SECTION 6

ENGINEERED SAFETY FEATURES

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(1) Head spray line has been removed; however, head spray line break is still the bounding analysis for the drywell head region.

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SECTION 6

ENGINEERED SAFETY FEATURES

6.0 GENERAL

The engineered safety features (ESFs) of this plant are those systems provided to mitigate the consequences of postulated serious accidents. The following ESFs are discussed in this section:

1. Containment systems - Section 6.2
   a. Primary containment
   b. Containment heat removal
   c. Containment Isolation System (CIS)
   d. Containment Atmosphere Control System.
2. Emergency Core Cooling Systems (ECCSs) - Section 6.3
   a. High Pressure Coolant Injection (HPCI) System
   b. Automatic Depressurization System (ADS)
   c. Core Spray System
   d. Low Pressure Coolant Injection (LPCI) system.
3. Control room habitability systems - Section 6.4
4. Filtration, Recirculation, and Ventilation System - (FRVS) Section 6.8

In addition to the ESFs discussed in this section, other ESF systems discussed elsewhere are provided to limit the consequences of postulated accidents. The ESF systems are described in the sections of Section 6 and the sections referenced in Table 6.0-1.

The information provided in this section and referenced sections demonstrates the following:

1. The operation of each system is based on concepts that have been proven by tests under simulated accident conditions and/or by conservative extrapolations from present knowledge and experience.

2. Component reliability, system interdependence, redundancy, and separation of components or portions of systems ensure that the ESF accomplishes its intended purpose and functions for the period required.

3. Provisions for testing, inspection, and surveillance ensure that the ESF is dependable and effective on demand.

4. The materials used can withstand the postulated accident environment, including radiation levels, and the radiolytic decomposition products that may occur cannot interfere with any ESF.

TABLE 6.0-1

ENGINEERED SAFETY FEATURES DISCUSSED IN OTHER CHAPTERS OF THE HOPE CREEK FSAR

Engineered Safety Feature	FSAR Location
Chapter 4	
Control rod velocity limiter	Section 4.2
Control rod drive housing supports	Section 4.6
Chapter 5	
Overpressure protection	Section 5.2.2
Main steam line flow restrictors	Section 5.4.4
Main steam line isolation valves	Section 5.4.5
Chapter 7	
Instrumentation and controls for ESF systems	Section 7.3
Chapter 8	
AC power systems	Section 8.3.1
DC power systems	Section 8.3.2
Chapter 9	
Station Service Water System	Section 9.2.1
Safety Auxiliaries Cooling System	Section 9.2.2
Ultimate heat sink	Section 9.2.5
Primary Containment Instrument Gas System (PCIGS)	Section 9.3.6

Engineered Safety Feature	FSAR Location
Control Room and Control Building HVAC Systems	Section 9.4.1
Equipment Area Cooling System (EACS)	Section 9.4.2
Diesel generator systems	Sections 9.5.4 - 9.5.8

6.1 ENGINEERED SAFETY FEATURE MATERIALS

Materials used in the ESF components have been evaluated to ensure that material interactions that could potentially impair operation of the ESF do not occur. Materials have been selected to withstand the environmental conditions encountered during normal operation and any postulated accident. Their compatibility with containment spray and demineralized water has been considered and the effects of radiolytic decomposition products have been evaluated.

Coatings used on exposed surfaces within the primary containment are suitable for the environmental conditions expected. The nonmetallic thermal insulation used is required to have the proper ratio of leachable sodium plus silicate ions to leachable chloride ions in order to minimize the possibility of stress corrosion cracking.

6.1.1 Metallic Materials

In general, metallic materials used in Engineered Safety Features (ESF) Systems comply with the material specifications of Section II of the ASME B&PV Code. Pressure retaining materials of the ESF systems comply with the quality requirements of their applicable quality group classification and ASME B&PV Code, Section III classification. Adherence to these requirements ensures that materials for the ESF systems are of the highest quality. Where it is not possible to adhere to the ASME material specifications, metallic materials have been selected in compliance with other nationally recognized standards, e.g., American Society of Testing and Materials (ASTM), where practicable, or chosen in compliance with current industry practice.

6.1.1.1 Materials Selection and Fabrication

In general, metallic materials in ESF systems have been selected for a service life of 40 years, with due consideration of the effects of the service conditions on the properties of the material, as required by Section III of the ASME B&PV Code, Articles NB-2160, NC-2160, and ND-2160.

Pressure retaining components are designed with appropriate corrosion allowances, considering the service conditions to which the material will be subjected, in accordance with the general requirements of Section III of the ASME B&PV Code, Articles NB-3120, NC-3120, and ND-3120.

6.1.1.1.1 NSSS-Supplied Components

6.1.1.1.1.1 NSSS-Material Specifications

Table 5.2-7 lists the principal pressure retaining materials, the appropriate material specifications for the reactor coolant pressure boundary (RCPB) components, and other principal components. Table 6.1-1 lists the principal pressure retaining materials and the appropriate material specifications for plant ESFs.

6.1.1.1.1.2 Compatibility of NSSS Construction Materials with Core Cooling Water and Containment Sprays

Section 5.2.3 discusses compatibility of the reactor coolant with construction materials exposed to the reactor coolant. These same construction materials are found in other ESF components.

Demineralized water with no additives is employed in boiling water reactor (BWR) core cooling water and containment sprays.

Materials are selected with the purpose of preventing detrimental effects like intergranular stress corrosion cracking in stainless steel resulting from allowable contaminant levels in this high purity water.

6.1.1.1.1.3 Controls for Austenitic Stainless Steel

Austenitic stainless steel controls are as follows:

1. Control of the use of sensitized stainless steel - Controls to avoid severe sensitization and compliance with Regulatory Guide 1.44 are discussed in Section 5.2.3.

2. Process controls to minimize exposure to contaminants - Process controls for austenitic stainless steel and compliance with Regulatory Guide 1.37 are discussed in Section 5.2.3.

3. Use of cold worked austenitic stainless steel - Cold worked austenitic stainless steel with a yield strength greater than 90,000 psi is not used in ESF systems.

4. Avoidance of hot cracking of stainless steel - Process controls to avoid hot cracking and compliance with Regulatory Guide 1.31 are discussed in Section 5.2.3.

6.1.1.1.1.4 Ferritic Steel Welding

Section 5.2.3 discusses both the fabrication and processing of ferritic materials and ferritic steel welding.

6.1.1.1.2 Non-NSSS Supplied Components

6.1.1.1.2.1 Non-NSSS Material Specifications

Material specifications for the principal pressure retaining ferritic, austenitic, and nonferrous metals for Non-nuclear Steam Supply System (NSSS) supplied components are listed in Table 6.1-2.

6.1.1.1.2.2 Compatibility of Non-NSSS Construction Materials with Core Cooling Water and Containment Sprays

Materials that would be exposed to the core cooling water and containment sprays if there is a loss of coolant accident (LOCA) are identified in Table 6.1-2. The metallic materials of the ESF systems have been evaluated for their compatibility with core cooling water and containment sprays. Demineralized water with no additives is employed for core cooling water and containment sprays. Materials are selected with the purpose of ensuring that no radiolytic or pyrolytic decomposition of ESF material can occur during accident conditions, and the integrity of the containment or function of any other ESF cannot be affected by the action of core cooling water or containment spray systems.

6.1.1.1.2.3 Controls for Austenitic Stainless Steel

6.1.1.1.2.3.1 Control of the Use of Sensitized Stainless Steel

Design specifications call for ASME material, which is to be supplied in the solution annealed condition. Design specifications prohibit the use of materials that have been exposed to sensitizing temperatures in the range of 800 to 1500°F unless they are subsequently solution annealed and water quenched. Where practicable, stainless steel with a carbon content of less than 0.03 percent is used. There are few exceptions to these requirements for components whose uses are not critical in nature or whose environment is not harsh. Compliance with Regulatory Guide 1.44 is discussed in Sections 5.2.3 and 1.8.

6.1.1.1.2.3.2 Process Controls to Minimize Exposure to Contaminants

Design specifications for austenitic stainless steel components require that the material be cleaned using low halide cleaning solutions and that special care be exercised in the fabrication, shipment, storage, and construction to avoid contaminants. There are few exceptions to this requirement for components whose uses are not critical in nature or whose environment is mild. Conformance to Regulatory Guide 1.37 is discussed in Sections 5.2.3 and 1.8.

6.1.1.1.2.3.3 Use of Cold Worked Austenitic Stainless Steel

Cold worked austenitic stainless steels with yield strengths greater than 90,000 psi are not used in ESF systems. Therefore, there are no compatibility problems with core cooling water or the containment sprays.

6.1.1.1.2.3.4 Use of Nonmetallic Thermal Insulation for Austenitic Stainless Steel

Stainless steel jacketed fiberglass blanket insulation is used exclusively for pipes inside the primary containment. Conformance to Regulatory Guide 1.36 is discussed in Sections 5.2.3 and 1.8.

6.1.1.1.2.3.5 Avoidance of Hot Cracking of Stainless Steel

Process controls to avoid hot cracking and compliance with Regulatory Guide 1.31 are discussed in Sections 5.2.3 and 1.8.

6.1.1.1.2.4 Ferritic Steel Welding

Compliance with Regulatory Guide 1.50 is discussed in Section 1.8. Section 5.2.3 discusses the fabrication and processing of ferritic materials.

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

To maintain containment integrity, the hydrogen generation resulting from the corrosion of metals by the containment sprays during a design basis accident (DBA) is controlled as described in Regulatory Guide 1.7, Control of Combustible Gas Concentrations in Containment Following a Loss-of-Coolant Accident, with the design exceptions noted in Section 1.8.

The High Pressure Coolant Injection (HPCI) System is supplied from either the condensate storage tank or the suppression pool. The core spray and low pressure coolant injection (LPCI) are supplied from the suppression pool only. Water in both of these sources is demineralized water. No corrosion inhibitors or other additives are present in either source.

The containment spray uses the suppression pool as its source of supply. No radiolytic or pyrolytic decomposition of ESF materials is induced by the containment sprays.

6.1.1.3 SRP Rule Review

6.1.1.3.1 Acceptance Criterion II.A.1.a.2

In SRP Section 6.1.1, acceptance criterion Item II.A.1.a.2 refers to the requirements of Regulatory Guide 1.44 for preventing intergranular corrosion of stainless steel ESF components. The criteria suggest that corrosion tests, as outlined in this regulatory guide, be conducted to verify nonsensitization of austenitic stainless steel materials prior to fabrication and to ensure that no deleterious sensitization occurs during welding.

The general practice at HCGS is to avoid sensitization that causes intergranular corrosion of stainless steel components before and during all stages of fabrication by controlled storage and fabrication practices. Contamination of the materials is prevented by proper preparation and storage. Because sensitization is avoided, corrosion testing is not required on a routine basis. Corrosion tests in accordance with ASTM A 262-70, Practice A or B are only performed when the maximum cooldown time specified is exceeded, or the solution heat treated condition is in doubt. Further discussion on compliance with Regulatory Guide 1.44 is presented in FSAR Section 1.8.

6.1.1.3.2 Acceptance Criterion II.A.1.a.4

Acceptance criterion Item II.A.1.a.4 in SRP Section 6.1.1 requires that ferrite content in austenitic stainless steel weld filler material be verified in accordance with Regulatory Guide 1.31 by tests using magnetic measuring devices.

At HCGS, the amount of delta ferrite in each lot of austenitic stainless steel filler material is based on the chemical analysis provisions of the ASME B&PV Code Section III, NE-2430, using the Schaeffler diagram. In the Code, this method is described as an alternate method of ferrite reading taken with a magnetic measuring instrument. Ferrite readings are only taken for comparative purposes. Based on the satisfactory agreement of the two methods, the chemical analysis method is considered acceptable for process welds.

6.1.1.3.3 Acceptance Criterion II.A.1.b.1

In SRP Section 6.1.1, acceptance criterion Item II.A.1.b.1 refers to the ASME Code and Regulatory Guide 1.50 for the control of preheat for welding of low alloy steel. At HCGS, weld procedures and practices are in full compliance with the Code, but not strictly with all the aspects of the regulatory positions of Regulatory Guide 1.50. The differences between the two references, with respect to the control of preheat, are discussed in FSAR Section 1.8.1.50. The requirements of the latest issues of Section III and IX of the Code are considered to be adequate to assure satisfactory welds.

6.1.1.3.4 Acceptance Criterion II.B.1

Acceptance criterion Item II.B.1 refers to Regulatory Guide 1.7 for control of hydrogen generation resulting from corrosion of metals by the containment sprays during a design basis accident. Regulatory Position C.1 of this regulatory guide requires that capability be provided to mix the atmosphere in the containment.

At HCGS, the drywell fans have not been classified as safety-related in order to provide post-accidental mixing of the containment atmosphere. Analyses performed indicate that adequate mixing is obtained from convection, diffusion, and turbulence following a LOCA. Mechanical means of mixing are therefore not required.

6.1.2 Organic Materials

Tables 6.1-3 and 6.1-4 list the significant organic materials and coatings, respectively, that exist within the primary containment. These materials in engineered safety features (ESF) components have been evaluated with regard to the expected service conditions and have been found to have no adverse effects on service, performance, or operation.

6.1.2.1 <u>NSSS Supplied Components</u>

The only significant organic materials on GE supplied equipment are the protective coatings used on carbon steel components. These coatings are suitable for the environmental conditions expected and most of the equipment is painted with a prime coat of inorganic zinc.

6.1.2.1.1 Assessment of Compliance to Regulatory Guide 1.54

For commitment, revision number, and scope, see Section 1.8.

This Regulatory Guide states that ANSI N101.4-1972, in conjunction with ANSI N45.2-1971, provides an adequate basis for complying with quality assurance requirements for protective coatings applied to ferritic steels, aluminum, stainless steel, galvanized steel, concrete, or masonry.

GE has specified that most Nuclear Steam Supply System (NSSS) equipment for this plant be coated with a prime coat of inorganic zinc. This coating was one of the first to be qualified under ANSI N101.2 for DBA, radiation, etc, in nuclear applications. Equipment specifications in place at the time of ordering equipment for this plant specified inorganic zinc.

The total amount of unqualified paint in the containment for the NSSS is estimated to be less than 12 kilograms. Equipment tightly covered with thermal insulation is not included in this total, since this source of potential paint debris could not escape to the suppression pool during a loss of coolant accident (LOCA).

The acceptance criterion of SRP Section 6.1.2 provides that a coating system to be applied inside a containment is acceptable if it meets the positions of Regulatory Guide 1.54 and the standards of ANSI N101.2. The quality assurance requirements in this Regulatory Guide were not imposed upon painting material and paint application, since most NSSS equipment was ordered prior to issuance of the Regulatory Guide.

6.1.2.2 <u>Non-NSSS Supplied Components</u>

The drywell and exposed structural metal surfaces inside the drywell are coated with modified phenolic epoxy. This coating has been qualified in accordance with ANSI N101.2.

The suppression chamber is coated with a phenolic epoxy (immersion) compound that has been qualified in accordance with ANSI N101.2.

Generally, exposed metal surfaces of equipment located inside the drywell and torus are coated with modified phenolic epoxy. This coating has been qualified in accordance with ANSI N101.2.

Certain items and locations have unqualified coatings due to lack of documentation, or improper surface preparation or application because of lack of accessibility to the area. The total quantity of unqualified coatings in the containment for non-NSSS supplied components is estimated to be less than 110 kilograms. This quantity is not considered to be significant.

6.1.3 Post-Accident Chemistry

This section does not apply to boiling water reactor (BWR) plants.

TABLE 6.1-1

NSSS-SUPPLIED ENGINEERED SAFETY FEATURES COMPONENT MATERIALS

COMPONENT	FORM	MATERIAL	SPECIFICATION (ASTM/ASME)
RHR Heat Exchanger:			
Shell, head, and channel	Plate	Carbon steel	SA-516, Gr 70
Tubesheet	Plate	Carbon steel	SA-516, Gr 70
Nozzles	Forging	Carbon steel	SA-105, Gr II
Flanges	Forging	Carbon steel	SA-105, Gr II
Tubes	Tubing	Stainless steel	SA-249, Type 304L
Bolts	Bolting	Low-alloy steel	SA-193, Gr 1B7
Nuts			
Shell side	Bolting	Low-alloy steel	SA-194, Gr 7
Tube side	Bolting	Carbon steel	SA-194, Gr 2H
RHR and CS Pumps:			
Bowl assembly	Casting	Ductile iron	ASTM A 536, Gr 65-45-12
Discharge head shell	Plate	Carbon steel	ASTM A 516, Gr 70
Discharge head cover	Plate	Carbon steel	ASTM A 516, Gr 70
Suction barrel shell and dished head	Plate	Carbon steel	ASTM A 516, Gr 70
Flanges	Forging	Carbon steel	ASTM A 350, LF 1
Pipe	Piping	Carbon steel	ASTM A 333, Gr 6
Shaft	Bar	Stainless steel	ASTM A 276, TI 410 cond A

COMPONENT	FORM	MATERIAL	SPECIFICATION (ASTM/ASME)
Impeller		Stainless steel	ASTM A 296, CA15
Studs	Bolting	Alloy steel	ASTM A 193, Gr B7
Nuts	Bolting	Alloy steel	ASTM A 194, Gr 7
Cyclone separator body and cover	Casting	Stainless steel	ASTM A 351, Gr CF8M
HPCI Pump			
Case	Casting	Carbon steel	ASTM 216, Gr WCB
Bearing housing	Casting	Gray iron	ASTM A 278 Cl 40
Impeller	Casting	CrNi Steel	ASTM A 296 Gr CA15
Shaft	Forging	CrNi Steel	ASTM 276, Type 410
Studs	Forging	Alloy steel	ASTM A 193 Gr B7
Standby Liquid Control Pump			
Fluid cylinder	Forging	Stainless steel	ASTM A 182, F304

COMPONENT	FORM	MATERIAL	SPECIFICATION (ASTM/ASME)
Cylinder head, valve cover, and stuffing box flange plate	Plate	Carbon steel	ASTM A 285, Gr C
Cylinder head extension, valve stop, and stuffing box	Bar	Stainless steel	ASTM A 479, Type 304A
Stuffing box gland and plungers	Bar	Stainless steel	ASTM A 461, Gr 630
Studs	Bar	Alloy steel	ASTM A 193, Gr B7
Nuts	Forging	Alloy steel	ASTM A 194, Gr 7
Standby liquid storage tank			
Tank	Plate	Stainless steel	SA-240, Type 304
Fittings	Forgings	Stainless steel	SA-182, Gr F304
Pipe	Piping	Stainless steel	SA-312, Type 304
Welds	Electrodes	Stainless steel	SFA 5.4, 5.9, Type 308, 308L, 316, 316L

TABLE 6.1-1 (Cont)

COMPONENT	FORM	MATERIAL	SPECIFICATION (ASTM/ASME)
Control rod velocity limiter	Casting	Stainless steel	A 351, Gr CF8
Main steam line flued heads	Forging	Carbon steel	SA-105, Gr 2
	Piping	Carbon steel	SA-106, Gr B

TABLE 6.1-2

PRINCIPAL PRESSURE RETAINING MATERIALS FOR NON-NSSS ESF COMPONENTS

SYSTEM/COMPONENT	MATERIAL
Drywell and suppression chamber[(1)]	SA-516, Gr 70
Drywell head[(1)]	SA-516, Gr 70
Penetrations[(1)]	SA-516, Gr 70 SA-312, Gr Type 304L SA-333, Gr 1 or 6 SA-537, Cl 1
Equipment hatches[(1)]	SA-516, Gr 70
Personnel access hatches[(1)]	SA-516, Gr 70
Suppression vent downcomers[(1)]	SA-516, Gr 70
MSIV and main steam relief valve accumulators[(1)]	SA-240, Type 304L
Vacuum relief valve assemblies[(1)]	SA-350, Gr LF1 SA-240, Type 316
Pressure retaining bolting[(1)]	SA-320, Gr L43

SYSTEM/COMPONENT	MATERIAL
Expansion joints[1]	
Bellows	SA-240, Type 304L
Pipes	SA-155, KC-70, Cl 1;
	SA-155, KCF-60, Cl 1;
	SA-106, Gr B
Flued heads	SA-105, Gr 2
	SA-350, Gr LF2,
	SA-182; Gr F316L
Drywell Cooling Units[1]	
Cooling Coil	
Casing, end plate & intermediate supports	Galv steel ASTM A 526
Headers (inlet & outlet, flanges)	Stainless steel, ASTM A 312, Type 304
Tubes	90/10 Co-Ni, SE III, Gr 706
Fins	Copper ASTM B 152
Vaneaxial Fan	
Housing (casing assembly)	
Plate	ASTM A 283D
Sheet	ASTM A 570C
Bar	ASTM A 576, 1012/1015
Wheel	
Blades	Aluminum ASTM B 108.356.F
Rotor	Aluminum ASTM SG 70A
Hub	Aluminum ASTM B 108.356.T6

SYSTEM/COMPONENT	MATERIAL
Shaft	Steel AISI C-1045
Inlet bell	Aluminum ASTM 990A
Lubricant	Nuclear grade grease
Weld filler metal	SFA 5.5, SFA 5.18, SFA 5.17
Accessories	
Drain pan, drain pipe	Stainless steel, ASTM A 240 Type 304
Insulation	Armaflex type closed cell insulation glued w/Armstrong 520 adhesive
Housing (plenum), access door, channel frame base	Stainless steel ASTM A 240, Type 304
Temporary air filter conduit box	Glass media pad, fiberglass per FF-14851
Ducts	ASTM A 526, A 527, A 36
Pipes	A 106, Gr B
Fittings	A 105
Valves	A 105 or A 216, Gr, WCB

SYSTEM/COMPONENT	MATERIAL
Reactor Building	
Secondary containment walls	4000 psi concrete
Ducts	A 526, A 527, A 36
Fire dampers	A 446, G90, Gr B
Tornado dampers	A 607, G-A123
Hinges	ASTM D 2000
Hinge posts	A 36, G-A123
Holding supports	5688 Type 302 stainless steel
Isolation dampers	A 36, A 500, M 1020
Containment heat removal	
Equipment(1)	(2)
Piping(1)	SA-106, Gr B SA-155, Gr KC-70, Cl 1 SA-333, Gr 6, SA-358, Type 304L, Cl 1
Valves(1)	SA-216, Gr WCB SA-105

SYSTEM/COMPONENT	MATERIAL
Pressure retaining bolting(1)	SA-193, Gr B7 SA-194, Gr 2H
Welding material(1)	SFA-5.1, Cl E7016 or E7018 SFA-5.4, Cl ER316L-15 & 16 SFA-5.9, Cl ER316L SFA-5.18, Cl E70S-2 or E70S-3
Containment Isolation System	
Valves(1)	SA-351, Gr CF8M SA-182, Gr F316L SA-216, Gr WCB SA-105
Pressure retaining bolting(1)	SA-193, Gr B7 SA-194, Gr 2H
Welding material(1)	SFA-5.1, Cl E7016 or E7018 SFA-5.4, Cl ER316L & 16 SFA-5.9, Cl ER316L SFA-5.18, Cl E70S-2 or E70S-3
Containment Atmosphere Control System	
Piping	SA-106, Gr B SA-155, Gr KC-70, Cl 1 SA-358, Gr 304L, Cl 1 SA-312, Gr Type 304L

SYSTEM/COMPONENT	MATERIAL
Valves	SA-216, Gr WCB SA-105 SA-351, Gr CF8M SA-182, Gr F316L
Recombiner	SA-182, SA-240, SA-312 or 376
Blower	SA-234 WPB CS
Pressure retaining bolting	SA-193, Gr B7 SA-194, Gr 2H
Welding material	SFA-5.1, Cl E7016 or E7018 SFA-5.9, Cl ER308L SFA-5.18, Cl E70S-2 or E70S-3
Emergency Core Cooling Systems	
High pressure coolant injection	
Equipment(1)	(2)
Piping(1)	SA-106, Gr B SA-155, Gr KC-70, Cl 1 SA-333, Gr 6
Valves(1)	SA-216, Gr WCB SA-105

SYSTEM/COMPONENT	MATERIAL
Pressure retaining bolting(1)	SA-193, Gr B7 SA-194, Gr 2H
Welding materials(1)	SFA-5.1, Cl E7016 or E7018 SFA-5.4, Cl ER316L-15 & 16 SFA-5.9, Cl ER316L SFA-5.18, Cl E70S-2 or E70S-3
Core spray	
Equipment(1)	(2)
Piping(1)	SA-106, Gr B SA-155, Gr KC-70, Cl 1 SA-312, Gr Type 304L SA-333, Gr 6
Valves(1)	SA-351, Gr CF8M SA-182, Gr F316L SA-216, Gr WCB SA-105
Pressure retaining bolting(1)	SA-193, Gr B7 SA-194, Gr 2H
Welding materials(1)	SFA-5.1, Cl E7016 or E7018 SFA-5.9, Cl ER308L SFA-5.18, Cl E70S-2 or E70S-3

SYSTEM/COMPONENT	MATERIAL
Low pressure coolant injection	
Equipment$^{(1)}$	(2)
Piping$^{(1)}$	SA-312, Type 304L SA-358, Type 304L, Cl 1 SA-333, Gr 6 SA-106, Gr B SA-155, Gr KC-70, Cl 1 SA-155, Gr KC-70, Cl 2
Valves$^{(1)}$	SA-351, Gr CF8M SA-182, Gr F316L SA-216, Gr WCB SA-105
Pressure retaining bolting$^{(1)}$	SA-193, Gr B7 SA-194, Gr 2H
Welding materials$^{(1)}$	SFA-5.1, Cl E7016 or E7018 SFA-5.4, Cl ER316L-15 & 16 SFA-5.9, Cl ER 316L SFA-5.18, Cl E70S-2 or E70S-3
Automatic Depressurization System	
Piping$^{(1)}$	SA-106, Gr B
Pressure retaining bolting$^{(1)}$	SA-193, Gr B7

SYSTEM/COMPONENT	MATERIAL
Welding materials[1]	SFA-5.18, Cl E70S-3
Control Room Habitability Systems	
Blowers	A 36, A 569
Dampers	A 36, A 526, A 527, A 167-304L ASTM D 2000, A 607 Galv A 123, A 446
Ducts	A 526, A 527, A 36
Housing	A 36
Filtration, Recirculation, and Ventilation Systems	
FRVS ventilation	
Ducts	A 526, A 527, A 36
Housing	A 36, A 240, A 570
Valves	A 36, A 516, Type 304
Dampers	A 526, 1008/1018 A 527, A 123, 1008/1015, A 165
Blowers	A 283, A 569, A 108, A 36 A 606, A 48, A 575

TABLE 6.1-2 (Cont)

SYSTEM/COMPONENT	MATERIAL
Pressure retaining bolting	A 307-74
Welding materials	F71-EL12, 70S-2, ER-4043
FRVS ventilation filter	
Air filter plenum	
Frame and plenum	ASTM A 570, Gr D, ASTM A 36
Drain pan	ASTM A 240
Anchor bolts	ASTM A 307
Remote control panel	ASTM A 240 Type 304
HEPA section	
Mounting frame	Type 304
Filter frame	MIL-F-51068 Type IIB
Separator	Aluminum
Filter media	Glass fiber to meet reqmt of MIL-F-51068 & MIL-F-51079

SYSTEM/COMPONENT	MATERIAL
Charcoal adsorber section	
Holder	Type 304
Adsorbent	Activated carbon chemically impregnated, reqmt of RDT M16-1T
Water spray nozzles, headers, and internal distribution piping	Type 304
Heating coil section (electric)	
Finned tubular elements	80 percent nickel 20 percent chromium (iron-free)
Fins, finned tubular sheath	ASTM A 240 Type 304
Heater casing	ASTM A 240 Type 304
Terminal box	ASTM A 240 Type 304
Control Room Emergency Fresh Air Filter System	
Ducts	A 526, A 517, A 36

SYSTEM/COMPONENT	MATERIAL
Dampers	A 526, A 527, A 36, A 167-304L ASTM D2000, A 607 Galv A 123 A 446
Housing	A 36, A 570 A 240
Blower	A 283, A 569, A 108, A 36, A 48, A 575, A 606
FRVS recirculation	
Ducts	A 526, A 527, A 36
Dampers	A 526, A 527, A 123, A 165, 1008/1015
Housing	A 36, A 570, A 500; A 240
Blower	A 283, A 36, A 606, A 48 A 108, A 575, A 569
FRVS recirculation filter	
Air filter plenum	
Frame and plenum	ASTM A 570 Gr D, ASTM A 36, ASTM A 500, Gr B
Drain pan	ASTM A 240

SYSTEM/COMPONENT	MATERIAL
Drain shelf and pipe	ASTM A 312 Type 304
Anchor bolts	ASTM A 307
Remote control panel	ASTM A 240 Type 304
Moisture separator section	
Frame	Type 304
Case	Type 304
Drain pan	Type 304
Inlet baffle	Type 304
Cell assembly	
Pans	Glass fiber
Grid	Type 304
Cooling coil section	
Frame - Side, center, and end plates	ASME SA-240, Type 304
Elements - Tubes, return bends	ASME SB-75, Alloy 122
Headers	ASME SB-42, Alloy 122

TABLE 6.1-2 (Cont)

SYSTEM/COMPONENT	MATERIAL
Header end caps	ASME SB-12, Alloy 122
Stubs	ASME SA-234, Gr WPB
Flanges	ASME SA-105
Fins	ASTM B 152, Alloy 110
Plug - Vent and drain	ASME SA-479, Type 410
Bushing, header cap	ASME SB-98, Alloy 651
Intermediate supports	ASME SA-240, Type 304
Bolts and nuts	ASTM A 307, Gr A
HEPA section	
Mounting frame	Type 304
Filter frame	MIL-F-51068, Type IIB
Separator	Aluminum
Filter media	Glass fiber to meet reqmt of MIL-F-51068 & MIL-F-51

SYSTEM/COMPONENT	MATERIAL
Charcoal adsorber section	
Holder	Type 304
Adsorbent	Activated carbon chemically-impregnated reqmt of RDT M16-1T
Water spray nozzles, headers, and internal distribution piping	Type 304
Heating coil section (electric)	
Finned tubular elements	80 percent nickel 20 percent chromium (iron-free)
Fins, finned tubular sheath	ASTM A 240, Type 304
Heater casing	ASTM A 240, Type 304
Terminal box	ASTM A 240, Type 304
<u>Other Systems</u>	

SYSTEM/COMPONENT	MATERIAL
Standby Liquid Control System	
Equipment	(2)
Pipe(1)	SA-312, Gr Type 304L
Valves(1)	SA-182, Gr F316L SA-351, Gr CF8M
Fitting(1)	SA-182, Gr F304L SA-403, Gr WP304L or WP304L W
Pressure retaining bolts	SA-193, Gr B7 SA-194, Gr 2H
Welding materials(1)	SFA-5.9, Cl ER308L SFA-5.4, Cl ER308L

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(1) Material may be subjected to containment spray or core cooling water if there is a LOCA.

(2) See Table 6.1-1 for material designation.

TABLE 6.1-3

ORGANIC MATERIALS WITHIN THE PRIMARY CONTAINMENT

MATERIAL	USE	LOCATION
Kerite Type FR-HT	Medium voltage electrical power cable jacketing and insulation material	Inside penetration
Okonite EPR/hypalon	Low voltage electrical and control power cable jacketing and insulation material	Throughout drywell
Samuel Moore FRE PDM/Hypalon	Instrumentation cable insulation and jacketing material	Throughout drywell
Brand-Rex FREP/ Hypalon	Instrumentation coaxial and triaxial insulation/ jacketing material	Throughout drywell
Lube oil	Reactor recirculation pump motor (two motors), 108 gallons	Drywell
Gear lube	Valve motor operators, 212 lb	Throughout drywell
Neoprene	Drywell ductwork and damper gaskets and seals	Throughout drywell
Silicon rubber	Drywell personnel lock, wiring	Drywell personnel lock

TABLE 6.1-3 (Cont)

MATERIAL	USE	LOCATION
Silicon-60 ethylene-propylene	Drywell hatch seals	Drywell equipment hatches and drywell top head

TABLE 6.1-4

COATINGS USED INSIDE THE PRIMARY CONTAINMENT

Category	Item Description	Coating Type: Special Coating	Coating Type: Mfr Std Coating	Uncoated	Generic Type (1)	Total Film Thickness	Shop Applied		Field Applied	Total Coating Thickness after 40 yrs
Steel plates	Inside of drywell head	x			Phenolic epoxy	8-16 mils			x	8-16 mils
	Inside of drywell shell	x			Phenolic epoxy	8-16 mils			x	8-16 mils
	Upper & lower bio-shield exposed exterior face	x			Phenolic epoxy	8-16 mils			x	8-16 mils
	Upper & lower bioshield exposed interior face				Inorganic zinc	2-4 mils			x	2-4 mils
	Suppression chamber	x			Phenolic epoxy (Immersion)	8-16 mils			x	8-16 mils
Structural steel	Heavy support steel	x			Phenolic epoxy on top of inorganic zinc,	6-10 mils			x	6-10 mils
					or on top of Phenolic epoxy	8-16 mils			x	8-16 mils
	Miscellaneous steel	x			Phenolic epoxy	8-16 mils			x	8-16 mils
	Handrails Gratings			Note 2	Phenolic epoxy	8-16 mils			x	8-16 mils
	Exposed surfaces of steel inserts	x			Phenolic epoxy	8-16 mils			x	8-16 mils
	Hatches (equipment & personnel)	x			Phenolic epoxy	8-16 mils	x	or	x	8-16 mils
Carbon steel pipes	Uninsulated (2-1/2" and larger)	x			Inorganic zinc silicate	2-5 mils	x	or	x	2-5 mils
Valve operators	All sizes		x		Inorganic zinc	2.5-4.5 m	x			2.5-4.5 mils

TABLE 6.1-4 (Cont)

Category	Item Description	Coating Type: Special Coating	Coating Type: Mfr Std Coating	Uncoated	Generic Type[1]	Total Film Thickness	Shop Applied	Field Applied	Total Coating Thickness after 40 yrs
Valves[7]	2 1/2 in. and larger			x	Inorganic zinc	2-5 mils	x		2-5 mils
	2 in. and smaller		x				x		
Pipe hangers	All sizes	x			Inorganic zinc or Phenolic epoxy	2-5 mils 8-16 mils	x or x or	x x	2-5 mils 8-16 mils
Mechanical equipment	Reactor recirculation pump			Note 3					
	Reactor recirculation pump motor		x		Alkyd resin base enamel	5 mils	x		5 mils
	Reactor pressure vessel				Inorganic zinc	2-5 mils		x	2-5 mils
	Fan cabinet (carbon steel)	x			Inorganic zinc	3 mils	x		
	Fan housing	x			Inorganic zinc	3 mils	x		
	HVAC ducts			Note 2					
Concrete[4]	RPV pedestal	x			Decontaminable epoxy surfacer	16-89 mils		x	16-89 mils
	Drywell floor	x			Decontaminable epoxy surfacer	16-89 mils		x	16-89 mils
Electrical equipment	Terminal and junction boxes[8]				Note 5				
	Cable trays			Note 5					
	Conduits			Note 2					
	Cables			Note 6					

Category	Item Description	Coating Type: Special Coating	Coating Type: Mfr Std Coating	Uncoated	Generic Type[1]	Total Film Thickness	Shop Applied	Field Applied	Total Coating Thickness after 40 yrs
Small miscellaneous equipment	Hoists				Phenolic epoxy				3 to 5 mils

(1) Generic coating systems acceptable for containment use have been selected from suppliers who are prequalified to project standards and test criteria. Systems other than those listed are acceptable for specific units based on analysis of requirements.
(2) Material is galvanized, no coating needed.
(3) Stainless steel, no coating needed.
(4) Concrete coating limited to minimum area required for decontamination purposes.
(5) Aluminum, no coating needed.
(6) Cables are insulated (EPR insulation or polyolefin insulation).
(7) Exterior coating is identical to the pipe system in which the valve is installed.
(8) Bakelite is used inside terminal boxes.
(9) Surfaces that cannot be painted are protected from rust by MIL-C-16173, Grades 2, 3, 4 or 5.

6.2 CONTAINMENT SYSTEMS

6.2.1 Containment Functional Design

6.2.1.1 <u>Pressure Suppression Containment</u>

6.2.1.1.1 Design Basis

The Pressure Suppression Containment System is designed to have the following functional capabilities:

1. The containment has the capability to maintain its functional integrity during and following peak transient pressures and temperatures that occur following any postulated loss-of-coolant accident (LOCA). The LOCA includes the worst single failure (which leads to maximum containment pressure and temperature) and is further postulated to occur simultaneously with a loss of offsite power (LOP) and a safe shutdown earthquake (SSE). A discussion of the postulated LOCA events is provided in Section 6.2.1.1.3. A discussion of mass and energy release is presented in Section 6.2.1.3.

2. The containment, in combination with other accident mitigation systems, limits fission product leakage during and following the postulated design basis accident (DBA) to values less than leakage rates that result in offsite doses greater than those set forth in 10CFR50.67.

3. The containment can withstand coincident fluid jet forces associated with the flow from the postulated rupture of any pipe within the containment.

4. The containment design permits removal of fuel assemblies from the reactor core after a postulated LOCA.

5. The containment is protected from or designed to withstand missiles from internal sources and excessive motion of pipes that could directly or indirectly endanger the integrity of the containment.

6. The containment provides a means to channel the flow from postulated pipe ruptures in the drywell to the suppression pool.

7. The containment is designed to allow for periodic testing at the calculated peak accident pressure, in order to confirm the leaktight integrity of the containment and its penetrations.

6.2.1.1.2 Design Features

Section 3.8 describes the design features of the containment and its internal structures. Figure 3.8-1 shows the general arrangement of the containment and its internal structures.

6.2.1.1.2.1 Protection from Dynamic Effects

The containment and the Engineered Safety Feature (ESF) System functions are protected from dynamic effects of postulated accidents, as described in Sections 3.5 and 3.6.

6.2.1.1.2.2 Codes, Standards, and Specifications

Table 3.8-1 lists the applicable codes, standards, and specifications for the containment. Codes, standards, and specifications applicable to the containment internal structures are given in Table 3.8-7.

Regulatory guides specific to the containment design are discussed in Sections 3.8.2.4 and 3.8.2.5.

6.2.1.1.2.3 Functional Capability Tests

The functional capability of the containment is verified by pressurizing the containment to 1.15 times the internal design pressure, as described in Section 3.8.2. A discussion of containment leakage testing is provided in Section 6.2.6.

6.2.1.1.2.4 External Pressure Loading Conditions

The containment is designed to withstand an external to internal differential pressure of 3 psi. To ensure that this design limit is not exceeded, vacuum relief valves are provided. The design and functional capability of the containment vacuum relief valves are discussed in Section 6.2.1.1.4.

6.2.1.1.2.5 Trapped Water That Cannot Return to Containment Sump

Not applicable to pressure suppression type containments.

6.2.1.1.2.6 Containment and Subcompartment Atmosphere Control

Section 3.11 provides the pressure, temperature, and humidity limits within which all Class 1E equipment located inside the containment is qualified to operate. Sections 6.2.1.1.4, 6.2.5, and 9.4.5 describe the functional capability and frequency of operation of the systems and equipment that maintain the containment and subcompartment atmospheres within prescribed limits during normal plant operation.

6.2.1.1.3 Design Evaluation

6.2.1.1.3.1 Introduction

The containment functional design evaluation is based on the consideration of several postulated accidents, each of which results in the release of reactor coolant to the containment environs. These postulated accidents include the following:

1. An instantaneous guillotine rupture of a recirculation line

2. An instantaneous guillotine rupture of a main steam line

3. An intermediate size Reactor Coolant System (RCS) break

4. A small size RCS break.

Analysis of this spectrum of accidents indicates that the maximum temperatures and pressures experienced inside the containment do not all result from a single accident. Maximum drywell and suppression chamber pressures occur as a result of the recirculation line break, while the most severe drywell temperature condition (peak temperature and duration) results from the small size steam line break. Consequently, there is no single DBA for the containment.

The most severe drywell temperature condition, peak temperature and duration, occurs for a small RCS rupture above the reactor water level that results in the blowdown of reactor steam to the drywell, a small steam break. To demonstrate that breaks smaller than the rupture of the largest RCS pipe will not exceed the containment design parameters, the containment system responses to an intermediate size liquid break and a small size steam break are evaluated. The results show that the containment design conditions are not exceeded for these smaller break sizes.

The design values and the maximum calculated accident values of key design parameters for the containment are as follows:

Parameter	Design Value	Calc Accident Value
Drywell pressure	62 psig	50.6 psig
Drywell temperature	340°F	340°F
Suppression chamber pressure	62 psig	27.7 psig
Suppression chamber temperature	310°F	212.3°F

NOTE: Calculated values above are conservatively based on 102% of an assumed thermal power rating of 3952 MWt compared to the licensed value of 3840 MWt. However, for LOP, peak long term suppression pool temperature is 213.6°F based on the licensed thermal power of 3840 MWt. Also, maximum drywell temperature conditions are based on steam line break super heat, which is not dependent on the initial reactor thermal power.

Table 6.2-1 lists the containment design parameters used in the accident response analyses. Table 6.2-2 provides the performance parameters of ESF equipment used for containment cooling purposes during post-blowdown, long term accident operation. Performance parameters given include those applicable to full capacity operation, as well as those applicable to conservatively reduced capacities assumed for accident response analysis purposes. All of the analyses assume that the RCS and the containment are initially at the maximum or minimum normal operating conditions given in Table 6.2-3. Mass and energy release sources and rates used for the containment analyses are as discussed in Section 6.2.1.3.

The containment pressure and temperature responses for each of the postulated accidents are discussed in Sections 6.2.1.1.3.2 through 6.2.1.1.3.5. Analytical models used to evaluate the containment responses are delineated in Section 6.2.1.1.3.6.

6.2.1.1.3.2 Recirculation Line Break

Immediately following guillotine rupture of the largest recirculation line, the flow from out of both sides of the break is limited to the maximum allowed by critical flow considerations. Figure 6.2-1 provides a schematic representation of flow paths to the break. In the side adjacent to the suction nozzle, the flow corresponds to critical flow in the pipe cross section.

The proprietary code, LAMB (Reference 6.2-1) was used to calculate the blowdown flow rates, which are then used as inputs to the proprietary code M3CPT (References 6.2-2 through 6.2-4) for the analysis of up-rated power at 4031 MWt. Note the analysis is conservative based on 102% of an assumed rated power of 3952 (4031 MWt) in contrast with 102% of Licensed Thermal Power of 3840 (3917 MWt). This approach differs from the previous analysis for 102% of the original rated thermal power of 3293 (3359 MWt), which used a blowdown model built into M3CPT. Application of the LAMB blowdown model for the analysis at 4031 MWt is identified in Reference 6.2-27. The proprietary code SHEX (Reference 6.2-27) is used for long-term containment response evaluations for the conditions at 4031 MWt as well as at 3359 MWt.

Table 6.2-3 provides the initial conditions for containment response analysis. Figure 6.2-2 shows the total effective blowdown area for the recirculation line break. This figure is provided for historical information, accordingly it is based on 102% of original rated thermal power of 3293 MWt (3359).

1. Assumptions for reactor blowdown - The response of the RCS during the blowdown period of the accident is analyzed using the following assumptions:

   a. The initial conditions for the recirculation line break accident are such that the system energy is maximized and the system mass is minimized. That is:

      (1) The reactor is operating at 102 percent of up-rated thermal power or 4031 MWt, which maximizes the post-accident decay heat.

      (2) The Safety Auxiliaries Cooling System (SACS) water temperature is at its maximum value.

      (3) The suppression pool mass is at the low water level for the long term analysis and at the high water level for the short term analysis.

      (4) The suppression pool temperature is at its maximum normal value.

   b. The recirculation line is considered to be severed instantly. This results in the most rapid coolant loss and depressurization of the vessel, with coolant being discharged from both ends of the break.

   c. Reactor power generation ceases at the time of accident initiation because of void formation in the core region. Reactor scram also occurs in less than 1 second from receipt of the high drywell pressure signal. The time difference between accident initiation and reactor scram is negligible.

d. The break flow rate and enthalpy following the DBA-LOCA are calculated using the Homogeneous Equilibrium Model (HEM) critical flow model.

e. The core decay heat and the sensible heat released in cooling the fuel to initial average coolant temperature are included in the RPV depressurization calculation. The rate of energy release is calculated using a conservatively high heat transfer coefficient throughout the depressurization period. The resulting high energy release rate causes the RPV to maintain nearly rated pressure for approximately 20 seconds. The high RPV pressure increases the calculated blowdown flow rates, which is again conservative for analysis purposes. The sensible fuel energy stored at temperatures below the initial average coolant temperature is released to the vessel fluid, along with the stored energy in the vessel and internals, as vessel fluid temperatures decrease during the remainder of the transient calculation.

f. The main steam isolation valves (MSIVs) start closing at 0.5 seconds after the accident. They are fully closed in the shortest possible time of 3 seconds following closure initiation. In actuality, the closure signal for the MSIVs results from low reactor water level, so the valves normally do not receive a signal to close for more than 4 seconds. Also, the valve closing time may be as long as 5 seconds.

g. The feedwater flow rate coasts down to zero in four seconds. The four second coastdown assumption maximizes the break flow and is consistent with Reference 6.2-1.

h. A complete LOP occurs simultaneously with the pipe break. This condition results in the loss of power conversion system equipment and also requires that all ESF systems for long term cooling be supported by onsite power supplies.

2. Assumptions for containment pressurization - The pressure response of the containment during the blowdown period of the accident is analyzed using the following assumptions:

   a. Thermodynamic equilibrium exists in the drywell and suppression chamber. Since nearly complete mixing is achieved, the analysis assumes complete mixing.

   b. The fluid flowing through the drywell to suppression chamber vents is formed from a homogeneous mixture of the fluid in the drywell. The use of this assumption results in complete carryover of the drywell atmosphere and a higher positive flow rate of liquid droplets, which conservatively maximizes vent system pressure losses.

c. The fluid flow in the drywell to suppression chamber vents is compressible, except for the liquid phase.

d. No heat loss occurs from the gases inside the containment. In reality, some steam condenses on the drywell surfaces.

3. Assumptions for long term cooling - Following the blowdown period of the accident, the Emergency Core Cooling System (ECCS) discussed in Section 6.3 and the Containment Heat Removal System discussed in Section 6.2.2 provide water for core flooding, containment spray, and long term decay heat removal. The containment pressure and temperature responses during this period are analyzed using the following assumptions:

   a. The residual heat removal (RHR) pumps, operating in the low pressure coolant injection (LPCI) mode, and the core spray pumps are used to flood the core during the first 600 seconds following the accident. The High Pressure Coolant Injection (HPCI) System is not operating for the DBA-LOCA.

   b. After 600 seconds, flow from one RHR pump can be diverted from the RPV to containment spray. This is a manual operation. Actually, containment spray need not be actuated to keep the containment pressure below the containment design pressure. Prior to actuation of containment spray, which is assumed to occur at 600 seconds after the accident, all of the RHR pump flow is used to flood the core.

c. After approximately 600 seconds, the RHR heat exchangers are manually aligned to remove energy from the containment via recirculation cooling of the suppression pool.

d. The effects of decay energy, stored energy, sensible energy, energy added by the ECCS pumps, and metal water reaction energy on the suppression pool temperature are considered.

e. The suppression pool and containment structures are the heat sinks available in the containment.

4. Initial conditions for accident analysis - Table 6.2-4 provides the initial conditions and numerical values assumed for the recirculation line break accident, as well as the sources of energy considered prior to the postulated pipe rupture. The assumed conditions for the reactor blowdown are also provided.

5. Chronology of accident events - A complete description of the containment response to the recirculation line break accident is provided in the following paragraphs. A chronological sequence of events for the accident from time zero is provided in Table 6.2-8. Analysis results for this accident are shown on Figures 6.2-3 through 6.2-9.

   a. Short term accident response - At the beginning of the accident, the suppression chamber is pressurized by the carryover of noncondensable gas from the drywell and by the heatup of the suppression pool. As the vapor formed in the drywell is condensed in the suppression pool, the temperature of the suppression pool peaks and the suppression chamber pressure stabilizes. The drywell pressure stabilizes at a slightly higher pressure, the difference being equal to the downcomer submergence. During the RPV depressurization phase, most of the non-condensable gas initially in the drywell is forced into the suppression chamber.

Table 6.2-5 provides the peak containment pressure and temperature for the recirculation line break, as predicted for the conditions of Tables 6.2-3 and 6.2-4 and as corresponding with the pressure and temperature responses shown on Figures 6.2-3 and 6.2-4. Figure 6.2-5 shows the time dependent response of the pressure differential between the drywell and the suppression chamber.

During the blowdown period of the LOCA, the drywell to suppression chamber vent system conducts the steam water gas mixture in the drywell to the suppression pool for condensation of the steam. The pressure differential between the drywell and the suppression chamber controls this flow. Figure 6.2-6 provides the mass flow versus time relationship through the vent system for this accident.

b. Long term accident responses - To assess the adequacy of the containment following the initial blowdown transient, an analysis is made of the long term temperature and pressure response. For the long term accident response analysis, following RPV depressurization, the non-condensable gas redistributes between the drywell and the suppression chamber vacuum relief valves, as discussed in Section 6.2.1.1.4. This redistribution takes place as steam in the drywell is condensed by the relatively cool ECCS water beginning to cascade from the break causing the drywell pressure to decrease.

The ECCS supplies core cooling water to control core heat-up and to limit the core-wide metal-water reaction to less than one percent. After the RPV is flooded to the height of the jet pump nozzles, the excess flow discharges through the recirculation line break into the drywell. This flow of water (steam flow is negligible) transports the core decay heat out of the RPV and through the broken recirculation line in the form of hot water, which flows into the suppression chamber via the drywell to suppression chamber vent system. This flow also provides a heat sink for the drywell atmosphere and thereby causes the drywell to depressurize.

The analysis assumptions are those discussed below for the three cases of interest. The initial pressure response of the containment, the first 600 seconds after the break, is the same for each of the following cases:

(1) Case A - All ECCS equipment operating, with containment spray - This case assumes that offsite power is available to operate the core cooling systems. During the first 600 seconds following the pipe break, the HPCI, the core spray, and all RHR (LPCI mode) pumps are assumed to be available. All flow is injected directly into the reactor vessel.

    After 600 seconds, both RHR heat exchangers are manually aligned to remove energy from the containment. During this mode of operation, the flow from two RHR pumps is routed through their associated RHR heat exchangers, where it is cooled before being discharged into the drywell and suppression chamber spray headers.

The containment pressure response to this set of conditions is shown as curve A on Figure 6.2-7. The corresponding drywell and suppression pool temperature responses are shown as curve A on Figures 6.2-8 and 6.2-9. After the initial blowdown and subsequent depressurization due to core spray and LPCI core flooding, energy addition due to core decay heat results in a gradual pressure and temperature rise in the containment. When the energy removal rate of the RHR system equals the energy addition rate from the decay heat, the containment pressure and temperature each reach a second peak value, and then gradually decrease to their pre-accident values. Table 6.2-6 summarizes the ECCS equipment operation, the peak long term containment pressure following the initial blowdown peak, and the peak suppression pool temperature for this analysis case.

(2) Case B - LOP, with containment spray - This case assumes that no offsite power is available following the accident and that only minimum onsite standby power is available, i.e., single standby diesel generator (SDG) failure. The RHR system, including the drywell and suppression chamber sprays, is in operation after 600 seconds. During this mode of operation, RHR system flow passes through only one RHR heat exchanger and is directed to the containment spray headers.

This is a non-limiting event. Accordingly, the related results are presented for historical purposes only and are based on 3359 MWt rather than the licensed thermal power of 3840 MWt.

The containment pressure response to this set of conditions is shown as curve B on Figure 6.2-7. The corresponding drywell and suppression pool temperature responses are shown as curve B on

Figures 6.2-8 and 6.2-9. A summary of this analysis case is given in Table 6.2-6.

(3) Case C - LOP, without containment spray - This case assumes that no offsite power is available following the accident and that only minimum onsite standby power is available. After 600 seconds, the sprays may be manually actuated to further reduce containment pressure if desired. However, this analysis assumes that the drywell and suppression chamber sprays are not actuated. After 600 seconds, one RHR heat exchanger is manually aligned to remove energy from the containment. The flow from one RHR pump, in the LPCI mode, is cooled by the RHR heat exchanger before being discharged into the reactor vessel.

The containment pressure response to this set of conditions is shown as curve C on Figure 6.2-7 for 3359 MWt to provide a historical basis for comparison between cases and Figure 6.2-7a for 102% of 3840 MWt (3917). The corresponding drywell and suppression pool temperature responses are shown as curve C on Figures 6.2-8 and 6.2-9 for 3359 MWt. Figures 6.2-8a and 6.2-9a are provided for 3917 MWt. A summary of the analysis case is given in Table 6.2-6. Note that the summary data for the extended power up-rate case is conservatively based on the assumed rated thermal power of 102% of 3952 rather than 3840 MWt.

When comparing case B (spray) with case C (no spray), the same RHR heat exchanger duty is obtained since the suppression pool temperature response is approximately the same, as shown on Figure 6.2-9. Thus, the same amount of energy is removed from the suppression pool whether the exit flow from the RHR heat exchanger is injected into the reactor vessel or is injected into the drywell as spray. However, the peak containment pressure is higher for the no-spray case but is still less than the containment design pressure. This comparison is based on analysis at 3359 MWt.

Figures 6.2-10 and 6.2-10a show the rate at which the RHR system removes heat from the suppression pool following a LOCA at 3359 and 4031 MWt, respectively.

6. Energy balance during accident - To establish an energy distribution in the containment as a function of time, short term or long term, for this accident, the following energy sources and sinks are required:

   a. Blowdown energy release rates

   b. Decay heat rate and fuel relaxation sensible energy

   c. Sensible heat rate (vessel and internals)

   d. Pump heat rate

   e. Heat removal rate from suppression pool (Figure 6.2-10)

   f. Metal water reaction heat rate.

   Items a., b., c., d., and f. are discussed in Section 6.2.1.3. A complete energy balance for the recirculation line break accident at 3359 MWt is given in Table 6.2-7 for the reactor system, the containment, and the containment cooling systems at time zero, at the time of peak drywell pressure, at the end of reactor blowdown, and at the time of the long term peak pressure in the containment.

6.2.1.1.3.3 Main Steam Line Break

NOTE – For the purposes of the Hope Creek Extended Power Up-rate (EPU), the General Electric Company determined the MSLB to be non-limiting. As such, the supporting analysis discussed below and presented in Tables and Figures of Section 6.2 were not reanalyzed for the licensed thermal power rating of 3840 MWt. Accordingly, the associated Tables and Figures are based on 102% of the original rated thermal power 3293 MWt (3353). While provided for historical purposes, the MSLB analysis determines the event to be temperature and not pressure limiting. Furthermore, maximum temperature for MSLB is based on limiting superheated steam conditions, which are not dependant on initial reactor power.

The assumed sudden rupture of a main steam line between the reactor vessel and the main steam flow restrictor results in the maximum flow rate of RCS fluid and energy to the drywell. The sequence of events immediately following the rupture of a main steam line between the reactor vessel and the flow restrictor is as follows. The flow on both sides of the break accelerates to the maximum allowed by critical flow considerations. On the side adjacent to the reactor vessel, the flow corresponds to critical flow in the steam line cross section. Blowdown through the other side of the break occurs because the steam lines are all interconnected at a point upstream of the main turbine by the main steam bypass header. This interconnection allows RCS fluid to flow from the three unbroken steam lines through the header and into the drywell via the broken line. Flow is limited by critical flow in the steam line flow restrictor of the broken line. Figure 6.2-11 shows the total effective blowdown area. The MSIVs are assumed to start closing at 0.5 seconds after the accident and are fully closed 5 seconds following closure initiation. By assuming slow closure of these valves, a large effective blowdown area is maintained for a longer period of time. The peak drywell pressure occurs before the reduction in effective blowdown area and is therefore insensitive to any additional delay in closure of the MSIVs.

Immediately following the break, the total steam flow rate leaving the vessel exceeds the steam generation rate in the core, causing an initial depressurization of the RPV. Void formation in the reactor vessel water causes a rapid rise in the water level. It is conservatively assumed that the water level reaches the vessel steam nozzles 1 second after the break occurs. This assumed water level rise time of 1 second is the fastest that can occur under any reactor operating condition. From this time on, a two phase mixture is discharged from the break. During the first second of the blowdown, the blowdown flow consists of saturated steam. This steam enters the containment in a superheated condition at approximately 330°F.

Figures 6.2-12 and 6.2-13 show the containment pressure and temperature responses during the RCS blowdown phase of the main steam line break accident.

Figure 6.2-13 shows that the drywell atmosphere temperature approaches a peak after approximately 1 second of RCS steam 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. The peak differential pressure between the drywell and the suppression chamber occurs shortly after the vent clearing transient. As the blowdown proceeds, the RCS pressure and fluid inventory decrease, which results in reduced blowdown rates. As a consequence, the flow rate in the vent system and the differential pressure between the drywell and the suppression chamber begin to decrease.

Table 6.2-5 presents the peak containment pressures and temperatures for this accident, as compared to those for the recirculation line break accident.

After the RCS pressure has dropped to the drywell pressure, the blowdown is over. At this time, the drywell contains saturated steam, and the drywell and suppression chamber pressures stabilize. The pressure difference between the drywell and the suppression chamber corresponds to the hydrostatic pressure of downcomer submergence.

The drywell and the suppression chamber remain in this equilibrium condition until the reactor vessel refloods. During this period, the ECCS pumps inject cooling water from the suppression chamber into the reactor. This injection of water eventually floods the reactor vessel to the level of the steam line nozzles and the ECCS flow spills into the drywell. The water spillage condenses the steam in the drywell and thus reduces the drywell pressure. As soon as the drywell pressure drops below the suppression chamber pressure, the drywell to suppression chamber vacuum relief valves open and noncondensable gas forced into the suppression chamber during the blowdown phase of the accident flows back into the drywell until the pressures in the two regions equalize.

6.2.1.1.3.4 Intermediate-Size Break

NOTE – This event was determined by the General Electric Company to be non-limiting for EPU purposes. As such, the results discussed below and presented in associated Tables and Figures are for 102% of the original rated thermal power (RTP) of 3293 MWt (3359 MWt) rather than 102% if licensed thermal power of 3840 MWt (3917 MWt). The information is provided for comparison and historical purposes.

An intermediate size break is analyzed as part of the containment functional design evaluation to demonstrate that the consequences are no more severe than those from a rupture of the largest RCS pipe. 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 containment of a 0.5-square-foot break below the RPV water level. This break area is chosen as being representative of the intermediate size break area range. These breaks can involve either reactor steam or liquid blowdown.

Following the 0.5-square-foot break, the drywell pressure increases at approximately 1 psi per second. This drywell pressure transient is sufficiently slow so that the dynamic effect of the water in the downcomers is negligible, and the downcomers clear when the drywell to suppression chamber differential pressure is equal to the hydrostatic pressure corresponding to the downcomer submergence.

Figures 6.2-14 and 6.2-15 show the short term containment pressure and temperature responses for this accident. The ECCS response is discussed in Section 6.3. Approximately 5 seconds after the 0.5-square-foot break occurs, noncondensable gas, steam, and water start to flow from the drywell to the suppression chamber; the steam is condensed in the suppression pool; and the noncondensable gas enters the suppression chamber free space. The continual purging of the drywell atmosphere to the suppression chamber results in a gradual pressurization of both the suppression chamber and the drywell. The containment continues to gradually increase in pressure due to the long term suppression pool heatup.

The ECCS is initiated as the result of the 0.5-square-foot break and provides emergency cooling of the core. The operation of this system is such that the reactor is depressurized in approximately 600 seconds. This terminates the blowdown phase of the transient.

The suppression pool end of blowdown temperature is the same as that for the recirculation line break accident because essentially the same amount of RCS energy is released during the blowdown. After reactor depressurization and reflood, water from the ECCS begins to flow out the break. 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 line break. The subsequent long term suppression pool and containment heatup transient is essentially the same as for the recirculation line break accident.

From this description, it is concluded that the consequences of an intermediate size break are less severe than those of a recirculation line break.

6.2.1.1.3.5 Small Size Break

This section discusses the containment transient associated with small RCS blowdowns. The sizes of RCS ruptures in this category are those that do not result in reactor depressurization due to either loss of reactor coolant or automatic operation of the ECCS equipment. Following the occurrence of a break of this size, it is assumed that the reactor operator initiates an orderly plant shutdown and depressurization of the reactor system. The thermodynamic process associated with the blowdown of RCS fluid is one of constant enthalpy. If the RCS break is below the water level, the blowdown flow consists of reactor water. Blowdown from reactor pressure to drywell pressure flashes approximately one-third of this water to steam, while two-thirds of the blowdown flow remains as liquid. Both phases are at saturation conditions corresponding to the drywell pressure.

If the RCS 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 constant enthalpy with depressurization of high pressure, saturated steam results in superheated conditions.

A small reactor steam leak, resulting in superheated steam, imposes the most severe temperature conditions on the drywell structures and on the safety equipment in the drywell. For larger steam line breaks, the superheat temperature is nearly the same as for small breaks, but the duration of the high temperature condition is less for the larger break. This is because larger breaks depressurize the reactor more rapidly than the orderly reactor shutdown that is assumed to terminate the small break.

1. Containment response - For drywell design considerations, the following sequence of events is assumed. With the reactor and 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, which scrams the reactor and actuates the containment isolation system. The drywell pressure continues to increase at a rate dependent upon the size of the steam leak. The pressure increase lowers the water level in the downcomers until the level reaches the bottom of the downcomers. At this time, noncondensable gas and steam start to enter the suppression chamber. The steam is condensed in the suppression pool and the noncondensable gas is carried over to the suppression chamber free space. The carryover of noncondensable gas from the drywell results in a gradual pressurization of

the suppression chamber at a rate dependent upon the size of the steam leak. Once all of the noncondensable gas in the drywell is carried over to the suppression chamber, short-term pressurization of the suppression chamber ceases, and the system reaches equilibrium. The drywell contains only superheated steam, and continued blowdown of reactor steam condenses in the suppression pool. The suppression pool temperature continues to increase until the RHR heat exchanger heat removal rate is equal to the decay heat release rate.

2. Recovery operations - The reactor operator is alerted to the incident by the high drywell pressure signal and by the reactor scram. For the purpose of evaluating the duration of the superheat condition in the drywell, it is assumed that the operator's response is to shut down the reactor in an orderly manner using the main condenser, while limiting the reactor cooldown rate to 100°F per hour. This results in the RCS being depressurized within 6 hours. At this time, the blowdown flow to the drywell ceases, and the superheat condition is terminated. If the plant operator elects to cool down and depressurize the RCS more rapidly than 100°F per hour, the duration of the drywell superheat condition is shorter.

3. Drywell design temperature considerations - For drywell design purposes, it is assumed that there is a blowdown of reactor steam for the 6-hour cooldown period. The corresponding design temperature is determined by finding the combination of RCS pressure and drywell pressure that produces the maximum superheat temperature. The maximum drywell steam temperature occurs when the RCS is at approximately 450 psia. Thus, for design purposes, it is assumed that the drywell is at 50 psia, with a resultant temperature of 340°F.

6.2.1.1.3.6 Accident Analysis Models

1. Short term pressurization model - The analytical models, assumptions, and methods used to evaluate the containment response during the reactor blowdown phase of a LOCA are described in References 6.2-2 through 6.2-4.

2. Long term response model - The analytical model used in evaluating the long term response to a LOCA is based on the mass and energy balance of the reactor vessel, drywell, suppression pool, and suppression chamber atmosphere. Auxiliary systems that are connected to the primary systems are also modeled. The two major auxiliary systems that have the greatest impact on the long term response are the emergency core cooling and pool cooling functions of the RHR system.

   The governing equations are integrated numerically, enabling the evaluation of the thermodynamic histories of both the primary and containment systems.

3. Analytical assumptions - The key assumptions employed in the model are as follows:

   a. The drywell free space is composed of a uniform mixture of steam, air, and liquid droplets.

   b. Flow through the vents is adiabatic.

   c. For short term analyses, the temperature of the suppression chamber atmosphere is equal to the temperature of the suppression pool.

   d. For short term analyses, no credit is taken for heat losses to the drywell wall, suppression chamber walls, and internal structures.

The HCGS Plant Unique Analysis Report (PUAR) has been submitted (letter from R. L. Mittl to A. Schwencer, February 10, 1984) to identify the analyses conducted to establish design basis loads. The PUAR identifies and justifies exceptions to NRC acceptance criteria (e.g., NUREG-0661, "Mark I Containment Long Term Program").

A post-implementation pool dynamic load audit of the Hope Creek PUAR has been completed to verify compliance with the generic acceptance criteria of NUREG-O661. This audit, performed by the NRC staff and Brookhaven National Laboratory, identified four exceptions to the generic acceptance criteria:

1) Use of alternative acceleration drag volumes to determine drag on sharp cornered structures.

2) Phasing of load harmonics used to analyze structures affected by condensation oscillation and post-chug loads.

3) Fluid Structure Interaction methodology used for condensation oscillation and chugging submerged structure loads.

4) Use of calibration factors developed from Monticello in-plant tests for use in defining SRV submerged structure drag loads.

All of these issues have been resolved. The review of the HCGS PUAR has been completed with no issues or concerns outstanding.

6.2.1.1.4 Negative Pressure Design Evaluation

6.2.1.1.4.1 Containment Vacuum Relief Valves

The containment is designed to withstand an external to internal differential pressure of 3 psi.

Vacuum in the drywell is relieved by eight 24-inch vacuum relief valves located on the vent header of the drywell to suppression chamber vent system. These valves are self-actuating, check type, that can also be remote manually operated from the main control room for testing purposes. The vacuum relief valves between the drywell and the suppression chamber are sized to provide a total flow area of no less than approximately one-sixteenth of the net vent system cross-sectional area.

Vacuum in the suppression chamber is relieved by a 24-inch vacuum breaker assembly located in each of two lines between the reactor building and the suppression chamber free space. Each assembly consists of a check type vacuum relief valve and a pneumatically operated butterfly valve mounted in series, with the butterfly valve located between the containment and the check type valve. The check type valves are self-actuating and can be remote manually operated from the main control room for testing purposes. The butterfly valves, which are normally closed for containment isolation purposes, are actuated by differential pressure between the reactor building and the suppression chamber free space. The butterfly valves can also be remote manually operated from the main control room for testing purposes. The controls and instrumentation for each butterfly valve are powered from different Class 1E electrical channels to ensure that failure of a single electrical channel does not disable more than one vacuum breaker assembly. The normal air supply for these valve actuator is from the instrument air system. To assure these butterfly valves can operate post-accident, they are provided with an accumulator which is designed to ASME Code, Section III, Class 3 requirements. The accumulators are provided with a makeup source from the safety-related Primary Containment Instrument Gas Supply System (See Plant Drawing M-57-1). Each vacuum breaker assembly is sized on the basis of the flow of air from the Reactor Building required to limit the containment collapse pressure to within 3.0 psi. The maximum containment depressurization rate is a function of the containment spray flow rate and temperature and the assumed initial conditions of the containment atmosphere. Low spray temperatures and containment atmospheric conditions that yield the minimum numbers of contained noncondensable moles of gas are assumed for conservatism.

The containment vacuum relief valves are qualified to Seismic Category I criteria and are designed and manufactured in accordance with the requirements of the ASME B&PV Code, Section III, Class 2. The valves and appurtenances are designed to operate at a maximum pressure and temperature of 62 psig and 340°F, respectively, concurrent with a maximum relative humidity of 100 percent. During such environmental conditions, the valves open fully within 1 second, with a 0.25 psi differential pressure existing across the valve. Each valve is equipped with redundant valve-position limit switches, which are suitably sensitive to provide main control room indication of valve closure to a tolerance of 0.01 inch.

GE Letter #MFN-094-82 dated July 2, 1982 is applicable to HCGS's suppression pool to drywell vacuum breaker design. These vacuum breakers have been modified in accordance with the recommendations from the Mark I BWR owners group. The Hope Creek Plant Unique Analysis Report (PUAR) was submitted for NRC review by a PSE&G letter dated February 10, 1984. A discussion of the torus to drywell vacuum breakers is included in the PUAR. Details of the plant unique calculation and the vacuum breaker modifications have been included in the response to the staff's request for additional information on the Hope Creek PUAR (letter from A. Schwencer (USNRC) to R. L. Mittl (PSE&G) dated November 16, 1984). This response was submitted to the staff by letter from R. L. Mittl (PSE&G) to A. Schwencer (USNRC), dated January 8, 1985 and revised by letter from R. L. Mittl, PSE&G, to W. Butler, NRC, dated June 12, 1985.

6.2.1.1.4.2 Containment Depressurization Evaluation

Negative pressure differentials (negative corresponding to an inward loading) across the drywell walls are caused by the rapid depressurization of the drywell. Events that cause depressurization in the drywell are:

1. Cooling cycles

2. Inadvertent containment spray actuation during normal operation

3. Steam condensation following RCS pipe ruptures with inadvertent containment spray actuation.

Cooling cycles result in minor pressure transients in the drywell, which occur slowly and are controlled by heating and ventilating equipment. Inadvertent spray actuation during normal operation results in a more significant pressure transient and becomes important in sizing the suppression chamber to Reactor Building vacuum breaker assemblies. Steam condensation following RCS pipe ruptures with inadvertent containment spray actuation within the drywell results in the most severe pressure transients. Following an RCS rupture, the drywell atmosphere is purged to the suppression chamber free space, leaving the drywell full of steam. Subsequent condensation of the steam in the drywell can be caused either by ECCS spillage from the rupture or by inadvertent containment spray actuation following a LOCA.

Pressure transients within the drywell and the suppression chamber free space, due to inadvertent containment spray actuation for post-LOCA steam condensation, were evaluated. The results of containment depressurization transients are provided in Table 6.2-29. Details of the limiting transient, including the analytical models, assumptions, and methods used, are provided in Appendix 6A. The results of this evaluation demonstrate the adequacy of the containment vacuum relief valves, since the calculated negative pressure loadings on the containment do not, under any circumstances, exceed the design limit.

6.2.1.1.5 Steam Bypass of the Suppression Pool

The pressure boundaries between the drywell and the suppression chamber, including the vent pipes, vent header, and downcomers, are fabricated, erected, and inspected by nondestructive examination methods in accordance with the acceptance standards of the ASME B&PV Code, Section III, Subsection NE. This special construction, inspection, and quality control ensures the integrity of this boundary. The design pressure and temperature for this boundary are defined in Table 6.2-1. Actual accident peak pressure and temperature for this boundary are provided in Table 6.2-5.

There are no flow paths that have been identified, other than an open vacuum relief valve between the suppression chamber and the drywell, that could permit bypassing of steam from the drywell directly to the suppression chamber free space. All penetrations of this boundary, except the drywell to suppression chamber vacuum relief valve seats, are welded. All penetrations are available for periodic visual inspection. Surveillance testing of the vacuum relief valves is as required by the plant technical specifications in Section 16.

The "light bulb torus" design of the containment makes it essentially impossible for an accident flow path to exist between the drywell and the suppression chamber free space. The vacuum relief valves between the drywell and the suppression chamber are simple and reliable devices. Redundant position switches on each vacuum relief valve and frequent testing of valve operability ensure that the possibility of an open relief valve coincident with an accident situation need not be considered.

6.2.1.1.6 Suppression Pool Dynamic Loads

The capability of the containment to withstand hydrodynamic loads due to main steam safety/relief valve (SRV) discharge and a LOCA is discussed in Section 3.8.2.

6.2.1.1.7 Asymmetric Loading Conditions

Asymmetric loads considered for the design of the containment include horizontal seismic loads and localized pipe rupture loads. Refer to Section 3.7 for a description of the seismic analysis methods. Refer to Sections 3.6 and 3.8 for descriptions of the analytical methods used for pipe rupture.

6.2.1.1.8 Containment Environment Control

The functional capability of the Containment Ventilation System to maintain the temperature, pressure, and humidity of the containment and subcompartments is discussed in Section 9.4.5.

6.2.1.1.9 Post-Accident Monitoring

A description of the post-accident monitoring systems is provided in Section 7.5.

6.2.1.1.10 Suppression Pool Temperature Analysis

The Hope Creek Generating Station takes advantage of the large thermal capacitance of the suppression pool during plant transients requiring SRV actuation. Steam is discharged from the main steam lines through the SRVs and their accompanying discharge lines into the suppression pool where it is condensed, resulting in an increase in the temperature of the suppression pool water. Although stable steam condensation is expected at all pool temperatures, the Nuclear Regulatory Commission (NRC) has imposed the following local temperature limits in the vicinity of T-type quencher discharge devices (Reference 6.2-24):

1. For all plant transients involving SRV operations during which the steam flux through the quencher perforations exceeds 94 lbm/ft^2-sec, the suppression pool local temperature shall not exceed 200°F.

2. For all plant transients involving SRV operations during which the steam flux through the quencher perforations is less than 42 lbm/ft^2-sec, the suppression pool local temperature shall be at least 20°F subcooled.

3. For all plant transients involving SRV operations during which the steam flux through the quencher perforations exceeds 42 lbm/ft^2-sec, but is less than 94 lbm/ft^2-sec, the suppression pool local temperature is obtained by linearly interpolating the local temperatures established under aforementioned Items 1 and 2.

HCGS T-quenchers have a submergence of 9.0 feet of water corresponding to 18.6 psia. The saturation temperature at 18.6 psia is 224.1°F. Thus, for limit 2 above, a 20°F subcooling translates into a suppression pool local temperature limit of 204.1°F.

Since the steam mass flux through the quencher perforations is directly dependent on reactor vessel pressure, mass fluxes of 42 lbm/ft^2-sec and 94 lbm/ft^2-sec correspond to reactor vessel pressures of 274 psia and 617 psia, respectively.

This section describes the plant unique transient analyses for suppression pool temperature to demonstrate satisfaction of the above limits. This section also describes the pool temperature monitoring system design as it pertains to the NRC requirements.

6.2.1.1.10.1 Design Transients, Initial Conditions and Assumptions

To demonstrate that the above limits are satisfied, the NRC has required that the following events be analyzed for local pool temperature response (Reference 6.2-24):

1. Stuck open SRV (SORV) during power operation with only one residual heat removal (RHR) train operable.

2. Stuck open SRV during power operation with the initiation of the main steam isolation valve (MSIV) closure signal at the beginning of the event.

3. SRV discharge following isolation and scram and assuming only one RHR train operable.

4. SRV discharge following a small-break loss-of-coolant accident (LOCA) and assuming only one RHR train operable.

5. SRV discharge following a small-break LOCA and assuming the loss of the shutdown cooling mode of the RHR system.

HCGS's current licensing basis for transient analysis is to assume no single failure other than the single equipment malfunction or operator error which initiated the event. Therefore, the failure of one RHR loop, as requested by previously mentioned NRC Events a, 3, and 4, is beyond the currently accepted licensing basis for anticipated operational transients. Even though these events exceed the currently accepted licensing bases, seven transient events have been identified. These seven transient events are summarized in Table 6.2-27. One of these events is expected to result in the maximum long term suppression pool temperature.

These HCGS specific transient event analyses were performed by the General Electric Company using proprietary methods and models which have been generically reviewed and accepted by the NRC. This acceptance was confirmed at a meeting between the NRC staff and the BWR Mark I Containment Owners Group on August 25, 1983. The HCGS analyses, including initial conditions and assumptions, are consistent with the generically approved methods (Reference 6.2-25).

6.2.1.1.10.2 Temperature Evaluation Results

A summary of the transients analyzed and the corresponding pool temperature results is presented in Table 6.2-27.

The analysis of Case 2C (a demonstration case; i.e., normal depressurization at isolated hot shutdown), see Table 6.2-27, shows a maximum local pool temperature of 194°F at 3359 MWt. This demonstrates that with no system failures and in the event of a non-mechanistic scram, depressurizing the reactor pressure vessel (RPV) with SRVs at 100°F/hr results in local pool temperatures that are below the condensation stability limit set by the NRC.

Case 2A (reactor rapid depressurization after isolation with one RHR loop available); see Table 6.2-27, resulted in a maximum local pool temperature of 199°F at 3359 MWt and 202°F at 4031 MWt, which is below the NRC limit of 204.1°F. High local temperatures are present in this case because of reduced mixing when the available RHR pool cooling system is being manually switched to the shutdown cooling mode.

The maximum local pool temperatures of all other cases also remained below the NRC limit throughout the transient. In general, local to bulk temperature differences at the time of maximum temperatures are about 24°F for cases where two RHR loops are assumed available and about 34°F for cases where one RHR loop is assumed available. Thus, bulk pool circulation induced by RHR pumps leads to good thermal mixing; and effectively lowers the local pool temperatures in the vicinity of quencher devices.

Several limiting transients involving SRV discharges have been analyzed, and the results show that in all cases the maximum local pool temperatures in the vicinity of the T-Quenchers are below the NRC limits.

6.2.1.1.10.3 Suppression Pool Temperature Monitoring System

The Suppression Pool Temperature Monitoring System (SPTMS) monitors bulk suppression pool temperature and is designed to meet the requirements of Regulatory Guide 1.97, Rev. 2, for Type A variables. The requirements of NUREG-0783 (Reference 6.2-24) are met as follows:

1. The HCGS SPTMS consists of one sensor for each suppression pool bay (total of 16), located on the outboard side of the suppression pool (relative to the RPV pedestal). These 16 sensors are divided into two redundant channels as shown on Figure 6.2-49. Each channel consists of eight sensors located symmetrically around the suppression pool in order to provide a reasonable measure of bulk temperature.

2. The sensors are located 3'-0 1/2" below the normal minimum water level. This will ensure that the sensors remain submerged and thus properly monitor pool temperature.

3. The eight individual sensor inputs per channel are continuously averaged by a seismically and environmentally qualified microprocessor system. Average (bulk) temperature is both indicated and recorded in the main control room for each channel of the SPTMS.

4. Each channel of the SPTMS has four alarm setpoints which will be consistent with the Technical Specification limits on pool temperature.

5. All SPTMS sensors are Seismic Category I, Quality Group B and are capable of being energized from onsite emergency power supplies.

6.2.1.2 Containment Subcompartments

The containment subcompartments considered for HCGS are the RPV shield annulus and the drywell head region. The modeling procedures and considerations are presented in Appendix 6B.

6.2.1.3 Mass and Energy Release Analyses for Postulated Loss-of-Coolant Accidents

This section presents information concerning the transient energy release rates from the RCS to the containment following a LOCA. Where the ECCS enters into the determination of energy released to the containment, the single failure criterion is applied in order to maximize the energy release to the containment following a LOCA.

6.2.1.3.1 Mass and Energy Release Data

Note the following description applies to rated thermal power of 3359 MWt and are provided for historical purposes.

Table 6.2-9 provides the mass and enthalpy release data for the recirculation line break. Blowdown steam and liquid flow rates approach zero in approximately 48 seconds and do not change significantly during the remainder of the 24-hour period following the accident. Figure 6.2-16 shows the blowdown flow rates for the recirculation line break graphically. These data are employed in the containment pressure temperature response analyses discussed in Section 6.2.1.1.

Table 6.2-10 provides the mass and enthalpy release data for the main steam line break. Blowdown steam and liquid flow rates approach zero in approximately 80 seconds and do not change significantly during the remainder of the 24-hour period following the accident. Figure 6.2-17 shows the vessel blowdown flow rates for the main steam line break as a function of time after the postulated rupture. For 102% of the assumed power up-rate value of 3952 MWt (4031 MWt), Table 6.2-9a provides the mass and enthalpy release data associated with a recirculation line break. Figure 6.2-16 shows the blowdown flow rates for the recirculation line break graphically. These data are employed in the containment pressure/temperature response analyses discussed in Section 6.2.1.1.

6.2.1.3.2 Energy Sources

The RCS conditions prior to the line break are presented in Tables 6.2-3 and 6.2-4. Reactor blowdown calculations for containment response analyses are based on these conditions during a LOCA.

The energy released to the containment during a LOCA is comprised of the following:

1. Stored energy in the reactor system

2. Energy generated by fission product decay

3. Energy from fuel relaxation

4. Sensible energy stored in the reactor structures

5. Energy being added by the ECCS pumps

6. Metal water reaction energy.

Following each postulated accident, the stored energy in the reactor system and the energy generated by fission product decay is released. The rate of release of core decay heat for the evaluation of the containment response to a LOCA is provided in Table 6.2-11 as a function of time after accident initiation.

Following a LOCA, the sensible energy stored in the RCS metal is transferred to the recirculating ECCS water and thus contributes to the suppression pool and containment heatup.

Figure 6.2-18 shows the temperature transients of the various RCS structures that contribute to this sensible energy transfer at 4031 MWt. Figure 6.2-19 shows the variation of the sensible heat content of the reactor vessel and internal structures during a recirculation line break accident based on the temperature transient responses at 3359 MWt. Figure 6.2-19 is included for historical purposes.

6.2.1.3.3 Reactor Blowdown Model Description

The RCS blowdown flow rates are evaluated using the model described in References 6.2-2 through 6.2-4.

6.2.1.3.4 Effects of Metal Water Reaction

The containment is designed to accommodate the effects of metal water reactions and other chemical reactions that may occur following a LOCA. The amount of metal water reaction that can be accommodated is consistent with the performance objectives of the ECCS. In evaluating the containment response, 14,938 Btu/s of heat from metal water reactions is included for the first 120 seconds. The containment response is insensitive to the reaction time, even for the conservative case where all of the energy is included prior to the occurrence of peak drywell pressure.

6.2.1.3.5 Thermal Hydraulic Data for Reactor Analysis

Sufficient thermal hydraulic data to perform thermodynamic evaluations of the containment are provided in Section 6.2.1.1.3 and associated tables.

6.2.1.4 Mass and Energy Release Analysis for Postulated Secondary System Pipe Ruptures Inside Containment (PWR)

Not applicable to boiling water reactors (BWRs).

6.2.1.5 Minimum Containment Pressure Analysis for Performance Capability Studies on Emergency Core Cooling System (PWR)

Not applicable to BWRs.

6.2.1.6 Testing and Inspection

Preoperational containment testing and inspection programs are described in Section 3.8 and Section 14. Operational containment leakage rate testing and inspection programs are described in Section 6.2.6. The requirements and bases for acceptability are described in Section 16.

6.2.1.7 Instrumentation Requirements

Containment pressure and temperature sensing and the associated actuating input to the ESF systems are discussed in Section 7.3. Refer to Section 7.5 for a discussion of the display instrumentation.

Containment airborne radioactivity monitoring is described in Section 12.3.4. Containment hydrogen monitoring is described in Section 6.2.5. Conformance to the requirements of GDC 13 and 64 of 10CFR50, Appendix A, is discussed in Section 3.1.

6.2.1.8 SRP Rule Review

Acceptance Criteria II.B.1 establish the acceptable initial atmospheric conditions within a subcompartment to calculate the maximum resultant differential pressure across the wall of the subcompartment. The initial conditions are to assume air at the maximum allowable temperature, minimum absolute pressure, and 0 percent relative humidity.

At HCGS, subcompartment analyses for the RPV shield annulus and the drywell head were performed at the following initial condition:

Temperature = 135°F

Relative humidity = 30 percent

Absolute pressure = 15.45 psia

An initial relative humidity of 30 percent was assumed because of computer code/analytical tool limitations. The 30 percent value is a realistic maximum value. The initial temperature of 135°F (normal condition) versus a temperature of 150°F is used in order to satisfy the intent of the SRP requirement to minimize the heat capacity of the air (0 percent relative humidity). The minimum pressure is not used since a 0.2 percent increase in the heat capacity is anticipated; hence a calculated and not a minimum pressure is used.

6.2.2 Containment Heat Removal

6.2.2.1 Design Basis

Containment heat removal is accomplished during and after an accident by the containment cooling modes of the Residual Heat Removal (RHR) System: the suppression pool cooling and the containment spray modes. The containment spray mode includes the capability to divert 5 percent of the flow to the suppression chamber spargers. The purpose of these two RHR modes is to prevent excessive containment temperatures and pressures, thus maintaining containment integrity following a loss-of-coolant accident (LOCA). To fulfill this purpose, the following safety design bases are met:

1. The long term bulk temperature of the suppression pool is limited to 170°F without spray operation when considering the energy additions to the containment following a LOCA. These energy additions, as a function of time, are provided in Section 6.2.1.

2. The single failure criterion applies to the RHR system.

3. The RHR system is safety-related and Seismic Category I.

4. The RHR system maintains operation during those environmental conditions imposed by the LOCA. Loss of offsite power (LOP), adverse natural phenomena, e.g., tornadoes, hurricanes, earthquakes, floods, etc, and

site related events, e.g., high and moderate energy pipe breaks, externally generated missiles, and transportation accidents, will not impair the system's post-LOCA function.

5. Each active component of the RHR system is testable during normal operation of the plant.

6.2.2.2 Containment Cooling System Design

6.2.2.2.1 System Design

The containment cooling modes are integral operational modes of the RHR system. Water is drawn from the suppression pool, pumped through one or both RHR heat exchanger loops, and delivered to the suppression pool, to the drywell spray header, or to the suppression chamber spray header. Water from the Safety Auxiliaries Cooling System (SACS) is pumped through the RHR heat exchanger tube side to remove heat from the process flow from the suppression pool. Two cooling loops are provided, each mechanically and electrically separate from the other to achieve redundancy. A piping and instrumentation diagram is provided in Section 5.4.7. The process diagram, including the process data, is provided in Section 6.3 for all RHR design operating modes and conditions. Minimum available net positive suction head (NPSH) for RHR pump suppression pool suction is discussed in Section 6.3.

All portions of the RHR system used for containment cooling are designed to withstand operating loads and loads resulting from natural phenomena. All operating components can be tested during normal plant operation so that reliability can be ensured. Construction codes and standards are covered in Sections 5.4.7 and 3.2.

The containment cooling modes of the RHR are started manually from the main control room. There are no signals that automatically initiate the containment cooling function. Rather, the low pressure coolant injection (LPCI) mode is automatically initiated from Emergency Core Cooling System (ECCS) signals, and the RHR system is realigned for containment cooling by the plant operator after the reactor vessel water level has been recovered. Refer to containment functional design in Section 6.2.1 for further details. Containment cooling is initiated by initiating SACS flow to the RHR heat exchanger, starting the RHR pump, opening the suppression pool return valve, and closing the heat exchanger bypass valve. Since RHR has initiated in the LPCI mode, the RHR and SACS pumps will already be running; the LPCI injection valve and suppression pool return valve must be overridden. In the event that a single failure has occurred, and the action that the plant operator is taking does not result in system initiation, the operator places the other totally redundant system into operation by following the same initiation procedure. If the operator chooses to use the containment spray, (s)he must close the LPCI injection valve and open the spray valves. The containment spray water establishes a closed loop to the suppression pool via the downcomers.

Preoperational tests are performed to verify individual component operation, individual logic element operation, and system operation up to the drywell spray spargers. A sample of the sparger nozzles are bench tested for flow rate versus pressure drop to evaluate the original hydraulic calculations. Finally, the spargers are tested by air and visually inspected to verify that all nozzles are clear. Refer to Section 5.4.7 for further discussion of preoperational testing.

6.2.2.2.2 Effects of Insulation on System Performance

Fiberglass blanket sections covered with 22-gauge, 304 stainless steel jacketing insulate structures, equipment and piping within the primary containment. This form of insulation was analyzed with respect to creating a debris clogging problem for containment cooling operation after a LOCA as set forth in USNRC Bulletin 96-03 and NUREG/CR-6224. The BWR Owner's Group ECCS Suction Strainer Committee has studied the performance of the materials during a simulated design basis accident (DBA). The results of the study have been submitted to the NRC as Utility Resolution Guidance for ECCS Suction Strainer Blockage Report, NRC Project 691. As indicated in the study:

1. The quantity of Drywell Insulation and other debris sources during a LOCA has been determined. These and other segments of insulation that are subjected to the violent forces of a component rupture, jet impingement, or pipe whip could be expected to become potential clogging debris.

2. The methodology for debris transport and settling has been established. The path for insulation to enter the suppression pool is through the vent pipes and the downcomer ring header. The jet deflectors prevent debris from entering the vent pipes directly. Floor grating, structural steel, and components in the drywell will retain insulation debris and restrict it from reaching the floor or the vent pipes. A portion of the insulation debris generated will be transported to the suppression pool. The openings at the jet deflectors will prevent all but smaller fragments from entering the vent pipes.

   Some of the insulation debris that is transported to the suppression pool is fast settling, the remainder settles more slowly. After the initial blowdown, the insulation debris that reaches the suppression pool begins to settle to the bottom. The flow velocity created by the ECCS pump operation for the bulk of the suppression pool is very low, therefore only a portion of the insulation debris in the suppression pool will collect on the ECCS strainers. The strainers are located above the bottom of the suppression pool and the velocities generated at the bottom of the suppression pool are not sufficient to reentrain insulation that has settled except very near the strainers. An evaluation of the transport and accumulation of postulated debris was performed in accordance with the guidelines of NRC Bulletin 96-03 NUREG/CR-6224. The flow restriction caused by the insulation accumulation on the strainers in this analysis does not adversely effect operation of the ECCS pumps.

3. If some fibers do pass through the 0.1225-inch strainer mesh, the study has shown that pump function and spray nozzle performance are not affected. Particles of this size or smaller will not impair the safe function of the suppression pool cooling or drywell spray modes of the RHR system.

   Details of suction strainer attachment to the strainer nozzles are provided in Section 5.4.7.

The NRC staff has completed its review of this issue (NRC Project 691, "ECCS Suction Strainer Blockage"), which is contained in Safety Evaluation by the Office of Nuclear Reactor Regulation Related to NRC Bulletin 96-03, BWR Owners Group Topical Report NF00-32686, "Utility Resolution Guidance for ECCS Suction Strainer Blockage". Based on the findings of this review, this issue is considered closed for HCGS.

6.2.2.3 Design Evaluation of the Containment Cooling Function

In the event of the postulated LOCA, the short term energy release from the reactor primary system is dumped to the suppression pool. Subsequent to the accident, fission product decay heat results in a continuing energy input to the pool. The containment cooling modes remove this energy, which is input to the Primary Containment System, thus resulting in acceptable suppression pool temperatures and containment pressures.

To evaluate the adequacy of the RHR system, the following sequence of events is assumed:

1. With the reactor initially operating at 102 percent of up-rated thermal power (3840 MWt) a LOCA occurs.

2. An LOP occurs and one standby diesel generator (SDG) fails to start and remains out of service during the entire transient. This is the worst single failure.

3. Only three RHR pumps are activated and operated as a result of there being no offsite power and minimum onsite power. Section 6.3 describes the ECCS equipment.

4. After 10 minutes, it is assumed that the plant operators activate one RHR heat exchanger in order to start containment heat removal. Once containment cooling has been established, no further operator actions are required.

6.2.2.3.1 Summary of Containment Cooling Analysis

When calculating the long term, post-LOCA suppression pool temperature transient, it is assumed that the initial suppression pool temperature and the RHR heat exchanger SACS water temperature are at their maximum values. This assumption maximizes the heat sink temperature to which the containment heat is rejected and thus maximizes the containment temperature. In addition, the RHR heat exchanger is assumed to be in the maximum design fouled condition at the time the accident occurs. Section 5.4.7 discusses sizing of the heat exchangers to account for fouling. This conservatively minimizes the heat exchanger heat removal capacity. The resultant suppression pool temperature transient is described in Section 6.2.1.1.3.2 and is shown on Figure 6.2-9a for 4031 MWt. Note that Figure 6.2-9 is based on rated power of 3359 MWt and is provided for historical purposes.

It should be noted that, when evaluating this long-term suppression pool transient, all heat sources in the containment are considered with heat losses through structural heat sinks as well as the RHR heat exchangers. These heat sources are discussed in Section 6.2.1.4. Figure 6.2-10a shows the actual heat removal rate of the RHR heat exchanger at 4031 MWt.

It can be concluded that the conservative evaluation procedure described above clearly demonstrates that the RHR system in the suppression pool cooling mode limits the post-LOCA containment temperature transient.

6.2.2.4 Tests and Inspections

The preoperational test program of the containment cooling system is described in Section 6.2.2.2. Preoperational testing is discussed in greater detail in Section 14.

Functional tests of the Suppression Pool Cooling and Suppression Pool Spray modes are performed during normal plant operation with the appropriate RHR pumps taking suction from the suppression pool and discharging back to the suppression pool. All discharge valves to the reactor pressure vessel (RPV) remain closed during the test, and reactor operation remains undisturbed. Control system design provides automatic return from the full flow test line valve alignment to the low pressure coolant injection (LPCI) valve alignment if LPCI is required during testing. The surveillance frequency for testing and inspection is discussed in Section 16.

The containment (i.e., drywell) spray discharge valves E-11-HV-F016 and E-11-HV-F021 are included in the Inservice Testing Program.

6.2.2.5 Instrumentation Requirements

The containment spray and suppression pool cooling modes of the RHR system are manually initiated from the main control room. Once initiated, containment cooling performance is monitored by suppression pool temperature, containment cooling flow, and containment pressure instrumentation. Details of the instrumentation are provided in Section 7.3.1.

6.2.3 Reactor Building Functional Design

The Reactor Building houses the reactor and its Pressure Suppression Containment System. Also housed in the Reactor Building are the refueling and reactor servicing equipment; the new and spent fuel storage facilities; the Filtration, Recirculation, and Ventilation System (FRVS); and various reactor auxiliary or service equipment, including the Reactor Core Isolation Cooling (RCIC) System, the Reactor Water Cleanup (RWCU) System, the Standby Liquid Control (SLC) System, the Control Rod Drive (CRD) Hydraulic System, the Residual Heat Removal (RHR) System, and the Emergency Core Cooling System (ECCS). The building also serves as the containment barrier for drywell components when the drywell is open during refueling or maintenance operations.

6.2.3.1 Design Basis

The Reactor Building, in conjunction with operation of the FRVS, is designed to limit radiation doses during a design basis accident (DBA) to within 10CFR50.67 guidelines.

The following items are considered in the reactor building design:

1. Conditions that could exist following a loss-of-coolant accident (LOCA) that require control of possible leakage paths from the primary containment into the Reactor Building

2. Functional capability of the ventilation system to maintain negative pressure in the Reactor Building with respect to the outdoors, as discussed in Sections 6.8 and 9.4.2

3. Seismic design, leaktightness, and design pressure of the Reactor Building, as discussed in Section 6.2.3.2 and Section 3

4. Capability for periodic inspection and functional testing of the Reactor Building, as discussed in Section 16

6.2.3.2 System Design

6.2.3.2.1 Reactor Building Design

The Reactor Building is designed and constructed in accordance with the design criteria presented in Section 3. It is a Seismic Category I reinforced concrete structure. The foundation is a 14-foot thick reinforced concrete mat. Above the base mat, the building is approximately 250 feet high, consisting of a cylinder with a torispherical dome, surrounded by a rectangular structure that reaches elevation 132 feet.

The Reactor Building and its penetrations are designed to limit the leakage rate into the building to 100 percent of the building's free volume per day maintaining a differential pressure of at least 0.25 inches water gauge. During normal plant operation, the Reactor Building pressure is maintained at a negative pressure by the Reactor Building Ventilation System (RBVS), which also maintains airflow from areas of lesser contamination to areas of greater potential contamination. Following a LOCA, the RBVS is automatically shut down, and the FRVS is actuated. The FRVS is designed to maintain a negative building differential pressure of at least 0.25 inches water gauge at all elevations in all climatic conditions. Design data for the Reactor Building, the RBVS, and the FRVS are presented in Table 6.2-12.

The openings providing access to the Reactor Building are listed in Table 6.2-14 and are shown on Plant Drawings A-4643-1 through A-4647-1 and A-0402-0. No plan views below Elevation 102 feet are shown as they are below grade and have no access openings.

Personnel access is through double door, vestibule systems, and therefore building ingress and egress do not jeopardize the integrity of the Reactor Building. In addition, all of the openings to the Reactor Building listed in Table 6.2-14 are monitored and alarmed in the main control room.

Access to the equipment airlock on Elevation 102 feet for refueling operations and maintenance is through the receiving bay door. The status of this door is continuously monitored and alarmed. When opened, an alarm is received in the control room and the equipment airlock thus becomes the secondary containment boundary. In order to ensure that the secondary containment is maintained, administrative procedures require that the access opening listed in Table 6.2-14a be closed when the receiving bay door is opened. Further, the motorized equipment hatch and ventilation supply and exhaust duct shutoff dampers are electrically interlocked with the receiving bay door such that the hatch and dampers must be closed before the door can be opened.

6.2.3.2.2 Reactor Building Isolation System

The Reactor Building Isolation System is described in Section 9.4.2.

6.2.3.2.3 Containment Bypass Leakage

Upon receipt of a LOCA or other high radioactivity signal, the FRVS is actuated automatically and simultaneously with Reactor Building isolation and shutdown of the normal RBVS. Radioactivity that exfiltrates the primary containment is collected and passed through the FRVS as described in Section 6.8.

Penetrations that pass through both primary and Reactor Building barriers and that have isolation valves, seals, gaskets, or welded joints are considered potential bypass leakage paths. Potential leakage paths that could bypass the areas serviced by the FRVS have been evaluated. Table 6.2-15 identifies those lines penetrating the Primary containment that do not terminate inside the Reactor

Building or in a closed system outside primary containment within the Reactor Building. Section 6.2.4.3.5 provides an evaluation of closed systems outside primary containment. Closed systems outside primary containment are considered effective bypass leakage barriers because they are dependable (i.e., Seismic Category I and Quality Group B) systems that are water filled by the use of the system jockey pumps. The systems are maintained leaktight by periodic visual inspection and the leak detection provisions identified in Section 5.2.5.2.2.

The types of bypass leakage barriers employed by lines listed in Table 6.2-15 are:

1. Redundant primary containment isolation valves

2. Closed Seismic Category I piping system inside or outside primary containment

3. A water seal maintained for at least 30 days following a LOCA

4. The line terminates outside the Reactor Building in a filtered area

5. Positive in-line air seal

6. A temporary spool piece in the line that is removed during normal operation and replaced by blind flanges so that any leakage through the flange is into the Reactor Building.

7. The line contains a spectacle flange that is inserted during normal operation so the line is blocked off and any leakage by the flange is into the reactor building enclosure.

Type 1. leakage barriers are considered to limit but not eliminate bypass leakage. Types 2. through 7. are considered to effectively eliminate any bypass leakage.

The design criterion for bypass leakage is to minimize allowable leakage because of the effect any allowed activity release would have on the accident dose analysis. No bypass leakage paths have been identified. Therefore, no bypass leakage is postulated to reach the environment. The quality group and seismic qualification of the closed systems that are relied upon to eliminate bypass leakage are identified in Table 3.2-1.

The containment leakage is monitored during periodic tests as discussed in Section 6.2.6. Those penetrations for which credit is taken for water seals as a means of eliminating bypass leakage, as outlined in Table 6.2-15, are preoperationally leak tested with air or water. For these water seals, either a loop seal is present, or the water for the seal is replenished from a large reservoir. For those valves maintaining a water seal, calculations have been done to verify that there is a sufficient water inventory for 30 days assuming leakage rates of 10 ml/hr of nominal valve diameter unless indicated otherwise below. Except for HPCI valve FD-V018 and RCIC valve FC-V016 all valves required to maintain a water seal are 10CFR50 Appendix J, Type C tested. Those valves that are not Type C tested will be identified in administrative procedures as requiring periodic leakage testing in order to ensure the existence of the water seal. These seals are in:

1. Feedwater line - The feedwater line fill network is normally used to maintain a water seal in the feedwater lines between the inboard and outboard containment isolation valves following a LOCA. The fill network consists of the HPCI and the RCIC jockey pump loops, as shown on Plant Drawings M-55-1, M-56-1, M-49-1 and M-50-1, and utilizes the HPCI and RCIC injection lines to the feedwater piping to provide makeup water to the piping between the isolation valves. In order to permit the fill network to perform its intended safety function following a single active failure, a piping crosstie is provided between the feedwater lines immediately upstream of the outboard containment isolation valves as illustrated in Plant Drawing M-41-1. This crosstie includes a normally closed key locked motor operated valve.

This valve, and its respective controls, is provided with Class 1E channelized power such that no single active failure could disable both the crosstie valve and either of the HPCI or RCIC injection valves or associated jockey pumps. The crosstie piping and valve is safety-related and designed to Seismic Category I criteria.

Following a LOCA, the feedwater line fill network is manually aligned from the main control room by opening the HPCI and RCIC injection valves to provide sealing water to the feedwater lines. In the unlikely event that either the HPCI or the RCIC injection line cannot be used as a flow path to the feedwater piping, the motor operated valve in the crosstie would be manually opened from the main control room. Manual operator action to align the fill network is not required sooner than 20 minutes following detection of a LOCA. This is due to the fact that during the time period required to refill the feedwater lines, no radioactive contaminants would be expected to leak through the feedwater isolation valves out to the environment as discussed below. The abnormal operating procedures will include the actions to be taken by the operator to mitigate the unlikely event of the HPCI or RCIC injection line being unavailable as a flow path to the feedwater piping.

An evaluation of the capability of the condensate/feedwater system to provide a water seal in the short term in the system piping following a postulated LOCA prior to initiation of the feedwater line fill system indicates that a water seal will be maintained in the piping and equipment upstream of the No. 3 feedwater heaters where a substantial amount of unflashed water would remain. This is based on the fact that the quality assurance during design and construction, as well as the continuous inspection during normal operation, of the feedwater/condensate piping and equipment are such that the system would realistically be expected to remain intact. Prior to the postulated LOCA, the feedwater system has been functioning at its operating pressure of 1000 psig. The feedwater system equipment and piping are designed to withstand the high pressures observed during operation; no system leakage is realistically expected at the relatively low post-LOCA containment pressures. For long term control, the feedwater fill system will reestablish a water seal at the feedwater containment isolation check valves to eliminate bypass leakage.

2. High pressure coolant injection (HPCI) turbine steam supply - The drain pot line Valve FD-V018 is contained in a Type 1 system. A water seal is not required for this valve because when the system containment isolation valves are closed, leakage to the FD-V018 valve is limited to the Appendix J acceptance criteria. The leakage is already included in the accident dose analysis.

3. Chilled water from and to drywell coolers - The lines in the Reactor Building are seismically analyzed with a vertical rise from the containment penetration of approximately 8 feet.

   There is sufficient water inventory for a 30-day seal for valves GB-V081, V082, V083, and V084.

4. RWCU supply - The lines in the primary containment are Seismic Category I and form a loop whose vertical leg is approximately 49 feet.

There is sufficient water inventory for a 30-day seal for valve BG-V001.

5. RCIC turbine steam supply - The drain pot line Valve FC-V016 is contained in a Type 1 system. A water seal is not required for this valve because when the system containment isolation valves are closed, leakage to the FC-V016 valve is limited to the Appendix J acceptance criteria. The leakage is already included in the accident dose analysis.

6. Main steam line drain - The line to the isolation valve is Seismic Category I. Steam would condense in the line and form a water seal during normal operation. Closure of the inboard and outboard isolation valves upon receipt of a containment isolation signal and the water seal provide a barrier to bypass leakage.

   There is sufficient inventory for a 30-day seal for valve AB-V039.

7. Drywell floor drain and drywell equipment drain sump discharges - The lines to the isolation valves are seismically analyzed, and the sump water acts as an effective water seal. The water barrier is maintained by instrumentation and controls that prevent the sumps from being pumped dry.

8. Reactor Auxiliaries Coolant System (RACS) supply and return - There are seismically analyzed lines in the Auxiliary Building, with containment isolation valves on each line.

The two isolation valves on each line, which include valves ED-V003 and ED-V004, are Type 1 leakage barriers. A water seal is not required for the supply and return lines because when containment isolation valves are closed, leakage is limited to the Appendix J acceptance criteria. This leakage is already included in the accident dose analysis.

9. Torus water cleanup supply and return - The suppression pool water forms an effective water seal for these lines. The suppression pool is a reliable source of water that can provide the required separation between the primary containment atmosphere and the environs. The Suppression Chambers Structural design is discussed in Section 3.8.2.

10. Post Accident Sampling System (PASS) supply and return - The liquid and gas sample lines to the isolation valves are Seismic Category I. The PASS sampling lines terminate in the PASS sample station. The PASS sample station location is described in Section 9.3.2.2.2.4. Any gaseous bypass leakage in the PASS sample station will be vented to the reactor building ventilation system/filtration, recirculation and ventilation system common return duct as described in Section 9.3.2.2.2.7. Any liquid bypass leakage in the PASS sample station will be collected in a sump located in the sample station which can be pressurized with the discharge being directed to the suppression pool.

11. Main steam – The steam lines to the main steam stop valves (MSSVs) are seismic category I. Leakage through the Main Steam Isolation Valves (MSIVs) is limited to Technical Specification acceptance criteria. The leakage is included in the accident dose analysis.

12. Recirculation Pump Seal Purge - There is sufficient inventory for a 30-day seal for valve BF-V098 and V099.

13. HPCI and RCIC Turbine Auxiliary Steam Supply - These lines contain a temporary spool piece that is removed during normal operation and replaced by a blind flange so that any leakage through the flange is into the reactor building enclosure.

14. Instrument Gas Supply to and Suction from Drywell - A positive air seal is maintained through the operation of the primary containment instrument gas system.

6.2.3.2.4 Access Doors

Access doors to secondary containment (Reactor Building) are provided with position indication and are monitored in the control room. See Table 6.2-28 for a list of Reactor Building openings.

6.2.3.3 Design Evaluation

The design evaluation of the Reactor Building Ventilation System is given in Sections 6.8 and 9.4.2. The high energy lines within the reactor building are identified and pipe ruptures are analyzed in Section 3.6.

The post-LOCA pressure transient for the design basis reactor building inleakage has been analyzed to determine the length of time, following a LOCA, for the building differential pressure to reach at least 0.25 inches water gauge. The results of this analysis for the slowest responding compartment in the reactor building are shown on Figure 6.2-26.

The design basis analysis was based on the initial conditions, design, and thermal characteristics listed in Tables 6.2-12, 6.2-13, and 6.2-13a. Further details of the FRVS design and operation are provided in Section 6.8. Heat transfer to the outside environment is assumed to be zero. The reactor building is considered to be in thermal equilibrium at the beginning of the pressure transient. This includes heat load contributions from the primary containment. Since the drawdown of the Reactor Building pressure by the FRVS is completed within the first 375 seconds following a LOCA, there is insufficient time for the temperature transient associated with the LOCA to propagate through the 3-foot-thick primary containment wall. Conductive, convective and radiative heat transfer from the torus during the transient is included in the analysis. Heat generation from equipment which operates after a LOCA is included in the analysis. All non-1E MCC, substation and lighting loads are included for the first 10 seconds of the analysis. The analysis assumes a single active failure of one standby diesel generator (SDG). The failure of SDG A was determined to be the worst single failure because it results in the loss of FRVS vent fan A (assumed to be the lead fan), FRVS recirculation fans A and E and SACS cooling water pump A. The operating vent fan exhausts 9000 cfm ± 10% to the atmosphere until the Reactor Building reaches a pressure of -0.25 in. w.g. Loss of offsite power (LOP) is assumed to occur coincident with the LOCA. The compressive effect of the primary containment expansion was considered by adding the air mass to the Reactor Building at the time of the LOCA, thereby increasing the initial pressure to greater than atmospheric even though HCGS is committed to maintaining the Reactor Building subatmospheric.

HCGS has been evaluated for drawdown time and doses associated with Reactor Building inleakages of 100 percent/day. The results of this analysis demonstrate that even with a reactor building inleakage rate of 100 percent/day the resulting doses would be less than the allowable limits of GDC 19 and 10CFR50.67.

The pressure versus time curve for this case is shown on Figure 6.2-26. The control room doses associated with 100 percent/day inleakages are shown in Table 6.4-4. The off-site dose consequences associated with 100 percent/day inleakage are discussed in Section 15.6.5.

6.2.3.4 Tests and Inspections

Detailed procedures will be available for NRC review prior to performance with the test. Doors and hatches are administratively maintained closed as discussed in Section 6.2.3.2. Therefore, open doors or hatches are not considered in the depressurization analysis or test.

The program for initial performance testing is described in Section 14. This test includes determination of depressurization time and inleakage rate. The uniformity of negative pressure throughout the Reactor Building is assured by the operation of the FRVS recirculation fans. The program for periodic functional testing of the reactor building structures, isolation system, FRVS, and system components is described in Section 16. Detailed procedures will be available for NRC review prior to plant operation.

6.2.3.5 Instrumentation Requirements

The control systems to be employed for the actuation of the Reactor Building Engineered Safety Feature (ESF) Air Handling Systems are described in Section 7.3.

The control and monitoring instrumentation for these control systems is discussed in Sections 6.8 and 9.4.2. Design details and instrumentation logic are discussed in Section 7.3.

6.2.3.6 SRP Rule Review

Acceptance Criterion II.3.e requires that the external design pressure of the reactor building be provided with an adequate margin above the maximum expected external pressure.

The Reactor Building is designed with an external pressure of -3 psig resulting from tornado depressurization. This is in agreement with Regulatory Guide 1.76 for the site location. Due to the low probability of occurrence of the tornado at the plant site and the conservative design basis of this structure, the Reactor Building is not provided with an additional margin for the external design pressure.

6.2.4 Containment Isolation System

The Containment Isolation System consists of piping, blind flanges, valves, valve operators, and controls arranged to provide isolation barriers for all fluid lines that penetrate the primary containment. The Containment Isolation System, in conjunction with the primary containment, is designed to establish an essentially leaktight barrier that will prevent or limit the release of radioactivity to the environment which may result from postulated accidents while allowing the normal or emergency passage of fluid through the containment boundary.

6.2.4.1 Design Bases

6.2.4.1.1 Safety Design Basis

1. The Containment Isolation System provides the necessary isolation of the containment in the event of accidents or other conditions when the unfiltered release of the containment's contents cannot be permitted.
2. The capability for rapid closure, or isolation of all pipes or ducts that penetrate the containment, is provided by a containment barrier in such pipes or ducts sufficient to maintain leakage within permissible limits.
3. The design of isolation valving for lines penetrating the containment follows the requirements of GDC 54 through 57 except where compliance is based on the "other defined basis" criterion.

6.2.4.1.2 Other Defined Bases

1. An Engineered Safety Feature (ESF) System may have only one containment isolation valve in a line penetrating primary containment, if the system is designed as a closed system outside primary containment. Such a configuration, one using a single containment isolation valve and a closed system outside of containment, can be used to increase ESF System reliability or to eliminate 10CFR50 Appendix J testing of the valve being replaced by the closed system outside of containment to provide the second barrier. Appendix J testing of the closed system boundary valves is not required as long as system integrity is maintained during normal plant operations and system pressure is maintained equal to or above containment design pressure.

The keep fill or alternate condensate transfer keep fill systems maintain the ESF closed systems outside containment sufficiently pressurized to preclude Appendix J testing of the closed system boundary valves. Acceptable means for providing boundary isolation of the closed system to minimize potential intersystem leakage are identified in Section 1.10 of the UFSAR. The Leakage Reduction Program periodically verifies the system integrity of the closed system outside containment up to and including the boundary isolation valves.

A closed system outside containment is protected from missiles, designed to Seismic Category I standards, classified as ASME B&PV Code, Section III, Class 1 or 2, and designed to have a design pressure and temperature rating at least equal to that for the primary containment. This other defined basis provides a second containment isolation barrier that is as reliable as the primary containment itself. The use of the second containment isolation boundary makes it possible for an ESF safety system to accommodate a single active failure with only one isolation valve.

2. Fluid instrument lines that penetrate primary containment conform to the isolation criteria of Regulatory Guide 1.11 (Safety Guide 11) to the greatest extent practicable, except as discussed and justified in Section 1.8.11. The flow limiting orifices in the instrument lines that penetrate the primary containment are 1/4 in. restriction orifices.

6.2.4.2 System Design

The general criteria governing the design of the Containment Isolation System is provided in Section 3.1.2 and 6.2.4.1. Specifically, the containment isolation valves and associated piping are designed as Seismic Category I and meet the requirements of the ASME B&PV Code, Section III, Class 1 or 2, commensurate with their respective importance to safety. The only exception to this design rule is certain portions of the Control Rod Drive (CRD) System, which are designed to special quality standards commensurate with their importance to safety and consistent with their safety function.

See Section 3.2 for further discussion of seismic and quality group classification and Section 3.10 for discussion of seismic qualification of Seismic Category I instrumentation.

The Containment Isolation System is designed to withstand the most severe plant-related event, such as missiles, pipe whip, and jet impingement without impairment of its function. Protection is provided for containment isolation valves, actuators, and controls against damage. Potential hazards are evaluated, and where possible hazards exist, protection is afforded by separation, by missile shields, or by location. For further discussion of protection against missiles, and the dynamic effects associated with a postulated pipe rupture, see Sections 3.5 and 3.6, respectively.

The Containment Isolation System is designed to be operable under the most adverse environmental conditions. The containment isolation valves and their actuators are designed to be operable under maximum differential pressures, steam laden atmospheres, high temperature, high humidity, and radiation. See Section 3.11 for further discussion of environmental qualification and Section 3.9.3 for further discussion of the operability of active components.

Generally, the Containment Isolation System is redundant and physically separated in its electrical and mechanical design, with diversity in parameters sensed for the initiation of containment isolation. Power for the actuation of the two isolation valves in a line is supplied by two redundant, independent power sources without crossties. In general, depending upon the system under consideration, the outboard and inboard containment isolation valves are powered and controlled by different electrical channels, with the supply source being Class 1E ac for both channels. See Section 7 for further discussion of the control and instrumentation of the containment isolation system and Section 8.3 for a further discussion of onsite power systems.

The Containment Isolation System is designed with provisions for administrative control, to ensure that the proper position of all nonpowered or power removed isolation valves is maintained. All power operated primary containment isolation valves which have power available have position indicators in the main control room.

Discussion of instrumentation and controls for the isolation valves is included in Section 7.

The design of the Primary Containment Isolation System gives consideration to the possible adverse dynamic effects, such as water hammer, sudden isolation valve closure under normal operation, and to thermal expansion in those portions of pipe between the containment isolation valves.

The Containment Isolation System is designed so that failure of motive power is in the direction of greater safety. Motor operated isolation valves remain in their last position upon failure of electrical power to the motor operator. Air operated containment isolation valves are spring loaded to close upon loss of air or electrical power to the pilot operated solenoid valve. Solenoid-operated isolation valves fail closed upon a loss of electrical power to the solenoid.

The 1.68 psig containment pressure setpoint that initiates containment isolation for nonessential penetrations is the minimum compatible with an acceptable plant availability for power production.

Table 6.2-16 lists all the process and instrument line penetrations of the primary containment. Also tabulated in Table 6.2-16 is detailed information about each penetration. Figure 6.2-27 shows diagrams for the various isolation valve arrangements.

The closure times of containment isolation valves are selected to ensure rapid isolation of the primary containment following postulated accidents. The isolation valves in lines that provide an open path from the primary containment to the environs have closure times that minimize the release of containment atmosphere to the environs and mitigate the offsite radiological consequences. The isolation valves for lines outside the containment, in which high energy line breaks can occur, have closure times that minimize the resultant pressure and temperature transients as well as the radiological consequences.

The design provisions for testing of operability of the isolation valves and the leakage rate of the containment isolation barriers are discussed in Section 6.2.6.

For a discussion of containment bypass leakage and of leakage detection capabilities for both manual and automatic initiation of containment isolation, see Sections 6.2.3 and 5.2.5, respectively.

6.2.4.3 Design Evaluation

All piping systems penetrating the containment, other than instrument lines, are designed in accordance with GDC 54.

6.2.4.3.1 Evaluation Against GDC 55

GDC 55 requires that lines that penetrate the primary containment and form a part of the reactor coolant pressure boundary (RCPB) must have two isolation valves, one inside the primary containment and one outside, unless it can be demonstrated that the containment isolation provisions for a specific class of lines are acceptable on some other basis.

The RCPB, as defined in 10CFR50, Section 50.2(v), consists of the reactor pressure vessel (RPV), pressure retaining appurtenances attached to the vessel, and valves and pipes that extend from the reactor pressure vessel, up to and including the outermost isolation valve.

The following sections discuss the process and instrument lines that connect directly to the RCPB and the methods of isolating these lines pursuant to the requirements of GDC 55.

Lines with containment isolation valves that receive isolation signals are identified, and the particular isolation signals that initiate closure are listed in Table 6.2-16.

6.2.4.3.1.1 Main Steam Lines

The four main steam lines penetrate the primary containment and extend from the RPV to the main turbine and the condensers. Each line is isolated by two independent main steam isolation valves (MSIVs), one inside containment and one just outside containment, and by a main steam stop valve (MSSV).

The MSIVs are wye-pattern globe valves that are mounted so that reactor pressure aids in closing the valve. The valves isolate automatically on the receipt of a containment isolation signal. The MSIVs are spring loaded, pneumatic, piston operated globe valves designed to fail closed on loss of pneumatic pressure or loss of power to the solenoid operated pilot valves. Each valve has two independent pilot valves supplied from independent power sources. Each MSIV has an air accumulator to assist in its closure upon loss of supply, loss of electrical power to the pilot valves, and/or failure of the loaded spring. The separate and independent action of either air pressure or spring force is capable of closing an isolation valve. See Section 5.4.5 for further discussion of their design and construction.

The MSSVs are motor operated gate valves that are manually operated from the main control room. The MSSVs perform no active safety function.

The MSIVs provide immediate containment isolation after receiving a containment isolation signal upon a postulated loss-of-coolant accident (LOCA) or a break in a steam line downstream of the MSIVs.

To limit the release of fission products after a postulated loss-of-coolant accident, the portion of the main steam lines downstream of the outboard MSIVs up to but not including the main turbine stop valves (MSVs) is credited as remaining intact as a deposition surface. In the accident analysis, leakage through the MSIVs flows through the main steam lines to the non-seismic piping boundary at the MSVs. A large fraction of the fission products deposit on the piping surfaces before being released to the turbine building as discussed in Section 15.6.5.

6.2.4.3.1.2 Feedwater Lines

The portion of the feedwater system that forms part of the RCPB and penetrates the primary containment has three containment isolation valves per line. The first valve, a check valve, is classified as a containment isolation valve and located inside the primary containment. The second valve, a positive acting check valve, is classified as a containment isolation valve and located outside the primary containment as close as possible to the primary containment penetration. Upon a loss of water flow into the RPV, these valves close as normal check valves, and, in addition, the main control room operator can assist in starting the outboard valve closure by sending a signal to open two fail-open solenoid valves arranged in parallel, releasing air pressure from the operator cylinder. If a break occurs in the feedwater line, the two containment isolation valves prevent significant loss of inventory and offer immediate isolation. During the postulated LOCA, it is desirable to maintain reactor coolant makeup from all sources of supply. For this reason, the feedwater containment isolation valves do not automatically close on a primary containment isolation signal.

A third valve in the feedwater line is a motor operated check valve located outside primary containment, is classified a containment isolation valve and is capable of being remotely closed from the main control room. This valve provides redundant isolation and long term leakage protection upon operator judgment that continued makeup through the feedwater line is unavailable.

After observing indication of low feedwater flow, the operator may close the third valve within 20 minutes after a postulated LOCA.

In addition to the third valve, there are containment isolation valves on the high pressure coolant injection (HPCI) and reactor core isolation cooling (RCIC) discharge lines, and on the Reactor Water Cleanup System (RWCU) return lines that connect to the feedwater lines between the two outside containment isolation valves. Those valves can be closed by operator action from the main control room. Additionally, the HPCI and/or RCIC valves can be opened from the main control room to provide a water seal on the third valve in addition to supplying water to the RPV. See Section 6.2.3.2.3 for further details.

See Section 5.4.9 for a further discussion of the design of the main steam lines and the feedwater lines.

6.2.4.3.1.3 Residual Heat Removal Shutdown Cooling Suction Line

The residual heat removal (RHR) shutdown cooling suction line penetrates primary containment and taps into one of the two recirculation loops. Two normally closed motor operated gate valves are interlocked closed by a reactor high pressure signal during normal operation and are maintained closed during an accident by a low water level isolation signal. One valve is located inside primary containment, and the second valve is located outside primary containment. Containment isolation is provided by the motor operated gate valve located outside primary containment and by the closed system outside containment that is capable of maintaining system integrity.

6.2.4.3.1.4 Residual Heat Removal Shutdown Cooling Return Lines

The RHR shutdown cooling return lines penetrate the primary containment and connect to the discharge side of each recirculation loop, which is connected to the RPV. Each line is provided with a single, normally closed, motor-operated primary containment isolation valve outside primary containment and a testable check valve inside primary containment. Containment isolation is provided by the motor-operated valve located outside primary containment and by the closed system outside containment that is capable of maintaining system integrity. The motor operated valves are interlocked closed by a reactor high pressure signal during normal operation and are maintained closed during an accident if a low water level isolation signal exists.

Each testable check valve is provided with a bypass line for testing purposes. These lines are isolated by an air operated, fail closed globe valve.

6.2.4.3.1.5 Residual Heat Removal Low Pressure Coolant Injection and Core Spray Discharge Lines

The RHR low pressure coolant injection (LPCI) and the core spray discharge lines penetrate the primary containment and discharge directly into the RPV. Each line includes a normally closed, motor operated containment isolation valve outside primary containment, and a testable check valve inside primary containment. Containment isolation is provided by the motor-operated valve located outside primary containment and by the closed system outside containment that is capable of maintaining system integrity.

In addition, there is a HPCI line which discharges into the RPV by way of one of the two core spray lines downstream of the containment isolation valve on that core spray line. This line is served by a normally closed motor-operated gate valve outside primary containment in series with the testable check valve on the core spray line. Containment isolation is provided by the motor-operated valve located outside primary containment and by the closed system outside containment that is capable of maintaining system integrity.

Each testable check valve is provided with a bypass line for testing purposes. These lines are isolated by an air operated fail-closed globe valve.

6.2.4.3.1.6 High Pressure Coolant Injection and Reactor Core Isolation Cooling Steam Supply Lines

The high pressure coolant injection (HPCI) and reactor core isolation cooling (RCIC) steam supply lines have two major containment isolation valves in series that are normally open, located inside and outside of the primary containment. The third containment isolation valve on these lines is a 2-inch, normally closed globe valve, on a 1-inch bypass line around the inside major containment isolation valve. These valves do not receive a containment isolation signal when a LOCA is detected. This permits these ESF systems to function during a LOCA. However, these valves automatically close when a break is detected in the portion of the steam supply line outside primary containment of the respective system.

6.2.4.3.1.7 Reactor Water Cleanup System Line

Reactor water processed through the RWCU system is taken out of containment from the reactor recirculation loops. The RWCU line is isolated by two, normally open, motor operated gate valves, one inside and one outside primary containment. Both these valves receive a containment isolation signal.

6.2.4.3.1.8 Reactor Pressure Vessel Headspray Line

6.2.4.3.1.9 Main Steam Drain Line

The main steam drain line is isolated by two motor operated gate valves that isolate upon a containment isolation signal.

6.2.4.3.1.10 Reactor Recirculation System Process Sample Lines

The Reactor Recirculation System process sample lines are isolated by two, normally open, solenoid operated globe valves that isolate on a containment isolation signal.

6.2.4.3.1.11 Standby Liquid Control Line

Provided that the Standby Liquid Control (SLC) System has not been used, the explosive-actuated valves provide the absolute seal for long term leakage control. After system operation, isolation is provided by a check valve inside primary containment, and two, independent, motor operated globe stop check valves located outside primary containment on branching lines. The stop check valves are manually closed from the main control room after system operation.

6.2.4.3.1.12 Reactor Recirculation Pump Seal Lines

The reactor recirculation pump seal lines are isolated by a check valve inside primary containment and a motor operated globe valve outside primary containment that closes on a containment isolation signal.

6.2.4.3.1.13 Post-Accident Liquid Sampling System

There are seven post-accident sampling lines that penetrate the primary containment. Only one of the seven forms part of the RCPB as well. See Section 6.2.4.3.2.16 for a discussion of the containment isolation provisions for these lines.

6.2.4.3.1.14 Instrument Lines

The instrument lines that penetrate the primary containment and form part of the RCPB are designed to optimize their monitoring function and to minimize uncontrolled releases of radioactivity to the environment. These instrument lines have a flow restriction orifice inside the primary containment and an excess flow check valve outside the primary containment for automatic containment isolation in the event of an instrument line break. If an instrument line develops a leak of 1.5 to 2.5 gpm outside containment, the resultant differential pressure of 3 to 10 psi across the excess flow check valve will cause the check valve to close automatically. If an excess flow check valve fails to close when required, the restriction orifice and the main flow path through the valve have a resistance to flow at least equivalent to a sharp edged orifice of 0.250 inches in diameter. Each valve is also provided with one limit switch that operate lights that indicate valve position and a solenoid valve for remote reset. The capability for remote operation has not been provided since there is no remote indication of failure of a specific line.

6.2.4.3.1.15 Control Rod Drive Lines

The CRD system has multiple, insert and withdraw lines, that penetrate the primary containment.

The classification of these lines is quality group B, and they are designed in accordance with ASME B&PV Code, Section III, Class 2. The basis upon which the CRD insert and withdraw lines are designed is commensurate with the safety importance of maintaining the pressure integrity of these lines.

It has been an accepted practice not to provide automatic isolation valves for the CRD insert and withdraw lines in order to preclude any possible failure of the scram function. The lines can be isolated by the solenoid valves provided on the hydraulic control units (HCUs) that are located outside the primary containment. The lines that extend outside the primary containment are 1 inch or smaller and terminate in systems that are designed to prevent outleakage. The solenoid valves are normally closed, but they open upon rod movement and during reactor scram. In addition, a ball check valve located in the CRD flange housing automatically seals the insert line if there is a break. Finally, manual shutoff valves are provided outside the primary containment.

Because of the unique function and features of the CRD system, the previously described design constitutes an acceptable "other defined basis" for containment isolation as recognized by the NRC in the Federal Register (48 FR 23809).

6.2.4.3.1.16 Conclusion on GDC 55

To ensure protection against the consequences of accidents involving the release of radioactive material, piping systems that form the RCPB are shown to have adequate isolation capabilities on a case by case basis. In all cases, a minimum of two barriers are shown to protect against the release of radioactive materials.

In addition to meeting the isolation requirements stated in GDC 55, the pressure retaining components that comprise the RCPB are designed to meet other requirements that minimize the probability or consequences of an accidental pipe rupture. The quality requirements for these components ensure that they are designed, fabricated, and tested to the highest quality standards.

6.2.4.3.2 Evaluation Against GDC 56

GDC 56 requires that lines that penetrate the primary containment and connect directly to the containment atmosphere must have two isolation valves, one inside the primary containment and one outside, unless it can be demonstrated that the containment isolation provisions for a specific class of lines are acceptable on some other basis.

Unless justified on some other defined bases, lines that penetrate the primary containment and connect directly to the containment atmosphere are provided with two isolation valves located outside the primary containment as close to the containment as is practical.

This arrangement is intended to satisfy GDC 56 on the "other defined basis" criterion in that:

1. There is limited space within the primary containment, and placing these valves inside would seriously impede accessibility for inspection and maintenance of these valves and other equipment.

2. Placing these valves inside the primary containment would subject them to a harsh environment and thus increase the probability of failure.

3. Some of the lines that fall into this category are not in use during normal operation, and, therefore, the isolation valves are normally closed.

4. Valves should be accessible in systems that must be available for long term operation following an accident. An example is the containment atmosphere sampling lines.

Typically, lines that connect directly to the suppression chamber are provided with a single isolation valve located outside the primary containment. These valves are located in the Torus Area Room (4102) in the Reactor Building, which has provisions for collection of any fluid leakage, adjacent to the primary containment. Whenever possible, lines to the suppression chamber are submerged to assist in trapping the primary containment atmosphere and preventing its escape to the environment.

The systems to which the lines from the suppression chamber connect outside the primary containment are closed systems meeting the appropriate "other defined basis" requirements of closed systems outside containment, except for those lines such as the suppression pool cleanup lines that have redundant containment isolation valves.

The valves in the lines from the suppression chamber provide a barrier outside containment to prevent loss of suppression pool water if a leak develops downstream of the valves. The valves are either closed from the main control room or automatically closed. Leak detection is provided for the lines outside the primary containment to aid the operator in determining which valve is to be closed. If a leak develops outside the primary containment, the fluid will be contained within the Reactor Building.

6.2.4.3.2.1 Drywell Purge Inlet and Drywell Purge Vent Lines

The drywell purge inlet line is isolated by five butterfly valves located outside primary containment. One valve is located as close as possible to the primary containment. The remaining four are located on branching lines upstream of the first. All valves receive a containment, isolation signal.

In addition to the containment isolation for the main drywell purge inlet line, there is a line to the B train containment hydrogen recombiner that connects to the drywell purge vent line between the primary containment and the first containment isolation valve. This line is isolated by two motor-operated gate valves that also receive a containment isolation signal.

The drywell purge vent line is isolated by two butterfly valves located outside primary containment.

In addition to the containment isolation for the main drywell purge vent line, there is an inlet line to the A train containment hydrogen recombiner that connects to the vent line between the primary containment and the first containment isolation valve. This line is isolated by two motor operated gate valves. All isolation valves receive a containment isolation signal.

Also connected to the primary containment purge vent line is a 2-inch exhaust line that connects to the vent line between the two main isolation valves. This line is isolated by the isolation valve on the purge line and by an air operated globe valve. The valve is normally closed and is maintained closed by a containment isolation signal. For a detailed evaluation of the primary containment venting operation against BTP CSB 6-4 requirements see Section 1.14.1.71.

During normal operation, the 6-, 24-, and 26-inch containment purge valves are administratively controlled closed, except as permitted by the Technical Specifications. These valves are qualified to close within 5 seconds, including an assumed 1-second instrument time delay, against the flow following a postulated LOCA.

To prevent the unlikely event of a containment purge valve being prevented from closing by debris that could be entrained in the containment purge lines, the drywell purge lines are provided with debris screens. Debris screens are not provided for the suppression pool purge lines for the following reasons:

1. There are no high energy lines in the suppression pool.

2. There is no insulation or other loose debris in the suppression pool to become entrained in exiting fluid.

The debris screens are designed based on the following criteria:

1. The debris screens are Seismic Category I and installed upstream of the inboard isolation valves, inside the primary containment.

2. The debris screens are designed to withstand the differential pressure resulting from a LOCA.

3. The debris screen openings are approximately 2 inches by 1 3/16 inches.

6.2.4.3.2.2 Residual Heat Removal Containment Spray Lines

Each of the two RHR containment spray lines have two, normally closed, motor operated gate valves located outside the primary containment. The valve closest to the penetration is the containment isolation valve.

This design is justified on the basis that RHR containment spray lines meet the "other design basis" requirements of a closed system outside primary containment and also because the RHR containment spray function is used only after a LOCA to lower the pressure in the primary containment. During normal operation, the valves are closed, and a system of interlocks ensures that only one valve can be opened at a time during system testing. Both valves can be opened only by manual action from the main control room after a high primary containment pressure signal is received.

After termination of the containment spray function, the valves are closed by manual operation from the main control room in order to isolate containment.

The containment isolation provisions of the RHR containment spray lines ensure dependability of the system to initiate a supply of cooling water while meeting the particular isolation requirements of these lines. The design takes credit for the RHR system being a closed system outside primary containment.

6.2.4.3.2.3 Liquid Radwaste Collection Lines

The liquid radwaste collection lines are isolated by two motor operated gate valves, one inside and one outside the primary containment, that close upon receipt of a containment isolation signal.

6.2.4.3.2.4 Compressed Air Service Line

The compressed air service line is normally closed. It is isolated during reactor operation by two manual, normally locked closed gate valves, one inside and one outside primary containment. In addition to the two isolation valves, the line is blocked off by a spectacle flange during plant operation.

6.2.4.3.2.5 Traversing Incore Probe Guide Tube Lines

The traversing incore probe (TIP) guide tube lines do not connect directly to the primary containment atmosphere. However, inside the primary containment, the indexing mechanism (a revolver like mechanism used for selecting a guide tube leading into the reactor vessel) is mounted inside a housing equipped with a pressure relief valve which communicates with primary containment atmosphere. This pressure relief valve is unique in that it will open on a negative or positive pressure inside the housing. The indexing mechanism (indexer) has a slip fitting with the guide tubes leading to the reactor vessel. If a LOCA occurred and the primary containment became pressurized, the pressure relief valve would open to reduce the pressure differential across the indexer housing and the containment atmosphere would leak past the slip fitting into the tip line. Under these conditions, GDC 56 applies.

The TIP insertion/withdrawal lines have two isolation valves outside the primary containment. One is a solenoid operated ball valve and the other is an explosive valve; both can be remote-manually closed for containment isolation. The solenoid operated ball valve is normally closed. It opens only to admit the insertion of the TIP probe into the reactor. If the probe is in the reactor, the containment isolation signal automatically retracts the probe and closes the ball valve. If this operation is not successful, the operator is alerted and can manually actuate the explosive shear valve which cuts the probe line to seal the primary containment penetration.

Automatic isolation is not provided, and the containment isolation valves are not provided with redundant standby power.

This arrangement is intended to satisfy GDC 56 on the "other defined basis criteria" in that:

1. It is designed commensurate with the importance to safety of isolating this line
2. Locating both valves outside containment improves the reliability of the system
3. Remote manual isolation decreases the probability that the valves will be inadvertently actuated
4. It is a standard design used in other BWR nuclear power plants of similar or identical design.
5. The information provided in IE Information Notice No. 86-75 was consulted and utilized in classifying the lines.

6.2.4.3.2.6 Traversing Incore Probe Purge Tube Line

The TIP purge tube line does not connect directly to the primary containment atmosphere However, the same situation described in Section 6.2.4.3.2.5 for the Traversing Incore Probe Guide Tube lines is applicable. Therefore, GDC 56 is applicable. By meeting the requirements of GDC 56, the system's isolation capability is commensurate with its importance to safety. The TIP purge tube line is isolated by a simple check valve inside primary containment and by a normally open, air operated globe valve outside primary containment. The containment isolation valve on the outside receives a containment isolation signal.

6.2.4.3.2.7 Primary Containment Instrument Gas Lines

The portion of the primary containment instrument gas system that is directly connected to the primary containment atmosphere consists of two instrument gas supply headers and a suction line. Isolation for each supply header is provided by a normally open, motor operated globe valve inside primary containment and a normally open, motor operated globe valve outside primary containment. The containment isolation valves isolate upon a containment isolation signal.

The intake line to the compressor is isolated by a normally open, motor operated globe valve inside primary containment and by two motor operated globe valves on branching lines outside primary containment. All three valves close upon a containment isolation signal.

6.2.4.3.2.8 High Pressure Coolant Injection and Reactor Core Isolation Cooling Exhaust Lines and Reactor Core Isolation Cooling Gland Seal Vacuum Pump Discharge Lines

The HPCI and RCIC turbine exhaust lines and the RCIC gland seal vacuum pump discharge lines have a motor operated valve that can be remote manually closed for containment isolation in the event of a postulated accident. These lines also have a check valve upstream of the motor operated valve. The check valve provides a second and immediate isolation barrier in the event of a break upstream of the check valve. In addition to closing the containment isolation valves to isolate the HPCI and RCIC turbine exhaust lines, the HPCI and RCIC turbine exhaust line vacuum breaker valve network must be isolated. Isolation of this system is described in Section 6.2.4.3.2.11.

Automatic isolation for accident protection is not provided since greater safety is ensured by providing the means to initiate a cooling water supply to the RPV.

6.2.4.3.2.9 Emergency Core Cooling System and Reactor Core Isolation Cooling Suction Lines

The Emergency Core Cooling System (ECCS) and RCIC suction lines from the suppression pool are isolated by a single, remote manually actuated, motor operated valve. The containment isolation valves on each of the RHR and core spray suction lines are normally open. The containment isolation valves on the HPCI and RCIC suction lines are normally closed. However, they both automatically open upon low condensate storage tank (CST) level and HPCI also opens on high suppression pool level.

Use of the single valve and the automatic opening of a containment isolation valve is again justified on the basis that greater safety is ensured by increasing system reliability so that a supply of cooling water can be initiated to the reactor. To enhance safety, the systems are designed as closed systems outside primary containment.

6.2.4.3.2.10 Emergency Core Cooling System and Reactor Core Isolation Cooling Suppression Pool Return Lines

The ECCS and RCIC suppression pool return lines include the following:

1. RCIC minimum flow return line

2. HPCI minimum flow return line

3. Core spray full flow test line

4. RHR suppression pool cooling and system test return line.

The HPCI minimum flow return line has a single motor operated containment isolation valve located outside the primary containment. The RCIC minimum flow return line has two solenoid-operated valves, one for minimum flow isolation and the other for containment isolation, located outside the primary containment. The primary containment isolation valves do not receive a containment isolation signal.

Each core spray full flow test line is isolated by one motor operated globe valve. The globe valve is normally closed. In addition, connecting to each core spray full flow test line, between the suppression chamber and the containment isolation valve, is a core spray minimum flow bypass line and a pressure relief valve discharge line. The relief valve isolates the discharge line and a normally open motor operated globe valve isolates the bypass line.

Two, normally closed, motor-operated globe valves in parallel isolate each of two RHR Suppression Pool Cooling and System Return Lines from the various RHR/LPCI pump discharge flow paths. The Division I line is isolated by RHR Loop A Test Return valve, BC-HV-F024A, and RHR Loop C Test Return valve, BC-HV-F010A, and the Division II line is isolated by RHR Loop B Test Return valve, BC-HV-F024B, and RHR Loop D Test Return valve, BC-HV-F010B. In addition, each Suppression Pool Return Line connects to two full flow test lines; a jockey pump discharge line; an abandoned in place, Steam-condensing Return to Suppression Pool line; two RHR pump minimum flow lines; and two LPCI injection line relief valve discharge lines. As previously mentioned, the two parallel, normally closed, motor-operated globe valves isolate the full flow test lines. A check valve (BC-V206, Division I line and BC-V260, Division II line) isolates the jockey pump discharge line. A normally open, motor-operated gate valve (BC-HV-F007A, BC-HV-F007B, BC-HV-F007C, and BC-HV-F007D) may provide isolation for each of the RHR pump miniflow lines. The pressure relief valves on each of the LPCI injection lines (BC-PSV-F025A, BC-PSV-F025B, BC-PSV-F025C, and BC-PSV-F025D) isolate their discharge lines from the Suppression Pool Return Lines. Finally, the Steam-condensing Return system was abandoned in place. Valve, BC-HV-F011A, isolates the Division I line and valve, BC-HV-F011B, isolates the Division II line. Both of these valves are permanently out of service with electrical power disconnected and their manual overrides chain-locked in the closed position.

Again, use of a single valve is justified on the basis that greater safety is achieved by increasing system reliability and because the system is designed as a closed system outside primary containment.

6.2.4.3.2.11 High Pressure Coolant Injection and Reactor Core Isolation Cooling Turbine Exhaust Line Vacuum Breaker Valve Network

The HPCI and RCIC turbine exhaust line vacuum breaker valve network runs between the suppression pool air space to the turbine exhaust lines on the HPCI and RCIC systems and the RHR heat exchanger relief valve discharge lines. The network is designed as a closed system outside primary containment. Each one of the two branching lines to the HPCI and RCIC system is isolated by a single normally open motor operated gate valve.

The system does not receive a containment isolation signal so that a supply of cooling water can be initiated to the reactor. However, should a break be detected in the steam supply line in either the HPCI or RCIC system, the respective portion of the network will automatically isolate.

6.2.4.3.2.12 Suppression Chamber Spray Header Lines

The RHR suppression chamber spray lines have a normally closed, motor operated isolation valve located outside the primary containment. This valve receives a containment isolation signal. Use of a single valve is justified on the basis that the system is designed as a closed system outside containment.

6.2.4.3.2.13 Residual Heat Removal Heat Exchanger Relief Valve Discharge Lines

Each of the RHR heat exchanger relief valve discharge lines to the suppression pool from the RHR heat exchangers is isolated by a relief valve.

6.2.4.3.2.14 Suppression to Containment Prepurge Cleanup Lines, Suppression Chamber Vacuum Relief and Suppression Chamber to Atmosphere

The suppression chamber to containment prepurge cleanup lines are isolated by two redundant valves outside the primary containment. The valves are normally closed. To limit the possibility of an uncontrolled release of radioactivity, the valves are administratively controlled closed during reactor operation, except as permitted by the Technical Specifications, and will be verified closed. In addition, there are connections to the containment hydrogen recombiners between the first containment isolation valves and the primary containment. These lines are isolated by two motor operated gate valves. All isolation valves receive a containment isolation signal.

A suppression chamber vacuum breaker assembly is attached to each of the above two 24 inch lines. Each assembly consists of a check type vacuum relief valve and a pneumatically operated butterfly valve. These assemblies are located outside the primary containment. Their operation is discussed in Section 6.2.1.1.4.1.

The suppression chamber to atmosphere line is isolated by two redundant valves outside the primary containment. The valves are normally closed. To limit the possibility of an uncontrolled release of radioactivity, the valves are administratively controlled closed during reactor operation, and will be verified closed. In addition, electric power to the outboard valve is administratively blocked out and a rupture disc is installed in series downstream of the outboard valve to contain primary containment bypass leakage within the secondary containment. The outboard isolation valve is configured as a sealed closed barrier, in accordance with NUREG 0737, Item II.E.4.2.7, Position 6.

6.2.4.3.2.15 Suppression Pool Cleanup Lines

The suppression pool cleanup lines are isolated by redundant containment isolation valves that close upon a containment isolation signal.

6.2.4.3.2.16 Post-Accident Sampling System Lines

The Post-Accident Sampling System penetrates the primary containment in seven locations. One line is for gathering liquid samples and it forms part of the RCPB. Two lines are sampling return lines to the suppression chamber. The other four lines sample the primary containment atmosphere at different locations within the drywell and suppression chamber. Isolation for these lines consists of two solenoid-operated valves in series, located outside of primary containment. The valves are normally closed, and the penetrations are designed to be a sealed closed system. Administrative procedures prevent the valves from being inadvertently opened by ensuring that power is not supplied to the normally deenergized solenoids until the system is required to operate.

6.2.4.3.2.17 Plant Leak Detection System Lines

The two plant leak detection lines penetrate primary containment and connect directly to the primary containment atmosphere. Each line is isolated by two motor operated globe valves, located outside primary containment, that receive a containment isolation signal.

6.2.4.3.2.18 Hydrogen/Oxygen Analyzer Lines

The eight hydrogen/oxygen analyzer lines penetrate primary containment and connect directly to the primary containment atmosphere. Four of these lines penetrate the drywell, and the remaining four penetrate the suppression chamber. Each of the eight lines are isolated by two motor-operated globe valves located outside containment.

6.2.4.3.2.19 Primary Containment Instrument Gas Header Line

The primary containment instrument gas header to the suppression chamber supplies instrument gas to vacuum relief valves located there. This line is isolated by two air operated globe valves outside primary containment. Each valve receives a containment isolation signal.

6.2.4.3.2.20 Integrated Leakage Rate Test Lines

The integrated leakage rate test (ILRT) lines are not used during normal plant operation. They are isolated by two manually locked closed globe valves, one inside and one outside primary containment.

6.2.4.3.2.21 Instrument Lines

Each instrument line that penetrates the primary containment and is connected directly to the containment atmosphere is isolated by a manual valve. This design is justified on the basis that system reliability is greater with a manual isolation valve, that these systems are closed systems outside containment designed to be reliable boundaries against containment leakage, and that the system is maintained by visually checking for leaks during normal instrument calibrations.

The instrument lines that sense suppression pool water level have a remote manual valve for isolation. Their design is justified on the "other defined basis" because system reliability is greater with a single isolation valve and because these systems are closed systems outside containment that can accommodate a single failure without loss of system reliability as a boundary against containment leakage.

6.2.4.3.2.22 Location of Outside Containment Isolation Valves

All outside primary containment isolation valves are located as close to containment as practical. Valve location is governed by many considerations, e.g., spatial limitations, the need to support the valves and valve actuators, dynamic loading and equipment accessibility considerations. The valves whose location appears to be somewhat removed from the containment and a short justification for their existing location are identified below.

P-22	GS-V020 GS-V022	This penetration shares containment isolation provisions with P-220. GS-V020 and V022 are located nearer to P-220 and therefore as close as practical but at some distance from P-22.
P-212A, 212B	BC-PSV-F025A BC-PSV-F025B BC-PSV-F025C BC-PSV-F025D	These safety relief valves were located as close as practical to the piping they are protecting protecting to meet the intent of ASME Section III.
P-217B	BE-PSV-F012	This safety relief valve is located as close as practical to the piping it is protecting to meet the intent of ASME Section III.
J-7D	GS-V053 GS-V042 GS-V043	This penetration shares containment isolation provisions with J-202. GS-V042 and V043 are located nearer to J-202 and therefore at some distance

		from J-7D. GS-V053 was located based on accessibility considerations.
J-202	GS-034	This penetration shares containment isolation provisions with J-7D. GS-V034 is located nearer to J-7D and therefore at some distance from J-202.

6.2.4.3.2.23 Conclusion on GDC 56

To ensure protection against the consequences of accidents involving release of significant amounts of radioactive materials, fluid lines that penetrate the primary containment have been demonstrated to provide isolation capabilities on a case by case basis in accordance with GDC 56.

In addition to meeting isolation requirements, the pressure retaining components of these systems are designed to the same quality standards as the containment.

6.2.4.3.3 Evaluation Against GDC 57

6.2.4.3.3.1 Chilled Water System Lines and Reactor Auxiliaries Cooling System Lines

The chilled water and the reactor auxiliaries cooling system (RACS) lines are closed systems inside primary containment. However, greater safety is achieved by meeting the requirements of GDC 56. Therefore, two redundant motor operated isolation valves that isolate on a containment isolation signal, one inside and one outside primary containment, are provided.

6.2.4.3.4 Evaluation Against Regulatory Guides

6.2.4.3.4.1 Evaluation Against Regulatory Guide 1.11 (Safety Guide 11)

Compliance with Regulatory Guide 1.11 (Safety Guide 11) is discussed in Section 1.8.11.

6.2.4.3.4.2 Evaluation Against Regulatory Guide 1.141

Compliance with Regulatory Guide 1.141 is discussed in Section 1.8.1.141.

Regulatory Guide 1.141 is not a requirement for HCGS. However, our assessment is that the other defined bases for complying with GDC 54, 55, 56, and 57 that were implemented on HCGS meet Regulatory Guide 1.141 requirements.

6.2.4.3.4.3 Failure Mode and Effects Analyses

A single failure can be defined as a failure of a component in any safety system that results in a loss or reduction of the system's capability to perform its safety function. Active mechanical components are defined in Regulatory Guide 1.48 as components that must perform a mechanical motion during the course of accomplishing a system safety function. Appendix A to 10CFR50 requires that electrical systems be designed against passive single failures as well as active single failures. Sections 3.1 and 15.9 describe the implementation of these requirements as well as the requirements of GDC 17, 21, 35, 41, 44, 54, 55, 56, and 57.

6.2.4.3.5 Evaluation of Other Defined Bases

An ESF System may use only one containment isolation valve if a closed system outside primary containment is used as a second isolation barrier to accommodate a single active failure. Such a configuration can be used to increase ESF System reliability or to eliminate 10CFR50 Appendix J testing of the valve being replaced by the closed system outside of containment as the second containment barrier. The Leakage Reduction Program periodically verifies the system integrity of the closed system outside of containment. Acceptable means for providing boundary isolation of the closed system are identified in Section 1.10 of the UFSAR.

In the case of a single failure, the closed system accommodates the failure by being an extension of the containment. Table 6.2-25 identifies those penetrations isolated with only a single isolation valve. Figures 6.2-45, 6.2-46, 6.2-47, and 6.2-48 show the limits of the extended containment boundary. All manual valves at the system boundary, vent valves, test valves, and drain valves are under administrative control to assure the integrity of the extended containment boundary. Isolation provisions for the extended containment boundaries are identified in Table 6.2-26. Table 6.2-26 also evaluates the ability of check valves and safety/relief valves to maintain the extended containment boundary. All extended containment boundaries are Quality Group B (i.e., ASME B&PV Code Class 2 piping), Seismic Category I, and designed to temperature and pressure ratings at least equal to that of the containment as identified in Figures 6.2-45 through 6.2-48.

Missile protection for plant systems and structures is discussed in Section 3.5.

6.2.4.3.5.1 Conclusion on Other Defined Bases

When equivalent or greater safety is ensured by using a single primary containment isolation valve, a dependable closed system outside primary containment is provided to act as a second barrier against the release of radioactive materials.

6.2.4.4 Tests and Inspections

The Containment Isolation System incorporates the components and isolation functions of all systems penetrating the primary containment. It also has the capability for periodic testing and the determination of containment system leakage.

As required by the testing requirements of the Technical Specifications, the system is periodically tested to meet the leakage testing requirements of 10CFR50, Appendix J, Option B, and the inservice testing requirements of ASME, Section XI. This is discussed in Sections 3.9.6 and 6.2.6. The hard seated containment purge isolation valves will be demonstrated operable in accordance with the Primary Containment Leakage Rate Testing Program, at least once per 24 months.

Specific exceptions to Appendix J are discussed below:

6.2.4.4.1 Thermal Relief Valves

10CFR50, Appendix J, Paragraph III.C.2(a) requires valves, unless pressurized with fluid from a seal system, to be pressurized with air or nitrogen at a pressure of Pa. Thermal relief valves that discharge into the primary containment atmosphere and also serve as containment isolation valves will have their integrity verified during the Type A test rather than during the Type C tests. This exemption is justified since relief valves that serve as containment isolation valves are designed so that their discharge piping will withstand temperature and pressure at least equal to the containment design temperature and pressure. In fact, LOCA pressure seats the valve's disk. The addition of another valve to form a test boundary would not only defeat the purpose for which the relief valves were installed but might also decrease the probability that the relief valves would function properly when required.

6.2.4.4.2 Instrument Lines

10CFR50, Appendix J, requires valves, unless pressurized with fluid from a seal system, to be pressurized with air or nitrogen at a pressure of Pa. Instrument lines that are not included in the Type C test program, i.e., suppression pool level and pressure instrumentation, drywell pressure instrumentation, and those lines containing excess flow check valves, will have their leak tightness verified during the Type A test. These instrument lines were designed on an "other defined basis" of GDC 56 (see

Sections 6.2.4.3.2.21 and 6.2.4.3.5) and hence are not capable of being Type C tested. Instrument lines are provided with a manual isolation valve outside containment for greater reliability. The systems they serve are closed systems outside containment, thereby providing reliable boundaries against containment leakage. The Type A test that will be conducted on these instrument lines serves to adequately assure integrity.

6.2.4.4.3 Main Steam Isolation Valves

10CFR50, Appendix J, paragraph III.C.2(a) requires valves to be pressurized with air or nitrogen to a test pressure not less than Pa. The main steam isolation valves (MSIVs) will be leakrate tested by pressurizing between the inboard and outboard MSIVs at reduced pressure of 5 psig. This restriction is necessary because a backpressure differential of 25 psi will lift the MSIV disk, unseating the valve. Therefore, testing of the two MSIVs simultaneously, between the valves, at Pa would lift the disk at the inboard valve and result in a meaningless test. A test will be conducted using air/nitrogen at 5 psig with the observed leakage through each main steam line limited to 41 scfh. This limit is the single steam line allowable leakage of 150.0 scfh (Technical Specification 3.6.1.2) corrected from 50.6 psig to 5 psig.

6.2.4.4.4 Containment Airlocks

10CFR50, Appendix J, Option B, requires airlock testing to be performed on a frequency of at least once every 30 months at a pressure not less than Pa. Airlock individual testable components which include the shaft seals and door seals shall also be performed on a frequency of at least once every 30 months. Airlock tests shall be performed in accordance with ANSI/ANS 56.8-1994. In addition to the 30-month testing requirement, following maintenance on a pressure retaining boundary, a leakage test shall be performed either on the airlock or the affected area or component.

Airlock door seals shall be tested within 7 days after each containment access whenever containment integrity is required. During periods when multiple containment entries are required more frequently than once every seven days, the door seals may be tested once per 30 days.

These commitments assured that when replacement, modifications, or other alternatives to the airlocks are made that affect sealing capability, surveillances will be conducted to verify that the airlock satisfies acceptance criteria. Therefore, the test that will be performed, i.e., after maintenance affecting the sealing capability, represents sufficient surveillance (in addition to the 30 month and 7 day requirements) to assure proper leakage verification.

6.2.4.4.5 Traversing Incore Probe System

10CFR50, Appendix J, Paragraph III.D.3 requires that valves classified as Type C valves be leak tested by local pressurization during each reactor shutdown for refueling but in no case at intervals greater than 2 years. The traversing incore probe (TIP) system's shear valves will not be Type C tested because the shear valves require testing to destruction. The following actions will be implemented as an alternative to Type C testing in order to ensure the shear valves will perform their intended functions. First, the continuity of the explosive charge will be verified at least once every 31 days. Second, the explosive squib from at least one explosive valve will be removed at least once every 18 months (such that each explosive squib in each explosive valve is removed at least once every 90 months) and tested by initiating the explosive squib. Third, the replacement charge for the exploded squib will be from the same manufactured batch as the one fired or from another batch which has been certified by having at least one of that batch successfully fired. Finally, all charges will be replaced according to the manufacturer's recommended life time.

6.2.4.4.6 Other Deviations

The following discussion details additional deviations from the requirements of Appendix J; however, these items need not be identified as exemptions since 10CFR50 allows an alternative or equivalent testing method.

1. Appendix J, indicates Type C tests should be performed in the same direction as that when the valve is utilized under accident conditions unless a pressure applied in a different direction will provide equivalent or more conservative results.

   Four types of valves are leak rate tested in a direction other than the anticipated accident flow direction. Justification that such testing will provide equivalent or more conservative results relative to those resulting from test pressure applied in the direction of anticipated accident flow includes:

a. Globe valves - Test pressure in the reverse direction will tend to unseat the valve

b. Butterfly valves - All applicable valves have seat constructions which are designed for sealing against pressure on either side

c. Gate valves - Some valves are tested by pressurizing between the seats. Pressurizing in the normal direction tends to seat one of the discs, whereas pressurizing between the discs has applies pressure equally to each seat.

d. Relief valves - Test pressure in the reverse direction will tend to unseat the valve.

2. Appendix J, requires valves unless pressurized with fluid from a seal system to be pressurized with air or nitrogen to Pa. Although the suppression pool is not a water seal system, it does provide a water seal for all valves identified in Table 6.2-24 except for feedwater lines. NUREG-0800, SRP 6.2.6 states that hydrostatic testing of containment isolation valves is permissible if the line is not a potential containment atmospheric leak path. Therefore, those identified valves will be tested at 1.1 P_a with water and total leakage limited to 10 gpm.

3. Appendix J, allows exclusion from combined 0.60La of leakage from valves that are sealed with fluid from a seal system if the fluid leakage rates do not exceed those specified in the Technical Specifications. Since the Control Rod Drive (CRD) System was designed on an "other defined basis" of GDC 55 system

integrity is verified by the following leakage monitoring capabilities in lieu of Type C tests.

a. CRD high temperature alarms

b. CRD position indication

c. Level instruments in the reactor building sumps

d. Area radiation monitors that indicate an alarm in the control room

Furthermore, leakage monitoring of the CRD lines will be provided during the CILRT when the reactor pressure vessel and the nonseismic portion of the CRD system are vented and the containment is pressurized.

Finally, leakage from the CRD system into the reactor building will be detected for the full spectrum of leakage rates. Small leaks will be detected by observation during daily inspection rounds of the control unit areas by operators. Large leaks will be detected by level indicators on the Reactor Building floor drain sumps. A large leak of reactor coolant from any insert line will be automatically isolated by the ball check valve in the CRD housing. Leaks of CRD supply water will be indicated by increased flow as continuously recorded in the control room. The CRD directional control valves are normally closed. Excessive leakage through the scram valves will be detected by level indicators in the floor drain sumps.

See Section 6.2.6 for a discussion of the test program.

6.2.4.5 SRP Rule Review

6.2.4.5.1 Acceptance Criterion II.6.d

Acceptance Criterion II.6.d requires that when it is not practical to provide one isolation valve inside and one outside containment, and both valves are located outside the primary containment, that the valve nearest the containment and the piping between the containment and the first valve, be enclosed in a leaktight or controlled leakage housing. The valve and/or piping compartment must be capable of detecting leakage from the valve shaft and/or bonnet seals and must terminate the leakage.

HCGS does not have a dedicated system for detecting leakage from individual containment isolation valves or from individual lines that penetrate primary containment. Nevertheless, the design is acceptable since Reactor Building sumps level alarms and flooding alarms in ECCS pump rooms alert the main control room operators of excess leakage. Furthermore, all leakage is collected within the Reactor Building sumps and processed in the radwaste system before its controlled release to the environment.

6.2.4.5.2 Acceptance Criterion II.6.h

Acceptance Criterion II.6.h of Section 6.2.4 requires that nonessential systems be automatically isolated by the containment isolation signal. HCGS complies with this requirement, with the exceptions that are identified and justified in our response to NUREG-0737, Item II.E.4.2 in Section 1.10.

6.2.4.5.3 Acceptance Criterion II.6.n

SRP Section 6.2.4.II.6.n states that for lines which provide an open path from the containment to the environs, isolation valve closure times on the order of 5 seconds or less may be necessary.

Furthermore, it states that closure times for these valves should be based on the radiological consequences.

The only penetrations that provide a direct path from the primary containment to the environs are P-22, P-23, P-219, and P-220. The valves isolating these penetrations that do not meet the 5 second recommended closure requirement are GS-V004, V005, V002, V003, V025, V007, V006, V076, V008, and V010. Eight of these ten valves isolate the lines to the containment hydrogen recombiner system which is considered a closed system. Only GS-V025 and V076 isolate direct paths to the environs. The adequacy of their closure times was confirmed by radiological analysis. The analysis is discussed in Section 1.14.1.71.2.11.1.

6.2.5 Combustible Gas Control in Containment

Following a postulated beyond design basis accident, hydrogen gas may be generated within the primary containment as a result of the following processes:

1. Metal water reaction involving the Zircaloy fuel cladding and the reactor coolant

2. Radiolytic decomposition of water in the reactor vessel and the suppression pool (oxygen also evolves in this process)

3. Corrosion of metals and paints in the primary containment.

To preclude the possibility of a combustible mixture of hydrogen and oxygen accumulating in the primary containment, the containment atmosphere is inerted with nitrogen gas before power operation of the reactor.

To control the hydrogen and oxygen concentration in the primary, the following features are provided:

1. A containment hydrogen recombiner system

2. A hydrogen/oxygen analyzer system (HOAS)

3. The capability for a controlled venting of the primary containment.

The Containment Atmosphere Control System (CACS) is composed of:

1. Hydrogen/Oxygen Analyzer System (HOAS)

2. Containment Hydrogen Recombiner System (CHRS)

3. Vacuum Relief Valve System (VRVS)

4. Containment Inerting and Purging System (CIPS)

The CACS interfaces with the Reactor Building Ventilation System (RBVS), with the Filtration, Recirculation and Ventilation System (FRVS), and with the Containment Prepurge Cleanup System (CPCS).

6.2.5.1 Design Bases

The CACS is designed to the following criteria:

1. The CACS is designed to remote manually introduce nitrogen gas into the primary containment at a high flow rate, thereby displacing air originally in the containment volume for the purpose of reducing the oxygen concentration in the containment atmosphere to four percent by volume in less than 4 hours prior to power operation.

2. The CACS, operating through remote manual control and in conjunction with the RBVS, is designed to provide a 9000-cfm of filtered outdoor air purge flow to the drywell

and suppression chamber to provide a safe atmosphere for personnel access.

3. The CACS is designed to control the containment pressure within the design specification limits of ~2 psig and to maintain the oxygen concentration below four percent during all normal modes of reactor operation by supplying nitrogen gas to and/or releasing gases from the primary containment in a controlled manner.

4. The CACS, through the remote-manual operation of the CPCS and the RBVS, is designed to remove radioactive contaminants from all primary containment gas prior to its release to the environment.

5. Following an accident, the CACS is designed to continuously monitor and, if necessary, alarm upon high concentration of hydrogen or oxygen in the primary containment (2.0 percent hydrogen or 3.8 percent oxygen by volume). The CACS is also designed to be available to monitor the hydrogen and oxygen content of the primary containment atmosphere during normal operation.

6. The CACS is designed to recombine hydrogen and oxygen after a beyond design basis accident with sufficient capacity to prevent the accumulation of a combustible concentration of gases inside the primary containment.

7. The CACS is designed to permit, through remote manual control, a controlled venting of the primary containment atmosphere at a low flow rate. The FRVS is used in this situation to remove radioactive contaminants from this vented gas prior to its release to the environment.

8. The CACS is designed to automatically isolate all lines that penetrate primary containment to ensure the integrity of the containment boundary during accident conditions. The isolation valves are designed to allow remote-manual reopening by pushbutton override switches protected by guards to prevent any accidental actuation.

9. The CACS is designed to monitor the pressure in the suppression chamber and the temperature in both the drywell and suppression chamber under post-LOCA conditions.

10. During normal plant operation, the CACS is designed to limit the pressure difference between the drywell and the suppression chamber to 2.5 psid and the pressure difference between the suppression chamber and Reactor Building to 3.0 psid.

11. The safety-related portions of the CACS are designed to remain functional after a safe shutdown earthquake (SSE). They are listed in Table 6.2-17.

12. The safety-related portions of the CACS are designed so that a single failure of any active component, assuming loss of offsite power (LOP), cannot result in the loss of safety function.

13. The portions of the CACS that operate under post-LOCA conditions are designed to facilitate periodic inspection and testing of safety-related features during all normal modes of plant operation.

14. The safety-related portions of the CACS are designed to remain operable in the environments existing in their respective areas following a LOCA.

15. The containment atmosphere is sufficiently mixed to prevent high concentrations of combustible gases from forming locally. The process is discussed in Section 6.2.5.2.6.

6.2.5.2 Containment Atmosphere Control System Description

The CACS uses dedicated and interface systems to accomplish a number of functions including inerting the primary containment with nitrogen, purging the primary containment, limiting the differential pressure between drywell and suppression chamber, monitoring hydrogen and oxygen concentrations in the primary containment, and controlling hydrogen and oxygen concentration in the primary containment.

The CACS controls the drywell and suppression chamber atmosphere during all modes of reactor operation (normal reactor operation, reactor shutdown, and post-accident conditions). Portions of the system are safety-related. See Table 6.2-17 for system design and performance data. All safety-related portions of the CACS are environmentally qualified to normal and accident environments according to Section 3.11 requirements.

The CACS is shown schematically on Plant Drawing M-57-1. The system is located within the Reactor Building except for the nitrogen vaporizer, which is located in the Auxiliary Building; the HOAS hydrogen bottles, which are located in the Yard adjacent to the Condensate Storage Tank; and the control cabinets, which are located in the Auxiliary Building.

6.2.5.2.1 Nitrogen Inerting

During normal power operation of the reactor, the oxygen content of the primary containment atmosphere is maintained at a concentration no greater than 4 percent by volume by the Containment Inerting and Purge System (CIPS). This limit is established to preclude the attainment of a combustible gas mixture inside the containment if combustible gases are released into the containment atmosphere following a beyond design basis accident. Oxygen monitoring during normal operation is done by analyzing grab samples taken either through the Leak Detection System (LDS) or the Hydrogen/Oxygen Analyzer System (HOAS). The LDS drywell sample skid is equipped with two connection points upstream of the sample pump (see Plant Drawing M-25-1), to which a portable oxygen monitor can be attached whenever a drywell oxygen sample is required. The HOAS contains a permanently connected oxygen monitor in only the "A" train between the suppression chamber sample suction and return lines of the HOAS panel (see Plant Drawing M-57-1), which can be utilized whenever a suppression chamber oxygen sample is required.

This low oxygen atmosphere is achieved by displacing air in the primary containment with nitrogen gas. The nitrogen is supplied from a liquid nitrogen facility, which consists of two liquid nitrogen storage tanks and one steam-heated water bath vaporizer.

Gaseous nitrogen flow rate from the discharge of the vaporizer is supplied to the drywell and/or the suppression chamber as controlled by the operator. Displaced gases released from the primary containment during nitrogen inerting are processed through the HEPA filters of the RBVS exhaust system and monitored for radioactivity before release to the environment. The RBVS is discussed in Section 9.4.2.

During the inerting operation, nitrogen is supplied to the containment through one RBVS supply purge penetration, and gases are released from the containment through one RBVS exhaust purge penetration. The 6-inch nitrogen supply butterfly valve (HV-4978) has been qualified to close against the dynamic effects associated with a LOCA. During the makeup operation, nitrogen is supplied to the containment through the 1-inch nitrogen makeup lines. The gases are released from the containment to the RBVS exhaust system by opening the inboard 26-inch and/or 24-inch purge exhaust valve and the 2-inch bypass valve around the closed 24- and/or 26-inch outboard purge exhaust valve (reference Plant Drawing M-57-1). Once the four percent by volume oxygen concentration in the primary containment has been achieved, nitrogen flow is terminated and the isolation valve(s) in the purge exhaust lines is/are closed.

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The nitrogen vaporizer receives liquid nitrogen from the off-gas treatment system liquid nitrogen tanks. Sufficient nitrogen is available to inert the primary containment one time (where inerting requires two volume changes) plus an equivalent 1/4 containment volume for makeup purposes that may be required to keep the oxygen concentration below four percent by volume during reactor operation.

The nitrogen vaporizer has the capability to provide sufficient gaseous nitrogen to satisfy the demand of the CIPS during inerting and makeup operation. Process conditions for the vaporizer are tabulated in Table 6.2-17.

The CIPS is capable of reducing the oxygen concentration in the primary containment atmosphere to less than four percent by volume in less than 4 hours. Makeup nitrogen will be supplied through the nitrogen vaporizer at approximately 100 cfm during makeup and 2500 cfm during inerting. Post-accident operation is not required.

The RBVS is capable of purging the primary containment atmosphere prior to or after each reactor shutdown. Prior to purging, the CPCS may be used to filter the containment atmosphere at a rate of 3000 cfm, as required. The CPCS and RBVS are discussed in Section 9.4.2.

Purging is performed during periods of reactor shutdown to maintain a well-ventilated environment for personnel occupancy of the primary containment. Purging also may be performed during the operational modes of startup, power operation, and hot shutdown for the purposes of inerting, prepurge cleanup, and deinerting the primary containment.

Purging during the latter three operational modes will be restricted as follows:

1. Inerting will be performed as specified in the Technical Specifications within 24 hours after reactor thermal power exceeds 15 percent of rated thermal power following startup.

2. Deinerting (i.e., purging) will be initiated no more than 24 hours prior to reducing reactor thermal power to 15 percent of rated thermal power prior to a scheduled reactor shutdown. (A scheduled reactor shutdown includes planned and forced outages.)

3. The CPCS operation may be initiated no more than 4 hours before the start of deinerting, as required.

The number of purge lines in use (i.e., both inboard and outboard valves open) during the operational modes of startup, power operation, and hot shutdown will be limited to one supply (inlet) and one exhaust (vent) line.

The 24- and 26-inch containment vent and purge butterfly valves are closed, except as otherwise allowed by the Technical Specifications, and under administrative control during normal plant operating conditions. During normal operation, power ascension, and descension, the 24- and/or 26-inch inboard vent valves (1-GS-HV-4964 & 4952), in conjunction with 2-inch air operated globe valves (1-GS-HV-4963 & 4951), may be open to vent the containment as required for thermal expansion of the air volume and control of oxygen concentration.

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6.2.5.2.2 Deleted (Combined with Section 6.2.5.2.1)

6.2.5.2.3 Containment Pressure Control Normal Operation

The CIPS controls thermal expansion of the containment atmosphere resulting from normal operating transients through the operation from the main control room of the inboard RBVS purge exhaust isolation valve at the drywell and the 2-inch bypass valve around the outboard isolation valve. Flow is directed to the RBVS exhaust ductwork.

The VRVS limits pressure differentials between the suppression chamber and drywell. Eight 24-inch vacuum relief valves are sized to prevent the drywell pressure from falling 2.5 psid below the suppression chamber pressure. The VRVS vacuum valves are fully open when the drywell pressure falls below that of the suppression chamber by 0.25 psid.

The VRVS also limits the pressure differentials between the Reactor Building and the suppression chamber to less than 3.0 psid through the operation of Reactor Building to suppression chamber vacuum relief valves. The two 24-inch valves are fully open at 0.25 psid and will vent air into the suppression chamber from the Reactor Building.

The VRVS operability can be demonstrated by exercising vacuum relief valves to the open position. Each valve is equipped with redundant valve position indicators that indicate and alarm in the main control room. The sensitivity of the indicators is sufficient to detect an offset greater than 0.01 (~0.005) inch at the valve centerline. The flow through the eight suppression pool to drywell vacuum breakers with each offset at 0.01 inch is equivalent to the flow through a 0.5 inch diameter hole.

The redundant position indicators are visually observed and verified at each refueling outage in accordance with ASME Section XI, Article IWV-330 to confirm that remote valve indications accurately reflect valve operation. The accuracy verification is in accordance with the instructions provided by the valve supplier.

6.2.5.2.4 Containment Hydrogen Recombiner System

The Containment Hydrogen Recombiner System (CHRS) is part of the CACS. The CHRS consists of two redundant hydrogen recombiner packages, each of which has adequate processing capacity to control the quantity of the hydrogen and oxygen postulated to be generated in the primary containment after a beyond design basis accident. The recombiners are thermal recombination type and are described in Reference 6.2-13.

A schematic diagram of one recombiner package is shown on Plant Drawing M-58-1. Each hydrogen recombiner package consists of three modules: the recombiner skid assembly, the power cabinet, and the control cabinet. The recombiner skid assembly, which is shown on Figure 6.2-31, contains the process components. The process components include flow control valves, canned motor/blower assembly, gas heater pipe, reaction chamber, water spray cooler, and water separator and associated instrumentation. The gas heater pipe and the reaction chamber are located within an insulated enclosure that also contains electric heater elements. The recombiner skid assembly is located outside the primary containment in the reactor building.

The power cabinet houses the power distribution components for the recombiner package. The cabinet is located near to its associated recombiner skid assembly and contains the 480 V power supply, control transformer, blower motor starter, circuit breakers, control relays, and the silicon controlled rectifiers (SCRs) that control electrical power to the heater elements.

The control cabinet contains all of the instrumentation, annunciators, lights, and switches necessary for operation of the recombiner package. The control cabinet is located in the control room.

Each recombiner is designed to process a minimum of 60 scfm of drywell gas containing five percent oxygen, or up to 150 scfm of drywell gas containing two percent oxygen, with the balance consisting of hydrogen, nitrogen, fission products, and water vapor. The system will also process 150 scfm of gas containing four percent hydrogen. The recombination process is accomplished by increasing the temperature of the process stream to approximately 1300°F, at which temperature the hydrogen and oxygen combine spontaneously to form water vapor. Virtually complete recombination occurs so that the oxygen concentration in the effluent from the recombiner is negligible when excess hydrogen is present in the process gas. Similarly, the hydrogen concentration in the effluent is negligible when excess oxygen is present in the process gas.

During the recombiner operation, gas from the drywell flows through the drywell purge penetrations to the inlet piping of the recombiner. The effluent from the recombiner flows through the outlet piping to the suppression chamber purge penetrations and into the suppression chamber. By taking suction from the drywell and discharging to the suppression chamber, a differential pressure is created between these two volumes. This differential pressure is limited to 0.25 psid by the primary containment vacuum relief valve assemblies that open to allow gas to flow from the suppression chamber back into the drywell.

The recombiner inlet and outlet lines are each provided with two normally closed automatic valves for containment isolation. These valves can be operated by handswitches in the control room and are automatically closed upon receipt of a containment isolation signal. The isolation signal can be overridden from the main control room to reopen the isolation valves. Containment isolation is discussed further in Section 6.2.4.

Recombined effluent flows from the reaction chamber to the water spray cooler, where the effluent is cooled to less than 250°F. The cooling water at 150°F maximum is supplied to the recombiners from the Residual Heat Removal (RHR) System. Cooled effluent flowing from the cooler is passed through a water separator that prevents any water droplets from entering the gas recirculation line. The separated water drains down to the suppression pool through the recombiner outlet piping. Recirculation (dilution) gas is drawn from the top of the water separator and is routed to the recombiner inlet piping. Recirculation is controlled from the main control room via a motor operated valve in the recirculation line. The amount of gas recirculated increases as the amount of excess hydrogen in the process gas exceeds four percent.

Operation of the hydrogen recombiner is initiated manually from the control cabinet. When process gas flow and cooling water has been established, the heater elements are energized automatically. Approximately 2 hours are required for the system to reach operating temperature. When the temperature at the gas heater pipe outlet reaches 1300°F, power to the heater elements is automatically turned off. When the temperature at the gas heater pipe outlet falls below 1300°F, an interlock is cleared and power is controlled to the heater elements at a lower level than during startup. Temperatures in the gas heater pipe stay below those required for recombination so that recombination occurs in the reaction chamber. A temperature indicator controller located in the control cabinet is used to maintain reaction chamber temperature at about 1300°F.

The CHRS is designed to be operable for 40 years including up to six full power tests per year and 180 days of post-accident operation.

Additional CHRS design and performance data is contained in Table 6.2-17. The CHRS environmental qualification plan is found in Reference 6.2-12. The CHRS meets the environmental qualification requirements described in Section 3.11 for conditions described in Sections 3.10 and 3.11.

6.2.5.2.5 Combustible Gas Analyzer

The HOAS is part of the Containment Atmosphere Control System, which is shown schematically on Plant Drawing M-57-1. The HOAS consists of two identical redundant analyzer packages, each of which contains a hydrogen analyzer cell and an oxygen analyzer cell. Each package takes samples from two different elevations in the drywell and from one point in the suppression chamber. Processed samples are returned to the suppression chamber.

PSEG has verified that the Hydrogen Monitoring System is capable of diagnosing the course of significant beyond design-basis accidents and has committed to maintain this capability. The Hydrogen Monitoring System is functional, reliable, and capable of measuring the concentration of hydrogen in the containment atmosphere following a significant beyond design-basis accident for accident management, including emergency planning. The Hydrogen Monitoring System is classified as Category 3, as defined in Regulatory Guide 1.97.

PSEG has verified that the Oxygen Monitoring System is capable of verifying the status of the inerted containment atmosphere and has committed to maintain this capability. The Oxygen Monitoring System is functional, reliable, and capable of measuring the concentration of oxygen in the containment atmosphere following a significant beyond design-basis accident for combustible gas control and accident management, including emergency planning. The Oxygen Monitoring System is classified as Category 2, as defined in Regulatory Guide 1.97.

Each analyzer package consists of a sample cabinet located in the Reactor Building, a remote oxygen indicator located also in the Reactor Building, and a remote control panel located in the control room. Sample points in the primary containment are located as follows:

HOAS Sample Locations

	Penetration	Elevation, ft	Azimuth	Radial Distance from Centerline of RPV, ft
System A				
Sample point A	J-9E	153'-0"	291°	28'-11"
Sample point B	J-10C	153'-0"	36°	27'-5"
Sample point C	J-212	87'-8"	191°	56'-4"
System B				
Sample point A	J-3B	153'-0"	169°	30'-6"
Sample point B	J-7D	153'-0"	157°	29'-1"
Sample point C	J-210	83'-7"	87°	66'-9"

Each sample suction and return line is provided with two, normally closed, motor-operated valves for containment isolation. These valves are operated by manual switches in the main control room and are automatically closed upon receipt of a containment isolation signal. The isolation signal to the valves can be overridden manually from the main control room. Containment isolation is discussed further in Section 6.2.4. Following an accident, one HOAS channel is manually initiated and operates continuously for the duration of the accident.

Each analyzer package can only sample one sample point at one time. The selection of a specific sample point is determined by the operator. Gases from the selected sample point are routed in parallel through a hydrogen analyzer cell and oxygen analyzer cell located in the analyzer panel inside the reactor building or, in the case of a sample from the suppression chamber, can be routed through the suppression chamber supplementary oxygen monitor bypassing the HOAS panel. This provision permits periodic measurement of suppression chamber compartment oxygen concentration during normal operation (see Section 6.2.5.2.1).

In Amendment 160 to the Hope Creek Facility Operating License, the station committed to maintaining at least one hydrogen/oxygen concentration analyzer channel and monitor operable during Operational Conditions 1, 2, and 3. With no hydrogen/oxygen analyzer channels operable, at least one channel should be restored to an operable status within 72 hours or an alternate method of monitoring the parameter should be established.

The hydrogen/oxygen concentration analyzer channels are demonstrated operable by the performance of a channel check at least once per month and by performance of a channel calibration at least once per quarter. The channel calibration is performed using a sample gas containing 5 volume % oxygen (balance nitrogen) for the oxygen analyzer and by use of a 5 volume % hydrogen (balance nitrogen) sample gas for the hydrogen monitor.

The operation of the hydrogen and oxygen analyzer cells is based on the measurement of thermal conductivity of the gas sample. The thermal conductivity of the gas mixture changes proportionally to

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the changes in the concentration of the individual gas constituents of the mixture. The thermal conductivity of hydrogen is far greater (approximately seven times the thermal conductivity of air) than any other gas expected to be present in the primary containment. The hydrogen analyzer cell incorporates a catalytic combustion feature in which hydrogen in the sample is removed by catalytic recombination with a reagent gas (oxygen). The thermal conductivity of the sample is measured before and after recombination, and the two measurements are compared. The difference in thermal conductivity is proportional to the concentration of hydrogen originally in the sample. The oxygen analyzer operates simultaneously in a similar manner, except that the reagent gas is hydrogen.

The hydrogen analyzer has dual range capability of 0 to 10 percent by volume and 0 to 30 percent by volume. The oxygen analyzer has dual range capability of 0 to 10 percent by volume and 0 to 25 percent by volume. The hydrogen and oxygen concentrations in the sample gas are indicated at the analyzer panel in the reactor building and at the remote control panel in the main control room. The concentrations are also recorded in the main control room. An additional oxygen indication is provided at the entrance to the drywell service hatch.

Sample gases are drawn through the analyzer cells by the diaphragm pump located in the analyzer panel. Sample gases and any excess moisture, either from the sample or created by the catalytic recombination, are routed back to the suppression chamber.

HOAS design and performance data is included in Table 6.2-17. The HOAS environmental qualification program is found in Reference 6.2-23. The HOAS meets the environmental qualification requirements described in Section 3.11 for conditions described in Sections 3.10 and 3.11.

6.2.5.2.6 Containment Atmosphere Mixing

The potential for hydrogen or oxygen concentration gradients within a single containment compartment is dependent upon the source of hydrogen or oxygen, the temperature of steam, and air flow conditions within the compartment.

In most cases with a hydrogen source, both hydrogen and steam will be entering a compartment at a high temperature and a high velocity compared to the pre-existing conditions in the room. The initial turbulence will cause a significant amount of mixing within the first few seconds after the hydrogen enters. Steam expansion likewise will create large initial mixing flows. NUREG/CR 2540 indicates that the hydrogen/steam mixtures will be at 500 to 2500°F, which will be well in excess of the 120 to 340°F expected in the containment air spaces.

For long term steady state conditions, e.g., hydrogen or oxygen evolving from radiolysis of water on the containment floor or hydrogen entering a compartment through a large vent opening, it is expected that convective mixing currents will be the major driving force to mix the hydrogen. For a discussion of this phenomenon, refer to NUREG/CR-1575.

The computer modeling discussed in NUREG/CR-1575 indicates that for the situation with an air temperature 2.8°K above the wall temperature, the maximum hydrogen concentration gradient observed was 0.14 percent. This modeling considered molecular diffusion, Eddy diffusion, and convective flows along the walls, all for an extremely simple model with only one major temperature gradient of 2.8°K. For a real situation with pumps and pipes at temperatures up to several hundred degrees hotter than the walls and the containment air, and with the complex geometries of heat sources, it is believed that highly complex and much more rapid air flow patterns would be established resulting in complete hydrogen mixing within the containment compartment.

These local mixing flows would be enhanced by the major convective heating flow that occurs in the containment in order to transport the heat from the vessel to the Containment Heat Removal System.

Within the Hope Creek containment, hydrogen or oxygen could accumulate in either the drywell or wetwell volumes. These volumes are connected by the downcomers, the vacuum breakers, and the recombiner supply and exhaust piping, thus allowing mixing between the volumes. Within the drywell, mixing and turbulence would be caused by the blowdown from the pipe break, the drywell sprays if they are manually initiated, and the large convective mixing air flows caused by the high temperatures of the reactor vessel and piping. There are no large volumes where pocketing is probable and where convective mixing would not mix the gases during the long times required for the accumulation of burnable mixtures. Within the wetwell, water turbulence and discharges would also enhance the air mixing due to the temperature differentials. Figures in Section 1.2 show the locations of the various floors and volumes of the primary containment where the combustible gases could be circulating post-LOCA.

6.2.5.2.7 Controlled Venting of Primary Containment

The capability to vent the primary containment in order to control oxygen and hydrogen concentration is provided. This controlled venting is non-safety-related except for portions that constitute part of the primary containment boundary. For compliance to Regulatory Guide 1.7, see Section 1.8.1.7.

Controlled venting of Primary Containment, if used, would be accomplished by use of a modified mode of the CACS.

Controlled venting of the containment would be through two 2-inch flow control valves as described in 6.2.5.2.3. Gases exhausted from the containment during controlled venting would be processed through the FRVS recirculation filters in order to remove radioactive particulate and Halogen contaminants prior to release to the environment. This system is discussed in Section 6.8.

6.2.5.3 Section deleted

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6.2.5.4 Tests and Inspections

The CACS is preoperationally tested in accordance with the requirements of Section 14 and periodically tested in accordance with the requirements of Section 16. Inservice inspection of the safety-related systems will be in accordance with the ASME B&PV Code, Section XI, for Section III, Class 2 components. See Section 6.2.6 for additional testing requirements.

6.2.5.5 Instrumentation Requirements

The instrumentation requirements for the CACS are discussed in Section 7.3.1.

6.2.5.6 Safety Evaluation

The CHRS, the VRVS and the HOAS, including supporting structures, are designed to Seismic Category I requirements as defined in Section 3.7, with the exception of the HOAS H2/O2 bottle racks, which are designed to Seismic Category III requirements. Except for tubing internal to the sample cabinets of the HOAS and the bottle station supply lines to the HOAS, piping and tubing associated with both systems are designed, fabricated, inspected, and tested in accordance with the requirements of the ASME B&PV Code, Section III, Class 2. The tubing internal to the sample cabinet and the bottle station supply lines conform to the requirements of ANSI B31.1.0. All portions of these systems, with the exception of the HOAS bottle stations, are located within the Reactor Building and Auxiliary Building, which are designed to Seismic Category I requirements as discussed in Section 3.8.4. The bottle stations are located in the Yard area, adjacent to the Condensate Storage Tank. Evaluation of the these systems with respect to the following areas is discussed in FSAR sections as indicated:

1. Protection from wind and tornado effects - Section 3.3

2. Flood design - Section 3.4

3. Missile protection - Section 3.5

4. Protection against dynamic effects associated with the postulated rupture of piping - Section 3.6

5. Environmental design - Section 3.11.

The CHRS and the HOAS both consist of two separate packages that are fully redundant and independent with the exception of the HOAS hydrogen and oxygen supply bottles. One set of hydrogen and oxygen bottles supply both HOAS packages. The redundant packages are powered from different divisions of Class 1E power. A single failure in either system would only render the affected package unavailable, with the redundant package fully capable of performing the required function at full capacity. Failure modes and effects analyses for the CHRS and the HOAS are provided in Tables 6.2-18 and 6.2-19, respectively.

The CACS lines penetrating the primary containment are provided with redundant isolation valves powered from different divisions of Class 1E power.

Loss of power to any individual valve or to all valves powered from the same division does not disable the containment isolation function. In the event of a failure of any single valve to close when required, the redundant valve on the same line provides the isolation function. The bypass of an isolation signal to any valve is annunciated in the control room. In the event of a failure of any single isolation valve to reopen when required, the redundant system will be used.

6.2.5.7 SRP Rule Review

Acceptance Criterion II.4 of Standard Review Plan 6.2.5 requires that the repressurization of the containment following a LOCA be limited to less than 50 percent of the containment design pressure. At HCGS, pressure increases originally due to MSIV seal system inleakage following a LOCA were eliminated by the deletion of the MSIV Sealing System.

6.2.6 Primary Reactor Containment Leakage Rate Testing

The proposed primary reactor containment leakage test program involves the following three tests:

1. Type A tests - Tests intended to measure the Primary Reactor Containment System overall integrated leakage rate, both after erection of the primary reactor

containment system has been completed and the system has been made ready for operation and at subsequent periodic intervals.

2. Type B tests - Tests intended to detect local leaks and to measure leakage across pressure containing or leakage-limiting boundaries other than valves.

3. Type C tests - Tests intended to measure primary reactor containment system isolation valve leakage rates.

The proposed testing program conforms to 10CFR50, Appendix J, Option B, "Primary Reactor Containment Leakage Testing for Water Cooled Power Reactors," and Appendix A, General Design Criteria (GDC) 52, "Capability for Containment Leakage Rate Testing," GDC 53 "Provisions for Containment Testing and Inspection," and GDC 54, Piping Systems Penetrating Containment.

6.2.6.1 Primary Containment Integrated Leakage Rate Test

The Type A test is performed to determine the total atmospheric (air) leakage from the containment. The leakage rate must not exceed the maximum allowable, L_a, at the calculated peak containment internal pressure, P_a.

Definitions of terms and pertinent test information are shown in Table 6.2-22. The Type A test piping and instrumentation are shown on Plant Drawing M-60-1. The Type A acceptance criteria are given in the Primary Containment Leakage Rate Testing Program as referenced in HCGS Technical Specifications in Section 16.

The absolute method of leakage determination is used for all Type A tests. This method of leakage rate determination is based on the measurement of temperature and pressure of the primary reactor containment atmosphere with corrections for changes in water vapor pressure. The absolute method assumes that the temperature and pressure variations during the test are insufficient to effect significant changes in the internal free air volume of the structure.

The mass point and total time analysis techniques are used for data analysis. Data from an absolute system are reduced to a contained air mass by application of the ideal gas law. This test data is a time-series of independent values of containment air mass. This test data can then be easily analyzed by the method of linear least squares. The method of least squares is a statistical procedure for finding the "best fitting" straight line, commonly called the regression line, to fit within the test data. The slope of the regression line is the leak rate.

The duration of the test period must be sufficient to enable adequate data to be accumulated and statistically analyzed so that a leakage rate and upper confidence limit (UCL) can be accurately determined. The calculated leakage rate and UCL are reported.

Upon construction completion of the primary containment, the structure must pass a structural integrity test (SIT), which demonstrates the capability of the primary containment to withstand specified internal pressure loads.

The preoperational Type A test is performed to verify that the actual primary containment leakage rate does not exceed the design limit. The requirements for this test are outlined in the HCGS Technical Specifications, Section 16. After completion of the preoperational test, subsequent Type A tests are done at intervals outlined in the Primary Containment Leakage Rate Testing Program as referenced in HCGS Technical Specifications in Section 16.

A general visual inspection is performed in accordance with the Primary Containment Leakage Rate Testing Program as referenced in HCGS Technical Specifications in Section 16. This involves inspection of accessible interior and exterior surfaces of the primary containment and components to uncover any evidence of structural deterioration that may affect either the structural integrity or leaktightness. If there is evidence of structural deterioration, an engineering evaluation is performed prior to a Type A test and corrective action may be required prior to performance of the test. Repairs or adjustments are made to components between the times of completion of one Type A test and the start of the containment inspection for the subsequent Type A test. If repairs and/or adjustments were performed on containment components during the outage prior to the completion of the Type A test, the change in local leak rate for these components must be used to determine the as found integrated leak rate. This is done by conducting local leakage rate tests on the affected components to determine the minimum pathway leakage before and after the repairs/adjustments. The difference in minimum pathway leakage is then added to the Type A test result to obtain the required As Found result. The minimum pathway leakage would be the smaller leakage rate for in-series valves tested individually, one-half the leakage rate for in-series valves tested in parallel. This differential of the leakage is the correction factor added to the as left integrated leak rate to determine the as found integrated leak rate.

The Type A test includes an assessment of the leaktightness of the test valves used for performing the Type C tests, as described in Section 6.2.6.3.

Before the start of a Type A test, the following set of requirements must be met:

1. Primary containment isolation valve closure - The primary containment isolation valves must be closed, by normal operation, for the Type A test. Tightening of remotely operated valves after closure or other adjustments is not allowed. Exercising valves to improve leakage performance is not permitted. In the event that a valve cannot be closed by normal methods, the method used is documented.

2. Periodic tests - A primary containment isolation system functional test, Type B, and Type C tests should be completed prior to the Type A test.

3. Preoperational tests - The preoperational Type A test follows the preoperational structural integrity test. A primary containment isolation system functional test, Type B, and Type C leakage tests should be completed before the preoperational Type A test.

4. System venting and draining - This procedure applies to the following systems:

a. Systems listed in Table 6.2-23 that are needed to properly conduct the test or to maintain the plant in a safe condition during the test must be operable in their normal mode. These systems do not need to be vented or drained.

b. Systems that are normally filled with water and operable under post-accident conditions do not need to be vented or drained.

c. Fluid systems that are part of the primary containment boundary and that may open directly to the primary containment or outside atmosphere under post-accident conditions must be opened or vented to the appropriate atmosphere during the test.

d. Those lines that are normally filled with a liquid and may be drained or have the fluid drawn off by the accident must be drained to the extent necessary to expose the primary containment isolation valve seats to the primary containment atmosphere. These lines include portions of closed systems inside the containment penetrating the primary containment, which could rupture due to a loss-of-coolant accident (LOCA).

e. Systems not vented or drained during the Type A test that could become exposed to the primary containment atmosphere during the design basis accident (DBA) must have been Type B or C tested within the last twenty-four (24) calendar months prior to the Type A test and the Type B and/or C results used to apply a correction to the Type A test results.

f. For planning or scheduling purposes, or ALARA considerations, system pathways that have been local leakage rate tested within the previous twenty-four (24) calendar months need not be drained or vented for the Type A test.

5. Liquid level monitoring - Liquid levels in the primary containment may vary. Therefore, changes in the primary containment free volume must be monitored. If the level change results in free volume changes during the test, it must be included in the final leakage rate.

6. Pressuring considerations - Pressurized components, e.g., tanks must be removed or depressurized and vented. Alternatively, the tank pressures measured prior to and after the Type A test can be compared to demonstrate that there is no leakage into the primary containment.

   Sources of instrument air or service air into the primary containment must be isolated and vented, or disconnected, during the Type A test. Components not designed to withstand the test pressure should be removed or otherwise protected.

7. Containment atmosphere stabilization - The primary containment atmosphere must be allowed to stabilize for at least 4 hours after the test pressure is reached before the Type A test can begin. Temperature stabilization is essential for controlling the pressure in the primary containment. Stabilization is achieved when the requirements of ANSI/ANS 56.8-1994 and/or BN-TOP-1 are met. The primary containment ventilation and cooling water systems may be run at this time to expedite air mixing.

After the primary containment atmosphere has stabilized, the Type A test may begin. The duration of the Type A test must be sufficient to enable adequate data to be accumulated and statistically analyzed so that the leakage rate and UCL can be determined. Test criteria, test duration and total number of data points will meet the requirements of ANSI/ANS 56.8-1994 and/or BN-TOP-1.

Depending on the sensitivity of the instrumentation, the stability of the primary containment, and the uncertainty associated with the calculated leakage rate, the duration of a Type A test may have to be extended beyond the required minimum time duration to reasonably ensure acceptability. If the leakage rate exceeds the acceptance criterion, corrective action is required. If, during the performance of a Type A test, excessive leakage occurs through locally testable penetrations or isolation valves to the extent that it would interfere with the satisfactory completion of the test, the leakage paths should be isolated and the Type A test continued. A local leakage test must be performed before and after the repair of each isolated leakage path.

A verification test must also be performed following each Type A test. This test ensures that systematic error or bias is given adequate consideration. It is accomplished by imposing a known leak on the containment. Verification test acceptance criteria are given in the HCGS Technical Specifications in Section 16.

If any Type A test fails to meet the acceptance criteria, the adjusted test schedule for subsequent Type A tests is described in the Primary Containment Leakage Rate Testing Program as referenced in HCGS Technical Specification in Section 16.

Systems or portions of systems outside containment which operate at a pressure less than P_a will be examined for leakage during the CILRT, as required by Section 1.10 Paragraph III.D.1.1.

6.2.6.2 Primary Containment Penetration Leakage Rate Test

Type B tests are used to detect local leaks and to measure leakage across pressure containing or leakage limiting boundaries other than valves. Type B tests apply to the following:

1. Penetrations whose design incorporates resilient seals, gaskets, sealant compounds, expansion bellows, or flexible seal assemblies.

2. Seals, including door operating mechanism penetrations that are part of the primary containment system.

3. Doors and hatches with resilient seals or gaskets, except for seal-welded doors.

All containment penetrations subject to Type B testing are listed in Table 6.2-30.

The Type B preoperational and periodic leakage rate tests are conducted in accordance with 10CFR50, Appendix J, Option B. All Type B tests are conducted at a pressure not less than pressure P_a, as defined in Table 6.2-22.

Penetrations are provided in the air lock to permit pressure testing of the door seals and the entire lock. The pressure testing penetrations have threaded caps.

The locations of all mechanical and electrical penetrations in the air lock are shown on Figure 6.2-42. Details of the door seals and the pressure test connections are shown on Figure 6.2-43.

The personnel access air lock volume is charged with air to containment peak accident pressure while undergoing periodic leak testing. The test schedule for the air lock is outlined in the Primary Containment Leakage Rate Testing Program as referenced in HCGS Technical Specifications in Section 16. The air lock containment bulkhead door is not designed to have a pressure differential greater than 3 psid in the reverse direction, air lock volume to primary containment volume. Therefore, 12 clamps are provided for holding the primary containment bulkhead door against internal pressure, P , during leak tests. The clamps shown on Figure 6.2-44 are installed for the duration of the internal pressure tests. The clamps are installed on the primary air lock side of the containment bulkhead door. The force exerted by the clamps during air lock leak testing is not monitored.

The air lock mechanical and electrical penetrations are also leak tested by charging the air lock volume to containment peak accident pressure, P_a.

The air lock bulkhead doors have testable seals; the seal test pressure is governed by the Primary Containment Leakage Rate Testing Program as referenced in HCGS Technical Specifications in Section 16. The seal test cannot be substituted for the periodic air lock leakage test at pressure, P_a.

6.2.6.3 Primary Containment Isolation Valve Leakage Rate Tests

Type C tests are intended to measure primary reactor containment system isolation valve leakage rates. Type-C test valves are primary containment isolation valves, including those valves that are closed, that close automatically upon receipt of an isolation signal in response to controls intended to effect primary containment isolation, or that operate under post-accident conditions to effect primary containment isolation. Type C tests are not required for those valves described above which do not present a potential primary containment atmospheric pathway during and following a design basis accident.

The valves that are Type-C-tested are listed in Table 6.2-24.

The Type B and C tests are performed by locally pressurizing components. The Type C test for a containment isolation valve is performed with the leakage through the valve in the same direction as leakage in a design basis LOCA. Valves may be tested in the "reverse" direction if the "reverse" direction test is shown to be conservative or equivalent to the test in the LOCA direction. For more information, see Table 6.2-24.

All valves that are exposed to the primary containment atmosphere after a DBA are tested with air or nitrogen at primary containment peak accident pressure, P_a, as defined in Table 6.2-22.

Valves in lines designed to remain filled with a liquid inside the containment boundary for a minimum of 30 days after a DBA, but have credible leakage pathways outside of the containment boundary, are leakage rate tested with the same liquid at a minimum pressure of 1.1 P_a.

Liquid leakage is not converted to equivalent air leakage, or added to the Type C testing total, but is reported separately as "liquid leakage" and included in the Technical Specifications. All the valves tested with liquid are identified in Table 6.2-24.

Containment isolation of the feedwater lines represents a unique situation which requires a combination of air and water testing and therefore merits further discussion. During the short term feedwater system line up, isolation of the feedwater lines is provided by valves AE-V002, AE-V003, AE-V006 and AE-V007 and the water seal upstream of the third feedwater heaters (see Section 6.2.3.2.3). Hence, a Type C air test will be performed on these valves with their leakage appropriately included in the 0.60 La criteria. During the long term feedwater system line up, isolation of the feedwater lines is provided by a water seal on the third feedwater check valves, AE-V001, and AE-V005. Identification of these valves as containment isolation valves requires a similar classification for the first valve in each branch line between the second and third feedwater check valves, BD-V005, BJ-V059, and AE-V021. Since the leakage past these valves will be into the RCIC, HPCI and RWCU systems, respectively, which are seismically qualified, water filled, closed systems outside containment, there is no requirement to identify their specific leakage in the Technical Specifications. However, leakage through the valves which form the long term seal boundary of the feedwater lines (i.e., AE-V001, AE-V005, AE-V021, BD-V005 and BJ-V059) will be determined by a Type C water test and will be limited to 10 gpm as specified in the Technical Specifications. Since these valves are sealed with water, the leakage determined from their Type C test need not be included in performance criteria per 10CFR50 Appendix J, Option B, paragraph III.B.

Within Tables 6.2.16 and 6.2.24 are penetrations where leak rate testing is not applicable for certain containment isolation valves which are located in lines that penetrate the primary containment and terminate below the minimum water level in the suppression chamber (i.e., torus). The torus is designed and operated so that the supply of water is assured during all design bases and post accident modes of operation keeping the isolation valves "sealed" by water for a minimum of 30 days. Also, the piping outside containment meets the requirements of a closed system identified in FSAR 6.2.4.1.2. Based on the above information, leak rate testing of CIV's is not necessary to insure that post accident radiological release from the containment is minimized. The CIVs will be tested in accordance with the applicable requirements of ASME Section XI, Article IWV-3000.

Figure 6.2-28, sheets 1 through 48, show the test valves that exist for the purpose of conducting the Appendix J Type C test. The test connections are not branch lines and they cannot be tested for leakage during the Appendix J Type C test as they are open during the Appendix J Type C test of the containment isolation valve.

The test valves are one inch manual valves and are under administrative control to ensure that they are closed. Their leaktightness is assessed as part of the leaktightness of the containment boundary during the integrated leak rate test (10CFR50 Appendix J, Option B, Type A test).

The Total Allowable Leakage acceptance criteria for penetrations and isolation valves subject to Type B and C tests are given in the Primary Containment Leakage Rate Testing Program as referenced by HCGS Technical Specifications in Section 16.

6.2.6.4 Scheduling and Reporting of Periodic Tests

The periodic leakage rate test schedules for Type A, B, and C testing are given in the Primary Containment Leakage Rate Testing Program as referenced by HCGS Technical Specifications in Section 16.

Type B and C tests are performed prior to initial criticality and periodically thereafter, during shutdown periods or normal plant operations.

The preoperational Type A test follows the preoperational ASME Section III pressure test. A primary containment isolation system functional test and Type B and C leakage tests are completed prior to the preoperational Type A test.

The procedure for reporting test results is given in the Primary Containment Leakage Rate Testing Program as referenced by HCGS Technical Specifications in Section 16.

6.2.6.5 Special Testing Requirements

6.2.6.5.1 Drywell to Pressure Suppression Chamber Atmosphere Bypass Area Test

A drywell to pressure suppression chamber atmosphere bypass area test is conducted periodically to determine the overall bypass area that would allow the drywell atmosphere to flow directly to the pressure suppression chamber atmosphere, after a LOCA, without passing through the pressure suppression pool water. The test is conducted at intervals determined by the HCGS Technical Specifications.

The leakage rate test is performed by pressurizing the drywell below a pressure that forces drywell air through the downcomer vent pipes to the suppression pool water and the suppression chamber atmosphere.

The drywell to pressure suppression chamber atmosphere bypass leakage rate test is performed with the drywell isolated from the pressure suppression chamber.

The test volume atmosphere is allowed to stabilize for 1 hour after attaining test pressure. The leakage rate tests commence after this stabilization period.

The test method is based on atmospheric pressures, temperatures, and the free air volumes. The leakage rate is calculated from the pressure and temperature data, taking elapsed time into account.

The drywell to pressure suppression chamber atmosphere bypass leakage rate test pressures, duration, periodic test interval, and acceptance criteria are specified in Section 16.

6.2.6.5.2 Reactor Building Bypass Leakage

The Reactor Building bypass leakage is discussed in Section 6.2.3.2.3.

6.2.7 Fracture Prevention of Containment Pressure Boundary

6.2.7.1 Containment Vessel and Pressure Boundary Component Materials

The ferritic materials of the containment vessel were purchased and impact tested prior to issue of the Summer 1977 addenda to ASME B&PV

Code, Section III. These materials have been found acceptable within the context of GDC 51 based on the following.

Materials for the pressure boundary components of the containment vessel, drywell head, penetrations, equipment hatch including personnel lock and control rod drive removal hatch are impact quality materials conforming to ASME B&PV Code, Section III, Subsection NE. All nonexempt materials and components were impact tested satisfactorily in accordance with the requirements of ASME B&PV Code Section III, 1974 edition, Winter 1974 addenda. The ASME B&PV Code requirements of 1974 Winter addenda and 1977 Summer addenda applicable to the fracture toughness review are the same except that spray nozzles, backing rings, and backing bars were added to the list of exempted materials in the 1977 Summer addenda. Records for all nonexempt materials of the containment vessel, drywell head, penetrations, equipment hatch including personnel lock and CRD removal hatch are available for inspection.

6.2.7.2 Piping, Pump, and Valve Materials

The ferritic materials of all piping, pumps, and valves attached to the containment vessel that are part of the containment pressure boundary were purchased and installed in accordance with the ASME B&PV Code Section III, Winter 1974 edition. Installation of welded attachment to Class 2 and 3 piping, after hydrostatic testing is in accordance with ASME Section III, 1980 Edition through 1981 Winter Addenda, Paragraphs NC/ND-4436. The NRC staff has performed an assessment of the fracture toughness of these materials based on the metallurgical characterization and fracture toughness data presented in NUREG-0577, "Potential for Low Fracture Toughness and Lamellar Tearing on PWR Steam Generator and Reactor Coolant Pump Supports"; and the ASME Code, Section III, Summer 1977 Addenda, Subsection NC. This review has indicated that all ferritic components of the HCGS containment pressure boundary, except feedwater check valves 1F074 A and B, have sufficient fracture toughness to meet GDC 51.

Based on a letter dated March 12, 1985 (R. L. Mittl, PSE&G, to A. Schwencer, NRC), these valves will undergo inspection of the entire valve bodies, both internal and external, as part of the inservice inspection (ISI) program, implemented at the first refueling outage. A more detailed program is described in the ISI program submitted 6 months after the start of commercial operation.

6.2.8 References

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6.2-5 I.E. Idel'chik, "Handbook of Hydraulic Resistance...", AEC-TR-6630, 1966, pp 2, 105, 416.

6.2-6 Crane Co, "Flow of Fluids," Crane Technical Paper 410, Chicago, 1969.

6.2-7 F.J. Moody, "Maximum Two-Phase Vessel Blowdown from Pipes," Topical Report APED-4827, General Electric, 1965.

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TABLE 6.2-1

CONTAINMENT DESIGN PARAMETERS

	Drywell	Suppression Chamber
Drywell and Suppression Chamber		
Internal design pressure, psig	62	62
External to internal design differential pressure, psid	3	3
Design temperature, °F	340	310
Drywell net free volume, ft^3	169,000(1)	-
Design leak rate, percent by weight/day	0.5(2)	0.5(2)
Maximum allowable leak rate, percent by weight/day	0.5(5)	0.5(5)
Suppression chamber free volume, ft^3		
Maximum (at low water level)	-	137,000
Minimum (at high water level)	-	133,500
Suppression pool water volume, ft^3		
Maximum (at high water level)	-	122,000(3)
Minimum (at low water level)	-	118,000(3)
Technical Specifications Minimum During Cold Shutdown Conditions	-	57,232
Suppression pool surface area, ft^2		
Maximum (at high water level)	-	10,710(4)
Minimum (at low water level)	-	10,680(4)

	Drywell	Suppression Chamber
Suppression pool depth, ft		
Maximum	-	14.37
Minimum	-	14.04
Vent System		
Number of vents	-	8
Vent inside diameter, ft	-	6.17
Net free discharge path area, ft^2 (area used for the pressure loss factor)	-	235.9
Number of downcomers	-	80
Downcomer inside diameter, ft	-	1.9375
Downcomer submergence, ft		
Maximum (at high water level)	-	3.33
Minimum (at low water level)	-	3.00
Pressure loss factor	-	5.51

(1) Includes free volume of vent system.

(2) At 62 psig test pressure.

(3) Does not include reduction for submerged structures; internal structure volumes assumed negligible.

(4) Area exposed to suppression chamber free space.

(5) At 50.6 psig peak design basis accident (DBA) pressure.

TABLE 6.2-2

ENGINEERED SAFETY FEATURE SYSTEMS INFORMATION FOR CONTAINMENT RESPONSE ANALYSES

	Full Capacity	Containment Analysis Value Case A	Case B	Case C
Drywell Spray				
Number of RHR pumps	2	2	1	0
Number of lines	2	2	1	0
Number of headers	2	2	1	0
Spray flow rate, gpm/pump	9500	9500	9500	0
Spray thermal efficiency, percent	100	100	100	-
Suppression Chamber Spray				
Number of RHR pumps	2	2	1	0
Number of lines	2	2	1	0
Number of headers	1	1	1	0
Spray flow rate, gpm/pump	500	500	500	0
Spray thermal efficiency, percent	100	100	100	-

TABLE 6.2-2 (Cont)

	Full Capacity	Containment Analysis Value Case A	Case B	Case C
Containment Cooling System				
Number of RHR pumps	2	2	1	1
Pump capacity, gpm/pump	10,000	10,000	10,000	10,000
RHR heat exchangers				
Type - Inverted U-tube, single-pass shell, multi-pass tubes, vertical mounting	-	-	-	-
Number	2	2	1	1
Heat transfer area, ft^2/unit	3740	-	-	-
Overall heat transfer coefficient, Btu/h - ft^2 - °F/unit	375	-	-	-
SACS water flow rate, gpm/unit	9000	8640	8640	8640
SACS water temperature, °F	-	100	100	100
Minimum design	32	-	-	-
Maximum design	100	-	-	-

	Full Capacity	Containment Analysis Value Case A	Case B	Case C
Containment heat removal capability per unit, using 95°F SACS water and 120°F pool temperature, Btu/h	$26x10^6$	-	-	-

TABLE 6.2-3

INITIAL CONDITIONS FOR CONTAINMENT RESPONSE ANALYSES

Reactor Coolant System[(1)]

Reactor power level, MWt	4031[(1)]
Average coolant pressure, psia	1020
Average coolant temperature, °F	547.0
Mass of Reactor Coolant System liquid, lbm	633,100
Mass of Reactor Coolant System steam, lbm	24,730
Volume of liquid in vessel, ft^3	11,716
Volume of steam in vessel, ft^3	9089
Volume of liquid in recirculation loops, ft^3	1214
Volume of steam in steam lines, ft^3	1699
Volume of liquid in feedwater lines, ft^3	12,410
Volume of liquid in miscellaneous lines, ft^3	1,860

TABLE 6.2-3 (Cont)

	Drywell	Suppression Chamber
Containment		
Pressure, psig	1.5	1.5
Atmosphere temperature, °F	135	95
Relative humidity, percent	20	100
Suppression pool water temperature, °F	-	95
Suppression pool water volume, ft^3	-	118,000
Downcomer submergence, ft		
Short term analysis		3.33
Long term analysis		3.00

(1) At 102 percent of up-rated thermal power (4031 MWt) and normal liquid levels. Note that 4031 is based on 102% of an assumed rated thermal power of 3952 MWt, which is conservative when compared with the licensed thermal power of 3840 MWt.

TABLE 6.2-4

ACCIDENT ASSUMPTIONS AND INITIAL CONDITIONS FOR CONTAINMENT RESPONSE ANALYSES

Components of Effective Blowdown Area (Recirculation Line Break), ft^2	
Recirculation line	3.452
Cleanup line	0.0884
Jet pumps	0.5481
Reactor Coolant System Energy Distribution[(1)], 10^6 Btu	
Steam energy	29.14
Liquid energy	366.5
Sensible energy	
Reactor vessel	94.42
Reactor internals (less core)	43.75
System piping	38.30
Fuel[(2)]	10.036
Other Assumptions Used in Analyses	
MSIV closure time, s	
Recirculation line break (includes 0.5 s delay)	3.5
Main steam line break (includes 0.5 s delay)	5.5
Scram time, s	0

(1) All energy values except fuel are based on a 32°F datum.

(2) Fuel energy is based on a datum of 285°F.

TABLE 6.2-5

SUMMARY OF SHORT TERM CONTAINMENT RESPONSES TO RECIRCULATION LINE AND MAIN STEAM LINE BREAKS

	Recirculation Line Break	Main Steam Line Break	Recirculation Line Break
102% of Rated Power*, MWt	3,359*	3,359*	4,031*
Peak drywell pressure, psig	48.1	31.8	50.6
Time of peak drywell pressure, s	4.42	1 7.3	9.83
Peak drywell temperature, °F	291	308	298
Peak suppression chamber pressure, psig	27.5	27.3	25.9
Time of peak suppression chamber pressure, s	38.2	63.7	29.5
Peak suppression pool temperature during blowdown, °F	133	134	126
Peak drywell to suppression chamber differential pressure, psid	30.6	11.7	29.8
Time of peak differential pressure, s	4.42	4.19	3.05
Calculated drywell pressure margin, percent	22	49	18
Calculated suppression chamber pressure margin, percent	56	56	58

TABLE 6.2-5 (Cont)

	Recirculation Line Break	Main Steam Line Break
Energy released to containment** at time of peak pressure, 10^6 Btu	368.5	367.0
Energy absorbed by passive heat sink** at time of peak pressure, 10^6 Btu	0	0

---

* Original Rated Power -------------------------------------- 3,293 MWt
Conservative analysis assumption for Rated thermal power -- 3,952 MWt
Licensed Thermal Power ------------------------------------ 3,840 MWt

** Historical values at 3,359 MWt

TABLE 6.2-6

SUMMARY OF LONG TERM CONTAINMENT RESPONSES TO RECIRCULATION LINE OR MAIN STEAM LINE BREAKS

	Historical Information			
	Case A[1]	Case B[1]	Case C[1]	Case C[2]
Secondary peak suppression chamber pressure, psia	22.7	28.0	31.0	34.2
Peak suppression pool temperature, °F	185	209	210	212.3[3]
HPCI flow rate, gpm	5600	5600	5600	5600
Min. core spray flow rate, gpm	12,300	6150	6150	6150
RHR flow rate, gpm	20,000	10,000	10,000	10,000

NOTES:

(1) Values in these columns are provided for comparison and historical purposes and are based on 102% of the original rated thermal power of 3293 MWt (3359 MWt).

(2) Unless otherwise noted, values in this column are calculated based on 102% of the assumed rated thermal power of 3952 MWt (4031 MWt). These values are conservative since the actual licensed thermal power is 3840 MWt (102% = 3917 MWt).

(3) Peak suppression pool temperature of 212.3°F is based on 3840 MWt. The corresponding value calculated for 4031 MWt is 214.5°F.

TABLE 6.2-7

ENERGY BALANCE FOR RECIRCULATION LINE BREAK ACCIDENT
(Values maintained for historical purposes only since they are based on 102% of original rated thermal power of 3293 MWt)

	Energy, 10^6 Btu			
	Initial	Drywell Peak Pressure	End of Blowdown	Long Term Peak Pressure
Reactor coolant	370.3	280.5	26.34	269.4
Fuel and cladding	9.124	9.110	8.961	-2.4 (1)
Core internals	42.32	42.32	42.32	15.59
Reactor vessel metal	94.41	94.41	94.41	34.79
Reactor Coolant System piping, pumps, and valves	38.38	38.38	38.36	14.14
Blowdown enthalpy	0	88.93	377.0	21,157
Decay heat	0	8.804	33.27	1110
Drywell structures	0	0	0	0
Drywell gas	1.224	0.3047	0	1.165
Drywell steam	0.2256	39.66	27.29	13.370
Suppression chamber gas	0.9481	1.901	2.267	1.124
Suppression chamber steam	0.3562	0.4163	0.9399	4.18

TABLE 6.2-7 (Cont)

(Values maintained for historical purposes only since they are based on 102% of original rated thermal power of 3293 MWt)

	Initial	Drywell Peak Pressure	End of Blowdown	Long Term Peak Pressure
Suppression pool water	477.4	525.7	819.1	1246
Energy transferred by heat exchangers	0	0	0	806.7
Passive heat sinks	0	0	0	0

(1) This value is negative because the reference temperature is 285°F.

TABLE 6.2-8

ACCIDENT CHRONOLOGY FOR RECIRCULATION LINE BREAK ACCIDENT

	Time, s		
	All ECCS In Operation	Minimum ECCS Available	Minimum ECCS Available (1)
Thermal Power, MWt	3359 (2)	3359 (2)	4031
Vents cleared	0.1965	0.1965	0.297
Drywell reaches peak pressure	4.422	4.422	9.83
Maximum drywell to suppression chamber differential pressure occurs	4.418	4.418	3.05
Suppression chamber reaches peak pressure	38.2	41.0	29.5
Initiation of the ECCS	30	30	27
End of blowdown	48.4	52.3	30
Vessel reflooded	75.0	95.1	N/A
Initiation of RHR heat exchanger	600	600	600

NOTES:

(1) Unless otherwise noted, values in this column are updates based on analysis for 102% of the assumed rated thermal power of 3952 MWt (4031 MWt). The actual licensed thermal power is 3840 MWt (102% = 3917 MWt).

(2) Note that 3359 MWt is based on 102% of the original Hope Creek rated thermal power of 3293 MWt.

TABLE 6.2-9

REACTOR BLOWDOWN DATA FOR RECIRCULATION LINE BREAK[(1)]
(Data is maintained for historical purposes only since it is based on 102% of original rated thermal power of 3293 MWt)

Time, s	RPV Pressure psia	Liquid Flow, lbm/s	Liquid Enthalpy, Btu/lbm	Steam Flow, lbm/s	Steam Enthalpy, Btu/lbm
0.0	1020	42,150	545.6	0.0	-
0.002197	1020	50,240	545.6	0.0	-
1.313	1010	48,450	544.1	0.0	-
1.314	1010	33,020	544.1	0.0	-
2.125	1007	32,660	543.7	0.0	-
3.563	1018	34,040	545.3	0.0	-
4.421	1031	35,400	547.3	0.0	-
4.422	1031	22,330	547.3	0.0	-
13.79	1100	23,310	557.5	0.0	-
17.03	1096	23,250	556.9	0.0	-
17.04	1096	10,250	556.9	4019	1189
18.28	1032	9361	547.4	3921	1192
19.65	962.1	8472	536.7	3785	1194
21.15	885.5	7565	524.3	3605	1197
22.53	817.5	6789	512.9	3426	1199
23.78	757.7	6130	502.3	3255	1200
25.15	694.7	5464	490.6	3066	1202
26.78	624.0	4746	476.7	2839	1203
28.53	552.9	4051	461.6	2594	1204
30.50	476.5	3394	443.9	2292	1205
33.37	372.6	2717	416.5	1793	1204
37.37	220.6	2517	364.4	800.8	1200
42.87	92.44	2099	292.7	159.3	1186
48.31	44.49	1137	242.8	27.33	1172
48.43	43.87	0.0	241.9	0.0	1172

(1) Data shown is for maximum ECCS operation.

TABLE 6.2-9a

REACTOR BLOWDOWN DATA FOR RECIRCULATION LINE BREAK AT 4031 MWt[1][2]

Time, sec	RPV Pressure psia	Blowdown Mass Flow, lbm/sec	Liquid-Steam Mixture Enthalpy, Btu/lbm
0.0	1020	0	525
0.00293	1020	62,710	523
0.0869	1018	42,680	524
0.149	1016	41,220	524
0.274	1014	42,560	524
0.399	1011	42,110	525
1.274	996	39,660	527
1.399	994	39,190	527
2.149	981	36,010	529
3.274	969	31,890	532
3.524	977	31,600	533
4.431	1002	31,220	536
4.462	1004	31,210	536
5.712	1056	30,240	545
6.919	1081	30,390	550
7.731	1077	27,750	551
8.231	1082	27,330	549
9.318	1045	28,580	595
9.969	976	14,010	820
10.40	958	11,100	857
13.77	835	10,780	732
15.27	792	10,740	703
17.02	742	10,210	686
18.27	709	9,864	679
19.77	671	9,488	670
21.15	637	8,916	666
22.65	600	8,439	663
23.77	573	8,026	659
25.16	537	7,509	656
26.76	496	6,938	652
28.54	448	6,277	647
28.57	447	6,264	647
30.04	408	5,750	641

(1) Data shown is for maximum short-term containment response condition.

(2) Analysis performed for an assumed RTP of 102% of 3952 MWt (4031 MWt).

TABLE 6.2-10

REACTOR BLOWDOWN DATA FOR MAIN STEAM LINE BREAK[(1)]

Based on 3359 MWt (102% of original RTP of 3293 MWt)[(2)]

Time, s	RPV Pressure, psia	Liquid Flow, lbm/s	Liquid Enthalpy, Btu/lbm	Steam Flow, lbm/s	Steam Enthalpy, Btu/lbm
0.0	1,020	0.0	-	9397	1192
.003906	1,020	0.0	-	10,960	1192
.1820	1,011	0.0	-	10,860	1193
.1821	1,011	0.0	-	8059	1193
.9999	988.3	0.0	-	7871	1193
1.000	988.3	18,090	540.7	707.9	1193
3.935	1,008	17,360	543.8	851.7	1193
4.373	1,011	16,250	544.2	823.3	1193
4.748	1,014	15,320	544.7	796.3	1192
5.201	1,018	14,210	545.3	761.0	1192
5.513	1,020	13,480	545.6	736.7	1192
16.33	1,028	11,990	546.8	1191	1192
21.83	970.0	10,680	537.9	1351	1194
26.83	901.4	9437	526.9	1448	1196
30.70	840.2	8460	516.7	1474	1198
35.20	745.8	7330	500.1	1413	1201
39.70	656.6	6318	483.2	1325	1203
44.70	562.6	5308	463.7	1202	1204
49.70	475.7	4425	443.7	1063	1205
56.20	377.3	3491	417.8	876.6	1204
62.45	241.6	2846	372.9	447.4	1201
69.61	113.4	2077	308.2	108.9	1189
79.54	44.56	1217	242.9	15.98	1172
79.88	43.41	0.0	241.2	0.0	1171

(1) Data shown is for maximum ECCS operation.

(2) Retained for historical purposes. Not reanalyzed for power uprate since MSLB is limiting for temperature only due to superheat conditions. Superheat conditions are not dependant on initial reactor power.

TABLE 6.2-11

CORE DECAY HEAT FOLOWING LOCA FOR CONTAINMENT ANALYSES (4031 MWt)

Time, s	Normalized Core Heat[(1)(2)]
0.0	1.0039
2.0	0.5502
4.0	0.5753
10	0.3670
20	0.1158
60	0.04081
120	0.03612
120	0.03221
150	0.03720
200	0.02907
600	0.02343
800	0.02195
1000	0.02077
2000	0.01706
4000	0.01370
6000	0.01209
8000	0.01113
1.0E4	0.01047
2.0E4	0.009177
4.0E4	0.007743
6.0E4	0.006980
1.0E5	0.002274
2.0E5	0.004918
4.0E5	0.003852
1.0E6	0.002669
2.0E6	0.002001

(1) Normalized to 4031 MWt (includes fuel relaxation energy and metal water reaction energy).

(2) The use of 102% of the assumed thermal power of 3952 MWt (4031) is conservative when compared to 102% of the Licensed Thermal Power of 3840 MWt (3917).

TABLE 6.2-12

REACTOR BUILDING DESIGN DATA

Free volume, ft^3	4×10^6
Differential pressure, inches water gauge	
Normal operation	Nominally 0.25
Post-accident	Not less than 0.25
Leak rate at post-accident pressure, percent/day	10
<u>RBVS System</u>	
Exhaust Fans	
Number	3
Type	Centrifugal
Filters	
Number	3 sets
Type	One low efficiency filter, (36 cells) and one HEPA filter (36 cells) in each set
<u>FRVS System</u>	
Recirculation fans	
Number	6
Type	Centrifugal

Filters	
Number	6 sets
Type	One upstream HEPA filter (30 cells) one charcoal filter 2-inches thick, and one downstream HEPA filter (30 cells) in each set
<u>Ventilation</u>	
Exhaust fans	
Number	2
Type	Centrifugal
Filters	
Number	2 sets
Type	Charcoal, 2-inches thick

TABLE 6.2-13

POST-LOCA PRESSURE TRANSIENT ANALYSIS DATA

Initial Conditions

Reactor Building pressure, psi	14.7025
Reactor Building air temperature, °F	96
Relative humidity, percent	50
Outside air pressure, psia	14.696
Assumed inleakage rate into Reactor Building, cfm	3324
Outleakage rate out of Reactor Building, cfm	0
Heat Loads, Btu/s	
$0 \leq t < 10$	737.45
$10 \leq t < 13$	433.79
$13 \leq t < 19$	753.39
$19 \leq t < 26$	928.98
$26 \leq t < 37$	1216.55
$37 \leq t < 45$	1324.78
$45 \leq t < 55$	1406.01
$t \geq 55$	1406.96
Concrete heat sinks in Reactor Building, ft^2	836,576
Steel heat sinks in Reactor Building, ft^2	172,000

TABLE 6.2-13 (Cont)

Design	
Primary containment average wall thickness, ft	3
Reactor Building average wall thickness, ft	3
Inleakage rate into Reactor Building, cfm	2778
Thermal Properties of Primary Containment and Reactor Building	
Thermal conductivity, Btu/h-ft-°F	0.8
Thermal capacitance, Btu/ft^3-°F	30.0
Heat Transfer Coefficients	
Primary containment atmosphere to primary containment wall, Btu/h-ft^2-°F	0*
Primary containment wall to reactor building atmosphere, h, Btu/h-ft^2-°F (where ΔT is in °F)	$0.14\ (\Delta T)^{1/3}$
Reactor Building atmosphere to Reactor Building walls, h, Btu/h-ft^2-°F (where ΔT is in °F)	$0.14\ (\Delta T)^{1/3}$
Reactor Building wall to outside environment, Btu/h-ft^2-°F	0

* See Section 6.2.3.3. No through-wall heat transfer from primary to secondary containment is assumed during short drawdown duration.

TABLE 6.2-13a

SEQUENCE OF EVENTS FOR POST-LOCA PRESSURE TRANSIENT

Time (seconds)	Events
t=0	DBA-LOCA, Loss of offsite power, standby diesel generators (SDS) start, SDG A fails to start
t=13	SDGs B, C and D reach full speed
t=19	FRVS recirculation fans B, C and D start
t=26	FRVS recirculation fans B, C and D reach full flow
t=30	FRVS recirculation fan F starts
t=37	FRVS recirculation fan F reaches full flow
t=45	SACS B, C and D start providing full flow to recirculation fan coolers B, D and F, half flow to recirculation fan cooler C
t=50	FRVS vent fan B starts
t=55	FRVS vent fan B reaches full flow

TABLE 6.2-14

MONITORED AND ALARMED
OPENINGS IN REACTOR BUILDING ENCLOSURE

Access Opening Number	Elev. ft	Near Column Coordinates	Type of Access Opening
4304	102-0	13.6, T	Pressure tight door
4323A	102-0	13.6, U	Pressure tight door
4313A	102-0	21R, Md	Pressure tight door
	132-0	21R, V	Equipment hatch
	132-0	16R, V	Equipment hatch
	132-0/145-0	18.9, W	Equipment hatch
	132-0	15R, P	Equipment hatch
	132-0	18.9, V	Blowout panels
4501A	145-0	17R, P	Pressure tight door
4302	102-0	22R, Md	Pressure tight door
	132-0	18.9, N	Steam tunnel ventilation barrier

TABLE 6.2-14a

ADMINISTRATIVELY CONTROLLED
OPENINGS IN EQUIPMENT AIRLOCK

Access Opening Number	Elev. ft	Near Column Coordinates	Type of Access Opening
4303B	102-0	14R, T	Pressure tight door
4323B	102-0	14R, U	Pressure tight door
4305	102-0	14R, U	Pressure tight door
4307A	102-0	14R, U	Pressure tight door
4322	102-0	15R, U	Pressure tight door
4326	102-0	22R, U	Pressure tight door
4324A	102-0	21R, U	Pressure tight door
4324B	102-0	21R, U	Pressure tight door
	102-0	18.9, U	Equipment hatch
	132-0	18.9, U	Motorized equipment hatch[1]
	102-0	21R, U	Pressure tight equip. access panel
	102-0	15R, U	Pressure tight equip. access panel
	102-0	14R, U	Pressure tight equip. access panel

Access Opening	Elev. ft	Near Column Coordinates	Type of Access Opening
	102-0	16R, U	Pressure tight equip. access panel

Notes:

1. The motorized equipment hatch and HVAC supply and exhaust shutoff dampers (HD-9450A & B) are electrically interlocked with the receiving bay door (4323A) such that the hatch and dampers must be closed before the door can be opened.

TABLE 6.2-15

POTENTIAL REACTOR BUILDING BYPASS LEAKAGE PATHS

Penetration	Line Description(2)	Number of Lines	Line Size, in.	Bypass Leakage Barrier Type(1)
P1A - P1D	Main steam	4	26	a
P2A, P2B	Feedwater	2	24	a,c
P7	HPCI turbine steam supply	1	10	a,i
P7	HPCI turbine auxiliary steam supply	1	6	f
P8A, P38B	Chilled water from drywell coolers	2	8	a,c
P8B, P38A	Chilled water to drywell coolers	2	8	a,c
P9	RWCU supply	1	6	a,c
P11	RCIC turbine steam supply	1	4	a,i
P11	RCIC turbine auxiliary steam supply	1	4	f
P12	Main steam line drain	1	3	a,c

TABLE 6.2-15 (Cont)

Penetration	Line Description (2)	Number of Lines	Line Size, in.	Bypass Leakage Barrier Type (1)
P19, P20	Recirc pump seal purge	2	0.75	a,c
P22	Drywell purge inlet	1	26	a,g
P23	Drywell purge outlet	1	26	a,g
P25	Drywell floor drain sump discharge	1	3	a,c
P26	Drywell equipment drain sump discharge	1	3	a,c
P27	Service air to drywell	1	3	a,h
P28A, P28B	Instrument gas supply to drywell	2	2	a,b,e
P29	RACS supply	1	4	a,i
P30	RACS return	1	4	a,i
P31	Breathing air to drywell	1	4	a,h
P39	Instrument gas suction	1	2	a,b

Penetration	Line Description[2]	Number of Lines	Line Size, in.	Bypass Leakage Barrier Type[1]
P222	Torus water cleanup return	1	8	a,c
P223	Torus water cleanup supply	1	8	a,c
P219	Torus purge outlet	1	24	a,g
P220	Torus purge inlet	1	24	a,g
P227,J7E,J10E,J50, J206,J220,J221	Post-accident sampling	7	1	a,d

(1) Key to bypass leakage barrier types:

a - Redundant primary containment isolation valves.

b - Closed Seismic Category I piping system insider or outside containment

c - Water seal maintained for 30 days following a LOCA

d - The line terminated outside the Reactor Building in a filtered area

e - Positive air seal in line

TABLE 6.2-15 (Cont)

f - The line contains a temporary spool piece that is removed during normal operation and replaced by blind flanges so that any leakage through the flange is into the Reactor Building enclosure.

g - The line leaks to FRVS

h - The line contains a spectacle flange that is inserted during normal operation so the line is blocked off and any leakage by the flange is into the reactor building enclosure.

i - Leakage is limited to Appendix J acceptance criteria as indicated in Section 6.2.3.2.3. Leakage is included in accident dose analysis.

(2) Identified here are all lines that penetrate the primary containment and do not terminate inside the Reactor Building or in a closed system within the Reactor Building

TABLE 6.2-16

CONTAINMENT PENETRATIONS

Containment Penetration Number	Line Isolated	Fluid	Line Size, in.	NRC General Design Criterion	ESF System(11)	Valve Number and/or Orifice Plate	Valve Type(1)	Valve Location	Valve Arrangement(2) P&ID(8)	Type C Test	Length of Pipe from Cont. to Outside Valves, ft.
PROCESS LINE PENETRATIONS											
P-1A	Main Steam	Steam/Water	26	55	No	AB-V028	GB	Inside	1/A	No	-
			26			AB-V032	GB	Outside		No	3.8
P-1B	Main Steam	Steam/Water	26	55	No	AB-V029	GB	Inside	1/A	No	-
			26			AB-V033	GB	Outside		No	3.8
P-1C	Main Steam	Steam/Water	26	55	No	AB-V030	GB	Inside	1/A	No	-
			26			AB-V034	GB	Outside		No	3.8
P-1D	Main Steam	Steam/Water	26	55	No	AB-V031	GB	Inside	1/A	No	-
			26			AB-V035	GB	Outside		No	3.8
P-2A	Feedwater	Water	24	55	No	AE-V003	CK	Inside	2/B	Yes (19)	-
			24			AE-V002	CK	Outside		Yes (19)	4.5
			4			AE-V021	CK	Outside		Yes (20)	34.0
			6			BD-V005	GT	Outside		Yes (20)	33.3
			24			AE-V001	CK	Outside		Yes (20)	40.12
P-2B	Feedwater	Water	24	55	No	AE-V007	CK	Inside	2/B	Yes (19)	0.5
			24			AE-V006	CK	Outside		Yes (19)	4.5
			4			AE-V021	CK	Outside		Yes (20)	34.0
			8			BJ-V059	GT	Outside		Yes (20)	31.5
			24			AE-V005	CK	Outside		Yes (20)	40.1
P-3	RHR Shutdown Cooling Suction	Water	20	55	Yes	BC-V071+	GT	Inside	3/C	No	-
			1			BC-PSV-4425+	PSV	Inside		No	-
			20			BC-V164	GT	Outside		No	0.5
P-4A	RHR Shutdown Cooling Return	Water	12	55	Yes	BC-V014+	CK	Inside	4/D	No	-
			1			BC-V118+	GB	Inside		No	-
			12			BC-V013	GB	Outside		No	0.0
P-4B	RHR Shutdown Cooling Return	Water	12	55	Yes	BC-V111+	CK	Inside	4/D	No	-
			1			BC-V117+	GB	Inside		No	-
			12			BC-V110	GB	Outside		No	0.0

+ - Not a containment isolation valve.

TABLE 6.2-16 (Cont)

CONTAINMENT PENETRATIONS

Containment Penetration Number	Primary Mode of Operation(3)	Secondary Method of Actuation(12)	Normal Valve Position(4)	Shutdown Valve Position(10)	Post-Accident Position(9)	Power Failure Valve Position	Containment Isolation Signal(5)	Valve Closure Time, S	Power Source(6)	Remarks(7)
P-1A	Instr. gas	Manual	0	C	C	C	D,E,F,G,K	5	W	a,t,cc
	Compr. air	Manual	0	C	C	C	D,E,F,G,K	5	Z	a,t,cc
P-1B	Instr. gas	Manual	0	C	C	C	D,E,F,G,K	5	W	a,t,cc
	Compr. air	Manual	0	C	C	C	D,E,F,G,K	5	Z	a,t,cc
P-1C	Instr. gas	Manual	0	C	C	C	D,E,F,G,K	5	W	a,t,cc
	Compr. air	Manual	0	C	C	C	D,E,F,G,K	5	Z	a,t,cc
P-1D	Instr. gas	Manual	0	C	C	C	D,E,F,G,K	5	W	a,t,cc
	Compr. air	Manual	0	C	C	C	D,E,F,G,K	5	Z	a,t,cc
P-2A	Flow	None	0	C	C	NA	-	NA	NA	s
	Flow	Manual (17)	0	C	C	C	None	NA	N	s
	Flow	Manual (13)	0	C	C	C	None	NA	D	t
	DC motor	Manual	C	C	0	AS IS	None	NA	B	s
	Flow	Manual (13)	0	C	C	C	None	NA	B	s
P-2B	Flow	None	0	C	C	NA	-	NA	NA	s
	Flow	Manual (17)	0	C	C	C	None	NA	N	s
	Flow	Manual (13)	0	C	C	C	None	NA	D	t
	DC motor	Manual	C	C	0	AS IS	None	NA	A	s
	Flow	Manual (13)	0	C	C	C	None	NA	A	s
P-3	AC motor	Manual	C	0	C	AS IS	J	45	A	b,s,cc
	Spring	None	C	C	C	NA	-	NA	NA	s,z,cc
	AC motor	Manual	C	0	C	AS IS	J	45	D	b,s,cc
P-4A	Flow	None (16)	C	0	C	NA	-	NA	NA	s,cc
	Spring	Manual	C	C	C	C	None	NA	B	t,cc
	AC motor	Manual	C	0	C	AS IS	J	45	D	b,s,cc
P-4B	Flow	None (16)	C	0	C	NA	-	NA	NA	s,cc
	Spring	Manual	C	C	C	C	None	NA	A	t,cc
	AC motor	Manual	C	0	C	AS IS	J	45	D	b,s,cc

TABLE 6.2-16 (Cont)

CONTAINMENT PENETRATIONS

Containment Penetration Number	Line Isolated	Fluid	Line Size, in.	NRC General Design Criterion	ESF System(11)	Valve Number and/or Orifice Plate	Valve Type(1)	Valve Location	Valve Arrangement(2) P&ID(8)	Type C Test	Length of Pipe from Cont. to Outside Valves, ft.
P-5A	Core Spray	Water	12	55	Yes	BE-V002+	CK	Inside	5/E	No	-
	To Reactor		1			BE-V072+	GB	Inside		No	-
			12			BE-V003	GT	Outside		No	0.0
P-5B	Core Spray	Water	12	55	Yes	BE-V006+	CK	Inside	5/E	No	-
	To Reactor		1			BE-V071+	GB	Inside		No	-
			12			BE-V007	GT	Outside		No	1.8
			14			BJ-V001	GT	Outside		No	4.6
P-6A	LPCI	Water	12	55	Yes	BC-V005+	CK	Inside	5/D	No	-
			1			BC-V122+	GB	Inside		No	-
			12			BC-V004	GT	Outside		No	0.0
P-6B	LPCI	Water	12	55	Yes	BC-V017+	CK	Inside	5/D	No	-
			1			BC-V120+	GB	Inside		No	-
			12			BC-V016	GT	Outside		No	0.0
P-6C	LPCI	Water	12	55	Yes	BC-V114+	CK	Inside	5/D	No	-
			1			BC-V119+	GB	Inside		No	-
			12			BC-V113	GT	Outside		No	0.0
P-6D	LPCI	Water	12	55	Yes	BC-V102+	CK	Inside	5/D	No	-
			1			BC-V121+	GB	Inside		No	-
			12			BC-V101	GT	Outside		No	0.0
P-7	HPCI Turbine	Steam	10	55	Yes	FD-V001	GT	Inside	6/F	Yes	-
	Steam Supply		10			FD-V002	GT	Outside		Yes	0.0
			1			FD-V051	GB	Inside		Yes	-
P-8A	Chilled Water	Water	8	56	No	GB-V082	GT	Inside	34/G	Yes	-
	from Drywell		1			GB-PSV-9523A	PSV	Inside		Yes	-
	Coolers		8			GB-V046	GT	Outside		Yes	0.8
P-8B	Chilled Water	Water	8	56	No	GB-V081	GT	Inside	34/G	Yes	-
	to Drywell		1			GB-PSV-9522A	PSV	Inside		Yes	-
	Coolers		8			GB-V048	GT	Outside		Yes	0.8
P-9	RWCU Supply	Water	6	55	No	BG-V001	GT	Inside	7/H	Yes	-
			6			BG-V002	GT	Outside		Yes	0.0
P-10	SPARE*										

+ - Not a containment isolation valve.

* Process piping capped inside and outside containment. Flued head remains in place.

TABLE 6.2-16 (Cont)

CONTAINMENT PENETRATIONS

Containment Penetration Number	Primary Mode of Operation(3)	Secondary Method of Actuation(12)	Normal Valve Position(4)	Shutdown Valve Position(10)	Post-Accident Position(9)	Power Failure Valve Position	Containment Isolation Signal(5)	Valve Closure Time, S	Power Source(6)	Remarks(7)
P-5A	Flow	None (16)	C	C	0	NA	-	NA	NA	s,cc
	Spring	Manual	C	C	C	C	None	NA	B	t,cc
	AC motor	Manual	C	C	0	AS IS	None	NA	B	s,x,cc
P-5B	Flow	None (16)	C	0	0	NA	-	NA	NA	s,cc
	Spring	Manual	C	C	C	C	None	NA	A	t,cc
	AC motor	Manual	C	C	0	AS IS	None	NA	A	s,x,cc
	DC motor	Manual	C	C	0	AS IS	None	NA	A	s,cc
P-6A	Flow	None (16)	C	C	0	NA	-	NA	NA	s,cc
	Spring	Manual	C	C	C	C	None	NA	D	t,cc
	AC motor	Manual	C	C	0	AS IS	None	NA	D	s,x,cc
P-6B	Flow	None (16)	C	C	0	NA	-	NA	NA	s,cc
	Spring	Manual	C	C	C	C	None	NA	B	t,cc
	AC motor	Manual	C	C	C	AS IS	None	NA	B	s,x,cc
P-6C	Flow	None (16)	C	C	0	NA	-	NA	NA	s,cc
	Spring	Manual	C	C	C	C	None	NA	A	t,cc
	AC motor	Manual	C	C	0	AS IS	None	NA	A	s,x,cc
P-6D	Flow	None (16)	C	C	0	NA	-	NA	NA	s,cc
	Spring	Manual	C	C	C	C	None	NA	C	t,cc
	AC motor	Manual	C	C	0	AS IS	None	NA	C	s,x,cc
P-7	AC motor	Manual	0	C	0	AS IS	None	NA	C	c,s
	AC motor	Manual	0	C	0	AS IS	None	NA	A	c,s
	AC motor	Manual	C	C	C	AS IS	None	NA	C	c,t
P-8A	AC motor	Manual	0	C	C	AS IS	H,K	60	C	t,x
	Spring	None	C	C	C	NA	-	NA	NA	t,AA
	AC motor	Manual	0	C	C	AS IS	H,K	60	D	t,x
P-8B	AC motor	Manual	0	C	C	AS IS	H,K	60	C	t,x
	Spring	None	C	C		NA	-	NA	NA	t,AA
	AC motor	Manual	0	C	C	AS IS	H,K	60	D	t,x
P-9	AC motor	Manual	0	C	C	AS IS	A,L,M,N,O	45	A	t
	AC motor	Manual	0	C	C	AS IS	A,L,M,N,O,P	45	D	t
P-10	SPARE*									

+ - Not a containment isolation valve.

* Process piping capped inside and outside containment. Flued head remains in place.

CONTAINMENT PENETRATIONS

Containment Penetration Number	Line Isolated	Fluid	Line Size, in.	NRC General Design Criterion	ESF System(11)	Valve Number and/or Orifice Plate	Valve Type(1)	Valve Location	Valve Arrangement(2) P&ID(8)	Type C Test	Length of Pipe from Cont. to Outside Valves, ft.
P-11	RCIC Turbine Steam Supply	Steam	4	55	No	FC-V001	GT	Inside	6/I	Yes	-
			4			FC-V002	GT	Outside		Yes	1.0
			1			FC-V048	GB	Inside		Yes	-
P-12	Main Steam Drain	Steam/Water	3	55	No	AB-V039	GT	Inside	9/J	Yes	-
			3			AB-V040	GT	Outside		Yes	0.5
P-13	Spare										
P-14	Not Used										
P-15	Spare										
P-16	Spare										
P-17	Reactor Recirc Water Sample	Water	3/4	55	No	BB-SV 4310	GB	Inside	10/K	Yes	-
			3/4			BB-SV 4311	GB	Outside		Yes	12.2
P-18	Standby Liquid Control	Sodium pen-taborated solution	1 1/2	55	Yes	BH-V029	CK	Inside	11/L	Yes	-
			1 1/2			BH-V028	SCK	Outside		Yes	12.6
			1 1/2			BH-V054	SCK	Outside		Yes	10.6
P-19	Recirc Pump Seal Water	Water	3/4	55	No	BB-V043	CK	Inside	12/K	Yes	-
			3/4			BF-V098	GB	Outside		Yes	15.8
P-20	Recirc Pump Seal Water	Water	3/4	55	No	BB-V047	CK	Inside	12/K	Yes	-
			3/4			BF-V099	GB	Outside		Yes	23.7
P-21	ISI Access Penetration										
P-22	Drywell Purge Supply Vent	Gas	26	56	Yes	GS-V009	BF	Outside	13/M	Yes	-
			6			GS-V023	BF	Outside		Yes	43.6
			26			GS-V021	BF	Outside		Yes	43.6
			4			GS-V004	GT	Outside		Yes	-
			4			GS-V005	GT	Outside		Yes	10.7
P-23	Drywell Purge Exhaust Vent	Gas	26	56	Yes	GS-V024	BF	Outside	14/M	Yes	-
			26			GS-V026	BF	Outside		Yes	5.3
			2			GS-V025	GB	Outside		Yes	25.7
			4			GS-V002	GT	Outside		Yes	-
			4			GS-V003	GT	Outside		Yes	7.4
P-24A	RHR Containment Spray	Water	16	56	Yes	BC-V019	GT	Outside	15/D	No	-
			16			BC-V018+	GT	Outside		No	6.0

+ - Not a containment isolation valve.

TABLE 6.2-16 (Cont)

CONTAINMENT PENETRATIONS

Containment Penetration Number	Primary Mode of Operation(3)	Secondary Method of Actuation(12)	Normal Valve Position(4)	Shutdown Valve Position(10)	Post-Accident Position(9)	Power Failure Valve Position	Containment Isolation Signal(5)	Valve Closure Time, S	Power Source(6)	Remarks(7)
P-11	AC motor	Manual	0	C	0	AS IS	None	NA	D	d,s
	AC motor	Manual	0	C	0	AS IS	None	NA	B	d,s
	AC motor	Manual	C	C	C	AS IS	None	NA	D	d,t
P-12	AC motor	Manual	0	C	C	AS IS	D,E,F,G,K	30	A	t
	AC motor	Manual	0	C	C	AS IS	D,E,F,G,K	30	D	t
P-13										m
P-14										
P-15										m
P-16										m
P-17	Spring	Manual	0	C	C	C	A,B	15	A	t
	Spring	Manual	0	C	C	C	A,B	15	D	t
P-18	Flow	None	C	C	C	NA	-	NA	NA	s
	Flow	Manual (13)	0	0	0	C	None	NA	A	s
	Flow	Manual (13)	0	0	0	C	None	NA	D	s
P-19	Flow	None	0	C	C	NA	-	NA	NA	t
	AC motor	Manual	0	C	C	AS IS	H,K	45	D	t
P-20	Flow	None	0	C	C	NA	-	NA	NA	t
	AC motor	Manual	0	C	C	AS IS	H,K	45	D	t
P-21										m
P-22	Spring	Manual	C	C	C	C	A,H,I	5	A	t,v,x
	Spring	Manual	C	C	C	C	A,H,I	5	D	t,x
	Spring	Manual	C	C	C	C	A,H,I	5	D	t,x
	AC motor	Manual	C	0	C	AS IS	A,H,I	45	B	s,x
	AC motor	Manual	C	0	C	AS IS	A,H,I	45	D	s,x
P-23	Spring	Manual	C	C	C	C	A,H,I	5	A	t,x
	Spring	Manual	C	C	C	C	A,H,I	5	D	t,x
	Spring	Manual	C	C	C	C	A,H,I	15	D	t,x
	AC motor	Manual	C	0	C	AS IS	A,H,I	45	A	s,x
	AC motor	Manual	C	0	C	AS IS	A,H,I	45	C	s,x
P-24A	AC motor	Manual	C	0	C	AS IS	None	NA	B	s,cc
	AC motor	Manual	C	0	C	AS IS	None	NA	B	s,cc

CONTAINMENT PENETRATIONS

Containment Penetration Number	Line Isolated	Fluid	Line Size, in.	NRC General Design Criterion	ESF System(11)	Valve Number and/or Orifice Plate	Valve Type(1)	Valve Location	Valve Arrangement(2) P&ID(8)	Type C Test	Length of Pipe from Cont. to Outside Valves, ft.
P-24B	RHR Containment Spray	Water	16	56	Yes	BC-V116	GT	Outside	15/D	No	-
			16			BC-V115+	GT	Outside		No	7.9
P-25	Drywell Floor Drain Sump Discharge	Water	3	56	No	HB-V005	GT	Inside	16/N	Yes	-
			3			HB-V006	GT	Outside		Yes	4.4
			3/4			IHBPSV-11701	PSV	Inside		Yes	
P-26	Drywell Equip. Drain Sump Discharge	Water	3	56	No	HB-V045	GT	Inside	16/N	Yes	-
			3			HB-V046	GT	Outside		Yes	4.5
			3/4			IHBPSV-11702	PSV	Inside		Yes	
P-27	Service Air to Drywell	Air	3	56	No	KA-V039	GT	Inside	17/O	Yes	-
			3			KA-V038	GT	Outside		Yes	0.2
P-28A	Instrument Gas to Drywell	Gas	2	56	Yes	KL-V026	GB	Inside	18/P	Yes	-
			2			KL-V025	GB	Outside		Yes	20.8
P-28B	Instrument Gas to Drywell	Gas	2	56	Yes	KL-V028	GB	Inside	18/P	Yes	-
			2			KL-V027	GB	Outside		Yes	17.5
P-29	RACS Supply	Water	4	56	No	ED-V020	GT	Inside	35/Q	Yes	1.0
			4			ED-V019	GT	Outside		Yes	
			3/4			IEDPSV-11699	PSV	Inside		Yes	
P-30	RACS Return	Water	4	56	No	ED-V022	GT	Inside	35/Q	Yes	1.0
			4			ED-V021	GT	Outside		Yes	
			3/4			IEDPSV-11700	PSV	Inside		Yes	
P-31	Breathing Air	Air	4	56	No	KG-V016	GB	Inside	17/R	Yes	-
						KG-V034	GT	Outside		Yes	2.5
P-32	Spare										
P-33	Spare										
P-34A	Probe Guide Tube	Gas	3/8	56	No	SE-V026	BL	Outside	19/P	Yes	1.0
			3/8	56		SE-V021	XP	Outside		No	
P-34B	Probe Guide Tube	Gas	3/8	56	No	SE-V027	BL	Outside	19/P	Yes	1.0
			3/8	56		SE-V022	XP	Outside		No	
P-34C	Probe Guide Tube	Gas	3/8	56	No	SE-V028	BL	Outside	19/P	Yes	1.0
			3/8	56		SE-V023	XP	Outside		No	
P-34D	Probe Guide Tube	Gas	3/8	56	No	SE-V029	BL	Outside	19/P	Yes	1.0
			3/8	56		SE-V024	XP	Outside		No	

+ - Not a containment isolation valve.

TABLE 6.2-16 (Cont)

CONTAINMENT PENETRATIONS

Containment Penetration Number	Primary Mode of Operation(3)	Secondary Method of Actuation(12)	Normal Valve Position(4)	Shutdown Valve Position(10)	Post-Accident Position(9)	Power Failure Valve Position	Containment Isolation Signal(5)	Valve Closure Time, S	Power Source(6)	Remarks(7)
P-24B	AC motor	Manual	C	0	C	AS IS	None	NA	A	s,cc
	AC motor	Manual	C	0	C	AS IS	None	NA	A	s,cc
P-25	AC motor	Manual	0	0	C	AS IS	A,H,I	30	D	t,x
	AC motor	Manual	0	0	C	AS IS	A,H,I	30	B	t,x
P-26	AC motor	Manual	0	C	C	AS IS	A,H,I	30	C	t,x
	AC motor	Manual	0	C	C	AS IS	A,H,I	30	B	t,x
P-27	None	Manual (14)	C	C	C	NA		NA	NA	r,t
	None	Manual (14)	C	C	C	NA		NA	NA	r,t
P-28A	AC Motor	Manual	0	0	C	AS IS	H,I,K	45	D	t,x
	AC Motor	Manual	0	0	C	AS IS	H,I,K	45	B	t,x
P-28B	AC Motor	Manual	0	0	C	AS IS	H,I,K	45	A	t,x
	AC Motor	Manual	0	0	C	AS IS	H,I,K	45	C	t,x
P-29	AC Motor	Manual	0	C	C	AS IS	H,K	45	D	t
	AC Motor	Manual	0	C	C	AS IS	H,K	45	B	t
P-30	AC Motor	Manual	0	C	C	AS IS	H,K	45	D	t
	AC Motor	Manual	0	C	C	AS IS	H,K	45	B	t
P-31	None	Manual (14)	C	C	C	NA	NA	NA	-	r,t
	None	Manual (14)	C	C	C	NA	NA	NA	-	r,t
P-32										m
P-33										m
P-34A	AC solenoid	Manual	C	C	C	C	H,A	15	N	t
	Explosive	Manual	0	0	0	AS IS	None	NA	N	t,cc
P-34B	AC solenoid	Manual	C	C	C	C	H,A	15	N	t
	Explosive	Manual	0	0	0	AS IS	None	NA	N	t,cc
P-34C	AC solenoid	Manual	C	C	C	C	H,A	15	N	t
	Explosive	Manual	0	0	0	AS IS	None	NA	N	t,cc
P-34D	AC solenoid	Manual	C	C	C	C	H,A	15	N	t
	Explosive	Manual	0	0	0	AS IS	None	NA	N	t,cc

TABLE 6.2-16 (Cont)

CONTAINMENT PENETRATIONS

Containment Penetration Number	Line Isolated	Fluid	Line Size, in.	NRC General Design Criterion	ESF System(11)	Valve Number and/or Orifice Plate	Valve Type(1)	Valve Location	Valve Arrangement(2) P&ID(8)	Type C Test	Length of Pipe from Cont. to Outside Valves, ft.
P-34E	Probe Guide Tube	Gas	3/8	56	No	SE-V030	BL	Outside	19/P	Yes	1.0
			3/8			SE-V025	XP	Outside		No	
P-34F	Tip Purge System	Gas	3/8	56	No	SE-V006	CK	Inside	19/P	Yes	-
			3/8			SE-V004	GB	Outside		Yes	12.5
P-34G	Spare										
P-35A	CRD Insert	Water	1	55	Yes		HCU	Outside	36/S	No	
P-35B	CRD Insert	Water	1	55	Yes		HCU	Outside	36/S	No	
P-35C	CRD Insert	Water	1	55	Yes		HCU	Outside	36/S	No	
P-35D	CRD Insert	Water	1	55	Yes		HCU	Outside	36/S	No	
P-36A	CRD Withdraw	Water	1	55	Yes		HCU	Outside	36/S	No	
P-36B	CRD Withdraw	Water	1	55	Yes		HCU	Outside	36/S	No	
P-36C	CRD Withdraw	Water	1	55	Yes		HCU	Outside	36/S	No	
P-36D	CRD Withdraw	Water	1	55	Yes		HCU	Outside	36/S	No	
P-37 (A-H)	Vent Pipe										
P-38A	Chilled Water to Drywell Coolers	Water	8	56	No	GB-V083	GT	Inside	34/G	Yes	-
			1			GB-PSV9522B	PSV	Inside		Yes	-
			8			GB-V070	GT	Outside		Yes	0.8
P-38B	Chilled Water from Drywell Coolers	Water	8	56	No	GB-V084	GT	Inside	34/G	Yes	-
			1			GB-PSV9523B	PSV	Inside		Yes	-
			8			GB-V071	GT	Outside		Yes	0.8

TABLE 6.2-16 (Cont)

CONTAINMENT PENETRATIONS

Containment Penetration Number	Primary Mode of Operation(3)	Secondary Method of Actuation(12)	Normal Valve Position(4)	Shutdown Valve Position(10)	Post-Accident Position(9)	Power Failure Valve Position	Containment Isolation Signal(5)	Valve Closure Time, S	Power Source(6)	Remarks(7)
P-34E	AC Solenoid	Manual	C	C	C	C	H,A	15	N	t
	Explosive	Manual	0	0	0	AS IS	None	NA	N	t,cc
P-34F	Flow	None	0	C	C	NA	None	NA	NA	t
	Spring	Manual	0	C	C	C	H,A,I	15	D	t
P-34G										m
P-35A										s,cc
P-35B										s,cc
P-35C										s,cc
P-35D										s,cc
P-36A										s,cc
P-36B										s,cc
P-36C										s,cc
P-36D										s,cc
P-37 (A-H)										k
P-38A	AC motor	Manual	0	C	C	AS IS	H,K	60	C	t,x
	Spring	None	C	C	C	NA	-	NA	NA	t,aa
	AC motor	Manual	0	C	C	AS IS	H,K	60	D	t,x
P-38B	AC motor	Manual	0	C	C	AS IS	H,K	60	C	t,x
	Spring	None	C	C	C	NA	-	NA	NA	t,aa
	AC motor	Manual	C	C	C	AS IS	H,K	60	D	t,x

TABLE 6.2-16 (Cont)

CONTAINMENT PENETRATIONS

Containment Penetration Number	Line Isolated	Fluid	Line Size, in.	NRC General Design Criterion	ESF System(11)	Valve Number and/or Orifice Plate	Valve Type(1)	Valve Location	Valve Arrangement(2) P&ID(8)	Type C Test	Length of Pipe from Cont. to Outside Valves, ft.
P-39	Instrument Gas	Gas	2	56	No	KL-V001	GB	Inside	18/P	Yes	-
	Suction		2			KL-V049	GB	Outside		Yes	32.5
	Coolers		2			KL-V002	GB	Outside		Yes	55.2
P-201	HPCI Turbine	Water/Steam	20	56	Yes	FD-V006	GT	Outside	20/F	Yes	17.8
	Exhaust		3			FD-V007	GT	Outside		Yes	31.0
			20			FD-V004	CK	Outside		Yes	16.0
P-202	HPCI Pump Suction	Water	16	56	Yes	BJ-V009	GT	Outside	21/F	No	69.5
P-203	HPCI Minimum Return	Water	4	56	Yes	BJ-V016	GB	Outside	22/F	No	27.9
P-204	HPCI & RCIC	Air/Water	3	56	Yes	FC-V007	GT	Outside	23/T	Yes	60.3
	Vacuum Network		3			FD-V010	GT	Outside		Yes	30.1
P-205	Spare										
P-206	Spare										
P-207	RCIC Turbine	Steam/	2	56	No	FC-V006	GT	Outside	20/I	Yes	2.0
	Exhaust	Water	10			FC-V005	GT	Outside		Yes	24.5
			10			FC-V003	CK	Outside		Yes	27.9
P-208	RCIC Pump Suction	Water	6	56	No	BD-V003	GT	Outside	21/I	No	38.6
P-209	RCIC Minimum Return	Water	2	56	No	BD-SV-F019 2.5 in.	GB	Outside	22/I	No	27.8
P-210	RCIC Vacuum	Water	2	56	No	FC-V011	GB	Outside	24/I	Yes	-
	Pump Discharge					FC-V010	CK	Outside		Yes	15.4
P-211A	RHR Pump Suction	Water	24	56	Yes	BC-V001	GT	Outside	25/D	No	29.4
P-211B	RHR Pump Suction	Water	24	56	Yes	BC-V006	GT	Outside	25/D	No	32.8
P-211C	RHR Pump Suction	Water	24	56	Yes	BC-V103	GT	Outside	25/D	No	32.8

CONTAINMENT PENETRATIONS

Containment Penetration Number	Primary Mode of Operation(3)	Secondary Method of Actuation(12)	Normal Valve Position(4)	Shutdown Valve Position(10)	Post-Accident Position(9)	Power Failure Valve Position	Containment Isolation Signal(5)	Valve Closure Time, S	Power Source(6)	Remarks(7)
P-39	AC motor	Manual	0	C	C	AS IS	H,I,K	45	A	t
	AC motor	Manual	0	C	C	AS IS	H,I,K	45	D	t
	AC motor	Manual	0	C	C	AS IS	H,I,K	45	C	t
P-201	DC Motor	Manual	0	C	0	AS IS	None	NA	A	s
	AC Motor	Manual	0	C	0	AS IS	None	NA	A	e,s,bb
	Flow	None	C	C	0	NA	-	NA	NA	s
P-202	DC Motor	Manual	C	C	0	AS IS	None	NA	A	c,s,cc
P-203	DC Motor	Manual	C	C	0	AS IS	None	NA	A	g,s,cc
P-204	AC Motor	Manual	0	C	0	AS IS	None	NA	D	f,s,bb
	AC Motor	Manual	0	C	0	AS IS	None	NA	C	e,s,bb
P-205										m
P-206										m
P-207	AC motor	Manual	0	C	0	AS IS	None	NA	B	f,s,bb
	DC motor	Manual	0	C	0	AS IS	None	NA	B	s
	Flow	None	C	C	0	AS IS	-	-		
P-208	DC motor	Manual	C	C	0	AS IS	None	NA	B	s,cc
P-209	Spring	Manual	C	C	0	C	None	NA	B	h,s,cc
P-210	DC motor	Manual	0	C	0	AS IS	None	NA	B	s
	Flow	Manual	C	C	0	NA	-	-	NA	
P-211A	AC motor	Manual	0	0	0	AS IS	None	NA	D	s,cc
P-211B	AC motor	Manual	0	0	0	AS IS	None	NA	B	s,cc
P-211C	AC motor	Manual	0	0	0	AS IS	None	NA	A	s,cc

Containment Penetration Number	Line Isolated	Fluid	Line Size, in.	NRC General Design Criterion	ESF System(11)	Valve Number and/or Orifice Plate	Valve Type(1)	Valve Location	Valve Arrangement(2) P&ID(8)	Type C Test	Length of Pipe from Cont. to Outside Valves, ft.
P-211D	RHR Pump Suction	Water	24	56	Yes	BC-V098	GT	Outside	25/D	No	29.4
P-212A	RHR Suppression Pool Cooling & System Test	Water	1	56	Yes	BC-PSV-F025D	SRV	Outside	26/D	No	214.0
			1			BC-PSV-F025B	SRV	Outside		No	293.3
			18			BC-V028	GB	Outside		No	51.0
			18			BC-V027	GB	Outside		No	63.1
			4			BC-V026	GT	Outside		No	99.3
			4			BC-V034	GT	Outside		No	68.5
			4			BC-V031	GT	Outside		No	70.4
			1			BC-V260	CK	Outside		No	68.2
P-212B	RHR Suppression Pool Cooling & System Test	Water	1	56	Yes	BC-PSV-F025C	SRV	Outside	26/D	No	218.5
			1			BC-PSV-F025A	SRV	Outside		No	170.4
			18			BC-V124	GB	Outside		No	49.8
			18			BC-V125	GB	Outside		No	63.5
			4			BC-V126	GT	Outside		No	100.1
			4			BC-V128	GT	Outside		No	62.4
			4			BC-V131	GT	Outside		No	40.8
			1			BC-V206	CK	Outside		No	65.7
P-213A	RHR Relief to Suppression Pool	Steam/Water	1	56	Yes	BC-PSV-4431B	SRV	Outside	27/D	No	95.5
P-213B	RHR Relief to Suppression Pool	Steam/Water	1	56	Yes	BC-PSV-4431A	SRV	Outside	27/D	No	71.3
P-214A	RHR to Suppression Chamber Spray Header	Water	6	56	Yes	BC-V015	GB	Outside	28/D	No	<21
P-214B	RHR to Suppression Chamber Spray Header	Water	6	56	Yes	BC-V112	GB	Outside	28/D	No	19.0
P-216A	Core Spray Pump Suction	Water	16	56	Yes	BE-V019	GT	Outside	29/U	No	31.0

CONTAINMENT PENETRATIONS

Containment Penetration Number	Primary Mode of Operation(3)	Secondary Method of Actuation(12)	Normal Valve Position(4)	Shutdown Valve Position(10)	Post-Accident Position(9)	Power Failure Valve Position	Containment Isolation Signal(5)	Valve Closure Time, S	Power Source(6)	Remarks(7)
P-211D	AC motor	Manual	0	0	0	AS IS	None	NA	C	s,cc
P-212A	Spring	None	C	C	C	NA	-	-	NA	n,s,cc
	Spring	None	C	C	C	NA	-	-	NA	n,s,cc
	AC motor	Manual	C	0	C	AS IS	H,K (18)	180	B	t,x,cc
	AC motor	Manual	C	C	C	AS IS	H,K (18)	180	D	t,cc
	None	Manual (14)	C	C	C	AS IS	NA	NA	NA	t,cc
	AC motor	Manual	0	C	C	AS IS	None	NA	D	i,s,cc
	AC motor	Manual	0	C	C	AS IS	-	-	B	i,s,cc
	Flow	None	0	C	C	NA	-	-	NA	s,cc
P-212B	Spring	None	C	C	C	NA	-	-	NA	n,s,cc
	Spring	None	C	C	C	NA	-	-	NA	n,s,cc
	AC motor	Manual	C	0	C	AS IS	H,K (18)	180	A	t,x,cc
	AC motor	Manual	C	C	C	AS IS	H,K (18)	180	C	t,cc
	None	Manual (14)	C	C	C	AS IS	NA	NA	NA	t,cc
	AC motor	Manual	0	C	C	AS IS	None	NA	A	i,s,cc
	AC motor	Manual	0	C	C	AS IS	None	NA	C	i,s,cc
	Flow	None	0	C	C	NA	-	-	NA	s,cc
P-213A	Spring	None	C	C	C	NA	-	-	NA	p,s,cc
P-213B	Spring	None	C	C	C	NA	-	-	NA	p,s,cc
P-214A	AC motor	Manual	C	0	C	AS IS	H,K (18)	75	B	s,x,cc
P-214B	AC motor	Manual	C	0	C	AS IS	H,K (18)	75	NA	s,x,cc
P-216A	AC motor	Manual	0	0	0	AS IS	None	NA	B	s,cc

Containment Penetration Number	Line Isolated	Fluid	Line Size, in.	NRC General Design Criterion	ESF System(11)	Valve Number and/or Orifice Plate	Valve Type(1)	Valve Location	Valve Arrangement(2) P&ID(8)	Type C Test	Length of Pipe from Cont. to Outside Valves, ft.
P-216B	Core Spray Pump Suction	Water	16	56	Yes	BE-V020	GT	Outside	29/U	No	32.3
P-216C	Core Spray	Water	16	56	Yes	BE-V018	GT	Outside	29/U	No	32.3
P-216D	Core Spray Pump Suction	Water	16	56	Yes	BE-V017	GT	Outside	29/U	No	32.3
P-217A	Core Spray Test to Suppression Pool	Water	2	56	Yes	BE-PSV-F012B	SRV	Outside	30/U	No	58.4
			10			BE-V026	GB	Outside		No	22.0
			4			BE-V036	GB	Outside		No	54.2
P-217B	Core Spray Test to Suppression Pool	Water	2	56	Yes	BE-PSV-F012A	SRV	Outside	30/U	No	108.3
			10			BE-V025	GB	Outside		No	21.8
			4			BE-V035	GB	Outside		No	33.5
P-219	Suppression Chamber Purge Exhaust & Vacuum Relief	Gas	24	56	Yes	GS-V080	BF	Outside	31/M	Yes	27.0
			24			GS-PSV-5030	PSV	Outside		Yes	27.0
			6			GS-V007	GT	Outside		Yes	-
			6			GS-V006	GT	Outside		Yes	30.9
			24			GS-V028	BF	Outside		Yes	-
			2			GS-VO76	BF	Outside		Yes	31.9
			24			GS-V027	BF	Outside		Yes	36.0
			12			GS-V201	BF	Outside		Yes	45.2
P-220	Suppression Chamber Purge Supply & Vacuum Relief	Gas	24	56	Yes	GS-V022	BF	Outside	32/M	Yes	33.3
			6			GS-V010	GT	Outside		Yes	33.3
			6			GS-V008	GT	Outside		Yes	41.8
			24			GS-V038	BF	Outside		Yes	-
			24			GS-PSV-5032	PSV	Outside		Yes	25.6
			24			GS-V020	BF	Outside	W	Yes	242
P-221A	Construction Drain										
P-221B	Construction Drain										
P-221C	Construction Drain										
P-221D	Construction Drain										

TABLE 6.2-16 (Cont)

CONTAINMENT PENETRATIONS

Containment Penetration Number	Primary Mode of Operation(3)	Secondary Method of Actuation(12)	Normal Valve Position(4)	Shutdown Valve Position(10)	Post-Accident Position(9)	Power Failure Valve Position	Containment Isolation Signal(5)	Valve Closure Time, S	Power Source(6)	Remarks(7)
P-216B	AC motor	Manual	0	0	0	AS IS	None	NA	D	s,cc
P-216C	AC motor	Manual	0	0	0	AS IS	None	NA	C	s,cc
P-216D	AC motor	Manual	0	0	0	AS IS	None	NA	A	s,cc
P-217A	Spring	None	C	C	C	NA	-	-	-	q,s,cc
	AC motor	Manual	C	C	C	AS IS	H,K (18)	80	B	t,cc
	AC motor	Manual	0	C	C	AS IS	None	NA	B	j,s,cc
P-217B	Spring	None	C	C	C	NA	-	-	-	q,s,cc
	AC motor	Manual	C	C	C	AS IS	H,K (18)	80	A	t,cc
	AC motor	Manual	0	C	C	AS IS	None	NA	A	j,s,cc
P-219	Spring	Manual	C	C	0	C	None	NA	A	s
	Flow	Manual	C	C	C	C	-	NA	N	s
	AC motor	Manual	C	0	C	AS IS	A,H,I	45	B	s,x
	AC motor	Manual	C	0	C	AS IS	A,H,I	45	D	s,x
	Spring	Manual	C	C	C	C	A,H,I	5	A	t,x
	Spring	Manual	C	C	C	C	A,H,I	15	D	t,x
	Spring	Manual	C	C	C	C	A,H,I	5	D	t,x
	Spring	Manual	C	C	C	C	None	NA	D	t
P-220	Spring	Manual	C	C	C	C	A,H,I	5	A	t,v,x
	AC motor	Manual	C	0	C	AS IS	A,H,I	45	A	s,x
	AC motor	Manual	C	0	C	AS IS	A,H,I	45	C	s,x
	Spring	Manual	C	C	0	C	None	NA	B	s
	Flow	None	C	C	C	C	-	NA	N	s
	Spring	Manual	C	C	C	C	A,N,I	5	D	t,x
P-221A										m
P-221B										m
P-221C										m
P-221D										m

TABLE 6.2-16 (Cont)

CONTAINMENT PENETRATIONS

Containment Penetration Number	Line Isolated	Fluid	Line Size, in.	NRC General Design Criterion	ESF System(11)	Valve Number and/or Orifice Plate	Valve Type(1)	Valve Location	Valve Arrangement(2) P&ID(8)	Type C Test	Length of Pipe from Cont. to Outside Valves, ft.
P-222	Torus Water Cleanup Return	Water	6	56	No	EE-V002	GT	Outside	33/W	Yes	16.0
			6			EE-V001	GT	Outside		Yes	19.3
P-223	Torus Water Cleanup Supply	Water	6	56	No	EE-V003	GT	Outside	33/W	Yes	20.4
			6			EE-V004	GT	Outside		Yes	22.0
P-224	Spare										
P-225	Not Used										
P-226	Spare										
P-227	Post Accident Liquid Sampling System Return	Water	1	56	No	RC-SV-0643A	GB	Outside	47/X	Yes	-
						RC-SV-0643B	GB	Outside		Yes	15.5
P-228	Suppression Pool Water Level	Water	2	56	Yes	BJ-V501	GT	Outside	46/F	No	23.0
P-229 (A-H)	Vent Pipe										
P-230 (A-H)	Vacuum Break Connection										
P-231 (A-H)	Vent Pipe Drain										
P-232 (A-R)	SRV Discharge										

TABLE 6.2-16 (Cont)

CONTAINMENT PENETRATIONS

Containment Penetration Number	Primary Mode of Operation(3)	Secondary Method of Actuation(12)	Normal Valve Position(4)	Shutdown Valve Position(10)	Post-Accident Position(9)	Power Failure Valve Position	Containment Isolation Signal(5)	Valve Closure Time, S	Power Source(6)	Remarks(7)
P-222	AC motor	Manual	C	C	C	AS IS	A,H,I	45	A	t
	AC motor	Manual	C	C	C	AS IS	A,H,I	45	B	t
P-223	AC motor	Manual	C	C	C	AS IS	A,H,I	45	A	t
	AC motor	Manual	C	C	C	AS IS	A,H,I	45	B	t
P-224										m
P-225										m
P-226										
P-227	Spring	Manual	C	0	C	C	None	NA	N	t
	Spring	Manual	C	0	C	C	None	NA	N	t
P-228	AC motor	Manual	0	0	0	AS IS	None	NA	A	s,cc
P-229 (A-H)										k
P-230 (A-H)										k
P-231 (A-H)										k
P-232 (A-R)										k

CONTAINMENT PENETRATIONS

Containment Penetration Number	Line Isolated	Fluid	Line Size, in.	NRC General Design Criterion	ESF System(11)	Valve Number and/or Orifice Plate	Valve Type(1)	Valve Location	Valve Arrangement(2) P&ID(8)	Type C Test	Length of Pipe from Cont. to Outside Valves, ft.
INSTRUMENTATION LINE PENETRATIONS											
J-2A	Spare										
J-2B	Spare										
J-2C	RPV Level & Pressure Switch	Water/Steam	1	55	-	3725	FO XV	Inside Outside	37/Y	No	- 0.9
J-2D	Spare										
J-2E	Spare										
J-2F	Spare										
J-3A	RPV Level	Water/Steam	1	55	-	3621	FO XV	Inside Outside	37/Y	No	- 0.9
J-3B	"B" Hydrogen/ Oxygen Analyzer Gas Inlet	Gas	1	56	Yes	GS-V031 GS-V032	GB GB	Outside Outside	38/AA	Yes Yes	- 35.0
J-3C	Spare										
J-3D	Spare										
J-3E	Spare										
J-3F	Spare										
J-4A	Spare										
J-4B	Spare										
J-4C	Spare										
J-4D	Spare										
J-4E	Spare										
J-4F	Spare										

CONTAINMENT PENETRATIONS

Containment Penetration Number	Primary Mode of Operation(3)	Secondary Method of Actuation(12)	Normal Valve Position(4)	Shutdown Valve Position(10)	Post-Accident Position(9)	Power Failure Valve Position	Containment Isolation Signal(5)	Valve Closure Time, S	Power Source(6)	Remarks(7)
INSTRUMENTATION LINE PENETRATIONS										
J-2A										m
J-2B										m
J-2C	Flow	None	0	0	0	NA	NA	NA	NA	u,cc
J-2D										m
J-2E										m
J-2F										m
J-3A	Flow	None	0	0	0	NA	NA	NA	NA	u,cc
J-3B	AC motor	Manual	C	0	C	AS IS	A,H,I	45	B	t,x
	AC motor	Manual	C	0	C	AS IS	A,H,I	45	D	t,x
										m
J-3C										m
J-3D										m
J-3E										m
J-3F										m
J-4A										m
J-4B										m
J-4C										m
J-4D										m
J-4E										m
J-4F										m

TABLE 6.2-16 (Cont)

CONTAINMENT PENETRATIONS

Containment Penetration Number	Line Isolated	Fluid	Line Size, in.	NRC General Design Criterion	ESF System(11)	Valve Number and/or Orifice Plate	Valve Type(1)	Valve Location	Valve Arrangement(2) P&ID(8)	Type C Test	Length of Pipe from Cont. to Outside Valves, ft.
J-5A	RCPB Leakage Radio Gas Sampler	Gas	1 1	56	No	SK-V008 SK-V009	GB GB	Outside Outside	38/BB	Yes Yes	24.9
J-5B	Spare										
J-5C	RPV Pressure & Head Drain	Water/Steam	1	55	-	3649	FO XV	Inside Outside	37/J	No	- 0.9
J-5D	Spare										
J-5E	Spare										
J-5F	Spare										
J-6A	Drywell Pressure	Gas	1	56	Yes	BB-V563	GB	Outside	39/Y	No	21.5
J-6B	Spare										
J-6C	Spare										
J-6D	Spare										
J-6E	Spare										
J-6F	Spare										
J-7A	Drywell Pressure	Gas	1	56	Yes	BB-V565	GB	Outside	39/Y	No	22.5
J-7B	Spare										
J-7C	Spare										
J-7D	"B" Hydrogen/ Oxygen Analyzer Inlet	Gas	1	56	Yes	GS-V033 GS-V034 GS-V053	GB GB GB	Outside Outside Outside	40/AA	Yes Yes Yes	- 39.7 223.8
J-7E	Post Accident Gas Sampling System	Gas	1	56	No	RC-SV-0730A RC-SV-0730B	GB GB	Outside Outside	47/CC	Yes Yes	- 35.2
J-7F	Spare										

TABLE 6.2-16 (Cont)

CONTAINMENT PENETRATIONS

Containment Penetration Number	Primary Mode of Operation(3)	Secondary Method of Actuation(12)	Normal Valve Position(4)	Shutdown Valve Position(10)	Post-Accident Position(9)	Power Failure Valve Position	Containment Isolation Signal(5)	Valve Closure Time, S	Power Source(6)	Remarks(7)
J-5A	AC motor	Manual	0	C	C	AS IS	A,H,I	45	A	t
	AC motor	Manual	0	C	C	AS IS	A,H,I	45	D	t
J-5B										m
J-5C	Flow	None	0	0	0	NA	NA	NA	NA	u,cc
J-5D										m
J-5E										m
J-5F										m
J-6A	None	Manual (14)	0	0	0	NA	NA	NA	NA	s,cc
J-6B										m
J-6C										m
J-6D										m
J-6E										m
J-6F										m
J-7A	None	Manual (14)	0	0	0	NA	NA	NA	NA	s,cc
J-7B										m
J-7C										m
J-7D	AC motor	Manual	C	C	0	AS IS	A,H,I	45	B	t,w,x
	AC motor	Manual	C	C	0	AS IS	A,H,I	45	D	t,x
	AC motor	Manual	C	C	0	AS IS	A,H,I	45	D	t,x
J-7E	Spring	Manual	C	0	C	C	None	NA	N	t
	Spring	Manual	C	0	C	C	None	NA	N	t
J-7F										m

TABLE 6.2-16 (Cont)

CONTAINMENT PENETRATIONS

Containment Penetration Number	Line Isolated	Fluid	Line Size, in.	NRC General Design Criterion	ESF System(11)	Valve Number and/or Orifice Plate	Valve Type(1)	Valve Location	Valve Arrangement(2) P&ID(8)	Type C Test	Length of Pipe from Cont. to Outside Valves, ft.
J-8A	Spare										
J-8B	Spare										
J-8C	RCPB Leak Detection	Gas	1	56	No	SK-V005 SK-V006	GB GB	Outside Outside	38/BB	Yes Yes	- 27.7
J-8D	Drywell Pressure	Gas	1	56	Yes	BB-V564	GB	Outside	39/Y	No	19.5
J-8E	Spare										
J-8F	Spare										
J-9A	Spare										
J-9B	Spare										
J-9C	Spare										
J-9D	Spare										
J-9E	"A" Hydrogen/ Oxygen Analyzer Inlet	Gas	1	56	Yes	GS-V045 GS-V046	GB GB	Outside Outside	38/AA	Yes Yes	- 35.9
J-9F	Spare										
J-10A	Spare										
J-10B	Spare										
J-10C	"A" Hydrogen/ Oxygen Analyzer Inlet	Gas	1	56	Yes	GS-V047 GS-V048	GB GB	Outside Outside	38/AA	Yes Yes	- 26.1
J-10D	Drywell Pressure	Gas	1	56	Yes	BB-V566	GB	Outside	39/Y	No	19.1
J-10E	Post-Accident Gas Sampling System	Gas	1	56	No	RC-SV-0731A RC-SV-0731B	GB GB	Outside Outside	47/CC 47	Yes Yes	- 31.3
J-10F	Spare										

CONTAINMENT PENETRATIONS

Containment Penetration Number	Primary Mode of Operation(3)	Secondary Method of Actuation(12)	Normal Valve Position(4)	Shutdown Valve Position(10)	Post-Accident Position(9)	Power Failure Valve Position	Containment Isolation Signal(5)	Valve Closure Time, S	Power Source(6)	Remarks(7)
J-8A										m
J-8B										m
J-8C	AC motor	Manual	0	C	C	AS IS	A,H,I	45	A	t
	AC motor	Manual	0	C	C	AS IS	A,H,I	45	D	t
J-8D	None	Manual (14)	0	0	0	NA	NA	NA	NA	s,cc
J-8E										m
J-8F										m
J-9A										m
J-9B										m
J-9C										m
J-9D										m
J-9E	AC motor	Manual	C	0	C	AS IS	A,H,I	45	A	t,x
	AC motor	Manual	C	0	C	AS IS	A,H,I	45	C	t,x
J-9F										m
J-10A										m
J-10B										m
J-10C	AC motor	Manual	C	0	C	AS IS	A,H,I	45	A	t,x
	AC motor	Manual	C	0	C	AS IS	A,H,I	45	C	t,x
J-10D	None	Manual (14)	0	0	0	NA	NA	NA	NA	s,cc
J-10E	Spring	Manual	C	0	C	C	None	NA	N	t
	Spring	Manual	C	0	C	C	None	NA	N	t
J-10F										m

CONTAINMENT PENETRATIONS

Containment Penetration Number	Line Isolated	Fluid	Line Size, in.	NRC General Design Criterion	ESF System(11)	Valve Number and/or Orifice Plate	Valve Type(1)	Valve Location	Valve Arrangement(2) P&ID(8)	Type C Test	Length of Pipe from Cont. to Outside Valves, ft.
J-11A	Reactor Recir Flow-Loop B	Water/ Steam	1	55	-	3732B	FO XV	Inside Outside	37/Y	No	- 0.9
J-11B	Reactor Recir Flow-Loop B	Water/Steam	1	55	-	3732D	FO XV	Inside Outside	37/Y	No	- 0.9
J-11C	Spare										
J-11D	Spare										
J-11E	Reactor Recir Flow-Loop B	Water/Steam	1	55	-	3732K	FO XV	Inside Outside	37/Y	No	- 0.9
J-11F	Spare Instr	Gas	1	NA	NA	NA	NA	NA	48A/-	NA	0.9
J-12A	Spare										
J-12B	Reactor Recir Flow-Loop B	Water/Steam	1	55	-	3732P	FO XV	Inside Outside	37/Y	No	- 0.9
J-12C	Reactor Recir Flow-Loop B	Water/Steam	1	55	-	3732S	FO XV	Inside Outside	37/Y	No	- 0.9
J-12D	Spare										
J-12E	Reactor Recir Flow-Loop B	Water/Steam	1	55	-	3732W	FO XV	Inside Outside	37/Y	No	- 0.9
J-12F	Reactor Recir Flow-Loop B	Water/Steam	1	55	-	3734D	FO XV	Inside Outside	37/Y	No	- 0.9
J-13A	Spare										
J-13B	Spare										
J-13C	Spare										
J-13D	Reactor Recirc Flow	Water/Steam	1	55	-	3738A	FO XV	Inside Outside	37/Y	No	- 0.9
J-13E	Spare										
J-13F	Spare										

TABLE 6.2-16 (Cont)

CONTAINMENT PENETRATIONS

Containment Penetration Number	Primary Mode of Operation(3)	Secondary Method of Actuation(12)	Normal Valve Position(4)	Shutdown Valve Position(10)	Post-Accident Position(9)	Power Failure Valve Position	Containment Isolation Signal(5)	Valve Closure Time, S	Power Source(6)	Remarks(7)
J-11A	Flow	None	0	0	0	NA	NA	NA	NA	u,cc
J-11B	Flow	None	0	0	0	NA	NA	NA	NA	u,cc
J-11C										m
J-11D										m
J-11E	Flow	None	0	0	0	NA	NA	NA	NA	u,cc
J-11F	NA	NA	NA	NA	NA	NA	NA	NA	NA	m
J-12A										m
J-12B	Flow	None	0	0	0	NA	NA	NA	NA	u,cc
J-12C	Flow	None	0	0	0	NA	NA	NA	NA	u,cc
J-12D										m
J-12E	Flow	None	0	0	0	NA	NA	NA	NA	u,cc
J-12F	Flow	None	0	0	0	NA	NA	NA	NA	u,cc
J-13A										m
J-13B										m
J-13C										m
J-13D	Flow	None	0	0	0	NA	NA	NA	NA	u,cc
J-13E										m
J-13F										m

TABLE 6.2-16 (Cont)

CONTAINMENT PENETRATIONS

Containment Penetration Number	Line Isolated	Fluid	Line Size, in.	NRC General Design Criterion	ESF System(11)	Valve Number and/or Orifice Plate	Valve Type(1)	Valve Location	Valve Arrangement(2) P&ID(8)	Type C Test	Length of Pipe from Cont. to Outside Valves, ft.
J-14A	Reactor Recir Flow-Loop A	Water/Steam	1	55	-	3732L	FO XV	Inside Outside	37/Y	No	- 0.9
J-14B	Reactor Recir Flow-Loop A	Water/Steam	1	55	-	3732N	FO XV	Inside Outside	37/Y	No	- 0.9
J-14C	Reactor Recir Flow-Loop A	Water/Steam	1	55	-	3732R	FO XV	Inside Outside	37/Y	No	- 0.9
J-14D	Reactor Recir Flow-Loop A	Water/Steam	1	55	-	3732T	FO XV	Inside Outside	37/Y	No	- 0.9
J-14E	Reactor Recir Flow-Loop A	Water/Steam	1	55	-	3732V	FO XV	Inside Outside	37/Y	No	- 0.9
J-14F	Reactor Recir Flow-Loop B	Water/Steam	1	55	-	3734C	FO XV	Inside Outside	37/Y	No	- 0.9
J-15A	Spare										
J-15B	Spare										
J-15C	Spare										
J-15D	Spare										
J-15E	Spare										
J-15F	Spare										
J-16A	Spare										
J-16B	Spare										
J-16C	Reactor Flow	Water/Steam	1	55	-	3737B	FO XV	Inside Outside	37/Y	No	- 0.9
J-16D	Spare										

CONTAINMENT PENETRATIONS

Containment Penetration Number	Primary Mode of Operation(3)	Secondary Method of Actuation(12)	Normal Valve Position(4)	Shutdown Valve Position(10)	Post-Accident Position(9)	Power Failure Valve Position	Containment Isolation Signal(5)	Valve Closure Time, S	Power Source(6)	Remarks(7)
J-14A	Flow	None	0	0	0	NA	NA	NA	NA	u,cc
J-14B	Flow	None	0	0	0	NA	NA	NA	NA	u,cc
J-14C	Flow	None	0	0	0	NA	NA	NA	NA	u,cc
J-14D	Flow	None	0	0	0	NA	NA	NA	NA	u,cc
J-14E	Flow	None	0	0	0	NA	NA	NA	NA	u,cc
J-14F	Flow	None	0	0	0	NA	NA	NA	NA	u,cc
J-15A										m
J-15B										m
J-15C										m
J-15D										m
J-15E										m
J-15F										m
J-16A										m
J-16B										m
J-16C	Flow	None	0	0	0	NA	NA	NA	NA	u,cc
J-16D										m

TABLE 6.2-16 (Cont)

CONTAINMENT PENETRATIONS

Containment Penetration Number	Line Isolated	Fluid	Line Size, in.	NRC General Design Criterion	ESF System(11)	Valve Number and/or Orifice Plate	Valve Type(1)	Valve Location	Valve Arrangement(2) P&ID(8)	Type C Test	Length of Pipe from Cont. to Outside Valves, ft.
J-16E	Recirc Flow	Water/Steam	1 1	55	-	3801C	FO XV	Inside Outside	37/K	No	- 0.9
J-16F	Recirc Flow	Water/Steam	1 1	55	-	3802C	FO XV	Inside Outside	37/K	No	- 0.9
J-17A	Spare										
J-17B	Spare										
J-17C	Spare										
J-17D	Spare										
J-17E	Spare										
J-17F	Spare										
J-18A	Spare										
J-18B	Recirc Flow	Water/Steam	1	55	-	3801A	FO XV	Inside Outside	37/K	No	- 0.9
J-18C	Spare										
J-18D	Spare										
J-18E	Spare										
J-18F	Recirc Flow	Water/Steam	1	55	-	3802A	FO XV	Inside Outside	37/K	No	- 0.9
J-19A	HPCI Turbine Steam Supply	Steam/Water	1	55	-	4800A	FO XV	Inside Outside	37/F	No	- 0.9
J-19B	HPCI Turbine Steam Supply	Steam/Water	1	55	-	4800C	FO XV	Inside Outside	37/F	No	- 0.9
J-19C	Core Spray Flow	Water	1	55	-	4575A F018A	FO XV	Inside Outside	37/U	No	- 0.9
J-19D	RWCU Flow	Water/Steam	1	55	-	3884A	FO XV	Inside Outside	37/H	No	- 0.1
J-19E	RWCU Flow	Water/Steam	1	55	-	3884C	FO XV	Inside Outside	37/H	No	- 0.1

CONTAINMENT PENETRATIONS

Containment Penetration Number	Primary Mode of Operation(3)	Secondary Method of Actuation(12)	Normal Valve Position(4)	Shutdown Valve Position(10)	Post-Accident Position(9)	Power Failure Valve Position	Containment Isolation Signal(5)	Valve Closure Time, S	Power Source(6)	Remarks(7)
J-16E	Flow	None	0	0	0	NA	NA	NA	NA	u,cc
J-16F	Flow	None	0	0	0	NA	NA	NA	NA	u,cc
J-17A										m
J-17B										m
J-17C										m
J-17D										m
J-17E										m
J-17F										m
J-18A										m
J-18B	Flow	None	0	0	0	NA	NA	NA	NA	u,cc
J-18C										m
J-18D										m
J-18E										m
J-18F	Flow	None	0	0	0	NA	NA	NA	NA	u,cc
J-19A	Flow	None	0	0	0	NA	NA	NA	NA	u,cc
J-19B	Flow	None	0	0	0	NA	NA	NA	NA	u,cc
J-19C	Flow	None	0	0	0	NA	NA	NA	NA	u,cc
J-19D	Flow	None	0	0	0	NA	NA	NA	NA	u,cc
J-19E	Flow	None	0	0	0	NA	NA	NA	NA	u,cc

CONTAINMENT PENETRATIONS

Containment Penetration Number	Line Isolated	Fluid	Line Size, in.	NRC General Design Criterion	ESF System(11)	Valve Number and/or Orifice Plate	Valve Type(1)	Valve Location	Valve Arrangement(2) P&ID(8)	Type C Test	Length of Pipe from Cont. to Outside Valves, ft.
J-19F	Spare Instr	Gas	1	NA	NA	NA	NA	NA	48A/-	NA	0.9
J-20A	RCIC Turbine Steam Supply	Steam/Water	1	55	-	4150A	FO XV	Inside Outside	37/I	No	- 0.9
J-20B	RCIC Turbine Steam Supply	Steam/Water	1	55	-	4150C	FO XV	Inside Outside	37/I	No	- 0.9
J-20C	Spare										
J-20D	Spare Instr	Gas	1	NA	NA	NA	NA	NA	48A/-	NA	0.9
J-20E	Spare										
J-20F	Spare										
J-21A	Main Steam Flow-Line C	Steam/Water	1	55	-	3667C	FO XV	Inside Outside	37/GG	No	- 0.9
J-21B	Spare										
J-21C	Spare										
J-21D	Main Steam Flow-Line D	Steam/Water	1	55	-	3667D	FO XV	Inside Outside	37/GG	No	- 0.9
J-21E	Main Steam Flow-Line C	Steam/Water	1	55	-	3668C	FO XV	Inside Outside	37/GG	No	- 0.9
J-21F	Main Steam Flow-Line D	Steam/Water	1	55	-	3668D	FO XV	Inside Outside	37/GG	No	- 0.9
J-22A	Main Steam Flow-Line A	Steam/Water	1	55	-	3667A	FO XV	Inside Outside	37/GG	No	- 0.9
J-22B	Main Steam Flow-Line A	Steam/Water	1	55	-	3668A	FO XV	Inside Outside	37/GG	No	- 0.9
J-22C	Main Steam Flow-Line B	Steam/Water	1	55	-	3667B	FO XV	Inside Outside	37/GG	No	- 0.9

CONTAINMENT PENETRATIONS

Containment Penetration Number	Primary Mode of Operation(3)	Secondary Method of Actuation(12)	Normal Valve Position(4)	Shutdown Valve Position(10)	Post-Accident Position(9)	Power Failure Valve Position	Containment Isolation Signal(5)	Valve Closure Time, S	Power Source(6)	Remarks(7)
J-19F	NA	NA	NA	NA	NA	NA	NA	NA	NA	m
J-20A	Flow	None	0	0	0	NA	NA	NA	NA	u,cc
J-20B	Flow	None	0	0	0	NA	NA	NA	NA	u,cc
J-20C										m
J-20D	NA	NA	NA	NA	NA	NA	NA	NA	NA	m
J-20E										m
J-20F										m
J-21A	Flow	None	0	0	0	NA	NA	NA	NA	u,cc
J-21B										m
J-21C										m
J-21D	Flow	None	0	0	0	NA	NA	NA	NA	u,cc
J-21E	Flow	None	0	0	0	NA	NA	NA	NA	u,cc
J-21F	Flow	None	0	0	0	NA	NA	NA	NA	u,cc
J-22A	Flow	None	0	0	0	NA	NA	NA	NA	u,cc
J-22B	Flow	None	0	0	0	NA	NA	NA	NA	u,cc
J-22C	Flow	None	0	0	0	NA	NA	NA	NA	u,cc

Containment Penetration Number	Line Isolated	Fluid	Line Size, in.	NRC General Design Criterion	ESF System(11)	Valve Number and/or Orifice Plate	Valve Type(1)	Valve Location	Valve Arrangement(2) P&ID(8)	Type C Test	Length of Pipe from Cont. to Outside Valves, ft.
J-22D	Main Steam Flow-Line B	Steam/Water	1	55	-	3668B	FO XV	Inside Outside	37/J	No	- 0.9
J-22E	Spare										
J-22F	Spare										
J-23A	RHR LPCI Check Valve Pressure	Water	1	55	-	4429B	FO XV	Inside Outside	37/D	No	- 0.9
J-23B	RHR LPCI Check Valve Pressure	Water	1	55	-	4411B	FO XV	Inside Outside	37/D	No	- 0.9
J-23C	Recirc Pump Differential Pressure	Water/Steam	1	55	-	3827	FO XV	Inside Outside	37/K	No	- 0.9
J-23D	Spare										
J-23E	Spare										
J-23F	Spare										
J-24A	Recirc Flow	Water/Steam	1 1	55	-	3803B	FO XV	Inside Outside	37/K	No	- 0.9
J-24B	Recirc Flow	Water/Steam	1 1	55	-	3804B	FO XV	Inside Outside	37/K	No	- 0.9
J-24C	RWCU Flow	Water	1	55	-	3882	FO XV	Inside Outside	37/H	No	- 0.9
J-24D	Spare Instr	Gas	1	NA	NA	NA	NA	NA	48A/-	NA	0.9
J-24E	Reactor Recirc Flow Loop B	Water/Steam	1	55		3732C	FO XV	Inside Outside	37/Y	No	- 0.9
J-24F	Spare										
J-25A	Main Steam Flow-Line A	Steam/Water	1	55	-	3666A	FO XV	Inside Outside	37/GG	No	- 0.9
J-25B	Spare										

CONTAINMENT PENETRATIONS

Containment Penetration Number	Primary Mode of Operation(3)	Secondary Method of Actuation(12)	Normal Valve Position(4)	Shutdown Valve Position(10)	Post-Accident Position(9)	Power Failure Valve Position	Containment Isolation Signal(5)	Valve Closure Time, S	Power Source(6)	Remarks(7)
J-22D	Flow	None	0	0	0	NA	NA	NA	NA	u,cc
J-22E										m
J-22F										m
J-23A	Flow	None	0	0	0	NA	NA	NA	NA	u,cc
J-23B	Flow	None	0	0	0	NA	NA	NA	NA	u,cc
J-23C	Flow	None	0	0	0	NA	NA	NA	NA	u,cc
J-23D										m
J-23E										m
J-23F										m
J-24A	Flow	None	0	0	0	NA	NA	NA	NA	u,cc
J-24B	Flow	None	0	0	0	NA	NA	NA	NA	u,cc
J-24C	Flow	None	0	0	0	NA	NA	NA	NA	u,cc
J-24D	NA	NA	NA	NA	NA	NA	NA	NA	NA	m
J-24E	Flow	None	0	0	0	NA	NA	NA	NA	u,cc
J-24F										m
J-25A	Flow	None	0	0	0	NA	NA	NA	NA	u,cc
J-25B										m

TABLE 6.2-16 (Cont)

CONTAINMENT PENETRATIONS

Containment Penetration Number	Line Isolated	Fluid	Line Size, in.	NRC General Design Criterion	ESF System(11)	Valve Number and/or Orifice Plate	Valve Type(1)	Valve Location	Valve Arrangement(2) P&ID(8)	Type C Test	Length of Pipe from Cont. to Outside Valves, ft.
J-25C	Main Steam Flow-Line A	Steam/Water	1	55	-	3669A	FO XV	Inside Outside	37/GG	No	- 0.9
J-25D	Spare										
J-25E	Spare										
J-25F	Spare										
J-26A	Main Steam Flow-Line B	Steam/Water	1	55	-	3666B	FO XV	Inside Outside	37/GG	No	- 0.9
J-26B	Spare										
J-26C	Main Steam Flow-Line B	Steam/Water	1	55	-	3669B	FO XV	Inside Outside	37/GG	No	- 0.9
J-26D	Spare										
J-26E	Spare										
J-26F	Spare										
J-27A	Main Steam Flow-Line C	Steam/Water	1	55	-	3666C	FO XV	Inside Outside	37/GG	No	- 0.9
J-27B	Spare										
J-27C	Spare Instr	Gas	1	NA	NA	NA	NA	NA	48A/-	NA	0.9
J-27D	Main Steam Flow-Line C	Steam/Water	1	55	-	3669C	FO XV	Inside Outside	37/GG	No	- 0.9
J-27E	Spare										
J-27F	Spare Instr	Gas	1	NA	NA	NA	NA	NA	48A/-	NA	0.9
J-28A	Main Steam Flow-Line D	Steam/Water	1	55	-	3666D	FO XV	Inside Outside	37/GG	No	- 0.9
J-28B	Recirc Flow	Steam/Water	1	55	-	3801A 3801B	FO XV	Inside Outside	37/K	No	- 0.9
J-28C	Spare										

CONTAINMENT PENETRATIONS

Containment Penetration Number	Primary Mode of Operation(3)	Secondary Method of Actuation(12)	Normal Valve Position(4)	Shutdown Valve Position(10)	Post-Accident Position(9)	Power Failure Valve Position	Containment Isolation Signal(5)	Valve Closure Time, S	Power Source(6)	Remarks(7)
J-25C	Flow	None	0	0	0	NA	NA	NA	NA	u,cc
J-25D										m
J-25E										m
J-25F										m
J-26A	Flow	None	0	0	0	NA	NA	NA	NA	u,cc
J-26B										m
J-26C	Flow	None	0	0	0	NA	NA	NA	NA	u,cc
J-26D										m
J-26E										m
J-26F										m
J-27A	Flow	None	0	0	0	NA	NA	NA	NA	u,cc
J-27B										m
J-27C	NA	NA	NA	NA	NA	NA	NA	NA	NA	m
J-27D	Flow	None	0	0	0	NA	NA	NA	NA	u,cc
J-27E										m
J-27F	NA	NA	NA	NA	NA	NA	NA	NA	NA	m
J-28A	Flow	None	0	0	0	NA	NA	NA	NA	u,cc
J-28B	Flow	None	0	0	0	NA	NA	NA	NA	u,cc
J-28C										m

CONTAINMENT PENETRATIONS

Containment Penetration Number	Line Isolated	Fluid	Line Size, in.	NRC General Design Criterion	ESF System(11)	Valve Number and/or Orifice Plate	Valve Type(1)	Valve Location	Valve Arrangement(2) P&ID(8)	Type C Test	Length of Pipe from Cont. to Outside Valves, ft.
J-28D	Main Steam Flow-Line D	Steam/Water	1	55	-	3669D	FO XV	Inside Outside	37/GG	No	- 0.9
J-28E	Spare										
J-28F	Recirc Flow	Water	1	55	-	3802A 3802B	FO XV	Inside Outside	37/K	No	- 0.9
J-29A	HPCI Turbine Steam Supply	Steam/Water	1	55	-	4800B	FO XV	Inside Outside	37/F	No	- 0.9
J-29B	HPCI Turbine Steam Supply	Steam/Water	1	55	-	4800D	FO XV	Inside Outside	37/F	No	- 0.9
J-29C	Spare										
J-29D	Recirc Flow	Water/Steam	1 1	55	-	3804B 3804A	FO XV	Inside Outside	37/K	No	- 0.9
J-29E	Spare										
J-29F	Recirc Flow	Water/Steam	1 1	55	-	3803B 3803A	FO XV	Inside Outside	37/K	No	- 0.9
J-30A	Spare										
J-30B	Recirc Pump Cooling-Loop A	Water/Steam	1	55	-	3789	FO XV	Inside Outside	37/K	No	- 0.9
J-30C	Recirc Pump Cooling-Loop A	Water	1	55	-	3787	FO XV	Inside Outside	37/K	No	- 0.9
J-30D	Spare										
J-30E	Spare										
J-30F	Core Spray Flow	Water	1	55	-	4575B F018B	FO XV	Inside Outside	37/U	No	- 0.9
J-31A	Spare										
J-31B	Spare										

CONTAINMENT PENETRATIONS

Containment Penetration Number	Primary Mode of Operation(3)	Secondary Method of Actuation(12)	Normal Valve Position(4)	Shutdown Valve Position(10)	Post-Accident Position(9)	Power Failure Valve Position	Containment Isolation Signal(5)	Valve Closure Time, S	Power Source(6)	Remarks(7)
J-28D	Flow	None	0	0	0	NA	NA	NA	NA	u,cc
J-28E										m
J-28F	Flow	None	0	0	0	NA	NA	NA	NA	u,cc
J-29A	Flow	None	0	0	0	NA	NA	NA	NA	u,cc
J-29B	Flow	None	0	0	0	NA	NA	NA	NA	u,cc
J-29C										m
J-29D	Flow	None	0	0	0	NA	NA	NA	NA	u,cc
J-29E										m
J-29F	Flow	None	0	0	0	NA	NA	NA	NA	u,cc
J-30A										m
J-30B	Flow	None	0	0	0	NA	NA	NA	NA	u,cc
J-30C	Flow	None	0	0	0	NA	NA	NA	NA	u,cc
J-30D										m
J-30E										m
J-30F	Flow	None	0	0	0	NA	NA	NA	NA	u,cc
J-31A										m
J-31B										m

TABLE 6.2-16 (Cont)

CONTAINMENT PENETRATIONS

Containment Penetration Number	Line Isolated	Fluid	Line Size, in.	NRC General Design Criterion	ESF System(11)	Valve Number and/or Orifice Plate	Valve Type(1)	Valve Location	Valve Arrangement(2) P&ID(8)	Type C Test	Length of Pipe from Cont. to Outside Valves, ft.
J-31C	Spare										
J-31D	Spare										
J-31E	Spare										
J-31F	Spare										
J-32A	Spare										
J-32B	Recirc Pump Cooler-Loop B	Water/Steam	1	55	-	3783	FO XV	Inside Outside	37/K	No	- 0.9
J-32C	Recirc Pump Cooler-Loop B	Water/Steam	1	55	-	3785	FO XV	Inside Outside	37/K	No	- 0.9
J-32D	Spare										
J-32E	Recirc Pump Differential Pressure	Water/Steam	1	55	-	3820	FO XV	Inside Outside	37/K	No	- 0.9
J-32F	Recirc Pump Differential Pressure	Water/Steam	1	55	-	3821	FO XV	Inside Outside	37/K	No	- 0.9
J-33A	RHR LPCI Check Valve Pressure	Water	1	55	-	4411A	FO XV	Inside Outside	37/DD	No	- 0.9
J-33B	Spare										
J-33C	Spare										
J-33D	RHR LPCI Check Valve Pressure	Water	1	55	-	4429A	FO XV	Inside Outside	37/DD	No	- 0.9
J-33E	Spare										
J-33F	Spare										
J-34A	RWCU Flow	Water/Steam	1	55	-	3884B	FO XV	Inside Outside	37/H	No	- 0.9
J-34B	Recirc Pump Differential Pressure	Water/Steam	1	55	-	3826	FO XV	Inside Outside	37/K	No	- 0.9

TABLE 6.2-16 (Cont)

CONTAINMENT PENETRATIONS

Containment Penetration Number	Primary Mode of Operation(3)	Secondary Method of Actuation(12)	Normal Valve Position(4)	Shutdown Valve Position(10)	Post-Accident Position(9)	Power Failure Valve Position	Containment Isolation Signal(5)	Valve Closure Time, S	Power Source(6)	Remarks(7)
J-31C										m
J-31D										m
J-31E										m
J-31F										m
J-32A										m
J-32B	Flow	None	0	0	0	NA	NA	NA	NA	u,cc
J-32C	Flow	None	0	0	0	NA	NA	NA	NA	u,cc
J-32D										m
J-32E	Flow	None	0	0	0	NA	NA	NA	NA	u,cc
J-32F	Flow	None	0	0	0	NA	NA	NA	NA	u,cc
J-33A	Flow	None	0	0	0	NA	NA	NA	NA	u,cc
J-33B										m
J-33C										m
J-33D	Flow	None	0	0	0	NA	NA	NA	NA	u,cc
J-33E										m
J-33F										m
J-34A	Flow	None	0	0	0	NA	NA	NA	NA	u,cc
J-34B	Flow	None	0	0	0	NA	NA	NA	NA	u,cc

TABLE 6.2-16 (Cont)

CONTAINMENT PENETRATIONS

Containment Penetration Number	Line Isolated	Fluid	Line Size, in.	NRC General Design Criterion	ESF System(11)	Valve Number and/or Orifice Plate	Valve Type(1)	Valve Location	Valve Arrangement(2) P&ID(8)	Type C Test	Length of Pipe from Cont. to Outside Valves, ft.
J-34C	RWCU Flow	Water/Steam	1	55	-	3884D	FO XV	Inside Outside	37/H	No	- 0.9
J-34D	Recirc Flow	Water/Steam	1	55	-	3803D	FO XV	Inside Outside	37/K	No	- 0.9
J-34E	Recirc Flow	Water/Steam	1	55	-	3726B 3804D	FO XV	Inside Outside	37/K	No	- 0.9
J-34F	Spare										
J-35A	RHR LPCI Check Valve Pressure	Water	1	55	-	4411C	FO XV	Inside Outside	37/DD	No	- 0.9
J-35B	Spare										
J-35C	RHR LPCI Check Valve Pressure	Water	1	55	-	4429C	FO XV	Inside Outside	37/DD	No	- 0.9
J-35D	Spare										
J-35E	Spare										
J-35F	Spare										
J-36A	RHR LPCI Check Valve Pressure	Water	1	55	-	4429D	FO XV	Inside Outside	37/C	No	- 0.9
J-36B	RHR LPCI Check Valve Pressure	Water	1	55	-	4411D	FO XV	Inside Outside	37/C	No	- 0.9
J-36C	ILRT Line	Gas	1	56	-	GP-V120 GP-V122	GB GB	Inside Outside	41/V	Yes Yes	- 0.7
J-36D	ILRT Line	Gas	1	56	-	GP-V001 GP-V002	GB GB	Inside Outside	41/V	Yes Yes	- 0.7
J-36E	Recirc Flow	Water/Steam	1 1	56	-	3801C 3801D	FO XV	Inside Outside	37/K	No	- 0.7
J-36F	Recirc Flow	Water/Steam	1 1	56	-	3802C 3802D	FO XV	Inside Outside	37/K	No	- 0.7

CONTAINMENT PENETRATIONS

Containment Penetration Number	Primary Mode of Operation(3)	Secondary Method of Actuation(12)	Normal Valve Position(4)	Shutdown Valve Position(10)	Post-Accident Position(9)	Power Failure Valve Position	Containment Isolation Signal(5)	Valve Closure Time, S	Power Source(6)	Remarks(7)
J-34C	Flow	None	0	0	0	NA	NA	NA	NA	u,cc
J-34D	Flow	None	0	0	0	NA	NA	NA	NA	u,cc
J-34E	Flow	None	0	0	0	NA	NA	NA	NA	u,cc
J-34F										m
J-35A	Flow	None	0		0	NA	NA	NA	NA	u,cc
J-35B										m
J-35C	Flow	None	0		0	NA	NA	NA	NA	u,cc
J-35D										m
J-35E										m
J-35F										m
J-36A	Flow	None	0	0	0	NA	NA	NA	NA	u,cc
J-36B	Flow	None	0	0	0	NA	NA	NA	NA	u,cc
J-36C	None	Manual (14)	C	C	C	NA	NA	NA	NA	r,t
	None	Manual (14)	C	C	C	NA	NA	NA	NA	t
J-36D	None	Manual (14)	C	C	C	NA	NA	NA	NA	r,t
	None	Manual (14)	C	C	C	NA	NA	NA	NA	t
J-36E	Flow	None	0	0	0	NA	NA	NA	NA	u,cc
J-36F	Flow	None	0	0	0	NA	NA	NA	NA	u,cc

CONTAINMENT PENETRATIONS

Containment Penetration Number	Line Isolated	Fluid	Line Size, in.	NRC General Design Criterion	ESF System(11)	Valve Number and/or Orifice Plate	Valve Type(1)	Valve Location	Valve Arrangement(2) P&ID(8)	Type C Test	Length of Pipe from Cont. to Outside Valves, ft.
J-37A	Reactor Recir Flow-Loop A	Water/Steam	1	55	-	3732A	FO XV	Inside Outside	37/Z	No	- 0.9
J-37B	Spare										
J-37C	Reactor Recir Flow Loop	Water/Steam	1	55	-	3732E	FO XV	Inside Outside	37/Z	No	- 0.9
J-37D	Reactor Recir Flow Loop	Water/Steam	1	55	-	3732G	FO XV	Inside Outside	37/Z	No	- 0.9
J-37E	Jet Pump Flow	Water/Steam	1	55	-	3732J	FO XV	Inside Outside	37/Y	No	- 0.9
J-37F	Spare Instr	Gas	1	NA	NA	NA	NA	NA	48A/-	NA	0.9
J-38A	Reactor Flow	Water/Steam	1	55	-	3737A	FO XV	Inside Outside	37/Y	No	- 0.9
J-38B	Reactor Flow	Water/Steam	1	55	-	3738B	FO XV	Inside Outside	37/Y	No	- 0.9
J-38C	Recirc Flow	Water/Steam	1	55	-	3803D 3803C	FO XV	Inside Outside	37/K	No	- 0.9
J-38D	Spare										
J-38E	Spare										
J-38F	Recirc Flow	Water/Steam	1	55	-	3804D 3804C	FO XV	Inside Outside	37/K	No	- 0.9
J-39A	Spare										
J-39B	Spare										
J-39C	Spare										
J-39D	Spare										
J-39E	Spare										

CONTAINMENT PENETRATIONS

Containment Penetration Number	Primary Mode of Operation(3)	Secondary Method of Actuation(12)	Normal Valve Position(4)	Shutdown Valve Position(10)	Post-Accident Position(9)	Power Failure Valve Position	Containment Isolation Signal(5)	Valve Closure Time, S	Power Source(6)	Remarks(7)
J-37A	Flow	None	0	0	0	NA	NA	NA	NA	u,cc
J-37B										m
J-37C	Flow	None	0	0	0	NA	NA	NA	NA	u,cc
J-37D	Flow	None	0	0	0	NA	NA	NA	NA	u,cc
J-37E	Flow	None	0	0	0	NA	NA	NA	NA	u,cc
J-37F	NA	NA	NA	NA	NA	NA	NA	NA	NA	m
J-38A	Flow	None	0	0	0	NA	NA	NA	NA	u,cc
J-38B	Flow	None	0	0	0	NA	NA	NA	NA	u,cc
J-38C	Flow	None	0	0	0	NA	NA	NA	NA	u,cc
J-38D										m
J-38E										m
J-38F	Flow	None	0	0	0	NA	NA	NA	NA	u,cc
J-39A										m
J-39B										m
J-39C										m
J-39D										m
J-39E										m

CONTAINMENT PENETRATIONS

Containment Penetration Number	Line Isolated	Fluid	Line Size, in.	NRC General Design Criterion	ESF System(11)	Valve Number and/or Orifice Plate	Valve Type(1)	Valve Location	Valve Arrangement(2) P&ID(8)	Type C Test	Length of Pipe from Cont. to Outside Valves, ft.
J-39F	Spare										
J-40A	RCIC Turbine Steam Supply Flow	Steam/Water	1	55	-	4150D	FO XV	Inside Outside	37/I	No	- 0.9
J-40B	RCIC Turbine Steam Supply Flow	Steam/Water	1	55	-	4150B	FO XV	Inside Outside	37/I	No	- 0.9
J-40C	Reactor Recirc Flow-Loop B	Water/Steam	1	55	-	3732F	FO XV	Inside Outside	37/Z	No	- 0.9
J-40D	Reactor Recirc Flow-Loop B	Water/Steam	1	55	-	3732U	FO XV	Inside Outside	37/Z	No	- 0.9
J-40E	Reactor Recirc Flow-Loop B	Water/Steam	1	55	-	3732H	FO XV	Inside Outside	37/Z	No	- 0.9
J-40F	Reactor Recirc Flow-Loop B	Water/Steam	1	55	-	3732M	FO XV	Inside Outside	37/Y	No	- 0.9
J-41	Reactor Pressure	Steam/Water	1	55	-	3727B	FO XV	Inside Outside	37/Y	No	- 0.9
J-42	Reactor Pressure	Steam/Water	1	55	-	3729B	FO XV	Inside Outside	37/Y	No	- 0.9
J-43	Reactor Pressure	Steam/Water	1	55	-	3730B	FO XV	Inside Outside	37/Y	No	- 0.9
J-44	Reactor Pressure	Steam/Water	1	55	-	3727A	FO XV	Inside Outside	37/Y	No	- 0.9
J-45	Spare Instr	Gas	1	NA	NA	NA	NA	NA	48A/-	NA	0.9
J-46	Spare Instr	Gas	1	NA	NA	NA	NA	NA	48A/-	NA	0.9
J-47	Reactor Pressure	Steam/Water	1	55	-	3734B	FO XV	Inside Outside	37/Y	No	- 0.9

TABLE 6.2-16 (Cont)

CONTAINMENT PENETRATIONS

Containment Penetration Number	Primary Mode of Operation(3)	Secondary Method of Actuation(12)	Normal Valve Position(4)	Shutdown Valve Position(10)	Post-Accident Position(9)	Power Failure Valve Position	Containment Isolation Signal(5)	Valve Closure Time, S	Power Source(6)	Remarks(7)
J-39F										m
J-40A	Flow	None	0	0	0	NA	NA	NA	NA	u,cc
J-40B	Flow	None	0	0	0	NA	NA	NA	NA	u,cc
J-40C	Flow	None	0	0	0	NA	NA	NA	NA	u,cc
J-40D	Flow	None	0	0	0	NA	NA	NA	NA	u,cc
J-40E	Flow	None	0	0	0	NA	NA	NA	NA	u,cc
J-40F	Flow	None	0	0	0	NA	NA	NA	NA	u,cc
J-41	Flow	None	0	0	0	NA	NA	NA	NA	u,cc
J-42	Flow	None	0	0	0	NA	NA	NA	NA	u,cc
J-43	Flow	None	0	0	0	NA	NA	NA	NA	u,cc
J-44	Flow	None	0	0	0	NA	NA	NA	NA	u,cc
J-45	NA	NA	NA	NA	NA	NA	NA	NA	NA	m
J-46	NA	NA	NA	NA	NA	NA	NA	NA	NA	m
J-47	Flow	None	0	0	0	NA	NA	NA	NA	u,cc

CONTAINMENT PENETRATIONS

Containment Penetration Number	Line Isolated	Fluid	Line Size, in.	NRC General Design Criterion	ESF System(11)	Valve Number and/or Orifice Plate	Valve Type(1)	Valve Location	Valve Arrangement(2) P&ID(8)	Type C Test	Length of Pipe from Cont. to Outside Valves, ft.
J-48	Spare Instr	Gas	1	NA	NA	NA	NA	NA	48A/-	NA	0.9
J-49	Spare Instr	Gas	1	NA	NA	NA	NA	NA	48A/-	NA	0.9
J-50	Jet Pump Flow/Post Accident Liquid Sampling	Water/Steam	1	55	-	3734A	FO	Inside	48/EE	No	-
							XV	Outside			0.9
					No	RC-SV-8903A	GB	Outside		Yes	-
					No	RC-SV-8903B	GB	Outside		Yes	17.3
J-51	Reactor Pressure	Water/Steam	1	55	-	3729A	FO	Inside	37/Y	No	-
							XV	Outside			0.9
J-52	Reactor Pressure	Water/Steam	1	55	-	3730A	FO	Inside	37/Y	No	-
							XV	Outside			0.9
J-201	Suppression Chamber Outlet to "A" Hydrogen/ Oxygen Analyzer	Gas	1	56	Yes	GS-V051	GB	Outside	42/AA	Yes	-
						GS-V052	GB	Outside		Yes	41.4
J-202	Suppression Chamber Outlet to "B" Hydrogen/ Oxygen Analyzer	Gas	1	56	Yes	GS-V042	GB	Outside	40/AA	Yes	-
						GS-V043	GB	Outside		Yes	74.6
J-203	Spare										
J-204	Spare										
J-205	Spare										
J-206	Post-Accident Gas Sampling System	Gas	1	56	No	RC-SV-0728A	GB	Outside	47/CC	Yes	-
						RC-SV-0728B	GB	Outside		Yes	16.5
J-207	Suppression Chamber Pressure	Gas	1	56	Yes	GS-V044	GB	Outside	43/AA	No	17.2
J-208	Suppression Chamber Pressure	Gas	1	56	Yes	GS-V087	GB	Outside	43/AA	No	32.8

CONTAINMENT PENETRATIONS

Containment Penetration Number	Primary Mode of Operation(3)	Secondary Method of Actuation(12)	Normal Valve Position(4)	Shutdown Valve Position(10)	Post-Accident Position(9)	Power Failure Valve Position	Containment Isolation Signal(5)	Valve Closure Time, S	Power Source(6)	Remarks(7)
J-48	NA	NA	NA	NA	NA	NA	NA	NA	NA	m
J-49	NA	NA	NA	NA	NA	NA	NA	NA	NA	m
J-50	Flow	None	0	0	0	NA	NA	NA	NA	u,cc
	Spring	None	C	0	C	C	None	NA	N	t
	Spring	None	C	0	C	C	None	NA	N	t
J-51	Flow	None	0	0	0	NA	NA	NA	NA	u,cc
J-52	Flow	None	0	0	0	NA	NA	NA	NA	u,cc
J-201	AC motor	Manual	C	0	C	AS IS	A,H,I	45	A	t,x
	AC motor	Manual	C	0	C	AS IS	A,H,I	45	C	t,x
J-202	AC motor	Manual	C	0	C	AS IS	A,H,I	45	B	t,w,x
	AC motor	Manual	C	0	C	AS IS	A,H,I	45	D	t,x
J-203										m
J-204										m
J-205										m
J-206	Spring	Manual	C	0	C	C	None	NA	N	t
	Spring	Manual	C	0	C	C	None	NA	N	t
J-207	None	Manual (14)	0	0	0	NA	NA	NA	NA	s,cc
J-208	None	Manual (14)	0	0	0	NA	NA	NA	NA	s,cc

CONTAINMENT PENETRATIONS

Containment Penetration Number	Line Isolated	Fluid	Line Size, in.	NRC General Design Criterion	ESF System(11)	Valve Number and/or Orifice Plate	Valve Type(1)	Valve Location	Valve Arrangement(2) P&ID(8)	Type C Test	Length of Pipe from Cont. to Outside Valves, ft.
J-209	Suppression Pool Water Level/ILRT	Gas	1	56	Yes	GP-V004	GB	Outside	45/FF	Yes	19.8
						GP-V005	GB	Outside		Yes	23.3
						BJ-V500	GT	Outside		No	31.8
J-210	Suppression Chamber Inlet to "B" Hydrogen/ Oxygen Analyzer	Gas	1	56	Yes	GS-V040	GB	Outside	42/AA	Yes	-
						GS-V041	GB	Outside		Yes	27.6
J-211	Instrument Air to Torus	Gas	1	56	No	KL-V019	GB	Outside	44/P	Yes	-
						KL-V018	GB	Outside		Yes	37.6
J-212	Suppression Chamber Inlet to "A" Hydrogen/ Oxygen Analyzer	Gas	1	56	Yes	GS-V049	GB	Outside	42/AA	Yes	-
						GS-V050	GB	Outside		Yes	40.7
J-213	Spare										
J-214A	Suppression Pool Temperature	Water				Thermowell			-/GG		
J-214B	Suppression Pool Temperature	Water				Thermowell			-/GG		
J-214C	Suppression Pool Temperature	Water				Thermowell			-/GG		
J-214D	Suppression Pool Temperature	Water				Thermowell			-/GG		
J-215A	Suppression Pool Temperature	Water				Thermowell			-/GG		
J-215B	Suppression Pool Temperature	Water				Thermowell			-/GG		

CONTAINMENT PENETRATIONS

Containment Penetration Number	Primary Mode of Operation(3)	Secondary Method of Actuation(12)	Normal Valve Position(4)	Shutdown Valve Position(10)	Post-Accident Position(9)	Power Failure Valve Position	Containment Isolation Signal(5)	Valve Closure Time, S	Power Source(6)	Remarks(7)
J-209	None	Manual (14)	C	C	C	NA	None	NA	None	r,t
	None	Manual (14)	C	C	C	NA	None	NA	None	r,t
	AC motor	Manual	0	0	0	AS IS	None	NA	A	s,cc
J-210	AC motor	Manual	C	0	C	AS IS	A,H,I	45	B	t,x
	AC motor	Manual	C	0	C	AS IS	A,H,I	45	D	t,x
J-211	Spring	Manual	0	C	C	C	A,H,I	15	A	t
	Spring	Manual	0	C	C	C	A,H,I	15	D	t
J-212	AC motor	Manual	C	0	C	AS IS	A,H,I	45	A	t,x
	AC motor	Manual	C	0	C	AS IS	A,H,I	45	C	t,x
J-213										m
J-214A										m,s
J-214B										m,s
J-214C										m,s
J-214D										m,s
J-215A										m,s
J-215B										m,s

TABLE 6.2-16 (Cont)

CONTAINMENT PENETRATIONS

Containment Penetration Number	Line Isolated	Fluid	Line Size, in.	NRC General Design Criterion	ESF System(11)	Valve Number and/or Orifice Plate	Valve Type(1)	Valve Location	Valve Arrangement(2) P&ID(8)	Type C Test	Length of Pipe from Cont. to Outside Valves, ft.
J-215C	Suppression Pool Temperature	Water				Thermowell			-/GG		
J-215D	Suppression Pool Temperature	Water				Thermowell			-/GG		
J-215E	Suppression Pool Temperature	Water				Thermowell			-/GG		
J-215F	Suppression Pool Temperature	Water				Thermowell			-/GG		
J-215G	Suppression Pool Temperature	Water				Thermowell			-/GG		
J-215H	Suppression Pool Temperature	Water				Thermowell			-/GG		
J-215J	Suppression Pool Temperature	Water				Thermowell			-/GG		
J-215K	Suppression Pool Temperature	Water				Thermowell			-/GG		
J-215L	Suppression Pool Temperature	Water				Thermowell			-/GG		
J-215M	Suppression Pool Temperature	Water				Thermowell			-/GG		
J-215N	Suppression Pool Temperature	Water				Thermowell			-/GG		

CONTAINMENT PENETRATIONS

Containment Penetration Number	Primary Mode of Operation(3)	Secondary Method of Actuation(12)	Normal Valve Position(4)	Shutdown Valve Position(10)	Post-Accident Position(9)	Power Failure Valve Position	Containment Isolation Signal(5)	Valve Closure Time, S	Power Source(6)	Remarks(7)
J-215C										m,s
J-215D										m,s
J-215E										m,s
J-215F										m,s
J-215G										m,s
J-215H										m,s
J-215J										m,s
J-215K										m,s
J-215L										m,s
J-215M										m,s
J-215N										m,s

TABLE 6.2-16 (Cont)

CONTAINMENT PENETRATIONS

Containment Penetration Number	Line Isolated	Fluid	Line Size, in.	NRC General Design Criterion	ESF System(11)	Valve Number and/or Orifice Plate	Valve Type(1)	Valve Location	Valve Arrangement(2) P&ID(8)	Type C Test	Length of Pipe from Cont. to Outside Valves, ft.
J-215P	Suppression Pool Temperature	Water				Thermowell			-/GG		
J-215Q	Suppression Pool Temperature	Water				Thermowell			-/GG		
J-215R	Suppression Pool Temperature	Water				Thermowell			-/GG		
J-216	Spare										
J-217	Suppression Pool Water Level	Water	1	56	Yes	BJ-V502	GB	Outside	46/F	No	28.7
J-218	Spare										
J-219	Suppression Pool Water Level	Water	1	56	Yes	BJ-V503	GB	Outside	46/F	No	13.5
J-220	Post Accident Gas Sampling System Return Line	Gas	1	56	No	RC-SV-0707A RC-SV-0707B	GB GB	Outside Outside	47/CC	Yes Yes	- 14.7
J-221	Post Accident Gas Sampling	Gas	1	56	No	RC-SV-0729A RC-SV-0729B	GB GB	Outside Outside	47/CC	yes Yes	- 16.5
J-1293	Spare					Thermowell					
J-1294	Spare					Thermowell					
J-1295	Spare					Thermowell					
J-1296	Spare					Thermowell					
J-1297	Spare					Thermowell					
J-1298	Spare					Thermowell					
J-1299	Spare					Thermowell					
J-1300	Spare					Thermowell					

CONTAINMENT PENETRATIONS

Containment Penetration Number	Primary Mode of Operation(3)	Secondary Method of Actuation(12)	Normal Valve Position(4)	Shutdown Valve Position(10)	Post-Accident Position(9)	Power Failure Valve Position	Containment Isolation Signal(5)	Valve Closure Time, S	Power Source(6)	Remarks(7)
J-215P										m,s
J-215Q										m,s
J-215R										m,s
J-216										m
J-217	AC motor	Manual	0	0	0	AS IS	None	NA	C	s,cc
J-218										m
J-219	AC motor	Manual	0	0	0	AS IS	None	NA	C	s,cc
J-220	Spring	Manual	0	C	C	C	None	NA	N	t
	Spring	Manual	0	C	C	C	None	NA	N	t
J-221	Spring	Manual	0	C	C	C	None	NA	N	t
	Spring	Manual	0	C	C	C	None	NA	N	t
J-1293										m
J-1294										m
J-1295										m
J-1296										m
J-1297										m
J-1298										m
J-1299										m
J-1300										m

TABLE 6.2-16 (Cont)

CONTAINMENT PENETRATIONS

Containment Penetration Number	Line Isolated	Fluid	Line Size, in.	NRC General Design Criterion	ESF System(11)	Valve Number and/or Orifice Plate	Valve Type(1)	Valve Location	Valve Arrangement(2) P&ID(8)	Type C Test	Length of Pipe from Cont. to Outside Valves, ft.
J-1301	Spare					Thermowell					
J-1302	Spare					Thermowell					
J-1303	Spare					Thermowell					
J-1304	Spare					Thermowell					
J-1305	Spare					Thermowell					
J-1306	Spare					Thermowell					
J-1307	Spare					Thermowell					
J-1308	Spare					Thermowell					
J-1309	Spare					Thermowell					
J-1310	Spare					Thermowell					
J-1311	Spare					Thermowell					
J-1312	Spare					Thermowell					
J-1313	Spare					Thermowell					
J-1314	Spare					Thermowell					
J-1315	Spare					Thermowell					

TABLE 6.2-16 (Cont)

CONTAINMENT PENETRATIONS

Containment Penetration Number	Primary Mode of Operation(3)	Secondary Method of Actuation(12)	Normal Valve Position(4)	Shutdown Valve Position(10)	Post-Accident Position(9)	Power Failure Valve Position	Containment Isolation Signal(5)	Valve Closure Time, S	Power Source(6)	Remarks(7)
J-1301										m
J-1302										m
J-1303										m
J-1304										m
J-1305										m
J-1306										m
J-1307										m
J-1308										m
J-1309										m
J-1310										m
J-1311										m
J-1312										m
J-1313										m
J-1314										m
J-1315										m

Containment Penetration Number	Line Isolated	Fluid	Line Size, in.	NRC General Design Criterion	ESF System(11)	Valve Number and/or Orifice Plate	Valve Type(1)	Valve Location	Valve Arrangement(2) P&ID(8)	Type C Test	Length of Pipe from Cont. to Outside Valves, ft.
J-1316	Spare					Thermowell					
J-1317	Spare					Thermowell					
J-1318	Spare					Thermowell					
J-1319	Spare					Thermowell					
J-1320	Spare					Thermowell					
J-1350	Reactor Level	Steam/Water	1	55	-	3726A	FO XV	Inside Outside	37/Y	No	- 0.9
J-1351	Reactor Level	Steam/Water	1	55	-	3728A	FO XV	Inside Outside	37/Y	No	- 0.9
J-1352	Reactor Level	Steam/Water	1	55	-	3731A	FO XV	Inside Outside	37/Y	No	- 0.9
J-1353	Reactor Level	Steam/Water	1	55	-	3726B	FO XV	Inside Outside	37/Y	No	- 0.9
J-1354	Reactor Level	Steam/Water	1	55	-	3728B	FO XV	Inside Outside	37/Y	No	- 0.9
J-1355	Reactor Level	Steam/Water	1	55	-	3731B	FO XV	Inside Outside	37/Y	No	- 0.9

TABLE 6.2-16 (Cont)

CONTAINMENT PENETRATIONS

Power

Containment Penetration Number	Primary Mode of Operation(3)	Secondary Method of Actuation(12)	Normal Valve Position(4)	Shutdown Valve Position(10)	Post-Accident Position(9)	Failure Valve Position	Containment Isolation Signal(5)	Valve Closure Time, S	Power Source(6)	Remarks(7)
J-1316										m
J-1317										m
J-1318										m
J-1319										m
J-1320										m
J-1350	Flow	None	0	0	0	NA	NA	NA	NA	u,cc
J-1351	Flow	None	0	0	0	NA	NA	NA	NA	u,cc
J-1352	Flow	None	0	0	0	NA	NA	NA	NA	u,cc
J-1353	Flow	None	0	0	0	NA	NA	NA	NA	u,cc
J-1354	Flow	None	0	0	0	NA	NA	NA	NA	u,cc
J-1355	Flow	None	0	0	0	NA	NA	NA	NA	u,cc

(1) Valve type:

Ball	BL
Butterfly	BF
Check valve	CK
Gate valve	GT
Globe	GB
Pressure relief	PSV
Stop check	SCK
Safety relief	SRV
Explosive (shear)	XP
Excess flow check	XV
Ball check	BLCK
Hydraulic control unit	HCU
Restriction orifice	FO

(2) See Figure 6.2-27. Numbers in this column refer to details in the figure.

(3) AC-operated valves required for isolation functions are powered from the AC standby power buses. DC-operated isolation valves are powered from the station batteries. The indicated mode of operation is for valve closure.

(4) Normal valve position (open or closed) is the position during normal power operation of the reactor.

(5) Table of isolation signal codes:

A - Reactor Vessel Low Water Level - L2
B - Main Steam Line Radiation - High High
C - Not used
D - Main Steam Line - High Flow
E - Main Turbine Inlet - Low Steam Pressure (Run Mode)
F - Main Condenser - Low Vacuum (Main Stop Valve Greater than 90% Open)
G - High Main Steam Line Tunnel - High Temperature
H - Drywell High Pressure
I - Reactor Building High Radiation
J - Reactor Vessel Low Water Level - L3
K - Reactor Vessel Low Water Level - L1
L - Reactor Water Cleanup System - Area High Temperature in the system's equipment compartment
M - Reactor Water Cleanup System - Area High Differential Temperature across the system's equipment compartment ventilation ducts
N - Reactor Water Cleanup System - High Differential Flow between the system influent and effluent piping outside the drywell
O - Standby Liquid Control System Operating
P - Reactor Water Cleanup - High Temperature at Outlet of Nonregenerative Heat Exchanger

For those valves that are identified with an isolation signal code, the primary method of actuation is automatic.

TABLE 6.2-16 (Cont)

(6) Power source:

Electrical Separation Channels:

A - Class 1E electrical channel
B - Class 1E electrical channel
C - Class 1E electrical channel
D - Class 1E electrical channel
W - Reactor protection system (RPS) electrical separation channel
X - RPS electrical separation channel
Y - RPS electrical separation channel
Z - RPS electrical separation channel
N - Non-Class 1E

For explanation of electrical separation channels, refer to Section 8.1.

(7) Remarks:

a. The main steam isolation valve requires that both solenoid pilots be deenergized to close the valve. Accumulator air pressure plus spring act together to close the valve when both pilots are deenergized. Voltage failure at only one pilot does not cause valve closure. The valve is designed to fully close in less than 10 seconds, but in no less than 3 seconds.

b. A separate pressure interlock closes the valve on high reactor pressure.

c. Separate HPCI system isolation provisions close this valve on exhaust pressure high, area temperature high, steam pressure low, or steam flow high.

d. Separate RCIC system isolation provisions close this valve on exhaust pressure high, area temperature high, steam pressure low, or steam flow high.

e. Valve closes on HPCI system steam line pressure low and drywell pressure high.

f. Valve closes on RCIC system steam line pressure low and drywell pressure high.

g. Valve closes on HPCI system high discharge flow.

h. Valve closes on RCIC system high discharge flow.

TABLE 6.2-16 (Cont)

i. Valve closes on RHR system high discharge flow.

j. Valve closes on core spray system high discharge flow.

k. This penetration is a boundary between the drywell and the suppression chamber. It is not a path from the primary containment to the environment.

l. Deleted.

m. Sealed penetration.

n. Relief valve set pressure - 410 psig.

o. Relief valve set pressure - 67 psig.

p. Relief valve set pressure - 495 psig.

q. Relief valve set pressure - 500 psig.

r. Locked closed valve.

s. System defined as essential per the definition in HCGS' response to NUREG-0737, Item II.E.4.2.

t. System defined as nonessential per the definition in HCGS' response to NUREG-0737, Item II.E.4.2

u. Designed and installed per Regulatory Guide 1.11 as discussed in Section 1.8.1.11.

v. Penetration P-22 and P-220 share primary containment isolation provisions.

w. Penetration J-7D and J-202 share primary containment isolation provisions.

x. Manual override of the isolation signal is provided to enable the operator to change the post-accident position of the valve.

y. Not used.

z. Relief valve set pressure - 1250 psig.

aa. Relief valve set pressure - 150 psig.

bb. Penetration P-201, P-204 and P-207, share primary containment isolation provisions.

cc. Where no Appendix J, Type C test is indicated, see Table 6.2-24 for further discussion.

TABLE 6.2-16 (Cont)

(8) P&ID(s) published as FSAR figures depicting the penetration configuration.

Note	Figures
A	5.1-3, Sh 1
	5.1-3, Sh 2
	6.7-1
B	5.1-3, Sh 1
	5.4-8
	5.4-17
	6.3-1
C	5.4-13, Sh 1
D	5.4-13, Sh 1
	5.4-13, Sh 2
E	6.3-7
	6.3-1
F	6.3-1
G	9.2-14, Sh 2
H	5.4-17
I	5.4-8
J	5.1-3, Sh 1
K	5.4-2, Sh 1
L	9.3-8
M	6.2-29
	6.2-30
N	9.3-7, Sh 1
	9.3-7, Sh 3
O	9.3-3
P	9.3-11, Sh 1
Q	9.2-17
R	9.5-32
S	4.6-6
T	6.3-1
	5.4-13, Sh 1
	5.4-8
U	6.3-7
V	6.2-41
W	9.1-5, Sh 2
X	9.3-5, Sh 1
Y	5.1-4, Sh 1
Z	Deleted
AA	6.2-29
BB	11.5-3, Sh 1
CC	9.3-5, Sh 2
DD	5.4-13, Sh 2
EE	5.4-2, Sh 1
	9.3-5
FF	6.3-1
	6.2-41
GG	5.1-3, Sh 1
	5.1-3, Sh 2

(9) Post-accident valve position (open or closed) is the position during the initial 10 minutes after an accident.

(10) Shutdown valve position (open or closed) is the position beyond the initial 10 minutes after an accident.

(11) The ESF System designation is applied to primary containment penetrations that are a part of an ESF System and where that part of the system provides or aids a function that is characteristic of a ESF System. Although reactivity control systems are not usually characterized as being ESF Systems, in this table reactivity control system penetrations are given the ESF system designation.

(12) Manual indicates remote manual initiation of valve closure from the main control room.

(13) The secondary mode of operation is AC motor.

(14) Operation is by local manual hand wheel.

(15) Deleted.

(16) The valve actuator is only used to exercise the valve disk during testing.

(17) This is a spring loaded piston-actuated check valve. When the valve operator is in the open position, it will not resist valve closure. In this position the valve will function much like a simple check valve. In the de-energized position, the spring-loaded piston will assist in closing the valve.

However, it will not close the valve against flow from the normal direction.

(18) The isolation signals for his valve are generated to provide proper system alignment for ECCS injection. By assuming the ECCS injection position, the valves also provide a containment isolation function.

(19) These valves are tested with air to a pressure of P_a and the leakage is included in the 0.60 L_a criteria of Appendix J.

(20) These valves form the boundary for the long-term seal of the feedwater lines and hence are tested with water at 1.10 P_a. Leakage from all valves is limited to 10 GPM.

(21) The closing times for the following valves include an assumed 1-second delay: GS-V009, GS-V020, GS-V021, GS-V022, GS-V023, GS-V024, GS-V026, GS-V027, GS-V028.

TABLE 6.2-17

CAC SYSTEM DESIGN AND PERFORMANCE DATA

Nitrogen Vaporizer (nonsafety-related)

Manufacturer	Process Eng, Inc
Quantity	1
Type	Water batch
Design conditions:	
Nitrogen	
Minimum purity	99.9 percent
Maximum moisture	2.5 ppm
Minimum temperature	70°F
Maximum temperature	110°F
Inlet liquid N_2 pressure	45 psig
Pressure drop (max) through vaporizer	5 psi
Maximum flow rate	2500 scfm
Makeup flow rate	100 scfm
Steam	
Maximum flow rate (saturated)	2000 lb/hr
Temperature	297°F
Pressure	50 psig

Vacuum Relief Valves (Drywell/Suppression Chamber)
(safety-related, Seismic Category I)

Manufacturer	GPE Controls
Quantity	8
Size	24 inches
Design conditions:	
Full open pressure differential	0.25 psid
Design pressure	62 psig

Design temperature	340°F
Relative humidity	100 percent

Vacuum Relief Valves (Reactor Building to Suppression Chamber)
(safety-related, Seismic Category I)

Manufacturer	GPE Controls
Quantity	2
Size	24 inches
Design conditions:	
Full open pressure differential	0.25 psid
Design temperature	340°F
Relative humidity	100 percent

Containment Hydrogen Recombiners (safety-related, Seismic Category I)

Manufacturer	Rockwell International
Quantity	2
Type	Thermal
Blower horsepower	20 hp
Electrical requirements	480 V, Class 1E, 60 hz 120 V, non-Class 1E (power to trickle heat)
Design conditions:	
Flow rate	60 to 150 cfm
Design pressure	62 psig
Max operating pressure (gas)	30 psia
Max operating temperature (gas)	200°F
Relative humidity	100 percent
Radiation dose, background	10^6 rads

TABLE 6.2-17 (Cont)

Hydrogen/Oxygen Analyzer (safety-related, Seismic Category I)

Manufacturer	Comsip, Inc
Quantity	2
Type	Thermal conductivity
Design conditions of sample gas:	
Operating pressure	-2 to 60 psig
Operating temperature	40° to 340°F
Relative humidity	0 to 100 percent
Measuring range	
Hydrogen	0 to 30 percent by volume
Oxygen	0 to 25 percent by volume

Suppression Chamber Supplementary Oxygen Analyzer
(nonsafety-related, Seismic Category II/I)

Manufacturer	Rosemount Beckman Industrial
Quantity	1
Type	Paramagnetic
Design conditions of sample gas:	
Operating pressure	-2 to 60 psig
Operating temperature	40° to 340°F
Relative humidity	0 to 100 percent
Measuring range	0 to 5 percent by volume

Drywell Supplementary Oxygen Analyzer
(nonsafety-related, Seismic Category II/I)

Manufacturer	Rosemount Beckman Industrial
Quantity	1
Type	Paramagnetic

TABLE 6.2-17 (Cont)

Design conditions of sample gas:

Operating pressure	-0.25 to 0 in. WC
Operating temperature	40° to 90°F
Relative humidity	20 to 90 percent
Measuring range	0 to 5 percent by volume

TABLE 6.2-18

CONTAINMENT HYDROGEN RECOMBINER SUBSYSTEM FAILURE MODES AND EFFECTS ANALYSIS

Component Failure System Component	Effect of Failure Mode	Failure Mode on the System	Effect of Failure Detection	On Plant Operation
Power supply	Loss of offsite power (LOP)	Loss of both recombiners	Alarm in the main control room	None. The recombiners are powered from the Class 1E buses. When standby power becomes available, the recombiners resume operation.
Power supply	Loss of one Class 1E bus or associated diesel generator	Loss of one recombiner	Alarm in the main control room	None. The redundant recombiner is unaffected and is activated manually by the operator.
Containment isolation valve in one gas inlet or gas outlet line	Failure of valve to reopen after containment isolation signal is bypassed	No flow through recombiner	Flow indication and low-flow alarm in the main control room	None. The redundant recombiner is unaffected and is activated manually by the operator.
Blower in one Recombiner	Abnormally low blower speed or complete failure to operate	Insufficient flow through recombiner	Flow indication and low-flow alarm in the main control room	None. The redundant recombiner is unaffected and is activated manually by the operator.
Heater elements or SCRs in one recombiner	Abnormal low heater output	Reaction chamber temperature too low for complete recombination	Alarm in the main control room	None. The redundant recombiner is unaffected and is activated manually by the operator.
Water inlet valve in one recombiner	Failure to open fully	Abnormally high return gas temperature	Alarm in the main control room	None. The redundant recombiner is unaffected and is activated manually by the operator.

TABLE 6.2-18 (Cont)

System Component	Component Failure Mode	Effect of Failure on the System	Failure Mode Detection	Effect of Failure On Plant Operation
Gas inlet valve in one recombiner	Case a: Excessive valve opening	High flow through the recombiner with the possibility of excessive temperatures in the reaction chamber	Flow indication and high-temperature alarm in the main control room	None. The redundant recombiner is unaffected and is activated manually by the operator.
	Case b: Insufficient valve opening	Insufficient flow through the recombiner package	Flow indication and low-flow alarm in the main control room	None. The redundant recombiner is unaffected and is activated manually by the operator.
Recirculation valve	Case a: Failed close capability	No recirculation design flow	No change in is not required under	None. Recirculation design basis scenario.
	Case b: Failed open	Unlimited recirculation	Low-flow indication through recombiner	None. The redundant recombiner is unaffected and is activated manually by the operator.

TABLE 6.2-19

COMBUSTIBLE GAS ANALYZER SUBSYSTEM FAILURE MODES AND EFFECTS ANALYSIS

Plant Operating Mode	System Component	Component Failure Mode	Effect of Failure on the System	Failure Mode Detection	Effect of Failure On Plant Operation
Normal or emergency	Power supply	LOP	Closure of containment isolation valves on all sample lines. Loss of both analyzer packages	Alarm in the main control room	None. The analyzer packages are powered from the Class 1E buses. When standby power becomes available, the containment isolation valves reopen and the analyzer packages resume operation.
LOCA or LOCA + LOP	Power supply	Loss of one Class 1E bus or the associated diesel generator	Loss of one analyzer package. Closure of containment isolation valves on associated sample lines	Alarm in the main control room	None. The redundant analyzer package is unaffected and continues to operate.
LOCA or LOCA + LOP	Sample pump in one analyzer package	Failure of pump	Loss of sample flow through the affected analyzer package	Alarm in the main control room	None. The redundant analyzer package is unaffected and continues to operate.
LOCA or LOCA + LOP	Analyzer cell compartment heater	Failure of the heater in one analyzer package	Incorrect concentration indication for the affected analyzer package	Alarm in the main control room	None. The redundant analyzer package is unaffected and continues to operate.
LOCA or LOCA + LOP	Hydrogen analyzer cell in one analyzer package	Analyzer cell failure	Incorrect concentration indication for the affected analyzer package	Alarm in the main control room	None. The redundant analyzer package is unaffected and continues to operate.
LOCA or LOCA + LOP	Sample line containment isolation valves	Failure of one valve to reopen when containment isolation signal is bypassed	Case a, sample suction line: inability to draw sample through affected line only	Case a: alarm in the main control room (due to low flow) when the affected line is selected	None. The redundant analyzer package is unaffected and continues to operate.
			Case b, sample return line: blockage of all flow through affected analyzer package	Case b: Alarm in the main control room (due to low flow) immediately	

Plant Operating Mode	System Component	Component Failure Mode	Effect of Failure on the System	Failure Mode Detection	Effect of Failure On Plant Operation
LOCA or LOCA + LOP	Sample line containment isolation valves	Failure of one valve to close when containment isolation signal is received	Reduction in containment isolation barriers from two valves to one in the affected line	Indicating lights in the main control room	None. The redundant isolation valve provides isolation.

TABLE 6.2-20

This Table has been deleted

TABLE 6.2-21

This Table has been deleted

TABLE 6.2-21a

This Table has been deleted

TABLE 6.2-22

TYPE A TEST DEFINITIONS

Term	Definition
Leakage design basis accident (LDBA)	The accident which results in the maximum primary containment internal peak pressure and also results in fission product release inside the primary containment.
Type A Test	The leakage test performed on the primary containment system by pressurizing the system to P_a and determining the overall integrated leakage rate.
Containment Integrated Leakage Rate Test (CILRT)	A description of all phases of the overall integrated leakage rate test of the primary containment system, including containment inspection, pressurization, stabilization, Type A test, verification test, and depressurization.
L_a (weight percent/24 h)	The maximum allowable leakage rate at pressure P_a. Generally specified for preoperational tests and periodic tests prescribed in the HCGS Technical Specifications
L_{am} (weight percent/24 h)	The measured primary containment leakage rate at pressure P_a, obtained from testing the Primary Reactor Containment System in the state as close as practical to that existing after an LDBA, which results in P_a.
L_c (weight percent/24 h)	The composite leakage rate measured using the IRLT instruments after L_o is superimposed
L_o (weight percent/24 h)	The known leakage rate superimposed on the primary containment during verification tests

TABLE 6.2-22 (Cont)

Term	Definition
P_a	The calculated peak primary containment internal pressure related to the LDBA. Generally specified in the Hope Creek Technical Specifications
Upper confidence limit (UCL)	A calculated value constructed from sample data with the intention of placing a statistical upper bound on the true leakage rate
Verification tests	Tests intended to confirm the capability of the Type A test method and equipment to determine the containment leakage rate, L_{am}
Test duration	After the primary containment atmosphere has stabilized, the Type A test begins. The duration of the Type A test must be sufficient to enable adequate data to be accumulated and statistically analyzed so that a leakage rate and UCL can be accurately determined. Test criteria, test duration and total number of data points will meet the requirements of ANSI/ANS 56.8-1994 or BN-TOP-1. The Type A test cannot be successfully completed until the acceptance criteria of Section 16 are met.

Term	Definition
Type A test drywell temperature limit	40 to 120°F
Containment free air volume (at high torus water level)	302,500 ft^3
Drywell free air volume	169,000 ft^3
Suppression chamber free air space maximum (at low water level)	137,500 ft^3
Suppression chamber free air volume minimum (at high water level)	133,500 ft^3

TABLE 6.2-23

SYSTEM VENTING AND DRAINING EXCEPTIONS FOR PRIMARY CONTAINMENT INTEGRATED LEAKAGE RATE TEST

Exception I - During the Type A test, the drywell chilled water system, located inside the primary containment, may be required to maintain the plant in a stabilized condition and is not vented, operating in its normal mode. If the drywell chilled water system is not required to operate, the system will either be drained and vented or the provisions of Exception III will be applied, if applicable.

Exception II - Portions of systems that are normally filled with water and operating under post-LOCA conditions, i.e., the RCIC, RHR, CS, and HPCI are not specifically vented to the primary containment atmosphere or to the outside atmosphere. They remain water filled during the Type A test. Venting to the primary containment atmosphere does occur for these systems, since the reactor vessel is vented to the primary containment atmosphere and/or system penetrations are open to the suppression pool or containment atmospheres. Systems not vented or drained during the Type A test that could become exposed to the primary containment atmosphere during the design basis accident (DBA) must have been Type B or C tested within the last twenty-four (24) calendar months prior to the Type A test and the Type B and/or C results used to apply a correction to the Type A test results.

Exception IIII - For planning or scheduling purposes, or ALARA considerations, system pathways that have been local leak rate tested within the previous twenty-four (24) calendar months need not be drained or vented for the Type A test.

TABLE 6.2-24

CONTAINMENT PENETRATIONS/ISOLATION VALVE COMPLIANCE WITH 10CFR50, APPENDIX J

Penet Number	P&ID Number	System Description	Test Type	Inboard Isolation Barrier Description/ Valve Number	Notes	Outboard Isolation Barrier Description/ Valve Number	Notes
P 1A	M-41	Main steam line A	-	AB V028	6	AB-V032	6
P 1B	M-41	Main steam line B	-	AB V029	6	AB-V033	6
P 1C	M-41	Main steam line C	-	AB V030	6	AB-V034	6
P 1D	M-41	Main steam line D	-	AB-V031	6	AB-V035	6
P 2A	M-41	Feedwater	C	AE-V003	-	AE-V002	-
			C(W)	-	-	AE-V001/021,BD-V005	9
P 2B	M-41	Feedwater	C	AE-V007	-	AE-V006	-
			C(W)	-	-	AE-V005/021,BJ-V059	9
P 3	M-51	RHR shutdown cooling	N/A	-	-	BC-V164	8,14,18
		suction	N/A	BC-V071+, PSV-4425+	-	-	
P 4A	M-51	RHR shutdown cooling return	N/A	-	-	BC-V013	14,18
			N/A	BC-V014+, BC-V118+	-	-	-
P 4B	M-51	RHR shutdown cooling return	N/A	-	-	BC-V110	14,18
			N/A	BC-V111+, BC-V117+	-	-	-
P 5A	M-52	Core spray to reactor	N/A	-	-	BE-V003	8,14,18
			N/A	BE-V002+, BE-V072+	-	-	-
P 5B	M-52	Core spray to reactor	N/A	-	-	BE-V007,BJ-V001	8,14,18
			N/A	BE-V006+, BE-V071+	-	-	-
P 6A	M-51	LPCI	N/A	-	-	BC-V004	8,14,18
			N/A	BC-V005+, BC-V122+	-	-	-
P 6B	M-51	LPCI	N/A	-	-	BC-V016	8,14,18
			N/A	BC-V017+, BC-V120+	-	-	-
P 6C	M-51	LPCI	N/A	-	-	BC-V113	8,14,18
			N/A	BC-V114+, BC-V119+	-	-	-
P 6D	M-51	LPCI	N/A	-	-	BC-V101	8,14,18
			N/A	BC-V102+, BC-V121+	-	-	-
P 7	M-55	HPCI turbine	C	FD-V001	8	FD-V002	8
		steam supply	C	FD-V051	-	-	-
P 8A	M-87	Chilled water from drywell	C	GB-V082	8	GB-V046	8
		coolers	C	GB-PSV-9523A	3,16	-	-

+ - Not a containment isolation valve.

Penet Number	P&ID Number	System Description	Test Type	Inboard Isolation Barrier Description/ Valve Number	Notes	Outboard Isolation Barrier Description/ Valve Number	Notes
P 8B	M-87	Chilled water to drywell	C	GB-V081	8	GB-V048	8
		coolers	C	GB-PSV-9522A	3,16	-	-
P 9	M-44	RWCU pump suction	C	BG-V001	8	BG-V002	8
P-10	SPARE*		-	-	-	-	-
P 11	M-49	RCIC turbine steam supply	C	FC-V001	8	FC-V002	8
			C	FC-V048	-	-	-
P 12	M-41	Main steam drain	C	AB-V039	8	AB-V040	8
P 17	M-43	Reactor recirc water sample	C	BB-SV4310	-	BB-SV4311	-
P 18	M-48	Standby liquid control	C	BH-V029	-	BH-V028, BH-V054	-
P 19	M-43	Recirc pump seal water purge	C	BB-V043	-	BF-V098	-
P 20	M-43	Recirc pump seal water	C	BB-V047	-	BF-V099	-
P 21		ISI access pen.	A	-	-	-	2
P 22	M-57	Drywell purge inlet vent	C	GS-V009	3,12	GS-V020, GS-V021	5
			C			GS-V022, GS-V023	5
			C	GS-V004	8	GS-V005	8
P 23	M-57	Drywell purge outlet vent	C	GS-V024	3,12	GS-V026, GS-V025	-
			C	GS-V002	8,12	GS-V003	8
P 24A	M-51	RHR containment spray	N/A	BC-V019	8,18	-	14
			N/A	-	-	BC-V018+	-
P 24B	M-51	RHR containment spray	N/A	BC-V116	8,18	-	14
			N/A	-	-	BC-V115+	-
P 25	M-61	Drywell floor drain sump	C	HB-V005	8	HB-V006	8
		discharge	C	1HBPSV-11701	3,16	-	-
P 26	M-61	Drywell equipment drain sump	C	HB-V045	8	HB-V046	8
		discharge	C	1HBPSV-11702	3,16	-	-
P 27	M-15	Service air to drywell	C	KA-V039	4,8	KA-V038	4,8
P 28A	M-59	Instr gas to drywell	C	KL-V026	3	KL-V025	-
P 28B	M-59	Instr gas to drywell	C	KL-V028	3	KL-V027	-
P 29	M-13	RACS supply	C	ED-V020	8	ED-V019	8
			C	1EDPSV-11699	3,16	-	-

+ - Not a containment isolation valve.

* Process piping capped inside and outside containment. Fluid head remains in place.

Penet Number	P&ID Number	System Description	Test Type	Inboard Isolation Barrier Description/ Valve Number	Notes	Outboard Isolation Barrier Description/ Valve Number	Notes
P 30	M-13	RACS return	C	ED-V022	8	ED-V021	8
			C	1EDPSV-11700	3,16	-	-
P 31	M-15	Breathing air	C	KG-V016	4	KG-V034	4,8
P 32		Spare	A	-	-	-	-
P 33		Spare	A	-	-	-	-
P 34A	M-59	Probe guide tube	C	SE-V027	12	-	-
			N/A	-	-	SE-V022	7,10
P 34B	M-59	Probe guide tube	C	SE-V026	12	-	-
			N/A	-	-	SE-V021	7,10
P 34C	M-59	Probe guide tube	C	SE-V029	12	-	-
			N/A	-	-	SE-V024	7,10
P 34D	M-59	Probe guide tube	C	SE-V028	12	-	-
			N/A	-	-	SE-V023	7,10
P 34E	M-59	Probe guide tube	C	SE-V030	12	-	-
			N/A	-	-	SE-V025	7,10
P 34F	M-59	Tip purge system	C	SE-V006	-	SE-V004	-
P 34G		Spare	A	-	-	-	2
P 35A-D	M-47	CRD insert	N/A	BF-V138	7,13	-	-
		(Typical of 185 HCUs)	N/A	BF-XV-126	7,13	-	-
			N/A	BF-SV-123	7,13	-	-
			N/A	BF-SV-120	7,13	-	-
P 36A-D	M-47	CRD withdrawal	N/A	BF-XV-127	7,12,13	-	-
		(Typical of 185 HCUs)	N/A	BF-SV-122	7,12,13	-	-
			N/A	BF-SV-121	7,12,13	-	-
P 38A	M-87	Chilled water to drywell coolers	C	GB-V083	8	GB-V070	8
			C	GB-PSV-9522B	3,16	-	-
P 38B	M-87	Chilled water from drywell coolers	C	GB-V084	8	GB-V071	8
			C	GB-PSV-9523B	3,16	-	-
P 39	M-59	Instrument gas suction	C	KL-V001	-	KL-V002/V049	-
P 201	M-55	HPCI turbine exhaust	C(W)	FD-V006/V007	7,8,9,12	FD-V004	7,9
P 202	M-55	HPCI pump suction	N/A	BJ-V009	18,12,14	-	-
P 203	M-55	HPCI minimum return	N/A	BJ-V016	18,12,14	-	-
P 204	M-55	HPCI & RCIC vacuum network	C	FC-V007	12	-	-
			C	FD-V010	8,12	-	-

Penet Number	P&ID Number	System Description	Test Type	Inboard Isolation Barrier Description/ Valve Number	Notes	Outboard Isolation Barrier Description/ Valve Number	Notes
P 207	M-49	RCIC turbine exhaust	C(W)	FC-V005/V006	7,8,9,12	FC-V003	7,9
P 208	M-49	RCIC pump suction	N/A	BD-V003	12,14,18	-	-
P 209	M-49	RCIC min return	N/A	BD-SV-F019	12,14,18	-	-
P 210	M-49	Non-condensable gas from RCIC vacuum pump	C(W)	FC-V011	7,9,12	FC-V010	7,9
P 211A	M-51	RHR pump suction	N/A	BC-V001	12,14,18	-	-
P 211B	M-51	RHR pump suction	N/A	BC-V006	12,14,18	-	-
P 211C	M-51	RHR pump suction	N/A	BC-V103	12,14,18	-	-
P 211D	M-51	RHR pump suction	N/A	BC-V098	12,14,18	-	-
P 212A	M-51	RHR torus water cooling & system test	N/A	BC-PSV-F025 D	12,14,18	-	-
			N/A	BC-PSV-F025 B	12,14,18	-	-
			N/A	BC-V028, BC-V027	12,14,18	-	-
			N/A	BC-V026, BC-V034	12,14,18	-	-
			N/A	BC-V031, BC-V260	12,14,18	-	-
P 212B	M-51	RHR torus water cooling & system test	N/A	BC-PSV-F025 A	12,14,18	-	-
			N/A	BC-PSV-F025 C	12,14,18	-	-
			N/A	BC-V124, BC-V125	12,14,18	-	-
			N/A	BC-V126, BC-V128	12,14,18	-	-
			N/A	BC-V131, BC-V206	12,14,18	-	-
P 213A	M-51	RHR relief to torus line	N/A	BC-PSV-4431B	12,14,18	-	-
P 213B	M-51	RHR relief to torus line	N/A	BC-PSV-4431A	12,14,18	-	-
P 214A	M-51	RHR to torus spray header	N/A	BC-V015	7,12,14,18	-	-
P 214B	M-51	RHR to torus spray header	N/A	BC-V112	7,12,14,18	-	-
P 216A	M-52	Core spray pump suction	N/A	BE-V019	12,14,18	-	-
P 216B	M-52	Core spray pump suction	N/A	BE-V020	12,14,18	-	-
P 216C	M-52	Core spray pump suction	N/A	BE-V018	12,14,18	-	-
P 216D	M-52	Core spray pump suction	N/A	BE-V017	12,14,18	-	-

TABLE 6.2-24 (Cont)

Penet Number	P&ID Number	System Description	Test Type	Inboard Isolation Barrier Description/ Valve Number	Notes	Outboard Isolation Barrier Description/ Valve Number	Notes
P 217A	M-52	Core spray test and min flow to torus	N/A	BE-PSV-F012B	12,14,18	-	-
			N/A	BE-V026/V036	12,14,18	-	-
P 217B	M-52	Core spray test & min flow to torus	N/A	BE-PSV-F012A	12,14,18	-	-
			N/A	BE-V025/V035	12,14,18	-	-
P 219	M-57	Torus purge outlet,torus vacuum relief & torus vent	C	GS-V080	3,12	GS-PSV-5030	-
			C	GS-V028	3,12	GS-V027/V076/V201	-
			C	GS-V007	8,12	GS-V006	8
P 220	M-57	Torus purge outlet & torus	C	GS-V022	3,5,12	GS-V020, GS-V021	5
			C			GS-V023, GS-V009	5
		Vacuum relief	C	GS-V010	8,12	GS-V008	8
			C	GS-V038	3,12	GS-PSV-5032	-
P 221A-D		Construction hatch	N/A	-	-	-	2
P 222	M-53	Torus water cleanup return	C(W)	EE-V002	8,9,12	EE-V001	8,9
P 223	M-53	Torus water cleanup supply	C(W)	EE-V003	8,9,12	EE-V004	8,9
P 224		Spare	A	-	-	-	-
P 225		Deleted	NA	-	-	-	-
P 226		Spare	A	-	-	-	-
P 227	M-38	Post-accident liquid sampling system	C	RC-SV-0643A	12	RC-SV-0643B	-
P 228	M-55	Torus water level	A	BJ-V501	11,12	-	-
P 229A-H		Vent pipe	NA	-	-	-	15
P 230A-H		Vacuum break connection	NA	-	-	-	15
P 231A-H		Vent pipe drain	NA	-	-	-	15
P 232A-R		MSRV discharge (A,B,C,D,E,F,G,H-J,K,LM-P,R)	NA	-	-	-	15
J 2A		Spare	A	-	-	-	-
J 2B		Spare	A	-	-	-	-
J 2C	M-42	RPV level & pressure switch	-	BB-XV3725	1,7,12	-	-
J 2D		Spare	A	-	-	-	-
J 2E		Spare	A	-	-	-	-

Penet Number	P&ID Number	System Description	Test Type	Inboard Isolation Barrier Description/ Valve Number	Notes	Outboard Isolation Barrier Description/ Valve Number	Notes
J 2F		Spare	A	-	-	-	-
J 3A	M-42	RPV level	-	BB-XV3621	1,7,12	-	-
J 3B	M-57	Hydrogen/oxygen analyzer inlet	C	GS-V031	12	GS-V032	-
J 3C-F		Spare	A	-	-	-	-
J 4A-F		Spare	A	-	-	-	-
J 5A	M-25	RCPB leakage detection gas sampler return	C	SK-V008	12	SK-V009	-
J 5B,D,E,F		Spare	A	-	-	-	-
J 5C	M-41	RPV pressure & head drain	-	BB-XV3649	1,7,12	-	-
J 6A	M-42	Drywell pressure	A	BB-V563	4,11	-	-
J 6B-F		Spare	A	-	-	-	-
J 7A	M-42	Drywell pressure	A	BB-V565	4,11	-	-
J 7B		Spare	A	-	-	-	-
J 7C		Spare	A	-	-	-	-
J 7D	M-57	Hydrogen/oxygen analyzer inlet	C C	GS-V033	12	GS-V034, GS-V053 GS-V042, GS-V043	5 5
J 7E	M-34	Post-accident gas sample	C	RC-SV-0730A	12	RC-SV-0730B	-
J 7F		Spare	A	-	-	-	-
J 8A&B		Spare	A	-	-	-	-
J 8C	M-25	RCPB leak detection gas sampler supply	C	SK-V005	12	SK-V006	-
J 8D	M-42	Drywell pressure	A	BB-V564	4,11	-	-
J 8E&F		Spare	A	-	-	-	-
J 9A-D,F		Spare	A	-	-	-	-
J 9E	M-57	Hydrogen/oxygen analyzer inlet	C	GS-V045	12	GS-V046	-

TABLE 6.2-24 (Cont)

Penet Number	P&ID Number	System Description	Test Type	Inboard Isolation Barrier Description/ Valve Number	Notes	Outboard Isolation Barrier Description/ Valve Number	Notes
J 10A		Spare	A	-	-	-	-
J 10B		Spare	A	-	-	-	-
J 10C	M-57	Hydrogen/oxygen analyzer inlet	C	GS-V047	12	GS-V048	-
J 10D	M-42	Drywell pressure	-	BB-V566	4,11,12	-	-
J 10E	M-38	Post-accident sampling system	C	RC-SV-0731A	12	RC-SV-0731B	-
J 10F		Spare	A	-	-	-	-
J 11A	M-42	Reactor recirc flow	-	BB-XV3732B	1,7,12	-	-
J 11B	M-42	Reactor recirc flow	-	BB-XV3732D	1,7,12	-	-
J 11C,D		Spare	A	-	-	-	-
J 11E	M-42	Reactor recirc flow	-	BB-XV3732K	1,7,12	-	-
J 11F		Spare Instrument Line	A	-	-	-	-
J 12A		Spare	A	-	-	-	-
J 12B	M-42	Reactor recirc flow	-	BB-XV3732P	1,7,12	-	-
J 12C	M-42	Reactor recirc flow	-	BB-XV3732S	1,7,12	-	-
J 12D		Spare	A	-	-	-	-
J 12E	M-42	Reactor recirc flow	-	BB-XV3732W	1,7,12	-	-
J 12F	M-42	Reactor recirc flow	-	BB-XV3734D	1,7,12	-	-
J 13A,B,C		Spare	A	-	-	-	-
J 13D	M-42	Reactor recirc flow	-	BB-XV3738A	1,7,12	-	-
J 13E,F		Spare	A	-	-	-	-
J 14A	M-42	Reactor recirc flow	-	BB-XV3732L	1,7,12	-	-
J 14B	M-42	Reactor recirc flow	-	BB-XV3732N	1,7,12	-	-
J 14C	M-42	Reactor recirc flow	-	BB-XV3732R	1,7,12	-	-

TABLE 6.2-24 (Cont)

Penet Number	P&ID Number	System Description	Test Type	Inboard Isolation Barrier Description/ Valve Number	Notes	Outboard Isolation Barrier Description/ Valve Number	Notes
J 14D	M-42	Reactor recirc flow	-	BB-XV3732T	1,7,12	-	-
J 14E	M-42	Reactor recirc flow	-	BB-XV3732V	1,7,12	-	-
J 14F	M-42	Reactor recirc flow	-	BB-XV3734C	1,7,12	-	-
J 15A-F		Spare	A	-	-	-	-
J 16A		Spare	A	-	-	-	-
J 16B		Spare	A	-	-	-	-
J 16C	M-42	Reactor flow	-	BB-XV3737B	1,7,12	-	-
J 16D		Spare	A	-	-	-	-
J 16E	M-43	Recirc flow	-	BB-XV3801C	1,7,12	-	-
J-16F	M-43	Recirc flow	-	BB-XV3802C	1,7,12	-	-
J 17A-F		Spare	A	-	-	-	-
J 18A		Spare	A	-	-	-	-
J 18B	M-43	Recirc flow	-	BB-XV3801A	1,7,12	-	-
J 18C	-	Spare	A	-	-	-	-
J 18D	-	Spare	A	-	-	-	-
J 18E	-	Spare	A	-	-	-	-
J 18F	M-43	Recirc flow	-	BB-XV3802A	1,7,12	-	-
J 19A	M-55	HPCI turbine steam supply	-	FD-XV4800A	1,7,12	-	-
J 19B	M-55	HPCI turbine steam supply	-	FD-XV4800C	1,7,12	-	-
J 19C	M-52	Core spray flow	-	BE-XVF018A	1,7,12	-	-
J 19D	M-44	RWCU flow	-	BG-XV3884A	1,7,12	-	-
J 19E	M-44	RWCU flow	-	BG-XV3884C	1,7,12	-	-
J 19F		Spare Instrument Line	A	-	-	-	-
J 20A	M-49	RCIC turbine steam supply	-	FC-XV4150A	1,7,12	-	-

Penet Number	P&ID Number	System Description	Test Type	Inboard Isolation Barrier Description/ Valve Number	Notes	Outboard Isolation Barrier Description/ Valve Number	Notes
J 20B	M-49	RCIC turbine steam supply	-	FC-XV4150C	1,7,12	-	-
J 20C		Spare	A	-	-	-	-
J 20D		Spare Instrument Line	A	-	-	-	-
J 20E&F		Spare	A	-	-	-	-
J 21A	M-41	Main steam flow line C	-	AB-XV3667C	1,7,12	-	-
J 21B		Spare	A	-	-	-	-
J 21C		spare	A	-	-	-	-
J 21D	M-41	Main steam flow line D	-	AB-XV3667D	1,7,12	-	-
J 21E	M-41	Main steam flow line C	-	AB-XV3668C	1,7,12	-	-
J 21F	M-41	Main steam flow line D	-	AB-XV3668D	1,7,12	-	-
J 22A	M-41	Main steam flow line A	-	AB-XV3667A	1,7,12	-	-
J 22B	M-41	Main steam flow line A	-	AB-XV3668A	1,7,12	-	-
J 22C	M-41	Main steam flow line B	-	AB-XV3667B	1,7,12	-	-
J 22D	M-41	Main steam flow line B	-	AB-XV3668B	1,7,12	-	-
J 22E		Spare	A	-	-	-	-
J 22F		Spare	A	-	-	-	-
J 23A	M-51	RHR LPCI check valve pressure	-	BC-XV4429B	1,7,12	-	-
J 23B	M-51	RHR LPCI check valve pressure	-	BC-XV4411B	1,7,12	-	-
J 23C	M-43	Recirc pump differential press.		-	BB-XV3827	1,7,12	- -
J 23D-F		Spare	A	-	-	-	-
J 24A	M-43	Recirc flow	-	BB-XV3803B	1,7,12	-	-
J-24B	M-43	Recirc flow	-	BB-XV3804B	1,7,12	-	-
J 24C	M-44	RWCU flow	-	BG-XV3882	1,7,12	-	-
J 24D		Spare Instrument Line	A	-	-	-	-

Penet Number	P&ID Number	System Description	Test Type	Inboard Isolation Barrier Description/ Valve Number	Notes	Outboard Isolation Barrier Description/ Valve Number	Notes
J 24E	M-42	Reactor Recirc Flow Loop B	-	BB-XV3732C	1,7,12	-	-
J 24F		Spare	A	-	-	-	-
J 25A	M-41	Main steam flow line A	-	AB-XV3666A	1,7,12	-	-
J 25B		Spare	A	-	-	-	-
J 25C	M-41	Main steam flow line A	-	AB-XV3669A	1,7,12	-	-
J 25D-F		Spare	A	-	-	-	-
J 26A	M-41	Main steam flow line B	-	AB-XV3666B	1,7,12	-	-
J 26B		Spare	A	-	-	-	-
J 26C	M-41	Main steam flow line B	-	AB-XV3669B	1,7,12	-	-
J 26D-F		Spare	A	-	-	-	-
J 27A	M-41	Main steam flow line C	-	AB-XV3666C	1,7,12	-	-
J 27B		Spare	A	-	-	-	-
J 27C		Spare Instrument Line	A	-	-	-	-
J 27D	M-41	Main steam flow line C	-	AB-XV3669C	1,7,12	-	-
J 27E		Spare	A	-	-	-	-
J 27F		Spare Instrument Line	A	-	-	-	-
J 28A	M-41	Main steam flow line D	-	AB-XV3666D	1,7,12	-	-
J 28B	M-43	Recirc flow	-	BB-XV3801B	1,7,12	-	-
J 28C		Spare	A	-	-	-	-
J 28D	M-41	Main steam flow line D	-	AB-XV3669D	1,7,12	-	-
J 28E		Spare	A	-	-	-	-
J 28F	M-43	Recirc flow	-	BB-XV3802B	1,7,12	-	-
J 29A	M-55	HPCI turbine steam supply	-	FD-XV4800B	1,7,12	-	-
J 29B	M-55	HPCI turbine steam supply	-	FD-XV4800D	1,7,12	-	-

Penet Number	P&ID Number	System Description	Test Type	Inboard Isolation Barrier Description/ Valve Number	Notes	Outboard Isolation Barrier Description/ Valve Number	Notes
J 29C		Spare	A	-	-	-	-
J 29D	M-43	Recirc flow	-	BB-XV3804A	1,7,12	-	-
J 29E		Spare	A	-	-	-	-
J 29F	M-43	Recirc flow	-	BB-XV3803A	1,7,12	-	-
J 30A,D,E		Spare	A	-	-	-	-
J 30B	M-43	Recirc pump cooler loop A	-	BB-XV3789	1,7,12	-	-
J 30C	M-43	Recirc pump cooler loop A	-	BB-XV3787	1,7,12	-	-
J 30F	M-52	Core spray flow	-	BE-XVF018B	1,7,12	-	-
J 31A		Spare	A	-	-	-	-
J 31B		Spare	A	-	-	-	-
J 31C		Spare	A	-	-	-	-
J 31D&E		Spare	A	-	-	-	-
J 31F		Spare	A	-	-	-	-
J 32A		Spare	A	-	-	-	-
J 32B	M-43	Recirc pump cooler loop B	-	BB-XV3783	1,7,12	-	-
J 32C	M-43	Recirc pump cooler loop B	-	BB-XV3785	1,7,12	-	-
J 32D		Spare	A	-	-	-	-
J 32E	M-43	Recirc pump differential press	-	BB-XV-3820	1,7,12	-	-
J 32F	M-43	Recirc pump differential press	-	BB-XV3821	1,7,12	-	-
J 33A	M-51	RHR LPCI check valve pressure	-	BC-XV4411A	1,7,12	-	-
J 33B		Spare	A	-	-	-	-
J 33C		Spare	A	-	-	-	-
J 33D	M-51	RHR LPCI check valve pressure	-	BC-XV4429A	1,7,12	-	-
J 33E&F		Spare	A	-	-	-	-

Penet Number	P&ID Number	System Description	Test Type	Inboard Isolation Barrier Description/ Valve Number	Notes	Outboard Isolation Barrier Description/ Valve Number	Notes
J 34A	M-44	RWCU flow	-	BG-XV3884B	1,7,12	-	-
J 34B	M-43	Recirc pump differential press	-	BB-XV3826	1,7,12	-	-
J 34C	M-44	RWCU flow	-	BG-XV3884D	1,7,12	-	-
J 34D	M-43	Recirc pump flow	-	BB-XV-3803D	1,7,12	-	-
J 34E	M-43	Recirc pump flow	-	BB-XV-3804D	1,7,12	-	-
J 34F		Spare	A	-	-	-	-
J 35A	M-51	RHR LPCI check valve pressure	-	BC-XV4411C	1,7,12	-	-
J 35B		Spare	A	-	-	-	-
J 35C	M-51	RHR LPCI check valve pressure	-	BC-XV4429C	1,7,12	-	-
J 35D-F		Spare	A	-	-	-	-
J 36A	M-51	RHR, LPCI check valve pressure	-	BC-XV4429D	1,7,12	-	-
J 36B	M-51	RHR, LPCI check valve pressure	-	BC-XV4411D	1,7,12	-	-
J 36C	M-60	ILRT line	C	GP-V120	4,12	GP-V122	4
J 36D	M-60	ILRT line	C	GP-V001	4,12	GP-V002	4
J 36E	M-43	Recirc flow	-	BB-XV3801D	1,7,12	-	-
J 36F	M-43	Recirc flow	-	BB-XV3802D	1,7,12	-	-
J 37A	M-42	Reactor recirc flow loop A	-	BB-XV3732A	1,7,12	-	-
J 37B		Spare	A	-	-	-	-
J 37C	M-42	Reactor recirc flow loop A	-	BB-XV3732E	1,7,12	-	-
J 37D	M-42	Reactor recirc flow loop A	-	BB-XV3732G	1,7,12	-	-
J 37E	M-42	Jet pump flow	-	BB-XV3732J	1,7,12	-	-
J 37F		Spare Instrument Line	A	-	-	-	-
J 38A	M-42	Reactor flow	-	BB-XV3737A	1,7,12	-	-
J 38B	M-42	Reactor flow	-	BB-XV3738B	1,7,12	-	-

Penet Number	P&ID Number	System Description	Test Type	Inboard Isolation Barrier Description/ Valve Number	Notes	Outboard Isolation Barrier Description/ Valve Number	Notes
J 38C	M-43	Recirc flow	-	BB-XV3803C	1,7,12	-	-
J 38D&E		Spare	A	-	-	-	-
J 38F	M-43	Recirc flow	-	BB-XV3804C	1,7,12	-	-
J 39A-F		Spare	A	-	-	-	-
J 40A	M-49	RCIC turbine steam supply	-	FC-XV4150D	1,7,12	-	-
J 40B	M-49	RCIC turbine steam supply	-	FC-XV4150B	1,7,12	-	-
J 40C	M-42	Reactor recirc flow loop B	-	BB-XV3732F	1,7,12	-	-
J 40D	M-42	Reactor recirc flow loop B	-	BB-XV3732U	1,7,12	-	-
J 40E	M-42	Reactor recirc flow loop B	-	BB-XV3732H	1,7,12	-	-
J 40F	M-42	Reactor recirc flow loop B	-	BB-XV3732M	1,7,12	-	-
J 41	M-42	Reactor pressure	-	BB-XV3727B	1,7,12	-	-
J 42	M-42	Reactor pressure	-	BB-XV3729B	1,7,12	-	-
J 43	M-42	Reactor pressure	-	BB-XV3730B	1,7,12	-	-
J 44	M-42	Reactor pressure	-	BB-XV3727A	1,7,12	-	-
J 45		Spare Instrument Line	A	-	-	-	-
J 46		Spare Instrument Line	A	-	-	-	-
J 47	M-42	Reactor pressure	-	BB-XV3734B	1,7,12	-	-
J 48		Spare Instrument Line	A	-	-	-	-
J 49		Spare Instrument Line	A	-	-	-	-
J 50	M-42	Jet pump flow/	-	BB-XV3734A	1,7,12	-	-
	M-38	Post accident sampling	C	RC-SV-8903A	12	RC-SV-8903B	-
J 51	M-42	Reactor pressure	-	BB-XV3729A	1,7,12	-	-
J 52	M-42	Reactor pressure	-	BB-XV3730A	1,7,12	-	-
J 201	M-57	Torus outlet to "A" hydrogen/oxygen analyzer	C	GS-V051	12	GS-V052	-

TABLE 6.2-24 (Cont)

Penet Number	P&ID Number	System Description	Test Type	Inboard Isolation Barrier Description/ Valve Number	Notes	Outboard Isolation Barrier Description/ Valve Number	Notes
J 202	M-57	Torus outlet to "B" hydrogen/oxygen analyzer	C C	GS-V042	12	GS-V043, GS-V053 GS-V033, GS-V034	5 5
J 203 - J205		Spare	A	-	-	-	-
J 206	M-38	Post-accident sampling system	C	RC-SV-0728A	12	RC-SV-0728B	-
J 207	M-57	Suppression chamber pressure	A	GS-V044	4,11,12	-	-
J 208	M-57	Suppression chamber pressure	A	GS-V087	4,11,12	-	-
J 209	M-55	Torus water level	A	BJ-V500	11,12	-	-
	M-60	ILRT	C	GP-V004	4,12	GP-V005	4
J 210	M-57	Torus inlet to "B": hydrogen/oxygen analyzer	C	GS-V040	12	GS-V041	-
J 211	M-59	Instrument air to torus	C	KL-V019	12	KL-V018	-
J 212	M-59	Torus inlet to "A" hydrogen/oxygen analyzer	C	GS-V049	12	GS-V050	-
J 213		Spare	A	-	-	-	-
J 214A-D	M-41	Suppression pool temp	A	-	-	-	-
J 215A-H	M-41	Suppression pool temp	A	-	-	-	-
J 215J-N	M-41	Suppression pool temp	A	-	-	-	-
J 215P-R	M-41	Suppression pool temp	A	-	-	-	-
J 216		Spare	A	-	-	-	-
J 217	M-55	Torus water level	A	BJ-V502	11,12	-	-
J 218		Spare	A	-	-	-	-
J 219	M-55	Torus water level	A	BJ-V503	11,12	-	-
J 220	M-38	Post-accident sampling system	C	RC-SV-0707A	12	RC-SV-0707B	-
J 221	M-38	Post-accident gas sampling	C	RC-SV-0729A	12	RC-SV-0729B	-
J-1293		Spare	A	-	-	-	-

Penet Number	P&ID Number	System Description	Test Type	Inboard Isolation Barrier Description/ Valve Number	Notes	Outboard Isolation Barrier Description/ Valve Number	Notes
J-1294		Spare	A	-	-	-	-
J-1295		Spare	A	-	-	-	-
J-1296		Spare	A	-	-	-	-
J-1297		Spare	A	-	-	-	-
J-1298		Spare	A	-	-	-	-
J-1299		Spare	A	-	-	-	-
J-1300		Spare	A	-	-	-	-
J-1301		Spare	A	-	-	-	-
J-1302		Spare	A	-	-	-	-
J-1303		Spare	A	-	-	-	-
J-1304		Spare	A	-	-	-	-
J-1305		Spare	A	-	-	-	-
J-1306		Spare	A	-	-	-	-
J-1307		Spare	A	-	-	-	-
J-1308		Spare	A	-	-	-	-
J-1309		Spare	A	-	-	-	-
J-1310		Spare	A	-	-	-	-
J-1311		Spare	A	-	-	-	-
J-1312		Spare	A	-	-	-	-
J-1313		Spare	A	-	-	-	-
J-1314		Spare	A	-	-	-	-
J-1315		Spare	A	-	-	-	-
J-1316		Spare	A	-	-	-	-
J-1317		Spare	A	-	-	-	-

Penet Number	P&ID Number	System Description	Test Type	Inboard Isolation Barrier Description/ Valve Number	Notes	Outboard Isolation Barrier Description/ Valve Number	Notes
J-1318		Spare	A				
J-1319		Spare	A				
J-1320		Spare	A				
J 1350	M-42	Reactor level	-	BB-XV3726A	1,7,12	-	-
J 1351	M-42	Reactor level	-	BB-XV3728A	1,7,12	-	-
J 1352	M-42	Reactor level	-	BB-XV3731A	1,7,12	-	-
J 1353	M-42	Reactor level	-	BB-XV3726B	1,7,12	-	-
J 1354	M-42	Reactor level	-	BB-XV3728B	1,7,12	-	-
J 1355	M-42	Reactor level	-	BB-XV3731B	1,7,12	-	-

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TABLE 6.2-24 (Cont)

1. Seismic Category I, Quality Group A instrument line with an orifice and excess flow-check valve or remote-manual isolation valve. The excess-flow check valve is subjected to functional testing which includes a qualitative leak check, but no Type C test is performed or required. The line does not isolate during a LOCA and can leak only if the line or instrument should rupture. Line and instrument leak tightness is verified during the ILRT Type A test.

2. Penetration is sealed by a blind flange or door with double O-ring seals. See Table 6.2-30.

3. Inboard valve tested in the reverse direction. Reverse pressure testing gives equivalent results to normal direction testing and therefore complies with Appendix J.

4. Manual containment isolation valve.

5. Valve is containment isolation valve for more than one penetration.

6. The main steam containment isolation valves are leak tested in accordance with the IST program (ASME OM Code, Subsection ISTC, Category A valves.) See also Question 410.35 and FSAR Sections 6.2.5.7 and 6.2.4.4.

7. Exception to Appendix J required. For further discussion and justification, see Section 6.2.4.4.

8. Gate valve is tested either by pressurizing between the seats through the bonnet, which equivalent to normal direction testing and therefore complies with Appendix J; or by applying pressure in the LOCA direction, as required by Appendix J.

9. The isolation barrier remains water filled post-LOCA and will be tested with water. Isolation valve leakage is not included in 0.60 La total for type B and C tests.

   All such systems are: a) protected against missiles and pipe whip, b) designed to Seismic Category I requirements, c) classified as Quality Group B, and d) will remain full of water for 30 days following an accident even after the assumption of a single active failure.

10. Explosive actuated valve. Not Type "C" tested. Explosive charge tested as category "D" valve per ASME OM Code, Subsection ISTC. See FSAR Section 6.2.4.4.

11. The valve does not receive an isolation signal but remains open to measure containment conditions post-LOCA. Leak tightness of the penetration is verified during the Type A test.

12. All isolation barriers are located outside containment.

13. The control rod drive (CRD) insert and withdraw lines can be isolated by solenoid valves outside containment. The CRD insert lines each have a ball check valve inside containment.

14. The isolation provisions for this penetration consist of at least one isolation valve and a closed system outside containment. A single active failure can be accommodated. The system is missile protected and Seismic Category I and becomes an extension of containment post-LOCA. System leak tightness is verified by the testing requirements of Section 1.10 Paragraph 111.D.1.1.

15. This penetration is a boundary between the drywell and the suppression chamber. It is not a path from the primary containment to the environment.

16. Pressure safety valves (PSVs) are type "C" tested when attached to a type "C" test boundary and as category "C" (relief) valves per ASME OM Code, Subsection ISTC and Mandatory Appendix I.

17. Construction opening welded closed upon completion of construction.

18. Containment isolation valves are not Type C tested. Containment atmospheric leakage is prevented since the line remains filled with water during and following a DBA. The system is fully qualified and meets the requirements of a closed loop, water-filled system. Refer to Paragraph 6.2.6.3.

TABLE 6.2-25

PENETRATIONS USING A CLOSED SYSTEM OUTSIDE PRIMARY CONTAINMENT AS A SECOND ISOLATION BARRIER

Containment Penetration Number	Line Isolated	Justification (1)
P-3	RHR Shutdown Cooling Suction	e
P-4A and 4B	RHR Shutdown Cooling Return	e
P-5A and 5B	Core Spray to Reactor	e
P-6A thru 6D	LPCI	e
P-24A and 24B	RHR Containment Spray	e
P-201	Vacuum Breaker Network Branch	a, c, d
P-202	HPCI Pump Suction	a, c
P-203	HPCI Minimum Return	a, c
P-204	HPCI & RCIC Vacuum Breaker Network	a, d
P-207	Vacuum Breaker Network Branch	a, c, d
P-208	RCIC Pump Suction	a, c
P-209	RCIC Minimum Return	a, c
P-211A thru 211D	RHR Pump Suction	a
P-212A, 212B	RHR Suppression Pool Cooling & System Test	a, c
P-214A, 214B	RHR to Suppression Pool Spray Header	a
P-216A thru 216D	Core Spray Pump Suction	a, c
P-217A, 217B	Core Spray Test to Suppression Pool	a, c

Containment Penetration Number	Line Isolated	Justification (1)
P-228, J-209, J-217, J-219	Suppression Pool Water Level	b

Notes:

(1) Justifications:

a. A single isolation valve is used because the system provides or aids the emergency passage of fluids into and out of primary containment. The addition of a second containment isolation valve decreases the reliability of the system by providing an additional source of active failure.

b. A single isolation valve is used because a second isolation valve would not add to the dependability of the containment boundary. These instrument lines are a reliable containment boundary. To add a second containment isolation valve would lengthen the containment boundary without a subsequent increase in the dependability of the containment boundary.

c. The line to the suppression pool is always submerged so that the primary containment atmosphere cannot impinge upon the valve.

d. The isolation provisions that are shared in common between containment penetrations P-201, P-204, and P-207 can be shown to provide isolation by redundant primary containment isolation valves, as an alternative to considering the vacuum breaker network as a closed system.

e. Although the line includes inboard and outboard valves which provide containment isolation and other safety related functions, only one of these valves is a containment isolation valve. The configuration of a single containment isolation valve in conjunction with the extended containment pressure boundary provided by the closed system outside containment is acceptable under the provisions of 10CFR50, Appendix A for alternative containment isolation arrangements under an "other defined basis". This configuration eliminates unnecessary 10CFR50 Appendix J testing and offers ALARA-occupational radiation exposure reductions.

TABLE 6.2-26

SYSTEM ISOLATION VALVES WITH PRIMARY CONTAINMENT ISOLATION(1)

Line Isolated	Valve(4) Number	Operator Number	Essential/ Non-Essential	Isolation Signals(2)	Comments (3)
RHR to Radwaste	BC-V042 BC-V041	HV-F049 HV-F040	Non-Essential Non-Essential	B,D B,D	A
RHR to Process Sampling	-- --	BC-SV-F079A BC-SV-F080A	Non-Essential Non-Essential	B,D B,D	A
RHR to Process Sampling	-- --	BC-SV-F079B BC-SV-F080A	Non-Essential Non-Essential	B,D B,D	A
RHR to Post-Accid. Sampling	-- --	RC-SV-F0645A RC-SV-F0645B	Non-Essential Non-Essential	None None	A,B,C
RHR to Post-Accid. Sampling	-- --	RC-SV-F0646A RC-SV-F0646B	Non-Essential Non-Essential	None None	A,B,C
RHR to Contain. Hydrogen Recomb.	BC-V520 GS-V150	HV-V055A HV-5057A	Non-Essential Non-Essential	A,B,C A,B,C	A
RHR to Contain. Hydrogen Recomb.	BC-V521 GS-V151	HV-5055B HV-5057B	Non-Essential Non-Essential	A,B,C A,B,C	A
HPCI/RCIC to CST	AP-V004	HV-F011	Non-Essential	A,B	
RCIC from CST	BD-V001	HV-F010	Essential	None	
RCIC to Lube Oil Cooler	BD-V022	HV-F046	Essential	None	
HPCI from CST	BJ-V005	HV-F004	Essential	None	
HPCI to Lube Oil Cooler	BJ-V028	HV-F059	Essential	None	
FLEX Tie-in Connection to RHR	BC-V636		Non-Essential	None	
HPCI Steam Supply	--	BC-PV-F051B	Non-Essential	None	E

Line Isolated	Valve[4] Number	Operator Number	Essential/ Non-Essential	Isolation Signals[2]	Comments (3)
Station Service Water	BC-V039	HV-F075	Non-Essential	None	
--	BJ-V027	None	--	--	F
--	BD-V023	None	--	--	F
--	BD-PSV-F017	None	--	--	G
--	BJ-PSV-F020	None	--	--	G
--	BC-PSV-F029	None	--	--	H
--	BC-PSV-F030A	None	--	--	H
	BC-PSV-F030B	None	--	--	H
--	BC-PSV-F030C	None	--	--	H
--	BC-PSV-F030D	None	--	--	H

NOTES:

(1) Where a single containment isolation valve is used, HCGS takes credit for the connecting system being a closed system outside primary containment (as defined in Regulatory Guide 1.141). In the case of a single failure, the closed system accommodates the failure by being an extension of the containment. The intersystem valves assure the integrity of the extended containment boundary. These valves meet all the requirements of primary containment isolation valves including the NUREG-0737, Item II.E.4.2 requirements.

(2) Table of Isolation Signal Codes

A - Reactor Vessel Low Water Level - Level 2
B - Drywell High Pressure
C - Reactor Building High Radiation
D - Reactor Vessel Low Water Level - Level 3

TABLE 6.2-26 (Cont)

(3) Comments

A. Using two intersystem isolation valves is conservative. If there is a single failure, and the containment isolation valve is unable to close, HCGS assumes credit for the closed system outside primary containment to accommodate the failure: Only one intersystem isolation valve in conjunction with the containment isolation valve is required to assure that the integrity of the closed system serving as an extension of the primary containment is maintained. If the single failure is loss of the intersystem isolation valves, the containment isolation valve will still be functional. Hence, the closed system would not constitute an extension of the primary containment and a second intersystem valve would not be required.

B. The post-accident sampling system is a fail-safe system, and will isolate on loss of power. The system meets the requirement of a sealed closed system. Power to open the system is provided only under administrative control.

C. Although the system is classified as non-essential, if the system is functional, it will be necessary to open the containment isolation valves after an accident, in order for the system to perform its intended function.

D. Deleted.

E. The valve is seal closed.

F. Use of a check valve as a system isolation valve is acceptable because it is located below the suppression pool and will be maintained closed in the reverse flow direction by the hydrostatic pressure in the suppression pool.

G. Use of a relief valve in the forward flow direction as an isolation valve is acceptable because its set pressure is greater than 1.5 times the containment pressure. The set pressure is 100 psig.

H. Use of relief valve in the forward flow direction as an isolation valve is acceptable because its set pressure is greater than 1.5 times the containment pressure. The set pressure is 170 psig.

(4) Drain valves, vent valves, and manual valves under administrative control have not generally been identified in this table for simplicity. However, they are identified in Figures 6.2-45, 6.2-46, 6.2-47, and 6.2-48.

TABLE 6.2-27

RESULT SUMMARY OF POOL TEMPERATURE RESPONSES (Note 3)

Case No.	Event	Number of SRVs Manually Opened	Maximum Cooldown Rate (°F/hr)	Maximum Bulk Pool Temperature (°F)	Maximum Local Pool Temperature (°F)
1A	SORV at Power, 1 RHR loop	0	1295 (1)	148	179
1B	SORV at Power, Spurious Isolation, 2 RHR Loops	1	448	175	198
2A	Rapid Depressurization at Isolated Hot Shutdown, 1 RHR Loop	5	1200	165	199
2B	SORV at Isolated Hot Shutdown, 2 RHR Loops	1	405	165	189
2C	Normal Depressurization at Isolated Hot Shutdown, 2 RHR Loops	5	100	177	194
3A	SBA-Accident Mode, 1 RHR Loop	5 (ADS) (2)	2277	163	189
3B	SBA-Failure of Shutdown Cooling Mode, 2 RHR Loops	5	100	176	186

(1) When the main condenser is available

(2) ADS = Automatic Depressurization System

(3) The values provided above are for 102% of the original plant rated thermal power of 3293 MWt (3359). The most temperature limiting case determined by the data above (Case 2A) was analyzed at 102% of an assumed power uprate value of 3952 MWt (i.e. 4031 MWt) and the peak local suppression pool temperature is 202.1°F. This value is below the limit of 204.1°F and is therefore acceptable. Note the analysis was conservatively based on the assumed rated thermal power of 3952 MWt rather than the actual Licensed Thermal Power of 3840 MWt.

TABLE 6.2-28

PERSONNEL AND EQUIPMENT OPENINGS INTO THE REACTOR BUILDING[1]

Reactor Building El.	Room	Coordinates[2]

Security Related Information
Table Withheld Under 10
CFR 2.390

(1) All openings into the Reactor Building are provided with position indicator and are monitored in the control room.

(2) See figures in Section 1.2 for location of openings.

(3) Equipment access panel is being replaced with two P.T. doors.

TABLE 6.2-29

RESULTS OF CONTAINMENT DEPRESSURIZATION TRANSIENTS

	Transients	Depressurization Pressure
1.	Cooling cycles	-0.5 psig
2.	Inadvertent spray actuation during normal operation	-2.65 psig
3.	Steam condensation following RCS pipe rupture with inadvertent containment spray actuation	-2.82 psig

TABLE 6.2-30

CONTAINMENT PENETRATIONS SUBJECT TO TYPE B TESTING
PER APPENDIX J

Penetration No.[1]	Nomenclature	Test Type
P1A	Main Steam A Penetration Double Bellows	B
P1B	Main Steam B Penetration Double Bellows	B
P1C	Main Steam C Penetration Double Bellows	B
P1D	Main Steam D Penetration Double Bellows	B
P2A	Feedwater B Penetration Double Bellows	B
P2B	Feedwater A Penetration Double Bellows	B
P3	RHR Shutdown Cooling Penetration Double Bellows	B
P4A	RHR Shutdown Cooling Penetration Double Bellows	B
P4B	RHR Shutdown Cooling Penetration Double Bellows	B

Penetration No.(1)	Nomenclature	Test Type
P5A	Core Spray Penetration Double Bellows	B
P5B	Core Spray Penetration Double Bellows	B
P6A	RHR, LPCI Penetration Double Bellows	B
P6B	RHR, LPCI Penetration Double Bellows	B
P6C	RHR, LPCI Penetration Double Bellows	B
P6D	RHR, LPCI Penetration Double Bellows	B
P7	HPCI - Turbine Steam Penetration Double Bellows	B
P8A	Chilled Water Penetration Double Bellows	B
P8B	Chilled Water Penetration Double Bellows	B
P9	RWCU Pump Suction Penetration Double Bellows	B
P10	SPARE Double Bellows *	B
P11	RCIC Turbine Steam Penetration Double Bellows	B

* Process piping capped inside and outside containment. Flued head remains in place.

Penetration No.(1)	Nomenclature	Test Type
P12	Main Steam Drain Penetration Double Bellows	B
P13	Spare	A(2)
P15	Spare	A(2)
P21	ISI Cable Penetration Cover	B
P34A	Tip Probe Tube Flange	B
P34B	Tip Probe Tube Flange	B
P34C	Tip Probe Tube Flange	B
P34D	Tip Probe Tube Flange	B
P34E	Tip Probe Tube Flange	B
P34F	Tip Purge Penetration Flange	B
P34G	Tip Probe Penetration Flange	B
P38A	Chilled Water Penetration Double Bellows	B
P38B	Chilled Water Penetration Double Bellows	B
C-1	Drywell Equipment Hatch Seal	B

Penetration No.(1)	Nomenclature	Test Type
C-2	Drywell Equipment Hatch Seal	B
C-2	Drywell Personnel Air Lock, Atmosphere Bulkhead Door Seal	B
C-2	Drywell Personnel Air Lock, Containment Bulkhead Door Seal	B
C-2	Drywell Personnel Air Lock, Atmosphere Bulkhead Foot Pedal	B
C-2	Drywell Personnel Air Lock, Atmosphere Bulkhead Remote Door Indicator	B
C-2	Drywell Personnel Air Lock, Atmosphere Bulkhead Handwheel Shaft	B
C-2	Drywell Personnel Air Lock, Containment Bulkhead Interlock Shaft	B
C-2	Drywell Personnel Air Lock, Containment Bulkhead Handwheel Shaft	B
C-2	Drywell Personnel Air Lock Chamber	B
C-3	Control Rod Drive Removal Hatch Cover Seal	B
C-4	Construction Hatch	A(2)
C-5	Drywell Head Inspection Hatch Seal	B

Penetration No.[1]	Nomenclature	Test Type
-	Drywell Head Seal	B
-	Drywell Shear Lug Inspection Cover Seal 0°	B
-	Drywell Shear Lug Inspection Cover Seal 45°	B
-	Drywell Shear Lug Inspection Cover Seal 90°	B
-	Drywell Shear Lug Inspection Cover Seal 135°	B
-	Drywell Shear Lug Inspection Cover Seal 180°	B
-	Drywell Shear Lug Inspection Cover Seal 225°	B
-	Drywell Shear Lug Inspection Cover Seal 270°	B
-	Drywell Shear Lug Inspection Cover Seal 315°	B
C201A	Torus Access Hatch Seal	B
C201B	Torus Access Hatch Seal	B
C201C	Torus Access Hatch Seal	B

Penetration No.(1)	Nomenclature	Test Type
C201D	Torus Access Hatch Seal	B
P221A	Torus Drain Cover Seal	B
P221B	Torus Drain Cover Seal	B
P221C	Torus Drain Cover Seal	B
P221D	Torus Drain Cover Seal	B
P229A	Drywell Vent Line Double Bellows	B
P229B	Drywell Vent Line Double Bellows	B
P229C	Drywell Vent Line Double Bellows	B
P229D	Drywell Vent Line Double Bellows	B
P229E	Drywell Vent Line Double Bellows	B
P229F	Drywell Vent Line Double Bellows	B
P229G	Drywell Vent Line Double Bellows	B
P229H	Drywell Vent Line Double Bellows	B
	Valve Flanges (Non-Isolable)	
P22	GS-V009 - Containment Side Flange to Spacer	B
P22	GS-V009 Spacer - Containment Side Flange	B

TABLE 6.2-30 (Cont)

Penetration No.(1)	Nomenclature	Test Type
P23	GS-V024 - Containment Side Flange to Spacer	B
P23	GS-V024 Spacer - Containment Side Flange	B
P23	GS-V024 - Valve Stem Packing	B
P212A	BC-PSV-F025B - Containment Side Flange	A
P212A	BC-PSV-F025D - Containment Side Flange	A
P212B	BC-PSV-F025A - Containment Side Flange	A
P212B	BC-PSV-F025C - Containment Side Flange	A
P213A	BC-PSV-4431B - Containment Side Flange	A
P213B	BC-PSV-4431A - Containment Side Flange	A
P217A	BE-PSV-F012B - Containment Side Flange	A
P217B	BE-PSV-F012A - Containment Side Flange	B
P219	GS-V028 - Containment Side Flange	B
P219	GS-V028 - Valve Stem Packing	B
P219	GS-V080 - Containment Side Flange to Spacer	B
P219	GS-V080 Spacer - Containment Side Flange	B
P219	GS-V080 - Valve Stem Packing	B

TABLE 6.2-30 (Cont)

Penetration No.(1)	Nomenclature	Test Type
P220	GS-V022 - Containment Side Flange	B
P220	GS-V038 - Containment Side Flange	B
P220	GS-V038 – Valve Stem Packing	B
	Electrical Penetrations	
W100A		B
W100B		B
W100C		B
W100D		B
W101A		B
W101B		B
W101C		B
W101D		B
W101E		B
W101F		B
W102A		B
W102B		B
W102C		B
W102D		B
W103A		B
W103B		B
W104A		B
W104B		B
W104C		B
W104D		B
W104E		B
W104F		B
W104G		B
W104H		B
W104J		B
W104K		B

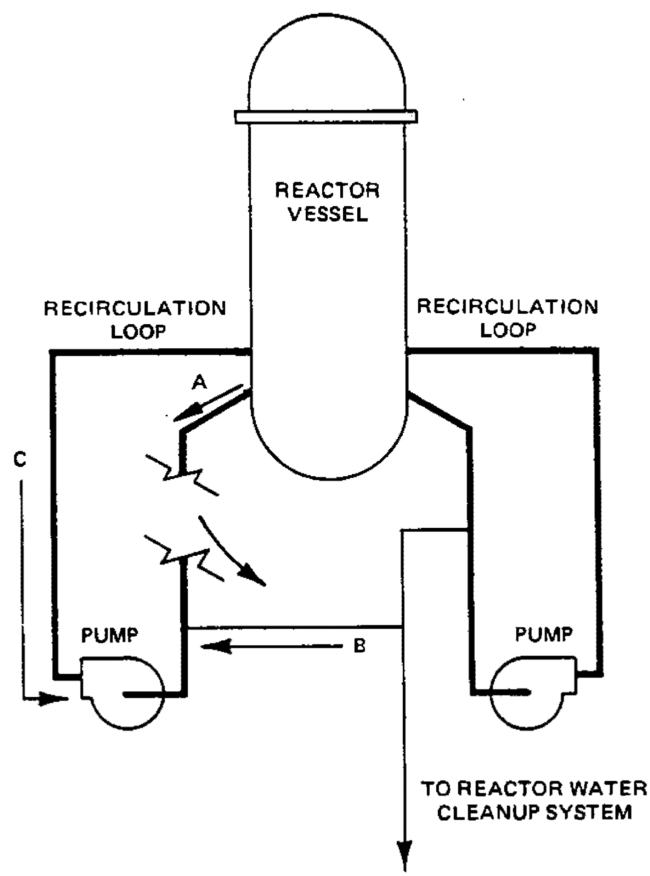
Penetration No.[1]	Nomenclature	Test Type
W105A		B
W105B		B
W105C		B
W105D		B
W105E		B
W105F		B
W105G		B
W105H		B
W106A		B
W106B		B
W106C		B
W201A		B
W201B		B
W201C		B
W201D		B
W202A		B
W203A		B

(1) Reference Drawings: M-60
C-0928
C-0929
C-0931

(2) Welded Closed

POINT OF CRITICAL FLOW

A. RECIRCULATION LINE
B. CLEANUP LINE
C. COMBINED AREA OF ALL JET PUMP NOZZLES ASSOCIATED WITH THE BROKEN LOOP



SCHEMATIC SHOWING COMPOSITION OF TOTAL RECIRCULATION LINE BREAK AREA

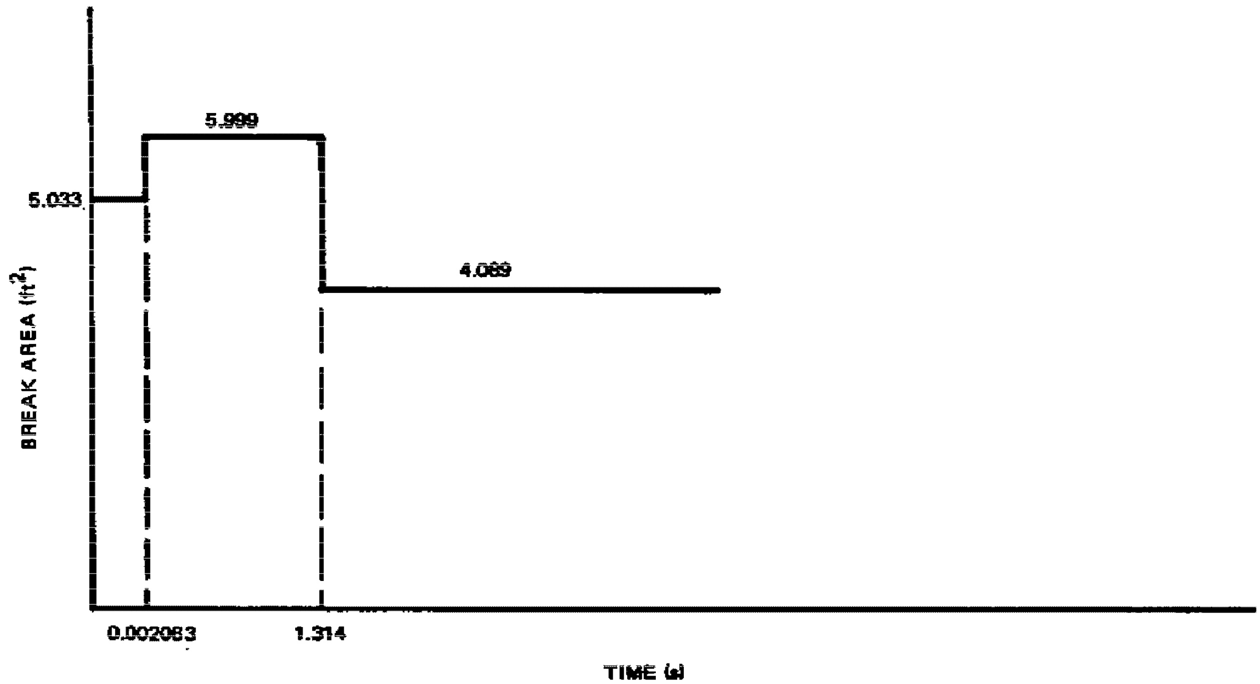
REVISION 0
APRIL 11, 1988

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
HOPE CREEK NUCLEAR GENERATING STATION

DIAGRAM OF THE RECIRCULATION LINE BREAK LOCATION

UPDATED FSAR

FIGURE 6.2-1



Retained for historical purposes based on thermal power of 3359 MWt.

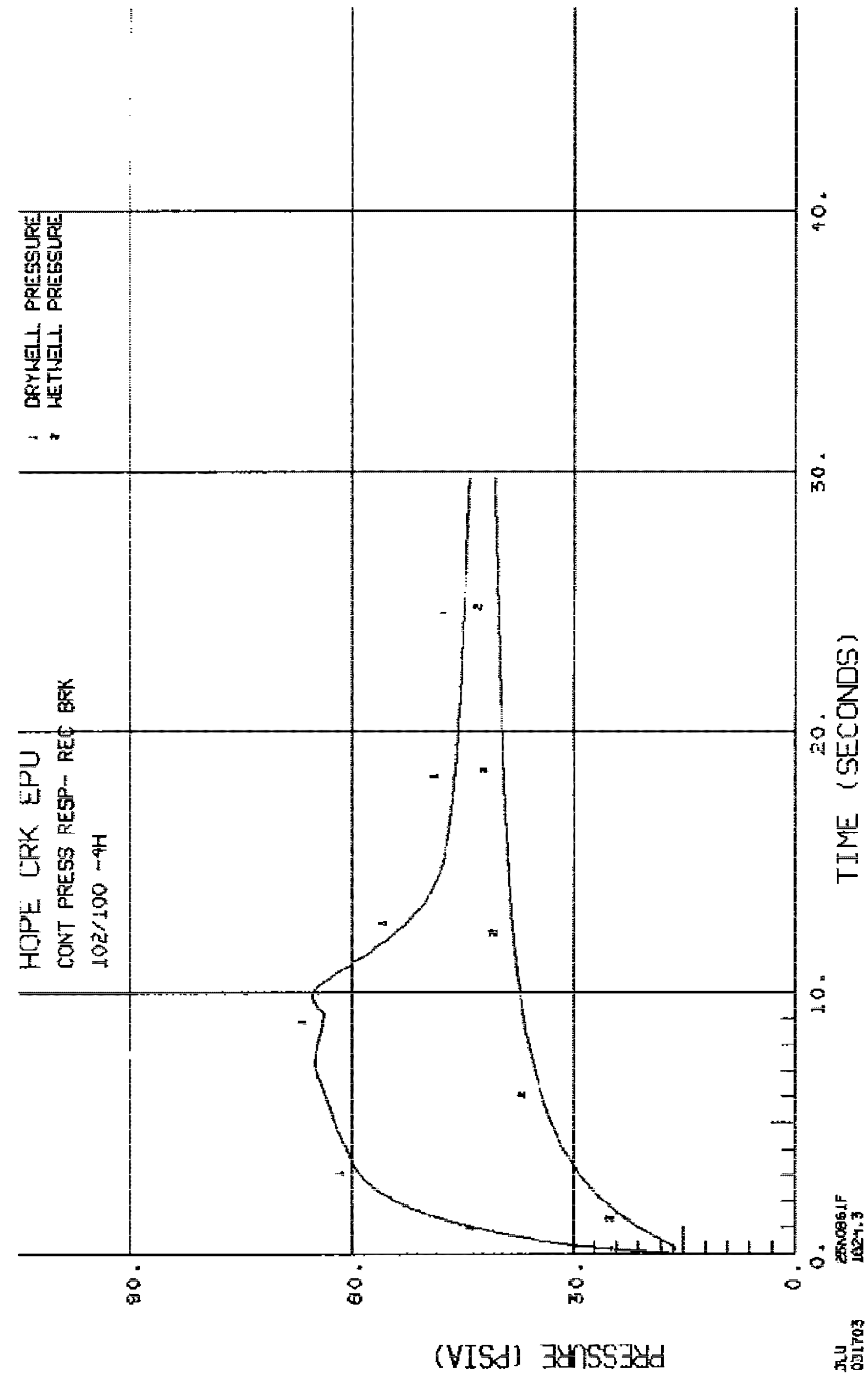
Revision 17, June 23, 2009

PSEG Nuclear, LLC HOPE CREEK NUCLEAR GENERATING STATION	Hope Creek Nuclear Generating Station EFFECTIVE BLOWDOWN AREA FOR RECIRCULATION LINE BREAK
	Updated FSAR Figure 6.2-2

REVISED UFSAR
FIGURE 6.2-3 FROM GE
LPU REPORT T0400 R6
FIGURE 3-1

GE-NE-0000-0005-4298-R6 TASK REPORT T0400

Figure 6.2-3- Short Term Containment Pressure Response Following Recirculation Line Break (102% of 3952 MWt)



Revision 17, June 23, 2009

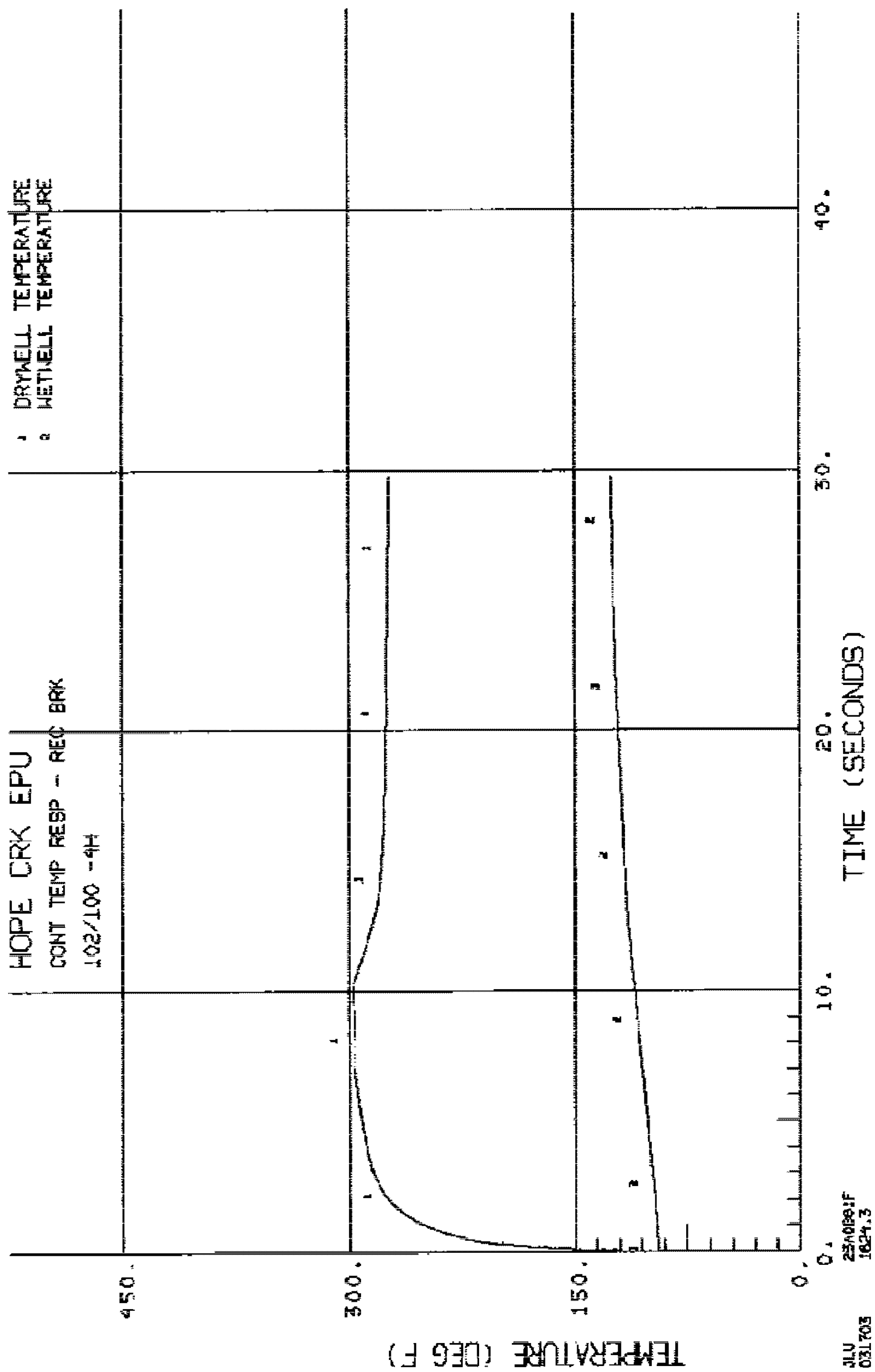
PSEG Nuclear, LLC HOPE CREEK NUCLEAR GENERATING STATION	Hope Creek Nuclear Generating Station SHORT-TERM CONTAINMENT PRESSURE RESPONSE FOLLOWING RECIRCULATION LINE BREAK	
	Updated FSAR	Figure 6.2-3

REVISED UFSAR
FIGURE 6.2-4 FROM
GE LPU REPORT
T0400 R6 Figure 3-2

GE-NE-0000-0005-4298-R6 TASK REPORT T0400

Figure 6.2-4- Short Term Containment Temperature Response Following Recirculation Line Break (102% of 3952 MWt)

Flow (102% of 3952 MWt)



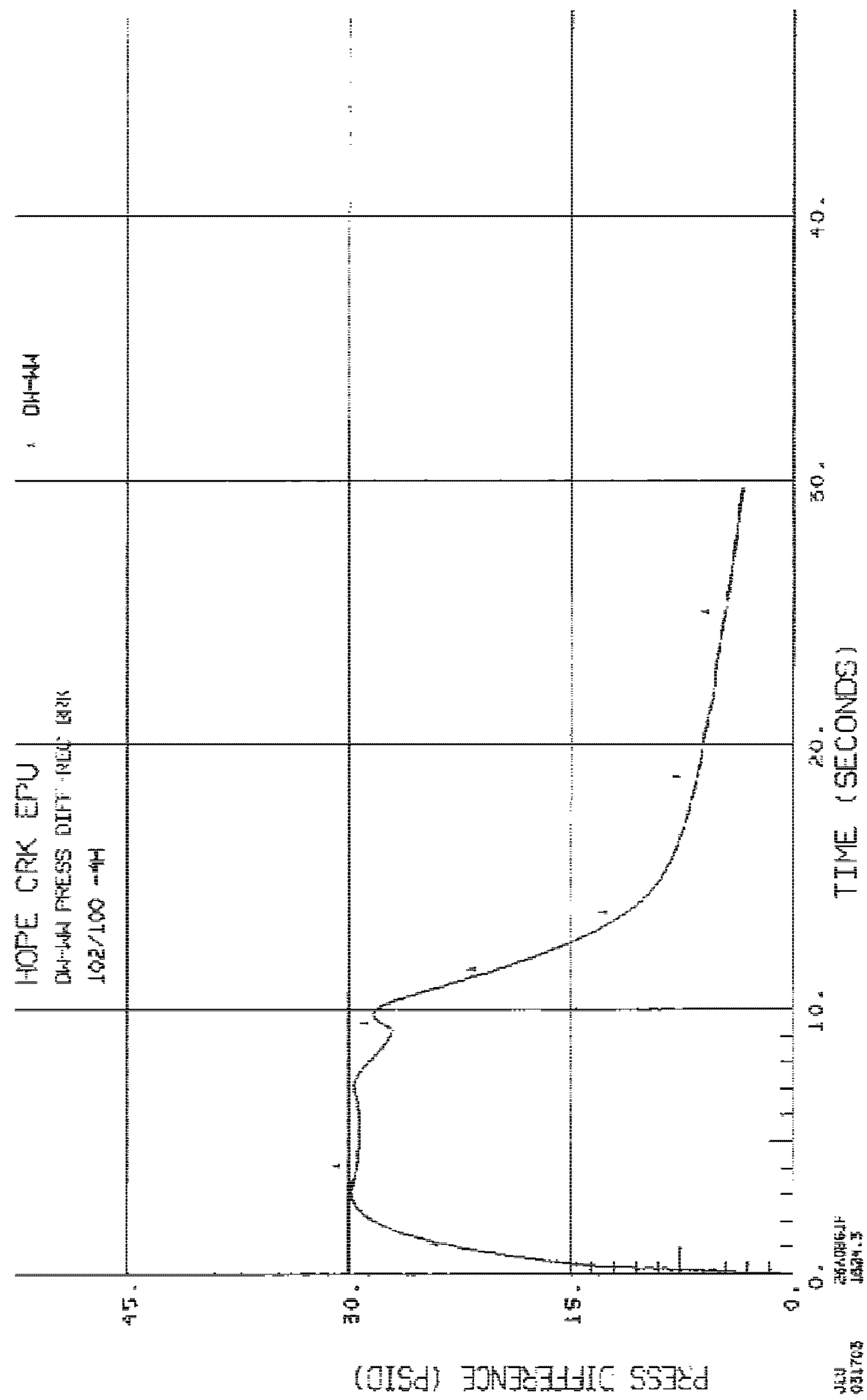
Revision 17, June 23, 2009

PSEG Nuclear, LLC HOPE CREEK NUCLEAR GENERATING STATION	Hope Creek Nuclear Generating Station SHORT-TERM CONTAINMENT PRESSURE RESPONSE FOLLOWING RECIRCULATION LINE BREAK
	Updated FSAR — Figure 6.2-4

REVISED UFSAR
FIGURE 6.2-5 FROM
GE LPU REPORT
T0400 R6 Figure 3-3

GE-NE-0000-0005-4298-R6 TASK REPORT T0400

Figure 6.2-5- Short Term Drywell to Suppression Chamber Differential Pressure Response Following Recirc Line Break (102% of 3952 MWt)



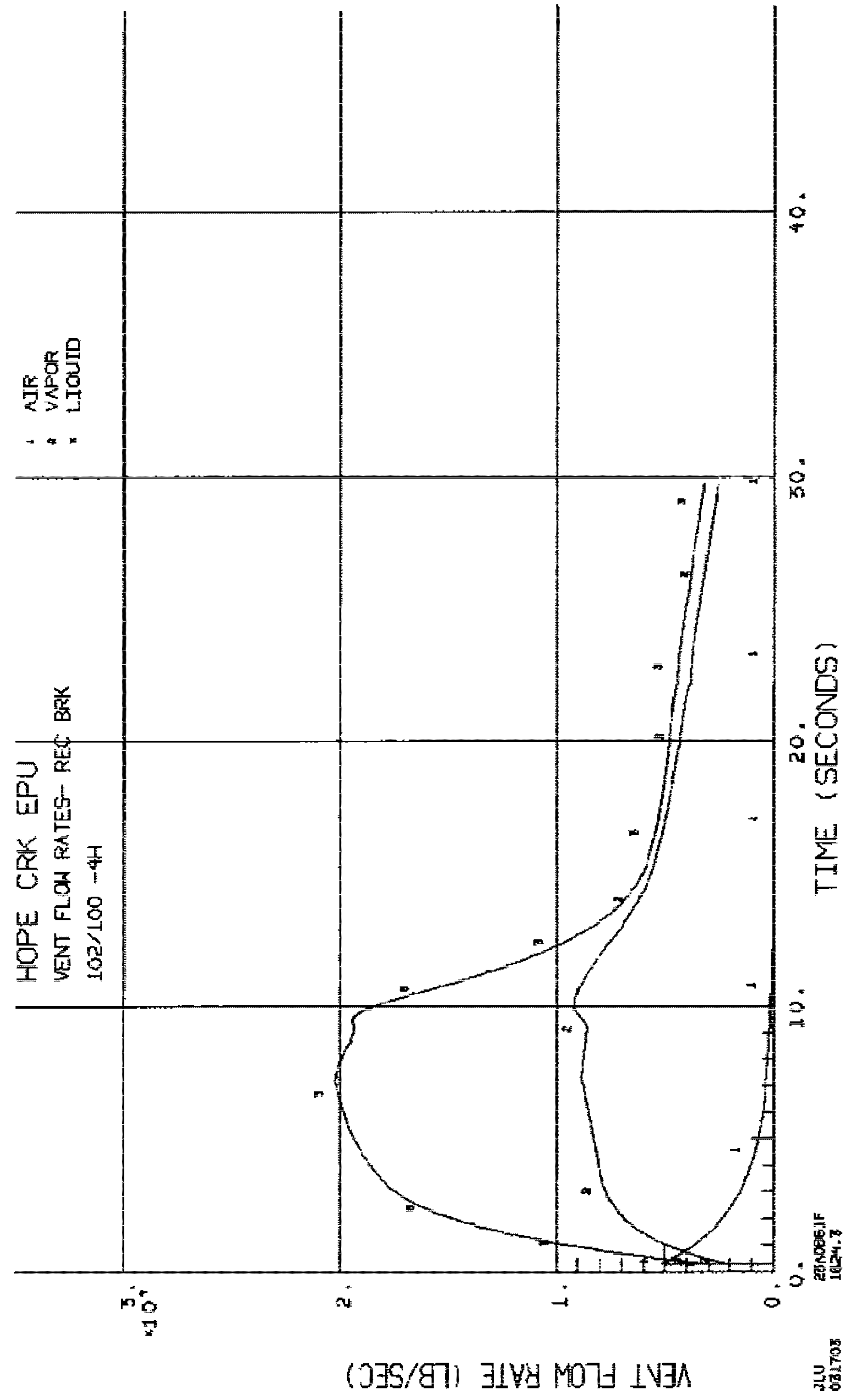
Revision 17, June 23, 2009

PSEG Nuclear, LLC HOPE CREEK NUCLEAR GENERATING STATION	Hope Creek Nuclear Generating Station SHORT-TERM DRYWELL TO SUPPRESS. CHAMBER DIFFERENTIAL PRESS. RESPONSE FOLLOWING RECIRC. LINE BREAK
	Updated FSAR — Figure 6.2-5

REVISED UFSAR
FIGURE 6.2-6 FROM
GE LPU REPORT
T0400 R6 Figure 3-4

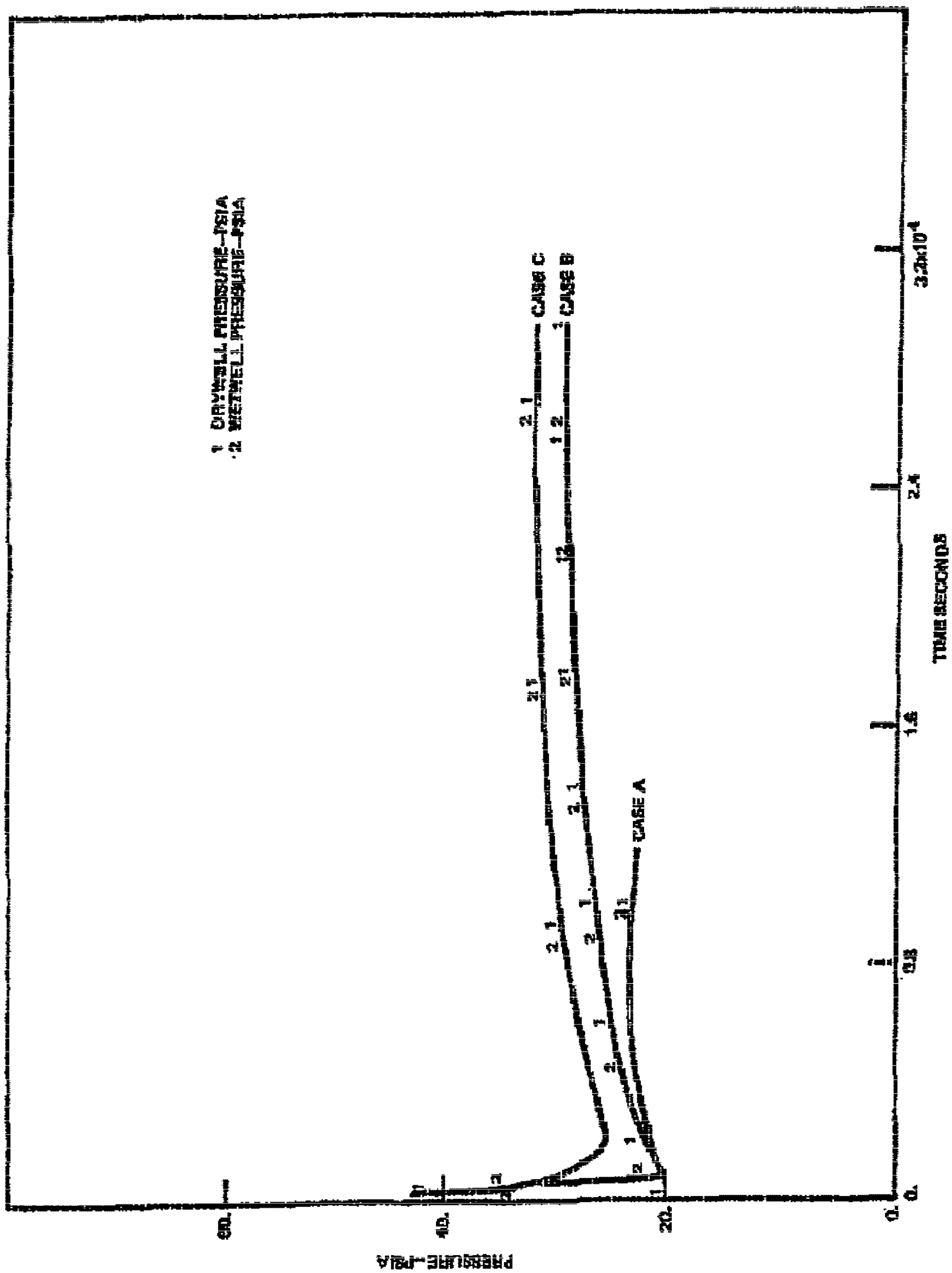
GE-NE-0000-0005-4298-R6 TASK REPORT T0400

Figure 6.2-6- Short Term Vent System Flow Following Recirculation Line Break (102% of 3952 MWt)



Revision 17, June 23, 2009

PSEG Nuclear, LLC HOPE CREEK NUCLEAR GENERATING STATION	Hope Creek Nuclear Generating Station SHORT-TERM VENT SYSTEM FLOW FOLLOWING RECIRCULATION LINE BREAK
	Updated FSAR — Figure 6.2-6



Retained for historical purposes and to provide comparison to alternate cases based on thermal power of 3359 MWt.

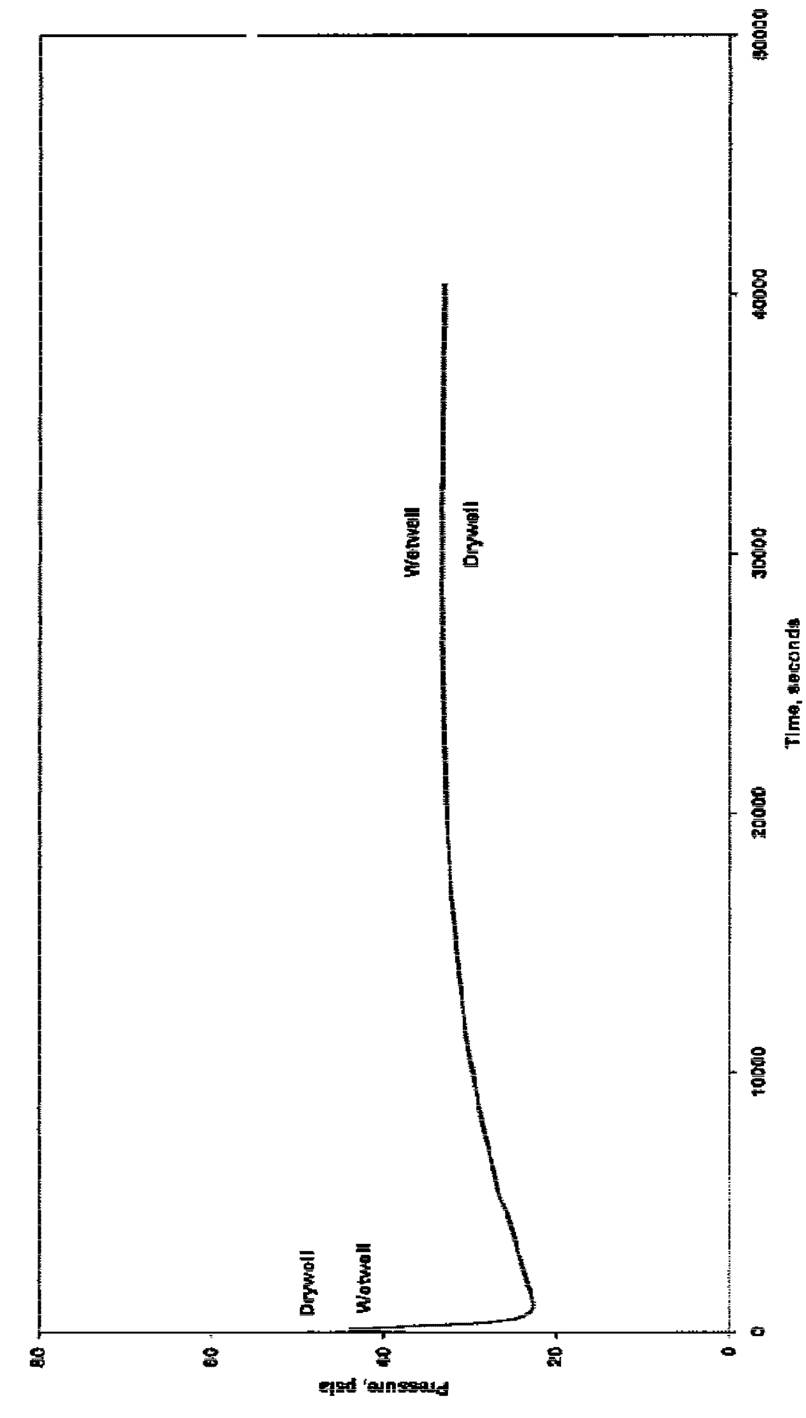
Revision 17, June 23, 2009

PSEG Nuclear, LLC HOPE CREEK NUCLEAR GENERATING STATION	Hope Creek Nuclear Generating Station LONG-TERM CONTAINMENT PRESSURE RESPONSE FOLLOWING RECIRCULATION LINE BREAK
	Updated FSAR — Figure 6.2-7

NEW UFSAR FIGURE 6.2-7a
FROM GE LPU REPORT
T0400 R6 Figure 5-26 for
102% of LPU of 3840 MWt

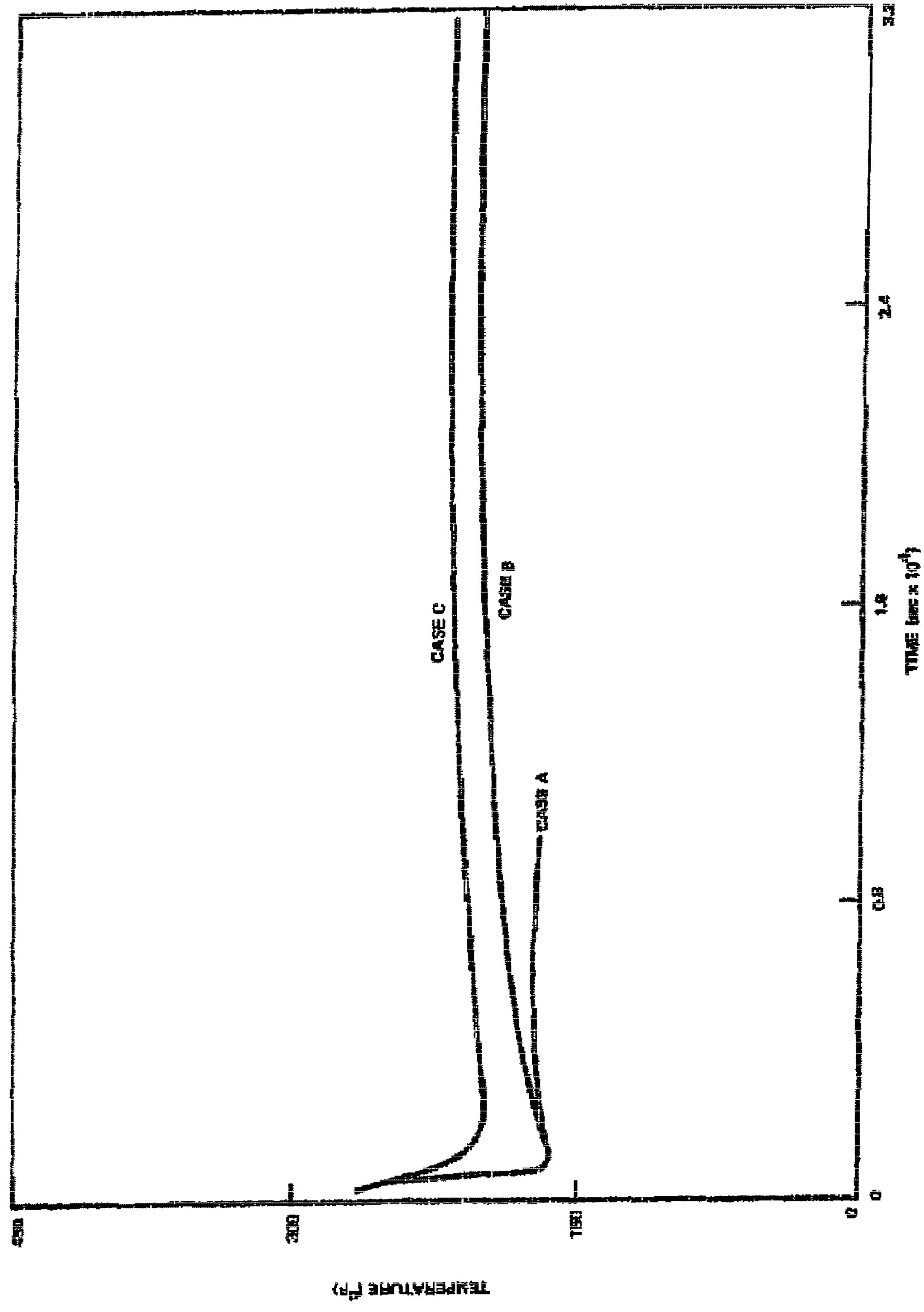
GE-NE-0000-0005-4298-R6 TASK REPORT T0400

Figure 6.2-7a- Long-Term Containment Pressure Response Following Recirculation Line Break (Case C (102% of 3840 MWt)



Revision 17, June 23, 2009

PSEG Nuclear, LLC HOPE CREEK NUCLEAR GENERATING STATION	Hope Creek Nuclear Generating Station LONG-TERM CONTAINMENT PRESSURE RESPONSE FOLLOWING RECIRCULATION LINE BREAK
	Updated FSAR — Figure 6.2-7a



Retained for historical purposes and to provide comparison to alternate cases based on thermal power of 3359 MWt.

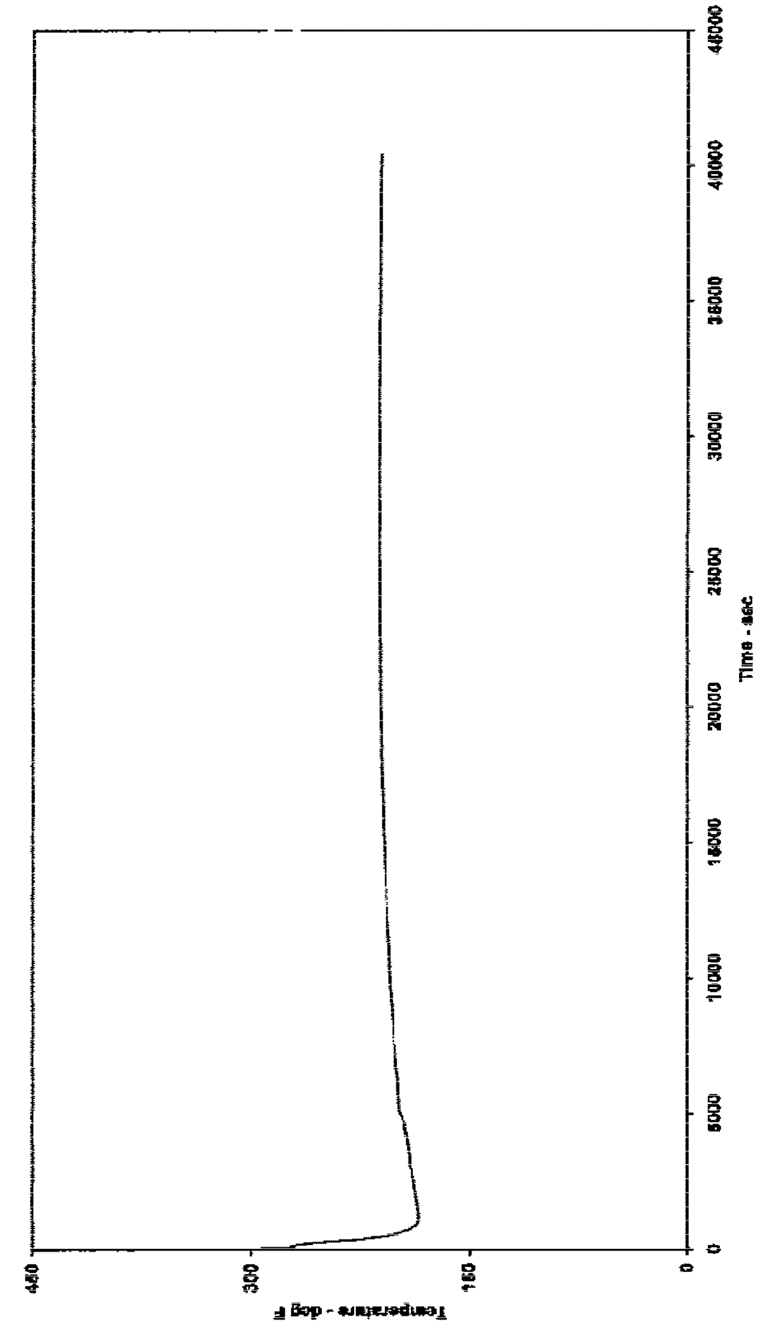
Revision 17, June 23, 2009

PSEG Nuclear, LLC HOPE CREEK NUCLEAR GENERATING STATION	Hope Creek Nuclear Generating Station LONG-TERM DRYWELL TEMPERATURE RESPONSE FOLLOWING RECIRCULATION LINE BREAK
	Updated FSAR — Figure 6.2-8

NEW UFSAR FIGURE 6.2-8a
FROM GE LPU REPORT
T0400 R6 Figure 5-28 for
102% of 3840 MWt

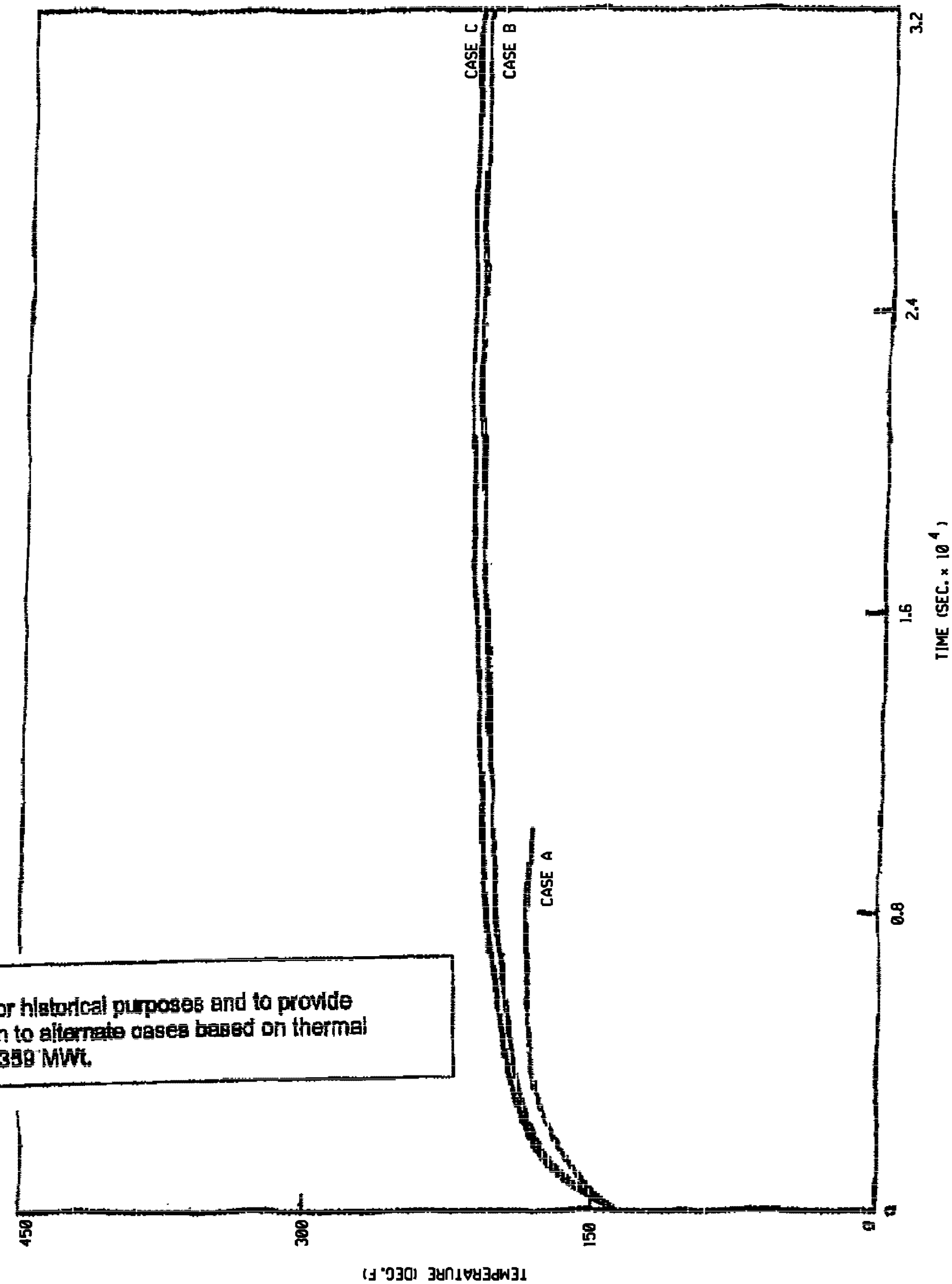
GE-NE- 0000-0005-4298-R6 TASK REPORT T0400

Figure 6.2-8a- Long-Term Drywell Temperature Response Following Recirculation Line Break (Case C at 102% of 3840 MWt)



Revision 17, June 23, 2009

PSEG Nuclear, LLC HOPE CREEK NUCLEAR GENERATING STATION	Hope Creek Nuclear Generating Station LONG-TERM DRYWELL TEMPERATURE RESPONSE FOLLOWING RECIRCULATION LINE BREAK
	Updated FSAR Figure 6.2-8a



Retained for historical purposes and to provide comparison to alternate cases based on thermal power of 3339 MWt.

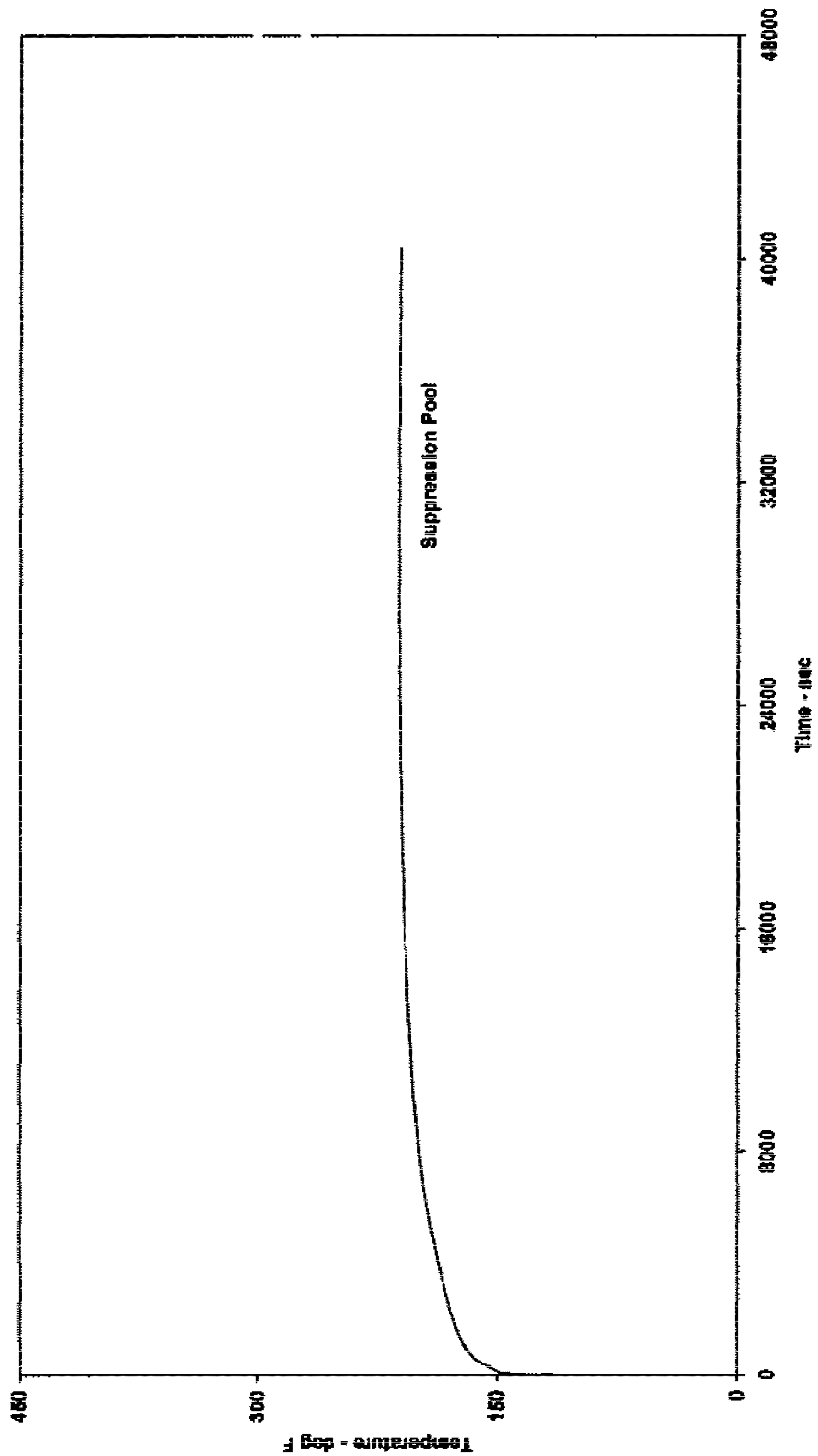
Revision 17, June 23, 2009

PSEG Nuclear, LLC HOPE CREEK NUCLEAR GENERATING STATION	Hope Creek Nuclear Generating Station LONG-TERM SUPPRESSION POOL TEMPERATURE RESPONSE FOLLOWING RECIRCULATION LINE BREAK
	Updated FSAR Figure 6.2-9

NEW UFSAR FIGURE
6.2-9a FROM GE REPORT
T0400 R6 Figure 5-30 for
102% of 3840 MWt

GE-NE-0000-0005-4298-R6 TASK REPORT T0400

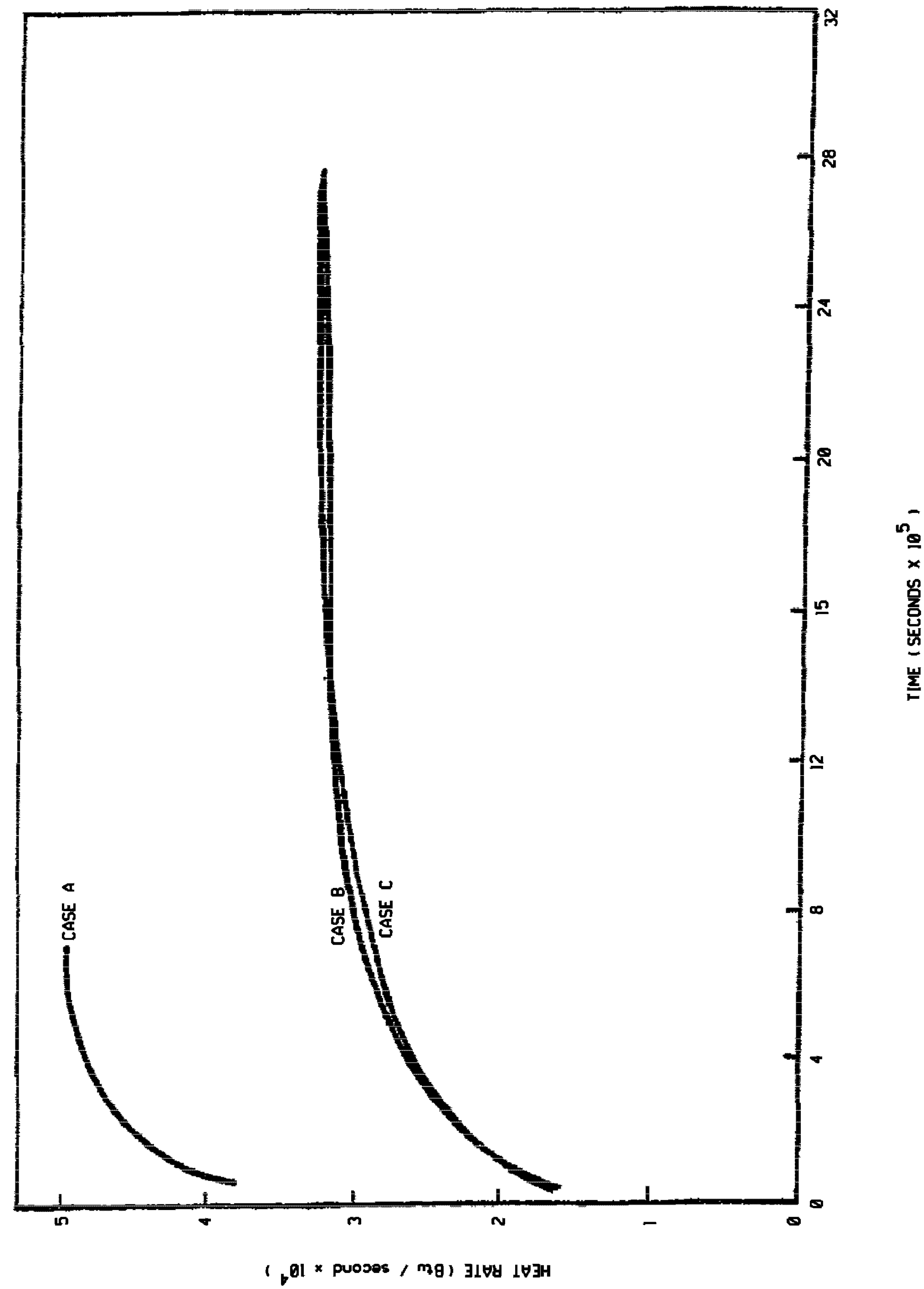
Figure 6.2-9a- Long Term Suppression Pool Temperature Response Following Recirculation Line Break (Case C at 102% of 3840 MWt



For UFSAR Markup

Revision 17, June 23, 2009

PSEG Nuclear, LLC HOPE CREEK NUCLEAR GENERATING STATION	Hope Creek Nuclear Generating Station LONG-TERM SUPPRESSION POOL TEMPERATURE RESPONSE FOLLOWING RECIRCULATION LINE BREAK
	Updated FSAR — Figure 6.2-9a



Retained for historical purposes and to provide comparison to alternate cases based on thermal power of 3359 MWt.

Revision 17, June 23, 2009

PSEG Nuclear, LLC HOPE CREEK NUCLEAR GENERATING STATION	Hope Creek Nuclear Generating Station RHR HEAT REMOVAL RATE FOLLOWING RECIRCULATION LINE BREAK
	Updated FSAR Figure 6.2-10

New UFSAR FIGURE 6.2-10a FROM GE LPU REPORT T0400 R6 Figure 5-8 for 102% of 3952 MWt

GE-NE- 0000-0005-4298-R6 TASK REPORT T0400

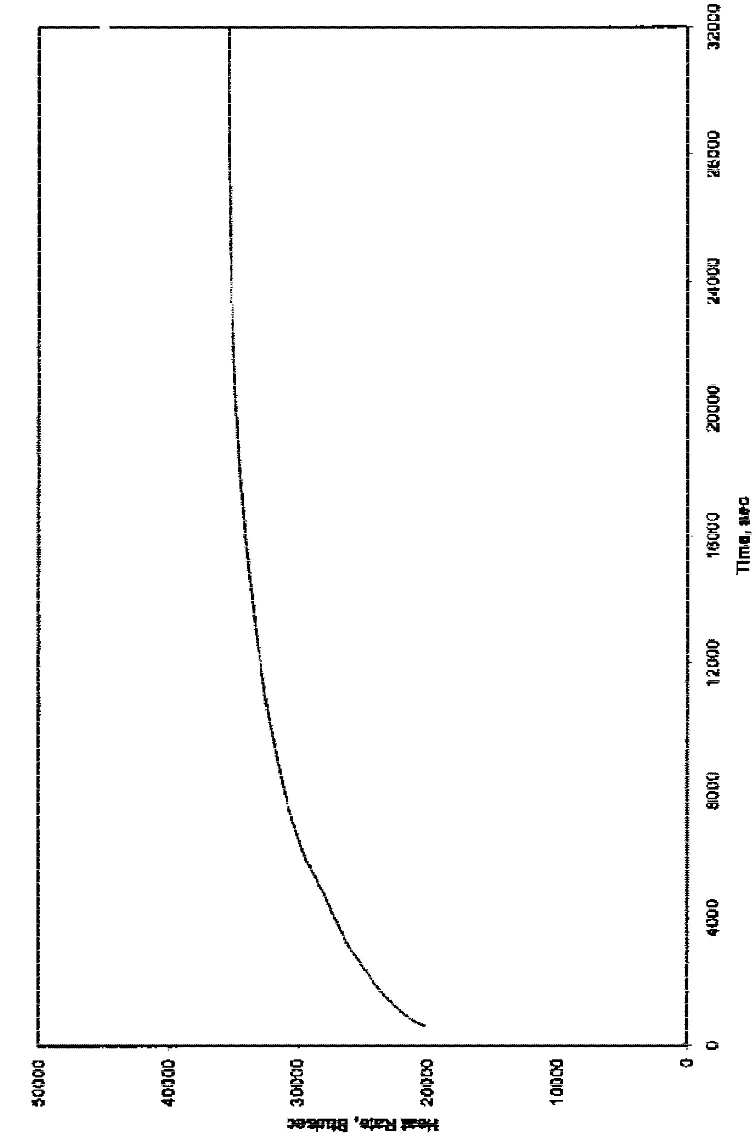
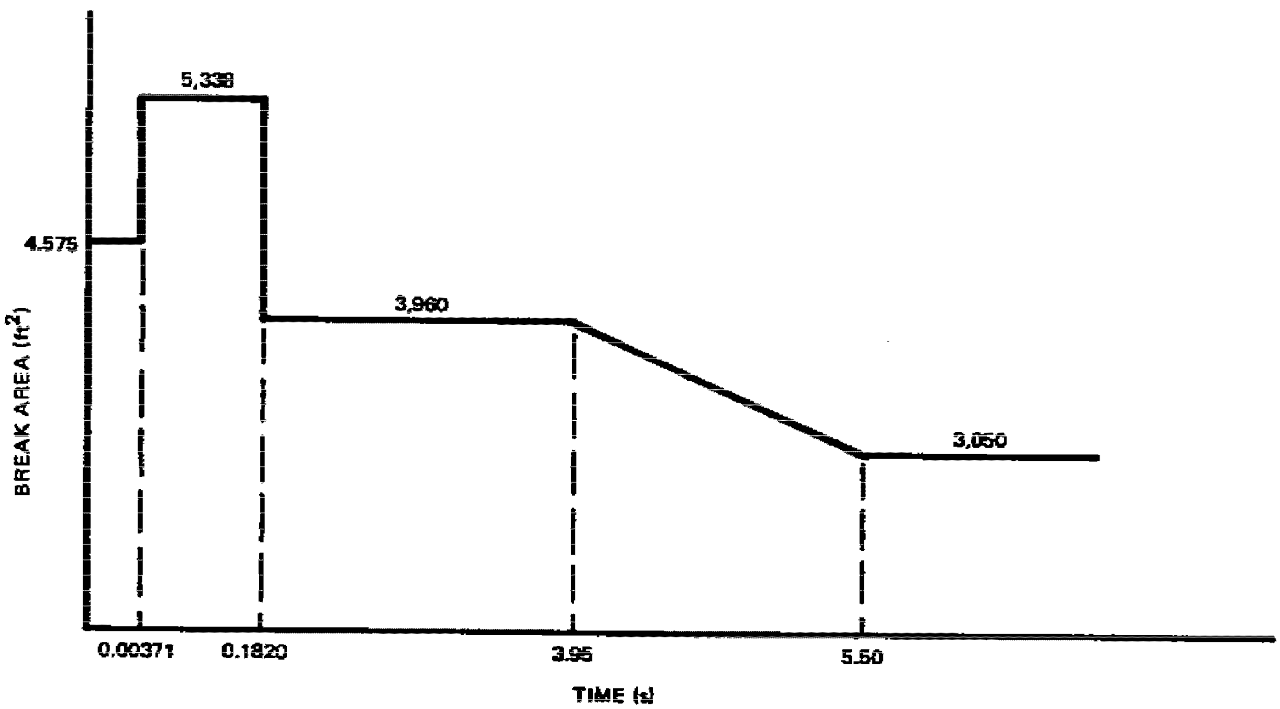


Figure 6.2-10a- RHR Heat Removal Rate Following Recirculation Line Break – Case C (102% of 3952 MWt)

Revision 17, June 23, 2009

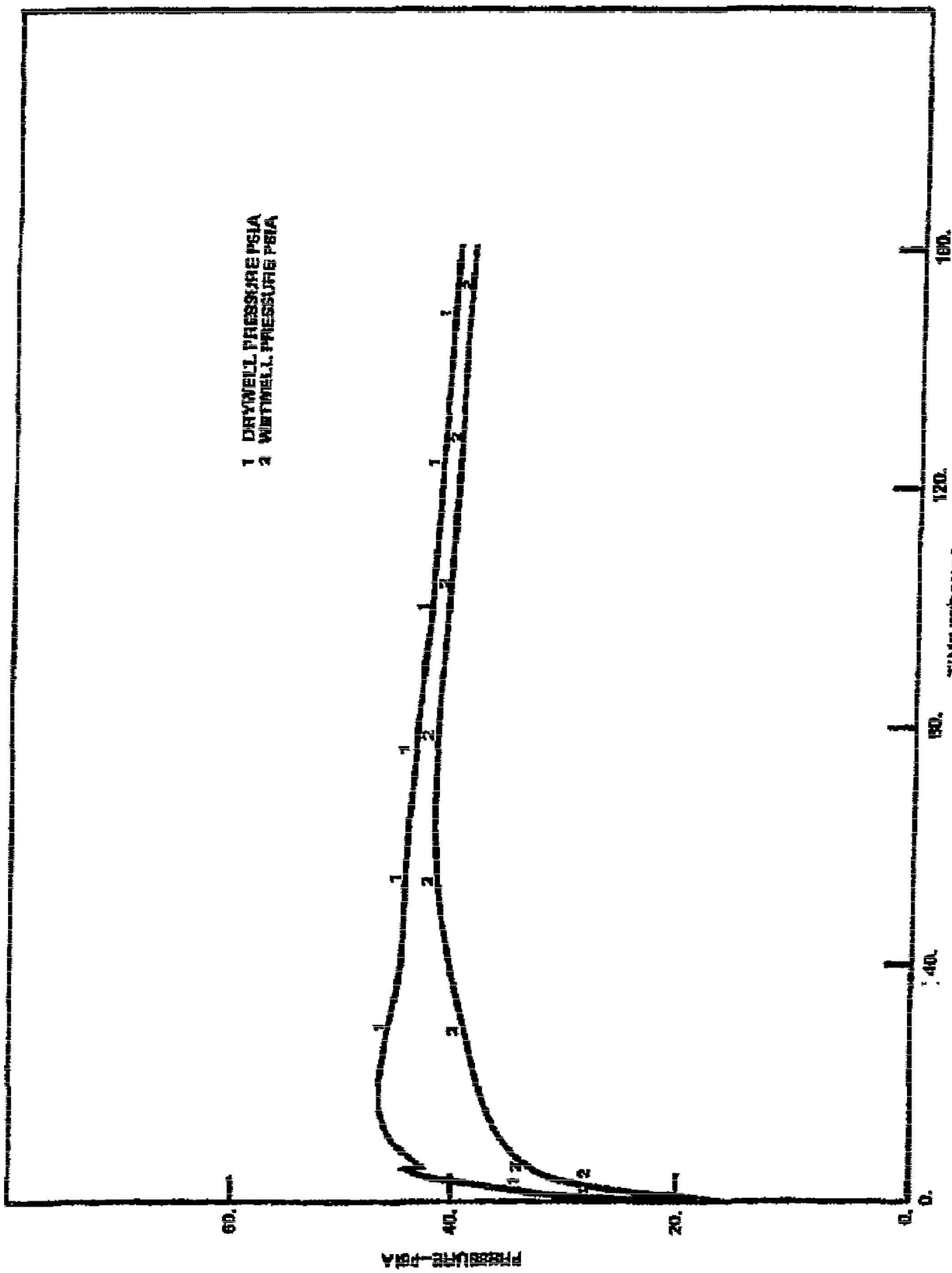
PSEG Nuclear, LLC HOPE CREEK NUCLEAR GENERATING STATION	Hope Creek Nuclear Generating Station RHR HEAT REMOVAL RATE FOLLOWING RECIRCULATION LINE BREAK
	Updated FSAR Figure 6.2-10a



Retained for historical purposes based on thermal power of 3359 MWt.

Revision 17, June 23, 2009

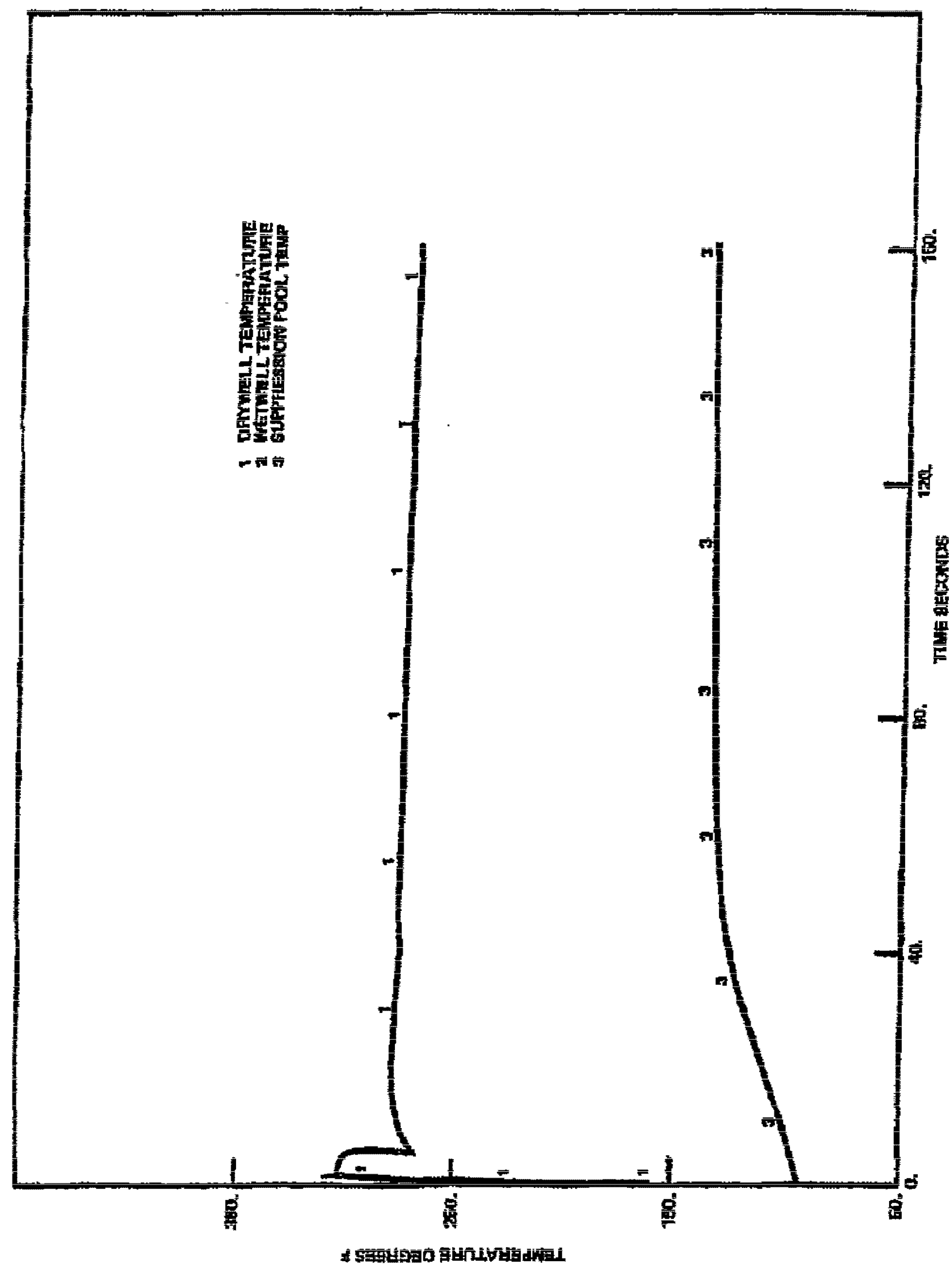
PSEG Nuclear, LLC HOPE CREEK NUCLEAR GENERATING STATION	Hope Creek Nuclear Generating Station EFFECTIVE BLOWDOWN AREA FOR MAIN STEAM LINE BREAK
	Updated FSAR — Figure 6.2-11



Based on thermal power of 3359 MWt. Not updated for current license power level of 3840MWt, since it is non-limiting for power uprate. Retained for historical purposes.

Revision 17, June 23, 2009

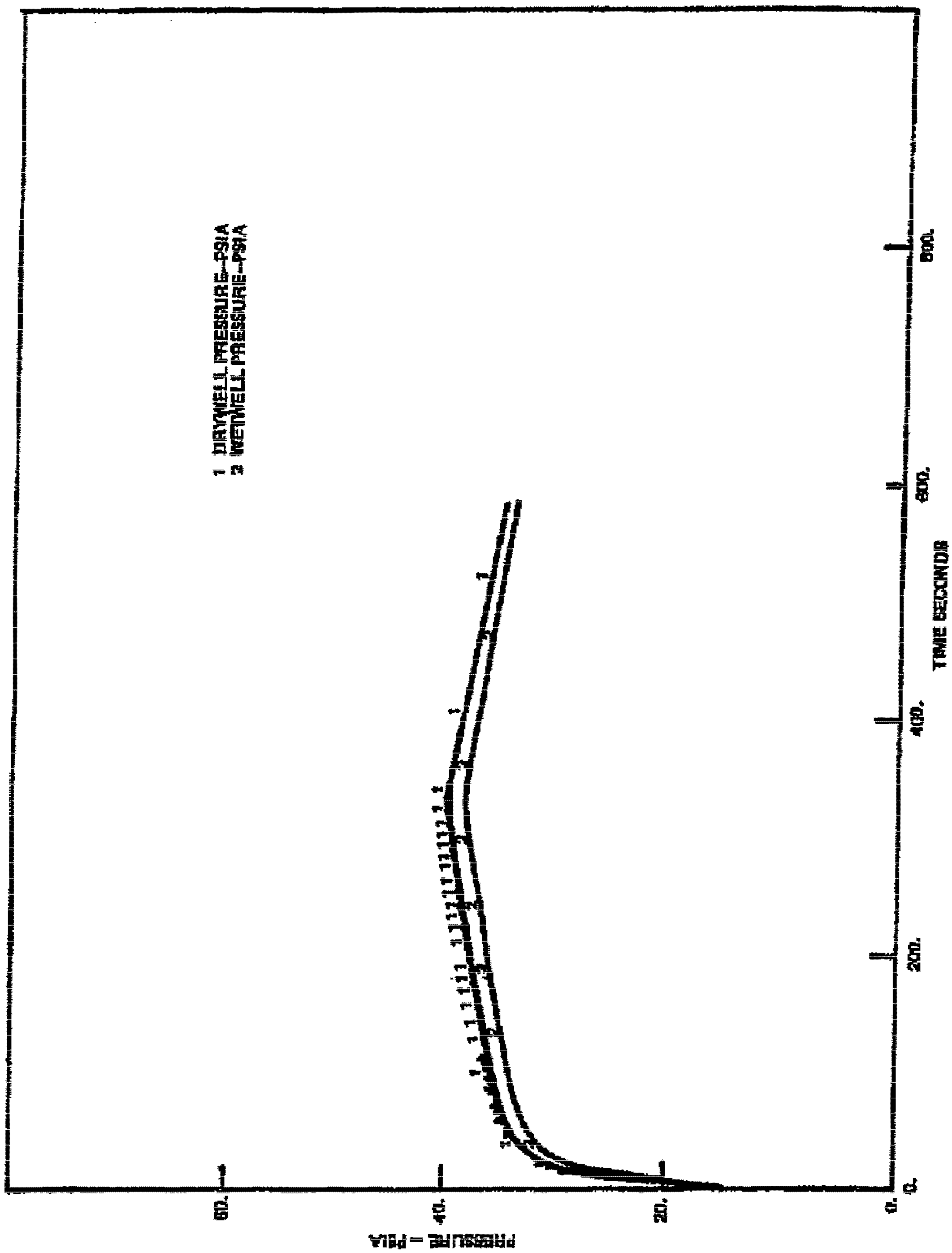
PSEG Nuclear, LLC HOPE CREEK NUCLEAR GENERATING STATION	Hope Creek Nuclear Generating Station SHORT-TERM CONTAINMENT PRESSURE RESPONSE FOLLOWING MAIN STEAM LINE BREAK
	Updated FSAR — Figure 6.2-12



Based on thermal power of 3359 MWt. Not updated for current license power level of 3840MWt, since it is non-limiting for power uprate. Retained for historical purposes.

Revision 17, June 23, 2009

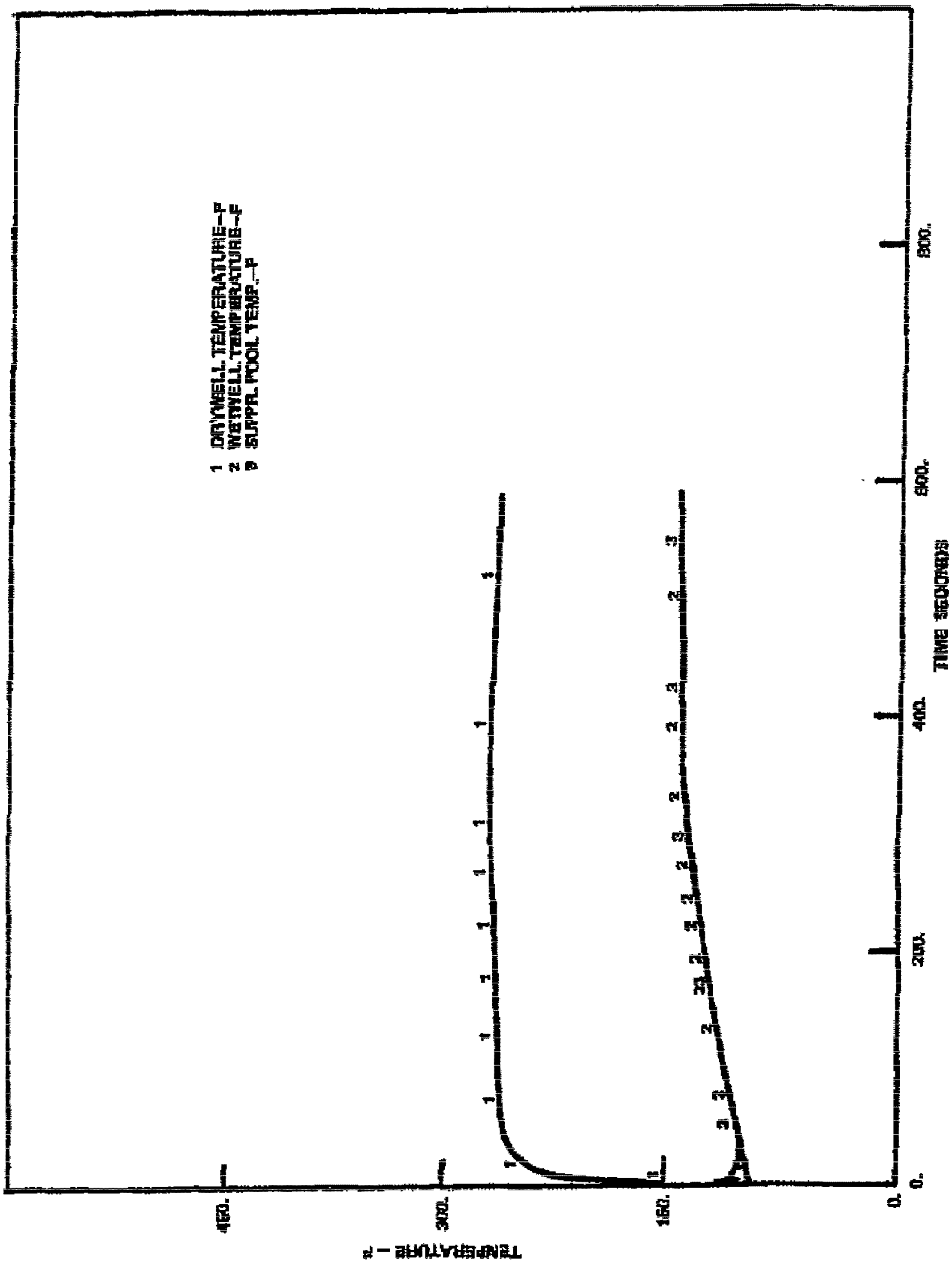
PSEG Nuclear, LLC HOPE CREEK NUCLEAR GENERATING STATION	Hope Creek Nuclear Generating Station SHORT-TERM CONTAINMENT TEMPERATURE RESPONSE FOLLOWING MAIN STEAM LINE BREAK	
	Updated FSAR	Figure 6.2-13



Based on thermal power of 3359 MWt. Not updated for current license power level of 3840MWt, since it is non-limiting for power uprate. Retained for historical purposes.

Revision 17, June 23, 2009

PSEG Nuclear, LLC HOPE CREEK NUCLEAR GENERATING STATION	Hope Creek Nuclear Generating Station SHORT-TERM CONTAINMENT PRESSURE RESPONSE FOLLOWING AN INTERMEDIATE-SIZE BREAK
	Updated FSAR — Figure 6.2-14



Retained for historical purposes based on thermal power of 3359 MWt

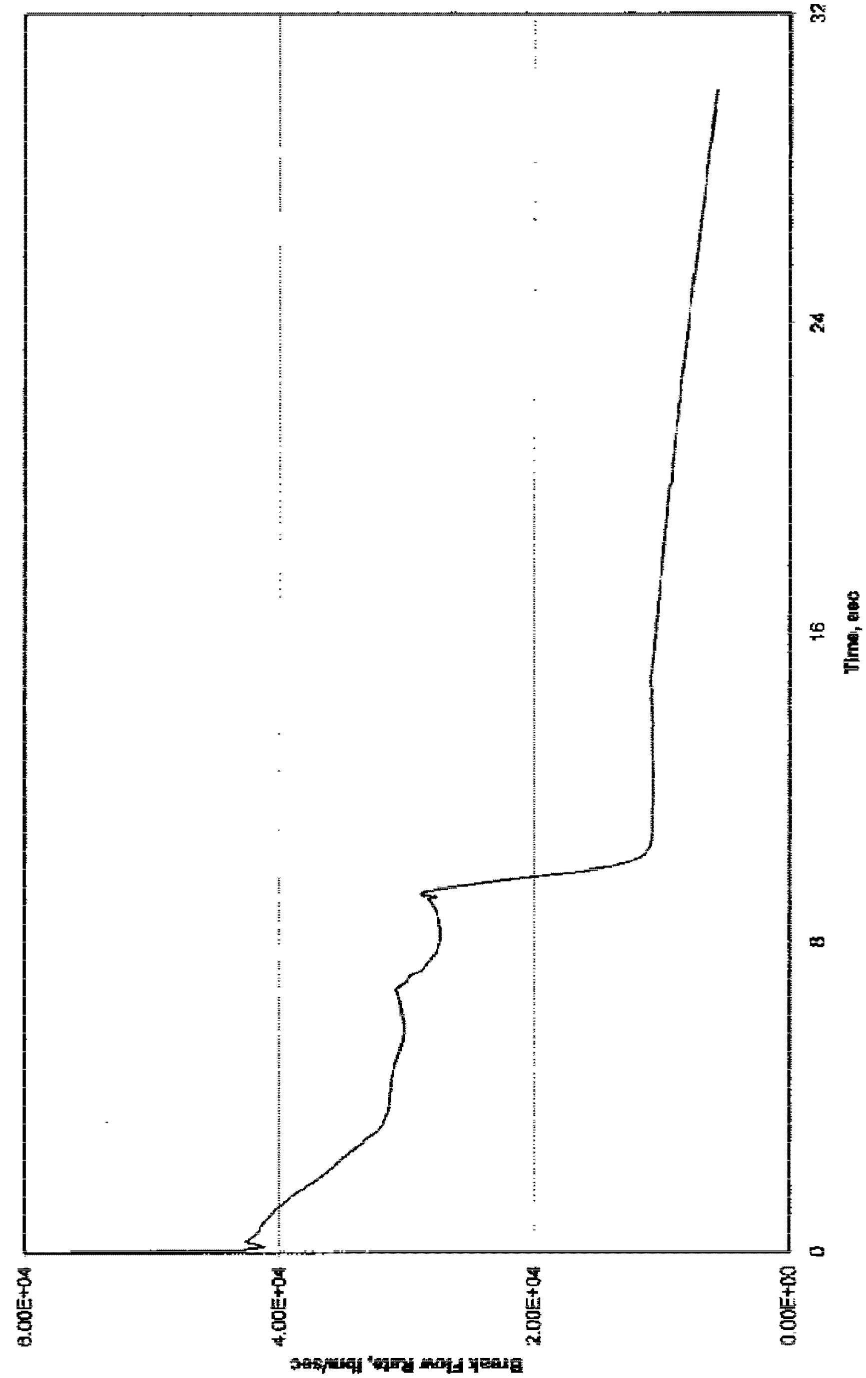
Revision 17, June 23, 2009

PSEG Nuclear, LLC HOPE CREEK NUCLEAR GENERATING STATION	Hope Creek Nuclear Generating Station SHORT-TERM CONTAINMENT TEMPERATURE RESPONSE FOLLOWING AN INTERMEDIATE-SIZE BREAK
	Updated FSAR Figure 6.2-15

NEW UFSAR FIGURE
6.2-16 FROM GE LPU
REPORT T0400 R6
Figure 3-5 for 102% of
3952 MWt

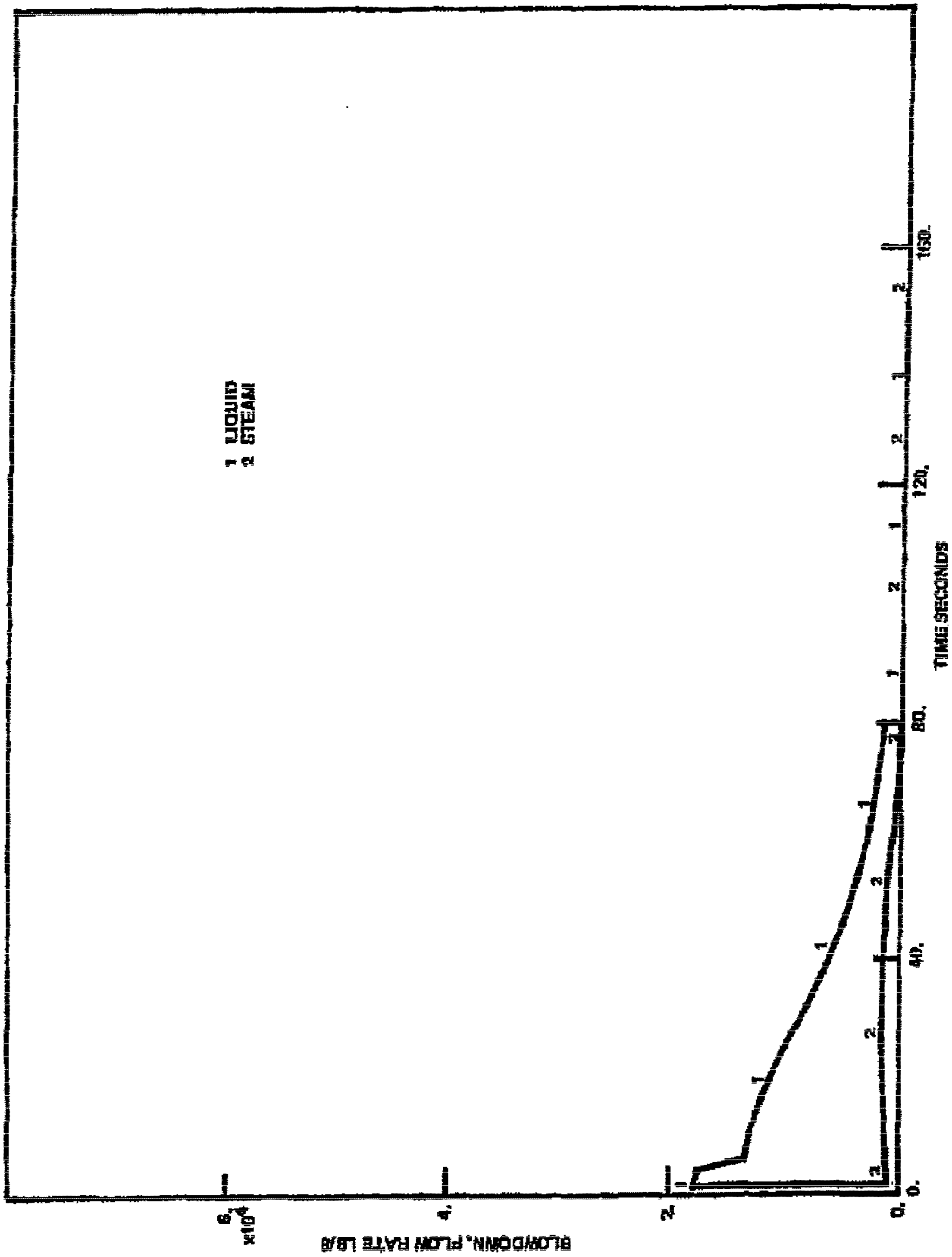
GE-NE- 0000-0005-4298-R6 TASK REPORT T0400

Figure 6.2-16 Reactor Vessel Blowdown Flow Rate Following Recirculation Line Break (4031 MWt)



Revision 17, June 23, 2009

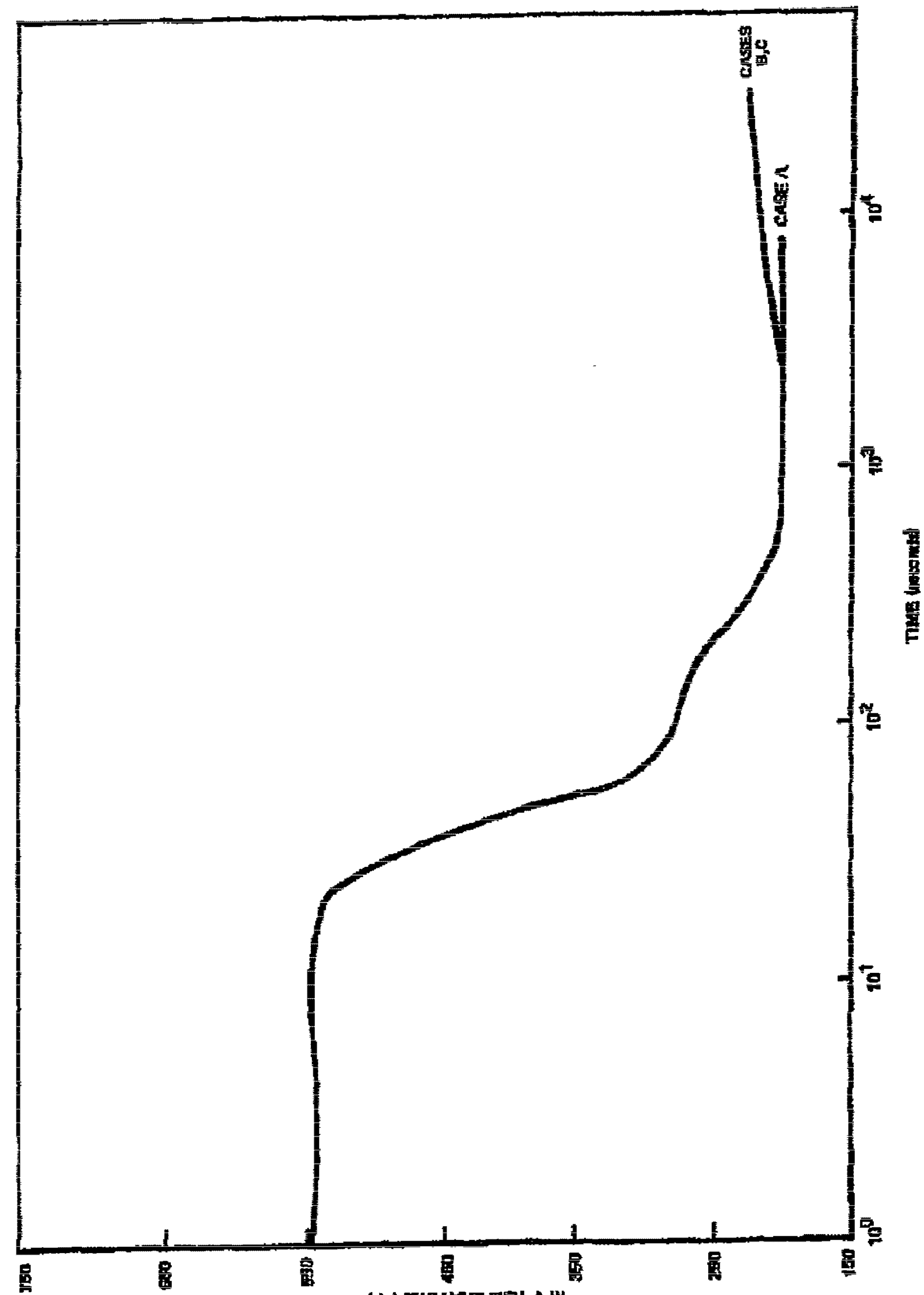
PSEG Nuclear, LLC HOPE CREEK NUCLEAR GENERATING STATION	Hope Creek Nuclear Generating Station REACTOR VESSEL BLOWDOWN FLOW RATE FOLLOWING RECIRCULATION LINE BREAK
	Updated FSAR Figure 6.2-16



Based on thermal power of 3359 MWt. Not updated for current license power level of 3840MWt, since it is non-limiting for power uprate. Retained for historical purposes.

Revision 17, June 23, 2009

PSEG Nuclear, LLC HOPE CREEK NUCLEAR GENERATING STATION	Hope Creek Nuclear Generating Station REACTOR VESSEL BLOWDOWN FLOW RATE FOLLOWING MAIN STEAM LINE BREAK
	Updated FSAR Figure 6.2-17



Retained for historical purposes based on thermal power of 3359 MWt in contrast to license power of 3840 MWt. See figure 6.2-18a for 102% of 3952MWt, which bounds current licensed power level.

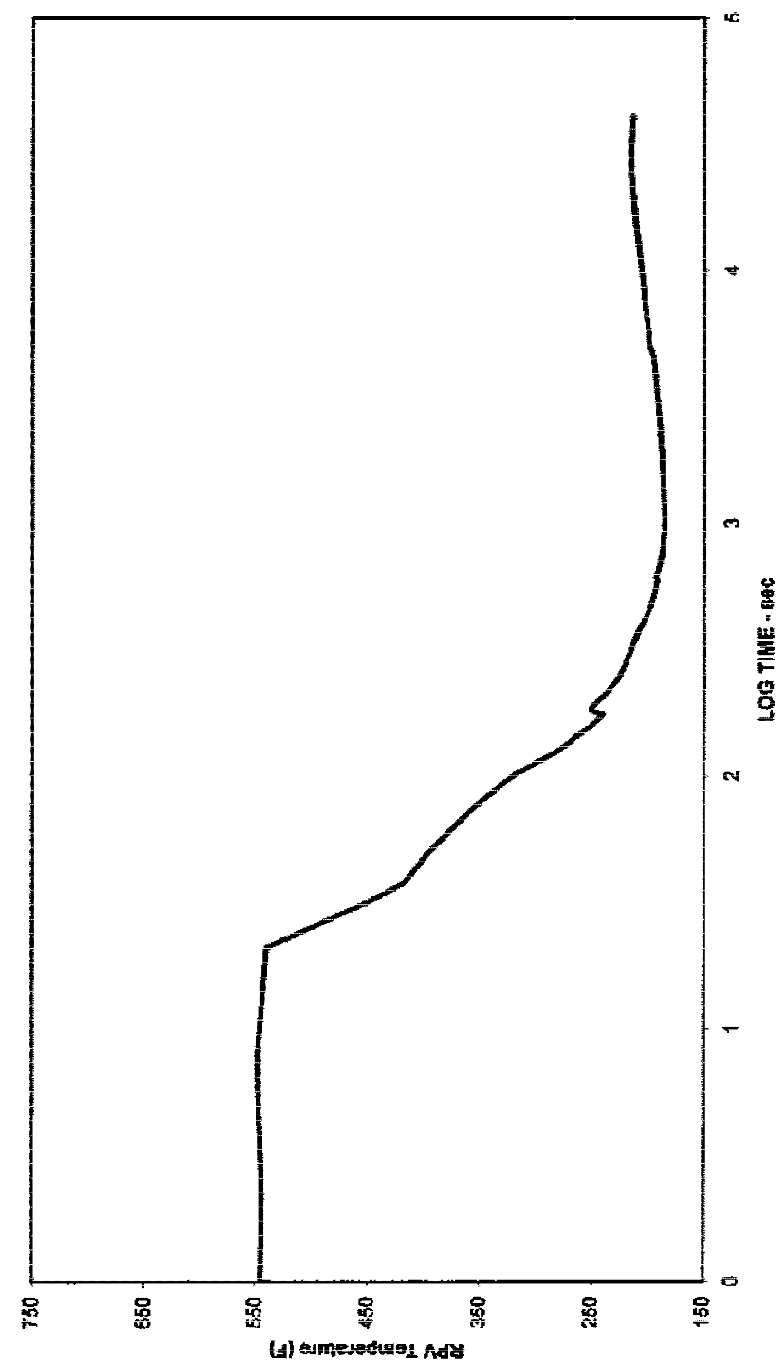
Revision 17, June 23, 2009

PSEG Nuclear, LLC HOPE CREEK NUCLEAR GENERATING STATION	Hope Creek Nuclear Generating Station REACTOR VESSEL TEMPERATURE RESPONSE FOLLOWING RECIRCULATION LINE BREAK
	Updated FSAR — Figure 6.2-18

NEW UFSAR FIGURE 6.2-18a FROM GE LPU REPORT T0400 R6 Figure 5-1 for 102% of 3952 MWt

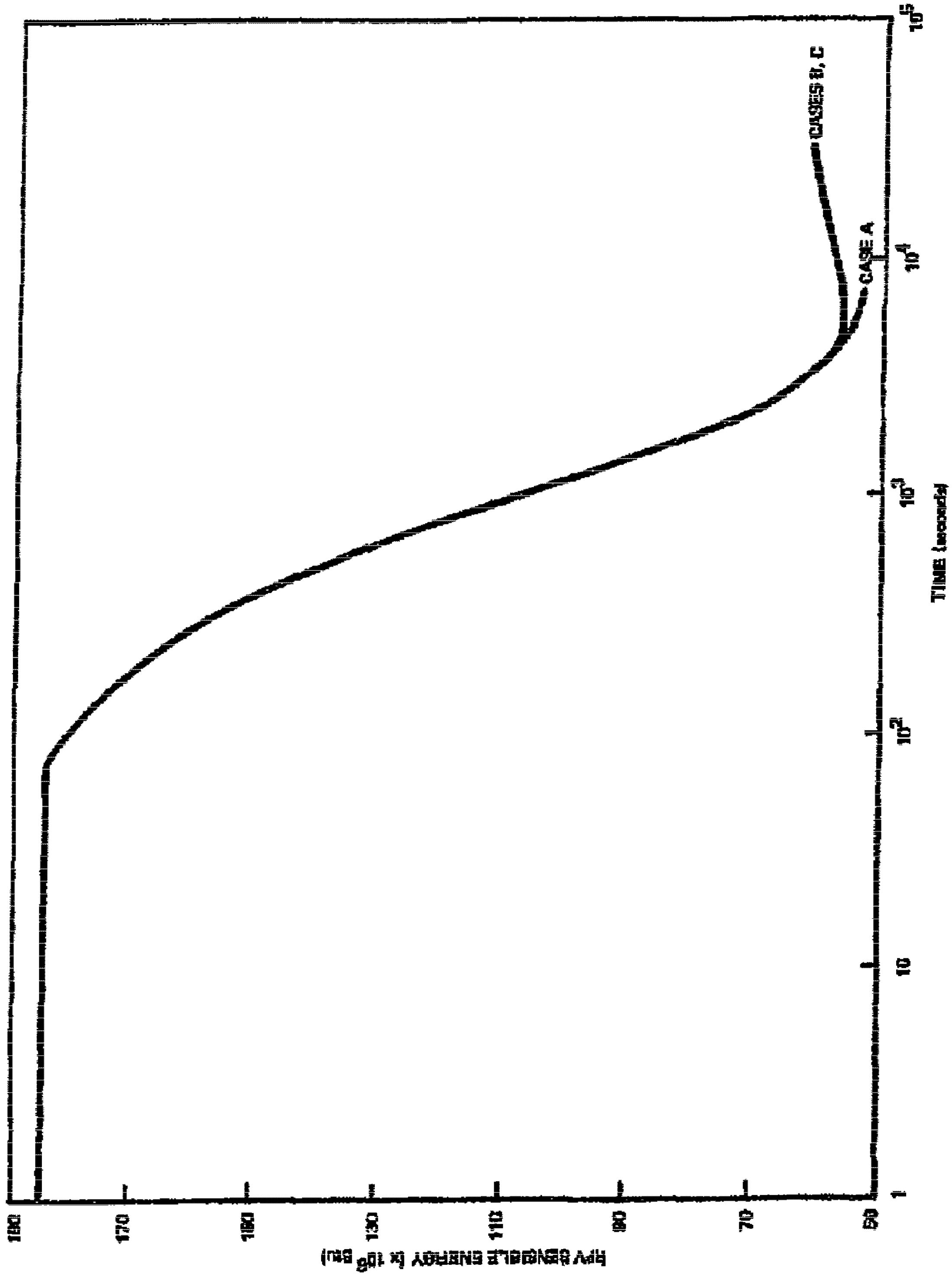
GE-NE- 0000-0005-4298-R6 TASK REPORT T0400

Figure 6.2-18a- Reactor Vessel Temperature Response Following Recirculation Line Break – UFSAR Case C (102% of 3952 MWt)



Revision 17, June 23, 2009

PSEG Nuclear, LLC HOPE CREEK NUCLEAR GENERATING STATION	Hope Creek Nuclear Generating Station REACTOR VESSEL TEMPERATURE RESPONSE FOLLOWING RECIRCULATION LINE BREAK
	Updated FSAR — Figure 6.2-18a



Retained for historical purposes based on thermal power of 3359 MWt

Revision 17, June 23, 2009

PSEG Nuclear, LLC HOPE CREEK NUCLEAR GENERATING STATION	Hope Creek Nuclear Generating Station SENSIBLE ENERGY IN REACTOR VESSEL AND INTERNAL STRUCTURE METALS FOLLOWING RECIRC. LINE BREAK
	Updated FSAR Figure 6.2-19

Figure F6.2-20 intentionally deleted.

Refer to Plant Drawing A-4643-1 in DCRMS

Figure F6.2-21 intentionally deleted.

Refer to Plant Drawing A-4644-1 in DCRMS

Figure F6.2-22 intentionally deleted.

Refer to Plant Drawing A-4645-1 in DCRMS

Figure F6.2-23 intentionally deleted.

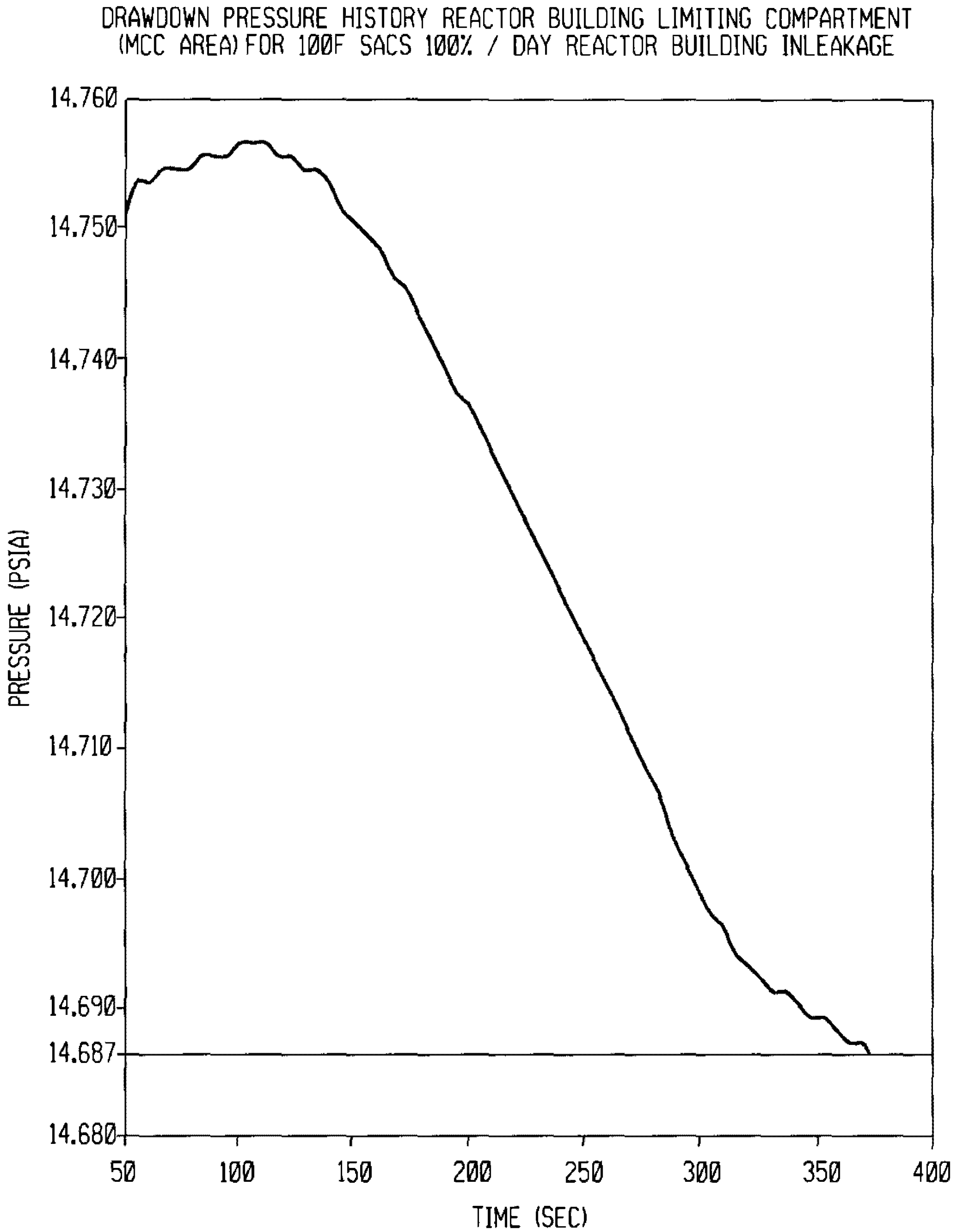
Refer to Plant Drawing A-4646-1 in DCRMS

Figure F6.2-24 intentionally deleted.

Refer to Plant Drawing A-4647-1 in DCRMS

Figure F6.2-25 intentionally deleted.

Refer to Plant Drawing A-0402-0 in DCRMS



Revision 12, May 3, 2002

PSEG Nuclear, LLC HOPE CREEK NUCLEAR GENERATING STATION	Hope Creek Nuclear Generating Station DRAWDOWN PRESSURE HISTORY REACTOR BUILDING LIMITING COMPARTMENT (MCC COMPARTMENT)
	Updated FSAR Figure 6.2-26

THIS FIGURE HAS BEEN DELETED

PSEG NUCLEAR L.L.C.
HOPE CREEK GENERATING STATION

HOPE CREEK UFSAR - REV 12 SHEET 1 OF 1

May 3, 2002 F6.2-26A

THIS FIGURE HAS BEEN DELETED

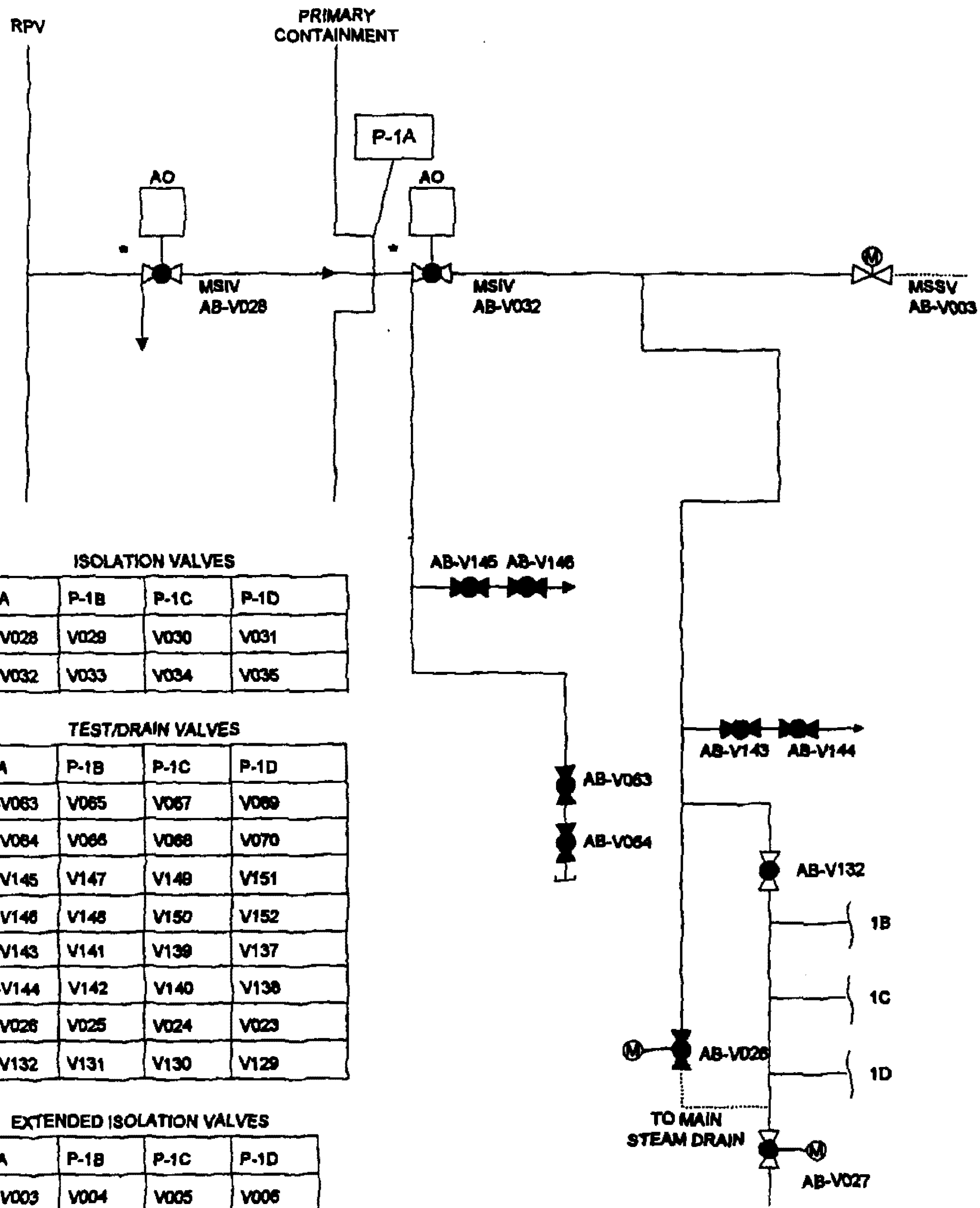
PSEG NUCLEAR L.L.C. HOPE CREEK GENERATING STATION	
HOPE CREEK UFSAR - REV 12	SHEET 1 OF 1
May 3, 2002	F6.2-26B

THIS FIGURE HAS BEEN DELETED

PSEG NUCLEAR L.L.C.
HOPE CREEK GENERATING STATION

HOPE CREEK UFSAR - REV 12 SHEET 1 OF 1

May 3, 2002 F6.2-26C



ISOLATION VALVES

P-1A	P-1B	P-1C	P-1D
AB-V028	V029	V030	V031
AB-V032	V033	V034	V035

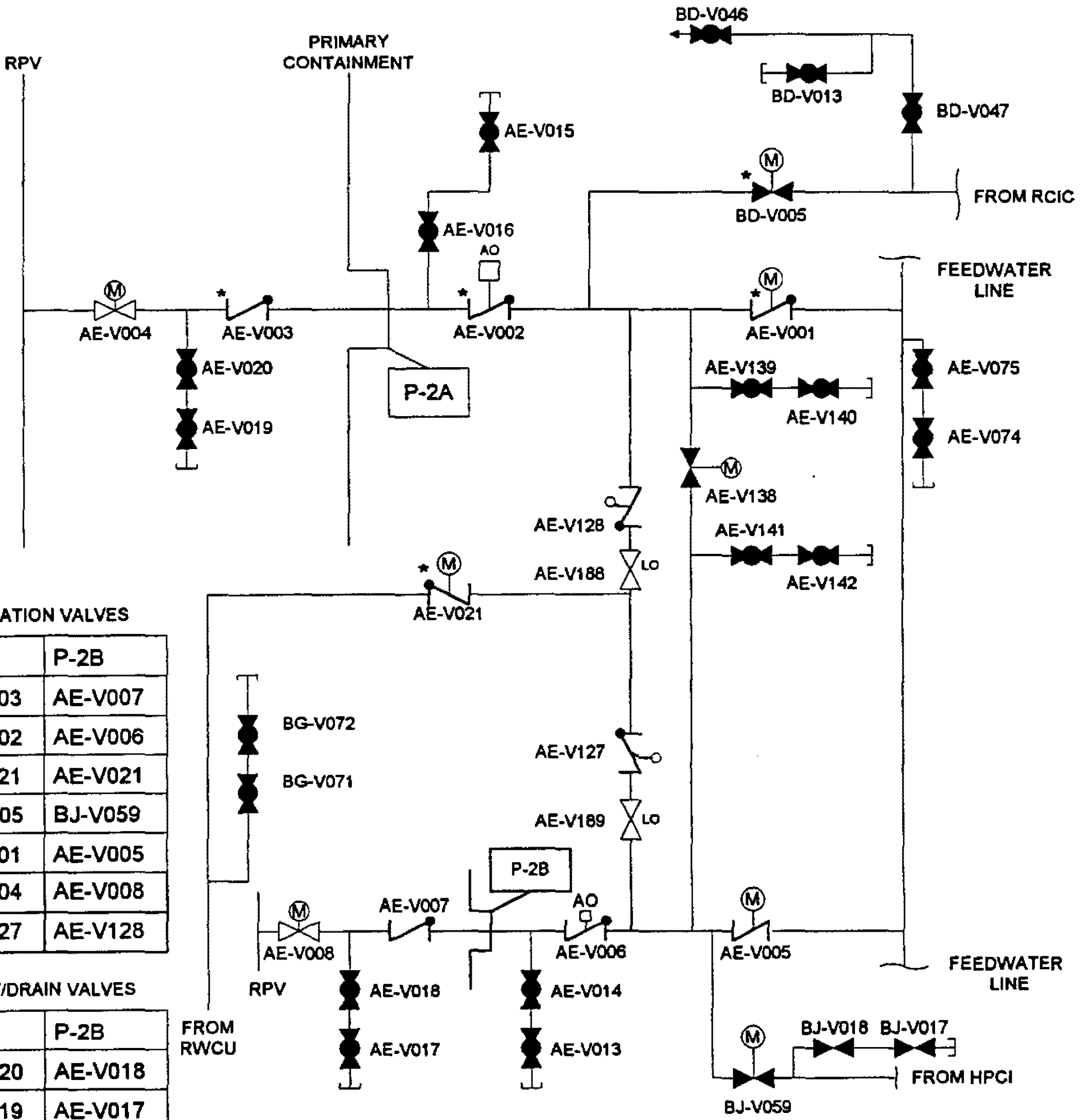
TEST/DRAIN VALVES

P-1A	P-1B	P-1C	P-1D
AB-V063	V065	V067	V069
AB-V064	V066	V068	V070
AB-V145	V147	V149	V151
AB-V146	V148	V150	V152
AB-V143	V141	V139	V137
AB-V144	V142	V140	V138
AB-V026	V025	V024	V023
AB-V132	V131	V130	V129

EXTENDED ISOLATION VALVES

P-1A	P-1B	P-1C	P-1D
AB-V003	V004	V005	V006
AB-V027	-	-	-

* (SEE LEGEND)



ISOLATION VALVES

P-2A	P-2B
AE-V003	AE-V007
AE-V002	AE-V006
AE-V021	AE-V021
BD-V005	BJ-V059
AE-V001	AE-V005
AE-V004	AE-V008
AE-V127	AE-V128

TEST/DRAIN VALVES

P-2A	P-2B
AE-V020	AE-V018
AE-V019	AE-V017
AE-V015	AE-V014
AE-V016	AE-V013
BG-V072	-
BG-V071	-
AE-V075	-
AE-V074	-
BD-V047	BJ-V018
BD-V046	BJ-V017

*(SEE LEGEND)

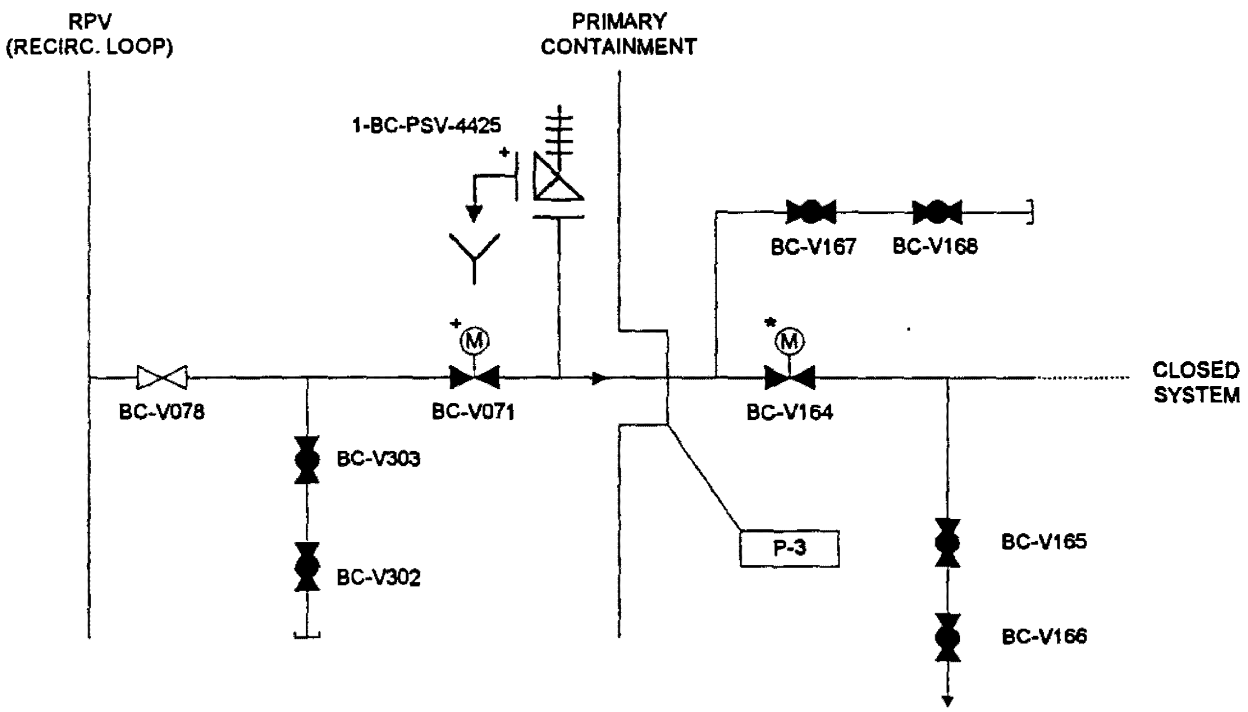
DETAIL 2

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
HOPE CREEK NUCLEAR GENERATING STATION

FEEDWATER LINES

Updated FSAR
Revision 8, September 25, 1996

Sheet 2 of 49
Figure 6.2-27



DETAIL 3

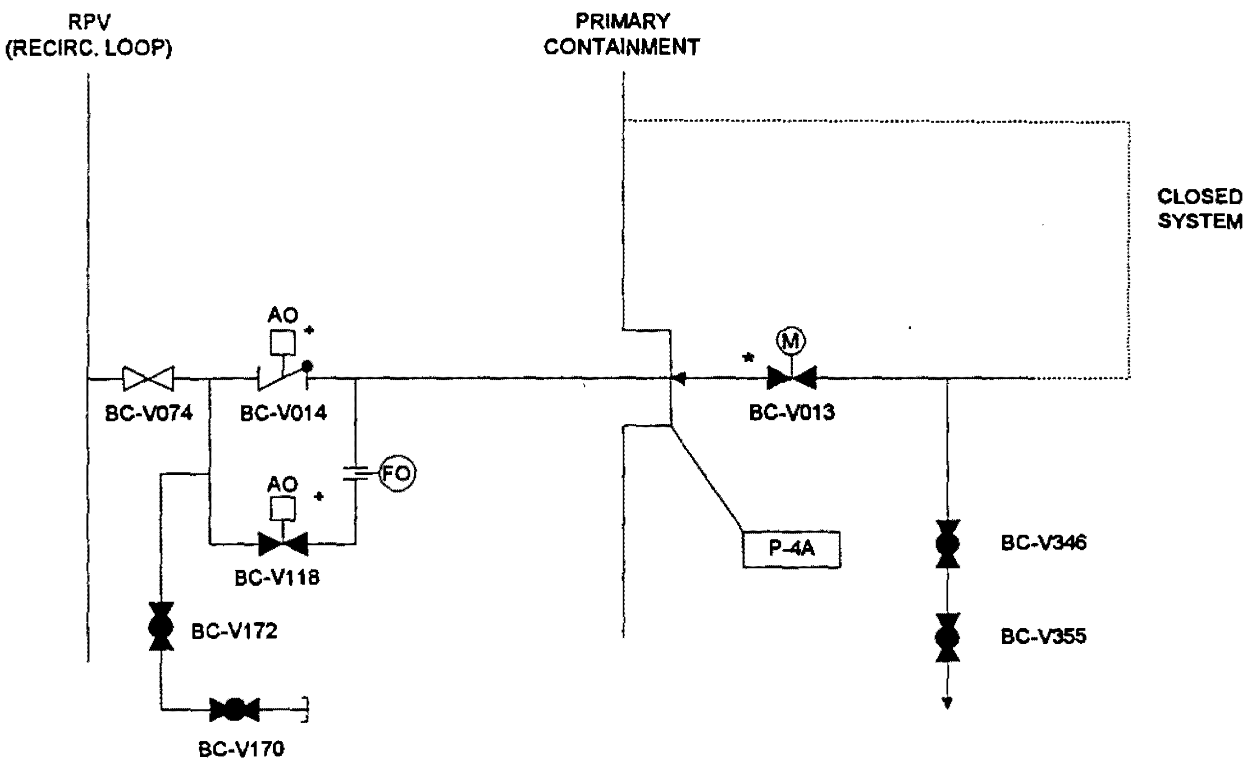
*+(SEE LEGEND)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
HOPE CREEK NUCLEAR GENERATING STATION

RHR SHUTDOWN
COOLING SUCTION LINE

Updated FSAR
Revision 8, September 25, 1996

Sheet 3 of 49
Figure 6.2-27



DETAIL 4

TEST/DRAIN VALVES

P-4A	P-4B
BC-172	V169
BC-170	V171
BC-V346	V334
BC-V355	V335
BC-V074	V183

SYSTEM VALVES

P-4A	P-4B
BC-V014+	V111+
BC-V013*	V110*
BC-V118+	V117+

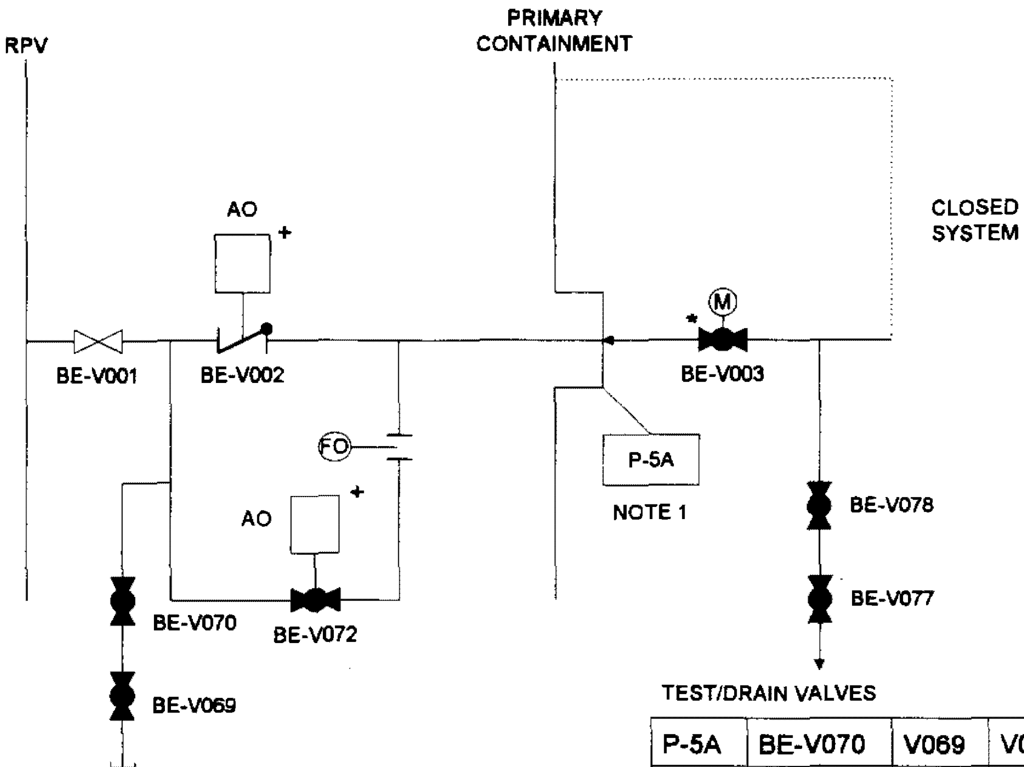
*+(SEE LEGEND)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
HOPE CREEK NUCLEAR GENERATING STATION

RHR SHUTDOWN
COOLING RETURN LINES

Updated FSAR
Revision 8, September 25, 1996

Sheet 4 of 49
Figure 6.2-27

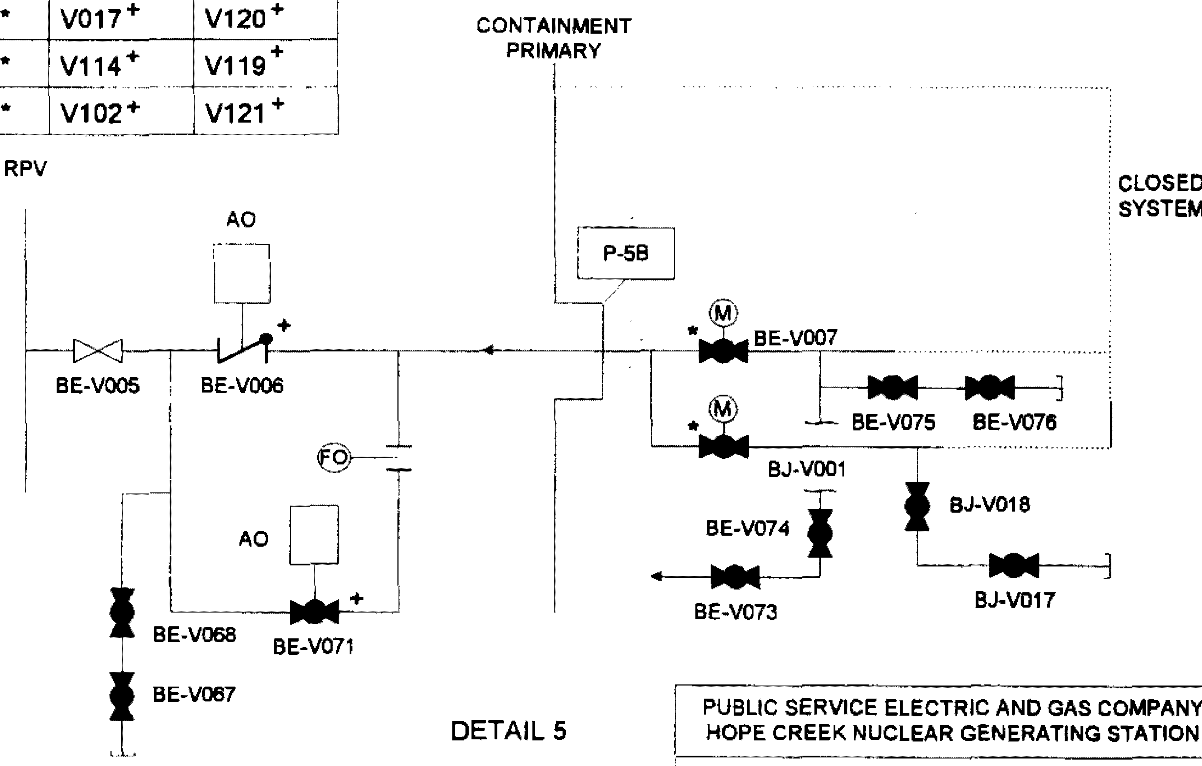


TEST/DRAIN VALVES

P-5A	BE-V070	V069	V078	V077	V001
P-6A	BC-V173	V177	V320	V321	V076
P-6B	BC-V174	V178	V324	V325	V075
P-6C	BC-V175	V179	V353	V354	V182
P-6D	BC-V176	V180	V332	V333	V181

SYSTEM VALVES

P-5A	BE-V003*	V002+	V072+
P-6A	BC-V004*	V006+	V122+
P-6B	BC-V016*	V017+	V120+
P-6C	BC-V113*	V114+	V119+
P-6D	BC-V101*	V102+	V121+



DETAIL 5

NOTES:
(1) THE CONFIGURATIONS FOR P-6A THROUGH 6D ARE SIMILAR TO THAT DEPICTED FOR P-5A.

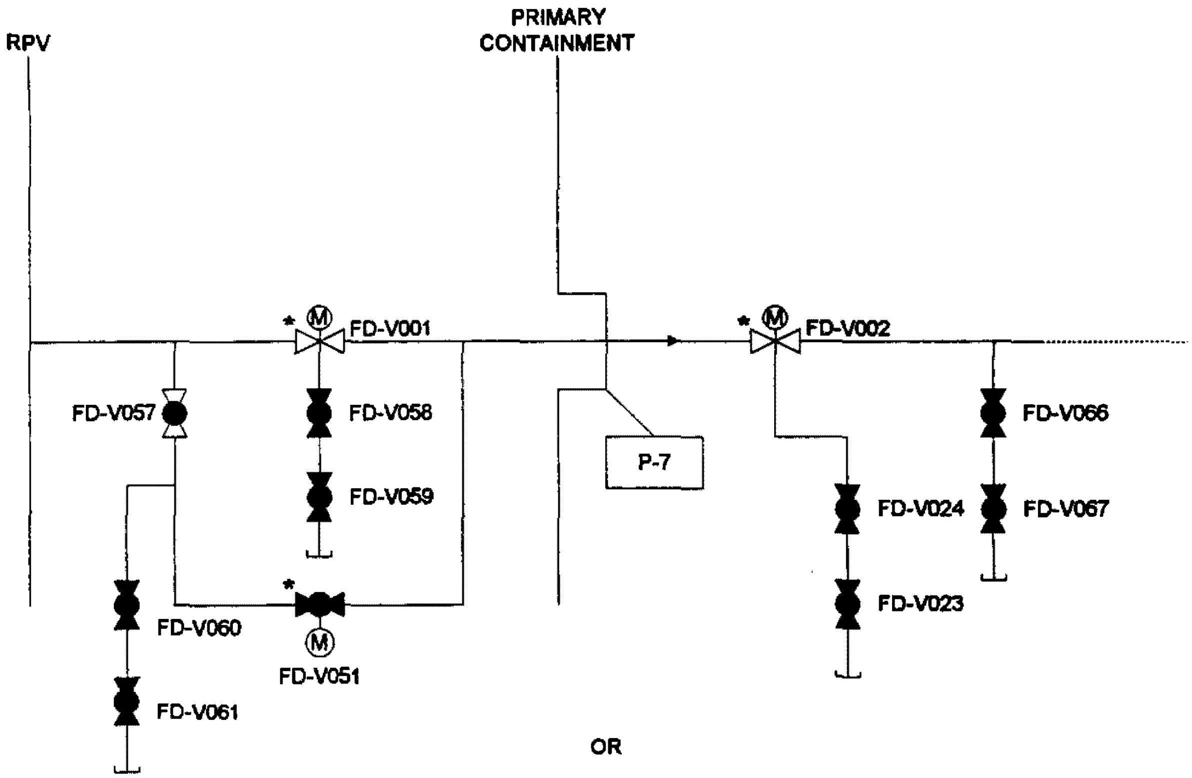
* + (SEE LEGEND)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
HOPE CREEK NUCLEAR GENERATING STATION

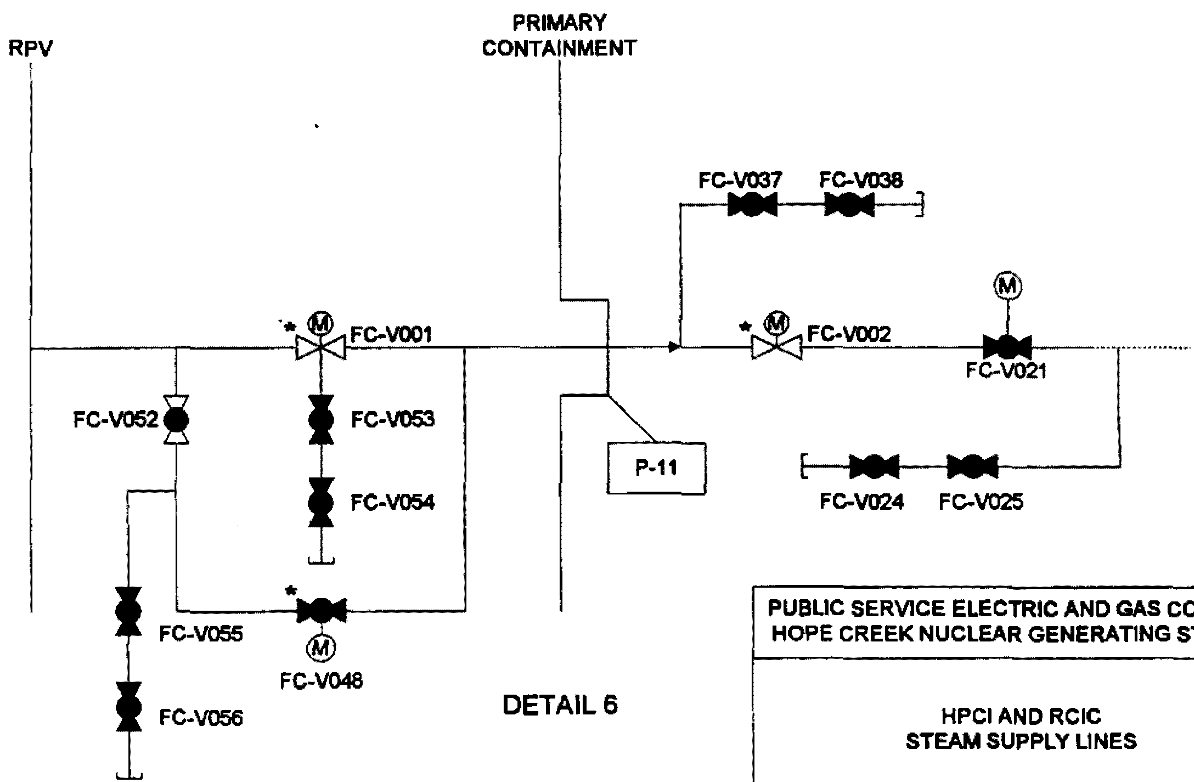
RHR LOW PRESSURE
COOLANT INJECTION AND
CORE SPRAY DISCHARGE LINE

Updated FSAR
Revision 9, June 13, 1998

Figure 6.2-27



OR



DETAIL 6

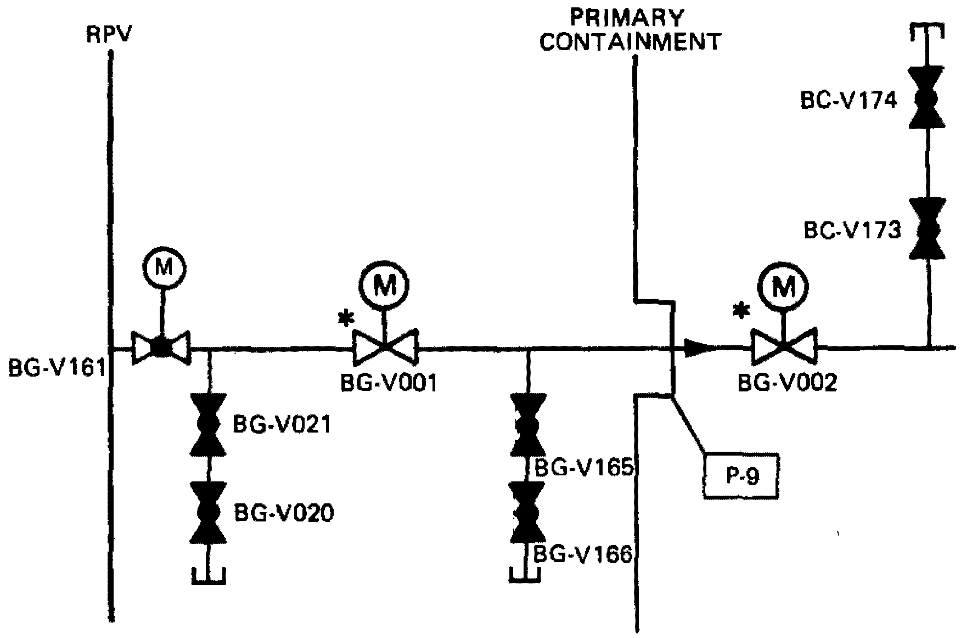
* (SEE LEGEND)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
HOPE CREEK NUCLEAR GENERATING STATION

HPCI AND RCIC
STEAM SUPPLY LINES

Updated FSAR
Revision 7, December 29, 1995

Sheet 6 of 49
FIGURE 6.2-27



DETAIL 7

REVISION 0
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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
HOPE CREEK NUCLEAR GENERATING STATION

RWCU LINE

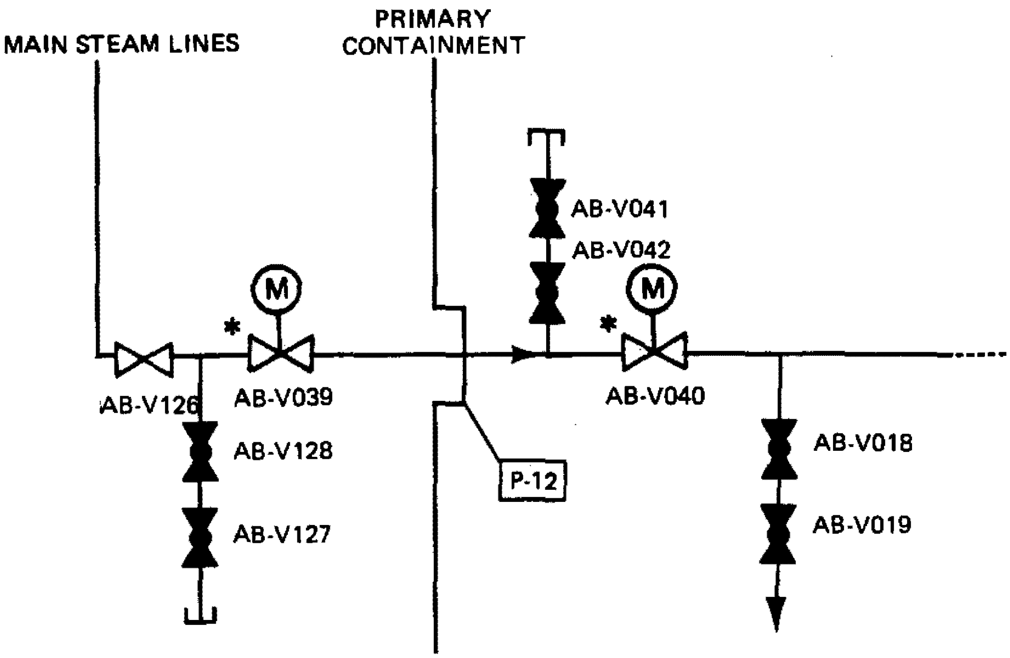
UPDATED FSAR

Sheet 7 of 49
FIGURE 6.2-27

*(SEE LEGEND)

THIS FIGURE HAS BEEN DELETED

PSEG NUCLEAR L.L.C.
HOPE CREEK GENERATING STATION



DETAIL 9

*(SEE LEGEND)

REVISION 0
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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
HOPE CREEK NUCLEAR GENERATING STATION

MAIN STEAM DRAIN LINE

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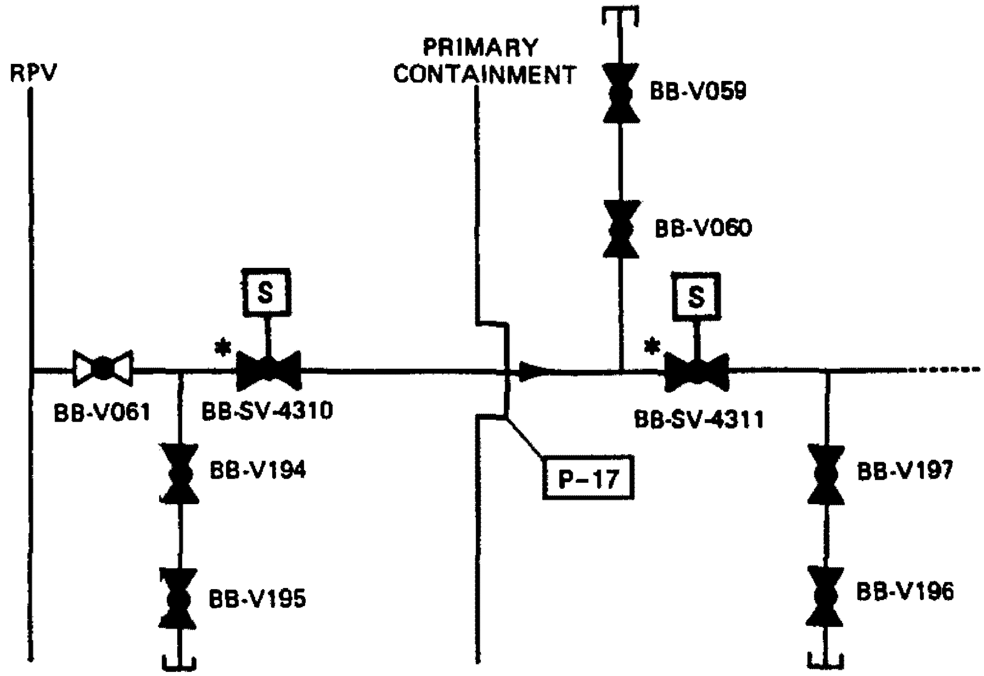
Sheet 9 of 49
FIGURE 6.2-27



DETAIL 10

*(SEE LEGEND)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
HOPE CREEK GENERATING STATION

REACTOR RECIRCULATION PUMP
WATER SAMPLE LINES

Updated FSAR
Revision 2, April 11, 1990

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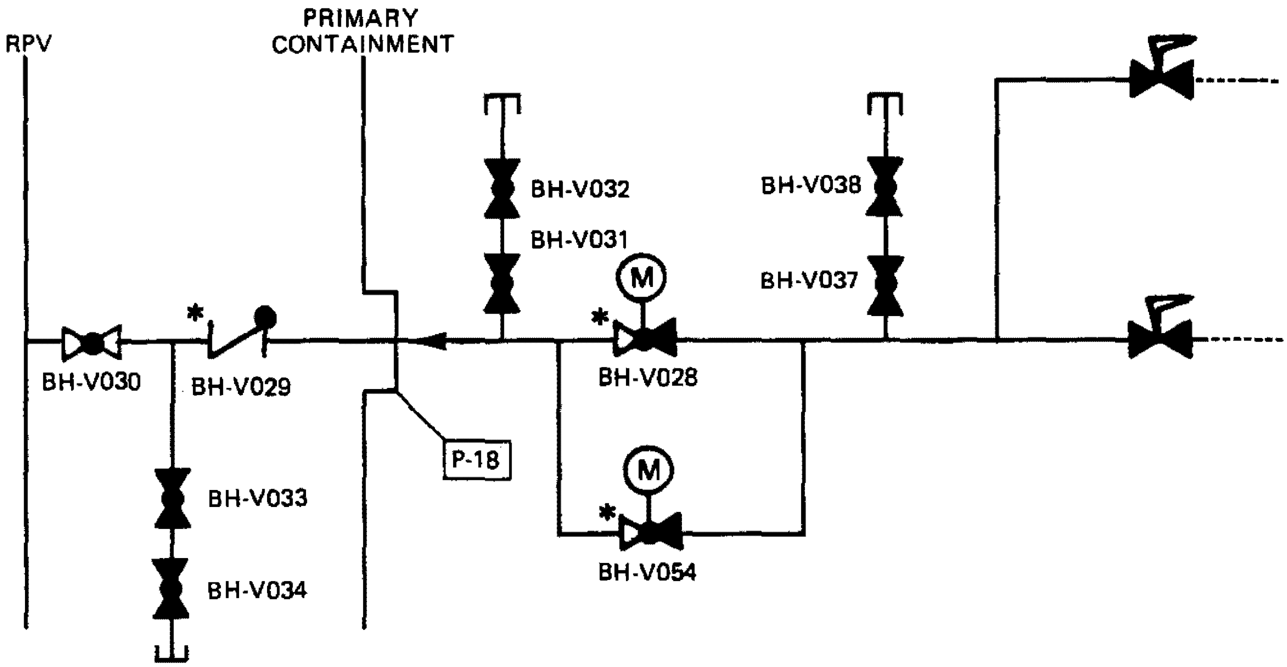
Fig. 6.2-27



DETAIL 11

*(SEE LEGEND)

REVISION 0
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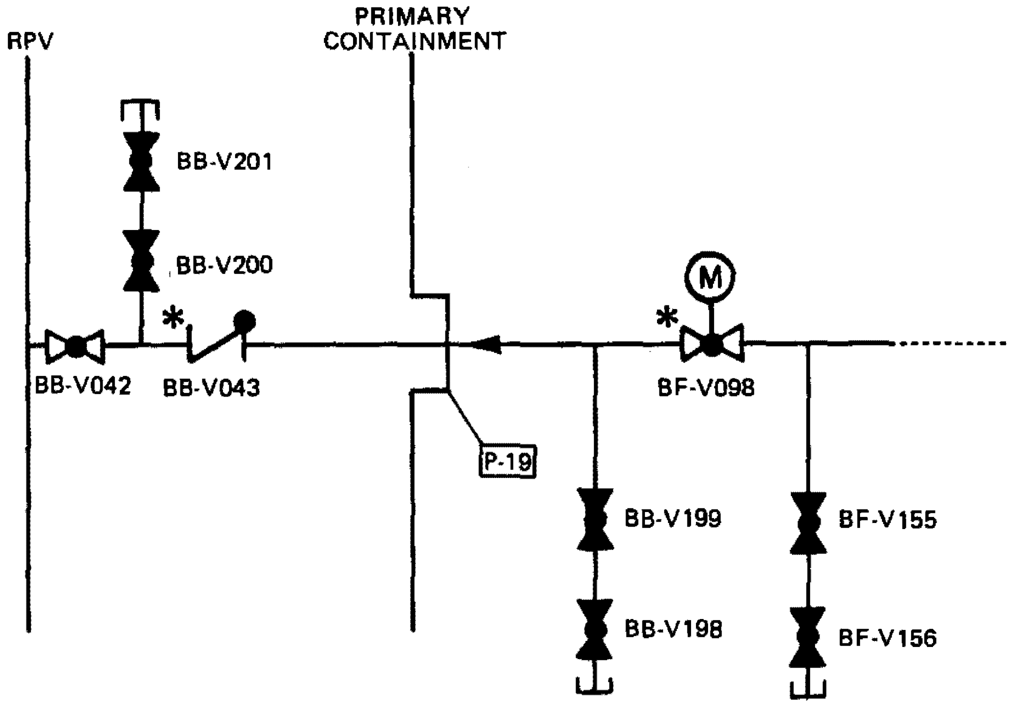
PUBLIC SERVICE ELECTRIC AND GAS COMPANY
HOPE CREEK NUCLEAR GENERATING STATION

STANDBY LIQUID CONTROL LINE

UPDATED FSAR

Sheet 11 of 49
FIGURE 6.2-27



DETAIL 12

ISOLATION VALVES

P-19	P-20
BB-V043	BB-V047
BF-V098	BF-V099

TEST VALVES

P-19	P-20
BB-V200	V204
BB-V201	V205
BB-V199	V203
BB-V198	V202
BF-V155	V772
BF-V156	V773
BB-V042	V046

*(SEE LEGEND)

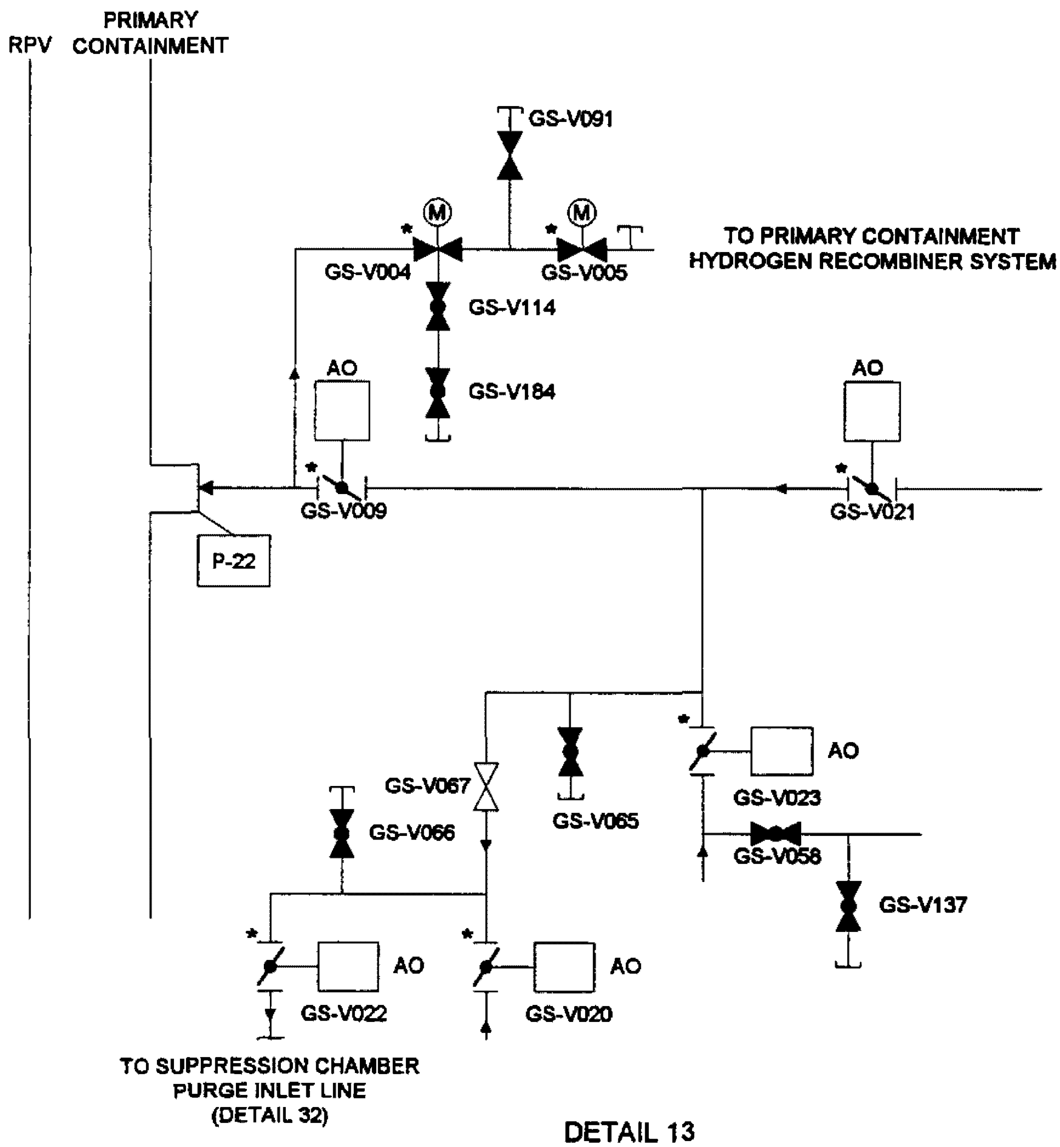
REVISION 0
APRIL 11, 1988

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
HOPE CREEK NUCLEAR GENERATING STATION

REACTOR RECIRCULATION
PUMP SEAL WATER LINES

UPDATED FSAR

Sheet 12 of 49
FIGURE 6.2-27



DETAIL 13

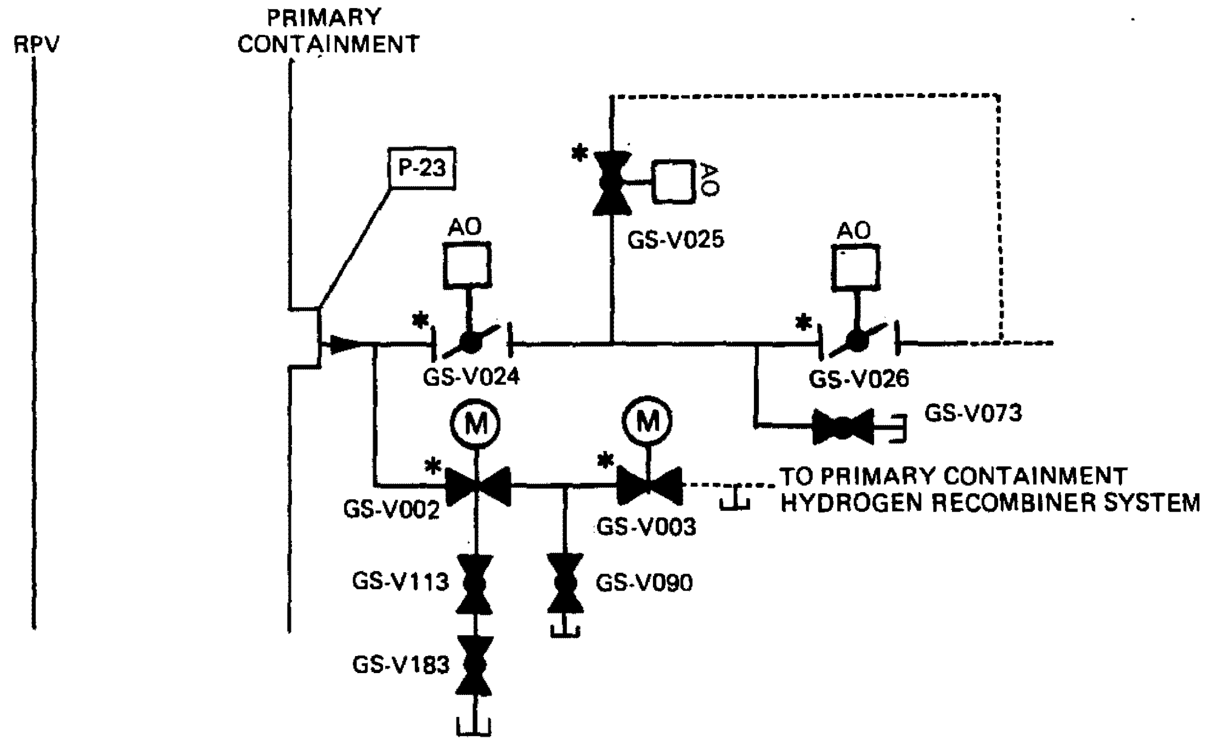
* (SEE LEGEND)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
HOPE CREEK NUCLEAR GENERATING STATION

DRYWELL PURGE
INLET VENT LINE

Updated FSAR
Revision 7, December 29, 1995

SHEET 13 OF 49
FIGURE 6.2-27



DETAIL 14

REVISION 0
APRIL 11, 1988

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
HOPE CREEK NUCLEAR GENERATING STATION

DRYWELL PURGE
VENT LINE

UPDATED FSAR

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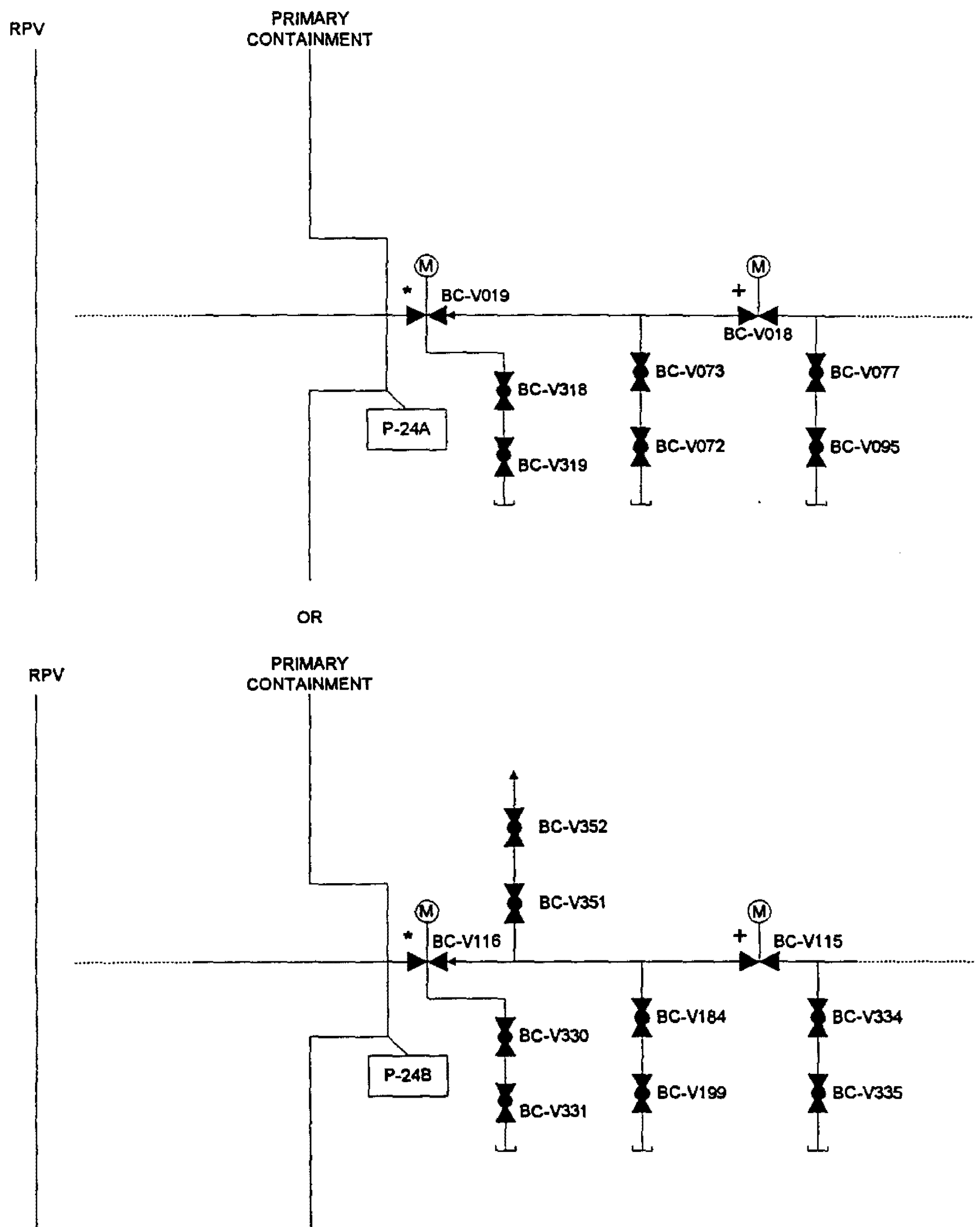
FIGURE 6.2-27

*(SEE LEGEND)



DETAIL 15

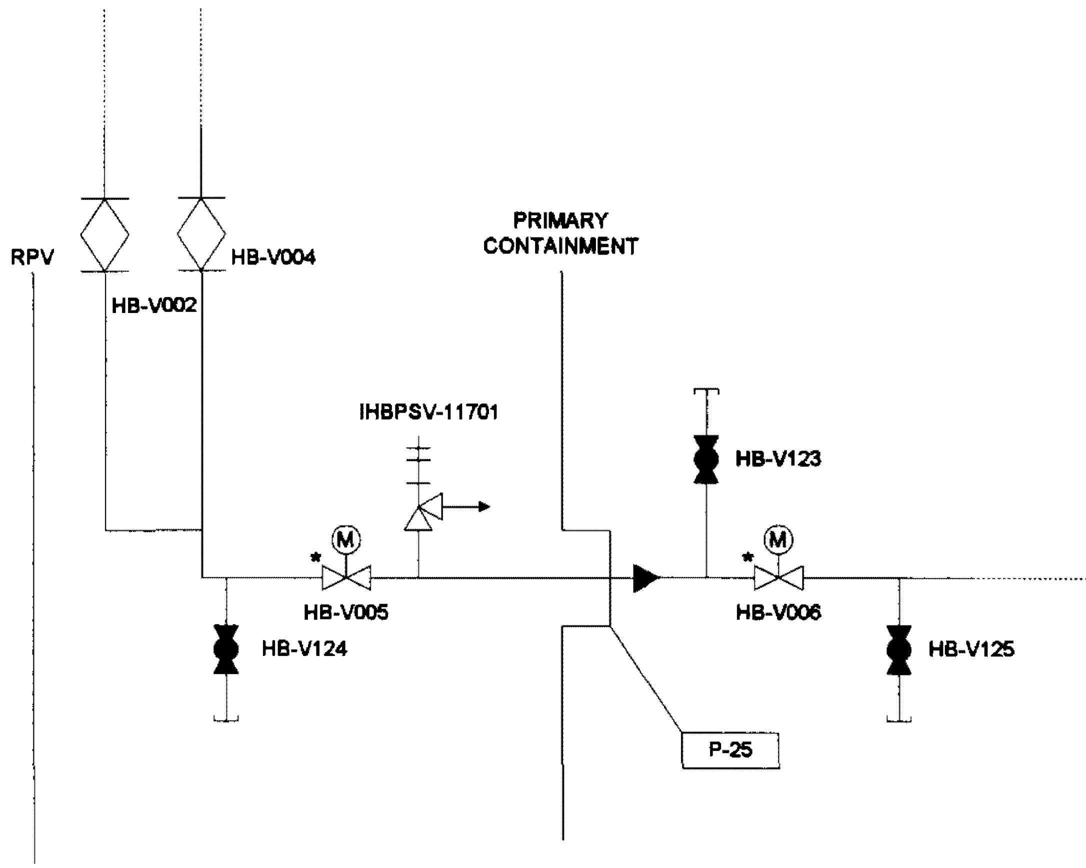
*+(SEE LEGEND)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
HOPE CREEK NUCLEAR GENERATING STATION

CONTAINMENT SPRAY LINES

Updated FSAR
Revision 8, September 25, 1996

Sheet 15 of 49
Figure 6.2-27



DETAIL 16

ISOLATION VALVES

P-25	P-26
HB-V005	HB-V045
HB-V006	HB-V046
IHBPSV-11701	IHBPSV-11702

TEST VALVES

P-25	P-26
HB-V002	HB-V042
HB-V004	HB-V044
HB-V124	HB-V127
HB-V123	HB-V126
HB-V125	HB-V128

*+(SEE LEGEND)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
HOPE CREEK NUCLEAR GENERATING STATION

LIQUID RADWASTE
COLLECTION LINES

Updated FSAR
Revision 9, June 13, 1998

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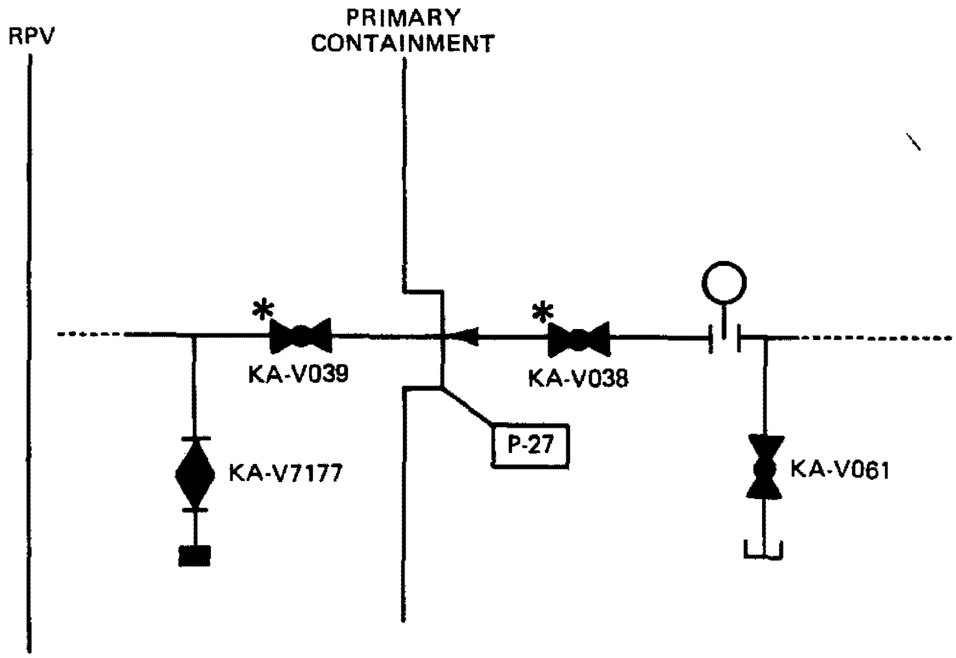
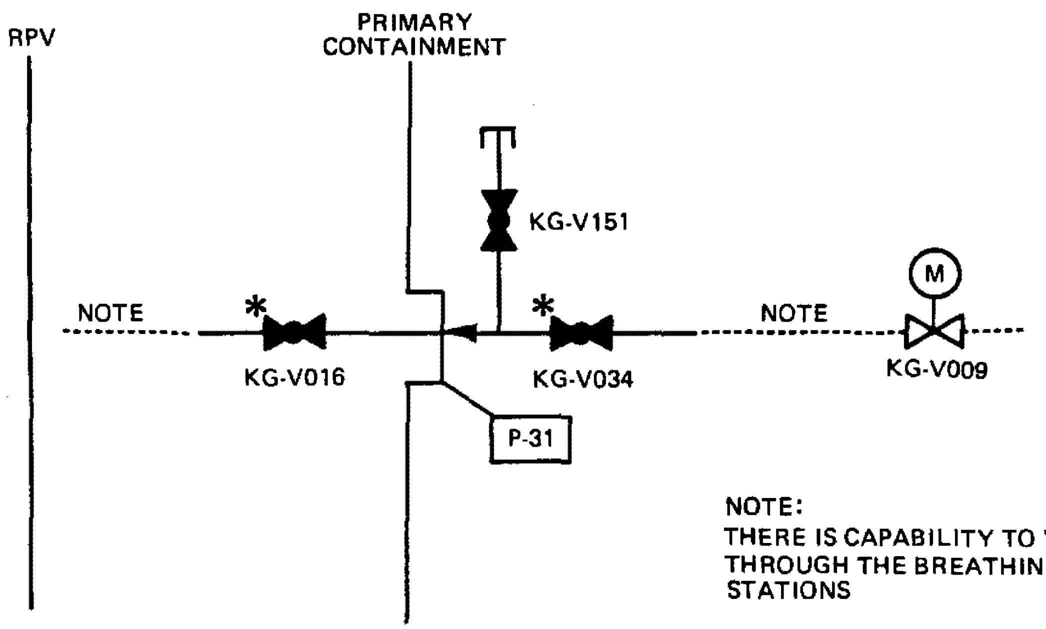
Figure 6.2-27



OR



NOTE:
THERE IS CAPABILITY TO VENT THROUGH THE BREATHING AIR STATIONS

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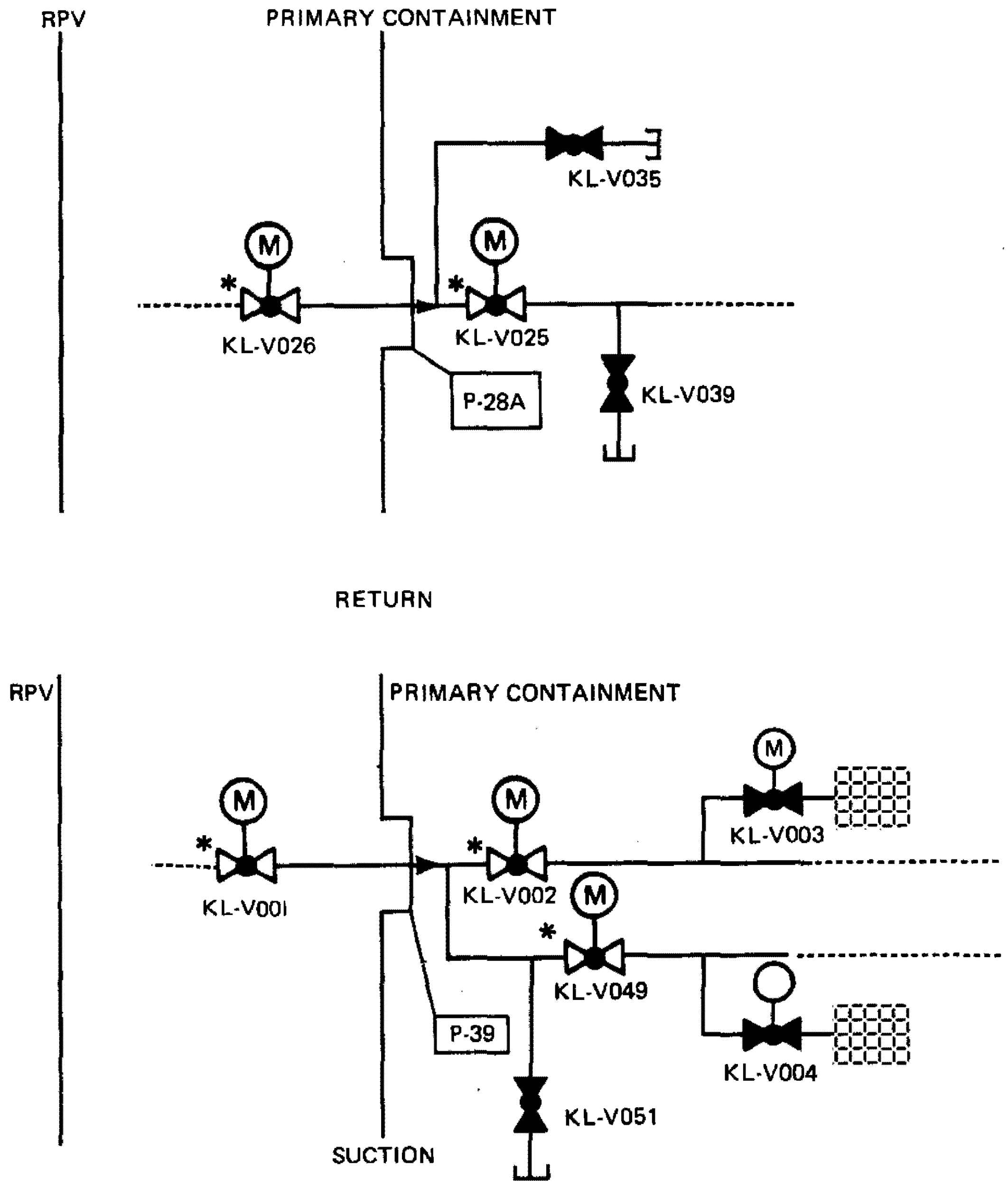
DETAIL 17

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
HOPE CREEK NUCLEAR GENERATING STATION

SERVICE AIR AND
BREATHING AIR TO DRYWELL

UPDATED FSAR	Sheet 17 of 49 FIGURE 6.2-27

*(SEE LEGEND)



DETAIL 18

ISOLATION VALVES

P-28A	P-28B
KL-V026	KL-V028
KL-V025	KL-V027

TEST VALVES

P-28A	P-28B
KL-V035	KL-V037
KL-V039	KL-V040

*(SEE LEGEND)

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
HOPE CREEK NUCLEAR GENERATING STATION

INSTRUMENT GAS LINES

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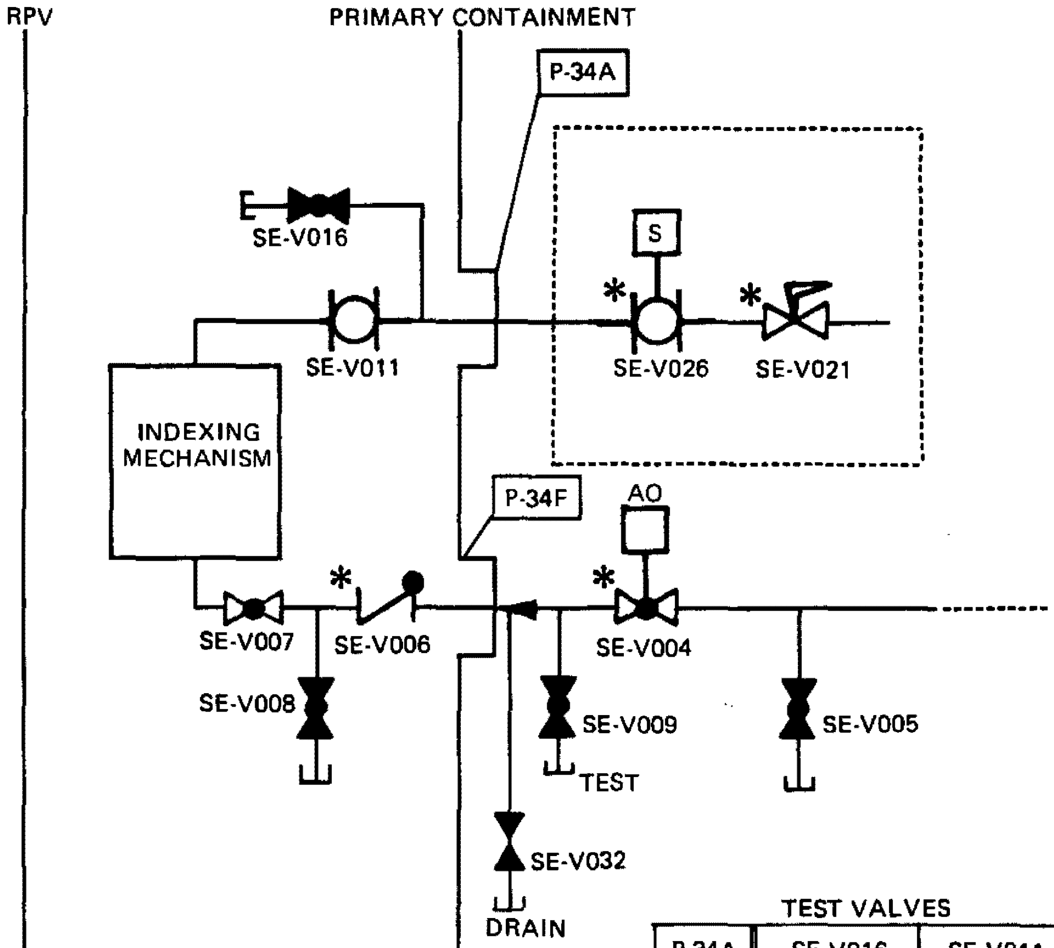
FIGURE 6.2-27



DETAIL 19

TEST VALVES

P-34A	SE-V016	SE-V011
P-34B	SE-V017	SE-V012
P-34C	SE-V018	SE-V013
P-34D	SE-V019	SE-V014
P-35E	SE-V020	SE-V015

ISOLATION VALVES

P-34A	SE-V026	SE-V021
P-34B	SE-V027	SE-V022
P-34C	SE-V028	SE-V023
P-34D	SE-V029	SE-V024
P-34E	SE-V030	SE-V025

*(SEE LEGEND)

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
HOPE CREEK NUCLEAR GENERATING STATION

TIP PROBE
GUIDE TUBE LINES

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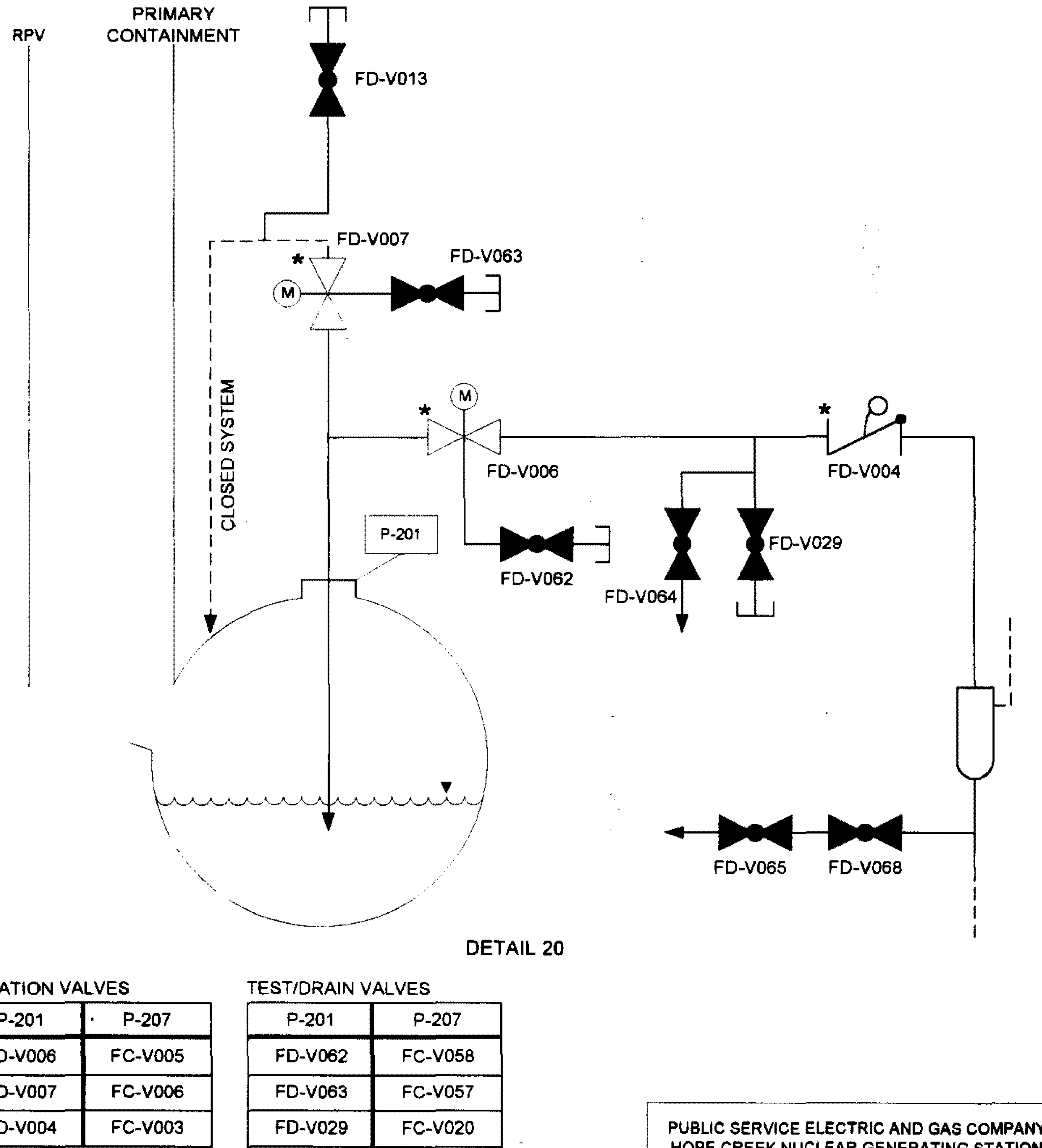
FIGURE 6.2-27



DETAIL 20

ISOLATION VALVES

P-201	P-207
FD-V006	FC-V005
FD-V007	FC-V006
FD-V004	FC-V003

TEST/DRAIN VALVES

P-201	P-207
FD-V062	FC-V058
FD-V063	FC-V057
FD-V029	FC-V020
FD-V013	FC-V040
FD-V068	FC-V063
FD-V065	FC-V062

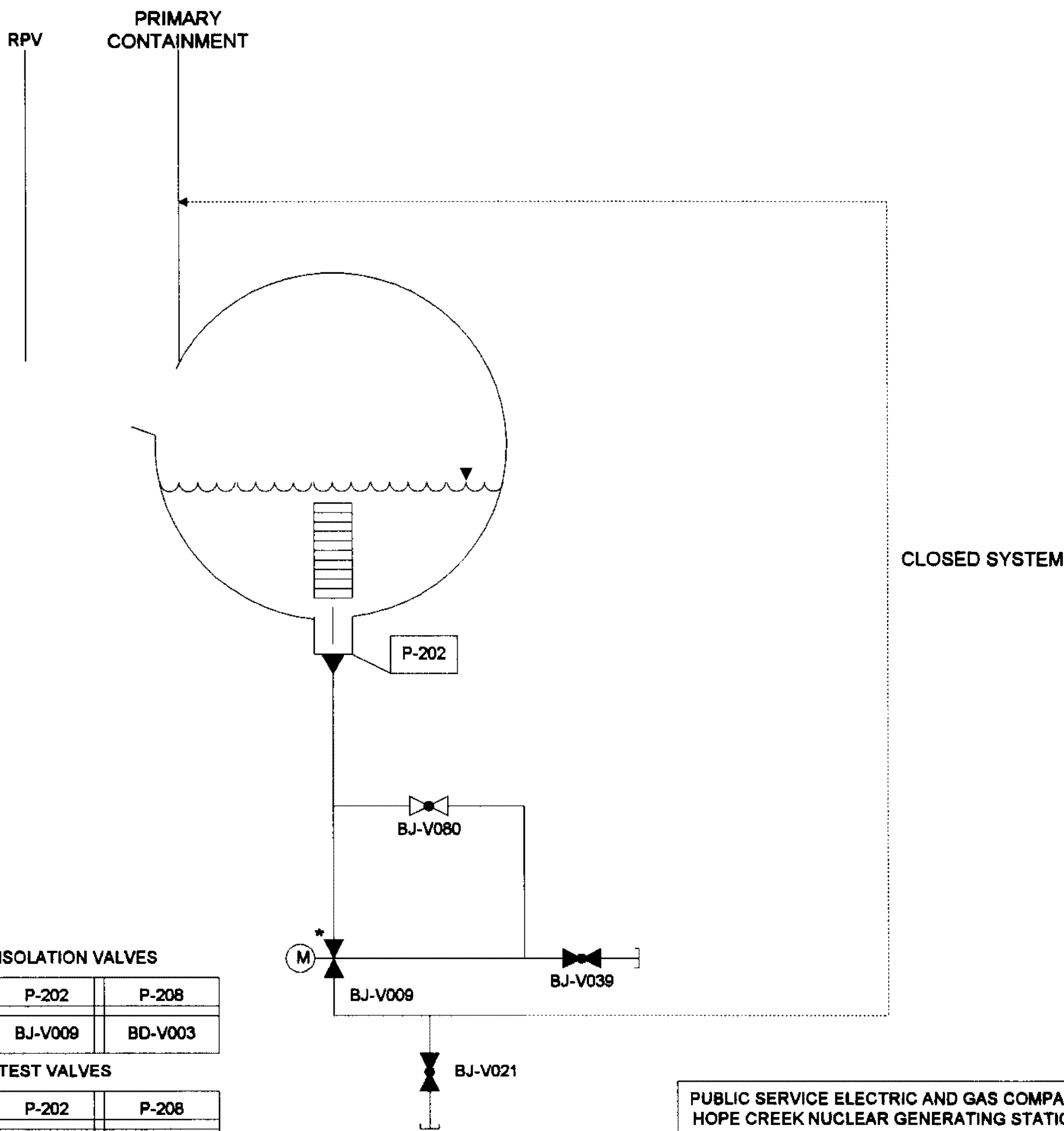
* (SEE LEGEND)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
HOPE CREEK NUCLEAR GENERATING STATION

HPCI AND RCIC EXHAUST LINES

UPDATED FSAR
Revision 9, June 13, 1998

Sheet 20 of 49
FIGURE 6.2-27



ISOLATION VALVES

P-202	P-208
BJ-V009	BD-V003

TEST VALVES

P-202	P-208
BJ-V039	BD-V035
BJ-V021	BD-V015

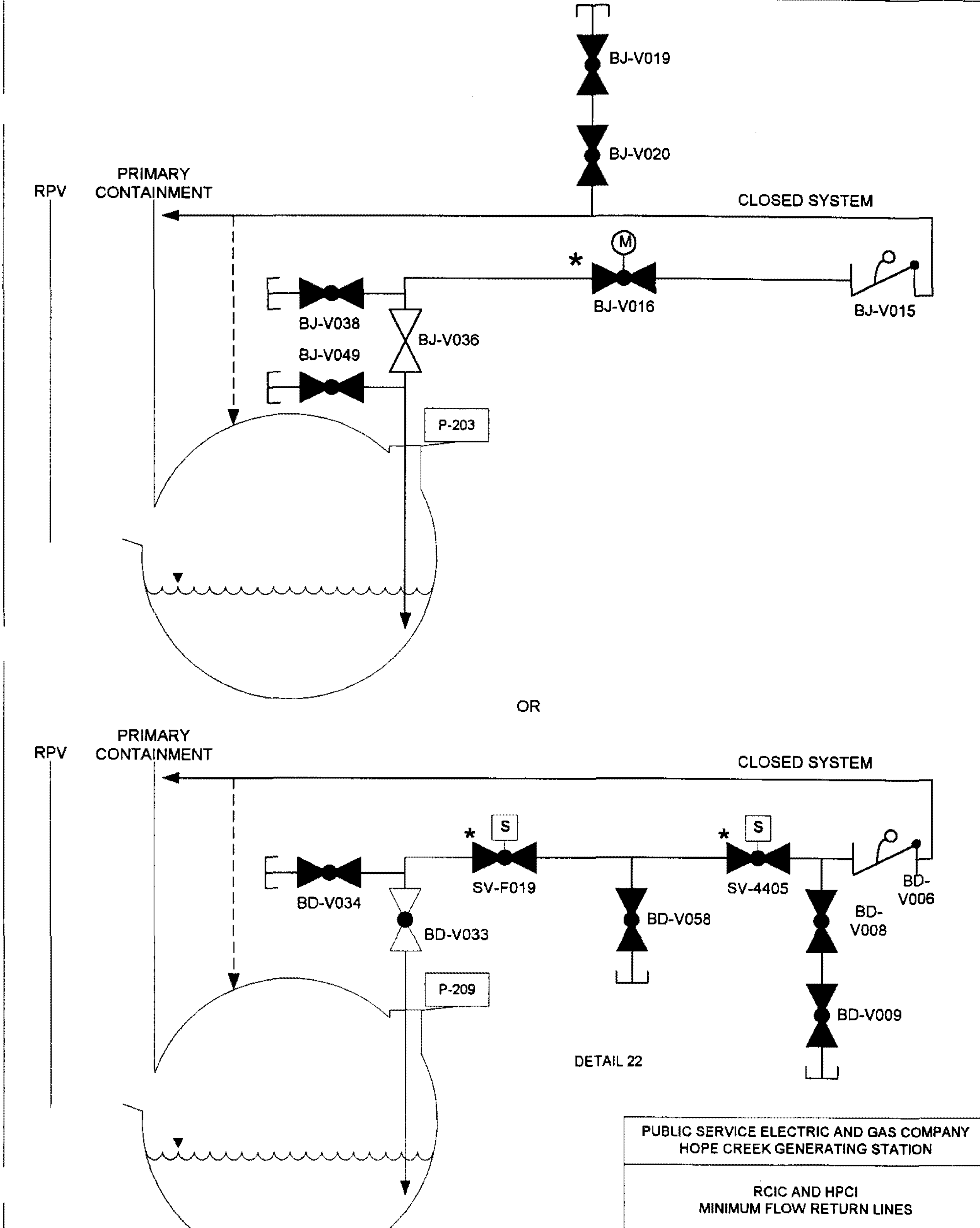
* (SEE LEGEND)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
HOPE CREEK NUCLEAR GENERATING STATION

HPCI AND RCIC PUMP SUCTION LINES

Updated FSAR
Revision 9, June 13, 1998

Sheet 21 of 49
Figure 6.2-27



* (SEE LEGEND)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
HOPE CREEK GENERATING STATION

RCIC AND HPCI
MINIMUM FLOW RETURN LINES

Updated FSAR
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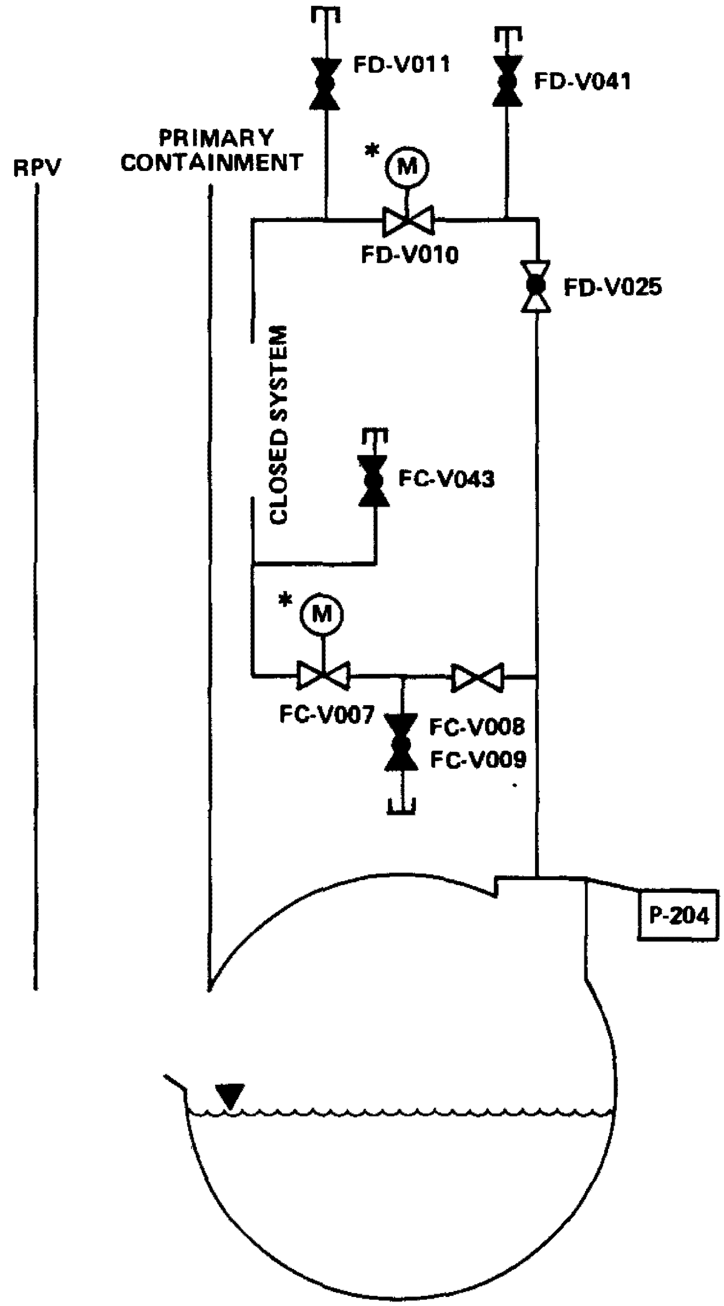
FIGURE 6.2-27



DETAIL 23

REVISION 0
APRIL 11, 1988

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
HOPE CREEK NUCLEAR GENERATING STATION

HPCI AND RCIC
VACUUM BREAKER NETWORK LINE

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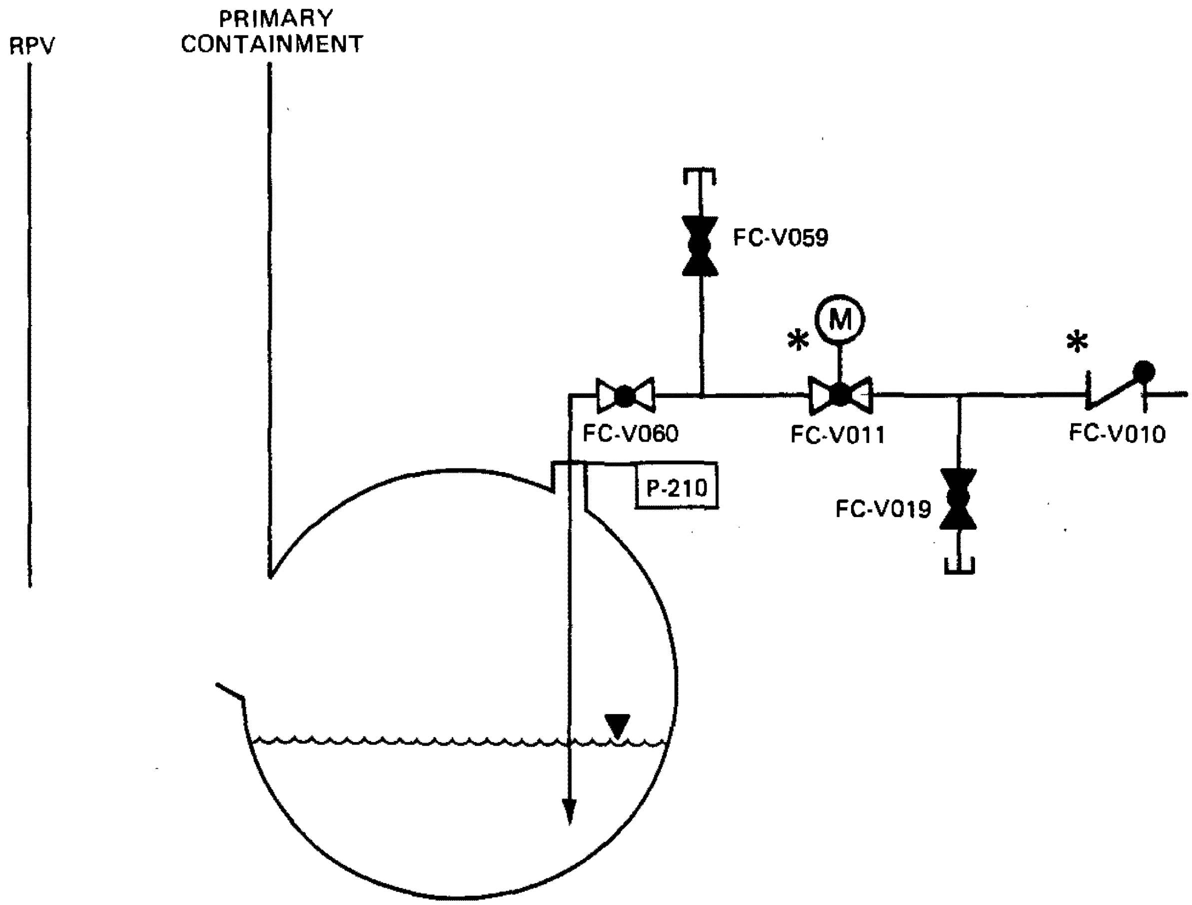
FIGURE 6.2-27

*(SEE LEGEND)



DETAIL 24

REVISION 0
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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
HOPE CREEK NUCLEAR GENERATING STATION

RCIC
VACUUM PUMP LINE

UPDATED FSAR

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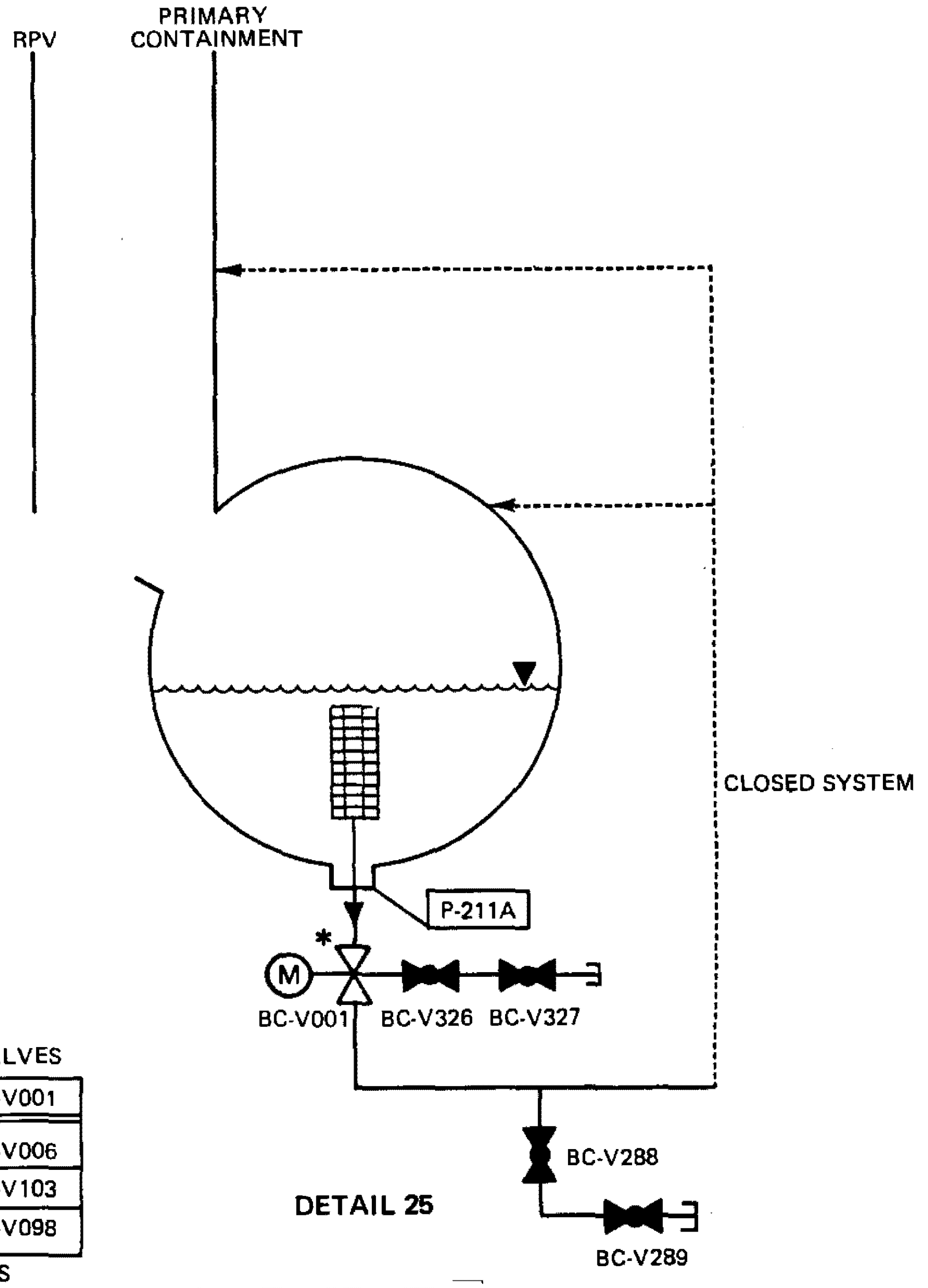
FIGURE 6.2-27

* (SEE LEGEND)



ISOLATION VALVES

P-211A	BC-V001
P-211B	BC-V006
P-211C	BC-V103
P-211D	BC-V098

DETAIL 25

TEST VALVES

P-211A	BC-V326	BC-V327	BC-V288	BC-V289
P-211B	BC-V328	BC-V329	BC-V282	BC-V283
P-211C	BC-V341	BC-V340	BC-V293	BC-V294
P-211D	BC-V342	BC-V343	BC-V292	BC-V291

*(SEE LEGEND)

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
HOPE CREEK NUCLEAR GENERATING STATION

RHR PUMP SUCTION LINES

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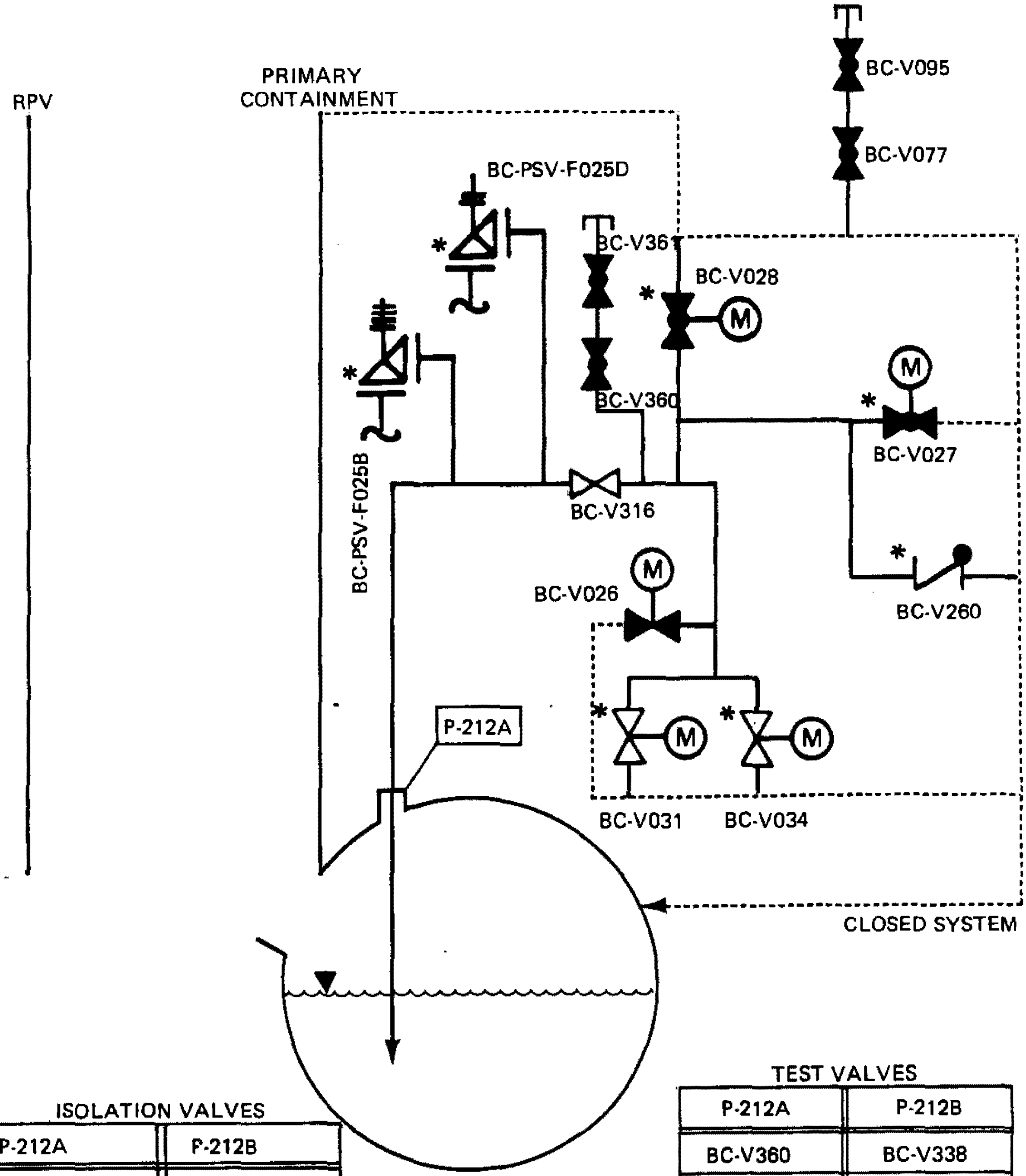
FIGURE 6.2-27



DETAIL 26

ISOLATION VALVES

P-212A	P-212B
BC-PSV-F025D	BC-PSV-F025C
BC-PSV-F025B	BC-PSV-F025A
BC-V028	BC-V124
BC-V027	BC-V125
BC-V026	BC-V126
BC-V034	BC-V128
BC-V031	BC-V131
BC-V260	BC-V206

TEST VALVES

P-212A	P-212B
BC-V360	BC-V338
BC-V361	BC-V339
BC-V077	BC-V334
BC-V095	BC-V335
BC-V316	BC-V317

NOTE: FOR THE PROPER VENTING OF BACKPRESSURE, FLOW CONTROL VALVES BC-LV-F053A AND B (NOT SHOWN) MUST BE OPENED DURING TESTING.

*(SEE LEGEND)

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
HOPE CREEK NUCLEAR GENERATING STATION

RHR SUPPRESSION POOL
WATER COOLING AND
SYSTEM TEST LINES

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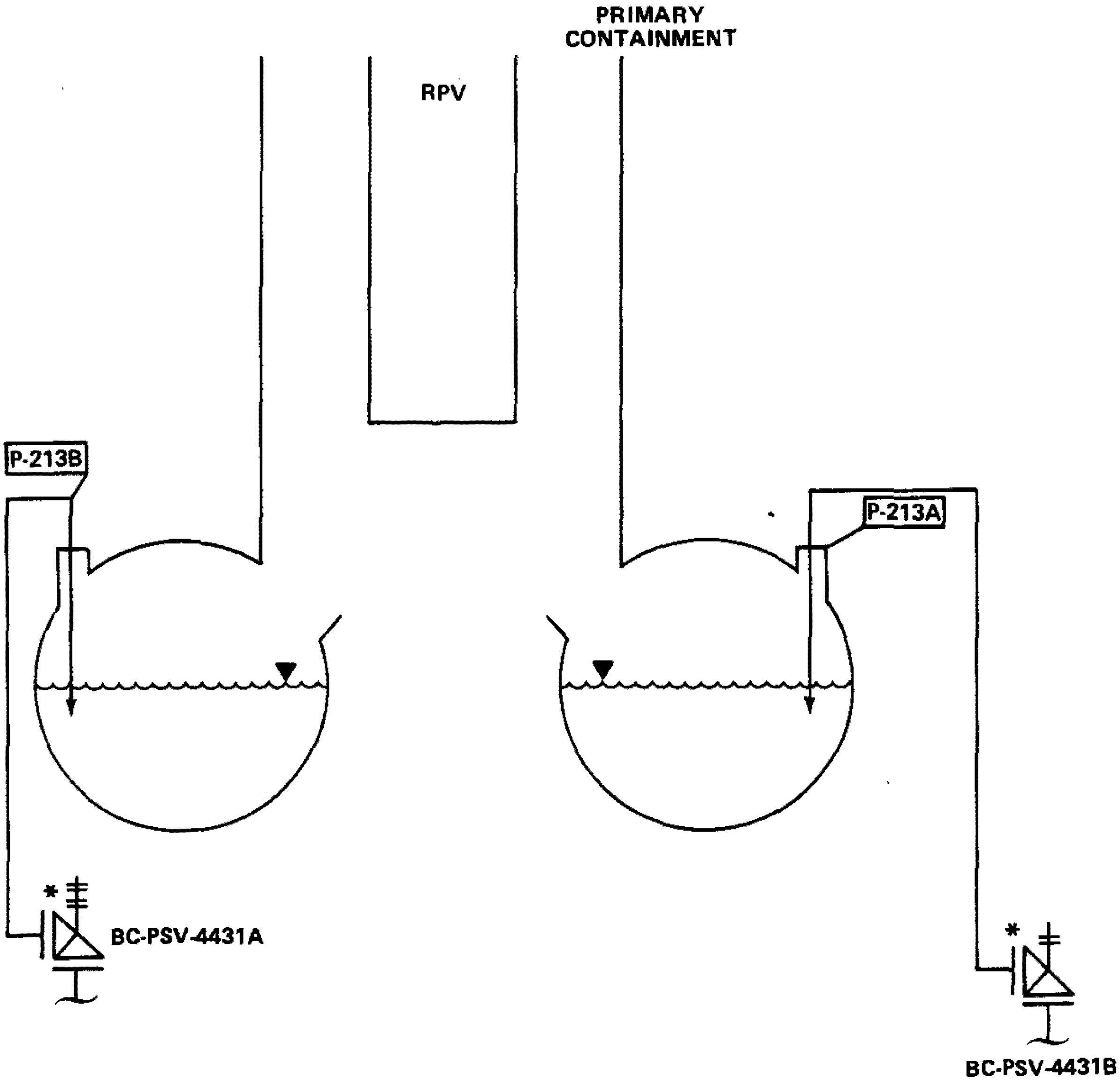
FIGURE 6.2-27



DETAIL 27

REVISION 0
APRIL 11, 1988

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
HOPE CREEK NUCLEAR GENERATING STATION

RHR RELIEF TO
SUPPRESSION CHAMBER LINES

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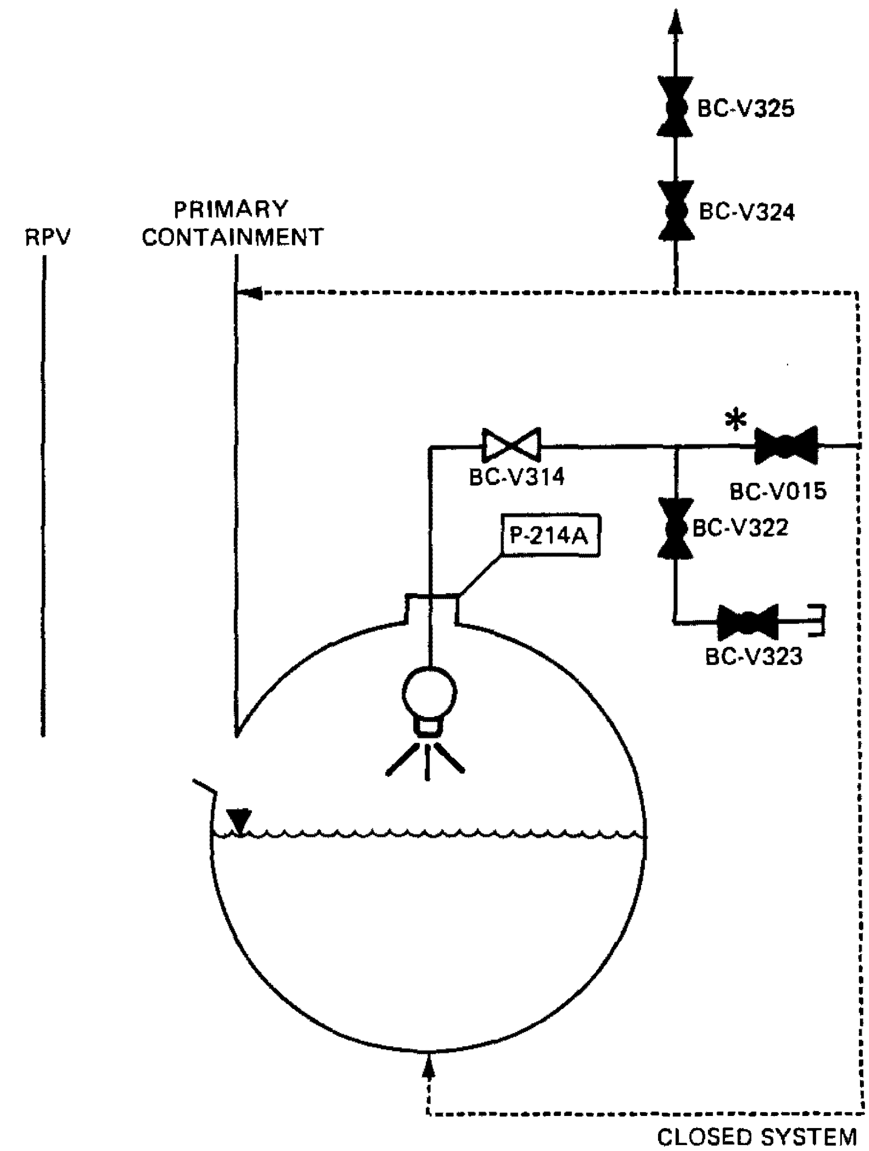
FIGURE 6.2-27

*(SEE LEGEND)



DETAIL 28

ISOLATION VALVES

P-214A	P-214B
BC-V015	BC-V112

TEST AND DRAIN VALVES

P-214A	P-214B
BC-V322	BC-V336
BC-V323	BC-V337
BC-V324	BC-V353
BC-V325	BC-V354
BC-V314	BC-V315

*(SEE LEGEND)

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
HOPE CREEK NUCLEAR GENERATING STATION

RHR TO SUPPRESSION CHAMBER
SPRAY HEADER LINES

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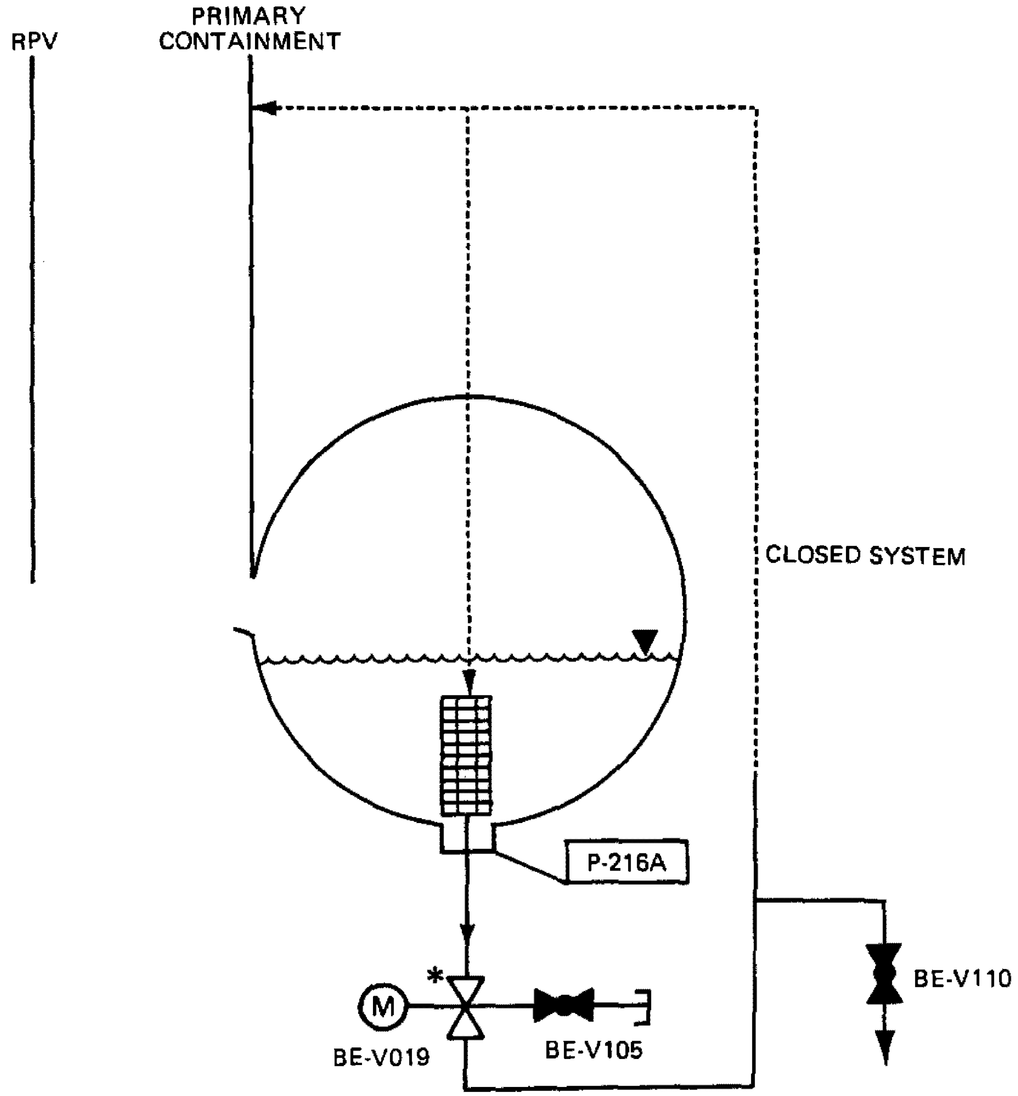
FIGURE 6.2-27



ISOLATION VALVES

P-216A	BE-V019
P-216B	BE-V020
P-216C	BE-V018
P-216D	BE-V017

DETAIL 29

TEST AND DRAIN VALVES

P-216A	BE-V105	BE-V110
P-216B	BE-V104	BE-V111
P-216C	BE-V106	BE-V109
P-216D	BE-V107	BE-V108

*(SEE LEGEND)

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
HOPE CREEK NUCLEAR GENERATING STATION

CORE SPRAY PUMP
SUCTION LINES

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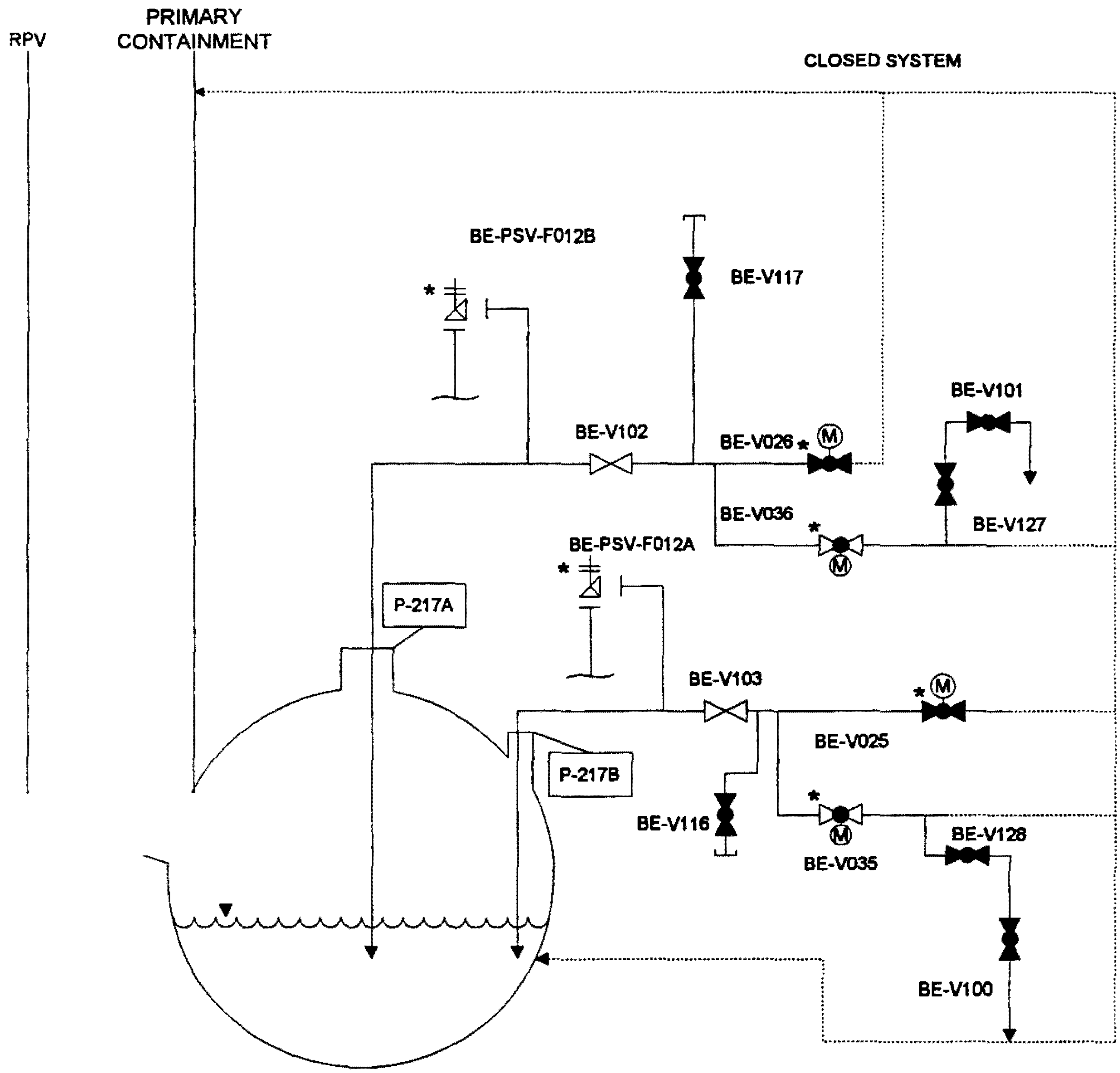
FIGURE 6.2-27



DETAIL 30

* (SEE LEGEND)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
HOPE CREEK NUCLEAR GENERATING STATION

CORE SPRAY TEST TO
SUPPRESSION CHAMBER LINES

Updated FSAR
Revision 7, December 29, 1995

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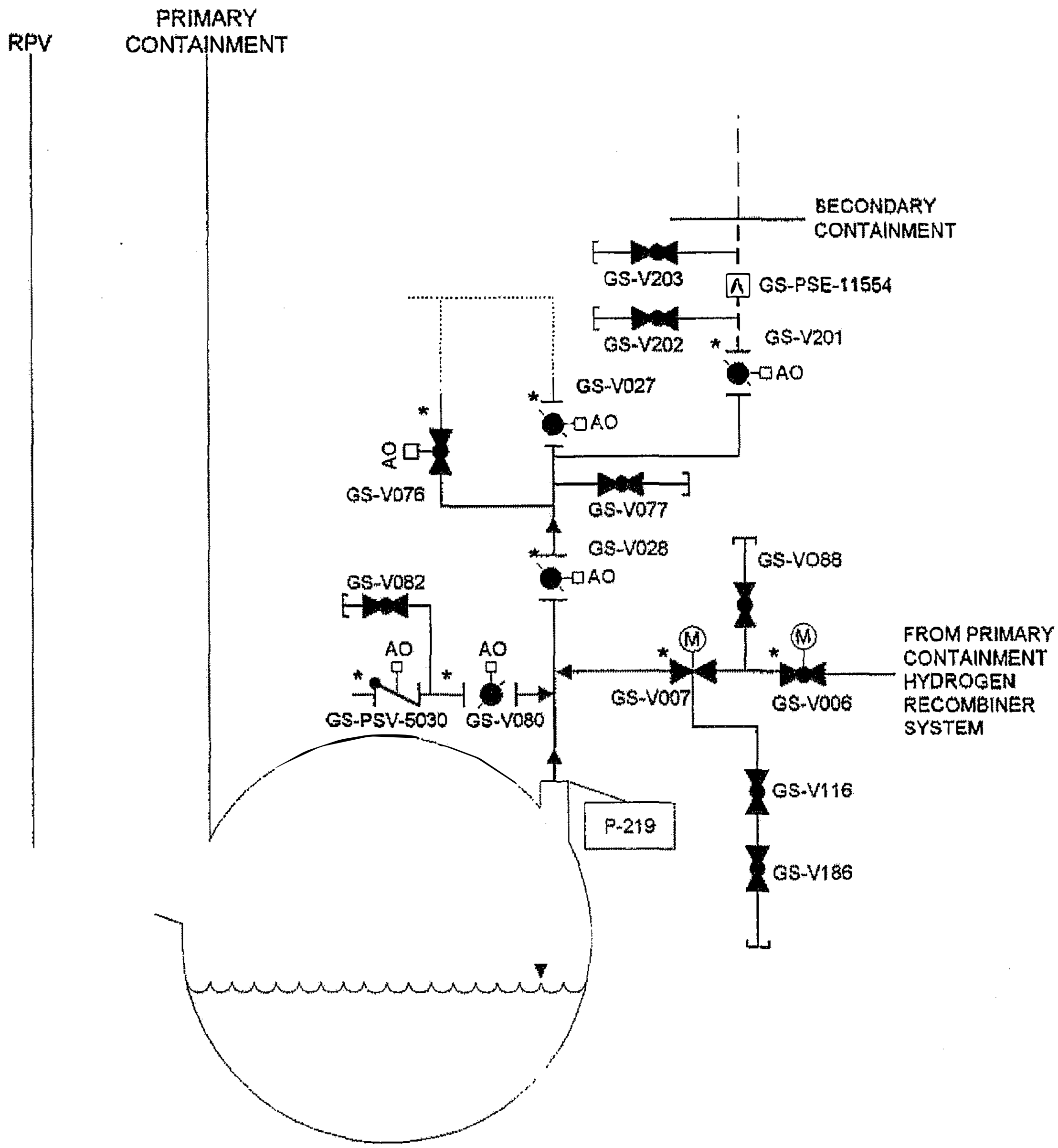
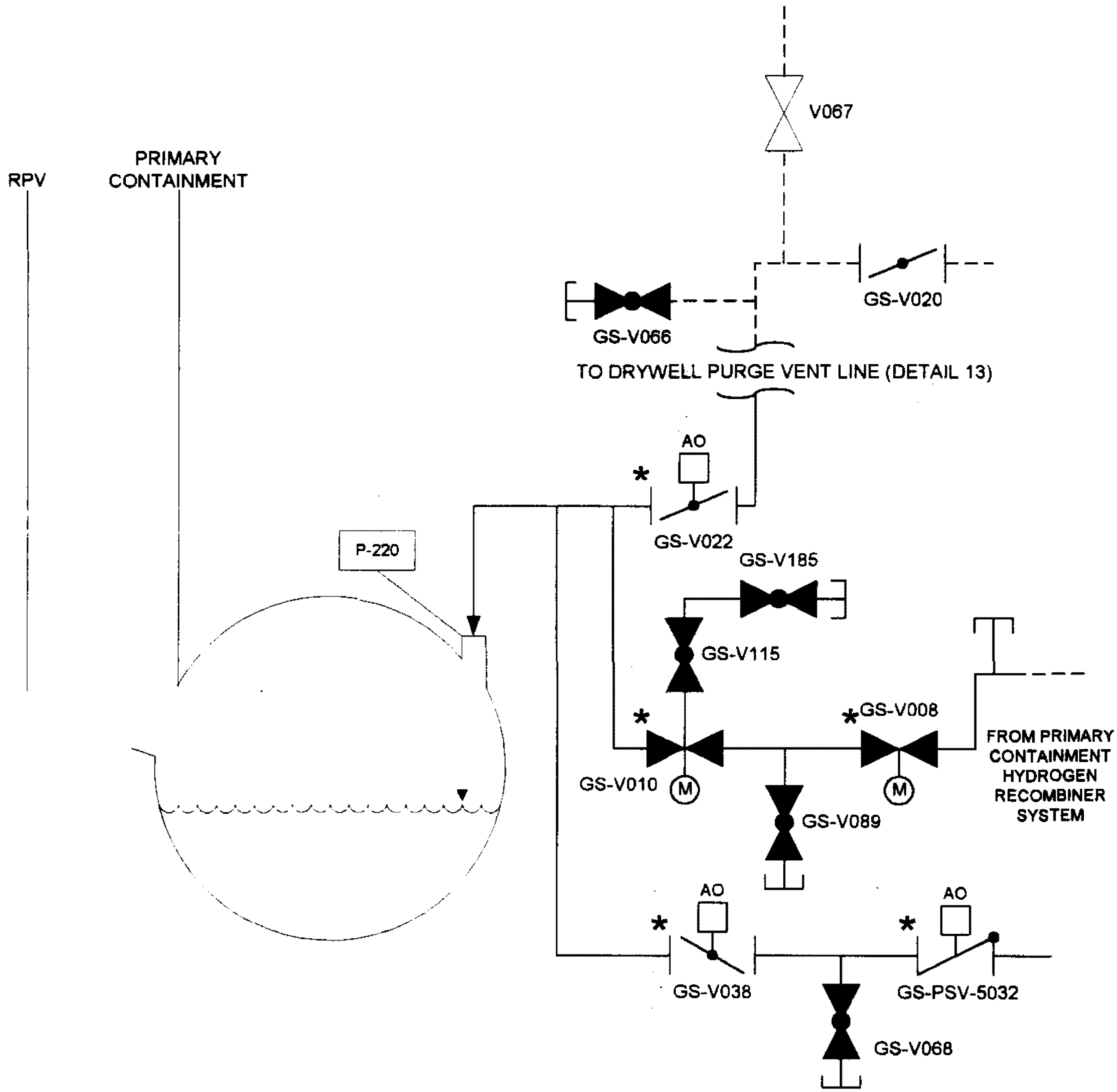
FIGURE 6.2-27



DETAIL 31

REVISION 22, MAY 9, 2017

PSEG Nuclear, LLC HOPE CREEK NUCLEAR GENERATING STATION	Hope Creek Nuclear Generating Station SUPRESSION CHAMBER PURGE AND SUPPRESSION CHAMBER VACUUM RELIEF LINE
	Updated FSAR Sheet 31 of 49 Figure 6.2-27



DETAIL 32

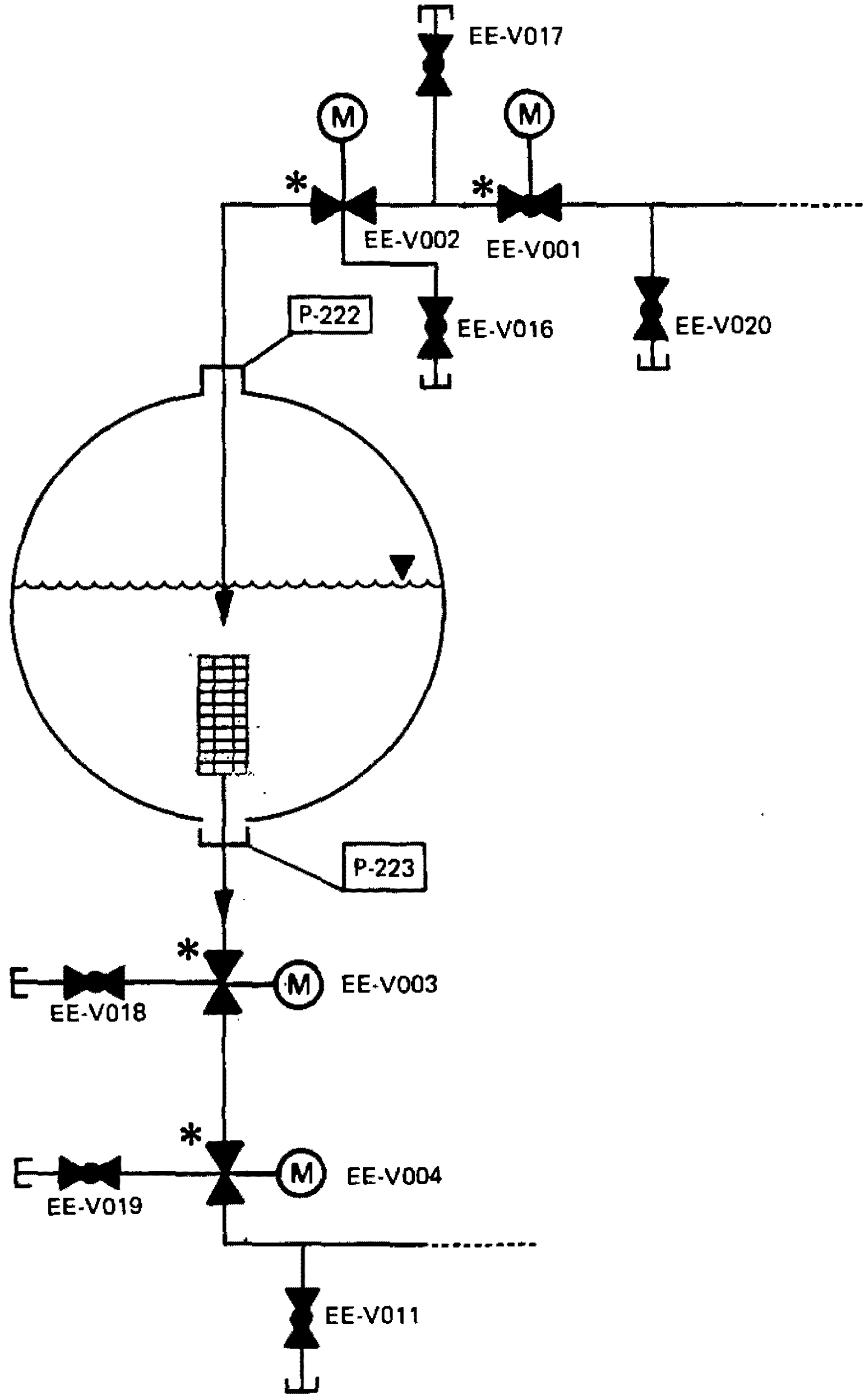
* (SEE LEGEND)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
HOPE CREEK NUCLEAR GENERATING STATION

SUPPRESSION CHAMBER PURGE INLET &
SUPPRESSION CHAMBER
VACUUM RELIEF LINE

Updated FSAR
Revision 9, June 13, 1998

Sheet 32 of 49
FIGURE 6.2-27



DETAIL 33

REVISION 0
APRIL 11, 1988

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
HOPE CREEK NUCLEAR GENERATING STATION

SUPPRESSION POOL CLEANUP
SUPPLY AND RETURN LINES

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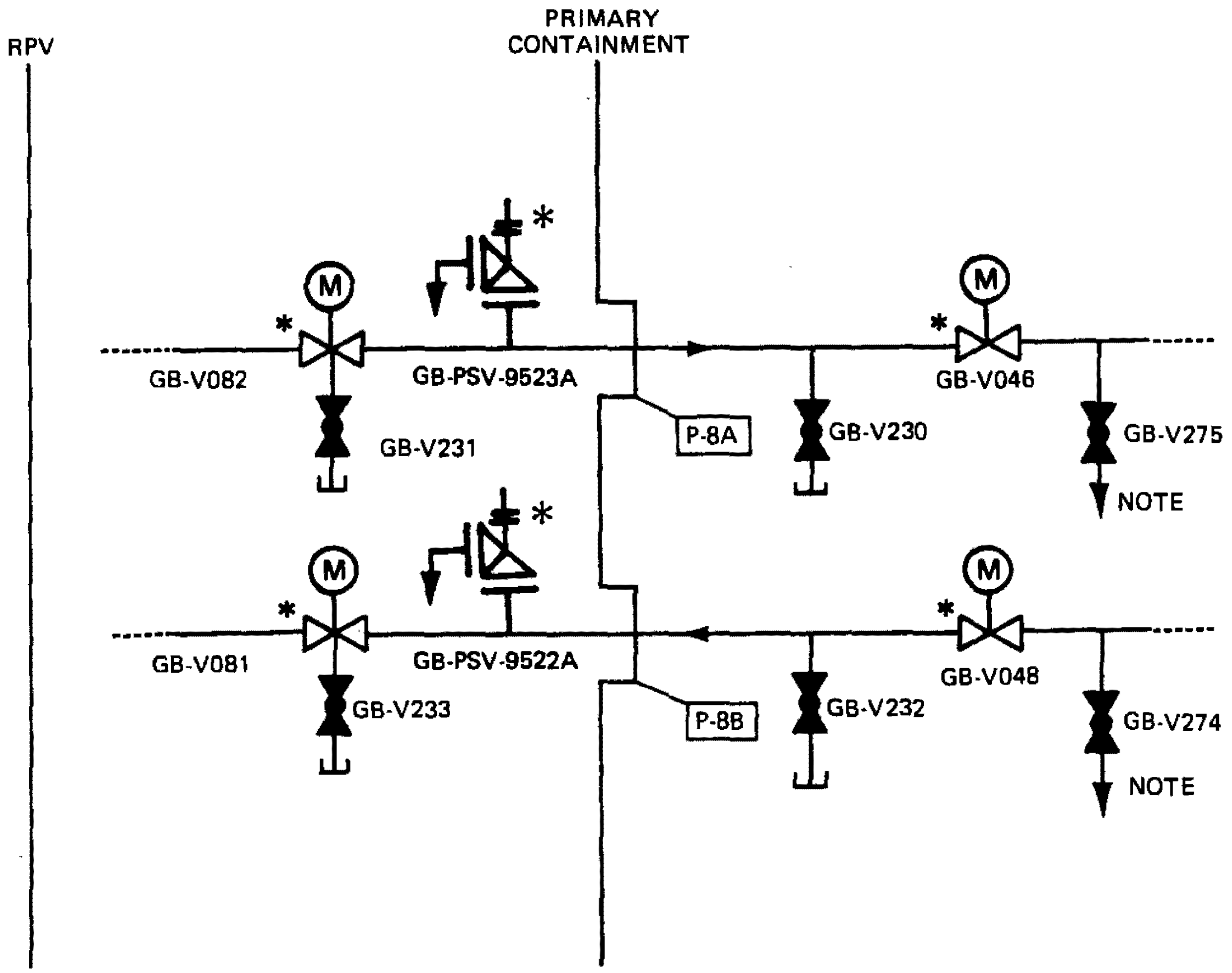
FIGURE 6.2-27

*(SEE LEGEND)



DETAIL 34

ISOLATION VALVES

P-8A	GB-V082	GB-V046	GB-PSV-9523A
P-38B	GB-V084	GB-V071	GB-PSV-9523B

ISOLATION VALVES

P-8B	GB-V081	GB-V048	GB-PSV-9522A
P-38A	GB-V083	GB-V070	GB-PSV-9522B

TEST VALVES

P-8A	GB-V231	GB-V230	GB-V275
P-38B	GB-V237	GB-V236	GB-V241

TEST VALVES

P-8B	GB-V233	GB-V232	GB-V274
P-38A	GB-V235	GB-V234	GB-V240

*(SEE LEGEND)

NOTE:
THIS IS A TEST TAP ON P-38A AND P-38B

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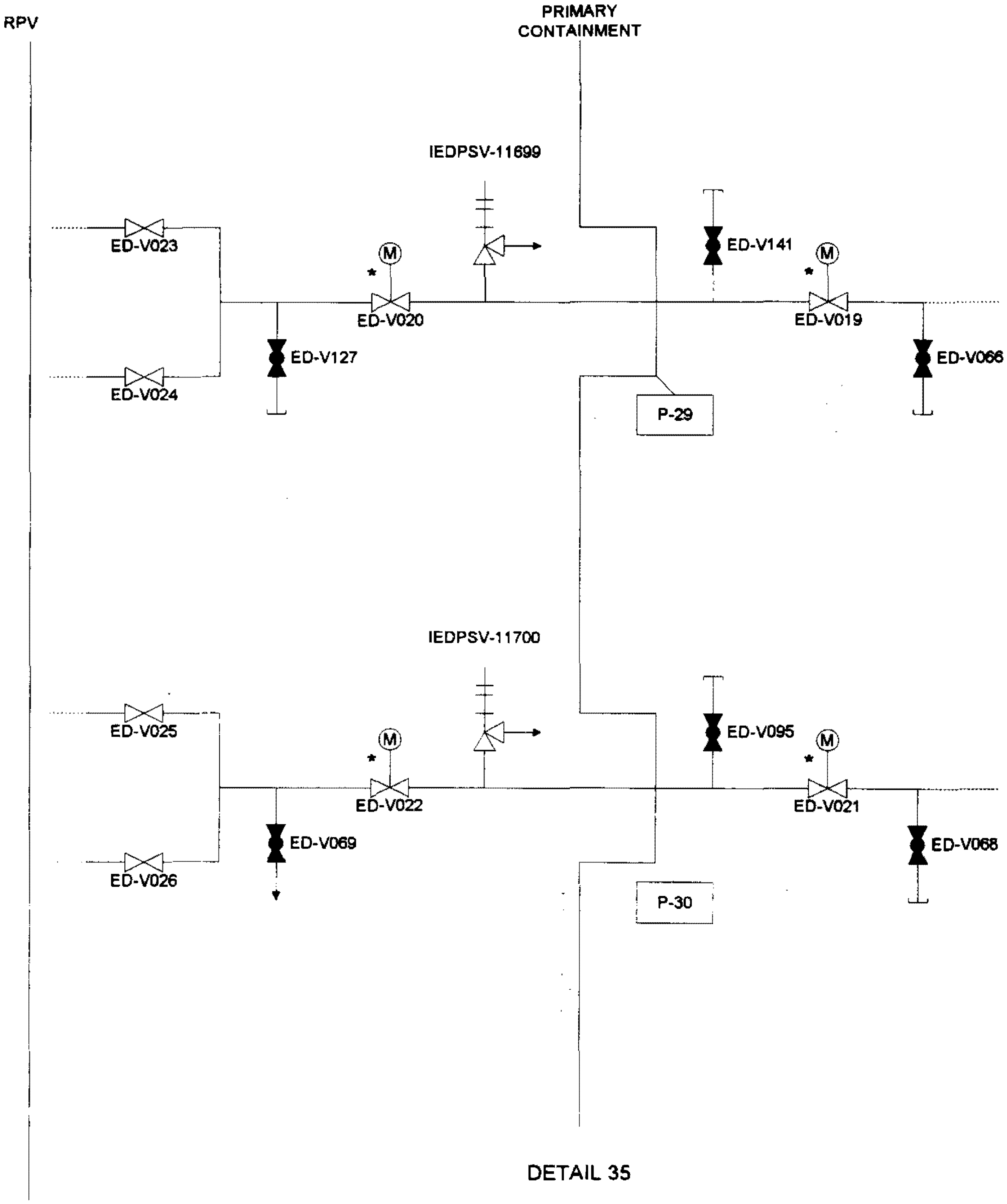
PUBLIC SERVICE ELECTRIC AND GAS COMPANY
HOPE CREEK NUCLEAR GENERATING STATION

CHILLER WATER SYSTEM LINES

UPDATED FSAR

Sheet 34 of 49
FIGURE 6.2-27



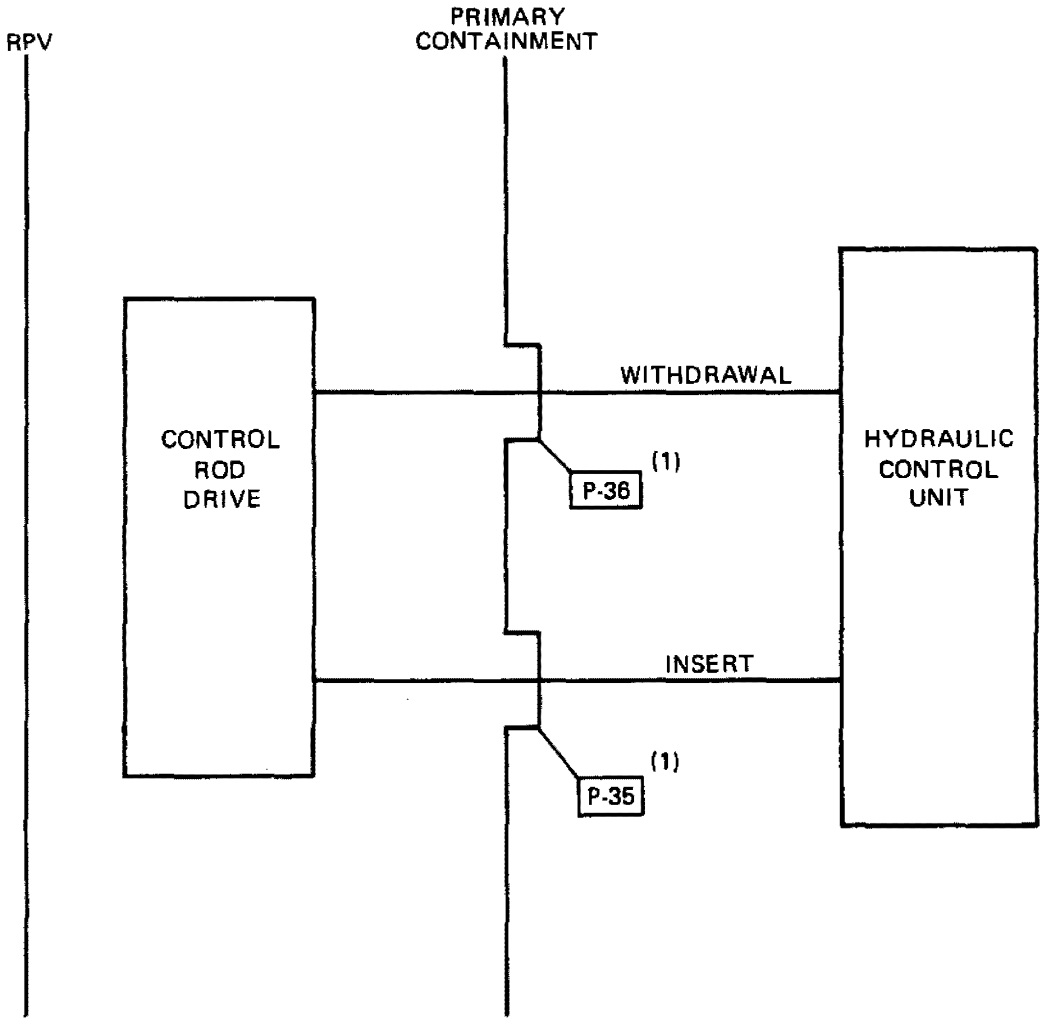
*+ (SEE LEGEND)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
HOPE CREEK NUCLEAR GENERATING STATION

REACTOR AUXILIARIES
COOLING LINES

Updated FSAR
Revision 9, June 13, 1998

Sheet 35 of 49
Figure 6.2-27



DETAIL 36

(1) TYPICAL OF PENETRATIONS A THRU D

REVISION 0
APRIL 11, 1988

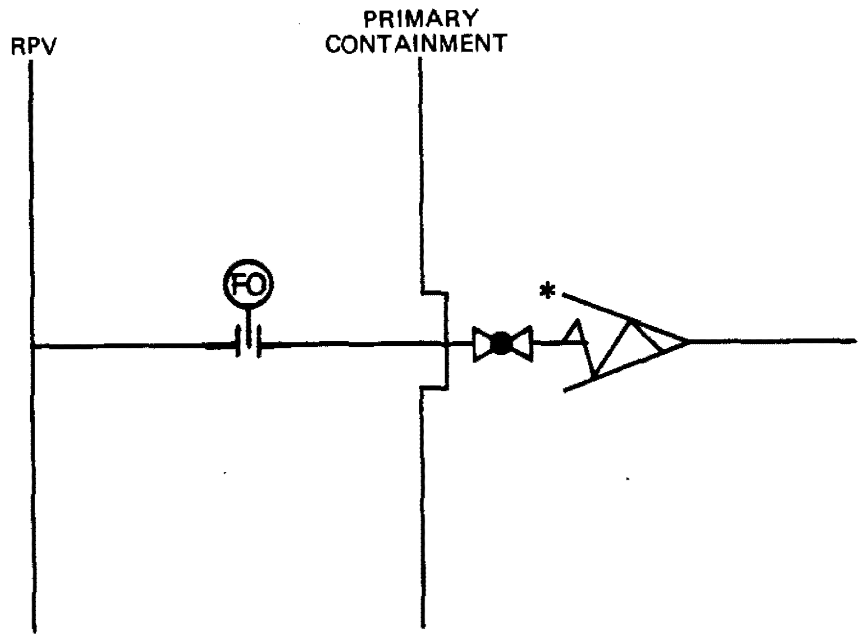
PUBLIC SERVICE ELECTRIC AND GAS COMPANY
HOPE CREEK NUCLEAR GENERATING STATION

CRD SYSTEM

UPDATED FSAR

Sheet 36 of 49
FIGURE 6.2-27

*(SEE LEGEND)



TYPICAL OF NUMEROUS
INSTRUMENT PENETRATIONS

DETAIL 37

REVISION 0
APRIL 11, 1988

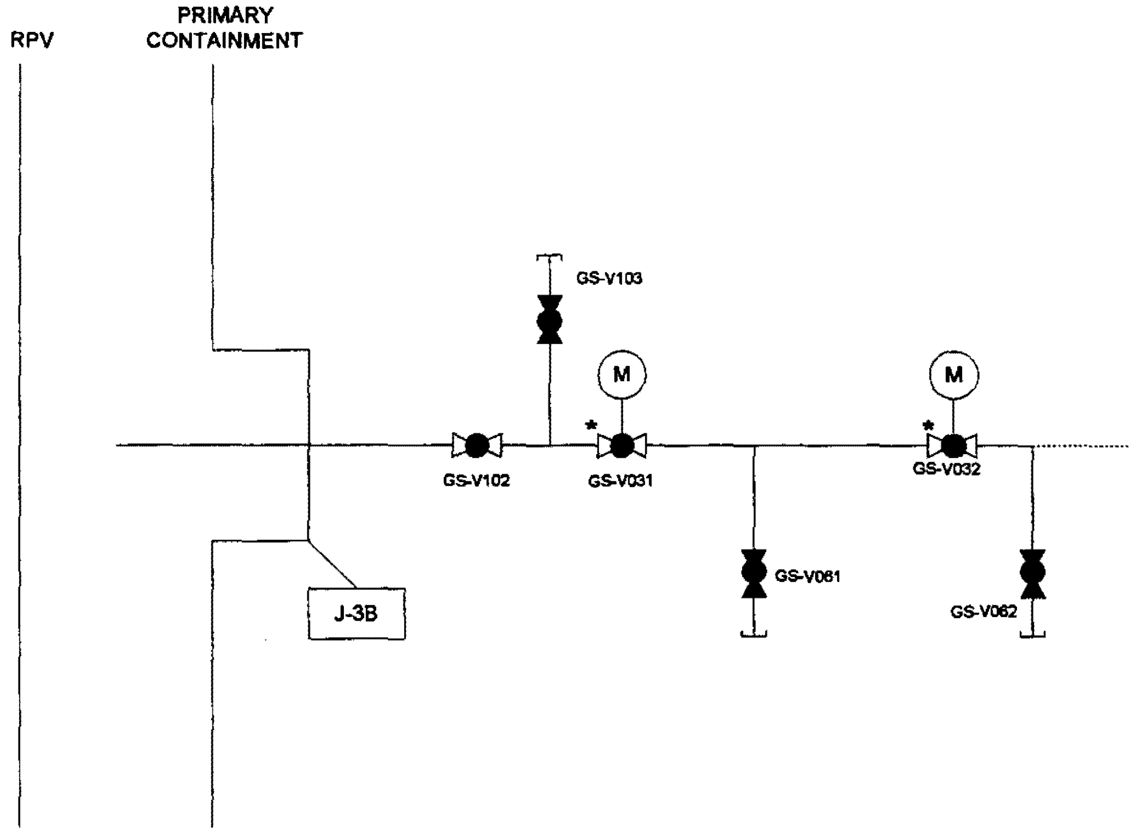
PUBLIC SERVICE ELECTRIC AND GAS COMPANY
HOPE CREEK NUCLEAR GENERATING STATION

TYPICAL OF INSTRUMENT LINES PENETRATING PRIMARY CONTAINMENT AND CONNECTING DIRECTLY TO REACTOR COOLANT PRESSURE BOUNDARY

UPDATED FSAR

Sheet 37 of 49
FIGURE 6.2-27

*(SEE LEGEND)



DETAIL 38

ISOLATION VALVES

J-3B	GS-V031	GS-V032
J-5A	SK-V008	SK-V009
J-8C	SK-V005	SK-V006
J-9E	GS-V045	GS-V046
J-10C	GS-V047	GS-0V48

TEST VALVES

J-3B	GS-V103	GS-V061	GS-V062	GS-V102
J-5A	SK-V016	SK-V017	SK-V025	SK-V007
J-8C	SK-V013	SK-V014	SK-V024	SK-V004
J-9E	GS-V095	GS-V074	GS-V078	GS-V094
J-10C	GS-V097	GS-V075	GS-V079	GS-V096

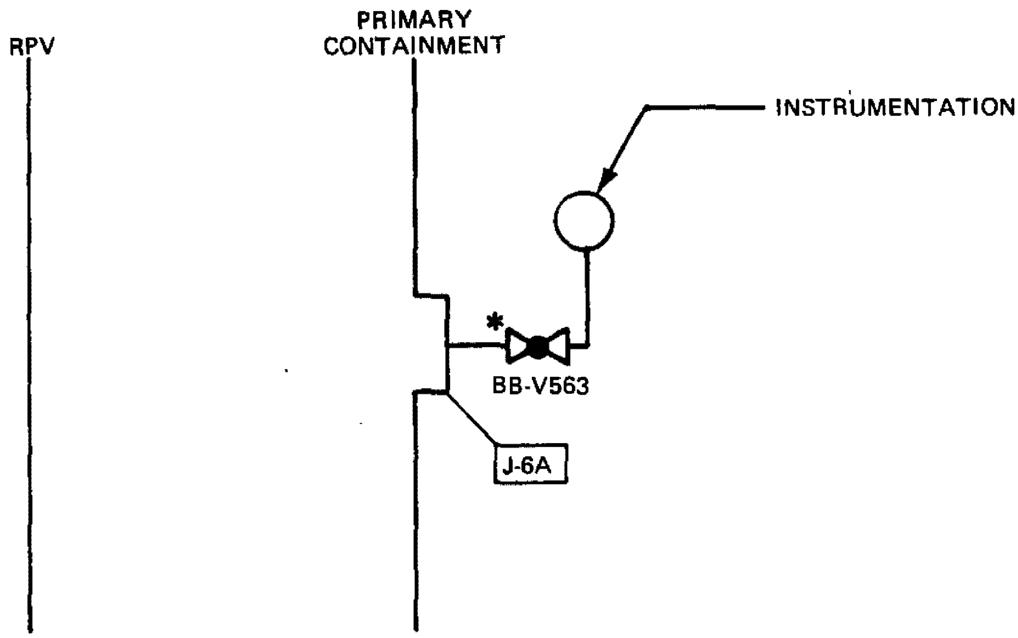
* (SEE LEGEND)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
HOPE CREEK NUCLEAR GENERATING STATION

TYPICAL OF INSTRUMENT LINES PENETRATING PRIMARY CONTAINMENT AND CONNECTING DIRECTLY TO THE CONTAINMENT ATMOSPHERE

Updated FSAR
Revision 7, December 29, 1995

Sheet 38 of 49
Figure 6.2-27



DETAIL 39

J-6A	BB-V563
J-7A	BB-V565
J-8D	BB-V564
J-10D	BB-V566

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APRIL 11, 1988

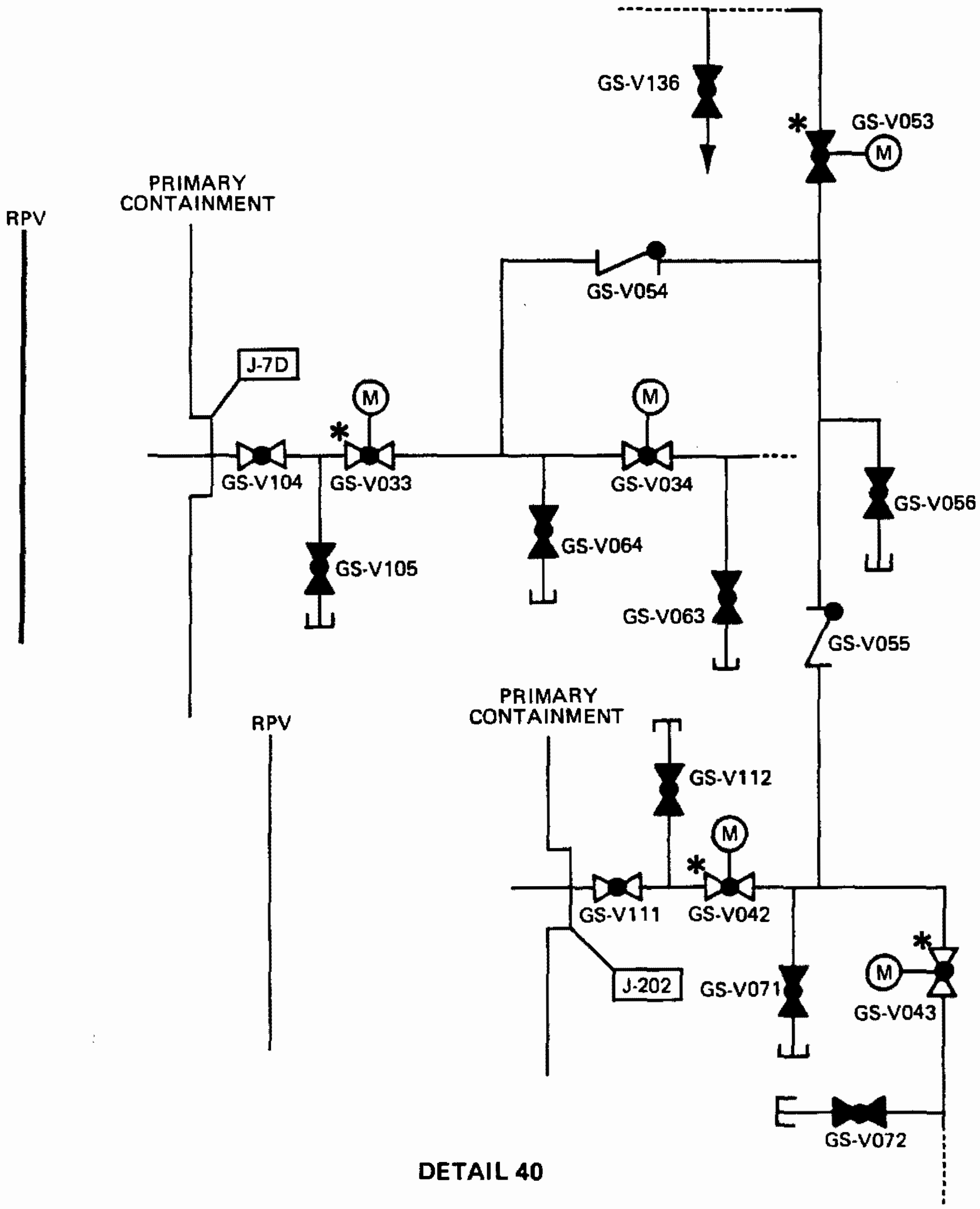
PUBLIC SERVICE ELECTRIC AND GAS COMPANY
HOPE CREEK NUCLEAR GENERATING STATION

TYPICAL OF INSTRUMENT
LINES FOR SENSING
CONTAINMENT ATMOSPHERE

UPDATED FSAR

Sheet 39 of 49
FIGURE 6.2-27

*(SEE LEGEND)



DETAIL 40

*(SEE LEGEND)

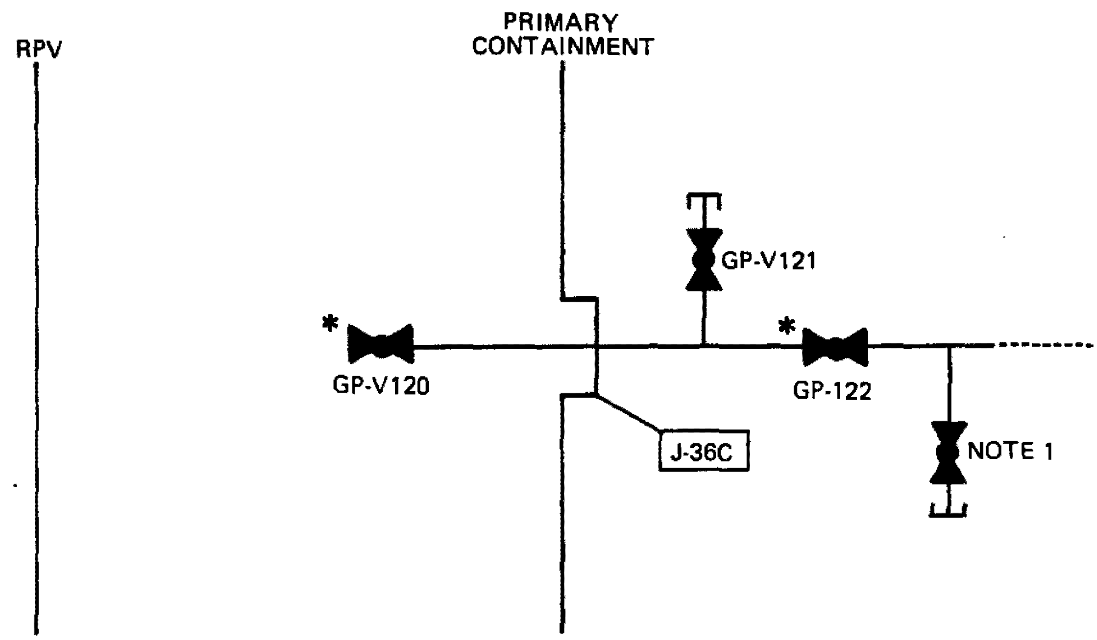
REVISION 0
APRIL 11, 1988

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
HOPE CREEK NUCLEAR GENERATING STATION

HYDROGEN/OXYGEN
ANALYZER LINE

UPDATED FSAR

Sheet 40 of 49
FIGURE 6.2-27



DETAIL 41

ISOLATION VALVES

J-36C	GP-V120	GP-122
J-36D	GP-V001	GP-V002

NOTE1: UNNUMBERED VALVE

TEST VALVES

J-36C	GP-121
J-36D	GP-V132

*(SEE LEGEND)

REVISION 0
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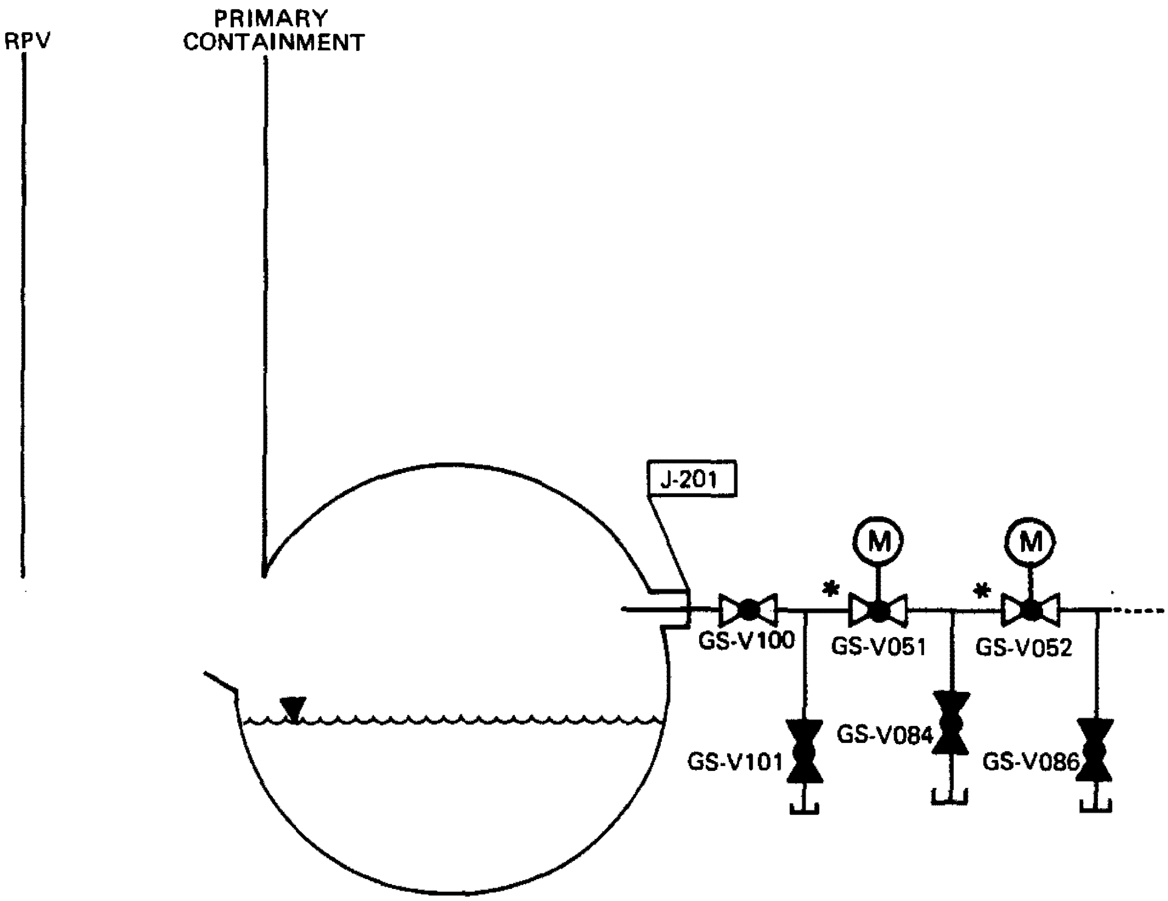
PUBLIC SERVICE ELECTRIC AND GAS COMPANY
HOPE CREEK NUCLEAR GENERATING STATION

PRIMARY CONTAINMENT LEAKAGE
RATE TESTING LINES

UPDATED FSAR

Sheet 41 of 49
FIGURE 6.2-27



DETAIL 42

ISOLATION VALVES

J-201	GS-V051	GS-V052
J-210	GS-V040	GS-V041
J-212	GS-V049	GS-V050

TEST VALVES

J-201	GS-V101	GS-V084	GS-V086	GS-V100
J-210	GS-V110	GS-V069	GS-V070	GS-V109
J-212	GS-V099	GS-V083	GS-V085	GS-V098

* (SEE LEGEND)

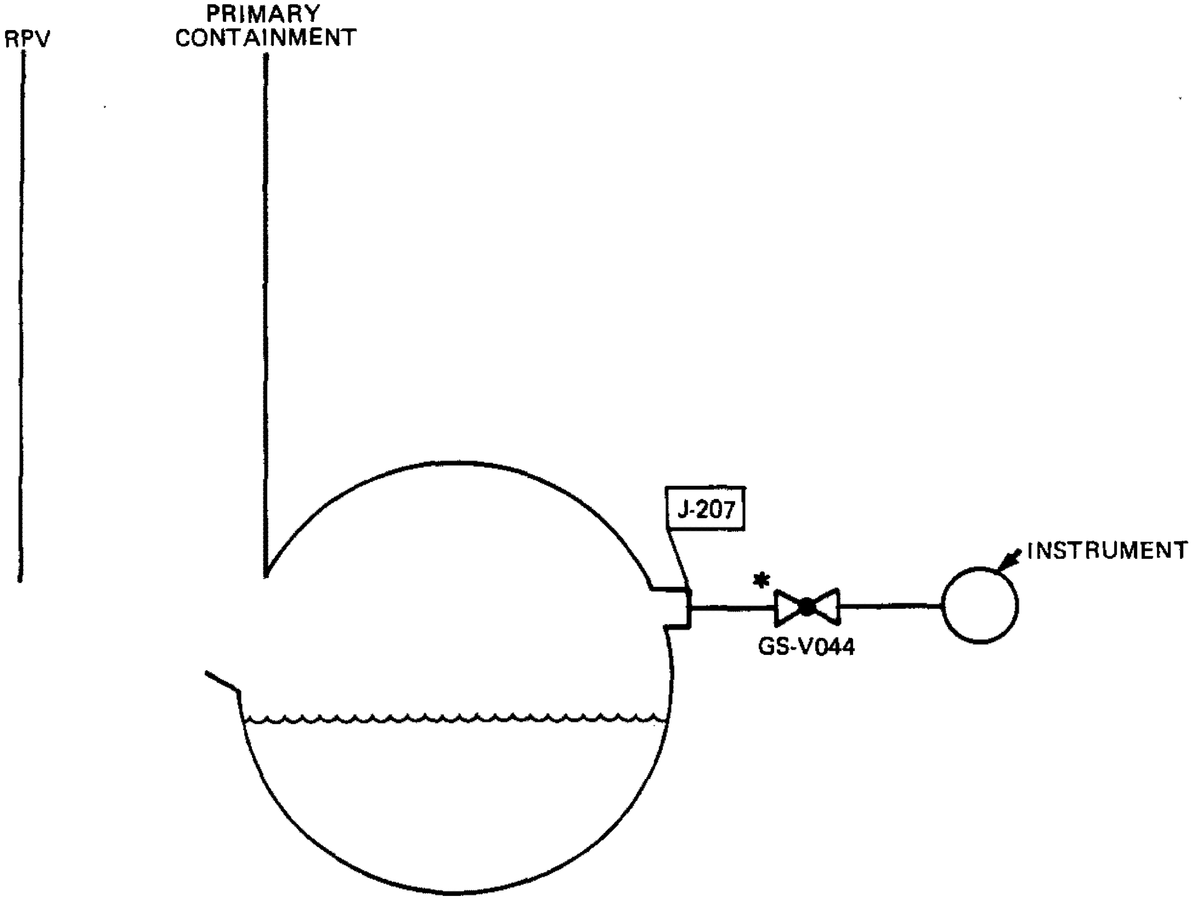
REVISION 0
APRIL 11, 1988

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
HOPE CREEK NUCLEAR GENERATING STATION

TYPICAL OF INSTRUMENT
LINES PENETRATING
THE SUPPRESSION CHAMBER

UPDATED FSAR

Sheet 42 of 49
FIGURE 6.2-27



DETAIL 43

J-207	GS-V044
J-208	GS-V087

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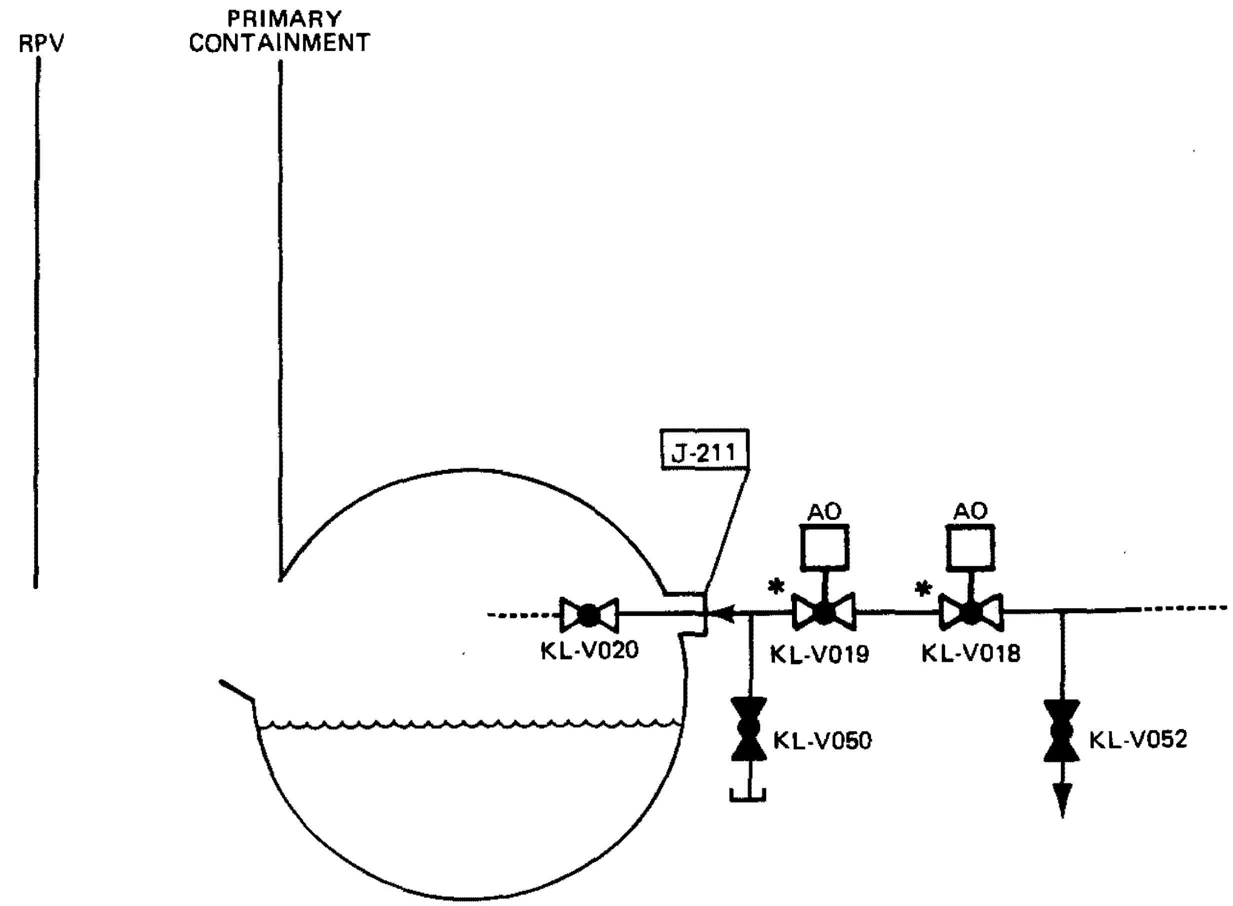
PUBLIC SERVICE ELECTRIC AND GAS COMPANY
HOPE CREEK NUCLEAR GENERATING STATION

TYPICAL OF LINES FOR SENSING SUPPRESSION CHAMBER PRESSURE

UPDATED FSAR

Sheet 43 of 49
FIGURE 6.2-27

*(SEE LEGEND)



DETAIL 44

REVISION 0
APRIL 11, 1988

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
HOPE CREEK NUCLEAR GENERATING STATION

INSTRUMENT AIR TO SUPPRESSION CHAMBER LINES

UPDATED FSAR

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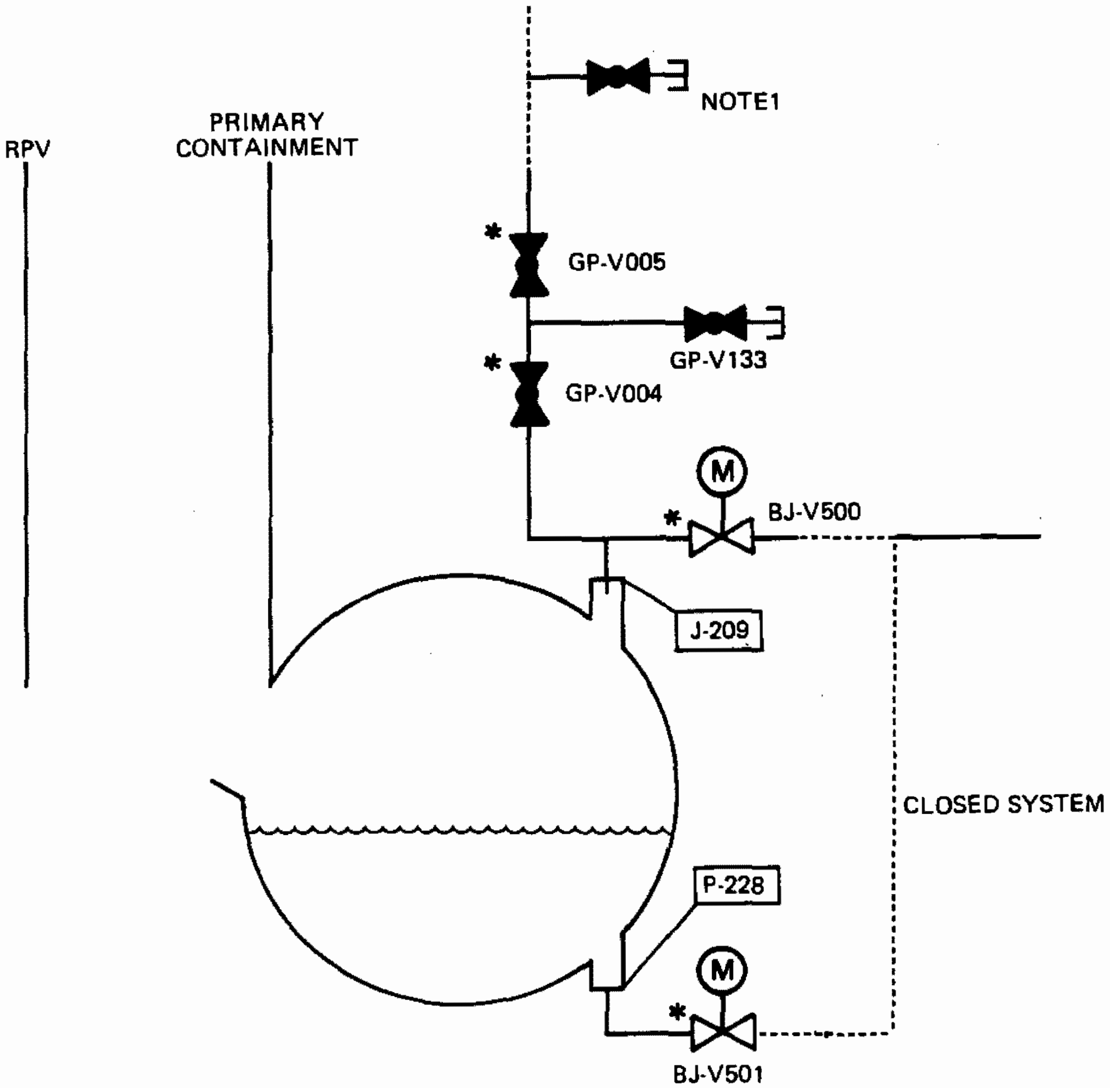
FIGURE 6.2-27

*(SEE LEGEND)



NOTE 1: UNNUMBERED VALVE

DETAIL 45

REVISION 0
APRIL 11, 1988

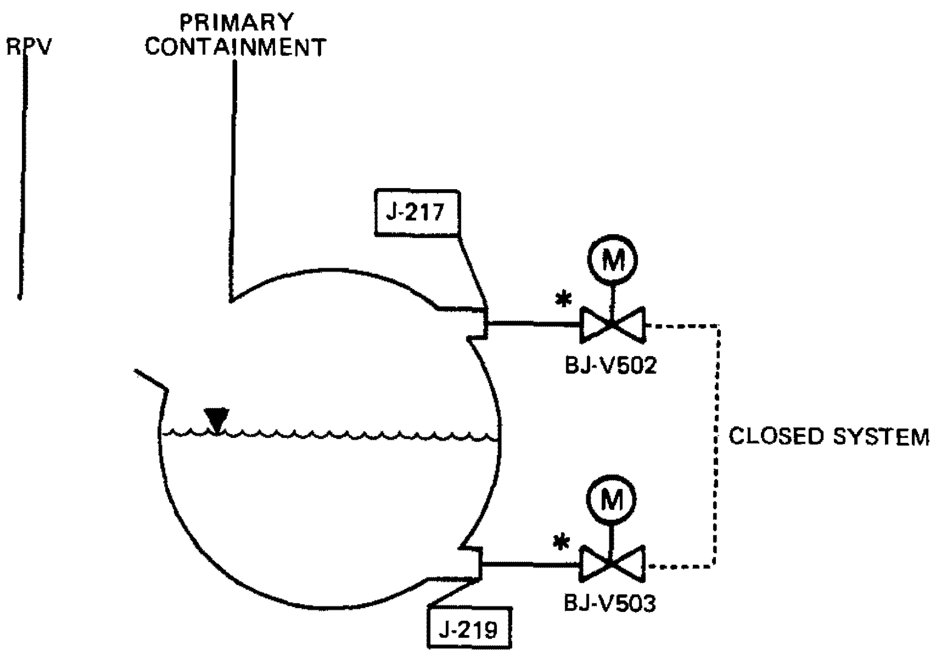
PUBLIC SERVICE ELECTRIC AND GAS COMPANY
HOPE CREEK NUCLEAR GENERATING STATION

SUPPRESSION POOL LEVEL LINE

UPDATED FSAR

Sheet 45 of 49
FIGURE 6.2-27

*(SEE LEGEND)



DETAIL 46

REVISION 0
APRIL 11, 1988

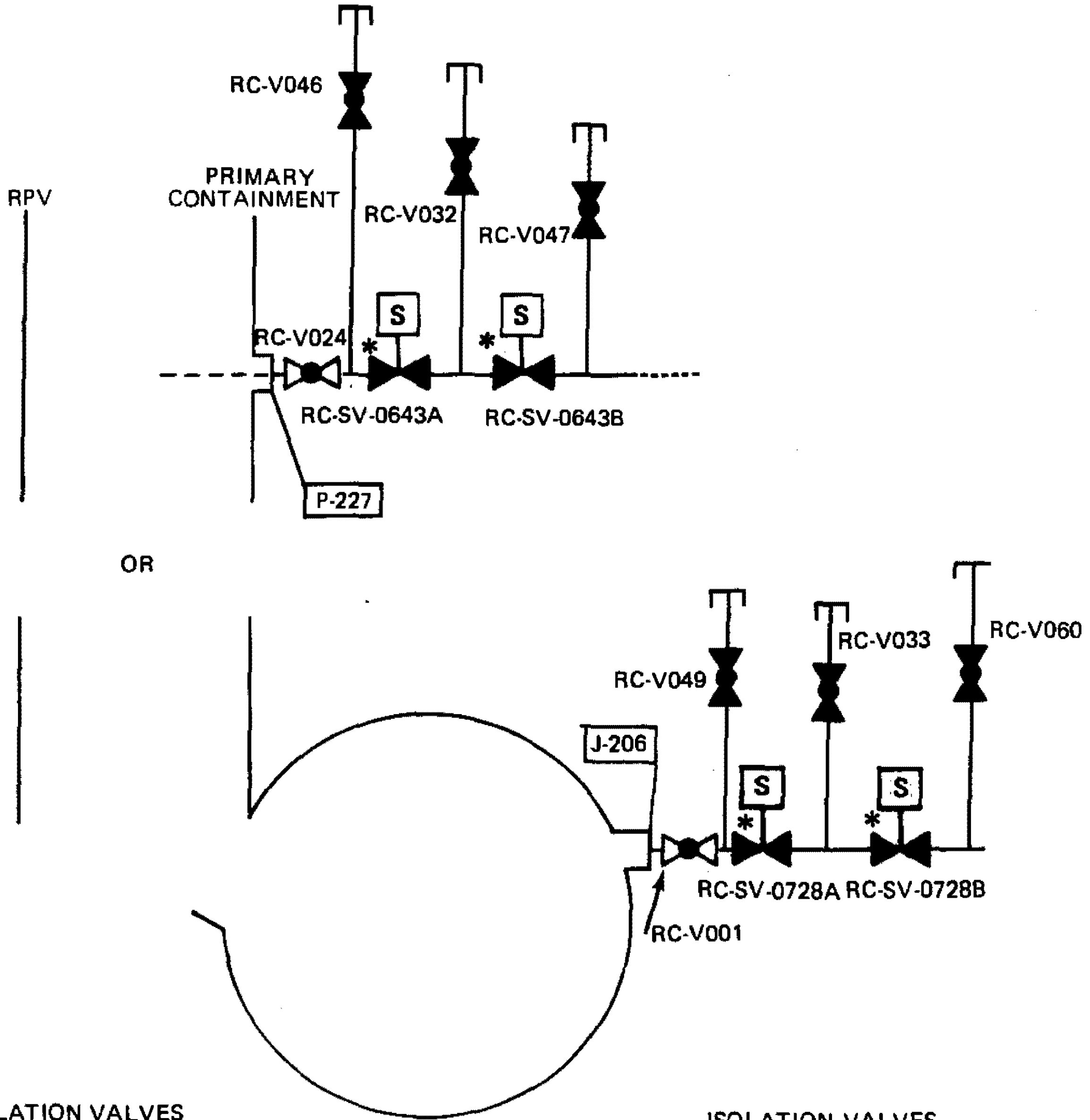
PUBLIC SERVICE ELECTRIC AND GAS COMPANY
HOPE CREEK NUCLEAR GENERATING STATION

TYPICAL OF INSTRUMENT
LINES FOR SENSING
SUPPRESSION POOL LEVEL

UPDATED FSAR

Sheet 46 of 49
FIGURE 6.2-27

*(SEE LEGEND)



ISOLATION VALVES

P-227	RC-SV-0643A	RC-SV-0643B
J-7E	RC-SV-0730A	RC-SV-0730B
J-10E	RC-SV-0731A	RC-SV-0731B

DETAIL 47

ISOLATION VALVES

J-206	RC-SV-0728A	RC-SV-0728B
J-220	RC-SV-0707A	RC-SV-0707B
J-221	RC-SV-0729A	RC-SV-0729B

TEST VALVES

P-227	RC-V046	RC-V032	RC-V047	RC-V024
J-7E	RC-V055	RC-V036	RC-V056	RC-V004
J-10E	RC-V057	RC-V037	RC-V058	RC-V005

TEST VALVES

J-206	RC-V049	RC-V033	RC-V050	RC-V001
J-220	RC-V051	RC-V034	RC-V052	RC-V002
J-221	RC-V053	RC-V035	RC-V054	RC-V003

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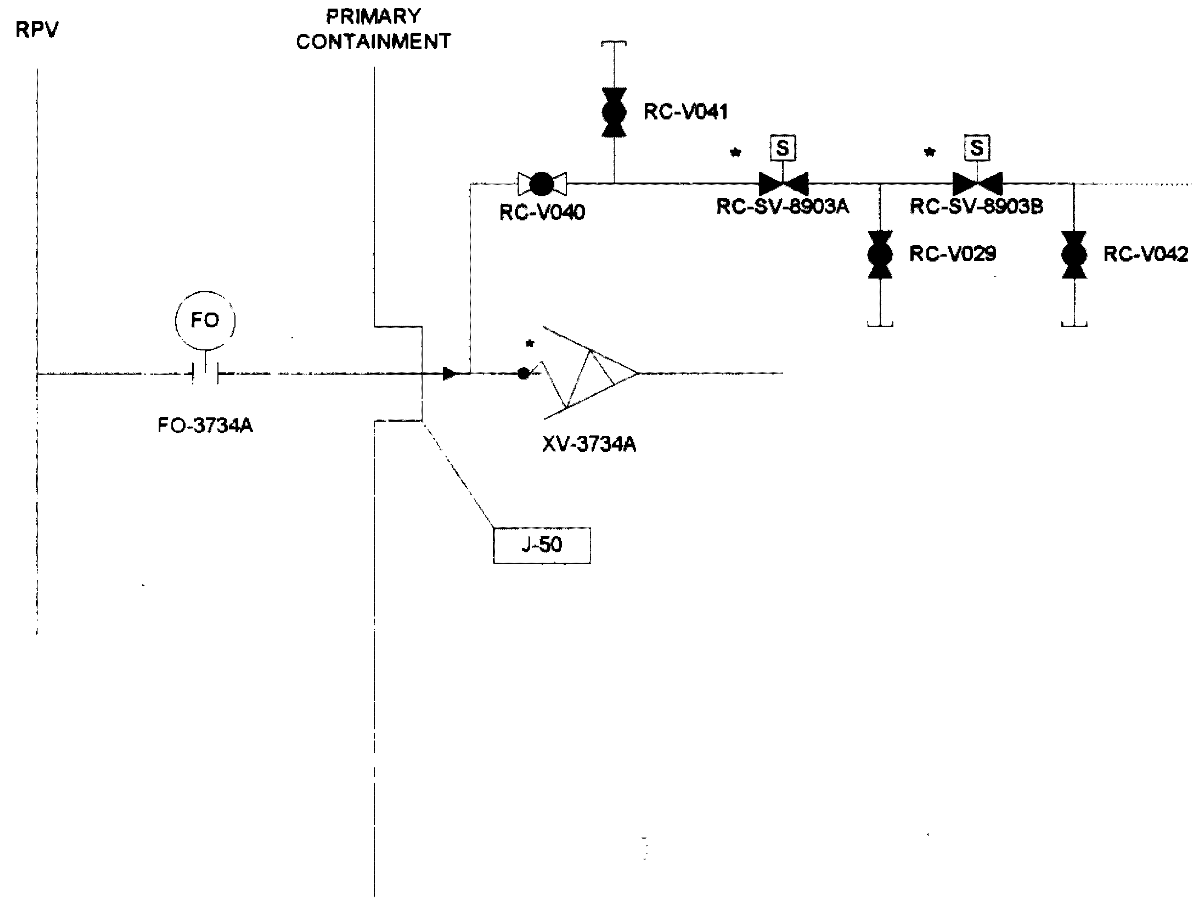
PUBLIC SERVICE ELECTRIC AND GAS COMPANY
HOPE CREEK NUCLEAR GENERATING STATION

POST-ACCIDENT SAMPLING

UPDATED FSAR

Sheet 47 of 49
FIGURE 6.2-27



DETAIL 48

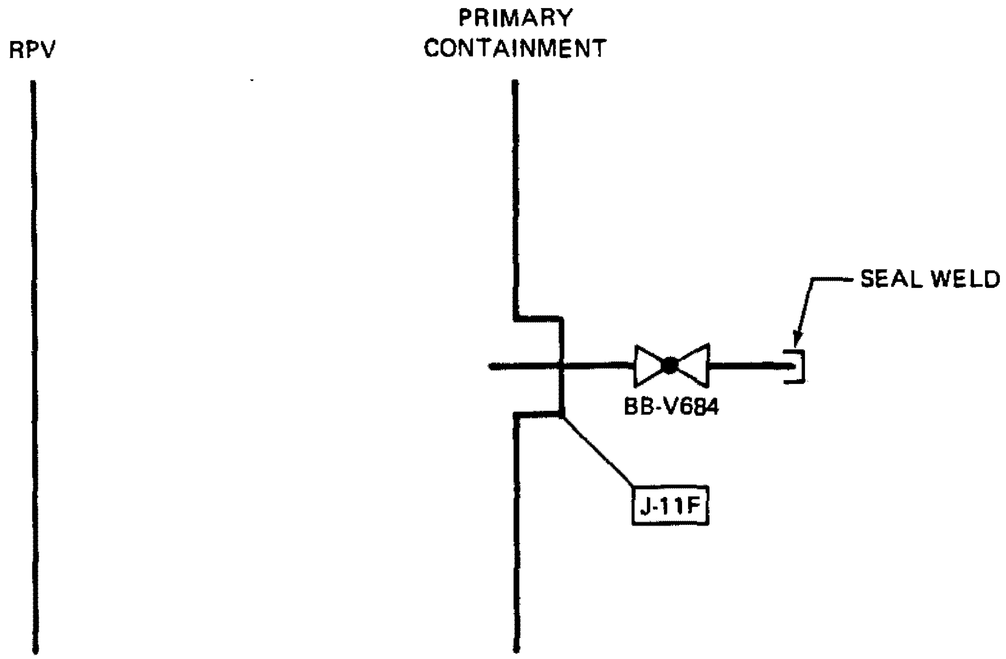
*+(SEE LEGEND)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
HOPE CREEK NUCLEAR GENERATING STATION

POST-ACCIDENT LIQUID SAMPLING AND REACTOR INSTRUMENTATION

Updated FSAR
Revision 9, June 13, 1998

Sheet 48 of 49
Figure 6.2-27



DETAIL 48A

PENETRATION	CONTAINMENT BOUNDRY VALVE
J-11F	BB-V684
J-19F	BB-V685
J-20D	BB-V687
J-24D	BB-V686
J-27C	QM-V002
J-27F	QM-V001
J-37F	BB-V683
J-45	BB-V688
J-46	BB-V689
J-48	BB-V691
J-49	BB-V690

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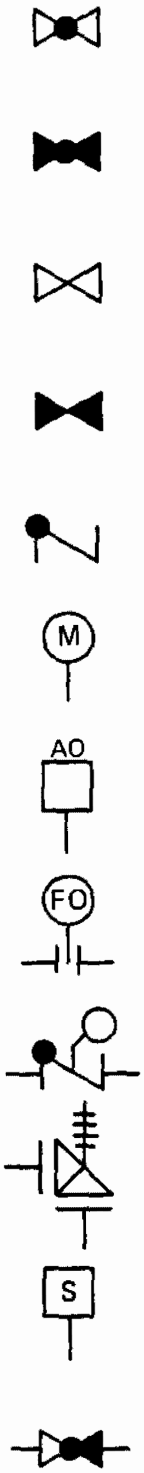
APRIL 11, 1988

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
HOPE CREEK NUCLEAR GENERATING STATION

SPARE INSTRUMENT LINES

UPDATED FSAR

Sheet 49 of 49
FIGURE 6.2-27



– NORMAL OPEN GLOBE VALVE

– NORMAL CLOSED GLOBE VALVE

– NORMAL OPEN GATE VALVE

– NORMAL CLOSED GATE VALVE

– CHECK VALVE

– MOTOR OPERATOR

– AIR OPERATOR

– RESTRICTION ORIFICE

– CHECK VALVE (WITH HAND OPERATOR)

– RELIEF VALVE

– SOLENOID OPERATOR

– STOP-CHECK VALVE

REVISION 0
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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
HOPE CREEK NUCLEAR GENERATING STATION

LEGEND

UPDATED FSAR

Sheet 1 of 2
FIGURE 6.2-28

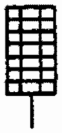
 – EXPLOSIVE VALVES

+ – NOT A CONTAINMENT ISOLATION VALVE

* – INDICATES CONTAINMENT ISOLATION VALVE

 – SPECTACLE FLANGE

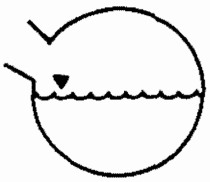
 – BALL VALVE

 – SCREEN

 – CHECK VALVE WITH MANUAL LEVER

 – SPRAY NOZZLE

 – EXCESS FLOW CHECK VALVE

 – SUPPRESSION CHAMBER

 – UNVALVED TEST CONNECTION

 – DRAINPOT

Revision 8
September 25, 1996

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
HOPE CREEK NUCLEAR GENERATING STATION

LEGEND

UPDATED FSAR

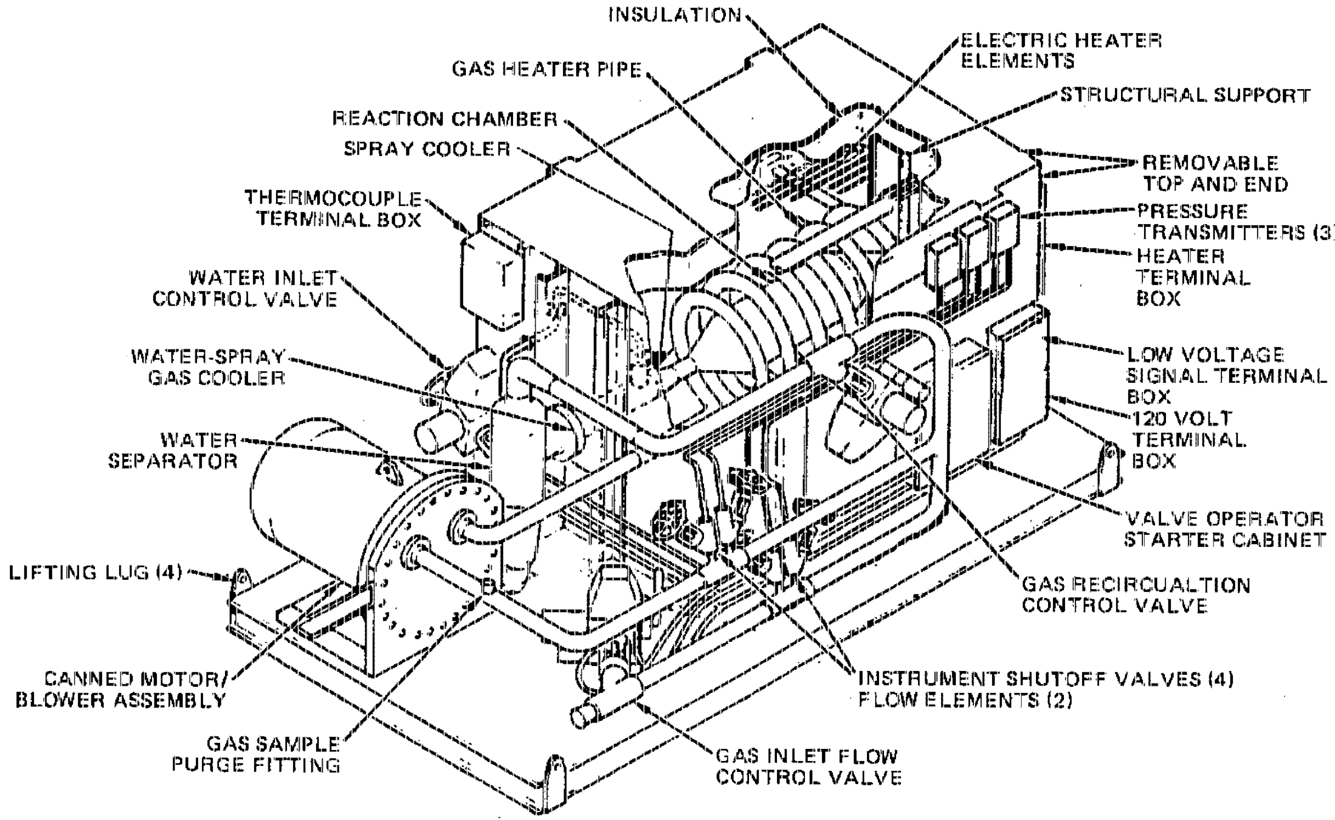
Sheet 2 of 2
FIGURE 6.2-28

Figure F6.2-29 intentionally deleted.

Refer to Plant Drawing M-57-1 in DCRMS

Figure F6.2-30 intentionally deleted.

Refer to Plant Drawing M-58-1 in DCRMS

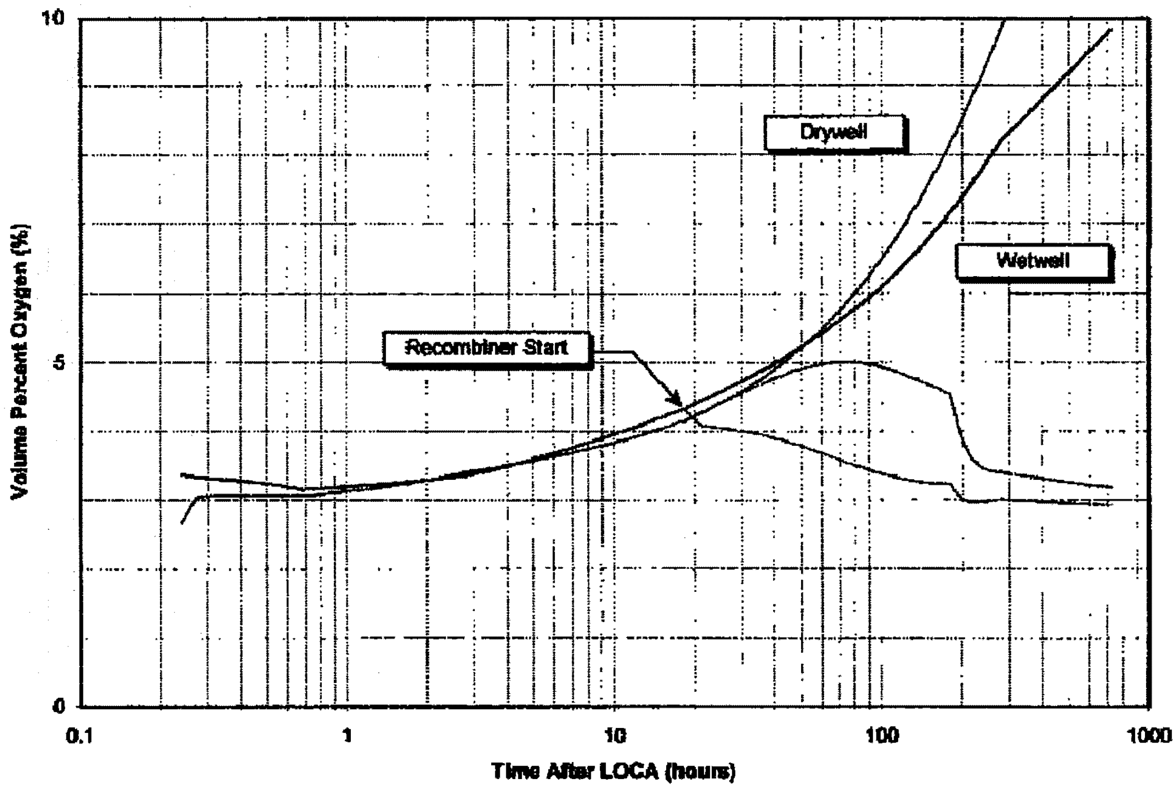


REVISION 0
APRIL 11, 1988

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
HOPE CREEK NUCLEAR GENERATING STATION

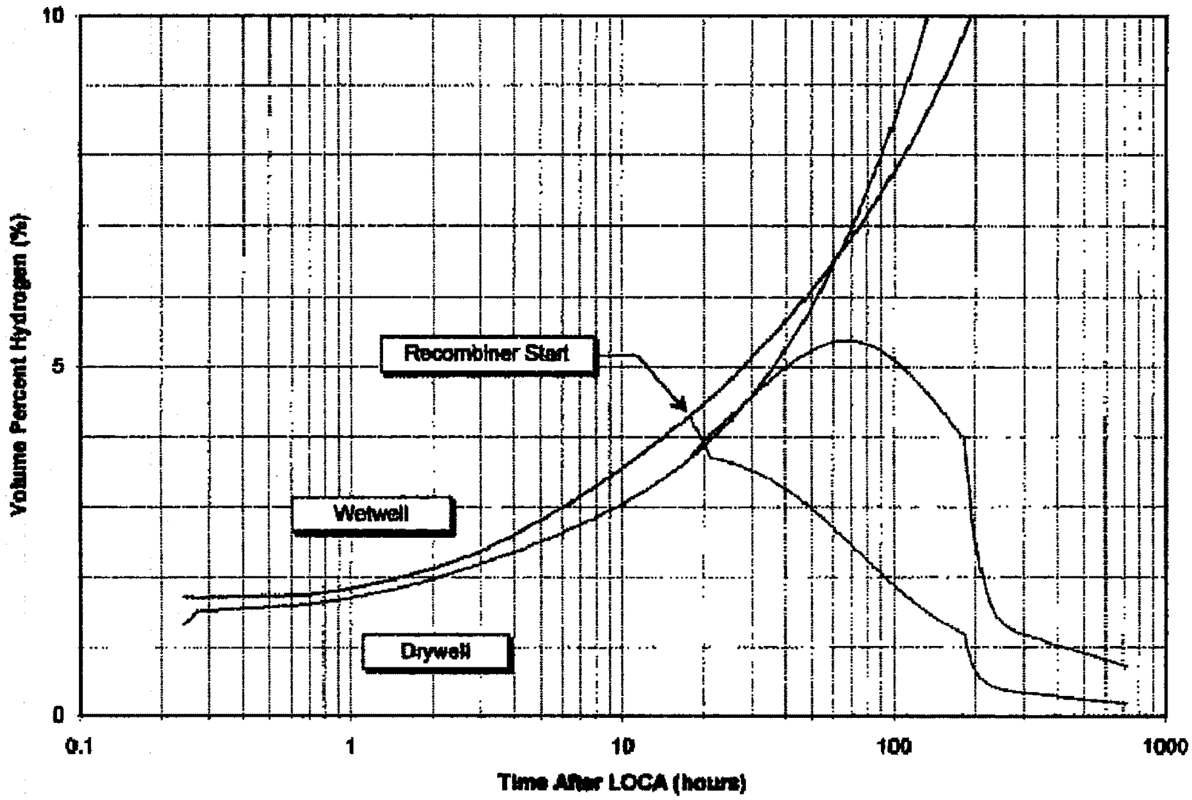
CONTAINMENT HYDROGEN
RECOMBINER SKID,
CUTAWAY VIEW

UPDATED FSAR FIGURE 6.2-31



Revision 17, June 23, 2009

PSEG Nuclear, LLC HOPE CREEK NUCLEAR GENERATING STATION	Hope Creek Nuclear Generating Station CONTROLLED AND UNCONTROLLED OXYGEN CONCENTRATIONS
	Updated FSAR — Figure 6.2-32



Revision 17, June 23, 2009

PSEG Nuclear, LLC HOPE CREEK NUCLEAR GENERATING STATION	Hope Creek Nuclear Generating Station CONTROLLED AND UNCONTROLLED HYDROGEN CONCENTRATIONS
	Updated FSAR — Figure 6.2-33

THIS FIGURE DELETED

Revision 17, June 23, 2009

PSEG Nuclear, LLC HOPE CREEK NUCLEAR GENERATING STATION	Hope Creek Nuclear Generating Station SUPPRESSION CHAMBER GAS CONCENTRATIONS
	Updated FSAR Figure 6.2-34

THIS FIGURE DELETED

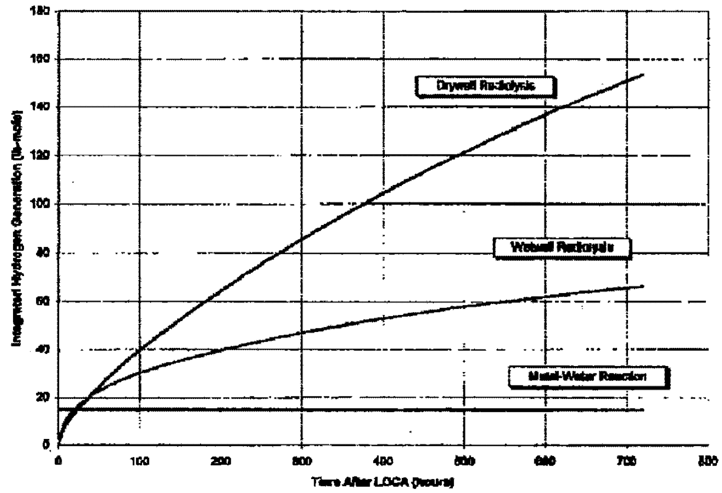
Revision 17, June 23, 2009

PSEG Nuclear, LLC HOPE CREEK NUCLEAR GENERATING STATION	Hope Creek Nuclear Generating Station 180 - DAY SUPPRESSION CHAMBER GAS CONCENTRATIONS
	Updated FSAR Figure 6.2-35

THIS FIGURE DELETED

Revision 17, June 23, 2009

PSEG Nuclear, LLC HOPE CREEK NUCLEAR GENERATING STATION	Hope Creek Nuclear Generating Station LONG TERM OXYGEN GENERATION - PRIMARY CONTAINMENT
	Updated FSAR — Figure 6.2-36



Revision 17, June 23, 2009

PSEG Nuclear, LLC HOPE CREEK NUCLEAR GENERATING STATION	Hope Creek Nuclear Generating Station LONG TERM HYDROGEN GENERATION PRIMARY CONTAINMENT
	Updated FSAR Figure 6.2-37

THIS FIGURE DELETED

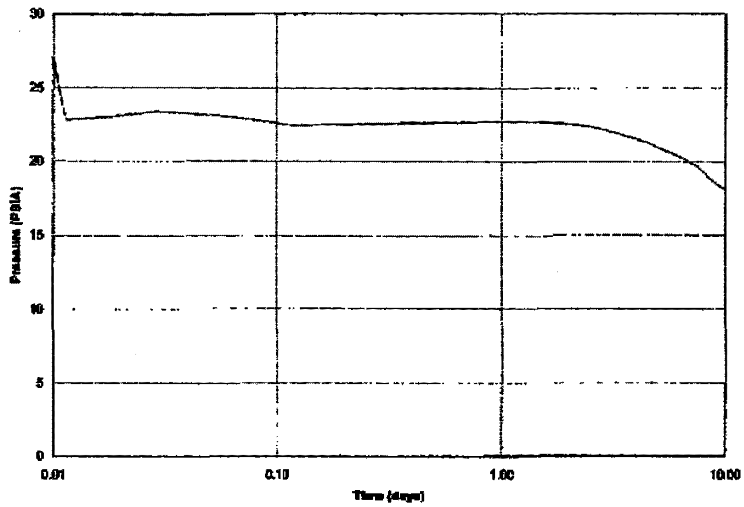
Revision 17, June 23, 2009

PSEG Nuclear, LLC HOPE CREEK NUCLEAR GENERATING STATION	Hope Creek Nuclear Generating Station ENERGY ABSORPTION RATE Updated FSAR — Figure 6.2-38

THIS FIGURE DELETED

Revision 17, June 23, 2009

PSEG Nuclear, LLC HOPE CREEK NUCLEAR GENERATING STATION	Hope Creek Nuclear Generating Station LONG TERM CONTAINMENT PRESSURE
	Updated FSAR — Figure 6.2-39

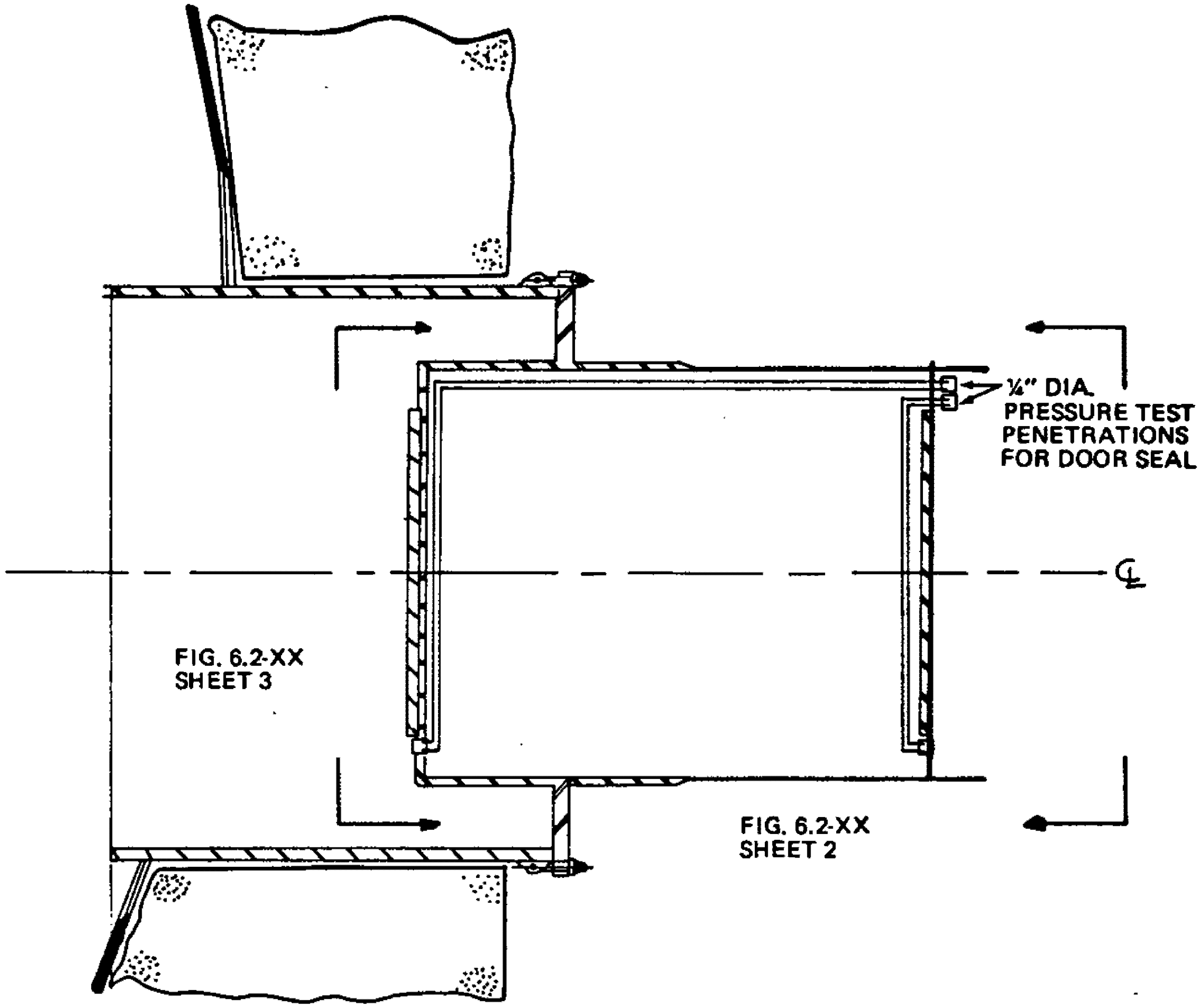


Revision 17, June 23, 2009

PSEG Nuclear, LLC HOPE CREEK NUCLEAR GENERATING STATION	Hope Creek Nucleor Generoling Stolion DRYWELL PRESSURE Updoled FSAR Figure 6.2-40

Figure F6.2-41 intentionally deleted.

Refer to Plant Drawing M-60-1 in DCRMS



PLAN VIEW OF PERSONNEL LOCK

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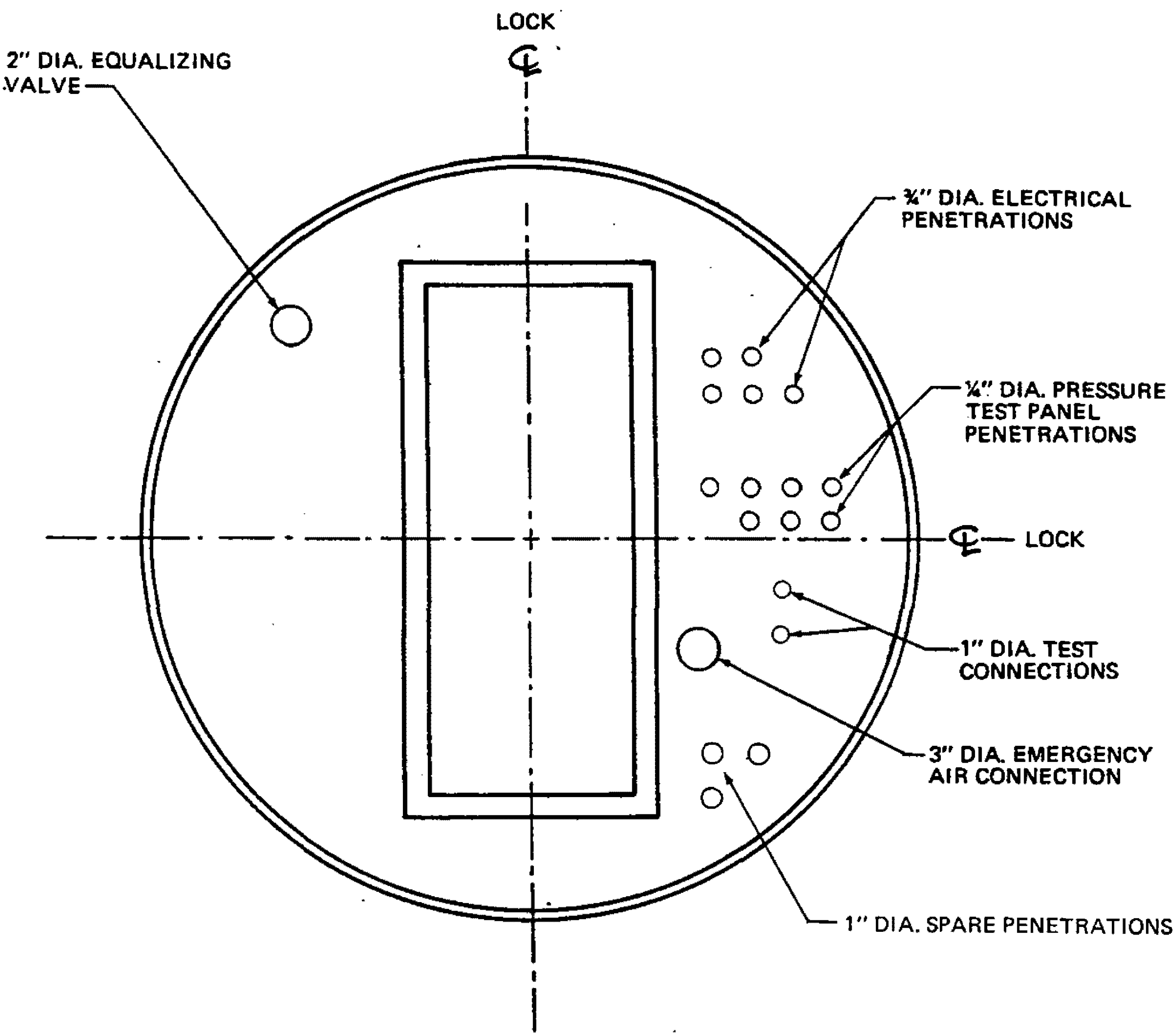
APRIL 11, 1988

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
HOPE CREEK NUCLEAR GENERATING STATION

CONTAINMENT PERSONNEL
LOCK DOOR PENETRATIONS

UPDATED FSAR

Sheet 1 of 3
FIGURE 6.2-42



ELEVATION VIEW OF ATMOSPHERIC
BULKHEAD FROM A ATMOSPHERE SIDE

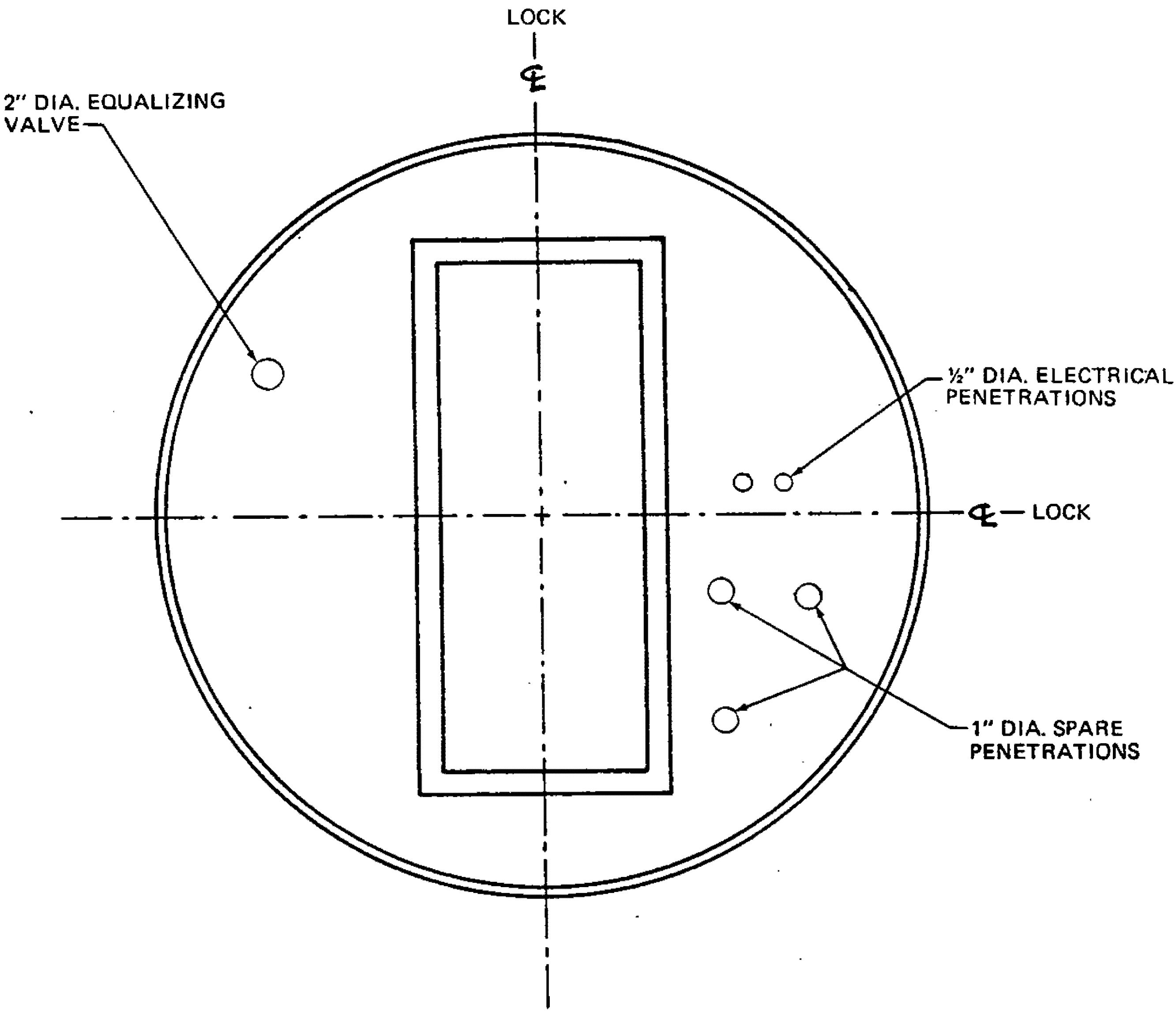
REVISION 0
APRIL 11, 1988

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
HOPE CREEK NUCLEAR GENERATING STATION

CONTAINMENT PERSONNEL
LOCK PENETRATIONS

UPDATED FSAR

Sheet 2 of 3
FIGURE 6.2-42



ELEVATION VIEW OF CONTAINMENT
BULKHEAD FROM INSIDE AIRLOCK

REVISION 0
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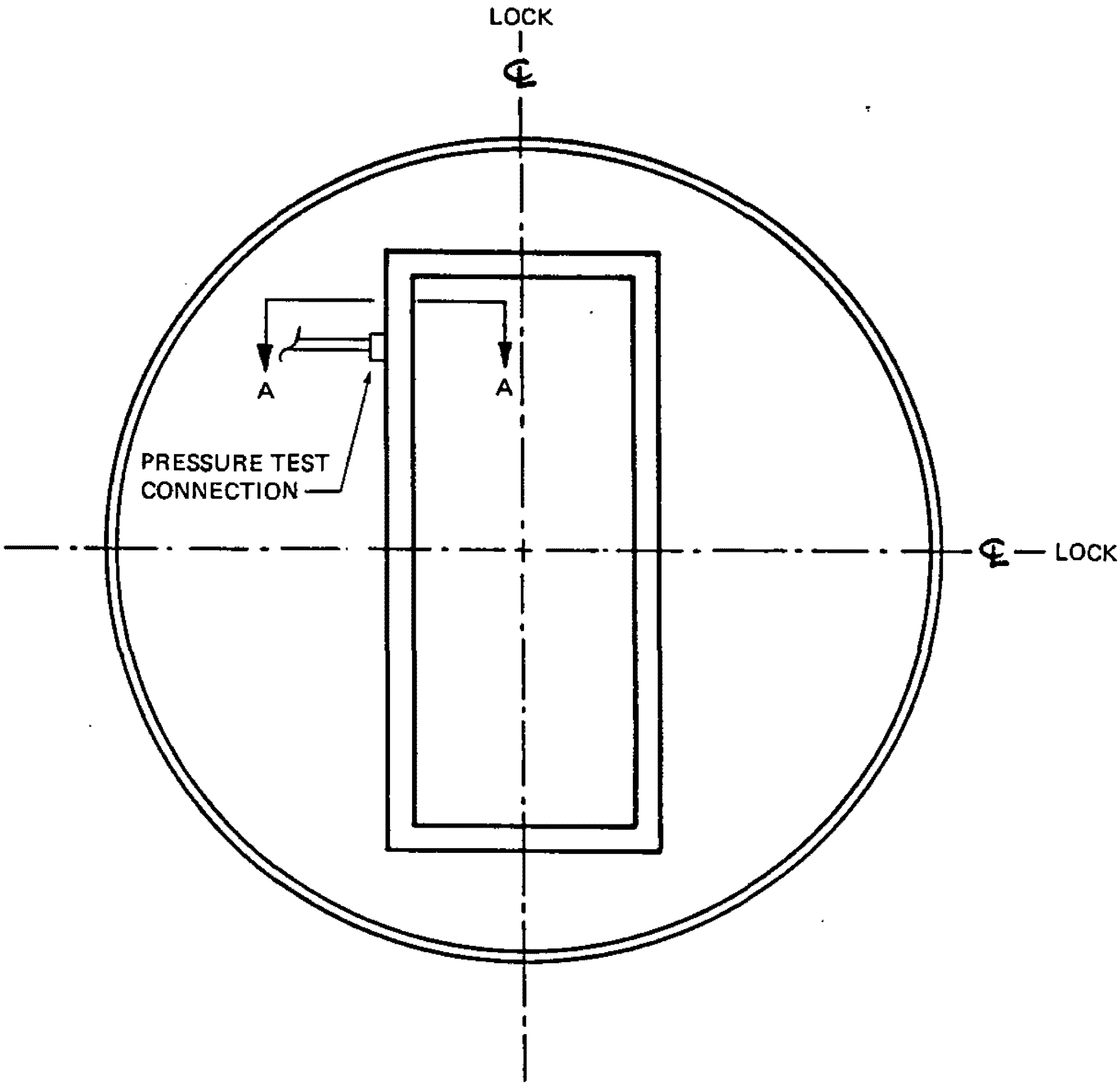
PUBLIC SERVICE ELECTRIC AND GAS COMPANY
HOPE CREEK NUCLEAR GENERATING STATION

CONTAINMENT PERSONNEL
LOCK PENETRATIONS

UPDATED FSAR

Sheet 3 of 3
FIGURE 6.2-42



ELEVATION VIEW OF TYPICAL INTERIOR
BULKHEAD FOR DOOR SEAL TESTING

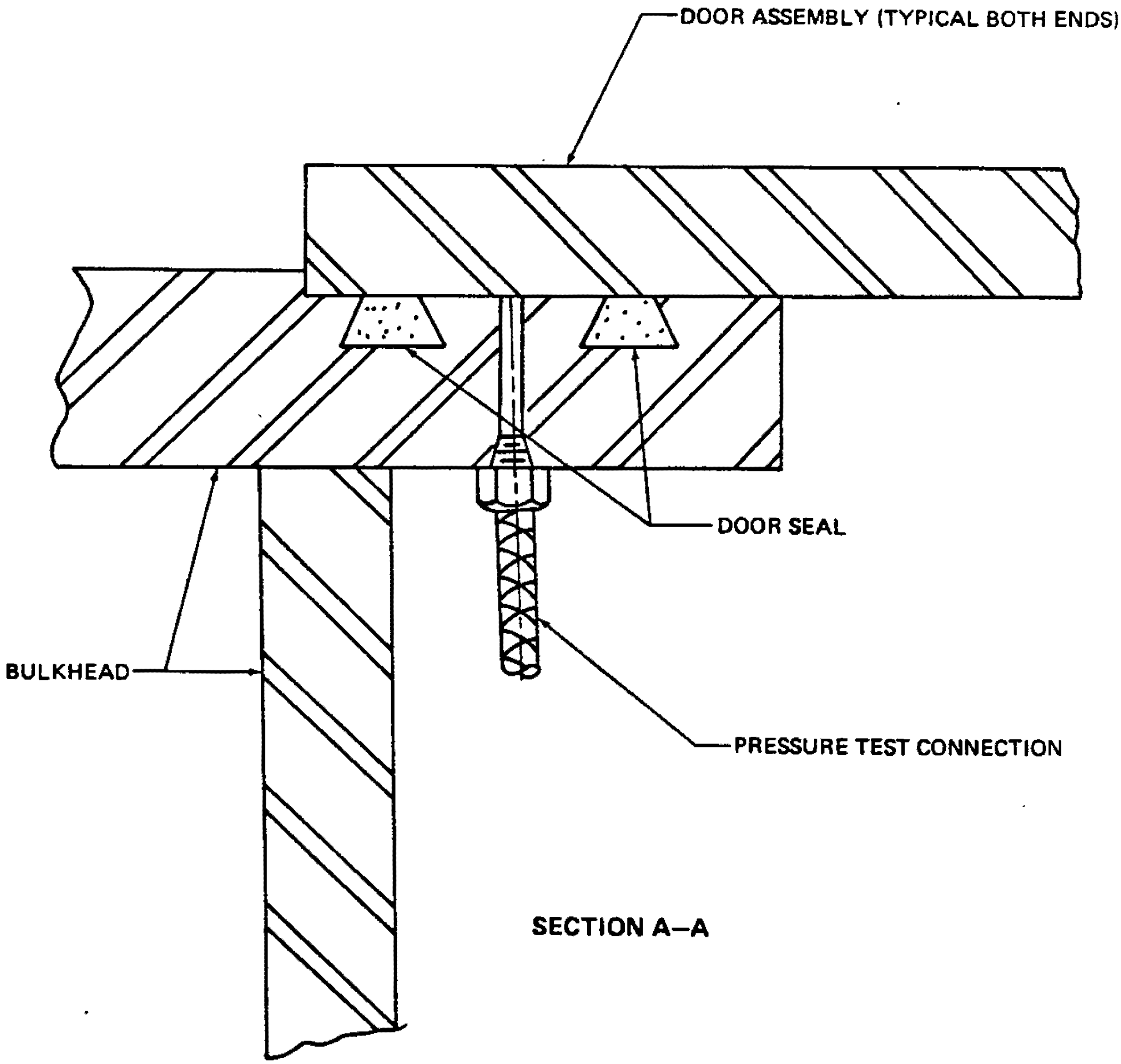
REVISION 0
APRIL 11, 1988

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
HOPE CREEK NUCLEAR GENERATING STATION

CONTAINMENT PERSONNEL
LOCK DOOR SEALS

UPDATED FSAR

Sheet 1 of 2
FIGURE 6.2-43



SECTION A–A

REVISION 0
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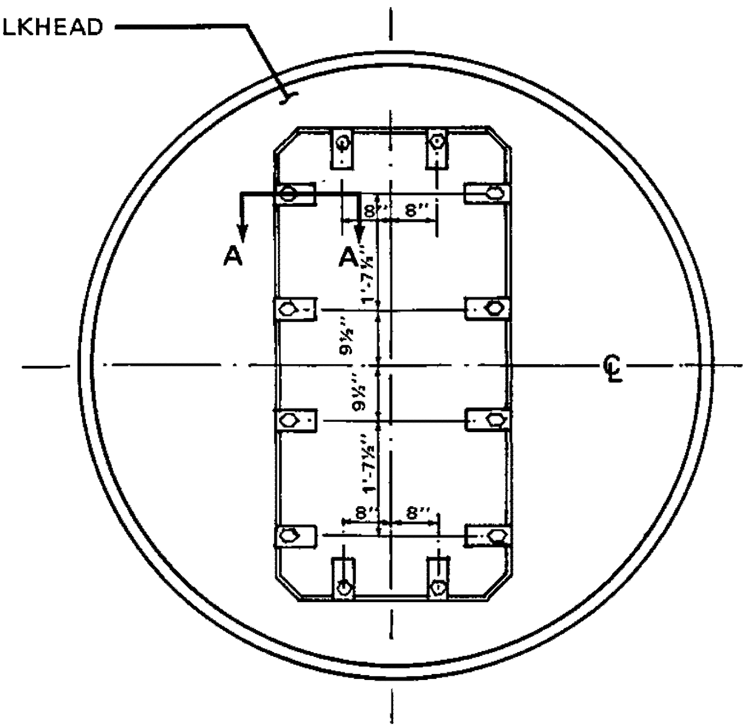
PUBLIC SERVICE ELECTRIC AND GAS COMPANY
HOPE CREEK NUCLEAR GENERATING STATION

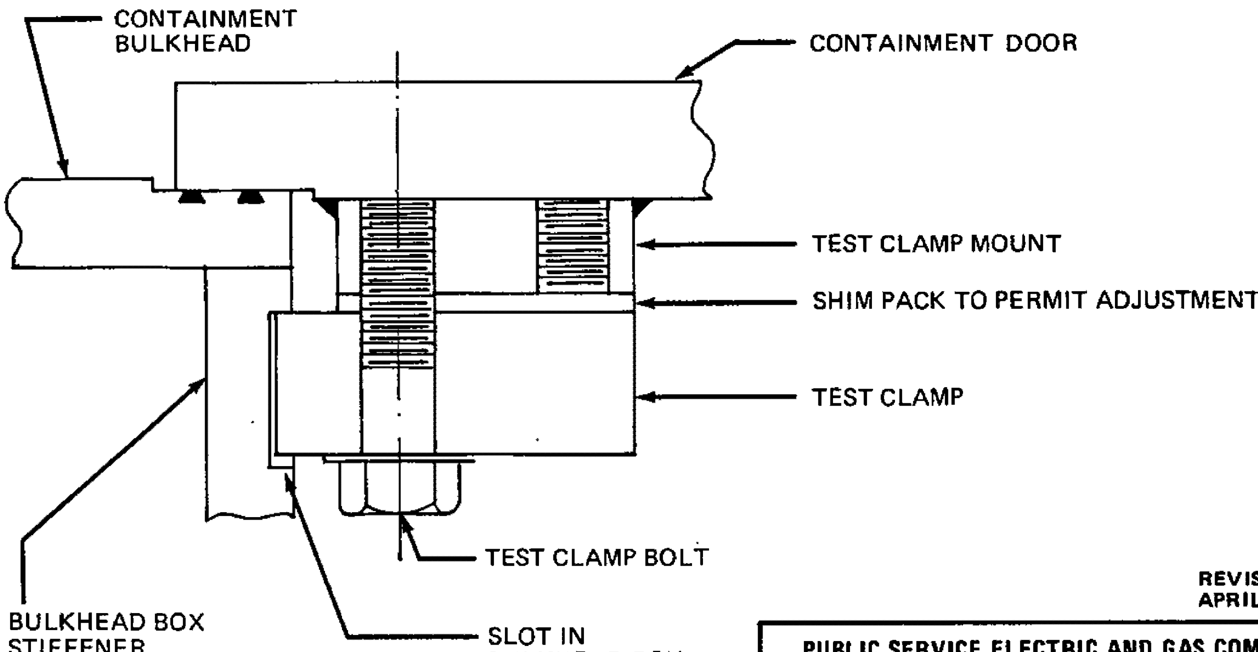
CONTAINMENT PERSONNEL
LOCK DOOR SEALS

UPDATED FSAR

Sheet 2 of 2
FIGURE 6.2-43



LOOKING AT INSIDE OF CONTAINMENT BULKHEAD: LOCATION OF DOOR TEST CLAMPS



SECTION A-A

REVISION 0
APRIL 11, 1988

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
HOPE CREEK NUCLEAR GENERATING STATION

CONTAINMENT PERSONNEL
LOCK INNER DOOR
TEST CLAMPS

UPDATED FSAR

FIGURE 6.2-44

Security Related Information
Table Withheld Under 10 CFR 2.390

- □ ISOLATION VALVE FOR PENETRATION WITH ONLY ONE ISOLATION VALVE
- △ ISOLATION VALVE FOR PENETRATION WITH REDUNDANT ISOLATION VALVES
- ○ SYSTEM ISOLATION VALVES ASSOCIATED WITH PRIMARY CONTAINMENT ISOLATION
- ++++ INDICATES THE EXTENDED CONTAINMENT BOUNDARY AFTER SINGLE FAILURE

PSEG NUCLEAR, L.L.C.
HOPE CREEK GENERATING STATION

RCIC AS AN EXTENDED
CONTAINMENT BOUNDARY

Updated FSAR Sheet 1 of 2
Revision 12, May 3, 2002 Fig.6.2-45

ISOLATION VALVE FOR PENETRATION WITH ONLY ONE ISOLATION VALVE

ISOLATION VALVE FOR PENETRATION WITH REDUNDANT ISOLATION VALVES

SYSTEM ISOLATION VALVES ASSOCIATED WITH PRIMARY CONTAINMENT ISOLATION

INDICATES THE EXTENDED CONTAINMENT BOUNDARY AFTER A SINGLE FAILURE

Security Related Information
Figure Withheld Under 10 CFR 2.390

THIS FIGURE IS BASED ON M-50-1, BUT HAS BEEN FROZEN AT REV 8

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
HOPE CREEK NUCLEAR GENERATING STATION

RCIC AS AN EXTENDED CONTAINMENT BOUNDARY

UPDATED FSAR

Sheet 2 of 2
FIGURE 6.2-45

Security Related Information
Figure Withheld Under 10 CFR
2.390

/EL TRANSMITTERS LT NOGIA & 61E ARE SHOWN ON CONDENSATE
ORAGE TANK P&ID (10855-M-08-0).

HE GE MPL NUMBER FOR THIS SYSTEM IS E-41

MPERATURE LEAK DETECTION FOR THIS SYSTEM IS SHOWN
PLANT LEAK DETECTION P&ID(SEE 10855-M-25)

HIS P&ID CONTAINS SYSTEMS OR PORTIONS OF SYSTEMS:
D- CONDENSATE
P- CONDENSATE STORAGE & TRANSFER
F- CONTROL ROD DRIVE HYDRAULIC SUPPLY
J- HIGH PRESSURE COOLANT INJECTION
D- HPCI TURBINE STEAM
B- MAIN STEAM
E- FEEDWATER
E- CORE SPRAY
P- PRIMARY CONTAINMENT LEAKAGE RATE TESTING

ETAILS OF TAPS ARE SHOWN ON VENDOR DRAWINGS, ISOMETRICS,
ND INSTALLATION DETAILS.
INES FD-1"-CCA-(010 THRU 013) HAVE CONDENSING CHAMBERS.
DELETED

SEE CIVIL DRAWING 10855-C-0931-0(Q) FOR THE PRESSURE
RATING MATERIAL & CODE CLASS OF PIPING INSIDE
THE SUPPRESSION CHAMBER.

EXCESS FLOW CHECK VALVE STATUS LIGHTS AND RESET
SWITCHES ARE LOCATED ON PANELS AS NOTED. ALARMS
AND COMPUTER READOUTS FOR ABNORMAL CON-
DITIONS WILL BE MONITORED FROM THE CONTROL
ROOM. SEE REF 4.

THE CONTENTS OF DCN #1 TO REVISION 1 OF THIS DOCUMENT
WERE INCORPORATED INTO REVISION 2 IN CONJUNCTION
WITH RELATED CHANGES TO SUPPRESSION CHAMBER
LEVEL INSTRUMENTATION AS NOTED IN ITEM 4 OF
THE LIST OF REVISIONS. REVISION 3 TO THIS DOCUMENT
IS INITIATED TO FORMALLY DOCUMENT INCORPORATION
OF THE CHANGE FOR ADMINISTRATIVE PURPOSES.
TAPS FOR FE 6813 ARE TO BE PROVIDED
FOR VERIFICATION OF HPCI FLOW SPLIT
DURING STARTUP. STARTUP INSTRUMENTATION WILL
BE REQUIRED TO VERIFY FLOW OF 2600 GPM ± 4%.

DELETED.

AFTER TESTING, REMOVE THE SPOOL PIECE AND INSTALL BLIND
FLANGES. (D,S)

□ ISOLATION VALVE FOR PROCESS PENETRATION WITH ONLY ONE ISOLATION VALVE

△ ISOLATION VALVE FOR PROCESS PENETRATION WITH REDUNDANT ISOLATION VALVES

○ SYSTEM ISOLATION VALVES ASSOCIATED WITH PRIMARY CONTAINMENT ISOLATION

INDICATES THE EXTENDED CONTAINMENT BOUNDARY AFTER A SINGLE FAILURE

PSEG NUCLEAR, L.L.C.
HOPE CREEK GENERATING STATION

HPCI AS AN EXTENDED
CONTAINMENT BOUNDARY

Updated FSAR Sheet 1 of 2
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LEGEND

□ ISOLATION VALVE FOR PROCESS PENETRATION WITH ONLY ONE ISOLATION VALVE

△ ISOLATION VALVE FOR PROCESS PENETRATION WITH REDUNDANT ISOLATION VALVES

○ SYSTEM ISOLATION VALVES ASSOCIATED WITH PRIMARY CONTAINMENT ISOLATION

┼┼┼┼┼ INDICATES THE EXTENDED CONTAINMENT BOUNDARY AFTER A SINGLE FAILURE

NOTES:

1. THE BJ MPL NUMBER FOR THIS SYSTEM IS E41
2. THE BAROMETRIC CONDENSER AND VACUUM TANK SHALL BE LOCATED SO THAT ITS WATER LEVEL IS BELOW THE BOTTOM OF THE TURBINE EXHAUST.
3. THIS P&ID CONTAINS SYSTEMS OR PORTIONS OF SYSTEMS:
   - BJ - HIGH PRESSURE COOLANT INJECTION
   - FD - HPCI TURBINE STEAM
   - DC - RHR
   - EG - SACS
4. PROVIDE BJ-4"-HBD-038 TO DRAIN AS DRIP PAN DRAIN FOR HPCI PUMP AND BOOSTER PUMP.
5. JOCKEY PUMP SEAL DRAIN WILL BE PIPED IN FIELD TO DRIP PAN.
6. CASING DRAIN ON PUMP OP217 SUCTION TO BE PLUGGED. CASING DRAIN ON OP208 DISCHARGE TO BE CAPPED.
7. DELETED
8. ROOT VALVES FOR NON Q PRESSURE GAGE IMPULSE LINES CONNECTED TO ASME SECTION III, CLASS 2 OR CLASS 3 PIPE ON THIS P&ID SHALL REMAIN IN THE OPEN POSITION ONLY WHILE BEING READ BY AN OPERATOR, OTHERWISE THESE VALVES SHALL REMAIN IN CLOSED POSITION.
9. LINE NUMBERS 1"-HBD-042, 1"-DBD-045, 3/4"-DBD-0[illegible], 3/4"-DBD-020 & 3/4"-DBD-021 ARE TO BE DESIGNED, FABRICATED AND INSTALLED TO Q, ASME III, CLASS 2 REQUIREMENTS. SINCE PIPE CAN'T BE HYDROTESTED THESE LINES ARE CLASSIFIED AS ANSI PIPING.
10. VIBRATION PROBES 1-FD-VE-4920-3 AND 1FD-VE-4920-4 ARE LOCATED ON THE INBOARD AND OUTBOARD BEARING CAPS ACCORDINGLY. KEYPHASOR (CONTINUED AT H,3)

THIS FIGURE IS BASED ON M-56-1, BUT HAS BEEN FROZEN AT REV 12

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
HOPE CREEK NUCLEAR GENERATING STATION

HPCI AS EXTENDED CONTAINMENT BOUNDARY

UPDATED FSAR

Sheet 2 of 2
FIGURE 6.2-46

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Figure Withheld Under 10 CFR 2.390

SYSTEM BC

REFERENCE DRAWINGS:

	BECHTEL NO.	GE NO.
1. RESIDUAL HEAT REMOVAL FCD	M-EH-1030-20	729E630AC
2. REACTOR PROTECTION SYS. IED	M-C71-1010-1	729E631AC
3. NUCLEAR BOILER SYS. FCD	M-B21-1030-21	761E507
4. LOGIC DIAGRAM	J-51-0	---------
5. PLANT LEAK DETECTION P&ID	M-25-1	---------
6. LOGIC DIAGRAM	J-104-0	---------
7. AUTO DEPRESS SYS. ED	M-B21-1060-63	791E483AC

TABLE I

RHR PUMP TEMPERATURE SENSORS (NOTE 18)

LOCATION	AP202 CMPTR PT ID	AP202 TE-	BP202 CMPTR PT ID	BP202 TE-	CP202 CMPTR PT ID	CP202 TE-	DP202 CMPTR PT ID	DP202 TE-
MOTOR UPPER GUIDE BEARING	A2543	4419A	A2544	4419B	A2545	4419C	A2546	4419D
MOTOR TRUST BEARING	A2547	4422A	A2548	4422B	A2549	4422C	A2550	4422D
MOTOR LOWER GUIDE BEARING	A2551	4423A	A2552	4423B	A2553	4423C	A2554	4423D
STATOR WINDING (1)	A2555	4448A	A2556	4448B	A2557	4448C	A2558	4448D
STATOR WINDING (2)	-----	4449A	-----	4449B	-----	4449C	-----	4449D
STATOR WINDING (3)	-----	4450A	-----	4450B	-----	4450C	-----	4450D
STATOR WINDING (4)	-----	4451A	-----	4451B	-----	4451C	-----	4451D
STATOR WINDING (5)	-----	4452A	-----	4452B	-----	4452C	-----	4452D
STATOR WINDING (6)	-----	4453A	-----	4453B	-----	4453C	-----	4453D

NOTES:

. THE G.E HPL NUMBER FOR THIS SYSTEM IS E-11.
. TEMPERATURE LEAK DETECTION IS SHOWN ON P&ID, M-25.
. TEMPERATURE ELEMENTS N035A&B ARE SHOWN ON RACS P&ID, M-13.
. DELETED
. CHEMICAL CLEANING CONNECTIONS TO BE ADDED LATER AS NECESSARY
. PROVISIONS SHALL BE MADE TO TRANSFER CONTROL FROM THE CONTROL ROOM TO THE REMOTE SHUTDOWN PANEL (C399).
. THIS P&ID CONTAINS SYSTEMS OR PORTIONS OF SYSTEMS:
AB-MAIN STEAM
AP-CONDENSATE STORAGE & TRANSFER
BC-RESIDUAL HEAT REMOVAL
BD-REACTOR CORE ISOLATION COOLING
EA-STATION SERVICE WATER
EC-FUEL POOL COOLING & CLEANUP
FD- HPCI TURBINE STEAM
RC-PROCESS SAMPLING
. A COMMON SUMMARY ALARM IS USED BY ALL OF THE ECCS FLOODING ALARM, SEE REFERENCES 4 & 5.
. FOLLOWING VALVES HAVE GE NUMBERS SHOWN IN PARENTHESES: V074 (F050G), V075 (F065B), V076 (F065D), V078 (F077), V101 (F065C), V102 (F065A), V133 (F060A).
0. SEE CIVIL DRAWING 10855-C-0931-0(0) FOR THE PRESSURE RATING, MATERIAL AND CODE CLASS OF THIS PIPING INSIDE THE PRIMARY CONTAINMENT.
1. EXCESS FLOW CHECK VALVE STATUS LIGHTS AND RESET SWITCHES ARE LOCATED ON LOCAL PANELS AS NOTED ALARMS AND COMPUTER READOUTS FOR ABNORMAL CONDITIONS WILL BE MONITORED FROM THE CONTROL ROOM SEE REFERENCE 6.
2. SEE CIVIL DRAWING 10855-C-0929-0(0) FOR THE PRESSURE RATING, MATERIAL AND CODE CLASS OF THIS PIPING INSIDE PRIMARY CONTAINMENT.
3. DELETED.
4. TE-4408 SPARE ELEMENT SHALL BE WIRED TO PANEL C399.
5. JOCKEY PUMP SEAL DRAIN WILL BE PIPED IN FIELD TO DRIP PAN.
6. DELETED
7. THE FOLLOWING VALVES CLOSE ON TRANSFER TO REMOTE SHUTDOWN PANEL, HV-F020B, HV-F016B, HV-F017B, HV-F027B, HV-F010B, HV-F021A, HV-F006A, RHR JOCKEY PUMP DP228 RUN ON TRANSFER TO RSP, HV-F004D, OPENS ON TRANSFER.
8. RHR PUMP TEMP SENSORS ARE THERMOCOUPLES PHYSICALLY ATTACHED TO THEIR APPLICABLE BEARING.
9. PIPE AND FITTINGS SHALL BE XXS.
0. THE TUBING FOR THE PRESSURE GAUGES SHOWN ON THIS P & ID HAVE BEEN INSTALLED PER ANSI B31.1 BUT WITH SEISMICALLY QUALIFIED SUPPORTS INSPECTED TO THE CRITERIA OF Q.
1. KEY LOCK LOCAL CONTROL SWITCHES FOR REMOTE SHUTDOWN SYSTEM ARE LOCATED IN THEIR RESPECTIVE MOV'S MCCS.
2. THE FOLLOWING VALVES ARE PERMANENTLY OUT OF SERVICE (ELECTRICAL POWER DISCONNECTED, AIR SUPPLY DISCONNECTED, MANUAL OVERRIDES CHAIN LOCKED IN CLOSED POSITION:
PV-F051 B, HV-F052 A & B, LY-F053 A & B,
HV-F011 A & B, HV-F026 A & B, HV-4420 A & B,
HV-4421 & HV-4428
3. WELD NECK BLIND FLANGES WELDED TO THE SEGMENTS OF THE PIPING THAT ARE OPEN TO THE PRIMARY CONTAINMENT ARE INSTALLED AT THE DISCHARGE OF RELIEF VALVES PSV-F056 A & B, PSV-F097 AND ALSO IN LINE AT THE LOCATIONS SHOWN ON THIS P&ID TO ISOLATE VALVES PSV-F101 A & B, PSV-F162 A & B, HV-4420 A & B, HV-4421 AND V288.
4. A 188# FLANGE IS REQUIRED FOR MATCH-UP WITH G.E SUPPLIED VALVE PSV-4431A, VALVE DISCHARGE PIPING REQUIREMENTS ARE DOWNRATED TO CLASS HBB RATING AS PERMITTED BY DELETIONS OF RHF; STEAM CONDENSING MODE.
5. FOR OPERATING ONE RHR PUMP IN THE FUEL POOL COOLING MODE, REPLACE FLOW ELEMENT FE-4462 A OR B WITH SPECIAL FLOW RESTRICTING ORIFICE DESIGNATED FOR THIS MODE OF OPERATION.
6. DEACTIVATED RELIEF VALVES PSV-F055 A & B AND F097 HAVE BLIND INLET NOZZLES, PREVENTING WATER FROM ENTERING THE VALVE BODIES.
7. VALVE 1-BC-HV-F024A IS INSTALLED WITH FLOW OVER THE SEAT. THIS VALVE IS MODIFIED TO ALLOW THROTTLING.
8. DELETED
9. ADDED 300# FLG. WITH A 1/4" NPT PRESSURE TAP, ON DISCHARGE SIDE OF PSV 4431 A & B WITH GASK-O-SEAL MARK I DOUBLE "O" RING INSERT, PARKER SEALS #868092, BETWEEN FLG'S
0. ADMINISTRATIVELY CONTROLLED KEYLOCK ISOLATION SWITCH BC-HS-11495. LOCATED AT M.C.C 10B242 CUBICLE 082 (MTD. ON DOOR)
1. 1" 300# ORIFICE FLANGE SA-105 NUC/CL.2 SCH.80 WITH GASK-O-SEAL, DOUBLE-O-RING INSERT PARKER P/N 868030
2. A WEEP HOLE HAS BEEN PROVIDED ON THE RPV SIDE OF THE VALVE DISCS TO PREVENT PRESSURE LOCKING.
3. WHEN THE RHR SYSTEM IS OPERATED IN PARALLEL WITH THE FPCC SYSTEM TO PROVIDE FUEL POOL COOLING DURING A FULL CORE UNLOAD, ONE RHR PUMP TAKES THE SUCTION EITHER FROM THE SKIMMER SURGE TANKS OR FROM THE REACTOR VESSEL VIA THE SHUTDOWN COOLING SUCTION PIPING, CIRCULATES THE WATER THROUGH ONE RHR HEAT EXCHANGER, AND RETURNS IT TO THE SPENT FUEL POOL VIA THE TWO RHR INTERTIE RETURN DIFFUSERS.
4. DELETED.
5. ALL PIPE WELDS FOR SPARED PENETRATION P10 SHALL BE CLASSED ASME HC.
6. MANUAL VALVES F050A, F060B & F077 HAVE THEIR HANDWHEELS REMOVED AND STORED OUTSIDE THE DRYWELL. HANDWHEELS ARE ON EL.102' IN THE NORTH EAST EQUIPMENT AND ACCESS AREA (RM. 4331) NEAR THE FIRE EXTINGUISHERS.
7. PY-F003A HAS BEEN REMOVED AND ALL INTERFACES DISCONNECTED.

□ ISOLATION VALVE FOR PROCESS PENETRATION WITH ONLY ONE ISOLATION VALVE

△ ISOLATION VALVE FOR PROCESS PENETRATION WITH ONLY ONE ISOLATION VALVES

SYSTEM ISOLATION VALVES ASSOCIATED WITH PRIMARY CONTAINMENT ISOLATION

INDICATES PORTIONS OF THE SYSTEM THAT ARE NOT PART OF THE EXTENDED CONTAINMENT BOUNDARY AFTER SINGLE FAILURE.

PEER REV

Ref. Dwg. M-51-1 sh.1

Rev. 37

PSEG NUCLEAR, LLC
HOPE CREEK GENERATING STATION

RHR AND CORE SPRAY AS EXTENDED CONTAINMENT BOUNDARY

Updated FSAR — Sheet 1 of 3
REVISION 22, MAY 9, 2017 — Fig. 6.2-47

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PSEG NUCLEAR, L.L.C.
HOPE CREEK GENERATING STATION

RHR AND CORE SPRAY AS EXTENDED CONTAINMENT BOUNDARY

Updated FSAR
Revision 22, MAY 9, 2017
Sheet 2 of 3
Fig.6.2-47

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Figure Withheld Under 10 CFR 2.390

PSEG NUCLEAR, L.L.C.
HOPE CREEK GENERATING STATION

RHR AND CORE SPRAY AS EXTENDED
CONTAINMENT BOUNDARY

Updated FSAR Sheet 3 of 3
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□ ISOLATION VALVE FOR PENETRATION WITH ONLY ONE ISOLATION VALVE

△ ISOLATION VALVE FOR PENETRATION WITH REDUNDANT ISOLATION VALVES

○ SYSTEM ISOLATION VALVES ASSOCIATED WITH PRIMARY CONTAINMENT ISOLATION

+++ INDICATES THE EXTENDED CONTAINMENT BOUNDARY AFTER A SINGLE FAILURE

Security Related Information Figure Withheld Under 10 CFR 2.390

THIS FIGURE IS BASED ON M-38-0, BUT HAS BEEN FROZEN AT REV 1

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EXTENDED CONTAINMENT BOUNDARY PASS AND CONTAINMENT HYDROGEN RECOMBINER SYSTEM

UPDATED FSAR

Sheet 1 of 2
FIGURE 6.2-48

ISOLATION VALVE FOR PROCESS PENETRATION WITH ONLY ONE ISOLATION VALVE

ISOLATION VALVE FOR PROCESS PENETRATION WITH REDUNDANT ISOLATION VALVES

SYSTEM ISOLATION VALVES ASSOCIATED WITH PRIMARY CONTAINMENT ISOLATION

INDICATES THE EXTENDED CONTAINMENT BOUNDARY AFTER A SINGLE FAILURE

Security Related Information
Figure Withheld Under 10 CFR 2.390

THIS FIGURE IS BASED ON M-58-1, BUT HAS BEEN FROZEN AT REV. 08

Rev. 08

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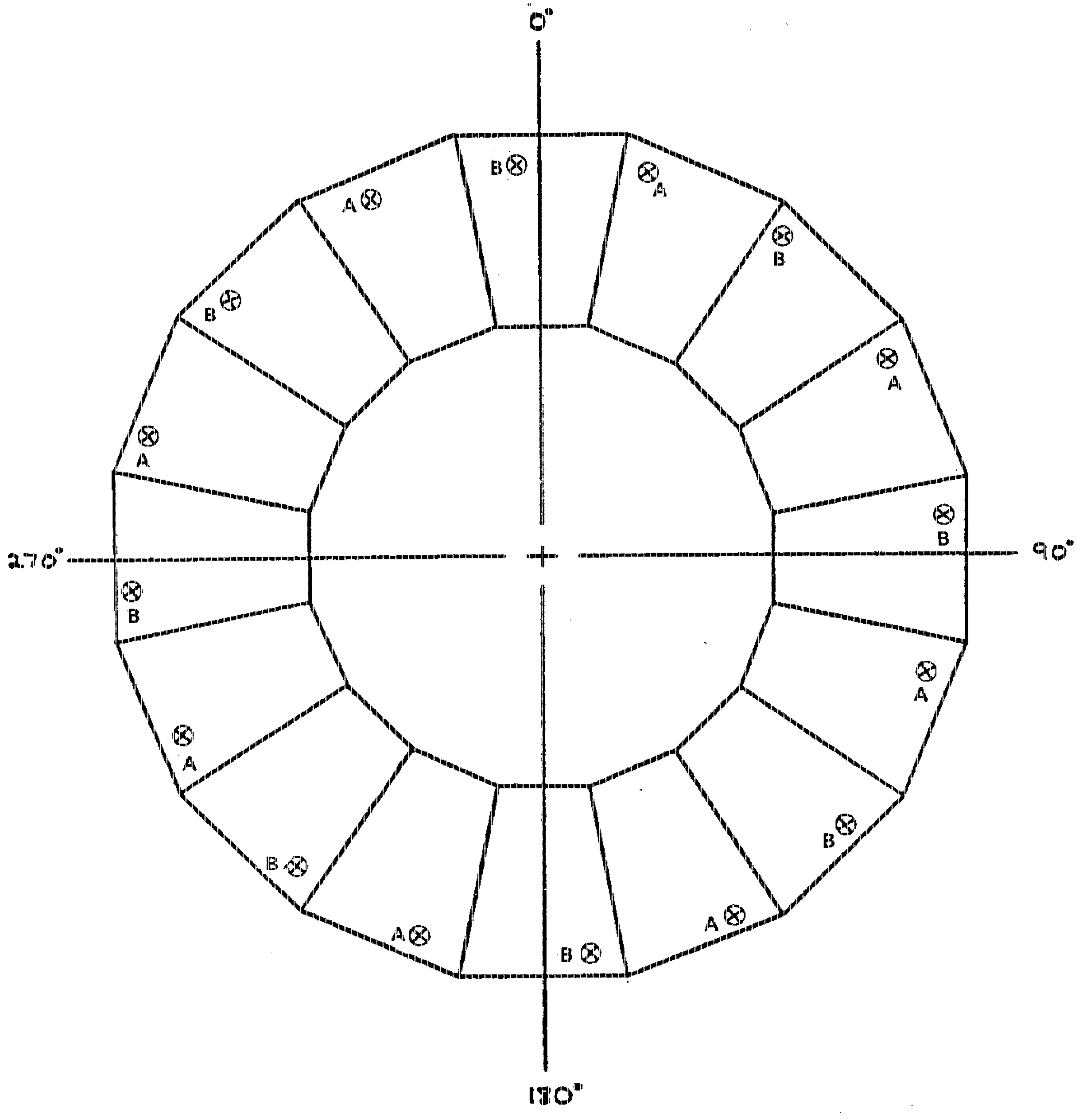
HOPE CREEK GENERATING STATION

EXTENDED CONTAINMENT BOUNDARY PASS AND CONTAINMENT HYDROGEN RECOMBINER SYSTEM

Updated FSAR Sheet 2 of 2
Revision 9, June 13, 1998 Fig. 6.2-48



NOTES:

⊗ SPTMS SENSOR

A, B SAFETY CHANNEL(POWER SUPPLY)

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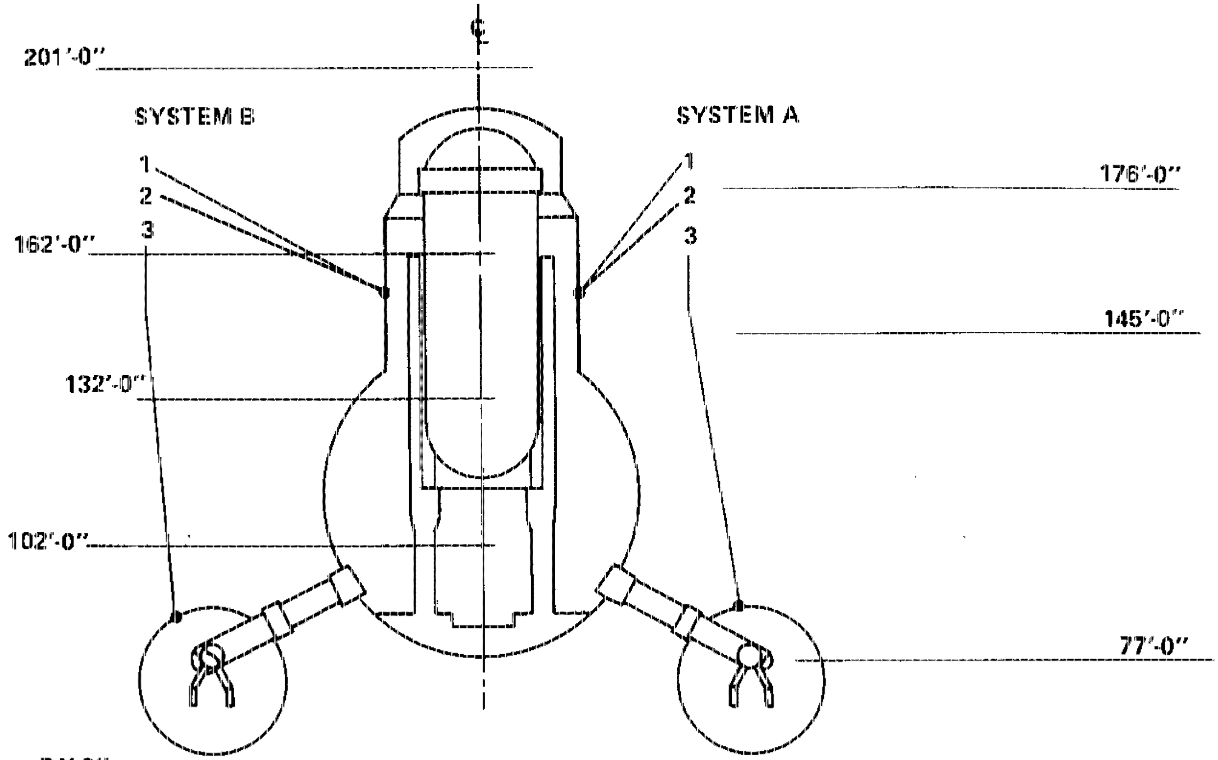
HOPE CREEK NUCLEAR GENERATING STATION

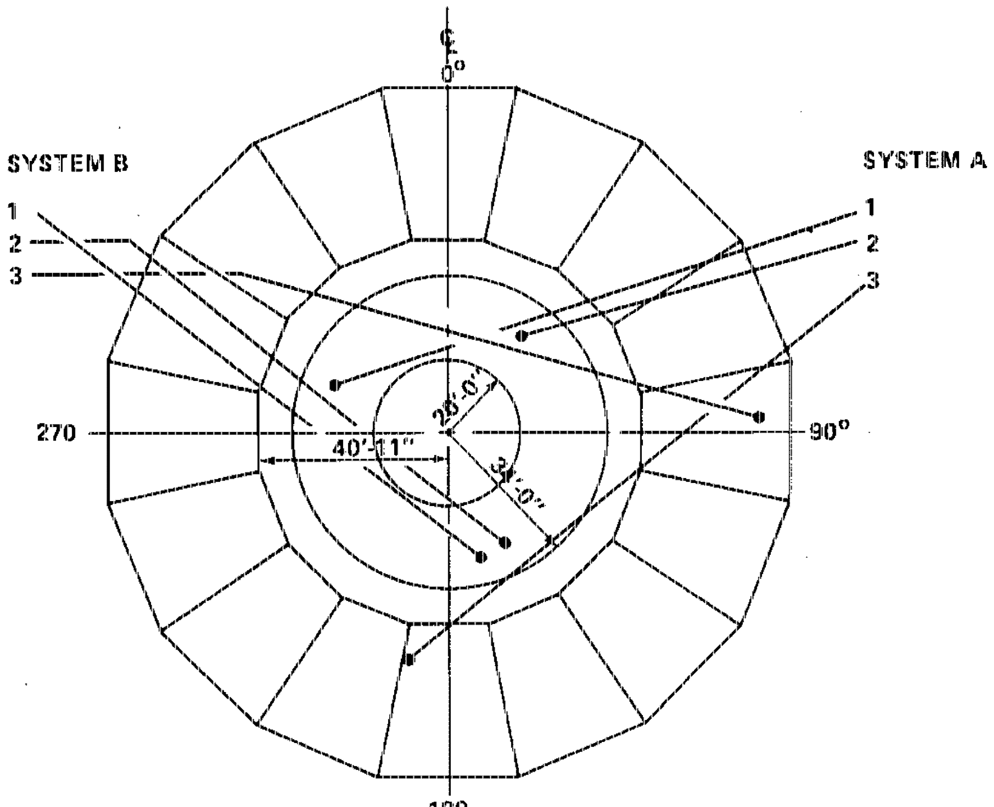
SUPPRESSION POOL
TEMPERATURE MONITOR SYSTEM
SENSOR ARRANGEMENT

UPDATED FSAR

FIGURE 6.2-49



ELEVATION



PLAN

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HOPE CREEK NUCLEAR GENERATING STATION

HYDROGEN-OXYGEN ANALYZER
SYSTEM SAMPLE LOCATION

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FIGURE 6.2-50

6.3 EMERGENCY CORE COOLING SYSTEM

6.3.1 Design Bases and Summary Description

This section provides the design bases for the Emergency Core Cooling System (ECCS) and a summary description of the several ECCS subsystems, as an introduction to the more detailed design descriptions provided in Section 6.3.2 and the performance evaluation provided in Section 6.3.3.

6.3.1.1 Design Bases

6.3.1.1.1 Performance and Functional Requirements

The ECCS is designed to provide protection against postulated loss-of-coolant accidents (LOCAs) caused by ruptures in reactor coolant pressure boundary (RCPB) piping. The functional requirements (e.g., coolant delivery rates) specified in Table 6.3-2 are such that the system performance under all LOCA conditions postulated in the design satisfies the requirements of Paragraph 50.46, Acceptance Criteria for Emergency Core Cooling Systems for Light Water Cooled Nuclear Power Reactors, of 10CFR50. These requirements are summarized in Section 6.3.3.2. The effects of known changes or errors on the calculated limiting peak cladding temperature transient applicable to HCGS have also been estimated in accordance with 10 CFR 50.46(a)(3)(i). In addition, the ECCS is designed to meet the following requirements:

1. Protection is provided for any RCPB line failure up to, and including, the guillotine failure of the largest line.

2. Two independent and diverse cooling methods (flooding and spraying) are provided to cool the reactor core.

3. One High Pressure Cooling System is provided which maintains the reactor vessel water level above the top of the core and prevents Automatic Depressurization System (ADS) actuation for breaks equivalent to a failure of a pipe less than 1 inch nominal diameter.

4. No operator action is required until 10 minutes after an accident, to allow for operator assessment and decision.

5. The ECCS is designed to satisfy all criteria specified in Section 6.3 for any normal mode of reactor operation.

6. Access to a sufficient water source, and the necessary piping, pumps, and other hardware are provided so that the primary containment and reactor core can be flooded for long term, post-LOCA core heat removal.

6.3.1.1.2 Reliability Requirements

The following reliability requirements apply:

1. The ECCS conforms to all licensing requirements and good design practices of isolation, separation, and common mode failure considerations.

2. The ECCS network has built-in redundancy so that adequate reactor core cooling can be provided, even in the event of specified failures. As a minimum, the following combination of equipment makes up the ECCS:

    a. One High Pressure Coolant Injection System (HPCI)

    b. Two core spray loops

    c. One Low Pressure Coolant Injection System (LPCI)

    d. One ADS

3. The ECCS is designed so that a single active or passive component failure cannot disable the ADS.

4. In the event of the failure of a pipe that is not part of the ECCS, no single active component failure in the ECCS

prevents automatic initiation and successful operation of less than one of the following combinations of ECCS equipment:

a. Three LPCI loops, one core spray loop, and the ADS and HPCI, i.e., single standby diesel generator (SDG) failure

b. Four LPCI loops, two core spray loops, and the ADS, i.e., HPCI failure.

5. In the event of the failure of a pipe that is part of the ECCS, no single active component failure in the ECCS prevents automatic initiation and successful operation of less than one of the following combinations of ECCS equipment:

   a. Three LPCI loops and the ADS, i.e., single SDG failure and core spray injection line failure

   b. Two LPCI loops, one core spray loop, and the ADS and HPCI, i.e., single SDG failure and LPCI injection line failure.

6. Long term (10 minutes after initiation signal) cooling requires the removal of reactor core decay heat via the Safety Auxiliaries Cooling System (SACS). In addition to the RCPB failure that initiated the loss of coolant event, the system can sustain one failure, either active or passive, and still have at least one low pressure ECCS injection loop (LPCI or core spray) operating for vessel makeup, and all required SACS water flow to the residual heat removal (RHR) heat exchanger operating for heat removal.

7. Offsite power is the preferred source for the ECCS network. However, onsite standby power is provided with sufficient redundancy and capacity so that all the above requirements are met, even if offsite power is not available.

8. The diesel load configuration is one RHR (LPCI) pump and one core spray pump connected to a single SDG (typical for four SDGs).

9. Systems that interface with, but are not part of, the ECCS are designed and operated such that failure(s) in the interfacing systems do not propagate to, and/or affect the performance of, the ECCS.

10. Non-Class 1E systems interfacing with the Class 1E buses are automatically shed from the Class 1E buses when a LOCA signal exists.

11. Each subsystem of the ECCS, including flow rate and sensing networks, is capable of being tested during shutdown. All active components are capable of being tested during plant operation, including logic required to automatically initiate component action.

12. Provisions for testing the ECCS network components (electronic, mechanical, hydraulic, and pneumatic, as applicable) are designed in such a manner that they are an integral and nonseparable part of the system.

6.3.1.1.3 ECCS Requirements for Protection from Physical Damage

The ECCS piping and components are protected against damage from the effects of movement, thermal stresses, a LOCA, and the safe shutdown earthquake (SSE).

The ECCS is protected against the effects of pipe whip, which might result from piping failures up to, and including, the design basis LOCA. This protection is provided by either spatial separation or pipe whip restraints. Either of these methods provides protection against damage to piping and components of the ECCS, which otherwise could reduce ECCS effectiveness to an unacceptable level.

For the purpose of mechanical separation, ECCS components are grouped into two divisions. The division A ECCS components include:

1. Core spray loop A

2. LPCI loops A and C

3. HPCI.

The division B ECCS components include:

1. Core spray loop B

2. LPCI loops B and D

3. ADS.

Each of the ECCS pumps and its associated components are located in individual compartments within the reactor building. This compartmentalization ensures that environmental disturbances, such as fire, pipe rupture, falling objects, etc, affecting one system do not affect the remaining systems. For ECCS mechanical components located outside the pump compartments, such as the outboard containment isolation valves, separation between the different divisions is provided by distance or by locating the components in different compartments.

Electrical separation is described in Sections 7.1 and 8.1.4.

6.3.1.1.4 ECCS Environmental Design Basis

Each subsystem of the ECCS injection network, except the HPCI system, has a safety-related injection/isolation testable check valve located in piping within the drywell. The HPCI system injects through the core spray and feedwater systems. However, the HPCI system has an isolation valve in the drywell portion of its steam supply piping. No portion of the ECCS piping is subject to drywell flooding (except during post-accident containment flooding), since water drains into the suppression chamber through the drywell to suppression chamber vent system. The safety-related valves within the drywell are qualified for the following environmental conditions:

1. Normal and upset plant operating ambient temperatures, relative humidities, and pressures, as shown in Reference 3.11-5.

2. Envelope of accident conditions for temperature, relative humidity, and pressure for various time periods following the accident, as shown in Reference 3.11-5.

3. Normal and envelope of accident radiation environment (gamma and neutron), as shown in Reference 3.11-5.

The portions of ECCS piping and equipment located outside the primary containment and within the Reactor Building are qualified for the following environmental conditions:

1. Normal and upset plant operating ambient temperatures, relative humidities, and pressures, as shown in Reference 3.11-5.

2. Envelope of accident conditions for temperature, relative humidity, and pressure for various time periods following the accident, as shown in Reference 3.11-5.

3. Normal and envelope of accident radiation environment (gamma and neutron), as shown in Reference 3.11-5.

6.3.1.2 Summary Descriptions of ECCS

The ECCS injection network consists of an HPCI system, a core spray system, and the LPCI mode of the RHR system. These systems are briefly described here as an introduction to the more detailed system design descriptions provided in Section 6.3.2. The ADS, which assists the ECCS injection network under certain conditions, is also briefly described. Boiling water reactors (BWRs) with similar ECCS designs are listed in Table 1.3-3.

6.3.1.2.1 High Pressure Coolant Injection

The HPCI system pumps water through one of the core spray spargers and one of the feedwater spargers. The primary purpose of HPCI is to maintain reactor vessel inventory after small breaks that do not depressurize the reactor vessel. The HPCI system is also used to maintain reactor vessel inventory following a reactor isolation and coincident failure of the non-ECCS Reactor Core Isolation Cooling (RCIC) System.

6.3.1.2.2 Automatic Depressurization System

The ADS uses a number of the reactor safety/relief valves to reduce reactor vessel pressure during small or isolated breaks, in the event HPCI fails. When reactor vessel pressure is reduced to within the design capability of the low pressure systems (core spray and LPCI), these systems provide reactor vessel coolant inventory makeup, so that acceptable post-accident reactor core coolant temperatures are maintained.

6.3.1.2.3 Core Spray

The two core spray system loops pump water into peripheral ring spray spargers mounted above the reactor core. The primary purpose of core spray is to provide reactor vessel inventory makeup and spray cooling during large breaks in which the reactor core is calculated to uncover. After ADS initiation, core spray also provides inventory makeup following a small break.

6.3.1.2.4 Low Pressure Coolant Injection

LPCI is an operating mode of the RHR system. Four pumps deliver water from the suppression chamber to four separate reactor vessel nozzles and inject directly into the core shroud region. The primary purpose of LPCI is to provide reactor vessel coolant inventory makeup following large breaks. After ADS initiation, LPCI also provides inventory makeup following a small break.

6.3.2 System Design

Detailed descriptions of the individual Emergency Core Cooling System (ECCS) subsystems, including individual design characteristics, are covered in Sections 6.3.2.2.1 through 6.3.2.2.4. The following discussion also provides details of the composite ECCS network and, in particular, those design features and characteristics that are common to all ECCS subsystems.

6.3.2.1 Schematic Piping and Instrumentation and Process Diagrams

The piping and instrumentation diagrams (P&IDs) for the ECCS injection systems, and the process diagrams that show the various operating modes of each injection system, are identified in Section 6.3.2.2.

6.3.2.2 Equipment and Component Descriptions

The initiation signal for the ECCS comes from independent and redundant sensors of high drywell pressure and low reactor water level. The ECCS is actuated automatically and requires no operator action during the first 10 minutes following the accident. A time sequence for starting of the ECCS subsystems is provided in Table 6.3-1.

Electric power for operation of the ECCS is from the preferred offsite power supply. Upon loss of the preferred source, operation is from the onsite standby power supply. Four standby diesel generators (SDGs) supplying individual ac buses have sufficient redundancy and capacity so that operation of any three units satisfies minimum ECCS requirements. One core spray pump and one residual heat removal (RHR)/low pressure coolant injection (LPCI) pump are powered by each ac bus. Section 8.3 contains a more detailed description of the power supplies for the ECCS.

See Section 3.11 for a discussion of environmental qualification of ECCS equipment and components.

6.3.2.2.1 High Pressure Coolant Injection System

The High Pressure Coolant Injection (HPCI) System consists of a steam turbine driven, constant flow pump assembly and associated system piping, valves, controls, and instrumentation. The P&IDs for HPCI, Plant Drawings M-55-1 and M-56-1, show the system components and their arrangement. The HPCI system process diagram, Vendor Technical Document PN1-E41-1020-0004, shows the design operating modes of the system.

The HPCI equipment is installed in the Reactor Building. Suction piping comes from both the condensate storage tank (CST) and the suppression chamber. Injection water is piped to the reactor vessel via the core spray loop A sparger and feedwater sparger A. Steam supply for the turbine is piped from main steam line C in the drywell. This piping is provided with an isolation valve on each side of the containment. Controls for valve and turbine operation are provided in the main control room. Valve position indication and instrumentation alarms are also displayed in the main control room. The controls and instrumentation of the HPCI system are described in Section 7.3.

The HPCI system ensures that the reactor core is not uncovered if there is a small break in the reactor coolant pressure boundary (RCPB) that does not result in rapid depressurization of the reactor vessel. This permits the plant to be safely shut down, by maintaining sufficient reactor vessel water inventory while the reactor vessel is depressurized. The HPCI system continues to operate until the reactor vessel is depressurized to the point at which LPCI and/or core spray system operation can maintain core cooling. The HPCI system also fulfills the objectives of the non-ECCS Reactor Core Isolation Cooling (RCIC) System, in the event RCIC becomes isolated or otherwise inoperative. The HPCI system head flow characteristics assumed for loss-of-coolant accident (LOCA) analyses are shown on Figures 6.3-4 and 6.3-5.

The HPCI system is designed to pump water into the reactor vessel over a wide range of pressures in the reactor vessel. Initially, demineralized water from the CST is used instead of water from the suppression chamber. This provides reactor grade water to the reactor vessel. A total reserve storage of 135,000 gallons is available from the CST for use by the HPCI and RCIC systems (see Section 9.2.6.2.1). During HPCI/RCIC system stand-by mode, if the water level in the CST drops below the reserved storage volume, suction source will be manually transferred to the torus. If the systems are operating, suction path will auto-transfer upon a low CST level. The minimum required suppression chamber water volume is approximately 118,000 ft^3(Technical Specification minimum during cold shutdown conditions is 57,232 ft^3). Water from either source is pumped into the reactor vessel through a core spray sparger and a feedwater sparger, to obtain proper mixing with the reactor hot water or steam.

The minimum HPCI flow available, 5600 gpm, was used in the accident analysis for simulation of the flow over the high pressure range, with 2000 to 3000 gpm injecting through the core spray sparger and the remainder through the feedwater sparger. When the vessel pressure drops below the shutoff head of the core spray system, it will inject water into the reactor vessel and the total flow of the HPCI/CS system will be a minimum of 6150 gpm at 105 psid. This is the combined HPCI/CS flow shown in Figure 6.3-5. Any additional HPCI/CS flow above the assumed minimums is conservatively ignored in the LOCA calculations presented in Section 6.3.3.

The CST level instrumentation used to automatically transfer the HPCI suction from the CST to the suppression chamber, and the portion of the suction piping exposed to outside air temperatures, are protected from cold weather effects respectively by 1 and 2 in. of insulation, along with a single non-1E powered heat trace on each line.

Motor control center (MCC) 1OB272015 supplies the normal power to the local heat tracing panel, 1OC284, that powers the heat tracing for the above two lines. The heat tracing is initiated automatically at 40°F, with backup auto initiation at 35°F if the 40°F thermostat (1-AP-TS-0110) fails.

Failure of the 35°F thermostat (1-AP-TS-0111) is alarmed on 1OC284 and in the main control room. Loss of power to 1OC284 (at any temperature) is also alarmed in the main control room. Diesel generator CG400 provides a backup source of power to 1OC284.

Additional heat tracing reliability for the 2-inch level sensing line is assured by an RTD (1-AP-TE-2048) that provides continuous monitoring of temperature in the line. The water temperature and an associated alarm are available in the main control room via the plant computer.

The HPCI pump assembly is located below the minimum water levels of the CST and the suppression chamber to ensure positive suction head to the pump assembly. The check valve at the pump discharge is also located below the water levels in the CST and the suppression chamber to ensure that piping upstream of the valve is maintained full of water. Pump net positive suction head (NPSH) requirements are met by providing adequate suction head and adequate suction line size. Available NPSH with suction from the CST is 51.9 feet [Reference Calculation BJ-0002, Rev. 6] and the suppression chamber is 21.4 feet. Both available NPSH values are calculated using the assumptions of Regulatory Guide 1.1 and incorporating all appropriate instrumentation uncertainty. The required NPSH of the HPCI Booster Pump at speed 2093 rpm and flow 5920 gpm is 19.7 feet [Reference Calculation BJ-0002, Rev. 6, Section 7.3].

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Pump characteristic curves are given on Figure 6.3-6.

The HPCI turbine pump assembly and piping are protected from detrimental physical effects of the design basis LOCA, such as pipe whip, flooding, and high temperature. The equipment is located outside the primary containment.

The HPCI turbine is driven by steam from the reactor vessel generated by decay and residual heat. The steam is extracted from main steam line C upstream of the main steam isolation valves (MSIVs). The inboard and outboard HPCI containment isolation valves in the steam line to the HPCI turbine are normally open. This keeps the piping to the turbine at an elevated temperature to permit rapid startup of the HPCI system. The inboard isolation valve has a bypass line containing a normally closed valve. This bypass line permits pressure equalization and drainage around the isolation valve and downstream line warmup prior to opening of the isolation valve. Signals from the HPCI control system open or close the steam supply shutoff valve adjacent to the turbine.

A condensate drain pot is provided upstream of the steam supply shutoff valve to prevent the HPCI steam supply line from filling with water. The drain pot normally routes the condensate to the main condenser. However, upon receipt of an HPCI initiation signal, or upon loss of control air pressure, isolation valves on the condensate line automatically close.

The turbine power is controlled by a flow controller that senses pump discharge flow and provides a variable signal to the turbine governor to maintain constant pump discharge flow over the pressure range of operation. The turbine control system is capable of limiting speed overshoot to 15 percent of maximum operating speed on a quick start while driving only the pump inertia load. Limit switches are provided on the turbine control (governor) valve to indicate fully open and closed positions. Both valve status lights are illuminated when the valve is in midposition.

As reactor steam pressure decreases, the HPCI turbine control valve opens further to pass the steam flow required to provide the necessary pump flow. The capacity of the system is selected to provide sufficient reactor core cooling to prevent cladding temperatures from exceeding the limits of 10CFR50.46 while the pressure in the reactor vessel is above the pressure at which core spray and LPCI can begin injection.

Exhaust steam from the HPCI turbine is discharged below the surface of the suppression pool. A drain pot at the low point in the exhaust line collects moisture present in the steam. Collected moisture is discharged through an orifice to the HPCI barometric condenser.

The HPCI turbine gland seals are vented to the barometric seal condenser for cooling. Noncondensable gases from the barometric condenser are normally pumped to the Filtration, Recirculation, and Ventilation System (FRVS). During testing of the HPCI turbine pump assembly, the noncondensable gases can be routed to the main condenser. However, an interlock and a motor-operated isolation valve are provided to prevent the use of the discharge path to the main condenser during periods of low reactor water level.

A system of vacuum relief valves and isolation valves is installed as a vacuum breaker line, which connects the free space in the suppression chamber with the HPCI turbine exhaust line. This mitigates the effects of water from the suppression pool being drawn into the HPCI turbine exhaust line. The isolation valves in this vacuum breaker line isolate automatically, via a combination of low reactor vessel pressure and high drywell pressure.

Startup of the HPCI system is completely independent of ac power. Only dc power from the station battery and steam extracted from the nuclear boiler system are necessary.

The HPCI controls automatically start the system and bring it to design flow rate within 35 seconds from receipt of a reactor pressure vessel (RPV) low water level signal or a primary containment (drywell) high pressure signal. Refer to Section 15 for more analysis details.

A large fraction of the 5600-gpm HPCI flow is delivered through one of the core spray spargers to inject makeup water directly over the core. Formerly, all the HPCI flow was injected into the core spray sparger. Analyses of anticipated transients without scram (ATWS) have resulted in the current design, which limits the HPCI flow through the core spray sparger to 3000 gpm and diverts the balance to the feedwater sparger. This change would minimize adverse reactivity effects from a postulated uninserted control rod during an ATWS. This change does not alter the ECCS analyses results presented in Section 6.3.3 since the loss of HPCI flow is assumed in the single failure scenario assumed in these analyses. During a small break accident for which the HPCI system was designed its primary purpose is to maintain reactor vessel inventory. This is accomplished with essentially the same degree of effectiveness whether the flow is injected via the feedwater system or the core spray system.

The ECCS separation criterion is that there should be both electrical and mechanical separation such that a LOCA plus any single failure would not result in the peak cladding temperature (PCT) exceeding the requirements of 10 CFR 50.46 (i.e., PCT is less than 2200°, the oxidation limits are met, etc.). The generic ECCS analysis has shown that this criterion is met with a portion of the HPCI flow injection into the core spray line. Plant specific ECCS analyses for other plants with this configuration have shown that the loss of both the core spray and HPCI systems from a break of their common line also would not violate this criterion.

An advantage of partial HPCI flow through the core spray sparger is the additional reflooding flow inside the shroud. Also, the effect of the loss of HPCI flow that would be due to a break in a recirculation line is reduced. A possible disadvantage of the partial HPCI flow through the core spray sparger is an adverse reactivity effect during a postulated ATWS event. This disadvantage has been minimized by limiting the HPCI flow through the core spray sparger to a maximum of 3000 gpm.

The HPCI flow through the feedwater system is automatic. The initiating and closing logic for the injection valve to the feedwater line is the same as the logic for the injection valve to the core spray line. Thus for any automatic or system-level manual initiation of the HPCI system, the flow to the reactor vessel will be divided between the core spray line and the feedwater line. As in the case of other accident modes (i.e., a LOCA), during an ATWS the HPCI system will be automatically initiated by a low water level-2 signal; the injection would be via the core spray and feedwater lines as represented by Modes F and G on the process diagram (Vendor Technical Document PN1-E21-1020-0003).

The HPCI turbine is shut down automatically by any one of the following signals:

1. HPCI turbine overspeed - preventing damage to the turbine

2. RPV high water level - indicating that core cooling requirements are satisfied

3. HPCI pump low suction pressure - preventing damage to the pump due to loss of flow

4. HPCI turbine exhaust high pressure - indicating a turbine or turbine control malfunction.

If an initiation signal is received after the turbine is shut down, the system restarts automatically if no shutdown signal exists.

Because the steam supply line to the HPCI turbine is part of the RCPB, certain signals automatically isolate this line and thereby shut down the HPCI turbine. However, automatic depressurization and the low pressure injection systems of the ECCS act as backup. Automatic shutoff of the steam supply to the HPCI turbine does not negate the ability of the ECCS to satisfy its safety objective. Automatic shutoff of the HPCI steam supply is described in Sections 7.3 and 7.6.1.3.

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

HPCI operation automatically actuates the following valves:

1. Opens the HPCI pump discharge shutoff valves

2. Opens the HPCI steam supply shutoff valve

3. Opens the HPCI turbine stop valve

4. Opens the HPCI turbine control (governor) valve

5. Closes the HPCI steam line drain isolation valves

6. Closes the HPCI test valve (if open)

7. Closes the HPCI pump minimum flow bypass valve (upon high flow).

Startup of the auxiliary oil pump and proper functioning of the hydraulic control system are required to open the turbine stop and control valves. Operation of the barometric condenser components prevents out leakage from the turbine shaft seals. Startup of the condenser equipment is automatic, but its failure does not prevent the HPCI system from fulfilling its core cooling objective. Prior to startup, the Turbine Control System is held at the low speed design condition. Upon receipt of an initiating signal, a speed ramp generator module automatically runs the control system toward its high speed design point, thereby controlling the transient acceleration of the turbine. The flow controller then automatically overrides the speed ramp generator. When rated flow is established, the flow controller signal adjusts the setting of the turbine control so that rated flow is maintained as nuclear system pressure decreases.

A minimum flow bypass is provided for pump protection. The bypass valve automatically opens on a low flow signal, and automatically closes on a high flow signal. When the bypass is open, flow is directed to the suppression chamber. A line used for full flow system testing branches from the HPCI pump discharge line to the CST. The shutoff valves in this line are sequenced to close by the signal that actuates system operation, and are interlocked closed when the suction valve from the suppression chamber is open. All automatically operated valves are equipped with a remote manual functional test feature.

The HPCI system initially injects water from the CST. When the water level in the tank falls below a predetermined level or the suppression chamber water level is high, the pump suction is automatically transferred to the suppression chamber. This transfer may also be made from the main control room using manual controls. When the pump suction has been transferred to the suppression chamber, a closed loop is established for recirculation of water escaping from a break in the RCPB.

To ensure continuous core cooling, signals to isolate the primary containment do not operate any HPCI valves. The HPCI system also incorporates a relief valve in the pump suction line to protect the components and piping from inadvertent overpressure conditions.

Provisions included in the HPCI system that permit system testing are:

1. A full flow test line to route water from and to the CST, without entering the RPV

2. A line to route noncondensible gases from the barometric condenser to the plant main condenser

3. Instrumentation to indicate system performance during test operations

4. Motor operated valves capable of manual operation for test purposes

5. Drains to leak test the major system valves.

All components of the HPCI system are capable of individual functional testing during normal plant operation. Except as indicated below, the HPCI control system design provides automatic alignment from test to operating mode if system initiation is required. The exceptions are as follows:

1. The auto/manual station is in "manual" on the flow controller. This feature is required for operator flexibility during system operation.

2. Closure of either or both of the steam inboard/outboard isolation valves requires operator action to properly sequence their opening. Indication of the status of these valves is provided in the main control room.

3. Parts of the system that are bypassed or deliberately rendered inoperative are indicated automatically or manually in the main control room.

Interlocks for the HPCI system are described in Section 7. Operating requirement parameters for the components of the HPCI system (listed below) are shown on Vendor Technical Document PN1-E41-1020-0004.

1. One 100 percent capacity booster and main pump assembly

2. One 100 percent capacity turbine driver, with accessories

3. Piping, valves, and instrumentation for:

   a. Steam supply to the turbine

   b. Turbine exhaust to the suppression pool

   c. Makeup supply from the CST to the pump suction

   d. Makeup supply from the suppression chamber to the pump suction

e. Pump discharge to the core spray loop A sparger and feedwater sparger A, a test line to the CST, a minimum flow bypass line to the suppression chamber, and a cooling water supply to accessory equipment.

6.3.2.2.2 Automatic Depressurization System

If the non-ECCS RCIC system or the HPCI system cannot maintain the reactor water level, the Automatic Depressurization System (ADS), which is independent of any other subsystem of the ECCS, reduces the reactor vessel pressure so that flow from the LPCI and/or core spray systems enters the reactor vessel in time to cool the core and limit fuel cladding temperature.

The ADS employs nuclear system safety/relief valves to relieve high pressure steam to the suppression pool. The design, number, location, description, operational characteristics, and evaluation of the safety/relief valves are discussed in Section 5.2.2. The instrumentation and controls for the ADS are discussed in Section 7.3.

6.3.2.2.3 Core Spray System

Each of the two redundant core spray system loops consists of two 50 percent capacity centrifugal pumps, a spray sparger in the reactor vessel above the core (a separate sparger for each core spray loop), piping and valves to convey water from the suppression chamber to the sparger, and associated controls and instrumentation. A connection to the HPCI system is provided to allow HPCI system injection through the core spray loop A sparger. Plant Drawing M-52-1, the core spray P&ID, presents the system components and their arrangement. The core spray process diagram, Vendor Technical Document PN1-E21-1020-0003, shows the design operating modes of the system. A simplified system flow diagram showing system injection into the reactor vessel is included on Vendor Technical Document PN1-E21-1020-0003.

When low water level in the reactor vessel or high pressure in the drywell is sensed, the core spray pumps automatically start. When reactor vessel pressure is low enough, the core spray injection valves are automatically opened, and water is injected into the reactor vessel to cool the core. Each core spray injection line enters the reactor 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 spargers to spray the water radially over the core and onto the top of the fuel assemblies.

The Core Spray System is designed to provide cooling to the reactor core only when the reactor vessel pressure is low, as is the case for large break loss-of-coolant accident (LOCA) sizes. However, when the Core Spray System operates in conjunction with the ADS, the effective core cooling capability of core spray is extended to all break sizes, because the ADS rapidly reduces the reactor vessel pressure to the core spray operating range. The Core Spray System head flow characteristics assumed for LOCA analyses are shown on Figure 6.3-9.

The core spray system injection (isolation) valves are interlocked with reactor pressure such that they do not receive an opening permissive signal, following an accident, until reactor pressure has fallen below the maximum allowable pressure (approximately 460 psig) for the core spray discharge pipe.

The core spray pumps and all motor operated valves can be operated individually by manual switches located in the main control room. Operating indication is provided in the main control room by a flow meter for each core spray injection loop and by valve and pump status lights. Provisions to preclude inadvertent openings of the injection valves are discussed in Section 7.6.

To ensure continuity of reactor core cooling, signals to isolate the primary containment do not operate any Core Spray System valves. However, the bypass valves for the testable check valves and the pump full flow test return valves are isolated on an automatic core spray initiation signal.

Each injection line to the reactor vessel is provided with two valves. One of these valves is a testable check valve located inside the drywell as close as practical to the reactor vessel. Core spray injection flow causes this valve to open during LOCA conditions, i.e., no power is required for valve actuation during a LOCA. If the core spray line breaks outside the primary containment, the check valve in the line inside the drywell prevents loss of reactor water.

The other valve, which is the containment isolation valve, and which is also referred to as the core spray injection valve, is a motor operated gate valve located outside the primary containment, as close as is practical to the core spray discharge line containment penetration. The connection to the HPCI system is located between the primary containment and the core spray loop A injection valve. The core spray injection valves are capable of opening against a maximum differential pressure equal to normal reactor vessel pressure minus the minimum core spray system shutoff pressure. These injection valves, which are normally closed to back up the testable check valves for primary containment integrity purposes, are capable of opening within 27 seconds of receipt of an automatic core spray initiation signal. Separate, independent power sources are provided for each core spray injection valve, so that failure of a single electrical channel does not disable more than one core spray injection loop. The primary containment isolation design of the Core Spray System is discussed in Section 6.2.4.

The Core Spray System piping and components are designed and arranged to avoid unacceptable damage from the physical effects of pipe whip, missiles, high temperature, high pressure, or high humidity. All principal, active core spray equipment is located outside the primary containment.

Check valves (one per core spray pump), a flow element, and a restricting orifice are provided in each core spray injection loop from the pumps to each injection valve. Each check valve is located below the minimum suppression chamber water level, so that the piping upstream of the valve is maintained full of water. The flow element is provided to measure system flow rate during LOCA and test conditions, and for automatic control of the minimum flow bypass valve. The measured flow is indicated in the main control room. The restricting orifice is sized during preoperational testing of the system to limit system flow to acceptable values, as described on the Core Spray System process diagram on Vendor Technical Document PN1-E21-1020-0003.

A minimum flow bypass line connects to each core spray pump discharge line upstream of each pump discharge check valve. The line bypasses water to the suppression chamber to prevent pump damage due to overheating when other discharge line valves are closed, or when reactor vessel pressure is greater than the Core Spray System discharge pressure following system initiation. A motor operated globe valve in each bypass line automatically closes when flow in the corresponding injection loop is sufficient.

Flow to each core spray pump passes through a motor operated pump suction valve that is normally open. This valve can be closed by a manual switch, located in the main control room, to isolate the core spray system from the suppression chamber should a leak develop in the system. This valve is located in the core spray pump suction line as close to the suppression chamber penetration as is practical. Because the Core Spray System conveys water from the suppression chamber, a closed loop is established for recirculation of water escaping from a break in the RCPB.

The minimum core spray flow is 6150 gpm at 105 psid differential pressure from RPV to Torus. The minimum HPCI flow is 5600 gpm. A maximum of 3000 gpm and a minimum of 2000 gpm of the HPCI flow enters the reactor vessel via core spray Loop A piping. The remainder of the HPCI flow enters the reactor via feedwater piping. Therefore, the present core spray piping is adequately sized for the flow from either system operating separately.

At reactor pressures above the core spray system capability (>289 psid), all flow will be from the HPCI system. At reactor pressures less than 289 psid, line flow will be provided by both systems; but in no case will this flow be less than core spray alone. As vessel pressure falls to the HPCI minimum rated case (150 psig), more of the core spray line flow will come from the core spray pump and less from the HPCI pump. HPCI will then pump a greater proportion of its total flow into the feedwater.

The core spray pumps are located in the Reactor Building below the water level in the suppression chamber to ensure positive suction head to the pumps. Pump NPSH requirements are met by providing adequate suction head and adequate suction line size. Available NPSH with suction from the CST is 41.8 feet [Reference Calculation BE-0016, Rev. 5, Page 27] at an approximate maximum pump flow of 3600 gpm; available NPSH with suction from the suppression pool is 11.3 feet at an approximate maximum pump flow of 4175 gpm. Both available NPSH values are calculated using the assumptions of Regulatory Guide 1.1.

The required NPSH for the core spray pumps is 5.6 feet at 4300 gpm. Pump characteristic curves are given on Figure 6.3-10.

Each Core Spray System injection loop incorporates relief valves to protect the components and piping from inadvertent overpressure conditions. One relief valve, located at the discharge of the pumps, is set at 500 psig, with a capacity of 100 gpm at 10 percent accumulation. Relief valves located at the suction of each pump are set at 100 psig, with a capacity of at least 10 gpm at 10 percent accumulation.

Provisions included in the Core Spray System that permit system testing are:

1. Full flow test lines to route suppression chamber water back to the suppression chamber, without entering the RPV.

2. A test line supplying water from the CST to the core spray pump suction, for testing discharge capacity to the RPV during normal plant shutdown.

3. Instrumentation to indicate system performance during test operations.

4. Motor operated valves and check valves capable of manual operation for test purposes.

5. Drains to leak test the major system valves.

All active core spray components are capable of individual functional testing during normal plant operation. Except as indicated below, the core spray control system design provides automatic alignment from test to operating mode if system initiation is required. The exceptions are as follows:

1. Closure of any of the motor operated pump suction valves requires operator action to reopen them. Indication of the status of these valves is provided in the main control room.

2. Parts of the system that are bypassed or deliberately rendered inoperative are indicated automatically or manually in the main control room.

6.3.2.2.4 Low Pressure Coolant Injection System

The LPCI system is an operating mode of the RHR system that is automatically actuated by low water level in the reactor vessel or high pressure in the drywell. It uses four motor driven RHR pumps to draw suction from the suppression chamber and inject cooling water into the reactor core via four separate reactor vessel nozzles and core shroud penetrations. Separate, independent power sources are provided for the electrically powered components in each LPCI injection loop, so that failure of a single electrical channel does not disable more than one injection loop. Using the suppression chamber as the source of water for LPCI establishes a closed loop for recirculation of water escaping from a break in the RCPB.

The LPCI system, like the Core Spray System, is designed to provide cooling to the reactor core only when the reactor vessel pressure is low, as is the case for large break LOCA sizes. However, when the

LPCI system operates in conjunction with the ADS, the effective core cooling capability of LPCI is extended to all break sizes, because the ADS rapidly reduces the reactor vessel pressure to the LPCI operating range. The LPCI system head flow characteristics assumed for LOCA analyses are shown on Figure 6.3-11.

Figure 6.3-12 shows a process diagram and process data for the RHR system, including LPCI. The RHR system P&ID is shown on Plant Drawing M-51-1. The process diagram and P&ID indicate that many flow paths are available other than the LPCI injection lines. However, the low reactor water level or high drywell pressure signals, which automatically initiate the LPCI mode, are also used to align RHR system valves to the LPCI lineup. Inlet and outlet valves for the RHR heat exchangers receive no automatic signals, since the system is designed to provide rated flow to the reactor vessel whether they are open or not. To ensure 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. Provisions to preclude inadvertent openings of the injection valves are discussed in Section 7.6.

A check valve in each pump discharge line is located below the minimum water level in the suppression chamber to ensure that piping upstream of the valve is maintained full of water. A flow element in each pump discharge line is used to provide a measure of pump flow and to originate automatic signals for control of each pump minimum flow bypass valve. The minimum flow bypass valves permit a small flow to the suppression chamber if no pump discharge valve is open, or if reactor vessel pressure is higher than the pump shutoff pressure.

The LPCI system incorporates a relief valve on each of the pump suction and discharge lines, which protects the components and piping from inadvertent overpressure conditions. These valves are set to relieve at pressures equal to the corresponding piping design pressures shown on Figure 6.3-12.

The RHR pumps, and equipment used for LPCI, are described in Section 5.4.7, which also describes the other functions served by the same pumps if they are not needed for the LPCI function. The RHR heat exchangers are not associated with the emergency core cooling function. The heat exchangers are discussed in Section 6.2.2.

The pumps used for LPCI are located in the Reactor Building below the water level in the suppression chamber to ensure positive suction head to the pumps. Pump NPSH requirements are met by providing adequate suction head and adequate line size. Available NPSH for the LPCI function is calculated using the assumptions of Regulatory Guide 1.1 and the following data:

1. Each pump is operating at its maximum flow rate.

2. Pump suction is from the suppression chamber, which is at its minimum normal operating water level of Elevation 71 feet.

3. Suppression chamber water is at its maximum temperature (for the given operating mode) of 212°F.

4. The free space in the suppression chamber is at atmospheric pressure.

5. The pump suction strainers (in the suppression chamber) are fouled uniformly with containment debris, both preexisting and that which was generated following a DBLOCA, based upon the criteria set forth in USNRC Bulletin 96-03 and NUREG/CR-6224.

6. The datum line for calculation of NPSH is the pump suction center line elevation of 55 ft. 9 in.

7. NPSH = hs - hf + ha - hvp

   using data from the limiting case ("D" pump):

   hs = static head = (71 feet – 55.8 feet) = 15.2 feet

hf = friction head loss = 5.2 feet

ha = atmospheric pressure head = 35.38 feet

hvp = vapor pressure (head loss) = 35.38 feet

NPSH = 10.0 feet

Minimum required NPSH for the RHR pumps is provided by the manufacturer's pump curves, and is shown on Figure 6.3-12. A representative pump characteristic curve is given on Figure 6.3-13.

Provisions included in the LPCI system that permit system testing are:

1. Full flow test lines to route suppression chamber water back to the suppression chamber, without entering the RPV

2. Instrumentation to indicate system performance during test operations

3. Motor operated valves and check valves capable of manual operation for test purposes

4. Shutdown cooling lines taking suction from the recirculation system to permit testing of the RHR discharge into the RPV after normal plant shutdown

5. Drains to leak test the major system valves.

All active LPCI components are capable of individual functional testing during normal plant operation. Except as indicated below, the LPCI control system design provides automatic alignment from test to operating mode if system initiation is required. The exceptions are as follows:

1. Closure of any of the motor operated pump suction valves in the suction lines from the suppression chamber requires operator action to reopen them. Indication of the status of these valves is provided in the main control room.

2. Parts of the system that are bypassed or deliberately rendered inoperative are indicated automatically or manually in the main control room.

6.3.2.2.5 ECCS NPSH Margin and Vortex Formation

NPSH calculations for ECCS pumps, such as the calculation in the previous section, have shown adequate margin to ensure capability of proper pump operation under accident conditions. This capability is verified during preoperational testing and by post-modification testing and engineering analysis. The geometries of the RHR, core spray and HPCI suction strainer and piping in the torus have been evaluated and the resulting Froude numbers are less than 0.8 for all strainers. Tests have shown that no air core vortices or air withdrawal are observed for BWR Mark I geometries where the Froude number is less than 0.8. Therefore the HCGS design avoids the formation of air core vortices and possible air ingestion.

6.3.2.2.6 ECCS Discharge Line Fill Network

A requirement of the ECCS is that cooling water flow to the RPV be initiated rapidly when the system is called upon to perform its function. This quick start system characteristic is provided by quick opening valves, quick start pumps, and standby 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 are empty when the systems are called upon, the large momentum forces associated with accelerating fluid into a dry pipe could cause physical damage to the piping. Therefore, the ECCS discharge line fill network is designed to maintain the ECCS pump discharge lines in a filled condition.

Since the ECCS discharge lines are elevated above the water level in the suppression chamber, check or stop-check valves are provided near the pumps to prevent backflow from emptying the lines into the suppression chamber. Past experience shows that these valves may leak slightly, producing a small backflow that could eventually empty the discharge piping. To ensure that this leakage from the discharge lines is replaced and the lines are always kept full, makeup flow is provided by the ECCS discharge line fill network.

The fill network consists of three independent jockey pump loops, as shown on Plant Drawings M-55-1, M-56-1, and M-51-1. Two of the pump loops serve the low pressure ECCS pump (LPCI and core spray) discharge lines; the third pump loop serves the HPCI pump discharge line. Each jockey pump, and its respective controls and instrumentation, is powered from a separate Class 1E electrical channel. Physical separation is provided by locating two of the jockey pumps in separate RHR pump compartments, and the third jockey pump in the HPCI equipment compartment. The fill network is safety-related and designed to Seismic Category I criteria, but is not considered an integral part of the ECCS. Nonetheless, a single failure of an active component in the fill network will not prevent the ECCS from performing its intended function.

Each of the jockey pumps operates continuously to maintain the ECCS pump discharge lines above atmospheric pressure, so that entrapped air pockets can be released through the piping high point vents during surveillance testing of the fill network. The jockey pumps serving the low pressure ECCS injection lines take suction from two different RHR pump suppression chamber suction lines. Jockey pump protection (from overheating) is provided by continuously recirculating this flow back to the suppression chamber via the RHR pump full flow test lines. The jockey pump serving the HPCI system takes its suction from the HPCI pump suction and recirculates flow back to the HPCI pump suction piping.

Controls for operation of the jockey pumps are provided in the main control room. Instrumentation is also provided to assist the operator in ascertaining the proper operation of the entire fill network. Controls and instrumentation associated with the fill network are discussed in Section 7.6.

Each ECCS injection loop is provided with a separate, isolable fill line to permit maintenance of individual ECCS injection loops without disabling other ECCS injection equipment. This isolation feature also ensures that the ECCS pump discharge lines remain filled and pressurized during maintenance of ECCS injection equipment.

There are times during normal operation, when a jockey pump must be removed from service to perform preventative or corrective maintenance or periodic testing. When a jockey pump must be removed from service, it is prudent not to impact availability of the associated ECCS or RCIC system(s). Therefore, availability of the affected system(s) is maintained by transferring the keepfill function to the Condensate Transfer and Storage System. Under these conditions, the jockey pump is removed from service in accordance with station administrative controls which ensure that the impact on system operability is assessed and appropriate compensatory actions are considered and implemented. Additionally, only a single jockey pump, associated with an operable ECCS or RCIC system is removed from service at a time.

Surveillance tests to determine if the discharge lines of the ECCS pumps are full are as required by the plant technical specifications in Section 16.

6.3.2.3 Applicable Codes and Classifications

The applicable codes and classifications 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 equipment and piping of the ECCS are also designed to the requirements of Seismic Category I. This seismic designation applies to all structures and equipment essential to the core cooling function. IEEE standards 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 Section 6.1. Nonmetallic materials, e.g., lubricants, seals, packings, paints and primers, insulation, etc, and 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 both radiolytic and pyrolytic decomposition, and attendant effects on safe operation of the ECCS.

6.3.2.5 System Reliability

Analysis shows that no single failure prevents either 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 expected that single failures will disable individual systems of the ECCS. The most severe single failure event with respect to loss of equipment is the LOCA, due to an ECCS pipe break coincident with a loss of offsite power. The consequences of the most severe single failure are shown in Table 6.3-6. See Section 15.9 for a system level, qualitative failure modes and effects analysis.

6.3.2.6 Protection Provisions

Protection provisions are included in the design of the ECCS. Protection is afforded against missiles, pipe whip, and flooding. Also accounted for in the design are thermal stresses, loadings from a LOCA, and seismic effects.

The ECCS piping and components located outside the primary containment are protected from internally and externally generated missiles by the reinforced concrete structure of the ECCS pump rooms.

The ECCS is protected against the effects of pipe whip which might result from piping failures up to, and including, the design basis LOCA. This protection is provided by either spatial separation or pipe whip restraints. Either of these methods provides protection against damage to piping and components of the ECCS, which otherwise could reduce ECCS effectiveness to an unacceptable level. See Section 3.6 for criteria on pipe failures.

The component supports that protect the ECCS against damage from movement and from seismic events are discussed in Section 5.4.14. The methods used to provide assurance that thermal stresses do not cause damage to the ECCS are described in Section 3.9.3.

6.3.2.7 Provisions for Performance Testing

Periodic system and component testing provisions for the ECCS are described in Section 6.3.2.2 as part of the individual system descriptions.

6.3.2.8 Manual Actions

The ECCS is actuated automatically and requires no operator action during the first 10 minutes following the accident.

During the long term cooling period (after 10 minutes), the operator takes action, as specified in Section 6.2.2.2, to place the Containment Cooling System into operation. Placing the Containment Cooling System into operation is the only manual action that the operator needs to accomplish during the course of the LOCA.

The operator has multiple instrumentation available in the main control room to assist him in assessing the post-LOCA conditions. This instrumentation indicates reactor vessel pressure and water level, and primary containment pressure, temperature, and radiation levels, as well as indicating the operation of the ECCS. ECCS flow indication is the primary parameter available to assess proper operation of the system. Other indications, such as position of valves, status of circuit breakers, and essential power bus voltage, are also available to assist the operator in determining system operating status. The instrumentation and controls for the ECCS are discussed in Section 7.3. Monitoring instrumentation available to the operator is discussed in more detail in Section 5 and Section 6.2.

Consideration has been given to the unlikely possibility that manual valves in the ECCS might be left in the wrong position and remain undetected when an accident occurs. Many of the manual valves in the ECCS are vent, drain, or test connection valves, which are normally closed and capped. Administrative controls, such as prestartup valve lineup checks, suffice to reasonably ensure that such valves will not degrade ECCS performance. In other cases, two isolation valves are provided in series to minimize the possibility of inter or intra system leakage. Position indication of manual valves that are in the main flowpaths of the ECCS, and that are inaccessible during normal plant operation, is provided in the main control room. Proper administrative controls and/or surveillance testing are relied upon to ensure the position of the remaining valves.

6.3.2.9 TMI Action Plans

See Section 1.10 for a discussion of TMI Task Action Plan requirements applicable to HCGS.

6.3.3 Performance Evaluation

The performance of the Emergency Core Cooling System (ECCS) is determined through application of the 10CFR50, Appendix K evaluation models, and demonstrated conformance to the acceptance criteria of 10CFR50.46. The analytical models are documented in Section S.2.2.3.2 of GESTAR II (Reference 6.3-3). The effects of known changes or errors on the calculated limiting peak cladding temperature transient applicable to HCGS have also been estimated in accordance with 10 CFR 50.46(a)(3)(i).

A SAFER/GESTR-LOCA analysis has been performed (Reference 6.3-4) using the NRC-approved methods contained in GESTAR II (Reference 6.3-3). This analysis further maintains the design basis analysis as contained in the following sections. The Reference 6.3-4 analysis was performed to support EPU operation, and the analysis incorporated all the known changes or errors on the calculated limiting peak cladding temperature transient applicable to HCGS in accordance with 10 CFR 50.46(a)(3)(i). Changes or errors in the ECCS evaluation models have been discovered since performance of the SAFER/GESTR-LOCA analysis supporting EPU operation. The effects of those known changes or errors in the acceptable ECCS evaluation models on the calculated limiting peak cladding temperature transient have also been evaluated and are shown in Table 6.3-7.

The ECCS performance is evaluated for the entire spectrum of break sizes for postulated LOCAs. The accidents, as listed in Section 15, for which ECCS operation is required are:

1. Section 15.6.6 - Feedwater piping break

2. Section 15.6.4 - Spectrum of boiling water reactor (BWR) steam system piping failures outside of containment

3. Section 15.6.5 - LOCAs

Section 15 provides a description of the radiological consequences of the events listed above.

6.3.3.1 ECCS Bases for Technical Specifications

The maximum average planar linear heat generation rates calculated in this performance analysis provide the basis for technical specifications designed to ensure conformance with the acceptance criteria of 10CFR50.46. An evaluation of the effects of known changes and errors in the acceptable ECCS evaluation models ensures the basis remains valid and the acceptance criteria are met. Minimum ECCS functional requirements are specified in Sections 6.3.3.4 and 6.3.3.5. Testing requirements are discussed in Section 6.3.4. Limits on minimum suppression chamber water level are discussed in Section 6.2.

6.3.3.2 Acceptance Criteria for ECCS Performance

The applicable acceptance criteria, extracted from 10CFR50.46, are listed below. For each criterion, applicable parts of Section 6.3.3 (where conformance is demonstrated) are indicated. A detailed description of the methods used to show compliance is contained in Section S.2.2.3.2 of Reference 6.3-3.

1. Criterion 1, Peak Cladding Temperature "The calculated maximum fuel element cladding temperature shall not exceed 2200°F." Conformance to Criterion 1 is shown in Sections 6.3.3.7.3, 6.3.3.7.4, 6.3.3.7.5, 6.3.3.7.6, and specifically in Table 6.3-3. The effects of known changes or errors in the acceptable ECCS evaluation models on the calculated limiting peak cladding temperature transient have also been evaluated and are shown in Table 6.3-7.

2. Criterion 2, Maximum Cladding Oxidation "The calculated total local oxidation of the cladding shall nowhere exceed 0.17 times the total cladding thickness before oxidation." Conformance to Criterion 2 is shown in Table 6.3-3.

3. Criterion 3, Maximum Hydrogen Generation "The calculated total amount of hydrogen generated from the chemical

reaction of the cladding with water or steam shall not exceed 0.01 times the hypothetical amount that would be generated if all the metal in the cladding cylinder surrounding the fuel, excluding the cladding surrounding the plenum volume, were to react." Conformance to Criterion 3 is shown in Table 6.3-3.

4. Criterion 4, Coolable Geometry "Calculated changes in core geometry shall be such that the core remains amenable to cooling." As described in Reference 6.3-4, conformance to Criterion 4 is demonstrated by conformance to Criteria 1 and 2.

5. Criterion 5, Long-Term Cooling "After any calculated successful initial operation of the ECCS, the calculated core temperature shall be maintained at an acceptably low value and decay heat shall be removed for the extended period of time required by the long lived radioactivity remaining in the core." Conformance to Criterion 5 is demonstrated in Reference 6.3-4. Briefly summarized, the core remains covered to at least the jet pump suction elevation, and the uncovered region is cooled by spray cooling and/or by steam generated in the covered part of the core.

6.3.3.3 Single Failure Considerations

The functional consequences of single failures, including operator errors that might cause any manually controlled, electrically operated valve in the ECCS to move to a position that could adversely affect the ECCS, and the potential for submergence of valve motors in the ECCS, are discussed in Sections 6.3.1.1.2 and 6.3.1.1.4. The most severe single failures are identified in Table 6.3-6. Therefore, only these single failures are considered in the ECCS performance analyses. For both large and small breaks, failure of the channel A dc source is the most severe failure. A single failure in the ADS (one ADS valve) has no effect in large breaks. Therefore, as a matter of calculational convenience, it is assumed in all calculations that one ADS valve fails to operate in addition to the identified single failure. This assumption reduces the number of calculations required in the performance analysis and bounds the effects of one ADS valve failure and the channel A dc source failure by themselves. The only effect of the assumed ADS valve failure on the calculations is a small increase (on the order of 100°F) in the calculated temperatures following small breaks.

6.3.3.4 System Performance During the Accident

In general, the system response to an accident can be described as the following:

1. An initiation signal is received.

2. A small lag time (to open all valves and run the pumps up to rated speed) occurs.

3. The ECCS flow enters the reactor vessel.

Key ECCS actuation setpoints and time delays are provided in Table 6.3-2. The minimization of the delay from the receipt of signal until the ECCS pumps have reached rated speed is limited by the physical constraints on accelerating the standby diesel generators (SDGs) and the ECCS pumps. The delay time due to valve motion in the high pressure system provides a suitably conservative allowance for valves available for this application. In the low pressure systems, the time delay for valve motion is such that the pumps are at rated speed prior to the time the reactor vessel pressure decreases to the pump shutoff pressure.

The flow delivery rates analyzed in Section 6.3.3 can be determined from the head flow curves on Figures 6.3-4, 6.3-5, 6.3-9, and 6.3-11, and from the pressure versus time plots discussed in Section 6.3.3.7. Piping and instrumentation diagrams for the ECCS injection network are identified in Section 6.3.2.2. Functional control diagrams (FCDs) for the ECCS are provided in Section 7.3. The operational sequence of the ECCS for the design basis LOCA is shown in Table 6.3-1.

Operator action is not required, except as a monitoring function, during the short term cooling period following the LOCA. During the long term cooling period, the operator takes action as specified in Section 6.2.2.2 to place the Containment Cooling System into operation.

6.3.3.5 Use of Dual Function Components for ECCS

With the exception of the Automatic Depressurization System (ADS) and the Low Pressure Coolant Injection (LPCI) System, the systems of the ECCS are designed to accomplish only one function: to cool the reactor core following a loss of reactor coolant. To this extent, components or portions of these systems, except for pressure relief, are not required for operation of other systems that have emergency core cooling functions, or vice versa. Because either the ADS initiating signal or overpressure of the reactor pressure vessel (RPV) opens the safety/relief valves, no conflict exists.

The LPCI system, however, uses the residual heat removal (RHR) pumps and some of the RHR valves and piping. When the reactor water level is low, the LPCI system has priority, through the valve control logic, over the other RHR modes of operation. Immediately following a LOCA, the RHR system is aligned to the LPCI mode.

6.3.3.6 Limits on ECCS System Parameters

Refer to Sections A.6.3.3.6 through A.6.3.3.7.2 of Appendix A of Reference 6.3-3.

Compliance with Regulatory Guide 1.47 is identified in Section 1.8.

6.3.3.7 ECCS Analyses for LOCA

Starting in Cycle 13, Hope Creek is analyzed with the SAFER/GESTR-LOCA methodology as described in GESTAR (Reference 6.3-3).The corresponding analysis results are reported in Reference 6.3-4 and have been incorporated into the UFSAR.

6.3.3.7.1 LOCA Analysis Procedures and Input Variables

Refer to Section S.2.2.3.2 of Reference 6.3-3. The significant input variables used by the LOCA codes are given in Table 6.3-2 and on Figure 6.3-15.

6.3.3.7.2 Accident Description

Reference to a detailed description of the LOCA calculation is provided in Section S.2.2.3.2 of Reference 6.3-3.

6.3.3.7.3 Break Spectrum Calculations

A complete spectrum of postulated break sizes and locations is considered in the evaluation of ECCS performance.

A summary of the results of the break spectrum calculations is shown in tabular form in Table 6.3-3 and graphically on Figure F6.3-14 for GE14 fuel. The effects of known changes or errors in the acceptable ECCS evaluation models on the calculated limiting peak cladding temperature transient have also been evaluated and are shown in Table 6.3-7. Conformance to the acceptance criteria (peak cladding temperature ≤ 2200°F, local oxidation ≤ 17 percent, and core wide metal water reaction ≤ 1 percent) is demonstrated. Details of calculations for specific breaks are included in subsequent paragraphs.

6.3.3.7.4 Large Recirculation Line Break Calculations

The characteristics that determine which is the most limiting large break are:

1. The calculated time for reflooding the hot node

2. The calculated time for uncovering the hot node

3. The calculated time of boiling transition.

The calculated time of boiling transition increases with decreasing break size, since the time of uncovering of the jet pump suction inlet, which leads to boiling transition, is determined primarily by the break size. The calculated time for uncovering the hot node also generally increases with decreasing break size, since it is determined primarily by the reactor coolant inventory lost during the blowdown.

The hot node reflooding time is determined by a number of interacting phenomena, such as depressurization rate, countercurrent flow limiting, and a combination of available ECCS.

The period between the uncovering of the hot node and its reflooding is the period when the hot node has the lowest heat transfer. Hence, the break that results in the longest period during which the hot node remains uncovered results in the highest calculated peak cladding temperature. If two breaks have similar times during which the hot node remains uncovered, then the larger of the two breaks will be limiting, as it would have an earlier boiling transition time (i.e., the larger break would have a more severe result from a blowdown heat transfer analysis).

The design basis accident (DBA) was determined to be the break that results in the highest calculated peak cladding temperature in the 1.0 ft^2 to 4.1 ft^2 region (the largest possible area of a recirculation system line break is 4.1 ft^2). Confirmation that this is the most limiting break over the entire break spectrum is shown in Figure 6.3-14.

Important variables from the analysis of the DBA are shown on Figures 6.3-20 through 6.3-23 for the GNF2 fuel type. These variables are:

6.3-20 Water level as a function of time

6.3-21 Pressure as a function of time

6.3-22 Fuel rod convective heat transfer coefficient as a function of time for GNF2.

6.3-23 Peak cladding temperature as a function of time for GNF2.

The maximum local oxidation, and peak cladding temperature are shown in Table 6.3-3. The effects of known changes or errors in the acceptable ECCS evaluation models have not been incorporated into the figures for peak cladding temperature as a function of time but have been evaluated and are shown in Table 6.3-7.

6.3.3.7.5 Transition Recirculation Line Break Calculations

Important variables from the analysis of the 60% DBA break are shown on Figures 6.3-30 through 6.3-33. These variables are:

6.3-30 Water level (large break methods) as a function of time

6.3-31 Pressure (large break methods) as a function of time

6.3-32 Fuel rod convective heat transfer coefficient (large break methods) as a function of time for GE14.

6.3-33 Peak cladding temperature (large break methods) as a function of time for GE14.

6.3.3.7.6 Small Recirculation Line Break Calculations

Important variables from the analysis of the small break yielding the highest cladding temperature are shown on Figures 6.3-38 through 6.3-41 for the GNF2 fuel type. These variables are:

6.3-38 Water level as a function of time

6.3-39 Pressure as a function of time

6.3-40 Fuel rod convective heat transfer coefficient as a function of time for GNF2.

6.3-41 Peak cladding temperature as a function of time for GNF2.

6.3.3.7.7 Calculations for Other Break Locations

In addition to the spectrum of recirculation line breaks, calculations were also performed to determine the peak clad temperatures for line breaks in the following systems and locations: core spray line, steam line inside containment, steam line outside containment, feedwater line, and LPCI line. The results for the other break locations are shown in Table 6.3-3a.

6.3.3.8 <u>LOCA Analysis Conclusions</u>

Having shown compliance with the applicable acceptance criteria of Section 6.3.3.2, it is concluded that the ECCS will perform its function in an acceptable manner and meet all of the 10CFR50.46 acceptance criteria, given operation at or below the maximum average planar linear heat generation rates used in the analysis. In addition, an evaluation of the effects of known changes or errors in the acceptable ECCS models in accordance with 10 CFR 50.46(a)(3)(i) as presented in Table 6.3-7.

6.3.4 Tests and Inspections

6.3.4.1 <u>ECCS Performance Tests</u>

All systems of the Emergency Core Cooling System (ECCS) are tested for their operational ECCS function during the preoperational and/or startup test program. Each component is tested for power source, range, direction of rotation, setpoint, limit switch setting, torque switch setting, etc, as applicable. Each ECCS pump is tested for flow capacity, for comparison with vendor data, and for verification of flow measuring capability. The flow tests involve the same suction and discharge source, i.e., suppression chamber or condensate storage tank (CST).

All logic elements are tested individually, and then as a system, to verify complete system response to emergency signals, including the ability of the valves to revert to the ECCS alignment from other positions.

Finally, the entire system is tested for response time and flow capacity, taking suction from its normal source and delivering flow into the reactor vessel. This last series of tests is performed with power supplied from both offsite power and onsite standby power sources.

See Section 14 for a thorough discussion of preoperational testing for these systems.

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 factors above were used to determine safe test intervals, utilizing the methods described in References 6.3-2, 6.3-5 and 6.3-6.

All of the active components of the High Pressure Coolant Injection (HPCI), Core Spray, and Low Pressure Coolant Injection (LPCI) Systems are designed so that they may be tested during normal plant operation. Full flow test capability of each ECCS injection system is provided by a test line back to its respective 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 such that by racking out the injection valve breaker, each ECCS loop can be tested for response time.

All of the active components of the Automatic Depressurization System (ADS), except the check valves for the ADS accumulators and the safety/relief valves and their associated solenoid valves, are designed so that they may be tested during normal plant operation. The safety/relief valves and associated solenoid valves are all tested at least once every 18 months during plant startup following a refueling outage. Safety/relief valves and their associated solenoid valves which have been overhauled during a plant outage are tested during the startup following that outage. Testing of the check valves for the ADS accumulators is done in accordance with ASME B&PV Code, Section XI. Inservice testing of the ECCS pumps and valves is in accordance with the ASME B&PV Code, Section XI (see Section 3.9.6).

Testing of the initiating instrumentation and controls portion of the ECCS is discussed in Section 7.3. The Standby Power System, which supplies electrical power to the ECCS if offsite power is unavailable, is tested as described in Section 8.3. The frequency of testing is specified in Section 16. Visual inspections of all the ECCS components located outside the primary containment can be made at any time during power operation. Components inside the primary containment can be visually inspected only during periods of access to the primary containment. When the reactor vessel is open, the spargers and other reactor vessel internals can be inspected.

6.3.4.2.1 HPCI Testing

The HPCI system can be tested at full flow with CST water at any time during plant operation, except when the reactor vessel water level is low, when the condensate level in the CST is below the reserve level, or when the valves from the suppression chamber to the pump are open. If an initiation signal occurs while the HPCI system is being tested, the system aligns automatically to the operating mode.

A design flow functional test of the HPCI system 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 HPCI system turbine pump is driven at its rated output by steam from the reactor. The suction valves from the suppression chamber and the discharge valves to the core spray and feedwater lines remain closed. These valves are tested separately to ensure their operability.

The HPCI test conditions are tabulated on the HPCI process diagram, Vendor Technical Document PN1-E41-1020-0004.

6.3.4.2.2 ADS Testing

The ADS valves are tested during the time when the reactor vessel is at reduced pressure prior to a refueling outage. This testing includes simulated automatic actuation of the system throughout its emergency operating sequence, but excludes actual valve actuation.

During plant operation, the ADS can be checked as discussed in Section 7.3.

6.3.4.2.3 Core Spray Testing

The Core Spray System pumps and valves are tested periodically during reactor operation. With the injection valve closed, and the return line to the suppression chamber open, full flow pumping 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 core spray system process diagram, Vendor Technical Document PN1-E21-1020-0003. The portion of the core spray system outside the drywell may be inspected for leaks during tests.

6.3.4.2.4 LPCI Testing

Each LPCI loop can be tested during reactor operation. The test conditions are tabulated in Figures 6.3-12. During plant operation, this test does not inject cold water into the reactor vessel, because the injection line check valve is held closed by the reactor vessel pressure, which is higher than the pump pressure. The injection line portion is 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 a residual heat removal (RHR)/(LPCI) pump at rated flow, the test line valve to the suppression chamber is opened, the pump suction valve from the suppression chamber is opened (this valve is normally open), and the pumps are started using the manual switches in the main control room. Correct operation is determined by observing instruments in the main control room.

If an LPCI initiation signal occurs during the test, the RHR system aligns to the LPCI operating mode. The valves in the test bypass lines close automatically to ensure that the RHR (LPCI) pump discharge is correctly routed to the reactor vessel.

6.3.5 Instrumentation Requirements

Design details, including redundancy and logic of the Emergency Core Cooling System (ECCS) instrumentation, are discussed in Section 7.3.

All instrumentation required for automatic and manual initiation of the High Pressure Coolant Injection System (HPCI), core spray, and Low Pressure Coolant Injection System (LPCI) systems and Automatic Depressurization System (ADS) is discussed in Section 7.3.2, and is designed to meet the requirements of IEEE 279 and other applicable standards.

The HPCI system is automatically initiated on low reactor water level or high drywell pressure. The core spray and LPCI systems are automatically initiated on low reactor water level or high drywell pressure (in combination with low reactor vessel pressure). The ADS is automatically actuated by sensed variables for reactor vessel low water level and drywell high pressure, plus the indication that at least one core spray loop or LPCI pump is operating. The HPCI, core spray, and LPCI systems automatically realign from system flow test modes to the emergency core cooling mode of operation following receipt of an automatic initiation signal. The core spray and LPCI systems begin injection into the reactor pressure vessel (RPV) when reactor vessel pressure decreases to system discharge shutoff pressure. HPCI injection begins as soon as the HPCI turbine-pump is up to speed. The injection valve is open, since the HPCI system is capable of injecting water at full flow into the RPV over a pressure range from 200 psig to reactor pressure specified in mode A of Vendor Technical Document PN1-E41-1020-0004.

6.3.6 References

6.3-1 Deleted.

6.3-2 H. M. Hirsch, "Methods for Calculating Safe Test Intervals and Allowable Repair Times for Engineered Safeguard Systems," NEDO-10739, General Electric, January 1973.

6.3-3 General Electric, "General Electric Standard Application for Reactor Fuel," including the "United States Supplement," NEDE-24011-P-A and NEDE-24011-P-A-US (latest revision).

6.3-4 *"SAFER/GESTR-LOCA Loss-of-Coolant Accident Analysis for Hope Creek Generating Station at Power Uprate,"* NEDC-33172P, March 2005.

6.3-5 General Electric Licensing Topical Report NEDC-30936P-A, "BWR Owner's Group Technical Specification Improvement Methodology," Parts 1 and 2, dated December 1988.

6.3-6 General Electric Licensing Topical Report GENE-770-06-2-A, "Addendum to Bases for Changes to Surveillance Test Intervals and Allowed Out-of-Service Times for Selected Instrumentation Technical Specifications," dated December 1992.

6.3-7 Deleted

6.3-8 Deleted

6.3-9 Deleted

6.3-10 ABB Combustion Engineering Nuclear Operations, "Reference Safety Report for Boiling Water Reactor Reload Fuel", CENPD-300-P-A.

6.3-11 Deleted.

6.3-12 NFS-0256 (latest revision), Hope Creek Generating Station, 10CFR50.46 Report Source Information.

6.3-13 NFVD-AB-2000-004-00, "HCGS LOCA Analysis Report", March 2000.

6.3-14 NFSI-04-056, "GE9B MAPLHGR Information Considering a Reduced LPCI Flow Rate", April 30, 2004.

6.3-15 "Hope Creek Generating Station GNF2 ECCS-LOCA Evaluation", 002N5176-R0, Revision 0, August 2016.

TABLE 6.3-1

OPERATIONAL SEQUENCE OF EMERGENCY CORE COOLING SYSTEM FOR

DESIGN BASIS ACCIDENT[1]

(Cycle 1 representative of later cycles)

Time (s)	Events
Approx. 0	Design basis loss-of-coolant accident is assumed to start; offsite power is assumed to be lost.
Approx. 0	Drywell high drywell pressure[2] and reactor vessel low water level (level 3) are reached. All SDGs are signaled to start, reactor scram is initiated, and HPCI, Core Spray, and LPCI receive the first signal to start on drywell high pressure.
Approx. 2	Reactor low-low water level (level 2) is reached. HPCI receives the second signal to start. The HPCI injection valve is signaled to open.
Approx. 5	Reactor low-low-low water level (level 1) is reached. The second signal to start LPCI and Core Spray is given. The auto-depressurization sequence begins: MSIVs are signaled to close.
Approx. 15	All SDGs are ready to load. Energizing of the Core Spray and RHR (LPCI) pump motors begins.
Approx. 22	Reactor low pressure is reached. The Core Spray injection valves receive the pressure permissive signal to open.
Approx. 24	LPCI injection valves receive pressure permissive signal to open.

TABLE 6.3-1 (Cont)

Time (s)	Events
Approx. 34	The core spray pumps are at rated flow and the core spray injection valves are open, which completes the core spray system startup.
Approx. 35	The HPCI injection valve is open and the pump is at design flow, which completes the HPCI startup.
Approx. 48	The LPCI pumps are at rated flow and the injection valves are open, which completes the LPCI system startup.
See Figure 6.3-20	The core is effectively reflooded, assuming the worst single failure; heatup is terminated.
>10 min	The operator shifts to containment cooling.

---

(1) For the purpose of all but the next-to-last entry on this table, all ECCS equipment is assumed to function as designed. Performance analysis calculations consider the effects of single equipment failures (see Sections 6.3.2.5 and 6.3.3.3).

(2) No credit is taken in the LOCA analysis for ECCS initiation on the high drywell pressure signal.

TABLE 6.3-2

SIGNIFICANT INPUT VARIABLES USED IN
LOSS-OF-COOLANT ACCIDENT ANALYSIS

Variable	Value
1. Plant Parameters	
Core thermal power	3917 MWt
Vessel steam output	17.198×10^6 lbm/h
Corresponding percent of rerated steam flow	Approx. 102.5%
Vessel steam dome pressure	1020 psia
Maximum area of recirculation line break	4.1 ft^2
2. Emergency Core Cooling System Parameters	
Low Pressure Coolant Injection System	
Vessel pressure at which flow may commence	≤286 psid (vessel to drywell)
Minimum rated flow at vessel pressure	36,000 gpm, at 20 psid (vessel to drywell)
Initiating signals	
Low water level, or	1.0 feet above top of active fuel

TABLE 6.3-2 (Cont)

Variable	Value
High drywell pressure	2.0 psig
Maximum allowable time delay from initiating signal to pumps at rated speed	40 seconds
Pressure at which injection valve may open	360 psig
Injection valve fully open	Greater of a) 40.0 sec after DBA b) 24.0 sec after pressure permissive
Core Spray System	
Vessel pressure at which flow may commence	≤289 psid (vessel to drywell)
Minimum required flow, at vessel pressure	5650 gpm, at 105 psid (vessel to drywell)
Initiating signals	
Low water level, or	1.0 feet above top of active fuel
High drywell pressure	2.0 psig
Minimum allowed (runout) flow per loop	7000 gpm

TABLE 6.3-2 (Cont)

Variable	Value
Maximum allowed delay time from initiating signal to pump at rated speed	27 seconds
Pressure at which injection valve may open	≤425 psig
Injection valve fully open	≤27 seconds after maximum break or 12 seconds after pressure permissive signal, whichever is greater
Combined HPCI/Core Spray System	
Minimum flow rate (independent of vessel pressure)	5600 gpm
Minimum core spray flow available to core, at vessel pressure	6050 gpm, at 105 psid (vessel to pump suction)
Initiating signals	
Low water level, or	8.6 feet above top of active fuel
High drywell pressure	2.0 psig

Variable	Value
Maximum allowed delay time from initiating signal to rated flow available and injection valve wide open	27 seconds (core spray system) 35 seconds (HPCI system)
HPCI flow rate injected through the core spray sparger	3000 gpm (maximum) 2000 gpm (minimum)
Automatic Depressurization System	
Total number of relief valves installed with ADS function	5
Number of ADS valves used in analysis	4 (for large break) 5 (for small break, see References 6.3-4 and 6.3-15)
Total minimum flow capacity for 5 valves, at a vessel pressure	4.0×10^6 lbm/h, at 1125 psig
ADS timer initiating signals	
a) Low water level, and	1.0 feet above top of active fuel
high drywell pressure, and a	2.0 psig

Variable	Value
signal that at least one RHR pump or one Core Spray System is running at a pump discharge pressure	145 psig (not modeled)
or	
b) Low water level, and	1.0 feet above top of active fuel
high drywell pressure bypass timer timed out and a	6 minutes from initiating signal
signal that at least one RHR pump or one Core Spray System is running at a pump discharge pressure	145 psig (not modeled)
ADS timer delay time from all initiating signals completed to the time valves are open	120 seconds
High drywell pressure bypass timer initiating signal low water level	1.0 feet above top of active fuel

TABLE 6.3-2 (Cont)

Variable	Value
3. Fuel Parameters	
Fuel type	Control cell core
Fuel bundle geometry	10 x 10
Number of fueled rods per bundle	92
Peak technical specification linear heat generation rate	MAPLHGR is defined in Technical Specifications Core Operating Limit Report
Initial minimum critical power ratio	1.25

TABLE 6.3-3

SUMMARY OF LOCA ANALYSIS RESULTS

1. Fuel Type	GNF2 Fuel	GE14 Fuel	Acceptance Criteria
2. Limiting Break	DBA Suction	DBA Suction	
3. Limiting Failure	Battery	Battery	
4. Peak Cladding Temperature (Licensing Basis)	1610°F	1380°F	≤ 2200°F
5. Maximum Local Oxidation	<1.0%	<1.0%	≤ 17%
6. Core-Wide Metal-Water Reaction	<0.1%	<0.1%	<1.0%
7. 4.1 ft^2 (DBA, Appendix K) (3)	1591°F(2)	1360°F(1)(4)	
8. 0.08 ft^2 (Appendix K)	1522°F(2)	1146°F(1)	

(1) SAFER/GESTR methodology

(2) SAFER/PRIME methodology

(3) This case assumes the LPCI minimum flow bypass valve remains open and has reduced LPCI flow.

(4) This does not include the effects on peak cladding temperature of known changes or errors in the acceptable ECCS evaluation models. Results of peak cladding temperature including 10CFR50.46 Notification Letters are provided in Table 6.3-7.

Table 6.3-3a

SUMMARY OF SAFER/GESTR-LOCA RESULTS

FOR NON-RECIRCULATION LINE BREAKS[1]

(Nominal Analysis Basis)

Break Size Break Location[4]	**Single Failure**	**GE14 PCT** (°F)
0.32 ft^2 Core Spray Line	Battery	616
3.89 ft^2 Steam Line inside Containment[3]	Battery	589[2]
3.64 ft^2 Steam Line outside Containment[3]	Battery	589[2]
1.07 ft^2 Feedwater Line	Battery	589[2]
0.50 ft^2 LPCI Line	Battery	589[2]

NOTES:

(1) All cases assume the LPCI minimum flow bypass valve is open. For GE14, peak local oxidation is <1% and core-wide metal-water reaction is <0.1% for all cases.

(2) Maximum PCT is at the initial operating temperature.

(3) Steam line break areas are prior to MSIV closure. Following MSIV closure, the inside containment break area is reduced to 2.98 ft^2 and the outside containment break area is zero.

(4) These break locations being historically shown non-limiting for the system, it is inferred they would remain so with a GNF2 core; therefore, the analysis is not repeated with the later fuel bundle design.

TABLE 6.3-4

THIS TABLE INTENTIONALLY DELETED

TABLE 6.3-5

THIS TABLE INTENTIONALLY DELETED

TABLE 6.3-6

SINGLE FAILURE EVALUATION

The following table shows the single active failures considered in the ECCS performance evaluation.

Assumed Failure[1]	Systems Remaining[2]
Channel A dc source	1 core spray loop + 3 LPCI + 4 ADS [3]
SDG	1 core spray loop + HPCI + 3 LPCI + 4 ADS[3]
LPCI injection valve	2 core spray loops + HPCI + 3 LPCI + 4 ADS[3]
HPCI	2 core spray loops + 4 LPCI + 4 ADS[3]

(1) Other postulated failures are not specifically considered, because they all result in at least as much ECCS capacity as one of the failures designated above.

(2) Systems remaining, as identified in this table, are applicable to all non-ECCS line breaks. For a LOCA from an ECCS line break, the systems remaining are those listed, less the ECCS system in which the break is assumed.

(3) Five ADS valves are assumed for the small break analyses. Four operable ADS valves (one non-functioning ADS in addition to the single failure) are conservatively assumed for large break analyses and a separate small break sensitivity study to determine the impact of an ADS valve out-of-service. Analysis of four ADS valves shows that the ADS failure is bounded by the battery failure.

TABLE 6.3-7

Changes or Errors in Acceptable ECCS Evaluation Models
Peak Cladding Temperature

The following results include the effects of known changes or errors (Reference 6.3-12) in the approved ECCS evaluation models described in Reference 6.3-3 on the calculated limiting peak cladding temperature transient applicable to HCGS as estimated in accordance with 10 CFR 50.46(a)(3)(i).

Licensing Basis Event	Licensing Basis Peak Cladding Temperature
4.1 ft^2 (DBA) Recirc. Suction/Channel A dc source	1380°F (GE14C) 1610°F (GNF2)

GE14C FUEL

Description of Change/Error	Impact	Final Peak Cladding Temperature
Impact of Database error for heat deposition on the Peak Cladding Temperature for 10x10 fuel bundles	+45°F	1425°F
Impact of updated formulation for gamma heat deposition to channel wall for 9x9 and 10x10 fuel bundles	+5°F	1430°F
PRIME code implementation for fuel rod T/M performance, replacing GESTR	+45°F	1475°F

TABLE 6.3-7 (Cont)

GE FUEL

Description of Change/Error	Impact	Final Peak Cladding Temperature
SAFER04A E4 Mass Non-Conservatism. Non-conservatism occurs when upper plenum liquid mass and core spray flow rate is low; system mass is gradually lost due to core spray being discarded, resulting in marginally less ECCS flow credited as reaching the core.	+10°F	1485°F
SAFER04A E4 Minimum Core DP Model. Due to calculation of a non-physical low Δp for droplet flow above a two-phase level in the core, a minimum core Δp was imposed. For cores with greater voiding (more steam flow), this minimum Δp could be non-conservative, actually driving the steam flow slightly, and offering inappropriate steam cooling benefit above the core two-phase level.	+20°F	1505°F
SAFER04A E4 Bundle/Lower Plenum counter current flow limitation (CCFL) Head. A CCFL is applied on the interface between the hot bundle and the lower plenum. The pressure head applied at that location should be based on the liquid water level in the bundle; however, the iteration scheme for CCFL would introduce a pressure head different than the pressure head based on the liquid water level in the bundle. The iteration scheme has been corrected.	-20°F	1485°F

Figure F6.3-1 intentionally deleted.

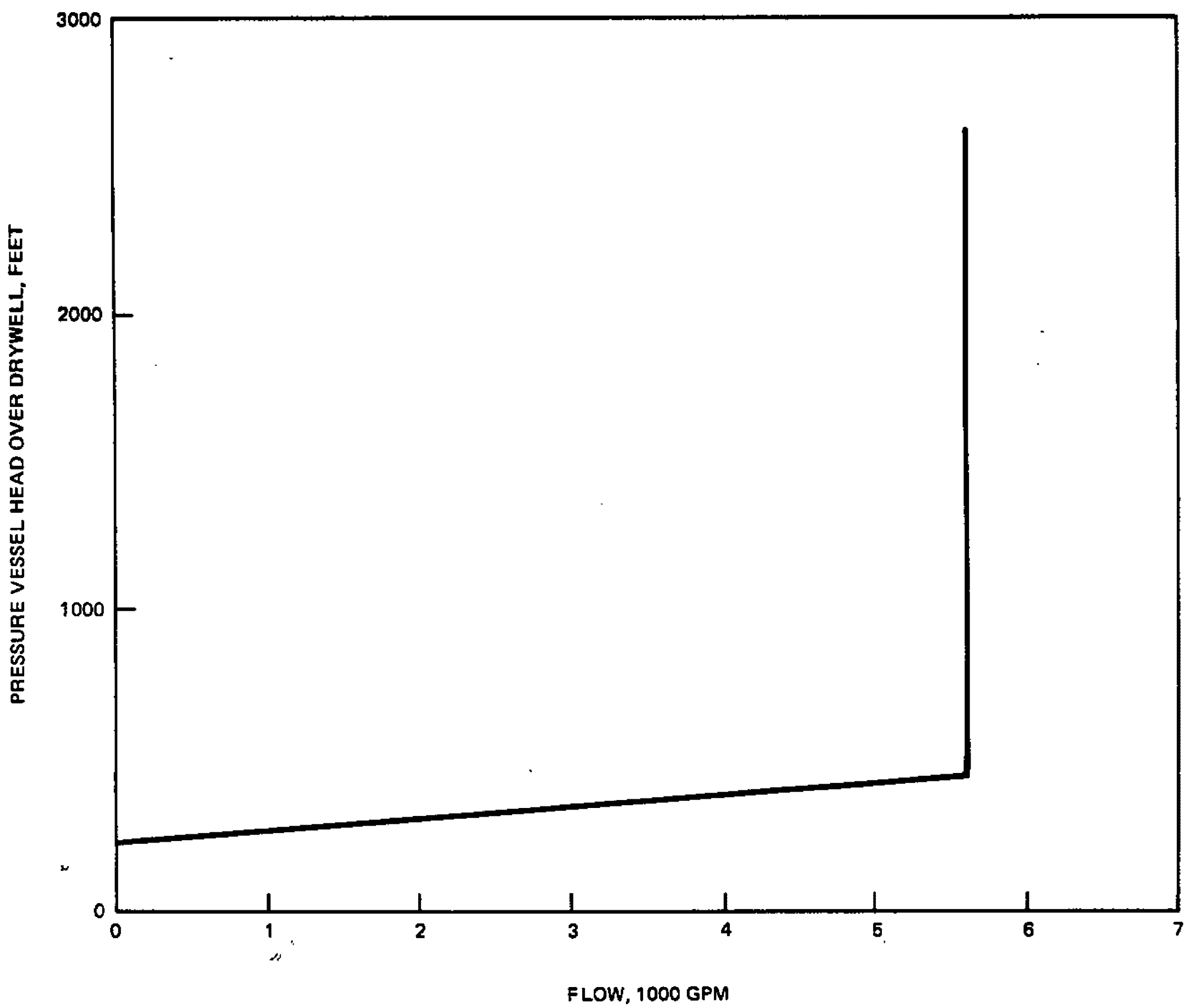
Refer to Plant Drawing M-55-1 in DCRMS

Figure F6.3-2 intentionally deleted.

Refer to Plant Drawing M-56-1 in DCRMS

Figure F6.3-3 intentionally deleted.

Refer to Vendor Technical Document PN1-E41-1020-0004 in DCRMS



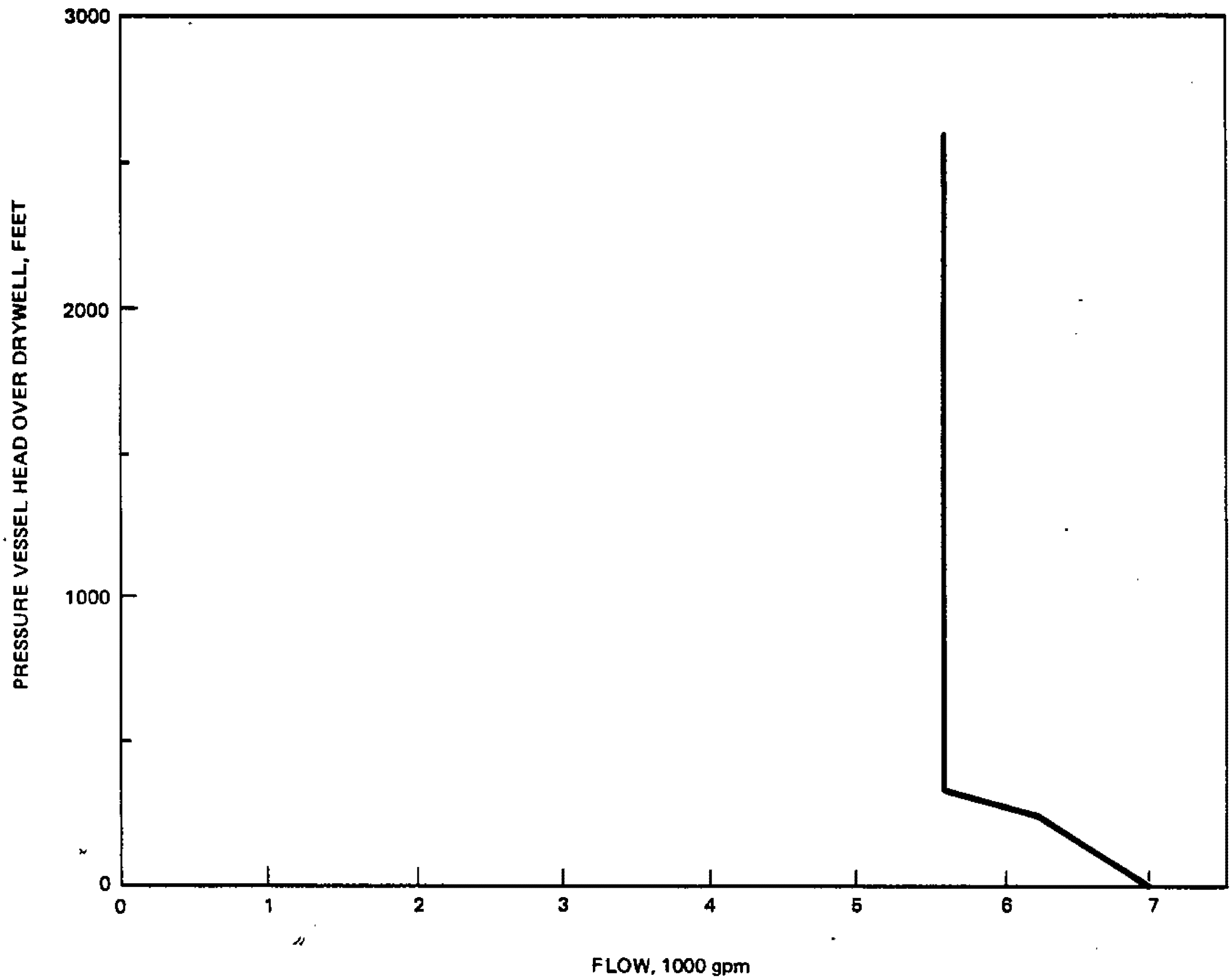
REVISION 0
APRIL 11, 1988

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
HOPE CREEK NUCLEAR GENERATING STATION

HEAD vs HIGH PRESSURE COOLANT INJECTION FLOW USED IN LOCA ANALYSES

UPDATED FSAR

FIGURE 6.3-4



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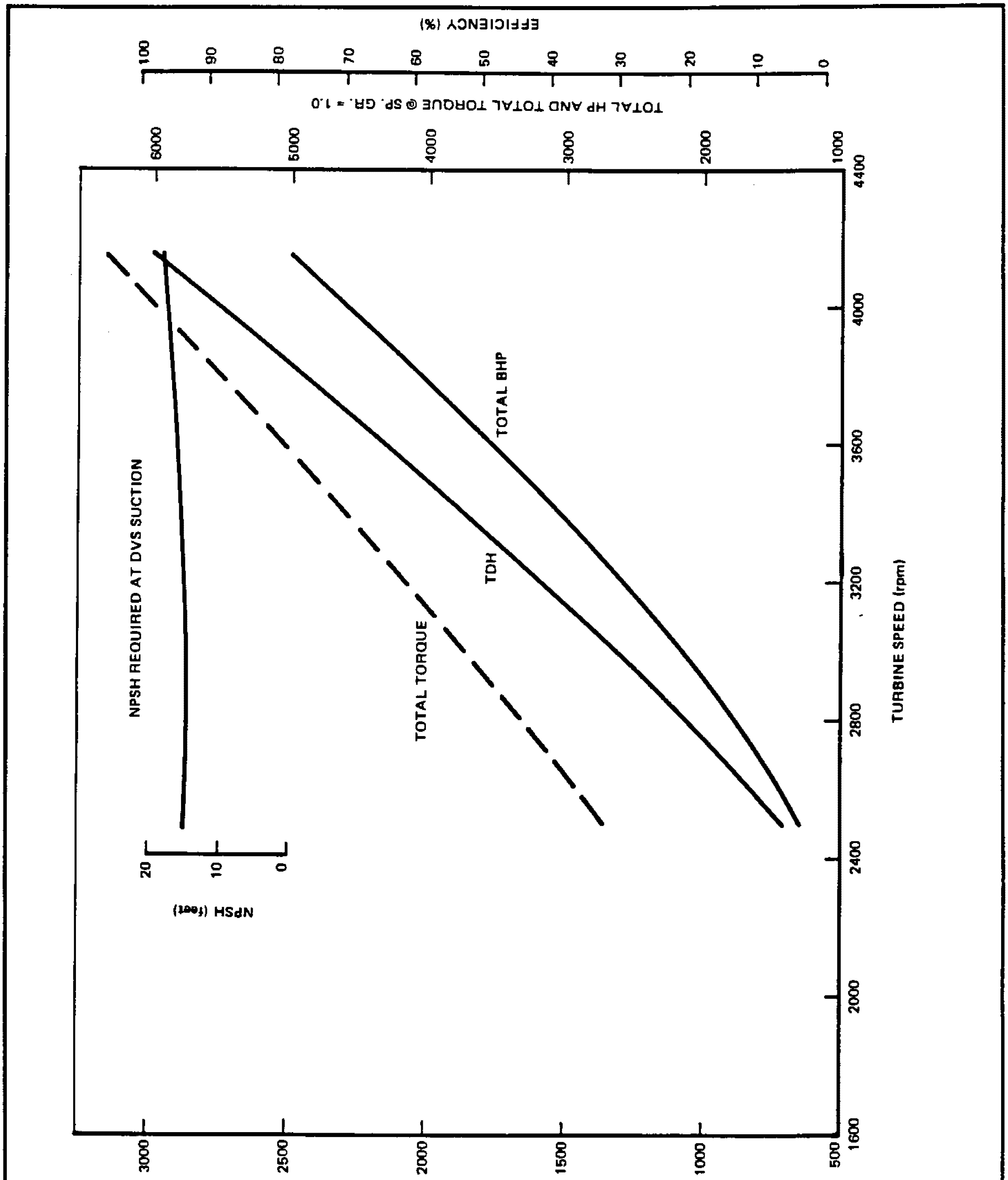
HOPE CREEK NUCLEAR GENERATING STATION

HEAD vs COMBINED HIGH PRESSURE COOLANT INJECTION/CORE SPRAY FLOW USED IN LOCA ANALYSES

UPDATED FSAR

FIGURE 6.3-5



PUBLIC SERVICE ELECTRIC AND GAS COMPANY
HOPE CREEK GENERATING STATION

HIGH PRESSURE COOLANT INJECTION PUMP CHARACTERISTICS AT 5600 GPM

Updated FSAR
Revision 6, October 22, 1994

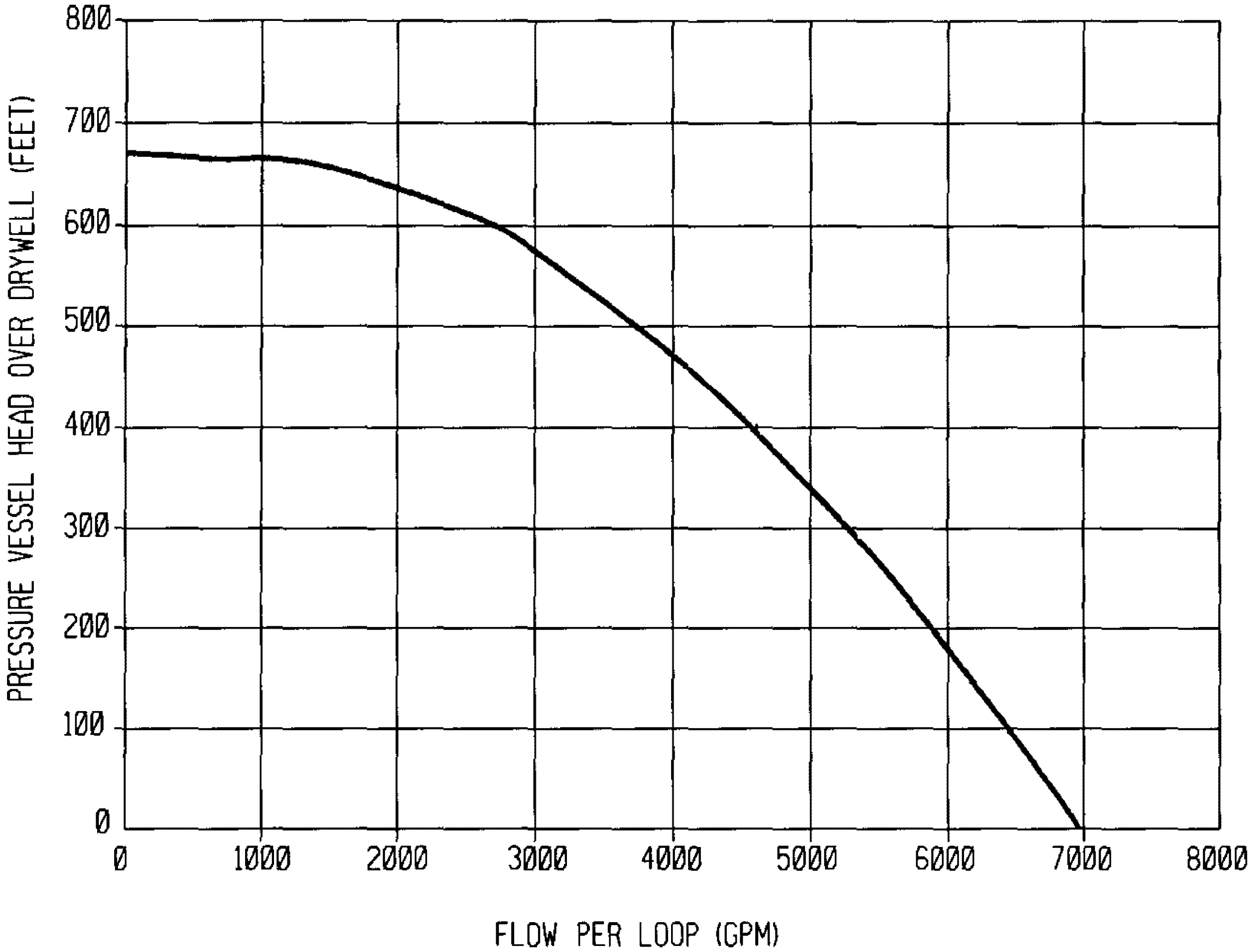
Sheet 1 of 1
Figure 6.3-6

Figure F6.3-7 intentionally deleted.

Refer to Plant Drawing M-52-1 in DCRMS

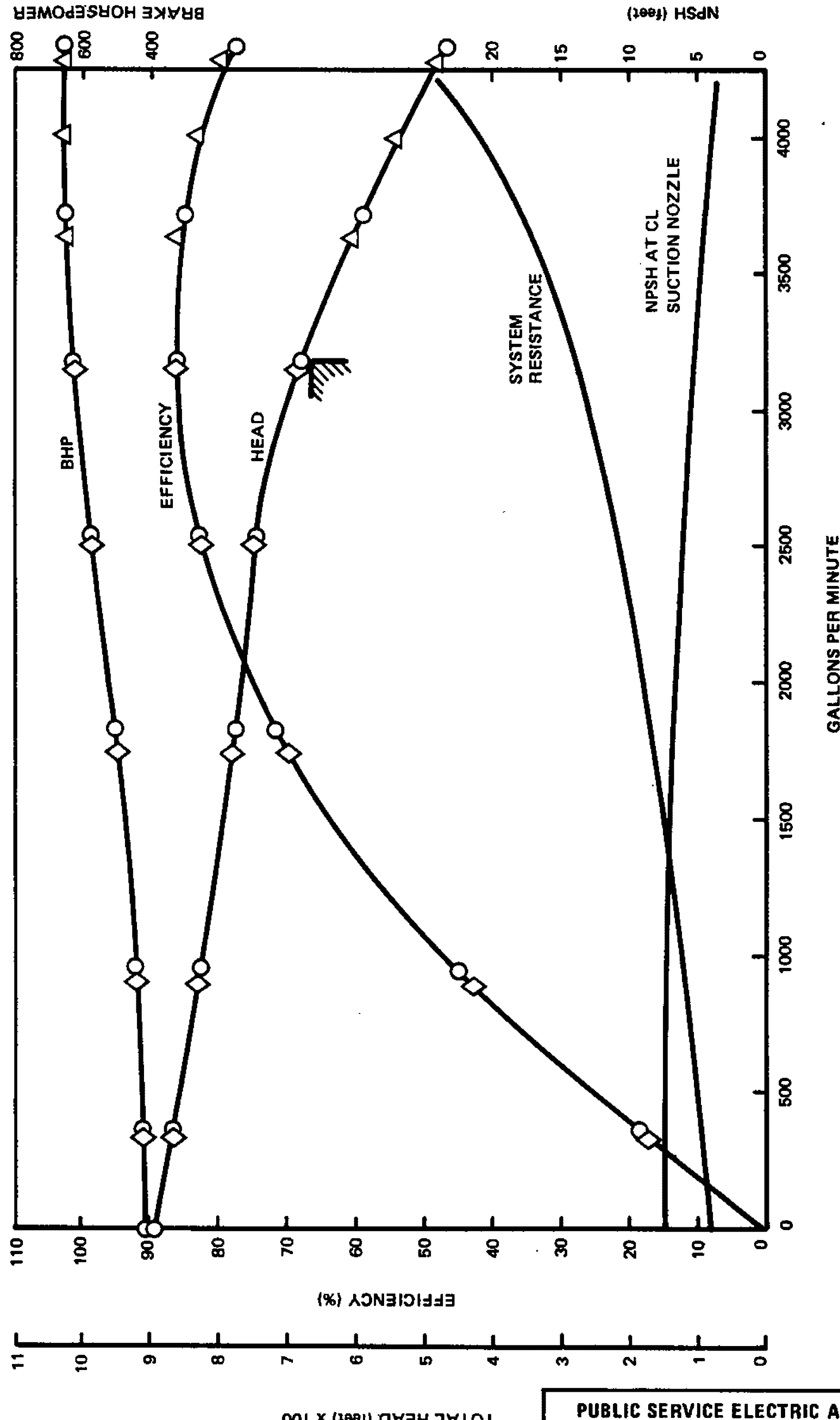
Figure F6.3-8 intentionally deleted.

Refer to Vendor Technical Document PN1-E21-1020-0003 in DCRMS



Revision 12, May 3, 2002

PSEG Nuclear, LLC HOPE CREEK NUCLEAR GENERATING STATION	Hope Creek Nuclear Generating Station HEAD vs CORE SPRAY FLOW ASSUMED IN LOCA ANALYSES
	Updated FSAR Figure 6.3-9



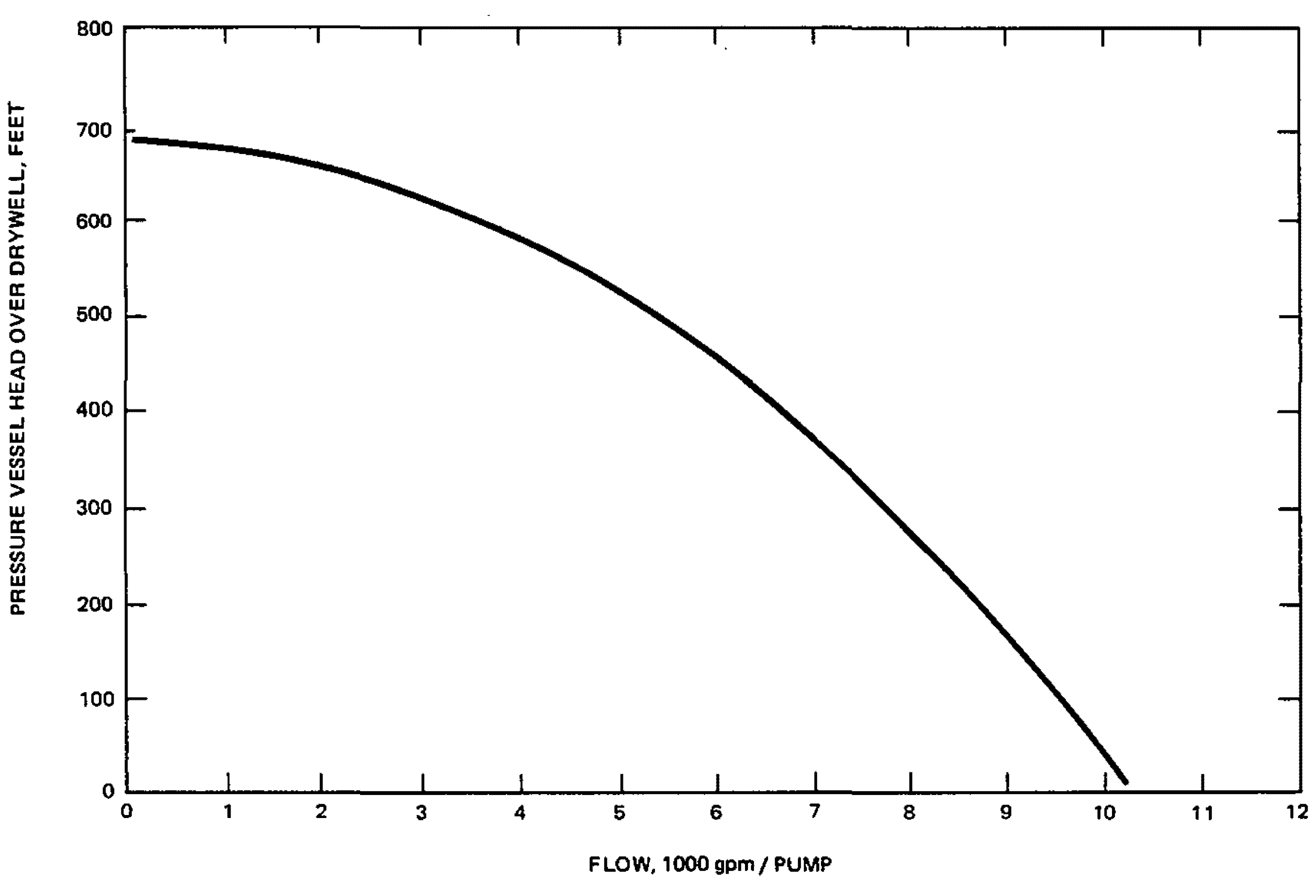
REVISION 0
APRIL 11, 1988

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
HOPE CREEK NUCLEAR GENERATING STATION

CORE SPRAY
PUMP CHARACTERISTICS

UPDATED FSAR

FIGURE 6.3-10



REVISION 0
APRIL 11, 1988

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
HOPE CREEK NUCLEAR GENERATING STATION

HEAD vs LOW PRESSURE COOLANT INJECTION FLOW USED IN LOCA ANALYSES

UPDATED FSAR

FIGURE 6.3-11

MODE F

(SEE NOTE 3)

POSITION ○	1	2	3	4	5	6	49	7	8	9	10	13	24	1
FLOW GPM	—	10150	←									→	10150	—
PRESS PSIA	14.7	X	X	X	X	X	X	X	X	X				14.7
TEMP F	—	20/40	←									→	120/40	—
MAX PRESS DROP FEET					TDH=350			—	—		---	---		

LOOPS A & B TEST
LOOPS C & D TEST

MODE G

SEE NOTE 12 — R PRESS 82 PSIG

POSITION ○	29	25	56.1	26	4	5	6	43	24	1		1	2	3	4	5	6	6.2 A&B	43 A&B	24 A&B	1
FLOW GPM	—	1000	←					→	1000	—		—	1000	←			→	1000	2000	2000	2000	—
PRESS PSIA	90	X	X	X	X	X			X	14.7		14.7	X	X	X	X				X	14.7
TEMP F	—	325	←					→	325	—		—	25/40	←					→	125/40	—
MAX PRESS DROP FEET						TDH (TE)										TDH 765					

LOOPS A & B — LOOPS C & D

MODE S

POSITION ○	1	2	3	4	5	6	18 A,B	19 A,B	20 A,B	9	10	46	11	48 A,B	21 A,B	30 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	1015	X	15.5	X	REF 4	X	1015	X	X
TEMP F	90/40	←									→	90/40	547	90/40	135	90/40	547	90/40	547	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		1015	10 5	X	X	X		X	X	X	X	X
TEMP F	AMB	AMB	AMB		SAT	SAT	AMB	90/40	90/40		90/40	90/40	AMB	AMB	AMB
MAX PRESS DROP FEET															

MODE C 2 (SEE NOTE 23)

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	—	18,000	←												→	18,000	—		9000	9000
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	←				→	120	114.8	←					→	114.8	—		95	100.8
MAX PRESS DROP FEET					TDH 350															

CAPABILITY PER POOL COOLING HX 36 X 10[6] BTU/HR (1HX OPERATING)

MODE A 1

(SEE NOTE 3 & 14)

POSITION ○	1	2	3	4	5	6	7	8	9	10	16	11	29
FLOW-GPM	—	10,150	←								→	10,150	—
PRESS PSIA	76.7/14.7	X	X	X	X								76.7/14.7
TEMP F	—	170/40	←								→	170/40	—
MAX PRESS DROP FEET					TDH=350								

LOOPS A & B
LOOPS C & D

MODE A 2

(SEE NOTE 14)

POSITION ○	1	2	3	4	5	6	7	8	9	10	16	11	29
FLOW-GPM	—	1600	←								→	1600	—
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 325			—					

LOOPS A & B
LOOPS C & D

MODE B

(TYPICAL OF A OR 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	15_B	14	21_B	22	23_B	1		60_B	61_B
FLOW-GPM	—	10,000	←													→	10,000	9500	—	500	—		9000	9000
PRESS-PSIA	76.7/14.7					X	X	X	X	X	X	X	X	X	X	X			76.7/14.7		76.7/14.7		X	X
TEMP F	—	212	←					→	212	187.7	←					→	187.7	—	187.7	—			95	122
MAX PRESS DROP FEET					TDH 350																			

CAPABILITY PER HX 121.7 X 10[6] BTU/HR (1 HX OPERATING)

PASSING THRU ABOVE POSITIONS (TYP)

MODE D 1 (SEE NOTE 13)

RX PRESSURE 35 PSIG

POSITION ⬡	29	25	56	4A	4C,B	5A	5C,B	6A	6C,B	9C 9E 12 16	7 7A	18A,B	19A,B	8A,B	9A B	10A B	14	27B	28	30	31	33	29	27A	28	29	60A,B	61A,B
FLOW GPM		20,000	20,000	0	10,000	0	10 000	0	10 000	10 000	10,000					→	10,000	9000	9000	1000	100	1000	—	10,000	10 000	—	9000	9000
PRESSURE - PSIA	50	X	X	X	X	X	X	X	X	X	X	X	X	X	X		X	X	X	X	X	X	50	X	X	50	X	X
TEMP F	—	281	281		281		281		281	281	28	281	244.2									→		240.2	240.2		85	130.3

MODE E 1 (SEE NOTE 8) RX PRESSURE 0 PSIG

POSITION ⬡	29	25	26	56.1	4B,C	5B,C	6B,C	10.1 C,D	7.2 A-B	18A,B	19A,B	9A,B	10A B	11A,B	16A,B	27A,B	28	29		60A,B	61A,B
FLOW-GPM	—	20,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000							→	—			9000	9000
PRESSURE-PSIA	14.7	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	14.7			X	X
TEMP F	—	125					→	116.7								→	—			85	94.3

MODE C

POSITION	1	2B	3B	4B	5B	6B	7B	17B	18B	19B	20B	9B	10B	13B	43B	24B	1	60B	61B
FLOW/GPM	--	10000	←												→	10000	--	9000	9000
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	--	212	←					→	212	187.7	←				→	187.7	--	85	122
MAX PRESS DROP FEET					TDH = 350														

CAPABILITY PER COOLING HX 121.7 X 10[6] Btu/HR (1HX OPERATING)

MODE D

(SEE NOTE 13) RX PRESS 35 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	28	29	$60_{A,B}$	$61_{A,B}$
FLOW/GPM	—	20,000	20,000	10,000	←						→	10,000	9000	9000	1000	1000		1000	—	10,000	10,000	—	9000	9000
PRESS PSIA	50			X	X	X	X	X	X	X	X	X	X	X				X	50	X	X	50	X	X
TEMP F	—	281	←			→	281	244.2	←						→	244.2		244.2	—	244.2	244.2	—	85	134.3
MAX PRESS DROP FEET					TDH 350										ΔH			Δ		ΔH	28			

CAPABILITY PER HX 203.8 X 10[6] BTU/HR (2HX'S OPERATING)

MODE E

(SEE NOTE 8) RX PRESS 0 PSIG

POSITION ○	29	25	26	56.1	4	5	6	$18_{A,B}$	$19_{A,B}$	9	10	11	$16_{A,B}$	$27_{A,B}$	28	29		$60_{A,B}$	$61_{A,B}$
FLOW GPM	—	20,000 / 10,000	20,000	10,000	←									→	10,000	—		9000	9000
PRESS PSIA	14.7	X	X	X	X	X	X	X	X	X	X	X			X	14.7		X	X
TEMP F	—	125	←				→	125	116.7	←				→	116.7	—		85	94.3
MAX PRESS DROP FEET						TDH=350		ΔH=23.3										ΔH	23.1

DUTY PER HX 41.6 X 10[6] BTU/HR (2 HX'S OPERATING)

LOOPS A & B TEST
LOOPS C & D TEST
LOOPS A & B

MODES

A-1 CC DEN TH REC RCULAT ON HE BRCA E THE DE AND HREE PUMP OPERATION. ONE TRA NER S PLUGGED

A-2 CC DENT WITH REC RCULA ON LINE BRCA E THE S DE AND THREE ... ERATION ONE ... 10)

B POST CC DENT CON NMENT SPRA TH HEAT REJEC ION TH ONE PUMP OPERA ION AND TRA NER 50S PLUGGED (PEAK SUPPRESS ON POOL TEMPERATURE)

POST ENT UP RESS ON POO OOLI

RMAL HUTDOWN AFTE LOWDOWN TO MAIN ONDEN ER (OTE)

D- RMAL HUTDOWN FTER LOWDOWN AIN NDEN ER IN RHR OSS-TI ALVES (570/V600 AND 57 /V60) (OTE)

NTINU TI RMAL HUTDOWN FR LANT M (PS G) AND FUNCTI AL UM TEST FTER HUTDOWN

NTINU TI RMAL HUTDOWN FR LANT D- (PS G) RHR OSS TI ALVES (V 570/V600 AND 57 /V60)

RHR STEM TEST URIN LANT RATI

INI UM FLOW PASS M

STEM STAND UTY

LEGE D

ESS E E EL E
E D
L C E D
O S
E E S

REFERENCE DOCUMENTS		MPL ITEM NO.
1	RE DUAL HEAT REMOV SYSTEM & D	E 1 0
2	RES DUAL HEAT REMOVAL SYSTEM DE GN SPEC	E 1 0
3	RC C E D	E 1 020
	REC RC SYSTEM PROCESS FLOW GRAM	B32 1040
5	E D	E21 1020

N TES

1

2 PIPING BETWEEN PO NTS WITH EMPTY DATA BLANKS (SEE ALSO ABLE) SHALL BE ED BY THERS BASED ON SPE ED OPERA ING COND ONS EMPTY DA BLANKS CAN BE LLED (BASED ON TUAL ARRANGEMEN), OR EQU ALENT HYDRAUL C DATA SUBMITTED TO GE BWRSD FOR REVIEW.

INDICATES THE DATA IS NO GN CANT

3 SHOWN AS TYP CAL FOR ONE OOP OOPS ON DE I AND DE II RE NOT SYMMETR CALLY ARRANGED VALUES OR BOTH DE SHALL BE SUBMITTED

VALUES FOR EQU PMENT WITHI GE BWRSD SCOPE ARE AS NOTED.

5 ELEVA ON ARE NOT NCLUDED AP ALUES YDR CL ONS SHAL BE NCLUDED WHEN DETERMI NG NAL VALUES OR THE EMPTY DATA BLANKS

6 INDICATES MAX MUM ( ) AND MI MUM ( ) ALUES OR THE MODE SPEC ED.

7 DASHED NES IND CATE FLOW DOES NOT PASS THRU THESE PO NTS

8 E E T E NCE OC ON E BOVE OUN E QUAL E E HE VALUE OWN E OOES. MODE A 2 WITH SUPPRESSION POOL AT 212°F 5 8 FEET AT 1 600 GPM E T B E E PUMP SUC IO E QUAL D PL NE NCE VA ON EE NE OC TI E TE E T UC O LE

9 E WA T ROV SHA L E S E O ON O N.

1 6 BE Z BA ED ON NO ON L L C AG N.

11 E DIC S VAL E S DU NG E O

12 EMPERATURE & PRESSURE OR VESSEL SUCT ON APPL TO LOOPS AB ONL

13 SHUTDOWN OPERAT ON MAY BE TED 82 PS G RX PRE SURE

TYP CAL UE OR MAX AND SUPPRESS ON POOL TEMP SHOWN. NAL EMPERATURE DEPEND ON AL POOL WATER TEMPERATURE & POOL ER VOLUME

15 WATER FLOWS ARE GPM, TEAM FLOWS ARE 1000 BS/HR.

16

17 FOR L NE I NG INFORMATION SEE REF 1.

18 THE VE ONT OF WATER THE SHUTDOWN COOL NG SUBSYSTEM NG, NCLUD NG THE HEAT EXCHANGERS AND PUMPS SHALL NO EXCEED 305,000# 7 F TO PREVEN DILUTION OF ABORT QU D CONTROL NEUTRON ABSORBER BELOW MI MUM REQU REMENTS

19 DELETED

20 PRESSURE AND TEMPERATURE AND THE MATED NE ES ARE FOR NFORMAT ON ONL ACTUAL DE GN PRESSURE & TEMPERATURE AND NE ZES AS DETERMINED BY OTHERS SHALL MEET THE PROCESS DATA HYDRAUL C REQU REMEN

21 S TS T AX

22. HPCI STEAM SUPPLY TO THE RHR SYSTEM AND FLU D D SCHARGE TO THE RCIC SYSTEM WAS OR GINALLY I STALLED FOR OPERAT ON OF THE RHR SYSTEM N THE STEAM CONDEN NG MODE THE STEAM CONDENS NG MODE HAS BEEN DELETED BUT THE ASSOC ATED PIPING AND VAL ES HAVE NOT BEEN REMOVED AND ARE THEREFORE SHOWN TO REFLECT THE EXIST NG PLANT CONFIGURATION

23 MODE C 2 IS INCLUDED FOR SUPPRESSION POOL COOLING CONDITION FOR LOP< 30 MINUTES ONLY

24. WHEN THE RHR SYSTEM IS OPERATED IN PARALLEL WITH THE FPCC SYSTEM TO PROVIDE FUEL POOL COOLING DURING A FULL CORE UNLOAD, ONE RHR PUMP TAKES THE SUCTION EITHER FROM THE SKIMMER SURGE TANKS OR FROM THE REACTOR VESSEL VIA THE SHUTDOWN COOLING SUCTION PIPING, CIRCULATES THE WATER THROUGH ONE RHR HEAT EXCHANGER, AND RETURNS IT TO THE SPENT FUEL POOL VIA THE TWO RHR INTERTIE RETURN DIFFUSERS.

Ref. Dwg. PN1-E11-1020-0001 (1) Rev. 15

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
HOPE CREEK GENERATING STATION

PROCESS DIAGRAM
RESIDUAL HEAT REMOVAL

Updated FSAR — Sheet 1 of 3

Revision 11, November 24, 2000 — Fig F6.3-12

SEE NOTE 20

POSITION ⬡	3.1	3.2	4	5	6	7	8	9	10	47	16	46	11	7	7.1	18	19	20	8	3.1	4 C/D	5 C/D	6	9	10	46	11	23	54.1	26	4 A/B	5 A/B	16	50	27
DESIGN PRESS. IN PSIG	125	150		RHR PUMP	500								1250	500	450		RHR Hx	450	500	125		RHR Hx	500				1250	SEE REF 4 PIS 1-2	150				500	SEE REF 4 PIS 11-16	
DESIGN TEMP IN °F	212	325			325							460	575	325	325			325	325	212			212				575		325				480		
ESTIMATED LINE SIZE	24"				18"							12"		18"				18"		24"			18"				12"	20"		18"	24"		12"		
	LPCI LINE (VIA RHR Hx BYPASS)													Hx LINE						LPCI LINE (DIRECT TO REACTOR)								SHUTDOWN SUCTION					SHUTDOWN RETURN LINE		

POSITION ⬡	34	35	36	37	17	18	19	20	38	39	40	40.1	41	42	14	30	31	51	33	40	40.2	44	47	48	21	15	52	25	15	53	44	43	24
DESIGN PRESS. IN PSIG	1250				450		450			450		125			500					450	125		500	125		500	125		500		125		
DESIGN TEMP IN °F	575				325		325			140		140			325					140	212		325	212		325	212		325		212		
ESTIMATED LINE SIZE	10"	8		18			18"	4"							6"					4"			16"			4"			18"				
	STEAM TO HX						CONDENSATE FROM HX								HEAD SPRAY LINE					CONDENSATE TO POOL			DRYWELL SPRAY			SUPPRESSION POOL SPRAY			SYSTEM TEST LINES (LOOPS A & B)				

SEE NOTE 22 SEE NOTE 22

POSITION ⬡	56	56.1	4	43	43.1	45	6 C/D	6.1 C/D	6.2	43	6 A/B	6.1 A/B	43
DESIGN PRESS. IN PSIG	150	125		500		125	500	125			500	125	
DESIGN TEMP IN °F	325	212		212			212				325	212	
ESTIMATED LINE SIZE	18"			18"			4"		4"		4"		
	SYSTEM TEST LINES (LOOP C/D)						MIN FLOW BYPASS LINES (LOOP C/D)				MIN FLOW BYPASS (LOOP A/B)		

V-570/V600
V-571/V601

TABLE 1 - VALVE POSITION CHART SEE NOTE 11

	F004 A&B	F004 C&D	F006A	F006B	F051	F052	F047	F048	F003	V-570/V600	V-571/V601	F007	F041	F015	F050	F016	F017	F027	F024	F023	F022	F019	F021	F053	F011	F054	F067A	F067B	F039	F008	F010	F026	STRAINER A&B	STRAINER C&D
MODE A-1	O	O						O					O				O																1-50% P	
MODE A-2	O	O						O					O				O																1-50% P	
MODE B	O	O					O		O							O		O					O										1-50% P	---
MODE C		O					O		O										T														CLEAR	
MODE D-1				O			O	T-C	O	O	O			T	O					T	O	O					O	C	O	O				
MODE E-1				O			O		O	O	O			O-T	O												O	C	O	O				
MODE E TEST		O						O					O				O												O	O	O			
MODE D			O	O			O	T-C	O					T	O					T	O	O							O	O				
MODE E			O	O			O		O					O-T	O														O	O				
MODE F	O	O						O											O-T												O-T		CLEAR	CLEAR
MODE G	O	O	O	O								O O															O	O	O	O			CLEAR	CLEAR
MODE S	O	O					O	O	O			O																					CLEAR	CLEAR

C - VALVE CLOSED
O - VALVE OPEN
T - VALVE THROTTLED
P - STRAINER PLUGGED
T-C - VALVE THROTTLED OR CLOSED
O-T - VALVE OPEN OR THROTTLED
BLANK SPACE INDICATES VALVE IS CLOSED

TABLE 3 LIMITING LINE LOSSES

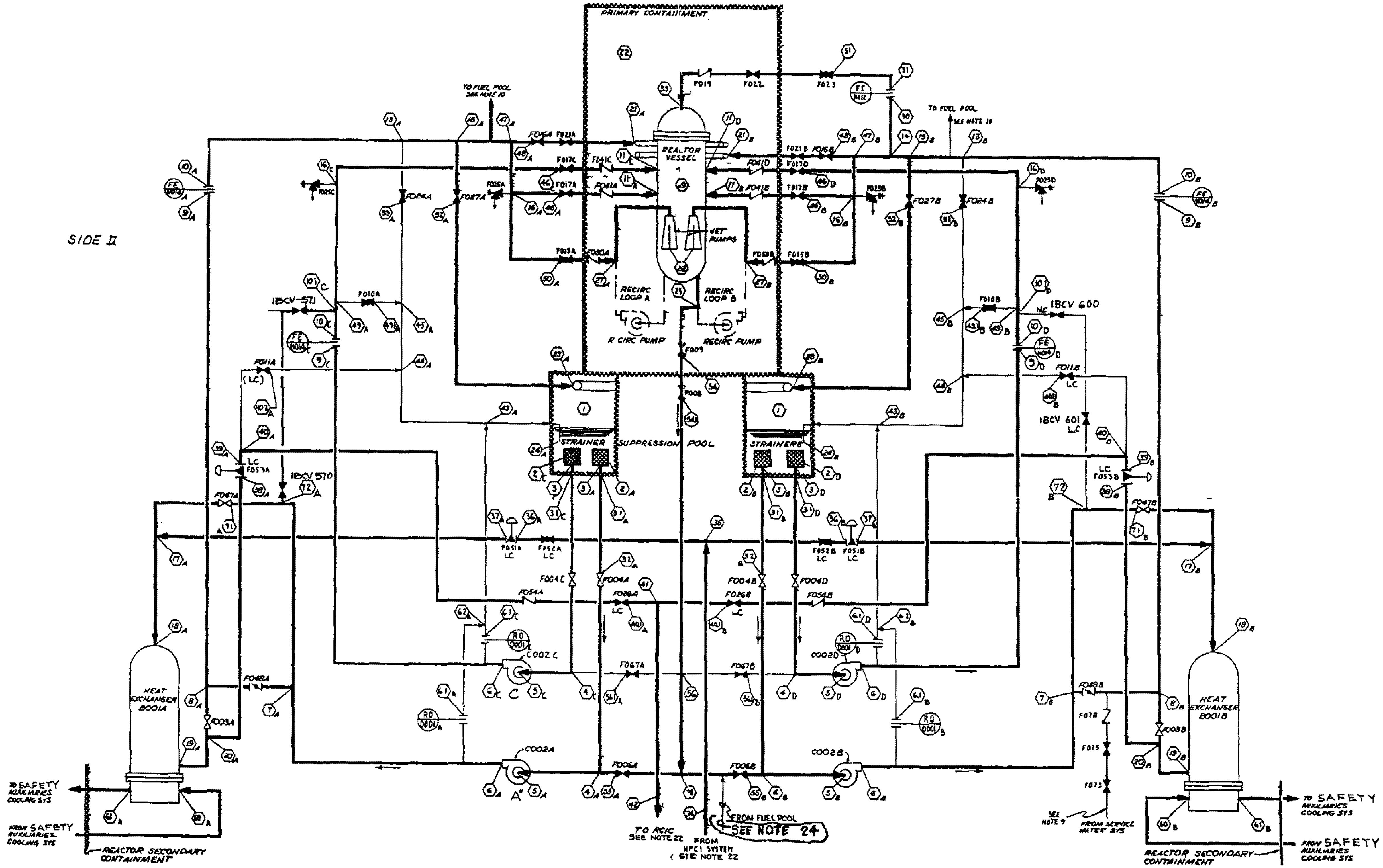
MODE A-1	6-11 PUMP DISCHARGE LINE TO RPV FLOODING PENETRATION
MODE A-2	1-2-5 (SUCTION LINE SUPPRESSION POOL TO PUMP)
MODE B	47-21 & 15-23 (CONTAINMENT SPRAY LINES PUMP DISCHARGE TO TO SPRAY HEADERS)
MODE C	NONE
MODE D	14-51-33-29 (VESSEL HEAD SPRAY LINE) SEE NOTE 10 19-25-5 (SHUTDOWN SUCTION LINE RPV TO PUMP) 56-4 (SHUTDOWN SUCTION LINE TEST BRANCH TO PUMP)
MODE E	16-27 (SHUTDOWN DISCHARGE LINE LPCI BRANCH TO RECIRC LOOP)
MODE F	13-43-24-11 43-45 (TEST LINE TO SUPPRESSION POOL)
MODE G	6-43 (PUMP MINIMUM BYPASS LINE)

Ref. Dwg. PN1-E11-1020-0001(2) Rev. 05

PSEG NUCLEAR, L.L.C.
HOPE CREEK GENERATING STATION

PROCESS DIAGRAM
RESIDUAL HEAT REMOVAL

Updated FSAR Sheet 2 of 3
Revision 12, May 3, 2002 Fig. 6.3-12



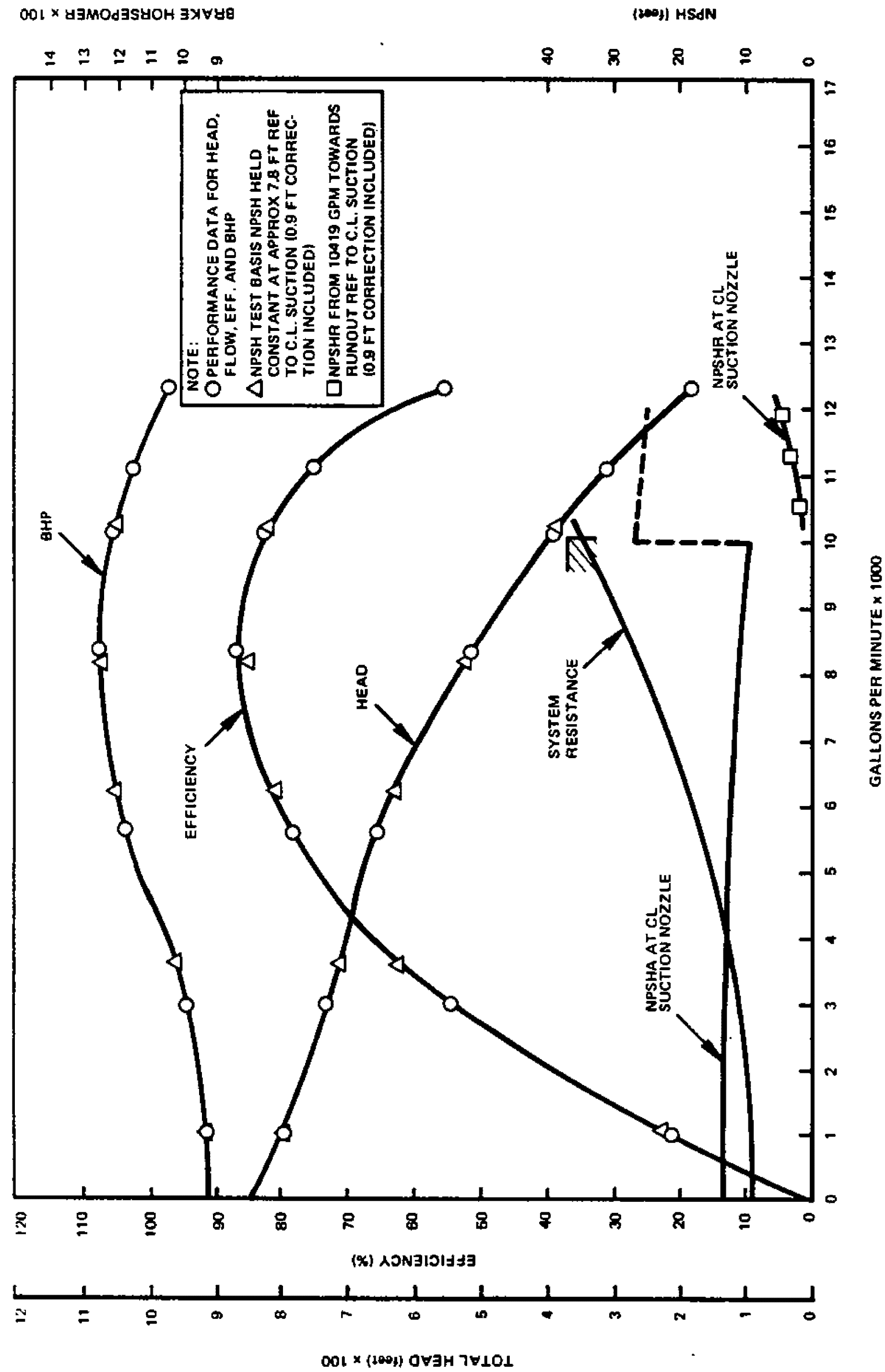
Ref. Dwg. PN1-E11-1020-0001(3) Rev. 05

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
HOPE CREEK GENERATING STATION

PROCESS DIAGRAM
RESIDUAL HEAT REMOVAL

Updated FSAR
Sheet 3 of 3

REVISION 9, JUNE 13, 1998
Fig 6.3-12

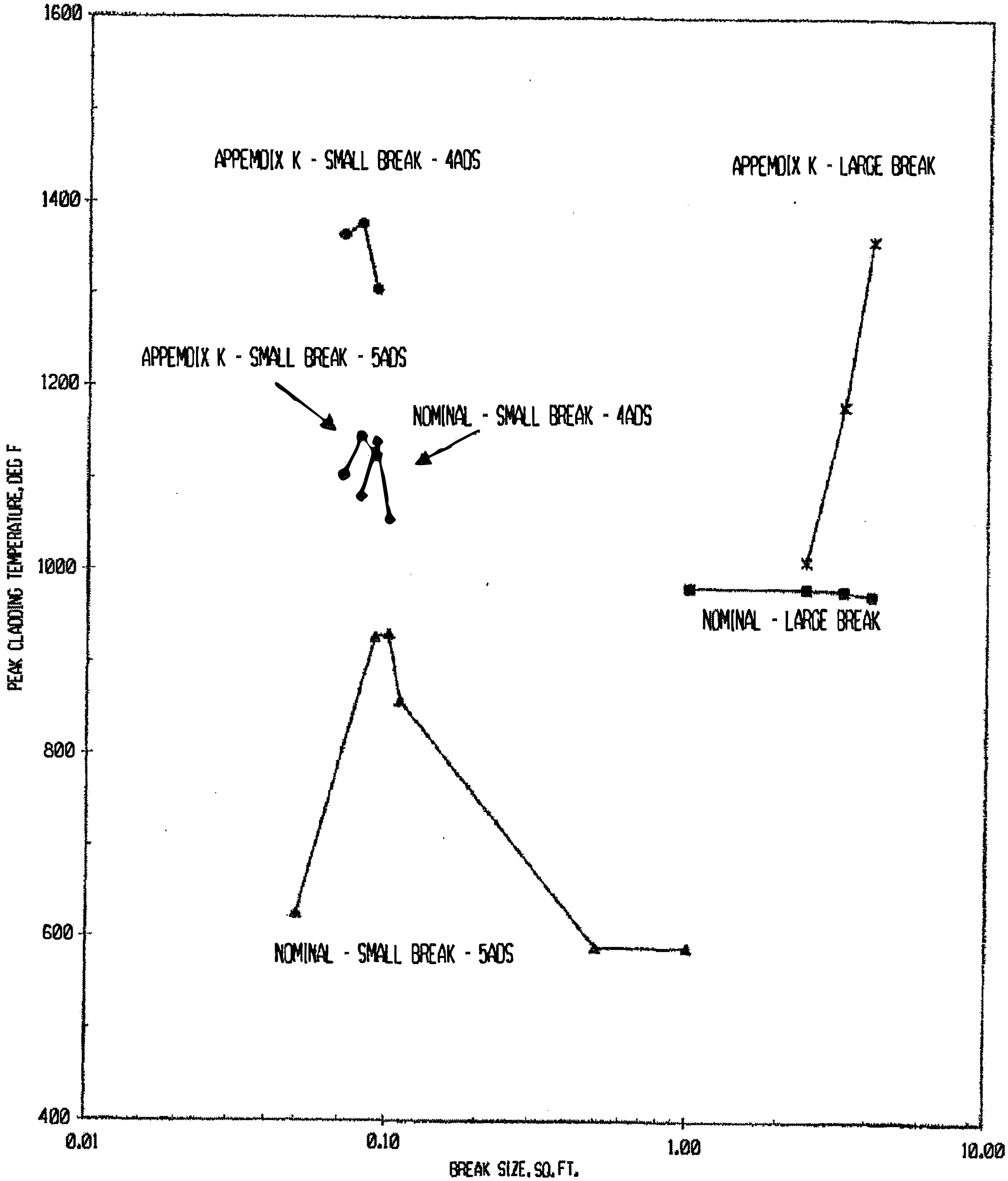


REVISION 0
APRIL 11, 1988

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
HOPE CREEK NUCLEAR GENERATING STATION

RHR (LPCI)
PUMP CHARACTERISTICS

UPDATED FSAR **FIGURE 6.3-13**



NOMINAL AND APPENDIX K LOCA BREAK SPECTRUM RESULTS(*)

(*) THESE RESULTS ARE FOR GE14C FUEL REPRESENTATIVE ONLY.

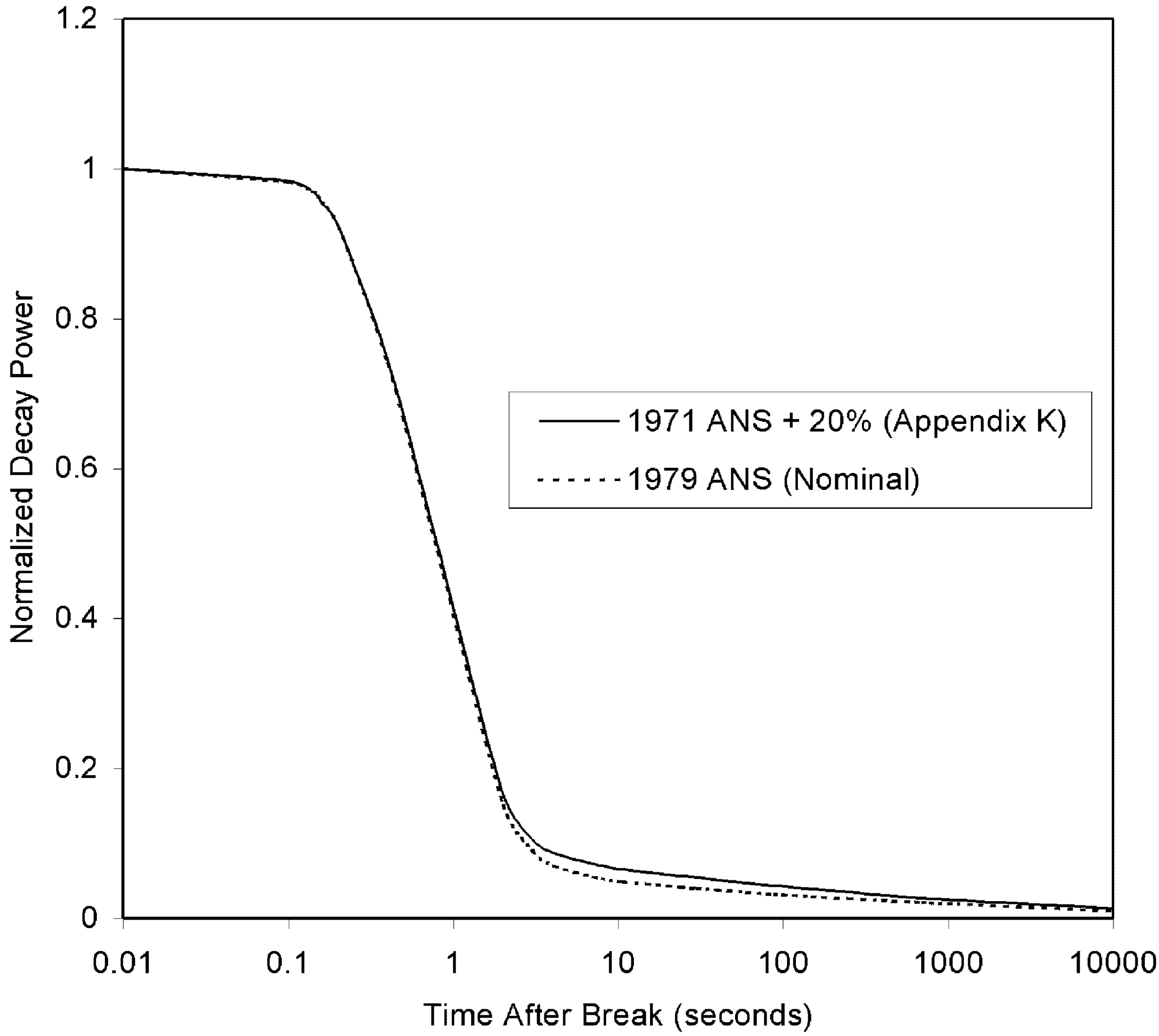
REVISION 22, MAY 9, 2017

PSEG Nuclear, LLC HOPE CREEK NUCLEAR GENERATING STATION	Hope Creek Nuclear Generating Station PEAK CLADDING TEMPERATURE AND MAXIMUM LOCAL OXIDATION VS BREAK AREA Updated FSAR Figure 6.3-14

THIS FIGURE HAS BEEN DELETED

Revision 20, May 9, 2014

PSEG Nuclear, LLC HOPE CREEK NUCLEAR GENERATING STATION	Hope Creek Nuclear Generating Station PEAK CLADDING TEMPERATURE AND MAXIMUM LOCAL OXIDATION VS BREAK AREA
	Updated FSAR Figure 6.3-14A



Decay Heat Used for ECCS/LOCA Calculations

Revision 14, July 26, 2005

PSEG Nuclear, LLC HOPE CREEK NUCLEAR GENERATING STATION	Hope Creek Nuclear Generating Station NORMALIZED CORE POWER VS TIME AFTER BREAK
	Updated FSAR Figure 6.3-15

THIS FIGURE HAS BEEN DELETED

PSEG NUCLEAR L.L.C.
HOPE CREEK GENERATING STATION

HOPE CREEK UFSAR - REV 14	SHEET 1 OF 1
July 26, 2005	F6.3-16

THIS FIGURE HAS BEEN DELETED

PSEG NUCLEAR L.L.C. HOPE CREEK GENERATING STATION	
HOPE CREEK UFSAR - REV 14	SHEET 1 OF 1
July 26, 2005	F6.3-17

THIS FIGURE HAS BEEN DELETED

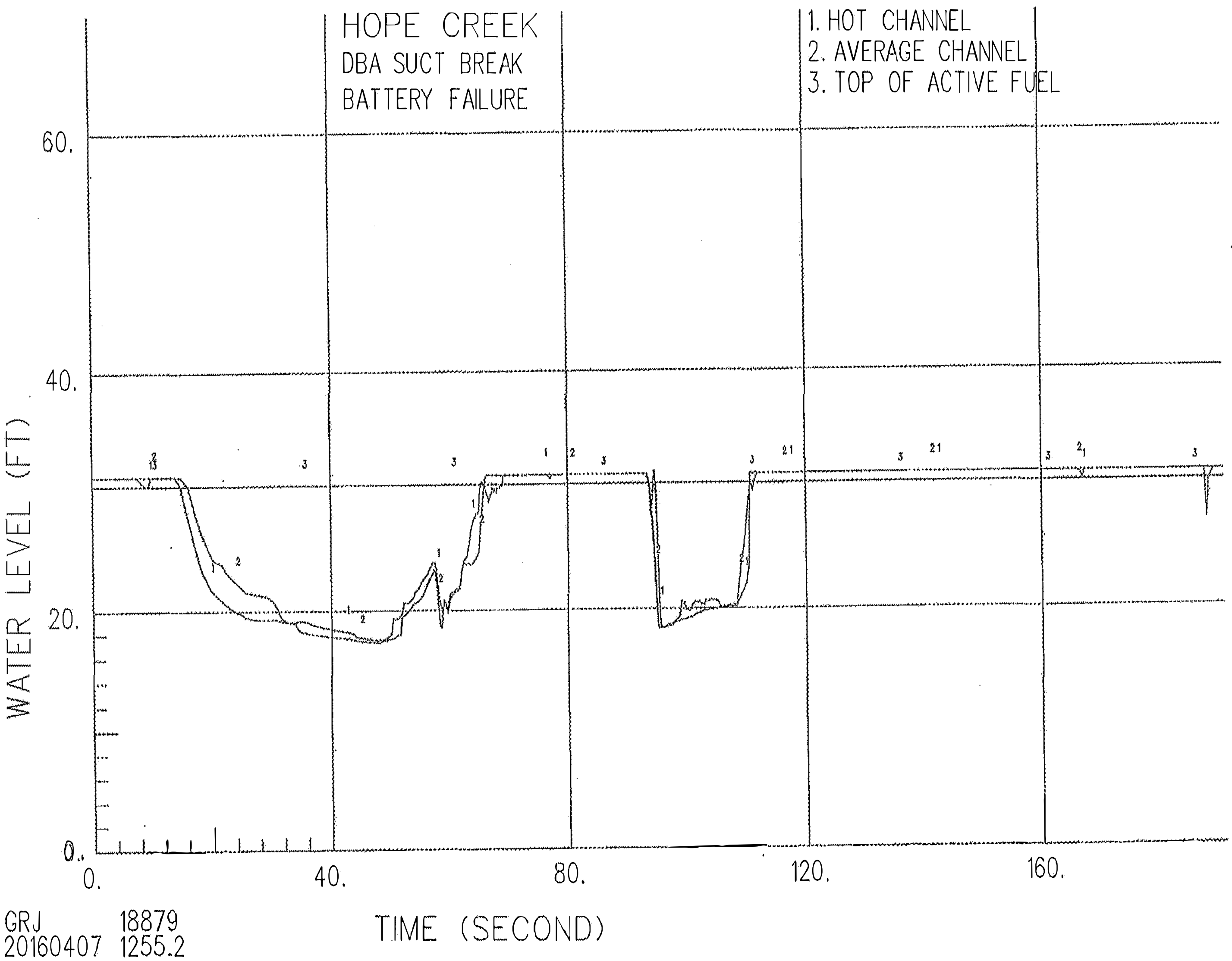
PSEG NUCLEAR L.L.C.
HOPE CREEK GENERATING STATION

THIS FIGURE HAS BEEN DELETED

PSEG NUCLEAR L.L.C.
HOPE CREEK GENERATING STATION

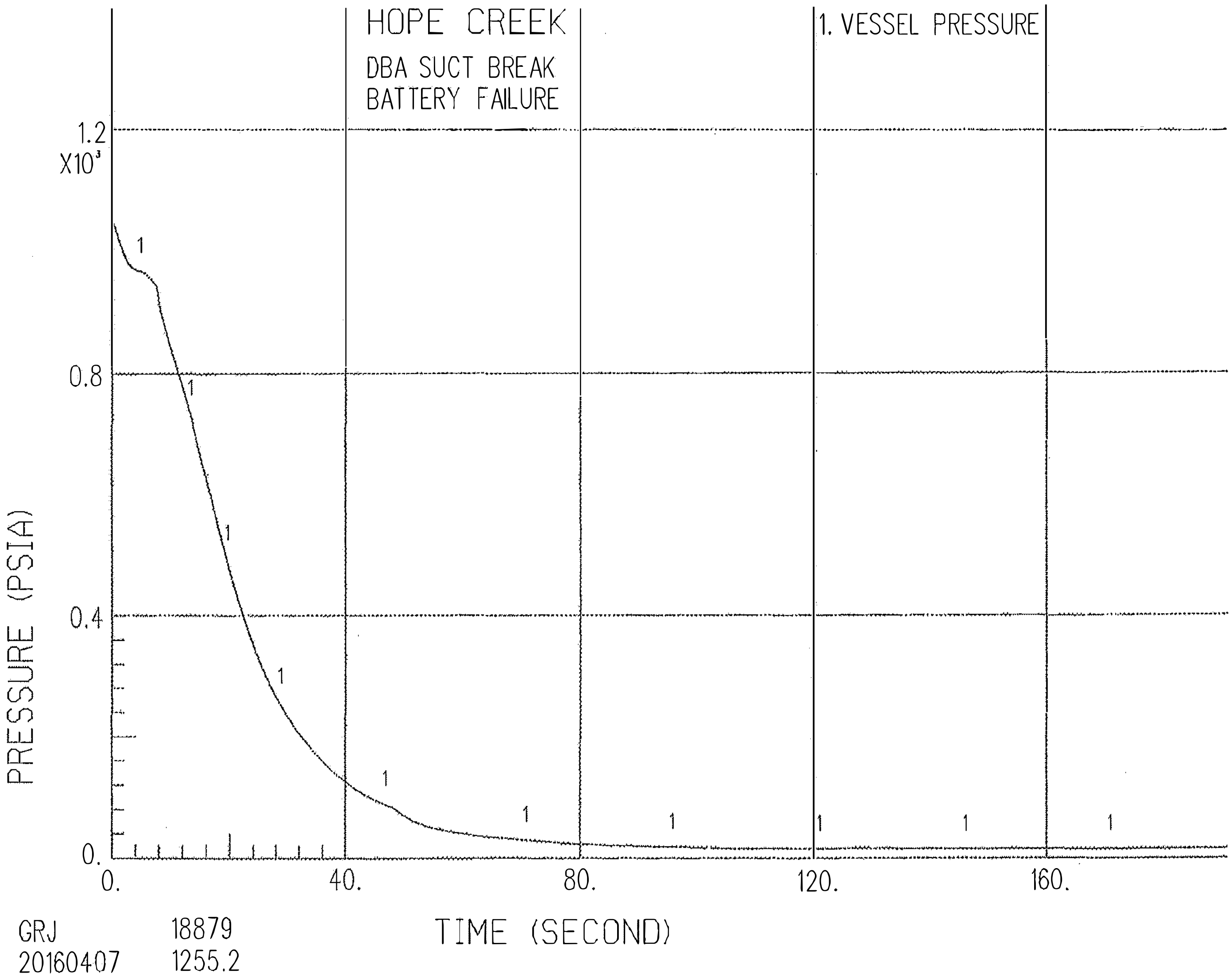
HOPE CREEK UFSAR - REV 14 SHEET 1 OF 1

July 26, 2005 F6.3-19



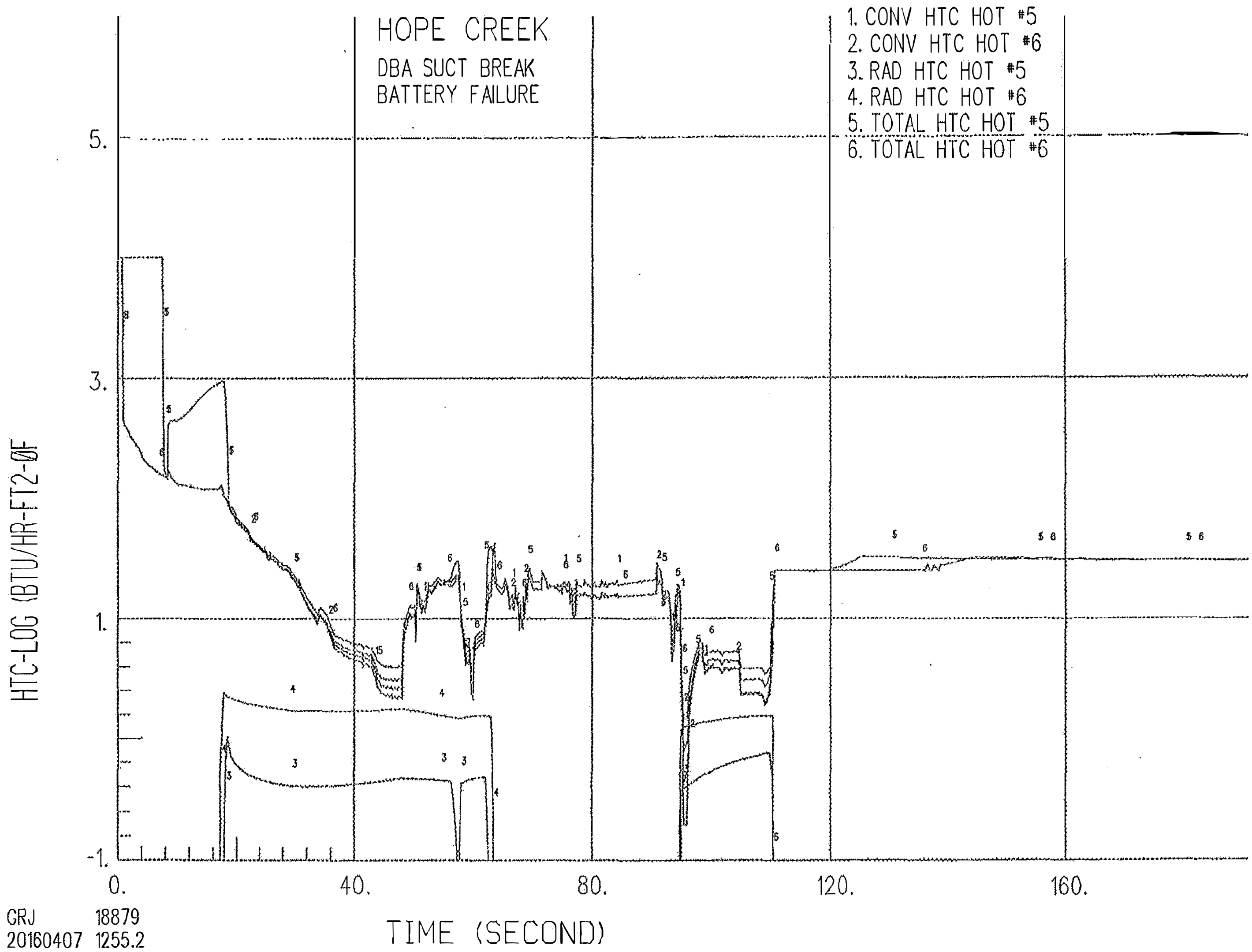
REVISION 22, MAY 9, 2017

PSEG Nuclear, LLC HOPE CREEK NUCLEAR GENERATING STATION	Hope Creek Nuclear Generating Station WATER LEVEL INSIDE SHROUD VS TIME AFTER BREAK (DBA, RECIRCULATION SUCTION BREAK, FAILURE OF CHANNEL A DC SOURCE)
	Updated FSAR Figure 6.3-20



REVISION 22, MAY 9, 2017

PSEG Nuclear, LLC HOPE CREEK NUCLEAR GENERATING STATION	Hope Creek Nuclear Generating Station REACTOR VESSEL PRESSURE VS TIME AFTER BREAK (DBA, RECIRCULATION SUCTION BREAK, FAILURE OF CHANNEL A DC SOURCE) Updated FSAR Figure 6.3-21



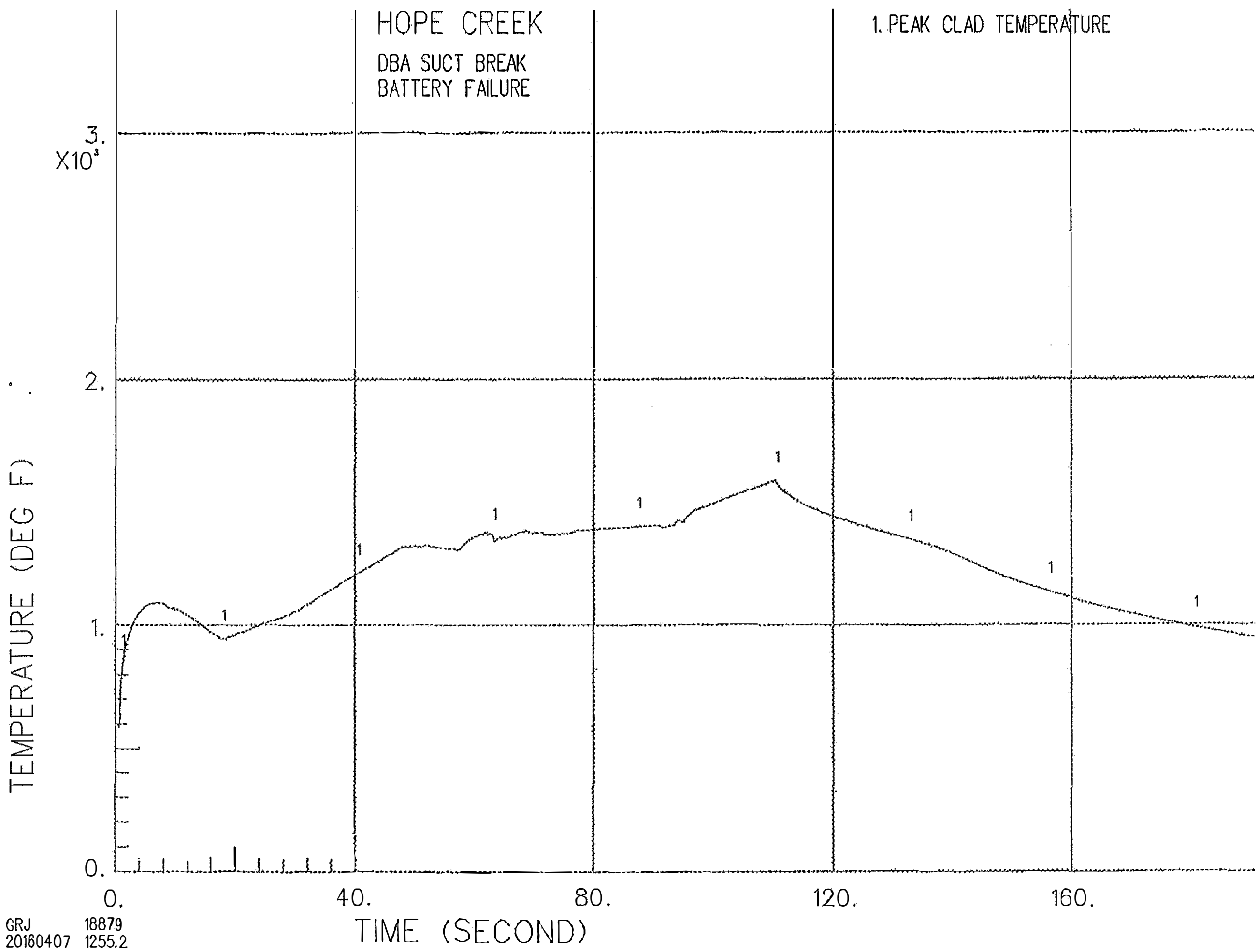
REVISION 22, MAY 9, 2Ø17

PSEG Nuclear, LLC HOPE CREEK NUCLEAR GENERATING STATION	Hope Creek Nuclear Generating Station FUEL ROD CONVECTIVE HEAT TRANSFER COEFFICIENT VS TIME AFTER BREAK (LARGE BREAK MODEL) (DBA, RECIRCULATION SUCTION BREAK, FAILURE OF CHANNEL A DC SOURCE)
	Updated FSAR Figure 6.3-22

THIS FIGURE HAS BEEN DELETED

Revision 20, May 9, 2014

PSEG Nuclear, LLC HOPE CREEK NUCLEAR GENERATING STATION	Hope Creek Nuclear Generating Station FUEL ROD CONVECTIVE HEAT TRANSFER COEFFICIENT VS TIME AFTER BREAK (LARGE BREAK MODEL) (DBA, RECIRCULATION SUCTION BREAK, FAILURE OF CHANNEL A DC SOURCE)
	Updated FSAR Figure 6.3-22A



REVISION 22, MAY 9, 2017

PSEG Nuclear, LLC HOPE CREEK NUCLEAR GENERATING STATION	Hope Creek Nuclear Generating Station PEAK CLADDING TEMPERATURE VS TIME AFTER BREAK (DBA, RECIRCULATION SUCTION BREAK, FAILURE OF CHANNEL A DC SOURCE) Updated FSAR Figure 6.3-23

THIS FIGURE HAS BEEN DELETED

Revision 20, May 9, 2014

PSEG Nuclear, LLC HOPE CREEK NUCLEAR GENERATING STATION	Hope Creek Nuclear Generating Station PEAK CLADDING TEMPERATURE VS TIME AFTER BREAK (DBA, RECIRCULATION SUCTION BREAK, FAILURE OF CHANNEL A DC SOURCE)
	Updated FSAR Figure 6.3-23A

THIS FIGURE HAS BEEN DELETED

PSEG NUCLEAR L.L.C. HOPE CREEK GENERATING STATION	
HOPE CREEK UFSAR - REV 14	SHEET 1 OF 1
July 26, 2005	F6.3-24

THIS FIGURE HAS BEEN DELETED

PSEG NUCLEAR L.L.C.
HOPE CREEK GENERATING STATION

THIS FIGURE HAS BEEN DELETED

PSEG NUCLEAR L.L.C.
HOPE CREEK GENERATING STATION

HOPE CREEK UFSAR - REV 14	SHEET 1 OF 1
July 26, 2005	F6.3-26

THIS FIGURE HAS BEEN DELETED

PSEG NUCLEAR L.L.C.
HOPE CREEK GENERATING STATION

HOPE CREEK UFSAR - REV 14	SHEET 1 OF 1
July 26, 2005	F6.3-27

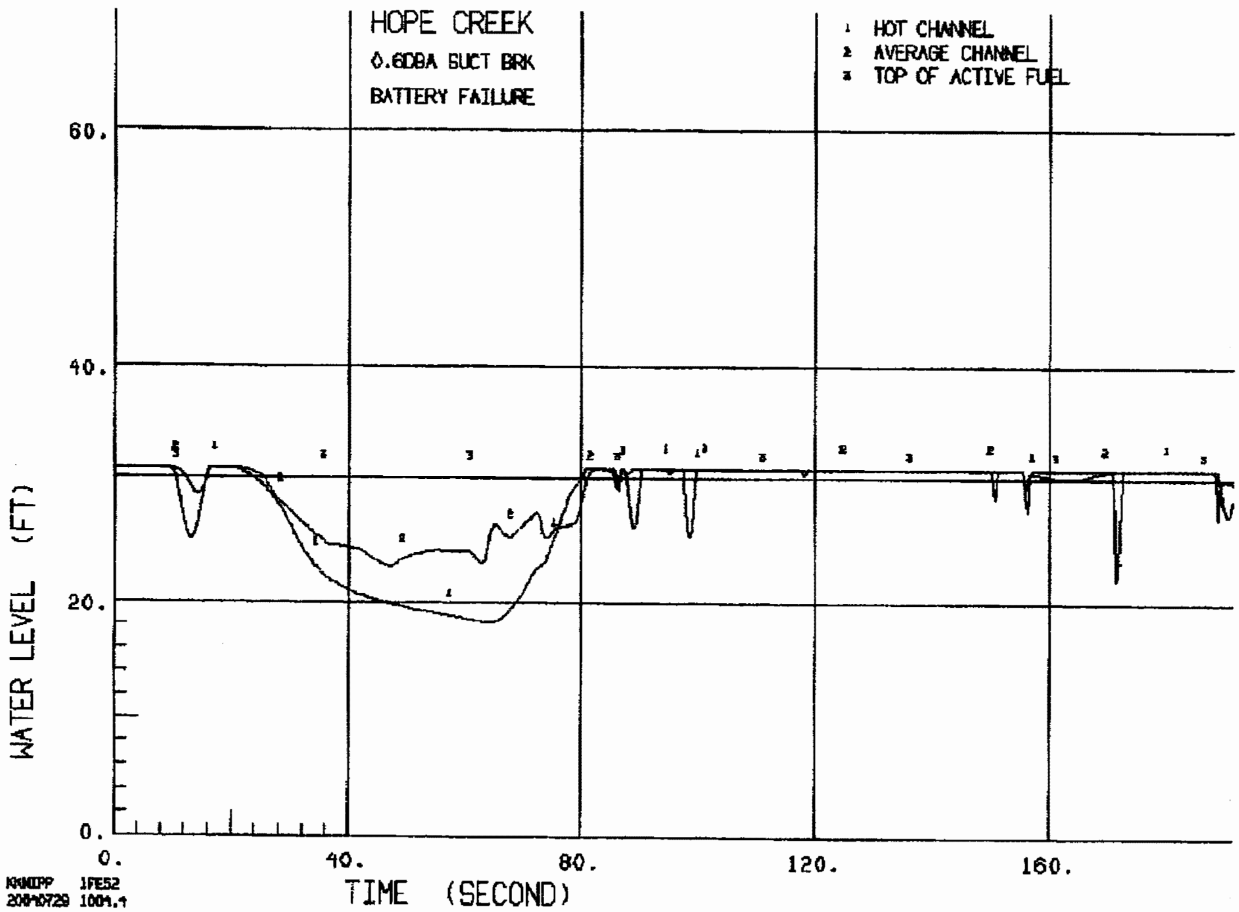
THIS FIGURE HAS BEEN DELETED

PSEG NUCLEAR L.L.C. HOPE CREEK GENERATING STATION

THIS FIGURE HAS BEEN DELETED

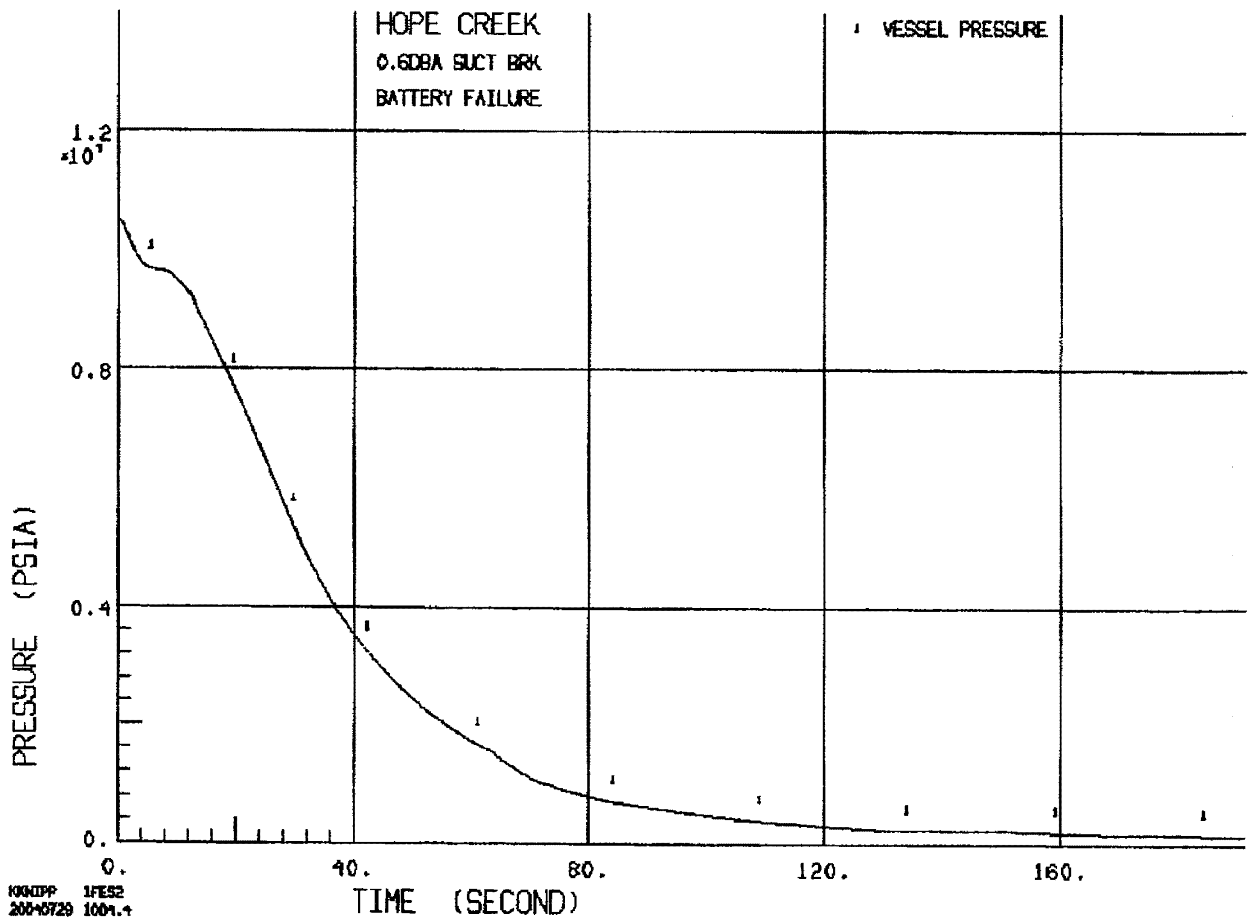
PSEG NUCLEAR L.L.C.
HOPE CREEK GENERATING STATION

HOPE CREEK UFSAR - REV 14	SHEET 1 OF 1
July 26, 2005	F6.3-29



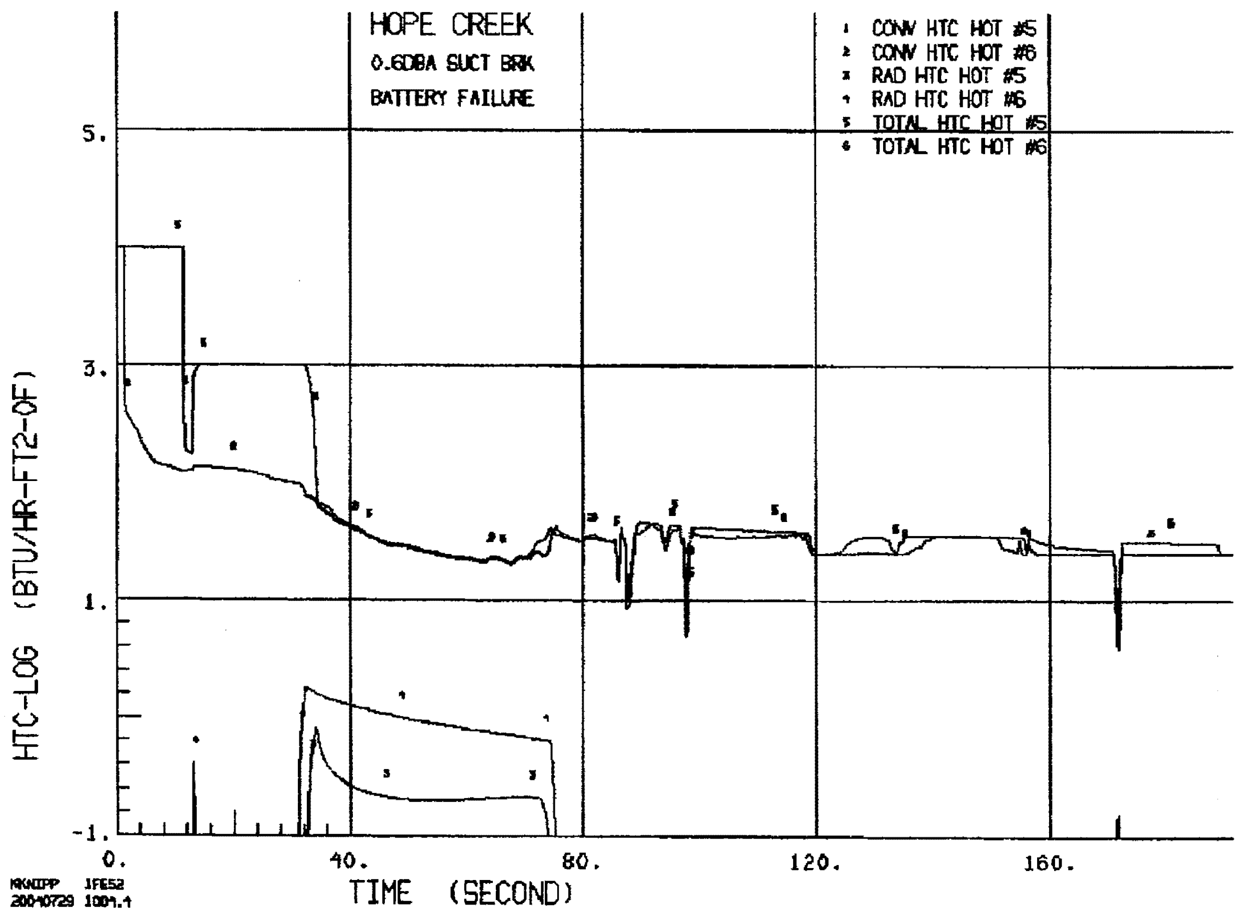
Revision 17, June 23, 2009

PSEG Nuclear, LLC HOPE CREEK NUCLEAR GENERATING STATION	Hope Creek Nuclear Generating Station WATER LEVEL INSIDE SHROUD VS TIME AFTER BREAK (LARGE BREAK MODEL) (60% DBA RECIRC. SUCTION BREAK, FAILURE OF CHANNEL A DC SOURCE)
	Updated FSAR — Figure 6.3-30



Revision 17, June 23, 2009

PSEG Nuclear, LLC HOPE CREEK NUCLEAR GENERATING STATION	Hope Creek Nuclear Generating Station REACTOR VESSEL PRESSURE VS TIME AFTER BREAK (LARGE BREAK MODEL) (60% DBA RECIRC. SUCTION BREAK, FAILURE OF CHANNEL A DC SOURCE)
	Updated FSAR — Figure 6.3-31



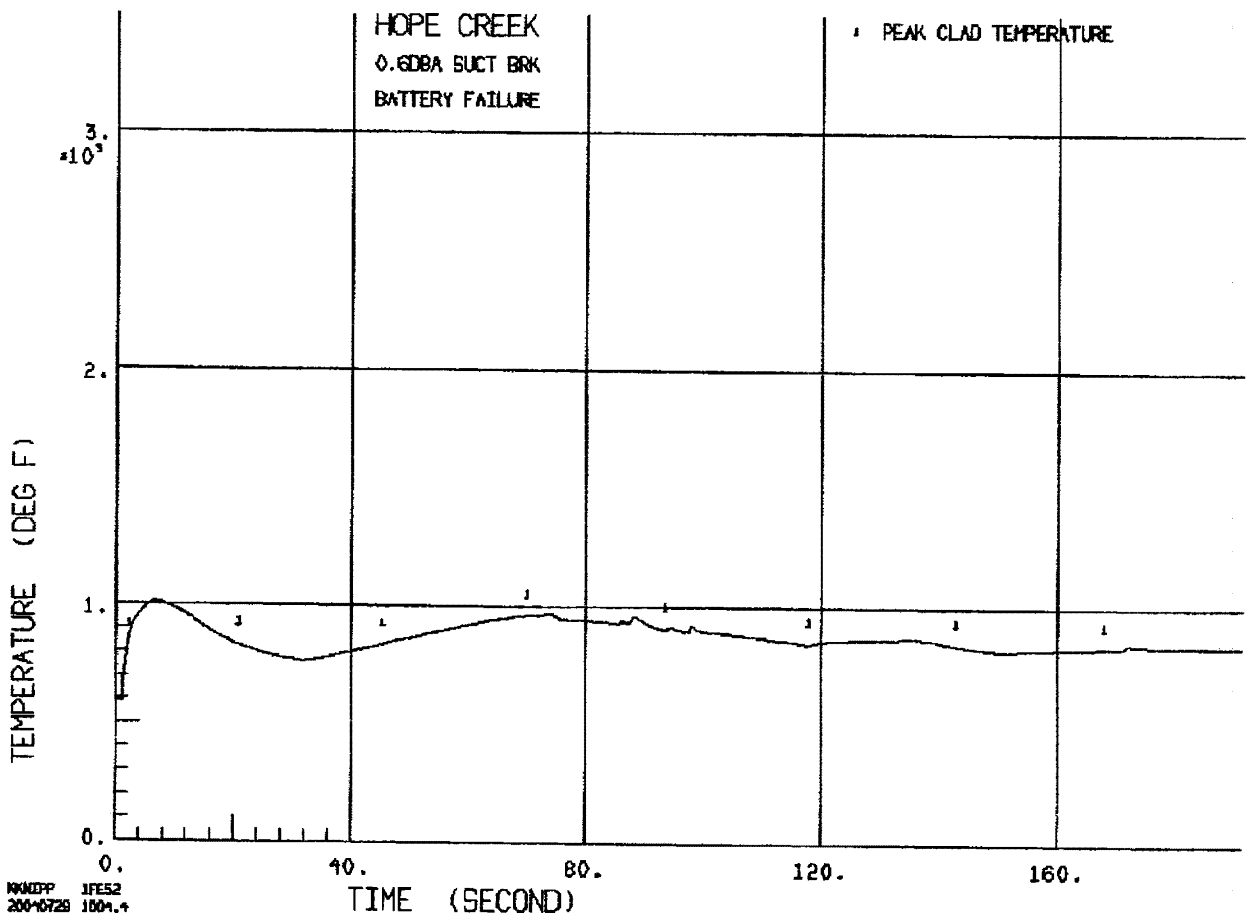
Revision 17, June 23, 2009

PSEG Nuclear, LLC HOPE CREEK NUCLEAR GENERATING STATION	Hope Creek Nuclear Generating Station FUEL ROD CONVECTIVE HEAT TRANSFER COEFFICIENT VS TIME AFTER BREAK (LARGE BREAK MODEL) (60% DBA RECIRC. SUCTION BREAK FAILURE OF CHANNEL A DC SOURCE)
	Updated FSAR Figure 6.3-32

THIS FIGURE HAS BEEN DELETED

Revision 20, May 9, 2014

PSEG Nuclear, LLC HOPE CREEK NUCLEAR GENERATING STATION	Hope Creek Nuclear Generating Station FUEL ROD CONVECTIVE HEAT TRANSFER COEFFICIENT VS TIME AFTER BREAK (LARGE BREAK MODEL) (60% DBA RECIRC. SUCTION BREAK FAILURE OF CHANNEL A DC SOURCE)
	Updated FSAR — Figure 6.3-32A



Revision 17, June 23, 2009

PSEG Nuclear, LLC HOPE CREEK NUCLEAR GENERATING STATION	Hope Creek Nuclear Generating Station PEAK CLADDING TEMPERATURE VS TIME AFTER BREAK (LARGE BREAK MODEL) (60% DBA RECIRCULATION SUCTION BREAK, FAILURE OF CHANNEL A DC SOURCE)
	Updated FSAR — Figure 6.3-33

THIS FIGURE HAS BEEN DELETED

Revision 20, May 9, 2014

PSEG Nuclear, LLC HOPE CREEK NUCLEAR GENERATING STATION	Hope Creek Nuclear Generating Station PEAK CLADDING TEMPERATURE VS TIME AFTER BREAK (LARGE BREAK MODEL) (60% DBA RECIRCULATION SUCTION BREAK, FAILURE OF CHANNEL A DC SOURCE)
	Updated FSAR Figure 6.3-33A

THIS FIGURE HAS BEEN DELETED

PSEG NUCLEAR L.L.C.
HOPE CREEK GENERATING STATION

HOPE CREEK UFSAR - REV 14	SHEET 1 OF 1
July 26, 2005	F6.3-34

THIS FIGURE HAS BEEN DELETED

PSEG NUCLEAR L.L.C.
HOPE CREEK GENERATING STATION

HOPE CREEK UFSAR - REV 14 SHEET 1 OF 1

July 26, 2005 F6.3-35

THIS FIGURE HAS BEEN DELETED

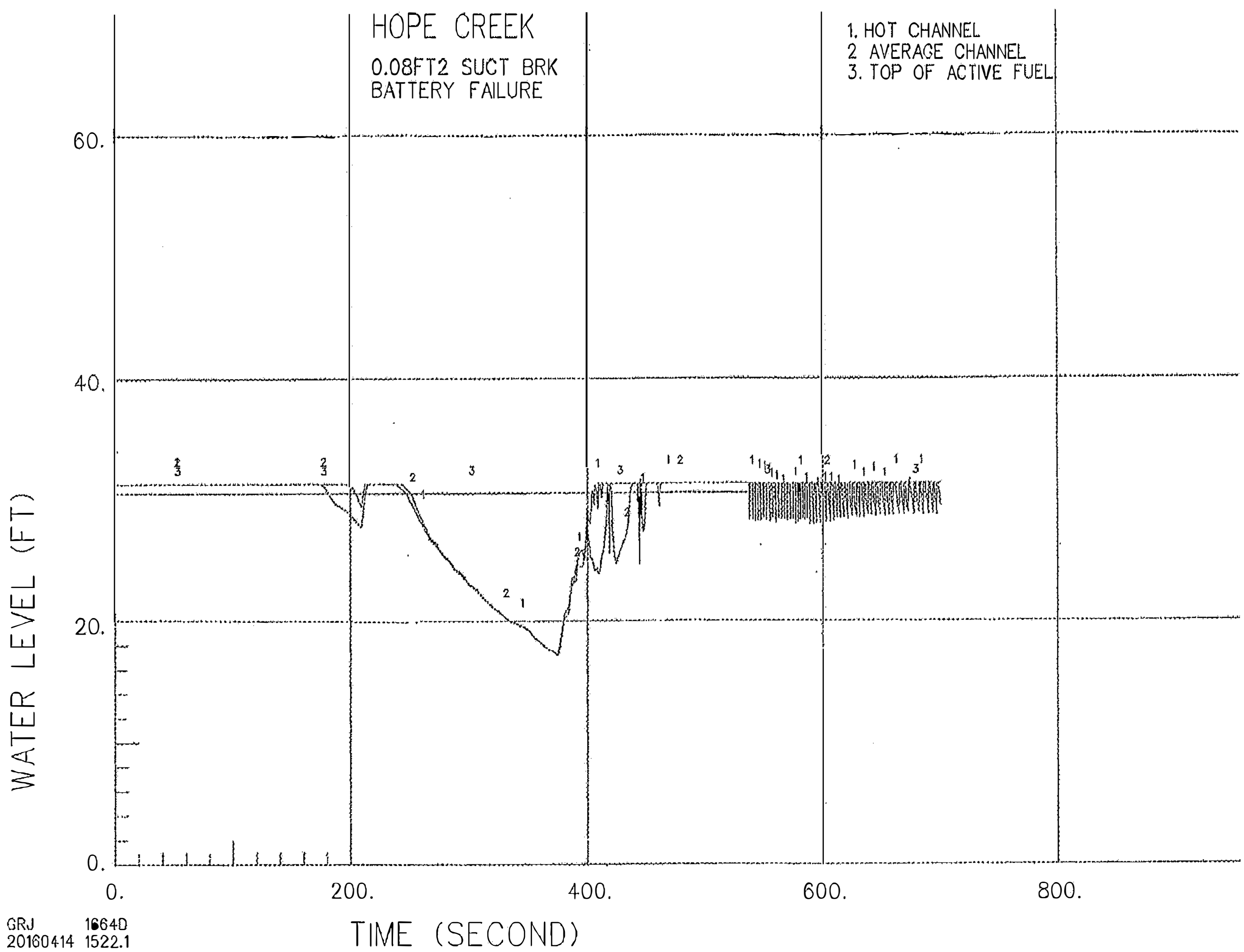
PSEG NUCLEAR L.L.C.
HOPE CREEK GENERATING STATION

HOPE CREEK UFSAR - REV 14 | SHEET 1 OF 1

July 26, 2005 | F6.3-36

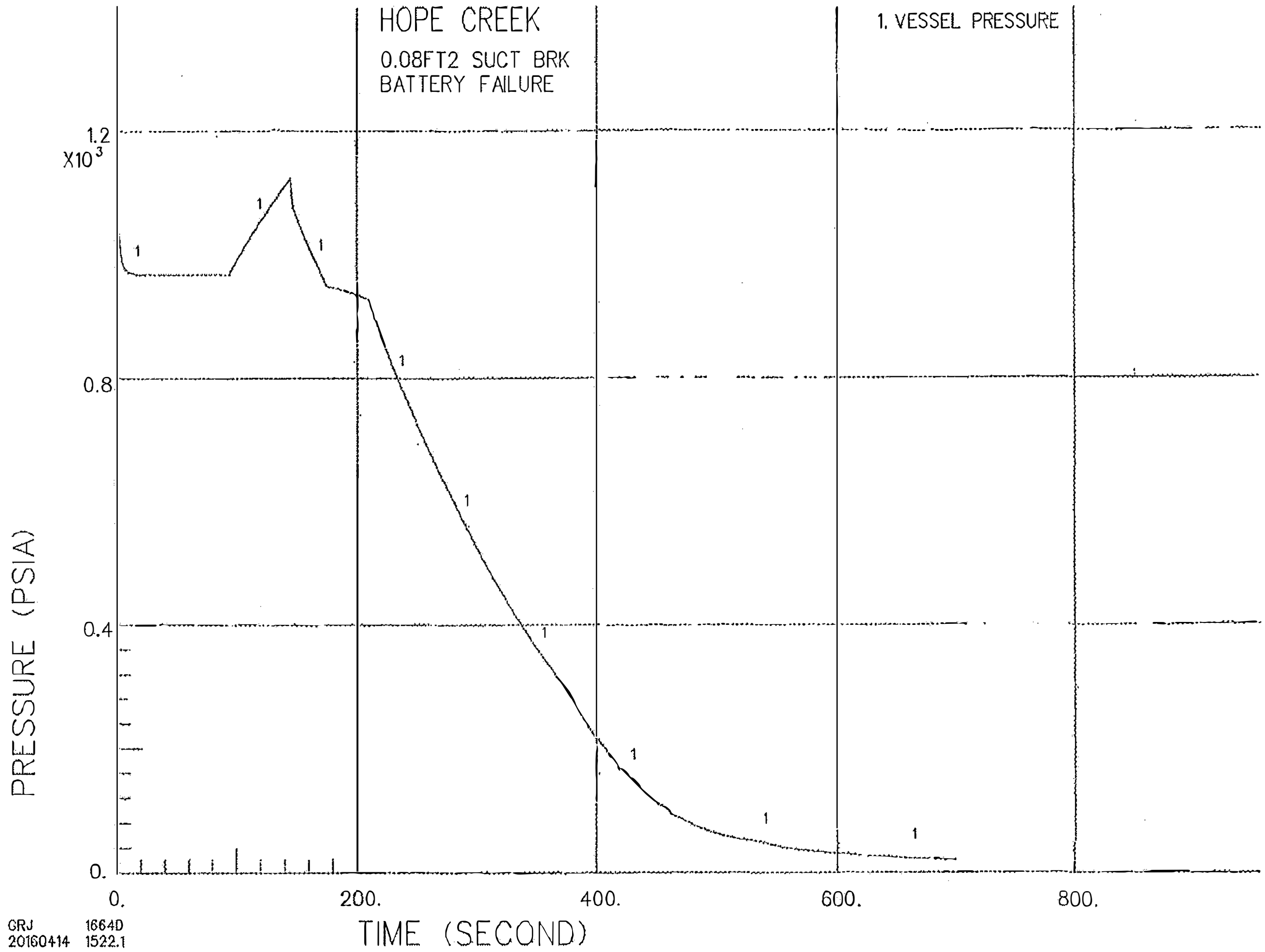
THIS FIGURE HAS BEEN DELETED

PSEG NUCLEAR L.L.C. HOPE CREEK GENERATING STATION	
HOPE CREEK UFSAR - REV 14	SHEET 1 OF 1
July 26, 2005	F6.3-37



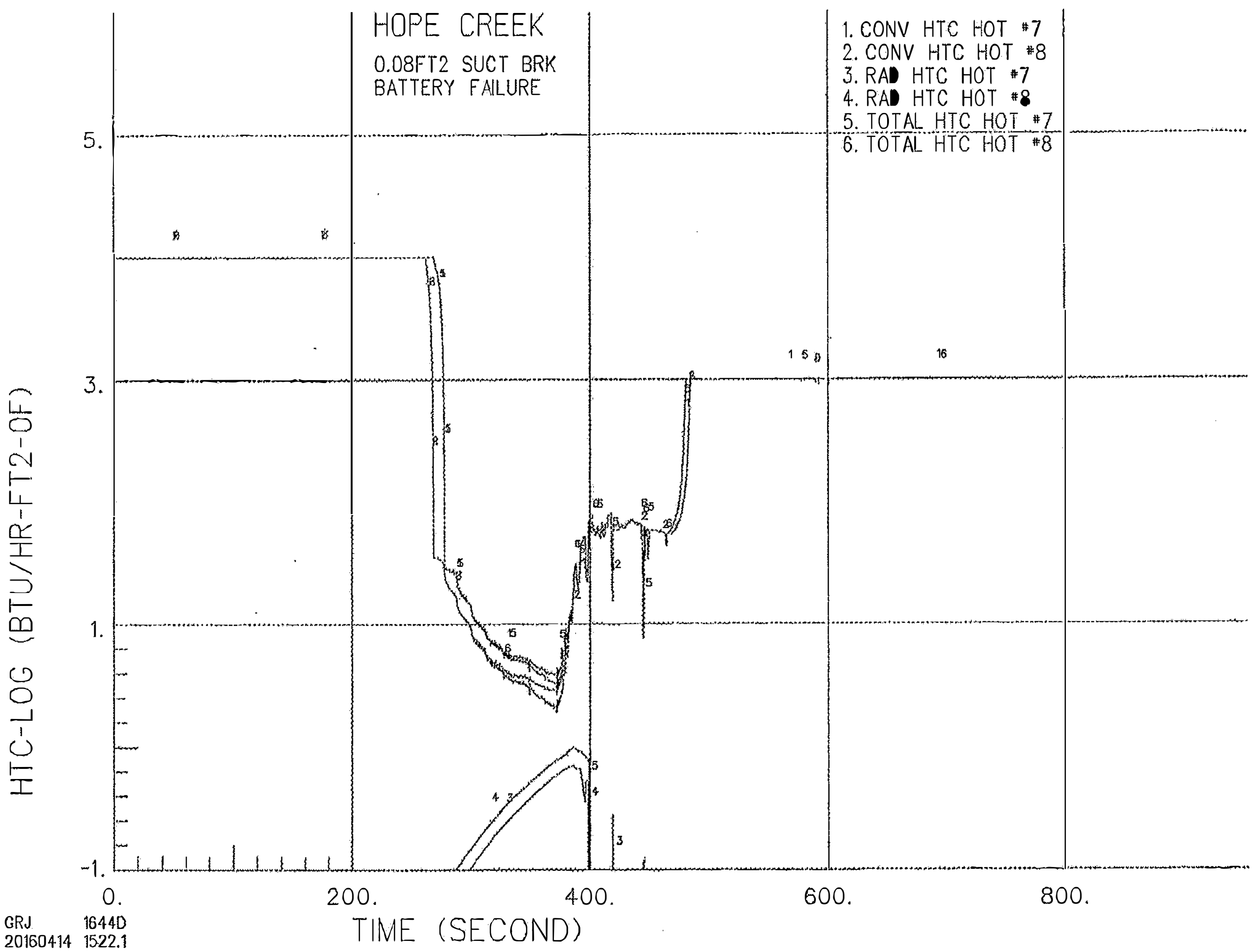
REVISION 22, MAY 9, 2017

PSEG Nuclear, LLC HOPE CREEK NUCLEAR GENERATING STATION	Hope Creek Nuclear Generating Station WATER LEVEL INSIDE SHROUD VS TIME AFTER BREAK (SMALL BREAK MODEL) (0.09 FT^2 RECIRCULATION SUCTION BREAK, FAILURE OF CHANNEL A DC SOURCE)
	Updated FSAR — Figure 6.3-38



REVISION 22, MAY 9, 2017

PSEG Nuclear, LLC HOPE CREEK NUCLEAR GENERATING STATION	Hope Creek Nuclear Generating Station REACTOR VESSEL PRESSURE VS TIME AFTER BREAK (SMALL BREAK MODEL) (0.09 FT^2 RECIRCULATION SUCTION BREAK, FAILURE OF CHANNEL A DC SOURCE)
	Updated FSAR Figure 6.3-39



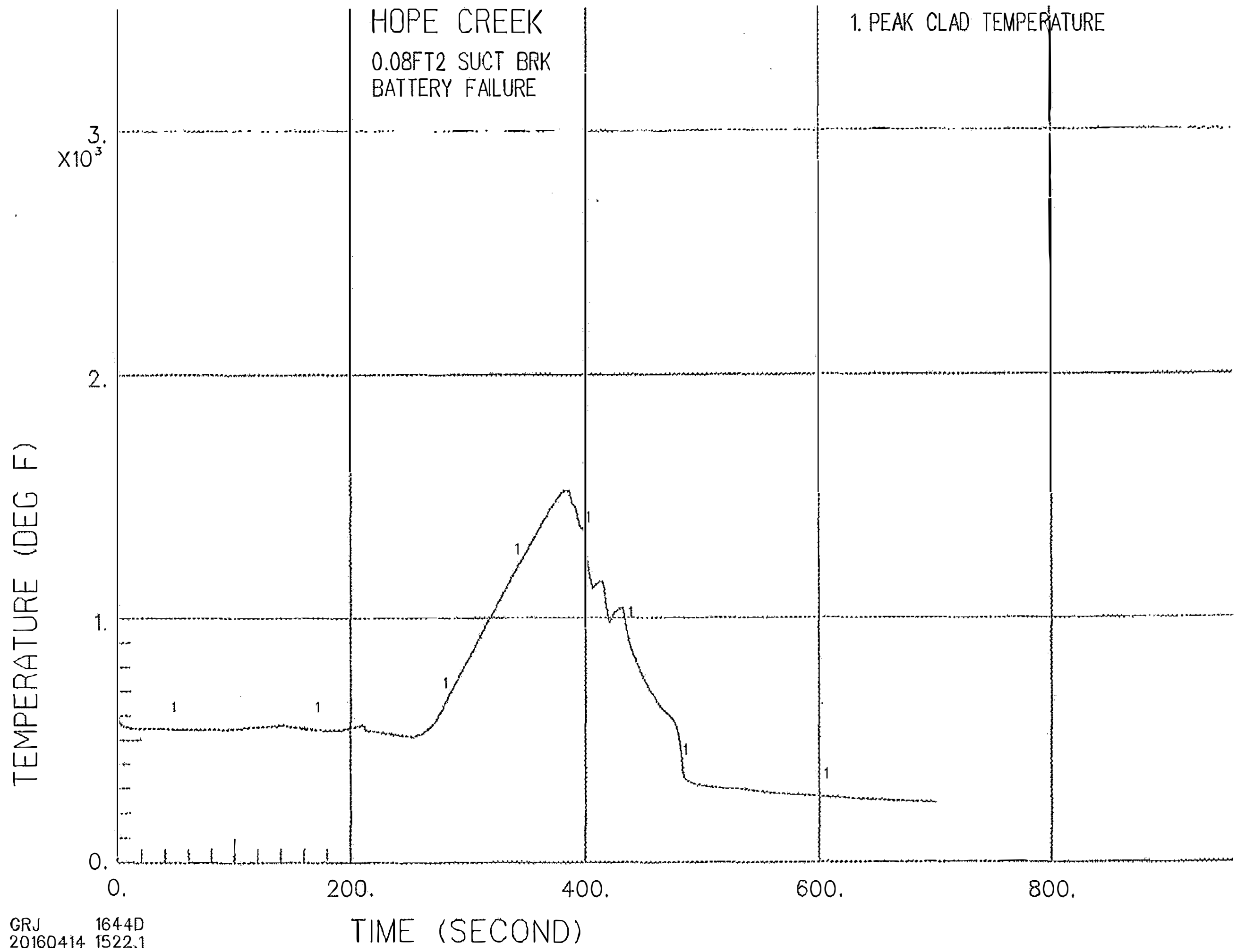
REVISION 22, MAY 9, 2017

PSEG Nuclear, LLC HOPE CREEK NUCLEAR GENERATING STATION	Hope Creek Nuclear Generating Station FUEL ROD CONVECTIVE HEAT TRANSFER COEFFICIENT VS TIME AFTER BREAK (SMALL BREAK MODEL) (0.09 FT^2 RECIRCULATION SUCTION BREAK, FAILURE OF CHANNEL A DC SOURCE) Updated FSAR Figure 6.3-40

THIS FIGURE HAS BEEN DELETED

Revision 20, May 9, 2014

PSEG Nuclear, LLC HOPE CREEK NUCLEAR GENERATING STATION	Hope Creek Nuclear Generating Station FUEL ROD CONVECTIVE HEAT TRANSFER COEFFICIENT VS TIME AFTER BREAK (SMALL BREAK MODEL) (0.09 FT^2 RECIRCULATION SUCTION BREAK, FAILURE OF CHANNEL A DC SOURCE)
	Updated FSAR Figure 6.3-40A



REVISION 22, MAY 9, 2017

PSEG Nuclear, LLC HOPE CREEK NUCLEAR GENERATING STATION	Hope Creek Nuclear Generating Station PEAK CLADDING TEMPERATURE VS TIME AFTER BREAK (SMALL BREAK MODEL) (0.09 FT^2 RECIRCULATION SUCTION BREAK, FAILURE OF CHANNEL A DC SOURCE)
	Updated FSAR Figure 6.3-41

THIS FIGURE HAS BEEN DELETED

Revision 20, May 9, 2014

PSEG Nuclear, LLC HOPE CREEK NUCLEAR GENERATING STATION	Hope Creek Nuclear Generating Station PEAK CLADDING TEMPERATURE VS TIME AFTER BREAK (SMALL BREAK MODEL) (0.08 FT^2 RECIRCULATION SUCTION BREAK, FAILURE OF CHANNEL A DC SOURCE)
	Updated FSAR Figure 6.3-41A

THIS FIGURE HAS BEEN DELETED

PSEG NUCLEAR L.L.C.
HOPE CREEK GENERATING STATION

THIS FIGURE HAS BEEN DELETED

PSEG NUCLEAR L.L.C.
HOPE CREEK GENERATING STATION

HOPE CREEK UFSAR - REV 14	SHEET 1 OF 1
July 26, 2005	F6.3-43

THIS FIGURE HAS BEEN DELETED

PSEG NUCLEAR L.L.C. HOPE CREEK GENERATING STATION	
HOPE CREEK UFSAR - REV 14	SHEET 1 OF 1
July 26, 2005	F6.3-44

THIS FIGURE HAS BEEN DELETED

PSEG NUCLEAR L.L.C. HOPE CREEK GENERATING STATION
HOPE CREEK UFSAR - REV 14   SHEET 1 OF 1 July 26, 2005   F6.3-45

THIS FIGURE HAS BEEN DELETED

PSEG NUCLEAR L.L.C.
HOPE CREEK GENERATING STATION

HOPE CREEK UFSAR - REV 14	SHEET 1 OF 1
July 26, 2005	F6.3-46

THIS FIGURE HAS BEEN DELETED

PSEG NUCLEAR L.L.C.
HOPE CREEK GENERATING STATION

HOPE CREEK UFSAR - REV 14 SHEET 1 OF 1

July 26, 2005 F6.3-47

THIS FIGURE HAS BEEN DELETED

PSEG NUCLEAR L.L.C. HOPE CREEK GENERATING STATION	
HOPE CREEK UFSAR - REV 14	SHEET 1 OF 1
July 26, 2005	F6.3-48

THIS FIGURE HAS BEEN DELETED

PSEG NUCLEAR L.L.C.
HOPE CREEK GENERATING STATION

HOPE CREEK UFSAR - REV 14	SHEET 1 OF 1
July 26, 2005	F6.3-49

THIS FIGURE HAS BEEN DELETED

PSEG NUCLEAR L.L.C. HOPE CREEK GENERATING STATION	
HOPE CREEK UFSAR - REV 14	SHEET 1 OF 1
July 26, 2005	F6.3-50

THIS FIGURE HAS BEEN DELETED

PSEG NUCLEAR L.L.C.
HOPE CREEK GENERATING STATION

THIS FIGURE HAS BEEN DELETED

PSEG NUCLEAR L.L.C.
HOPE CREEK GENERATING STATION

HOPE CREEK UFSAR - REV 14	SHEET 1 OF 1
July 26, 2005	F6.3-52

THIS FIGURE HAS BEEN DELETED

PSEG NUCLEAR L.L.C.
HOPE CREEK GENERATING STATION

HOPE CREEK UFSAR - REV 14 SHEET 1 OF 1

July 26, 2005 F6.3-53

THIS FIGURE HAS BEEN DELETED

PSEG NUCLEAR L.L.C.
HOPE CREEK GENERATING STATION

HOPE CREEK UFSAR - REV 14	SHEET 1 OF 1
July 26, 2005	F6.3-54

THIS FIGURE HAS BEEN DELETED

PSEG NUCLEAR L.L.C.
HOPE CREEK GENERATING STATION

HOPE CREEK UFSAR - REV 14	SHEET 1 OF 1
July 26, 2005	F6.3-55

THIS FIGURE HAS BEEN DELETED

PSEG NUCLEAR L.L.C. HOPE CREEK GENERATING STATION	
HOPE CREEK UFSAR - REV 14	SHEET 1 OF 1
July 26, 2005	F6.3-56

THIS FIGURE HAS BEEN DELETED

PSEG NUCLEAR L.L.C.
HOPE CREEK GENERATING STATION

HOPE CREEK UFSAR - REV 14	SHEET 1 OF 1
July 26, 2005	F6.3-57

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PSEG NUCLEAR L.L.C. HOPE CREEK GENERATING STATION	
HOPE CREEK UFSAR - REV 14	SHEET 1 OF 1
July 26, 2005	F6.3-58

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HOPE CREEK UFSAR - REV 14 SHEET 1 OF 1
July 26, 2005 F6.3-59

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HOPE CREEK UFSAR - REV 14	SHEET 1 OF 1
July 26, 2005	F6.3-60

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HOPE CREEK UFSAR - REV 14	SHEET 1 OF 1
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6.4 HABITABILITY SYSTEMS

The main control room habitability systems provide safety and comfort for operating personnel during normal operations and during postulated emergency conditions. These habitability systems include radiation shielding; charcoal air filter systems; heating, ventilating, and air conditioning (HVAC); storage for food and water; sanitary facilities; and fire protection. The habitability systems are designed to meet 10 CFR 50.67 requirements (Reference 6.4-2). The technical support center (TSC), which serves to back up the control room monitoring and diagnosis during emergency conditions, is discussed in Section 12.3.3. The TSC is designed for the same environmental habitability requirements as for the main control room.

6.4.1 Design Bases

The design bases for the habitability systems are summarized as follows:

1. The control room environmental envelope is designed for continuous occupation during normal and abnormal conditions to maintain an indoor design condition as indicated in Section 9.4.1. Occupancy by operating personnel is ensured for a minimum of 30 days after a design basis accident (DBA).

2. The habitability systems are designed to support five people during normal and abnormal station operating conditions. An initial 5-day emergency supply of food and water is provided within the control room habitability envelope.

3. Sanitary facilities and medical supplies for minor injuries are provided within the boundary of the control room habitability envelope for the use of control room personnel during normal and accident conditions.

4. The radiological effects on the control room personnel that could exist as a consequence of the postulated DBA described in Section 15 do not exceed the guidelines set by 10CFR50.67.

5. Respiratory and skin protection and emergency breathing apparatus are provided within the control room envelope for control room operators.

6. The Control Room Ventilation System is capable of automatic transfer from its normal operational mode to its emergency pressurization recirculation mode upon detection of high radiation. It is also capable of manual transfer to the isolation recirculation mode.

7. The Control Room Ventilation System is designed to remain functional during and after an operating basis earthquake (OBE) or a safe shutdown earthquake (SSE).

8. The habitability systems are designed to remain functional following an active failure of any one of the HVAC system components.

9. Radiation monitors continuously monitor the outside air at the control room envelope outside air intake. The detection of high radiation is alarmed in the main control room, and radiological protection functions are automatically initiated, as described in Section 6.4.3.2.

10. Smoke detectors are provided in the normal and emergency outside air ducts. They alarm in the main control room.

11. The control room HVAC system design bases are discussed in Section 9.4.1.

12. The seismic category, quality group classification, and corresponding codes and standards that apply to the

design of the habitability systems are discussed in Section 3.2.

13. Regulatory Guides 1.52, 1.78, and 1.95 apply to the design of habitability systems. Section 1.8 analyzes plant requirements associated with these Regulatory Guides. Conformance to design aspects of the guides is as follows:

    a. There is partial conformance with Regulatory Guide 1.52, as discussed in Sections 6.5.1 and 1.8. Section 6.5.1 also provides a detailed description of the air filters.

    b. As discussed in Section 2.2.3, the only toxic chemical that may accumulate to any appreciable amount is ammonia resulting from an ammonium hydroxide release at the SGS. Sufficient time exists from the time of detection in the control room to the time of when the concentrations exceed the toxicity limit established in Regulatory Guide 1.78. Therefore, the design considerations of Regulatory Guide 1.78 are applicable to HCGS as denoted in Section 1.8.

    c. As discussed in Section 2.2.3, chlorine does not pose a danger to HCGS control room personnel. Therefore, the design considerations of Regulatory Guide 1.95 are not applicable to HCGS.

14. The control room outside air intakes have been located to prevent the possibility of diesel gas exhaust concentrations in the main control room during operation of the standby diesel generators (SDGs).

The design of the habitability systems with respect to the following aspects is discussed in separate FSAR sections as indicated:

1. Protection from wind and tornado effects - Section 3.3

2. Flood design - Section 3.4

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3. Missile protection - Section 3.5

4. Protection against dynamic effects associated with postulated rupture of piping - Section 3.6

5. Environmental design - Section 3.11.

6.4.2 System Design

6.4.2.1 Definition of Control Room Envelope

The control room envelope maintained under habitable conditions following an accident is shown on Plant Drawing A-5655-0. The envelope consists of the main control room, computer room, shift supervisors' office, ready room, instructional viewing area, corridors, toilets, kitchen and storage room, all at Auxiliary Building Elevation 137 feet and the console pit at Elevation 132 feet and 4 inches.

Ingress and egress are provided by one door from the shift supervisors' office to the work control center, one door from the control room corridor to the work control center, one door from the control room corridor to the radwaste building service area corridor, one door from the control room corridor to the elevator lobby corridor, and one door from the rear of the control room to the electrical tray space corridor.

The volume of the control room envelope served by the Heating, Ventilating, and Air Conditioning (HVAC) System is approximately 85,000 cubic feet. The allowable carbon dioxide buildup and the occupancy time period when the control room is completely isolated are described in Section 9.4.1.

6.4.2.2 Ventilation System Design

The control room HVAC system, including the major equipment design parameters, is discussed in detail in Section 9.4.1, and the system is shown schematically on Plant Drawing M-78-1.

Figure 6.4-2 shows the plant layout, including the location of the control room and its outside air intakes. The main control room arrangement is shown on Plant Drawing A-5655-0. The seismic category and quality group classification of components, instrumentation, and ducts are listed in Section 3.2 and 7.3 and shown on Plant Drawing M-78-1.

Principal equipment in the Control Room Ventilation System includes:

1. Two 100 percent capacity air handling units, including low and high efficiency filters, fans, chilled water cooling coils, and electric heating coils, are provided for use during normal operation or following an accident. Electric pan humidifiers are provided for use during normal operation.

2. Two 100 percent capacity return air fans are provided for use during normal plant operation and following a design basis accident (DBA).

3. Two 100 percent capacity emergency air filtration units are provided for use following an accident. Each unit has its own fan, low efficiency prefilters, electric heating coils, upstream high efficiency particulate air (HEPA) filters, charcoal adsorbers, and downstream HEPA filters.

4. An exhaust fan is provided to exhaust air from the control room, and toilet facilities during normal operation.

5. Two separate outside air intakes with plenum, through a common missile shielded tube are provided for use during normal operation or following a DBA.

6. The dampers for control room isolation purposes are bubbletight, with a closure time of 5 seconds maximum.

6.4.2.3 Leaktightness

Control room envelope construction joints and penetrations for cable, pipe, HVAC duct, HVAC equipment, dampers, and doors are designed specifically for leaktightness. A list of potential leak paths to the control room is provided in Table 6.4-1, along with the type of material, joint, or penetration. Periodic tests to verify control room leaktightness are discussed in Section 6.4.5.

CREF boundary operability is demonstrated periodically by performance of unfiltered air inleakage testing in accordance with the CRE Habitability Program described in plant Technical Specification 6.16.

6.4.2.4 Interaction with Other Zones and Pressure-Containing Equipment

Design of the control room envelope boundaries, ductwork, penetrations, and isolation dampers minimizes leakage of exterior radioactive gases into the control room envelope.

The control room envelope, as shown on Plant Drawing A-5655-0, is surrounded by an electrical access area and a corridor, which are served by the Control Equipment Room Supply (CERS) System; the work control center and control area office space (formerly Unit 2 control room area), which are served by the Unit 2 control area HVAC system (GC); and the access control area of the Radwaste Building, which is served by the Service Area Supply (SAS) System. The control equipment mezzanine at Elevation 117 feet 6 inches and the inverter rooms at Elevation 124 feet, below the envelope, are served by the CERS system. The control area heating and ventilating equipment room, also served by the CERS system, is above the envelope at Elevation 155 feet 3 inches. The CERS and SAS systems are described in Sections 9.4.1 and 9.4.3, respectively.

The control room return air ductwork, under negative pressure in the control area HVAC equipment room, is gas tight up to the flexible connection to the control room return air (CRRA) fan. Pressure with respect to the HVAC equipment room is positive from the outlet of the CRRA fan through the control room supply (CRS) system. Dampers in the negative pressure ductwork have welded frames and shafts in oil impregnated bearings. These dampers are provided with gaskets and are bolted to the ductwork.

Steam lines and central carbon dioxide fire prevention system tanks, and any other equipment or piping containing hazardous materials, are not located within the control room envelope. Failure of any pressure containing tank, equipment, or piping located outside the control room envelope will not cause transfer of hazardous material into the control room, as the control room is maintained at a positive pressure with respect to its adjacent areas at all times during normal plant operation by the Control Room Supply System.

6.4.2.5 Shielding Design

Control room shielding is discussed in Section 12.3.2. Section 12.3.2 identifies the radiation sources, shielding zones, and shielding thickness.

6.4.3 System Operational Procedures

6.4.3.1 Normal Operation

During normal plant operation, the control room supply (CRS system, control room return air (CRRA) fan, and control area exhaust (CAE) system maintain the design conditions in the control room envelope. The CRS/CRRA system consists of redundant, 100 percent capacity units, each supplied by a separate Class 1E power source. Each CRS system consists of an outside air intake louver and plenum, tornado damper, smoke detector, radiation sensor, radiation monitor, outside air intake isolation dampers, ASHRAE 55 percent dust spot low efficiency prefilters, 80 percent to 85 percent ASHRAE dust spot high efficiency filters, humidifier, electric heating coil, supply fan, and chilled water coil. See Section 9.2.7 for a description of the chilled water system ductwork, controls, and monitoring. A fixed amount of outside air, 3000 cfm, is provided to satisfy ventilation, exhaust, and pressurization requirements. The control room envelope is maintained at a positive pressure of at least 1/8" water gauge with respect to its adjacent areas during normal plant operation, by supplying more air to than exhausting from the control room envelope. Air is returned from the air conditioned space through the CRRA fan to the CRS system supply unit. The excess air is exhausted outdoors by the CAE fan and by exfiltration.

6.4.3.2 Post-Accident Operation

The Control Room Envelope Heating, Ventilation and Air Conditioning (HVAC) Systems are designed to ensure habitability during any design basis radiological accident with redundant trains. Upon receipt of a reactor vessel low water level (L1)/high drywell pressure signal from a loss of coolant accident (LOCA), the following occurs for both ventilation trains: the normal outside air intake isolation dampers for CRS system close, the CAE fan stops, the CAE exhaust isolation dampers close, and both control room emergency filter (CREF) trains start automatically to filter 2000 cfm emergency outside air intake for room pressurization when the mode switch is in the outdoor air position.

On high radioactivity in the outside air intake, the following occurs for both ventilation trains: the normal outside air intake isolation dampers for the CRS system close, the CAE fan stops, the CAE exhaust isolation dampers close, and the control room emergency filter (CREF) train connected to the operating CRS unit starts automatically to filter 1000 cfm emergency outside air intake for room pressurization when the mode switch is in the outdoor air position. On a high radiation signal, the redundant CREF train remains on standby. Low flow or a loss of airflow in the operating CREF automatically trips and isolates the operating CREF train and alarms in the main control room. Manual actuation of the redundant CREF train is then required. The CREF system consists of two 100 percent capacity trains, each supplied by a separate Class 1E power system and interlocked with one of the CRS/CRRA systems. Each CREF train consists of an outside air connection to the CRS outside air intake plenum, radiation sensor, tornado damper, smoke detector, outside and return air dampers, fan, 80 to 85 percent ASHRAE dust spot efficiency filters, electric heating coil for humidity control, upstream high efficiency particulate air (HEPA) filter, charcoal adsorber, a downstream HEPA filter, and a discharge damper. The CREF system may operate in one of the two following modes:

1. A pressurizing mode in which 1000 cfm of outside air is mixed with 3000 cfm of control room return air before entering the CREF unit, thus pressurizing the control room envelope above the surrounding space This mode is an automatic mode following a detection of high airborne radioactivity in the control room normal air intake.

2. The operator can override the control room pressurization mode to initiate isolation mode by manually closing the outside air intake isolation damper for the operating CREF unit. However, this mode is not automatically used following a radiological accident. The recirculation (isolation) mode is circulating 4000 cfm of return air, without introduction of outside air, through a CREF unit.

6.4.4 Design Evaluations

The Control Room Habitability System is designed with redundancy and separation of active components to provide reliable operation under normal conditions and to ensure operation under accident conditions. The design basis accident (DBA) radiation source terms used for control room dose evaluation are in accordance with Regulatory Guide 1.183 (Reference 6.4-3).

6.4.4.1 Radiological Protection

A detailed discussion of the dose calculation model for control room operators following the postulated DBA is provided in Section 6.4.7.

The design basis accidents have been evaluated to determine the worse case accident scenario for control room habitability design purposes. The control room operator doses can be derived for each of the accidents by the methodology described in Section 6.4.7 with the radiation source terms defined in the appropriate sections in Section 15 and the release locations relative to the control room intake shown in Figure 6.4-2 and Table 6.4-6.

The release locations for the DBA LOCA are:

(a) For primary containment leakage and leakage from engineered safety feature (ESF) components outside primary containment:
    (1) Directly to the atmosphere before Reactor Building drawdown, and
    (2) The FRVS exhaust vent at the top of the Reactor Building after Reactor Building drawdown.

(b) For main steam isolation valve (MSIV) leakage, exfiltration from the Turbine Building

The release locations for the fuel handling accident, which occurs in the Reactor Building, are assumed to be through the Reactor Building truck bay door.

The release location for the main steam line break, occurring outside the Reactor Building is the blowout panels.

The release location for the instrument line break accident occurring in the Reactor Building is the FRVS exhaust vent at the top of the Reactor Building.

The release location for the control rod drop accident is the Turbine Building louvers.

Of all the accidents with their various combinations of source terms and atmospheric dispersions, the accident yielding the most severe control room dose consequences is the DBA LOCA, which has been designated the worst-case accident for control room habitability.

The resulting calculated dose for control room occupancy on a rotating shift basis, for the containment, ESF, and MSIV leakages, is shown in Table 6.4-4 and is less than 5 rem total effective dose equivalent (TEDE) which is consistent with the requirements of 10CFR50.67.

Control room shielding design, based on the most limiting radiological accident, a design basis LOCA, is discussed in Section 12.3.2. The evaluations in Section 15 demonstrate that radiation exposures to control room personnel originating from containment shine, external cloud shine, and control room filter shine are reduced to a small fraction of the total by means of the walls surrounding the main control room (see Table 6.4-4).

6.4.4.2 Toxic Gas Protection

As discussed in Section 2.2.3, there is no danger to control room personnel from toxic chemicals stored onsite or offsite or transported near Hope Creek Generating Station (HCGS).

Response to a hazardous chemical release by Industrial Safety and Fire Protection per the Artificial Island Spill Plan will limit the release to a short duration accident. Although the ammonium hydroxide release may pose a danger, the control room would remain habitable by a combination of design and operator responses.

The possibility of diesel gas exhaust concentrations in the control room has been analyzed. The concentration of NO_x has been calculated. Using the control room dose model with X/Q values determined by the Modified Halitsky Methodology, as discussed in Section 6.4.7. The calculated NO_x concentration, 1.6 ppm, is below the TLV of 3 ppm from Reference 6.4-1.

6.4.4.3 Chlorine Protection

As discussed in Section 2.2.3, chlorine does not pose a danger to HCGS control room personnel.

6.4.4.4 Smoke Protection

Detectors in the outside air intakes alarm upon presence of smoke. The operator can then manually start the Control Room Emergency Filter (CREF) System in the recirculation mode, isolating the control room from outside air.

6.4.4.5 Respiratory Protection

Full faced, self-contained breathing apparatus and protective clothing are available for control room operators.

Respiratory equipment designs and capabilities are constantly improving. For this reason, specific equipment has not yet been selected for HCGS. In selecting the respiratory equipment, consideration is given to these improvements, as well as to reliability, durability, and serviceability. The minimum number of respiratory devices provides an onsite 6-hour air supply for each of five people with unlimited bottled air replenishment available from nearby locations. One extra respiratory device is provided for every three respiratory devices needed to meet the minimum capacity.

Control room operators are included in the provisions of the respiratory protection program. The respiratory protection program includes training in the method of putting on the equipment, proper use and care of the equipment, equipment limitations, and verification of individual capability to achieve and maintain a proper facial seal. Personnel familiar with the equipment should be able to put on and start use of the respirator within 2 minutes.

A program for periodic inspection of control room operator respiratory equipment is established. The program addresses inspection for defects, storage conditions, and, as necessary, cleaning, disinfecting, and repairing. In addition, the equipment will be cleaned, disinfected, and inspected after each use. Replacements and repairs are made only by trained personnel using parts designed for that equipment. The equipment is stored to protect against dust, sunlight, extreme heat or cold, excessive moisture, and damaging chemicals.

6.4.5 Testing and Inspection

The Control Room Heating, Ventilating, and Air Conditioning (HVAC) Emergency System filtration components are tested in a program with the following classifications:

1. Shop tests and factory component qualification tests to ensure the quality of the manufactured product. Refer to Table 9.4-6 for details of inspection and testing.

2. Preoperational tests in accordance with the requirements of Section 14.

3. Periodic tests during power generation in accordance with the requirements of Section 16.

The frequency of tests and inspections is selected to ensure the continued integrity of the system. Charcoal testing frequency is in accordance with Regulatory Guide 1.52 for the efficiency claimed and the bed depth specified.

Written test procedures establish minimum acceptable values for all tests. Test results are recorded as a matter of performance records, thus permitting early detection of faulty operating performance.

The shop and factory component qualification tests in place and laboratory testing criteria are in accordance with the recommendations and guidelines presented in Regulatory Guide 1.52 Section C-3, C-5, and C-6. High efficiency particulate air (HEPA) filters have a minimum efficiency of 99.97 percent when measured with a 0.3-micron dioctyl phthalate (DOP) aerosol. Carbon lot testing is required and certified by a qualified testing agency to establish gas adsorption efficiency, uniformity of density, ignition temperature, hardness, and impregnant content.

Filter plenums are tested for leakage under positive pressure. Plenums are pressurized to 125 percent of the design pressure with soap bubble tests at all welds. The maximum permissible leakage rate is 0.1 percent of the filter plenum rated flow in cfm at 125 percent of the positive design plenum pressure. The ductwork associated with each emergency filtration system is also tested for the same maximum permissible 0.1 percent leakage of the rated flow as used for testing the filter plenums.

Preoperational tests are conducted in accordance with the requirements of Section 14. In general, the tests include:

1. Visual inspection
2. Isolation valve leak tests
3. Airflow capacity verification test
4. Airflow distribution verification test
5. In place HEPA test
6. In place adsorber test
7. Laboratory test of adsorbent
8. Electric heater test.

Periodic tests for leaktightness of the control room envelope are conducted in accordance with the requirements of Chapter 16.

Periodic in place testing of HEPA filters and charcoal adsorbers and laboratory testing of charcoal adsorbers is performed in accordance with the requirements of Section 16.

6.4.6 Instrumentation Requirements

Differential pressure indicators are provided locally to measure the pressure drop across each filter element. The overall pressure drop across the CRS filters alarms in the main control room on high differential pressure. The differential pressure across the upstream high efficiency particulate air (HEPA) filter is transmitted to a local panel and alarms in the main control room. It is also recorded by the plant computer.

The instrumentation required for the deluge system of each charcoal adsorber is described in Section 9.5.1, Fire Protection System. In addition, the charcoal adsorber temperature is continuously indicated locally. High charcoal temperature alarms in the main control room. Deluge flow is sensed at high high charcoal temperature and alarms locally and in the main control room. The CREF fans are manually tripped which closes the outside air, return air, and discharge dampers of the emergency filter unit. Deluge flow is manually initiated.

The electric heating coils upstream of the filter are modulated to maintain a maximum of 70 percent relative humidity entering the charcoal adsorber. High relative humidity alarms in the main control room. Because of the small amount (1000 cfm), 25 percent of the control room emergency filter (CREF) unit flow rate, of outside air and the anticipated 3000 cfm return air of 76°F dry bulb and 50 percent relative humidity under summer conditions, it is anticipated that the heater will rarely operate, and no additional heat load is presumed for the CRS system. Assuming the 1000 cfm outside air is 100 percent relative humidity at 94°F dry bulb (conservative), and is mixed with 3000 cfm return air at 76°F dry bulb, 50 percent relative humidity, the resulting mixed air entering the charcoal adsorber is at 76.5°F dry bulb and 64 percent relative humidity which is still below the maximum 70 percent relative humidity limit.

Radiation monitors are provided in the outside air intake plenum. The monitors alarm in the main control room and start the CREF system upon high radiation.

Smoke detectors are provided in the normal and emergency outside air ducts. They alarm in the main control room.

The handswitches for heating, ventilating, and air conditioning (HVAC) equipment required for control room habitability are located in the control room. Flows and temperatures are indicated at the local panel in the control equipment room.

Sections 9.4.1 and 7.3 address the controls, instrumentation, and logic requirements for the control room HVAC systems.

Tornado damper position is monitored and alarmed by the computer.

6.4.7 Control Room Dose Evaluation Models

The radiological effects of a loss of coolant accident (LOCA) were analyzed using the models described below.

6.4.7.1 Control Room Atmospheric Dispersion Model

The ARCON96 computer code (Reference 6.4-4) was used to calculate relative concentrations at the control room air intake that would be exceeded no more than 5 percent of the time for primary containment leakage, leakage from ESF outside primary containment, and MSIV leakage. These concentrations are calculated for averaging periods ranging from one hour to 30 days in duration. The ARCON96 code uses site-specific hourly meteorological data and plant-specific data relating to release locations, building wake surface areas, the air intake location, and directions from the release locations to the air intake. The resulting atmospheric dispersion factors are shown in Table 6.4-2.

6.4.7.2 Control Room Dose Model

The control room is modeled as a single region with a volume of approximately 85,000 cubic feet.

The RADTRAD computer code (Version 3.02) (Reference 6.4-5) was used to determine doses within the control room resulting from primary containment leakage, leakage from ESF components outside the primary containment, and leakage from the main steam isolation valves (MSIVs) based on the parameters listed in Table 15.6-12.

The methods, assumptions, and conditions used to evaluate this accident are in accordance with those guidelines set forth in the NRC Standard Review Plan (SRP) 15.0.1 and Regulatory Guide 1.183. These are:

0 to 1 day	=	1
1 to 4 days	=	.6
4 to 30 days	=	.4

A breathing rate of $3.5 \times 10^{-4}\ m^3/s$ is assumed in accordance with the guidance provided in Regulatory Guide 1.183.

6.4.8 References

6.4-1 American Conference of Governmental Industrial Hygienists, "Threshold Limit Values for Chemical Substances and Physical Agents in the Workroom Environment with Intended Changes for 1981."

6.4-2 10 CFR 50.67, “Accident Source Term.”

6.4-3 US NRC Regulatory Guide 1.183, “Alternate Radiological Source Terms for Evaluating Design Basis Accidents at Nuclear Power Reactors”, July 2000.

6.4-4 J. V. Ramsdell, Jr., C. A. Simonen, “Atmospheric Relative Concentrations in Building Wakes”, NUREG/CR-6331, USNRC, May 1997.

6.4-5 S. L. Humphreys et al., “RADTRAD: A simplified Model for Radionuclide Transport and Removal and Dose Estimation, “NUREG/CR-6604, USNRC, April 1998.

TABLE 6.4-1

CONTROL ROOM POTENTIAL LEAK PATHS

Potential Leak Paths	Type of Material, Joint, or Penetration
Control room walls	Computer room, kitchen, and toilets, 2 feet 6 inches of concrete; corridor, nonrated drywall; remaining walls, 8 inches of concrete
Control room ceiling	12-inch concrete supported by steel plate
Control room floor	12-inch concrete supported by steel plate
Doors - personnel access	5 doors, each 3 ft x 7 ft, weather stripped, same 3-hour fire rating as walls
Electrical cable penetrations	In accordance with Specification A400
HVAC duct penetrations	Embedded flanged metal sleeves through concrete walls, bolted, with gaskets, to ducts
Control room HVAC ducts (negative pressure) exterior to main control room	Bolted and seal welded gastight galvanized steel, maximum leakage 0.1 percent of the rated flow

TABLE 6.4-1 (Cont)

Potential Leak Paths	Type of Material, Joint, or Penetration
Dampers, (frames, shaft penetrations, flanges) in control room ducts (negative pressure) exterior to main control room	Welded frames, and shafts oil impregnated bronze bearings with flanges bolted with gaskets to ducts
HVAC isolation dampers	Pneumatic or motor operated butterfly dampers, bubble tight
Piping penetrations	Sealed to maintain fire rated integrity of walls
Control room emergency filter unit	Welded cabinet construction; hinged, gas tight access doors
Control room supply unit	Welded cabinet construction; access doors bolted, with gaskets; coil connections bolted, with gaskets; inlet and discharge connections with gaskets.
Control room return air fans	Flexible connections bolted, with gaskets, to ductwork

TABLE 6.4-2

CONTROL ROOM DBA LOCA ATMOSPHERIC DISPERSION FACTORS

Control Room

Containment & ESF leakages and RCS release from FRVS vent

0 - 2 hours	1.25E-3 sec/m^3
2 - 8 hours	8.09E-4 sec/m^3
8 - 24 hours	3.04E-4 sec/m^3
24 - 96 hours	2.10E-4 sec/m^3
96 - 720 hours	1.59E-4 sec/m^3

MSIV leakage release from Turbine Building

0 - 2 hours	6.17E-4 sec/m^3
2 - 8 hours	4.00E-4 sec/m^3
8 - 24 hours	1.44E-4 sec/m^3
24 - 96 hours	1.00E-4 sec/m^3
96 - 720 hours	7.49E-5 sec/m^3

TABLE 6.4-3

THIS TABLE NOT USED

TABLE 6.4-4

DBA LOCA CONTROL ROOM DOSE[1]

Airborne exposure due to primary containment leakage:	0.526 rem TEDE
Airborne exposure due to ESF leakage:	2.45 rem TEDE
Airborne exposure due to MSIV leakage:	0.982 rem TEDE
Control room filter shine:	0.00357 rem TEDE
External cloud shine:	negligible
Shine from Reactor Building and primary containment:	negligible
TOTAL:	3.96 rem TEDE

1. The above results of the radiological consequence evaluations include the impact of introduction of 12 GE14i assemblies at HCGS.

TABLE 6.4-5

DBA LOCA CONTROL ROOM DOSE[1]

(Historical Information)

I. FOR 50 PERCENT/DAY REACTOR BUILDING INLEAKAGE

	Control Room Dose, rem
Thyroid	0.144
Whole body	0.024
Skin	0.630

II. FOR 100 PERCENT/DAY REACTOR BUILDING INLEAKAGE

	Control Room Dose, rem
Thyroid	0.255
Whole-body	0.0363
Skin	0.910

Notes:

(1) The following pathways are considered:

a) Control room airborne activity.

b) Ingress and egress.

c) External cloud dose.

TABLE 6.4-6

RADIOACTIVE RELEASE LOCATIONS RELATIVE TO CONTROL ROOM INTAKE

Receptor/ Release Point	Elevation of Centerline (ft)	Distance from Control Room Intake to Release Point Centerline (ft) X (North/South)	Y (East/West)

Security Related Information
Figure Withheld Under 10 CFR 2.390

Figure F6.4-1 intentionally deleted.

Refer to Plant Drawing A-5655-0 in DCRMS

SECURITY - RELATED
INFORMATION WITHHELD
UNDER 10 CFR 2.390

SK.A 0305 0 REV. 3

REVISION 0
APRIL 11, 1988

PSEG NUCLEAR, L.L.C.
HOPE CREEK NUCLEAR GENERATING STATION

PLANT LAYOUT WITH RESPECT
TO CONTROL ROOM INTAKE

Updated FSAR

Fig. 6.4-2

6.5 FISSION PRODUCT REMOVAL AND CONTROL SYSTEMS

6.5.1 Engineered Safety Feature Filter Systems

During post loss of coolant accident (post-LOCA) conditions, the Engineered Safety Features (ESF) Filtration Systems indicated below are required to perform the following safety-related functions:

1. The main control room emergency filter (CREF) units remove halogens and particulates that are potentially present in the air following a postulated accident, to ensure that radiation exposures to operating personnel in the main control room are maintained within the guideline values of 10CFR50, Appendix A, GDC 19. The air is then introduced into the main control room Heating, Ventilating, and Air Conditioning (HVAC) System, as discussed in Sections 6.5.1.1 and 9.4.1.

2. The Filtration, Recirculation, and Ventilation System (FRVS) units filter the air in the Reactor Building following a LOCA or other accidents involving large radioactivity releases. This is to reduce the concentration of radioactive halogens and particulates potentially present in the Reactor Building atmosphere. The FRVS is described in detail in Section 6.8.

6.5.1.1 Control Room Emergency Filter System

6.5.1.1.1 Design Bases

The design bases for the CREF system filters, fans, and associated ductwork are as follows:

1. Two 100 percent filter trains are each sized and specified for treating 4000 cfm (25 percent of the main control room area HVAC system capacity).

2. Filter train capacity and efficiency is maintained with all particulate filters fully loaded (dirty)

3. Two banks of high efficiency particulate air (HEPA) filters operate in series, in each filter train, and each is rated for a maximum airflow resistance of 1 inch water gauge when clean and 3 inches water gauge when dirty. An inplace percentage penetration of less than 0.05 percent when DOP tested in accordance with Section 10 to ANSI-N510 verifies acceptability of the filter bank and can be considered to warrant a 99 percent removal efficiency for particulates in accident dose evaluations.

4. The 4-inch deep charcoal adsorber is assigned a decontamination efficiency of 99 percent for trapping radioactive iodine as elemental iodine (I_2), and 99 percent for trapping radioactive iodine as methyl iodide (CH_3I) when processing air at 70 percent relative humidity. An electric heater assures the relative humidity is maintained lower than 70 percent.

5. Tornado dampers are provided in outside air intakes for tornado protection

6. Missile protection is provided for the equipment, ducts, and accessories.

See Sections 6.4 and 9.4.1 for further discussion of the CREF system.

6.5.1.1.2 System Design

The CREF system consists of two 100 percent redundant filter trains, each supplied by a separate Class 1E power source. Each CREF unit consists of a prefilter, electric heating coil, upstream HEPA filters, charcoal adsorber, and downstream HEPA filters, as shown in

Table 6.5-1. The filter train is located downstream of its supply fan. Each CREF unit is capable of handling 4000 cfm of air recirculated from the main control room and adjacent areas, or handling a combination of 3000 cfm recirculated air mixed with 1000 cfm of outdoor air.

Each filter train, fan, and duct system is Seismic Category I design. The CREF system is located within the control area of the Seismic Category I Auxiliary Building.

Under normal plant conditions, the CREF system is not in operation; however, when high radiation is detected at the outside air intake, the main control room outside air supply is automatically diverted through the CREF system. Total room air recirculation may be manually selected if a high radioactive noble gas concentration is detected in the outside air intake.

When the CREF system is in operation, the volume of air flowing through it is continuously indicated on a local panel. Low flow or a loss of airflow in the CREF automatically trips and isolates the operating CREF train(s) and alarms in the main control room. High differential pressure across the upstream HEPA filter is also alarmed in the main control room.

Each CREF train contains the following components:

1. An electric heater to maintain relative humidity of the entering air below 70 percent - If relative humidity is 70 percent or higher, the heater is energized by a humidity controller when sufficient airflow is maintained, and provides approximately 15°F temperature rise to the air. This ensures that the entering air, ranging from 58 to 80°F, enters the charcoal adsorber with a relative humidity of less than 70 percent.

2. A 4-inch deep permanent single unit (PSU) adsorber, gasketless and welded, containing approximately 1450 pounds of coconut shell charcoal (30 lb/ft^3) impregnated with potassium iodide and/or triethylene diamine. Eight test canisters are provided which contain the same depth of identical charcoal as the adsorber. The canisters are located so that airflow through each canister is representative of the adsorber. A laboratory test is performed on the carbon absorbent initially (before loading), every 18 months thereafter, after 720 hours of system operation, and following painting, fire, or chemical release in any ventilation zone communicating with the system. Testing conforms to Regulatory Guide 1.52-1978 using ASTM D3803 Method A. The adsorber is evacuated and recharged with bulk charcoal when it fails to meet the acceptance criteria.

3. HEPA filters - One bank is upstream of the charcoal adsorber and one is downstream of the charcoal adsorber. The filter is rated at 4000 cfm ±10 percent with a maximum airflow resistance of 1 inch water gauge across the filter bank when clean and 3 inches water gauge when dirty. The filter bank is considered to warrant a 99 percent removal efficiency for particulates in the accident dose evaluation when it meets the criteria of Section C.5.c of Regulatory Guide 1.52-1978 using Section 10 of ANSI N510-1980. The differential pressure across the upstream HEPA filter bank is indicated and any high value is alarmed in the main control room. The differential pressure is monitored by the plant computer.

4. A prefilter bank with an airflow rating of 4000 cfm ±10 percent - Maximum airflow resistance is 0.35 inches water gauge when clean, and 1.0 inch water gauge when dirty. Minimum filter efficiency is 80 percent by dust spot test method.

5. A housing of carbon steel welded construction and designed to withstand 23 inches water gauge positive internal pressure - Each housing is provided with individual access doors for servicing the heater and filter banks.

   The access doors are provided with transparent windows to allow inspection of components without violating the housing integrity.

   Filter housings, including water drains, are in accordance with recommendations in Section 4.3 of ERDA-76-21.

   Interior lights, with external switches and outside access for bulb replacement, are provided to facilitate inspection, testing, and replacement of components.

6. A direct drive centrifugal fan with a nonoverloading blade design - Fan performance and motor selection are based on the maximum air density and maximum system pressure drop anticipated during CREF operation. A manual switch for the fan is located in the main control room. Flow instrumentation controls the fan inlet vanes to maintain a constant airflow

7. Galvanized steel ductwork - Designed and qualified by analysis and testing to be Seismic Category I.

A Fire Protection Water Deluge System is provided to extinguish any ignition within the charcoal adsorber. This system is described in Section 9.5.1.

See Section 6.4 for further information on the CREF operation.

The work, equipment, and materials for the CREF system conform to the applicable requirements and recommendations of the guides, codes, and standards listed in Section 3.2.

The system design is consistent with recommendations of Regulatory Guide 1.52 using ANSI N509 as a guide for the design, construction, and testing of the unit, and ANSI N510 for field testing, as described in Section 1.8, and as summarized in Tables 6.5-2 and 6.5-4.

The CREF is designed to Seismic Category I requirements.

The power supply meets the IEEE-308 criteria and ensures that, in the event of loss of normal offsite ac power, standby power is supplied from the Class 1E standby diesel generator (SDG).

6.5.1.1.3 Safety Evaluation

The CREF system is designed to maintain functional integrity and performance during a design basis accident (DBA).

The equipment is located within the Auxiliary Building, a tornado protected Seismic Category I structure. During loss of offsite power (LOP), standby power is available from the Class 1E diesel generators to ensure operation of the CREF equipment.

The single failure criteria for safety-related equipment are met by using redundant equipment and controls, and by switching from one redundant train to the other in the event one fails. Active equipment such as fans, controls, and dampers are redundant. Since redundant HVAC systems are provided to control the ambient conditions for safety-related equipment, operating temperature limits are not exceeded and no degradation of CREF equipment performance is anticipated.

A redundant radiation monitoring system is provided in the outside air intake to detect high radiation, initiate measures to ensure that personnel safety and equipment functions in the main control room are not impaired, and see that the requirements of 10CFR20 are satisfied. In the event of a high outside air radiation condition, the normal outside air supply to the HVAC system is automatically diverted to the CREF train before being delivered by the HVAC system to the main control room, and all outside air isolation dampers, except those on the emergency intake, are closed. The operator may elect to go to a total recirculation mode, which diverts 4000 cfm of air from the main control room area to the CREF.

The operating mode of the CREF system is indicated in the main control room.

The CREF system and the Auxiliary Building shielding envelope are designed to limit the occupational dose level in the main control room, as required by GDC 19 of 10CFR50.

The introduction of a controlled quantity of outside air maintains the main control room and the adjoining areas served by the main control room HVAC system at a positive pressure with respect to surrounding areas. This positive pressure is maintained during all plant operating conditions, except when the HVAC and CREF systems are in the total recirculation mode.

Maximum permissible leakage rates for filter housing and ductwork shall be as defined in Section 4.12 of ANSI N509.

6.5.1.1.4 Test and Inspections

Preoperational and inservice tests and inspections are described in Sections 6.4 and 9.4.1.

6.5.1.1.5 Instrumentation

Instrumentation requirements are discussed in Sections 6.4 and 9.4.1.

6.5.1.1.6 Materials

Construction materials used in the CREF system are given in Table 6.5-3.

Materials used in the CREF system are selected to ensure that system operability is not adversely affected by radiation, temperature, or other environmental effects, nor susceptible to any fire or other detrimental hazard. Environmental qualification of the system is discussed in Section 3.11.

Since the CREF system is located in the control area of the Auxiliary Building, it is protected from extremes of radiation and temperature that could potentially produce radiolytic or pyrolytic decomposition of materials. Thus, decomposition products are not generated.

6.5.1.2 SRP Rule Review

Acceptance criteria II in SRP 6.5.1 requires design of instrumentation for ESF atmosphere cleanup systems to the guidelines of Regulatory Guide 1.52 and to the recommendations of ANSI N509 as summarized in SRP Table 6.5.1-1.

Compliance with the minimum instrumentation requirements for the EREF system is discussed in Table 6.5-4.

Compliance with the minimum instrumentation requirements for the FRVS is discussed in Table 6.8-5.

6.5.2 The Primary Containment Spray System

The Primary Containment Spray System, which is an integral part of the Residual Heat Removal (RHR) System, is designed to aid in reducing drywell pressure and temperature following a loss-of- coolant accident (LOCA). A description of the design features and operating mode of the Primary Containment Spray System (Containment Cooling System) is given in Section 6.2.2.1. The system is started manually after the Low Pressure Coolant Injection (LPCI) System cooling requirements have been satisfied.

The Primary Containment (drywell) Spray System is not designed to perform a fission product removal function following any accident, including a design basis accident (DBA).

Although not designed for such a function, the spray action of the system would probably result in a substantial reduction of fission product concentrations introduced to the drywell atmosphere during an accident. However, no credit is given to this possible activity reduction in any of the drywell airborne activity release calculations.

6.5.3 Fission Product Control Structures and Systems

In the unlikely event of an accident, any release of fission products from the reactor core or from a dropped spent fuel assembly is controlled by a number of passive and active design features. The passive control of released fission products is by containment in two major plant structures: the primary containment and the reactor building. Active control is attained through the operation of air filter systems in the reactor building only.

6.5.3.1 Primary Containment

The primary containment structure consists of the drywell and the pressure suppression chamber (torus), connected by vent pipes. The suppression chamber is in the shape of a torus concentrically surrounding the drywell, which has the shape of a light bulb. The primary containment pressure suppression concept is the GE Mark I design. The drywell is made of welded steel plate and is provided with a domed steel head. The structural design of the primary containment is discussed in Section 3.8.2. Plan and elevation views and design details of the primary containment are shown on Figures 3.8.2-1 through 3.8.2-17. The suppression chamber is also made of welded steel plate and is connected to the drywell by eight symmetrically located vent pipe sections.

The primary containment structure and its penetrations, isolation devices, hatches, and locks function to limit the release of radioactive materials subsequent to postulated accidents, so that the resulting offsite doses are less than the guideline values of 10CFR50.67. Primary containment parameters affecting fission product release accident analysis are given in Section 6.2.1.

The primary containment does not have a filter system for post-accident airborne fission product cleanup. The primary Containment Prepurge Cleanup System (CPCS) is used only prior to normal purge operations by the Reactor Building Ventilation System (RBVS) during normal plant shutdowns. A detailed description of the CPCS and its design function is given in Section 9.4.2.

Section 6.2.4 gives a detailed description of the primary containment isolation modes responding to specific isolation signals. A detailed description of the Primary Containment Isolation Control System is given in Section 7.1.

6.5.3.2 Reactor Building Enclosure

The Reactor Building completely encloses both the drywell and the suppression chamber and is provided to contain radioactive leakage from the primary containment, so that such leakage can be processed by filtration systems prior to release to the environment. The Reactor Building enclosure boundary is formed by the exterior walls of the Reactor Building. The design of the Reactor Building is discussed in Section 3.8.4, and plan and elevation views of the Reactor Building complex are shown on Plant Drawings P-0001-0 through P-0007-0 and P-0011-0.

The Filtration Recirculation Ventilation System (FRVS) removes fission products from Reactor Building enclosure air following an accident resulting in the release of radioactivity in either the primary containment or the Reactor Building. Besides the cleanup of air, the FRVS also maintains a differential pressure of at least 0.25 inches water gauge inside the Reactor Building enclosure in order to minimize the potential for unfiltered release of fission products to the environment. A detailed description of the FRVS design and its function is given in Section 6.8. Section 7.1 describes in detail the Reactor Building Isolation Control System. Reactor Building design parameters affecting fission product releases are given in Section 6.2.3.

For a detailed description of the isolation modes for the Reactor Building responding to specific isolation signals, see Section 9.4.2.

6.5.4 Ice Condensers as a Fission Product Cleanup System

Hope Creek Generating Station does not have an Ice Condenser System.

TABLE 6.5-1

CONTROL ROOM EMERGENCY FILTER SYSTEMS DESIGN PARAMETERS

Type	Welded steel casing
Number of trains	2
Flow rate, each, cfm	4000 ± 10 percent
COMPONENTS	
Fan	
Type	Centrifugal
Drive	Direct
Number of fans per train	1
Total pressure, inches w.g.	13.25
Fan, bhp	14.9
Motor, each, hp	25
Air heater	
Number per train	1
Heating capacity, each	
Btu/h	44,370
(kW)	(13)
Pressure drop, in. w.g.	0.10
Prefilter	
Quantity, per train	4
Pressure drop, inches w.g.	
Clean	0.35
Dirty	1.0
Efficiency[1], percent	80

HEPA filter	
Quantity per bank	4
Banks per train	2
Pressure drop, inches, w.g. (each bank)	
Clean	1.0
Dirty	3.0
Efficiency(2), percent	99.97
Removal efficiency -	
Accident dose evaluation, percent	99
Charcoal adsorber	
Type	Permanent single unit all welded vertical bed
Depth, inches	4
Adsorbent	Impregnated activated charcoal (rechargeable in place)
Pressure drop, inches w.g.	1.4
Assigned Activated Carbon Decontamination Efficiencies at R.H. $\leq$ 70 percent(3)	
Removing inorganic iodine, percent	99(4)
Removing organic iodine, percent	99(4)

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(1) Dust spot test on atmospheric dust when tested by the manufacturer.

(2) By MIL Standards 282 DOP test method on 0.3 micron particles when tested by the manufacturer.

(3) By Regulatory Guide 1.52, Table 2.

(4) Per Test Method A in ASTM D3803 at a relative humidity of 70 percent for a methyl iodide penetration of less than 0.175 percent.

TABLE 6.5-2

CREF COMPLIANCE WITH RECOMMENDATIONS OF REGULATORY GUIDE 1.52[1]

Regulatory Position	Complied with Yes/No	Description or Reference	Remarks
System Design Criteria			
Position c.2-a	Yes	Table 6.5-1 Figure 9.4-1	Mist eliminators not provided on CREF: no entrained water droplets in outside air entering the system
Position c.2-b	Yes		Missile protection walls separate the redundant units from each other and from adjacent rotating equipment
Position c.2-c	Yes	All components are Seismic Category I	
Position c.2-d	NA	NA	Located outside both primary containment and reactor building enclosure
Position c.2-e	Yes	Tables 6.5-3 and 6.1-1	
Position c.2-f	Yes	4000 cfm	Flow rates, each train
Position c.2-g	Yes	Recorded: System flow rate Pressure differential across first HEPA filter Alarms: See Section 9.4.1.5 and Table 6.5-4	
Position c.2-h	Yes	Sections 7.3 and 9.4.1.5	
Position c.2-i	Yes	Sections 6.4 and 9.4.1	Upon radiation detection only
Position c.2-j	Yes	Section 1.8, response to Regulatory Guide 1.52	
Position c.2-k	Yes	Section 6.5.1.1.2	
Position c.2-l	Yes	Section 6.5.1.1.4	

(1) See Section 1.8 for additional information.

TABLE 6.5-3

MATERIALS USED IN THE CONTROL ROOM EMERGENCY FILTER SYSTEM

Component	Material
Housing	
Structural steel	
Plate	CS ASTM A36
Angle	CS ASTM A36
Bar-stock	CS ASTM A36
Piping	CS ASTM A120
	SS ASTM A312-TP304
	CS ASTM A105
	SS ASTM A182-F304
Internal structure	
Filter supports	
Plate	SS ASTM A240 304
Sheet	SS ASTM A240 304
Angle	SS ASTM A240 304
Bar-stock	SS ASTM A276 304
Studs	CS ASTM A108
	SS AISI 166-304

Component	Material
Filter elements	
Prefilter	
Frame	Steel
Filter media	Glass fiber
HEPA	
Frame	Chromized steel
Filter media	Glass fiber per MIL-F-51079
Carbon adsorber	Activated impregnated coconut-base charcoal per RDT-M-16-1T
Paint	
Interior	Carboline Carbo Zinc 11
Exterior	Mobil Val Chem Zinc Chromate primer, red base 13-R-56B with finish coat Mobil Val Chem Hi-Build Epoxy 89 series

TABLE 6.5-4

CREF COMPLIANCE WITH MINIMUM INSTRUMENTATION REQUIREMENTS

Minimum instrumentation, readout, recording and alarm provisions for ESF atmosphere cleanup systems

References: ANSI N509 and Regulatory Guide 1.52

Sensing Location	Local Readout/Alarm	Continuously Staffed Control Panel (main control room or auxiliary control panel if staffing is a tech spec requirement)	Control Room Emergency Filter Exceptions and Justifications
Unit inlet or outlet	Flow rate (indication)	Flow rate (recorded indication, high alarm and low alarm signals)	No high flow alarm and no flow recorder(1)
Demister	Pressure Drop (indication) (optional high alarm signal)		Not applicable. No demister provided. See Section 1.8.1.52
Electric heater	Status indication		Full compliance
Space between heater and prefilter	Temperature (indication, high alarm and low alarm signals)	Temperature (indication, high alarm, low alarm, trip alarm signals)	No control room temperature indication and no alarms(2)(3)
Prefilter	Pressure drop (indication, high alarm signal)		No high alarm signal(4)
First HEPA (Pre-HEPA)	Pressure drop (indication, high alarm signal)	Pressure drop (recorded indication)	High alarm signal is provided in main control room instead of being provided locally
Space between Adsorber and second HEPA (Post-HEPA)	Temperature (two stage high alarm signal)	Temperature (indication, two-stage high alarm signal)	No temperature indication(5)
Second HEPA (Post-HEPA)	Pressure drop (indication, high alarm signal)		No high alarm signal(6)
Fan	(Optional hand switch and status indication)	Hand switch, status indication	Full compliance
Valve/damper operator	(Optional status indication)	Status indication	No status indication(7)

TABLE 6.5-4 (Cont)

Sensing Location	Local Readout/Alarm	Continuously Staffed Control Panel (main control room or auxiliary control panel if staffing is a tech spec requirement)	Control Room Emergency Filter Exceptions and Justifications
Deluge valves	Hand switch, status indication	Hand switch, status indication	Full compliance provided by fire protection system
System inlet to outlet		Summation of pressure drop across total system, high alarm signal	No summation pressure drop high alarm signal provided(8)

Justifications:

(1) Unit air flow is maintained constant by modulating fan inlet vanes in response to flow control. Air flow values are available at the plant computer.

(2) The electrical heater is controlled by a humidity control instrumentation loop and not by temperature. Heater failure with concurrent high relative humidity would result in a high humidity signal indicated locally and alarmed in the control room. Electric heater status and humidity value is indicated locally.

(3) The temperature immediately upstream of the carbon adsorber is indicated at a local control panel for the CREF system. Since the electric heating coil is energized in response to relative humidity measurement, large temperature variations can occur normally. Therefore, no high or low temperature alarms are provided. Low temperature would only be a concern in the event of high relative humidity which is alarmed as described in justification(2). High temperature would only be a concern if generated by the carbon adsorber and would be alarmed in two stages by the fire protection system.

(4) No pressure drop high alarm is provided for the CREF system prefilter since the prefilter is not a critical component in the filtration process, The first HEPA filter which is provided with a high alarm in the control room is the most critical component for dust collection.

(5) No air temperature indication is provided for comparison to the air temperature upstream. Such a comparison would only duplicate an indication of carbon adsorber bed heat generation that would be alarmed at the control room in two stages by the fire protection system.

(6) No pressure drop high alarm is provided for the second HEPA filter in the CREF units. Dust loading would result in high pressure drop across the first HEPA filter, which is alarmed, before it would cause high pressure drop across the second HEPA filter.

(7) No status indication is provided for upstream or downstream filter train shutoff dampers but is provided for the outside air intake dampers. These dampers are normally closed and fail in either the open or indeterminate position. Refer to Table 9.4-2 and response to Question 410.99 for a discussion of the failure mode and effects analysis for these dampers.

(8) The CREF pre-HEPA would reach maximum pressure drop (which is alarmed) before all other CREF filter components since the prefilter is only 80 percent efficient. The control room is considered a clean area (low dust) since it is supplied with clean filtered air by the control room supply system. The CREF handles a mixture of 3000 cfm control room return air and 1000 cfm outside air, therefore high dust loading is not anticipated. Since this system does not normally operate, maintenance and surveillance testing will ensure filter pressure drops are in normal operating ranges.

6.6 INSERVICE INSPECTION OF ASME B&PV CODE CLASS 2 AND CLASS 3 COMPONENTS

The construction permit for the Hope Creek Generating Station (HCGS) was issued November 4, 1974, and the preservice inspection program was required to meet the 1974 ASME B&PV Code, Section XI, with Addenda through Summer 1975. In accordance with the provisions of 10CFR50.55a(g), which allows for the use of subsequent effective editions and addenda of the ASME B&PV Code, the preservice inspection program will be written to meet the requirements of the 1977 ASME B&PV Code, Section XI, through Summer 1978 Addenda (hereafter referred to as ASME XI, 77S78) to the extent practical. The inservice inspection program will be in accordance with 10CFR50.55a(g).

This section addresses the preservice and inservice inspection (PSI/ISI) requirements of quality group B and C ASME B&PV Code, Section III, Class 2 and 3 components in accordance with ASME XI, 77S78 as amended by 10CFR50.55a for the Emergency Core Cooling System (ECCS) and Residual Heat Removal (RHR) System. The inservice testing of Class 2 and 3 pumps and valves in accordance with the requirements of Subsections IWP and IWV of ASME B&PV Code, Section XI, is addressed in Section 3.9.6 of the FSAR.

6.6.1 Components Subject To Examination

The scope of the program encompasses those components classified as Quality Group B (Class 2) and Quality Group C (Class 3) as defined in Regulatory Guide 1.26. The preservice inspection of Class 2 components, except for RHR and ECCS piping, is in accordance with Subarticle IWC-2200, ASME XI, 77S78. The preservice inspection of Class 2 piping in the ECCS and RHR systems is in accordance with Subarticle IWC-2100 of the 1974 ASME B&PV Code, Section XI with Addenda through Summer 1975 (hereafter referred to as ASME XI, 74S75).

Class 2 components subject to Inservice Inspection are in accordance with the requirements of ASME Section XI pursuant to 10CFR50.55a(g).

The preservice inspection of Class 3 components is in accordance with Subarticle IWD-2100. Class 3 components subject to Inservice Inspection are in accordance with the requirements of ASME Section XI pursuant to 10CFR50.55a(g).

6.6.2 Accessibility

Access has been evaluated in accordance with ASME XI, 74S75, and ASME XI, 77S78. Physical arrangement of the vessels, piping, pumps, valves, and supports provides personnel access to the extent practical for examination and, if necessary, repair of welds. Removable insulation is provided on piping systems that require volumetric and/or surface examinations. Temporary platforms, scaffolding, and ladders are provided for the removal of the insulation and pump and valve parts whose removal is necessary to permit access for examination. During design fabrication, weld joint configuration and surface finish were considered to permit thorough ultrasonic and surface examinations. All welds requiring examination are permanently identified with weld identification numbers scribed adjacent to the examination area. In addition, the weld number of the weld enclosed by insulation is identified on that section of insulation covering the weld with a weld identifier tag.

6.6.3 Examination Techniques and Procedures

Inservice examination techniques and procedures for ASME B&PV Code Class 2 and 3 components conform to the requirements of

Sub-article IWA-2200 of ASME XI, pursuant to 10CFR50.55a(g). Manual ultrasonic examination techniques are used to satisfy the volumetric examination requirements of Class 2 components. All reportable indications are mapped and records are made of maximum signal amplitude, depth below the scanning surface, and length of reflector. The data compilation format provides comparison data for subsequent examinations.

For areas where manual surface or direct visual examinations are to be performed, all reportable indications are mapped with respect to size and location in a manner that allows comparison with data from subsequent examinations.

Class 3 components may be examined during hydrostatic testing or during operation without removing insulation, as permitted by the ASME B&PV Code.

6.6.4 Inspection Intervals

The inspection interval program for in-service examinations and system pressure tests for Class 2 components is in accordance with Table IWC-2412-1 inspection program B of ASME XI, pursuant to 10CFR50.55a(g). The inspection interval, as defined in Section XI, is 10 years. The inspection intervals represent the calendar years after the reactor facility has been placed into commercial service. The interval may be extended by as much as 1 year to permit inspections to be concurrent with refueling or maintenance shutdowns. The frequency of examinations within each inspection interval is defined in ASME XI, Table IWC-2500-1, pursuant to 10CFR50.55a(g). Essentially 100 percent of pressure retaining welds in components and piping initially selected for ISI, with the exception of piping in the ECCS and RHR system, is examined prior to plant startup. All detailed examinations listed in ASME XI, 74S75, Table IWC-2520, categories C-F and C-G, are performed completely on piping welds in the ECCS and RHR system prior to plant startup. System hydrostatic tests and examinations of Class 3 systems are conducted near the end of each 10-year interval. In addition, Class 3 components are functional or in-service tested each period during operation.

6.6.5 Examination Categories and Requirements

Class 2 examination categories are in accordance with Table IWC-2500-1 of ASME XI, pursuant to 10CFR50.55a(g). Class 3 components are examined in accordance with Sub-article IWD-2600. Examination of Class 2 and 3 components complies with the requirements of IWC-2200 and IWD-2100, respectively, except for the RHR and ECCS.

In compliance with 10CFR50.55a, the extent of examination for ASME B&PV Code Class 2 piping in the ECCS and RHR system is determined by the requirements of Sub-article IWC-1200, Table IWC-2520, categories C-F and C-G, and Paragraph IWC-2411 in the ASME XI, pursuant to 10CFR50.55a(g).

6.6.6 Evaluation of Examination Results

Evaluation of examination results for Class 2 and 3 components is in accordance with Articles IWA-3000 and IWB-3000 of ASME XI, pursuant to 10CFR50.55a(g).

6.6.7 System Pressure Test

Class 2 systems subject to hydrostatic tests are tested in accordance with Article IWC-5000 of ASME XI, pursuant to 10CFR50.55a(g).

Class 3 systems subject to hydrostatic tests are tested in accordance with the requirements of Article IWD-5000 of ASME XI, pursuant to 10CFR50.55a(g).

6.6.8 Augmented In-service Inspection To Protect Against Postulated Piping Failures

For those portions of high-energy fluid piping, pre-service and subsequent in-service examinations are performed in accordance with the requirements specified in ASME Section XI. During each inspection interval, as defined in IAW-2400, an ISI is performed on all non-exempt ASME Code Section XI circumferential and longitudinal welds contained within the break exclusion region for high-energy fluid system piping as required per the approved risk informed break exclusion region (RI-BER) process.

6.6.8.1 References

1. EPRI TR-1006937 "Extension of the EPRI Risk Informed ISI Methodology to Break Exclusion Region Programs," April 4, 2002.

6.7 Not Used

TABLE 6.7-1

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HOPE CREEK GENERATING STATION

6.8 FILTRATION, RECIRCULATION, AND VENTILATION SYSTEM

The Filtration, Recirculation, and Ventilation System (FRVS) consists of two subsystems that are required to perform post-accident, safety-related functions simultaneously. These subsystems are:

1. Recirculation system - The FRVS Recirculation System is an Engineered Safety Feature (ESF) System, located inside the Reactor building that reduces offsite doses significantly below 10CFR50.67 guidelines during a loss-of-coolant accident (LOCA), refueling accident, or high radioactivity in the Reactor Building. Upon Reactor Building isolation, the FRVS Recirculation System is actuated and recirculates the Reactor Building air through filters for cleanup. This subsystem is the initial cleanup system before discharge is made via the FRVS ventilation subsystem to the outdoors.

2. Ventilation system - The FRVS Ventilation System is an ESF system, located inside the Reactor Building that maintains the building at a negative pressure with respect to the outdoors. The system takes suction from the discharge duct of the FRVS Recirculation System and discharges the air through filters to the outdoors via a vent at the top of the Reactor Building.

6.8.1 FRVS Recirculation System

6.8.1.1 Design Bases

The FRVS Recirculation System is designed to accomplish the following objectives:

1. Recirculates and filters the air in the Reactor Building following a LOCA, or other high radioactivity accident, to reduce the concentration of radioactive halogens and

particulates potentially present in the Reactor Building. See Plant Drawing M-76-1 for design airflow rates in the Reactor Building. The circulating rate is approximately 3.0 percent of Reactor Building free volume per minute.

2. Maintain air flow from the low to the high contamination areas.

3. Cools the air in the reactor building to limit its expansion and reduce its temperature to the maximum average of 140°F and to the maximum localized of 148°F during a LOCA, with the exception of pipe chase 4329, which reaches a maximum of 151°F.

4. Ensures that failure of any component of the system, assuming loss of offsite power (LOP), cannot impair the ability of the system to perform its safety function.

5. Remains intact and functional in the event of a safe shutdown earthquake (SSE).

6. Automatically starts in response to any one of the following signals within one minute:

   a. High drywell pressure

   b. Low reactor pressure vessel (RPV) water level (level 2)

   c. Refueling floor exhaust duct high radioactivity

   d. Reactor Building exhaust air high radioactivity

   e. Manual PCIS initiation

   The FRVS recirculation units can also be started manually from the main control room

7. The design bases employed for sizing the filters, fans, and associated ductwork are as follows:

   a. Each filter train is sized and specified for treating incoming air at 30,000 cfm at 140°F.

   b. The system capacity is maintained with all filters fully loaded (dirty), and Reactor Building atmosphere at maximum calculated relative humidity.

   c. The high efficiency particulate air (HEPA) filter bank has an airflow rating of 30,000 cfm ±10 percent with maximum airflow resistance of 1 inch water gauge when clean and 3 inches water gauge when dirty. The filter bank is considered to warrant a 99 percent removal efficiency for particulates in the accident dose evaluation when the filter bank is tested and meets the criteria of Section C.5.c of Regulatory Guide 1.52-1978 using Section 10 of ANSI N510-1980.

   d. Each charcoal adsorber is assigned a decontamination efficiency of 95 percent removal efficiency for radioactive iodine as elemental iodine (I_2), and 95 percent removal efficiency for radioactive iodine as methyl iodide (CH_3I) when passing through the charcoal at 70 percent relative humidity and 30°C.

   e. Each operating equipment train contains the amount of charcoal required to adsorb the inventory of fission products calculated to be released from the primary containment during a LOCA, with adequate margin to prevent charcoal ignition.

6.8.1.2 System Description

The FRVS Recirculation System is an ESF system located inside the Reactor Building. This system consists of six 25 percent capacity recirculation fans and filter trains connected to ducts, controls, and instrumentation. It is connected in parallel with the Reactor Building Ventilation System (RBVS), to the extensive supply and exhaust duct network within the Reactor Building. All six FRVS recirculation units include fan inlet vanes and isolation dampers, moisture separators to recirculate the Reactor Building air, high efficiency particulate air (HEPA) filters, charcoal filters, HEPA afterfilters, and water cooling coils. Upon a LOCA signal, all six FRVS recirculation units start with the two units designed as standby manually stopped and re-aligned to "Auto" mode. Four of the six FRVS recirculation units recirculate the Reactor Building air for at least 10 minutes after a LOCA signal. Cooling provided by the four operating FRVS recirculation units limits the expansion and temperature of the Reactor Building air following a LOCA. The cooling coils are provided with water from the Safety Auxiliaries Cooling System (SACS). One of the two 100 percent SACS cooling water loops supplies water to the three cooling coils while the redundant loop supplies the three remaining coils. Assuming one Safety Auxiliaries Cooling System (SACS) cooling water loop fails after 10 minutes, three FRVS recirculating cooling coils operate to maintain Reactor Building space temperatures below 148°F maximum and 140°F average except as noted in paragraph 6.8.1.1.3, above.

The airflow diagram for the FRVS Recirculation System is shown on Plant Drawing M-76-1. The instruments and controls are shown on Plant Drawing M-83-1. The system design parameters are provided in Table 6.8-1.

The quality group classification and corresponding applicable codes and standards that apply to the design of the FRVS system are discussed in Section 3.2.

Compliance of the system design with Regulatory Guide 1.52 is described in Section 1.8 and Tables 6.8-2 and 6.8-5.

Each redundant FRVS recirculation unit has a constant capacity of 30,000 cfm. Fan performance and motor selection are based on a maximum pressure drop of 3 inches water gauge across each of the two banks of HEPA filters, in addition to other design pressure drops in the system. The air flow is maintained at a constant rate by modulating the fan inlet vanes in response to flow sensors mounted in the ductwork.

Each permanent single unit (PSU) adsorber is gasketless and all welded stainless steel, filled with charcoal impregnated with potassium iodide and/or triethylenediamine. Each adsorber holds a total of approximately 5260 pounds of charcoal that has a minimum ignition temperature of 330°C. The charcoal adsorber is bulk filled and bulk evacuated at its installed location by supplementary equipment.

A water deluge spray system is provided for each charcoal adsorber. The spray system is connected to the Fire Protection System, as discussed in Sections 9.5.1.1.17 and 9.5.1.2.7, with the water deluge valve assembly mounted outside the charcoal adsorber. Multiple thermistors on the inlet of the adsorber provide continuous temperature indication.

Eight test canisters are provided in each charcoal adsorber. These canisters contain the same depth of the same charcoal that is in the adsorber. The canisters are so mounted that a parallel flow path is created between each canister and the adsorber. A laboratory test is performed on the carbon adsorbent initially (before loading), every 18 months thereafter, after 720 hours of system operation, and following painting, fire, or chemical release in any ventilation zone communicating with the system. Testing conforms to Regulatory Guide 1.52-1978 using ASTM D3803 Method A.

The moisture separator is a passive component used to remove gross and micrometer sized droplets of water or condensed steam from the air stream in order to prevent downstream HEPA filters from becoming clogged with water. The water is drained away and prevented from reentering the airstream.

The upstream HEPA filters remove the fine discrete particulate matter and pass the air stream to the adsorber. The HEPA filters downstream of the adsorption units collect carbon fines and provide redundant protection against particulate release in case of failure of the upstream HEPA filter bank.

An access door is provided for each access compartment in the FRVS recirculation unit. The doors have transparent portholes to allow inspection of components without violating train integrity.

Each FRVS filter plenum is of all welded carbon steel construction. Gas tight interior lights (with external light switches and fixture access) are provided for access compartments to facilitate inspection, testing, and replacement of components.

The FRVS Recirculation System is actuated either automatically by separate, redundant trip circuits, or manually from the main control room. The automatic actuation is originated by the signals listed in Section 6.8.1.1. The automatic actuation results in the start of all six recirculation units. Two standby units are subsequently manually stopped. Associated controls are then activated to open or modulate appropriate dampers so that the system function is accomplished. See Section 7 for detail discussion of startup and operating conditions. If any one of the four fans fails to operate, a standby fan starts automatically, and its filter train is activated.

The FRVS recirculation units and ducts are designed to Seismic Category I requirements.

The FRVS is supplied with diesel generator power automatically during a LOCA coincident with LOP.

See Appendix 6C for the structural design criteria for Seismic Category I HVAC ducts and duct supports.

6.8.1.3 Safety Evaluation

The FRVS Recirculation System is Seismic Category I design and located in a Seismic Category I, tornado protected structure. It has redundant automatic startup signals and manual actuation capability from the main control room. It is normally in a standby mode of operation and is available for testing, inspection, and maintenance.

The FRVS Recirculation System is designed to filter contaminated air in the Reactor Building following a postulated accident or abnormal occurrence that could result in high airborne radiation in the Reactor Building. It also limits the expansion and temperature of the Reactor Building air during a LOCA. FRVS equipment is powered from separate Class 1E buses, and all power circuits meet IEEE-279 and 308 requirements to ensure uninterrupted FRVS operation in the event of LOP. Redundant components are provided to ensure that a single failure does not impair or preclude system operation and performance. The FRVS is designed to Seismic Category I requirements, as discussed in Section 3.7, to ensure that the system remains intact and functional in the event of an SSE. Components and materials of the FRVS have been selected to ensure integrity of the system under postulated accident conditions. An FRVS failure mode and effect analysis is presented in Table 6.8-3.

6.8.1.4 Tests and Inspections

Tests and inspections are described in Table 6.8-6 and Section 9.4.2.4. Conformance with Regulatory Guide 1.52 is discussed in Table 6.8-2. The system is preoperationally tested in accordance with the requirements of Section 14, and periodically tested during power generation in accordance with the requirements of Section 16.

6.8.1.5 Instrument Requirements

The FRVS recirculation units can be actuated manually from the main control room. Each FRVS train is designed to function automatically upon receipt of an ESF system actuation signal. The status of system equipment, including indication of fan motor readiness, filter pressure drops, air temperatures, and air flow rates, is displayed in the main control room during both normal and accident conditions.

Tables 6.8-2 and 6.8-5 addresses the extent to which the recommendations of Regulatory Guide 1.52 are followed with respect to instrumentation.

All instrumentation performing safety related functions is qualified to Seismic Category I requirements. Redundancy and separation of the instrumentation is maintained, equal to the redundancy and separation of the equipment.

The following alarms are annunciated in the main control room:

1. Fan failure

2. High pressure drop across the upstream HEPA filter bank

3. High pressure drop across all filter banks (a group alarm)

4. Preignition charcoal temperature

5. Ignition charcoal temperature

6. Charcoal fire detection system failure (includes the deluge valve solenoid circuit discontinuity).

6.8.1.6 Materials

The materials used for the FRVS Recirculation System are given in Table 6.1-2. They are selected to ensure that system operability is not affected by radiation, temperature, or other environmental effects. Environmental qualification of the FRVS is discussed in Section 3.11.

The filter materials selected will not decompose due to radiation during the specified useful life of the filter. High temperature buildup effects are minimized by the fire protection system for the charcoal adsorber.

6.8.2 FRVS Ventilation System

6.8.2.1 Design Bases

The Filtration, Recirculation, and Ventilation System (FRVS) Ventilation System is designed to accomplish the following objectives:

1. Exhausts sufficient filtered air from the Reactor Building to maintain a differential pressure of at least 0.25 inches water gauge with respect to the outdoors, at all elevations and in all climatic conditions following Reactor Building Ventilation System Isolation, as discussed in Section 9.4.2 for LOCA and high radioactivity accidents.

2. Filters the exhaust air to remove radioactive particulate, and elemental forms of iodine to limit offsite doses significantly below the guidelines of 10CFR50.67.

3. Ensures that the failure of any component of the system, assuming loss of offsite power (LOP), cannot impair the ability of the system to perform its safety function

4. Remains intact and functional in the event of an safe shutdown earthquake (SSE)

5. Automatically starts in response to any one of the following signals within one minute:

   a. High drywell pressure

   b. Low reactor pressure vessel (RPV) water level (level 2)

   c. Refueling floor exhaust duct high radioactivity

   d. Reactor Building exhaust air high radioactivity

   e. Manual PCIS initiation

   The FRVS vent units can also be started manually from the main control room

6. The design bases employed for sizing the filters, fans, and associated ductwork are as follows:

   a. Each filter unit is sized and specified for treating incoming air at 9000 cfm ±10 percent maximum flow and 107°F

   b. System design performance is maintained with all filters fully loaded (dirty) and Reactor Building atmosphere at maximum calculated relative humidity

   c. The HEPA filterbank is considered to warrant a 99 percent removal efficiency for particulate in the accident dose evaluation by meeting the acceptance criteria of Section C.5.c of Regulatory Guide 1.52-1978.

d. The adsorber is assigned a decontamination efficiency of 95 percent for elemental iodine (I_2) and methyl iodide (CH_3I) when a sample is tested at 70 percent relative humidity and 30°C in accordance with Method A of ASTM D3803.

e. The FRVS ventilation system short-term maximum ventilating capacity (9000 cfm ±10 percent) is based on:

   (1) The calculated leakage into the Reactor Building with the Reactor Building maintaining a differential pressure of at least 0.25 inches of water with respect to the outdoors in all climatic conditions

   (2) An allowance for thermal expansion of the Reactor Building air volume due to LOCA heat generation

   (3) An allowance for leakage from the containment into the Reactor Building

f. The FRVS Ventilation System long term ventilating capacity (250 cfm) is based on (a) and (c), defined above.

6.8.2.2 System Description

The FRVS Ventilation System is an Engineered Safety Feature (ESF) System located inside the Reactor Building, and it consists of two 100 percent capacity centrifugal fans, filter trains, ducts, controls, and instrumentation. Each fan is provided with inlet vanes and isolation dampers. One vent unit runs while the other is on standby. Each vent unit takes the discharge from the FRVS Recirculation System and processes the air through a charcoal filter and HEPA filter. It exhausts to the outdoors through a vent at the top of the Reactor Building. The exhaust is monitored for radioactivity before release to the environment.

The airflow diagram for the FRVS Ventilation System is shown on Plant Drawing M-76-1. The system instruments and controls are shown on Plant Drawing M-84-1, and system design parameters are provided in Table 6.8-1.

The quality group classification and corresponding applicable codes and standards are discussed in Section 3.2.

Compliance of the system design with Regulatory Guide 1.52 is described in Section 1.8 and Tables 6.8-2 and 6.8-5.

Each redundant FRVS ventilating unit, consisting of a fan and a filter plenum, has a maximum exhaust capacity of 9000 cfm ±10 percent and a design minimum exhaust rate of 250 cfm in response to an indoor-outdoor differential pressure controller.

The fan performance and motor selection are based on a maximum system pressure drop of 4 inches water gauge across the component filters and the ductwork. The airflow is maintained at a constant rate through the filter train by modulating the fan inlet vanes in response to flow sensors mounted in the ductwork. Excess flow is returned to the building as required by the differential pressure controller.

Each charcoal adsorber consists of 2-inch-deep removable trays filled with charcoal impregnated with potassium iodide and/or triethylenediamine. The bank holds a total of approximately 2160 pounds of charcoal having a minimum ignition temperature of 330°C.

A water deluge spray system is provided for each charcoal adsorber. The spray system is connected to the Fire Protection System, as discussed in Sections 9.5.1.1.17 and 9.5.1.2.7, with the water deluge valve assembly mounted outside the charcoal adsorber. Multiple thermistors are provided on the inlet of the adsorber.

The HEPA filters downstream of the adsorption units collect carbon fines.

Eight test canisters are provided in each charcoal adsorber. These canisters contain the same depth of the same charcoal that is in the adsorber. The canisters are so mounted that a parallel flow path is created between each canister and the adsorber. A laboratory test is performed on the carbon adsorbent initially (before loading), every 18 months thereafter, after 720 hours of system operation, and following painting, fire, or chemical release in any ventilation zone communicating with the system. Testing conforms to Regulatory Guide 1.52-1978 using ASTM D 3803 Method A.

An access door is provided for each access compartment in the FRVS vent units. The doors have transparent portholes to allow inspection of components without violating train integrity.

Each FRVS filter plenum is of all-welded carbon steel construction. Gas-tight interior lights (with external light switches and fixture access) are provided for access compartments to facilitate inspection, testing, and replacement of components.

The FRVS Ventilation System is actuated automatically by separate, redundant trip circuits, or manually from the main control room. The automatic actuation is originated by the signals listed in Section 6.8.2.1. The automatic actuation results in the start of one ventilation unit. Associated controls are then activated to open or modulate appropriate dampers so that the system function is accomplished. See Section 7 for a detailed discussion of startup and operating conditions. If the lead fan fails to operate, the standby fan starts automatically, and its filter train is activated.

The FRVS ventilation units and ducts are designed to Seismic Category I requirements and the exhaust duct vent atop the reactor building is protected by tornado dampers.

The FRVS is supplied with diesel generator power automatically during a loss-of-coolant accident (LOCA) coincident with LOP.

6.8.2.3 Safety Evaluation

The FRVS ventilation system is Seismic Category I design and located in a Seismic Category I, tornado protected structure. It has redundant automatic startup signals and manual actuation from the main control room. It is normally in a standby mode and is available for testing, inspection, and maintenance.

The FRVS ventilation system is designed to preclude direct exfiltration of contaminated air from the Reactor Building following an accident or abnormal occurrence that could result in high airborne radiation in the Reactor Building. Equipment is powered from separate Class 1E buses, and all power circuits meet IEEE-279 and -308 requirements. Redundant components are provided to ensure that a single failure does not impair or preclude system operation. FRVS failure mode and effect analysis is presented in Table 6.8-5.

6.8.2.4 Tests and Inspections

Tests and inspections are described in Table 6.8-6 and Section 9.4.2.4. Conformance with Regulatory Guide 1.52 is discussed in Table 6.8-2. The system is preoperationally tested in accordance with the requirements of Section 14, and periodically tested during power generation in accordance with the requirements of Section 16.

6.8.2.5 Instrument Requirements

Each FRVS Ventilation System unit is designed to function automatically upon receipt of an ESF system actuation signal. The FRVS Ventilation System can also be actuated manually from the main control room. The status of system equipment, including indication of fan motor readiness, filter pressure drops, air temperature, and air flow rates, is displayed in the main control room during both normal and accident plant conditions.

Tables 6.8-2 and 6.8-15 address the extent to which the recommendations of Regulatory Guide 1.52 are followed with respect to instrumentation.

All instrumentation performing safety related functions is qualified to Seismic Category I requirements. Redundancy and separation of the instrumentation is maintained consistent with the redundancy and separation of the equipment.

The following alarms are annunciated in the main control room:

1. Fan failure

2. High pressure drop across all filter banks (a group alarm)

3. Preignition charcoal temperature

4. Ignition charcoal temperature

5. Charcoal fire detection system failure (includes the deluge valve solenoid circuit discontinuity)

6. High and low building pressure.

6.8.2.6 Materials

Materials used for the ventilation system of the FRVS are given in Table 6.1-2. They are selected to ensure that system operability is not affected by radiation, temperature, or other environmental effects. Environmental qualification of the ventilation system of the FRVS is discussed in Section 3.11.

Filter materials used does not decompose due to radiation during the specified useful life of the filter. High temperature buildup effects are minimized by the fire protection system for the charcoal adsorber.

TABLE 6.8-1

FILTRATION, RECIRCULATION, AND VENTILATION SYSTEM

Item	Recirculation System	Ventilation System
Type of unit	Built-up unit	Built-up unit
Number of units	6	2
Number operating	4	1
Flow rate, each, scfm	30,000	250 to 9000
Fan		
Type	Centrifugal	Centrifugal
Drive	Direct	Direct
Number of fans per unit	1	1
Total pressure, inches w.g.	19	8
Motor, hp, each	150	25
Moisture separator		
Number per unit	1	NA
Quantity of cells	18	NA
Cell size, inches	24 by 24 by 24	NA
Media	304SS and fiberglass mesh	NA
Efficiency(1), gal/1000 cfm	1	NA
Pressure drop, inches w.g.		
Initial (dry)	1	NA
Maximum (wet)	2	NA

TABLE 6.8-1 (Cont)

Item	Recirculation System	Ventilation System
Air heater		
Number per unit	1	1
Heating capacity, Btu/h	342,000	109,000
kW	100	32
HEPA filters, (upstream bank)		
Quantity	30	NA
Size, inches	24 by 24 by 12	NA
Pressure drop, inches w.g.		
Clean	1	NA
Dirty	3	NA
Efficiency(2), percent	$\geq$99.97	NA
Removal Efficiency Accident Dose evaluations(3), percent	99	NA
Charcoal adsorber		
Number per unit	1	1
Type	Gasketless	Tray
Adsorbent depth, inches	2	2
Adsorbent	Impregnated activated charcoal	Impregnated activated charcoal
Pressure drop, inches w.g.	1	1
Efficiency		
Removing methyliodine, percent	95	95
Removing elemental iodine, percent	95	95

TABLE 6.8-1 (Cont)

Item	Recirculation System	Ventilation System
HEPA filters, (downstream bank)		
Quantity	30	9
Size, inches	24 by 24 by 12	24 by 24 by 12
Pressure drop, inches w.g.		
Clean	1	1
Dirty	3	3
Efficiency(2), percent	$\geq$99.97	399.97
Removal Efficiency-Accident Dose, percent Evaluations(3)	99	99

(1) Per Underwriters' Laboratories Standard UL-900.

(2) By MIL Standard 282 DOP test method using 0.3 micron particles when tested by the manufacturer.

(3) Per Section C.5.c of Regulatory Guide 1.52-1978.

TABLE 6.8-2

FRVS COMPLIANCE WITH RECOMMENDATIONS OF REGULATORY GUIDE 1.52[1]

Regulatory Position	Complied With Yes/No	Description or Reference: Recirculation System	Description or Reference: Ventilation System	Remarks
System Design Criteria				
Position a	Yes	Table 6.8-1 Figure 9.4-4	Table 6.8-1 Figure 9.4-5	
Position b	Yes	Dwg P-0044-1 P-0046-1	Dwg P-0045-1	Missile protection walls separate the redundant units, from each other and from adjacent rotating equipment
Position c	Yes	All required components are Seismic Category I	All required components are Seismic Category I	Required components are those which perform safety related functions.
Position d	NA	NA	NA	Located outside primary containment, but inside the Reactor Building
Position e	Yes	Tables 6.8-3 and 6.1-1	Tables 6.8-4 and 6.1-1	
Position f	Yes	30,000 cfm	9000 cfm	Flow rates, each train
Position g	Yes	Recorded: system flow rate PD across first HEPA filter Alarms: Section 6.8.1.5 Table 6.8-5	Recorded: system flow rate PD across combined filters Bldg PD Alarms: Section 6.8.2.5 Table 6.8-5	
Position h	Yes	Section 7.3 and 6.8.1.5	Section 7.3 and 6.8.2.5	
Position i	NA	NA	NA	No permanent bypass arrangement installed
Position j	Yes	Section 1.8, response to Regulatory Guide 1.52	Section 1.8, response to Regulatory Guide 1.52	
Position k	Yes	Section 6.8.1.2	Section 6.8.2.2	
Position l	Yes	Section 6.8.1.4	Section 6.8.2.4	

TABLE 6.8-2 (Cont)

Regulatory Position	Complied With Yes/No	Description or Reference: Recirculation System	Description or Reference: Ventilation System	Remarks
System Design Criteria				
Component Design Criteria and Qualification Testing				
Position a	Yes	Table 6.8-1 and Section 6.8.1.2	Table 6.8-1 and Section 6.8.2.2	
Position b	N/A	N/A	N/A	
Position c	Yes	Table 6.8-1	Table 6.8-1	
Position d	Yes	Table 6.8-1	Table 6.8-1	
Position e	Yes	Section 6.8.1.2	Section 6.8.2.2	
Position f	Yes	Section 6.8.1.2	Section 6.8.2.2	
Position g	Yes	Section 6.8.1.2	Section 6.8.2.2	
Position h	NA	NA	NA	Both systems are located in control structure
Position i	Yes	Table 6.8-1	Table 6.8-1	
Position j	Yes	Section 6.8.1.2	Section 6.8.2.2	
Position k	Yes	Section 6.8.1.2	Section 6.8.2.2	
Position l	Yes	Section 6.8.1.2	Section 6.8.2.2	
Position m	Yes	Section 6.8.1.2	Section 6.8.2.2	
Position n	Yes	See remarks	See remarks	Both systems are in compliance

Regulatory Position	Complied With Yes/No	Description or Reference: Recirculation System	Description or Reference: Ventilation System	Remarks
Maintenance				
Position a	Yes	See remarks	See remarks	Charcoal of the recirculation system is removed by a carbon recharging system that draws the charcoal out by a blower. Charcoal of the ventilation system is removed by sliding the tray out of its frame cavity. Moisture separator cells and HEPA filters can be easily unclamped
Position b	Yes	Inside clear height approximately 8 ft	Inside clear height approximately 8 ft	
Position c	See remarks	See remarks	See remarks	30-by-50-in. and 20-by-50-in. access doors provided with no vacuum breakers. Administrative controls are used to preclude any work inside of the housing when the unit is in operation. Both systems are normally not used
Position d	Yes			
Position e	Yes	See remarks	See remarks	Both systems are in compliance

(1) See Section 1.8 for further information.

TABLE 6.8-3

FRVS RECIRCULATION SYSTEM FAILURE MODE AND EFFECT ANALYSIS

Plant Operating Mode	System Component	Component Failure Mode	Effect of Failure On the System	Failure Mode Detection	Effect of Failure On Plant Operation
Emergency	Power supply	Loss of offsite power (LOP)	None. All units are powered from standby diesel generators	Alarm in the main control room	No loss of safety function
Emergency (LOCA or LOCA & LOP)	Recirculation fans	Loss of one or two fans	None. The standby train automatically starts and maintains four fans in operation	Alarm in the main control room	No loss of safety function
Emergency (LOCA or LOCA & LOP)	Upstream & downstream HEPA filters	High differential pressure across any of these components	None. The fan inlet vanes modulate to maintain air flow. However, if the system flow rate drops below the setting of the system flow switch, the standby train automatically starts	Alarm in the main control room	No loss of safety function
Emergency (LOCA or LOCA & LOP)	Charcoal adsorbers	High-high temperature (ignition temperature)	None. At ignition temperature, the recirculation fan is tripped, the whole train is isolated, the fire protection system is actuated, and the standby train automatically starts	Alarm in the main control room at pre-ignition temperatures	No loss of safety function
Emergency (LOCA or LOCA & LOP)	Fans inlet dampers	Damper failed closed	None. The operating train is tripped, and the standby train automatically starts	Alarm in the main control room	No loss of safety function
Emergency (LOCA or LOCA & LOP)	Filter trains outlet dampers	Damper failed closed	None. The operating train is tripped, and the standby train automatically starts	Alarm in the main control room	No loss of safety function

TABLE 6.8-3 (Cont)

Plant Operating Mode	System Component	Component Failure Mode	Effect of Failure On the System	Failure Mode Detection	Effect of Failure On Plant Operation
Emergency (LOCA or LOCA & LOP)	Seismically analyzed fire protection backup deluge water valve	Valve failed closed	None. These valves are normally closed and are designed to fail safe in the closed position. They are backup to the regular non-Seismic Category I deluge valves	None. However, when the non-seismically qualified deluge valves open, an alarm sounds in the main control room	No loss of safety function
Emergency (LOCA or LOCA & LOP)	Fans variable inlet vanes	Dampers fail	None. These dampers are designed to fail open. The volume dampers continue to maintain maximum airflow	None	No loss of safety function
Emergency (LOCA or LOCA & LOP)	Charcoal adsorbers temperature detection units	Failure of the temperature detection unit	At high-high charcoal adsorber temperature, the train will trip automatically, and the standby train starts automatically	Temperature detection unit trouble alarm in the main control room	No loss of safety function

TABLE 6.8-4

VENT SYSTEM FAILURE MODE AND EFFECT ANALYSIS

Plant Operating Mode	System Component	Component Failure Mode	Effect of Failure on the System	Failure Mode Detection	Effect of Failure On Plant Operation
Emergency	Power supply	Loss of offsite power (LOP)	None; each of the redundant fans and associated dampers are powered from separate standby diesel generators	Alarm in the main control room	No loss of safety function
Emergency (LOCA or LOCA & LOP)	Vent fans	Loss of one fan	None, the standby fan automatically starts	Alarm in the main control room	No loss of safety function
Emergency (LOCA or LOCA & LOP)	Dampers on duct from recirculation system to ventilation system	Damper failed closed	None. The operating train is tripped, and the standby train starts automatically	Alarm in the main control room	No loss of safety function
Emergency (LOCA or LOCA & LOP)	Filter trains outlet dampers	Damper failed closed	The operating train is tripped, and the standby train starts automatically	Alarm in the main control room	No loss of safety function
Emergency (LOCA or LOCA & LOP)	Dampers on duct from ventilation system to recirculation system	Damper failed closed	None, these dampers are designed to fail safe in the closed position	Damper position indication in the main control room	No loss of safety function
Emergency (LOCA or LOCA & LOP)	Dampers on duct from ventilation system to exhaust outlet	Damper failed closed	None; the failed dampers trip the operating fan and start the standby train automatically	Damper position indication in the main control room	No loss of safety function

TABLE 6.8-5

FRVS COMPLIANCE WITH MINIMUM INSTRUMENTATION REQUIREMENTS

Minimum instrumentation, readout, recording and alarm provisions for ESF atmosphere cleanup systems

References: ANSI N509 and Regulatory Guide 1.52

Sensing Location	Local Readout/Alarm	Continuously Staffed Control Panel (main control room or auxiliary control panel if staffing is a tech spec requirement)	FRVS Recirculation System Exceptions & Justifications	FRVS Vent System Exceptions & Justifications
Unit inlet or outlet	Flow rate (indication)	Flow rate (recorded indication, high alarm and low alarm signals)	No high flow alarm[(1)]	No high flow alarm[(1)]
Demister	Pressure Drop (indication) (optional high alarm signal)		Full compliance	Not applicable. No demister provided. See Section 1.8.1.52
Space between heater and prefilter	Temperature (indication, high alarm and low alarm signals)	Temperature (indication, high alarm, low alarm)	No local temperature indication and no alarms[(2)(3)]	No local temperature indication and no alarms[(2)(3)]
Prefilter	Pressure drop (indication, high alarm signal)		Not applicable. Demister also serves as prefilter. No high alarm signal[(4)]	Not applicable. No prefilter system downstream of FRVS recirculation units
First HEPA (Pre-HEPA)	Pressure drop (indication, high alarm signal)	Pressure drop (recorded indication)	Full compliance high alarm signal is provided in control room.	Not applicable. No first HEPA filter downstream of FRVS recirculation units.
Space between Adsorber and second HEPA (Post-HEPA)	Temperature (two stage high alarm signal)	Temperature (indication two-stage high alarm signal)	No temperature indication[(5)]	No temperature indication[(5)]
Second HEPA (Post-HEPA)	Pressure drop (indication, high alarm signal)		No high alarm signal[(6)]	No high alarm signal[(7)]

Sensing Location	Local Readout/Alarm	Continuously Staffed Control Panel (main control room or auxiliary control panel if staffing is a tech spec requirement)	FRVS Recirculation System Exceptions & Justifications	FRVS Vent System Exceptions & Justifications
Fan	(Optional hand switch and status indication)	Hand switch, status indication	Full compliance	Full compliance
Valve/damper operator	(Optional status indication)	Status indication	No status indication (8)	No status indication (8)
Deluge valves	Hand switch, status indication	Hand switch, status indication	Full compliance provided by fire protection system	Full compliance provided by fire protection system
System inlet to outlet		Summation of pressure drop across total system, high alarm signal	Full compliance	Full compliance

Justifications:

(1) Unit air flow is maintained constant by modulating fan inlet vanes in response to flow controls. Air flow values are recorded in the control room.

(2) The electrical heater and humidity control instrumentation loop is deleted.

(3) The temperature immediately upstream of the carbon adsorber is indicated in the control room for the FRVS recirculation and vent units. No high or low temperature alarms are provided. High temperature would only be a concern if generated by the carbon adsorber and would be alarmed in two stages by the Fire Protection System.

(4) No pressure drop high alarm is provided for the FRVS recirculation unit demisters which also acts as a prefilter since the prefilter is not a critical component in the filtration process. The first HEPA filter which is provided with a high alarm in the control room is the most critical component for dust collection.

TABLE 6.8-5 (Cont)

(5) No air temperature indication is provided for comparison to the air temperature upstream. Such a comparison would only duplicate an indication of carbon adsorber bed heat generation that would be alarmed at the control room in two states by the Fire Protection System.

(6) No pressure drop high alarm is dedicated for the second HEPA filter in the FRVS recirculation units. Dust loading would result in high pressure drop across the first HEPA filter, which is alarmed before it would cause high pressure drop across the second HEPA filter.

(7) No pressure drop high alarm is dedicated for the second HEPA filter in the FRVS ventilation units. Dust loading will be collected in the upstream FRVS recirculation units, which have two HEPA filters in series.

(8) No status indication is provided for upstream or downstream filter train shutoff dampers. These dampers are normally closed, fail closed for the FRVS recirculation and vent units. In the event a damper fails closed during system operation the low flow alarm will indicate loss of system flow and a redundant train will be energized.

TABLE 6.8-6

FILTRATION, RECIRCULATION, AND VENTILATION SYSTEM
TESTS AND INSPECTIONS

1. GENERAL

a. Safety-related components are designed, fabricated, installed, and tested under quality assurance requirements, in accordance with Appendix B to 10CFR50.

b. For systems that must perform a safety-related function, periodic inservice testing of fans, valves, controls, and instrumentation in the systems is performed. Motor operated valves and dampers are tested by opening and closing the valve or damper. Temperature, differential pressure readings, and flow capacity are recorded.

c. Equipment in Seismic Category I systems is required by specification to meet the seismic requirements for this project. Before each equipment item is shipped, the supplier of that item is required to submit an adequate analysis or applicable test data as evidence of seismic compliance.

d. Components designed to meet Seismic Category I requirements are subjected to a program of vendor shop and field testing.

e. Standby units are tested at periodic intervals to verify the operation of essential features. Periodic tests of the activation circuitry and the system components are conducted during normal plant operation.

2. FANS

Centrifugal fans are shop tested in accordance with the AMCA Standard Test Code for Air Moving Devices, Bulletin 210.

3. MOTORS

Motors are built, designed, rated, and tested in accordance with NEMA-MG-1. Seismic Category I motors are certified for the NEMA tests required in Publication No. MG-1.

4. COOLING COILS

Cooling coils are furnished in accordance with ASME Section III, ASHRAE 33 and ARI 410. Coils are hydrostatically and pneumatically tested. Seismic Category I coils are seismically qualified by analysis or testing on a shaker table.

5. HEATING COILS

The electric heating coils are furnished in accordance with the requirements of UL 1096 and the National Electric Code, Article 424. The electric heating coils are installed according to the National Fire Protection Association Pamphlets 90A and 90B.

6. MOISTURE SEPARATORS

The moisture separators are furnished in accordance with the requirements of ANSI N509, MSAR 71-45 and UL-900 Class 1.

7. HEPA FILTERS

a. Qualification Tests Before Installation

1. HEPA filters meet the construction, material, test, and qualification requirements of military specification MIL-F-51068 and have fiberglass media conforming to the requirements of military specification MIL-F-51079.

2. Radiation resistance of filter media meets the requirements of MIL-F-51079.

3. The assembled filters are type-tested in accordance with UL 586, High Efficiency Air Filter Units, to minimize fire hazards. The filters are approved UL Class 1.

4. Each filter is tested for flow resistance at rated flow. The filter resistance is not to exceed the rated pressure drop of 1 inch w.g. under this condition.

5. Each filter design and combination of materials of construction shall be qualified by testing at least two of the size and design to rough handling in accordance with Method 105.9 of MIL-STD-282 for 15 min. at 3/4 in. total amplitude and a frequency of 200 Hz, with pleats and filter faces in a vertical orientation, without visible damage or loss of filtration efficiency, as determined by testing.

6. Filters are subjected to acceptance tests made by the manufacturer. The filter efficiency is no less than

99.97 percent when tested with mondispersed, thermally generated DOP aerosol having a mean particle size of 0.3 micron.

7. Filters selected at random from the manufacturer's production line are subjected to moisture, overpressure resistance, and filter dust loading tests in order to initially qualify the filters. The moisture and overpressure resistance tests are performed in accordance with MIL-F-51068.

8. Each filter is individually tested at 100 percent and 20 percent of the rated capacity to IES Standard CS-1.

b. Preoperational Tests for Acceptance (Performed in Filter Train Housing)

1. Visual and performance checks of the housing and mounting frames are made in the field in accordance with Sections 5, 6, and 7 of ANSI N510 to check for conformance with design specifications. Nonconforming items are rejected and replaced with acceptable equipment.

2. After installation, inplace testing of the HEPA filter bank is conducted in accordance with Section 10 of ANSI N510-1980. The tests are conducted at the rated airflow, using the DOP aerosol test equipment, test procedures, and test reports specified in ANSI N510-1980. The percentage penetration of less than 0.05 percent verifies acceptability of the filter bank. An engineered safety feature air filtration system

satisfying this condition can be considered to warrant a 99 percent removal efficiency for particulates in accident dose evaluations. When leaks exist that would result in an inability to meet the specified system parameters, they are located and repaired by increasing the filter's gasket compression or by filter replacement. The system is then tested again to ensure conformance with acceptance criteria.

8. CARBON ADSORBERS

Carbon adsorbers are tested as follows:

a. Qualification Tests Before Installation

1. Representative samples, taken from each batch of carbon used for filling the adsorbers, are tested per the requirements of Regulatory Guide 1.52 Position C-6 for adsorption efficiencies of molecular iodine (elemental) and methyl iodide (organic). The performance requirements are given in Table 5-1 of ANSI N509. For systems operating outside of primary containment, with relative humidities controlled to 70%, the removal efficiencies and residence times for iodine forms are as follows:

Adsorbent Depth	Assigned Activated Carbon Decontamination Efficiencies
2 inches (0.25 res time)	95 percent elemental 95 percent organic

Adsorbent Depth	Assigned Activated Carbon Decontamination Efficiencies
4 inches (0.50 res time)	99 percent elemental 99 percent organic

Tests or calculations demonstrate that the residence times shown above are met.

2. Laboratory tests are conducted on the carbon absorbent in accordance with RDT M16-1T to determine the following:

   a) Particle size

   b) Ignition temperature

   c) Apparent density

   d) Moisture content

   e) Carbon tetrachloride activity.

b. Inplace Testing of Adsorber

   1. Each charcoal adsorber is tested for leakage using the test method presented in ANSI N510. In this test Refrigerant (R-11 or R-112) is introduced into the upstream side of the adsorber at rated airflow. A downstream concentration of less than 0.05 percent verifies an acceptable inplace leak test.

2. The installed carbon adsorber filter bank is checked for conformance to the design specifications by a visual and a performance test in accordance with ANSI N510.

9. FILTER HOUSINGS

In addition to the housing manufacturer's shop tests, a field performance test is conducted for each housing. The housings are designed to withstand pressures ranging from 6 to 23 inches w.g.

10. FILTER INSERVICE TESTS AND INSPECTIONS

a. The air filtering systems are subject to inplace testing before initial startup, at least once per 18 months thereafter, after each HEPA filter or adsorber change, following painting, fire, or chemical release in any ventilation zone communicating with the system, and following removal of an adsorber sample for laboratory testing.

b. Periodic testing of the HEPA filter banks ensures that the filter bank performance is not degraded through normal use, or during standby, to a level below that assumed in the accident analyses. Test methods and acceptance criteria are the same as or equal to those for initial acceptance of the system components. If the test results indicate that performance of a component is below the acceptance criteria, the component is repaired or replaced.

c. The following filter inservice tests and inspections are performed at regular intervals during plant life to

TABLE 6.8-6 (Cont)

determine that the filtration systems are functioning correctly:

1. With the fan running, readings on the differential pressure gauges, which are mounted on the filter plenum, are observed and recorded.

2. HEPA filters are replaced when the pressure drop across them reaches 3.0 inches w.g. Where there are two HEPA filter banks in series, the second one is changed at 4 inches w.g.

3. Field leak tests are conducted initially, every 18 months thereafter, after each partial or complete replacement of HEPA or charcoal filters in a system, following painting, fire or chemical release in any ventilation zone communicating with the system.

4. Field leak tests of HEPA filter banks are conducted with dioctylphtholate, and a light scattering aerosol photometer is used for measuring percentage penetration. A percentage penetration of 0.05 percent or greater requires corrective action, as stated previously.

5. Corrective action after a leak test may consist of increasing the contact pressure on a seal or replacement of a filter or filters. After corrective action is taken, an additional leak test is made.

6. A laboratory test is performed on the carbon adsorbent initially (before loading), every 18 months thereafter, after 720 hours of system operation, and following painting, fire, or chemical release in any

ventilation zone communicating with the system. Testing conforms to Regulatory Guide 1.52 using ASTM D3803 Method A. Tests for hardness, ignition temperature, and radioactivity are not made on these samples.

11. <u>DUCTWORK</u>

a. Leakage tests on all ductwork are conducted during construction.

b. All air distribution systems are tested and balanced to provide design air quantities at each outlet, within a tolerance of ±10 percent.

c. Seismic Category I ductwork is supported by seismically designed duct hangers.

d. All Seismic Category I ductwork is seismically designed.

12. <u>CONTROLS</u>

a. All controls and instrumentation are tested prior to plant operation.

b. Inservice tests and inspection procedures are incorporated in the plant operations manual, and they are performed at regular intervals during the life of the plant to show that the instruments are functioning properly. Recalibration, when necessary, is made at that time.