems.

Leak detection methods used to obtain conformance with RG 1.45 for plant areas inside the primary containment differ from those for areas located outside the primary containment. These areas are considered separately in the following sections.

5.2.5.1.1 Detection of Leakage Within the Primary Containment

The primary detection methods for small unidentified leaks within the primary containment include continuous monitoring of drywell floor drain tank fill rate and airborne gaseous and particulate radioactivity increases. (The sensitivities of these primary detection methods for unidentified leakage within the primary containment are listed in Table 5.2-8.) These variables are continuously indicated and/or recorded in the control room. If the unidentified leakage increases to a total of 5 gpm, the detecting instrumentation channel(s) will trip and activate an alarm in the main control room. This does not result in a containment isolation signal.

The secondary detection methods (i.e., the monitoring of pressure and temperature of the primary containment atmosphere) are used to detect gross unidentified leakage. High primary containment pressure will alarm and trip the isolation logic which results in closure of the containment isolation valves.

The detection of small identified leakage within the primary containment is accomplished by continuous drywell equipment drain tank fill rate monitoring. An alarm will be activated in the main control room when the leak rate reaches 25 gpm averaged over a 24-hr period.

The determination of the source of identified leakage within the primary containment is accomplished by monitoring the drain lines to the drywell equipment drain tank from various potential leakage sources. These include reactor recirculation pump seal drain flow and reactor vessel head seal drain line pressure. Additionally, temperature is monitored in the SRVDLs to the suppression pool to detect leakage through each of the SRVs. All

TABLE 5.2-5

REACTOR COOLANT PRESSURE BOUNDARY MATERIALS

Component	Form	Material	Specification (ASTM/ASME)
<u>Reactor Pressure Vessel</u>			
Reactor vessel heads, shells	Rolled plate or forgings Welds	Low-alloy steel Low-alloy steel	SA-533 Gr. B Cl. 1 or SA-508 Cl. 2 SFA5.5
Closure flange	Forged ring Welds	Low-alloy steel Low-alloy steel	SA-508 Cl. 2 SFA5.5
Nozzles	Forged shapes Welds	Low-alloy steel Low-alloy steel	SA-508 Cl. 2 SFA5.5
Nozzle safe ends	Forgings or plates	Stainless steel	SA-182, F304, or F316 SA-336, F8 or F8M SA-240, 304 or 316
	Welds	Stainless steel	SFA5.9 Tp. 308L or 316L SFA5.4 Tp. 308L or 316L
Nozzle safe ends	Forgings Welds	Ni-Cr-Fe Ni-Cr-Fe	SB-166 or SB-167 SFA5.14 Tp. ER NiCr-3 or SFA5.11 Tp. ENi CrFe-3
Nozzle safe ends	Forgings Welds	Carbon steel Carbon steel	SA-508 Cl. 1 SFA5.1, SFA5.18 GPA or SFA5.17 F70
Nozzle to safe end weld	Weld overlay repair	Alloy 52	Code Case 2142/2143 UNS N06052/UNS W86152
Cladding	Weld overlay	Austenitic stainless steel	N/A
<u>Main Steam Safety Relief Valve</u>			
Body	Cast	Carbon steel	SA-352 LCB
Seat	Forging	Carbon steel	SA-350 LF2
Disc	Cast	Stainless steel	SA-351 CF3A

TABLE 5.2-5 (Cont'd.)

Component	Form	Material	Specification (ASTM/ASME)
Main Steam Flow Element			
Instrument nozzle	Forging	Carbon steel	SA-105
Upstream casting	Cast	Stainless steel	SA-351 Tp. CF8
Downstream casting	Cast	Stainless steel	SA-216 Gr. WCB

TABLE I: SAFETY/RELIEF VALVE SUFFIX ASSIGNMENT AND ASSOCIATED EQUIPMENT

		A	B	C	D	E	F	G	H	J	K	L	M	N	P	R	S	U	V
SAFETY/RELIEF VALVE	F013	F013-1	F013-1	F013-5	F013-2	F013-2	F013-3	F013-3	F013-5	F013-2	F013-4	F013-4	F013-4	F013-5	F013-3	F013-4	F013-3	F013-5	F013-2
ACCUMULATOR	A003 (ADS)	—	—	C	—	—	—	—	H	—	K	—	M	N	—	R	—	U	—
	A004	A	B	C	D	E	F	G	H	J	K	L	M	N	P	R	S	U	V
CHECK VALVE	F036	A	B	C	D	E	F	G	H	J	K	L	M	N	P	R	S	U	V
	F040 (ADS)	—	—	C	—	—	—	—	H	—	K	—	M	N	—	R	—	U	—
VACUUM BREAKER	F037 & F101	A	B	C	D	E	F	G	H	J	K	L	M	N	P	R	S	U	V
TEMP ELEMENT	N004	A	B	C	D	E	F	G	H	J	K	L	M	N	P	R	S	U	V
COMPUTER INPUTS FOR VALVE POS (SUPPL DOC. 3)		C1732	C1733	C1734	C1735	C1736	C1737	C1738	C1739	C1740	C1741	C1742	C1743	C1744	C1745	C1746	C1747	C1748	C1749
ADS FUNCTION				YES					YES		YES		YES	YES		YES		YES	
PRESS IND SWITCH	N668	A/E	A/E	—/—	—/—	—/—	—/—	—/—	—/—	—/—	—/—	—/—	—/—	—/—	—/—	—/—	—/—	—/—	—/—
PRESSURE SWITCH	N669	—/—	—/—	—/—	A/E	A/E	—/—	—/—	—/—	A/E	—/—	—/—	—/—	—/—	—/—	—/—	—/—	—/—	A/E
	N670	—/—	—/—	—/—	—/—	—/—	A/E	A/E	—/—	—/—	—/—	—/—	—/—	—/—	A/E	—/—	A/E	—/—	—/—
	N671	—/—	—/—	—/—	—/—	—/—	—/—	—/—	—/—	—/—	A/E	A/E	A/E	—/—	—/—	A/E	—/—	—/—	—/—
	N672	—/—	—/—	A/E	—/—	—/—	—/—	—/—	A/E	—/—	—/—	—/—	—/—	A/E	—/—	—/—	—/—	A/E	—/—

ADS - SAFETY/RELIEF VALVE FOR AUTO DEPRESSURIZATION
FOR THE NUMBER OF SRV'S WHICH SHALL BE CONTROLLABLE
FROM THE REMOTE SHUTDOWN SYSTEM (BY AE) - SEE NOTE 4

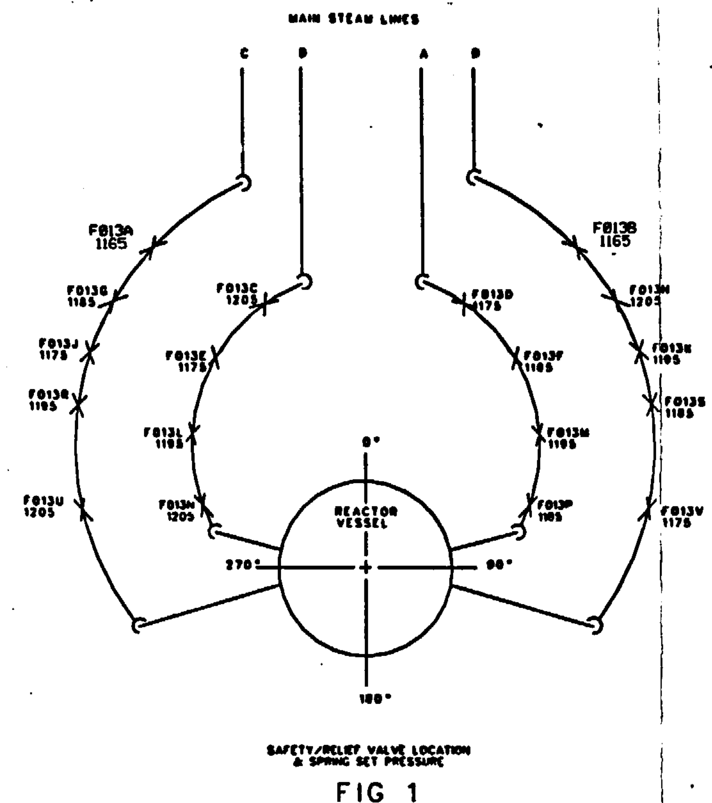
TABLE II: JET PUMP INSTRUMENTATION SUFFIX LETTER ASSIGNMENT

LOOP	A										B									
JP NO.	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
FT N034	A	C	E	G	J	L	N	R	T	V	B	D	F	H	K	M	P	S	U	W
E/S N615																				
DPI R600	A	C	E	G	J	L	N	R	T	V	B	D	F	H	K	M	P	S	U	W
√ K600	A	C	E	G	J	L	N	R	T	V	B	D	F	H	K	M	P	S	U	W
Σ	K601A				K601C				K607A		K601B				K601D				K607B	
Σ	K602A										K602B									
⚠C	A1751	A1752	A1753	A1754	A1755	A1756	A1757	A1758	A1759	A1760	A1761	A1762	A1763	A1764	A1765	A1766	A1767	A1768	A1769	A1770
FT N033	—	—	—	—	A	—	—	—	—	C	—	—	—	—	B	—	—	—	—	D
√ K605	—	—	—	—	A	—	—	—	—	C	—	—	—	—	B	—	—	—	—	D
FI R609	—	—	—	—	A	—	—	—	—	C	—	—	—	—	B	—	—	—	—	D

TABLE VI: ELEVATION CORRELATION CHART

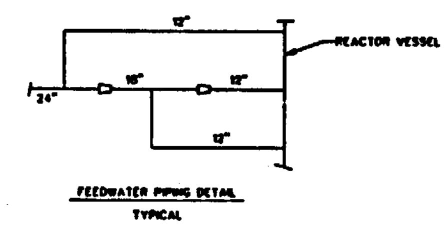
REFERENCE	(COLD VESSEL) INCHES ABOVE VESSEL ZERO	DESCRIPTION OF TRIPS	INSTRUMENT(S) PROVIDING TRIP	REACTOR VESSEL LEVEL IDENTITY (SEE SUPPL DOC 25 OF P&ID)	CONTROL ROOM WATER LEVEL INDICATION AND TRIP LEVELS (SEE NOTE 3): SAFEGUARDS – FUEL ZONE LR R615 LI R610	SAFEGUARDS – WIDE RANGE LR/PR R623A,B LI R604	SAFEGUARDS – NARROW RANGE C33 LR R608	FEEDWATER – NARROW RANGE C33 LI R606A,B,C	UPSET C33 LR R608	SHUTDOWN LI R605
										345"
TOP OF HEAD FLANGE	808 MAX								323"	
STEAM LINE NOZZLE N3	646									
INSTRUMENT LINE NOZZLE N14	568					205"	206"	206"		
		TRIP RCIC & CLOSE HPCS INJECTION VALVE CLOSE MAIN TURBINE STOP VALVES. TRIP FEED PUMPS	TABLE IV SUPPL DOC 2	8		202.3"	202.3"	202.3"		
		HIGH LEVEL ALARM	SUPPL DOC 2	7				187.5"		
		NORMAL WATER LEVEL	SUPPL DOC 2							
		LOW LEVEL ALARM RUN RECIRC FLOWBACK*	SUPPL DOC 2	4				178.3"		
		SCRAM & CLOSE RHR SHUTDOWN COOLING ISOLATION VALVES CONTRIBUTE TO AUTO DEPRESSURIZATION TRIP RECIRC PUMPS TO LOW FREQUENCY MG SETS (LFMG)*	TABLE IV SUPPL DOC 2	3			159.5"	159.5"		
BOTTOM OF DRYER SKIRT -18 IN. FOR BOTTOM OF NARROW, UPSET & SHUTDOWN SCALES	528.7						145"	145"	146"	146"
INSTRUMENT LINE NOZZLE N13	517	INITIATE RCIC & HPCS. CLOSE PRIMARY SYSTEMS ISOLATION VALVES EXCEPT RHR SHUTDOWN COOLING. DRYWELL FAN COOLER'S COOLING WATER ISOLATION VALVES. ISOLATION VALVES FOR MSIV'S AIR SUPPLY AND MSIV'S PROVIDE SIGNAL TO RRCS.**	TABLE IV	2	35"	108.8"				
WATER LEVEL INSTRUMENT ZERO	380.7	INITIATE RESIDUAL HEAT REMOVAL PUMPS & CORE SPRAY SYSTEM, CONTRIBUTE TO AUTO-DEPRESSURIZATION, AND START STANDBY DIESEL GENERATOR. CLOSE: MSIV'S ISOLATION VALVES FOR AIR SUPPLIES TO THE MSIV'S, AND DRYWELL COOLING WATER ISOLATION VALVES.	TABLE IV	1		17.8" / -5"	0"	0"	0"	0"
TOP OF ACTIVE FUEL	362.3				-18.4"					
INSTRUMENT LINE NOZZLE N12	366				-185"					
JET PUMP INSTRUMENT NOZZLE N9	192.0									
JET PUMP DIFFUSER TAP	143.5									

* FUNCTION IS IN FEEDWATER CONTROL SYSTEM (SUPPL DOC 2)
** SUPPL DOC. 6 & 7

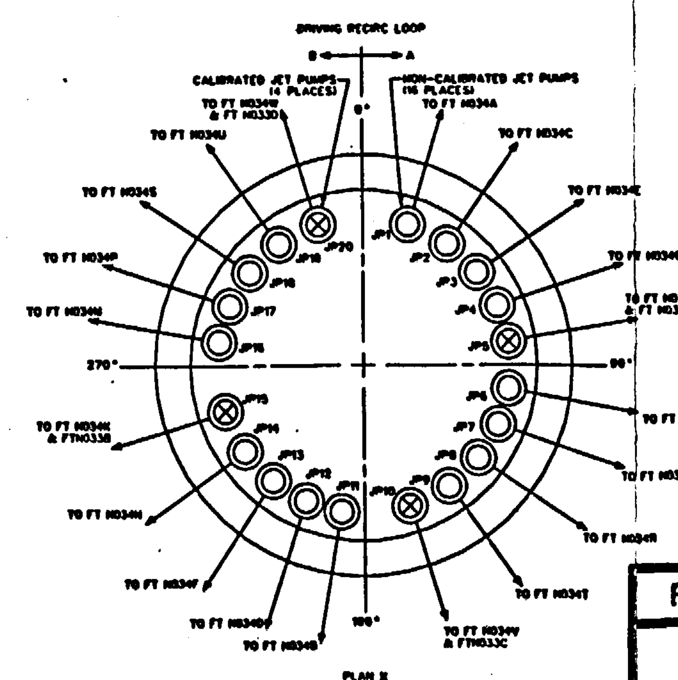


SAFETY/RELIEF VALVE LOCATION & SPRING SET PRESSURE

FIG 1



FEEDWATER PIPING DETAIL
TYPICAL



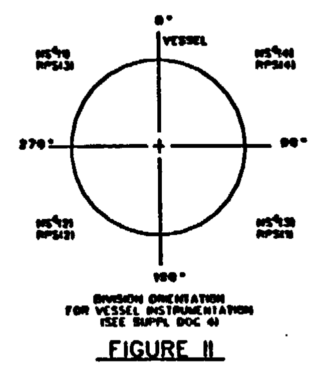
PLAN II

NOTES

1. SUPPL. DOC. 1 SHALL BE USED WITH AND FORM A PART OF THIS P&ID DATA. IF THERE ARE ANY CONFLICTS BETWEEN THE P&ID AND THIS P&ID DATA, THE P&ID DATA SHALL GOVERN.
2. MPL NO.'S ARE PREFIXED BY B22 UNLESS OTHERWISE NOTED.
3. WATER LEVEL INSTRUMENTS FOR VARIOUS RANGES ARE CALIBRATED AS STATED BELOW. ALL WATER LEVEL SWITCH SETPOINTS ARE NOMINAL; I.E., THE ANALYSES ARE PERFORMED WITH THE SWITCH TRIP UNCERTAINTY INCLUDED. REACTOR BUILDING TEMPERATURE ASSUMED TO BE 75°F.
   A. FUEL ZONE: THE INSTRUMENTS ARE CALIBRATED FOR SATURATED WATER STEAM CONDITIONS AT 0 PSIG IN THE VESSEL AND THE DRYWELL WITH NO JET PUMP FLOW.
   B. WIDE RANGE: THE INSTRUMENTS ARE CALIBRATED FOR 1020 PSIG IN THE VESSEL, 135°F IN THE DRYWELL AND 20 BTU/LB SUB-COOLING BELOW THE MIDDLE WATER LEVEL NOZZLE AND SATURATED CONDITIONS ABOVE THE MIDDLE WATER LEVEL NOZZLE WITH NO JET PUMP FLOW.
   C. NARROW RANGE: (SAFEGUARDS AND FEEDWATER): THE INSTRUMENTS ARE CALIBRATED FOR SATURATED WATER STEAM CONDITIONS AT 1020 PSIG IN THE VESSEL AND 135°F IN THE DRYWELL.
   D. UPSET RANGE: THE INSTRUMENT IS CALIBRATED FOR SATURATED WATER STEAM CONDITIONS AT 1020 PSIG IN THE VESSEL AND 135°F IN THE DRYWELL.
   E. SHUTDOWN: THE INSTRUMENT IS CALIBRATED FOR 120°F. WATER AT 0 PSIG IN THE VESSEL AND 80°F IN THE DRYWELL.
4. THE NUMBER OF SRV'S WHICH SHALL BE CONTROLLABLE (OPEN-CLOSED) FROM THE REMOTE SHUTDOWN SYSTEM SHALL BE ADEQUATE TO BRING THE REACTOR TO COLD SHUTDOWN TAKING THE FOLLOWING INTO ACCOUNT:
   - REACTOR DECAY HEAT
   - HEAT REMOVAL FOR REACTOR COOLDOWN (DEPRESSURIZATION) TO BELOW THE RHR SHUTDOWN COOLING PRESSURE PERMISSIVE (~100 PSIG)
   - SUPPRESSION POOL HEAT UP - ASSUME REACTOR ISOLATED IMMEDIATELY AFTER SCRAM WITH ALL HEAT DUMP GOING TO THE POOL. REACTOR DEPRESSURIZATION RATE MUST BE RAPID ENOUGH TO AVOID SRV DISCHARGE CONDENSATION OSCILLATION PROBLEMS IN THE POOL.

SUPPLEMENTAL DOCUMENTS UNDER THE FOLLOWING IDENTITIES ARE TO BE USED IN CONJUNCTION WITH THIS DRAWING:

	REFERENCE DESIGNATOR
1. NUCLEAR BOILER SYSTEM P&ID	B22-1010
2. FEEDWATER CONTROL SYSTEM IED	C33-1010
3. NUCLEAR BOILER SYSTEM FCD	B22-1030
4. ELEC EQPT SEP SAFEGUARD SYS	A62-4090
5. REMOTE SHUTDOWN SYSTEM IED	BY AE
6. REDUNDANT REACTIVITY CONTROL SYSTEM DES. SPEC	C22-4010
7. REDUNDANT REACTIVITY CONTROL SYSTEM ELEM DIA.	C22-1010



DIVISION ORIENTATION FOR VESSEL INSTRUMENTATION (SEE SUPPL DOC 4)

FIGURE II

SOURCE: 761E445AF - 07

FIGURE 5.2-4

NUCLEAR BOILER SYSTEM
P&ID
SHEET 1 OF 2

NIAGARA MOHAWK POWER CORPORATION
NINE MILE POINT-UNIT 2
UPDATED SAFETY ANALYSIS REPORT

5.3 REACTOR VESSEL

5.3.1 Reactor Vessel Materials

5.3.1.1 Materials Specifications

The materials used in the RPV and appurtenances are listed in Table 5.2-5 together with the applicable specifications.

5.3.1.2 Special Processes Used for Manufacturing and Fabrication

The RPV is primarily constructed from low-alloy, high-strength steel plate and forgings. Plates are ordered to ASME SA-533 Grade B, Safety Class 1, and forgings to ASME SA-508, Safety Class 2. These materials are melted to fine grain practice and are supplied in the quenched and tempered condition. Further requirements include vacuum degassing to lower the hydrogen level and improve the cleanliness of the low-alloy steels.

Studs, nuts, and washers for the main closure flange are ordered to ASME SA-540, Grade B23 or B24. Welding electrodes are low-hydrogen type ordered to ASME SFA-5.5, SFA-5.1, SFA-5.4, SFA-5.9, SFA-5.11, SFA-5.14, SFA-5.17, and SFA-5.18.

All plate, forgings, and bolting are 100-percent ultrasonically tested and surface examined by magnetic particle methods or liquid penetrant methods in accordance with ASME Section III standards. Fracture toughness properties are also measured and controlled in accordance with ASME Section III requirements. Refer to Appendix 5A, Section 5A.1, for discussion.

The RPV was fabricated in accordance with GE-approved drawings, fabrication procedures, and test procedures. The shells and vessel heads are made from formed plates, and the flanges and nozzles from forgings. Welding performed to join these vessel components is in accordance with procedures qualified in accordance with ASME Section III and IX requirements. Weld test samples are required for each procedure for major vessel full penetration welds. Tensile and impact tests are performed to determine the properties of the base metal, heat-affected zone (HAZ), and weld metal.

Submerged arc and manual stick electrode welding processes are employed. Electroslag welding is not permitted. Preheat and interpass temperatures employed for welding of low-alloy steel meet or exceed the requirements of ASME Section III. Postweld heat treatment at 1,100°F minimum is applied to all carbon and low-alloy steel welds.

Radiographic examination is performed on all pressure-containing welds in accordance with requirements of ASME Section III, Subsubarticle NB-5320. In addition, all welds are given a supplemental ultrasonic examination.

The materials, fabrication procedures, and testing methods used in the construction of BWR RPVs meet or exceed requirements of ASME Section III, Safety Class 1 vessels.

5.3.1.3 Special Methods for Nondestructive Examination

The materials and welds on the RPV were examined in accordance with methods prescribed and meet the acceptance requirements specified by ASME Section III. In addition, the pressure-retaining welds were ultrasonically examined using manual techniques. The ultrasonic examination method, including calibration, instrumentation, scanning sensitivity, and coverage, was based on the requirements imposed by ASME Section XI, 1980 Edition through the Winter 1980 Addenda, Appendix I. Acceptance standards were equivalent to or more restrictive than those required by ASME Section XI, 1980 Edition through the Winter 1980 Addenda. Nozzle weld overlays for FWS are examined per the guidance of Code Case N504-1 and EPRI guidelines.

5.3.1.4 Special Controls for Ferritic and Austenitic Stainless Steels

5.3.1.4.1 Compliance With Regulatory Guides

Regulatory Guide 1.31 Controls on stainless steel welding are discussed in Section 5.2.3.4.2.

Regulatory Guide 1.34 Electroslag welding was not employed for the RPV fabrication.

Regulatory Guide 1.43 RPV specifications require that all low-alloy steel be produced to fine grain practice. The requirements of this regulatory guide are not applied to BWR vessels.

Regulatory Guide 1.44 Controls to avoid severe sensitization are discussed in Section 5.2.3.4.1.

Regulatory Guide 1.50 Preheat controls are discussed in Section 5.2.3.3.2.

Regulatory Guide 1.71 Qualification for areas of limited accessibility is discussed in Section 5.2.3.4.2.

Regulatory Guide 1.99 Predictions for changes in transition temperature and upper shelf energy were assessed to be in accordance with the requirements of RG 1.99.

5.3.1.5 Fracture Toughness

5.3.1.5.1 Compliance with 10CFR50 Appendix G

The interpretation of and compliance to Appendix G of 10CFR50 for Safety Class 1 RCPB components is as discussed in Section 5.3.2 and Appendix 5A with the following exceptions:

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In areas where brackets, such as the surveillance specimen holder brackets, are located, additional nondestructive examinations are performed on the vessel base metal and stainless steel weld-deposited cladding or weld buildup pads during vessel manufacture. The base metal is ultrasonically examined by straight beam techniques to a depth at least equal to the thickness of the bracket being joined. The area examined is the area of the subsequent attachment weld plus a surrounding band of width equal to at least half the thickness of the part joined. The required stainless steel weld-deposited cladding is similarly examined. The full penetration welds are liquid penetrant examined to ASME Section III standards. Cladding thickness is required to be at least 1/8 in. The above requirements have been successfully applied to a variety of bracket designs that are attached to weld-deposited stainless steel cladding or weld buildups in many operating BWR RPVs.

ISI examinations of core beltline pressure-retaining welds are performed from the outside surface of the RPV. If a bracket for mechanically-retaining surveillance specimen capsule holders were located at or adjacent to a vessel shell weld, it would not interfere with the straight beam or half node angle beam ISI ultrasonic examinations performed from the outside surface of the vessel.

NOTE: Surveillance specimen capsule at 3° azimuth location has been removed for testing to comply with Technical Specification 4.4.6.1.3 requirements.

5.3.1.7 Reactor Vessel Fasteners

The reactor vessel closure head (flange) is fastened to the reactor vessel shell flange by multiple sets of threaded studs and nuts. The lower end of each stud is installed in a threaded hole in the vessel shell flange. A nut and washer are installed on the upper end of each stud. The proper amount of preload can be applied to the studs by a sequential tensioning using hydraulic tensioners. The design and analysis of this area of the vessel is in full compliance with all ASME Section III, Safety Class 1, code requirements. The material for studs, nuts, and washers is SA-540 Grade B23 or B24 at the 130,000 psi-specified minimum yield strengths level.

Hardness tests are performed on all main closure bolting to demonstrate that heat treatment has been properly performed. A minimum of 45 ft-lb Charpy V-notch (C_V) energy and 25 mils lateral expansion is required at 70°F. The maximum reported ultimate tensile strength is below the 170,000-psi maximum specified in RG 1.65. Also, the Charpy impact test requirements of 10CFR50 Appendix G are satisfied, since the lowest reported C_v energy is 46 ft-lb at +10°F, compared to the requirement of 45 ft-lb at 70°F, and the lowest reported C_v expansion was 26 mils, compared to the 25 mils required. Studs, nuts, and washers are ultrasonically examined in accordance with ASME Section III, Paragraph NB-2585, and the following additional requirements:

1. Examination was performed after heat treatment and prior to machining threads.

2. Straight beam examination was performed on 100 percent of each stud. Reference standard for the radial scan is a 1/2-in diameter flat-bottom hole having a depth equal to 10 percent of the material thickness. For the end scan the standard of Paragraph NB-2585 is used.

3. Nuts and washers were examined by angle beam from the outside circumference in accordance with ASME SA-388 in both the axial and circumferential directions.

The surface examinations required by Paragraph NB-2583 are applied after heat treatment and threading.

There are no metal platings applied to closure studs, nuts, or washers. A manganese-phosphate coating is applied to threaded areas of studs and nuts and bearing areas of nuts and washers to assist in retaining lubricant on these surfaces. Subsequent to fabrication, the studs are lubricated with a graphite/alcohol or nickel powder base lubricant.

RG 1.65 defines acceptable materials and testing procedures with regard to reactor vessel closure stud bolting for light-water-cooled reactors.

The RPV closure studs are SA-540 Grade B23 or B24 (AISI-4340) and have a maximum ultimate tensile strength of 170 ksi. Additionally, the bolting material was specified to have Charpy V-notch impact properties of 45 ft-lb minimum with 25 mils lateral expansion. Nondestructive examination before and after threading is specified to be in accordance with ASME Section III, Subsubarticle NB-2580, which complies with RG 1.65 (C.2).

In accordance with RG 1.65 (C.2.b), the bolting materials were ultrasonically examined after final heat treatment and prior to threading. As required for compliance, the examination was done in accordance with SA-388. The procedures approved for use in practice were judged to ensure comparable material quality and, moreover, were considered adequate on the basis of compliance with the applicable requirements of ASME Section III, Paragraph NB-2583. Additionally, straight beam examination was performed on 100 percent of cylindrical surfaces, and from both ends of each stud using a 3/4-in maximum diameter transducer. In addition to the code-required notch, the reference standard for the radial scan contained a 1/2-in diameter flat-bottom hole with a depth equal to 10 percent of the thickness. The end scan standard contained a 1/4-in diameter flat-bottom hole 1/2-in deep. Angle beam ultrasonic examination was performed on the outer cylindrical surface in both a flat and circumferential direction. Surface examinations were performed on the studs and nuts after final heat treatment and threading, as specified by RG 1.65, in accordance with Paragraph NB-2583 of the applicable ASME Code.

Radial scan calibration is based on a 1/2-in (12.7-mm) diameter flat-bottom hole of a depth equal to 10 percent of the material thickness. Angle beam examination is performed on the outer cylindrical surface of nuts and washers in accordance with ASME SA-388 in both axial and circumferential directions. No indication greater than the indication from the applicable calibration feature was acceptable. A distance-amplitude correction curve in accordance with Paragraph NB-2858 is used for the longitudinal wave examination.

In relationship to RG 1.65 (C.3), stud bolting surfaces are allowed to be exposed to high-purity fill water; nuts and washers are dry stored during refueling.

5.3.2 Pressure-Temperature Limits

5.3.2.1 Limit Curves

The fracture toughness requirements for the pressure vessel for testing and operational conditions are specified in Section IV of 10CFR50 Appendix G (May 1983). This appendix requires implementation of the acceptance and performance criteria of Appendix G to Section III of the ASME Code. The basis for the technical requirements of the ASME Code is discussed in Welding Research Council Bulletin 175. Appendix G to 10CFR50 requires that the effects of neutron irradiation on the RT_{NDT} of the beltline materials must be included in the P-T curve calculations. The latest revision (Revision 2) to RG 1.99 is used for this purpose. Calculated adjusted nil ductility transition reference temperature (ART_{NDT}) values and temperature limits are given in this section for limiting locations in the reactor vessel. The P-T limit curves are presented in Figures 5.3-2a through 5.3-2e.

All vessel shell and head areas remote from discontinuities, plus the feedwater nozzles, were evaluated and the operating limit curves are based on the limiting location. The boltup limits for the flange and adjacent shell region are based on a minimum metal temperature of the RT_{NDT} of the flange and adjacent shell region (10°F) plus 60°F. The maximum through-wall temperature gradient from continuous heating or cooling at 100°F/hr was used. The safety factors applied were as specified in ASME Code Section III, Appendix G.

P-T curve calculations are performed on the beltline material which has the highest ART_{NDT} over the period for which the P-T curves are valid. Therefore, ART_{NDT} calculations were performed using RG 1.99 Revision 2, and the results are presented in Tables 5.3-2a and 5.3-2b. The limiting material is plate C3147.

5.3.2.1.1 Temperature Limits for Boltup

A minimum temperature of 70°F is required for the closure studs. A sufficient number of studs can be fully tensioned at 70°F to seal the closure flange O-rings for the purpose of raising the reactor water level above the closure flanges to assist in warming them. The flanges and adjacent shell are required to be warmed to minimum temperature of 70°F before they are stressed by the required bolt preload. The fully preloaded boltup limits are shown on Figures 5.3-2a through 5.3-2e.

The RT_{NDT} is no greater than +10°F for both the vessel and the head flange material as well as the plate material that is connected to the closure flanges.

5.3.2.1.2 Temperature Limits for Preoperational System Hydrostatic Tests and Inservice Pressure Tests

Based on 10CFR50 Appendix G, if there is no fuel in the reactor, the preoperational system hydrostatic test at 1,563 psig may be performed at a minimum temperature of 100°F.

The fracture toughness analysis for in-service system pressure test with fuel in the vessel resulted in the P-T limits shown on Figure 5.3-2a. The curves are based on an initial RT_{NDT} of 0°F.

The calculated adjustment to the RT_{NDT} shown on Figure 5.3-3 (based on Revision 2 to RG 1.99) is used in the analysis to account for the effect of fast neutrons.

The predicted shift in the RT_{NDT} from Figure 5.3-3 (based on the neutron fluence at 1/4 T of the vessel wall thickness) is added to the beltline curve to account for the effect of fast neutrons.

5.3.2.1.3 Operating Limits During Heatup, Cooldown, and Core Operation

The fracture toughness analysis was done for the assumed heatup or cooldown rate of 100°F/hr. The temperature gradients and thermal stress effects corresponding to this rate were included. The results of the analyses are a set of operating limits for noncritical heatup, noncritical cooldown, and critical operations (heatup and cooldown) as shown on Figures 5.3-2b through 5.3-2e. Figures 5.3-2d and 5.3-2e apply whenever the core is critical.

RG 1.99 Revision 2 requires an estimation of the standard deviation (σ_I) of the initial RT_{NDT}. The RT_{NDT} for plate C3147 was

c. Operational margins to be observed with regard to the transition temperature are specified for each mode of operation.

5.3.3.1.3 Power Generation Design Basis

The design of the reactor vessel and appurtenances meets the following power generation design bases:

1. The reactor vessel has been designed for a useful life of 40 yr.

2. External and internal supports that are integral parts of the reactor vessel are located and designed so that stresses in the vessel and supports that result from reactions at these supports are within ASME Code limits.

3. Design of the reactor vessel and appurtenances allows for a suitable program of inspection and surveillance.

5.3.3.1.4 Reactor Vessel Design Data

The reactor vessel design pressure is 1,250 psig and the design temperature is 575°F. The maximum installed test pressure is 1,563 psig.

Vessel Support

The concrete and steel vessel support pedestal is constructed as an integral part of the building foundation. Steel anchor bolts, set in the concrete, extend through the bearing plate and secure the flange of the reactor vessel support skirt to the bearing plate, and thus to the support pedestal.

Control Rod Drive Housings

The CRD housings are inserted through the CRD penetrations in the reactor vessel bottom head and are welded to the reactor vessel. Each housing transmits loads to the bottom head of the reactor. These loads include the weights of a control rod, a CRD, a control rod guide tube, a four-lobed fuel support piece, and the four fuel assemblies that rest on the fuel support piece. The housings are fabricated of Type 304 austenitic stainless steel.

In-core Neutron Flux Monitor Housings

Each in-core neutron flux monitor housing is inserted through the in-core penetrations in the bottom head and is welded to the inner surface of the bottom head. An in-core flux monitor guide tube is welded to the top of each housing and either a source range monitor/intermediate range monitor (SRM/IRM) drive unit or a local power range monitor (LPRM) is bolted to the seal ring flange at the bottom of the housing (Section 7.6).

Reactor Vessel Insulation

The reactor vessel insulation has an average maximum heat transfer rate of approximately 44.0 Btu/hr/sq ft of insulation surface at the operating conditions of 550°F for the vessel and 135°F for the drywell air. The bottom head insulation heat transfer rate is 80 Btu/hr/sq ft. The insulation panels for the cylindrical shell of the vessel are held in place by insulation supports located on the biological shield. The bottom head insulation is supported by the skirt flange. The insulation is designed to be removable over those portions of the vessel where inspection is required by the ISI program plan.

Reactor Vessel Nozzles

All piping connected to the reactor vessel nozzles has been designed so as not to exceed the allowable loads on any nozzle.

The vessel top head nozzle has a flange with large groove facing. The drain nozzle is of the full penetration weld design. The recirculation inlet nozzles (located as shown on Figure 5.3-4), feedwater inlet nozzles, core spray inlet nozzles, and the LPCI nozzles all have thermal sleeves. Nozzles connecting to stainless steel piping have safe ends or extensions made of stainless steel (316) with Inconel weld. These safe ends or extensions are welded to the nozzles after the pressure vessel is heat treated to avoid furnace sensitization of the stainless steel. The material used is compatible with the material of the mating pipe, as shown in Table 5.2-5.

The nozzle for the standby liquid control (SLC) pipe is designed to minimize thermal shock effects on the reactor vessel in the event that use of the standby liquid control system (SLCS) is required.

The solution to the feedwater nozzle cracking problem involved several elements including nozzle clad removal and thermal sleeve redesign. A description of the design changes incorporated for Unit 2 and appropriate analysis to support such changes are presented in Reference 2.

Materials and Inspections

The reactor vessel was designed and fabricated in accordance with the appropriate ASME Boiler and Pressure Vessel Code as defined in Section 5.2.1. Table 5.2-5 defines the materials and specifications. Section 5.3.1.6 defines the compliance with reactor vessel material surveillance program requirements.

Reactor Vessel Schematic (BWR)

The reactor vessel schematic is contained on Figure 5.3-4. Trip system water levels are indicated as shown on Figure 5.3-5.

5.3.3.2 Materials of Construction

All materials used in the construction of the RPV conform to the requirements of ASME Section II materials. The vessel heads, shells, flanges, and nozzles are fabricated from low-alloy steel plate and forgings purchased in accordance with ASME Specifications SA-533 Grade B, Safety Class 1, and SA-508, Safety Class 2. Special requirements for the low-alloy steel plate and forgings are discussed in Section 5.3.1.2. Cladding employed on the interior surfaces of the vessel consists of austenitic stainless steel weld overlay. These materials of construction were selected because they provide adequate strength, fracture toughness, fabricability, and compatibility with the BWR environment. Their suitability has been demonstrated by long-term successful operating experience in reactor service.

5.3.3.3 Fabrication Methods

All fabrication of the RPV was performed in accordance with GE-approved drawings, fabrication procedures, and test procedures. The shell and vessel head were made from formed low-alloy steel plates, and the flanges and nozzles from low-alloy steel forgings. Welding performed to join these vessel components was in accordance with procedures qualified in accordance with ASME Section III and IX requirements. Weld test samples were required for each procedure for major vessel full penetration welds.

Submerged arc and manual stick electrode welding processes were employed. Electroslag welding was not permitted. Preheat and interpass temperatures employed for welding of low-alloy steel met or exceeded the requirements of ASME Section III, Subsection NA. Postweld heat treatment of 1,100°F minimum is applied to all carbon and low-alloy steel welds.

All previous BWR pressure vessels have employed similar fabrication methods. These vessels have operated for periods up to 20 yr and their service history is excellent. The vessel fabricator, CBI Nuclear Company, has had extensive experience with BWR reactor vessels and has been a primary supplier for domestic BWR vessels and some foreign vessels.

5.3.3.4 Inspection Requirements

All plate, forgings, and bolting were 100 percent ultrasonically tested and surface examined by magnetic particle methods or liquid penetrant methods in accordance with ASME Section III requirements. Welds on the RPV were examined in accordance with methods prescribed and meet the acceptance requirements specified by ASME Section III. In addition, the pressure-retaining welds were ultrasonically examined using acceptance standards that were required by ASME Section XI, 1980 Edition through the Winter 1980 Addenda.

5.3.3.5 Shipment and Installation

The completed reactor vessel was thoroughly cleaned and examined prior to shipment. The vessel was tightly sealed for shipment to prevent entry of dirt or moisture. Preparations for shipment were in accordance with detailed written procedures. On arrival at the reactor site the reactor vessel was carefully examined for evidence of any contamination as a result of damage to shipping covers. Suitable measures were taken during installation to ensure that vessel integrity was maintained; for example, access controls were applied to personnel entering the vessel, weather protection was provided, and periodic cleanings were performed.

5.3.3.6 Operating Conditions

Procedural controls on plant operation are implemented to hold thermal stresses within acceptable ranges. These restrictions on coolant temperature are:

1. The average rate of change of reactor coolant temperature during normal heatup and cooldown will not exceed 100°F during any 1-hr period.

2. If the coolant temperature difference between the dome (inferred from P) and the bottom head drain exceeds 145°F, neither reactor power level nor recirculation pump flow will be increased.

3. The pump in an idle reactor recirculation loop will not be started unless the coolant temperature in that loop is within 50°F of saturated reactor coolant temperature corresponding to the steam dome pressure.

The limit regarding the normal rate of heatup and cooldown (Item 1) assures that the vessel closure, closure studs, vessel support skirt, and CRD housing and stub tube stresses and usage remain within acceptable limits. The limit regarding a vessel temperature limit on recirculating pump operation and power level increase restriction (Item 2) augments the Item 1 limit. This limit ensures that the vessel bottom head region is not warmed at an excessive rate, caused by rapid sweepout of cold coolant in the vessel lower head region by recirculating pump operation or natural circulation (cold coolant can accumulate as a result of control drive in-leakage and/or low recirculation flow rate during startup or hot standby). The Item 3 limit further restricts operation of the recirculating pumps to avoid high thermal stress effects in the pumps and piping, while also minimizing thermal stresses on the vessel nozzles.

These operational limits when maintained ensure that the stress limits within the reactor vessel and its components are within the thermal limits to which the vessel was designed for normal operating conditions. To maintain the integrity of the vessel in the event that these operational limits are exceeded, the reactor

TABLE 5.3-1

UNIT 2 REACTOR VESSEL CHARPY TEST RESULTS
VESSEL BELTLINE CHEMICAL COMPOSITION

I. Vessel Beltline Material Identification

A. No. 2 shell ring

Plates	Pc. 22-1-1	Heat	C3065-1
	Pc. 22-1-2	Heat	C3121-2
	Pc. 22-1-3	Heat	C3147-1

Welds in No. 2 shell ring. Vertical seams BD, BE, BF
RACO-1NMM, Heat 5P5657, Lot 0931

B. No. 1 shell ring

Plates	Pc. 21-1-1	Heat	C3147-2
	Pc. 21-1-2	Heat	C3066-2
	Pc. 21-1-3	Heat	C3065-2

Welds in No. 1 shell ring. Vertical seams BA, BB, BC
RACO-1NMM, Heat 5P6214B, Lot 0331

C. Girth weld between No. 1 and No. 2 shell rings. Seam AB
RACO-1NMM, Heat 4P7465, Lot 0751
RACO-1NMM, Heat 4P7216, Lot 0751

II. Chemical Analyses For Beltline Materials (wt %)

A. Plates	C	Mn	P	S	Cu	Si	Ni	Mo	V	Al
Pc. 22-1-1, C3065-1	0.21	1.36	0.010	0.015	0.06	0.25	0.63	0.58	0	0.021
Pc. 22-1-2, C3121-2	0.20	1.25	0.012	0.015	0.09	0.26	0.65	0.56	0	0.030
Pc. 22-1-3, C3147-1	0.19	1.28	0.012	0.015	0.11	0.24	0.63	0.56	0	0.020
Pc. 21-1-1, C3147-2	0.19	1.28	0.012	0.015	0.11	0.24	0.63	0.56	0	0.020
Pc. 21-1-2, C3066-2	0.19	1.25	0.012	0.015	0.07	0.21	0.64	0.56	0	0.018
Pc. 21-1-3, C3065-2	0.21	1.36	0.010	0.015	0.06	0.25	0.63	0.58	0	0.021
B. Welds										
Ht. 5P5657(1)	0.075	1.47	0.015	0.021	0.07	0.42	0.71	0.42	0.007	0.024
Lot 0931(2)	0.078	1.45	0.016	0.020	0.04	0.44	0.89	0.50	0.006	0.016
Ht. 5P6214B(1)	0.051	1.39	0.013	0.017	0.02	0.53	0.82	0.52	0.004	0.007
Lot 0331(2)	0.085	1.24	0.011	0.014	0.014	0.51	0.70	0.44	0.003	0.007
Ht. 4P7465(1)	0.050	1.63	0.010	0.013	0.02	0.39	0.82	0.45	0.006	0.010
Lot 0751(2)	0.061	1.50	0.012	0.014	0.02	0.33	0.80	0.42	0.006	0.006
Ht. 4P7216(1)	0.07	1.40	0.011	0.011	0.06	0.45	0.85	0.43	0.07	0.01
Lot 0751(2)	0.087	1.45	0.011	0.012	0.04	0.33	0.83	0.41	0.05	0.01

TABLE 5.3-1 (Cont'd.)

III. Unirradiated Fracture Toughness Properties

Plates Ht. No.	Drop Wt. NDT, °F	Transverse Charpy V-Notch ft-lb	MLE	Temperature (°F)	Reference Temperature (°F)	Upper Shelf (ft-lb)
C3065-1						
Top	-30	55, 60, 63	48, 46, 48	+40		
Bottom	-30	70, 50, 50	42, 52, 41	+50	-10	94 min
C3121-2						
Top	-30	50, 51, 50	46, 41, 44	+40		71 min
Bottom	-50	50, 53, 50	46, 46, 45	+60	0	75 ave
C3147-1						
Top	-20	50, 51, 50	45, 44, 41	+60		70 min
Bottom	-30	50, 50, 52	46, 44, 42	+60	0	74 ave
C3147-2						
Top	-20	52, 50, 50	48, 44, 44	+60	0	86 min
Bottom	-30	51, 56, 51	48, 51, 48	+30		
C3066-2						
Top	-30	58, 72, 58	58, 48, 48	+40		
Bottom	-40	55, 52, 52	45, 42, 45	+40	-20	86 min
C3065-2						
Top	-10	56, 56, 60	50, 48, 46	+70		
Bottom	-40	51, 53, 51	46, 45, 43	+70	+10	83 min
Weld Metal						
5P5657[1]	-60	51, 55, 68	50, 50, 63	0	-60	88 min
Lot 0931[2]	-80	51, 57, 55	50, 54, 40	0	-60	88 min
5P6214B[1]	-50	56, 50, 54	45, 41, 46	+10	-50	88 min
Lot 0331[2]	-40	50, 61, 64	46, 50, 52	+10	-40	96 min
4P7465[1]	-70	63, 57, 68	54, 45, 63	0	-60	102 min
Lot 0751[2]	-60	79, 83, 74	66, 60, 54	0	-60	110 min
4P7216[1]	-60	64, 60, 72, 66, 60	48, 41, 60, 53, 41	+10	-50	89 min
Lot 0751[2]	-80	62, 73, 84	40, 51, 56	-20	-80	98 min

(1) Single Wire.
(2) Tandem Wire.

TABLE 5.3-2a

ADJUSTED RT_{NDT} FOR NINE MILE POINT UNIT 2 BELTLINE MATERIALS

Plates - Beltline

Heat No.	Wt. % Cu	Wt. % Ni	ASME NB-2300 Start RT_{NDT} (°F)	12.8 EFPY[3]			32 EFPY[3]		
				RT_{NDT} (°F)	Margin (°F)	ART_{NDT} (°F)	RT_{NDT} (°F)	Margin (°F)	ART_{NDT} (°F)
C3065-1	0.06	0.63	-10	13	24	27	20	28	38
C3121-2	0.09	0.65	0	20	28	48	31	37	68
C3147-1	0.11	0.63	0	26	39	65[2]	40	45	85[2]
C3147-2[1]	0.11	0.63	0	26	39	65[2]	40	45	85[2]
C3066-2	0.07	0.64	-20	15	25	20	24	31	35
C3065-2	0.06	0.63	+10	13	24	47	20	28	58

NOTE: Peak EOL fast (E>1Mev) fluence is 1.724×10^{18} n/cm^2 at vessel ID surface. All calculations based on Revision 2 to Regulatory Guide 1.99.

(1) These materials are also in the reactor vessel surveillance program.
(2) Limiting plate.
(3) Calculations performed at vessel ID surface using peak beltline flux.

TABLE 5.3-2b

ADJUSTED RT_{NDT} FOR NINE MILE POINT UNIT 2 BELTLINE MATERIALS

Welds - Beltline

Weld Seam	Heat/Lot No.	Wt. % Cu	Wt. % Ni	ASME NB-2300 Start RT_{NDT} (°F)	12.8 EFPY[5] RT_{NDT} (°F)	12.8 EFPY[5] Margin (°F)	12.8 EFPY[5] ART_{NDT} (°F)	32 EFPY[5] RT_{NDT} (°F)	32 EFPY[5] Margin (°F)	32 EFPY[5] ART_{NDT} (°F)
BD,BB,BF	5P5657/0931[1,2]	0.07	0.71	-60	33	39	12	51	55	46[4]
	5P5657/0931[1,3]	0.04	0.89	-60	19	27	-14	29	35	4
BA,BB,BC	5P6214B/0331[2]	0.02	0.82	-50	9	22	-19	14	25	-11
	5P6214B/0331[3]	0.014	0.70	-40	8	21	-11	12	23	-5
AB	4P7465/0751[2]	0.02	0.82	-60	9	22	-29	14	25	-21
	4P7465/0751[3]	0.02	0.80	-60	9	22	-29	14	25	-21
	4P7216/0751[2]	0.06	0.85	-50	28	35	13[4]	44	48	42
	4P7216/0751[3]	0.04	0.83	-80	19	27	-34	29	35	-16

NOTE: Peak EOL fast (E>1Mev) fluence is 1.724×10^{18} n/cm^2 at vessel ID surface. All calculations based on Revision 2 to Regulatory Guide 1.99.

(1) These materials are also in the reactor vessel surveillance program.
(2) Single wire submerged arc process.
(3) Tandem wire submerged arc process.
(4) Limiting weld.
(5) Calculations performed at vessel ID surface using peak beltline flux.

6. Radiation: 1.5 x 10^8 rads gamma (100-day integrated accident dose).

The MSIV systems are Category I equipment and the valves are designed, fabricated, inspected, and tested in accordance with ASME Section III, Safety Class 1. The valves are designed to be operable when subjected to various combinations of the following loads:

1. Operating base earthquake (OBE) and SSE.

2. A double-ended guillotine pipe break outside containment during plant operation at full power.

3. Worst-case loading imposed by the attached piping.

4. Suppression pool dynamic loads resulting from the discharge of SRVs and LOCA.

Operability, as used above, is defined as the ability of the valve system, when subjected to the described loadings, to close and remain closed.

The valve body and associated internal pressure boundary components are modeled using finite element techniques. Application of the described loadings results in stresses within the limits of ASME Section III, Subarticle NB-3500. Deformations were evaluated for worst-case conditions, for all regions where critical clearances or alignments might conceivably be compromised so as to jeopardize functional capability. Acceptable margins were determined for all such regions. A flaw was identified in the valve-to-pipe weld of MSIV 7A during the baseline examination of the replacement activities for this valve under ASME Section XI. This flaw was evaluated and meets the acceptance criteria of ASME Section XI, 1980 Edition through the Winter 1980 Addenda, Table IWB-3514-1.

All Class 1E electrical equipment of the MSIV system is qualified in accordance with IEEE-323-1974 and RG 1.89. Assurance of operability of the MSIV actuators and their control logic cabinets is demonstrated by a comprehensive dynamic testing program, in accordance with IEEE-344-1975 and RG 1.100. The ability of the operator to perform its safety function before, during, and after the tests, is demonstrated.

The qualification of all Class 1E electrical equipment of the MSIV system meets or exceeds the requirements for Category II qualification in accordance with NUREG-0588.

5.4.5.3 Safety Evaluation

In a direct-cycle nuclear power plant, the reactor steam goes to the turbine and to other equipment outside the containment.

Radioactive materials in the steam can be released to the environs through process openings (leaks) in the steam system, or escape from pipe breaks. A large break in the steam system can drain the water from the reactor core faster than it is replaced by feedwater. The MSIVs are provided to limit both the release of radioactive material and the drainage of water from the reactor due to a MSLB outside containment.

The analysis of a complete, sudden steam line break outside the containment is described in Chapter 15. The analysis shows that the fuel barrier is protected against loss of cooling if MSIV closure is within specified limits, including instrumentation delay to initiate valve closure after the break. The calculated radiological effects of the radioactive material postulated to be released following a MSLB are presented in Section 15.6.4.

The shortest closing time (approximately 3 sec) of the MSIVs is also shown in Chapter 15 to be satisfactory. The switches on the valves initiate reactor scram when specific conditions (extent of valve closure, number of pipelines included, and reactor power level) are exceeded (Section 7.2.1). The pressure rise in the system from stored and decay heat may cause the nuclear system relief valves to open briefly, but the rise in fuel cladding temperature is insignificant. No fuel damage results.

The ability of this 45-degree, Y-design globe valve to close in a few seconds after a steam line break, under conditions of high pressure differentials and fluid flows with fluid mixtures ranging from mostly steam to mostly water, has been demonstrated in a series of dynamic tests. A full-size, 20-in valve was tested in a range of steam-water blowdown conditions simulating postulated accident conditions.[3]

The following specified hydrostatic, leakage, and stroking tests, as a minimum, are performed by the valve manufacturer in shop tests:

1. To verify its capability to close between 3 and 10 sec, each valve is tested at 1,000 psig line pressure and no flow. The valve is stroked several times, and the closing time is recorded. The valve is closed by spring only and by the combination of air cylinder and springs. The closing time is slightly greater when closure is by springs only.

2. Leakage is measured with the valve seated and backseated. The specified maximum seat leakage, using cold water at design pressure, is 2 cm^3/hr/in of nominal valve size. In addition, an air seat leakage test is conducted using 50 psig pressure upstream. Maximum permissible leakage is 0.1 scfh/in of nominal valve size. There must be no visible leakage from either set of stem packing at hydrostatic test pressure. The valve stem is operated a minimum of

reactor vessel. An alternate source of water is available from the suppression pool. The RCIC system allows automatic switchover of pump suction from the CST to the suppression pool if the RCIC pump suction pressure falls to a preset low level. Two level transmitters are used to detect low pressure for the RCIC pump suction. If either transmitter senses low pressure (indicating low CST level), pump suction is automatically transferred to the suppression pool. The turbine is driven with a portion of the decay heat steam from the reactor vessel and exhausts to the suppression pool. Suppression pool water is not maintained demineralized and is used only in the event all sources of demineralized water have been exhausted.

If the main feedwater system is not operable, a reactor scram is automatically initiated when reactor water level falls to Level 3. The Operator can then remotely manually initiate the RCIC system from the main control room, or the system is automatically initiated as follows. Reactor water level continues to decrease due to boiloff until Level 2 is reached. At this point, the HPCS and the RCIC systems are automatically initiated to supply makeup water to the RPV. These systems continue automatic injection until the reactor water level reaches Level 8, at which time the HPCS injection valve is closed and the RCIC steam supply valve is closed.

In the nonaccident case, the RCIC system is normally the only makeup system used to furnish subsequent makeup water to the RPV. The Operator remotely manually shuts down the HPCS system from the main control room. When level reaches Level 2 again due to loss of inventory through the main steam relief valves or to the main condenser, the RCIC system automatically restarts as described in Section II.K.3.13. This system then maintains the coolant makeup supply. RPV pressure is regulated by the automatic or remote manual operation of the main steam relief valves which discharge to the suppression pool.

To remove decay heat during a planned isolation event, assuming that the main condenser is not available, the steam-condensing mode of the RHR system can be manually initiated. Residual steam is routed through the RHR heat exchangers where it is condensed and cooled, then returned to the RPV through an interconnection with the RCIC pump. Thus, closed loop cooling is provided by this mode.

If the steam-condensing mode is unavailable for any reason, the SRVs can be used to dump the residual steam to the suppression pool. The suppression pool will then be cooled by remote manual alignment of the RHR system in the suppression pool cooling mode which routes the pool water through the RHR heat exchangers, cools it, and returns it to the suppression pool in a closed cycle. Makeup water to the RPV is still supplied by the RCIC system.

For the accident case with the RPV at high pressure, the HPCS system can also be used to automatically provide the required makeup flow. No manual operations are required. If the HPCS system is postulated to fail at these conditions and the RCIC capacity is insufficient, the ADS will automatically initiate depressurization of the RPV to permit the condensate pumps or the low-pressure ECCS (LPCI and LPCS) to provide makeup coolant.

Whenever the RCIC system is initiated, the large steam turbine generator (LSTG) turbine is tripped to prevent water induction into the turbine, and the control room is alarmed that the RCIC injection valve is open.

Therefore, although manual actions can be taken to mitigate the consequences of a loss of feedwater, there are no short-term manual actions which must be taken. Sufficient systems exist to automatically mitigate these consequences.

During RCIC operation, the suppression pool acts as the heat sink for steam generated by reactor decay heat. This results in a rise in pool water temperature. Heat exchangers in the RHR system are used to maintain the pool water temperature within acceptable limits by cooling the water directly or by condensing generated steam. The condensate discharge from the RHR heat exchangers may be used as RCIC pump suction supply or it may be directed to the suppression pool.

The RCIC system is equipped with a discharge line fill pump that operates to maintain the pump discharge line in a filled condition. Keeping the discharge line filled reduces the lag time between pump startup and attainment of full flow to the RPV. Additionally, its operation eliminates the possibility of RCIC pumps discharging into a dry pipe and minimizes water hammer effects. The fill pump is classified as Category I and Safety Class 2. The pump motor is Class 1E and is powered from a Class 1E source. Indication of pump operating status is provided in the main control room. Low discharge line pressure is also indicated in the main control room.

Pump discharge pipe routing and valve locations inside and outside containment ensure that a maximum amount of piping is maintained full of water.

In addition to the fill pump, the RCIC water discharge line is designed to accommodate water hammer loads due to postulated voids in the piping between the reactor and injection valve (MOV126). This section of piping is normally isolated from the fill pump circuit by the isolation valve. To fill this section of piping between the injection valve and the check valve (AOV157) near the reactor, a bypass line around the injection valve has been provided to facilitate a manual fill to limit voiding in that section of pipe. Also, appropriate drain and vent lines are provided in the discharge line.

In addition to the physical design features described above, the RCIC pump discharge piping has been analyzed and conservatively designed for the effects of possible water hammer forces using the methods described in Appendix 3A, Section 3A.24.

5.4.6.1.1 Residual Heat Removal and Isolation

Residual Heat Removal

The RCIC system initiates and discharges, within 30 sec, a 600-gpm constant flow to the reactor vessel over a 165 to 1,215 psia pressure range. The temperature of RCIC water discharged into the reactor vessel varies from 40° to 140°F when using water from the CST. The mixture of the cool RCIC water and the hot steam does the following:

1. Quenches the steam.
2. Removes reactor residual heat.
3. Replenishes reactor vessel inventory.

Redundantly, the HPCS system performs the same function, hence providing single-failure protection. Both systems use separate and independent electrical power sources of high reliability, which permit operation with either onsite or offsite power. Additionally, the RHR system performs a residual heat removal function.

RCIC system design includes interfaces with redundant leak detection devices, namely:

1. High pressure drop across a flow device in the steam supply line equivalent to 300 percent of the steady state steam flow (with a 3 to 5 sec delay for TMI modification) at the reactor high-pressure steam condition.
2. High area temperature, utilizing temperature switches as described in the LDS. High area temperature is alarmed in the main control room.
3. Low reactor pressure of 50 psig minimum.
4. High pressure between the RCIC turbine exhaust rupture diaphragms.

These redundant leak detection devices, activated by the redundant power supplies, automatically isolate the steam supply to the RCIC turbine. Other isolation bases are defined in the following section. The HPCS provides redundancy for the RCIC should the RCIC become isolated, hence providing single-failure protection.

Isolation

Isolation valve arrangements include the following:

1. Two RCIC lines penetrate the RCPB. The first is the RCIC steam line which branches off one of the MSLs between the reactor vessel and the MSIV. This line has two automatic motor-operated isolation valves, one located inside and the other outside the primary containment. An automatic motor-operated inboard RCIC isolation bypass valve is used to equalize the line pressure across the inboard isolation valves and warm up the downstream line. The isolation signals noted earlier close these isolation valves.

2. The second RCIC line that penetrates the RCPB is the RCIC pump discharge line, which has two testable check valves (one inside the primary containment and the other outside). Additionally, an automatic MOV, in parallel with a manual locked closed valve, is located outside primary containment.

3. The RCIC turbine exhaust line vacuum breaker system line has two automatic MOVs and two check valves. This line runs between the suppression pool air space and the turbine exhaust line downstream of the exhaust line check valve. Positive isolation is automatic via a combination of low reactor pressure and high drywell pressure. The vacuum breaker valve complex is placed outside the primary containment where there is a more desirable environment. In addition, the valves are readily accessible for maintenance and testing.

4. The RCIC pump suction line, minimum flow pump discharge line, and turbine exhaust line all penetrate the primary containment and are submerged in the suppression pool. The isolation valves for these lines are all outside the primary containment and require remote-manual operation, except for the minimum flow valves that actuate automatically.

5.4.6.1.2 Reliability, Operability, and Manual Operation

Reliability and Operability

The RCIC system (Table 3.2-1) is designed commensurate with the safety importance of the system and its equipment. Each component is individually tested to confirm compliance with system requirements. The system as a whole is tested during both the startup and preoperational phases of the plant to set a baseline for system reliability. To confirm that the system maintains this line, functional and operability testing is performed at predetermined intervals throughout the life of the reactor plant in accordance with Technical Specifications.

A design flow functional test of the RCIC system may be performed during normal plant operation by drawing suction from the CST and discharging through a full flow test return line to the CST. The discharge valve to the head cooling spray nozzle remains closed during the test, and reactor operation remains undisturbed. All components of the RCIC system are capable of individual functional testing during normal plant operation. System control provides automatic return from test to operating mode if system initiation is required, with the following three exceptions:

1. Auto/manual initiation on the flow controller is required for Operator flexibility during system operation.

2. Closure of either or both of the steam inside/outside isolation valves requires Operator action to properly sequence their opening. An alarm sounds when either of these valves leaves the fully-open position.

3. Other bypassed or otherwise deliberately rendered inoperable parts of the system are automatically indicated in the main control room at the system level.

To demonstrate proper system response, RCIC may be periodically initiated with flow through the discharge valve to the head spray cooling nozzle during reactor operation, with the main turbine shut down and reactor power at approximately 10 to 15 percent.

Manual Operation

In addition to the automatic operational features, provisions are included for remote-manual startup, operation, and shutdown of the RCIC system, provided initiation or shutdown signals do not exist.

After the RHR system is placed in the steam-condensing mode, the Operator selects the condensate discharge from the RHR steam-condensing heat exchangers as the RCIC pump suction supply. The steam-condensing mode of the RHR system is manually placed in operation. Once steam condensing has been established, water level in the RHR heat exchangers is automatically maintained by means of a regulating valve in the condensate discharge line. Initially, the condensate discharge is directed to the suppression pool. After proper water quality is obtained, the condensate discharge may be directed to the RCIC pump suction. The level control for the RHR heat exchangers is independent from the RCIC control system. The Operator selects the flow setpoint of the RCIC system to match the condensate flow rate from the RHR heat exchangers.

5.4.6.1.3 Loss of Offsite Power

The RCIC system power is derived from an emergency auxiliary power distribution system that is normally energized from offsite power sources. Upon loss of offsite power (LOOP), this is automatically energized from standby onsite power sources (diesel generator or battery). All components necessary for initiation of the RCIC system are capable of startup independent of auxiliary ac power, plant service air, and external cooling water systems.

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5.4.6.1.4 Physical Damage

The system is designed to the requirements of Table 3.2-1 commensurate with the safety importance of the system and its equipment. The RCIC turbine and pump are located in a different quadrant of the reactor building and utilize different divisional power (and separate electrical routings) than that of its redundant system HPCS (Sections 5.4.6.1.1 and 5.4.6.2.4).

5.4.6.1.5 Environment

The system operates for the time intervals and the environmental conditions specified in Section 3.11.

The RCIC system takes suction from the CSTs during normal modes of operation. The CSTs are located within the condensate storage building which is maintained at a minimum temperature of 65°F, as described in Section 9.4.7.2.5.

All interconnecting piping is located within piping tunnels which are beneath heated structures and below the frost line. To provide a Category I source of cooling water for the RCIC system, automatic transfer circuitry has been provided to transfer suction from the CSTs to the suppression pool, which is inside the reactor building and protected from cold weather. All other RCIC piping is located within the reactor building and is protected from cold weather.

5.4.6.2 System Design

5.4.6.2.1 General

Description

A summary description of the RCIC system is presented in Section 5.4.6.1, which defines in general the system functions and components. The detailed description of the system, its components, and operation is presented in the following sections.

Diagrams

The following diagrams are included for the RCIC systems:

1. A schematic P&ID (Figure 5.4-9) shows all components, piping, points where interface system and subsystems tie together, and instrumentation and controls associated with subsystem and component actuation.

2. A schematic process diagram (Figure 5.4-10) shows temperature, pressures, and flows for RCIC operation and system process data hydraulic requirements.

3. Performance curves showing temperature, pressure, steam flow, brakehorsepower, and shaft speed for the RCIC

turbine manufactured by the Terry Corporation, are shown on Figures 5.4-10a and 5.4-10b.

Interlocks

The following defines the various electrical interlocks:

1. There are three keylocked switches controlling valves F063, F064, F068 (2ICS*MOV128, 2ICS*MOV121, 2ICS*MOV122), and two keylocked reset switches that reset the isolation signal seal-in feature.

2. The F031 (2ICS*MOV136) limit switch activates when fully open and closes F010 (2ICS*MOV129), F022 (2ICS*FV108), and F059 (2ICS*MOV124).

3. The F068 (2ICS*MOV122) limit switch activates when fully open and clears F045 (2ICS*MOV120) permissive so F045 (2ICS*MOV120) can open.

4. The F045 (2ICS*MOV120) limit switch activates when F045 (2ICS*MOV120) is not fully closed and energizes a 25-sec time delay for alarms for low pump discharge flow, low turbine bearing oil pressure, and low gland seal air pressure, also energizing a 10-sec time delay which closes F019 (2ICS*MOV143), initiates startup ramp functions, and alarms low water leg pump discharge pressure. This ramp resets each time F045 (2ICS*MOV120) is closed.

5. The F045 (2ICS*MOV120) limit switch activates when fully closed; this permits F004 (2ICS*AOV109), F005 (2ICS*AOV110), F025 (2ICS*AOV131), and F026 (2ICS*AOV130) to open and closes F013 (2ICS*MOV126). When the limit switch opens it activates a 10-sec time delay to drop out the coil causing the F004 (2ICS*AOV109), F005 (2ICS*AOV110), F025 (2ICS*MOV131), and F026 (2ICS*AOV130) to close and open F013 (2ICS*MOV126).

6. The turbine trip throttle valve limit switch activates when fully closed and closes F013 (2ICS*MOV126) and F019 (2ICS*MOV143).

7. The steam line isolation valves F063 (2ICS*MOV128) and F064 (2ICS*MOV121) are closed by RCIC Division I and II isolation signals. These divisions are different from the ECCS divisions.

8. High turbine exhaust pressure, low pump suction pressure, or an isolation signal actuate and close the turbine trip throttle valve. When the signal is cleared, the trip throttle valve must be reset from the main control room.

9. Overspeed of 116.2 percent trips the mechanical trip at the turbine which closes the trip throttle valve. The mechanical trip is reset at the turbine.

10. An isolation signal closes F063 (2ICS*MOV128), F064 (2ICS*MOV121), F076 (2ICS*MOV170), and other valves as noted in Items 6 and 8.

11. An initiation signal opens F045 (2ICS*MOV120), F010 (2ICS*MOV129), if closed, and F013 (2ICS*MOV126), and closes F059 (2ICS*MOV124) if open. The initiation signal causes F022 (2ICS*FV108) to receive a close signal; however, this is not sealed in. Valve F059 (2ICS*MOV124) closes and seals in. An initiation signal also trips the LSTG turbine.

12. High and low inlet RCIC steam line drain pot levels, respectively, and open and close F054 (LV132).

13. The combined signal of low flow plus high pump discharge pressure opens and with increased flow closes F019 (2ICS*MOV143) (Items 5 and 6).

14. The F013 (2ICS*MOV126) limit switch activates when F013 (2ICS*MOV126) is not fully closed and energizes a control room relay to alarm the control room that valve F013 (2ICS*MOV126) is not fully closed.

15. A LOCA signal prevents turbine trip and throttling valve motor operation.

5.4.6.2.2 Equipment and Component Description

Design Conditions

Operating parameters for the components of the RCIC system, defined as follows, are shown on Figure 5.4-10. The RCIC components are:

1. One 100-percent capacity turbine and accessories.

2. One 100-percent capacity pump assembly and accessories.

3. Piping, valves, and instrumentation for:

    a. Steam supply to the turbine.

    b. Steam supply to RHR steam-condensing heat exchanger.

    c. Turbine exhaust to the suppression pool.

    d. Supply from the CST to the pump suction.

e. Supply from the suppression pool to the pump suction.

f. Makeup supply from the RHR steam-condensing heat exchangers.

g. Pump discharge to the head cooling spray nozzle, including a test line to the CST, a minimum flow bypass line to the suppression pool, and a coolant water supply to the turbine lube oil cooler.

4. System pressure pump to maintain injection lines full of water to the outside containment isolation valves.

The basis for the design conditions is ASME Section III.

Design Parameters

Design parameters for the RCIC system components are listed as follows (see Figure 5.4-9 for a cross-reference of component numbers):

1. RCIC Pump Operation (C001)

Flow rate	Injection flow - 600 gpm Cooling water flow - 25 gpm Total pump discharge - 625 gpm (includes no margin for pump wear)
Water temperature range	40° to 140°F
NPSH	22 ft minimum
Developed head (Required)	≤3,080 ft @ 1,215 psia reactor pressure 610 ft @ 165 psia reactor pressure
BHP, not to exceed	750 hp @ 3,080 ft developed head 130 hp @ 610 ft developed head
Design pressure	1,525 psig
Design ambient temperature	60° to 122°F

2. RCIC Turbine Operation (C002)

	H.P. Condition (psia)	L.P. Condition (psia)
Reactor pressure (saturated temperature)	1,215	165

	H.P. Condition (psia)	L.P. Condition (psia)
Steam inlet pressure	1,190, min	150, min
Turbine exhaust pressure	65, max	65, max
Turbine design inlet pressure	1,250 psig at saturated temperature	
Turbine exhaust casing design pressure	165 psig at saturated temperature	

3. RCIC Orifice Sizing

Coolant loop orifice (D012)	Sized to maintain a minimum of 16 gpm to a maximum of approximately 40 gpm to the lube oil cooler based upon pump suction line pressure varying from 50 psig to minimum NPSH (and the PCV operating within its normal band).
Minimum flow orifice (D005)	Sized with piping arrangement to ensure minimum flow of 75 gpm with MO-F019 (MOV143) fully open.
Test return orifice (D006)	Sized with piping arrangement to simulate pump discharge pressure required when the RCIC system is injecting design flow with the reactor vessel pressure at 165 psia.
Leakoff orifices (D008, D010)	Sized for 1/8-in diameter minimum, 3/16-in diameter maximum.

4. Valve Design Requirements

The following are the design differential pressure requirements. However, the actuator sizing/setting is based on maximum operating differential pressure.

Steam supply valve (F045) (MOV120)	Open and/or close against full differential pressure of 1,200 psi within 15 sec.
Pump discharge valve (F013) (MOV126)	Open and/or close against full differential pressure of 1,450 psi within 15 sec.
Pump minimum flow bypass valve (F019) (MOV143)	Open and/or close against full differential pressure of 1,450 psi within 6 sec.

RHR steam supply isolation valves (F063 & F064) (MOV128 and MOV121)	Open and/or close against full differential pressure of 1,200 psi within 30 sec.
Cooling water pressure control valve (F015) (PCV115)	Air-operated valve capable of maintaining constant downstream pressure of 125 psia.
Pump suction relief valve (F017) (RV114)	150 psig relief setting; 10 gpm at 10% accumulation.
Cooling water relief valve (F018) (RV112)	Sized to prevent overpressurizing piping, valves, and equipment in the coolant loop in event of failure of pressure control valve F015.
Pump test return valve (F022) (FV108)	Capable of throttling against 1,000 psi differential pressure and closure against differential pressures of 1,450 psi.
Pump suction valve, suppression pool (F031) (MOV136)	Located outside as close as practical to the primary containment.
Testable check valves (F065-F066) (AOV156+AOV157)	System test mode bypasses this valve, and its functional capability is demonstrated separately. Therefore, valve test provisions are provided, including limit switches to indicate disc movement. The valve and valve-associated equipment are capable of proper functional operation during maximum ambient conditions.
Warmup line isolation valve (F076) (MOV170)	Opens and/or closes against differential pressure of 1,200 psi within 9 sec.
Vacuum breaker valves (F080, F086) (MOV148+MOV164)	Opens and/or closes against differential pressure of 160 psi at a minimum rate of 4 in/min.
5. <u>Rupture Disc Assemblies (D001 & D002)</u>	Utilized for turbine casing protection; includes a mated vacuum support to prevent rupture disc reversing under vacuum conditions.
Rupture pressure flow capacity	150 ±10 psig. 60,000 lb/hr at 165 psig.

6.	<u>Instrumentation</u>	For instruments and control definition refer to Chapter 7.
7.	<u>Condensate Storage Requirements</u>	Total required reserve storage for RCIC and HPCS systems is 135,000 gal.
8.	<u>Piping RCIC Water Temperature</u>	The maximum water temperature range for continuous system operation will not exceed 140°F. However, due to potential short-term operation at higher temperatures, piping expansion calculations were based on 170°F.
9.	<u>Turbine Exhaust Vertical Reaction Force</u>	The turbine exhaust sparger is capable of withstanding a vertical pressure unbalance of 20 psi. Pressure unbalance is due to turbine steam discharge below the suppression pool water level.

10. <u>Ambient Conditions</u>

	Temperature (°F)	Relative Humidity (%)
Normal plant operation	60-100	95
Isolation conditions (Isolation of the primary system requiring RCIC operation)	150	100

5.4.6.2.3 Applicable Codes and Classifications

The RCIC system components within the drywell up to and including the outer isolation valve are designed in accordance with ASME Section III, Safety Class 1. The RCIC system component classifications and those for the condensate storage system are given in Table 3.2-1.

5.4.6.2.4 System Reliability Considerations

To assure that the RCIC operates when necessary and in time to prevent inadequate core cooling (ICC), the power supply for the system is taken from immediately available energy sources of high reliability. Added assurance is given in the capability for periodic testing during Station operation. Evaluation of reliability of the instrumentation for the RCIC shows that no failure of a single initiating sensor either prevents or falsely starts the system. In order to assure HPCS or RCIC availability for the operational events noted previously, certain design considerations are utilized in design of both systems.

The most limiting operating condition for the RCIC pump occurs when the pump takes suction from the suppression pool and discharges at its rated flow of 625 gpm. This represents the limiting operating condition because of the minimum static suction head (17.4 ft) and the maximum temperature/vapor pressure (170°F/6.0 psia) of the water that might exist during RCIC system operation. The NPSH margin during this condition is 8.0 ft (NPSH available = 30.0; NPSH required = 22 ft). The RCIC system meets the requirements of RG 1.1, since the calculation of NPSH available takes no credit for increased containment atmospheric pressure accompanied by a LOCA, and is computed using the maximum anticipated water temperature of 170°F.

Physical Independence

The HPCS and RCIC systems are located in separate areas of the secondary containment. Piping runs are separated, and the water delivered from each system enters the reactor vessel via different nozzles.

Prime Mover Diversity and Independence

Prime mover independence is achieved by using a steam turbine to drive the RCIC pump and an electric motor-driven pump for the HPCS system. The HPCS motor is supplied from emergency ac power or a separate diesel generator.

Control Independence

Control independence of HPCS and RCIC is provided by using different battery systems to provide control power to each unit. Separate detection initiation logics are also used for each system.

Portions of HPCS and RCIC within the RCPB are designed to meet Safety Class 1 requirements. Environment in the equipment rooms is maintained by separate auxiliary systems.

Periodic Testing

A design flow functional test of the RCIC can be performed during plant operation (Section 5.4.6.1.2). Periodic inspections and maintenance of the turbine-pump unit are conducted in accordance with manufacturer's instructions. Valve position indication and instrumentation alarms are displayed in the main control room.

5.4.6.2.5 System Operation

Automatic startup of the RCIC system due to an initiation signal from reactor low water level requires no Operator action. The test operation mode and hot standby steam-condensing mode are both manually initiated by the Operator. The Operator actions associated with these modes are defined in the operating procedures.

The most limiting single failure with the RCIC system and its HPCS backup system is the failure of the HPCS. With a HPCS failure, if the capacity of the RCIC system is adequate to maintain reactor water level, the Operator follows specific procedures to facilitate the automatic operation. If, however, the RCIC capacity is inadequate, the same procedures still apply, but the Operator may also initiate the ADS (Section 6.3.2).

Operation of the RCIC system following a Station blackout is addressed in Section 8.3.1.5.

5.4.6.3 Performance Evaluation

The analytical methods and assumptions in evaluating the RCIC system are presented in Chapter 15 and Appendix 15A. The RCIC system provides the flows required from the analysis (Figure 5.4-10) within a 30-sec interval based upon considerations noted in Section 5.4.6.2.4. If the piping downstream of the injection valve is void, the water injection into the reactor vessel will be delayed. However, the water level in the reactor vessel will be above the top of active fuel (TAF) and will avoid a reactor vessel Level 1 (L1) trip.

5.4.6.4 Preoperational Testing

The preoperational and initial startup test program for the RCIC system is presented in Chapter 14.

5.4.7 Residual Heat Removal System

5.4.7.1 Design Bases

The RHR system is composed of three independent loops, each containing a motor-driven pump, piping, valves, instrumentation, and controls. Each loop has a suction source from the suppression pool and is capable of discharging water to either the reactor vessel via a separate nozzle, or back to the suppression pool via a full-flow test line. The A and B loops have heat exchangers that are cooled by service water. Loops A and B can also take suction from the reactor recirculation system suction and can discharge into the reactor recirculation discharge or to the suppression pool and drywell spray spargers. The A and B loops also have connections to reactor steam via the RCIC steam line and can discharge the resultant condensate to the RCIC pump suction or to the suppression pool. In addition, Loops A and B take suction from the fuel pool and discharge to the fuel pool cooling discharge.

5.4.7.1.1 Functional Design Basis

The RHR system has five subsystems, each of which has its own functional requirements. Each subsystem is discussed separately as follows.

Residual Heat Removal Mode (Shutdown Cooling Mode)

The functional design basis of the shutdown cooling mode is to have the capability to remove decay and sensible heat from the reactor primary system so that the reactor outlet temperature is reduced to 125°F, in approximately 20 hr after the control rods have been inserted, to permit refueling when the service water temperature is 72°F, the core is "mature," and the RHR heat exchanger tubes are assumed to be completely fouled (see Section 5.4.7.2.2 for exchanger design details). The capacity of the heat exchangers is such that the time to reduce the vessel outlet water temperature to 212°F corresponds to a maximum cooldown rate of 100°F/hr with both loops in service. However, the flushing operation associated with normal initiation of the shutdown cooling mode prevents attaining 212°F coolant temperature at the minimum time.

If flushing is performed in 2 hr, the minimum time required to reduce vessel coolant temperature to 212°F is depicted on Figure 5.4-11.

The design basis for the most limiting single failure for the RHR system (shutdown cooling mode) is that the shutdown line can be made usable by manual action (Section 15.2.9) and the plant is then shut down using the capacity of a single RHR heat exchanger and related service water capability. Figure 5.4-12 shows the time required to reduce vessel coolant temperature to 212°F using one RHR heat exchanger and allowing 2 hr for flushing.

In the event that the RHR shutdown cooling suction line is not available because of single failure, the alternate shutdown cooling method may be used to accomplish the shutdown cooling function as discussed in Section 15.2.9. This alternate shutdown cooling path uses the RHR and ADS/SRV systems. The RHR pump flow is directed to the RPV from the suppression pool through the RHR heat exchanger via the LPCI lines. A sufficient number of SRVs are powered open to establish a liquid flow path back to the suppression pool.

Alternatively, when the Operator is using EOPs to control RPV parameters and shutdown cooling is not available, the Operator is permitted to continue cooldown using the systems previously used for depressurization. These systems include SRVs, MSL drains, RWCU, RCIC and RHR steam condensing.

Further operational description of the alternate shutdown cooling method is discussed in Section 15.2.9. The adequacy of the SRVs for liquid flow in this mode of operation is discussed in Section 1.12.

Design calculations demonstrate that, at a flow of 982 lbm/sec, the RHR pumps have sufficient head to satisfy the requirement of the alternate shutdown cooling mode of operation.

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Calculations also demonstrate that sufficient head exists to ensure the return of the water from the RPV to the suppression pool with four SRVs open, even with no credit taken for any pressure head which may exist within the RPV.

Low-Pressure Coolant Injection Mode

The functional design basis for the LPCI mode is to provide cooling to the reactor core only when the reactor vessel pressure is low, as is the case for large LOCA break sizes. The head flow characteristics assumed in the LOCA analyses for the LPCI pumps are shown on Figure 6.3-5a.

The initiating signals are: vessel level 1.0 ft above the active core or drywell pressure greater than or equal to 2.0 psig. The pumps attain rated speed in 27 sec and injection valves fully open in 40 sec.

Suppression Pool Cooling Mode

The functional design basis for the suppression pool cooling mode (SPCM) is that it will have the capacity to ensure that the suppression pool temperature, upon manual initiation after a blowdown or isolation event, does not exceed design limits.

a normal shutdown are certain manual valve lineups and system flushings.

Two separate shutdown cooling loops are provided. Although both loops are normally used for shutdown, the reactor coolant can be brought to 212°F in less than 20 hr after control rod insertion with only one loop in operation. A single RHR suction line can supply either or both shutdown cooling loops. With the exception of the shutdown cooling suction, shutdown cooling return, and steam supply and condensate discharge lines, the entire RHR system is part of the ECCS and containment spray and suppression pool cooling system. It is designed with the redundancy, flooding protection, piping protection, power separation, and other features required of such systems (see Section 6.3 for an explanation of the design bases for the ECCS). Shutdown cooling suction and discharge valves are provided with both offsite and standby emergency power supplies for purposes of isolation and shutdown. The power supply to the suction supply valves will be de-energized during normal plant operation and will be administratively controlled due to main control room Appendix R fire concerns. In the event either of the two shutdown cooling supply valves fails to operate, an Operator is sent to open the valve manually. If this is not feasible, the shutdown line is isolated using manual valve E12-F020 and repairs are made to the shutdown cooling valves so that they can be opened to supply shutdown cooling suction to the RHR pumps. While repairs are in process, residual heat is absorbed by the main condenser or by the suppression pool, which is cooled by the RHR system. In the event that the RHR shutdown cooling suction line is not available because of single failure, alternate shutdown cooling methods may be used to accomplish the shutdown cooling function (see Section 5.4.7.1.1). Thus, no single failure in either system design or power source will result in the loss of shutdown cooling capability, because the plant may use the normal shutdown cooling through the recirculation loops or the alternate shutdown cooling using the ADS SRVs and suppression pool cooling.

The RHR system takes suction from either the recirculation piping or the suppression pool. All piping is within the reactor building and is protected from cold weather.

The RHR heat exchangers dissipate their heat to the service water system. All service water piping and components supplying the RHR heat exchangers are either within heated structures or underground piping tunnels located below the frost line. Design provisions which protect water in the service water intake and discharge system from freezing are described in Section 9.2.5.

5.4.7.1.5 Design Basis for Protection from Physical Damage

Pumps A, B, and C as well as heat exchangers A and B are physically separated. Each is housed in a separate cubicle. Pump A and heat exchanger A are in separate cubicles in the reactor building auxiliary bay north. Pumps B and C and heat exchanger B are in separate cubicles in the reactor building auxiliary bay south. The RHR system pressure pump P2, which maintains the loop B and C discharge header full of water and pressurized, is located in the same cubicle as pump C. The same function is provided by LPCS system pressure pump P2 for RHR loop A, located in a separate cubicle with LPCS pump P1.

The design basis for protection from physical damage, such as flooding, internally-generated missiles, pipe break, and seismic effects, is discussed in Sections 3.4, 3.5, 3.6B, and 3.7B, respectively.

5.4.7.2 System Design

5.4.7.2.1 System Diagrams

All components of the RHR system are shown on Figure 5.4-13. A description of the controls and instrumentation is presented in Sections 7.3.1.1.4 and 7.6.1.2.

Figure 5.4-14 is the RHR process diagram and data. All sizing modes of the system are shown in the process data. The flow values were used for original pipe and component sizing and do not represent design basis flow requirements. The functional control diagram (FCD) for the RHR system is provided on Figure 7.3-10.

Interlocks are provided: 1) to prevent draining vessel water to the suppression pool, 2) to prevent opening the RHR shutdown cooling suction valve if vessel pressure is above the RHR suction line design pressure, or the discharge line design pressure with the pump at shutoff head, 3) to prevent inadvertent opening of drywell spray valves while in shutdown, 4) to prevent opening low-pressure steam supply valve F087 when vessel pressure is above line design rating, and 5) to prevent pump start when suction valve(s) are not open.

The RHR system is connected to higher-pressure piping at shutdown suction, shutdown return, LPCI injection, head spray, and heat exchanger steam supply lines. The vulnerability to overpressurization of each location is discussed in the following paragraphs.

Shutdown suction has two gate valves in series, F008 and F009, that have independent pressure interlocks to prevent opening at high inboard pressure for each valve. The pressure interlock setpoint for RHR shutdown suction valves F008 and F009 is 128 psig. Shutdown suction valves F006A and B are not interlocked because valves F008 and F009 provide the required overpressurization protection. No single-active failure nor Operator error will result in overpressurization of the low-pressure piping.

In the event of leakage past F008 and F009, pressure transmitter N057 provides indication and alarm to the Control Room Operator.

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installed. Steam pressure-reducing valves are designed to regulate steam flow into the heat exchangers from full reactor pressure upstream to maintain a maximum downstream pressure at 200 psig.

The RHS service water crosstie valves 2RHS*MOV115 and 2RHS*MOV116 have been modified to meet the requirements of Generic Letter 95-07 for pressure locking.

Valves 2RHS*MOV4A, B and C have been modified to meet the requirements of Generic Letter 95-07 for pressure locking.

<u>ECCS Portions of the RHR System</u>

The ECCS portions of the RHR system include those sections described through Mode A-1 and A-2 of Figure 5.4-14. The flow path includes suppression pool suction strainers, suction piping, RHR pumps, discharge piping, injection valves, and drywell piping into the vessel nozzles and core region of the reactor vessel. Steam-condensing components include steam supply piping and valves, heat exchangers, and condensate piping. Pool cooling components include pool suction strainers, suction piping, pumps, heat exchangers and pool return lines. Containment spray components are the same as suppression pool cooling components except that the spray headers replace the suppression pool return lines.

5.4.7.2.3 Controls and Instrumentation

Controls and instrumentation for the RHR system are described in Sections 7.3.1.1.1 and 7.4.1.3.

5.4.7.2.4 Applicable Standards, Codes, and Classifications

<u>Piping, Pumps, and Valves</u>

Process side	Safety Class 1 and 2
Service water side	Safety Class 3

<u>Heat Exchangers</u>

Process side	Safety Class 2 TEMA Class C
Service water side	Safety Class 3 TEMA Class C

Electrical Portions

BOD	NSSS
IEEE-279-1971	IEEE-279-1971
IEEE-308-1974	IEEE-308-1971
IEEE-384-1974	IEEE-323-1971
IEEE-379-1977	IEEE-384-1974
IEEE-323-1974	

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5.4.7.2.5 Reliability Considerations

The RHR system design includes the redundancy requirements of Section 5.4.7.1.5. Two completely redundant loops, each powered from a separate emergency bus, remove residual heat. All mechanical and electrical components, except for the common cooling shutdown suction line, are separate. Either loop is capable of shutting down the reactor within a reasonable length of time. The system design features, which assure that the systems connected to the RHR system do not degrade the reliability of the RHR system, are discussed in Section 6.3.2.5.

5.4.7.2.6 Manual Action

Residual Heat Removal (Shutdown Cooling Mode)

In shutdown cooling operation, when vessel pressure is 128 psig or less, the pool suction valve may be closed for the initial shutdown loop or loops. Flushing valves connecting the RHR condensate and makeup system are manually opened, and the stagnant water flushed to the radwaste through valves 2RHS*MOV142 (E12-F040) and 2RHS*MOV149 (E12-F049). At the end of this flush, service water flow is established through the heat exchanger. This is followed by the gradual warming of the cooling loop by permitting vessel water to warm the shutdown cooling loop (RHR pump not running). The vessel water used in prewarming is directed to radwaste, and a temperature element is used to monitor the effluent temperature. When the prewarming is completed, the radwaste effluent valves are closed, and the RHR heat exchanger bypass is opened. The RHR pump is started and the total flow is regulated through 2RHS*MOV40A/B (E12-F053A/B), shutdown cooling throttle valve. Vessel cooldown is started when the RHR heat exchanger is placed in service by opening its inlet and outlet valves. The vessel cooldown rate is then normally controlled by regulating total flow using 2RHS*MOV40A/B (E12-F053A/B) for total flow control, and/or regulating heat exchanger bypass flow using 2RHS*MOV8A/B (E12-F048A/B).

The manual actions required for the most limiting failure are discussed in Section 15.2.9.

Steam Condensing

In order to initiate or terminate the steam-condensing mode, certain manual actions must be taken by the main Control Room Operator in conjunction with local Operators. In preparation for steam-condensing operations, the heat exchanger is initially isolated by closing the shellside (RHR) inlet and outlet valves. Prior to steam admission, the Operator will start additional service water (SWP) pumps, if necessary, and establish cooling water flow by opening the tubeside (SWP) inlet and outlet valves. Also prior to steam admission, the water level in the heat exchanger is lowered to a preset value, and the motor-operated transfers heat from the influent (tubeside) to the effluent (shellside). The effluent returns to the reactor. The nonregenerative heat exchanger cools the process influent further by transferring heat to the RBCLCW system.

The filter demineralizer units (Figures 5.4-16d through 5.4-16f and 5.4-19) are pressure precoat-type filters, using a nonregenerable, mixed ion-exchange resin precoat material with or without a fiber filter aid material. Spent resins are not regenerable and are sluiced from the filter demineralizer unit to a phase separator tank in the radwaste system for processing and disposal (the resin backwash transfer system is described in Section 11.2.2.4). Resins are discarded based on filter demineralizer performance, as indicated by monitoring effluent conductivity, differential pressure across the unit, and sample analysis. Initial total capacity is not measured on resin that is finely ground and mixed since separation into anion and cation components is not practical. To prevent resins from entering the reactor coolant system in the event of failure of a filter demineralizer resin support, a strainer is installed in the effluent line of each filter demineralizer. Each strainer and filter demineralizer vessel has a control room alarm that is energized by high differential pressure. Upon further increase in differential pressure from the alarm point, the filter demineralizer automatically isolates.

The backwash and precoat cycle for each filter demineralizer is semiautomatic; however, permissives and interlocks are installed in the logic program to prevent human operational errors, such as inadvertent opening of valves that would initiate a backwash or contaminate reactor water with precoat material or resins. The filter demineralizer piping configuration is arranged to ensure that transfers are complete and crud traps are eliminated. A bypass line is provided around the filter demineralizer units.

The vent line from each filter demineralizer is routed to the phase separator tanks which are vented directly to the reactor building heating, ventilating, and air conditioning (HVAC) system (Section 9.4.2).

In the event of low flow or loss of flow in the system, flow is maintained through each filter demineralizer by its own holding pump. This ensures that the precoat and resin material are held in place on the septum screens. Sample points are provided in the common influent header and in each effluent line of the filter demineralizer units for continuous indication and recording of system conductivity. High conductivity is annunciated in the main control room. The control room alarm setpoints of the conductivity meters at the inlet and outlet lines are 1.0 umho/cm and 0.1 umho/cm, respectively. The influent sample point is also used as the normal source of reactor coolant grab samples. Sample analysis also indicates the effectiveness of the filter demineralizer units.

The suction line (RCPB portion) of the RWCU system contains two motor-operated isolation valves, which automatically close in response to signals from the RPV (low water level), the LDS, and actuation of the SLCS. Activation of the SLCS closes the outside isolation valve from Division I logic and the inside isolation valve from Division II logic. Nonregenerative heat exchanger high outlet temperature closes the outside isolation valve only. Section 7.6 describes the LDS requirements which are summarized in Table 5.2-8. This isolation prevents the loss of reactor coolant and release of radioactive material from the reactor. The isolation valves close automatically to prevent removal of liquid boron reactivity control material from the reactor vessel in the event of SLCS activation. In addition, the outside isolation valve closes automatically to prevent damage of the filter demineralizer resins if the outlet temperature of the nonregenerative heat exchanger is high. The RCPB isolation valves may be remote manually operated to isolate the system equipment for maintenance or servicing. The requirements for the RCPB are specified in Section 5.2.

A remote manually-operated globe valve on the return line to the reactor provides long-term leakage control. Instantaneous reverse flow isolation is provided by check valves in the RWCU system piping.

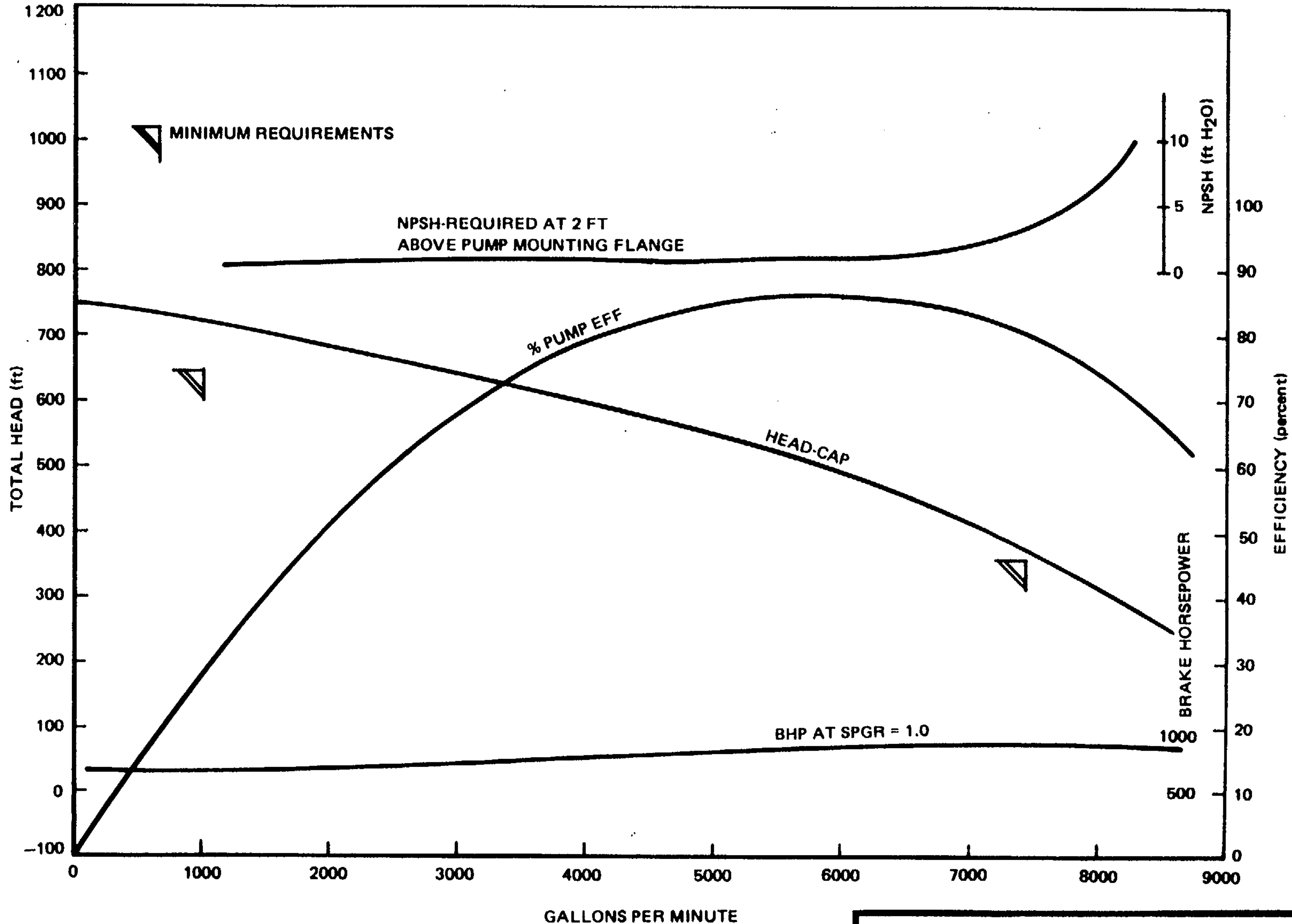
The RWCU return line is split into two branches connecting to the two feedwater loops outside the primary containment. Each branch is equipped with a MOV. Under normal plant operation, both MOVs are open and RWCU water is returned to the RPV via two feedwater loops. During plant startup when the reactor power is below 20 percent, one of the MOVs may be closed directing all RWCU flow into a single feedwater loop. This will be done to minimize thermal stratification in the feedwater line during startup and shutdown and allow sharing the thermal cycles between the two feedwater loops. Both valves may be closed as necessary to support surveillance testing during plant shutdown.

Operation of the RWCU system is controlled from the main control room. Resin-changing operations, which include backwashing and precoating, are controlled from a local control panel.

A FCD is provided on Figure 7.3-7. Controls for valves 2WCS*MOV404A and B are shown on Figure 10.4-11.

5.4.8.3 System Evaluation

The RWCU system, in conjunction with the CND system, maintains reactor water quality during all reactor operating modes (normal, hot standby, startup, shutdown, and refueling). During refueling mode, the spent fuel pool cooling and cleanup system (SFC) also contributes to this function. This type of pressure precoat cleanup system has been used in all operating BWR plants since 1971. Operating plant experience has shown that the RWCU system, as designed, maintains the required BWR water quality. The



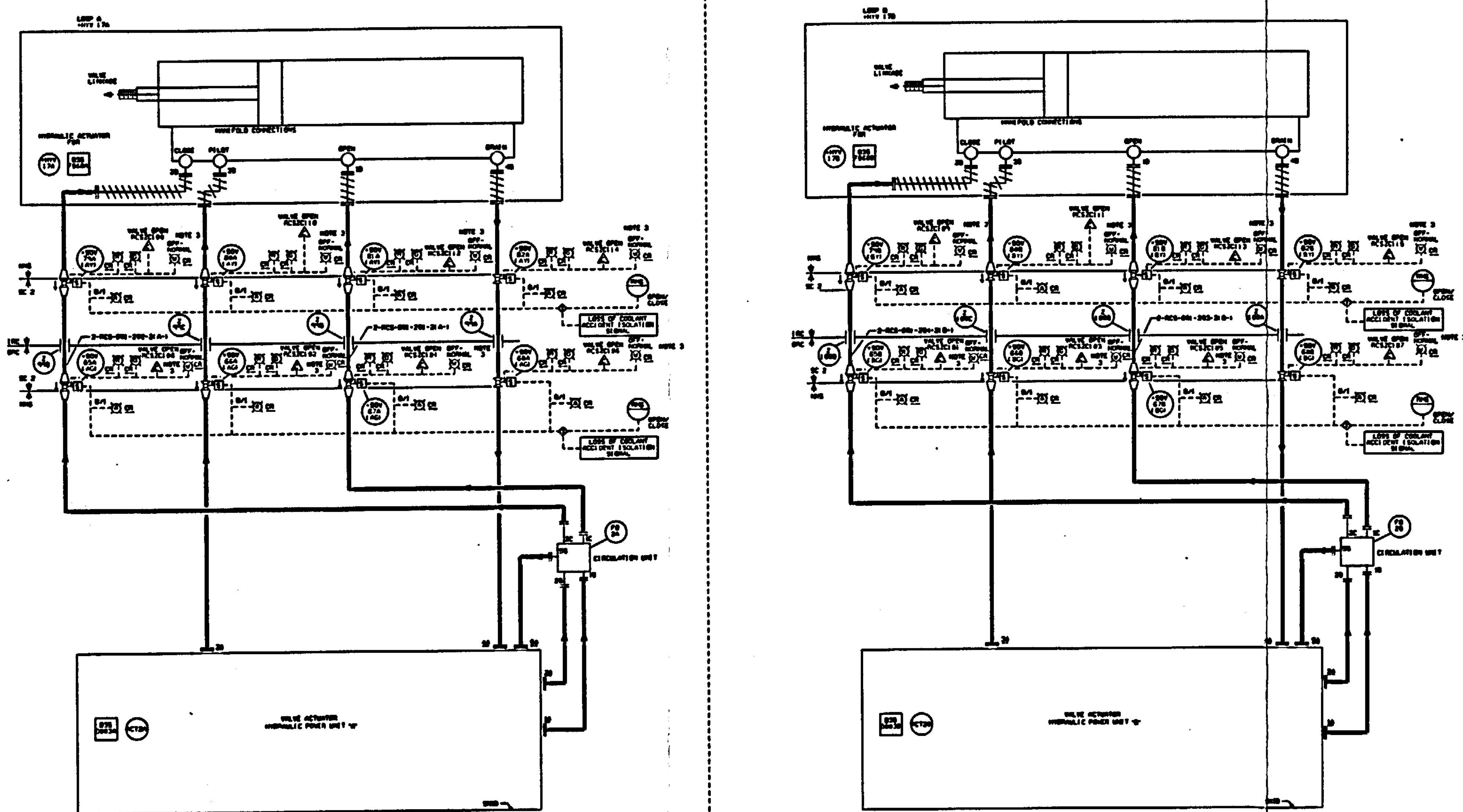
Note: Pump curve represents manufacturer's test curve. Installed performance and minimum acceptable Technical Specification performance is below this curve.

SOURCE: 731E961AF

FIGURE 5.4-15

RHR PUMP CHARACTERISTIC CURVES

NIAGARA MOHAWK POWER CORPORATION
NINE MILE POINT-UNIT 2
UPDATED SAFETY ANALYSIS REPORT



NOTES:

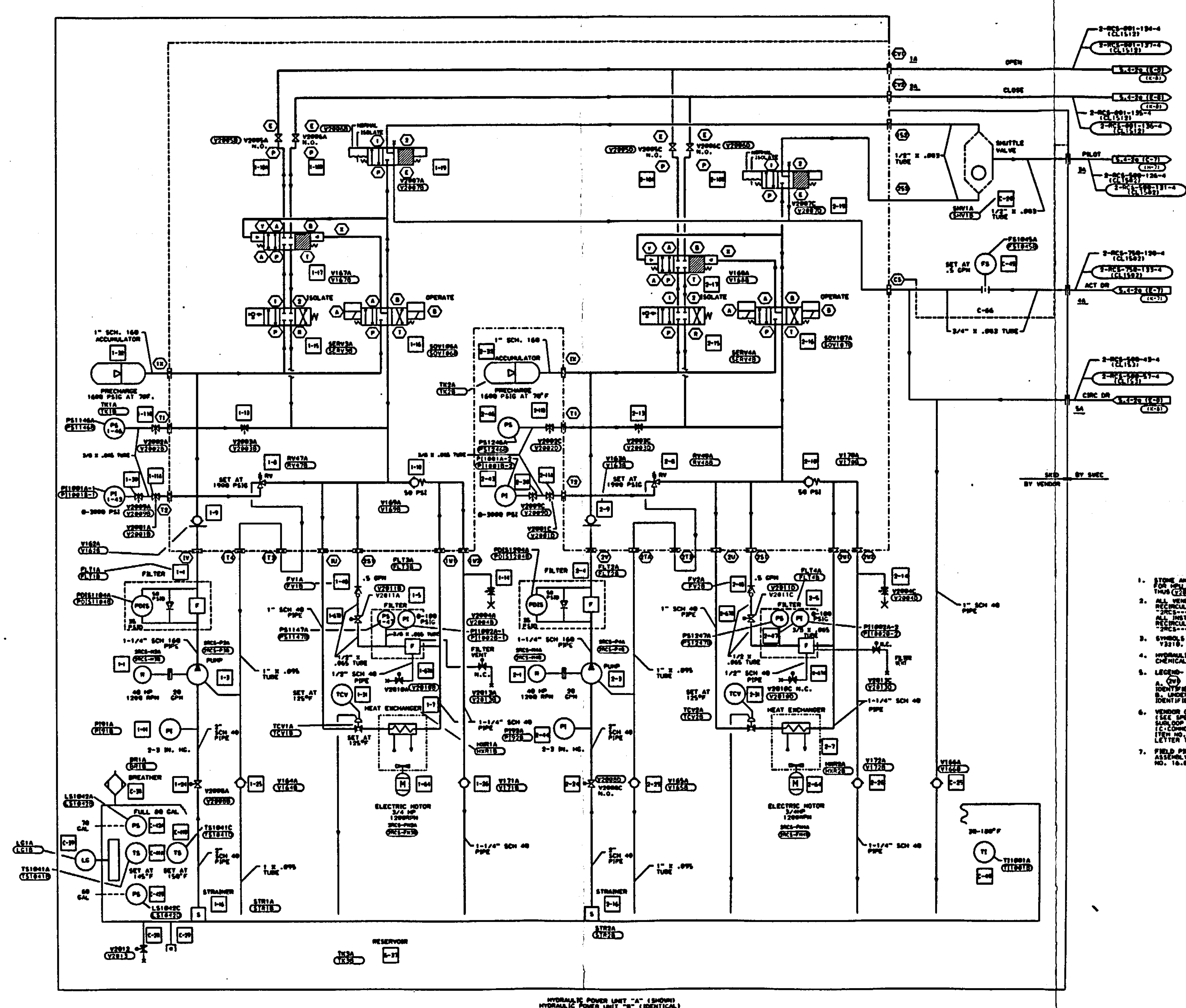
1. ALL INSTRUMENT & EQUIPMENT NUMBERS TO BE PREFIXED WITH "2RCS-" EXCEPT WHERE A DIFFERENT PREFIX IS SHOWN. AN ASTERISK (*) WILL REPLACE THE DASH (-) IN THE PREFIX FOR EQUIPMENT OR INSTRUMENTS WHICH ARE A PART OF THE NUCLEAR SAFETY FEATURES SYSTEMS.
2. [illegible] IDENTIFICATION NUMBERS ARE SHOWN IN SQUARES (PREFIXED BY [illegible]) EXCEPT AS OTHERWISE SHOWN.
3. OFF-NORMAL STATUS DISPLAY SYSTEM IS [illegible] IN PLACE.

SOURCE 12177-PID-29A-B
TITLE: REACTOR RECIRCULATION SYSTEM

FIGURE 5.4-2a

REACTOR COOLANT (RECIRCULATION)

NIAGARA MOHAWK POWER CORPORATION
NINE MILE POINT-UNIT 2
UPDATED SAFETY ANALYSIS REPORT



SOURCE, PID-29D-8
TITLE, REACTOR RECIRCULATION SYSTEM

SOLENOID CHART				
CONDITION	VLV 1-16		VLV 2-16	
	OPER SOL	ISO SOL	OPER SOL	ISO SOL
BOTH SUBLOOPS ISOLATED ACTUATOR LOCKED	●	●	●	●
SUB. 1 CONTROL'G ACTUATOR SUB. 2 ISOLATED	X	●	●	●
SUB. 2 CONTROL'G ACTUATOR SUB. 1 ISOLATED	●	●	X	●

KEY- X MUST BE ENERGIZED
● MUST BE DE-ENERGIZED
● NORMALALLY ENERGIZED BUT MAY BE DE-ENERGIZED

NOTE 7

FIELD PIPING CONNECTIONS			
CONN NO.	FUNCTION	SAE FLG. SIZE	PIPE SIZE
1A	OPEN	1-1/4" 6000 PSI	1
2A	CLOSE	1-1/4" 6000 PSI	1
3A	PILOT	3/4" 3000 PSI	1/2
4A	ACT. DR.	1" 3000 PSI	3/4
5A	CIRC DR.	3/4" 3000 PSI	1/2

LINE LEGEND

PRESSURE LINE

DRAIN, RETURN OR PILOT LINE

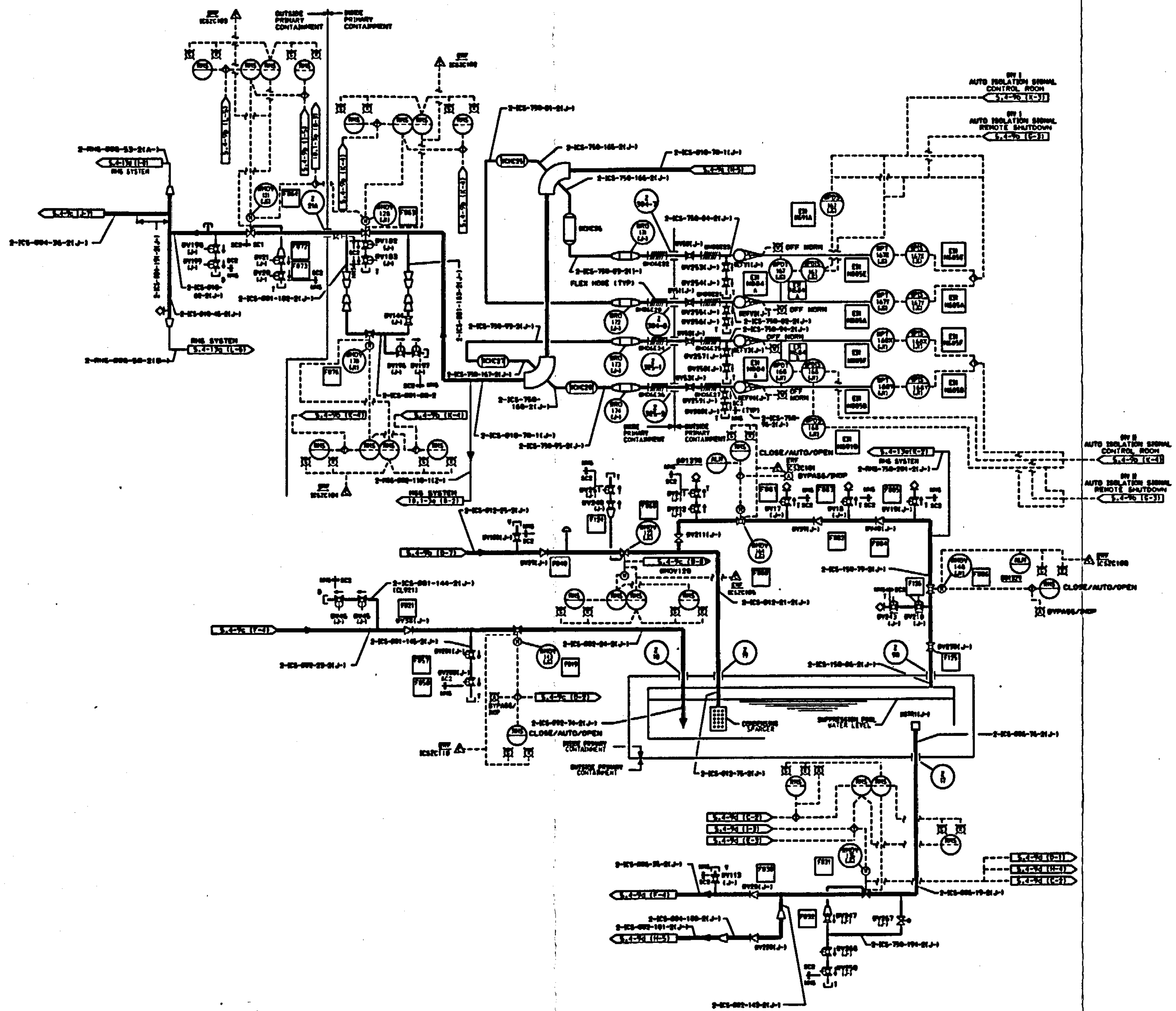
1. STONE AND WEBSTER VALVE, LINE AND INSTRUMENT NUMBERS FOR HPU "A" SHOWN THUS V2011A, FOR HPU "B" SHOWN THUS V2011B
2. ALL VENDOR INSTRUMENT & EQUIPMENT NUMBERS IN THE RECIRCULATION LOOP "A" TO BE PREFIXED WITH "2RCS---A" EXCEPT WHERE A DIFFERENT PREFIX IS SHOWN. ALL INSTRUMENT & EQUIPMENT NUMBERS IN THE RECIRCULATION LOOP "B" TO BE PREFIXED WITH "2RCS---B" EXCEPT WHERE A DIFFERENT PREFIX IS SHOWN.
3. SYMBOLS NOT PER S&W STANDARDS ARE PER ANSI Y32.10.
4. HYDRAULIC FLUID - PYROGUEL EHC.AS HFDG BY STAUFFER CHEMICAL ACCUM PRE-CHARGE WITH NITROGEN.
5. LEGEND-
A. (2V) LETTER, NUMBER, OR COMBINATION IDENTIFIES A PORT.
B. UNDERLINED LETTER-NUMBER COMBINATION IDENTIFIES FIELD PIPING CONNECTION.
6. VENDOR COMPONENT IDENT. CODE (SEE SPEC NMP2-P000A-035) SUBLOOP NO. (C-COMMON) ITEM NO. B/M LETTER TO DISTINGUISH IDENTICAL ITEMS
7. FIELD PIPING CONNECTION NO.'S SAME AS ON ASSEMBLY AND OUTLINE DWGS. SEE S&W FILE NO. 16.030-5006.

THIS DRAWING WAS PRODUCED ELECTRONICALLY, DO NOT MAKE ANY CHANGES MANUALLY.

FIGURE 5.4-2d

REACTOR RECIRCULATION SYSTEM

NIAGARA MOHAWK POWER CORPORATION
NINE MILE POINT-UNIT 2
UPDATED SAFETY ANALYSIS REPORT



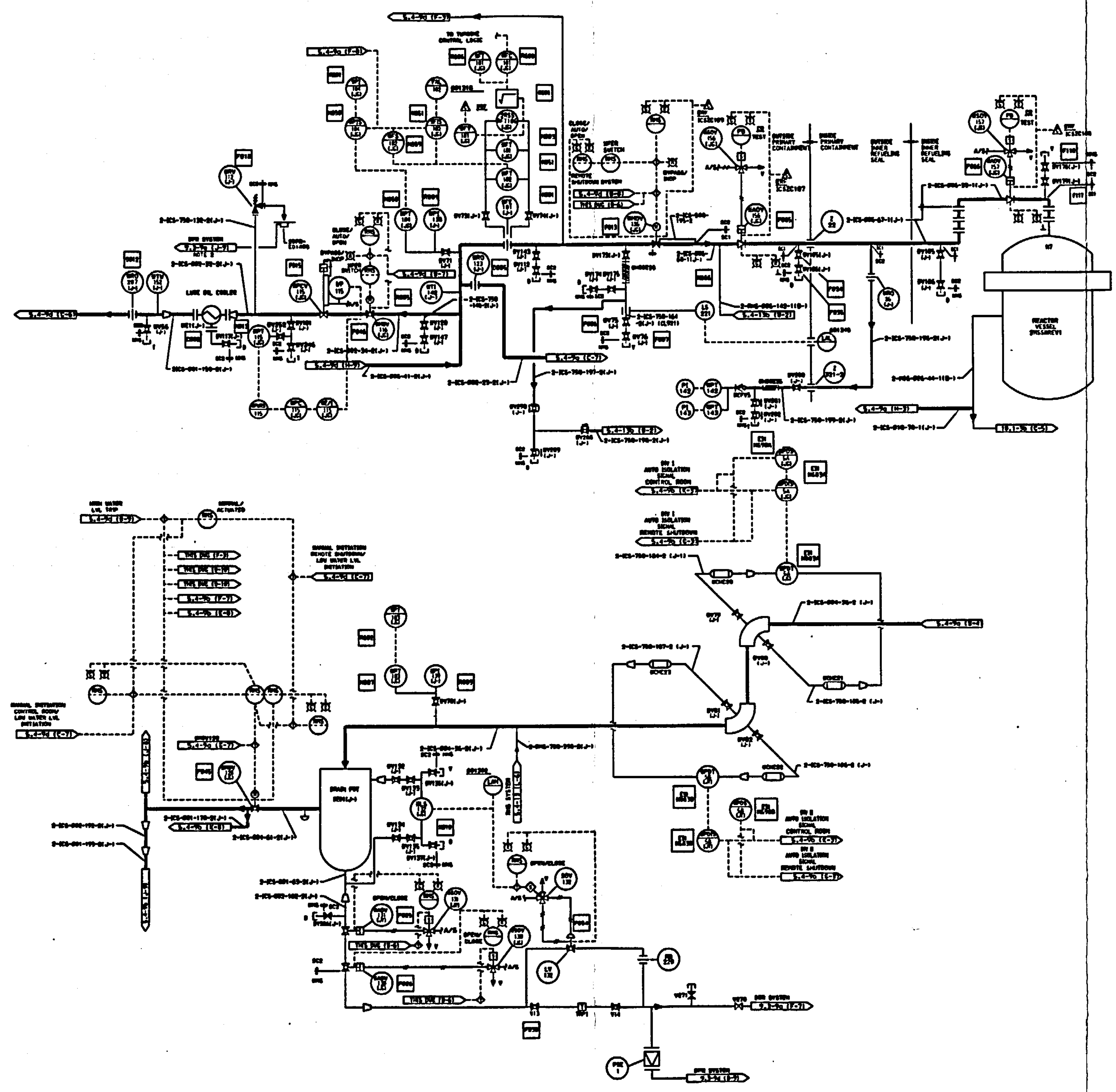
NOTES:
1. ALL INSTRUMENT AND EQUIPMENT NUMBERS TO BE PREFIXED WITH "2ICS-" EXCEPT WHERE A DIFFERENT PREFIX IS SHOWN. AN ASTERISK (*) WILL REPLACE THE DASH (-) IN THE PREFIX FOR EQUIPMENT OR INSTRUMENTS WHICH ARE A PART OF THE NUCLEAR SAFETY FEATURES SYSTEM.

SOURCE: PID-35A-18
TITLE: REACTOR CORE ISOLATION COOLING

FIGURE 5.4-9a

REACTOR CORE ISOLATION COOLING

NIAGARA MOHAWK POWER CORPORATION
NINE MILE POINT-UNIT 2
UPDATED SAFETY ANALYSIS REPORT



SOURCE, PID-35C-20
TITLE, REACTOR CORE ISOLATION COOLING

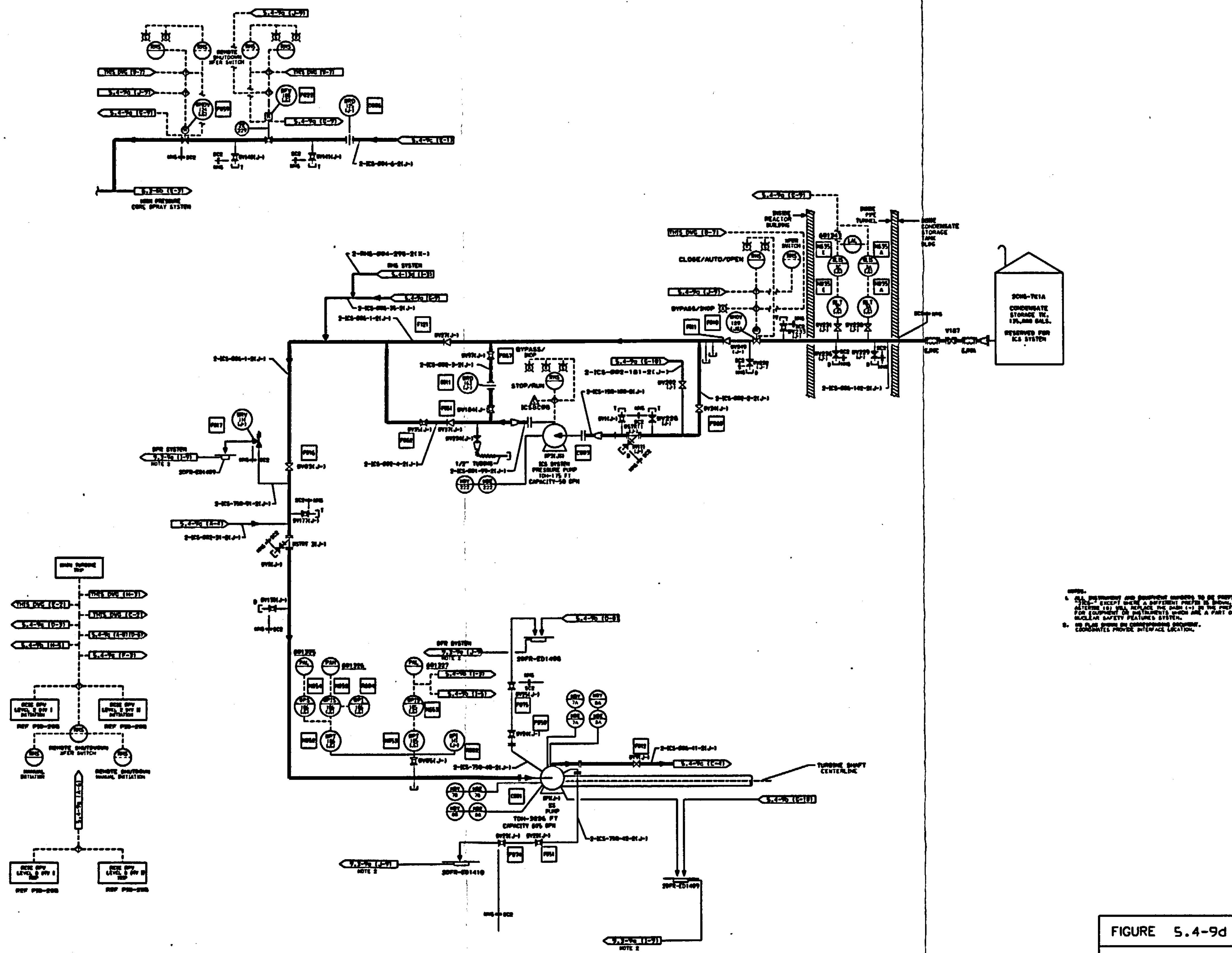
THIS DRAWING WAS PRODUCED ELECTRONICALLY. DO NOT MAKE ANY CHANGES MANUALLY.

FIGURE 5.4-9c

REACTOR CORE ISOLATION COOLING

NIAGARA MOHAWK POWER CORPORATION
NINE MILE POINT-UNIT 2
UPDATED SAFETY ANALYSIS REPORT

USAR REVISION 13 OCTOBER 2000



SOURCE, PID-35D-11
TITLE, REACTOR CORE ISOLATION COOLING

FIGURE 5.4-9d

REACTOR CORE ISOLATION COOLING

NIAGARA MOHAWK POWER CORPORATION
NINE MILE POINT-UNIT 2
UPDATED SAFETY ANALYSIS REPORT

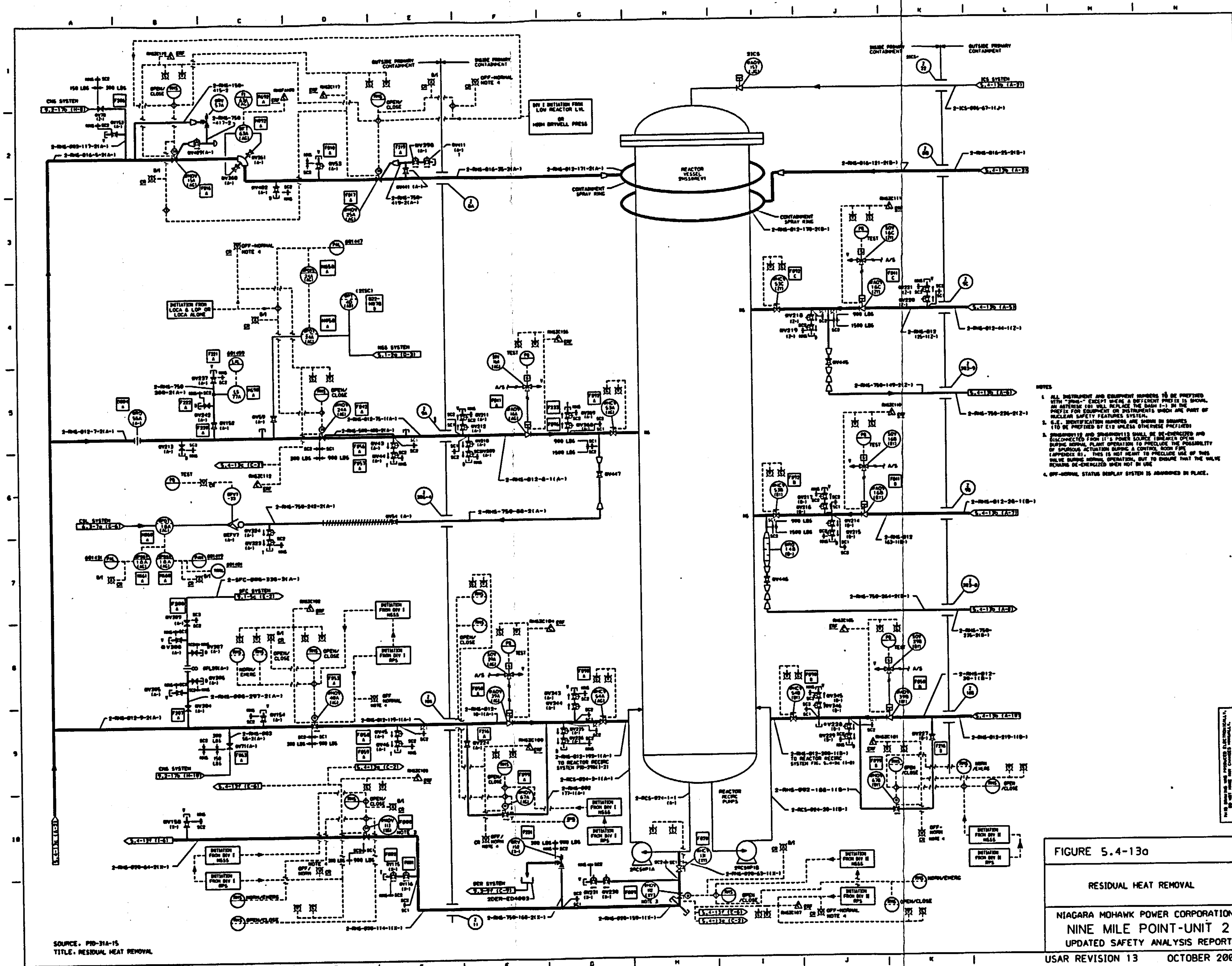
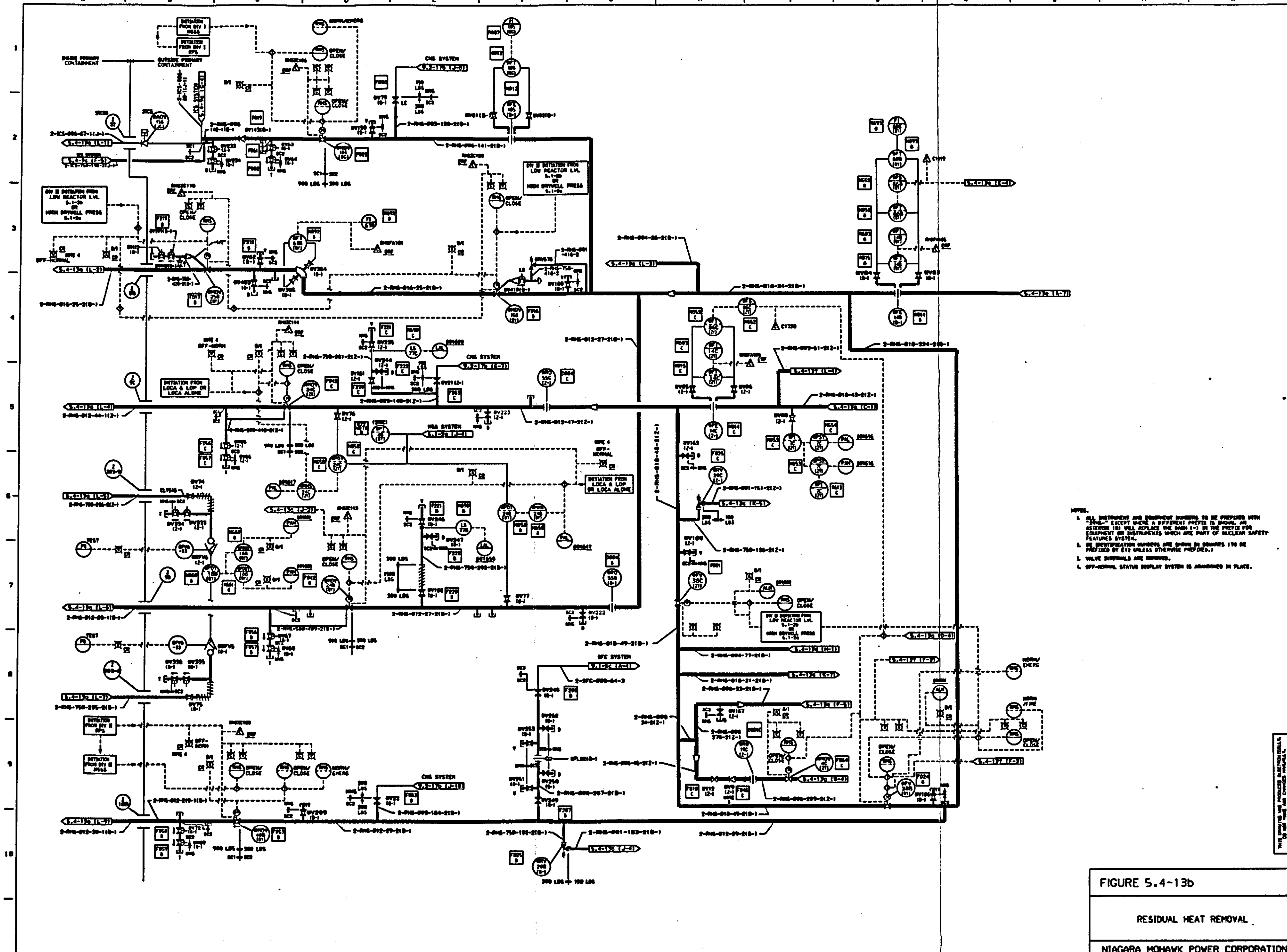


FIGURE 5.4-13a

RESIDUAL HEAT REMOVAL

NIAGARA MOHAWK POWER CORPORATION
NINE MILE POINT-UNIT 2
UPDATED SAFETY ANALYSIS REPORT

USAR REVISION 13 OCTOBER 2000



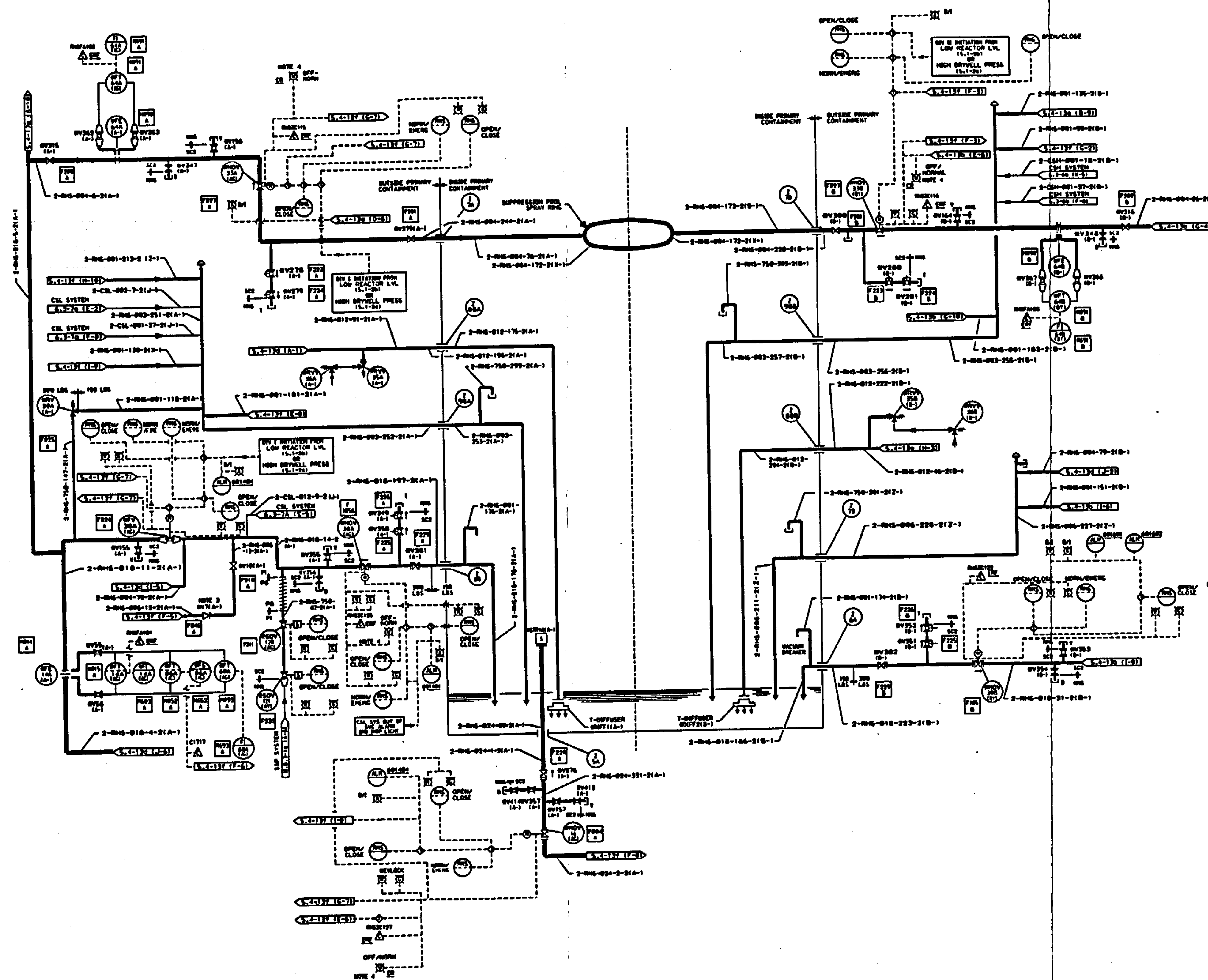
SOURCE: PID-31B-12
TITLE: RESIDUAL HEAT REMOVAL

FIGURE 5.4-13b

RESIDUAL HEAT REMOVAL

NIAGARA MOHAWK POWER CORPORATION
NINE MILE POINT-UNIT 2
UPDATED SAFETY ANALYSIS REPORT

USAR REVISION 13 OCTOBER 2000



NOTES:
1. ALL INSTRUMENT AND EQUIPMENT NUMBERS TO BE PREFIXED WITH "2RHS" EXCEPT WHERE A DIFFERENT PREFIX IS SHOWN. AN ASTERISK (*) WILL REPLACE THE DASH (-) IN THE PREFIX FOR EQUIPMENT OR INSTRUMENTS WHICH ARE PART OF NUCLEAR SAFETY FEATURES SYSTEM.
2. GE IDENTIFICATION NUMBERS ARE SHOWN IN SQUARES (TO BE PREFIXED BY E12 UNLESS OTHERWISE PREFIXED.)
3. VALVE INTERNALS ARE REMOVED.
4. OFF-NORMAL STATUS DISPLAY SYSTEM IS ABANDONED IN PLACE.

SOURCE: PID-31C-12
TITLE: RESIDUAL HEAT REMOVAL

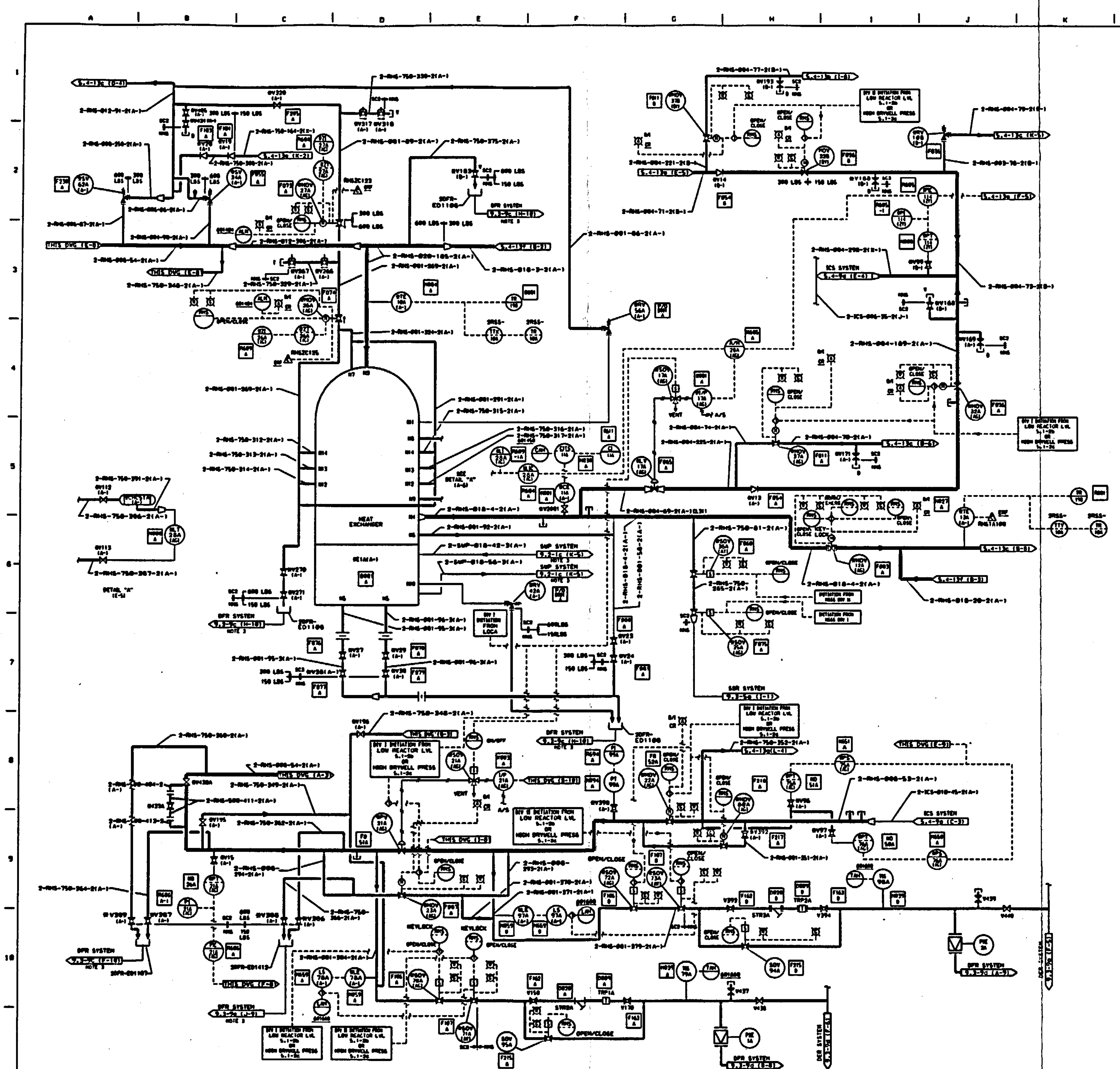
THIS DRAWING WAS PRODUCED ELECTRONICALLY. DO NOT MAKE ANY CHANGES MANUALLY.

FIGURE 5.4-13c

RESIDUAL HEAT REMOVAL

NIAGARA MOHAWK POWER CORPORATION
NINE MILE POINT-UNIT 2
UPDATED SAFETY ANALYSIS REPORT

USAR REVISION 13 OCTOBER 2000



SOURCE, PID-31D-15
TITLE, RESIDUAL HEAT REMOVAL

NOTES:

1. ALL INSTRUMENT AND EQUIPMENT NUMBERS TO BE PREFIXED WITH "2RHS" EXCEPT WHERE A DIFFERENT PREFIX IS SHOWN. AN ASTERISK (*) WILL REPLACE THE DASH (-) IN THE PREFIX FOR EQUIPMENT OR INSTRUMENTS WHICH ARE PART OF NUCLEAR SAFETY FEATURES SYSTEM.
2. GE IDENTIFICATION NUMBERS ARE SHOWN IN SQUARES (TO BE PREFIXED BY E12 UNLESS OTHERWISE PREFIXED.)
3. NO FLAG SHOWN ON CORRESPONDING DOCUMENT. COORDINATES PROVIDE INTERFACE LOCATION.

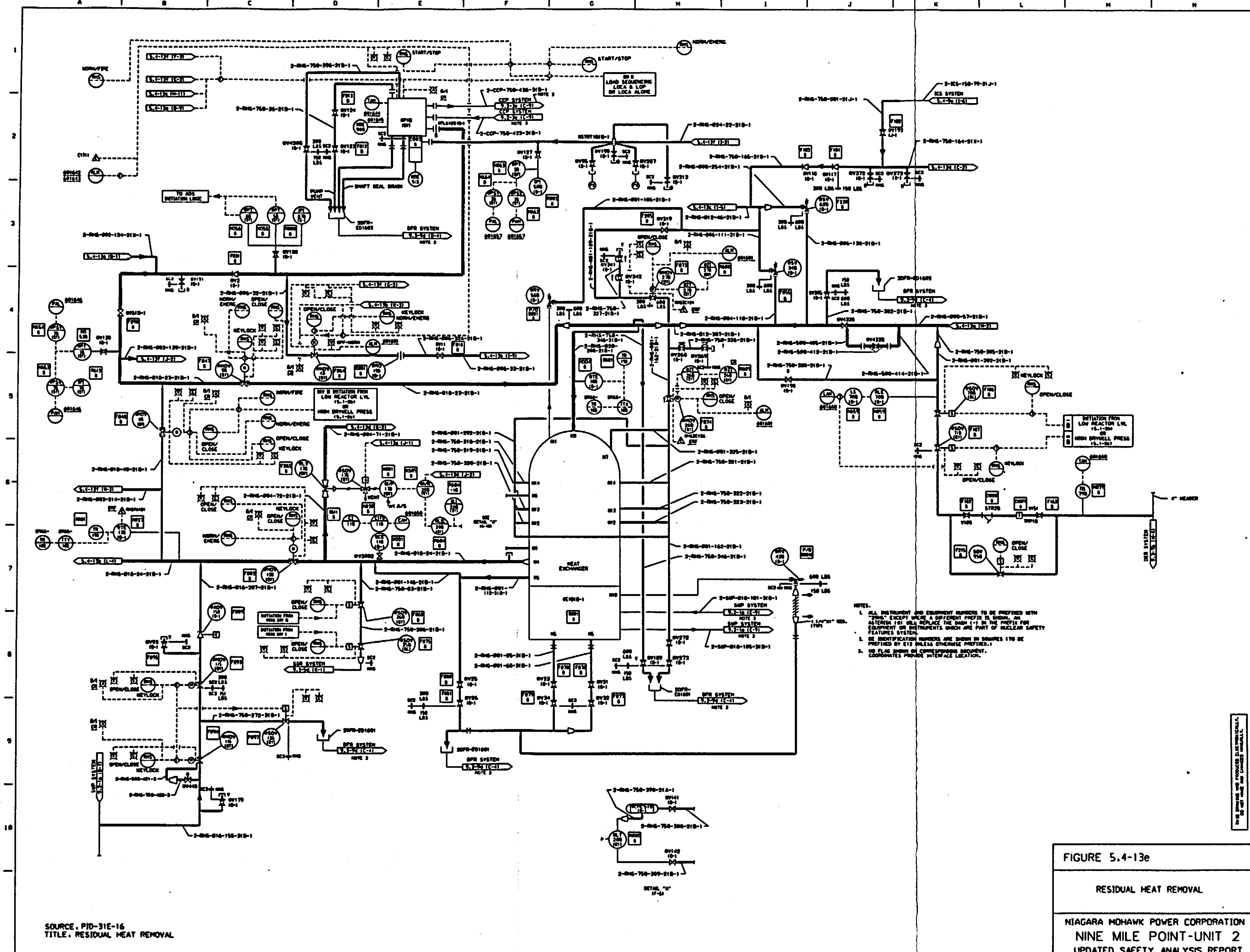
THIS DRAWING WAS PRODUCED ELECTRONICALLY. DO NOT MAKE ANY CHANGES MANUALLY.

FIGURE 5.4-13d

RESIDUAL HEAT REMOVAL

NIAGARA MOHAWK POWER CORPORATION
NINE MILE POINT-UNIT 2
UPDATED SAFETY ANALYSIS REPORT

USAR REVISION 13 OCTOBER 2000



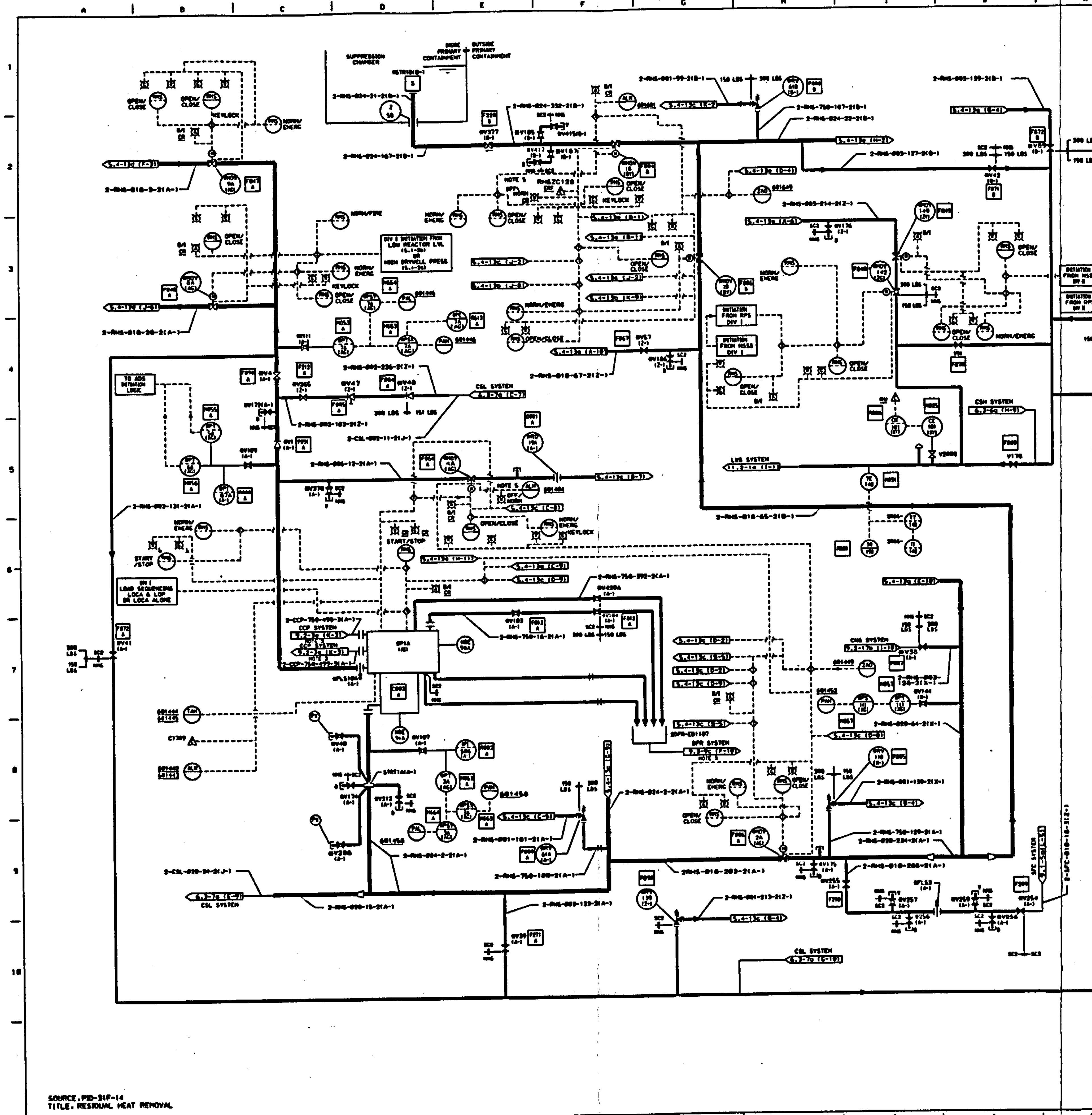
SOURCE: PID-31E-16
TITLE: RESIDUAL HEAT REMOVAL

FIGURE 5.4-13e

RESIDUAL HEAT REMOVAL

NIAGARA MOHAWK POWER CORPORATION
NINE MILE POINT-UNIT 2
UPDATED SAFETY ANALYSIS REPORT

USAR REVISION 13 OCTOBER 2000



SOURCE. PID-31F-14
TITLE. RESIDUAL HEAT REMOVAL

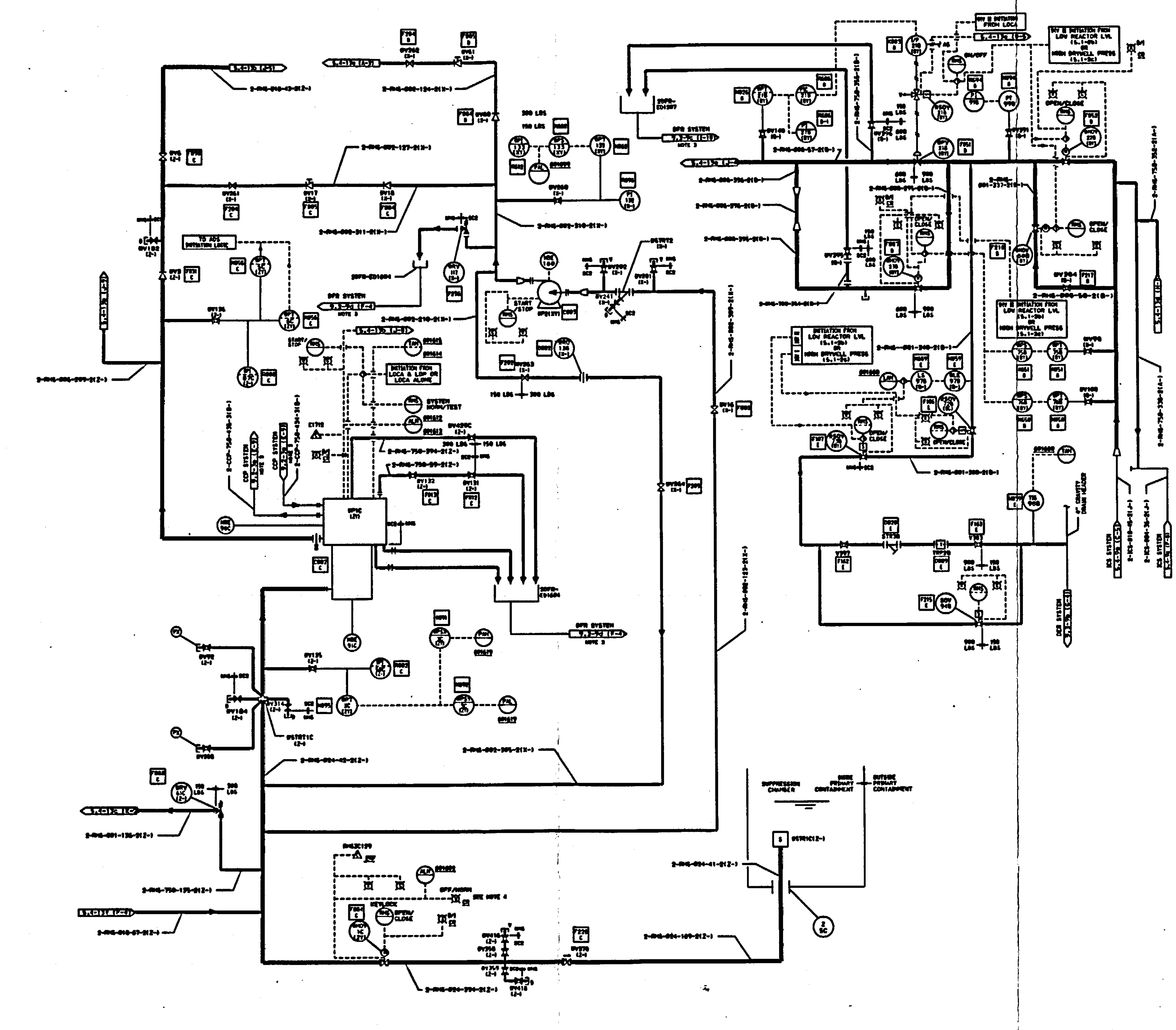
NOTES:

1. ALL INSTRUMENT AND EQUIPMENT NUMBERS TO BE PREFIXED WITH "2RHS" EXCEPT WHERE A DIFFERENT PREFIX IS SHOWN. AN ASTERISK (*) WILL REPLACE THE DASH (-) IN THE PREFIX FOR EQUIPMENT OR INSTRUMENTS WHICH ARE PART OF NUCLEAR SAFETY FEATURES SYSTEM.
2. GE IDENTIFICATION NUMBERS ARE SHOWN IN SQUARES (TO BE PREFIXED BY E12 UNLESS OTHERWISE PREFIXED.)
3. NO FLAG SHOWN ON CORRESPONDING DOCUMENT. COORDINATES PROVIDE INTERFACE LOCATION.
4. 2RHS*MOV142 AND 2RHS*MOV149 SHALL BE DE-ENERGIZED AND DISCONNECTED FROM IT'S POWER SOURCE (BREAKER OPEN) DURING NORMAL PLANT OPERATION TO PRECLUDE THE POSSIBILITY OF SPURIOUS ACTUATION DURING A CONTROL ROOM FIRE (APPENDIX R). THIS IS NOT MEANT TO PRECLUDE USE OF THIS VALVE DURING NORMAL OPERATION, BUT TO ENSURE THAT THE VALVE REMAINS DE-ENERGIZED WHEN NOT IN USE.
5. OFF-NORMAL STATUS DISPLAY SYSTEM IS ABANDONED IN PLACE.

FIGURE 5.4-13f

RESIDUAL HEAT REMOVAL

NIAGARA MOHAWK POWER CORPORATION
NINE MILE POINT-UNIT 2
UPDATED SAFETY ANALYSIS REPORT



NOTES.

1. ALL INSTRUMENT AND EQUIPMENT NUMBERS TO BE PREFIXED WITH "2RHS" EXCEPT WHERE A DIFFERENT PREFIX IS SHOWN. AN ASTERISK (*) WILL REPLACE THE DASH (-) IN THE PREFIX FOR EQUIPMENT OR INSTRUMENTS WHICH ARE PART OF NUCLEAR SAFETY FEATURES SYSTEM.
2. DE IDENTIFICATION NUMBERS ARE SHOWN IN SQUARES (TO BE PREFIXED BY E12 UNLESS OTHERWISE PREFIXED.)
3. NO FLAG SHOWN ON CORRESPONDING DOCUMENT. COORDINATES PROVIDE INTERFACE LOCATION.
4. OFF-NORMAL STATUS DISPLAY SYSTEM IS ABANDONED IN PLACE.

SOURCE.PID-31C-12
TITLE.RESIDUAL HEAT REMOVAL

THIS DRAWING WAS PRODUCED ELECTRONICALLY. DO NOT MAKE ANY CHANGES MANUALLY.

FIGURE 5.4-13g

RESIDUAL HEAT REMOVAL

NIAGARA MOHAWK POWER CORPORATION
NINE MILE POINT-UNIT 2
UPDATED SAFETY ANALYSIS REPORT

USAR REVISION 13 OCTOBER 2000

FCF238X184AF (E12-1020)

MODE F (SEE NOTE 3)

POSITION ○	1	2	3	4	5	6	7	8	9	10	13	43	24	1
FLOW-GPM	—	7450 ←											→ 7450	—
PRESS-PSIA	14.7	X	X	X	X	X	X	X	X	X	X	X	X	14.7
TEMP °F	—	120/40 ←											→ 120/40	—
MAX. PRESS DROP-FEET	←				TDH 368									→

LOOP C — LOOPS A & B

MODE G (R_x PRESS. 135 PSIG)

POSITION ○	29	25	26	4	5	6	43	24	1		1	2	3	4	5	6	6.2	43	24	1
FLOW-GPM	—	1000 ←						→ 1000	—		—	1000 ←					→ 1000	1000/1000	1000/1000	—
PRESS-PSIA	190	X	X	X				X	14.7		14.7	X	X	X					X	14.7
TEMP °F	—	350 ←						→ 350	—		—	125/40 ←							→ 125/40	—
MAX. PRESS DROP-FEET	←				TDH 650				→		←					TDH 650				→

SEE NOTE 22 — SEE NOTE 22

MODE S

POSITION ○	1	2 A.B.C	3 A.B.C	4 A.B.C	5 A.B.C	6 A.B.C	18 A.B	19 A.B	20 A.B	9 A.B.C	10 A.B.C	46 A.B.C	11 A.B.C	48 A.B	21 A.B	50 A.B	27 A.B	51	33	52 A.B	53 A.B
FLOW-GPM	N/A	←																		→	N/A
PRESS-PSIA	14.7	X	X	X	X	X	X	X	X	X	X	X	X	X	15.5	X	X	X	1035	X	X
TEMP °F	90/40	←									→	90/40	X	90/40	135	90/40	X	90/40	549	90/40	90/40
MAX. PRESS DROP-FEET					- 0 -																

MODE S (CONT'D)

POSITION ○	54	56	55 A.B		34	35	36 A.B	37 A.B	17 A.B		20 A.B	38 A.B	40 A.B	41	42
FLOW-GPM	N/A	N/A	N/A		N/A	←		→	N/A		N/A	←		→	N/A
PRESS-PSIA	X	X	X		X	X	X	X	X		X	X	X	X	X
TEMP °F	AMB	AMB	AMB		AMB	AMB	AMB	90/40	90/40		90/40	90/40	AMB	AMB	AMB
MAX. PRESS DROP-FEET															

MODE C-3 (4 HRS 135 PSIG R_x PRESS)

POSITION ○	29	64	65	34	35	36 A.B	37 A.B	17 A.B	18 A.B	19 A.B	20 A.B	38 A.B	39 A.B	40 A.B	41	42					60 A.B	61 A.B		
FLOW (SEE NOTE 15)	—	119.6	114.4	←→	114.4	57.7	←	→	57.7	116	←			116	232	232					7400	7400		
PRESS-PSIA	190					X	X	X	>60	X	X	X	X	X		59.7/14.7					X	X		
TEMP °F	—	323 ←							→ 323	148 ←						→ 148					82	98.8		
MAX. PRESS DROP-FEET	←					$\Delta P = 90.3/135.3$										→								

HEAT REMOVAL PER STEAM CONDENSING H_x 62.15 X 10^6 BTU/HR (2 H_x STEAM CONDENSING)

MODE C-4 (8 HRS 135 PSIG R_x PRESS)

POSITION ○	29	64	65	34	35	36_A	37_A	17_A	18_A	19_A	20_A	38_A	39_A	40_A	41	42					60_A	61_A		
FLOW (SEE NOTE 15)	—	98.7	93.5 ←					→	93.5	190 ←					→	190					7400	7400		
PRESS-PSIA	190	X	X	X	X				>60	X					X	59.7/14.7					X	X		
TEMP °F	—	323 ←							→ 323	148 ←						→ 148					82	109.5		
MAX. PRESS DROP-FEET	←					$\Delta P = 90.3/135.3$										→								

HEAT REMOVAL PER STEAM CONDENSING H_x 101.6 X 10^6 BTU/HR (1 H_x STEAM CONDENSING)

Note: Mode data on this sheet was used for original pipe and component sizing. Design requirements are based on Mode specific analysis.

MODE A-1 (SEE NOTE 3 & 14)

POSITION ○	1	2	3	4	5	6	7	8	9	10	16	11	29
FLOW-GPM	—	7450 ←										→ 7450	—
PRESS-PSIA	59.7/14.7	X	X	X	X								59.7/14.7
TEMP °F	—	170/40 ←										→ 170/40	—
MAX. PRESS DROP-FEET	←				TDH 368				ΔH 17			ΔH 46	→

LOOP C — LOOPS A & B

MODE A-2 (SEE NOTE 14)

POSITION ○	1	2	3	4	5	6	7	8	9	10	16	11	29
FLOW-GPM	—	8400 ←										→ 8400	—
PRESS-PSIA	14.7	X	X	X	X	X	X	X	X	X	X	X	14.7
TEMP °F	—	180/90 ←										→ 180/90	—
MAX. PRESS DROP-FEET	←				TDH 326								→

LOOP C — LOOPS A & B

MODE B

POSITION ○	1	2_B	3_B	4_B	5_B	6_B	7_B	17_B	18_B	19_B	20_B	8_B	9_B	10_B	13_B	14	15_B	21_B	22	23_B	1		60_B	61_B
FLOW-GPM	—	8400 ←															→ 8400	7950	—	450	—		7400	7400
PRESS-PSIA	59.7/14.7					X	X	X	X	X	X	X	X	X	X	X			59.7/14.7		59.7/14.7		X	X
TEMP °F	—	212 ←							→ 212	182 ←									→	182	—		82	114.7
MAX. PRESS DROP-FEET	←				TDH 326														→					

HEAT REMOVAL PER H_x 120.0 X 10^6 BTU/HR (1 H_x OPERATING) SEE NOTES 16 & 21 — INDICATES FLOW PASSING THRU ABOVE POSITIONS (TYP) — SEE NOTE 7 (TYP)

MODE C-1 (R_x PRESS 1000 PSIG)

POSITION ○	29	34	35	36 A.B	37 A.B	17 A.B	18 A.B	19 A.B	20 A.B	38 A.B	39 A.B	40 A.B	41	42	44 A.B	24 A.B	1		60 A.B	61 A.B
FLOW (SEE NOTE 15)	—	107.1	107.1	93.95 ←			→ 93.95	190				→ 190	380	380	190	190	—		7400	7400
PRESS-PSIA	1014.7	X	X	X	214.7	X	X	X	X	X	X	X			59.7		14.7		X	X
TEMP °F	—	546	546	546	387.7	387.7	387.7	148 ←								→ 148	—		82	109.4
MAX. PRESS DROP-FEET	←	ΔP=800		→	←			ΔP=200 / ΔP=155						→			→			

HEAT REMOVAL PER H_x 101.4 X 10^6 BTU/HR (2 H_x STEAM CONDENSING)

MODE C-2 (R_x PRESS 110 PSIG)

POSITION ○	29	34	35	36_A	37_A	17_A	18_A	19_A	20_A	38_A	39_A	40_A	41	42		60_A	61_A
FLOW (SEE NOTE 15)	—	136.2 ←					→ 136.2	277 ←						→ 277		7400	7400
PRESS-PSIA	1014.7	X	X	X	214.7	X	X	X					X	59.7		X	X
TEMP °F	—	546	546	546	387.7	387.7	387.7	148 ←						→ 148		82	122
MAX. PRESS DROP-FEET	←	ΔP=800		→	←			ΔP=155						→			

DUTY PER STEAM CONDENSING H_x 147.5 X 10^6 BTU/HR (1 H_x STEAM CONDENSING)

MODE C-2 (CONT'D) (SEE NOTE 14)

POSITION ○	1	2_B	3_B	4_B	5_B	6_B	7_B	17_B	18_B	19_B	20_B	9_B	10_B	13_B	43_B	24_B	1		60_B	61_B
FLOW-GPM	—	7450 ←														→ 7450	—		7400	7400
PRESS-PSIA	14.7	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	14.7		X	X
TEMP °F	—	120/70 ←							→ 120/70	111.0 ←						→ 111.0	—		82	91.0
MAX. PRESS DROP-FEET	←				TDH 368											→				

HEAT REMOVAL PER POOL COOLING H_x 33.86 X 10^6 BTU/HR (1 H_x OPERATING)

MODE D (SEE NOTE 13 & 24) (R_x PRESS 110 PSIG)

POSITION ○	29	25	26	4 A.B	5 A.B	6 A.B	18 A.B	19 A.B	8 A.B	9 A.B	10 A.B	14	27_B	28	30	31		33	29	27_A	28	29	60 A.B	61 A.B
FLOW-GPM	—	14900	14900	7450	7450	7450	[illegible]	[illegible]	7450	←	→	7450	6500	6500	870	870		870	—	7450	7450	—	7400	7400
PRESS-PSIA	124.7			X	X	X	X	X	X	X	X	X	X	X				X	124.7	X	X	124.7	X	X
TEMP °F	—	335 ←					→ 335	269 ←													→ 269	—	72	133.9
MAX. PRESS DROP-FEET	←				TDH 368										ΔH 17			ΔH	→			→		

HEAT REMOVAL PER H_x 220.6 X 10^6 BTU/HR (2 H_x OPERATING) — LOOP A — LOOP B — SEE RCIC (REF 3)

MODE E (R_x PRESS 0 PSIG)

POSITION ○	29	25	26	56	4 A.B.C	5 A.B.C	6 A.B.C	18 A.B	19 A.B	9 A.B.C	10 A.B.C	16 A.B.C	11 A.B.C	27 A.B	28 A.B	29		60 A.B	61 A.B
FLOW-GPM	—	14900/7450	14900	7450 ←											→ 7450	—		7400	7400
PRESS-PSIA	14.7	X	X	X	X	X	X	X	X	X	X	X	X		X	14.7		X	X
TEMP °F	—	125/AMB ←						→ 125/AMB	112.5 ←		LOOPS A & B ONLY				→ 112.5	—		72	84.5
MAX. PRESS DROP-FEET	←				TDH		ΔH 32.1							ΔH 16		→		ΔH 23.1	

DUTY PER H_x 46.1 X 10^6 BTU/HR (2 H_x OPERATING) — LOOP C TEST — LOOP A & B TEST — LOOP A & B

MODES:

A-1 ACCIDENT WITH RECIRCULATION LINE BREAK IN EITHER SIDE AND THREE PUMP OPERATION. ONE STRAINER PLUGGED WITH A PLANT SPECIFIC DEBRIS MIX.
A-2 ACCIDENT WITH RECIRCULATION LINE BREAK IN EITHER SIDE AND THREE PUMP OPERATION. ONE STRAINER PLUGGED WITH A PLANT SPECIFIC DEBRIS MIX. (10 MIN)
B POST ACCIDENT CONTAINMENT SPRAY WITH HEAT REJECTION WITH ONE PUMP OPERATION AND STRAINER PLUGGED WITH A PLANT SPECIFIC DEBRIS MIX. (PEAK SUPPRESSION POOL TEMP)
C-1 REACTOR ISOLATION - 2HX STEAM CONDENSING @T ½ HR
C-2 REACTOR ISOLATION - 1HX STEAM CONDENSING AND 1HX POOL COOLING @T 1½ HR
C-3 REACTOR ISOLATION - 2HX STEAM CONDENSING @T 4 HR
C-4 REACTOR ISOLATION - 1HX STEAM CONDENSING @T 8 HR
D NORMAL SHUTDOWN AFTER BLOWDOWN TO MAIN CONDENSER (SEE NOTE 13)
E CONTINUATION OF NORMAL SHUTDOWN FROM PLANT MODE "D" @T 0 PSIG AND FUNCTIONAL PUMP TEST AFTER SHUTDOWN.
F RHR SYSTEM TEST DURING PLANT OPERATION.
G MINIMUM FLOW BYPASS MODE.
S SYSTEM ON STANDBY DUTY.

LEGEND:

RX PRESS	REACTOR VESSEL PRESSURE
SOH	SHUTOFF HEAD
TDH	TOTAL DYNAMIC HEAD
ΔH	HEAD LOSS
ΔP	PRESSURE LOSS

NOTES:

1. PROCESS DIAGRAM 736E966 SHALL BE USED WITH AND FORM A PART OF THIS PROCESS DATA. IF THERE ARE ANY CONFLICTS BETWEEN THE PROCESS DIAGRAM AND THIS PROCESS DATA, THE PROCESS DATA SHALL GOVERN.
2. PIPING BETWEEN POINTS WITH EMPTY DATA BLANKS (SEE ALSO TABLE 3) SHALL BE SIZED BY OTHERS BASED ON SPECIFIED OPERATING CONDITIONS. EMPTY DATA BLANKS CAN BE FILLED IN BASED ON ACTUAL ARRANGEMENT BY OTHERS.
   ☒ - INDICATES THE DATA IS NOT SIGNIFICANT
3. SHOWN AS TYPICAL FOR ONE LOOP. IF LOOPS ON SIDE I AND SIDE II ARE NOT SYMMETRICALLY ARRANGED, VALUES FOR BOTH SIDES SHALL BE SUBMITTED.
4. ΔH VALUES FOR EQUIPMENT WITHIN GE-SUPPLIED SCOPE ARE AS NOTED.
5. ELEVATIONS ARE NOT INCLUDED IN ΔP. VALUES GIVEN. ELEVATIONS SHALL BE INCLUDED WHEN DETERMINING FINAL VALUES FOR THE EMPTY DATA BLANKS.
6. [box] - INDICATES MAXIMUM ON AND MINIMUM ON VALUES FOR THE MODE SPECIFIED.
7. DASHED LINES INDICATE FLOW DOES NOT PASS THRU THESE POINTS.
8. THE NPSH AVAILABLE IN MODES B & D AT A REFERENCE LOCATION 2 FT. ABOVE THE PUMP MOUNTING FLANGE MUST EQUAL OR EXCEED 14.8 FEET. THE NPSH AVAILABLE AT THE PUMP SUCTION NOZZLE MUST EQUAL OR EXCEED THIS VALUE PLUS THE DIFFERENCE IN ELEVATION BETWEEN THE REFERENCE LOCATION AND THE CENTERLINE OF THE PUMP SUCTION NOZZLE.
9. SERVICE WATER CROSSTIE, IF PROVIDED, SHALL BE SIZED TO FLOW 300 GPM.
10. THIS PORTION OF PIPING TO BE SIZED BASED ON FLOW SHOWN ON FUEL POOL SYSTEM DRAWINGS.
11. TABLE 1 INDICATES VALVE POSITIONS DURING VARIOUS MODES OF OPERATION.
12.
13. FOR LINE LOSSES FROM POINT 60 TO POINT 61 SEE REF. 3.
14. TYPICAL VALUES FOR MAX. AND MIN. SUPPRESSION POOL TEMP SHOWN. FINAL TEMPERATURES DEPEND ON INITIAL POOL WATER TEMPERATURE & POOL WATER VOLUME.
15. WATER FLOWS ARE IN GPM, STEAM FLOWS ARE IN 1000 LBS/HR.
16. HX DUTY BASED UPON 7,400 GPM SHELL SIDE FLOW.
17. FOR LINE SIZING INFORMATION SEE REF. 5.
18. THE WEIGHT OF WATER IN THE SHUTDOWN COOLING SUBSYSTEM PIPING, INCLUDING THE HEAT EXCHANGERS AND PUMPS SHALL NOT EXCEED 300,000 AT 70°F TO PREVENT DILUTION OF STANDBY LIQUID CONTROL NEUTRON ABSORBER BELOW MINIMUM REQUIREMENTS.
19.
20. PIPING SYSTEM DESIGN PRESSURE AND TEMPERATURE AND THE ESTIMATED LINE SIZES ARE FOR INFORMATION ONLY. ACTUAL DESIGN PRESSURE & TEMPERATURE AND LINE SIZES AS DETERMINED BY OTHERS SHALL MEET THE PROCESS DATA HYDRAULIC REQUIREMENT.
21. HEAT EXCHANGER HEAT REMOVAL SHOWN FOR THE FULL FLOW AND MAXIMUM TEMPERATURE DIFFERENCE UNDER NORMAL OPERATING CONDITIONS. THE TUBE SIDE OUTLET TEMPERATURE SHOULD NOT EXCEED 125°F.
22. MAXIMUM PERMISSIBLE SHUTOFF HEAD = 800FT.
23. THE HX STEAM INLET PRESSURE SHALL BE GREATER THAN 60 PSIA TO MINIMIZE THE POSSIBILITY OF FLOW INDUCED VIBRATION.
24. THE HEAT REMOVAL RATE SHOWN IS BASED ON THE HEAT REMOVAL CAPABILITY OF THE HEAT EXCHANGER ONLY. ACTUAL OPERATING HEAT REMOVAL RATE MUST BE REDUCED (E.G. BY BYPASS SHELL SIDE FLOW THRU THE HX BYPASS LINE) TO AVOID EXCESSIVE REACTOR COOLDOWN RATE AND TO REDUCE HX SERVICE WATER OUTLET TEMPERATURE IN ORDER TO AVOID EXCESSIVE HX FOULING.

REFERENCE DOCUMENTS	MPL ITEM NUMBER
1. RHR SYSTEM P&ID	E12-1010
2. RHR SYSTEM DESIGN SPEC	E12-4010
3. RCIC PFD	E51-1020
4. RECIRC SYSTEM PFD	B35-1010
5. LPCS PFD	E21-1020

SOURCE: 731E966C

FIGURE 5.4-14

RESIDUAL HEAT REMOVAL SYSTEM PROCESS DIAGRAM AND DATA SHEET 2 OF 3

NIAGARA MOHAWK POWER CORPORATION
NINE MILE POINT-UNIT 2
UPDATED SAFETY ANALYSIS REPORT

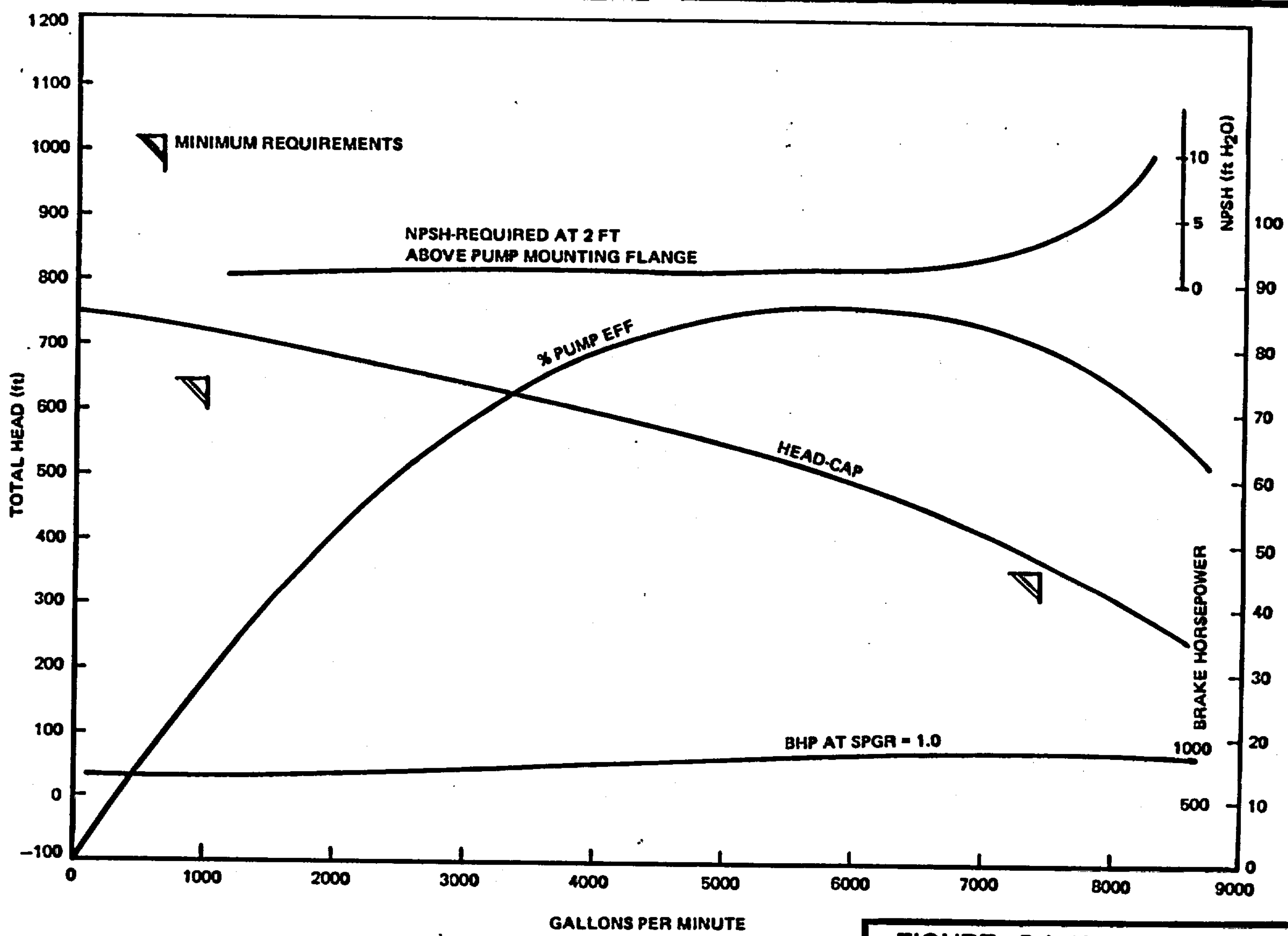


FIGURE 5.4-15

RHR PUMP CHARACTERISTIC CURVES

Note: Pump curve represents manufacturer's test curve. Installed performance and minimum acceptable Technical Specification performance is below this curve.

SOURCE: 731E961AF

NIAGARA MOHAWK POWER CORPORATION
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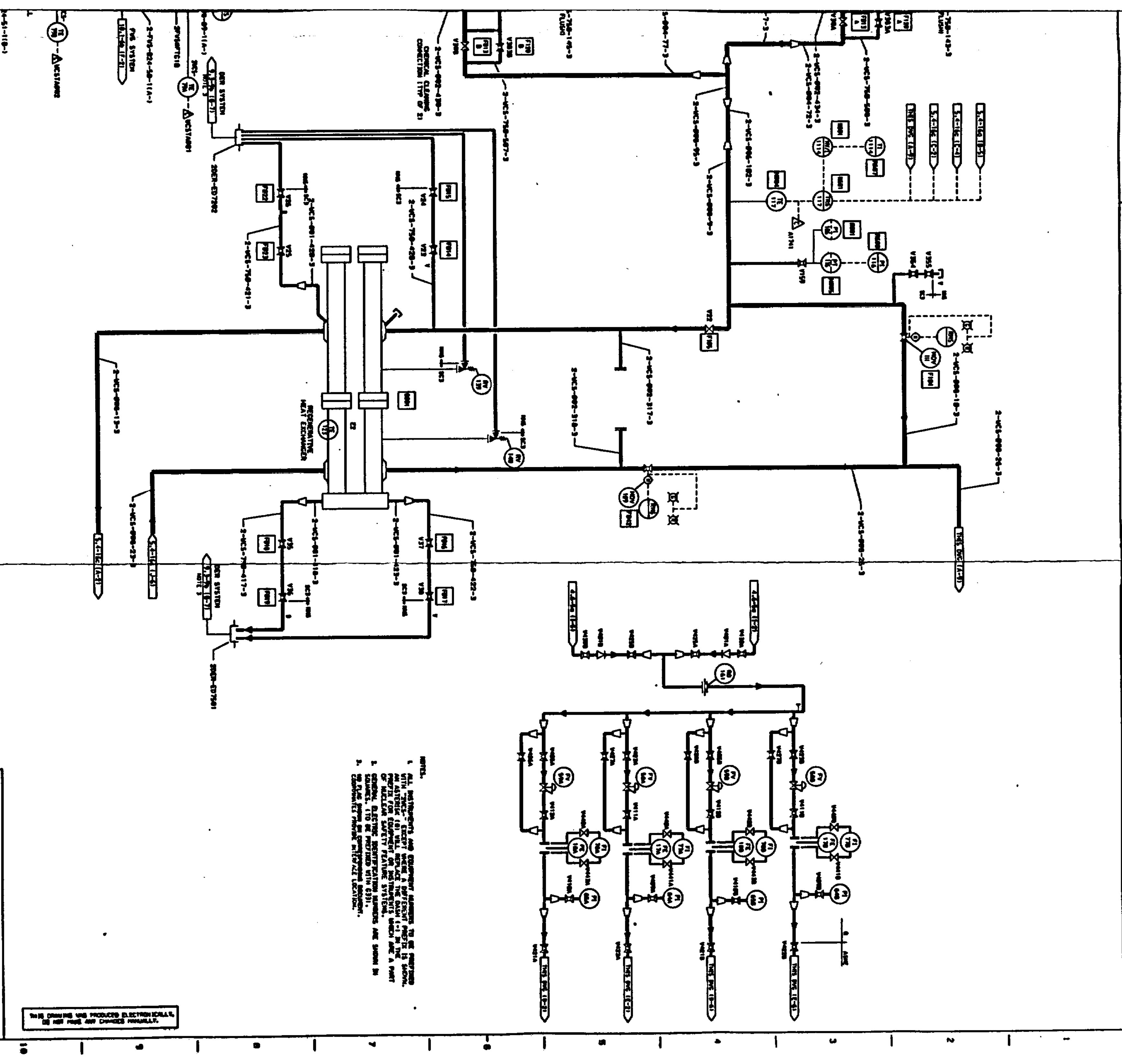
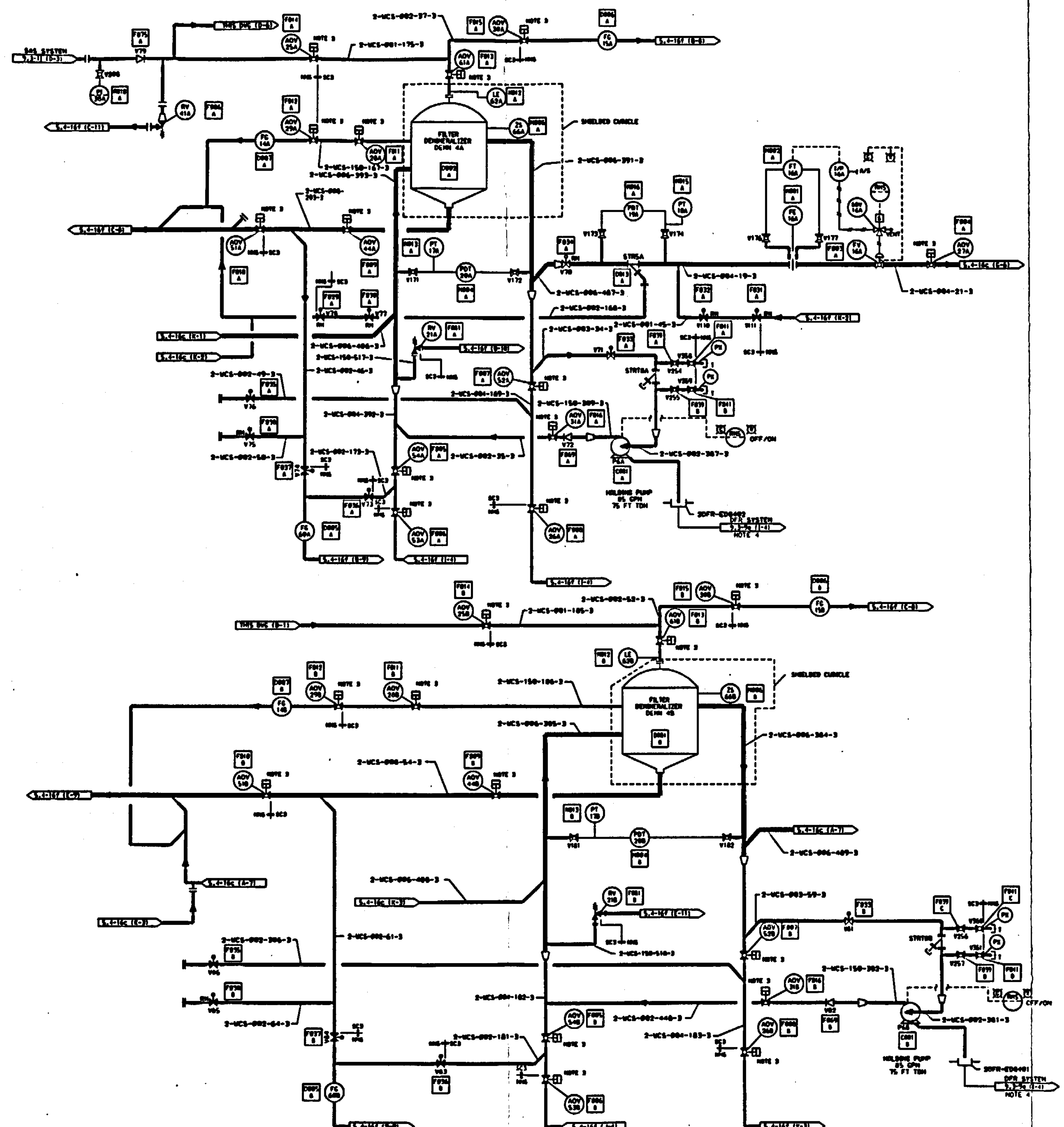


FIGURE 5.4-16b

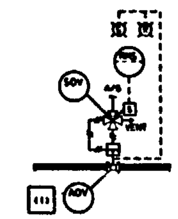
REACTOR WATER CLEANUP SYSTEM

NIAGARA MOHAWK POWER CORPORATION
NINE MILE POINT-UNIT 2
UPDATED SAFETY ANALYSIS REPORT



SOURCE: PID-37D-9
TITLE: REACTOR WATER CLEANUP

TYPICAL AIR OPERATED VALVE ARRANGEMENT (SEE TABLE BELOW)



TABLE

AREA	AOV	(11)	SOV
(D-1)	25A	F014 A	25A
(D-2)	29A	F012 A	29A
(E-2)	28A	F011 A	28A
(F-1)	30A	F015 A	30A
(F-2)	61A	F013 A	61A
(D-3)	51A	F018 A	51A
(E-3)	44A	F009 A	44A
(G-4)	53A	F007 A	53A
(D-4)	31A	F016 A	31A
(E-5)	54A	F005 A	54A
(E-5)	52A	F006 A	52A
(G-5)	26A	F008 A	26A
(F-6)	25B	F014 B	25B
(H-6)	30B	F015 B	30B
(H-6)	61B	F013 B	61B
(E-7)	29B	F012 B	29B
(F-7)	28B	F011 B	28B
(D-8)	51B	F018 B	51B
(F-8)	44B	F009 B	44B
(H-9)	52B	F007 B	52B
(H-10)	31B	F016 B	31B
(G-10)	54B	F005 B	54B
(G-10)	53B	F006 B	53B
(I-10)	26B	F008 B	26B
(J-3)	27A	F004 A	27A

NOTES.

1. ALL INSTRUMENTS AND EQUIPMENT NUMBERS TO BE PREFIXED WITH "2WCS-" EXCEPT WHERE A DIFFERENT PREFIX IS SHOWN.
2. G.E. IDENTIFICATION NUMBERS ARE SHOWN IN SQUARES (TO BE PREFIXED WITH G36).
3. SEE TABLE FOR TYPICAL AIR OPERATED VALVES ARRANGEMENT THIS DWG (M-3).
4. NO FLAG SHOWN ON CORRESPONDING DOCUMENT. COORDINATES PROVIDE INTERFACE LOCATION.

THIS DRAWING WAS PRODUCED ELECTRONICALLY. DO NOT MAKE ANY CHANGES MANUALLY.

FIGURE 5.4-16d

REACTOR WATER CLEANUP SYSTEM

NIAGARA MOHAWK POWER CORPORATION
NINE MILE POINT-UNIT 2
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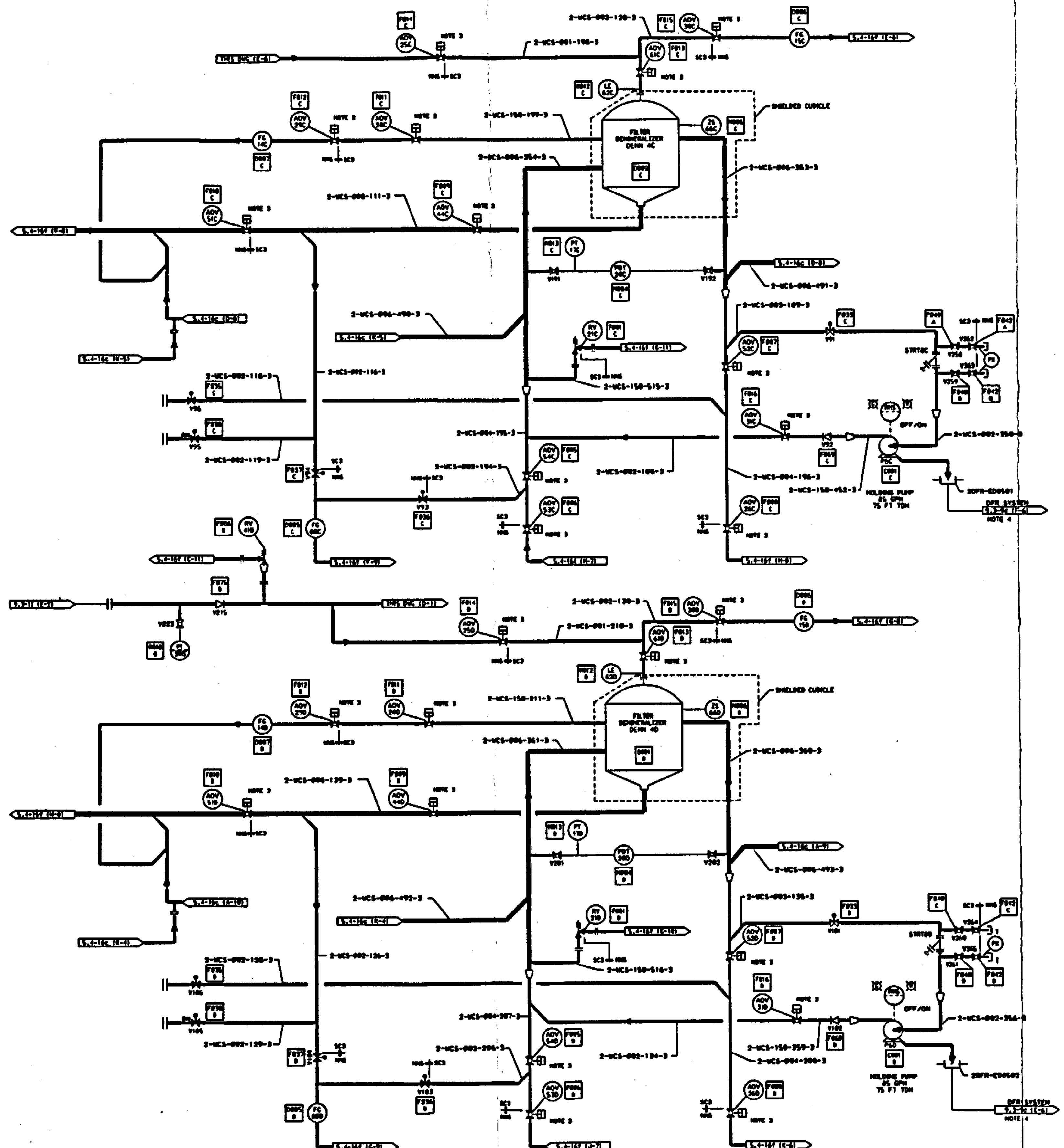
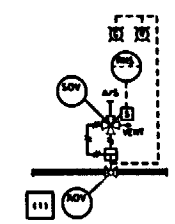


TYPICAL AIR OPERATED VALVE ARRANGEMENT (SEE TABLE BELOW)



TABLE

AREA	AOV	(1)	SOV
(F-1)	25C	F014 C	25C
(H-1)	30C	F015 C	30C
(H-2)	61C	F013 C	61C
(E-2)	29C	F012 C	29C
(E-2)	28C	F011 C	28C
(D-3)	51C	F010 C	51C
(F-3)	44C	F009 C	44C
(I-4)	53C	F007 C	53C
(I-5)	31C	F016 C	31C
(G-5)	54C	F005 C	54C
(I-6)	26C	F006 C	26C
(G-5)	53C	F004 C	53C
(I-6)	30D	F015 D	30D
(G-7)	25D	F014 D	25D
(H-7)	61D	F013 D	61D
(E-7)	29D	F012 D	29D
(F-7)	28D	F011 D	28D
(D-8)	51D	F010 D	51D
(F-8)	44D	F009 D	44D
(I-9)	53D	F007 D	53D
(I-10)	31D	F016 D	31D
(G-10)	54D	F005 D	54D
(G-11)	53D	F004 D	53D
(I-11)	26D	F006 D	26D

NOTES.

1. ALL INSTRUMENTS AND EQUIPMENT NUMBERS TO BE PREFIXED WITH "2WCS-" EXCEPT WHERE A DIFFERENT PREFIX IS SHOWN.
2. G.E. IDENTIFICATION NUMBERS ARE SHOWN IN SQUARES (TO BE PREFIXED WITH G36).
3. SEE TABLE FOR TYPICAL AIR OPERATED VALVES ARRANGEMENT THIS DWG (H-3).
4. NO FLAG SHOWN ON CORRESPONDING DOCUMENT. COORDINATES PROVIDE INTERFACE LOCATION.

SOURCE, PID-37E-9
TITLE, REACTOR WATER CLEANUP

FIGURE 5.4-16e

REACTOR WATER CLEANUP SYSTEM

NIAGARA MOHAWK POWER CORPORATION
NINE MILE POINT-UNIT 2
UPDATED SAFETY ANALYSIS REPORT

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TABLE 5A-4

SURVEILLANCE CAPSULE CONTENTS AND LOCATIONS

Capsule No.	Number of Transverse Charpy Specimens: Azimuth	Base	HAZ	Weld	Number of Specimens Flux Wires: Fe	Cu
1	3°	12	12	12	2	2
2	177°	12	12	12	2	2
3	183°	12	12	12	2	2

Note: Surveillance specimen capsule at 3° azimuth location has been removed for testing to comply with Technical Specification 4.4.6.1.3 requirements.

APPENDIX 5B

LEAD FACTORS FOR SURVEILLANCE CAPSULES

APPENDIX 5B

LEAD FACTORS FOR SURVEILLANCE CAPSULES

CONCERN

During a NRC conference call with NMPC, the NRC indicated that NMPC needed to provide some additional information regarding the lead factors for the Unit 2 surveillance coupon. Additionally, the NRC wanted some information relative to the justification for the lead factors for Unit 2 and their compliance with 10CFR50 Appendix H; whether test results from another reactor could be utilized for Nine Mile Point; and whether there were constraints on relocating the Unit 2 surveillance capsules. These were followed by a letter dated November 16, 1984, which had specific requests. The information below addresses the staff concerns regarding the Unit 2 lead factors.

RESOLUTION

The Unit 2 neutron materials surveillance samples provide a reactor vessel neutron lead factor of 0.29 for the inside surface of the reactor vessel and 0.41 for the 1/4 T position.

There should be no significant temperature difference between the capsule and RPV inner wall. The downcomer fluid flow, during normal operation, is very turbulent and well mixed before it reaches the vessel beltline.

There is no significant neutron spectrum difference between the surveillance material and RPV inner wall. The calculated shift for any energy group above 1.0 MEV is ±2.5 percent max.

Currently, 10CFR50 Appendix H requires that "surveillance specimen capsules must be located near the inside vessel wall in the beltline region so that the radiation history duplicates to the extent practical within the physical constraints of the system, the neutron spectrum, temperature history, and maximum neutron fluence experienced by the reactor vessel inner surface."

For Unit 2, surveillance specimen baskets are located about the core midplane at azimuths (i.e., 3 deg, 177 deg, and 183 deg) that are physically advantageous for specimen withdrawal and yet duplicate as much as possible the neutron spectrum and temperature history of the vessel inner surface. These locations were specifically located to ease removal and, thus, reduce occupational radiation to the technicians removing the sample. Specifically, the holder was located to avoid interferences from the jet pumps, core spray lines, and other reactor vessel internals to ensure that the vessel sample could be removed expeditiously.

The ASTM E185-73, ASTM E185-79, and ASTM 185-82 standards, which are incorporated by reference into 10CFR50 Appendix H, provide the standard practice for conducting surveillance tests for light-water-cooled nuclear power reactor vessels. This specification recommends that "the surveillance capsule lead factors (the ratio of the instantaneous neutron flux density at the specimen located to the maximum calculated neutron flux density at the inside surface of the reactor vessel wall) be in the range of 1 to 3." However, it is NMPC's position that the effects of neutron radiation on RT_{NDT} and upper shelf energy can still be reliably predicted, given Unit 2's somewhat lower lead factor readings. Using RG 1.99 as a model, the results of the fracture toughness test data obtained from the specimens can be adjusted to the fluence levels that correspond to present and future periods of vessel service. Therefore, the Unit 2 surveillance program can effectively monitor changes in the fracture toughness properties of the beltline materials.

NMPC has confirmed, based upon information from General Electric, that the capsule bracket can be moved to improve the lead factor ranges to about 0.8 to 0.9. However, this relocation could change the flux spectrum in certain energy ranges by as much as 40 percent. Further, moving the capsule bracket raises several other issues that have not yet been evaluated:

- Relocation of the surveillance holder will put it closer to jet pump and core annulus flow stream. This may require a redesign of the neutron surveillance holder.
- Annulus flow obstruction and flow-induced vibration of the holder may change.
- The effect of annulus flow on the dosimeter, attached to the side of the holder and currently held by gravity, is unknown.
- There is a potential for interference of the holders for removal of a jet pump and other internals for their repair.

NMPC intends to remove the first capsule at 10 effective full-power years (EFPY). At that time, NMPC will determine the shift and reference transition temperature in the specimen and reactor vessel. This assessment will be accomplished by using RG 1.99.

Additionally, NMPC has determined that several operating BWR plants with 251 series (764 bundle) vessels are available to provide supplemental surveillance data. These plants include WNP-2 and LaSalle 1 and 2. The surveillance data for these plants will be utilized to supplement Unit 2 data.

Finally, NMPC has determined that the NRC has previously accepted the current locations of another similar plant previously licensed. This includes a BWR 6 plant which NMPC understands has a lead factor of 0.4.

In conclusion, NMPC believes that the current location of the capsule meets the requirements of 10CFR50 Appendix H. However, NMPC commits to supplement the data from Unit 2 with data from other operating BWR 5 251 series vessels. This supplemental data will be used to provide a trending estimate for Unit 2. The supplemental data evaluation will consider operational history, fluence values, neutron spectrum, and material similarity.

NMPC will monitor material radiation damage using the Unit 2 capsules and test data from all LaSalle 1 and 2 and WNP-2 capsules. This program is described in the Reactor Vessel Material Surveillance Program submitted to the NRC in a letter dated September 30, 1985.

CHAPTER 6

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CHAPTER 6

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CHAPTER 6

LIST OF FIGURES

CHAPTER 6

LIST OF FIGURES (Cont'd.)

CHAPTER 6

ENGINEERED SAFETY FEATURES

6.1 ENGINEERED SAFETY FEATURE MATERIALS

Materials used in Nine Mile Point Nuclear Station - Unit 2 (Unit 2) engineered safety feature (ESF) components have been selected on the basis of engineering review and evaluation to ensure that material interactions that could impair operation do not occur. Materials have been selected to withstand environmental conditions encountered during both normal operations and postulated accidents without adverse effects on ESF service, performance, or operation.

6.1.1 Metallic Materials

Most metallic materials used in ESF systems comply with the material specifications of ASME Boiler and Pressure Vessel Code Section II. In cases where it is impossible to adhere to ASME specifications, metallic materials have been selected in compliance with other standards (e.g., ASTM).

6.1.1.1 Materials Selection and Fabrication

6.1.1.1.1 Specifications for Principal ESF Pressure-Retaining Materials

Principal pressure-retaining materials and appropriate material specifications for reactor coolant pressure boundary (RCPB) components are given in Table 5.2-5. Tables 6.1-1 and 6.1-2 list the principal pressure-retaining materials and appropriate materials specifications for plant ESF components.

6.1.1.1.2 ESF Construction Material

All ESF materials are resistant to intergranular stress corrosion cracking (IGSCC) in the environment of the boiling water reactor (BWR) coolant. Piping for IGSCC service sensitive systems is constructed from carbon steel or solution heat-treated, low-carbon (0.035 percent maximum) stainless steel (L grades) except for the shear plug in the standby liquid control system (SLCS) which is Type 304 stainless steel. Periodic testing of this valve requires parts replacement during every other refueling outage to ensure its integrity.

A conservative corrosion allowance of 0.08 in minimum is provided for all surfaces of carbon and low-alloy steel piping exposed to reactor water. General corrosion on stainless steel is negligible. Demineralized water with no additives is used in the reactor water. Following a loss-of-coolant accident (LOCA), this demineralized water has no detrimental effect on ESF materials.

6.1.1.1.3 Integrity of ESF Components During Manufacturing and Construction

<u>Control of Sensitized Stainless Steel</u>

Controls applied to nuclear steam supply system (NSSS)-supplied ESF components to avoid severe sensitization are the same as controls applied to RCPB components (Section 5.2.3.4). An assessment of compliance with Regulatory Guide (RG) 1.44 for the NSSS-supplied ESF is provided in Section 5.2.3.4.

All non-NSSS supplied ESF components comply with RG 1.44 recommendations. Low carbon stainless steel grades (L grades) are used in systems with operating temperatures in excess of 200°F. Use of non-L grade material is restricted to low temperature piping (200°F or less). An intergranular corrosion test on the base metal heat-affected zones (HAZ) of weldments is not performed in the latter case. Refer to Section 1.8 for the Unit 2 position on RG 1.44.

<u>Cleaning and Contamination Protection Procedures</u>

Specifications for NSSS-supplied ESF piping and component cleanliness and contamination protection during fabrication, shipment, and storage are discussed in Section 5.2.3.4.1.

All non-NSS specifications are provided for ESF piping and component cleanliness and contamination protection during fabrication, shipment, and storage in the construction phase in accordance with RG 1.37, 1.38, and 1.44.

During fabrication, contamination of austenitic stainless steel by compounds that may alter physical or metallurgical structure and/or properties is controlled or avoided. Painting stainless steel is not permitted unless a case-by-case review demonstrates that contamination is controlled or avoided. Mechanical cleaning (grinding, wire brushing, etc.) is done with tools not used on other materials.

Internal surfaces of completed components are cleaned to the appropriate level of cleanness defined by ANSI N45.2.1. Water quality for final flushes of fluid systems is equivalent to the quality of the operating system water except for oxygen content.

Onsite and preoperational cleaning of ESF components is in accordance with the Unit 2 position on RG 1.37 described in Section 1.8.

<u>Cold Worked Stainless Steel</u>

Austenitic stainless steel with a yield strength of greater than 90,000 psi is not used in ESF systems. In the field, cold bending is allowed only on 2-in and smaller pipe.

Thermal Insulation

Two types of external insulation are used on Unit 2. Stainless steel reflective metal insulation does not contribute to any surface contamination and has no effect on plant materials. Nonmetallic insulation materials in ESF systems comply with RG 1.36 and have the proper ratio of leachable sodium plus silicate ions to leachable chloride plus fluoride ions. See Section 1.8 for the Unit 2 position on RG 1.36.

6.1.1.1.4 Weld Fabrication and Assembly of Stainless Steel ESF Components (Non-NSSS Supplied Components)

Recommendations of RG 1.31 for stainless steel filler metal have been followed. RG 1.50 is applied for preheat temperature control requirements and welding procedure qualifications used for welding low-alloy steel. Where it is impractical to maintain preheat until postweld heat treatment, a temperature of 300°F or applicable preheat temperature, whichever is higher, is maintained for 2 hr/in of thickness to ensure hydrogen removal.

Recommendations of RG 1.71 for welder qualification for areas of limited accessibility have been followed. In lieu of regulatory guide requirements for welder qualification, additional volumetric weld inspection may be used. Refer to Section 1.8 for the Unit 2 positions on RG 1.31, 1.50, and 1.71.

Control of welding for NSSS-supplied components is discussed in Section 5.2.3.3.

6.1.1.2 Composition, Compatibility, and Stability of Containment and Core Spray Coolants

Containment spray and core cooling water for the ESF systems are supplied from the condensate storage tanks (CST) or suppression pool. The quality of water stored in the CSTs is maintained as described in Section 9.2.6.1.2.

The suppression pool is initially filled with high-purity water of the quality described in Section 9.2.6.1.2 from either the condensate storage or demineralized water makeup system. Chloride concentration in the suppression pool water is originally established at less than 0.5 ppm Cl. Grab sample analyses are performed, as needed, on suppression pool water (Section 9.3.2). If required, provision has been made for periodic filtration and demineralization by processing through the radwaste treatment system. No detrimental effects occur on ESF materials from this demineralized water.

Hydrogen generation resulting from the corrosion of materials by the containment spray during a design basis accident (DBA) is discussed in Section 6.2.5.

6.1.2 Organic Materials

Organic materials used within the primary containment include protective coatings, as identified below, and other materials, as identified in Table 6.1-3.

Hydrogen generation by protective coatings and other organic materials, and combustible gas control are discussed in Section 6.2.5.

6.1.2.1 Protective Coatings in the Suppression Pool

The only use of protective coatings in the suppression pool is on certain valve actuator enclosures, as listed in Table 6.1-3.

All other materials exposed to the suppression pool atmosphere, including the primary containment liner, floor liner, pedestal liner, downcomers, piping, and valves, are stainless steel or other corrosion-resistant alloys.

6.1.2.2 Protective Coatings in the Drywell

The majority of the exposed surfaces within the drywell, i.e., primary containment liner, drywell head, biological shield wall, structural steel cranes, pipe rupture restraints, pipe supports, piping, and concrete, are coated with materials qualified in accordance with ANSI N101.2 and applied in accordance with RG 1.54 as addressed in Table 1.8-1. The coating systems used on metallic surfaces are either an inorganic zinc primer with or without a catalyzed epoxy enamel topcoat, or a catalyzed epoxy enamel primer with or without a catalyzed epoxy enamel topcoat. A catalyzed epoxy surface covering with a catalyzed epoxy enamel topcoat is used on concrete surfaces.

The total estimated area of any unqualified protective coating used on surfaces within the drywell is given in Table 6.1-3. These surfaces include, but are not limited to, items such as valve bodies, handwheels, electrical and control panels, loudspeakers, emergency light cases, etc. The amount of other organic materials used, such as cable insulation, is also included in the table.

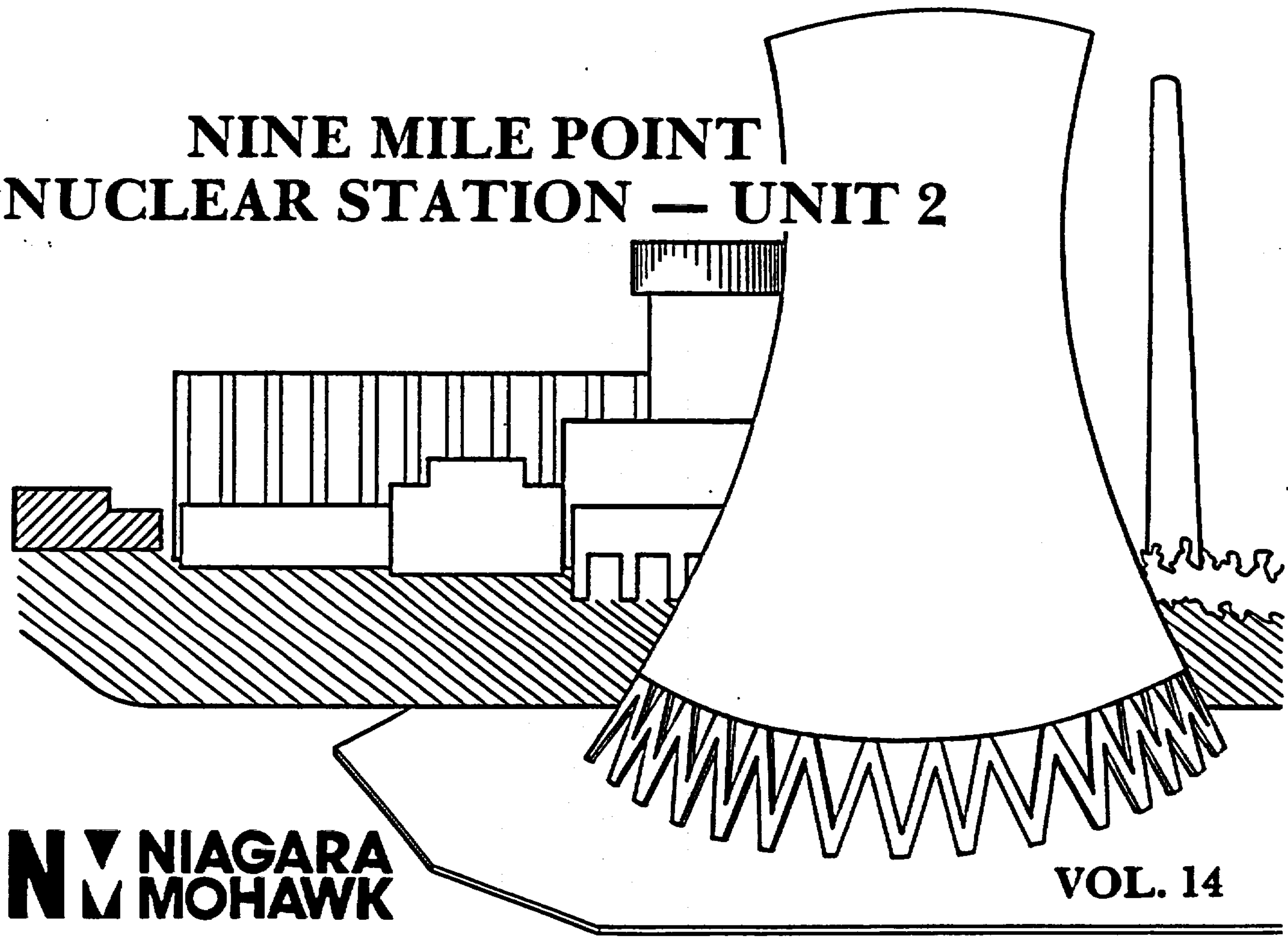
Untopcoated Carbo-Zinc 11 (CZ-11), an inorganic zinc primer, has been tested and DBA qualified for the thickness range of 2.0 to 3.3 mils (reference Carboline Test Program No. 02294, dated May 1, 1985). Similar tests were conducted by Oak Ridge National Laboratory in 1982 (reference Test No. ORNL A9675, 10-13-2, dated October 21, 1982). Although the CZ-11 does not possess the same physical characteristics of hardness as the material represented by the ORNL test, the mode of degradation in both tests was by granulation. The resulting very fine particles, less than 20 microns in size, have been evaluated in strainer head loss tests, paint debris evaluations and calculations in accordance with the guidance provided in RG 1.82 Revision 2, and the Boiling Water

Reactor Owners' Group (BWROG) Utility Resolution Guidance (NEDO-32686 Revision 0). The results of these tests, evaluations and calculations were utilized to conservatively size the emergency core cooling system (ECCS) suction strainers. There also exists in the primary containment untopcoated CZ-11 in the thickness range of 3.3 to 6.0 mils that has not been specifically tested. Extrapolating the results of the tests performed on other thicknesses of the same material and on the same thicknesses of comparable material, the untopcoated CZ-11 for thicknesses greater than 3.3 mils will behave in a similar manner in that degradation, if it occurs, will be by granulation. However, since material of this thickness range has not been specifically qualified, it is included in Table 6.1-3.

The total amount of all unqualified protective coatings, if assumed to create debris under DBA conditions, is determined not to be a safety problem since the sizing of the ECCS strainers assumed failure and 100-percent transport to the suppression pool of all unqualified coatings included in Table 6.1-3, plus that within the break zone of influence (ZOI) during a LOCA. The coating debris, along with other plant-specific debris (i.e., fibrous insulation, dust, dirt and sludge), was evaluated and utilized to conservatively size the ECCS strainers in accordance with the guidance and requirements of RG 1.82 Revision 2 and the BWROG Utility Resolution Guidance (NEDO-32686 Revision 0).

UPDATED SAFETY ANALYSIS REPORT

NINE MILE POINT NUCLEAR STATION — UNIT 2



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area and the flow restrictor area. Section 6.2.1.3 provides information on the mass and energy release rates.

The decrease in steam pressure at the turbine inlet initiates closure of the MSIVs within approximately 200 msec after the break occurs. Also, MSIV closure signals are generated as the differential pressure across the main steam line flow restrictors increases above isolation setpoints. The instruments sensing flow restrictor differential pressure generate isolation signals within approximately 500 msec after the break occurs.

After 4 sec, the MSIVs in the broken line have closed sufficiently so that the MSIV flow area equals the flow restrictor area. At that time, the critical flow location changes from the flow restrictor to the MSIVs. Subsequent closure of the MSIVs in the broken line terminates flow from the flow restrictor side of the break at 5.5 sec after the postulated failure of the main steam line. Figures 6.2-13 and 6.2-14 show the break schematic and total effective break area versus time, respectively. The closing time of the MSIVs is between 3 and 5 sec.

Immediately following the break, the total flow rate of steam leaving the vessel exceeds the steam generation rate. This steam flow to steam generation mismatch causes an initial depressurization of the reactor vessel, and the resultant formation of steam bubbles within the reactor vessel liquid causes a rapid rise in water level. When the froth level reaches the vessel steam nozzles and the top of the steam dryers, flow out of the break changes from steam to a two-phase mixture. The two-phase critical flow rates are determined from the Moody model with the known values of vessel pressure and mixture enthalpy. During the first second of the blowdown, the blowdown flow will consist of saturated reactor steam. This initial period of all steam discharge results in a drywell atmosphere temperature condition of approximately 310°F. Figures 6.2-15 through 6.2-18 and 6.2-19 through 6.2-22 show the pressure and temperature response of the drywell and suppression chamber during the primary system blowdown phase of the accident. Suppression pool temperature response is shown on Figure 6.2-23.

Figure 6.2-21 shows that the drywell atmosphere temperature approaches approximately 310°F after 1 sec of primary system blowdown. At that time, the water level in the vessel reaches the steam line nozzle elevation and the blowdown flow changes to a two-phase mixture. This increased flow causes a more rapid drywell pressure rise. However, the peak differential pressure is 14.90 psi, which occurs shortly after the downcomer vent clearing transient. As the blowdown proceeds, the primary system pressure and fluid inventory decrease, resulting in reduced break flow rates.

Approximately 75 sec after the start of the accident, the primary system pressure has dropped significantly. At this time the drywell atmosphere contains only steam. The blowdown continues because the RPV is still being pressurized from the hot feedwater addition until approximately 250 sec, at which time the peak drywell pressure occurs. Following this, drywell pressure is equal to the reactor vessel pressure and initial blowdown is over. Passive heat sinks continue to remove the energy and the drywell and suppression chamber pressure gradually reduce.

Table 6.2-4 presents the peak pressures, peak temperatures, and times of this accident with feedwater addition as compared to the recirculation line break.

The drywell and suppression chamber remain in this equilibrium condition until the RPV refloods. During this period, the ECCS pumps inject cooling water from the suppression pool into the reactor. This injection of water eventually floods the reactor vessel to the level of the steam line nozzles, and at this time, the ECCS flow spills into the drywell and thus reduces the drywell pressure. As soon as the drywell pressure drops below the suppression chamber pressure, the drywell vacuum breakers open and noncondensable gases from the suppression chamber flow back into the drywell. This process continues until the pressure in the two regions equalizes.

Intermediate Breaks

This classification covers those breaks for which the blowdown results in reactor depressurization and operation of the ECCS. This section describes the consequences to the primary containment of a 0.1-sq ft liquid break. This break area was chosen as being representative of the intermediate size break area range for both steam and liquid breaks.

Following an intermediate size break, the drywell pressure increases at a sufficiently slow rate that the dynamic effect of downcomer vent clearing is negligible and the downcomer clear when the drywell-to-wetwell differential pressure is equal to the downcomer submergence pressure. For Unit 2 primary containment design, the maximum distance between the pool surface and the bottom of the downcomer is 11 ft; thus the water level in the downcomers will reach this point when the drywell-to-containment pressure differential reaches 4.77 psid.

The ECCS is initiated by a LOCA signal from the 0.1-sq ft break and provides emergency cooling of the core. The operation of these systems is such that the reactor is depressurized in approximately 600 sec. This terminates the blowdown phase of the transient. The ECCS response is discussed in Section 6.3.

Approximately 5 sec after the break occurs, air, steam, and water start to flow from the drywell to the suppression pool; the steam is condensed and the air enters the suppression chamber. The continual purging of drywell air to the suppression chamber results in a gradual pressurization of both the wetwell and drywell over a period of approximately 1800 sec. The peak pressure will not exceed 39.75 psig. Operator action is assumed at 30 min (1800 sec) to initiate containment spray. This results in a rapid drop in containment pressure.

In addition, the suppression pool temperature is the same as following the recirculation suction line rupture (DBA) because essentially the same amount of primary system energy is released during the blowdown. After reactor depressurization, the flow through the break changes to suppression pool water that is being injected into the RPV by the ECCS. This flow condenses the drywell steam and eventually causes the drywell and suppression chamber pressures to equalize in the same manner as following a recirculation suction line rupture (DBA). The subsequent long-term suppression pool and primary containment heatup transient that follows is essentially the same as for the recirculation suction line break (DBA). From this analysis, it is concluded that the consequences of an intermediate size break are less severe than those from a recirculation suction line rupture (DBA).

Small Breaks

This section discusses the primary containment transient response associated with small breaks. The RCPB ruptures in this category are those blowdowns that will not result in reactor depressurization either due to loss of reactor coolant or automatic operation of the ECCS equipment.

Reactor System Blowdown Considerations Following the occurrence of a break of this size, it is assumed that the Reactor Operators will initiate an orderly plant shutdown and depressurization of the reactor system. The thermodynamic process associated with the blowdown of primary system reactor coolant is one of constant enthalpy. If the primary system break is below the water level the blowdown flow will consist of reactor water. Blowdown from reactor pressure to the drywell pressure will flash approximately one-third of the water to steam and two-thirds will remain as liquid. Both phases will be at saturation conditions corresponding to the drywell pressure. Thus, if the drywell is at atmospheric pressure, the steam and liquid associated with a liquid blowdown will be at 212°F. Similarly, if the primary containment is assumed to be at its design pressure of 45 psig, the reactor coolant will blow down to approximately 293°F steam and water.

If the primary system rupture is located so that the blowdown flow consists of reactor steam only, the resultant steam temperature in the containment is significantly higher than the temperature associated with liquid blowdown. This is because the enthalpy of high-energy saturated steam is nearly twice that of the saturated liquid.

Based upon this thermodynamic process, it is concluded that a small reactor steam leak will impose the most severe temperature conditions on the drywell structures and the safety-related equipment in the drywell. For larger steam line breaks, the temperature is nearly the same as for small breaks, but the duration of the high temperature condition is shorter. This is because the larger steam breaks will depressurize the reactor more rapidly than the orderly reactor shutdown that is assumed to terminate the small break.

<u>Containment Response</u> For drywell design consideration, the following sequence of events is assumed to occur. With the reactor and primary containment operating at the maximum normal conditions, a small break occurs that allows blowdown of reactor steam to the drywell. The resulting pressure increase in the drywell leads to a high drywell pressure signal that scrams the reactor and activates the primary containment isolation system. The drywell pressure continues to increase at a rate dependent on the size of the steam leak. This pressure increase lowers the water level in the vents until the level reaches the bottom of the vents. At this time, air and steam start to enter the suppression pool. The steam is condensed and the air is carried over to the suppression chamber. The air carryover results in a gradual pressurization of the suppression chamber at a rate dependent on the size of the steam leak. Once all the drywell air is carried over to the suppression chamber, the primary containment pressure very slowly increases due to suppression pool heatup.

For a 0.1-sq ft liquid break, the drywell and wetwell pressurize over a significantly longer period than as described for the 1.0-sq ft break (approximately 7200 sec <39.75 psig). Operator action is assumed at less than 120 min (7200 sec) to initiate containment spray. This results in a rapid drop in containment pressure.

<u>Recovery Operation</u> The Reactor Operators are alerted to the incident by the high drywell pressure signal and the reactor scram. It is assumed that their response will be to cool down the reactor in an orderly manner using the RHR heat exchangers or main condenser and limiting the reactor cooldown rate to 100°F/hr.

It is assumed that the Operator initiates the sprays and they become effective for reduction of containment pressure 20 min after the drywell reaches 30 psig. Vacuum breakers open and the pressure between the drywell and wetwell equalizes. When the suppression pool temperature reaches 185°F the Operator transfers the one RHR pump from the containment spray mode to the reactor shutdown cooling mode. An additional 16 min is provided for the Operators to complete this action, during which time it is assumed that no cooling takes place in the RHR heat exchanger.

The reactor primary system is completely depressurized in 6 hr. At this time, the blowdown flow to the drywell ceases and the primary containment pressure and temperature begin to reduce.

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Downcomers and vacuum breakers are modeled in the program to relieve pressure buildup in the drywell or suppression chamber. Since this program is written for small or intermediate breaks, the pressure buildup in the drywell is expected to be significantly slower than the large breaks. The dynamic clearing at the downcomer is not analyzed in the program. The hydrostatic pressure at the downcomer discharge is calculated and compared with the pressure differential between the drywell and suppression chamber to determine if there is any vent flow. Flow through the downcomer is a homogeneous mixture of air and steam.

Water in excess of an input-specified maximum limit on the drywell floor is assumed to overflow through the downcomer system and is added to the suppression pool inventory in the next time step. The suppression pool and water accumulated on the drywell floor are assumed to be saturated water. The vacuum breakers will be open if the pressure differential between the suppression chamber and drywell is greater than the input vacuum breaker pressure setpoint. Vacuum breaker flow is assumed to be a homogeneous steam and air mixture.

Heat sinks are modeled in CONSBA to determine the amount of energy absorbed by various structures of the primary containment. Concrete and steel structures (passive heat sinks) may absorb energy from the local environment after an accident due to elevated temperature in the drywell, suppression chamber, and suppression pool.

CONSBA models the ECCS and heat removal through the RHR heat exchangers. Unit 2 has two RHR heat exchanger loops. Both loops can be used for pool cooling; only one can be used for reactor shutdown cooling at a given time. Pool cooling mode is achieved by pumping suppression pool water through the heat exchanger and discharging it back to the pool. Shutdown cooling is achieved by recirculating the reactor vessel coolant through the RHR heat exchanger.

CONSBA also determines the steam or air/steam leakage rate from the drywell to the suppression chamber atmosphere bypassing the suppression pool. The Darcy equation is used to calculate this leakage.

6.2.1.1.4 Sensitivity of Suppression Chamber Air Space Temperature Increase on LOCAs

The large break LOCA analysis described in Section 6.2.1.1.3 is done using 90°F suppression chamber air space temperature. The maximum allowed temperature is 122°F. This change results in a reduction of initial suppression chamber air mass and a small decrease in the maximum calculated drywell pressure. Thus, use of 90°F is conservative.

6.2.1.1.5 Impact of Power Uprate on Large Break Containment Response Analysis

Section 6.2.1.1.3 provides the results of the original analyses of the Unit 2 containment response to various postulated accidents that constitute the design basis for the containment, based on operation at the original rated core thermal power of 3,323 MWt. Operation with power uprate changes some of the conditions for the large break analyses. For example, the short-term DBA LOCA containment response during the blowdown is governed by the blowdown flow rate. This blowdown flow rate is dependent on the reactor initial thermal-hydraulic conditions, such as vessel dome pressure and the mass and energy of the vessel fluid inventory, which change slightly with power uprate. Also, the long-term heatup of the suppression pool following a LOCA is governed by the ability of the RHR system to remove decay heat. Since the decay heat depends on the initial reactor power level, the long-term containment response is affected by power uprate. The Unit 2 containment pressure and temperature response has been reanalyzed to demonstrate the plant's capability to operate with a rated power increase to 3,467 MWt. These analyses use General Electric Company (GE) codes and models (References 6 and 7) and ANS 5.1-1979 decay heat assumptions. The input assumptions are consistent with those used for the original containment analyses, as described in Section 6.2.1.1.3. The HPCS, LPCS, and LPCI pump curves used as input to the power uprate containment response evaluation have been reconciled using the Technical Specification performance curves as shown on Figures 6.3-3a, 6.3-4a, and 6.3-5a.

<u>Short-Term Accident Response - DBA LOCA</u>

Short-term containment response analyses are performed for the limiting DBA LOCA (a double-ended guillotine break of a recirculation suction line) to demonstrate that operation with power uprate will not result in exceeding the containment design limits. The short-term analysis covers the blowdown period during which the maximum drywell pressure, wetwell pressure and differential pressure between the drywell and wetwell occur. These analyses are performed at 102 percent of the uprated power level. The results of these short-term analyses are summarized in Table 6.2-4. As shown by these results, the maximum pressure values with power uprate are bounded by the original analysis values and by the design pressures.

Analysis of the short-term containment response was also performed for power uprate operating conditions using the original analysis methods (i.e., LOCTVS computer code) and assumptions described in Section 6.2.1.1.3 to confirm the expected minor impact of power uprate. This analysis confirmed that power uprate results in peak values for drywell pressure, suppression chamber pressure, and drywell floor differential downward pressure that are slightly higher than the original analysis values but continue to be less than design values.

The drywell design temperature (340°F) has been determined based on a bounding analysis of the superheated gas temperature which can be reached with blowdown of steam to the drywell during a LOCA. The short-term peak drywell temperature is controlled by the initial steam flow rate during a large steam line break. Since the vessel dome pressure assumed for the original containment analysis (1,055 psia) is unchanged by power uprate, the initial break flow rate for this event will be unchanged. Therefore, there is no change to the original analysis short-term peak drywell temperature value of 303°F.

The wetwell gas space peak temperature response is calculated assuming thermal equilibrium between the pool and wetwell gas space. As discussed below, the bulk pool temperature will increase by approximately 2°F with power uprate. Therefore, the wetwell gas space will also increase by approximately 2°F. This increase results in wetwell gas space temperatures which are well below the design temperature of 270°F.

Long-Term Accident Response - DBA LOCA

The long-term bulk pool temperature response with power uprate is evaluated with the GE containment model for the limiting DBA LOCA, identified in Section 6.2.1.1.3 as Case C. The analysis is performed at 102 percent of the uprated power, and uses current values for the RHR heat exchanger coefficient (240.2 Btu/°F-sec) and service water temperature (82°F). Table 6.2-4 summarizes the analysis results. The peak bulk suppression pool temperature calculated with the uprated power is 207.9°F. This temperature is approximately 1°F higher than the originally calculated value but is within the design value of 212°F. The reconciliation using the Technical Specification pump curves against the assumed pump curves used as input for the power uprate analysis shows a maximum containment pressure of <39.75 psig. Peak suppression pool temperature is not affected since suppression pool cooling flow rates are met with the Technical Specification curve.

6.2.1.2 Containment Subcompartments

6.2.1.2.1 Design Bases

The drywell subcompartments are designed in accordance with the following criteria:

1. A pressure response analysis is given for each primary containment subcompartment containing high-energy piping in which breaks are postulated. The definition of high-energy piping and the criteria for postulating breaks are outlined in Section 3.6A.

   The break selected for the design evaluation produced, by virtue of its size and location, the greatest release of blowdown mass and energy into the subcompartment, during normal operation and hot standby condition. The breaks used in the design evaluations are listed in Section 6.2.1.2.3.

2. All circumferential breaks are considered to be fully double ended and no credit is taken for limiting blowdown generation due to pipe restraint locations. The effective cross-sectional flow area of the pipe is used in the jet discharge evaluation for breaks.

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3. The suppression chamber and suppression pool are assumed not available to relieve pressure from the drywell region.

4. No heat sink credit is taken.

5. The design pressure differentials for all subcompartments are higher than the calculated peak pressure differentials resulting from the postulated pipe breaks.

6. No credit is taken for blowout panels in the subcompartment analyses.

6.2.1.2.2 Design Features

For the most part, the drywell is a large continuous volume interrupted at various locations by piping, grating, ventilation ducting, etc. Two volumes within the drywell classified as subcompartments are:

1. Reactor Pressure Vessel (RPV) - Biological Shield Wall (BSW) Annulus The 1 ft 8 1/2-in thick cylindrical primary shield wall surrounds the RPV. It has an outside radius of 15 ft 9 1/4 in and extends from the reactor pedestal elevation to el 314 ft 1 1/2 in. Breaks in the recirculation water discharge and suction piping, LPCI piping, LPCS piping, and feedwater piping are analyzed. Venting occurs through the top of this annular region to the drywell and also through the flow diverter doors on the recirculation suction lines for the case of a DER of a recirculation suction line.

2. Drywell Head The drywell head surrounds the RPV head. The detachable portion connects to the refueling bulkhead (Figure 6.2-30) at el 329 ft 7 1/8 in. The vent area supplied through the refueling bulkhead consists of two ventilation exhaust openings at azimuths 45 and 285 deg and four annular vent areas at azimuths 105, 165, 225, and 345 deg (Figure 6.2-30A). All vent areas are normally open and are closed only during refueling.

   The ductwork that extends up to or penetrates the refueling bulkhead openings is not considered available vent area. However, the open annular areas around the ductwork are considered available as open vent area.

   Breaks are postulated in the RCIC head spray line and the recirculation suction piping.

   Drawings depicting piping, equipment, and compartment/venting locations are provided in Section 3.6A. The volumes and vent areas are discussed in

Net Positive Suction Head

Design data at a system runout flow of 8,200 gpm allow a pressure drop across the strainer of 1.91 ft with a plant-specific debris loading. A pressure drop of 1.91 ft is assumed across the strainers in all net positive suction head (NPSH) calculations, ensuring adequate available NPSH to the RHR pumps at all times. The available NPSH was determined in accordance with RG 1.1.

Insulation

Types of insulation used for piping and equipment within the drywell and suppression chamber are discussed in the following paragraphs.

For piping and equipment located within the drywell that require insulation to minimize heat loss, primarily metal-reflective-type insulation is used.

Metal-reflective insulation is an all-metal construction-type insulation that has a stainless steel inside and outside jacket which encapsulates multiple layers of stainless steel insulation material. Metal-reflective insulation is installed in sections with overlapping edges and quick-release latches with keepers.

Two other types of insulation are used inside the drywell for special and limited application: Min-k and Temp-Mat insulation. Min-k is a powder-type insulation used where space is limited and is encapsulated in stainless steel so as to be watertight. Temp-Mat is a borated, spun glass, blanket-type insulation used where it is necessary to lower the neutron flux (i.e., at the primary shield wall penetration), and is also encapsulated in stainless steel (see Table 6.2-64).

No antisweat insulations are used within the primary containment.

Fibrous insulation in the ZOI for a worst-case DBA LOCA is assumed to become debris. The worst-case DBA LOCA for generating fibrous insulation debris is a double-ended recirculation line break outside the bioshield. This break is assumed to destroy all Min-K insulation in the ZOI. ZOI calculations were performed in accordance with the BWROG Utility Resolution Guidance for ECCS Suction Strainer Blockage (BWROG 96125 and NEDO-32686).

All of this insulation was assumed to be 100-percent transportable to the suppression pool, with the exception of the outer covering. The outer covering is not transportable since air jet tests demonstrate the covering is not destroyed, and all Min-K insulation is above drywell gratings at el 261' and 249'. The fibrous insulation and other plant-specific debris were evaluated and utilized to conservatively size the ECCS strainers in accordance with the guidance and requirements of RG 1.82 Revision 2 and NEDO-32686 Revision 0.

6.2.2.3 Design Evaluation

The DBA for the containment spray system is failure of a steam line having a break area equal to 0.3 sq ft with suppression pool steam bypass of 0.05 sq ft ($A/\sqrt{K}$). In the long term, this accident is similar to the DER of a recirculation suction or a main steam line. If such an event occurred, the short-term (prior to the actuation of the RHR heat exchangers) energy released from the RCS would be absorbed by the suppression pool, and the suppression pool temperature would increase. In the long term, fission product decay heat would continue to be absorbed by the pool. Unless this energy is removed from the suppression pool, a high containment pressure/temperature would result.

The containment cooling mode of the RHR system with the containment sprays is used to remove heat from the suppression pool and to limit the long-term, post-LOCA primary containment internal pressure and the suppression pool temperature to less than 45 psig and 212°F, respectively.

To evaluate the adequacy of the containment heat removal system, the following sequence of events is assumed to occur:

1. With the reactor initially at 102 percent of rated thermal power, a steam line failure with a rupture area of 0.3 sq ft occurs. The bypass of steam is assumed, with an area of 0.05 sq ft ($A/\sqrt{K}$ factor) through the drywell floor.

2. LOOP occurs and one standby diesel generator fails to start and remains out of service during the entire transient. This is the most limiting single failure, failure of the Division II electrical system.

3. Only three ECCS pumps are functional following the postulated LOOP and one standby diesel generator failure. Thus, one HPCS pump, one LPCS pump, and one

However, this pressure increase will be limited by the vacuum breakers which will open to permit any uncondensed steam in the wetwell to flow into the drywell and condense. For these reasons, the Unit 2 LOCA steam bypass analysis is not sensitive to reduced wetwell spray effectiveness.

6.2.2.3.1.3 Design Evaluation

Due to the redundancy and separation of the containment spray loops, containment spray is available to rapidly reduce containment pressure during the postaccident period. The long-term containment pressure response is shown on Figures 6.2-3 and 6.2-4 (recirculation pump suction line break) and Figures 6.2-16 and 6.2-17 (main steam line break) for the spray and no-spray cases. Even with minimum ECCS operation and no containment spray, the postaccident containment pressure remains significantly below the containment design value of 45 psig.

6.2.2.3.2 NPSH Availability

The available NPSH for the RHR pumps is calculated based on the regulatory position of RG 1.1 considering:

1. Water level of the suppression pool is at a minimum water level of el 197 ft 8 in.

2. Suppression pool water temperature is 212°F.

3. No credit is taken for any increase in containment pressure (atmospheric pressure is assumed).

4. Strainers are clogged with a plant-specific debris mix in accordance with RG 1.82 Revision 2.

The minimum NPSH at 8,200 gpm flow is 14.955 ft, which is greater than the RHR pump required NPSH of 11.5 ft, at a point 2 ft above the pump mounting flange.

6.2.2.3.3 Heat Removal

Analysis of the containment heat removal capability is performed for large and intermediate breaks with the LOCTVS and CONSBA codes (Section 6.2.1.1). The resultant primary containment pressure and temperature responses are described in Section 6.2.1.1.

Even with the very degraded conditions of heat exchanger and service water temperature previously outlined, the peak primary containment pressure does not exceed the containment design pressure of 45 psig, and the peak suppression pool water temperature does not exceed the design suppression pool water temperature of 212°F.

A system-level/qualitative-type plant failure modes and effects analysis (FMEA) of the RHR system is provided in Appendix 15A, Plant Nuclear Safety Operational Analysis (NSOA). Originally, the FMEA of the balance-of-plant (BOP) instrumentation and control components of the RHR system (suppression pool cooling mode and containment spray cooling mode) was contained in the Unit 2 FMEA document, which is historical. FMEAs for plant systems are now performed and controlled by the design process.

Figures and tables showing the calculated performance of the key variables as a function of time following the occurrence of a DBA, assuming minimum ESFs available, are summarized as follows:

1. Accident parameters used in the analysis (Table 6.2-52).

2. Primary containment pressure for the steam line break area of 0.3 sq ft (Figure 6.2-28A).

3. Suppression pool water temperature for the steam line break area of 0.3 sq ft (Figure 6.2-45).

4. Integrated energy content of the water containment and the suppression pool (Table 6.2-53).

5. Integrated energy absorbed by the passive heat sinks and removed by the RHR heat exchanger (Table 6.2-53).

6. Heat removal rate of the RHR heat exchanger for the steam line break area of 0.3 sq ft (Figure 6.2-46).

7. Suppression pool water temperature for DER of recirculation suction line (Figure 6.2-11).

The very conservative evaluation procedure previously described clearly demonstrates that the RHR system in the containment cooling mode can meet its design objective of safely terminating the post-accident primary containment temperature transient.

6.2.2.4 Tests and Inspections

Preoperational and operational testing and periodic inspection of containment heat removal system components are described in Sections 5.4.7.4, 6.3.2.7, 14.2, and the Technical Specifications. Logic is provided to prevent normal testing of one drywell spray isolation valve when the other valve in the same loop is open.

6.2.2.5 Instrumentation Requirements

The RHR containment spray cooling mode and the RHR suppression pool cooling mode of the RHR system are manually initiated from the main control room. Details of the instrumentation are provided in Sections 7.3.1.1.3 and 7.3.1.1.4, respectively.

The reactor building pressure control instrumentation is designed to eliminate fluctuations in reactor building pressure caused by such factors as wind gusts. Reactor building pressure is indicated and recorded and loss of negative pressure is alarmed in the main control room.

6.2.3.2.3 Bypass Leakage Paths

Table 6.2-56 presents a tabulation of all primary containment process piping penetrations including the potential reactor building bypass leakage paths. The potential bypass leakage paths are routed through the reactor building and terminate in the radwaste, standby gas treatment, turbine generator buildings, or yard. No guard pipes are used on penetrations and, therefore, guard pipes cannot constitute a bypass leakage path. All process lines that rely on a closed system within the primary containment as a leakage boundary terminate within the reactor building; therefore, these lines are not considered potential bypass leakage paths.

Bypass leakage is included in the radiological evaluation of design basis events. This is discussed in Section 15.6.5.5. Tables 6.2-55a, b, c, and d show the bypass leakage paths considered. They include four main steam lines, two main steam drain lines, one RWCU line, one feedwater line, four post-accident sampling lines, six primary containment purge lines, four drywell floor and equipment vent and drain lines, and six nitrogen/instrumentation lines.

All leakage is conservatively assumed to be across isolation valve seats and to remain within the system piping until released to the environment. Any leakage escaping across outboard isolation valve stem packing would be released to the secondary containment or main steam tunnel. Any leakage into the secondary containment would be processed by the SGTS. Contaminants leaked into the main steam tunnel will be transported to the environment more slowly due to the much larger cross-sectional area of the tunnel and the resulting slower average velocities.

No credit is taken for a reduction in bypass leakage due to water inboard of or trapped between isolation valves. The isolation valves are assumed to leak containment atmosphere instantaneously following the accident. No credit is taken for the time required to initially pressurize the volume between the isolation valves. Leakage transport time to the environment is based on 1/2 of the available horizontal and vertically downward flow piping located between the isolation valve and the environment.

Further conservatism is added to the analysis by the assumption that all isolation valves in these paths, except the MSIV and feedwater check valves, leak at a rate equal to the maximum permissible recommended acceptance level of 7.5 scf/day per inch of nominal valve diameter at functional pressure, based on the 1983 Edition, Summer 1983 Addenda, of ASME Section XI, IWV-3426.

The MSIVs are assumed to leak at 24 scfh, nearly ten times the valve design limit, with credit for post-LOCA isolation of the more contaminated of the east and west control room outside air intakes. For an assumed MSIV leak rate of 15 scfh or less, no control room air intake isolation is required. Leakage across check valves, except the feedwater check valves, is assumed to be at twice the recommended rate of 7.5 scf/day per inch of nominal valve diameter, based on ASME Section XI, 1983 Edition, Summer 1983 Addenda, Subsection IWV-3426. Leakage across the feedwater valves is assumed to be 12 scfh.

Several process lines eliminate bypass leakage by the use of water seals. These are discussed below and include condensate makeup and drawoff (CNS), RCIC, and HPCS. Feedwater system (FWS) is also discussed below, but no credit for water seal is applied for that system. A typical loop seal is shown on Figure 6.2-88.

CNS

While not directly connected to the primary containment, the CNS system is used as the alternate fill source to the RHR, HPCS, LPCS, and RWCU systems. Each condensate fill connection to these systems is isolated by means of a normally closed globe valve. The main supply line into the secondary containment contains a check valve at the low point which, in case of a pipe break outside the containment, is sealed by a 70-ft leg of water. Although the CNS system is not of seismic design, any line break within the reactor building would provide a preferential flow path, for containment atmosphere leakage, into the reactor building atmosphere. Under this condition gaseous leakage would be collected by the SGTS and thus not be classified as bypass leakage.

RCIC

The RCIC path from the primary containment to the condensate storage building is protected from bypass leakage. When RCIC is taking suction from the CST (2CNS-TK1A), the tank static head pressure maintains a 23-psig water seal at valve 2ICS*V28 and/or 2ICS*MOV136 (Figure 6.2-81). Also, the piping arrangement as shown on Figure 6.2-81 provides a loop seal with a high point at 2ICS*MOV136. Thus, any containment atmosphere leakage through this valve during the period that containment pressures exceed water seal pressure would be trapped at this high point. If a LOCA and a SSE take place simultaneously and a condensate line break occurs, 2ICS*MOV129 on the condensate tank line will shut automatically, creating an additional barrier to bypass leakage.

HPCS

The arrangement of the HPCS suction line from CST 2CNS-TK1B provides enough static head pressure to keep a 75-ft (32-psig) water seal at the line low point (valve 2CSH*MOV101) on Figure

6.2-83. Further, the piping arrangement, as shown on Figure 6.2-83, provides two intermediate loop seals with high points at

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Protection is provided for isolation valves, actuators, and controls against damage from missiles. All potential sources of missiles are evaluated. Where possible hazards exist, protection is afforded by separation, missile shields, or location. See Section 3.5 for a discussion of evaluation techniques.

Isolation valves are designed to be operable under adverse environmental conditions (Section 3.11) such as maximum differential pressures, extreme seismic occurrences, high temperature, and high humidity. Overpressurization protection is provided on penetrations susceptible to overpressure of an isolated segment due to post-accident primary containment temperature.

Redundancy and physical separation are provided in the electrical and/or mechanical design to ensure that no single failure in the primary containment isolation system prevents the system from performing its intended functions. Where a penetration is part of a redundant train in an ESF system, isolation valves for that train receive power from a single electrical division. This is necessary so that single failure of an electrical division cannot disable both trains of the ESF system.

The MSIVs are globe valves designed to fail closed on loss of power.

The MSIVs shall be Type C tested in accordance with 10CFR50 Appendix J. The test medium shall be air/nitrogen and the test pressure shall be 40.00 psig.

The design and operation of the MSIVs is described in Section 5.4.5.

It should be noted that all motor-operated isolation valves remain in the as-is position upon failure of valve power. On the other hand, all air-operated valves (AOV) (not applicable to air-testable check valves) close on loss of air.

The swing-check valves located on the drywell-to-wetwell vacuum breaker lines cycle open and closed based on the difference in atmospheric pressure between the drywell and wetwell. A pneumatic source is not required in order for these valves to perform their safety function; however, a pneumatic supply is available for test purposes.

The design of the isolation valve as well as the associated system includes consideration of the possible adverse effects of sudden isolation valve closure when the plant systems are functioning under normal operation.

Outside isolation valves are located as close as practical to the primary containment. Except as listed below, outside isolation valves are within 10 ft of the containment wall.

Valve Number	Penetration Number	Pipe Length From Outside Containment
2RHS*MOV1B	Z-5B	20'-9"
2RHS*MOV33A	Z-7A	18'-3"
2CSH*MOV111	Z-13	50'-0"
2CSH*MOV105	Z-13	45'-6"
2DFR*MOV139	Z-43	20'-10"
2CPS*SOV119	Z-59	14'-6"
2MSS*MOV208	Z-1A-1D	36'-0"
2RHS*MOV30A	Z-6B	10'-6"
2RHS*MOV30B	Z-6A	19'-3"
2RCS*V59A	Z-38A	33'-0"
2RCS*V59B	Z-38B	31'-0"
2CMS*SOV26C	Z-61B	15'-0"
2CMS*SOV35A	Z-61C	18'-3"
2ICS*MOV148	Z-90	23'-10"
2ICS*MOV164	Z-90	29'-11"
2WCS*MOV200	Z-4A	57'-8"
2WCS*MOV200	Z-4B	65'-8"
2RHS*V192	Z-90	26'-6"

For the above outboard isolation valves, locations have been established as close as practical to the containment while also satisfying pipe supporting and flexibility requirements, clearing other equipment in the area, and providing access for maintenance, testing, and in-service inspection (ISI). As discussed in Sections 3.5, 3.6, and Appendix 3C, the lines between the containment and the isolation valves are analyzed to ensure that their integrity is maintained against the effects of missiles, pipe whip, and jet impingement loads.

The penetrations shown on Table 6.2-63 involve relief valve discharge headers which combine inputs from several sources into one pipe penetrating to the primary containment. In this manner, they reduce the amount of piping and number of containment penetrations needed to satisfy system process requirements. In Table 6.2-63, piping lengths from outside the containment are separated into two lengths; first, from the containment isolation valve to the common piping header to the containment penetration. In all cases, relief and safety valves which serve as outside containment isolation valves have been located as close as practical to the containment, considering available piping arrangements and the requirement of ASME Code Section III, Subsection NC-7100, that relieving devices be located as close as practical to the major source of overpressure.

The 12-in lines passing through containment penetrations Z-88A and Z-88B originate from RHS*SV34A and B and RHS*SV62A and B. The layout of the 12-in lines is dictated by the required location of SV34 and SV62, which are positioned on the inlet piping to the RHR heat exchangers. These 12-in headers are protected from the effects of rapid depressurization, caused by condensation of steam vented by SV34 and SV62, by vacuum breakers electrically-operated valves that are automatically actuated can also be manually actuated from the main control room. Therefore, a single failure in any electrical system is analyzed regardless of whether the loss of a safety function is caused by a component failing to perform a requisite mechanical motion or a component performing an unnecessary mechanical motion.

6.2.4.3.4 Operator Actions

A trip of an isolation control system channel is annunciated in the main control room so that the Operator is immediately informed. All motor-operated and air-operated isolation valves have open-close status lights. The following general information is presented to the Operator by the isolation system:

1. Annunciation of each process variable that has reached a trip point.

2. Computer readout of trips on main steam line tunnel temperature or main steam line excess flow.

3. Control power failure annunciation for each channel.

4. Annunciation of steam leaks in each of the systems monitored (main steam, RWCU, and RHR).

The leakage detection system detects possible leakage from lines inside/outside containment and provides the Operator in the main control room with information required to isolate fluid systems equipped with remote manual isolation valves. Parameters used to detect leakage are high radiation, high area temperature, high sump level, and RPV level and pressure as discussed in Sections 5.2.5.1.3, 7.6.1.3, and 12.3.4.1. System parameters such as flow, pressure, and temperature are indicated and/or alarmed in the main control room. These enable the Operator to detect degraded system performance attributable to system leakage and take appropriate action to isolate systems that are potential leakage paths.

This information will enable the Operator to decide if he needs to operate a remote manual valve in the event of a LOCA.

6.2.4.4 Tests and Inspections

The primary containment isolation system is scheduled to undergo periodic testing during reactor operation. The functional capabilities of power-operated isolation valves are tested manually from the main control room. By observing position indicators and changes in the affected system operation, the closing ability of a particular isolation valve is demonstrated. A discussion of testing and inspection pertaining to primary containment isolation valves is provided in Section 6.2.6, TRM Section 3.6.1, and Technical Specifications. Table 6.2-56 lists all primary containment isolation valves.

Instruments will be periodically tested and inspected. Test and/or calibration points will be supplied with each instrument.

Excess flow check valves will be periodically tested by opening a test drain valve downstream of the excess flow check valve and verifying proper operation. Preoperational testing is discussed in Section 14.2.12.

Containment isolation valve leak testing is discussed in Section 6.2.6.

Leakage testing of the closed ESF systems outside containment is performed, as required, in accordance with the inservice testing (IST) program, the inservice pressure testing (ISPT) program, 10CFR50.55a, and the applicable Code, as discussed in Sections 6.6 and 3.9A.6. Any airborne radioactivity resulting from leakage from these ESF systems following a LOCA is processed through the SGTS prior to discharge to the environment. The offsite doses from this source are small. This contribution has been accounted for in the radiological assessment of the site. Section 15.6.5.5.3 and Table 15.6-13 discuss the methodology and assumptions used in determining the radiological consequences of leakage from the primary containment and from ESF systems following a LOCA.

Additional requirements for the PCRVICS will be provided in accordance with Section 1-10, Task II.E.4.2.

6.2.5 Combustible Gas Control in Containment

To assure that the primary containment integrity is not endangered by generation of combustible gases following a postulated LOCA, the primary containment (drywell and suppression chamber) will be inerted with nitrogen (Section 1.10). Systems for controlling the relative concentrations of oxygen and hydrogen are provided within the plant. The system includes subsystems for mixing the primary containment atmosphere, monitoring oxygen and hydrogen concentrations, and reducing oxygen and hydrogen concentrations without relying on primary containment purging to the environment. The primary containment purge system is available to aid in post-accident cleanup operations.

6.2.5.1 Design Bases

The following design bases were used for the combustible gas control system (CGCS) design:

1. The CGCS is designed to limit the oxygen or hydrogen concentration to 5 volume percent within the primary containment following a LOCA.

2. A recombiner mixes the drywell atmosphere and the suppression chamber atmosphere. Prior to initiation of

the recombiner, the drywell and the suppression chamber will be mixed uniformly due to natural convection and

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6.2.5.2.3 Primary Containment Nitrogen Inerting System

Oxygen control within primary containment during normal plant operation is achieved by means of the nitrogen inerting system. During normal plant operation, oxygen concentration is maintained at or below 4 volume percent using this system.

The system is designed to supply nitrogen to the primary containment for initial inerting and for makeup during normal operation.

6.2.5.2.4 Primary Containment Purge

Primary containment purge capability is provided in accordance with RG 1.7 and as an aid in cleanup following an accident. This function is fulfilled by the combined operation of the CPS and the SGTS.

During normal plant operation, the CPS also functions, in conjunction with the nitrogen inerting system (GSN) and the SGTS, to maintain primary containment pressure at about 0.75 psig and oxygen concentration at or below 4 percent by volume. This is accomplished by injecting the required quantity of nitrogen into the primary containment through the CPS and/or extracting the required volume of gas through the CPS exhaust. The exhaust flow is routed through piping to the SGTS, where it passes through the SGTS filters and a radiation monitor before being released from the plant stack to the environment. All CPS primary containment isolation valves are automatically closed after 15 sec when a high radiation level is detected in the exhaust flow. This time delay of 15 sec prevents automatic closure of CPS primary containment isolation valves due to spurious power transients.

The CPS P&ID (Figure 9.4-8) shows the piping and instrumentation used in this mode of operation.

6.2.5.2.5 Hydrogen and Oxygen Monitoring System

The hydrogen and oxygen concentrations are monitored by the two fully-independent hydrogen/oxygen analyzer trains. The redundant system design ensures that the volumes are sampled in the event of the functional failure of one of the analyzer trains. The location of oxygen and hydrogen sample points within the drywell and the suppression chamber are provided in Table 6.2-59A. These sampling points are distributed vertically and radially throughout the drywell and suppression chamber. Structures and equipment within the region of the sampling points are listed in Table 6.2-59B. Following an accident, this system will be activated manually to monitor combustible gas concentrations. After activation, the system continuously monitors the primary containment hydrogen and oxygen concentration by drawing samples from five different areas: three from the drywell and two from the suppression chamber. For the drywell samples, the sample source and the return points are selected by a sequencing timer that controls the opening and closing of SOVs in the sample and return lines. All the samples drawn are returned to their origins. When the sequencing timer is utilized, each sample valve in the drywell remains open for 20 min.

For the suppression chamber, the sample source and the return point are selected manually. The sample is drawn from both areas simultaneously, combined, and then analyzed by the hydrogen/oxygen analyzer and returned to the suppression chamber.

The accuracy of the hydrogen and oxygen analyzer is ±5 percent of full scale, and the 90-percent response time to sample the concentration is less than 60 sec. Both hydrogen and oxygen analyzers are supplied with two range readouts. The hydrogen analyzer has 0-10 and 0-30 percent ranges, and the oxygen analyzer has 0-10 and 0-25 percent ranges.

6.2.5.3 Design Evaluation

The Unit 2 primary containment atmosphere will be inerted with nitrogen during normal operation of the plant. Oxygen concentration within the primary containment will be maintained at or below 4 volume percent (based on noncondensable gases). Following an accident, oxygen and hydrogen concentrations will be controlled by means of the recombiner system.

In evaluating the CGCS design, it is necessary to consider:

1. Oxygen and hydrogen sources in a postaccident environment.

2. Distribution of oxygen and hydrogen in the drywell and the suppression chamber.

3. Primary containment pressure and temperature during the containment cooldown phase of the accident.

6.2.5.3.1 Sources of Oxygen and Hydrogen

<u>Short-Term Hydrogen Generation</u>

In the period immediately after the LOCA, hydrogen is generated by both radiolysis and metal-water reaction. However, the short-term contribution from radiolysis is insignificant compared to that of the metal-water reaction. The metal-water reaction of steam with the zirconium fuel cladding which produces hydrogen is:

$$Zr + 2H_2O \;\text{-->}\; ZrO_2 + 2H_2 \qquad (6.2\text{-}14)$$

and discharge promotes mixing of the two volumes in the primary containment.

6.2.5.3.3 Analysis

Based on the preceding hydrogen and oxygen generation sources and the accident description, the oxygen and hydrogen concentration in the drywell and suppression chamber is obtained as a function of time. However, the analysis conservatively assumes that the recombiner system is manually activated prior to either the hydrogen concentration reaching 4 volume percent or the oxygen concentration reaching 4.5 volume percent. To calculate the redistribution of the hydrogen and oxygen between the drywell and suppression chamber, a two-region computer model of the primary containment system is used. This model takes into consideration hydrogen and oxygen generation from the metal-water reaction and radiolysis. The calculation determines the inventory, partial pressure, and mole fraction of each atmospheric constituent in both regions as a function of time.

Tables 6.2-58, 6.2-59, 6.2-59C, and 6.2-59D present the parameters used in the analysis of the oxygen and hydrogen buildup within the primary containment. The minimum recombiner flow necessary to control the formation of combustible gases is 120 scfm. Although the recombiner has a design processing capacity of 150 scfm, the analysis to determine post-accident hydrogen and oxygen concentrations within primary containment uses the 120 scfm flow. The hydrogen and oxygen concentration transient plots are shown on Figures 6.2-72H and 6.2-72I.

Operation of the recombiner at 150 scfm, as opposed to 120 scfm, would reduce at a faster rate the post-accident concentrations of combustible gases in primary containment.

6.2.5.3.4 Failure Modes and Effects Analysis

Originally, the FMEA for the CGCS was contained in the Unit 2 FMEA document, which is historical. FMEAs for plant systems are now performed and controlled by the design process.

6.2.5.4 Tests and Inspections

Each active component of the CGCS is testable during normal reactor power operation. This system will be tested periodically to assure that it will operate correctly whenever required. Preoperational tests of the CGCS are conducted during the final stages of plant construction prior to initial startup. These tests assure correct functioning of all controls, instrumentation, recombiners, piping, and valves. System reference characteristics such as pressure differentials and flow rates are documented during the preoperational tests and will be used as base points for measurement in subsequent operational tests.

During normal operation, the recombiner system piping, valves, instrumentation, wiring, and other components can be inspected

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visually at any time, since they are outside the primary containment. Further information may be found in Chapter 14.

6.2.5.5 Instrumentation Requirements

Description

Safety-related instruments and controls are provided for automatic and manual control of the hydrogen recombiners. The controls and monitors described below are located in the main control room. The control logic is shown on Figure 6.2-72K.

Instrumentation requirements for the CPS and the SGTS portions of the CGCS are described in Sections 9.4.2.5 and 6.5.1.5, respectively.

Operation

The hydrogen recombiner inlet and outlet isolation valves close automatically on a LOCA or manual isolation signal and can be opened manually during a LOCA by means of the associated hydrogen recombiner LOCA override keylock switch.

The redundant cooling water block valves located in the water supply lines are manually operated. These valves are interlocked with the recombiner discharge line containment isolation valves so that they cannot be opened unless the isolation valves are already open. They will also automatically close if the isolation valves are closed.

The strainer blowdown drain valves are interlocked with the redundant cooling water block valves. In the automatic mode, the blowdown drain valves close when the associated block valve is opened and will open when the block valves close. The blowdown valves can also be closed manually and opened manually.

Recombiner cooling water inlet valves close automatically when the associated recombiner unit is turned off. The air inlet valves are manually closed after the recombiner unit is turned off and they will stop when the associated control switch is released.

Recombiner gas heaters and the gas blower are turned on manually, after which the reaction chamber temperature is automatically controlled by the SCR controller. Temperatures are set at manual/automatic stations. Interlocks prevent operation of the recombiner when its cooling water inlet and block valves are less than fully open, when through gas flow is low, when heater gas inlet or outlet temperature is high, or when high temperature or pressure conditions prevail. Gas blowers are turned off under recombiner high temperature or pressure conditions.

TABLE 6.2-4

RESULTS OF LARGE BREAK ACCIDENT ANALYSIS (CASE C)

		Original Pre-Uprate Analysis		Power Uprate
		Recirculation Line Break	Steam Line Break	Recirculation Line Break
1.	Peak drywell pressure, psig	39.75	38.16	36.8[1]
2.	Time of peak drywell pressure, sec	252.60	245.60	-
3.	Peak drywell floor differential downward pressure, psid	16.89	14.90	16.3
4.	Time of peak drywell floor differential, sec	0.95	0.95	-
5.	Peak suppression chamber pressure, psig	33.98	31.87	31.8
6.	Time of peak suppression chamber pressure, sec	444.09	247.60	-
7.	Peak drywell temperature, °F	286.21	303.24	See Section 6.2.1.1.5
8.	Peak suppression chamber temperature, °F	206.70	207.17	207.9
9.	Peak bulk pool temperature, °F	206.84	207.52	207.9

[1] Additional analysis to reconcile the Technical Specification pump curves against the assumed pump curves used as input for the power uprate analysis shows a maximum containment pressure of <39.75 psig.

TABLE 6.2-6

ENGINEERED SAFETY FEATURE SYSTEMS
INFORMATION FOR CONTAINMENT RESPONSE ANALYSES

For Large Break Accidents

	Full Capacity	Case A	Case B	Case C	Case C**
Drywell Spray (RHR System)					
1. Number of pumps[1]	2	2	1	0	0
2. Capacity per pump			See Figure 6.2-47[4]		
3. Number of headers	2	2	1	0	0
4. Flow distribution, %	95	95	95	0	0
5. Spray thermal efficiency, %	100	90	90	0	0
Suppression Chamber Spray (RHR System)					
1. Number of pumps[1]	2	2	1	0	0
2. Capacity per pump			See Figure 6.2-47[4]		
3. Number of headers	1	1	1	0	0
4. Flow distribution, %	5	5	5	0	0
5. Spray thermal efficiency, %	100	0	0	0	0
RHR Heat Exchanger					
1. Number of heat exchangers	2	2	1	1	1
2. Type of heat exchanger	Shell/tube	Shell/tube	Shell/tube	Shell/tube	Shell/tube
3. K-factor, Btu/sec-°F	N/A	199	199	199*	240
4. Design service water temperature, °F					
a. Minimum	32				
b. Maximum	77	77	77	77*	82

TABLE 6.2-6 (Cont'd.)

	Full Capacity	Case A	Case B	Case C	Case C**
<u>Emergency Core Cooling Systems (ECCS)</u>					
1. High-pressure core spray (HPCS) system					
a. Number of pumps	1	1	1	1	1
b. Capacity of pump			See Figure 6.2-48[3]		
2. Low-pressure core spray (LPCS) system					
a. Number of pumps	1	1	0	0	0
b. Capacity of LPCS pump			See Figure 6.2-49[3]		
3. Low-pressure coolant injection (LPCI) mode[2]					
a. Number of pumps	3	3	2	2	2
b. Capacity of each LPCI (RHR) pump			See Figure 6.2-50[3]		
4. Automatic depressurization system					
a. Total number of safety/relief valves	18	0	0	0	0
b. Number actuated on ADS	7	0	0	0	0

* See Section 6.2.1.1.3 for discussion.

** Power uprate analysis. See Section 6.2.1.1.5.

(1) Containment spray mode is operational within 30 min following LOCA.

(2) Ten min after LOCA, LPCI mode is switched to either containment spray mode (Cases A, B) or pool cooling mode (Case C), leaving one RHR pump in LPCI mode for long-term coolant injection.

(3) The HPCS, LPCS, and LPCI pump curves used as input to the power uprate containment response evaluation have been reconciled using the Technical Specification performance curves as shown on Figures 6.3-3a, 6.3-4a, and 6.3-5a.

(4) The containment spray flow rate used as input to the power uprate containment response evaluation has been reconciled using the Technical Specification performance curves for the RHR pumps.

TABLE 6.2-43B

BLOWDOWN DATA

10-Inch Low-Pressure Core Spray Line Break
RPV-BSW Annulus

Time (sec)	Blowdown Mass Flow Rate (lbm/sec)*	Blowdown Enthalpy (Btu/lbm)	Blowdown Energy Release Rate (Btu/sec)*	Total Effective Break Area (ft^2)
0.000000	2,184.2	531.8	1.162×10^6	1.010
0.002260	2,184.2	531.8	1.162×10^6	1.010
0.002261	2,830.7	531.8	1.505×10^6	0.904
0.002940	2,830.7	531.8	1.505×10^6	0.904
0.002941	3,909.8	531.8	2.079×10^6	0.904
0.117940	3,909.8	531.8	2.079×10^6	0.904
0.117941	1,751.6	531.8	9.315×10^5	0.405
3.000000	1,751.6	531.8	9.315×10^5	0.405

* Due to symmetry in the nodalization, the tabulated blowdown represents one half of the total blowdown.

TABLE 6.2-44A

SUBCOMPARTMENT VENT PATH DESCRIPTION

12-Inch Recirculation Inlet Line Break
RPV-BSW Annulus

Vent Path No.	From Volume Node No.	To Volume Node No.	Description of Vent Path Flow (Choked/Unchoked)	Vent Area (ft^2)	L/A (ft/ft^2)	Head Loss Coefficient				
						Friction	Turning	Expansion	Contraction	Total
1	1	2	Unchoked	35.913	0.181	0.028	0.062	0.023	0.018	0.131
2	1	20	Choked	15.389	0.602	0.042	-	0.006	0.040	0.088
3	2	3	Unchoked	40.489	0.161	0.027	0.066	0.002	0.022	0.117
4	2	8	Unchoked	12.980	1.252	0.073	-	0.050	0.112	0.235
5	3	4	Unchoked	40.489	0.161	0.027	0.066	0.002	0.022	0.117
6	3	9	Unchoked	12.980	1.252	0.073	-	0.050	0.112	0.235
7	4	5	Unchoked	37.129	0.176	0.027	0.066	0.015	0.062	0.170
8	4	10	Unchoked	9.620	1.689	0.073	-	0.180	0.212	0.465
9	5	6	Unchoked	40.489	0.161	0.027	0.066	0.002	0.022	0.117
10	5	11	Unchoked	9.620	1.689	0.073	-	0.180	0.212	0.465
11	6	12	Unchoked	12.980	1.252	0.073	-	0.050	0.112	0.235
12	7	8	Unchoked	35.791	0.182	0.026	0.062	0.016	-	0.104
13	7	13	Unchoked	16.702	0.869	0.065	-	-	-	0.065
14	8	9	Unchoked	39.029	0.167	0.026	0.068	0.002	0.023	0.119
15	8	14	Unchoked	16.702	0.929	0.070	-	-	-	0.070
16	9	10	Unchoked	36.475	0.179	0.026	0.068	0.012	0.054	0.160
17	9	15	Unchoked	12.980	1.196	0.070	-	0.050	0.112	0.232
18	10	11	Unchoked	35.669	0.183	0.026	0.068	0.016	0.064	0.174
19	10	16	Unchoked	16.009	0.970	0.070	-	0.002	0.021	0.093
20	11	12	Unchoked	36.475	0.179	0.026	0.068	0.012	0.054	0.160
21	11	17	Unchoked	16.009	0.970	0.070	-	0.002	0.021	0.093
22	12	18	Unchoked	12.980	1.196	0.070	-	0.050	0.112	0.232
23	13	14	Unchoked	34.926	0.187	0.026	0.066	0.009	0.048	0.149
24	13	19	Choked	8.956	1.667	0.067	-	0.872	0.232	1.171
25	14	15	Unchoked	38.648	0.169	0.026	0.066	-	-	0.092
26	14	19	Choked	10.524	1.419	0.067	-	0.850	0.185	1.102
27	15	16	Unchoked	33.065	0.197	0.026	0.066	0.021	0.072	0.185
28	15	19	Choked	10.524	1.419	0.067	-	0.850	0.185	1.102
29	16	17	Unchoked	37.955	0.172	0.026	0.066	0.0003	0.009	0.1013
30	16	19	Choked	9.831	1.519	0.067	-	0.861	0.206	1.134
31	17	18	Unchoked	33.065	0.197	0.026	0.066	0.021	0.072	0.185
32	17	19	Choked	10.524	1.419	0.067	-	0.850	0.185	1.102
33	18	19	Choked	10.524	1.419	0.067	-	0.850	0.185	1.102
34	20	2	Choked	3.263	1.998	0.026	0.130	0.852	0.182	1.190
35	20	7	Choked	16.702	0.538	0.040	-	-	-	0.040
36	20	8	Choked	3.263	1.998	0.026	0.130	0.846	0.182	1.184

TABLE 6.2-44B

BLOWDOWN DATA

12-Inch Recirculation Inlet Line Break
RPV-BSW Annulus

Time (sec)	Blowdown Mass Flow Rate (lbm/sec)*	Blowdown Enthalpy (Btu/lbm)	Blowdown Energy Release Rate (Btu/sec)*	Total Effective Break Area (ft^2)
0.000000	3,124.8	532.8	1.665×10^6	1.4450
0.009580	3,124.8	532.8	1.665×10^6	1.4450
0.009581	4,686.2	532.8	2.497×10^6	1.4450
0.170000	4,686.2	532.8	2.497×10^6	1.4450
0.170001	3,358.4	532.8	1.789×10^6	0.7765
3.000000	3,358.4	532.8	1.789×10^6	0.7765

* Due to symmetry in the nodalization, the tabulated blowdown represents one half of the total blowdown.

TABLE 6.2-45

SUBCOMPARTMENT NODAL DESCRIPTION

24-Inch Recirculation Suction Break
RPV-BSW Annulus

Volume No.	Volume (ft^3)	Initial Conditions			DBA Break Conditions				Calculated Peak Pressure Difference[1] (psid)	Design Peak Pressure Difference[1] (psid)	Design Margin (%)
		Temp. (°F)	Pressure (psia)	Humidity (%)	% Break in Vol.	Break Line	Area (ft^2)	Break Type			
1	227.9	150	14.2	20	0				8.26	70.60	88.3
2	276.4	150	14.2	20	0				6.05	70.60	91.4
3	276.4	150	14.2	20	0				5.88	70.60	91.7
4	276.4	150	14.2	20	0				5.86	70.60	91.7
5	276.4	150	14.2	20	0				6.71	70.60	90.5
6	273.9	150	14.2	20	0				7.85	70.60	88.9
7	218.1	150	14.2	20	0				7.53	70.60	89.3
8	264.8	150	14.2	20	0				4.71	70.60	93.3
9	266.7	150	14.2	20	0				4.79	70.60	93.3
10	266.7	150	14.2	20	0				4.68	70.60	93.4
11	266.7	150	14.2	20	0				4.91	70.60	93.0
12	264.1	150	14.2	20	0				4.89	70.60	93.1
13	251.8	150	14.2	20	0				4.53	70.60	93.6
14	248.6	150	14.2	20	0				3.63	70.60	94.9
15	250.5	150	14.2	20	0				3.67	70.60	94.8
16	251.9	150	14.2	20	0				3.33	70.60	95.3
17	250.0	150	14.2	20	0				4.35	70.60	93.8
18	251.8	150	14.2	20	0				5.18	70.60	92.7
19	44,750.0	150	14.2	20	85	Recirc. Suction	(See Table 6.2-45B)		0.00	-	-
20	92.06	150	14.2	20	15				18.74	70.60	73.5

(1) Peak pressure difference [(Pi-P19) peak] is shown on Figure 6.2-66A.
(2) Design margin: 1-(Calculated Δpeak/design Δpeak).

TABLE 6.2-45A

SUBCOMPARTMENT VENT PATH DESCRIPTION

24-Inch Recirculation Suction Line Break
RPV-BSW Annulus

Vent Path No.	From Volume Node No.	To Volume Node No.	Description of Vent Path Flow (Choked/Unchoked)	Vent Area (ft^2)	L/A (ft/ft^2)	Head Loss Coefficient				
						Friction	Turning	Expansion	Contraction	Total
1	20	1	Choked	16.83	0.581	0.060	-	-	-	0.0600
2	20	2	Choked	6.01	0.915	0.0255	0.098	0.74	0.110	0.9735
3	20	8	Choked	6.01	0.898	0.0255	0.098	0.73	0.110	0.9635
4	20	7	Choked	16.83	0.571	0.027	-	-	-	0.0270
5	1	2	Unchoked	34.73	0.188	0.0279	0.062	-	-	0.0899
6	2	3	Unchoked	40.74	0.160	0.0275	0.068	0.002	0.020	0.1175
7	2	8	Unchoked	13.45	1.208	0.074	-	0.0403	0.100	0.2143
8	3	4	Unchoked	39.55	0.165	0.0275	0.068	0.0046	0.034	0.1341
9	3	9	Unchoked	12.26	1.325	0.074	-	0.0737	0.136	0.2837
10	4	5	Unchoked	40.74	0.160	0.0275	0.068	0.002	0.020	0.1175
11	4	10	Unchoked	13.45	1.208	0.074	-	0.0403	0.100	0.2143
12	5	6	Unchoked	40.74	0.160	0.0275	0.068	0.002	0.020	0.1175
13	5	11	Unchoked	13.45	1.208	0.074	-	0.0403	0.100	0.2143
14	6	12	Unchoked	11.96	1.359	0.074	-	0.084	0.140	0.2980
15	7	8	Unchoked	32.61	0.200	0.0255	0.098	-	-	0.1235
16	7	13	Unchoked	16.20	0.865	0.058	-	0.002	0.020	0.0800
17	8	9	Unchoked	37.56	0.174	0.0255	0.068	0.007	0.040	0.1405
18	8	14	Unchoked	13.45	1.154	0.071	-	0.0403	0.010	0.2113
19	9	10	Unchoked	39.25	0.166	0.0255	0.068	0.002	0.020	0.1155
20	9	15	Unchoked	16.83	0.922	0.071	-	-	-	0.0710
21	10	11	Unchoked	39.25	0.166	0.0255	0.068	0.002	0.020	0.1155
22	10	16	Unchoked	16.83	0.922	0.071	-	-	-	0.0710
23	11	12	Unchoked	37.56	0.174	0.0255	0.068	0.007	0.040	0.1405
24	11	17	Unchoked	13.45	1.154	0.071	-	0.0403	0.100	0.2113
25	12	18	Unchoked	16.20	0.958	0.071	-	0.0014	0.020	0.0924
26	13	14	Unchoked	35.31	0.185	0.0255	0.066	0.0077	0.040	0.1392
27	13	19	Unchoked	9.00	1.676	0.067	-	0.876	0.233	1.1760
28	14	15	Unchoked	34.15	0.194	0.0255	0.066	0.0140	0.060	0.1655
29	14	19	Unchoked	7.57	1.991	0.067	-	0.895	0.275	1.2370
30	15	16	Unchoked	35.31	0.185	0.0255	0.066	0.0077	0.040	0.1392
31	15	19	Unchoked	7.57	1.991	0.067	-	0.895	0.275	1.2370
32	16	17	Unchoked	38.69	0.169	0.0255	0.066	-	-	0.0915
33	16	19	Unchoked	9.00	1.676	0.067	-	0.876	0.233	1.1760
34	17	18	Unchoked	33.62	0.194	0.0255	0.066	0.0173	0.070	0.1788
35	17	19	Unchoked	9.00	1.676	0.067	-	0.876	0.233	1.1760
36	18	19	Unchoked	8.375	1.801	0.067	-	0.884	0.251	1.2020

TABLE 6.2-45B

BLOWDOWN DATA

24-Inch Recirculation Suction Line Break
RPV-BSW Annulus

Time (sec)	Blowdown Mass Flow Rate (lbm/sec)*	Blowdown Enthalpy (Btu/lbm)	Blowdown Energy Release Rate (Btu/sec)*	Total Effective Break Area (ft^2)
0.0000	17,247	529.0	9.124×10^6	5.072
1.5400	17,247	529.0	9.124×10^6	5.072
1.5401	13,108	529.0	6.934×10^6	2.891
2.0000	13,108	529.0	6.934×10^6	2.891

* Due to symmetry in the nodalization, the tabulated blowdown represents one half of the total blowdown. Of the tabulated blowdown, 85 percent is directed to Node 19 and 15 percent to Node 20 by the flow diverter.

TABLE 6.2-46

FORCE AND MOMENT SENSITIVITY STUDY SUMMARY

Subcompartment	Model	Design Basis Line Description	Tables	Figures	
			Data Sheet	Forces	Moments
RPV-BSW annulus	21-node	Feedwater	6.2-48	6.2-68	6.2-69
RPV-BSW annulus	37-node	Feedwater	6.2-49	6.2-68A	6.2-69A

NOTES:

1. Maximum forces and moments are listed in Table 6.2-47.
2. The annulus pressurization geometry for force and moment calculations is shown on Figure 6.2-67.

TABLE 6.2-47

MAXIMUM FORCES AND MOMENTS ON THE BSW
FEEDWATER LINE BREAKS
RPV-BSW ANNULUS

	21 Node Model	37 Node Model
X-Direction Force:	509.90 kips at 0.03100 sec	485.29 kips at 0.03100 sec
Z-Direction Force:	-2701.84 kips at 0.64000 sec	-2461.74 kips at 0.62000 sec
Resultant Force:	2703.10 kips at 0.64000 sec	2466.08 kips at 0.61000 sec
X-Direction Moment:	-64496.49 kip-ft at 0.62000 sec	-58806.14 kip-ft at 0.61000 sec
Z-Direction Moment:	-18297.80 kip-ft at 0.02700 sec	-17485.39 kip-ft at 0.02700 sec
Resultant Moment:	64588.45 kip-ft at 0.62000 sec	59114.79 kip-ft at 0.60000 sec

NOTES:

1. There are no forces nor moments with respect to the y-axis as defined on Figure 6.2-67.
2. These forces and moments are based on a half-annular model.

TABLE 6.2-48

PROJECTED AREAS AND MOMENT ARMS FOR FORCE AND MOMENT CALCULATIONS
12-INCH FEEDWATER LINE BREAK
21 NODE MODEL
RPV-BSW ANNULUS

Node No.	Nodal Height (ft)	Boundary Azimuths(°)	Span (°)	Projected X-Area (sq ft)	Projected Z-Area (sq ft)	Moment Arm (ft)
1	16.54	180.00 - 210.00	30.00	116.29	-31.16	8.269
2	16.54	150.00 - 180.00	30.00	85.13	-85.13	8.269
3	16.54	120.00 - 150.00	30.00	31.16	-116.29	8.269
4	16.54	90.00 - 120.00	30.00	-31.16	-116.29	8.269
5	16.54	60.00 - 90.00	30.00	-85.13	-85.13	8.269
6	16.54	30.00 - 60.00	30.00	-116.29	-31.16	8.269
7	15.96	180.00 - 210.00	30.00	112.22	-30.07	24.518
8	15.96	150.00 - 180.00	30.00	82.15	-82.15	24.518
9	15.96	120.00 - 150.00	30.00	30.07	-112.22	24.518
10	15.96	90.00 - 120.00	30.00	-30.07	-112.22	24.518
11	15.96	60.00 - 90.00	30.00	-82.15	-82.15	24.518
12	15.96	30.00 - 60.00	30.00	-112.22	-30.07	24.518
13	7.06	180.00 - 210.00	30.00	49.64	-13.30	36.028
14	15.08	150.00 - 180.00	30.00	77.65	-77.65	40.041
15	15.08	120.00 - 150.00	30.00	28.42	-106.07	40.041
16	15.08	90.00 - 120.00	30.00	-28.42	-106.07	40.041
17	15.08	60.00 - 90.00	30.00	-77.65	-77.65	40.041
18	15.08	30.00 - 60.00	30.00	-106.07	-28.42	40.041
19	6.00	180.00 - 210.00	30.00	42.19	-11.30	42.558
20	2.02	180.00 - 210.00	30.00	14.24	-3.82	46.571
21	0.0	0.00 - 0.00	0.00	0.00	0.00	0.00

TABLE 6.2-49

PROJECTED AREAS AND MOMENT ARMS FOR FORCE AND MOMENT CALCULATIONS
12-INCH FEEDWATER LINE BREAK
37 NODE MODEL
RPV-BSW ANNULUS

Node No.	Nodal Height (ft)	Boundary Azimuths(°)	Span(°)	Projected X-Area (sq ft)	Projected Z-Area (sq ft)	Moment Arm (ft)
1	15.82	180.00 - 210.00	30.00	111.26	-29.81	7.911
2	15.82	150.00 - 180.00	30.00	81.45	-81.45	7.911
3	16.53	120.00 - 150.00	30.00	31.15	-116.24	8.265
4	2.42	105.00 - 120.00	15.00	-1.16	-8.80	15.323
5	14.11	105.00 - 120.00	15.00	-6.76	-51.37	7.057
6	2.42	90.00 - 105.00	15.00	-3.40	-8.20	15.323
7	14.11	90.00 - 105.00	15.00	-19.83	-47.87	7.057
8	16.53	60.00 - 90.00	30.00	-85.09	-85.09	8.265
9	16.53	30.00 - 60.00	30.00	-116.24	-31.15	8.265
10	16.13	200.00 - 210.00	10.00	39.38	-3.45	23.885
11	16.13	180.00 - 200.00	20.00	74.01	-26.94	23.885
12	16.13	160.00 - 180.00	20.00	60.33	-50.62	23.885
13	16.13	150.00 - 160.00	10.00	22.67	-32.38	23.885
14	15.96	135.00 - 150.00	15.00	22.42	-54.13	24.510
15	15.96	120.00 - 135.00	15.00	7.65	-58.08	24.510
16	24.85	90.00 - 120.00	30.00	-46.83	-174.76	28.958
17	26.02	60.00 - 90.00	30.00	-133.94	-133.94	29.542
18	15.96	45.00 - 60.00	15.00	-54.13	-22.42	24.510
19	15.96	30.00 - 45.00	15.00	-58.08	-7.65	24.510
20	6.88	200.00 - 210.00	10.00	16.79	-1.47	35.385
21	6.88	180.00 - 200.00	20.00	31.55	-11.48	35.385
22	6.88	160.00 - 180.00	20.00	25.72	-21.58	35.385
23	6.88	150.00 - 160.00	10.00	9.67	-13.81	35.385
24	8.90	135.00 - 150.00	15.00	12.50	-30.17	36.937
25	8.90	120.00 - 135.00	15.00	4.26	-32.38	36.937
26	10.06	45.00 - 60.00	15.00	-34.13	-14.14	37.521
27	10.06	30.00 - 45.00	15.00	-36.63	-4.82	37.521
28	3.05	190.00 - 210.00	20.00	14.68	-2.59	46.057
29	5.71	190.00 - 210.00	20.00	27.45	-4.84	41.677
30	3.05	180.00 - 190.00	10.00	6.78	-3.16	46.057
31	5.71	180.00 - 190.00	10.00	12.68	-5.91	41.677
32	5.03	150.00 - 180.00	30.00	25.90	-25.90	45.067
33	3.73	150.00 - 180.00	30.00	19.19	-19.19	40.688
34	6.20	120.00 - 150.00	30.00	11.68	-43.58	44.404
35	6.20	90.00 - 120.00	30.00	-11.68	-43.58	44.484
36	5.03	30.00 - 90.00	60.00	-61.27	-35.38	45.067
37	0.00	0.00 - 0.00	0.00	0.00	0.00	0.00

TABLE 6.2-50

MASS AND ENERGY RELEASE DATA - ORIGINAL ANALYSIS

Main Steam Line DER With Feedwater (Case C)

Pipe ID (in)	23.362
Effective break area	Figure 6.2-14
Blowdown code	LOCTVS

Blowdown Table

Time (sec)	Blowdown Rate (lb/sec)	Enthalpy (Btu/lb)	Reactor Vessel Pressure (psia)
0.01	11,564	1,189.6	1,055
0.12(1)	11,482	1,189.9	1,048
0.13	8,606	1,189.9	1,047
0.50	8,444	1,190.7	1,028
1.11(2)	8,182	1,191.8	999
1.50	27,125	581.5	987
2.00	27,345	576.8	981
5.00	22,450	575.1	949
10.00	18,889	581.8	897
20.00	15,426	572.2	714
30.00(5)	12,187	548.6	534
50.00	7,764	471.6	273
100.10	4,055	353.8	87
200.10	5,540	264.1	59
245.6(6)	1,652	380.4	-
247.6(3)	0	-	-
338.1(4)	0	-	-
338.6	2,387	231.2	-
1,000.1	2,197	180.7	-
10,000	2,184	171.0	-

(1) Inventory period ends.
(2) Froth level reaches top of steam dryer.
(3) Blowdown ends.
(4) Water level recovers to steam line elevation.
(5) ECCS pump starts.
(6) Peak drywell pressure.

TABLE 6.2-51

CONTAINMENT SPRAY PARAMETERS

Drywell		
1.	No. of independent loops	2
2.	No. of spray nozzles/loop	64/Loop A 59/Loop B
3.	Nozzle manufacturer	SPRACO
4.	Nozzle No. (SPRACO)	47-1815-26
5.	Flow rate and pressure drop a. Loop A b. Loop B	 104 gpm @ 42 psi* 111 gpm @ 47 psi*
6.	Drop size (Sauter mean)	959 microns
7.	Spray drop efficiency	100%
Suppression Chamber		
1.	No. of loops	1 (common to both RHR pumps)
2.	No. of spray nozzles	35
3.	Nozzle manufacturer	SPRACO
4.	Nozzle No. (SPRACO)	47-0516-14
5.	Flow rate and pressure drop	11 gpm @ 30 psi*
6.	Drop size (Sauter mean)	773 microns
7.	Spray drop efficiency	100%

* Values shown are from nozzle test data. The hydraulic analysis for the containment spray system flow rates used a resistance coefficient (k) which is 56 percent greater than the k given by this test data.

TABLE 6.2-52

ACCIDENT ANALYSIS PARAMETERS USED FOR DBA OF CONTAINMENT HEAT REMOVAL

1.	Design basis accident (for containment sprays)	Steam line break area of 0.3 ft^2
2.	Steam bypass factor	0.05 ft^2 ($A/\sqrt{K}$ factor)
3.	Containment spray initiation	a. Manual action b. Spray operation within 30 min after break
4.	Containment parameters	Tables 6.2-1, 6.2-2, and 6.2-3
5.	Spray rate, gpm	
	Drywell	6,672
	Suppression chamber	428
6.	Heat exchanger K factor	239 Btu/sec/°F
7.	No. of downcomers	121
8.	Spray drop efficiency	90%

TABLE 6.2-53

ENERGY/MASS BALANCE

Steam Line Break: 0.3 Ft^2

Control Volume: Suppression Pool, Reactor Vessel, Drywell Atmosphere, Suppression Chamber Atmosphere, and Liquid on Drywell Floor

	Seconds				
	0	900	1,800	21,003	36,000
Total mass, lbm	10293942.4	10293315.4	10301145.4	10468211.5	10598685.4
Total internal energy, Btu	940335705.1	1071191462.1	1147890247.9	1668854263.1	1699385105.3
<u>Integrated Flow and Energy into Control Volume</u>					
Coastdown heat/decay heat	0	125748728.9	194404337.9	990921439.2	1442048824.8
Feedwater metal heat	0	56490542.1	71624743.2	110429368.9	144504489.9
Feedwater mass	0	0.0	0.0	0.0	0.0
Feedwater energy	0	0.0	0.0	0.0	0.0
CRD-Mass	0	7830.0	15660.0	182726.1	313200.0
CRD-Energy	0	845640.0	1691280.0	19734418.8	33825600.0
Pump heat	0	1811040.0	3754975.0	58733164.0	100589986.0
Total mass into control volume	0	7830.0	15660.0	182726.1	313200.0
Total energy into control volume	0	184895951.0	271475336.1	1179818391.0	1720968900.7
<u>Integrated Flow and Energy Out of Control Volume</u>					
RHR heat exchanger shutdown cooling mode	0	0	0	0	408440154.4
RHR heat exchanger pool cooling mode	0	0	0	0	0
Main steam mass	0	8457.0	8457.0	8457.0	8457.0
Main steam energy	0	10073333.7	10073333.7	10073333.7	10073333.7
Drywell and suppression chamber spray heat exchanger (RHR)	0	0.0	48051.8	374541850.6	429671679.6
Drywell heat sinks	0	41993245.3	48403648.3	51707053.5	85507110.0
Suppression chamber heat sinks	0	1175973.7	3712435.5	-162200.5	6379837.1
P1 heat sinks	0	797641.3	1683323.9	15139795.5	21847385.7
Total mass out of control volume	0	8457.0	8457.0	8457.0	8457.0
Total energy out of control volume	0	54040194.0	63920793.3	451299833.0	961919500.4
Total offset in control volume mass balance evaluated from 0 sec		0	0	0	0
Total offset in control volume energy balance evaluated from 0 sec		0	0	0	0

TABLE 6.2-54

SECONDARY CONTAINMENT DATA

1.	Total Volume	4.1×10^6 cu ft
	Reactor building refueling area	1,590,000 cu ft
	Reactor building volume below refueling area	1,970,000 cu ft
	HPCS room	22,000 cu ft
	LPCS room	20,000 cu ft
	RHR pump room A	20,000 cu ft
	RHR pump room B	20,000 cu ft
	RHR pump room C	20,000 cu ft
	RHR heat exchanger room A	25,000 cu ft
	RHR heat exchanger room B	25,000 cu ft
	North auxiliary bay	201,000 cu ft
	South auxiliary bay	164,000 cu ft
2.	Area Environmental Conditions	See Table 9.4-1
3.	SGTS System (see Figure 6.2-78)	
	SGTS flow without recirculation	3,720 cfm
	SGTS flow with recirculation	4,000 cfm
4.	In-leakage Rate (maximum)	2,670 cfm of outside air at -0.25 in W.G. ΔP at the roof, when outside air is -20°F and secondary containment at 105°F
5.	Cooling System Data	See Table 9.4-3* (Historical)

* The heat removal rates are for 104°F inlet air temperature, 77°F inlet cooling water temperature and dry air condition.

TABLE 6.2-55

THIS TABLE HAS BEEN DELETED

TABLE 6.2-55a (Cont'd.)

Line Description	Termination Region	Bypass Leakage Barrier	Leak Rate[3] Tech. Spec. SCFH[1,4]	Leak Rate[3] Fraction/ Day[2]	Containment Bypass Leak Rate (Fraction/Day)[5] 0-2 hr	0-8 hr	8-24 hr	1-4 day	4-30 day
CPS supply line to supp. chamber[6]	Standby Gas Treatment Area	2-2" valves	0.625	0.871×10^{-5}	0.845×10^{-5}	0.770×10^{-5}	0.749×10^{-5}	0.677×10^{-5}	0.478×10^{-5}
Inst. air to SRV accumulators	Yard	1-1 1/2" SOV							
Inst. air to drywell	Yard	1-1 1/2" SOV							
Inst. air to drywell	Yard	1-1 1/2" SOV	Combined Leakage						
Inst. air to CPS valve in supp. chamber	Yard	1-1 1/2" check valve	3.6[7]	0.834×10^{-4}	0.122×10^{-3}	0.110×10^{-3}	0.106×10^{-3}	0.954×10^{-4}	0.660×10^{-4}
Inst. air to CPS valve in supp. chamber	Yard	1-1 1/2" check valve							
N_2 purge to TIP index mechanism	Yard	1-1/2" check valve							
Inst. air to ADS accumulators	Yard	1-1 1/2" check valve	0.9375	0.217×10^{-4}	0.317×10^{-4}	0.286×10^{-4}	0.277×10^{-4}	0.249×10^{-4}	0.172×10^{-4}
Inst. air to ADS accumulators	Yard	1-1 1/2" check valve	0.9375	0.217×10^{-4}	0.317×10^{-4}	0.286×10^{-4}	0.277×10^{-4}	0.249×10^{-4}	0.172×10^{-4}

(1) Std Conditions: 14.7 psia and 68°F.
(2) Fraction/Day is defined as fraction of drywell volume leakage/day per line under test conditions.
(3) Test Conditions: Air medium; 40 psig and 80°F.
(4) The leak rate is based on ASME Section XI, 1983 Edition through Summer 1983 Addenda (Subsection IWV-3426) applied to each valve, except for main steam and feedwater lines.
(5) Fraction/Day is defined as fraction of drywell volume leakage/day under LOCA conditions.
(6) Leak rate is defined as a fraction of entire primary containment volume under LOCA conditions.
(7) All these paths terminate at 2GSN-TK2 within the reactor building, and only one line goes out of the reactor building.
(8) Technical Specification leak rate for MSIVs is 24 SCFH, but fraction/day leak rates are not computed for isothermal conditions. The isentropic flow case (see Table 6.2-55b) is most conservative and is used in the radiological analysis.

TABLE 6.2-55b (Cont'd.)

Line Description	Termination Region	Bypass Leakage Barrier	Leak Rate[3]		Containment Bypass Leak Rate (Fraction/Day)[5][8]				
			Tech. Spec. SCFH[1,4]	Fraction/ Day[2]	0-2 hr	0-8 hr	8-24 hr	1-4 day	4-30 day
Inst. air to SRV accumulators	Yard	1-1 1/2" SOV							
Inst. air to drywell	Yard	1-1 1/2" SOV							
Inst. air to drywell	Yard	1-1 1/2" SOV	Combined Leakage						
Inst. air to CPS valve in supp. chamber	Yard	1-1 1/2" check valve	3.6[7]	0.834×10^{-4}	0.127×10^{-3}	0.118×10^{-3}	0.115×10^{-3}	0.108×10^{-3}	0.848×10^{-4}
Inst. air to CPS valve in supp. chamber	Yard	1-1 1/2" check valve							
N_2 purge to TIP index mechanism	Yard	1-1/2" check valve							
Inst. air to ADS accumulators	Yard	1-1 1/2" check valve	0.9375	0.217×10^{-4}	0.331×10^{-4}	0.307×10^{-4}	0.298×10^{-4}	0.282×10^{-4}	0.221×10^{-4}
Inst. air to ADS accumulators	Yard	1-1 1/2" check valve	0.9375	0.217×10^{-4}	0.331×10^{-4}	0.307×10^{-4}	0.298×10^{-4}	0.282×10^{-4}	0.221×10^{-4}

(1) Std Conditions: 14.7 psia and 68°F.
(2) Fraction/Day is defined as fraction of drywell volume leakage/day per line under test conditions.
(3) Test Conditions: Air medium; 40 psig and 80°F.
(4) The leak rate is based on ASME Section XI, 1983 Edition through Summer 1983 Addenda (Subsection IWV-3426) applied to each valve, except for main steam lines and feedwater lines.
(5) Fraction/Day is defined as fraction of drywell volume leakage/day under LOCA conditions.
(6) Leak rate is defined as a fraction of entire primary containment volume under LOCA conditions.
(7) All these paths terminate at 2GSN-TK2 within the reactor building, and only one line goes out of the reactor building.
(8) Alternate MSIV leak rates below those indicated may be applied.

TABLE 6.2-55c (Cont'd.)

Line Description	Termination Region	Bypass Leakage Barrier	Leak Rate[3] Tech. Spec. SCFH[1,4]	Leak Rate[3] Fraction/Day[2]	Containment Bypass Leak Rate (Fraction/Day)[5] 0-2 hr	0-8 hr	8-24 hr	1-4 day	4-30 day
Inst. air to SRV accumulators	Yard	2-1 1/2" SOV	Combined Leakage 3.6[7]	0.834×10^{-4}	0.810×10^{-4}	0.738×10^{-4}	0.717×10^{-4}	0.649×10^{-4}	0.458×10^{-4}
Inst. air to drywell	Yard	2-1 1/2" SOV							
Inst. air to drywell	Yard	2-1 1/2" SOV							
Inst. air to CPS valve in supp. chamber	Yard	1-1" valve & 1-1 1/2" check valve							
Inst. air to CPS valve in supp. chamber	Yard	1-1" valve & 1-1 1/2" check valve							
N_2 purge to TIP index mechanism	Yard	1-1" valve & 1-1 1/2" check valve							
Inst. air to ADS accumulators	Yard	1-1 1/2" valve & 1-1 1/2" check valve	0.9375	0.217×10^{-4}	0.211×10^{-4}	0.192×10^{-4}	0.187×10^{-4}	0.169×10^{-4}	0.119×10^{-4}
Inst. air to ADS accumulators	Yard	1-1 1/2" valve & 1-1 1/2" check valve	0.9375	0.217×10^{-4}	0.211×10^{-4}	0.192×10^{-4}	0.187×10^{-4}	0.169×10^{-4}	0.119×10^{-4}

(1) Std. conditions: 14.7 psia and 68°F.
(2) Fraction/Day is defined as fraction of drywell volume leakage/day per line under test conditions.
(3) Test Conditions: Air medium; 40 psig and 80°F.
(4) The leak rate is based on ASME Section XI, 1983 Edition through Summer 1983 Addenda (Subsection IWV-3426) applied to each valve, except for main steam and feedwater lines.
(5) Fraction/Day is defined as fraction of drywell volume leakage/day under LOCA conditions.
(6) Leak rate is defined as a fraction of entire primary containment volume under LOCA conditions.
(7) All these paths terminate at 2GSN-TK2 within the reactor building, and only one line goes out of the reactor building.
(8) Technical Specification leak rate for MSIVs is 24 SCFH, but Fraction/Day leak rates are not computed for isothermal conditions. The isentropic flow case (see Table 6.2-55d) is most conservative and is used in the radiological analysis.

TABLE 6.2-55d (Cont'd.)

Line Description	Termination Region	Bypass Leakage Barrier	Leak Rate[3] Tech. Spec. SCFH[1,4]	Leak Rate[3] Fraction/ Day[2]	Containment Bypass Leak Rate (Fraction/Day)[5][6] 0-2 hr	0-8 hr	8-24 hr	1-4 day	4-30 day
Inst. air to SRV accumulators	Yard	2-1 1/2" SOV	Combined Leakage 3.6[7]	0.834×10^{-4}	0.977×10^{-4}	0.909×10^{-4}	0.887×10^{-4}	0.825×10^{-4}	0.617×10^{-4}
Inst. air to drywell	Yard	2-1 1/2" SOV							
Inst air to drywell	Yard	2-1 1/2" SOV							
Inst. air to CPS valve in supp. chamber	Yard	1-1" valve & 1-1 1/2" check valve							
Inst. air to CPS valve in supp. chamber	Yard	1-1" valve & 1-1 1/2" check valve							
N_2 purge to TIP index mechanism	Yard	1-1" valve & 1-1 1/2" check valve							
Inst. air to ADS accumulators	Yard	1-1 1/2" valve & 1-1 1/2" check valve	0.9375	0.217×10^{-4}	0.254×10^{-4}	0.237×10^{-4}	0.231×10^{-4}	0.215×10^{-4}	0.161×10^{-4}
Inst. air to ADS accumulators	Yard	1-1 1/2" valve & 1-1 1/2" check valve	0.9375	0.217×10^{-4}	0.254×10^{-4}	0.237×10^{-4}	0.231×10^{-4}	0.215×10^{-4}	0.161×10^{-4}

(1) Std. Conditions: 14.7 psia and 68°F.
(2) Fraction/Day is defined as fraction of drywell volume leakage/day per line under test conditions.
(3) Test Conditions: Air medium; 40 psig and 80°F.
(4) The leak rate is based on ASME Section XI, 1983 Edition through Summer 1983 Addenda (Subsection IWV-3426) applied to each valve, except for main steam lines and feedwater lines.
(5) Fraction/Day is defined as fraction of drywell volume leakage/day under LOCA conditions.
(6) Leak rate is defined as a fraction of entire primary containment volume under LOCA conditions.
(7) All these paths terminate at 2GSN-TK2 within the reactor building, and only one line goes out of the reactor building.
(8) Alternate MSIV leak rates below those indicated may be applied.

Pene. No.	System Designation	GDC or Reg. Guide	ESF Sys.	Fluid	Size (in)	FSAR Arrange. Figure[1]	Location of Valve Inside/ Outside Primary Containment	Length of Pipe - Cont. to Outside Isolation Valve	Type Test[1]	Poten. Bypass Lkg. Path	Number		Valve[9]											
															Actuator Mode		Position							
											SWEC	GE	Type	Oper.	Primary	Secondary	Norm.[3]	Shtdwn	Post-Acc.	Power Fail.[10]	Isolation Signal[4]	Closure Time[5,6]	Power Src.[7]	Notes
Z-5A	RHS Pump A Suction from Supp. Pool	56	Yes	Water	24	5.4-13c	Outside	5'-6"	N/A	No[29]	2RHS*MOV1A	E12-F004A	Tri-cent. Btr-fly	MOV	Elec.	Manual	Open	Closed	Open	FAI	RM	45	Div I	13
Z-5B	RHS Pump B Suction from Supp. Pool	56	Yes	Water	24	5.4-13f	Outside	20'-9"	N/A	No[29]	2RHS*MOV1B	E12-F004B	Tri-cent. Btr-fly	MOV	Elec.	Manual	Open	Closed	Open	FAI	RM	45	Div II	13
Z-5C	RHS Pump C Suction from Supp. Pool	56	Yes	Water	24	5.4-13g	Outside	9'-9"	N/A	No[29]	2RHS*MOV1C	E12-F004C	Tri-cent. Btr-fly	MOV	Elec.	Manual	Open	Closed	Open	FAI	RM	45	Div II	13
Z-6A	RHS Test Line Loop B to Supp. Pool	56	Yes	Water	18	5.4-13c	Outside	19'-3"	C	No[29]	2RHS*MOV30B	E12-F201B	Tri-cent. Btr-fly	MOV	Elec.	Manual	Open	Closed	Open	FAI	RM	85	Div I	15
Z-6B	RHS Test Line Loop A to Supp. Pool	56	Yes	Water	18	5.4-13c	Outside	10'-6"	C	No[29]	2RHS*MOV30A	E12-F201A	Tri-cent. Btr-fly	MOV	Elec.	Manual	Open	Closed	Open	FAI	RM	85	Div II	15
Z-7A	RHS Containment Spray Loop A to Supp. Pool	56	Yes	Water	4	5.4-13c	Outside	18'-3"	C	No[29]	2RHS*MOV33A	E12-F027A	Globe	MOV	Elec.	Manual	Closed	Closed	Open	FAI	X*,F*,RM	15	Div I	14,15
Z-7B	RHS Containment Spray Loop B to Supp. Pool	56	Yes	Water	4	5.4-13c	Outside	4'-6"	C	No[29]	2RHS*MOV33B	E12-F027B	Globe	MOV	Elec.	Manual	Closed	Closed	Open	FAI	X*,F*,RM	15	Div II	14,15
Z-8A	RHS Containment Spray Loop A to Drywell	56	Yes	Water	16	5.4-13a	Outside Outside	2'-0" 11'-2"	C C	No[29]	2RHS*MOV25A 2RHS*MOV15A	E12-F017A E12-F016A	Gate Gate	MOV MOV	Elec. Elec.	Manual Manual	Closed Closed	Closed Closed	Open Open	FAI FAI	RM RM	77 90	Div I Div I	13,15
Z-8B	RHS Containment Spray Loop B to Drywell	56	Yes	Water	16	5.4-13b	Outside Outside	2'-0" 9'-6"	C C	No[29]	2RHS*MOV25B 2RHS*MOV15B	E12-F017B E12-F016B	Gate Gate	MOV MOV	Elec. Elec.	Manual Manual	Closed Closed	Closed Closed	Open Open	FAI FAI	RM RM	77 90	Div II Div II	13,15
Z-9A	RHS/LPCI Loop A to RPV	55	Yes	Water	12	5.4-13a	Outside Inside	7'-0"	C C	No[29]	2RHS*MOV24A 2RHS*AOV16A	E12-F042A E12-F041A	Gate Check	MOV AOV	Elec. Process	Manual Air (test only)	Closed Closed	Closed Closed	Open Open	FAI Closed	RM Reverse flow	19 N/A	Div I Div I	11,13, 15
Z-9B	RHS/LPCI Loop B to RPV	55	Yes	Water	12	5.4-13a, 5.4-13b	Outside Inside	6'-6"	C C	No[29]	2RHS*MOV24B 2RHS*AOV16B	E12-F042B E12-F041B	Gate Check	MOV AOV	Elec. Process	Manual Air (test only)	Closed Closed	Closed Closed	Open Open	FAI Closed	RM Reverse flow	19 N/A	Div II Div II	11,13, 15
Z-9C	RHS/LPCI Loop C to RPV	55	Yes	Water	12	5.4-13a, 5.4-13b	Outside Inside	6'-6"	C C	No[29]	2RHS*MOV24C 2RHS*AOV16C	E12-F042C E12-F041C	Gate Check	MOV AOV	Elec. Process	Manual Air (test only)	Closed Closed	Closed Closed	Open Open	FAI Closed	RM Reverse flow	19 N/A	Div II Div II	11,13, 15
Z-10A	RHS Shutdown Return Loop A to Reactor Recirc Loop A	55	No	Water	12	5.4-13a	Outside Inside	6'-0"	C C	No[29]	2RHS*MOV40A 2RHS*AOV39A	E12-F053A E12-F050A	Globe Check	MOV AOV	Elec. Process (test only)	Manual Air	Closed Closed	Open Open	Closed Closed	FAI Closed	A,L,M,Z, RM,CC,DD Reverse flow	25 N/A	Div I Div I	11
	RHS Shutdown Cooling Return Line Inboard Valve Bypass Line	55	No	Water	2	5.4-13a	Inside		C		2RHS*MOV67A	E12-F099A	Globe	MOV	Elec.	Manual	Closed	Closed	Closed	FAI	A,L,M,Z, RM,CC,DD	9	Div I	

Pene. No.	System Designation	GDC or Reg. Guide	ESF Sys.	Fluid	Size (in)	FSAR Arrange Figure[1]	Location of Valve Inside/ Outside Primary Containment	Length of Pipe - Cont. to Outside Isolation Valve	Type Test[1]	Poten. Bypass Lkg. Path	Number: SWEC	Number: GE	Valve[9]: Type	Oper.	Actuator Mode: Primary	Actuator Mode: Secondary	Position: Norm.[3]	Position: Shtdwn	Position: Post-Acc.	Position: Power Fail.[10]	Isolation Signal[4]	Closure Time[5,6]	Power Src.[7]	Notes
Z-22	ICS to RPV	55	Yes	Water	6	5.4-9c, 5.4-13b	Outside	0'-6"	C	No[29]	2ICS*AOV156	E51-F065	Check	AOV	Process	Air (test only)	Closed	Open	Open	Closed	Reverse flow	N/A	125 VDC	
							Inside		C		2ICS*AOV157	E51-F066	Check	AOV	Process	Air (test only)	Closed	Open	Open	Closed	Reverse flow	N/A	125 VDC	
							Outside	4'-3"	C		2ICS*MOV126	E51-F013	Gate	MOV	Elec.	Manual	Closed	Closed	Open	FAI	RM	15		
					3/4		Outside	5'-11"	C	No	2ICS*V288	-	Globe	Man.	Manual	N/A	Closed	Closed	Closed	N/A	LC	N/A		
	RHR Reactor Head Spray			Water	6	5.4-9c, 5.4-13b	Outside	29'-5"	C		2RHS*MOV104	E12-F023	Globe	MOV	Elec.	Manual	Closed	Open	Closed	FAI	A,L,M,CC, RM,DD,Z	32	Div I	
Z-23	WCS Supply from RCS & RPV	55	No	Water	8	5.4-16a	Inside		C	Yes	2WCS*MOV102	G33-F001	Globe	MOV	Elec.	Manual	Open	Open	Closed	FAI	B,J,U,S, RM,DD,Z	13	Div II	
				Water	8		Outside	1'-3"	C		2WCS*MOV112	G33-F004	Globe	MOV	Elec.	Manual	Open	Open	Closed	FAI	B,J,S,U, W,Z,RM,DD	12	Div I	
Z-24	Spare		No		3				A															
Z-25	RDS Lines to RPV 53 Insert 53 With-drawal		Yes	Water	1 3/4	N/A	Outside Outside	125'-0" 125'-0"		No[29]							See Note 17							
Z-26	RDS Lines to RPV 39 Insert 39 With-drawal		Yes	Water	1 3/4	N/A	Outside Outside	125'-0" 125'-0"		No[29]							See Note 17							
Z-27	RDS Lines to RPV 54 Insert 54 With-drawal		Yes	Water	1 3/4	N/A	Outside Outside	125'-0" 125'-0"		No[29]							See Note 17							
Z-28	RDS Lines to RPV 39 Insert 39 With-drawal		Yes	Water	1 3/4	N/A	Outside Outside	125'-0" 125'-0"		No[29]							See Note 17							
Z-29	SLCS to RPV	55	Yes	Boron Solu-tion	1 1/2	9.3-17a	Inside		C	No[31]	2SLS*V10	C41-F007	Check	N/A	Process	N/A	Closed	Closed	Closed	N/A	Reverse flow	N/A	N/A	
							Outside	2'-10"	C		2SLS*MOV5A	C41-F006A	Stop Check Globe	MOV	Elec.	Manual	Closed	Closed	Closed	FAI	Reverse flow, RM	N/A	N/A	36
							Outside	3'-10"	C		2SLS*MOV5B	C41-F006B	Stop Check Globe	MOV	Elec.	Manual	Closed	Closed	Closed	FAI	Reverse Flow, RM	N/A	N/A	36
Z-30A	Spare		No		3				A															
Z-30B	Spare		No		3				A															
Z-31A	TIP Drive Guide Tube to RPV	1.11	No	Note 19	1 1/2	6.2-70	Outside	2'-4"	C	No[31]	N/A	2MSS*SOV1A	Ball	SOV	Elec.	N/A	Closed	Closed	Closed	Closed	B,F,RM,Z	N/A	120 VAC	18,19, 28,34
							Outside				N/A	2NMS*VEX1A	Shear	N/A	N/A	N/A	Open	Open	Open	Open	RM	N/A	125 VDC	
Z-31B	TIP Drive Guide Tube to RPV	1.11	No	Note 19	1 1/2	6.2-70	Outside	5'-4"	C	No[31]	N/A	2NMS*SOV1B	Ball	SOV	Elec.	N/A	Closed	Closed	Closed	Closed	B,F,RM,Z	N/A	120 VAC	18,19, 28,34
							Outside				N/A	2NMS*VEX1B	Shear	N/A	N/A	N/A	Open	Open	Open	Open	RM	N/A	125 VDC	
Z-31C	TIP Drive Guide Tube to RPV	1.11	No	Note 19	1 1/2	6.2-70	Outside	2'-4"	C	No[31]	N/A	2NMS*SOV1C	Ball	SOV	Elec.	N/A	Closed	Closed	Closed	Closed	B,F,RM,Z	N/A	120 VAC	18,19, 28,34
							Outside				N/A	2NMS*VEX1C	Shear	N/A	N/A	N/A	Open	Open	Open	Open	RM	N/A	125 VDC	
Z-31D	TIP Drive Guide Tube to RPV	1.11	No	Note 19	1 1/2	6.2-70	Outside	2'-4"	C	No[31]	N/A	2NMS*SOV1D	Ball	SOV	Elec.	N/A	Closed	Closed	Closed	Closed	B,F,RM,Z	N/A	120 VAC	18,19, 28,34
							Outside				N/A	2NMS*VEX1D	Shear	N/A	N/A	N/A	Open	Open	Open	Open	RM	N/A	125 VDC	
Z-31E	TIP Drive Guide Tube to RPV	1.11	No	Note 19	1 1/2	6.2-70	Outside	2'-7"	C	No[31]	N/A	2NMS*SOV1E	Ball	SOV	Elec.	N/A	Closed	Closed	Closed	Closed	B,F,RM,Z	N/A	120 VAC	18,19, 28,34
							Outside				N/A	2NMS*VEX1E	Shear	N/A	N/A	N/A	Open	Open	Open	Open	RM	N/A	125 VDC	

Pene. No.	System Designation	GDC or Reg. Guide	ESF Sys.	Fluid	Size (in)	FSAR Arrange. Figure[1]	Location of Valve Inside/ Outside Primary Containment	Length of Pipe - Cont. to Outside Isolation Valve	Type Test[1]	Poten. Bypass Lkg. Path	Number: SWEC	Number: GE	Valve[9]: Type	Valve[9]: Oper.	Actuator Mode: Primary	Actuator Mode: Secondary	Position: Norm.[3]	Position: Shtdwn	Position: Post-Acc.	Position: Power Fail.[10]	Isolation Signal[4]	Closure Time[5,6]	Power Src.[7]	Notes
Z-32	N_2 Purge to TIP Index Mechanism	56	No	N_2	1 1/2	9.3-20b	Outside	7'-6"	C	Yes	2GSN*SOV166	-	Globe	SOV	Elec.	N/A	Open	Closed	Closed	Closed	B,F,RM,Z	5	120 VAC	
							Inside	-	C		2GSN*V170	-	Check	N/A	Process	N/A	Open	Closed	Closed	N/A	Reverse flow	N/A	N/A	

Pene. No.	System Designation	GDC or Reg. Guide	ESF Sys.	Fluid	Size (in)	FSAR Arrange. Figure[1]	Location of Valve Inside/ Outside Primary Containment	Length of Pipe - Cont. to Outside Isolation Valve	Type Test[1]	Poten. Bypass Lkg. Path	Number: SWEC	Number: GE	Valve[9]: Type	Valve[9]: Oper.	Actuator Mode: Primary	Actuator Mode: Secondary	Position: Norm.[3]	Position: Shtdwn	Position: Post-Acc.	Position: Power Fail.[10]	Isolation Signal[4]	Closure Time[5,6]	Power Src.[7]	Notes
Z-33A	CCP Supply to RCS Pump A	56	No	Water	4	9.2-3d, 9.2-1m	Inside Outside Inside	7'-0"	C C C	No[31]	2CCP*MOV94A 2CCP*MOV17A 2CCP*RV1019A	- - -	Gate Gate Rlf.	MOV MOV N/A	Elec. Elec. Auto	Manual Manual N/A	Open Open Closed	Open Open Closed	Closed Closed Closed	FAI FAI N/A	B,F,RM,Z B,F,RM,Z N/A	26 26 N/A	Div II Div I N/A	6
Z-33B	CCP to RCS Pump B	56	No	Water	4	9.2-3b, 9.2-1f	Inside Outside Inside	7'-0"	C C C	No[31]	2CCP*MOV94B 2CCP*MOV17B 2CCP*RV170	- - -	Gate Gate Rlf.	MOV MOV N/A	Elec. Elec. Auto	Manual Manual N/A	Open Open Closed	Open Open Closed	Closed Closed Closed	FAI FAI N/A	B,F,RM,Z B,F,RM,Z N/A	26 26 N/A	Div II Div I N/A	
Z-34A	CCP Return from RCS Pump A	56	No	Water	4	9.2-3d	Inside Outside Inside	7'-0"	C C C	No[31]	2CCP*MOV16A 2CCP*MOV15A 2CCP*RV1020A	- - -	Gate Gate Rlf.	MOV MOV N/A	Elec. Elec. Auto	Manual Manual N/A	Open Open Closed	Open Open Closed	Closed Closed Closed	FAI FAI N/A	B,F,RM,Z B,F,RM,Z N/A	26 26 N/A	Div II Div I N/A	
Z-34B	CCP Return from RCS Pump B	56	No	Water	4	9.2-3a	Inside Outside Inside	7'-0"	C C C	No[31]	2CCP*MOV16B 2CCP*MOV15B 2CCP*RV171	- - -	Gate Gate Rlf.	MOV MOV N/A	Elec. Elec. Auto	Manual Manual N/A	Open Open Closed	Open Open Closed	Closed Closed Closed	FAI FAI N/A	B,F,RM,Z B,F,RM,Z N/A	26 26 N/A	Div II Div I N/A	
Z-35	Spare				4				A															
Z-36	Service Air to Drywell	56	No	Air	2	9.3-1j	Outside Inside	0'-7"	C	No[31]	2SAS*HCV161 2SAS*HCV163	- -	Globe Globe	Man. Man.	Manual Manual	N/A N/A	Closed Closed	Open Open	Closed Closed	N/A N/A	LMC,LC LMC,LC	N/A N/A	Div I Div II	
Z-37	Breathing Air to Drywell	56	No	Air	2	9.3-3e	Outside Inside	0'-7"	C C	No[31]	2AAS*HCV134 2AAS*HCV136	- -	Globe Globe	Man. Man.	Manual Manual	N/A N/A	Closed Closed	Open Open	Closed Closed	N/A N/A	LMC,LC LMC,LC	N/A N/A	Div I Div II	
Z-38A	RDS to Recirc Pump A Seal	55	No	Water	3/4	5.4-2b	Inside Outside Outside	 0'-0" 33'-0"	C C C	No[29]	2RCS*V60A 2RCS*V90A 2RCS*V59A	B35-F013A B35-F009A B35-F017A	Check Check Check	N/A N/A N/A	Process Process Process	N/A N/A N/A	Open Open Open	Closed Closed Closed	Closed Closed Closed	N/A N/A N/A	Reverse flow Reverse flow Reverse flow	N/A N/A N/A	N/A	
Z-38B	RDS to Recirc Pump B Seal	55	No	Water	3/4	5.4-2c	Inside Outside Outside	 0'-0" 31'-0"	C C C	No[29]	2RCS*V60B 2RCS*V90B 2RCS*V59B	B35-F013B B35-F009B B35-F017B	Check Check Check	N/A N/A N/A	Process Process Process	N/A N/A N/A	Open Open Open	Closed Closed Closed	Closed Closed Closed	N/A N/A N/A	Reverse flow Reverse flow Reverse flow	N/A N/A N/A	N/A	
Z-39	Drywell Floor Drain Line	56	No	Air	6	9.3-9e	Inside Outside Inside	1'-6"	C C C	Yes	2DFR*MOV121 2DFR*MOV120 2DFR*RV228	- - -	Gate Gate Rlf.	MOV MOV N/A	Elec. Elec. Auto	Manual Manual N/A	Open Open Closed	Closed Closed Closed	Closed Closed Closed	FAI FAI N/A	B,F,RM,Z B,F,RM,Z N/A	36 28 N/A	Div II Div I N/A	
Z-40	Equipment Drains from Drywell	56	No	Water	4	9.3-9f	Inside Outside Inside	4'-2"	C C C	Yes	2DER*MOV119 2DER*MOV120 2DER*RV344	- - -	Gate Gate Rlf.	MOV MOV N/A	Elec. Elec. Auto	Manual Manual N/A	Open Open Closed	Closed Closed Closed	Closed Closed Closed	FAI FAI N/A	B,F,RM,Z B,F,RM,Z N/A	22 22 N/A	Div II Div I N/A	
Z-41	Reactor Coolant Recirc to Sample Cooler/CAVS	55	No	Water	3/4	5.4-2b	Inside Outside	0'-0"	C C	No[31]	2RCS*SOV104 2RCS*SOV105	B35-F019 B35-F020	Globe Globe	SOV SOV	Elec. Elec.	N/A N/A	Open Open	Closed Closed	Closed Closed	Closed Closed	B,C,RM,Z B,C,RM,Z	5 5	Div II Div I	
Z-42A	Fire Protection for Reactor Recirc Pump	56	No	Air	2	9.5-1g	Inside Outside	3'-0"	C C	No[31]	2FPW*SOV219 2FPW*SOV218	-	Globe Globe	SOV SOV	N/A N/A	N/A N/A	Closed Closed	Closed Closed	Closed Closed	N/A N/A	35	N/A N/A	N/A N/A	35 35
Z-42B	Fire Protection Water for Reactor Recirc Pump	56	No	Air	2	9.5-1g	Inside Outside	3'-0"	C C	No[31]	2FPW*SOV221 2FPW*SOV220	- -	Globe Globe	SOV SOV	N/A N/A	N/A N/A	Closed Closed	Closed Closed	Closed Closed	N/A N/A	35	N/A N/A	N/A N/A	35 35
Z-43	Drywell Floor Drain Tank Vent	56	No	Water	6	9.3-9c, 9.3-9e	Inside Outside	20'-10"	C C	Yes	2DFR*MOV140 2DFR*MOV139	- -	Gate Gate	MOV MOV	Elec. Elec.	Manual Manual	Open Open	Closed Closed	Closed Closed	FAI FAI	B,F,RM,Z B,F,RM,Z	13 13	Div II Div I	
Z-44A	Capped Spare				3				A															
Z-44B	Capped Spare				3				A															
Z-44C	Capped Spare				3				A															
Z-44D	Capped Spare				3				A															
Z-44E	Service Air to Drywell	56	No	Air	2	9.3-1j	Outside Inside	0'-5"	C C	No[31]	2SAS*HCV160 2SAS*HCV162	- -	Globe Globe	Man. Man.	Manual Manual	N/A N/A	Closed Closed	Open Open	Closed Closed	N/A N/A	LMC,LC LMC,LC	N/A N/A	Div I Div II	
Z-44F	Breathing Air to Drywell	56	No	Air	2	9.3-3e	Outside Inside	0'-5"	C C	No[31]	2AAS*HCV135 2AAS*HCV137	- -	Globe Globe	Man. Man.	Manual Manual	N/A N/A	Closed Closed	Open Open	Closed Closed	N/A N/A	LMC,LC LMC,LC	N/A N/A	Div I Div II	

Pene. No.	System Designation	GDC or Reg. Guide	ESF Sys.	Fluid	Size (in)	FSAR Arrange. Figure[1]	Location of Valve Inside/ Outside Primary Containment	Length of Pipe - Cont. to Outside Isolation Valve	Type Test[1]	Poten. Bypass Lkg. Path	Number: SWEC	Number: GE	Valve[9]: Type	Valve: Oper.	Actuator Mode: Primary	Actuator Mode: Secondary	Position: Norm.[3]	Position: Shtdwn	Position: Post-Acc.	Position: Power Fail.[10]	Isolation Signal[4]	Closure Time[5,6]	Power Src.[7]	Notes
Z-45	Equipment Drain Tank (2DER-TK1) Vent to Drywell	56	No	Air	2	9.3-9f	Inside Outside	0'-0"	C C	Yes	2DER*MOV130 2DER*MOV131	- -	Globe Globe	MOV MOV	Elec. Elec.	Manual Manual	Open Open	Closed Closed	Closed Closed	FAI FAI	B,F,RM,Z B,F,RM,Z	9 9	Div II Div I	
Z-46A	CCP Supply to Drywell Space Cooler	56	No	Water	8	9.2-3c	Inside Outside Inside	7'-0"	C C C	No[31]	2CCP*MOV273 2CCP*MOV265 2CCP*RV1021A	- - -	Gate Gate Rlf.	MOV MOV N/A	Elec. Elec. Auto	Manual Manual N/A	Open Open Closed	Open Open Closed	Closed Closed Closed	FAI FAI N/A	B,F,RM,Z B,F,RM,Z N/A	36 38 N/A	Div II Div I N/A	
Z-46B	Capped Spare				4				A															
Z-46C	Fire Protection Water for Containment Hose Reel Standpipe						See Note 20		B	No[31]														
Z-46D	Capped Spare				4				A															
Z-47	CCP Return from Drywell Space Cooler	57	No[31]	Water	8	9.2-3c	Inside Outside Inside	7'-3"	C C C	No[31]	2CCP*MOV122 2CCP*MOV124 2CCP*RV1022A	- - -	Gate Gate Rlf.	MOV MOV N/A	Elec. Elec. Auto	Manual Manual N/A	Open Open Closed	Open Open Closed	Closed Closed Closed	FAI FAI N/A	B,F,RM,Z B,F,RM,Z N/A	38 36 N/A	Div II Div I N/A	
Z-48	Purge Exhaust from Drywell	56	No	Air	14	9.4-8k	Inside Outside	- 7'-4"	C C	No[31]	2CPS*AOV108 2CPS*AOV110	- -	Btr-fly Btr fly	AOV AOV	Pneumatic Pneumatic	Manual Manual	Closed Closed	Closed Closed	Closed Closed	Closed Closed	B,F,Y,RM, Z B,F,Y,RM, Z	5 5	Div II Div I	
Z-49	Purge Inlet to Drywell	56	No	Air/ N_2	14	9.4-8k	Inside Outside	- 4'-0"	C C	Yes	2CPS*AOV106 2CPS*AOV104	- -	Btr-fly Btr-fly	AOV AOV	Pneumatic Pneumatic	Manual Manual	Closed Closed	Closed Closed	Closed Closed	Closed Closed	B,F,Y,RM, Z B,F,Y,RM, Z	5 5	Div II Div I	21
Z-50	Purge Inlet to Wetwell	56	No	Air/ N_2	12	9.4-8k	Inside Outside	- 4'-3"	C C	Yes	2CPS*AOV107 2CPS*AOV105	- -	Btr-fly Btr-fly	AOV AOV	Pneumatic Pneumatic	Manual Manual	Closed Closed	Closed Closed	Closed Closed	Closed Closed	B,F,Y,RM, Z B,F,Y,RM, Z	5 5	Div II Div I	
Z-51	Purge Exhaust from Wetwell	56	No	Air	12	9.4-8k	Inside Outside	- 6'-6"	C C	No[31]	2CPS*AOV109 2CPS*AOV111	- -	Btr-fly Btr-fly	AOV AOV	Pneumatic Pneumatic	Manual Manual	Closed Closed	Closed Closed	Closed Closed	Closed Closed	B,F,Y,RM, Z B,F,Y,RM, Z	5 5	Div II Div I	
Z-52A	Capped Spare				1				A															
Z-52B	Capped Spare				1				A															
Z-53A	Instrument Air to ADS Valve Accumulators	56	No	N_2	1 1/2	9.3-1d	Outside Inside	1'-0"	C C	Yes	2IAS*SOV164 2IAS*V448		Globe Check	SOV N/A	Elec. Process	N/A N/A	Open Open	Open Open	Open Open	Closed N/A	B,F,RM,Z Reverse flow	5 N/A	Div I N/A	
Z-53B	Instrument Air to ADS Valve Accumulators	56	No	N_2	1 1/2	9.3-1f	Outside Inside	1'-0"	C C	Yes	2IAS*SOV165 2IAS*V449	- -	Globe Check	SOV N/A	Elec. Process	N/A N/A	Open Open	Open Open	Open Open	Closed N/A	B,F,RM,Z Reverse flow	5 N/A	Div II N/A	
Z-53C	Instrument Air to MSRV Accumulator Tank	56	No	N_2	1 1/2	9.3-1d	Outside Inside	1'-0"	C C	Yes	2IAS*SOV166 2IAS*SOV184	- -	Globe Globe	SOV SOV	Elec. Elec.	N/A N/A	Open Open	Open Open	Closed Closed	Closed Closed	B,F,RM,Z B,F,RM,Z	5 5	Div I Div II	
Z-54A	Capped Spare				3				A															
Z-55A	Hydrogen Recombiner 1A Supply to Wetwell	56	Yes	Air	3	6.2-72a	Inside Outside	2'-0"	A,C A,C	No[31]	2HCS*MOV4A 2HCS*MOV1A	- -	Gate Gate	MOV MOV	Elec. Elec.	Manual Manual	Closed Closed	Closed Closed	Open Open	FAI FAI	B,F,RM,Z B,F,RM,Z	19 19	Div I Div I	12,22
Z-55B	Hydrogen Recombiner 1B Supply to Wetwell	56	Yes	Air	3	6.2-72a	Inside Outside	2'-0"	A,C A,C	No[31]	2HCS*MOV4B 2HCS*MOV1B	- -	Gate Gate	MOV MOV	Elec. Elec.	Manual Manual	Closed Closed	Closed Closed	Open Open	FAI FAI	B,F,RM,Z B,F,RM,Z	19 19	Div II Div II	12,22
Z-56A	Hydrogen Recombiner 1A Return from Drywell	56	Yes	Air	3	6.2-72a	Inside Outside	2'-0"	A,C A,C	No[31]	2HCS*MOV6A 2HCS*MOV3A	- -	Gate Gate	MOV MOV	Elec. Elec.	Manual Manual	Closed Closed	Closed Closed	Open Open	FAI FAI	B,F,RM,Z B,F,RM,Z	19 19	Div I Div I	12,22

TABLE 6.2-63

CONTAINMENT PENETRATIONS WITH
RELIEF VALVE DISCHARGE HEADERS

Valve Number	Penetration Number	Pipe Length and Size Outside Containment (±1 ft)	
		Valve to Header	Header to Containment
2RHS*RV108	Z-73	4" Line, Length 45'-0"	6" Line, Length 4'-8"
2RHS*RV20C	Z-73	1" Line, Length 26'-4"	6" Line, Length 3'-2"
2RHS*SV34A	Z-88A	N/A	6" and 12" Line, Length 97'-7"
2RHS*SV62A	Z-88A	N/A	8" and 12" Line, Length 95'-2"
2RHS*RV56A	Z-88A	1" Line, Length 38'-3"	12" Line, Length 90'-4"
2RHS*MOV26A	Z-88A	1" Line, Length 25'-6"	12" Line, Length 91'-2"
2RHS*MOV27A	Z-88A	1" Line, Length 24'-0"	12" Line, Length 91'-2"
2RHS*V20	Z-88A	3/4" Line, Length 9'-4"	12" Line, Length 93'-1"
2RHS*V19	Z-88A	3/4" Line, Length 11'-4"	12" Line, Length 93'-1"
2RHS*RVV35A & 36A	Z-88A	10" Line, Length 3'-2" & 4'-4"	12" Line, Length 36'-0"
2RHS*SV34B	Z-88B	N/A	6" and 12" Line, Length 84'-6"
2RHS*SV62B	Z-88B	N/A	8" and 12" Line, Length 82'-2"
2RHS*RV56B	Z-88B	1" Line, Length 51'-10"	6" and 12" Line, Length 81'-0"
2RHS*MOV26B	Z-88B	1" Line, Length 32'-5"	6" and 12" Line, Length 81'-0"
2RHS*MOV27B	Z-88B	1" Line, Length 29'-11"	6" and 12" Line, Length 81'-0"
2RHS*V117	Z-88B	3/4" Line, Length 9'-10"	12" Line, Length 80'-0"

TABLE 6.2-63 (Cont'd.)

Valve Number	Penetration Number	Pipe Length and Size Outside Containment (±1 ft)	
		Valve to Header	Header to Containment
2RHS*V118	Z-88B	3/4" Line, Length 8'-10"	12" Line, Length 80'-0"
2RHS*RVV35B & 36B	Z-88B	10" Line, Length 3'-2" & 4'-4"	12" Line, Length 27'-5"
2RHS*RV20A	Z-98A	1" Line, Length 10'-6"	3" Line, Length 27'-6"
2RHS*RV61A	Z-98A	1" Line, Length 13'-5"	3" Line, Length 19'-1"
2RHS*RV110	Z-98A	1" Line, Length 26'-7"	3" Line, Length 36'-5"
2RHS*RV139	Z-98A	1" Line, Length 19'-7"	3" Line, Length 39'-7"
2CSL*RV105	Z-98A	1" Line, Length 183'-9"	3" Line, Length 38'-1"
2CSL*RV123	Z-98A	1" Line, Length 21'-3"	3" Line, Length 37'-1"
2RHS*RV20B	Z-98B	1" Line, Length 25'-0"	3" Line, Length 15'-9"
2CSH*RV113	Z-98B	1" Line, Length 108'-0"	3" Line, Length 16'-6"
2CSH*RV114	Z-98B	1" Line, Length 81'-5"	3" Line, Length 18'-0"
2RHS*RV61B	Z-98B	1" Line, Length 9'-6"	3" Line, Length 25'-6"
2RHS*RV61C	Z-98B	1" Line, Length 13'-6"	3" Line, Length 30'-6"

TABLE 6.2-65

REVERSE TESTED CONTAINMENT ISOLATION VALVES

Penetration No.	System	Valve I.D.	Valve Type	Justification
Z8A	RHS	MOV25A	Flexible Disc Gate	1
Z8B	RHS	MOV25B	Flexible Disc Gate	1
Z12	CSH	MOV118	Flexible Disc Gate	1
Z18	ICS	MOV143	Globe	2
Z17	ICS	MOV136	Flexible Disc Gate	1
Z19	ICS	MOV122	Flexible Disc Gate	1
Z21A	ICS	MOV128	Flexible Disc Gate	1
Z22	ICS	MOV126	Flexible Disc Gate	1
Z48	CPS	AOV108	Butterfly	3
Z51	CPS	AOV109	Butterfly	3
Z50	CPS	AOV107	Butterfly	3
Z49	CPS	AOV106	Butterfly	3
Z55A	HCS	MOV4A	Flexible Disc Gate	1
Z55B	HCS	MOV4B	Flexible Disc Gate	1
Z56A	HCS	MOV6A	Flexible Disc Gate	1
Z57A	HCS	MOV5A	Globe	2
Z56B	HCS	MOV6B	Flexible Disc Gate	1
Z57B	HCS	MOV5B	Globe	2
Z58	CPS	SOV122	Globe	4
Z59	CPS	SOV121	Globe	4
Z60A	CMS	SOV61A	Globe	4
Z60C	CMS	SOV63A	Globe	4
Z60D	CMS	SOV33A	Globe	4
Z61C	CMS	SOV34A	Globe	4
Z60E	CMS	SOV61B	Globe	4
Z60G	CMS	SOV63B	Globe	4
Z60H	CMS	SOV33B	Globe	4
Z61F	CMS	SOV34B	Globe	4
Z11	RHS	RV152	Relief	5
Z33B	CCP	RV170	Relief	5
Z34B	CCP	RV171	Relief	5
Z33A	CCP	RV1019A	Relief	5
Z34A	CCP	RV1020A	Relief	5
Z46A	CCP	RV1021A	Relief	5
Z47	CCP	RV1022A	Relief	5
Z39	DFR	RV228	Relief	5
Z40	DER	RV344	Relief	5

Justification Notes:

1. Flexible disc gate valves may be tested using a test connection (TC) between the disc seats. (This is an alternate method of reverse direction testing by

TABLE 6.2-65 (Cont'd.)

pressurizing the area between the disc seats. This method is used in lieu of the forward flow test.) This is a conservative test since both LOCA and non-LOCA seat leakage is measured.

2. Globe valves are oriented to ensure LLRT test pressure tends to unseat the valve, whereas LOCA pressure will tend to seat the valve. This is conservative for testing.

3. Butterfly valves are reverse tested which will provide equivalent results since the seating area(s) and test pressure force(s) will be equal in either direction.

4. Solenoid valves are of the pressure-balanced bellows type or equivalent. By design, neither upstream nor downstream pressure can exert a force on the disc, and the spring force of the bellows is the only force tending to seat the valve disc. Reverse flow testing is therefore equivalent to testing in the same direction as post-accident flow.

5. Relief valves are nozzle-type, spring-actuated relief valves. The valves are orientated to ensure test pressure tends to unseat the valve, whereas LOCA pressure will tend to seat the valve. This is conservative for testing.

THIS FIGURE HAS BEEN DELETED

FIGURE 6.2-24

NIAGARA MOHAWK POWER CORPORATION
NINE MILE POINT-UNIT 2
UPDATED SAFETY ANALYSIS REPORT

THIS FIGURE HAS BEEN DELETED

FIGURE 6.2-25

NIAGARA MOHAWK POWER CORPORATION
NINE MILE POINT-UNIT 2
UPDATED SAFETY ANALYSIS REPORT

THIS FIGURE HAS BEEN DELETED

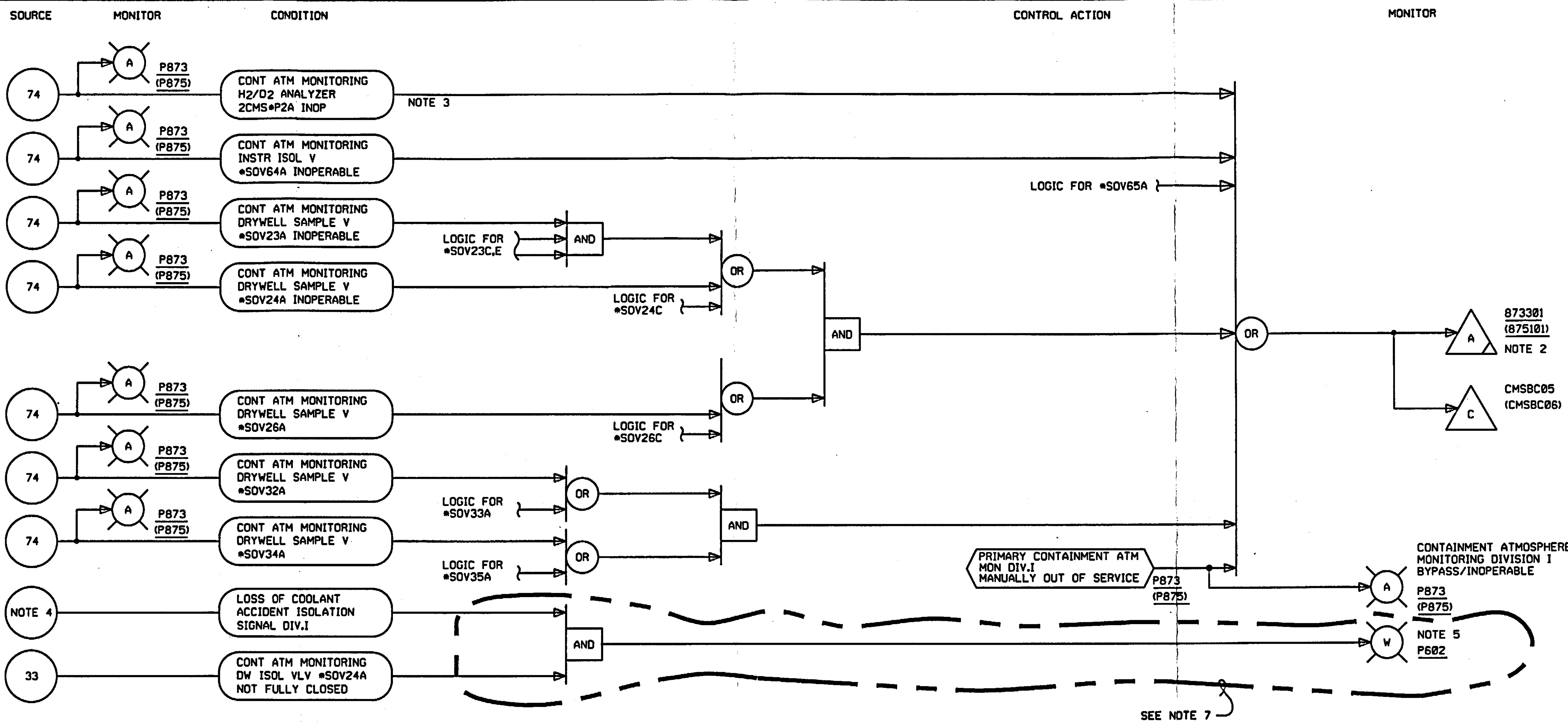
FIGURE 6.2-26

NIAGARA MOHAWK POWER CORPORATION
NINE MILE POINT-UNIT 2
UPDATED SAFETY ANALYSIS REPORT

THIS FIGURE HAS BEEN DELETED

FIGURE 6.2-27

NIAGARA MOHAWK POWER CORPORATION
NINE MILE POINT-UNIT 2
UPDATED SAFETY ANALYSIS REPORT



NOTES:

1. ALL INSTRUMENT AND EQUIPMENT NUMBERS TO BE PREFIXED WITH "2CMS-" EXCEPT WHERE A DIFFERENT PREFIX IS SHOWN. AN ASTERISK (*) WILL REPLACE THE DASH (-) IN THE PREFIX FOR EQUIPMENT OR INSTRUMENTS WHICH ARE A PART OF NUCLEAR SAFETY FEATURES SYSTEM.
2. COMMON BYPASS INOPERABLE ANNUNCIATION FOR ALL DIV.I CONTAINMENT ATMOSPHERE MONITORING H_2/O_2 ANALYZER, PUMPS, SAMPLING VALVES AND PRIMARY CONTAINMENT ISOLATION VALVES. SEE ASSOCIATED EQUIPMENT MARK NUMBERS.
3. DIVISION I INOPERABLE LOGIC IS SHOWN. DIV.II IS SIMILAR. SEE NOTE 6.
4. SEE LSK-27-19 FOR LOSS OF COOLANT ACCIDENT ISOLATION SIGNAL LOGIC DEVELOPMENT.
5. LOGIC FOR CONTAINMENT ATMOSPHERE MONITORING DRYWELL ISOLATION VALVE *SOV24A OFF-NORMAL STATUS IS DESCRIBED. LOGIC FOR ALL CONTAINMENT ATMOSPHERE MONITORING DRYWELL AND SUPPRESSION CHAMBER ISOLATION VALVES OFF NORMAL STATUS IS SIMILAR. SEE NOTE 3 ON LSK-33-2M AND NOTE 4 ON LSK-33-2H FOR ASSOCIATED VALVE NUMBERS.
6. ASSOCIATED EQUIPMENT MARK NUMBERS:

DIV.I		DIV.II	
*P2A	*SOV26A	*P2B	*SOV26B
*SOV23A	*SOV26C	*SOV23B	*SOV26D
*SOV23C	*SOV32A	*SOV23D	*SOV32B
*SOV23E	*SOV33A	*SOV23F	*SOV33B
*SOV24A	*SOV34A	*SOV24B	*SOV34B
*SOV24C	*SOV35A	*SOV24D	*SOV35B
	*SOV64A		*SOV64B
	*SOV65A		*SOV65B

7. THE OFF-NORMAL STATUS DISPLAY SYSTEM HAS BEEN ABANDONED IN PLACE.

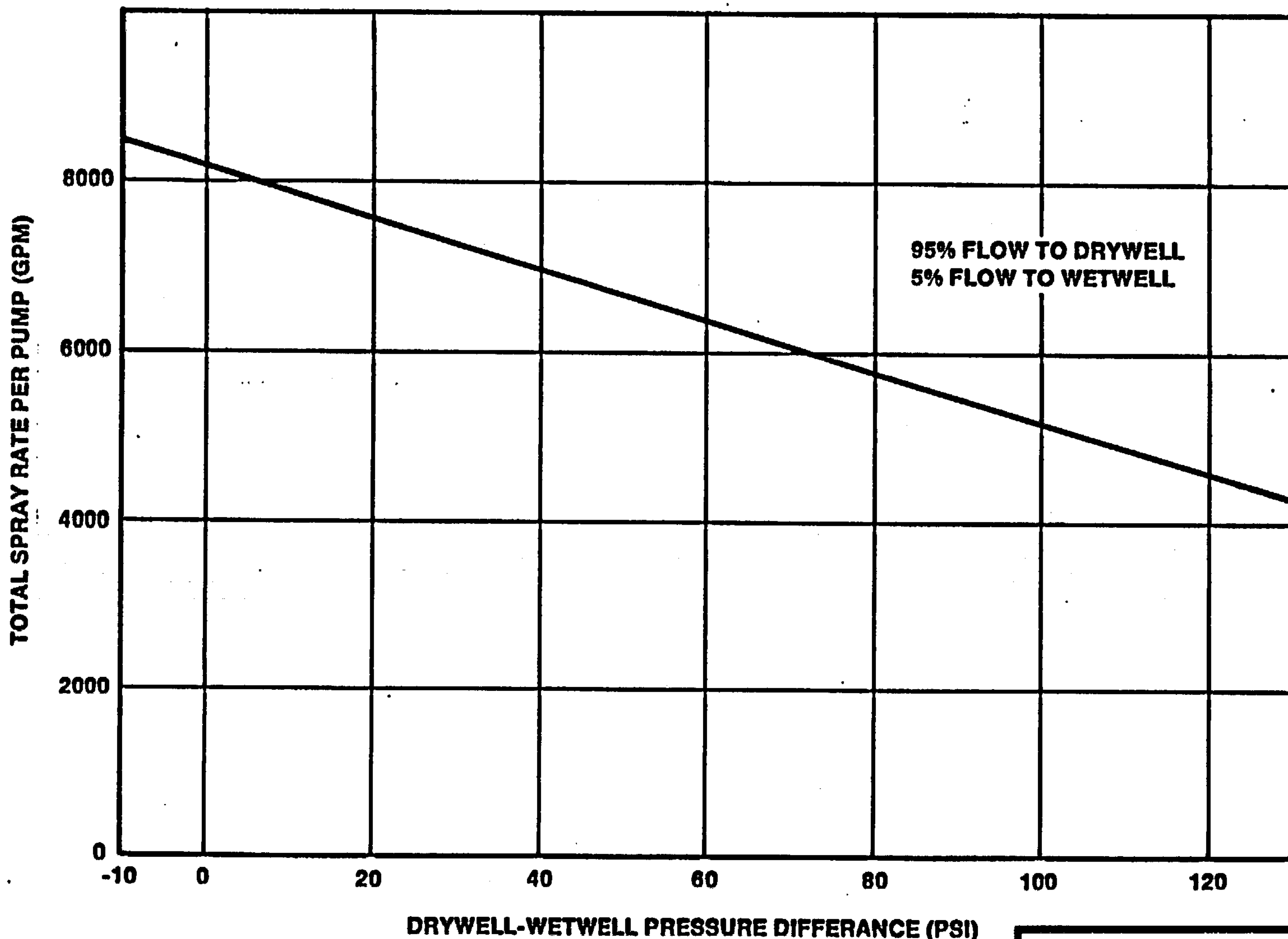
SETPOINTS SHOWN ON LOGIC DIAGRAMS ARE FOR LOGIC CLARIFICATION ONLY AND MAY BE ONLY APPROXIMATIONS OF THE ACTUAL PROCESS SETPOINT. REFER TO SETPOINT DATA SHEETS FOR ACTUAL PROCESS SETPOINTS.

SOURCE: LSK- 33-2G

FIGURE 6.2-38

CONTAINMENT ATMOSPHERE MONITORING SYSTEM LOGIC DIAGRAM SHEET 7 OF 12

NIAGARA MOHAWK POWER CORP.
NINE MILE POINT-UNIT 2
UPDATED SAFETY ANALYSIS REPORT



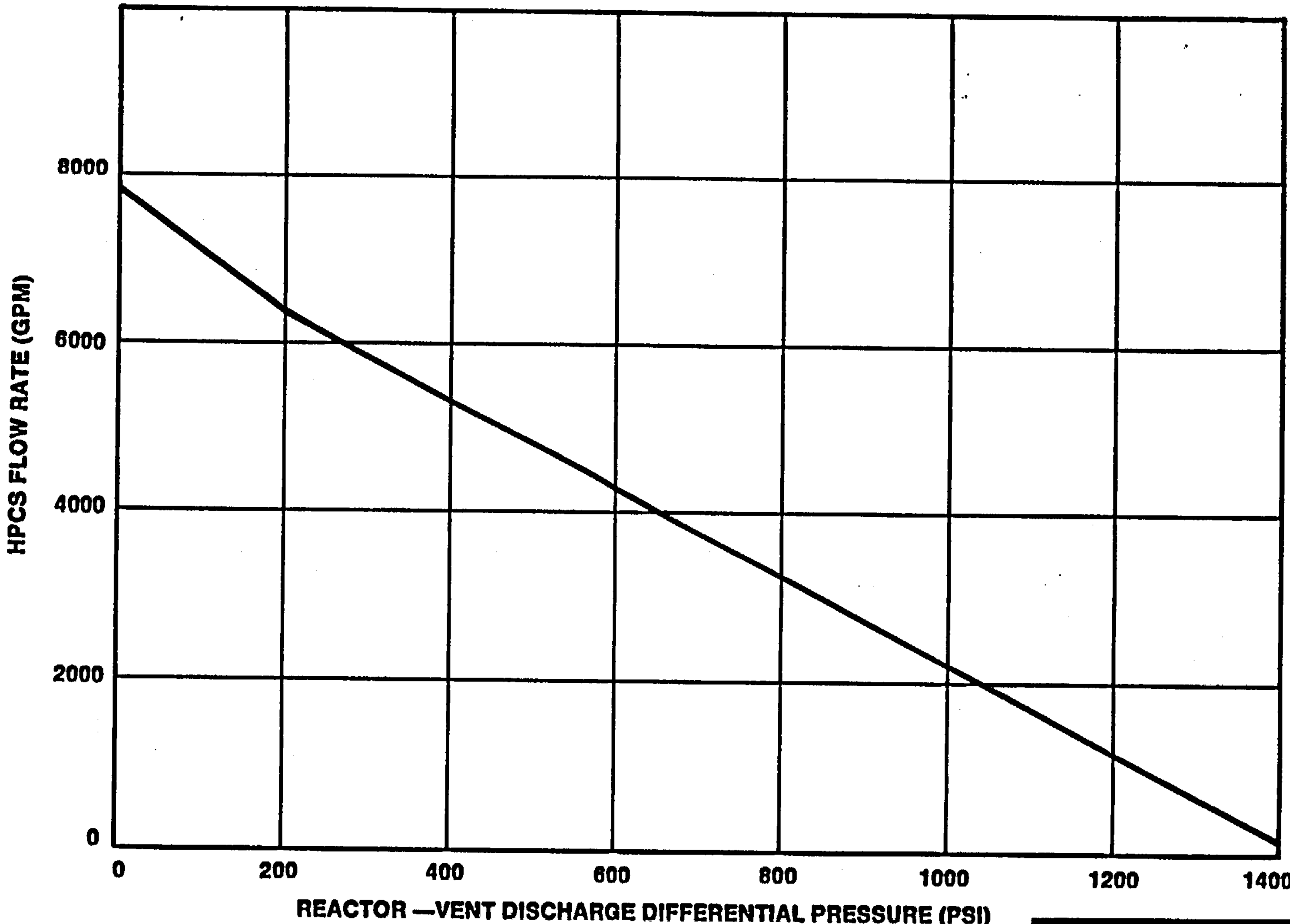
SOURCE: ES-121

Note: This curve applicable to Pre-Power Uprate containment response evaluation in Section 6.2.1.1.3. The Containment Spray flow rate used as input to the Power Uprate containment response evaluation has been reconciled using the Technical Specification performance curves for the RHR pumps.

FIGURE 6.2-47

CONTAINMENT SPRAY FLOW RATE

NIAGARA MOHAWK POWER CORPORATION
NINE MILE POINT-UNIT 2
UPDATED SAFETY ANALYSIS REPORT



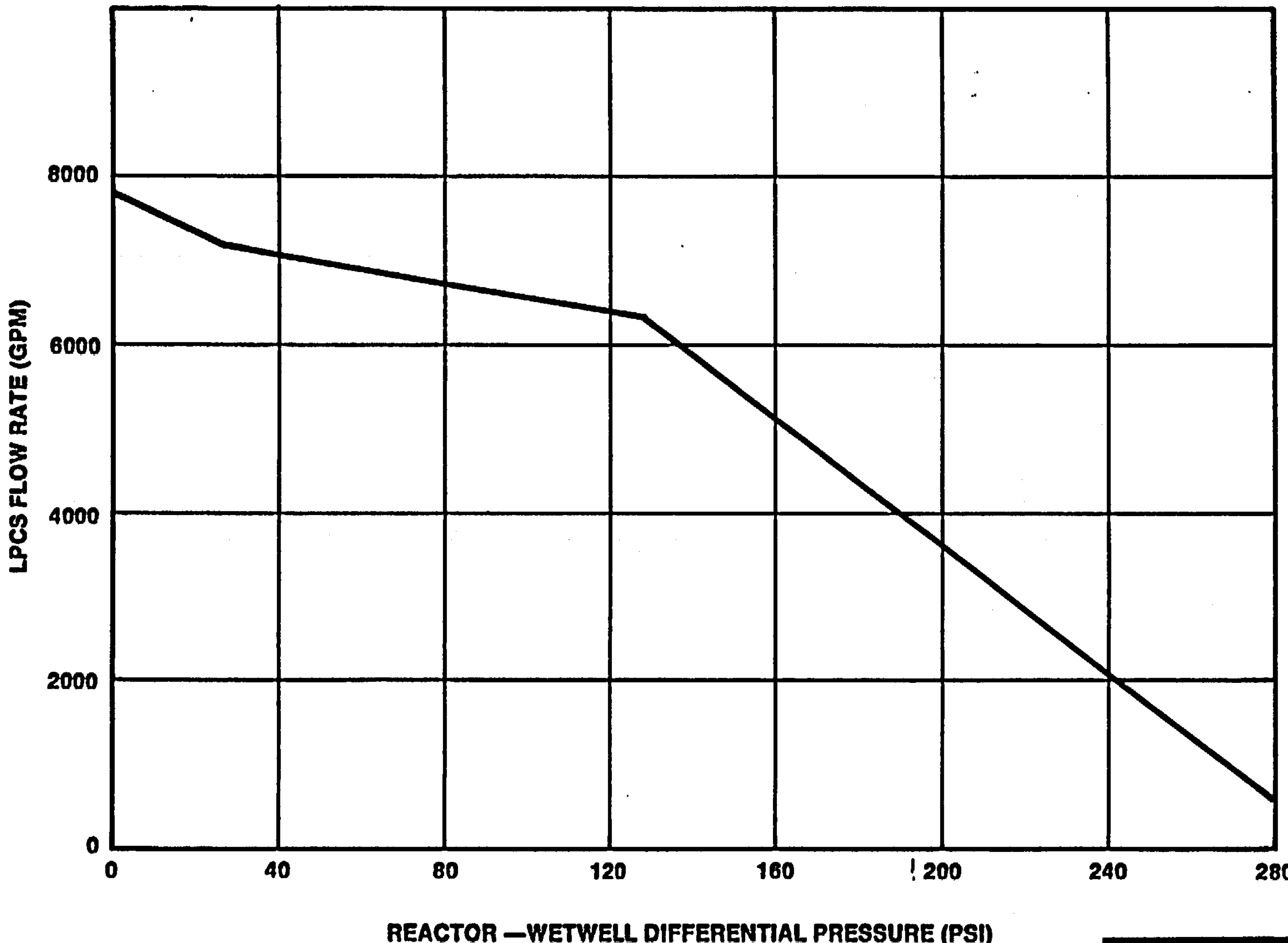
SOURCE: ES-121

Note: This curve applicable to Pre-Power Uprate containment response evaluation in Section 6.2.1.1.3. For reconciled performance curve see Figure 6.3-3A.

FIGURE 6.2-48

HIGH PRESSURE CORE SPRAY FLOW RATE

NIAGARA MOHAWK POWER CORPORATION
NINE MILE POINT-UNIT 2
UPDATED SAFETY ANALYSIS REPORT



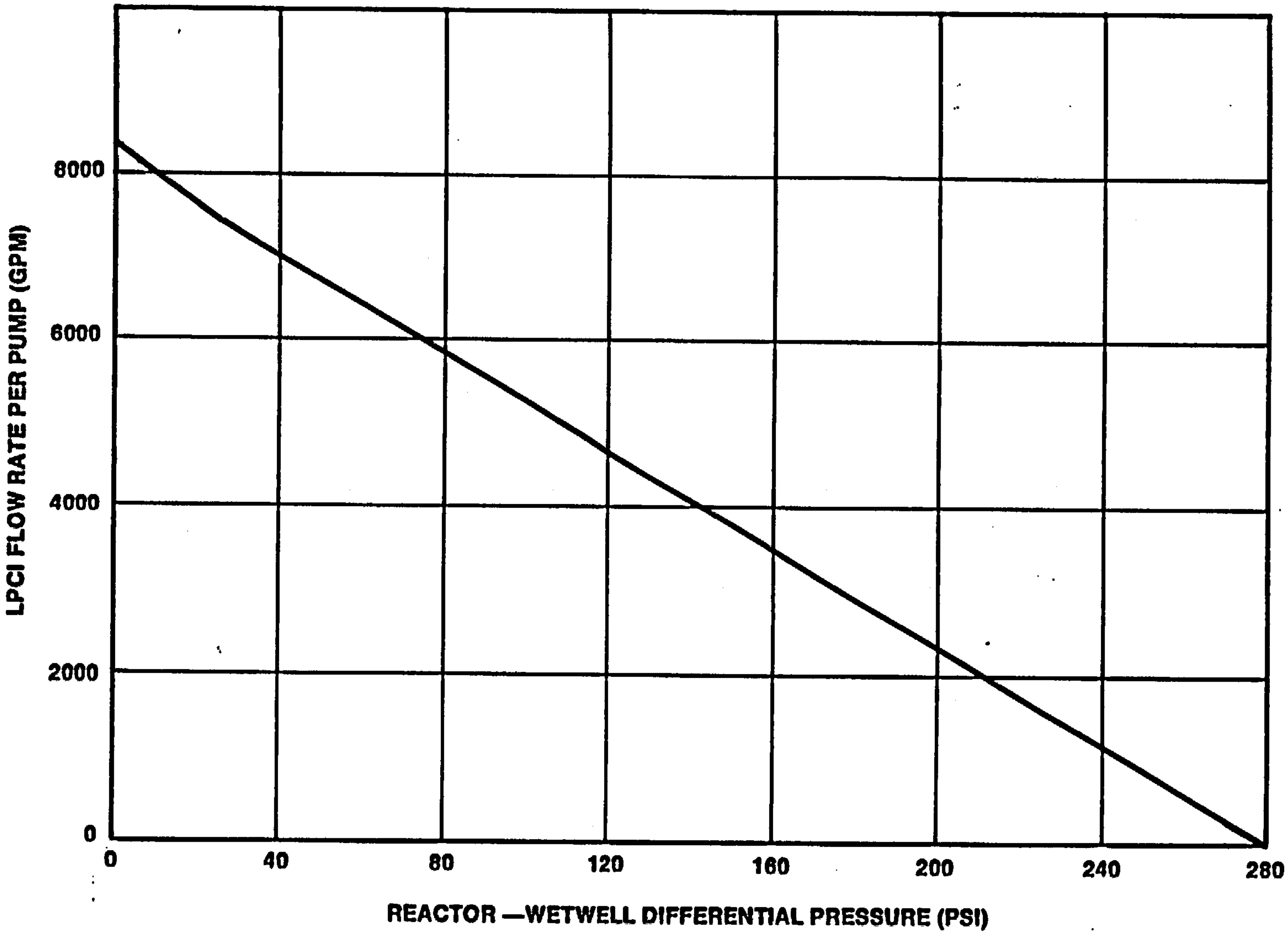
SOURCE: ES-121

<u>Note: This curve applicable to Pre-Power Uprate containment response evaluation in Section 6.2.1.1.3. For reconciled performance curve see Figure 6.3-4A.</u>

FIGURE 6.2-49

LOW PRESSURE CORE SPRAY
FLOW RATE

NIAGARA MOHAWK POWER CORPORATION
NINE MILE POINT-UNIT 2
UPDATED SAFETY ANALYSIS REPORT



SOURCE: ES-121

Note: This curve applicable to Pre-Power Uprate containment response evaluation in Section 6.2.1.1.3. For reconciled performance curve see Figure 6.3-5A.

FIGURE 6.2-50

LOW PRESSURE COOLANT
INJECTION FLOW RATE

NIAGARA MOHAWK POWER CORPORATION
NINE MILE POINT-UNIT 2
UPDATED SAFETY ANALYSIS REPORT

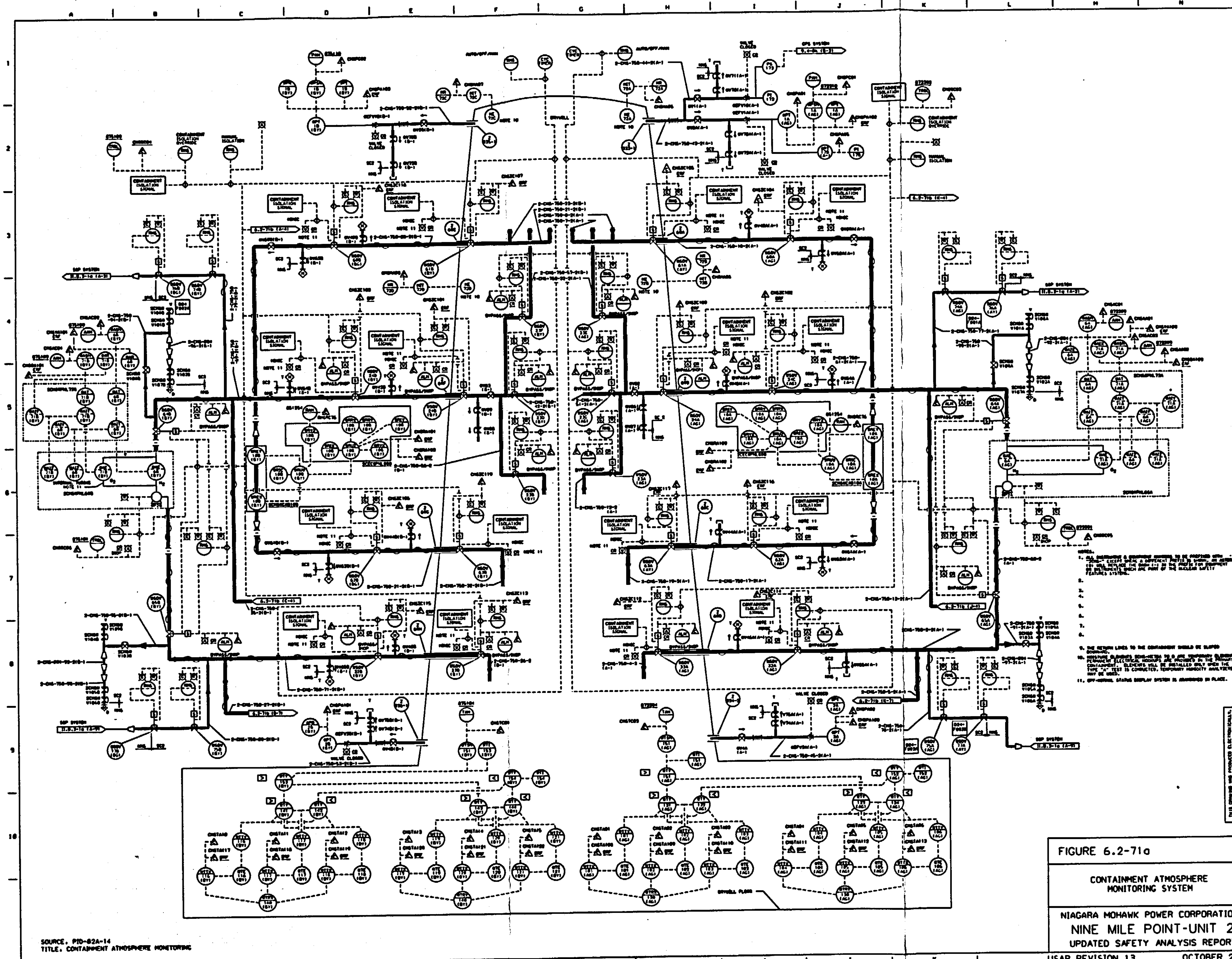


FIGURE 6.2-71a

CONTAINMENT ATMOSPHERE MONITORING SYSTEM

NIAGARA MOHAWK POWER CORPORATION
NINE MILE POINT-UNIT 2
UPDATED SAFETY ANALYSIS REPORT

USAR REVISION 13 OCTOBER 2000

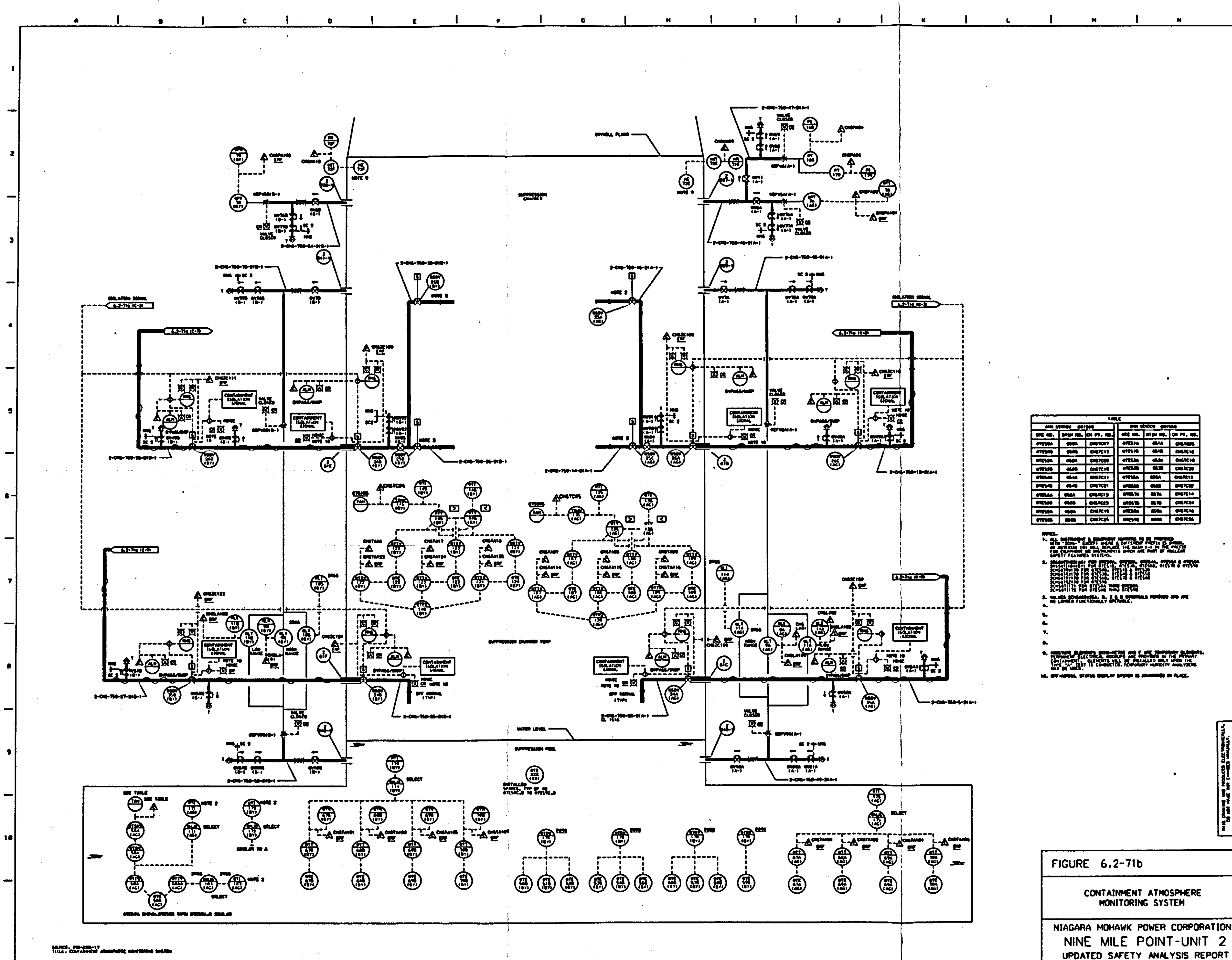


FIGURE 6.2-71b

CONTAINMENT ATMOSPHERE
MONITORING SYSTEM

NIAGARA MOHAWK POWER CORPORATION
NINE MILE POINT-UNIT 2
UPDATED SAFETY ANALYSIS REPORT

USAR REVISION 13 OCTOBER 2000

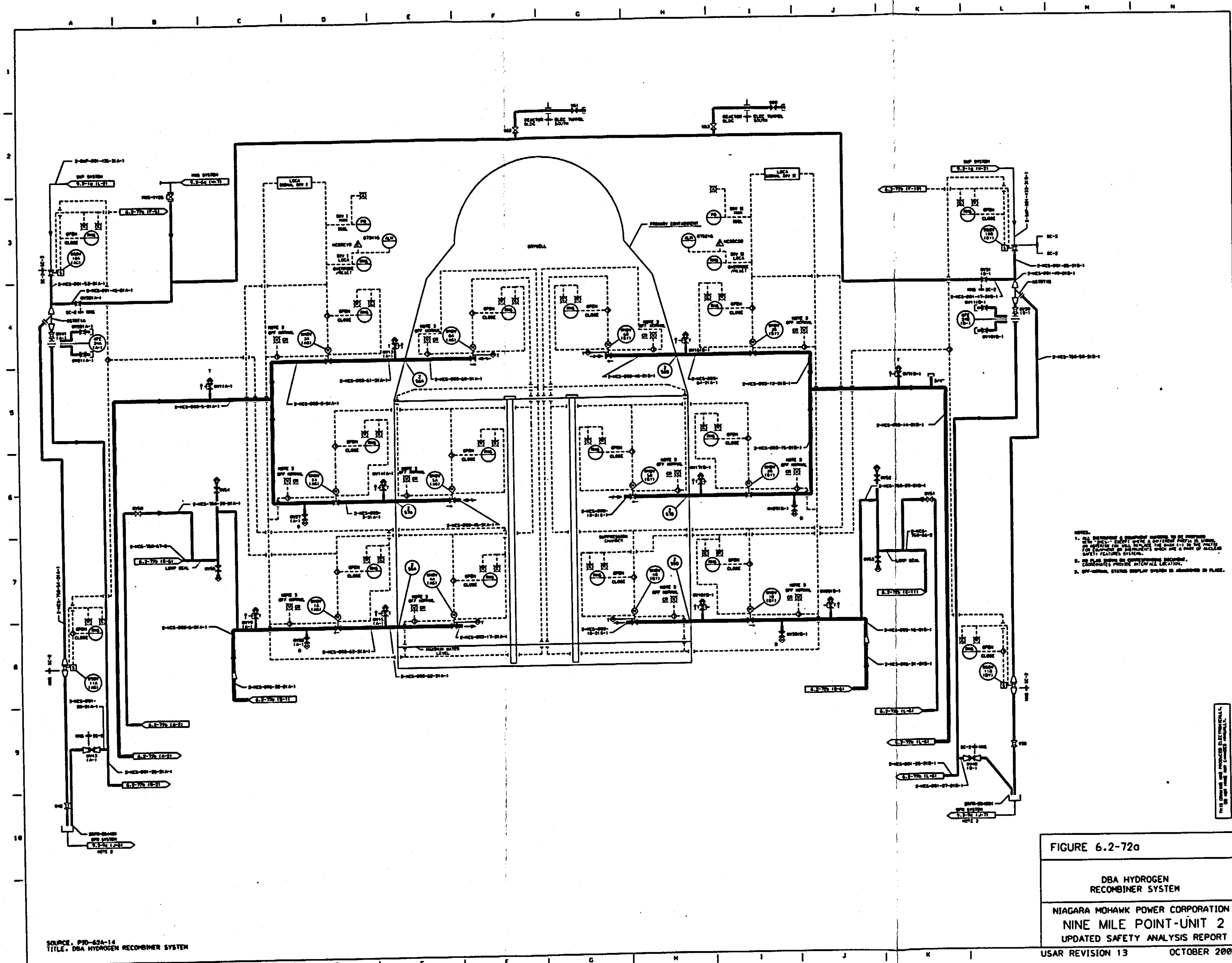


FIGURE 6.2-72a

DBA HYDROGEN RECOMBINER SYSTEM

NIAGARA MOHAWK POWER CORPORATION
NINE MILE POINT-UNIT 2
UPDATED SAFETY ANALYSIS REPORT

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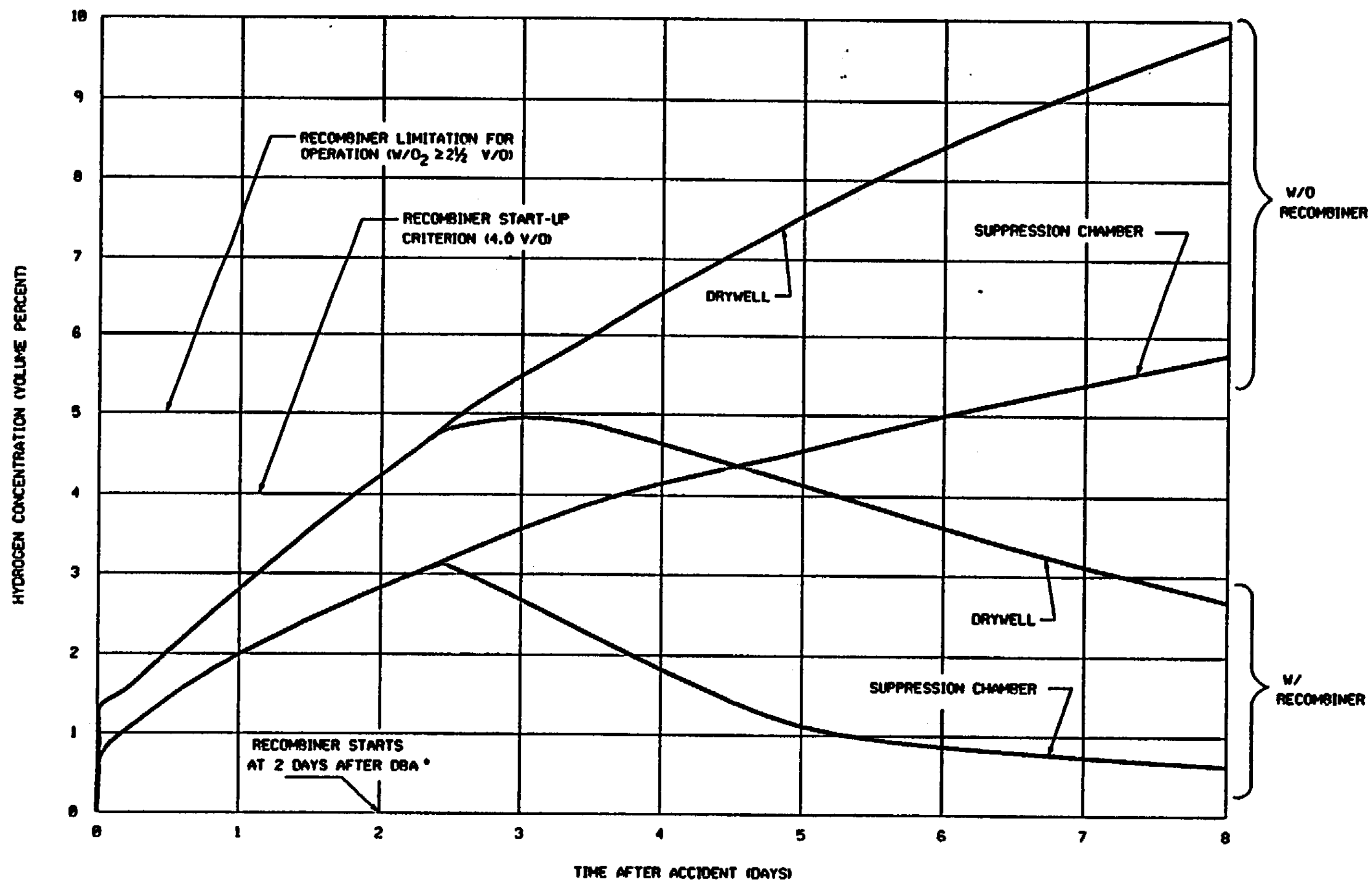


NOTE: THE RECOMBINER STARTS APPROXIMATELY TWO DAYS AFTER THE DBA BASED ON 4.0 V/O HYDROGEN CONCENTRATION.

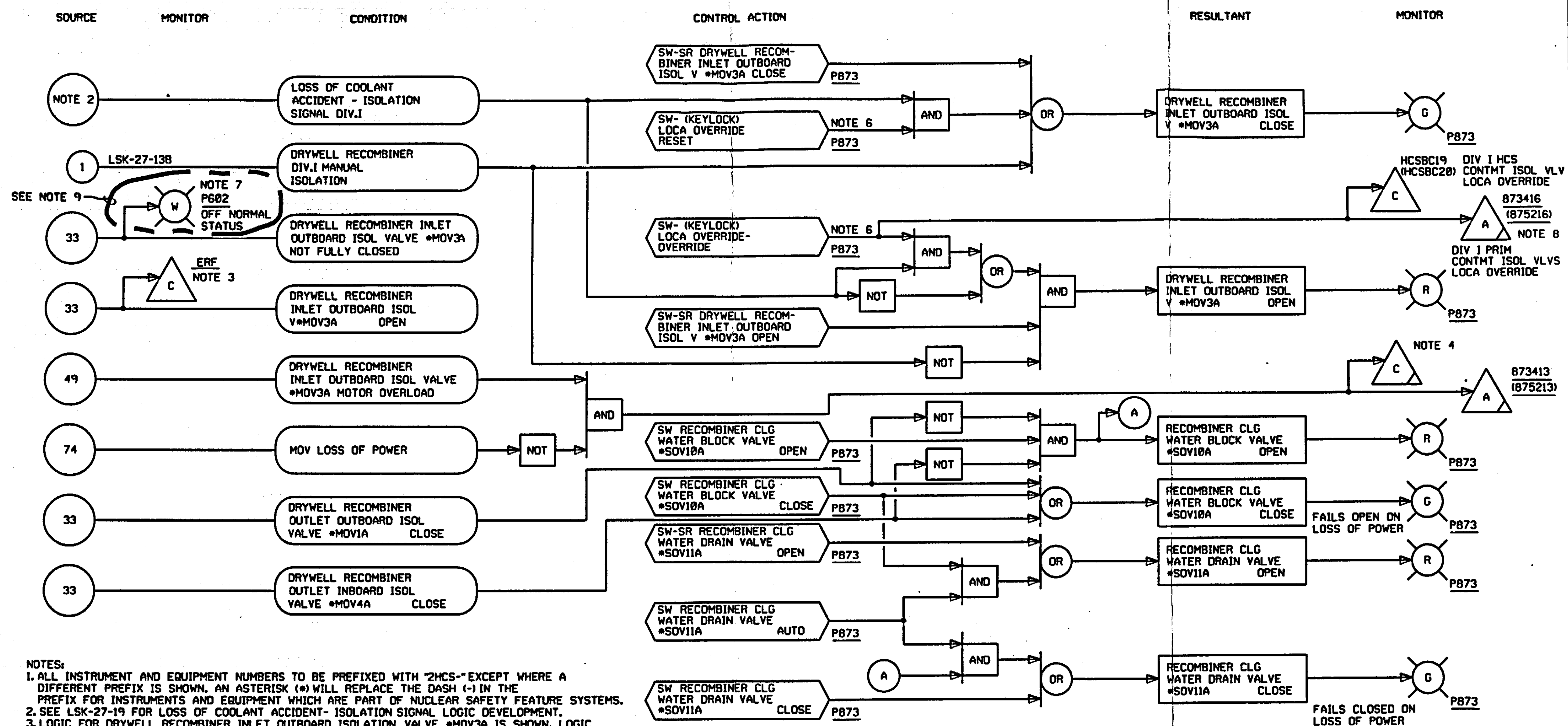
SOURCE: CALC ES-135- 04

THIS DRAWING CREATED ELECTRONICALLY

FIGURE 6.2-72I

HYDROGEN CONCENTRATIONS FOLLOWING A DESIGN BASIS ACCIDENT (DBA)

NIAGARA MOHAWK POWER CORPORATION
NINE MILE POINT-UNIT 2
UPDATED SAFETY ANALYSIS REPORT



NOTES:

1. ALL INSTRUMENT AND EQUIPMENT NUMBERS TO BE PREFIXED WITH "2HCS-" EXCEPT WHERE A DIFFERENT PREFIX IS SHOWN. AN ASTERISK (*) WILL REPLACE THE DASH (-) IN THE PREFIX FOR INSTRUMENTS AND EQUIPMENT WHICH ARE PART OF NUCLEAR SAFETY FEATURE SYSTEMS.
2. SEE LSK-27-19 FOR LOSS OF COOLANT ACCIDENT- ISOLATION SIGNAL LOGIC DEVELOPMENT.
3. LOGIC FOR DRYWELL RECOMBINER INLET OUTBOARD ISOLATION VALVE *MOV3A IS SHOWN. LOGIC FOR ALL RECOMBINER ISOLATION VALVES IS SIMILAR (SEE ASSOCIATED EQUIPMENT MARK NUMBERS, NOTE 4)
4. ASSOCIATED EQUIPMENT MARK NUMBERS:

DIV.I	CMPTR NO.	DIV.II	CMPTR NO.
*MOV1A	HCSTC21	*MOV1B	HCSTC22
*MOV2A	HCSTC21	*MOV2B	HCSTC22
*MOV3A	HCSTC21	*MOV3B	HCSTC22
*MOV4A	HCSTC21	*MOV4B	HCSTC22
*MOV5A	HCSTC21	*MOV5B	HCSTC22
*MOV6A	HCSTC21	*MOV6B	HCSTC22
*P873		*P875	

5. LOGIC FOR RECOMBINER COOLING WATER BLOCK VALVE *SOV10A AND DRAIN VALVE *SOV11A IS SHOWN. LOGIC FOR RECOMBINER COOLING WATER BLOCK VALVE *SOV10B AND DRAIN VALVE *SOV11B IS SIMILAR.
6. ONE SWITCH PER DIVISION.
7. OFF NORMAL STATUS INDICATING LIGHT. ONE LIGHT PER ISOLATION VALVE.
8. COMMON ANNUNCIATOR FOR BOTH SYSTEMS HCS AND CPS IN EACH DIVISION.
9. OFF-NORMAL STATUS DISPLAY SYSTEM IS ABANDONED IN PLACE.

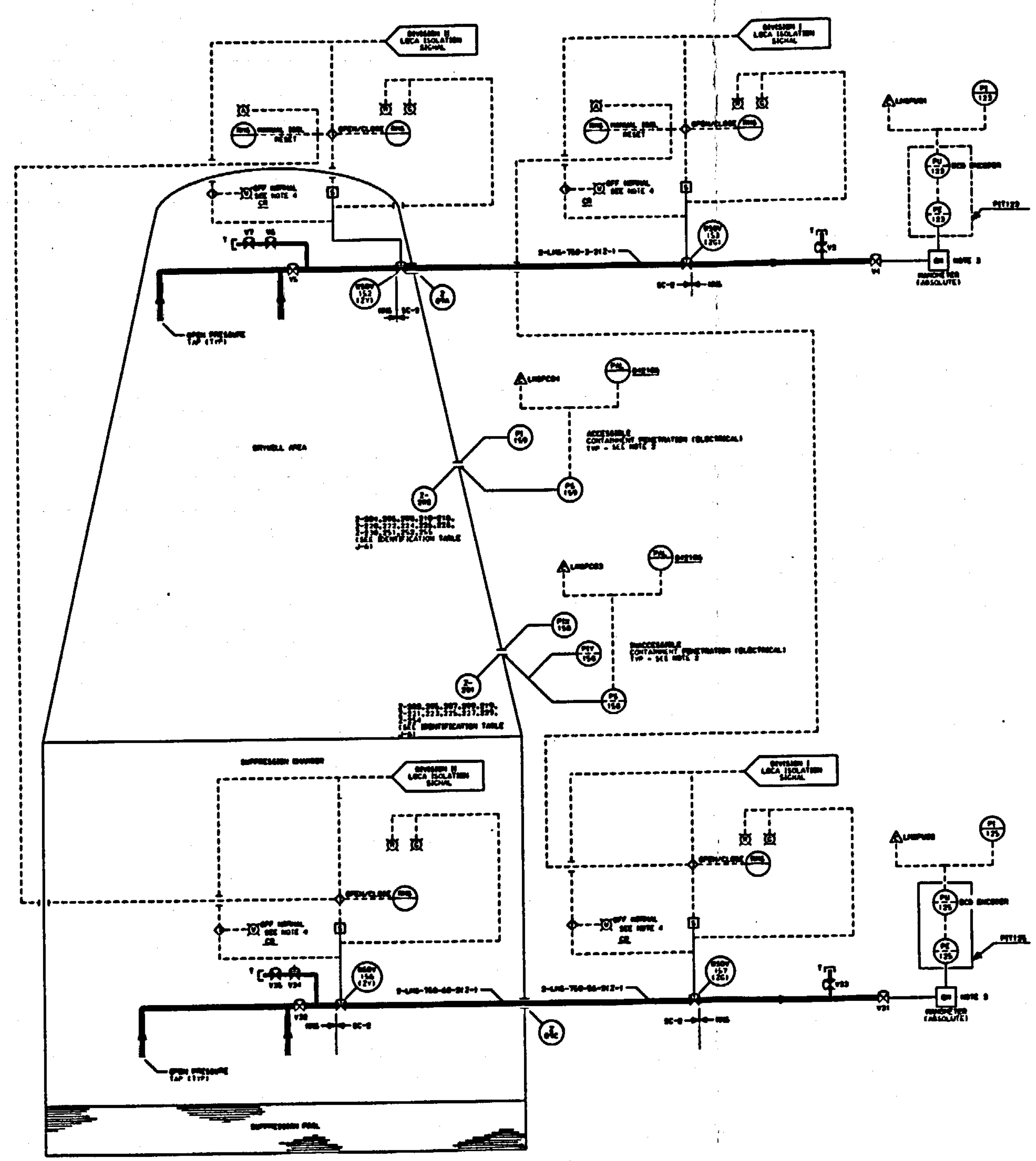
SETPOINTS SHOWN ON LOGIC DIAGRAMS ARE FOR LOGIC CLARIFICATION ONLY AND MAY BE ONLY APPROXIMATIONS OF THE ACTUAL PROCESS SETPOINT. REFER TO SETPOINT DATA SHEETS FOR ACTUAL PROCESS SETPOINTS.

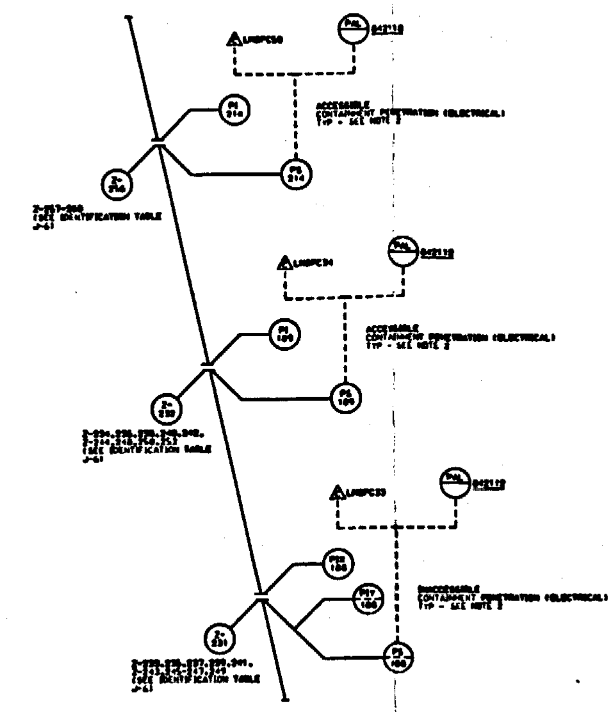
SOURCE: LSK- 27-13A

FIGURE 6.2-72K

COMBUSTIBLE GAS CONTROL SYSTEM LOGIC DIAGRAM SHEET 1 OF 5

NIAGARA MOHAWK POWER CORP.
NINE MILE POINT-UNIT 2
UPDATED SAFETY ANALYSIS REPORT





CONTAINMENT PENETRATION IDENTIFICATION TABLE									
CONT. PEN NO.	PS	PI	PDI	PDT	CONT. PEN NO.	PS	PI	PDI	PDT
2-201	158	—	158	158	2-231	188	—	188	188
2-202	159	159	—	—	2-232	189	189	—	—
2-203	160	—	160	160	2-233	190	—	190	190
2-204	161	161	—	—	2-234	191	191	—	—
2-205	162	—	162	162	2-235	192	—	192	192
2-206	163	163	—	—	2-236	193	193	—	—
2-207	164	—	164	164	2-237	194	—	194	194
2-208	165	165	—	—	2-238	195	195	—	—
2-209	166	—	166	166	2-239	196	—	196	196
2-210	167	167	—	—	2-240	197	197	—	—
2-211	168	168	—	—	2-241	198	—	198	198
2-212	169	169	—	—	2-242	199	199	—	—
2-213	170	170	—	—	2-243	201	—	201	201
2-214	171	171	—	—	2-244	202	202	—	—
2-215	172	172	—	—	2-245	203	—	203	203
2-216	173	173	—	—	2-246	204	—	204	204
2-217	174	174	—	—	2-247	205	—	205	205
2-218	175	175	—	—	2-248	206	206	—	—
2-219	176	—	176	176	2-249	207	—	207	207
2-220	177	177	—	—	2-250	208	208	—	—
2-221	178	—	178	178	2-251	209	209	—	—
2-222	179	179	—	—	2-252	210	210	—	—
2-223	180	—	180	180	2-253	211	211	—	—
2-224	181	181	—	—	2-254	212	—	212	212
2-225	182	—	182	182	2-255	213	213	—	—
2-226	183	183	—	—	2-256	214	214	—	—
2-227	184	—	184	184	2-257	215	215	—	—
2-228	185	185	—	—	2-258	216	216	—	—
2-229	186	—	186	186	2-259	217	217	—	—
2-230	187	187	—	—	2-260	218	218	—	—

NOTES:

1. ALL INSTRUMENT & EQUIPMENT NUMBERS TO BE PREFIXED WITH "2LMS-" EXCEPT WHERE A DIFFERENT PREFIX IS SHOWN. AN ASTERISK (*) WILL REPLACE THE DASH (-) IN THE PREFIX FOR INSTRUMENTS OR EQUIPMENT WHICH IS PART OF NUCLEAR SAFETY FEATURES SYSTEM.
2. SEE ACCOMPANYING TABLE FOR LISTING OF CONTAINMENT PENETRATIONS (ELECTRICAL) AND CORRESPONDING PI & PS NO'S.
3. TO PROTECT THESE DEVICES FROM DAMAGE, THE QUARTZ MANOMETERS WILL BE ISOLATED, DISCONNECTED AND STORED WHEN NOT IN USE. PIT 134 (AN ABSOLUTE MANOMETER) IS A PURCHASED BUT NOT INSTALLED SPARE. TEMPORARY QUARTZ DIGITAL-TYPE ABSOLUTE PRESSURE GAUGES MAY BE USED.
4. OFF-NORMAL STATUS DISPLAY SYSTEM IS ABANDONED IN PLACE.

SOURCE: PID-81A-9
TITLE: CONTAINMENT LEAKAGE MONITORING SYSTEM

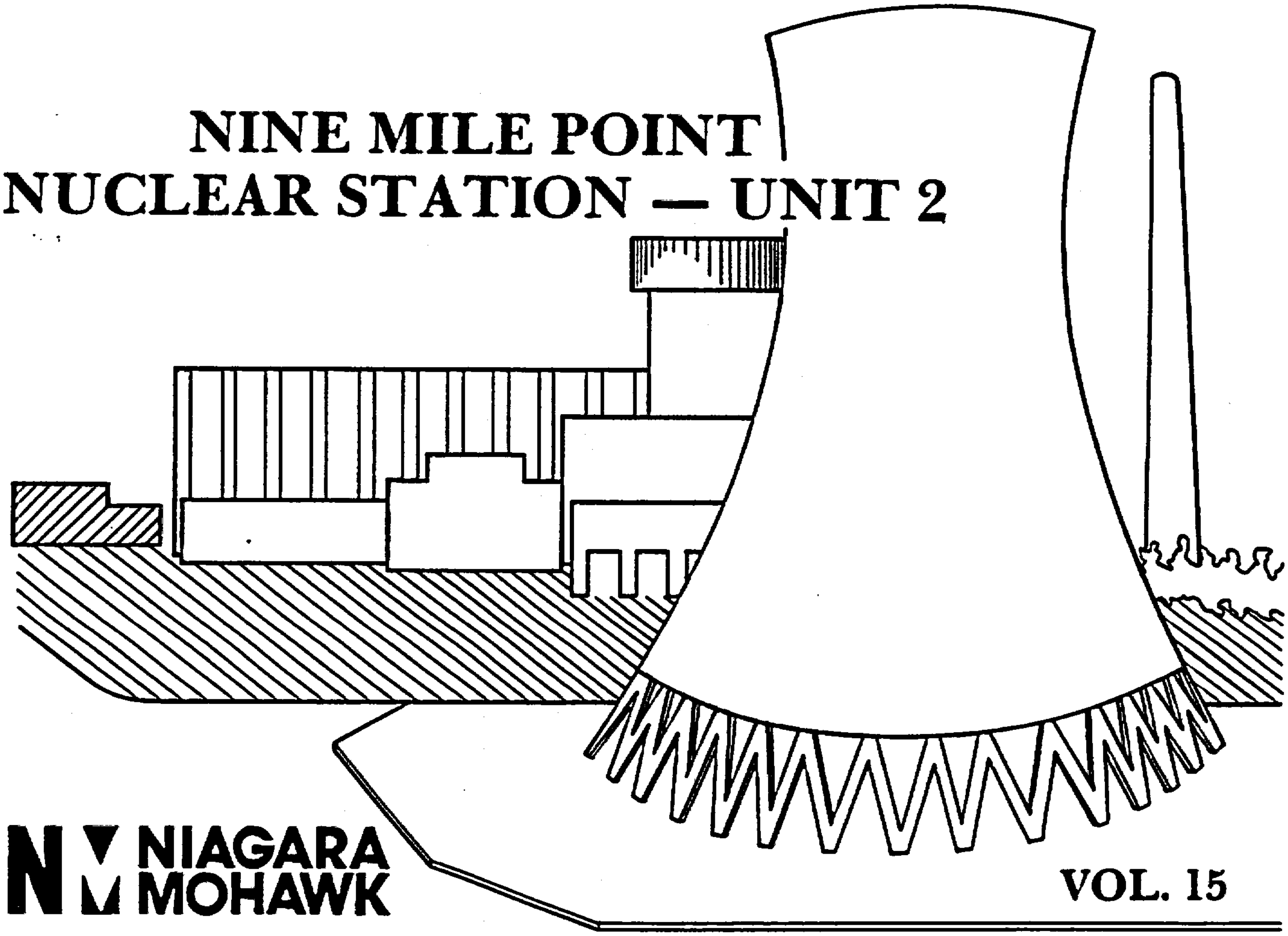
FIGURE 6.2-73a

CONTAINMENT LEAKAGE MONITORING SYSTEM

NIAGARA MOHAWK POWER CORPORATION
NINE MILE POINT-UNIT 2
UPDATED SAFETY ANALYSIS REPORT

UPDATED SAFETY ANALYSIS REPORT

NINE MILE POINT NUCLEAR STATION — UNIT 2



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supply bus and the two remaining LPCIs are powered from a third and separate ac supply bus (Division II). The HPCS has its own diesel generator as its alternate power supply. The LPCS and one LPCI loop switch to the Division I diesel generator supply and the other two LPCI loops switch to the Division II diesel generator power supply. Section 8.3 contains a more detailed description of the onsite emergency ac power system.

RG 1.1 prohibits design reliance on pressure and/or temperature transients expected during a LOCA for assuring adequate NPSH. The requirements of this regulatory guide are met for the Unit 2 HPCS, LPCS, and LPCI pumps. The ECCS design conservatively assumes 0 psig containment pressure and maximum expected temperatures of the pumped fluids. Thus no reliance is placed on pressure and/or temperature transients to assure adequate NPSH. Requirements for NPSH for each pump are given on pump characteristic curves (Figures 6.3-3b [HPCS], 6.3-4b [LPCS], and 6.3-5b [LPCI]).

All ECCS pressure relief valve discharge lines are designed to accommodate the effects of water hammer due to relief valve actuation. For a discussion of the analyses used to verify the design adequacy of piping systems subjected to occasional dynamic loads, including water hammer, see Section 3.9A.1.5.2.

The limiting condition for NPSH available occurs for all of the ECCS pumps when suction is taken from the suppression pool. In addition to the requirements of RG 1.1, the following design features/criteria were applied to calculations of NPSH available for ECCS suction piping from the suppression pool:

1. Suppression pool level is assumed to be at its minimum drawdown level of 197 ft and 8 in.

2. Suppression pool suction strainers are assumed clogged with a plant-specific debris mix meeting the requirements of RG 1.82 Revision 2; the pressure drop across the CSH and CSL strainers is 1.59 ft and 1.87 ft, respectively, and the drop across the RHR strainer is 1.91 ft.

3. Pumps are assumed to be operating at maximum runout flow with the suppression pool temperature at 212°F.

4. Listed below is the NPSH required to be available at a point 2 ft above the pump mounting flange:

HPCS:	5.3 ft @ 7,175 gpm
LPCS:	7.5 ft @ 7,800 gpm
RHR:	11.5 ft @ 8,200 gpm

5. Liquid continuity is ensured throughout the entire length of the suction piping.

The following discussion with supporting calculations demonstrates that the available NPSH at all points in ECCS pump suction is adequate to preclude local flashing and pump cavitation under worst postulated conditions. NPSH available is NPSH minimum minus NPSH required:

$$NPSH_{avail} = NPSH_{min} - NPSH_{req}$$

HPCS

The HPCS pump can take suction from the CST or the suppression pool. However, the combination of minimum static head, maximum fluid vapor pressure, and frictional losses in piping and fittings make suction from the suppression pool the limiting condition of NPSH available.

$$NPSH_{min} = P_B + L_H - V_p - h_f - h_s$$

Where:

P_B = Barometric pressure of containment, absolute (ft)

L_H = Net static suction head from minimum drawdown suppression pool level at el 197 ft 8 in to el 177 ft 4 in (a point 2 ft above top of pump mounting flange)

V_p = Absolute vapor pressure of liquid at maximum (hypothetical) suppression pool temperature of 212°F

h_f = Friction loss in suction pipe at maximum runout flow, including valve and fittings. An additional 10 percent has been added for corrosion allowance.

h_s = Strainer loss with a plant-specific debris mix.

Containment barometric pressure coincident with suppression pool drawdown is 0 psig.

Then:

P_B = 14.7 psia

Converting to feet at maximum specific volume

P_B = (14.7 lbs/in^2) (144 in^2/ft^2) (0.016719 ft^3/lb) = 35.39 ft

L_H = 197.67 - 177.33 = 20.34 ft

V_p = (14.7 lbs/in^2) (144 in^2/ft^2) (0.016719 ft^3/lb) = 35.39 ft

h_f = 4.86 ft

h_s = 1.59 ft

Evaluating all factors yields

$NPSH_{min}$ = 35.39 + 20.34 - 35.39 - 4.86 - 1.59 = 13.89 ft

$NPSH_{ref}$ = 5.3 ft

$NPSH_{avail}$ = 8.59 ft

LPCS

The LPCS pump takes suction from either the suppression pool or the RHR system. However, suction from the RHR system is used only during shutdown for test purposes and does not constitute the limiting condition for NPSH available. The combination of minimum static head, maximum fluid vapor pressure, and frictional losses in piping and fittings make suction from the suppression pool the limiting condition of NPSH available.

Evaluating all factors as defined above.

P_B = (14.7 lbs/in^2) (144 in^2/ft^2) (0.016719 ft^3/lb) = 35.39 ft

L_H = 197.67 - 177.33 = 20.34 ft

V_P = (14.7 lbs/in^2) (144 in^2/ft^2) (0.016719 ft^3/lb) = 35.39 ft

h_f = 7.65 ft

h_s = 1.87 ft

$NPSH_{min}$ = 35.39 + 20.34 - 35.39 - 7.65 - 1.87 = 10.82 ft

$NPSH_{ref}$ = 7.5 ft

$NPSH_{avail}$ = 3.32 ft

LPCI

This ECCS mode of RHR system operation constitutes the limiting condition of NPSH available for the RHR pumps. With all other conditions equal, the NPSH available for RHR pump B is the least of the three due to the greatest frictional losses in suction piping and fittings. The ECCS mode of operation is the worst case based upon the fluid vapor pressure. Accordingly, the following NPSH calculation is for this pump only while performing its ECCS function.

Evaluation all factors as defined above:

P_B = 14.7 psia (144 in^2/ft^2)(0.016719) = 35.39 ft

L_H = 197.67 - 177.29 = 20.38 ft

V_P = (14.7 psia) (144 in^2/ft^2)(0.016719) = 35.39 ft

h_f = 3.51 ft

h_s = 1.91 ft

$NPSH_{min}$ = 35.39 + 20.38 - 35.39 - 3.51 - 1.91 = 14.96 ft

$NPSH_{req}$ = 11.5 ft

$NPSH_{avail}$ = 3.46 ft

The submergence depth of ECCS suction lines in the suppression pool is adequate to prevent vortex formation from adversely affecting ECCS pump performance. Submergence depth is based on calculations which include the requirements of NUREG-0869 (draft issued for comments dated April 1983). For the LPCI pumps, the elevation at the top of the suction strainer inlet (189 ft 8 in) is 8 ft below the minimum drawdown water level (el 197 ft 8 in). For HPCS and LPCS pumps, these submergence depths are 8 and 9.5 ft, respectively.

6.3.2.2.1 High-Pressure Core Spray System

The system is designed to pump water into the reactor vessel over a wide range of pressures. For small breaks that do not result in rapid reactor depressurization, the system maintains reactor water level and reduced vessel pressure. For large breaks the HPCS system cools the core by a spray.

The HPCS system consists of a single motor-driven centrifugal pump located outside the primary containment, an independent spray sparger in the reactor vessel located above the core (separate from the LPCS sparger), and associated system piping, valves, controls, and instrumentation. The system is designed to operate from offsite power or from the Division III diesel generator supply if offsite power is not available. The P&ID (Figure 6.3-6 for the HPCS) shows the system components and their arrangement. The HPCS system process diagram (Figure 6.3-1) shows the design operating modes of the system. The flow values were used for original pipe and component sizing and do not represent design basis flow requirements. A simplified system flow diagram showing system injection into the reactor vessel is included on Figure 6.3-1.

The principal active HPCS equipment is located outside the primary containment. Suction piping is provided from the CST and the suppression pool. Such an arrangement provides the capability to use reactor grade water from the CST when the HPCS system functions to back up the RCIC system. The RCIC system is discussed in Section 5.4.6. In the event that the condensate storage water supply becomes exhausted or is not available, automatic switchover to the suppression pool water source assures a closed cooling water supply for continuous operation of the HPCS system. HPCS pump suction is also automatically transferred to the suppression pool if the suppression pool water level exceeds a prescribed value. One of two CSTs reserves water for use by the HPCS with the other CST reserved for RCIC use.

After the HPCS injection piping enters the vessel, it divides and enters the shroud at two points near the top of the shroud. A semicircular sparger is attached to each outlet. Nozzles are spaced around the spargers to spray the water radially over the core and into the fuel assemblies.

The HPCS discharge line to the reactor is provided with two isolation valves. One of these valves is an air testable check valve located inside the drywell as close as practical to the reactor vessel. HPCS injection flow causes this valve to open during LOCA conditions (i.e., no power is required for valve actuation during LOCA). If the HPCS line should break outside the containment, the check valve in the line inside the drywell prevents the loss of reactor coolant outside the containment. The other isolation valve (which is also referred to as the HPCS injection valve) is a motor-operated gate valve located outside the primary containment as close as practical to HPCS discharge line penetration into the containment. This valve is capable of opening against the maximum differential pressure across the valve for any system operating mode including HPCS pump shutoff head. The valve opens following receipt of a signal to open in order to support the LOCA analysis which assumes that full HPCS flow is available as discussed in the system performance which follows. This valve is normally closed to back up the inside testable check valve for containment integrity purposes. A drain line is provided between the two valves. The test connection line is normally closed with two valves to assure containment integrity.

Controls for the motor-operated components and associated diesel generator are provided in the main control room. The controls and instrumentation of the HPCS system are discussed in Chapter 7.

If a LOCA should occur, a low water level signal or high drywell pressure signal initiates the HPCS and its support equipment. The system can also be placed in operation manually.

The HPCS system is capable of delivering rated flow into the reactor vessel within 17 sec after the emergency diesel generator is ready to accept electrical loads. The LOCA analysis assumes that full HPCS flow is available 52 sec after the receipt of an automatic initiation signal (includes emergency diesel generator startup, loading, HPCS startup and injection valve opening).

The HPCS automatically stops when a high water level in the reactor vessel signals the injection valve to close, and it automatically starts again when a low water level is signaled. The HPCS system also serves as a backup to the RCIC system in the event the reactor becomes isolated from the main condenser during operation and feedwater flow is lost.

The HPCS pump head flow characteristics used in LOCA analyses are shown on Figure 6.3-3A. When the system is started, the initial flow rate is established by primary system pressure. As vessel pressure decreases, flow increases. When vessel pressure reaches 100-psi differential pressure between the reactor vessel and the suction source, the system reaches rated core spray flow. The HPCS motor size is based on peak horsepower requirements.

The floor elevation of the HPCS pump (el 175 ft) is sufficiently below the water level of both the CST and the suppression pool to provide a flooded pump suction. Pump NPSH requirements are met even with the containment at atmospheric pressure, and the suction strainer clogged with a plant-specific debris mix meeting the requirements of RG 1.82 Revision 2. The available NPSH has been

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calculated in accordance with RG 1.1. In the event of a loss of the CST suction source, the NPSH available to the pump up to the time of switchover to the suppression pool source is approximately 50 ft greater than the required NPSH.

The minimum water level available from the CST supply prior to switchover is at el 245 ft 0 in. The HPCS pump suction nozzle is located at el 177 ft 11 in.

A MOV is provided in the suction line from the suppression pool. The valve is located as close to the suppression pool penetration as practical. This valve is used to isolate the suppression pool water source when HPCS system suction is from the condensate storage system and to isolate the system from the suppression pool in the event a leak develops in the HPCS system. The HPCS pump characteristics of head, flow, horsepower, and required NPSH are shown on Figure 6.3-3B.

The design pressure and temperature of the system components are established based on the ASME Section III Boiler and Pressure Vessel Code. The design pressures and temperatures at various points in the system can be obtained from the information on the HPCS process diagram (Figure 6.3-1).

A check valve and flow element are provided in the HPCS discharge line from the pump to the injection valve. The check valve is located below the minimum suppression pool water level and is provided so the piping downstream of the valve can be maintained full of water by the discharge line fill system (Section 6.3.2.2.5). The flow element is provided to measure system flow rate during LOCA and test conditions, and for automatic control of the minimum low flow bypass gate valve. The measured flow is indicated in the main control room.

A low flow bypass line with a motor-operated gate valve connects to the HPCS discharge line upstream of the check valve on the pump discharge line. The line bypasses water to the suppression pool to prevent pump damage due to overheating when other discharge line valves are closed. The valve automatically closes when flow in the main discharge line is sufficient to provide required pump cooling.

To assure continuous core cooling, signals to isolate the containment do not operate any HPCS valves.

The HPCS system incorporates relief valves to protect the components and piping from overpressure conditions. One relief valve, set to relieve at 1,575 psig, is located on the discharge side of the pump downstream of the check valve to relieve thermally-expanded fluid. A second relief valve is located on the suction side of the pump and is set at >100 psig with a capacity of >10 gpm at 10-percent accumulation. This valve relieves any high pressure buildup due to leakage past the injection valves from the reactor.

The HPCS components and piping are positioned to avoid damage from the physical effects of DBAs, such as pipe whip, missiles, and high temperature, pressure, and humidity.

The HPCS equipment and support structures are designed in accordance with Category I criteria (Chapter 3). The system is assumed to be filled with water for seismic analysis.

Provisions are included in the HPCS system which permit the HPCS system to be tested. These provisions are:

1. All active HPCS components are testable during normal plant operation.

2. A full flow test line is provided to route water from and to the CST without entering the reactor pressure vessel (RPV). The suction line from the CST also provides reactor grade water to fully test the HPCS including injection into the RPV during shutdown.

3. A full flow test line is provided to route water from and to the suppression pool without entering the RPV.

4. Instrumentation is provided to indicate system performance during normal test operations.

5. All MOVs are capable of remote manual operation for test purposes.

6. System relief valves are removable for benchtesting during plant shutdown.

6.3.2.2.2 Automatic Depressurization System

If the RCIC and HPCS cannot maintain the reactor water level, the ADS, which is independent of any other ECCS, reduces the reactor pressure so that flow from LPCI and LPCS enters the reactor vessel in time to cool the core and limit fuel cladding temperature.

The ADS employs seven nuclear steam system pressure relief valves to relieve high-pressure steam to the suppression pool. Evaluation of one ADS valve out of service is included in this section. Evaluations of a second ADS valve out of service is presented in Appendix 15C. The design, location, description, operational characteristics, and evaluation of the pressure relief valves are discussed in Section 5.2.2. The instrumentation and controls for the ADS are discussed in Section 7.3.1.

6.3.2.2.3 Low-Pressure Core Spray System

The LPCS is designed to provide cooling to the reactor core only when the reactor vessel pressure is low, as is the case for large

LOCA break sizes. However, when the LPCS operates in conjunction with the ADS, then the effective core cooling capability of the LPCS is extended to all break sizes because the ADS rapidly reduces the reactor vessel pressure to the LPCS operating range. The system head flow characteristic assumed for LOCA analyses is shown on Figure 6.3-4a.

The LPCS consists of: a centrifugal pump that is powered by normal auxiliary power or the Division I emergency diesel generator; a spray sparger in the reactor vessel above the core (separate from the HPCS sparger); piping and valves to convey water from the suppression pool to the sparger; and associated controls and instrumentation. Figure 6.3-7, the LPCS system P&ID, presents the system components and their arrangement. The LPCS system process diagram (Figure 6.3-2) shows the design operating modes of the system. The flow values were used for original pipe and component sizing and do not represent design basis flow requirements. Figure 6.3-2 includes a simplified system flow diagram showing injection into the reactor vessel by the LPCS system. The LPCS pump characteristics of head, flow, horsepower, and required NPSH are shown on Figure 6.3-4b.

When low water level in the reactor vessel or high pressure in the drywell is sensed, and with reactor vessel pressure low enough, the LPCS system automatically starts and sprays water into the top of the fuel assemblies to cool the core. The LPCS injection piping enters the vessel, divides and enters the core shroud at two points near the top of the shroud. A semicircular sparger is attached to each outlet. Nozzles are spaced around the sparger to spray the water radially over the core and into the fuel assemblies.

The LPCS pump and all MOVs can be operated individually by manual switches located in the main control room. Operating indication is provided in the main control room by a flowmeter and valve indicator lights. To assure continuity of core cooling, signals to isolate the containment do not operate any LPCS system valves.

The LPCS discharge line to the reactor has two isolation valves. One of these valves is an air testable check valve located inside the drywell as close as practical to the reactor vessel. LPCS injection flow causes this valve to open during LOCA conditions (i.e., no power is required for valve actuation during LOCA). If the LPCS line should break outside the containment, the check valve in the line inside the drywell prevents loss of reactor water outside the containment.

The other isolation valve (which is also referred to as the LPCS injection valve) is a motor-operated gate valve located outside the primary containment as close as practical to LPCS discharge line penetration into the containment. Signals for opening are based on the differential pressure across the valve. This valve is capable of opening against the maximum expected differential pressure across the valve for any system operating mode. The valve is capable of opening against a differential pressure equal to normal reactor pressure minus the minimum LPCS system shutoff pressure. The valve installation is modified to prevent bonnet pressure locking. The valve is capable of opening following a maximum recirculation line break accident. This valve is normally closed to back up the inside testable check valve for containment integrity purposes. A drain line is provided between the two valves. The test connection line is normally closed with two valves to assure containment integrity.

The LPCS system components and piping are arranged to avoid unacceptable damage from the physical effects of DBAs, such as pipe whip, missiles, and high temperature, pressure, and humidity. All principal active LPCS equipment is located outside the primary containment except for the injection line testable check valve.

A check valve, flow element, and restricting orifice are provided in the LPCS discharge line from the pump to the injection valve. The check valve is located below the minimum suppression pool water level and is provided so the piping downstream of the valve can be maintained full of water by the discharge line fill system (Section 6.3.2.2.5). The flow element is provided to measure system flow rate during LOCA and test conditions and for automatic control of the minimum low flow bypass gate valve. The measured flow is indicated in the main control room. The restricting orifice is sized during the preoperation test of the system to limit system flow to acceptable values as described on the LPCS system process diagram.

A low flow bypass line with a motor-operated gate valve connects to the LPCS discharge line upstream of the check valve on the pump discharge line. The line bypasses water to the suppression pool to prevent pump damage due to overheating when other discharge line valves are closed or reactor pressure is greater than the LPCS system discharge pressure following system initiation. The valve automatically closes when flow in the main discharge line is sufficient to provide required pump cooling.

LPCS flow passes through a motor-operated pump suction valve that is normally open. This valve can be closed by a remote manual switch (located in the main control room) to isolate the LPCS system from the suppression pool should a leak develop in the system. This valve is located in the LPCS pump suction line as close to the suppression pool as practical. Because the LPCS conveys water from the suppression pool, a closed loop is established for reactor water makeup.

The design pressure and temperature of the system components are established based on the ASME Section III Boiler and Pressure Vessel Code. The design pressures and temperatures at various points in the system can be obtained from the miscellaneous information blocks on the LPCS process diagram (Figure 6.3-2).

The high-pressure portion of the LPCS pump discharge line, which extends from the injection valve (F005) up to the RPV, is designed to withstand reactor pressure. The low-pressure portion of the discharge line is designed to withstand the maximum discharge pressure of the pump at shutoff conditions. Following a signal for LPCS initiation, valve F005 will open once the ΔP across it is less than or equal to 88 psi. However, injection will not begin until the pressure on the downstream side of F006 is below the pump discharge head at bypass flow (approximately 500 psig). The low-pressure portion of the LPCS is further protected from overpressure by relief valve F018 (see Figure 6.3-2).

The LPCS pump is located in the reactor building sufficiently below the water level in the suppression pool to assure a flooded pump suction and to meet pump NPSH requirements with the containment at atmospheric pressure and the suction strainers clogged with a plant-specific debris mix meeting the requirements of RG 1.82 Revision 2. A pressure gauge is provided to indicate the suction.

The LPCS system incorporates relief valves to prevent the components and piping from overpressure conditions. One relief valve, located on the pump discharge, is set to protect 550-psig piping with capacity of 100 gpm at 10-percent accumulation. The second relief valve is located on the suction side of the pump and is set to protect 60-psig piping at a capacity of >10 gpm at 10-percent accumulation.

The LPCS system piping and support structures are designed in accordance with Category I criteria (Chapter 3). The system is assumed to be filled with water for seismic analysis.

The following provisions that permit the LPCS system to be tested are included in the LPCS system:

1. All active LPCS components are testable during normal plant operation.

2. A full flow test line is provided to route water from and to the suppression pool without entering the RPV.

3. A suction test line supplying reactor grade water is provided to test pump discharge into the RPV during plant shutdown.

4. Instrumentation is provided to indicate system performance during normal and test operations.

5. All MOVs and air-operated check valves are capable of operation for test purposes.

6. Relief valves are removable for benchtesting during plant shutdown.

6.3.2.2.4 Low-Pressure Coolant Injection

The LPCI, like the LPCS system, is designed to provide cooling to the reactor core only when the reactor vessel pressure is low, as is the case for large LOCA break sizes. However, when the LPCI operates in conjunction with the ADS, the effective core cooling capability of the LPCI is extended to all break sizes because the ADS rapidly reduces the reactor vessel pressure to the LPCI operating range.

The head flow characteristics assumed in the LOCA analyses for the LPCI pumps are shown on Figure 6.3-5a.

Figure 5.4-14 shows a process diagram and process data for the RHR system, including the LPCI. The flow values were used for original pipe and component sizing and do not represent design basis flow requirements. The LPCI pumphead flow characteristics of head, flow, horsepower, and required NPSH are shown on Figure 6.3-5b.

The LPCI subsystem is an operating mode of the RHR system. The LPCI system is automatically actuated by low water level in the reactor or high pressure in the drywell, and uses the three RHR motor-driven pumps to draw suction from the suppression pool and inject cooling water into the reactor core, and accomplish cooling of the core by flooding. Each loop has its own suction and discharge piping and separate vessel nozzle which connects with the core shroud to deliver flooding water on top of the core. In this mode, the RHR system is a high-volume, core-flooding system.

The pump, piping, controls, and instrumentation of the LPCI loops are separated and protected so that any single physical event, or missiles generated by rupture of any pipe in any system within the drywell, cannot make all loops inoperable.

To assure continuity of core cooling, signals to isolate the primary containment do not operate any RHR system valves that interfere with the LPCI mode of operation.

Each LPCI discharge line to the reactor has two isolation valves. The valve inside the drywell is a testable check valve, and the valve outside the drywell is a motor-operated gate valve. No power is required to operate the check valve inside the drywell; rather, it opens as a result of LPCI injection flow. If a break were to occur outside of the check valve, it would close to isolate the reactor from the line break.

The MOV outside of the drywell is called the LPCI injection valve and is located as close as practical to the drywell penetration. It is capable of opening against the maximum differential pressure expected for the LPCI mode; i.e., normal reactor pressure minus the upstream pressure with the RHR pump running at minimum flow. The valve is equipped with a pressure differential switch that permits valve opening below a predetermined pressure setting, thus protecting the components and piping upstream of the valves from excessive pressure.

The RHR-LPCI mode is assumed to deliver full flow into the vessel within 65 sec following an accident signal, including time to start and load the emergency diesel generators, start the LPCI pumps, and open the LPCI injection valve.

The process diagram (Figure 5.4-14) and the P&ID (Figure 5.4-13) indicate a great many flow paths are available other than the LPCI injection line. However, the low water level or high drywell pressure signals which automatically initiate the LPCI mode are also used to isolate all other modes of operation and revert other system valves to the LPCI lineup except when the system is operating in the shutdown cooling mode. Inlet and outlet valves from the heat exchangers receive no automatic signals as the system is designed to provide rated flow to the vessel whether they are open or not.

A check valve in the pump discharge line is used together with a discharge line fill system (Section 6.3.2.2.5) to prevent water hammer resulting from pump start against a potential shutoff condition. A flow element in the pump discharge line is used to provide a measure of system flow and to originate automatic signals for control of the pump minimum flow valve. The minimum flow valve permits a small flow to the suppression pool in the event that either no discharge valve is open, or in the case of a LOCA, vessel pressure is higher than the pump shutoff head.

Using the suppression pool as the source of water for LPCI establishes a closed loop for recirculation for reactor water makeup.

The design pressures and temperatures, at various points in the system, during each of the several modes of operation of the RHR subsystems, can be obtained from the LPCI process diagram (Figure 5.4-14).

LPCI pumps and equipment are described in detail in Section 5.4.7, which also describes the other functions served by the same pumps if not needed for the LPCI function. The heat exchangers are discussed in Section 6.2.2. The portions of the RHR required for accident protection, including support structures, are designed in accordance with Category I criteria (Chapter 3). The available NPSH for the LPCI pumps was calculated in accordance with RG 1.1. The LPCI pump characteristics are shown on Figure 6.3-5b.

The LPCI system incorporates a relief valve on each of the pump discharge lines that protects the components and piping from inadvertent overpressure conditions. These valves are set to relieve pressure at 500 psig. Section 5.2.2 discusses relief valve settings and capacities.

The following provisions are included in the LPCI system to permit testing of the system:

1. All active LPCI components are designed to be testable during normal plant operation.

2. A discharge test line is provided for the three pumps to route suppression pool water back to the suppression pool without entering the RPV.

3. A suction test line supplying reactor grade water is provided to the test loop to discharge into the RPV during plant shutdown.

4. Instrumentation is provided to indicate system performance during normal and test operations.

5. All MOVs and AOVs are capable of manual operation for test purposes.

6. All relief valves are removable for benchtesting during plant shutdown.

6.3.2.2.5 ECCS Discharge Line Fill System

A requirement of the ECCS is that cooling water flow to the reactor vessel be initiated rapidly when the system is called on to perform its function. This quick-start system characteristic is provided by quick-opening valves, quick-start pumps, and the emergency ac power sources. The lag between the signal to start the pump and the initiation of flow into the RPV can be minimized by keeping the ECCS pump discharge lines full. Additionally, if these lines were empty when the systems were called for, large momentum forces associated with accelerating fluid into a dry pipe could cause physical damage to the piping. Therefore, the ECCS discharge line fill system is designed to maintain the pump discharge lines in a filled condition.

Since the ECCS discharge lines are elevated above the suppression pool, check or stop-check valves are provided near the pumps to prevent backflow from emptying the lines into the suppression pool. Past experience has shown that these valves could leak slightly, producing a small backflow that eventually empties the discharge piping. To ensure that this leakage from the discharge lines is replaced and the lines are always kept filled, a water-leg pump is provided for each of the three ECCS divisions. The power supply to these pumps is classified as essential when the main ECCS pumps are deactivated. For the HPCS system when the water-leg pump is inoperative, the system discharge piping can be maintained full by ensuring alignment of the system to the CST with a sufficient static head in the CST to keep the HPCS system full. Indication is provided in the main control room as to whether these pumps are operating, and alarms indicate low discharge line pressure.

6.3.2.3 Applicable Codes and Classifications

The applicable codes and classification of the ECCS are specified in Section 3.2. All piping systems and components (pumps, valves, etc.) for the ECCS comply with applicable codes, addenda, code cases, and errata in effect at the time the equipment is procured. The piping and components of each system of the ECCS within the containment and out to and including the pressure-retaining injection valve are Safety Class 1. The remaining piping and components are Safety Class 2, 3, or noncode as indicated in Section 3.2, and as indicated on the individual system P&IDs. The equipment and piping of the ECCS are designed to the requirements of Category I. This seismic designation applies to all structures and equipment essential to the core cooling function. IEEE codes applicable to the controls and power supplies are specified in Section 7.1.

6.3.2.4 Materials Specifications and Compatibility

Materials specifications and compatibility for the ECCS are presented in Sections 6.1 and 3.2. Nonmetallic materials such as lubricants, seals, packings, paints and primers, and insulation, as well as metallic materials, are selected as a result of an engineering review and evaluation for compatibility with other materials in the system and the surroundings with concern for chemical, radiolytic, mechanical, and nuclear effects. Materials used are reviewed and evaluated with regard to radiolytic and pyrolytic decomposition and attendant effects on safe operation of the ECCS.

6.3.2.5 System Reliability

A system level, qualitative-type plant failure modes and effects analysis (FMEA) of the ECCS is provided in Appendix 15A, Plant Nuclear Safety Operational Analysis (NSOA).

Originally, the FMEA of the balance-of-plant (BOP) instrumentation and control components of the ECCS (HPCS, LPCS, and LPCI) was contained in the Unit 2 FMEA document, which is historical. FMEAs for plant systems are now performed and controlled by the design process.

A single-failure analysis shows that no single failure prevents the starting of the ECCS when required, or the delivery of coolant to the reactor vessel. No individual system of the ECCS is single-failure proof with the exception of the ADS; hence it is possible that single failures may disable individual subsystems of the ECCS. The consequences of the most severe single failures are shown in Table 6.3-3. The most severe effects of single failures with respect to loss of equipment occur if the LOCA occurs in combination with an ECCS pipe break coincident with a LOOP.

For protection against and mitigation of passive ECCS failures, a Class 1E-level instrument is mounted just above floor level in each ECCS pump room to detect passive failures during long-term

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6.3.4.2 Reliability Tests and Inspections

The average reliability of a standby (nonoperating) safety system is a function of the duration of the interval between periodic functional tests. The factors considered in determining the periodic test interval of the ECCS are: the desired system availability (average reliability), the number of redundant functional system success paths, the failure rates of the individual components in the system, and the schedule of periodic tests (simultaneous versus uniformly staggered versus randomly staggered). For the ECCS the above factors were used to determine test intervals[4].

All active components of the HPCS system, ADS, LPCS, and LPCI systems are designed so that they may be tested during normal plant operation. Full flow test capability is provided by a test line back to the suction source. The full flow test is used to verify the capacity of each ECCS pump loop while the plant remains undisturbed in the power generation mode. In addition, each individual valve may be tested during normal plant operation. Input jacks are provided so that by racking out the injection valve breaker, each ECCS loop can be tested for response time.

All active components of the ADS except the SRVs and their associated solenoid valves are designed so that they may be tested during normal plant operation. The ADS SRVs and associated solenoid valves are all tested at least once each 18 months during plant startup following a refueling outage.

Testing of the initiating instrumentation and controls portion of the ECCS is discussed in Section 7.3.1. The emergency power system, which supplies electrical power to the ECCS in the event that offsite power is unavailable, is tested as described in Section 8.3.1. The frequency of testing is specified in Technical Specifications. Visual inspections of all ECCS components located outside the drywell can be made at any time during power operation. Components inside the drywell can be visually inspected only during periods of access to the drywell. When the reactor vessel is open, the spargers and other internals can be inspected.

6.3.4.2.1 HPCS Testing

The HPCS can be tested at full flow with CST water at any time during plant operation except when the reactor vessel water level is low, or when the condensate level in the CST is below the reserve level, or when the valves from the suppression pool to the pump are open. If an initiation signal occurs while the HPCS is being tested, the system returns automatically to the operating mode. The two MOVs in the test line to the condensate storage system are interlocked closed when the suction valve from the suppression pool is open.

A design flow functional test of the HPCS over the operating pressure and flow range is performed by pumping water from the CST and back through the full flow test return line to the CST.

The suction valve from the suppression pool and the discharge valve to the reactor remain closed. These two valves are tested separately to ensure their operability.

The HPCS test conditions are tabulated on the HPCS process diagram (Figure 6.3-1).

6.3.4.2.2 ADS Testing

Periodic surveillance testing requirements for the ADS are described in Technical Specifications. During plant operation the ADS can be checked as discussed in Section 7.3.1.

6.3.4.2.3 LPCS Testing

The LPCS pump and valves are tested periodically during reactor operation. With the injection valve closed and the return line open to the suppression pool, full flow pump capability is demonstrated. The injection valve and the check valve are tested in a manner similar to that used for the LPCI valves. The system test conditions during reactor shutdown are shown on the LPCS system process diagram (Figure 6.3-2).

6.3.4.2.4 LPCI Testing

Each LPCI loop can be tested during reactor operation. The test conditions are tabulated on Figure 5.4-14. During plant operation, this test does not inject cold water into the reactor because the injection line check valve is held closed by vessel pressure, which is higher than the pump pressure. The injection line portion may be tested with reactor water when the reactor is shut down and when a closed system loop is created. This prevents unnecessary thermal stresses.

To test the LPCI pump at rated flow, the test line valve to the suppression pool is opened, the pump suction valve from the suppression pool is opened (this valve is normally open), and the pumps are started using the remote/manual switches in main control room. Correct operation is determined by observing the instruments in the main control room.

If an initiation signal occurs during the test, the LPCI system automatically returns to the operating mode. The valves in the test bypass lines are closed automatically to assure that the LPCI pump discharge is correctly routed to the vessel.

6.3.5 Instrumentation Requirements

Design details including redundancy and logic of the ECCS instrumentation are discussed in Section 7.3.

All instrumentation required for automatic and manual initiation of the HPCS, LPCS, LPCI, and ADS is discussed in Section 7.3.2 and is designed to meet the requirements of IEEE-279 and other applicable regulatory requirements. The HPCS, LPCS, LPCI, and ADS can be manually initiated from the main control room.

The HPCS, LPCS, and LPCI are automatically initiated on low reactor water level or high drywell pressure. (See Table 6.3-1 for specific initiation levels for each system.) The ADS is automatically actuated by sensed variables for reactor vessel low water level plus indication that at least one LPCI or LPCS pump is operating. The HPCS, LPCS, and LPCI automatically return from system flow test modes to the emergency core cooling mode of operation following receipt of an automatic initiation signal. The LPCS and LPCI system injection into the RPV begin when reactor pressure decreases to system discharge shutoff pressure.

HPCS injection begins as soon as the HPCS pump is up to speed and the injection valve is open, since the HPCS is capable of injecting water into the RPV over a pressure range from approximately 1100 psid to 0 psid (psid = differential pressure between RPV and pump suction source). See Figure 6.3-3a.

6.3.6 References

1. General Electric Standard Application for Reactor Fuel, including United States Supplement, NEDE-24011-P-A and NEDE-24011-P-A-US (latest approved revision).

2. General Electric Company Analytical Model for Loss-of-Coolant Analysis in Accordance with 10CFR50, Appendix K, NEDE-20566-P-A, September 1986.

3. Nine Mile Point Nuclear Power Station - Unit 2 SAFER/GESTR-LOCA Loss-of-Coolant Accident Analysis, NEDC-31830P Rev. 1, November 1990.

4. Hirsch, H. M. Methods for Calculating Safe Test Intervals and Allowable Repair Times for Engineered Safeguard Systems, January 1973 (NEDO-10739).

TABLE 6.3-1

SIGNIFICANT INPUT VARIABLES USED IN THE SAFER/GESTR LOSS-OF-COOLANT ACCIDENT ANALYSIS[3]

(Cycle-specific fuel parameters are covered in Appendix A, Table A.6-2)

	Nominal Analysis	Appendix K Analysis
A. Plant Parameters		
Core thermal power	3,467 MWt	3,536 MWt
Vessel steam output	15.0×10^6 lbm/hr	15.35×10^6 lbm/hr
Corresponding percent of rated steam flow	100	102
Vessel steam dome pressure	1,055 psia	1,055 psia
Maximum area of recirculation suction line break	3.1 ft^2	3.1 ft^2
B. ECCS Parameters		
B.1 LPCI system		
Vessel pressure at which flow may commence	See Figure 6.3-5a	
Minimum rated flow at vessel pressure	See Figure 6.3-5a	
Initiating signals:		
Low water level (L1) or High drywell pressure	0.0 ft above top of active fuel 2.0 psig	
Maximum allowable time delay from initiating signal to pumps at rated speed and capable of rated flow (including diesel generator start/load time)	65 sec[4]	

TABLE 6.3-1 (Cont'd.)

	Pressure at which injection valve may open	225 psig(1)
	Maximum allowable injection valve stroke time	25 sec
B.2	LPCS system	
	Vessel pressure at which flow may commence	See Figure 6.3-4a
	Minimum rated flow at vessel pressure	See Figure 6.3-4a
	Initiating signals:	
	Low water level (L1)	0.0 ft above top of active fuel
	or	
	High drywell pressure	2.0 psig
	Minimum runout flow	6,600 gpm
	Maximum allowed delay time from initiating signal to pump at rated speed and capable of rated flow (including diesel generator start/load time)	65 sec(4)
	Pressure at which injection valve may open	305 psig(2)
	Maximum allowable injection valve stroke time	25 sec
B.3	HPCS system	
	Vessel pressure at which flow may commence	See Figure 6.3-3a

TABLE 6.3-1 (Cont'd.)

	Minimum rated flow available at vessel pressure	See Figure 6.3-3a
	Initiating signals:	
	Low water level (L2) or High drywell pressure	7.6 ft above top of active fuel 2.0 psig
	Minimum runout flow	6,250 gpm
	Maximum allowed delay time from initiating signal to pump at rated speed and capable of rated flow and injection valve wide open (including diesel generator start/load time)	52 sec
B.4	ADS system	
	Total number of valves installed	7
	Number of valves used in analysis (also see Appendix 15C)	6
	Minimum flow capacity of six valves at pressure	5.04×10^6 lbm/hr 1,080 psig
	Initiating signals:	
	Low water level (L1) and Signal that at least one LPCS or LPCI pump is running (pump discharge pressure)	0.0 ft above top of active fuel LPCS (145) psig LPCI 125 psig

TABLE 6.3-1 (Cont'd.)

Maximum delay time from all initiating signals completed to the time valves are open	120 sec		

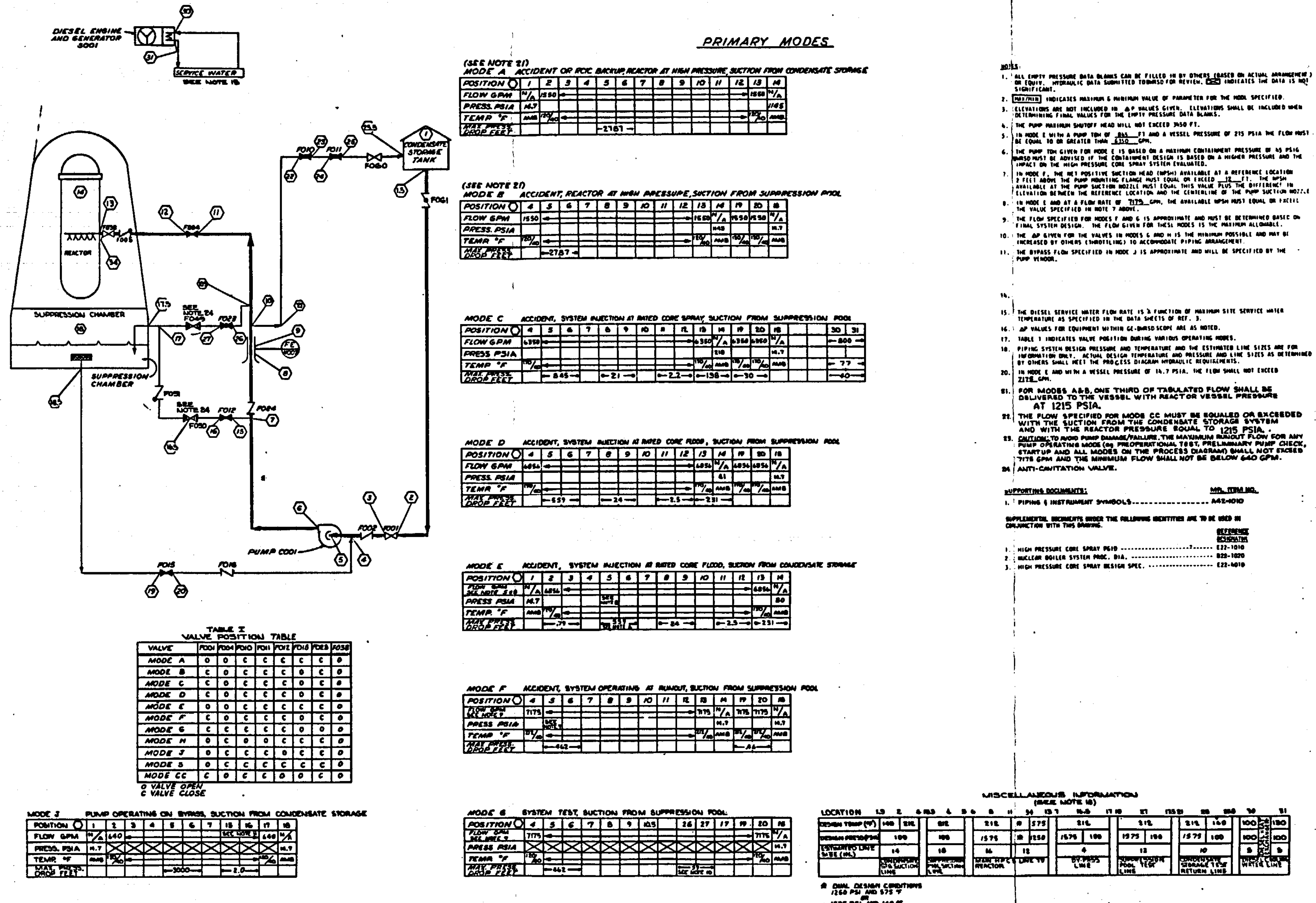
C. Fuel Parameters[3][6]

	BP8x8R/P8x8R	GE8x8EB/NB	GE11
Fuel type	BP8x8R/P8x8R	GE8x8EB/NB	GE11
Fuel bundle geometry	8x8	8x8	9x9
Lattice	C	C	C
Number of fueled rods/assembly	62	60	66 (full length) 8 (part length)
Peak LHGR (kW/ft)			
- Appendix K	13.4	14.4	14.4
- Nominal	12.8	13.8	13.8
MAPLHGR (kW/ft)	13.0	14.0	12.9
Initial MCPR			
- Nominal	1.19	1.19	1.19
- Appendix K	1.17	1.17	1.17
Axial peaking factor	1.4	1.4	1.4
Worst-case pellet exposure for ECCS evaluation (MWd/MTU)[5]	23,000	14,590	13,500

(1) Corresponds to injection valve differential pressure of 8 psid.

(2) Corresponds to injection valve differential pressure of 0 psid.

(3) LOCA and isolation transient analyses use a maximum vessel to source differential pressure of 1175 psid for HPCS flow; the acceptability of this HPCS pump head capability has been demonstrated by the analyses during isolated reactor conditions with the two SRVs out of service and +3 percent tolerance allowance for the remaining SRV setpoints.



SOURCE: 731E932AF

Note: Mode data on this sheet was used for original pipe and component sizing. Design requirements are based on Mode specific analysis.

FIGURE 6.3-1

HIGH PRESSURE CORE SPRAY
PROCESS DIAGRAM
SHEET 1 OF 2

NIAGARA MOHAWK POWER CORPORATION
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MODE A SYSTEM TEST, SUCTION FROM SUPPRESSION POOL

POSITION ⬡	1	2	3	4	5	6	7	8	9	10	12	13	14
FLOW GPM	N/A	7800	←	—	—	→	7800	0	0	0	0	0	7800
PRESSURE PSIA	14.7	X	X	X	X	X		X	X	X	X	X	
TEMPERATURE °F	120/40	←	—	—	—	→	120/40	AMB	←	—	→	AMB	120/40
MAX PRESSURE DROP FEET		500											

MODE B SYSTEM TEST, SUCTION FROM RESIDUAL HEAT REMOVAL SYSTEM

POSITION ⬡	1	2	3	4	5	6	7	8	9	10	12	13	14
FLOW GPM	N/A	8200	←	—	—	—	—	—	—	—	→	8200	0
PRESSURE PSIA	14.7		X	X	X	X	X	X	X	14.7			X
TEMPERATURE °F	N/A	125/40	←	—	—	—	—	—	—	—	→	125/40	AMB
MAX PRESSURE DROP FEET		450											

MODE C PUMP OPERATING ON BYPASS, SUCTION FROM SUPPRESSION POOL

POSITION ⬡	1	2	3	4	5	6	7	8	9	10	12	13	14
FLOW GPM	N/A	1000	1000	1000	0	0	0	0	0	0	0	0	1000
PRESSURE PSIA	14.7	X	X		X	X	X	X	X	X	X	X	
TEMPERATURE °F	212/40	←	→	212/40	AMB	←	—	—	—	—	→	AMB	212/40
MAX PRESSURE DROP FEET		1175/820											

MODE D ACCIDENT, SYSTEM INJECTION AT RATED CORE SPRAY (128 PSID)

POSITION ⬡	1	2	3	4	5	6	7	8	9	10
FLOW GPM	N/A	6350	←	—	—	—	—	—	→	6350
PRESSURE PSIA	14.7									142.7
TEMPERATURE °F	170	←	—	—	—	—	—	—	→	170
MAX PRESSURE DROP FEET		674			17				198	

MODE F ACCIDENT, SYSTEM OPERATING AT RUNOUT

POSITION ⬡	1	2	3	4	5	6	7	8	9	10
FLOW GPM	N/A	7800	←	—	—	—	—	—	→	7800
PRESSURE PSIA	14.7		X	X	X	X	X	X	X	14.7
TEMPERATURE °F	212	←	—	—	—	—	—	—	→	212
MAX PRESSURE DROP FEET		500								

MODE S SYSTEM ON STANDBY DUTY

POSITION ⬡	1	2	3	4	5	6	7	8	9	10	12	13	14
FLOW GPM	N/A	0	←	—	—	—	—	—	—	—	—	→	0
PRESSURE PSIA	14.7		X	X	X	X	X	X	X	REF 4	X	X	X
TEMPERATURE °F	120/40	←	—	—	—	→	120/40	AMB	AMB	AMB	120/40	← →	120/40
MAX PRESSURE DROP FEET		0											

MISCELLANEOUS INFORMATION–SEE NOTE 12

POSITION ⬡ 1.5 2 3 4 5 6 7 8 8.5 9 4 4.5 14 7 7.5 14 12 13

	1.5–2	2–3	3–8	8–8.5	8.5–9	9–4	4–4.5	4.5–14	14–7	7–7.5	7.5–14	14–12	12–13
DESIGN TEMPEATURE °F	212	LPCS PUMP	←212→	488	SEE REF 4		←212	→		←212	→		←212→
DESIGN PRESSURE PSIG	100		←550	→	SEE REF 4		550	100		550	100		←100→
ESTIMATED LINE SIZES–INCHES	18"		←18"	→	12"		←4"	→		←12"	→		←18"→
	MAIN CORE SPRAY LINE TO REACTOR						BYPASS LINE			TEST LINE			RHR SUCTION TEST LINE

TABLE II
LIMITING LINE LOSS

MODE	FLOW PATH	COMMENTS
F	1.5–13–2	SEE NOTE 5
D OR E	3–4–5–6–15–16–8–8.5–9–10	
A	7–7.5–14	
C	4–4.5–14	
B	12–13	SEE NOTE 6

VALVE POSITION

CONDITION	VALVE NUMBER			
	F074	F005	F011	F012
MODE A	O	C	C	P
MODE B	C	O	C	C
MODE C	O	C	O	C
MODE D	O	O	C	C
MODE E	O	O	C	C
MODE F	O	O	C	C
MODE S	O	C	O	C

P–PARTIALLY OPEN
C–FULLY CLOSED
O–FULLY OPEN

NOTES

1 ALL EMPTY PRESSURE DATA BLANKS CAN BE FILLED IN BY OTHERS BASED ON ACTUAL ARRANGEMENTS OR EQUIVALENT HYDRAULIC DATA SUBMITTED TO NEBO FOR REVIEW. ⊠ INDICATES THE DATA IS NOT SIGNIFICANT.

2 ◫ INDICATES MAXIMUM AND MINIMUM VALUE OF PARAMETER FOR THE MODE SPECIFIED.

3 ELEVATIONS ARE NOT INCLUDED IN THE ΔP VALUES GIVEN. ELEVATIONS SHALL BE INCLUDED WHEN DETERMINING FINAL VALUES FOR THE EMPTY DATA BLANKS.

4 DELETED

5 IN MODE F, THE NET POSITIVE SUCTION HEAD (NPSH) AVAILABLE AT A REFERENCE LOCATION 2 FEET ABOVE THE PUMP MOUNTING FLANGE MUST EQUAL OR EXCEED 11.17 FEET. THE NPSH AVAILABLE AT THE PUMP SUCTION NOZZLE MUST EQUAL THIS VALUE PLUS THE DIFFERENCE IN ELEVATION BETWEEN THE REFERENCE LOCATION AND THE CENTERLINE OF THE PUMP SUCTION NOZZLE.

6 IN MODE B, THE NPSH AVAILABLE MUST EQUAL THE VALUE SPECIFIED IN NOTE 5 PLUS 20 FEET.

7 100 GPM IS INCLUDED IN THE FLOW GIVEN FOR MODE D TO COMPENSATE FOR LEAKAGE IN THE RACTOR INTERNALS. (114 GPM IN MODE E).

8 IN MODE D, 128 PSID IS THE DIFFERENTIAL PRESSURE BETWEEN THE REACTOR VESSEL AND THE SUPPRESSION POOL.

9 THE FLOW SPECIFIED FOR MODE F IS THE MAXIMUM ALLOWABLE.

10 THE ΔP BETWEEN POSITION 15 AND 16 WILL BE DETERMINED IN PRE-OPERATIONAL TEST. THE ΔP WILL BE ADJUSTED TO MEET THE FLOW REQUIREMENTS OF MODE D, E OR F.

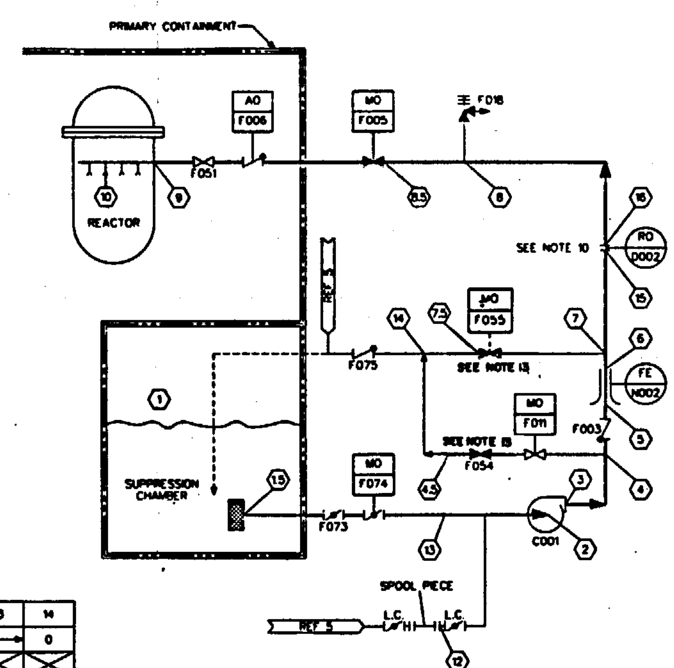
11 DELETED

12 PIPING SYSTEM DESIGN PRESSURE AND TEMPERATURE AND THE ESTIMATED LINE SIZES ARE FOR INFORMATION ONLY. ACTUAL DESIGN TEMPERATURE AND PRESSURE AND LINE SIZE AS DETERMINED BY OTHERS SHALL MEET THE PROCESS DIAGRAM HYDRAULICS REQUIREMENTS.

13. ANTI-CAVITATIONAL VALVES

REFERENCE DOCUMENTS	MPL ITEM NO
1 LPCS SYSTEM P&ID	E21–1010
2 LPCS SYSTEM DESIGN SPECIFICATION	E21–4010
3 DELETED	
4 NUCLEAR BOILER SYSTEM PROCESS DIAGRAM	B22–1020
5 RESIDUAL HEAT REMOVAL SYSTEM P&ID	E12–1010

SUPPORTING DOCUMENTS	MPL ITEM NO.
1. PIPING & INSTRUMENT SYMBOLS	A42–1010



CORE SPRAY PROCESS DIAGRAM
SEE NOTE 3

Note: Mode data on this sheet was used for original pipe and component sizing. Design requirements are based on Mode specific analysis.

SOURCE: 761E220AF

FIGURE 6.3-2

LOW PRESSURE CORE SPRAY SYSTEM PROCESS DIAGRAM SHEET 1 OF 1

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NINE MILE POINT–UNIT 2
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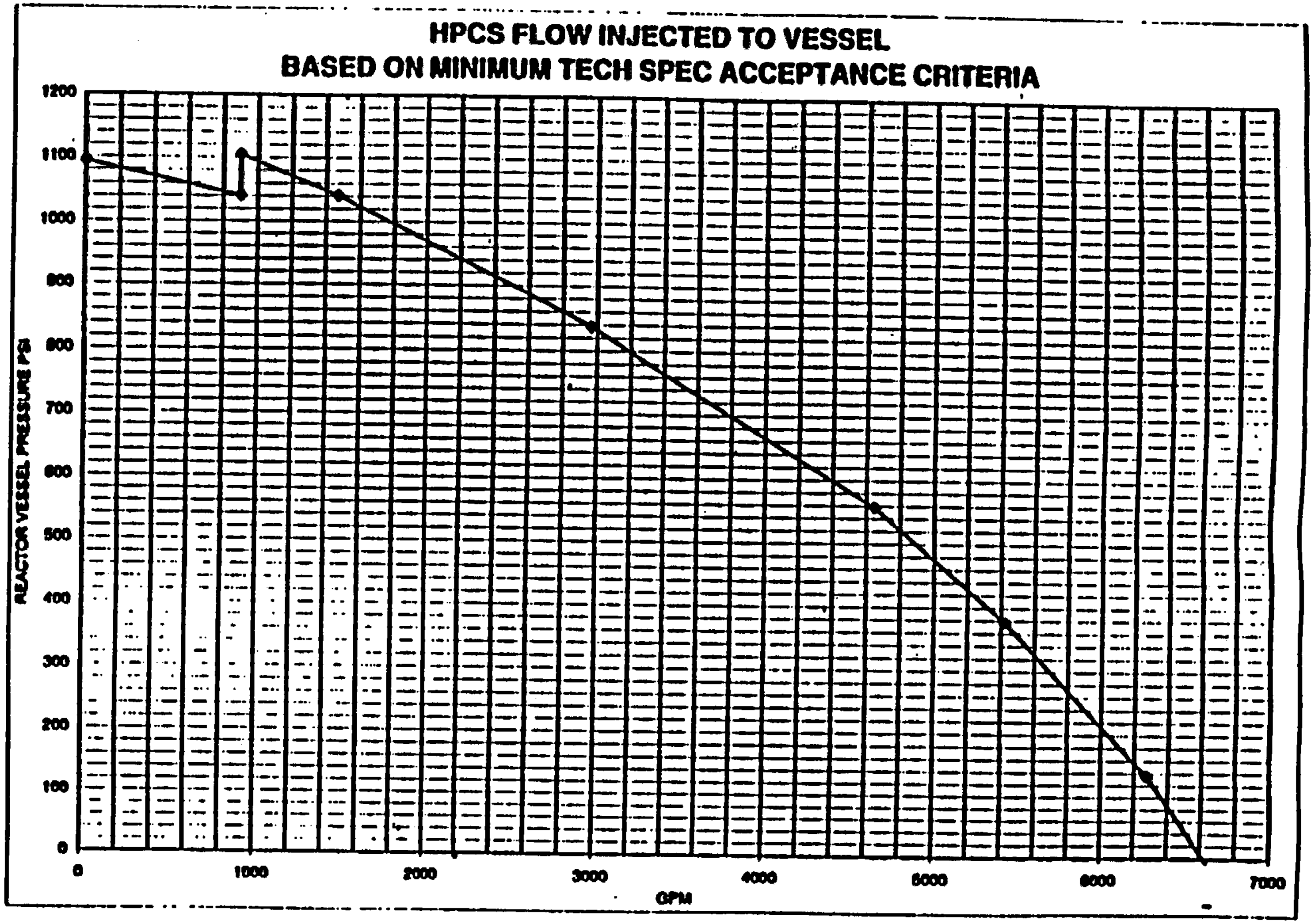

FIGURE 6.3-3a

HEAD VERSUS HIGH PRESSURE CORE SPRAY FLOW USED IN LOCA ANALYSIS

NIAGARA MOHAWK POWER CORPORATION
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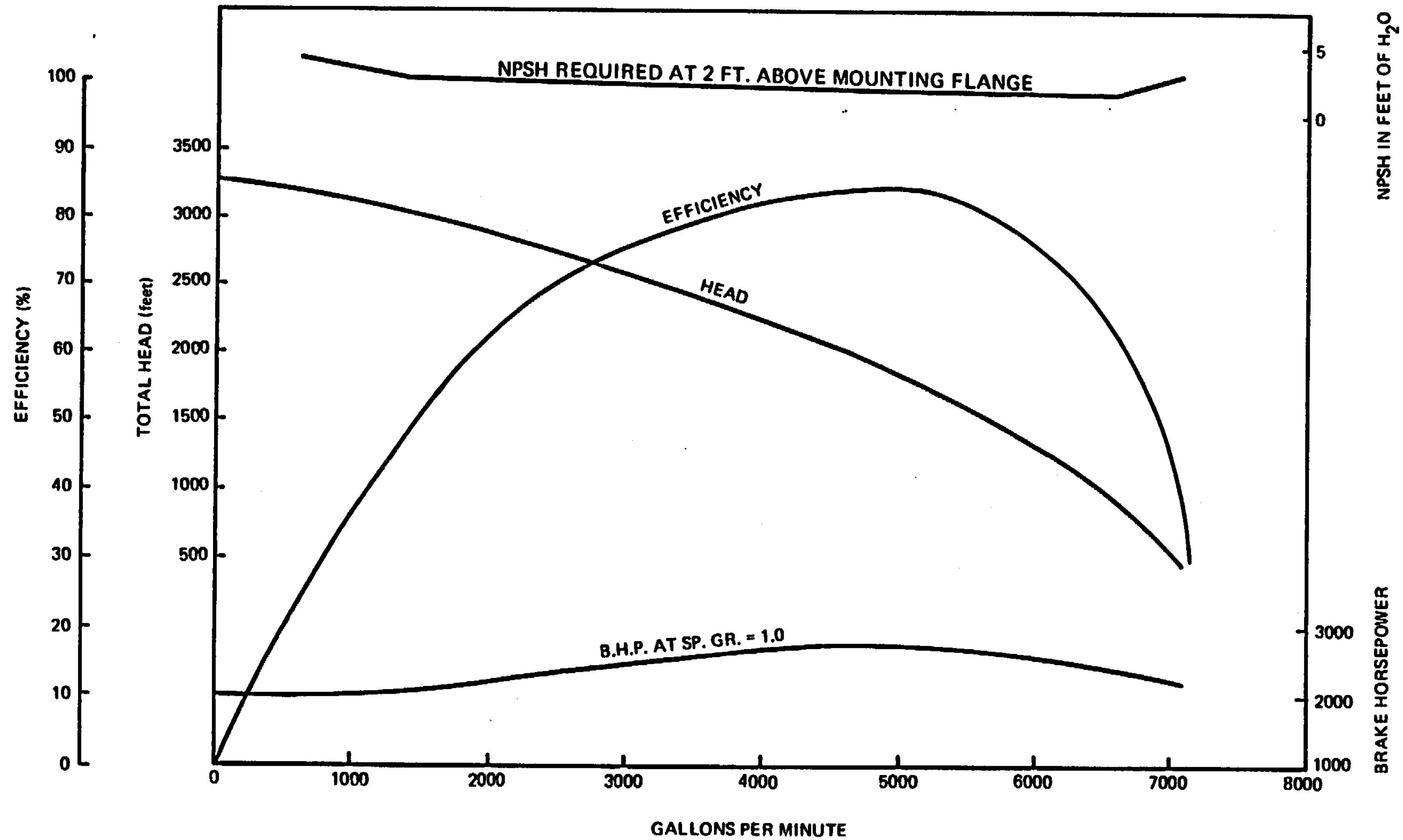

Note: Pump curve represents manufacturer's test curve. Installed performance and minimum acceptable Technical Specification performance is below this curve.

FIGURE 6.3-3b

HIGH PRESSURE CORE SPRAY
PUMP CHARACTERISTICS

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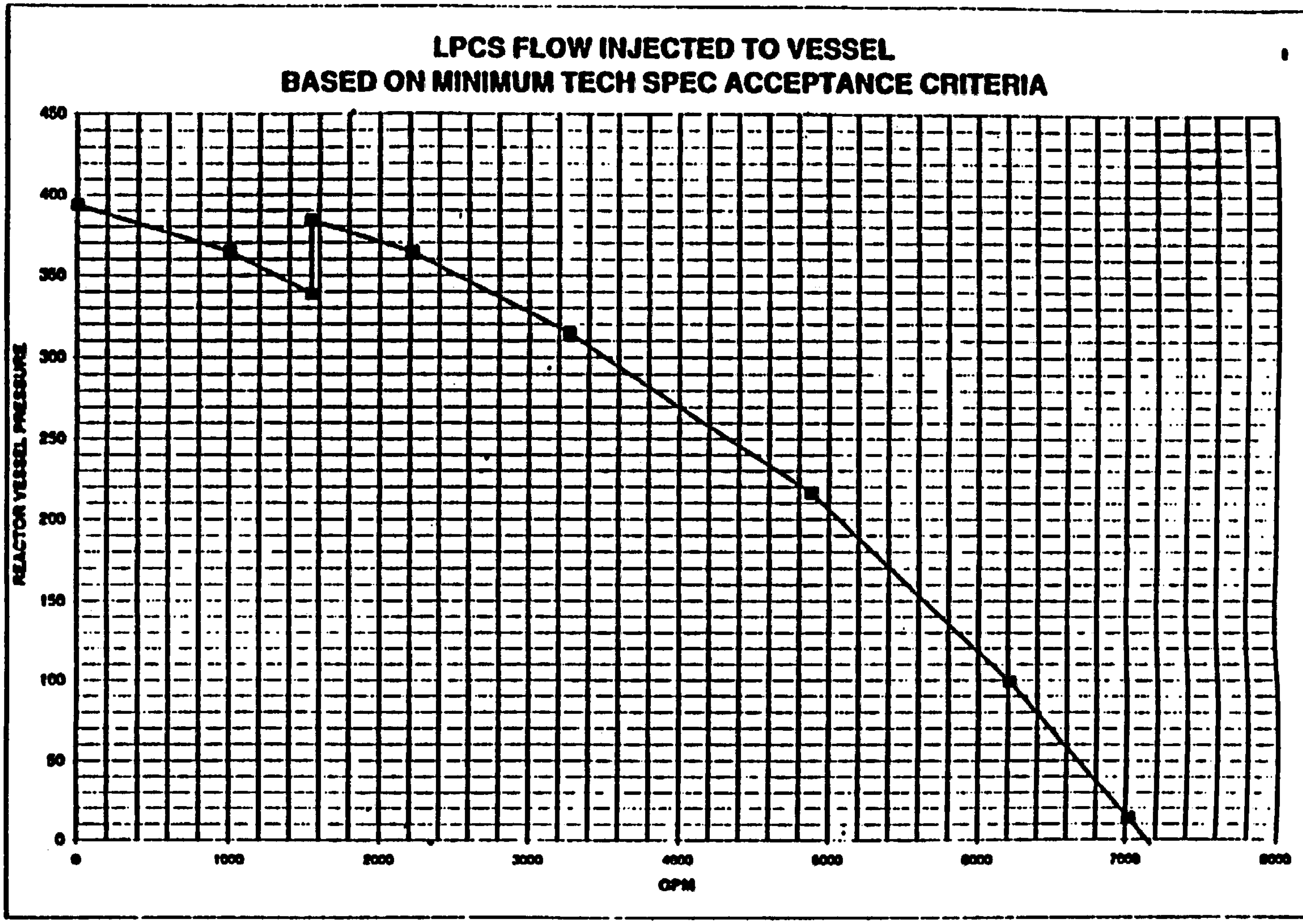
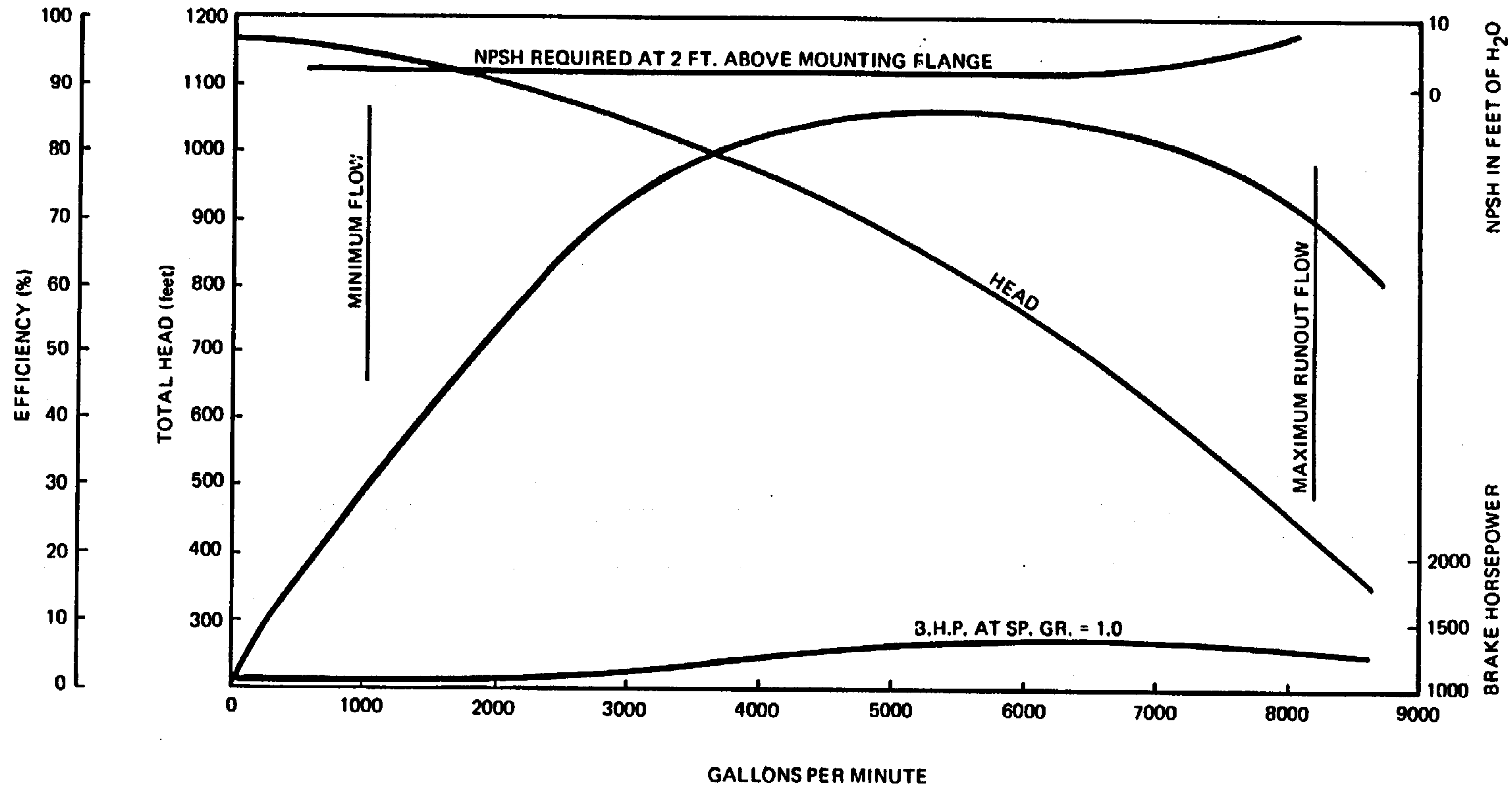


FIGURE 6.3-4a

HEAD VERSUS LOW PRESSURE CORE SPRAY FLOW USED IN LOCA ANALYSIS

NIAGARA MOHAWK POWER CORPORATION
NINE MILE POINT-UNIT 2
UPDATED SAFETY ANALYSIS REPORT



Note: Pump curve represents manufacturer's test curve. Installed performance and minimum acceptable Technical Specification performance is below this curve.

FIGURE 6.3-4b

LOW PRESSURE CORE SPRAY
PUMP CHARACTERISTICS

NIAGARA MOHAWK POWER CORPORATION
NINE MILE POINT-UNIT 2
UPDATED SAFETY ANALYSIS REPORT

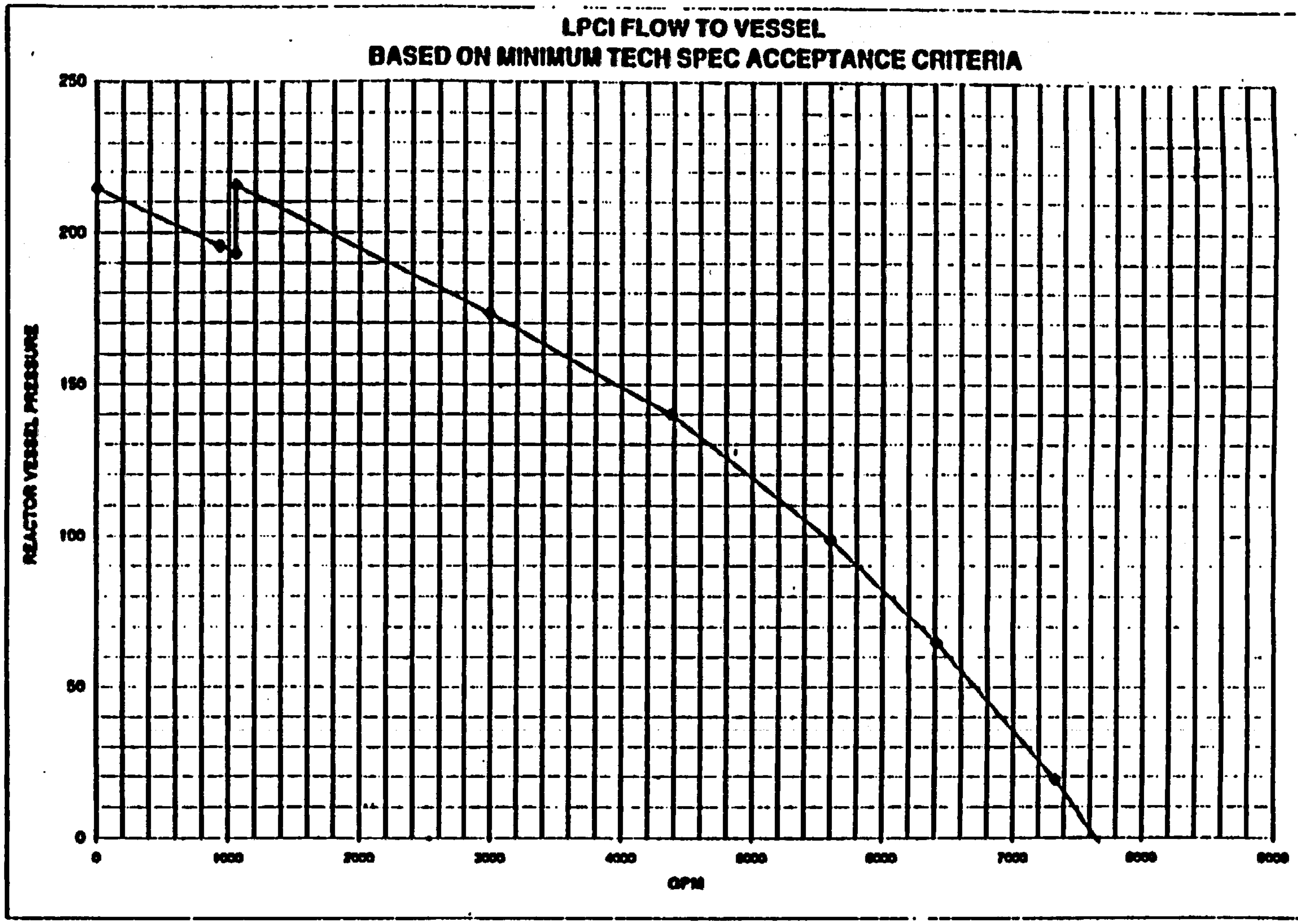


FIGURE 6.3-5a

HEAD VERSUS LOW PRESSURE COOLANT INJECTION FLOW USED IN LOCA ANALYSIS

NIAGARA MOHAWK POWER CORPORATION
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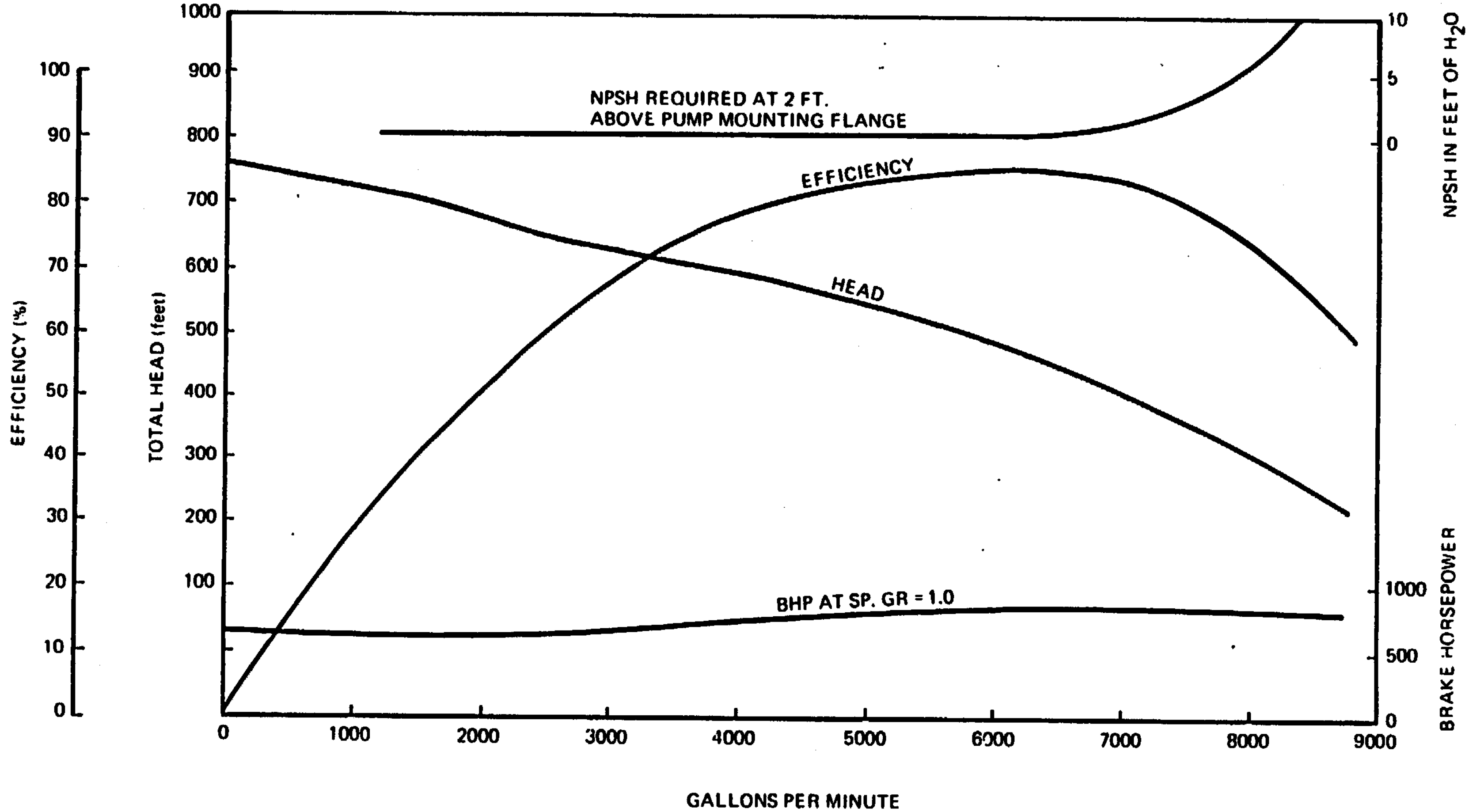

Note: Pump curve represents manufacturer's test curve. Installed performance and minimum acceptable Technical Specification performance is below this curve.

FIGURE 6.3-5b

RHR (LPCI)
PUMP CHARACTERISTICS

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UPDATED SAFETY ANALYSIS REPORT

6.4 HABITABILITY SYSTEMS

Habitability systems are provided to ensure that the plant Operators can remain in the main control room and take actions to operate the plant safely under normal conditions and to maintain it in a safe condition under all accident conditions.

The main control room habitability systems include missile protection, radiation shielding, radiation monitoring, air filtration and ventilation systems, lighting, personnel and administrative support, and fire protection.

Detailed descriptions of the various habitability systems and provisions are discussed in the following sections:

Equipment and systems are discussed in this section only as necessary to describe their connection with main control room habitability. References to other sections are made where appropriate.

6.4.1 Design Basis

The main control room is designed so that it provides a location from which the reactor may be safely operated during all modes of plant operation. Access to the control room to provide for food and personal comfort items is provided via analyzed routes as found on Figure 12.3-69. This includes a 30-day period following the DBA. The main control room habitability systems:

1. Provide the capability to detect and limit the introduction of radioactive material and smoke into the main control room.

2. Provide the occupants with fresh, filtered breathing air and a comfortable working atmosphere.

3. Provide the occupants with fire protection warning and firefighting equipment.

4. Maintain acceptable temperature and humidity conditions.

5. Provide the occupants with respiratory, eye, and skin protection for emergency use within areas of the main control room pressure boundary.

The main control room envelope or pressure boundary includes all instrumentation and controls necessary for safe shutdown of the plant and is limited to those areas requiring Operator access during and after a DBA.

The radiation exposure of main control room personnel through the duration of any one of the postulated DBAs discussed in Chapter 15 does not exceed the guidelines set by 10CFR50 Appendix A, GDC 19.

The main control room air conditioning system is designed to provide temperature and humidity conditions of 75°F and 50 percent, respectively, which are based on optimum room conditions for personal comfort as established by the American Society of Heating, Refrigeration and Air Conditioning Engineers. The system equipment has sufficient surplus cooling capacity to maintain these conditions during normal and post-accident modes of operation such as LOCA, LOOP, and concurrent single failure, including operation with outdoor air diverted through a safety-related charcoal air filter train, as a result of a monitored smoke, high-radiation condition at the outdoor air intake, or LOCA signal.

All components of the HVAC systems serving the main control room that are required to ensure main control room habitability and essential equipment operations are redundant, Category I, powered from Class 1E buses, and Safety Class 3.

If there is a LOOP, power to the main control room air conditioning equipment is interrupted for about 60 sec. No significant temperature rise within the main control room is expected before the system is returned to operation via emergency power from the standby diesel generators.

Two redundant, 100-percent capacity water chillers supply chilled water to two 100-percent capacity air supply systems. If a failure occurs in either chilled water system or its associated air supply system, an alarm is annunciated in the main control room and the redundant system is automatically placed in operation. The control building chilled water system is described in Section 9.4.10. Service water (Section 9.2.1) can be utilized as an alternate cooling medium.

Instrumentation is provided to warn the Operators of dangerous conditions that could affect their lives and safety. Firefighting equipment is also supplied. Maintaining a positive pressure in the main control room provides a continuous purge of the main control room and also protects the Operators against infiltration of smoke or airborne radioactivity from the surrounding areas. Cables and pipes penetrating the main control room pressure boundary are sealed. This aids in the pressurization of the main control room and also limits the spread of fire and smoke that may enter pipe or cable chases.

6.4.2 System Design

6.4.2.1 Definition of the Main Control Room Envelope

The main control room envelope consists of all rooms and areas located in the main control room (el 306 ft) and relay room (el 288 ft 6 in) of the control building. Included in the envelope are the main control room, relay room, instrument shop, training room, shift supervisor's office, lunch room, toilets, corridors, work release room and HVAC equipment rooms. Airtight doors are provided at access points to and from the main control room envelope.

6.4.2.2 Ventilation System Design

The main control room HVAC system is described in detail in Section 9.4.1.

Figure 1.2-2 shows the plant layout, including the location of potential radiological release points with respect to the main control room air intakes. Potential sources of toxic gas release are identified in Section 2.2. A description of main control room instrumentation for monitoring radioactivity is given in

Sections 11.5 and 12.3.4. Protection of the main control room HVAC system from internally-generated missiles is discussed in Section 3.5.

Smoke removal from the main control room is achieved by a separate smoke removal fan which uses normal HVAC ductwork (Section 9.4.1). The air conditioning unit serving the main control room is turned off during the smoke removal mode.

Removal of radioiodines from the main control room ventilation outdoor air supply during a DBA is accomplished through use of charcoal filter trains. To comply with GDC 19, Appendix A of 10CFR50, two 100-percent redundant charcoal filter trains are provided. The main control room charcoal filter trains are designed in accordance with RG 1.52. Both filter trains and associated air handling equipment, designed to Category I, are located within the main control room pressure boundary.

Each train is rated to process 100 percent of the required system airflow. Outdoor air is supplied from the outdoor air intake. Separate intakes provide alternative sources of outdoor air with the capability of selecting either source from the main control room. Redundant radiation monitors in the main control room air supply duct system monitor the radiation level of outdoor air.

6.4.2.3 Leak-tightness

The main control room envelope boundary is designed with low leakage construction to minimize the potential for the infiltration of air into the main control room. The walls, floor, and roof are constructed of poured-in-place reinforced concrete that is essentially leak-tight. The access doors are of airtight design with self-closing devices that shut the doors automatically following the passage of personnel. All cable and air duct penetrations have fire-retardant seals that provide leak-tight construction.

The main control room in-leakage analysis was performed using the methods and assumptions given in RG 1.78 and conform with general design criteria discussed in Section 3.1.

The leak paths considered are concrete walls and floors, wall and floor joints, doors with frames, electric cable penetrations, duct penetrations, and pipe penetrations.

The system that pressurizes the main control room is described in Section 9.4.1. A periodic test is performed to verify that the makeup airflow is ±10 percent of design value.

6.4.2.4 Interaction with Other Zones and Pressure-Containing Equipment

The main control room air conditioning system is provided with radiation detectors. A high radiation or LOCA signal automatically diverts airflow from the air intake through the charcoal filter train.

6.4.2.5 Shielding Design

The floor plan of the main control room is provided on Figure 1.2-15. The main control room shielding, air supply system, and administrative procedures are such that the amount of radiation received by personnel during an accident would be within the dose guidelines set forth in GDC 19, Appendix A of 10CFR50, as follows:

Whole-body gamma dose	5 Rem
Thyroid dose	30 Rem
Beta skin dose	30 Rem

Shielding of the control room is provided by reinforced concrete floors and walls of the following thicknesses:

Structure	Envelope Boundary	Minimum Concrete Thickness
Walls	All exterior walls of control building	2'
	Interior walls	1'
Floor slabs	Main control room, floor el 306'	0'-9"
	Control building roof, low point el 326' high point el 328'	2'

Section 12.3.2 discusses the design objectives of shielding provided for the main control room envelope.

6.4.2.6 Portable Self-Contained Air Breathing Units

Ten full-face pressure demand self-contained breathing apparatuses (SCBA) which conform to NIOSH standards are supplied in the main control room. Additionally, at least one spare air bottle per SCBA is supplied. Each SCBA supplies an Operator for approximately 30 min during moderate exertion. Operator training is provided in donning and operating this equipment. Inspection of SCBAs is performed periodically and after each use to ensure operational readiness.

Ten full-face respirators with high-efficiency particulate air (HEPA) filters are also provided in the main control room.

6.4.3 System Operational Procedures

During normal and emergency operation, the main control room Operator selects the air handling unit that operates to maintain design temperatures in the main control room. Periodically the operating unit is stopped and the standby unit started so that the service time of both units is approximately equal. In the event the operating unit fails, the standby unit starts automatically.

6.4.4 Design Evaluation

6.4.4.1 Radiological Protection

Under normal plant conditions, outside air enters the main control room through either of two local outside air intakes located on the east and west sides of the control building. Each local air intake is capable of providing 100 percent of the fresh air required in the control room envelope. The two air intake ducts combine to form one common duct. Upon detection of a high radiation level by radiation monitors located in the common ductwork or a LOCA signal, airflow is automatically diverted to special charcoal/HEPA filter trains. Isolation valves in the unfiltered duct close immediately upon receiving the high radiation signal. All habitability systems are designed to meet the single-failure criterion.

Originally, the FMEA for the control room habitability system (control building air conditioning) was contained in the Unit 2 FMEA document, which is historical. FMEAs for plant systems are now performed and controlled by the design process.

6.4.5 Testing and Inspection

Preoperational testing of equipment is described in Chapter 14, Initial Test Program.

Surveillance testing is conducted as prescribed in Technical Specifications and TRM Section 3.7.2.

6.4.6 Instrumentation Requirements

The instrumentation requirements for the main control room area HVAC system are described in Section 9.4.1.5.2. The instrumentation requirements for the control building chilled water system which supplies chilled water to the main control room air conditioning units is described in Section 9.4.10.1.5.

The ESFs for the main control room area HVAC system and the chilled water system are described in Section 7.3.1.

Conformance with GDC 19 is described in Section 3.1.2.19.

6.5 FISSION PRODUCT REMOVAL AND CONTROL SYSTEMS

6.5.1 Engineered Safety Feature Filter Systems

The filter systems required to perform safety-related functions following a DBA are:

1. Standby gas treatment system.

2. Control building supply air system special filter train.

The control building supply air special filter train system is discussed in Sections 9.4.1 and 6.4. The SGTS is discussed in this section.

6.5.1.1 Design Bases

The design bases of the SGTS are as follows:

1. To limit the release of radioactive gases from the reactor building to the environment within the guidelines of 10CFR100 in the event of a LOCA.

2. To maintain a negative pressure in the reactor building under accident conditions.

3. To provide redundant filter trains, each train is physically separated, so that damage to one train does not cause damage to the other.

4. To provide SGTS filters, fans, and associated components that are sized for at least one reactor building volume air change per 24-hr period.

5. The SGTS is designed to Category I requirements. The SGTS electrical components are Class 1E equipment.

6. The SGTS charcoal filter assemblies are designed in accordance with RG 1.52 (Section 1.8).

7. The SGTS filter assemblies and appurtenances are designed to withstand operational and environmental conditions specified in Table 9.4-1.

6.5.1.2 System Design

6.5.1.2.1 General System Description

The SGTS is schematically shown on Figure 9.4-8. Design data of the SGTS principal equipment are listed in Table 6.5-1.

The SGTS consists of two identical, parallel, physically separated, 100-percent capacity air filtration assemblies with associated piping, valves, controls, and centrifugal exhaust fans. Effluents from the SGTS connect to a common exhaust line discharging to the exhaust tunnel leading to the main stack. The SGTS draws air from the reactor building.

6.5.1.2.1.1 SGTS Modes of Operation

The SGTS has three modes of operation:

1. Safety-Related Mode - To maintain negative pressure in the reactor building secondary containment (post-LOCA) via connection to the reactor building recirculation ventilation system.

2. Nonsafety-Related Mode - To provide charcoal filtration of the primary containment atmosphere when inerting (startup) or deinerting (shutdown) via connection to the CPS full-flow 20-in line.

3. Nonsafety-Related Mode - To provide charcoal filtration of the primary containment atmosphere during normal power operation to control primary containment pressure via connection to the CPS 2-in bypass line.

Within 25 sec of a high radiation or LOCA signal, the SGTS draws 4,000 cfm from the discharge duct of the emergency recirculation unit cooler (Section 9.4.2) to either maintain or restore a subatmospheric pressure within the reactor building.

The SGTS is started automatically by any of the following signals:

1. High radiation or low airflow in the exhaust ducts above and below the refueling floor.

2. High pressure in the drywell.

3. Low reactor water level.

The SGTS can also be started manually and used to exhaust the primary containment purge system (Section 9.4.2.2.3).

The Plant Operator can stop one of the SGTS filter trains from the main control room after system initiation is completed. Because of the possibility of iodine desorption and charcoal ignition at high temperatures, a deluge system is provided for the charcoal adsorber section of the SGTS filter trains. Each charcoal bed has a temperature switch to detect any abnormal temperature rise at the outlet of the charcoal adsorber. When the temperature exceeds a predetermined setpoint, there is an alarm in the main control room, the exhaust fan is manually stopped and, if warranted, the fire protection system is manually initiated.

6.5.1.2.2 System Component Description

Principal system components are listed and described in Table 6.5-1. The SGTS consists of two 100-percent capacity filter trains, each of which consists of the following components in series:

1. A demister (moisture separator) to remove entrained water droplets and mist from the entering airstream.

2. An electric heating coil powered from Class 1E buses to reduce the relative humidity of the airstream to 70 percent.

3. A bank of prefilters to remove particulates from the airstream. The prefilters have 78-percent efficiency based on ASHRAE Standard 52-76.

4. A bank of HEPA filters to remove virtually all airborne particulates from the airstream. The HEPA filters have a minimum filtration efficiency of 99.97 percent for 0.3 micron diameter homogeneous particulates of dioctylphthalate (DOP) based on tests performed in accordance with MIL-STD-282.

5. A 4-in nominal depth bank of charcoal adsorber filters. Filter elements are of an all-welded, gasketless design and are sized for a maximum air velocity of 40 fpm through the charcoal at rated airflow. The adsorber material is activated coconut shell charcoal, impregnated for iodine and methyl iodine adsorption.

6. A second bank of HEPA filters identical to Item 4 above, to capture charcoal particles that may escape from the charcoal filters.

All the components listed above are mounted in an all-welded steel housing. Each charcoal filter train has an integrally mounted water (deluge) fire extinguishing facility consisting of discharge nozzles and distribution pipe. Temperature switches are provided for each charcoal bed adsorber section for annunciation in the event of high temperature. Housing floor drains are provided for the demister, the occasional washdown required for decontamination, and the deluge system in the event of a fire, in accordance with the recommendations of ERDA 76-21.

A 4,000-cfm capacity centrifugal fan is provided downstream of each SGTS filter train. This fan is a direct-drive type with a single-speed motor powered from Class 1E buses. The decay heat produced by the radioactive particles in the inactive charcoal filter train is removed by passing equipment room air through the inactive filter train. The air is then exhausted to the main stack by the fan of the active filter train. A missile-protected opening with a backdraft-type tornado damper located in the equipment room allows outside air to be induced into the room when makeup air for decay heat cooling is required.

The SGTS charcoal filter trains are located in the standby gas treatment building at el 261 ft.

Airtight access doors are provided to give complete accessibility to all components for servicing.

6.5.1.3 Design Evaluation

The SGTS is designed to preclude direct release of fission products from the reactor building to the environment during all modes of operation by the following features:

1. The SGTS is housed in a Category I structure. All surrounding equipment, components, and supports are designed to pertinent safety class and Category I requirements.

2. The SGTS consists of two 100-percent capacity, physically separated filter trains. Should any component in one train fail, filtration can be performed by the redundant train.

3. The SGTS component design and qualification testing are in accordance with the recommendations of RG 1.52 to the extent discussed in Section 1.8.

4. During LOOP, all active components such as motors, damper operators, controls, and instrumentation operate from their respective independent standby power supplies.

Should a LOCA occur during primary containment purge with the SGTS operating in the pressure control mode, the calculated accident doses are within the 10CFR100 guideline values, as required by BTP-CSB 6-4.

Should a LOCA occur while the SGTS is operating in the pressure control mode, the resultant pressure at the SGTS filter is below the design pressure of 1 psig. The following are considered in this analysis:

1. The inboard and outboard CPS isolation valves to the drywell (14 in) and wetwell (12 in) are fully open at time=0 when the LOCA occurs. These lines are tied together to a 20-in header.

2. The 20-in line is shut off from the SGTS filters via a safety-related fail close valve (2GTS*AOV101), and the 2-in bypass line is open via a safety-related fail close valve (2GTS*SOV102).

3. The CPS containment isolation valves close in 5 sec.

4. The LOCA pressure at t=5 sec is 26.6 psig.

5. For purposes of conservatism, the LOCA pressure of 26.6 psig is assumed to occur instantaneously at t=0 sec, the pressure control valve (2GTSPV104) in the 2-in bypass line is full open, and the resulting pressure spike at the SGTS filter occurs instantaneously.

The radiological consequences of this event are discussed in Section 15.6.5.

6.5.1.4 Tests and Inspection

The SGTS and its components are thoroughly tested in a program consisting of the following:

1. Manufacturer's qualification.

2. Preoperational tests.

3. Periodic surveillance tests.

The above tests are performed in accordance with the objectives of RG 1.52.

6.5.1.4.1 Preoperational Testing

The SGTS charcoal filter train housings are pressure tested for leakage in accordance with ANSI N510, Section 6. Leak rates shall be in accordance with the requirements of ANSI N509-1980, Section 4.12.

HEPA filters are shop tested prior to installation, in accordance with MIL-F-51068 and MIL-STD-282, at 100 percent and 20 percent of rated flow.

Impregnated activated carbon is tested before installation in accordance with the methods specified in RDT Standard MI6-IT. Tests determine apparent density, degree of activation, percent hardness, percent moisture, particle size distribution, and ash content. These tests meet the intent of RG 1.52. Elemental and methyl iodine removal and retention capabilities are measured (at postulated accident conditions) in accordance with RDT Standard MI6-IT. Impregnate content, leachout, and charcoal ignition temperature are also determined. HEPA filter banks are tested in place before operation to verify 99.97 percent retention based on the DOP smoke penetration test.

The charcoal filter banks are preoperationally leak tested using a gaseous halogenated hydrocarbon refrigerant to measure bypass leakage and element imperfection in accordance with ANSI N510, Section 12.

6.5.1.4.2 In-service Testing

In-service testing of the SGTS is conducted in accordance with the surveillance requirements given in the Technical Specifications and TRM Section 3.6.4.3.

6.5.1.5 Instrumentation Requirements

Description

Safety-related instruments and controls are provided for automatic and manual control of the SGTS. The controls and monitors described below are located in the main control room. The control logic is shown on Figure 6.5-1.

Operation

Both filter trains are started automatically when there is a LOCA or a reactor building refueling area exhaust vent duct low airflow or high radiation signal. Stopping one of the trains manually after automatic initiation will reset its start signal and place it in standby. The standby filter train will start automatically when a high filter charcoal temperature occurs in the operating filter train or when the indoor negative/outdoor atmospheric pressure differential falls below a predetermined setpoint, coincident with either a LOCA or high radiation signal. The filter trains can also be started manually.

A SGTS inlet valve from the reactor building ventilation system will open automatically when the associated filter train start signal is present and close when the signal is reset. The valves can also be opened and closed manually.

SGTS filter train inlet and fan discharge valves will open automatically when the associated filter train start signal is present and close when the signal is reset or when the filter train fan has failed to start after a preset time. The valves can also be opened and closed manually.

The SGTS filter train decay heat removal air inlet valves can be opened and closed manually.

A SGTS filter train fan will start automatically when its associated filter train start signal is present and stop when the signal is reset. The fans can also be started and stopped manually. Interlocks prevent a fan from running unless its discharge valve is open.

Negative pressure in the reactor building is automatically controlled by the SGTS filter train recirculation line pressure control valves. Differential pressure is set by manual/automatic stations. The valves can also be controlled manually. If problems arise in the filter bypass line, the line may be closed. This may result in a greater vacuum in the reactor building, but will not impact the GTS system's capability to perform its safety function. An interlock closes a valve when its fan is not running.

The primary containment purge exhaust and depressurization to SGTS isolation valves are opened and closed manually.

Monitoring

Indicators are provided for:

1. Reactor building differential pressure (redundant).
2. Each filter train inlet and outlet temperature.
3. SGTS exhaust radiation level (local microprocessor).

Recorders are provided for:

1. Each filter train flow and filter differential pressure.

Alarms are provided for each:

1. SGTS train inoperable.
2. SGTS train heater differential temperature low.
3. Reactor building positive differential pressure high.
4. Reactor building negative differential pressure low.
5. SGTS train trouble.
6. SGTS train airflow low.
7. SGTS fan auto trip/fail to start.
8. (SGTS effluent) radiation monitor trouble.
9. SGTS MOV motor overload.
10. SGTS fan motor overload.
11. Process airborne radiation (SGTS effluent) monitor activated.

6.5.1.6 Materials

The housings and all framing materials of the SGTS filter trains are fabricated of steel alloys and, as such, are nonflammable. The following is a list of the materials used in the various components of the SGTS filter trains:

1. <u>Demisters</u> The demister (moisture separator) section of each SGTS filter assembly is a Mine Safety Appliance Company (MSA) Model G separator consisting of wire mesh and fiberglass-coated wire mesh in series, separated by grid assemblies. The frame is 16-gauge Type 304 stainless steel. The demisters are designed and constructed to a manufacturer's standard design that has been qualified by testing in accordance with MSAR 71-45, and meet the Underwriters' Laboratories Inc. (UL) Class 1 requirements.

2. <u>Heater</u> An electric heating coil is provided upstream of the prefilters to reduce the relative humidity of the airstream to 70 percent (maximum). A heating element is integrally mounted in the filter train and connected to a terminal box. Heating elements are of the U-bent, finned tubular type with stainless steel sheaths and monel helical fins wound onto the sheaths. Heater enclosure frame and remote control panel are constructed of 14-gauge and 12-gauge Type 304 stainless steel, respectively. Heat baffles are of 16-gauge Type 304 stainless steel.

3. <u>Prefilters</u> Prefilters are of the high-efficiency, extended medium, dry type with pleated media and full depth rigid frames. The medium is MSA Dustfoe M-1000 and is stamped UL Class 1. The filter medium is fiberglass encased in a Type 304 stainless steel frame.

4. <u>HEPA Filters</u> There are two banks of HEPA filters, one before and one after the charcoal adsorber filters, on each SGTS filter train. The filters are MSA HEPA P/N 465062 and consist of waterproof fiberglass media in Type 304 stainless steel frame with aluminum separators.

5. <u>Charcoal Adsorber Filters</u> The charcoal adsorbent material is steam-activated coconut shell carbon MSA P/N 463563. The minimum ignition temperature is 594°F at 40 fpm face velocity. Each carbon adsorber module is fabricated from Type 304 stainless steel.

6. <u>Piping, Piping Components, and Valves</u> All nuclear safety-related piping is classified as ASME III, Code Class 2, and is designed, fabricated, installed, and inspected in accordance with ASME III. All nuclear safety-related piping components and valves are designed in accordance with the rules of Subsection NC, ASME III. All nonnuclear-safety piping, piping components, and valves are designed in accordance with ANSI B31.1.

   All safety-related valves and accumulator tanks associated with the GTS air supplies are designed and fabricated in accordance with the requirements of ASME III Class 3.

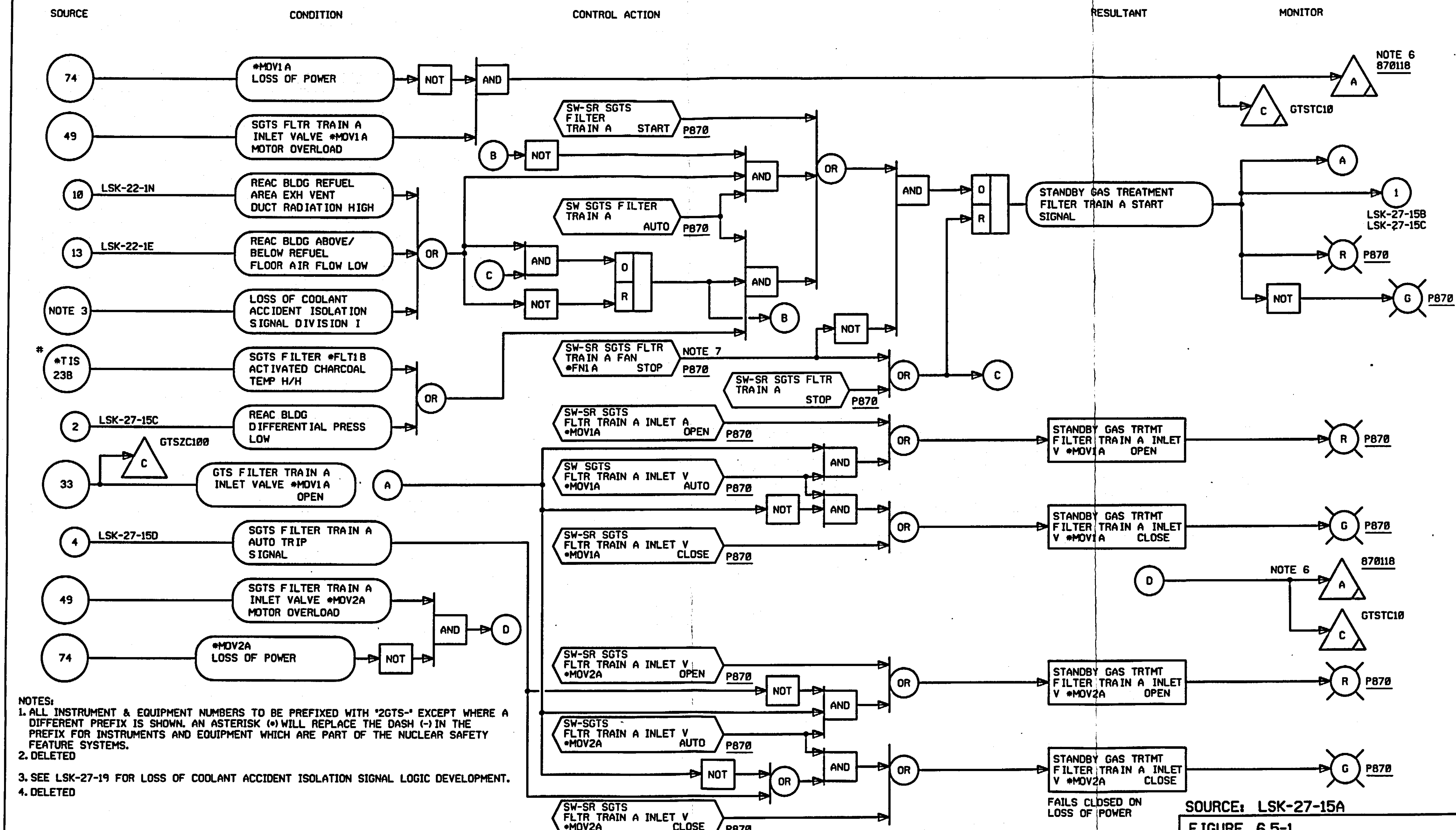
The SGTS is not exposed to accident environments of extreme temperature or radiation that could potentially produce pyrolytic or radiolytic decomposition of filter materials; thus filter train decomposition products are not present. A fire from external sources, which could cause pyrolytic decomposition of construction materials of the charcoal filters, is not postulated to occur simultaneously with any other plant accident requiring the operation of the SGTS for radioiodine removal credit.

6.5.2 Containment Spray System

The containment spray system is not relied on to perform a fission product removal function following a DBA. The containment spray system design is described in Section 6.2.2.

6.5.3 Fission Product Control System

The SGTS is used to control the cleanup of fission products from the secondary containment following an accident and is described in detail in Section 6.5.1. Detailed descriptions of the primary and secondary containments are provided in Sections 6.2.1 and 6.2.3, respectively. A detailed description of the hydrogen recombiner system is provided in Section 6.2.5.



NOTES:

1. ALL INSTRUMENT & EQUIPMENT NUMBERS TO BE PREFIXED WITH "2GTS-" EXCEPT WHERE A DIFFERENT PREFIX IS SHOWN. AN ASTERISK (*) WILL REPLACE THE DASH (-) IN THE PREFIX FOR INSTRUMENTS AND EQUIPMENT WHICH ARE PART OF THE NUCLEAR SAFETY FEATURE SYSTEMS.
2. DELETED
3. SEE LSK-27-19 FOR LOSS OF COOLANT ACCIDENT ISOLATION SIGNAL LOGIC DEVELOPMENT.
4. DELETED
5. # INDICATES VENDOR SUPPLIED EQUIPMENT.
6. COMMON ANNUNCIATOR MOV MOTOR OVERLOAD TRAIN A.
7. ADDITIONAL LOGIC SHOWN ON LSK-27-15B.

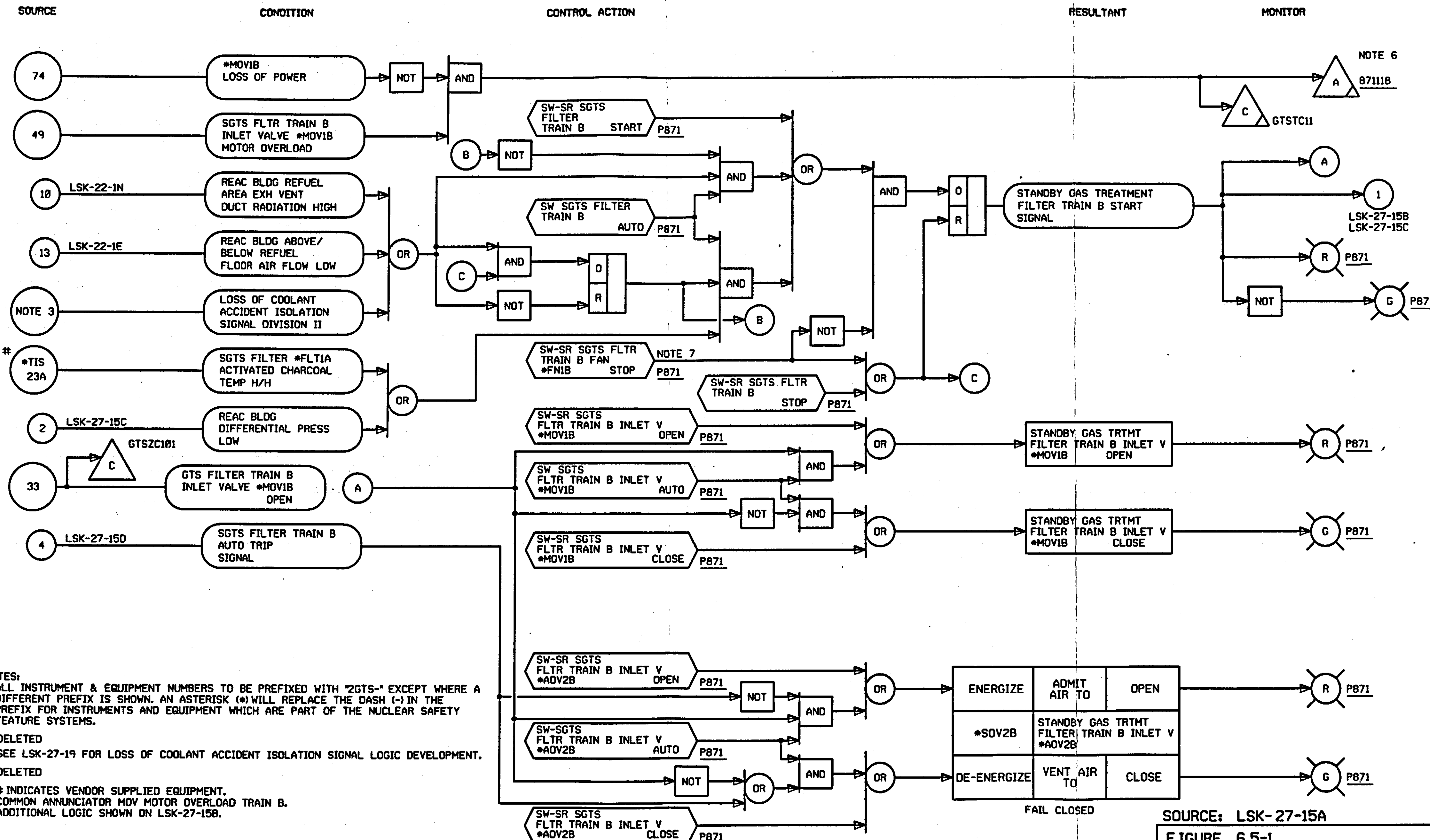
SETPOINTS SHOWN ON LOGIC DIAGRAMS ARE FOR LOGIC CLARIFICATION ONLY AND MAY BE ONLY APPROXIMATIONS OF THE ACTUAL PROCESS SETPOINT. REFER TO SETPOINT DATA SHEETS FOR ACTUAL PROCESS SETPOINTS.

SOURCE: LSK-27-15A

FIGURE 6.5-1

STANDBY GAS TREATMENT SYSTEM LOGIC DIAGRAM SHEET 1 OF 8

NIAGARA MOHAWK POWER CORP.
NINE MILE POINT-UNIT 2
UPDATED SAFETY ANALYSIS REPORT



NOTES:

1. ALL INSTRUMENT & EQUIPMENT NUMBERS TO BE PREFIXED WITH "2GTS-" EXCEPT WHERE A DIFFERENT PREFIX IS SHOWN. AN ASTERISK (*) WILL REPLACE THE DASH (-) IN THE PREFIX FOR INSTRUMENTS AND EQUIPMENT WHICH ARE PART OF THE NUCLEAR SAFETY FEATURE SYSTEMS.
2. DELETED
3. SEE LSK-27-19 FOR LOSS OF COOLANT ACCIDENT ISOLATION SIGNAL LOGIC DEVELOPMENT.
4. DELETED
5. # INDICATES VENDOR SUPPLIED EQUIPMENT.
6. COMMON ANNUNCIATOR MOV MOTOR OVERLOAD TRAIN B.
7. ADDITIONAL LOGIC SHOWN ON LSK-27-15B.

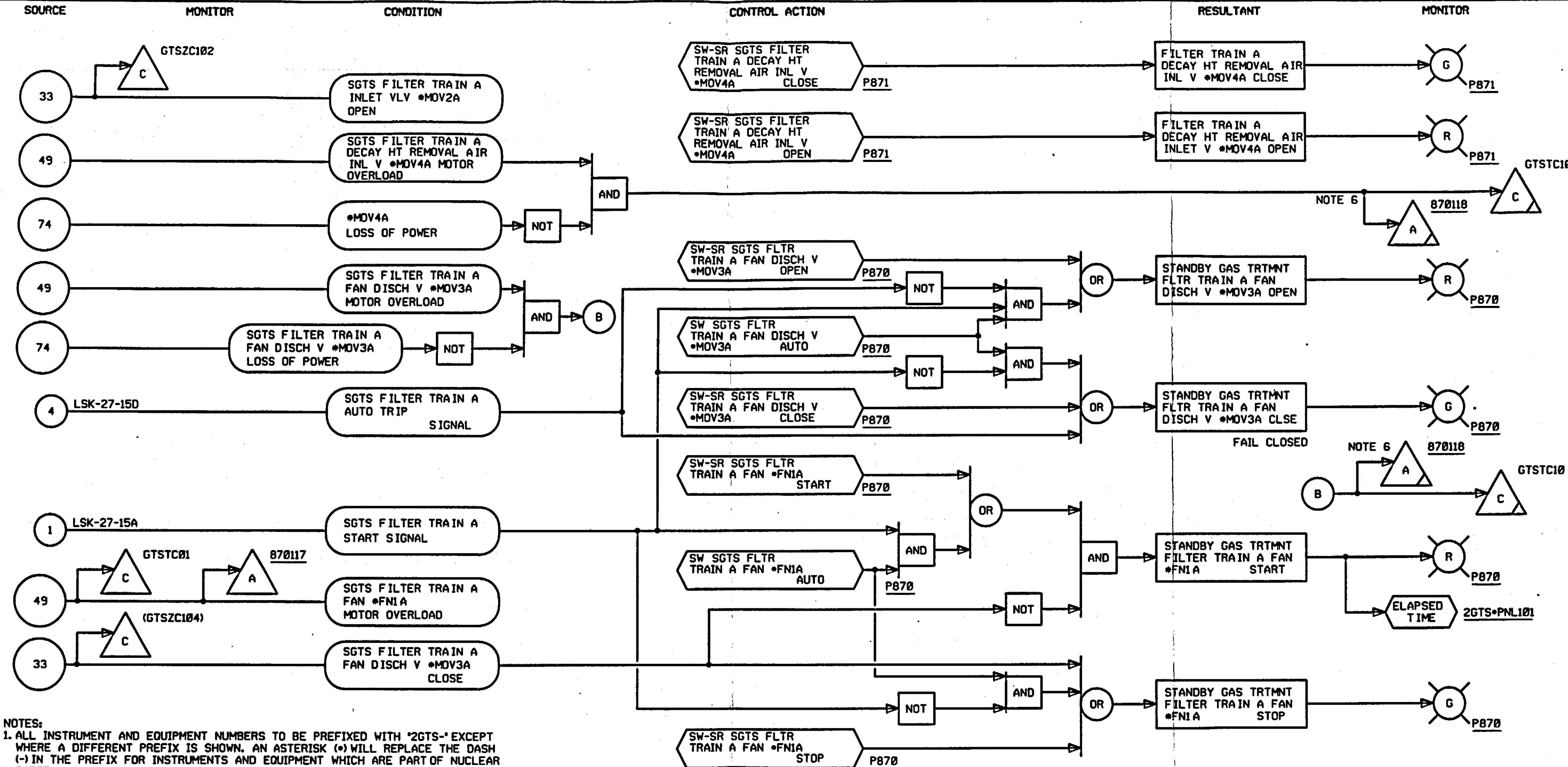
SETPOINTS SHOWN ON LOGIC DIAGRAMS ARE FOR LOGIC CLARIFICATION ONLY AND MAY BE ONLY APPROXIMATIONS OF THE ACTUAL PROCESS SETPOINT. REFER TO SETPOINT DATA SHEETS FOR ACTUAL PROCESS SETPOINTS.

SOURCE: LSK-27-15A

FIGURE 6.5-1

STANDBY GAS TREATMENT SYSTEM LOGIC DIAGRAM SHEET 1A OF 8

NIAGARA MOHAWK POWER CORP.
NINE MILE POINT-UNIT 2
UPDATED SAFETY ANALYSIS REPORT



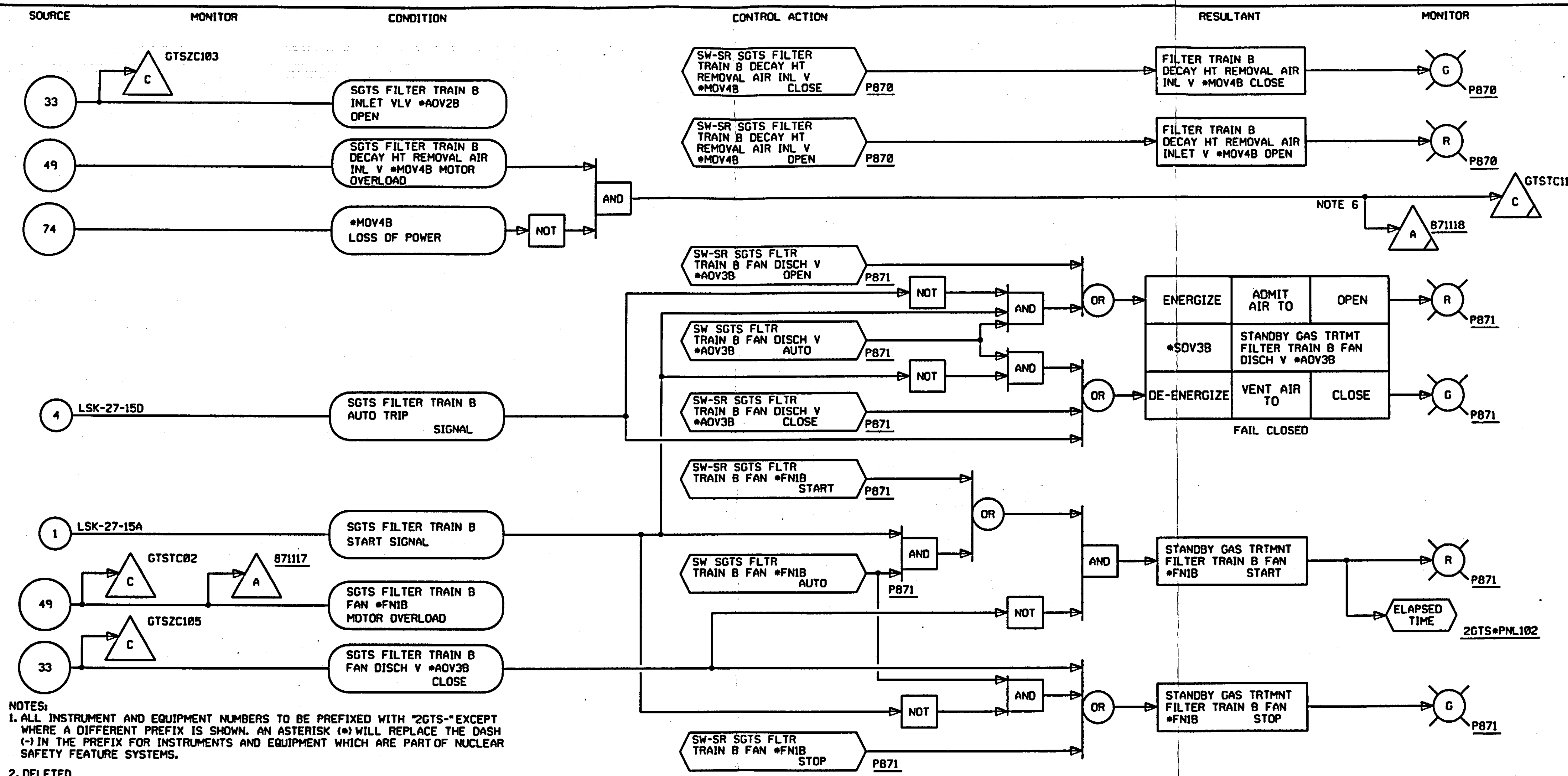
NOTES:
1. ALL INSTRUMENT AND EQUIPMENT NUMBERS TO BE PREFIXED WITH "2GTS-" EXCEPT WHERE A DIFFERENT PREFIX IS SHOWN. AN ASTERISK (*) WILL REPLACE THE DASH (-) IN THE PREFIX FOR INSTRUMENTS AND EQUIPMENT WHICH ARE PART OF NUCLEAR SAFETY FEATURE SYSTEMS.
2. DELETED
3. DELETED
4. DELETED
5. DELETED
6. COMMON ANNUNCIATOR MOV MOTOR OVERLOAD TRAIN A.

SETPOINTS SHOWN ON LOGIC DIAGRAMS ARE FOR LOGIC CLARIFICATION ONLY AND MAY BE ONLY APPROXIMATIONS OF THE ACTUAL PROCESS SETPOINT. REFER TO SETPOINT DATA SHEETS FOR ACTUAL PROCESS SETPOINTS.

SOURCE: LSK-27-15B

FIGURE 6.5-1
STANDBY GAS TREATMENT SYSTEM
LOGIC DIAGRAM
SHEET 2 OF 8

NIAGARA MOHAWK POWER CORP.
NINE MILE POINT-UNIT 2
UPDATED SAFETY ANALYSIS REPORT



NOTES:

1. ALL INSTRUMENT AND EQUIPMENT NUMBERS TO BE PREFIXED WITH "2GTS-" EXCEPT WHERE A DIFFERENT PREFIX IS SHOWN. AN ASTERISK (*) WILL REPLACE THE DASH (-) IN THE PREFIX FOR INSTRUMENTS AND EQUIPMENT WHICH ARE PART OF NUCLEAR SAFETY FEATURE SYSTEMS.
2. DELETED
3. DELETED
4. DELETED
5. DELETED
6. COMMON ANNUNCIATOR MOV MOTOR OVERLOAD TRAIN B.

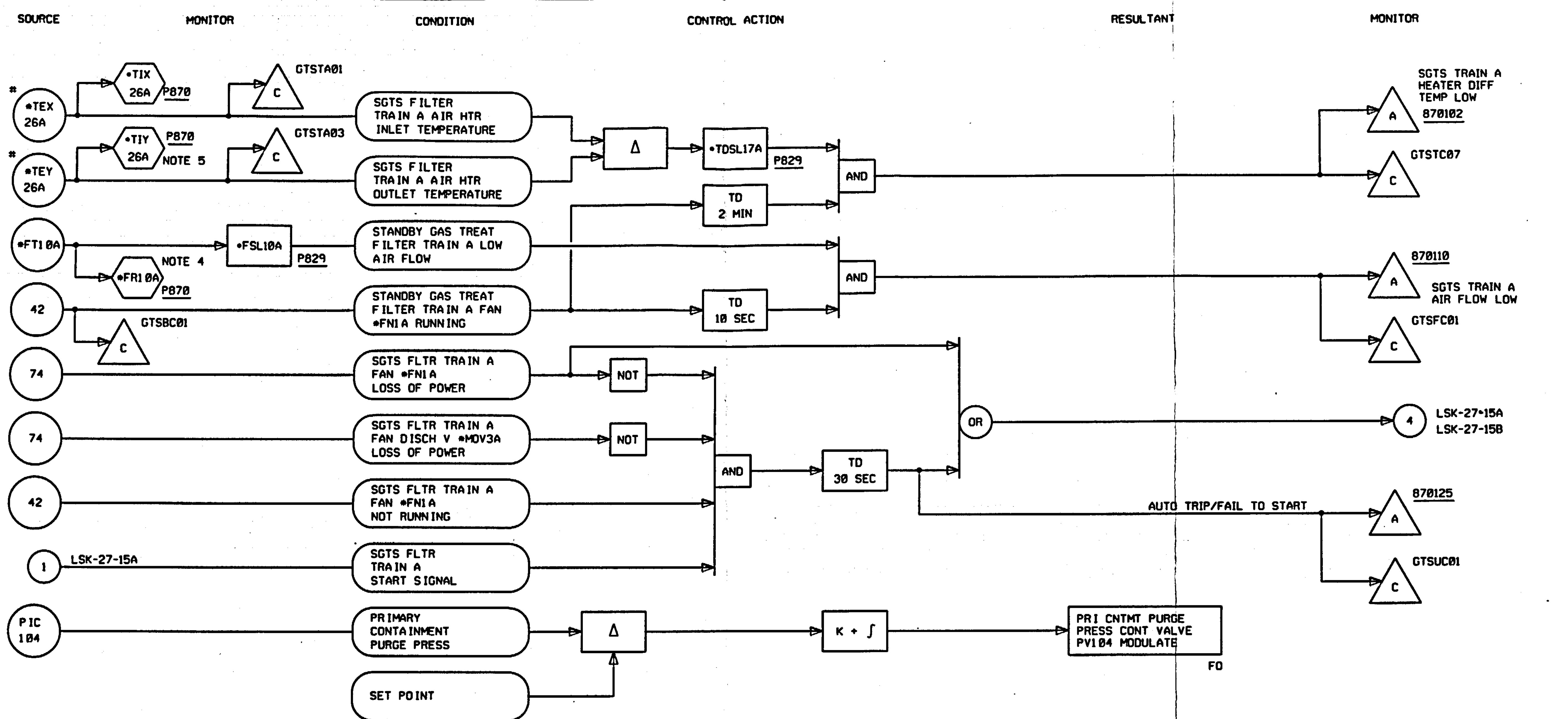
SETPOINTS SHOWN ON LOGIC DIAGRAMS ARE FOR LOGIC CLARIFICATION ONLY AND MAY BE ONLY APPROXIMATIONS OF THE ACTUAL PROCESS SETPOINT. REFER TO SETPOINT DATA SHEETS FOR ACTUAL PROCESS SETPOINTS.

SOURCE: LSK-27-15B

FIGURE 6.5-1

STANDBY GAS TREATMENT SYSTEM
LOGIC DIAGRAM
SHEET 2A OF 8

NIAGARA MOHAWK POWER CORP.
NINE MILE POINT-UNIT 2
UPDATED SAFETY ANALYSIS REPORT



NOTES:

1. ALL INSTRUMENT & EQUIPMENT NUMBERS TO BE PREFIXED WITH "2GTS-" EXCEPT WHERE A DIFFERENT PREFIX IS SHOWN. AN ASTERISK (*) WILL REPLACE THE DASH (-) IN THE PREFIX FOR INSTRUMENTS AND EQUIPMENT WHICH ARE PART OF THE NUCLEAR SAFETY FEATURE SYSTEMS.
2. DELETED
3. DELETED
4. 2-PEN RECORDER ADDITIONAL LOGIC SHOWN ON LSK-27-15C (SHARED WITH *PDIT21A)
5. *TEY26A ADDITIONAL LOGIC SHOWN ON LSK-27-15F.
6. # INDICATES VENDOR SUPPLIED EQUIPMENT.

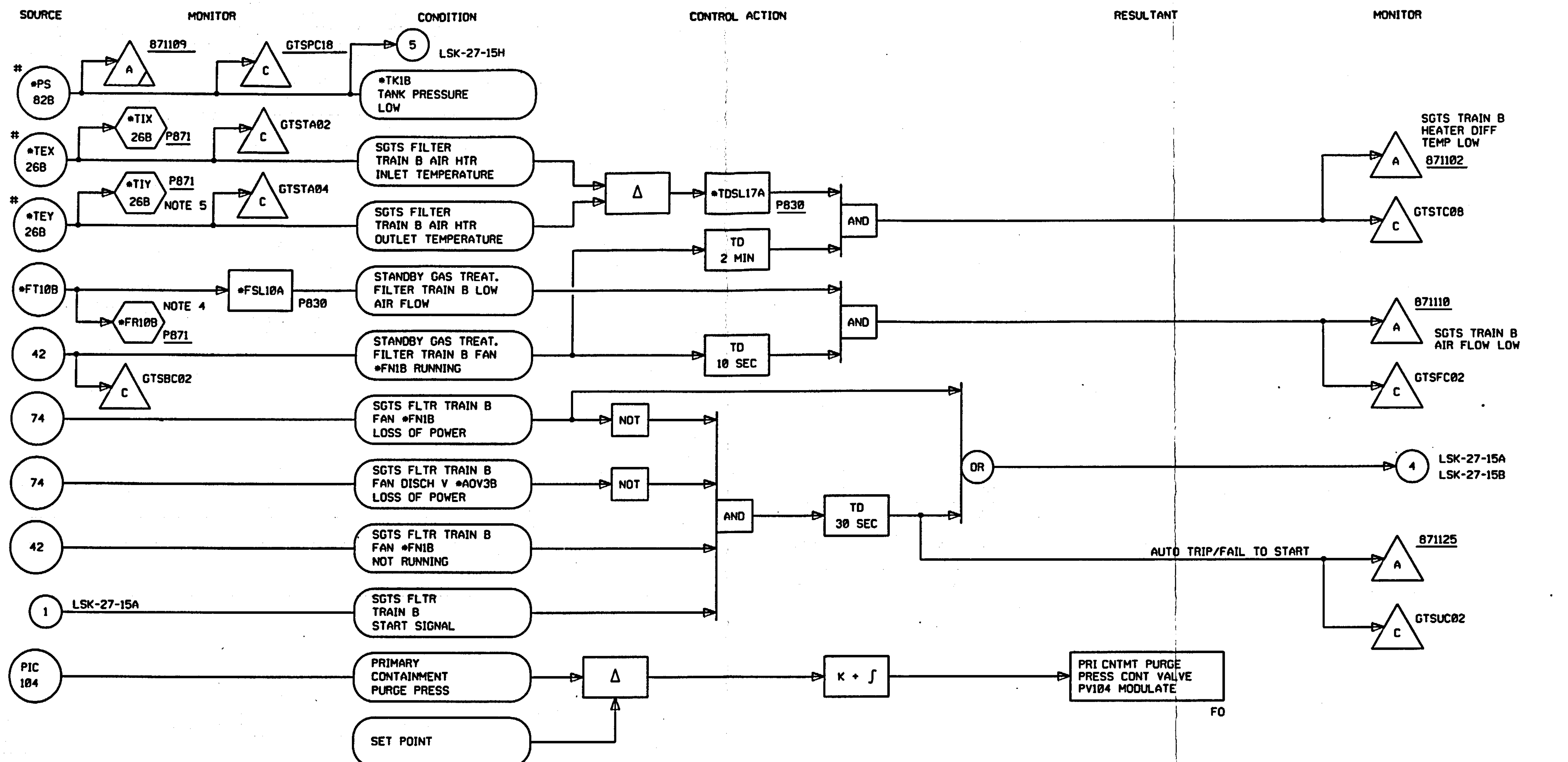
SETPOINTS SHOWN ON LOGIC DIAGRAMS ARE FOR LOGIC CLARIFICATION ONLY AND MAY BE ONLY APPROXIMATIONS OF THE ACTUAL PROCESS SETPOINT. REFER TO SETPOINT DATA SHEETS FOR ACTUAL PROCESS SETPOINTS.

SOURCE: LSK-27-15D

FIGURE 6.5-1

STANDBY GAS TREATMENT SYSTEM LOGIC DIAGRAM SHEET 4 OF 8

NIAGARA MOHAWK POWER CORP.
NINE MILE POINT-UNIT 2
UPDATED SAFETY ANALYSIS REPORT



NOTES:

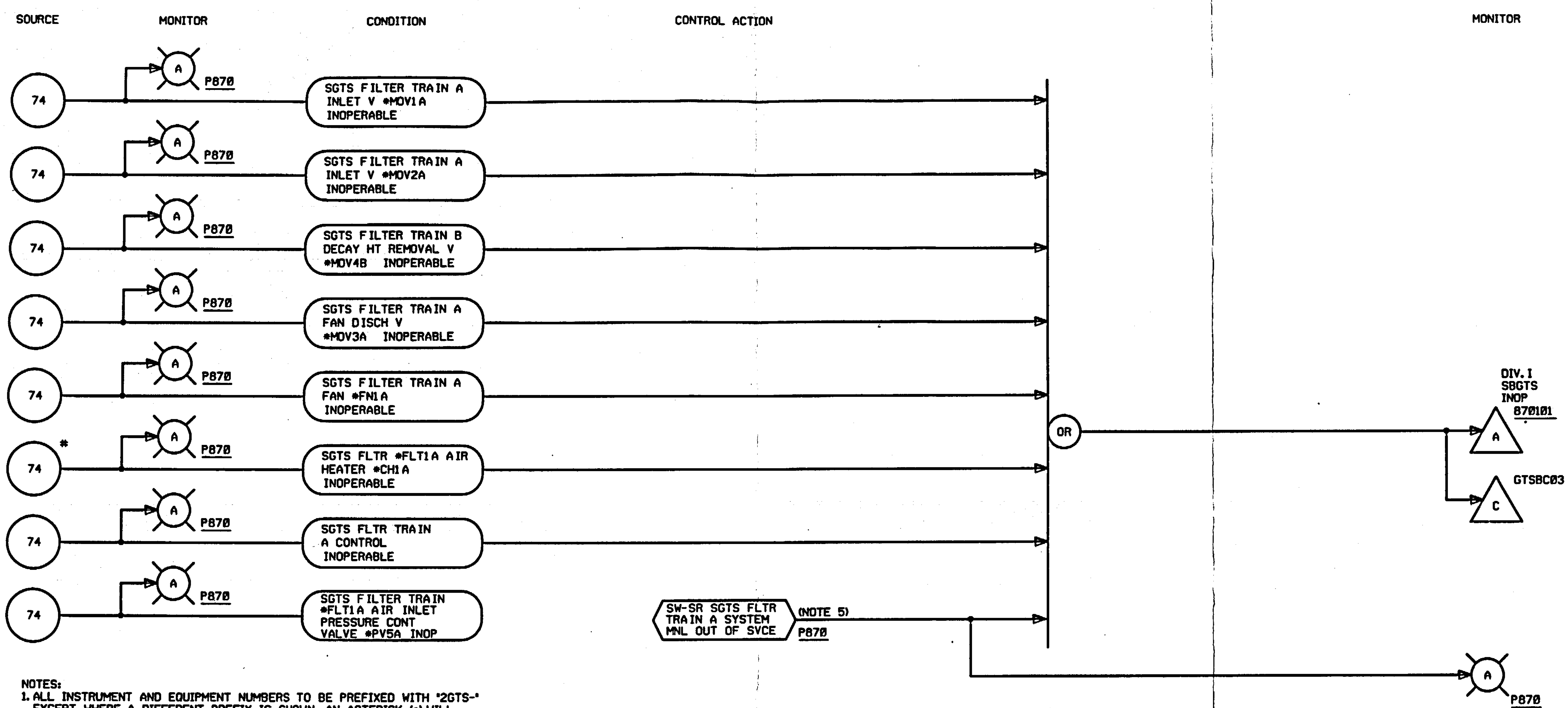
1. ALL INSTRUMENT & EQUIPMENT NUMBERS TO BE PREFIXED WITH "2GTS-" EXCEPT WHERE A DIFFERENT PREFIX IS SHOWN. AN ASTERISK (*) WILL REPLACE THE DASH (-) IN THE PREFIX FOR INSTRUMENTS AND EQUIPMENT WHICH ARE PART OF THE NUCLEAR SAFETY FEATURE SYSTEMS.
2. DELETED
3. DELETED
4. 2-PEN RECORDER ADDITIONAL LOGIC SHOWN ON LSK-27-15C (SHARED WITH *PDIT21B)
5. *TEY26B ADDITIONAL LOGIC SHOWN ON LSK-27-15F.
6. # INDICATES VENDOR SUPPLIED EQUIPMENT.

SETPOINTS SHOWN ON LOGIC DIAGRAMS ARE FOR LOGIC CLARIFICATION ONLY AND MAY BE ONLY APPROXIMATIONS OF THE ACTUAL PROCESS SETPOINT. REFER TO SETPOINT DATA SHEETS FOR ACTUAL PROCESS SETPOINTS.

SOURCE: LSK-27-15D

FIGURE 6.5-1
STANDBY GAS TREATMENT SYSTEM
LOGIC DIAGRAM
SHEET 4A OF 8

NIAGARA MOHAWK POWER CORP.
NINE MILE POINT-UNIT 2
UPDATED SAFETY ANALYSIS REPORT



NOTES:

1. ALL INSTRUMENT AND EQUIPMENT NUMBERS TO BE PREFIXED WITH "2GTS-" EXCEPT WHERE A DIFFERENT PREFIX IS SHOWN. AN ASTERISK (*) WILL REPLACE THE DASH (-) IN THE PREFIX FOR INSTRUMENTS AND EQUIPMENT WHICH ARE PART OF NUCLEAR SAFETY FEATURE SYSTEM.
2. DELETED
3. DELETED
4. # INDICATES VENDOR SUPPLIED EQUIPMENT.
5. ALTERNATE ACTION SWITCH.

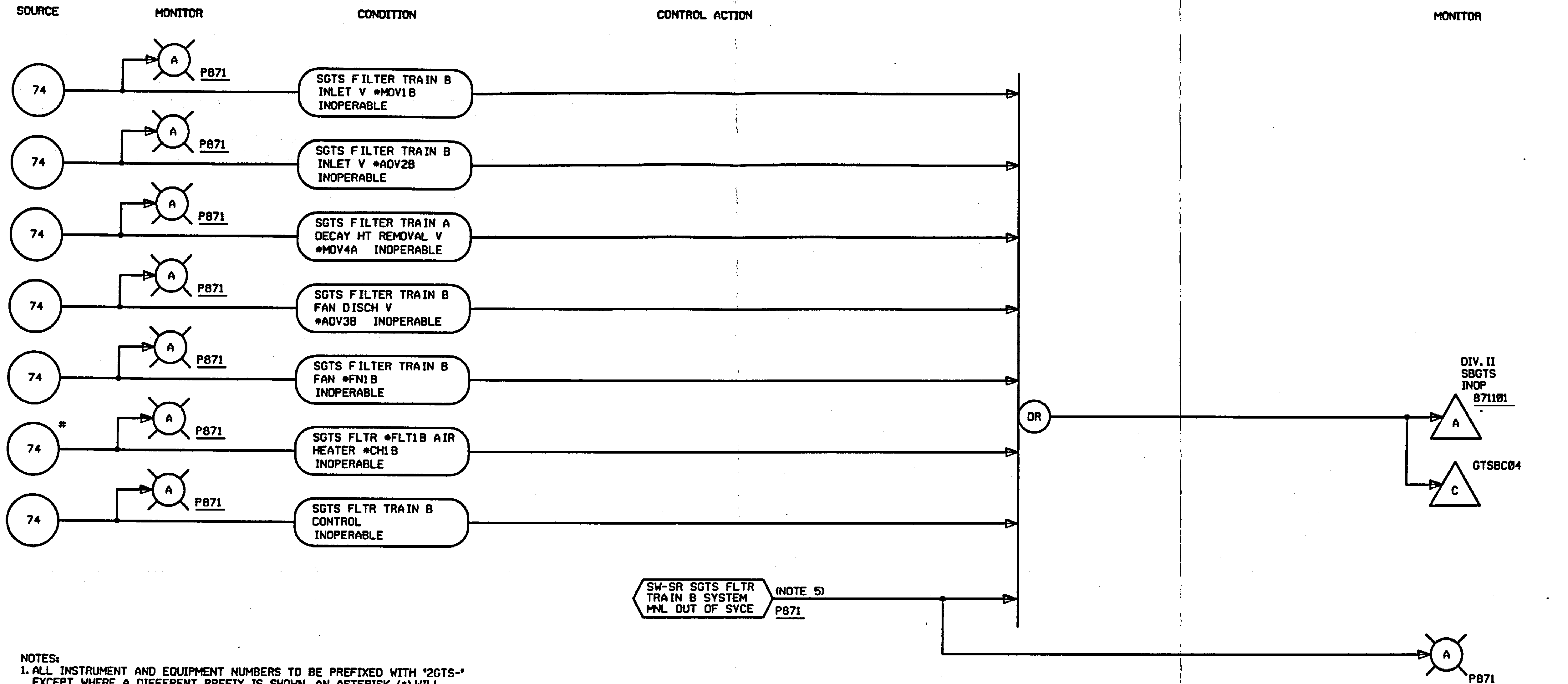
SETPOINTS SHOWN ON LOGIC DIAGRAMS ARE FOR LOGIC CLARIFICATION ONLY AND MAY BE ONLY APPROXIMATIONS OF THE ACTUAL PROCESS SETPOINT. REFER TO SETPOINT DATA SHEETS FOR ACTUAL PROCESS SETPOINTS.

SOURCE: LSK-27-15E

FIGURE 6.5-1

STANDBY GAS TREATMENT SYSTEM
LOGIC DIAGRAM
SHEET 5 OF 8

NIAGARA MOHAWK POWER CORP.
NINE MILE POINT-UNIT 2
UPDATED SAFETY ANALYSIS REPORT



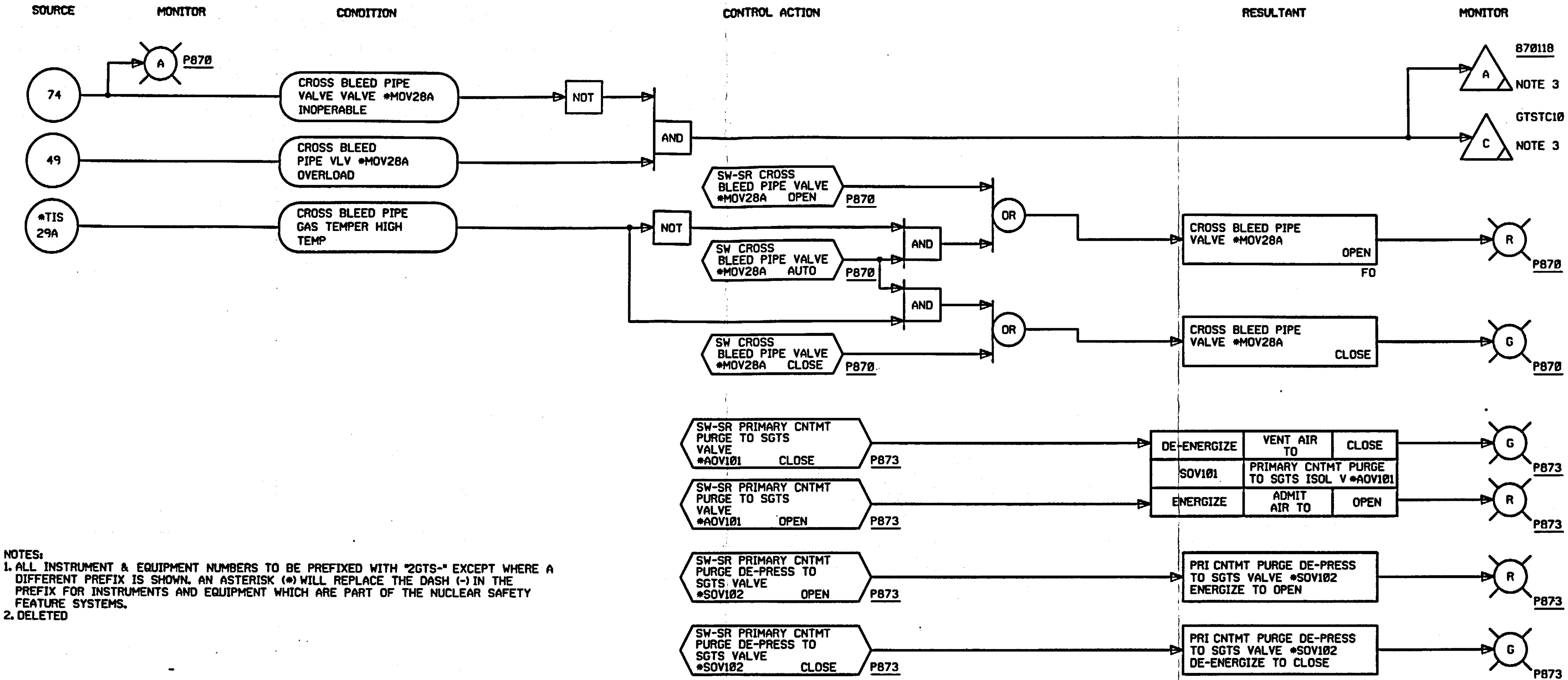
NOTES:
1. ALL INSTRUMENT AND EQUIPMENT NUMBERS TO BE PREFIXED WITH '2GTS-' EXCEPT WHERE A DIFFERENT PREFIX IS SHOWN. AN ASTERISK (*) WILL REPLACE THE DASH (-) IN THE PREFIX FOR INSTRUMENTS AND EQUIPMENT WHICH ARE PART OF NUCLEAR SAFETY FEATURE SYSTEM.
2. DELETED
3. DELETED
4. # INDICATES VENDOR SUPPLIED EQUIPMENT.
5. ALTERNATE ACTION SWITCH.

SOURCE: LSK-27-15E

FIGURE 6.5-1
STANDBY GAS TREATMENT SYSTEM
LOGIC DIAGRAM
SHEET 5A OF 8

SETPOINTS SHOWN ON LOGIC DIAGRAMS ARE FOR LOGIC CLARIFICATION ONLY AND MAY BE ONLY APPROXIMATIONS OF THE ACTUAL PROCESS SETPOINT. REFER TO SETPOINT DATA SHEETS FOR ACTUAL PROCESS SETPOINTS.

NIAGARA MOHAWK POWER CORP.
NINE MILE POINT-UNIT 2
UPDATED SAFETY ANALYSIS REPORT



NOTES:
1. ALL INSTRUMENT & EQUIPMENT NUMBERS TO BE PREFIXED WITH "2GTS-" EXCEPT WHERE A DIFFERENT PREFIX IS SHOWN. AN ASTERISK (*) WILL REPLACE THE DASH (-) IN THE PREFIX FOR INSTRUMENTS AND EQUIPMENT WHICH ARE PART OF THE NUCLEAR SAFETY FEATURE SYSTEMS.
2. DELETED

3. COMMON ANNUNCIATOR OR COMPUTER POINT FOR MOV MOTOR OVERLOAD.

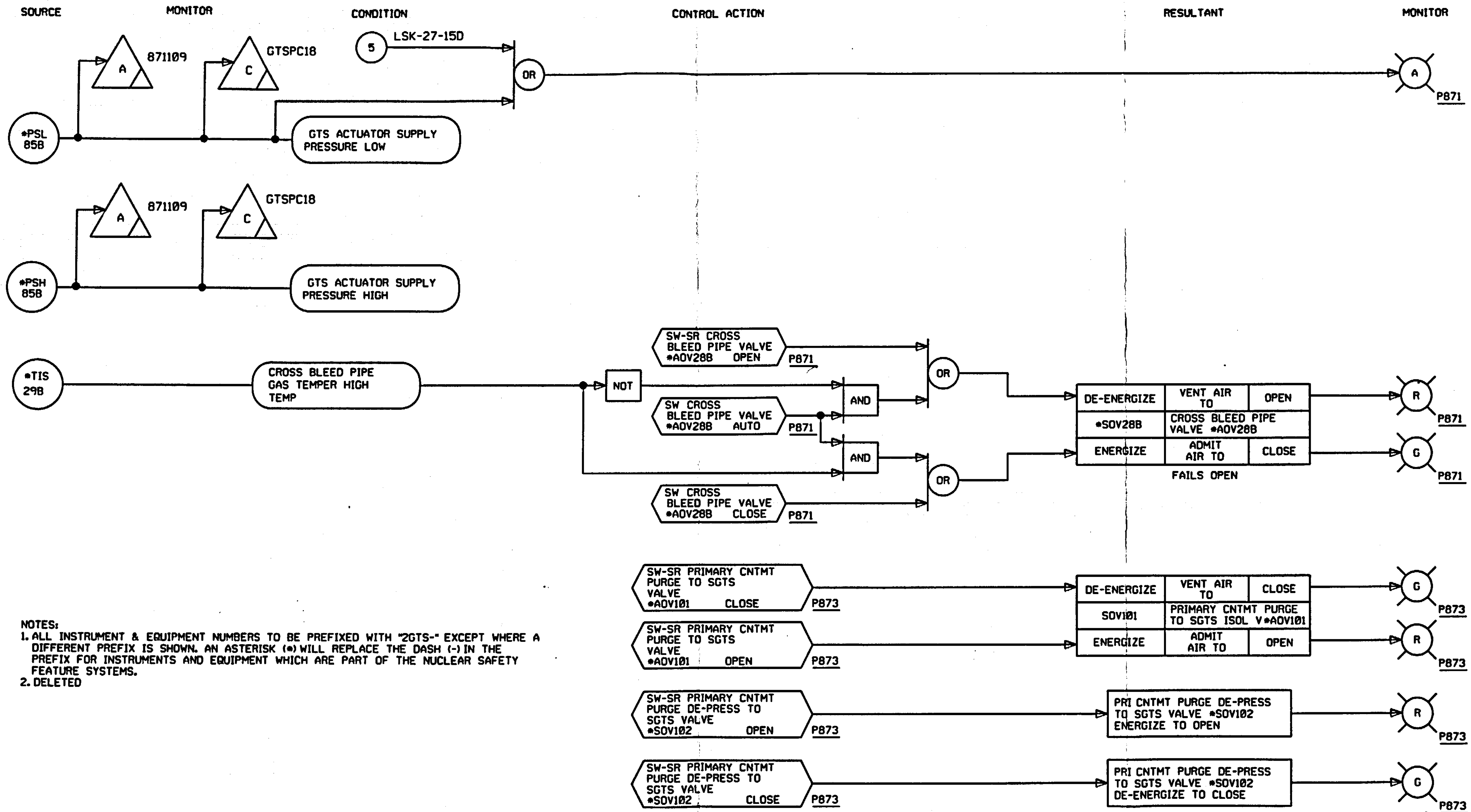
SETPOINTS SHOWN ON LOGIC DIAGRAMS ARE FOR LOGIC CLARIFICATION ONLY AND MAY BE ONLY APPROXIMATIONS OF THE ACTUAL PROCESS SETPOINT. REFER TO SETPOINT DATA SHEETS FOR ACTUAL PROCESS SETPOINTS.

SOURCE: LSK-27-15H

FIGURE 6.5-1

STANDBY GAS TREATMENT SYSTEM
LOGIC DIAGRAM
SHEET 8 OF 8

NIAGARA MOHAWK POWER CORP.
NINE MILE POINT-UNIT 2
UPDATED SAFETY ANALYSIS REPORT



NOTES:
1. ALL INSTRUMENT & EQUIPMENT NUMBERS TO BE PREFIXED WITH "2GTS-" EXCEPT WHERE A DIFFERENT PREFIX IS SHOWN. AN ASTERISK (*) WILL REPLACE THE DASH (-) IN THE PREFIX FOR INSTRUMENTS AND EQUIPMENT WHICH ARE PART OF THE NUCLEAR SAFETY FEATURE SYSTEMS.
2. DELETED

SETPOINTS SHOWN ON LOGIC DIAGRAMS ARE FOR LOGIC CLARIFICATION ONLY AND MAY BE ONLY APPROXIMATIONS OF THE ACTUAL PROCESS SETPOINT. REFER TO SETPOINT DATA SHEETS FOR ACTUAL PROCESS SETPOINTS.

SOURCE: LSK-27-15H

FIGURE 6.5-1
STANDBY GAS TREATMENT SYSTEM
LOGIC DIAGRAM
SHEET 8A OF 8

NIAGARA MOHAWK POWER CORP.
NINE MILE POINT-UNIT 2
UPDATED SAFETY ANALYSIS REPORT

6.6 INSERVICE INSPECTION OF SAFETY CLASS 2 AND 3 COMPONENTS

In compliance with the applicable portions of GDC 37, 40, 43, and 46, an inspection program was developed that includes preservice and periodic inservice inspections (ISI) of ASME Class 2 and 3 components. The preservice examinations were based on the ASME Boiler and Pressure Vessel Code, Section XI, 1980 Edition through the Winter 1980 Addenda, except for the ASME Class 2 piping in the RHR system, ECCS systems, and containment heat removal system. These examinations were based on ASME Section XI, 1974 Edition through Summer 1975 Addenda. All ASME Class 2 and 3 components that require inservice inspection or inservice testing, as required by 10CFR50.55a and specified by the applicable Code, are designed, fabricated, and erected with the objective of full compliance with the requirements of 10CFR50.55a. See Table 3.2-1 for systems or portions of systems which are nonsafety related but were designed, fabricated and erected to ASME Class 2 or 3 requirements (optionally upgraded) and are not inservice inspected to ASME Section XI.

6.6.1 Components Subject to Examination

ASME Class 2 and 3 components are classified in accordance with the criteria of RG 1.26. ASME Class 2 components will be inservice inspected in accordance with and to the extent required by ASME XI, Subsection IWC and Table IWC-2500-1 (except as noted in Table 3.2-1), per the requirements of 10CFR50.55a.

ASME Class 3 components will be inservice inspected in accordance with and to the extent required by ASME Section XI, Subsection IWD and Table IWD-2500-1 (except as noted in Table 3.2-1), per the requirements of 10CFR50.55a.

Refer to Section 3.9A.6 for a description of inservice testing (IST) of pumps and valves.

6.6.2 Accessibility

The design and arrangement of ASME Class 2 components provide access for ISI required by ASME Section XI, Subsection IWC. Wherever possible, adequate access is provided for performance of required volumetric and surface examinations specified in ASME Section XI, Table IWC-2500-1. ASME Class 2 welds that will receive ultrasonic examination are smoothed, contoured, and finished in order to permit an acceptable examination of the welds.

The design and arrangement of ASME Class 3 and exempt ASME Class 2 components provide for performance of all visual inspection techniques and surveys to meet the requirements of ASME Section XI, Subsection IWD, Table IWD-2500-1. Special design considerations are given to those systems that are intended to be examined during normal plant operation. In some cases, special access platforms and ladders are provided to expedite ISI activities where no other permanent access is available. Items that are not readily accessible will be identified in the ISI program.

6.6.3 Examination Techniques and Procedures

ISI examination techniques for ASME Class 2 systems and components are volumetric, surface, and visual, in accordance with the requirements of Table IWC-2500-1 of ASME Section XI. Ultrasonic techniques are generally employed where volumetric examination is required, and either liquid penetrant or magnetic particle techniques are employed where surface examination is required. Visual examinations are conducted in accordance with the requirements of ASME Section XI, Table IWC-2520-1 and Subsubarticle IWA-2210.

ASME Class 3 systems and components are given a visual examination during system inservice tests, component functional tests, or system pressure tests, in order to detect evidence of component leakage, structural distress, or corrosion, in accordance with the requirements of Table IWD-2500-1 and Subsubarticle IWA-2210 of ASME Section XI.

6.6.4 Inspection Intervals

For ASME Class 2 systems and components, an ISI schedule will be developed in accordance with ASME Section XI, Subarticle IWC-2400, and Table IWC-2500-1. The inspection schedule will be detailed in the ISI program. ISI for ASME Class 3 systems and components is conducted when systems are undergoing either a system inservice test, component functional test, or system pressure test as specified by ASME Section XI, Subarticle IWD-2400 and Table IWD-2500-1.

6.6.5 Examination Categories and Requirements

The ISI categories and requirements for ASME Class 2 systems and components are in agreement with and are designed to permit ISI required by ASME Section XI, Table IWC-2500-1.

ISI categories and requirements for ASME Class 3 systems and components are in agreement with and are designed to permit ISI required by ASME Section XI, Table IWD-2500-1.

6.6.6 Evaluation of Examination Results

Evaluation of preservice examination results of ASME Class 2 and 3 components will be in accordance with the evaluation criteria specified in ASME Section XI, Article IWB-3000. Repair procedures for ASME Class 2 components will comply with the repair rules of ASME Section XI, IWC-4000. Repair procedures for ASME Class 3 components will comply with the repair rules of ASME XI, IWD-4000.

6.6.7 System Pressure Tests

System pressure tests on ASME Class 2 systems and components will be conducted to comply with the criteria established in ASME Section XI, Article IWC-5000. System pressure tests on ASME Class 3 systems and components will be conducted to comply with the criteria established in ASME Section XI, Article IWD-5000.

6.6.8 Augmented Inservice Inspection to Protect Against Postulated Piping Failures

No augmented ISI will be required for ASME Class 2 and 3 systems and components since there is no ASME Class 2 or 3 high-energy piping between containment isolation valves. As indicated in Table 1.9-1, Note 12, Difference 3, B31.1 Class 2 and Class 3 piping exists between the containment isolation valve and the associated first restraint. During each inspection interval, as defined in IWA-2400, an ISI is performed on all nonexempt ASME Code, Section XI circumferential and longitudinal welds within the break exclusion region for B31.1 Class 2 and 3 high-energy fluid system piping. These inspections consist of augmented volumetric examinations (nominal pipe size greater than or equal to 4 in) and augmented surface examinations (nominal pipe size less than 4 in) such that 100 percent of the previously defined welds are inspected at each interval. The break exclusion zone consists of those portions of high-energy fluid system piping between the moment limiting restraint(s) outboard of the outside primary containment isolation valve and the moment limiting restraint(s) beyond the inside primary containment isolation valve. The criteria that determine which restraint(s) are chosen to determine the limits of the break exclusion zone are based upon those restraints which are necessary to ensure the operability of the primary containment isolation valves.

APPENDIX 6B

THREED SUBCOMPARTMENT ANALYTICAL MODEL

APPENDIX 6B

THREED SUBCOMPARTMENT ANALYTICAL MODEL

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APPENDIX 6B

THREED SUBCOMPARTMENT ANALYTICAL MODEL

6B.1 FUNCTIONAL DESCRIPTION OF THREED CODE

The THREED computer program is used to calculate the transient conditions of pressure, temperature, and humidity in various subcompartments following a postulated rupture in a moderate- or high-energy pipeline. The results obtained from THREED analyses are used to calculate loads on structures and to define environmental conditions for equipment qualification.

The THREED computer program is similar to RELAP4 and will give the same results as RELAP4 if similar options are chosen[1,2]. THREED was formulated to perform subcompartment analyses with capabilities and options extended beyond those available in RELAP4. A significant improvement in THREED is that the homogeneous equilibrium model (HEM) has been extended to include two-phase, two-component flow which is encountered in subcompartment analysis.

6B.2 DESCRIPTION OF THE MODEL

The THREED computer code can be viewed as a numerical integrator for the macroscopic form of the basic field equations describing the conservation of mass, energy, and momentum. The conservation equations, along with the equation of state for the fluid, give a complete solution to the fluid flow phenomena. THREED solves a stream tube form of the field equations based on the assumptions of one-dimensional, homogeneous, thermal-equilibrium flow. Although THREED does not prohibit the use of multidimensional flow paths, the flow paths are modeled to approximate a one-dimensional equation.

Subcompartments are modeled in THREED as a hydraulic network that consists of a series of interconnecting, user-defined nodes (mass and energy control volumes). Nodes are connected by internal junctions (momentum control volumes) with the internodal flow rates determined by the solution of the momentum equation. An internal junction control volume is defined as the composite volume between the centers of adjacent nodes. This difference in control volumes (i.e., a different control volume for momentum than for mass and energy) is illustrated on Figure 6B-1. This "staggered mesh" approximation is necessary for purposes of solving the equations.

Fill junctions are used to simulate flow originating external to the network (i.e., blowdown). These fill junctions are dissimilar to internal junctions in that they have no initial node, and their flow rate is dependent only on the junction area and time. Mathematically, they are treated as boundary conditions.

THREED numerically solves finite difference equations that account for mass and energy flows into and out of a node. Figure 6B-2 summarizes the computational approach used in THREED.

The fluid conservation equations used by THREED can be obtained by integrating the stream tube equations over a fixed volume, V. The mass and energy equations are developed for the generalized i^{th} node, while the momentum equation is developed for the generalized j^{th} internal junction connecting nodes K and L. Neglecting kinetic energy effects, the resulting equations are as follows.

Conservation of Mass The mass equation is[1]:

$$\frac{dM_i}{dt} = \sum_j w_{ij} \tag{6B-1}$$

Where:

M_i = Total mass of fluid in node i ($M_i = M_{wi} + M_{ai}$)

M_{wi} = Total mass of water in node i

M_{ai} = Total mass of air in node i

W_{ij} = Mass flow rate into node i from junction j

Conservation of Energy The energy equation for homogeneous flow is[1]:

$$\frac{dU_i}{dt} = \sum_j w_{ij} \left(h_{ij} + Z_{ij} - \overline{Z_i}\right) \tag{6B-2}$$

Where:

U_i = Total fluid internal energy of water in node i

h_{ij} = Local enthalpy at junction j of the fluid entering or leaving node i

$Z_{ij} - Z_i$ = Elevation change from the center of mass in node i at Z_i to junction j

Conservation of Momentum The incompressible equation for homogeneous flow is[1]:

$$I_j \frac{dW_j}{dt} = \left(P_K + P_{Kgj}\right) - \left(P_L + P_{Lgj}\right) - F_j \qquad (6B-3)$$

Where:

I_j = Geometric "inertia" for junction j

W_j = Mass flow rate in junction j

P_K = Total static pressure in node K (at center)

P_{Kgj} = Gravity pressure differential from the center of node K to junction j

P_L = Total static pressure in node i (at center)

P_{Lgj} = Gravity pressure differential from junction j to the center of node L

F_j = Static pressure change term

Equation of State The functional form of the equation of state is:

$$P_i = f\ (U_i,\ M_{wi},\ M_{ai}) \qquad (6B-4)$$

Where:

P_i = Total static pressure in node i

The following assumptions are made in deriving the equation of state:

1. The components of water and air form a homogeneous mixture at a uniform temperature.

2. Water, if present, occupies the entire volume. Air, if present, occupies the same volume as the water vapor according to the Gibbs-Dalton Law. Air is assumed to be insoluble in water, and there can be no air present if the volume is filled with water.

3. Air is treated as a perfect gas.

4. If air and water are present, the water vapor is saturated (relative humidity of 100 percent).

5. If air is present, the water conditions are the saturated conditions for P_{wi}. A more accurate model would have liquid at the subcooled conditions corresponding to P_i and T_i. This assumption is made

to limit calls to the water property routines to one per iteration.

If no water is present in the volume ($M_w = 0$), the detailed form of the equation of state is:

$$U_i = M_{ai} C_{va} T_i \tag{6B-5}$$

$$P_i = \frac{M_{ai} R_a T_i}{V_i} \tag{6B-6}$$

Where:

C_{va} = Constant volume heat capacity of air

T_i = Temperature in node i

R_a = Gas constant of air

V_i = Volume of node i

If water is present in the volume ($M \neq 0$), the detailed form of the equation of state is:

$$V_{wi} = M_{wi}/V_i \tag{6B-7}$$

$$U_i = M_{wi} U_{wi}(T_i, V_{wi}) + M_{ai} C_{va} T_i \tag{6B-8}$$

$$P_{ai} = \frac{M_{ai} R_a T_i}{X_i M_{wi} V_{gi}(T_i, V_{wi})} \tag{6B-9}$$

$$P_i = P_{wi}(T_i, V_{wi}) + P_{ai} \tag{6B-10}$$

Where:

V_{wi} = Specific volume of water in node i

U_{wi} = Specific internal energy of water in node i

P_{ai} = Partial pressure of air in node i

X_i = Quality in node i

V_{gi} = Specific volume of water vapor in node i

P_{wi} = Partial pressure of water in node i

The internal code calculations are done in SI units. The reference temperature used for the calculation of the internal energy of air is 0°K. The properties of steam are based on the 1967 ASME formulation of the properties of steam.

Fill Junctions These are normally used to input blowdown (mass and energy release) into a node(s). Their functional form is:

$$W_j = f(t) \tag{6B-11}$$

$$h_{ij} = f(t) \tag{6B-12}$$

Fan Junctions These junctions may be used to model ventilation fan operation in situations where such modeling is appropriate. Their functional form is:

$$W_j = f(H_j) \tag{6B-13}$$

Where:

H_j = Head difference across the fan junction

Choked Flow Options For Internal Junctions Since an incompressible flow model has no mechanism to restrict flow through a junction to the maximum allowable (choked) flow rate, it is necessary to use a separate calculation to restrict the flow rate. To determine if the flow is choked, the momentum equation 6B-3 is solved using a forward finite difference approximation and compared with a calculated choked flow (HEM or Moody). The lesser flow is selected as the junction flow rate for the time step.

Both the HEM and the Moody flow models are based on stagnation properties. Since it is not usually possible to calculate the velocity in a node, it is assumed that the static and stagnation properties in a node are the same (i.e., neglect kinetic energy effects). This may result in an underprediction of the choked flow rate, which is conservative in most cases.

Homogeneous Equilibrium Model The HEM is approximated in THREED using an "ideal gas" approximation. That is, the choked isentropic ideal gas flow equation is used and the isentropic exponent is modified to accommodate two-phase, two-component flow. The isentropic exponent is defined as:

$$\gamma_i = -\frac{V_{wi}}{P_i}\left(\frac{\partial P_i}{\partial V_{wi}}\right)_s$$

(B-14)

Where:

γ_i = Isentropic exponent in node i

The equation used by THREED to calculate the HEM is:

$$W_j = 12\, A_j \left(\frac{2}{\gamma_i + 1}\right)^b \left(g_c \gamma_i \frac{P_{ai}}{V_{ai}}\right)^{1/2}$$

(6B-15)

Where:

b = $(\gamma_i + 1)/2(\gamma_i - 1)$

A_j = Flow area of junction' j, sq ft

γ_i = Isentropic exponent of source node i

g_c = Proportionality constant - 32.174, ft-lbm/lbf-sec^2

P_{ai} = Stagnation pressure in source node i, psia

V_{ai} = Stagnation specific volume of air in source node i, cu ft/lbm

W_j = Mass flow in junction j, lbm/sec

Moody Choked Flow Model The Moody flow model, used in THREED, is based on the interpolation of tables from RELAP4/MOD5[1,3]. The model is for one-component flow and, when air is present, the tables are accessed with the total pressure and average enthalpy of the node.

Junction Check Valves A valve may be modeled in any nonfan internal junction as follows:

Normally closed - trips open instantaneously

Normally open - trips closed instantaneously

Time Step Control If the automatic time step control option is selected, the maximum time step will be limited by the following calculation, based on the nodal conditions[1]:

$$DT = \min \left\{ 0.01 \left| \frac{P_i}{\dot{P}_i} \right| \right\} \tag{6B-16}$$

Where:

i	=	1,...,n
DT	=	Time step size
$\dot{P}_i$	=	dP/dt

6B.3 ASSUMPTIONS EMPLOYED IN THREED

The following assumptions are employed in THREED:

1. Lumped parameter (control volume) approach utilized.
2. Adiabatic process.
3. Independent inflow (blowdown).
4. Thermodynamic equilibrium in each node.
5. One-dimensional formulation.
6. Staggered mesh for the conservation equations.
7. Homogeneous flow, unless the Moody choking option is chosen.
8. Incompressible form of the momentum equation.
9. Kinetic energy effects neglected.
10. For choked flow models, static properties in the nodes considered to be stagnation properties.
11. Valves open or close instantaneously.

6B.4 REFERENCES

1. RELAP4/MOD5: A Computer Program for Transient Thermal Hydraulic Analysis of Nuclear Reactors and Related Systems. User's Manual, Vol. I-III, Report ANCR-NUREG-1335. Aerojet Nuclear Company, September 1976.

2. Moore, K. V. and Rettig, W. H. RELAP4 - A Computer Program for Thermal Hydraulic Analysis. Report ANCR-1127 Aerojet Nuclear Company, August 1974.

3. Moody, L. J. Maximum Flow Rate of a Single Component, Two-Phase Mixture. Journal of Heat Transfer, Trans ASME, Vol. 87, 1965, pp 134-142.

CHAPTER 7

INSTRUMENTATION AND CONTROL SYSTEMS

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CHAPTER 7

INSTRUMENTATION AND CONTROL SYSTEMS

7.1 INTRODUCTION

Chapter 7 presents specific detailed design and performance information for instrumentation and control of safety-related and major plant control systems. The design and performance considerations of these systems, their safety functions, and their mechanical aspects are described in other chapters. See Section 1.2 for plant layout drawings.

7.1.1 Identification of Safety-Related Systems

The systems discussed in Chapter 7 are categorized as reactor protection (trip) system (RPS), engineered safety feature (ESF) systems, safe shutdown systems, safety-related display instrumentation (SRDI), other systems required for safety, and control systems not required for safety. Table 7.1-1 lists safety-related systems and identifies the designer and/or the supplier. Nonsafety-related systems are listed in Table 7.7-1. Table 7.1-2 identifies plant instrumentation and control systems that are similar or identical to those of nuclear power plants of similar design that have recently received Nuclear Regulatory Commission (NRC) design or operation approval through the issuance of either a construction permit or an operating license. The comparisons shown in Table 7.1-2 were considered valid at the time the operating license was issued.

Unit 2 safety-related systems are designed to conform with the requirements of IEEE Standard 279-1971. The inherent redundancy designed in the control of the reactor is such that all trip functions are redundant at the trip system level, trip function level, or both.

> Example 1: Redundant instrument channels, each causing the closure of a valve, are redundant at the trip system level.
>
> Example 2: Two completely independent trip functions, each causing the closure of one isolation valve (one inboard, the other outboard), are redundant at the trip function level.

The following is an identification of RPS, ESF systems, safe shutdown systems, SRDI, and other systems required for safety. Detailed descriptions of the controls and instrumentation for these systems are provided in Sections 7.2 through 7.6.

7.1.1.1 Reactor Protection (Trip) System

Instrumentation and controls initiate reactor shutdown via automatic control rod insertion (scram) if selected variables exceed preestablished limits. This action prevents fuel damage, limits nuclear system pressure, and restricts the release of radioactive material.

7.1.1.2 Engineered Safety Features Systems

The following is a list of ESF systems and a cross-reference to the sections where design and performance characteristics are discussed:

	Section
Emergency core cooling systems (ECCS, HPCS, ADS, LPCS, and LPCI)	6.3, 7.3.1.1.1
Primary containment and reactor vessel isolation control system (PCRVICS)	7.3.1.1.2
RHR/containment spray cooling mode (RCSCM)	7.3.1.1.3
RHR/suppression pool cooling mode (RSPCM)	7.3.1.1.4
Standby gas treatment system (SGTS)	6.5.1
Combustible gas control system (CGCS)	6.2.5
Reactor building heating, ventilating, and air conditioning (HVAC) system	9.4.2
Service water system (SWP)	9.2.1
Service water pump bays ventilation system	9.4.7.2.2
Control building heating, ventilating, and air conditioning (HVAC) system	9.4.1
Control building chilled water system	9.4.10
Standby power system	9.5.4-9.5.8
Diesel generator building, heating, ventilating, and air conditioning (HVAC) system	9.4.6

7.1.1.3 Systems Required For Safe Shutdown

The following is a list of systems required for safe shutdown and a cross-reference to the sections where the design and performance characteristics are discussed:

7.2 REACTOR PROTECTION (TRIP) SYSTEM INSTRUMENTATION AND CONTROLS

7.2.1 Reactor Protection System Description

7.2.1.1 Reactor Protection System Function

The RPS is a dual-trip electrical alarm and actuating system designed to prevent the reactor from operating under unsafe or potentially unsafe conditions. The RPS is designed to provide a signal to cause rapid insertion of control rods (scram) and shut down the reactor when specific variables exceed predetermined limits.

7.2.1.2 Reactor Protection System Operation

Arrangements of RPS logic, instrumentation, equipment, and information displayed to the Operator are shown on Figure 7.2-1. The RPS instrumentation is shown in Table 7.2-1. Sensor channel arrangements are shown on Figure 7.2-1. The RPS power supply is discussed in Chapter 8.

The RPS instrumentation is divided into trip channels, trip logics, and trip actuator logics. During normal operation all trip channels, trip logics, and trip actuator logics essential to safety are energized.

The RPS design is based on two separate (A and B) trip systems. Each trip system has at least two independent trip channels (A1, A2, and B1, B2). Each trip channel is associated with trip logics of the same designation.

Trip logics A1 and A2 (Trip System A) outputs are combined in a one-out-of-two logic arrangement to control the A pilot scram valve solenoid in each of the four rod groups (a rod group consists of approximately 25 percent of the total of control rods). Trip logics B1 and B2 (Trip System B) outputs control the B pilot scram valve solenoid in each of the four rod groups.

When a trip channel contact opens, the trip logic de-energizes the trip actuator logic which de-energizes the pilot scram valves associated with that trip actuator logic. However, the other pilot scram valves for each rod must also be de-energized before the scram valves provide a reactor scram.

There is one dual-coil pilot scram valve and two scram valves for each control rod. The pilot scram valve is solenoid operated, with both solenoids normally energized. The pilot scram valves control the air supply to the scram valves for each control rod. With either pilot scram valve solenoid energized, air pressure holds the scram valves closed. The scram valves control the supply and discharge paths for CRD water.

When trip logics A1 or A2 and B1 or B2 are tripped, air is vented from the scram valves and allows CRD water to act on the CRD piston. This logic is one-out-of-two twice logic. Thus, all control rods are scrammed. The water displaced by the movement of each rod piston is exhausted into a scram discharge volume (SDV).

To restore the RPS to normal operation following any single actuator logic trip or a scram, the trip actuators must be reset manually. After a 10-sec delay, reset is possible only if the conditions that caused the scram have been cleared. The trip actuators are reset by operating switches in the control room. Four reset switches (one per trip channel) are provided.

There are two 125-V dc solenoid-operated backup scram valves that provide a second means of controlling the air supply to the scram valves for all control rods. When the solenoid for either backup scram valve is energized, the associated backup scram valve vents the air supply for the scram valves. This action initiates insertion of any withdrawn control rods regardless of the action of the scram pilot valves. The backup scram valves solenoids are energized (initiate scram) when the trip logics A1 or A2 and B1 or B2 are both tripped. They are energized by two separate Class 1E 125-V dc buses (Div. I, Div. II) making them electrically independent from the ac-operated pilot scram solenoid valve. Verification of backup pilot scram solenoid valve operation will be determined by postscram analysis as required by procedures.

The RPS power system is discussed in Section 8.3.1.

Sensor trip channel inputs to the RPS causing reactor scram are discussed in the following paragraphs.

7.2.1.2.1 Neutron Monitoring System

Neutron flux is monitored to initiate a reactor scram when predetermined limits are exceeded.

NMS instrumentation is described in Section 7.6.

The NMS sensor channels are part of the NMS and not the RPS; however, the NMS logics are part of the RPS. Each NMS-IRM logic receives its signal from one intermediate range monitor (IRM) channel, each average power range monitor (APRM) logic receives its signal from one APRM channel, and each oscillation power range monitor (OPRM) logic receives its signal from one OPRM channel. The output logics of the APRM, OPRM and IRM are combined to initiate the RPS trip circuit.

The NMS logics are arranged so that failure of any one logic cannot prevent the initiation of a high neutron flux, thermal power, or oscillation scram. As shown on Figure 7.6-8, there are eight NMS logics associated with the RPS. Each RPS trip channel receives inputs from two NMS logics. See Sections 7.6.1.4.1 and

7.6.1.4.3, respectively, for further discussions concerning the IRM and APRM/OPRM trip functions to RPS.

For the initial fuel load, high-high flux trip inputs from each source range monitor (SRM) produce a noncoincident reactor NMS trip. Following the initial fuel loading this noncoincident trip is removed. For subsequent refueling operations, the ability of the SRMs to produce a noncoincident NMS trip signal is governed by the method of refueling and the associated Technical Specifications implications.

The NMS scram logic trip contacts for IRM and APRM/OPRM can be bypassed by selector switches located in the main control room. IRM channels A, C, E, and G bypasses are controlled by one selector switch, and channels B, D, F, and H bypasses are controlled by a second selector switch. Each selector switch will bypass only one IRM channel at any time.

A single selector switch allows bypass of one of the four APRM/oscillation power range monitor (OPRM) channels. None of the four two-out-of-four voter channels may be bypassed.

Bypassing either an APRM/OPRM or an IRM channel will not inhibit the NMS from providing protective action where required.

Intermediate Range Monitor The IRMs monitor neutron flux between the upper portion of the SRM range to the lower portion of the APRM range. The IRM detectors are positioned in the core by remote control from the control room.

The IRM is divided into two groups of four IRM channels in each group. Two IRM channels are associated with each of the trip channels of the RPS. The arrangement of IRM channels allows one IRM channel in each group to be bypassed.

Each IRM channel includes four trip circuits. One trip circuit is used as an instrument trouble trip. It operates on three conditions:

1. When the high voltage drops below a present level,
2. When one of the modules is not plugged in, or
3. When the OPERATE-CALIBRATE switch is not in the OPERATE position.

Each of the other trip circuits is specified to trip when preset downscale or upscale levels are reached.

The trip functions actuated by the IRM trips are indicated in Table 7.6-4. The reactor mode switch determines whether IRM trips are effective in initiating a reactor scram. With the reactor mode switch in REFUEL, STARTUP, or SHUTDOWN, an IRM upscale or inoperative trip signal actuates a NMS trip of the

RPS. Only one of the IRM channels must trip to initiate a NMS trip of the associated RPS trip channel.

Average Power Range Monitors The APRM channels receive and average input signals from the local power range monitoring (LPRM) channels and can provide a continuous indication of average reactor power from a few percent to greater than rated reactor power.

The APRMs supply trip signals to the RPS via two-out-of-four voter channels. Table 7.6-6 lists the APRM trip functions. The APRM upscale thermal power scram trip setpoints vary as a function of reactor recirculation loop flow. Each APRM channel receives a flow signal representative of total recirculation flow. This signal is provided by summing the flow signals from the two recirculation loops. These flow signals are sensed from four pairs of elbow taps, two in each recirculation loop. The APRM signal for the thermal power scram trip is passed through a 6-sec time constant circuit to simulate thermal power. A faster response (approximately 0.09 sec) APRM upscale trip has a fixed setpoint, not variable with recirculation flow. Any APRM upscale or inoperative trip initiates a NMS trip in the RPS. Only the trip logic associated with that APRM is affected. At least two APRM channels must trip to cause a scram. The Operator can bypass only one APRM channel.

In addition to the IRM upscale trip, an APRM trip function with a setpoint of 15-percent power is active when the reactor mode switch is in the STARTUP position or while in the refueling operational condition and performing shutdown margin demonstrations.

Diversity of trip initiation for excursions in reactor power is provided by the NMS trip signals and reactor vessel high-pressure trip signals. An increase in reactor power will initiate protective action from the NMS as discussed in the above paragraphs.

This increase in power results in a reactor pressure increase due to a higher rate of steam generation. The turbine control valve will stay open until the load limit of the turbine generator occurs. Once the pressure control limits are reached, reactor pressure will increase until the reactor vessel high-pressure trip results. These variables are independent of one another and provide diverse protective action for this condition.

Oscillation Power Range Monitor Each APRM chassis includes an OPRM function. The OPRM monitors LPRM detector signals to detect thermal-hydraulic instabilities in the reactor and initiates a reactor scram if the oscillations exceed predefined levels. An OPRM channel processes LPRM detector data and total recirculation flow data associated with the APRM channel in which the OPRM is located. The OPRMs supply trip signals to the RPS via two-out-of-four voter channels. In addition, the OPRM trips are voted separately from the APRM trips in the two-out-of-four voter channels. The OPRM trip is enabled only when the reactor core flow, as measured by the recirculation, is below approximately 60 percent and the reactor power is above approximately 30 percent. The OPRM is discussed in Section 7.6.1.4.3 and the OPRM functions are listed in Table 7.6-6.

7.2.1.2.2 Other Trip Signals

1. Reactor Vessel High Pressure A reactor vessel pressure increase during reactor operation compresses the steam voids and results in increased reactivity; this causes increased core heat generation that could lead to fuel barrier failure and reactor overpressurization. A scram counteracts a pressure increase by quickly reducing core fission heat generation. The reactor vessel high-pressure scram works in conjunction with the pressure relief system to prevent reactor vessel

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7.2.2.2.1 Conformance to IEEE-279-1971

Paragraph 4.1 The RPS automatically initiates the appropriate protective actions, whenever the conditions described in Section 7.2.1 reach predetermined limits, with precision and reliability assuming the full range of conditions and performance discussed in Section 7.2.1.4.

Paragraph 4.2 Each of the conditions (variables) described in Section 7.2.1 is monitored by redundant sensors supplying input signals to redundant trip logics. Independence of redundant RPS equipment, cables, instrument tubing, etc., is maintained and single-failure criteria preserved through the application of the separation criteria, as described in Section 8.3, to assure that no single credible event can prevent the RPS from accomplishing its safety function.

Paragraph 4.3 For a discussion of the quality of RPS components and modules, refer to Sections 3.2 and 3.11.

Paragraph 4.4 All safety-related equipment, as defined in Tables 3.10-1 and 3.10-2, is designed to meet its performance requirements under the postulated range of operational and environmental constraints. Detailed discussion of qualification is contained in Sections 3.10 and 3.11.

Paragraph 4.5 For a discussion of RPS channel integrity under all extremes of conditions described in Section 7.2.1.4, refer to Sections 3.10, 3.11, 8.2.1, and 8.3.1.

Paragraph 4.6 RPS channel independence is maintained through the application of the separation criteria as described in Section 8.3.

Paragraph 4.7 The RPS has no direct interaction with any plant control system. However, the RPS receives inputs from the reactor mode switch and the NMS which also provide inputs to plant control systems through isolation devices.

Paragraph 4.8 The RPS trip variables are direct measures of the following possible conditions: reactor overpressure, reactor overpower, gross fuel damage, or abnormal conditions within the RCPB except as follows:

> Due to the normal throttling action of the turbine control valves with changes in the plant power level, measurement of control valve position is not an appropriate variable from which to infer the desired variable, which is "rapid loss of the reactor heat sink." Consequently, a measurement of a control valve fast closure trip is used, as the trip signal (indicative of load reject).

Paragraph 4.9 Refer to RG 1.22 described in Section 7.2.2.3.

<u>Paragraph 4.10</u> Refer to RG 1.22 described in Section 7.2.2.3.

<u>Paragraph 4.11</u> The following RPS trip variables have no provision for sensor removal from service because of the use of valve position limit switches as the channel sensor:

1. MSIV closure trip.

2. Turbine stop valve closure trip.

During periodic test of any one trip channel, a sensor may be valved out of service and returned to service under administrative control procedures. Since only one sensor is valved out of service at any given time during the test interval, protection action capability for RPS automatic initiation is maintained through the remaining redundant instrument channels.

A sufficient number of IRM channels has been provided to permit any one IRM channel in a given trip system to be manually bypassed and still ensure that the remaining operable IRM channels comply with the IEEE-279 single-failure design requirements.

One IRM manual bypass switch has been provided for each RPS trip system. The mechanical characteristics of this switch permit only one of the four IRM channels of that trip system to be bypassed at any time. In order to accommodate a single failure of this bypass switch, electrical interlocks have also been incorporated into the bypass logic to prevent bypassing of more than one IRM in that trip system at any time. Consequently, with any IRM bypassed in a given trip system, three IRM channels remain in operation to satisfy the protection system requirements.

One APRM manual bypass switch has been provided to permit one of the four APRMs/OPRMs to be bypassed at any time. Mechanical interlocks have been provided in the bypass switch and electrical interlocks have been provided in the bypass circuitry to accommodate the possibility of switch failure. With an APRM/OPRM bypassed by the switch, sufficient APRM/OPRM channels remain in operation to provide the necessary protection for the reactor.

The mode switch produces operating bypasses which need not be annunciated because they are removed by normal reactor operating sequence.

<u>Paragraph 4.12</u> For a discussion of RPS operating bypasses, refer to Section 7.2.1.2.

<u>Paragraph 4.13</u> For a discussion of bypass and inoperability indication, refer to Section 7.1.2.3, RG 1.47.

TABLE 7.2-2 (Cont'd.)

Group # (4)	Line Ref. (1)	Line Tees		Source Valve (S/V)	FSK	Line Code	Instrument Tag No.		Location	Remarks	
		To	From				SWEC	GE		(5)	(6)
008(2)	--	--	--	--	27-19A	Z-	2ISC*PDT110(H)	C33-N017(H)	2CES*RAK027	030	--
cont'd.	R-579	--	K-038A	--	27-19A	BY	2RSS*LT116(H)	--	LOCAL	028	010
009(2)	K-041	K-041A,B,C	--	2ISC*EFV21	27-19C	--	--	--	--	--	--
	K-041A	--	K-041	--	36-1C	--	2RDS-PDT114(L)	C12-N008(L)	2CES-RAK103	--	--
	--	--	--	--	36-1C	--	2RDS-PDT117(L)	C12-N011(L)	2CES-RAK103	--	--
	K-041B	K-041C	K-041	--	27-4C	ZP	2CSH*PDT109(L)	E22-N057(L)	2CES*RAK024	--	--
	K-041C	--	K-041B	--	27-19C	Z-	2ISC-PDT114(L)	B22-N032(L)	2CES*RAK009	031	--
010(2)	K-068	K-068A,B,C,D	--	2ISC*EFV7	27-19A	--	--	--	--	--	--
	K-068A	K-068D	K-068	--	27-19A	AO	2ISC*LT7A(H)	B22-N080C(H)	2CES*RAK026	006	008
	--	--	--	--	27-19A	A-	2ISC*PDT14A(H)	C33-N004A(H)	2CES*RAK026	006	008
	K-068B	K-068C	K-068	--	27-19A	AG	2ISC*LT12A(H)	B22-N095A(H)	2CES*RAK004	005	008
	--	--	--	--	27-19A	AB	2ISC*LT7D(H)	B22-N080D(H)	2CES*RAK004	005	008
	K-068C	--	K-068B	--	27-19C	Z-	2ISC*PDI103(L)	B22-R005(L)	2CES*RAK010	032	--
	K-068D	--	K-068A	--	27-19A	AG	2RSS*LT115(H)	--	LOCAL	006	008
011(2)	K-107	K-107A/K-107B	--	2WCS*EFV222	26-3A	--	--	--	--	--	--
	K-107A	--	K-107	--	26-3A	Z-	2WCS*PDIS115(L)	G33-N025(L)	2CES*RAK006	012	--
	K-107B	--	K-107	--	26-3A	ZG	2WCS*FT67X(L)	E31-N036A(L)	2CES*RAK010	012	--
012(2)	K-113	K-113A/K-113B	--	2WCS*EFV300	26-3A	--	--	--	--	--	--
	K-113A	--	K-113	--	26-3A	Z-	2WCS*PDIS115(H)	G33-N025(H)	2CES*RAK006	011	--
	K-113B	--	K-113	--	26-3A	ZG	2WCS*FT67X(H)	E31-N036A(H)	2CES*RAK010	011	--
013(3)	K-003	--	--	2MSS*EFV1A	3-1H	AY	2MSS*FT15A(L)	E31-N086B(L)	2CES*RAK015	014	002
	--	--	--	--	3-1H	AO	2MSS*FT14A(L)	E31-N086C(L)	2CES*RAK015	014	002
014(3)	K-004	--	--	2MSS*EFV4A	3-1H	AY	2MSS*FT15A(H)	E31-N086B(H)	2CES*RAK015	013	001
	--	--	--	--	3-1H	AO	2MSS*FT14A(H)	E31-N086C(H)	2CES*RAK015	013	001
015(3)	K-007	--	--	2MSS*EFV1B	3-1H	BY	2MSS*FT15B(L)	E31-N087B(L)	2CES*RAK015	016	004
	--	--	--	--	3-1H	BO	2MSS*FT14B(L)	E31-N087C(L)	2CES*RAK015	016	004
016(3)	K-008	--	--	2MSS*EFV4B	3-1H	BY	2MSS*FT15B(H)	E31-N087B(H)	2CES*RAK015	015	003
	--	--	--	--	3-1H	BO	2MSS*FT14B(H)	E31-N087C(H)	2CES*RAK015	015	003
017(3)	K-009	--	--	2MSS*EFV3C	3-1H	C-	2MSS*FT11C(H)	C33-N003C(H)	2CES*RAK025	018	--
	--	--	--	--	3-1H	CG	2MSS*FT12C(H)	E31-N088A(H)	2CES*RAK025	018	020
	--	--	--	--	3-1H	CB	2MSS*FT13C(H)	E31-N088D(H)	2CES*RAK025	018	020
018(3)	K-010	--	--	2MSS*EFV2C	3-1H	C-	2MSS*FT11C(L)	C33-N003C(L)	2CES*RAK025	017	--
	--	--	--	--	3-1H	CG	2MSS*FT12C(L)	E31-N088A(L)	2CES*RAK025	017	019
	--	--	--	--	3-1H	CB	2MSS*FT13C(L)	E31-N088D(L)	2CES*RAK025	017	019

TABLE 7.2-2 (Cont'd.)

Group # (4)	Line Ref. (1)	Line Tees		Source Valve (S/V)	FSK	Line Code	Instrument Tag. No.		Location	Remarks	
		To	From				SWEC	GE		(5)	(6)
019(3)	K-011	--	--	2MSS*EFV1C	3-1H	CO	2MSS*FT14C(L)	E31-N088C(L)	2CES*RAK022	020	018
	--	--	--	--	3-1H	CY	2MSS*FT15C(L)	E31-N088B(L)	2CES*RAK022	020	018
020(3)	K-012	--	--	2MSS*EFV4C	3-1H	CO	2MSS*FT14C(H)	E31-N088C(H)	2CES*RAK022	019	017
	--	--	--	--	3-1H	CY	2MSS*FT15C(H)	E31-N088B(H)	2CES*RAK022	019	017
021(3)	K-013	--	--	2MSS*EFV3D	3-1H	D-	2MSS*FT11D(H)	C33-N003D(H)	2CES*RAK025	022	--
	--	--	--	--	3-1H	DG	2MSS*FT12D(H)	E31-N089A(H)	2CES*RAK025	022	024
	--	--	--	--	3-1H	DB	2MSS*FT13D(H)	E31-N089D(H)	2CES*RAK025	022	024
022(3)	K-014	--	--	2MSS*EFV2D	3-1H	D-	2MSS*FT11D(L)	C33-N003D(L)	2CES*RAK025	021	--
	--	--	--	--	3-1H	DG	2MSS*FT12D(L)	E31-N089A(L)	2CES*RAK025	021	023
	--	--	--	--	3-1H	DB	2MSS*FT13D(L)	E31-N089D(L)	2CES*RAK025	021	023
023(3)	K-015	--	--	2MSS*EFV1D	3-1H	DO	2MSS*FT14D(L)	E31-N089C(L)	2CES*RAK022	024	022
	--	--	--	--	3-1H	DY	2MSS*FT15D(L)	E31-N089B(L)	2CES*RAK022	024	022
024(3)	K-016	--	--	2MSS*EFV4D	3-1H	DO	2MSS*FT14D(H)	E31-N089C(H)	2CES*RAK022	023	021
	--	--	--	--	3-1H	DY	2MSS*FT15D(H)	E31-N089B(H)	2CES*RAK022	023	021
025(3)	K-021	--	--	2ISC*EFV15	27-19B	AP	2ISC*LT10A(H)	B22-N073L(H)	2CES*RAK026	006	029
	--	--	--	--	27-19B	AP	2ISC*LT10C(H)	B22-N073R(H)	2CES*RAK026	006	029
	--	--	--	--	27-19B	AO	2ISC*LT11C(H)	B22-N081C(H)	2CES*RAK026	006	029
026(3)	K-027	K-027A	--	2ISC*EFV17	27-19B	A-	2ISC*PDI31A(H)	B22-R009A(H)	2CES*RAK004	005	027
	--	--	--	--	27-19B	AG	2ISC*LT8A(H)	B22-N402A(H)	2CES*RAK004	005	027
	--	--	--	--	27-19B	AB	2ISC*LT11D(H)	B22-N081D(H)	2CES*RAK004	005	027
	--	--	--	--	27-19B	AG	2ISC*LT8B(H)	B22-N402E(H)	2CES*RAK004	005	027
	--	--	--	--	27-19B	AG	2ISC*LT9A(H)	B22-N091A(H)	2CES*RAK004	005	027
	--	--	--	--	27-19B	AG	2ISC*LT9C(H)	B22-N091E(H)	2CES*RAK004	005	027
	K-027A	--	K-027	--	27-19B	AG	2RSS*LT101(H)	--	LOCAL	005	027
027(3)	K-031	R-578	--	2ISC*EFV10	27-19B	BY	2ISC*LT11B(H)	B22-N081B(H)	2CES*RAK027	007	026
	--	--	--	--	27-19B	BY	2ISC*LT9B(H)	B22-N091B(H)	2CES*RAK027	007	026
	--	--	--	--	27-19B	BY	2ISC*LT9D(H)	B22-N091F(H)	2CES*RAK027	007	026
	--	--	--	--	27-19B	BY	2ISC*LT8C(H)	B22-N402B(H)	2CES*RAK027	007	026
	--	--	--	--	27-19B	BY	2ISC*LT8D(H)	B22-N402F(H)	2CES*RAK027	007	026
	--	--	--	--	27-19B	B-	2ISC*PDI31B(H)	B22-R009B(H)	2CES*RAK027	007	026
	R-578	--	K-031	--	27-19B	BY	2RSS*LT112(H)	--	LOCAL	007	026
028(3)	K-032	R-580	--	2ISC*EFV3	27-19A	B-	2ISC*PDT14C(L)	C33-N004C(L)	2CES*RAK005	008	006
	--	--	--	--	27-19A	BG	2ISC*LT7C(L)	B22-N080A(L)	2CES*RAK005	008	006
	--	--	--	--	27-19A	BO	2ISC*PT4C	B22-N078A	2CES*RAK005	--	006

TABLE 7.2-2 (Cont'd.)

Group # (4)	Line Ref. (1)	Line Tees		Source Valve (S/V)	Line Code	Instrument Tag. No.		Location	Remarks	
		To	From			SWEC	GE		(5)	(6)
036(3)	K-060 --	-- --	-- --	2ISC*EFV11 --	B- B-	2ISC-FT48B(L) 2ISC-FT47K(L)	B22-N033B(L) B22-N034K(L)	2CES*RAK009 2CES*RAK009	037 031	033 033
037(3)	K-061 --	-- --	-- --	2ISC*EFV40 --	B- BY	2ISC-FT48B(H) 2ISC*LT13B(H)	B22-N033B(H) B22-N044B(H)	2CES*RAK009 2CES*RAK009	036 007	034 034
038(3)	K-066 --	-- --	-- --	2ISC*EFV42 --	B- B-	2ISC-FT48D(L) 2ISC-FT47W(L)	B22-N033D(L) B22-N034W(L)	2CES*RAK009 2CES*RAK009	-- 031	033 033
039(3)	K-075 -- --	-- -- --	-- -- --	2RCS*EFV47A -- --	AB AG A-	2RCS*FT8A(H) 2RCS*FT6A(H) 2RCS*FT83A(H)	B35-N014B(H) B35-N014A(H) B35-N011A(H)	2CES*RAK009 2CES*RAK009 2CES*RAK009	040 040 040	059 059 059
040(3)	K-077 -- --	-- -- --	-- -- --	2RCS*EFV48A -- --	AB AG A-	2RCS*FT8A(L) 2RCS*FT6A(L) 2RCS*FT83A(L)	B35-N014B(L) B35-N014A(L) B35-N011A(L)	2CES*RAK009 2CES*RAK009 2CES*RAK009	039 039 039	058 058 058
041(3)	K-080 --	-- --	-- --	2RCS*EFV45B --	BO BO	2RCS*FT7B(L) 2RCS*FT9B(L)	B35-N024C(L) B35-N024D(L)	2CES*RAK015 2CES*RAK015	043 043	060 060
042(3)	K-081 --	-- --	-- --	2IAS*EFV201 --	ZG --	2IAS*PT230 2RSS-PT108	-- --	LOCAL LOCAL	-- --	-- --
043(3)	K-082 --	-- --	-- --	2RCS*EFV46B --	BO BO	2RCS*FT7B(H) 2RCS*FT9B(H)	B35-N024C(H) B35-N024D(H)	2CES*RAK015 2CES*RAK015	041 041	061 061
044(3)	K-083 --	-- --	-- --	2RCS*EFV62A --	-- --	2RCS-PI43A 2RCS-PT44A	B35-R002A B35-N006A	2CES*RAK006 2CES*RAK006	-- --	-- --
045(3)	K-084 --	-- --	-- --	2RCS*EFV63A --	-- --	2RCS-PI41A 2RCS-PT42A	B35-R001A B35-N005A	2CES*RAK006 2CES*RAK006	-- --	-- --
046(3)	K-085 --	-- --	-- --	2RCS*EFV62B --	-- --	2RCS-PI43B 2RCS-PT44B	B35-R002B B35-N006B	2CES*RAK022 2CES*RAK022	-- --	-- --
047(3)	K-086 --	-- --	-- --	2RCS*EFV63B --	-- --	2RCS-PI41B 2RCS-PT42B	B35-R001B B35-N005B	2CES*RAK022 2CES*RAK022	-- --	-- --
050(3)	K-099 --	-- --	-- --	2ICS*EFV1 --	JG JG	2ICS*PDT167(L) 2ICS*PT167X	E31-N084A(L) E31-N085E	2CES*RAK017 2CES*RAK017	051 --	-- --
051(3)	K-100 --	-- --	-- --	2ICS*EFV2 --	JG JG	2ICS*PDT167H 2ICS*PT167Y	E31-N084A(H) E31-N085A	2CES*RAK017 2CES*RAK017	050 --	-- --

TABLE 7.2-2 (Cont'd.)

Group # (4)	Line Ref. (1)	Line Tees		Source Valve (S/V)	FSK	Line Code	Instrument Tag No.		Location	Remarks	
		To	From				SWEC	GE		(5)	(6)
052(3)	K-105 --	-- --	-- --	2ICS*EFV3 --	27-6E 27-6E	JY JY	2ICS*PDT168(L) 2ICS*PT168X	E31-N084B(L) E31-N085F	2CES*RAK029 2CES*RAK029	053 --	-- --
053(3)	K-106 --	-- --	-- --	2ICS*EFV4 --	27-6E 27-6E	JY JY	2ICS*PDT168(H) 2ICS*PT168Y	E31-N084B(H) E31-N085B	2CES*RAK029 2CES*RAK029	052 --	-- --
054(3)	K-109 -- --	-- -- --	-- -- --	2ISC*EFV9 -- --	27-19B 27-19B 27-19B	BP BP BO	2ISC*PT16B 2ISC*PT16D 2ISC*PT15C	B22-N067C B22-N067G C72-N050A	2CES*RAK005 2CES*RAK005 2CES*RAK005	-- -- --	056 056 056
055(3)	K-110 -- --	-- -- --	-- -- --	2ISC*EFV19 -- --	27-19C 27-19C 27-19C	AG AG AB	2ISC*PT17A 2ISC*PT17C 2ISC*PT15D	B22-N094A B22-N094E C72-N050D	2CES*RAK004 2CES*RAK004 2CES*RAK004	-- -- --	057 057 057
056(3)	K-111 -- --	-- -- --	-- -- --	2ISC*EFV16 -- --	27-19B 27-19B 27-19B	AG AP AP	2ISC*PT15A 2ISC*PT16C 2ISC*PT16A	C72-N050C B22-N067R B22-N067L	2CES*RAK026 2CES*RAK026 2CES*RAK026	-- -- --	054 054 054
057(3)	K-112 -- --	-- -- --	-- -- --	2ISC*EFV12 -- --	27-19C 27-19C 27-19C	BY BY BY	2ISC*PT17B 2ISC*PT17D 2ISC*PT15B	B22-N094B B22-N094F C72-N050B	2CES*RAK027 2CES*RAK027 2CES*RAK027	-- -- --	055 055 055
058(3)	K-115 -- --	-- -- --	-- -- --	2RCS*EFV47B -- --	25-1C 25-1C 25-1C	B- BG BB	2RCS*FT83B(L) 2RCS*FT6B(L) 2RCS*FT8B(L)	B35-N011B(L) B35-N024A(L) B35-N024B(L)	2CES*RAK025 2CES*RAK025 2CES*RAK025	059 059 059	040 040 040
059(3)	K-117 -- --	-- -- --	-- -- --	2RCS*EFV48B -- --	25-1C 25-1C 25-1C	B- BG BB	2RCS*FT83B(H) 2RCS*FT6B(H) 2RCS*FT8B(H)	B35-N011B(H) B35-N024A(H) B35-N024B(H)	2CES*RAK025 2CES*RAK025 2CES*RAK025	058 058 058	039 039 039
060(3)	K-119 --	-- --	-- --	2RCS*EFV45A --	25-1A 25-1A	AO AO	2RCS*FT7A(L) 2RCS*FT9A(L)	B35-N014C(L) B35-N014D(L)	2CES*RAK006 2CES*RAK006	061 061	041 041
061(3)	K-121 --	-- --	-- --	2RCS*EFV46A --	25-1A 25-1A	AO AO	2RCS*FT7A(H) 2RCS*FT9A(H)	B35-N014C(H) B35-N014D(H)	2CES*RAK006 2CES*RAK006	060 060	043 043
062(3) ---(2)	K-122 -- -- K-122A	K-122A -- -- K-125	-- -- -- K-122	2CMS*EFV8B -- -- --	33-2D 33-2D 33-2D --	BY BY BY --	2CMS*LT9B(L) 2CMS*LT11B(L) 2RSS*LT105(L) --	-- -- -- --	LOCAL LOCAL LOCAL --	063 063 063 --	064 064 064 --
063(3)	K-125 -- --	K-122A -- --	-- -- --	2CMS*EFV9B -- --	33-2D 33-2D 33-2D	BY BY BY	2CMS*LT9B(H) 2CMS*LT11B(H) 2RSS*LT105(H)	-- -- --	LOCAL LOCAL LOCAL	062 062 062	065 065 065

TABLE 7.2-2 (Cont'd.)

Group # (4)	Line Ref. (1)	Line Tees		Source Valve (S/V)	FSK	Line Code	Instrument Tag No.		Location	Remarks	
		To	From				SWEC	GE		(5)	(6)
078(2)	R-254 R-410	R-410 --	-- R-254	2SWP*V143A --	9-10B 9-10B	AG AG	2SWP*FT13A(H) 2SWP*FT201A(H)	E12-N007A(H) --	2CES*RAK018 LOCAL	079 079	-- --
079(2)	R-255 R-411	R-411 --	-- R-255	2SWP*V144A --	9-10B 9-10B	AG AG	2SWP*FT13A(L) 2SWP*FT201A(L)	E12-N007A(L) --	2CES*RAK018 LOCAL	078 078	-- --
080(2)	R-256 -- R-492	R-492 -- --	-- -- R-256	2RHS*V56 -- --	27-7B 27-7B 27-7B	AG AG AG	2RHS*FT14A(H) 2RHS*FT86A(H) 2RHS*FT60A(H)	E12-N015A(H) E12-N052A(H) --	2CES*RAK018 2CES*RAK018 LOCAL	081 081 081	084 084 084
081(2)	R-257 -- R-493	R-493 -- --	-- -- R-257	2RHS*V55 -- --	27-7B 27-7B 27-7B	AG AG AG	2RHS*FT14A(L) 2RHS*FT86A(L) 2RHS*FT60A(L)	E12-N015A(L) E12-N052A(L) --	2CES*RAK018 2CES*RAK018 LOCAL	080 080 080	085 085 085
082(2)	R-270 R-288	R-288 --	-- R-270	2RHS*V127 --	27-7H 27-7H	B- BY	2RHS*PI50B 2RHS*PT3B	E12-R002B E12-N063B	2CES*RAK021 LOCAL	-- --	075 075
083(2)	R-271 R-289	R-289 --	-- R-271	2RHS*V135 --	27-7G 27-7G	Z- ZY	2RHS*PI50C 2RHS*PT3C	E12-R002C E12-N095	2CES*RAK021 LOCAL	-- --	-- --
084(2)	R-276 -- R-287	R-287 -- --	-- -- R-276	2RHS*V83 -- --	27-7D 27-7D 27-7D	BY BY BY	2RHS*FT14B(H) 2RHS*FT86B(H) 2RHS*FT60B(H)	E12-N015B(H) E12-N052B(H) --	2CES*RAK021 2CES*RAK021 LOCAL	085 085 085	080 080 080
085(2)	R-277 -- R-286	R-286 -- --	-- -- R-277	2RHS*V84 -- --	27-7D 27-7D 27-7D	BY BY BY	2RHS*FT14B(L) 2RHS*FT86B(L) 2RHS*FT60B(L)	E12-N015B(L) E12-N052B(L) --	2CES*RAK021 2CES*RAK021 LOCAL	084 084 084	081 081 081
086(3)	R-017 --	-- --	-- --	2CSH*V18 --	27-4B 27-4B	ZP Z-	2CSH*PT102 2CSH*PI103	E22-N052 E22-R001	2CES*RAK024 2CES*RAK024	-- --	-- --
087(3)	R-019 --	-- --	-- --	2CSH*V25 --	27-4B 27-4B	ZP ZP	2CSH*FT104(L) 2CSH*FT105(L)	E22-N005(L) E22-N056(L)	2CES*RAK024 2CES*RAK024	088 088	-- --
088(3)	R-020 --	-- --	-- --	2CSH*V26 --	27-4B 27-4B	ZP ZP	2CSH*FT104(H) 2CSH*FT105(H)	E22-N005(H) E22-N056(H)	2CES*RAK024 2CES*RAK024	087 087	-- --
089(3)	R-171 --	-- --	-- --	2ICS*V90 --	27-6C 27-6C	JG JG	2ICS*PT2A 2ICS*PT2C	E51-N055A E51-N055E	2CES*RAK017 2CES*RAK017	-- --	090 090
090(3)	R-172 --	-- --	-- --	2ICS*V91 --	27-6C 27-6C	JY JY	2ICS*PT2B 2ICS*PT2D	E51-N055B E51-N055F	2CES*RAK029 2CES*RAK029	-- --	089 089

TABLE 7.2-2 (Cont'd.)

Group # (4)	Line Ref. (1)	Line Tees		Source Valve (S/V)	FSK	Line Code	Instrument Tag No.		Location	Remarks	
		To	From				SWEC	GE		(5)	(6)
119	2EGA*PS20A *PS22A PI12A			2EGA*V53A -- --	12-4A 12-4A 12-4A	A- A- --	2EGA*PS20A 2EGA*PS22A 2EGA-PI12A	-- -- --	LOCAL (DG) LOCAL (DG) LOCAL (DG)	-- -- --	-- -- --
120	2EGA*PS19A *PS21A -PI11A			2EGA*V53B -- --	12-4A 12-4A 12-4A	C- C- --	2EGA*PS19A 2EGA*PS21A 2EGA-PI11A	-- -- --	LOCAL (DG) LOCAL (DG) LOCAL (DG)	-- -- --	-- -- --
121	2EGA*PS20B *PS22B PI12B			2EGA*V54A -- --	12-4B 12-4B 12-4B	B- B- --	2EGA*PS20B 2EGA*PS22B 2EGA-PI12B	-- -- --	LOCAL (DG) LOCAL (DG) LOCAL (DG)	-- -- --	-- -- --
122	2EGA*PS19B *PS21B -PI11B			2EGA*V54B -- --	12-4B 12-4B 12-4B	D- D- --	2EGA*PS19B 2EGA*PS21B 2EGA-PI11B	-- -- --	LOCAL (DG) LOCAL (DG) LOCAL (DG)	-- -- --	-- -- --
123	2EGA*PS110 *PS109			2EGA*V36A --	12-4C --	J- J-	2EGA*PS110 2EGA*PS109	-- --	LOCAL (DG) LOCAL (DG)	-- --	-- --
124	2EGA*PS106 *PS117			2EGA*V36B --	12-4C --	J- J-	2EGA*PS106 2EGA*PS117	-- --	LOCAL (DG) LOCAL (DG)	-- --	-- --
125	2EGA*PS120 *PS122 -PI124			2EGA*V55A -- --	12-4C -- --	J- J- --	2EGA*PS120 2EGA*PS122 2EGA-PI124	-- -- --	LOCAL (DG) LOCAL (DG) LOCAL (DG)	-- -- --	-- -- --
126	2EGA*PS119 *PS121 -PI119			2EGA*V55B -- --	12-4C -- --	J- J- --	2EGA*PS119 2EGA*PS121 2EGA-PI119	-- -- --	LOCAL (DG) LOCAL (DG) LOCAL (DG)	-- -- --	-- -- --
127	R-122 R-293	R-293 --	-- R-122	2WCS*V165 --	26-3D --	ZG ZY	2WCS*FT69X(H) 2WCS*FT69Y(H)	E31-N015A E31-N015B	2CES*RAK002 2CES*RAK002	128 128	-- --
128	R-123 R-294	R-294 --	-- R-123	2WCS*V166 --	26-3D --	ZG ZY	2WCS*FT69X(L) 2WCS*FT69Y(L)	E31-N015A E31-N015B	2CES*RAK002 2CES*RAK002	127 127	-- --
129	R-250 R-565	R-565 --	-- R-250	2CSL*V26 --	27-5B --	J- JG	2CSL*PI111 2CSL*PT130	E21-R001 E21-N057	2CES*RAK001 LOCAL	-- --	-- --
130	K-097 R-562	R-562 --	-- K-097	2CSL*EFV1 --	27-7A 27-5A	AG JG	2RHS*PDT18A(L) 2CSL*PDT132(L)	E12-N060A E21-N050	2CES*RAK018 2CES*RAK001	-- --	-- --

TABLE 7.2-2 (Cont'd.)

Group # (4)	Line Ref. (1)	Line Tees		Source Valve (S/V)	FSK	Line Code	Instrument Tag No.		Location	Remarks	
		To	From				SWEC	GE		(5)	(6)
131	R-258	--		2RHS*V109 -- --	27-7F 27-7F 27-7F	AG AG A-	2RHS*PT5A 2RHS*PT6A 2RHS*PI87A	E12-N055A E12-N056A E12-R008A	2CES*RAK018 2CES*RAK018 2CES*RAK018	-- -- --	098 098 098
132	R-110	--	--	2SFC*V110B --	34-2C 34-2C	BY --	2SFC*PT30B 2SFC-PI60B	-- --	LOCAL LOCAL	-- --	-- --
133(3)	R-182	--	--	2ICS*V78 --	27-6D 27-6D	JG J-	2ICS*PT103 2ICS*PI139	E51-N007 E51-R003	2CES*RAK017 2CES*RAK017	-- --	-- --
134(3)	K-142	--	--	2ICS*EFV5 --	PID-35C PID-35C	J- J-	2ICS*PT142 2ICS*PT143	-- --	LOCAL LOCAL	-- --	-- --

GENERAL NOTES:

A. All instruments are located in the reactor building unless otherwise noted.
B. Only lines in the reactor building are assigned a line reference number.
C. (T) - Turbine Building Location
D. (DG) - Diesel Generator Building
E. (SW) - Service Water Pump Room
F. In some instances only an instrument's high or low side may be indicated. The instrument's other leg does not tie into another instrument and so is not indicated here.

(1) Line reference numbers with a "K" prefix represent lines that originate in the primary containment. Line reference numbers with an "R" prefix represent lines that originate in the secondary containment. In the absence of a "K" or "R" prefix the line is tagged with the instrument numbers being supplied.
(2) Those lines which tee somewhere between source and instrument to service instruments (local or rack mounted) in different areas of the building with a common source.
(3) Those lines which tee inside the rack (close couple in case of locally mounted instruments) to service more than one instrument.
(4) The Group Reference number was generated for this table only; it is used to allow cross-referencing of related lines (see 5 and 6).
(5) A number in this column refers you to the high press side or low press side by group number for differential type instruments.
(6) A number in this column refers you to the redundant instrument train by group number.

TABLE 7.2-3

REACTOR PROTECTION SYSTEM RESPONSE TIMES

	Functional Unit	Response Time (sec)
1.	Intermediate Range Monitors:	
	a. Neutron Flux - High	N/A
	b. Inoperative	N/A
2.	Average Power Range Monitor[1]:	
	a. Neutron Flux - Upscale, Setdown	N/A
	b. Flow Biased Simulated Thermal Power - Upscale	N/A
	c. Fixed Neutron Flux - Upscale	N/A
	d. Inoperative	N/A
	e. Two-Out-Of-Four Voter	$\leq$0.05[1]
	f. OPRM Upscale	N/A
3.	Reactor Vessel Steam Dome Pressure - High	$\leq$0.55[3]
4.	Reactor Vessel Water Level - Low, Level 3	$\leq$1.05[3]
5.	Main Steam Line Isolation Valve - Closure	$\leq$0.06
6.	Main Steam Line Radiation - High	N/A
7.	Drywell Pressure - High	N/A
8.	Scram Discharge Volume Water Level - High	
	a. Level Transmitter/Trip Unit	N/A
	b. Float Switch	N/A
9.	Turbine Stop Valve - Closure	$\leq$0.06
10.	Turbine Control Valve Fast Closure, Valve Trip System Oil Pressure - Low	$\leq$0.08[4]
11.	Reactor Mode Switch Shutdown Position	N/A
12.	Manual Scram	N/A

NOTE: The elimination of response time testing (RTT) is only applicable to devices listed in the NRC Safety Evaluation for BWROG NEDO-32291.

TABLE 7.2-3 (Cont'd.)

(1) Neutron detectors, APRM/OPRM channel and two-out-of-four channel digital electronics are exempt from RTT. Response time shall be measured from activation of the two-out-of-four voter output relay.

(2) Deleted.

(3) Sensor is eliminated from RTT for the RPS circuits. Response to a process step function shall be <5 sec. RTT and conformance to the administrative limits for the remaining channel including trip unit and relay logic are required. Time delay relays in the RTT loops require response verification through calibration.

(4) Measured from start of turbine control valve fast closure.

provide for additional operational flexibility, e.g., test and maintenance.

7.3.1.2.3 Prudent Operational Limits

Operational limits for each safety-related variable trip setting are selected with sufficient margin that a spurious ESF system initiation is avoided. It is then verified by analysis that the release of radioactive materials, following postulated gross failures of the fuel or the nuclear system process barrier, is kept within acceptable bounds.

7.3.1.2.4 Margin

Adequate margin between safety limits and instrument setpoints is provided to allow for instrument error. The appropriate trip setpoints and allowable values are listed and the bases stated in Technical Specifications.

7.3.1.2.5 Levels

Levels requiring protective action are established in Technical Specifications.

7.3.1.2.6 Range of Transient, Steady-State, and Environmental Conditions

Refer to Section 3.11 and the Environmental Qualification Document (EQD) for environmental conditions. Refer to Sections 8.2.1 and 8.3.1 for the maximum and minimum range of energy supply to ESF instrumentation and controls. All ESF instrumentation and controls are specified and purchased to withstand the effects of energy supply extremes.

7.3.1.2.7 Malfunctions, Accidents, and Other Unusual Events That Could Cause Damage to Safety Systems

Chapter 3 describes the following accidents and events: floods, storms, tornadoes, earthquakes, fires, and pipe breaks outside containment. LOCA events are discussed in Chapters 6 and 15. Each of these events is discussed below for the ESF systems.

<u>Floods</u>

The buildings containing ESF system components are protected against floods as described in Section 3.4.

<u>Storms and Tornadoes</u>

All buildings, except the turbine building containing ESF system components, are protected against storms and tornadoes as described in Section 3.3.

Earthquakes

All structures, except the turbine building, containing ESF system components have been seismically qualified as described in Sections 3.7 and 3.8. Seismic qualification of instrumentation and electrical equipment is discussed in Section 3.10.

Fires

The functions of the ESF systems are protected from the effects of fire as described in Section 9.5.1.

LOCA

The ESF system components located inside the drywell and functionally required during and/or following a LOCA have been environmentally qualified to remain functional as discussed in Section 3.11.

Missiles

Protection for safety-related components is described in Section 3.5.

7.3.1.2.8 Minimum Performance Requirements

Minimum performance requirements for ESF instrumentation and controls are provided in Technical Specifications.

7.3.1.3 Final System Drawings

The final system drawings, including piping and instrumentation diagrams (P&ID) and functional control diagrams (FCD)/control logic diagrams have been provided for the ESF systems in the FSAR. ESF system elementary diagrams are identified in Section 1.7. Functional and architectural design differences between the PSAR and FSAR are listed in Tables 1.3-8 and 1.3-9.

7.3.2 Analysis

7.3.2.1 ESF Systems - Instrumentation and Controls

Chapters 6 and 15 evaluate the individual and combined capabilities of the ESF systems. The ESF systems are designed in such a way that a loss of instrument air, a plant load rejection, or a turbine trip will not prevent the completion of the safety function.

Originally, the FMEA of: 1) the BOP instrumentation and control components of the ECCS (HPCS, LPCS, and LPCI), and 2) the SGTS, CGCS, reactor building HVAC, service water, service water pump bays ventilation, control building HVAC, control building chilled water, standby power, and diesel generator building HVAC systems were contained in the Unit 2 FMEA document, which is historical.

FMEAs for plant systems are now performed and controlled by the design process.

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Position C.3 The redundant RHR loops use separate control switches which are not shared.

Position C.4 Failure of a single loop logic will not disable the system function, since a redundant loop is available on a separate divisional power source.

Regulatory Guide 1.62 The HPCS, LPCS, and the Division II LPCI systems can be manually initiated at the system level from the main control room by actuation of an armed push button for each system. The LPCS push button also initiates the Division I LPCI system. The ADS and PCRVICS are manually initiated at the system (division) level by actuation of two armed push buttons (one for each logic channel).

The RCSCM is manually initiated at the system (division) level by actuation of the RHR pump start control switch and by opening the containment spray and/or suppression chamber spray valves.

The RSPCM is manually initiated from the main control room by initiation of system pump and valve controls.

The SGTS, CGCS, reactor building HVAC system, SWP system, service water pump bays ventilation system, control building HVAC system, control building chilled water system, standby power system, and diesel generator building HVAC system equipment are manually initiated at the system (division) level by actuation of individual control switches in the main control room.

Actuation of the system level manual initiation switches simulates actions of automatic or manual (individual equipment initiation) system actuation.

Review of NSSS ESF systems and Category I BOP systems revealed that the logic for manual initiation in several instances is interlocked with permissive logic from various sensors. This permissive logic is dependent upon the same sensors as those used for automatic initiation of the system. Each of these systems, however, has redundancy and/or diversity in its design such that a single-failure of a system will not prevent the safety function (protective action) from being initiated and carried to completion by the manual or automatic initiation of the redundant or diverse portion of the system.

In some cases, Category I BOP systems use interlocks to provide protection for safety-related equipment, i.e., limit switches of dampers interlocked with starting of fans. In each case, redundant equipment is available so that no single failure in the manual, automatic, or common portion of the protection system will prevent initiation by manual or automatic means of the redundant portion of the system. Additionally, an objective of the surveillance program is to address high-pressure/low-pressure interlocks in the surveillance testing.

The system design meets the single-failure criterion by providing redundancy so that a single-failure will not prevent initiation of the protective action. FMEAs have been performed to verify the above for all BOP Category I systems. Originally, the FMEA was contained in the Unit 2 FMEA document, which is historical. FMEAs for plant systems are now performed and controlled by the design process.

ESF and RCIC Reset Controls

The ADS reset controls return each ADS SRV to its closed position. This deliberate Operator action closing the ADS SRVs B22-F013 C, H, K, M, N, R, and U to prevent or limit inadvertent reactor depressurization is considered an allowed exception to IE 80-06 compliance. Besides this exception, there is no deviation from the guidance indicated in IE Bulletin 80-06.

In addition, RCIC (not considered an ESF) was reviewed and found to be in conformance with the guidance of IE Bulletin 80-06.

TABLE 7.3-11

SERVICE WATER SYSTEM
INSTRUMENTATION SPECIFICATIONS

Service Water Function	Instrument	Instrument Range[1]
Service water to TBCLCW system pressure	Pressure transmitter	0 - 100 psig
	Pressure switch	0 - 100 psig
RBCLCW-RCS pumps pressure	Pressure transmitter	0 - 200 psig
Service water pumps discharge flow	Flow transmitter	0 - 12,000 gpm
HPCS emergency diesel generator water header pressure	Pressure transmitter	0 - 100 psig
Emergency diesel generator water header pressure	Pressure transmitter	0 - 100 psig
Control building air conditioning chiller SW outlet temperature	Temperature transmitter	35 - 130°F
Control building chiller inlet water temperature low	Temperature switch	32 - 100°F
SW header flow to lake	Flow transmitter	0 - 35,000 gpm
SW header discharge pressure	Pressure transmitter	0 - 100 psig
Reactor building emergency ventilation recirculation air temperature high	Temperature indicating switch	-40 - 180°F

TABLE 7.3-11 (Cont'd.)

Service Water Function	Instrument	Instrument Range[1]
Electrical tunnels north unit cooler suction temperature high/low	Temperature switch high Temperature switch low	45 - 120°F 45 - 120°F
Discharge bay water level high/high	Level switch	N/A
SW pump suction bay level low	Level switch	N/A
Intake tunnel 2 water temperature low	Temperature switch	25 - 80°F
RHR heat exchanger SW discharge radiation[2]	Radiation monitor	10^{-7} - 10^{-1} uCi/ml
SW effluent loop A&B radiation[2]	Radiation monitor	10^{-7} - 10^{-1} uCi/ml

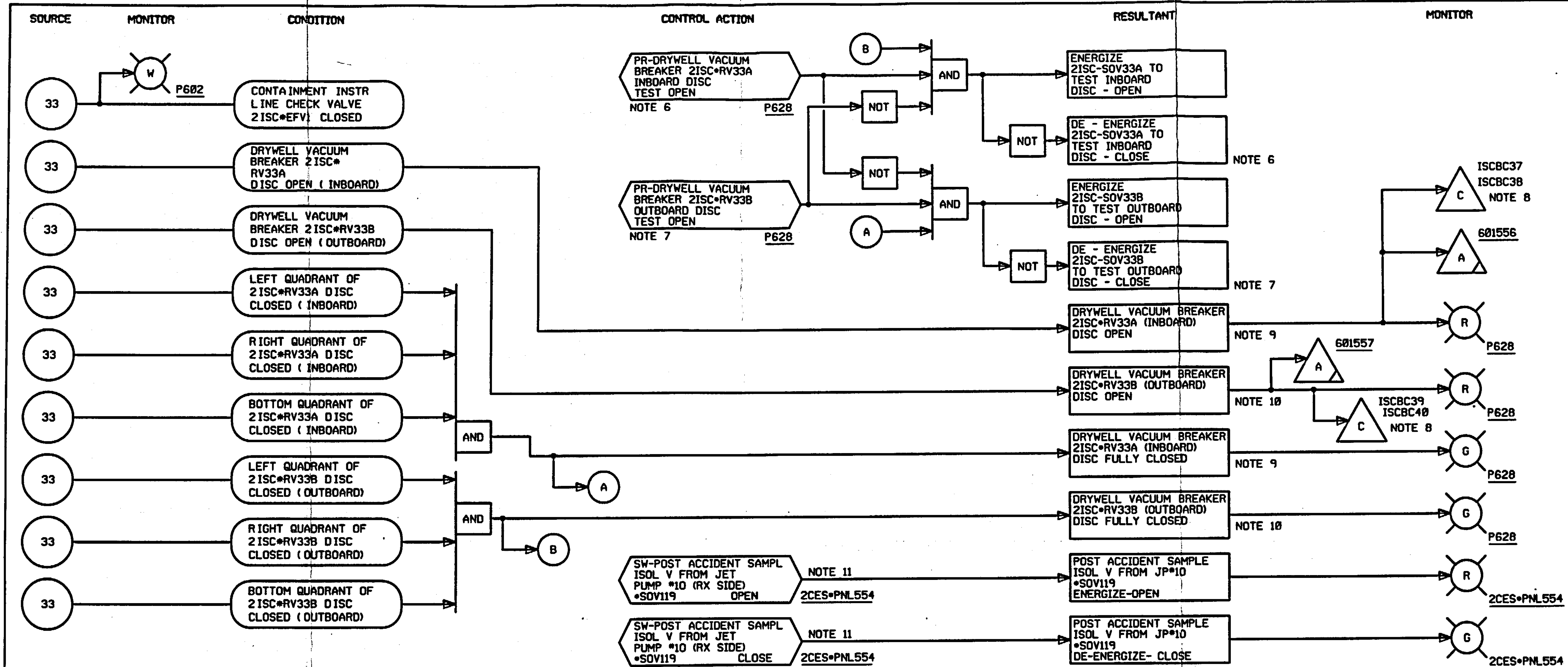
(1) See Technical Specifications for operational limits, including trip setpoints.

(2) Low end of range is the design value. Actual range observed is subject to area background.

TABLE 7.3-17

TECHNICAL SPECIFICATION INSTRUMENTATION

REACTOR PROTECTION SYSTEM		
FUNCTIONAL UNIT[1]	TOTAL CHANNELS/ TRIP SYSTEM	MINIMUM[1] OPERABLE CHANNELS/ TRIP SYSTEM
1. Intermediate Range Monitors		
a. Neutron Flux - High	4	3
b. Inoperative	4	3
2. Average Power Range Monitor		
a. Neutron Flux - Upscale, Setdown	4[12]	3[12]
b. Flow Biased Simulated Thermal Power - Upscale	4[12]	3[12]
c. Fixed Neutron Flux - Upscale	4[12]	3[12]
d. Inoperative	4[12]	3[12]
e. Two-Out-Of-Four Voter		
f. OPRM Upscale	4[12]	3[12]
3. Reactor Vessel Steam Dome Pressure - High	2	2
4. Reactor Vessel Water Level - Low, Level 3	2	2
5. Main Steam Line Isolation Valve - Closure	4	4
6. Main Steam Line Radiation - High	2	2
7. (Drywell) Pressure - High	2	2
8. Scram Discharge Volume Water Level - High		
a. Transmitter/Trip Units	2	2
b. Float Switches	2	2
9. Turbine Stop Valve - Closure	4	4
10. Turbine Control Valve Fast Closure, Valve Trip System Oil Pressure - Low	2	2
11. Reactor Mode Switch Shutdown Position	2	2
12. Manual Scram	2	2



NOTES:

1. ALL INSTRUMENT & EQUIPMENT NUMBERS TO BE PREFIXED WITH "2ISC-" EXCEPT WHERE A DIFFERENT PREFIX IS SHOWN. AN ASTERISK (•) WILL REPLACE THE DASH (-) IN THE PREFIX FOR INSTRUMENTS AND EQUIPMENT WHICH ARE PART OF THE NUCLEAR SAFETY FEATURE SYSTEMS.
2. LOGIC SHOWN FOR CONTAINMENT INSTRUMENT LINE CHECK VALVE 2ISC•EFV1. LOGIC FOR THE FOLLOWING INSTRUMENT LINE CHECK VALVE IS SIMILAR.

2ISC•EFV2 TO •EFV42	2ICS•EFV1,2,3,4,5
2CSH•EFV1,2,3	2WCS•EFV221 TO •EFV224, •EFV300
2CSL•EFV1,31	2RHS•EFV5 TO •EFV10
2DER•EFV31	2CMS•EFV1A,1B,3A,3B,5A,5B,6,8A,8B,9A,9B,1C

2RCS•EFV44A,44B,45A,45B,46A,46B,47A,47B,48A,48B,52A,52B,53A,53B,62A,62B,63A,63B,43A,43B
2MSS•EFV1A,1B,2C,1D,2A,2B,2C,2D,3A,3B,3C,3D,4A,4B,4C,4D
2IAS•EFV200,201,202,203,204,205,206

3. ASSOCIATED EQUIPMENT NUMBERS

VACUUM BREAKER	TEST SOLENOID
2ISC•RV 33A(Z-)	2ISC-SOV 33A
2ISC•RV 33B(Z-)	2ISC-SOV 33B
2ISC•RV 34A(Z-)	2ISC-SOV 34A
2ISC•RV 34B(Z-)	2ISC-SOV 34B
2ISC•RV 35A(Z-)	2ISC-SOV 35A
2ISC•RV 35B(Z-)	2ISC-SOV 35B
2ISC•RV 36A(Z-)	2ISC-SOV 36A
2ISC•RV 36B(Z-)	2ISC-SOV 36B

4. QA CAT I FOR PRESSURE BOUNDARY ONLY.
5. LOGIC IS SHOWN FOR •SOV119. LOGIC IS SIMILAR FOR:
   - •SOV120-JET PUMP *20 (RX SIDE)
   - •SOV123-JET PUMP *10 (SAMPL SIDE)
   - •SOV124-JET PUMP *20 (SAMPL SIDE)
6. LOGIC FOR 2ISC-SOV33A IS SHOWN. LOGIC IS SIMILAR FOR 2ISC-SOV34A,35A,36A.
7. LOGIC FOR 2ISC-SOV33B IS SHOWN. LOGIC IS SIMILAR FOR 2ISC-SOV34B,35B,36B.
8. ASSOCIATED COMPUTER POINT IDENTIFICATION:

2ISC•RV 33A	ISCBC 37	2ISC•RV 35A	ISCBC 38
2ISC•RV 33B	ISCBC 39	2ISC•RV 35B	ISCBC 40
2ISC•RV 34A	ISCBC 37	2ISC•RV 36A	ISCBC 38
2ISC•RV 34B	ISCBC 39	2ISC•RV 36B	ISCBC 40

9. LOGIC FOR 2ISC•RV33A IS SHOWN. LOGIC IS SIMILAR FOR 2ISC•RV34A,35A,36A.
10. LOGIC FOR 2ISC•RV33B IS SHOWN. LOGIC IS SIMILAR FOR 2ISC•RV34B,35B,36B.
11. KEYLOCK SWITCH.

SETPOINTS SHOWN ON LOGIC DIAGRAMS ARE FOR LOGIC CLARIFICATION ONLY AND MAY BE ONLY APPROXIMATIONS OF THE ACTUAL PROCESS SETPOINT. REFER TO SETPOINT DATA SHEETS FOR ACTUAL PROCESS SETPOINTS.

SOURCE: LSK-27-19J

FIGURE 7.3-10

BALANCE OF PLANT
ESF ACTUATION
LOGIC DIAGRAM SHEET 2 OF 2

NIAGARA MOHAWK POWER CORP.
NINE MILE POINT-UNIT 2
UPDATED SAFETY ANALYSIS REPORT