6.0 ENGINEERED SAFETY FEATURES

The engineered safety features (ESF) of this plant are those structures, systems and/or components provided to prevent, limit, or mitigate the release of energy and radioactive material in excess of 10CFR50.67 limits in the event of a design basis accident. ESF can be divided into five general groups: containment structures/systems, emergency core cooling systems, habitability systems, fission product removal and control systems, and other structures, systems, and components which perform an ESF function. The systems, or portions of systems, within these groups, are as follows:

Containment Structures/Systems:

- Primary containment,
- Secondary containment,
  - Standby Gas Treatment System (SGTS)
  - Reactor Building Recirculation System
- Containment heat removal system,
  - Containment Spray Cooling (CSC) mode of RHR system
  - Suppression Pool Cooling (SPC) mode of RHR system
- Containment isolation system,
  - Primary Containment Isolation System
- Containment combustible gas control,
  - Primary Containment Ventilation System (only safety-related drywell unit cooler fans, CRD area ventilation fans and associated safety-related ductwork),
  - Containment Atmosphere Control System.

Emergency Core Cooling Systems:

- High pressure coolant injection (HPCI),
- Automatic depressurization system (ADS),
- Core spray (CS), and
- Low pressure coolant injection (LPCI mode of RHR system).

Habitability Systems:

Control Structure HVAC systems which service the Habitability envelope, including:

- Control Room HVAC,
- Control Structure HVAC,
- Computer Room HVAC

Control Structure Emergency Outside Air Supply Sytsem,
Battery Room Exhaust,
Kitchen and Toilet Exhaust.

Fission Product Removal and Control Systems:

Standby Gas Treatment System (SGTS)
Reactor Building Recirculation System
Control Structure Emergency Outside Air Supply System,

Other Systems/Components:

Main Steam line isolation system (See Section 5.4.5),
Control rod drive housing support systems (See Sections 4.5.3 and 4.6.1.2),
Control rod velocity limiter (See Section 4.2),
Main steam line flow restrictor (See Section 5.4.4),
Standby liquid control system (See Section 9.3.5), and
Main steam isolation valve - leakage isolated condenser treatment method (ICTM).

6.1 ENGINEERED SAFETY FEATURE MATERIALS

The materials used in the SSES engineered safety feature (ESF) systems have been selected on the basis of an engineering review and evaluation for compatibility with:

a) The normal and accident service conditions of the ESF system

b) The normal and accident environmental conditions associated with the ESF system

c) The maximum expected normal and accident radiation levels to which the ESF will be subjected

d) Other materials to preclude material interactions that could potentially impair the operation of the ESF systems.

The materials selected for the ESF systems are expected to function satisfactorily in their intended service without adverse effects on the service, performance, or operation of any ESF.

6.1.1 METALLIC MATERIALS

In general, metallic materials used in 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 materials of the highest quality for the ESF systems. Where it is not possible to adhere to the ASME material specifications, metallic materials have been selected in compliance with other nationally recognized standards, eg, ASTM, where practicable, or chosen in compliance with current industry practice.

6.1.1.1 Materials Selection and Fabrication

Metallic materials in ESF systems have been designed for a service life of 40 years, with due consideration of the effects of the service conditions upon the properties of the material, as required by Section III of the ASME B&PV Code, Articles NB-2160, NC-2160, and ND-2160. Since the affected systems must perform for the period of extended operation, aging of equipment is managed to ensure it continues to perform its intended function.

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

The metallic materials of the ESF systems have been evaluated for their compatibility with core and containment spray solutions. No radiolytic or pyrolytic decomposition of ESF material will occur during accident conditions, and the integrity of the containment or function of any other ESF will not be affected by the action of core or containment spray solutions. Core and containment sprays use high purity water that meets the limits of Table 3.11-7.

Material specifications for the principle pressure retaining ferritic, austenitic, and nonferrous metals in each ESF system are listed in Tables 6.1-1a and 6.1-1b. Materials that would be exposed to the core cooling water and containment sprays in the event of a LOCA are identified in these tables. Sensitization of austenitic stainless steel is prevented by the following actions:

a) Design specifications call for ASME material which is to be supplied in the solution annealed unsensitized condition.

b) Design specifications prohibit the use of materials that have been exposed to sensitizing temperatures in the range of 800 to 1500°F unless subsequently solution annealed and water quenched.

In addition, design specifications for austenitic stainless steel components require that the material be cleaned using halide free cleaning solutions and that special care be exercised in fabrication, shipment, storage, and construction to avoid contaminants.

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.

Reflective metallic insulation, Min-K insulation, phenolic foam insulation and small amounts of fibrous insulation are used inside the primary containment. Metallic reflective thermal insulation, phenolic foam insulation and fiberglass wool thermal insulation (outside 7 pipe diameters from postulated HELB locations) are used inside the primary containment. To avoid the possibility of chloride induced stress corrosion cracking in austenitic stainless steel, design specifications on the nonmetallic insulation require that it conform to the requirements of Regulatory Guide 1.36, (2/73). This includes not only non-metallic insulation in direct contact with austenitic stainless steel, but also situations where leachate from non-metallic insulation components could contaminate austenitic stainless steel components.

Regulatory Guide 1.31, is complied with to the extent specified in Section 3.13, to avoid fissuring in austenitic stainless steel welds that are part of the engineered safety features.

6.1.1.1.1 NSSS Material Specifications

Table 5.2-4 lists the principal pressure retaining materials and the appropriate material specifications for the reactor coolant pressure boundary components.

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

Subsection 5.2.3.2.3 discusses compatibility of the reactor coolant with materials of construction exposed to the reactor coolant. These same materials of construction are found in the engineered safety feature components.

6.1.1.1.3 NSSS Controls for Austenitic Stainless Steel

a) Control of the use of Sensitized Stainless Steel.

Controls to avoid severe sensitization are discussed in Subsection 5.2.3.4.1.1.

b) Process Controls to Minimize Exposure to Contaminants.

Process controls for austenitic stainless steel are discussed in Subsection 5.2.3.4.1.2.

c) Use of Cold Worked Austentic Stainless Steel.

Austenitic stainless steel with a yield strength greater than 90,000 psi was not used in ESF systems.

d) Avoidance of Hot Cracking of Stainless Steel.

Process controls to avoid hot cracking are discussed in Subsection 5.2.3.4.2.1.

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

The HPCI system is supplied from either the condensate storage tank or the suppression pool. The core spray and LPCI are supplied from the suppression pool only. Water in both of these sources is high purity water that meets the limits of Table 3.11-7. 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 are induced by the containment sprays. The containment sprays will not cause stress-corrosion cracking in austenitic stainless steel during a LOCA.

6.1.2 ORGANIC MATERIALS

Protective Coatings, both organic and inorganic, are used on items in containment as stated in Tables 6.1-1b and 6.1-2. All of these materials that are used as coatings on or are part of equipment have been evaluated with regard to the expected service conditions and have been found to have no potential for adversely affecting service, performance, or operation. No radiolytic or pyrolytic decomposition or interaction with other ESF materials will result from the use of these coatings.

Much of the equipment in containment is coated with zinc, either as galvanizing or by a paint comprising inorganic zinc compounds. The total amount of zinc and estimated total area of zinc coating is shown in Table 6.2-13. The remainder is primarily red oxide primer or epoxy.

Qualified coatings are expected to remain intact following a DBA. Unqualified coatings are assumed to fail and produce post-LOCA debris in the form of particulate or flakes.

The effect of the paint debris on ECCS pump suction strainer blockage has been evaluated to have no safety impact on suction strainer operation.

For Core Spray and RHR, conservative amounts of paint are assumed to be transported to the suppression pool immediately after LOCA, despite evidence that coating failure will not occur until between 6 and 96 hours into the postulated event. This paint, excluding a portion of flakes that will settle to the bottom of the suppression pool, is assumed to be filtered by the strainers and is accounted for in the calculation of strainer pressure drop as described in Sections 6.3.2.2.3 and 6.3.2.2.4.

For HPCI (and RCIC), the events for which HPCI (and RCIC) will operate are not expected to produce significant coating debris. Furthermore, such events will not result in flows from drywell to wetwell that will be high enough to transport significant coating debris to the suppression pool.

The current quantities of qualified and unqualified paint in the Unit 1 and 2 containments, as inventoried in 1994, are provided in Table 6.1-3.

Most of the NSSS equipment was ordered prior to issuance of Regulatory Guide 1.54 so the requirements of that guide were not imposed. However, the coatings were among the first to be qualified under ANSI N101.2 for DBA, radiation, etc., in nuclear applications. Of the paint used on NSSS equipment within containment, less than 12 Kg was not qualified to ANSI N101.2, not including the paint tightly covered with insulation.

The coating on the drywell liner and structural steel within the drywell was qualified in accordance with ANSI N101.2 and applied in accordance with Regulatory Guide 1.54.

In addition both containments were constructed with significant amounts (52,000 sq. ft. - Unit 1 and 46,100 sq. ft. - Unit 2) of unqualified inorganic zinc paint applied to the pipe supports and hangers, non-NSSS equipment, and ductwork. Approximately, 42,100 sq. ft. in each unit was DBA qualifiable paint, however, it was applied without the proper documentation and in accordance with a non-Q procedure. Another 4,000 sq. ft. in each unit was applied to galvanized duct work and is not DBA qualifiable. In addition, Unit 1 contains 5,900 sq. ft. of unqualified inorganic zinc applied to surfaces in the suppression pool.

In order to reduce the quantity of non-Q paint, an in-situ DBA test was conducted on representative samples of the 42,100 sq. ft. of qualifiable paint in each drywell. The testing resulted in an approximate 90% reduction of non-Q, qualifiable inorganic zinc. The Unit 1 test description and results are provided in Advanced Corrosion Engineering report, LOCA Simulation Testing of Specimens Representing Drywell Hanger Steel Painted with Carbo-Zinc 11 Unit 1 SSES, dated 11/30/93. The Unit 2 test description and results are provided in Advanced Corrosion Engineering report, LOCA simulation Testing of Specimens Representing Drywell Hanger Steel Painted with Inorganic Zinc Unit 2 SSES, dated 9/5/94.

The remaining 10,600 sq. ft. of the non-Q inorganic zinc in Unit 1 and the 6,150 sq. ft. in Unit 2, when subjected to LOCA conditions, is assumed to fail as particulate.

The 4,000 sq. ft. of non-Q inorganic zinc applied to the galvanized ductwork in each unit is assumed to fail in flake form following a LOCA.

The second type of unqualified coating found in the Susquehanna containments is red oxide primer. There is approximately 3000 sq. ft. of it in each wetwell and 3000 sq. ft. in each drywell. The red oxide applied to the wetwell surfaces is likely to remain intact following a DBA LOCA. Testing has shown that 240°F temperature is required to achieve coating failure. At Susquehanna, wetwell vapor phase temperatures only reach around 210°F following a LOCA.

The 3000 sq. ft. applied to drywell piping is assumed to fail in flake form following a LOCA.

In addition to the unqualified paint identified above, small quantities of inorganic zinc and/or epoxy were added to the containments in the form of touch-ups and modifications of systems and components. Walkdowns and inspections of both containments has determined the touch-ups and additions to be minimal (see Table 6.1-3).

6.1.3 POST ACCIDENT CHEMISTRY

Not applicable to BWR plants.

Table 6.1-2

CONTAINMENT COMPONENTS – COATING SCHEDULE

Category	Item/Type/ Description	Coated		Uncoated		Generic Type (Notes 1, 2)	Film Thickness (Mils)	General Comments
		Q Coating	Mfr. Std. Coat	Stls	Galv.			
Carbon Steel Liner Plate	Containment – Dome	X				Inorganic zinc	2-4 or 5-10	Coating repairs may be done with two coats of phenolic epoxy to a thickness of 8-12 mils on the dome and 10-16 mils on the drywell walls, or one coat of epoxy at 5-10 mils, (PP&L Spec C1051).
	Drywell – Walls	X				Inorganic zinc or Inorganic zinc w/epoxy topcoat	2-4	
	Drywell – Floor	X				Inorganic zinc w/ epoxy topcoat	10-16	
	Suppression Pool-Walls	X				Inorganic zinc	4-5	
	Suppression Pool-Floor	X				Inorganic zinc	4-5	
	Drywell Wainscot - Wall	X				Inorganic zinc w/ epoxy topcoat	7-11	Coating repairs may be done with two coats of epoxy to a thickness of 8-12 mils, or one coat at 5-10 mils, (PP&L Spec C1051).

Table 6.1-2

CONTAINMENT COMPONENTS – COATING SCHEDULE

Category	Item/Type/ Description	Coated		Uncoated		Generic Type (Notes 1, 2)	Film Thickness (Mils)	General Comments
		Q Coating	Mfr. Std. Coat	Stls	Galv.			
Structural Steel	Diaphragm Support Columns in Suppression Pool	X				Inorganic zinc	4-5	
	Heavy Support Steel	X				Inorganic zinc or epoxy	2-4 or 5-10	
	Miscellaneous Steel	X	or		X	Inorganic zinc or epoxy	2-4 or 5-10	
	Handrails & Gratings				X			
	Exposed Surface of steel inserts	X				Inorganic zinc or epoxy	2-4 or 5-10	
	Hatches (Equipment & Personnel)	X				Inorganic zinc	2-4 in drywell 4-5 in Suppression Pool	
Carbon steel Pipe, Hangers and Valves	Insulated Piping		X			Red oxide/ Mill Varnish	> 2	Coating on insulated pipe is not accessible to sump
	Uninsulated Piping		X	or	X	Inorganic zinc or Red oxide	2-4	Surfaces exposed in Rad Zones IV & require protection & shall have specified surface preparation and inorganic zinc coating in the shop
	Pipe Hangers	X or	X	or	X	Inorganic zinc or epoxy	2-4 or 5-10	
	Valves & Valves Operators		X					

Table 6.1-2

CONTAINMENT COMPONENTS – COATING SCHEDULE

Category	Item/Type/ Description	Coated		Uncoated		Generic Type (Notes 1, 2)	Film Thickness (Mils)	General Comments
		Q Coating	Mfr. Std. Coat	Stls	Galv.			
Equipment	Pumps	X	X	or	X	Inorganic zinc	2-4	
	Fans & Fan Housings (Carbon Steel)	X				Inorganic zinc	2-4	Applied to surfaces exposed to spray or insulated
	HVAC Ducts		X	or	X	Inorganic zinc	2-4	
	Hydrogen Recombiners			X				
	Containment Coolers				X			
	Heat Exchangers		X					
Electrical	Motors	X or	X			Inorganic zinc	2-4	
	Connection Boxes	X	or		X	Inorganic zinc	2-4	Large items with non-Q Coating – Recoat in field.
	Control Panels, Instrument Panels		X			Alkyd, urethane	1-2	
	Raceways, Cable Trays			X				
Concrete	RPV Concrete Pedestal	X				Epoxy Surfacer & Topcoat	1/8" surfacer & 4-20 mil topcoat	See Note (2)

(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) Concrete coatings shall be limited to minimum area required for decontamination purposes.

(3) Exposed areas of coatings are listed in Table 6.2-13.

TABLE 6.1-3

Inventory of Qualified and Unqualified Containment Coatings

Unit 1 Drywell	Ft^2
1. Qualified Coatings	
a. A-29[2] Inorganic Zinc	16,200
Epoxy Topcoat	16,900
b. C-63 Inorganic Zinc	15,900
c. M-27 & M-204 Epoxy Topcoat	7,400
d. A-50 Epoxy Concrete Surfacer	4,000
e. G-4 Inorganic Zinc with In-situ DBA Qualification	37,400[3]
Total	97,800
2. Unqualified Coatings	
a. G-4 Inorganic Zinc	4,700[3]
b. G-4 Red Oxide	3,000[3]
c. Inorganic Zinc Touch-up of Galvanized Ductwork	4,000[3]
Total	11,700
Unit 1 Suppression Pool	
1. Qualified Coatings	
a. A-57 Inorganic Zinc	34,900
Total	34,900
2. Unqualified	
a. G-4 Inorganic Zinc	5,900
b. G-4 Red Oxide	3,000[3]
Total	8,900
Total Qualified - Unit 1	132,700
Total Unqualified - Unit 1	20,600

TABLE 6.1-3

Inventory of Qualified and Unqualified Containment Coatings

Unit 2 Drywell	Ft[2]
1. Qualified Coatings	
a. A-29 Inorganic Zinc	16,200
Epoxy Topcoat	16,900
b. C-63 Inorganic Zinc	15,900
c. M-27 & M-204 Epoxy Topcoat	7,400
d. A-50 Epoxy Concrete Surfacer	4,000
e. G-4 Inorganic Zinc with In-situ DBA Qualification	35,950[3]
Total	96,350
2. Unqualified	
a. G-4 Inorganic Zinc	6,150
b. G-4 Red Oxide	3,000[3]
c. Inorganic Zinc Touch-up of Galvanized Ductwork	4,000[3]
Total	13,150
Unit 2 Suppression Pool	
1. Qualified Coatings	
a. A-57 Inorganic Zinc	34,900
Total	34,900
2. Unqualified	
a. G-4 Red Oxide	3,000[3]
Total	3,000
Total Qualified - Unit 2	131,250
Total Unqualified - Unit 2	16,150

1 In addition to the quantities of qualified coatings, listed below, small quantities of qualified epoxy paint has been added via touchups and modifications.

2 The specification numbers listed adjacent to each type of coating (i.e., G-4, A-57, etc.) indicate the Bechtel specification used to apply the coatings.

3 The reported quantities indicate adjustments from the original Bechtel estimates and those previously reported in the FSAR. These numbers are based on walkdowns of the drywell and suppression pool and the results of the in-situ LOCA Simulation Testing of inorganic zinc.

TABLE 6.1-1a

NSSS SUPPLIED ENGINEERED SAFETY FEATURES COMPONENT MATERIALS

COMPONENT	FORM	MATERIAL	SPECIFICATION (ASTM/ASME)
RHR Heat Exchanger			
Shell, Head, and Channel	Plate	Carbon Steel	A516 Gr. 70
Tube Sheet	Forging	Carbon Steel	A350 Gr. LF2
Tubes	Tube	Copper-Nickel	SB395 Alloy 715
Flanges and Nozzles	Forging	Carbon Steel	A105 Gr. 2 and A350 Gr. LF2
Bolts	Bar	Alloy Steel	A193 Gr. B7
Nuts	Bar	Alloy Steel	A194 Gr. 7
RHR and CS Pumps			
Shell Plates and Dished Head	Plate	Carbon Steel	A516 Gr. 70
Shell Aligning Ring	Forging	Carbon Steel	A350 Gr. LF2
Shell Ribs	Plate	Carbon Steel	A516 Gr. 70
Discharge Head Flanges	Plate	Carbon Steel	A516 Gr. 70
	Forging	Carbon Steel	A350 Gr. LF2
Discharge Head Elbow	Piping Fitting	Carbon Steel	A234 Gr. WPB
Discharge Head Plates	Plate	Carbon Steel	A516 Gr. 70
Discharge Head Bar	Piping Fitting	Carbon Steel	A350 Gr. LF2
Discharge Head Pipe	Pipe, Plate	Carbon Steel	A333 Gr. 6, A516 Gr. 70
Cap Screws	Bar	Alloy Steel	A193 Gr. B7
Nuts	Bar	Alloy Steel	A194 Gr. 7
HPCI Main Pump and Booster Pump			
Case, Top and Bottom	Castings	Carbon Steel	A216 Gr. WCB
Seal Flange	Forging	Alloy Steel	A182 Gr. F6
Balance Line (Main Pump Only)	Piping	Carbon Steel	A106 Gr. B
Welding Bosses (Vents and Drains)	Forging	Carbon Steel	A181 Gr. II
Studs, Case and Seal Flange	Bar	Alloy Steel	A193 Gr. B7, A193 Gr. B6
Nuts, Case and Seal Flange	Bar	Alloy Steel	A194 Gr. 7
Interconnecting Piping	Piping	Carbon Steel	A106 Gr. B
Interconnecting Piping Fittings	Forging	Carbon Steel	A234 Gr. WPB, A181 Gr. II
Interconnecting Piping Bolts and Nuts	Bar	Alloy Steel	A193 Gr. B7, A194 Gr. 7
Standby Liquid Control Pumps			
Fluid Cylinder	Forging	Stainless Steel	A182 Gr. F304
Cylinder Head Cover, Discharge Valve Cover, and Stuffing Box Flange Plate	Plate	Carbon Steel	A285 Gr. C
Cylinder Head Extension, Discharge Valve Stop, and Stuffing Box	Shapes	Stainless Steel	A479 Type 304
Stuffing Box Gland	Bar	17-4PH (H1075)	A461 Gr. 630
Plunger	Bar	17-4PH (H1075)	A461 Gr. 630
Suction Flange		Stainless Steel	A182 Gr.F304L
Discharge Flange	Forging	Stainless Steel	A182 Gr. F304L
Pipe Nipples – Suction and Discharge Flange Nipples	Pipe	Stainless Steel	A312 Gr. TP304L
Studs	Bar	Alloy Steel	A193 Gr. B7
Nuts	Bar	Alloy Steel	A194 Gr. 7
Standby Liquid Control Explosive Valves			
Body, Inlet Fittings and Trigger Body	Shapes	Stainless Steel	A479 Type 304
Flange	Forging	Stainless Steel	A182 Gr. F304
Cap Screws	Bar	Stainless Steel	A193 Gr. B8

TABLE 6.1-1a

NSSS SUPPLIED ENGINEERED SAFETY FEATURES COMPONENT MATERIALS

COMPONENT	FORM	MATERIAL	SPECIFICATION (ASTM/ASME)
Standby Liquid Storage Tank			
TankShell, Top Plate, Bottom Plate, Bottom Ring	Plate	Stainless Steel	A240 Type 304
Nozzles			
Fittings	Forging	Stainless Steel	A182 Gr. F304, F316
Pipe	Plate	Stainless Steel	A312 Type 304
Plate	Plate	Stainless Steel	A240 Type 316L
Welds	N/A	Stainless Steel	SFA 5.4, SFA 5.9
Main Steam Isolation Valves			
Body	Casting	Carbon Steel	A216 Gr. WCB
Bonnet and Poppet	Forging	Carbon Steel	A105 Gr. 2
Stem	Bar	Stainless Steel	A276 Type 410
		17-4PH	SA564 Type 630 (H1100)
Studs	Bar	Alloy Steel	A193 Gr. B7, SA540 Gr.B23 Class 5
Nuts	Bar	Carbon Steel	A194 Gr. 2H
Nuts, Superbolt Nuts		Alloy Steel	SA194 Gr. 7
Superbolt Nut Jack Bolt		Alloy Steel	SA540-B21 Class 1
Pipe	Smls Pipe	Carbon Steel	A106 Gr. B
Drain Boss	Forging	Carbon Steel	A105 Gr. 2
Main Steam Safety Relief Valves			
Body and Bonnet	Forging	Carbon Steel	A105 Gr. 2
Disc Holder	Forging	Inconel 718	ASM 5662B
Disc Insert	Shape	Alloy Steel	SA637 Gr. 718
Spindle Point	Bar	17-4PH (H1075)	A564 Type 630
		17-4PH(H1150)	A564 Type 630
Spindle Ball	Shape	Stellite	Stellite #6
		Stainless Steel	A276 Type 440C
Nozzle	Forging	Stainless Steel	A182 F316
Spring	Bar	Alloy Steel	A304-66 Gr. 4161 H
Spring Washers (Top & Bottom)	Forging	Carbon Steel	A105 Gr. 2
Adjusting Bolt	Bar	Alloy Steel	A193 Gr. B6
Adjusting Bolt Button	Bar	Alloy Steel	A193 Gr. B6
Thrust Bearing Adapter	Bar	Alloy Steel	A193 Gr. B6
Studs	Bar	Alloy Steel	A193 Gr. B7
Nuts	Bar	Carbon Steel	A194 Gr. 2H
Superbolt Nut		Alloy Steel	SA194 Gr. 7
Superbolt Nut Jack Bolt		Alloy Steel	SA540-B21 Class 1
Control Rod Velocity Limiter		(Section 4.2)	
Main Steam Flow Restrictor			
Upstream part	Casting	Stainless Steel	A351 Gr. CF8
Downstream part	Casting	Carbon Steel	A216 Gr. WCB
Control Rod Drive Housing Support System (1) Structural Support Steel (See Section 4.5.3)	Structural Steel	Carbon Steel	ATSM A36

(1) Component/materials that would be exposed to core cooling water and containment sprays in the event of a LOCA.

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Table 6.1-1b

ENGINEERING SAFETY FEATURES MATERIALS

Item	Commercial Name	Chemical Composition (Metallic)	Chemical (Organic)
1	Primary Containment	(15)(17)	
2	Secondary Containment (See Reactor Building Recirculation System and Standby Gas Treatment System)		
3	Containment Isolation System Containment Isolation Valves	(See-Table 6.1-1a)	
4	Containment Combustible Gas Control		
	a) Primary Containment Ventilation System (only safety-related drywell unit cooler fans, CRD area ventilation fans and associated safety-related ductwork)	(11)(12)(17)	
	b) Containment Atmosphere Control	(2)(17)	
5	Containment Heat Removal		
	a) Containment Spray Cooling (CSC) Mode of RHR System (Equipment See Table 6.1-1a)	(1)(17)	
	b) Suppression Pool Cooling (SPC) Mode of RHR System (Equipment See Table 6.1-1a)	(1)(17)	
6	HPCI (Equipment See Table 6.1-1a)	(1)	(3)(5)(6)
7	Core Spray (Equipment See Table 6.1-1a)	(1)(2)(17)	(3)(5)(6)
8	LPCI (Equipment See Table 6.1-1a)	(1)(2)(17)	(3)(5)
9	Auto Depressurization System(MSRV See Table 6.1-1a)	(1)(17)	(3)(6)
10	Standby Gas Treatment System	(10)(12)(13)(14)	
11	Reactor Building Recirculation System	(9)(13)(12)	
12	Habitability System Control Structure HVAC systems which service the Habitability envelope, including Control Room HVAC, Control Strucure HVAC, Computer HVAC, CSEOASS, Battery Room Exhaust, Kitchen and Toilet Exhaust	(8)(10)(12)(13)	
13	Main Steam Isolation Valve Leakage Isolated Condenser Treatment Method (ICTM)	(1)(17)	

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Table 6.1-1b

ENGINEERING SAFETY FEATURES MATERIALS

Size - 26"≥	
Pipe:	SA-155 KC-70 Class I welded
Fittings:	SA-234 WPBW
Flanges:	SA-181 II SA-105
Valves:	SA-105 SA-216 WCB
Nuts:	SA-194 Gr 2H JA-194 Gr 7
Bolts:	SA-193 Gr B7
Size - 24"≤	
Pipe:	SA-106 Gr B Seamless
Fittings:	SA-234 WPB SA-105 (2" and smaller)
Flanges:	SA-181 II SA-105
Valves:	SA-105 SA-216 WCB
Nuts:	SA-194 Gr 2H SA-194 Gr 7
Bolts:	SA-193 Gr B7

Table 6.1-1b

ENGINEERING SAFETY FEATURES MATERIALS

Size - All	
Pipe:	SA-358 Gr 304 Class 1 Welded
	SA-358 Gr 304 Class 1 Welded (0.030 Carbon Max)
	SA-376 TP 304
	SA-312 TP 304
	SA-312 TP 304L (0.030 Carbon Max)
Fittings:	SA-403 WP304W
	SA-403 304W (0.030 Carbon Max)
	SA-403 304 (0.030 Carbon Max)
	SA-403 304L (0.030 Carbon Max)
	SA-182 Gr F3046 (0.030 Carbon Max)
Flanges:	SA-182 Gr F316
	SA-182 Gr F316 (0.030 Carbon Max)
	SA-182 Gr F316L (0.030 Carbon Max)
Valves:	SA-351 Gr
	CF8M
	CF8
	SA-351 Gr.
	SA-182 F316 (2" & smaller)
Nuts:	SA-194 Gr 2H
	SA-194Gr 7
Bolts:	SA-193 Gr B7

(1) Carbon steel systems per ASME II, Part A, as follows:

(2) Stainless steel systems per ASME II, Part A, as follows:
(Refer to Figure 6.1-1)

(3) Insulation materials are as listed below:
  a) Fiberglass wool (minimal use inside containment)
  b) Stainless steel all metal reflective
  c) Needled glass fiber encapsulated in aluminum bonded fiberglass cloth fabric (outside containment only)
  d) Phenolic foam insulation (RBCW piping only)
  e) Min-k insulation (restricted to pipe whip restraints when used in containment)

(4) Unless specified otherwise, gaskets are typically of the spiral-wound metalic type with nonmetalic filler (per ASME B16.5-1996, Annex E, Group Number 1.

Table 6.1-1b

ENGINEERING SAFETY FEATURES MATERIALS

(5) Valve gland packings typically are graphite packings meeting PP&L Technical Specification M-1434.

(6) Uninsulated carbon steel piping inside the primary containment is coated as follows:

a) Drywell

1)	MSRV discharge lines - (where not insulated)	part inorganic zinc part red oxide part uncoated
2)	Water lines to unit coolers -	red oxide
3)	Drywell spray header -	red oxide

b) Wetwell

1)	MSRV discharge lines -	uncoated
2)	Wetwell spray header -	red oxide

(7) Intentionally left blank

(8) Fans (Centrifugal)
SA-515 GR-55, AISI-C-1045, A-569, A-366, A-568, ASME-SA285 GrC

(9) Fans (Vane Axial)
Housing ASTM A283, ASTM A36-75
Hub and Blades Cast Aluminum A356 (ASTM B108), A365-40E(ASTM B26)

(10) Filter Housings
A-36, A-53B, A-105, A-240TP304, 554 MT 304, A-276TP304, A-283, A-569

(11) Containment Coolers Fans (Safety Related)
Fan - A-283, AISI-420, Cast Iron, 17-4Ph
Housing - A-570D, A123-73, Unit 2 housing painted with Carbozinc II in lieu of galvanizing, insulation ultralite (glass fibers)

(12) Ductwork Construction
(Or Engineer Approved Equal)
Material for ductwork - ASTM A446 Grade B, ASTM 527 or ASTM 526
Structural steel shapes, plates, and bars - ASTM A36 with galvanizing per ASTM A123-73
Bolts, nuts, and washers - ASTM A307 with galvanizing per ASTM A153 or zinc plated per ASTM B633 or A164 Type RS (discontinued)
Structural tubing – (duct supports) ASTM A501 or A500 Grade B
Cadmium plating of bolts, nuts, and washers - ASTM A165 type TS

(13) Damper Construction
Carbon Steel Sheet Metal for damper - ASTM, A526 or A527 with A525G-90 coating designation

Table 6.1-1b

ENGINEERING SAFETY FEATURES MATERIALS

Steel rod, bar, and shaft - ASTM A108, A29, AISI 1008/1018, AISI M1020 with A123 coating designation or Cadmium coating per ASTM A165 Type OS
Stainless Steel Sheet Metal for Damper - ASTM A167 Type 304
Stainless Steel rod, bar and shaft – ASTM A276 TP304, A582 TP303 Carbon Steel Structural Shapes – A36 with G90 coating

(14) SGTS Centrifugal Fans
Housing ASTM A283, ASTM A36
Hub and Blades ASTM A48, ASTM A242

(15) Primary Containment
Liner Plate ASTM A285 Grade A, ASME SA516 Grade 60 or 70
Penetration assemblies (electrical and piping), locks, hatches, and other materials approved for use, ASME SA516, Grade 60 or 70 normalized, ASME SA537, Grade B, SA193 B7, SA194 Gr 7, SA350 LF2, SA182 F304, SA 182 F316, SA541 Class 1, SA234, WPB, SA479 TP304, SA105 Gr 11, SA333 Gr 1 or 6

(16) Primary Containment Isolation Valves
SA216 Gr WCB
SA105 Gr 11
SA182 Gr F304L, F316, F316L
SA351 CF3, CF3M, CF8, CF8M
SA352 Grade LCB
SA515 Gr 70
SA240 Gr 304, 316
SA516 Gr 55
SA181 Gr 11
SA182 Gr F22

(17) Components/materials that would be exposed to core cooling water and containment sprays in the event of a LOCA.

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FSAR REV. 65

SUSQUEHANNA STEAM ELECTRIC STATION UNITS 1 & 2 FINAL SAFETY ANALYSIS REPORT
Figure Deleted
FIGURE 6.1-1, Rev. 55

AutoCAD Figure 6_1_1.doc

6.2 CONTAINMENT SYSTEMS

6.2.1 PRIMARY CONTAINMENT FUNCTIONAL DESIGN

6.2.1.1 Pressure Suppression Containment

6.2.1.1.1 Design Basis

The pressure suppression containment system is designed to have the following functional capabilities:

a. The containment has the capability to maintain its functional integrity during and following the peak transient pressures and temperatures which would occur following any postulated loss-of-coolant accident (LOCA). The LOCA scenario used for containment functional design includes the worst single failure (which leads to maximum coincident containment pressure and temperature), postulated to occur simultaneously with loss of offsite power and a safe shutdown earthquake (SSE). A detailed discussion of the LOCA events is contained in Subsection 6.2.1.1.3.3.

b. 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 which would result in offsite doses greater than those set forth in 10CFR 50.67.

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

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

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

f. The containment system provides means to channel the flow from postulated pipe ruptures in the drywell to the pressure suppression pool.

g. The containment system is designed to allow for periodic testing at the peak pressure calculated to result from the postulated DBA 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 structure and internal structures. Dwgs. C-331, Sh. 1, C371, Sh. 2, C-1932, Sh. 3, C-1932, Sh. 4, and C-1932, Sh. 5 show the general arrangement of the containment and internal structures.

6.2.1.1.2.1 Protection from Dynamic Effects

The containment structure and ESF system functions have been 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 Guides

Table 3.8-1 lists the applicable codes, standards, guides, and specifications for the containment structure and internal structures.

6.2.1.1.2.3 Functional Capability Tests

The functional capability of the containment structure is verified by pressurizing the containment to 1.15 times the design accident pressure as required by NRC Regulatory Guide 1.18 (Rev. 1). Refer to Subsections 3.8.1.7, 3.8.2.7, and 3.8.3.7 for a description of the structural acceptance test.

6.2.1.1.2.4 External Pressure Loading Conditions

The containment structure has been designed for an external differential pressure of 5 psi.

6.2.1.1.2.5 Trapped Water that Cannot Return to Containment Sump

Not applicable to pressure suppression containment.

6.2.1.1.2.6 Containment and Subcompartment Atmosphere

Subsection 9.4.5 describes the pressure, temperature, and humidity limits and the system which will maintain these limits during normal plant operation.

6.2.1.1.3 Design Evaluation

6.2.1.1.3.1 Summary Evaluation

The key design parameters and the maximum calculated accident parameters for the pressure suppression containment are as follows:

	Paramenter	Design Parameter	Calculated Accident Parameter
a.	Drywell Pressure	53 psig	48.6 psig
b.	Drywell Temperature	340°F	337°F
c.	Suppression Chamber Pressure	53 psig	36.5 psig
d.	Suppression Chamber Temperature	220°F	211.2°F

The foregoing design and maximum calculated accident parameters are not determined from a single accident event but from an envelope of accident conditions. As a result, there is no single DBA for this containment system.

The maximum drywell pressure occurs during the short-term blowdown phase of the LOCA. The maximum suppression chamber pressure occurs during the pool swell phase of the transient when the suppression chamber air space is compressed by the rising pool slug. Both the break of the main steam line and recirculation line were evaluated to determine the most severe pressure transients.

For the long-term suppression pool temperature response to the applicable design basis scenarios were analyzed. The result for the most limiting case concluded that the peak calculated temperature remains within the design limit of 220°F.

The maximum drywell temperature occurs during the short-term blowdown from a main steam line break. A small steam line break was also evaluated and the results show that the main line steam break is bounding. The peak drywell temperature remains within the design limit of 340°F.

The analyses assume that the primary system and containment are initially at the maximum normal operating conditions. References 6.2-1, 6.2-24, and 6.2-26 that describe relevant experimental verification of the analytical models used to evaluate the containment system response.

6.2.1.1.3.2 Containment Design Parameters

Table 6.2-1 provides a listing of the key design parameters of the primary containment system including the design characteristics of the drywell, suppression pool, and the pressure suppression vent system.

A diagram showing the geometric configuration of the downcomer is shown in Figure 6.2-56. The five downcomers that have vacuum breakers attached are closed at the bottom end by a pipe cap with a three (3) inch drain line as shown in Figure 6.2-56. The head loss coefficient for the downcomer vent is evaluated by General Electric Co. for use in containment pressure and temperature transient response calculations using the 82 open downcomers. The method used is similar to the vent head loss evaluation performed in NEDO-10320, Supplement 2. See Reference 6.2-1.

The normally closed vacuum breaker valves start to open under a preset differential pressure. The setpoint of each valve is verified by preoperational tests at the manufacturers shop. The set pressure is determined by applying slowly increasing pressure to the valve inlet side, and observing the peak manometer reading across the valve. Inservice testing to verify the opening time and setpoint will not be conducted and is not necessary because:

a. The valves are simple mechanical devices qualified for the environment,
b. The setpoint and opening time are verified in manufacturers preoperational tests, and

c. The valves are exercised and inspected in accordance with the Technical Specifications.

The containment depressurization rate analysis for a postulated inadvertent spray actuation assumed that the vacuum breakers begin to open at a wetwell to drywell –P of 2.81 psid and are fully open when the wetwell to drywell –P is 4.48 psid. These vacuum breaker opening pressures are based upon actual valve opening data increased by the amount of other flow losses in the wetwell to drywell flow path. These pressure choices are conservative for both the Phase IIIa vacuum breaker valve designs. One set out of five sets of vacuum breakers was assumed not to open in the analysis.

The orifice diameter of the valves is 19.4 inches based on flow measurement. The loss coefficient was calculated based on actual flow measurements conducted in the manufacturer's shop. Refer to Subsection 6.2.1.1.3.2.2. Each of the inboard vacuum breakers is connected to a common alarm which indicates when any valve is not closed. Each of the outboard vacuum breakers is connected to a common alarm which indicates when any valve is not closed. There is individual vacuum breaker position indication in the main control room for each valve.

Table 6.2-2 provides the performance parameters of the related engineered safety feature systems which supplement the design conditions of Table 6.2-1 for containment cooling purposes during post blowdown long term accident operation. Performance parameters given include those applicable to full capacity operation and to conservatively reduced capacities assumed for containment analyses.

6.2.1.1.3.2.1 Downcomer Vent Flow Loss Coefficient

The downcomer vent flow loss coefficient, K, is defined by:

$$\Delta P = K \frac{\rho V^2}{2g}$$

is calculated from standard references (6.2-19, 6.2-20). In the above equation –P is the total pressure drop across the downcomer, Ψ is the fluid density, and V is the flow velocity. The total downcomer flow loss coefficient is modeled as the sum of three contributors: an entrance loss, a length loss, and an exit loss. The entrance loss coefficient is calculated from Reference 6.2-19 using a hooded duct entrance geometry which very nearly approximates the standoff je reflector shield feature of the SSES downcomer. The entrance loss is calculated to be 0.84. The length loss is represented by an fL/D loss with f calculated from Reference 6.2-20. The length loss is calculated to be 0.33. The exit loss coefficient is calculated to be 1.0 from Reference 6.2-20, which when combined with the above yields an overall loss coefficient value of K=2.17.

6.2.1.1.3.2.2 Vacuum Breaker Flow Loss Coefficient

The loss coefficient for the wetwell to drywell flowpath includes losses due to the vacuum breaker inlet, vacuum breaker valves, turning and downcomer inlet. The loss coefficient calculated for this flow path is 0.495 based on the vacuum breaker flow area.

The loss coefficient of the vacuum breaker is calculated based on actual flow measurements conducted by the manufacturer. The valve was mounted on a test rig, a differential pressure established across the valve, the flow measured and then K calculated for 24" pipe size based on the measured flow rate. For a single valve, K = 2.65. For two valves mounted in series, K = 5.30 as prescribed by the manufacturer (Reference 6.2-21).

The manufacturer's shop test for these valves consisted basically of an induction flow system in which dry, saturated air was drawn through the valve system and the corresponding flow rate pressure drops and fluid temperature measured. The tests were conducted for varying flow rates and pressure drops. From these data, one can calculate the loss factor, "K", for the valve system.

The calculated "K" factor is somewhat sensitive to flow at low flow rates. This is due to the increasing influence of fluid compressibility, as well as setting up the flow pattern through the valve system. The manufacturer's tests were, therefore, conducted up to a condition sufficient to set up the fully-developed flow pattern through the valve system as well as include the effects of compressibility. At this condition, the calculated "K" factor reaches a maximum and exhibits no further sensitivity to increase in flow.

The anticipated condition of operation for these valves would differ from those for which they were tested only in the type of fluid passing through the system. It is expected that the valve system will be required to pass a dispersed steam-air mixture during the postulated transient. The anticipated fluid state would, therefore, have a density different from that of the test. However, the effect of fluid density is incorporated in the calculations of "K". Thus, compressibility, density and flow pattern effects have been suitably represented in the tests so as to yield a valve system "K" factor which is appropriate to conservatively model these valves in their anticipated condition of service.

6.2.1.1.3.3 Accident Response Analysis

The containment functional evaluation is based upon the consideration of several postulated accident conditions resulting in release of reactor coolant to the containment. These accidents include:

a. an instantaneous guillotine rupture of the recirculation suction line

b. a main steam line rupture.

Energy release from these accidents is reported in Subsection 6.2.1.3.

6.2.1.1.3.3.1 Recirculation Line Rupture

Immediately following the rupture of the recirculation line, the flow out both sides of the break will be limited to the maximum allowed by critical flow considerations. Figure 6.2-1 shows a schematic view of the flow paths to the break. In the side adjacent to the suction nozzle, the flow will correspond to critical flow in the pipe cross-section. In the side adjacent to the injection nozzle, the flow will correspond to critical flow at the 10 jet pump nozzles associated with the broken loop. In addition, the cleanup line crosstie will add to the critical flow area.

6.2.1.1.3.3.1.1 Assumptions for Reactor Blowdown

The response of the reactor coolant system 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 That is:

    1) The reactor is operating at 102 percent of the uprated reactor thermal power.

    2) The service water temperature is the maximum UHS Design Temperature.

    3) The suppression pool level and mass are at the value corresponding to the maximum Technical Specification limit for the short term evaluation and the minimum Technical Specification limit for the long term evaluation. These conditions result in maximizing the drywell pressure response for the short term analysis and the suppression pool temperature response for the long term analysis.

    4) The suppression pool temperature is equal to the maximum Technical Specification limit.

b. The recirculation suction 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. Scram also occurs in less than one second from receipt of the high drywell pressure signal. The difference between the shutdown times is negligible.

d. The vessel depressurization flow rates are calculated using Moody's critical flow model (Reference 6.2-3) assuming "liquid only" outflow, since this assumption maximizes the energy release to the drywell. "Liquid only" outflow implies that all vapor formed in the reactor pressure vessel (RPV) by bulk flashing rises to the surface rather than being entrained in the existing flow. In reality, some of the vapor would be entrained in the break flow which would significantly reduce the RPV discharge flow rates. Further, Moody's critical flow model, which assumes annular, isentropic flow, thermodynamic phase equilibrium, and maximized slip ratio, accurately predicts vessel outflows through small diameter orifices. Actual rates through larger flow areas, however, are less than the model indicates because of the effects of a nearly homogeneous two-phase flow pattern and phase nonequilibrium. These effects are conservatively neglected in the analysis.

e. The core decay heat and the sensible heat released in cooling the fuel to 545°F 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 10 seconds. The high RPV pressure increases the calculated blowdown flow rates, which is again conservative for analysis purposes. The sensible energy of the fuel stored at temperatures below 545°F is released to the vessel fluid along with the stored energy in the vessel and internals as vessel fluid temperatures decrease below 545°F during the remainder of the transient calculation.

f. For the recirculation suction line break evaluation, the main steam isolation valves start closing at 0.5 seconds after the accident. They are fully closed at two seconds. By assuming rapid closure of these valves, the RPV is maintained at a high pressure, which maximizes the calculated discharge of high energy water into the drywell.

g. Reactor Feedwater Flow into the vessel continues until all of the high energy feedwater (above 198°F) is injected into the vessel. This is conservative for the recirculation suction line break because it maximizes the duration of single-phase liquid blowdown to the drywell, thus maximizing the peak drywell pressure. This assumption is also conservative for the long term evaluation because it maximizes the suppression pool temperature.

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

6.2.1.1.3.3.1.2 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 pool 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 air and a higher positive flow rate of liquid droplets which conservatively maximizes vent pressure losses.

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

d. No heat loss from the gases inside the primary containment is assumed. In reality, condensation of some steam on the drywell surfaces would occur. Additional assumptions are provided in Table 6.2-4a.

6.2.1.1.3.3.1.3 Assumptions for Long-Term Cooling

Following the blowdown period, the emergency core cooling system (ECCS) discussed in Section 6.3 provides water for core flooding, containment spray, and long-term decay heat removal. The containment pressure and temperature response is analyzed using the following assumptions:

a. The LPCI pumps are used to flood the core prior to 600 seconds after the accident. The HPCI is assumed available for the entire accident, but no credit is taken for operation.

b. After 600 seconds, the LPCI pump flow may be diverted from the RPV to the containment spray. This is a manual operation. Actually, the containment spray need not be activated at all to keep the containment pressure below the containment design pressure. Prior to activation of the containment cooling mode (assumed at 600 seconds after the accident) all of the LPCI pump flow will be used to flood the core.

c. The effects of decay energy, stored energy, and energy from the metal-water reaction on the suppression pool temperature are considered.

d. The initial suppression pool mass is the value corresponding to low water level. Additional assumptions are listed in Table 6.2-5a.

e. After approximately 600 seconds, the RHR heat exchangers are activated to remove energy from the containment via recirculation cooling from the suppression pool with the RHR service water systems.

f. The performance of the Containment System during the long-term cooling period is evaluated for each of the following four cases of interest.

Case A Offsite power available - all ECCS equipment and containment spray operating.

Case B Loss of offsite power minimum diesel power available for ECCS and containment spray.

Case C Same as Case B except no containment spray.

Case D Loss of Offsite Power – All Pumps Running

6.2.1.1.3.3.1.4 Initial Conditions for Accident Analyses

Tables 6.2-3a and 6.2-4a provide the initial reactor coolant system and containment conditions used in the accident response evaluations. The tabulation includes parameters for the reactor, the drywell, the suppression chamber and the vent system.

The mass and energy release sources and rates for the containment response analyses are given in Subsection 6.2.1.3.

6.2.1.1.3.3.1.5 Short Term Accident Response

The calculated containment pressure and temperature responses for the recirculation line break are shown on Figures 6.2-2 and 6.2-3, respectively.

The suppression chamber is pressurized by the carryover of noncondensables from the drywell and by heatup of the suppression pool. As the vapor formed in the drywell is condensed in the suppression pool, the temperature of the suppression pool water peaks and the suppression chamber pressure stabilizes. The drywell pressure stabilizes at a slightly higher pressure, the difference being equal to the downcomer submergence. Drywell pressure decreases as the rate of energy dumped to the suppression pool via the downcomers exceeds the rate of energy released into the drywell from the primary system. During the RPV depressurization phase, most of the noncondensable gases initially in the drywell are forced into the suppression chamber. However, following the depressurization the noncondensables will redistribute between the drywell and suppression chamber via the vacuum breaker system. This redistribution takes place as steam in the drywell is condensed by the relatively cool ECCS water which is beginning to cascade from the break causing the drywell pressure to decrease.

Two cases leading to potentially rapid drywell depressurization were considered for wetwell-to-drywell vacuum breaker sizing. These are:

1. The inadvertent actuation of one containment spray train (10700 gpm @ 50°F, assumed),

2. Maximum ECCS spillage (7750 lbm/sec @ 140°F exit temperature, assumed) during the depressurization phase of the large recirculation outlet line break LOCA.

Each case was considered to determine the adequacy of the vacuum breaker valve assemblies to ensure that the maximum differential pressure across the diaphragm slab does not exceed allowables. The present design allowable across the diaphragm slab is 28 psid downward and 27.8 psid upward.

In the analysis done for both cases 1 & 2, it has been conservatively assumed that all non-condensables have been removed to the wetwell vapor region prior to drywell depressurization. The details of the analysis performed for the Case 1 study are presented in Subsection 6.2.1.1.4. Case 1 results are also presented in this section and indicate a worst-case differential upward pressure of 4.6 psid across the diaphragm slab for this case - well below the 27.8 psid upward design allowable. This time-dependent differential pressure response is illustrated in Figure 6.2-65.

The analysis for Case 2 assumes a drywell temperature of 262°F, an ECCS drop fall height of 42 feet, an average drop diameter of 1 inch (for calculating condensation heat transfer to the falling ECCS spillage), and an average heat transfer coefficient of 2300 BTU/Hr,Ft^2,F. (For calculating heat transfer from the drywell vapor region to the pool of ECCS spillage collected on the drywell floor). These considerations, combined with the assumptions regarding non-condensables and ECCS spillage rate and temperature, yield a net drywell energy removal rate of approximately 320,000 BTU/Sec for an ECCS spillage spray effectiveness of 34%.

The two cases yield energy removal rates of the same order of magnitude, with the inadvertent containment spray case being the larger, 400,000 BTU/Sec. As such, this inadvertent spray actuation case controls the vacuum breaker sizing. Four vacuum breaker valve assemblies, having a seat I.D. of 19.4 inches, are adequate to ensure a diaphragm slab differential pressure below design allowables. An additional fifth valve assembly is employed to cover single-active failure concerns.

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, 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 provides a heat sink for the drywell atmosphere, and thereby causes the drywell to depressurize.

The results of the short-term analyses are summarized in Table 6.2-6a. The short-term containment pressure response is shown in Figure 6.2-2. The peak calculated drywell-to-wetwell pressure response is shown in Figure 6.2-4. The short-term containment temperature response is shown in Figure 6.2-12.

During the blowdown period of the LOCA, the pressure suppression vent system conducts the flow of the steam-water gas mixture in the drywell to the suppression pool for condensation of the steam. The pressure differential between the drywell and suppression pool controls this flow. Figure 6.2-5 provides the mass flow versus time relationship through the vent system for this accident.

6.2.1.1.3.3.1.6 Long Term Accident Responses

To assess the adequacy of the containment following the initial blowdown transient, an analysis was made of the long term temperature and pressure response following the accident. The analysis assumptions are those discussed in Subsection 6.2.1.1.3.3.1.3. The initial pressure response of the containment (the first 600 seconds after break) is the same for each case. Operator performance during Emergency Procedure validation exercises shows that under accident conditions alignment of an RHR heat exchanger for containment cooling within 10 minutes is difficult to achieve. Consequently, a sensitivity analysis has been performed which demonstrates that if operator actions are delayed for up to 20 minutes, the peak suppression pool temperatures calculated in the long term DBA/LOCA containment analyses discussed herein (which are based on an operator response time of 10 minutes) would remain valid and bounding. Although the sensitivity analysis was performed for the Case D (worst case) scenario, the analysis results apply to the Case A through C long term DBA/LOCA containment analyses included herein as well. The sensitivity analysis assumes that average RHRSW temperatures would be at or below 91 F for the first two hours of the transient, which remains below the average UHS (THTSW) design temperatures for this time frame, rather than at the peak RHRSW temperature of 97 F assumed throughout the containment analyses. Although the containment analyses were not rerun with an operator response time of 20 minutes, the sensitivity analysis demonstrates that this short term reduction in assumed RHRSW temperature offsets the impact of increasing operator response time to 20 minutes on peak suppression pool temperatures for the Case A – D long term containment analyses and justifies an operator response time of up to 20 minutes to establish the containment heat removal function.

CASE A: All ECCS equipment operating - with containment spray-

This case assumes that offsite ac power is available to operate all cooling systems. During the first 600 seconds following the pipe break, the HPCI, CS and all LPCI pumps are assumed operating. All flow is injected directly into the reactor vessel.

After 600 seconds, an operator initiates the containment cooling mode by activating the RHR heat removal system to maintain containment pressure and temperature within specified limits. Suction is drawn from the suppression pool, passed through a RHR heat exchanger, and discharged to the containment via the drywell and wetwell spray spargers. There are two RHR loops, each includes two pumps and one heat exchanger. One pump operating in one RHR loop is sufficient to provide the containment cooling function.

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 exceeds the energy addition rate from the decay heat, the containment pressure and temperature reach a second peak value and decrease gradually.

CASE B: Loss of Offsite Power - With Containment Spray

This case assumes no offsite power is available following the accident with only minimum diesel power. The containment spray is operating and spraying water into the containment after 600 seconds. During this mode of operation the LPCI flow through only one RHR heat exchanger is directed to the containment spray nozzles.

CASE C: Loss of Offsite Power - No Containment Spray

This case assumes that no offsite power is available following the accident with only minimum diesel power. For the first 600 seconds following the accident, two LPCI pumps are used to cool the core. After 600 seconds the spray may be manually activated to further reduce containment pressure if desired. This analysis assumes that the containment spray is not activated. After 600 seconds, one RHR heat exchanger is activated to remove energy from the containment. During this mode of operation, one of the two LPCI pumps is shut down and the service water pumps to the RHR heat exchanger are activated. The LPCI flow is cooled by the RHR heat exchanger before being discharged into the reactor vessel.

CASE D: Loss of Offsite Power – All Pumps Running

This case assumes that no offsite power is available following the accident and no operation of the HPCI pump. All four CS pumps and all four LPCI pumps are injecting into the vessel for the duration of the event. A single active failure prevents RHRSW cooling water flow through one of the RHR heat exchangers. At 600 seconds, one loop of LPCI flow is cooled by a single RHR heat exchanger before being discharged into the reactor vessel.

These four cases were analyzed using the initial plant conditions listed in Table 6.2-3a. The inputs and assumptions for these cases are provided in Tables 6.2-2 and 6.2-5a. Of these cases, Case D produces the highest suppression pool temperature. The resulting calculated peak bulk suppression pool temperature is given in Table 6.2-6a. The long-term containment pressure response is shown in Figure 6.2-6, the long term drywell temperature response is shown in Figure 6.2-7, and the long-term suppression pool temperature response is shown in Figure 6.2-8.

6.2.1.1.3.3.1.7 Energy Balance During Accident

To establish an energy distribution in the containment as a function of time (short term, 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 6.2-9)

f. Metal-water reaction heat rate.
g. Passive heat sinks in containment

6.2.1.1.3.3.2 Main Steamline Break

The assumed sudden rupture of a main steamline between the reactor vessel and the flow limiter would result in the maximum flow rate of primary system fluid and energy to the drywell. This would in turn result in the maximum drywell temperature. The sequence of events immediately following the rupture of a main steamline between the reactor vessel and the flow limiter have been determined. For the short term main steam line break evaluation, feedwater flow into the vessel is assumed to stop at the start of the event. This is conservative since continued feedwater flow would result in a reduction in the RPV pressure and the blowdown flow rates. The flow in both sides of the break will accelerate to the maximum allowed by the critical flow considerations. The break flow rates are calculated based on the Moody Slip flow critical model. The vessel model of Reference 6.2.1 and 6.2.26 is used in calculating these break flow rates. The Mark III analytical model from Reference 6.2.26 is made applicable to the Mark II containment analysis by reducing the horizontal portion of the vent to zero. In the side adjacent to the reactor vessel, the flow will correspond to critical flow in the steamline break area. Blowdown through the other side of the break will occur because the steamlines are all interconnected at a point upstream of the turbine. This interconnection allows primary system fluid to flow from the three unbroken steam lines, through the header, and back into the drywell via the broken line. Flow will be limited by critical flow in the steamline flow restrictor. A slower closure rate of the isolation valves in the broken line would result in a slightly longer time before the total valve area of the three unbroken lines equals the flow limiter area in the broken line. Subsection 6.2.1.3 provides the mass and energy release rates.

Immediately following the break, the total steam flow rate leaving the vessel would be approximately 8400 lb/sec, which exceeds the steam generation rate in the core of 3931 lb/sec. This steam flow to steam generation mismatch causes an initial vessel depressurization of the reactor vessel at a rate of approximately 48 psi/sec. Void formation in the reactor vessel water causes a rapid rise in the water level, and it is conservatively assumed that the water level reaches the vessel steam nozzles one second after the break occurs. The water level rise time of one second is the minimum that could occur under any reactor operating condition. From that time on, a two-phase mixture would be discharged from the break. During the first second of the blowdown, the blowdown flow will consist of saturated steam. This steam will enter the containment in a superheated condition of approximately 340°F.

Figures 6.2-11 and 6.2-12 show the pressure and temperature responses of the drywell and suppression chamber during the primary system blowdown phase of the steamline break accident.

Figure 6.2-12 shows that the drywell atmosphere temperature approaches 337°F at approximately one second of primary system steam blowdown. At that time, the water level in the vessel will reach the steamline nozzle elevation and the blowdown flow will change to a two-phase mixture. This increased flow causes a more rapid drywell-pressure rise. The peak differential pressure occurs shortly after the vent clearing transient.

As the blowdown proceeds, the primary system pressure and fluid inventory will decrease and this will result in reduced break flow rates. As a consequence, the flow rate in the vent system and the differential pressure between the drywell and suppression chamber begin to decrease.

At this time in the accident scenario, the drywell will contain primarily steam, and the drywell and suppression chamber pressures will stabilize. The pressure difference corresponds to the hydrostatic pressure of vent submergence.

The drywell and suppression pool will remain in this equilibrium condition until the reactor vessel refloods. During this period, the emergency core cooling pumps will be injecting cooling water from the suppression pool into the reactor. This injection of water will eventually flood the reactor vessel to the level of the steamline nozzles and the ECCS flow will spill into the drywell. The water spillage will condense the steam in the drywell and thus reduce the drywell pressure. As soon as the drywell pressure drops below the suppression chamber pressure, the drywell vacuum breakers will open and noncondensable gases from the suppression chamber will flow back into the drywell until the pressure in the two regions equalize.

6.2.1.1.3.3.3 Hot Standby Accident Analysis

The containment pressure design parameters based on hot standby accident analyses are enveloped by the full reactor power operating condition analysis.

6.2.1.1.3.3.4 Intermediate Size Breaks

The failure of a recirculation line results in the most severe pressure loading on the drywell structure. However, as part of the containment performance evaluation, the consequences of intermediate breaks are also analyzed. This classification covers those breaks for which the blowdown will result in reactor depressurization and operation of the ECCS. This section describes the consequences to the containment of a 0.1 sq. ft. break below the RPV water level. This break area was chosen as being representative of the intermediate size break area range. These breaks can involve either reactor steam or liquid blowdown.

Following the 0.1 sq. ft. 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 vents is negligible and the vents will clear when the drywell-to-suppression chamber differential pressure is equal to the vent submergence hydrostatic pressure.

The ECCS response is discussed in Section 6.3. Approximately 5 seconds after the 0.1 sq. ft break occurs, air, steam, and water will start to flow from the drywell to the suppression pool; the steam will be condensed and the air will enter the suppression chamber free space. The containment will continue to gradually increase in pressure due to the long-term pool heatup.

The ECCS will be initiated as a result of the 0.1 sq. ft break and will provide emergency cooling of the core. The operation of these systems is such that the reactor will be depressurized in approximately 600 seconds. This will terminate the blowdown phase of the transient.

In addition, the suppression pool end of blowdown temperature will be the same as that of the DBA because essentially the same amount of primary system energy is released during the blowdown. After reactor depressurization and reflood, water from the ECCS will begin to flow out the break. This flow will condense the drywell steam and eventually cause the drywell and suppression chamber pressures to equalize in the same manner as following a recirculation line rupture.

The subsequent long term suppression pool and containment heat-up transient that follows is essentially the same as for the recirculation line break.

From this description, it can be concluded that the consequences of an intermediate size break are less severe than from a recirculation line rupture. This conclusion remains unchanged for the power uprate conditions because the effect of power uprate on the intermediate size break analysis is expected to be similar to the power uprate effect on the recirculation suction line rupture. Therefore, the intermediate size break peak drywell pressure will still be bounded by the recirculation suction line peak drywell pressure value.

6.2.1.1.3.3.5 Small Size Breaks

6.2.1.1.3.3.5.1 Reactor System Blowdown Considerations

This subsection discusses the containment transient associated with small breaks in the primary system. The sizes of primary system ruptures in this category are those blowdowns that will not result in reactor depressurization due either to 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 operators will initiate an orderly plant shutdown and depressurization of the reactor system. The thermodynamic process associated with the blowdown of primary system fluid is one of constant enthalpy. If the primary system break is below the water level, the blowdown flow will consist of reactor water. Blowdown from reactor pressure to the drywell pressure will flash approximately one-third of this water to steam and two-thirds will remain as liquid. Both phases will be at saturation conditions corresponding to the drywell pressure.

If the primary system rupture is located so that the blowdown flow consists of reactor steam only, the resultant steam temperature in the containment is significantly higher than the temperature associated with liquid blowdown. This is because the constant enthalpy depressurization of high pressure, saturated steam will result in superheated conditions. For example, decompression of 1000 psia saturated steam to atmospheric pressure will result in 298°F superheated steam (86°F of superheat).

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

6.2.1.1.3.3.5.2 Containment Response

For drywell design considerations, the following sequence of events is assumed to occur. 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 will lead to a high drywell pressure signal that will scram the reactor and activate the containment isolation system. The drywell pressure will continue to increase at a rate dependent upon the size of the steam leak. The pressure increase will lower the water level in the vents until the level reaches the bottom of the vents. At this time, air and steam will start to enter the suppression pool. The steam will be condensed and the air will be carried over to the suppression chamber free space. The air carryover will result in a gradual pressurization of the suppression chamber at a rate dependent upon the size of the steam leak. Once all the drywell air is carried over the suppression chamber, pressurization of the suppression chamber will cease and the system will reach an equilibrium condition. The drywell will contain only superheated steam, and continued blowdown of reactor steam will condense in the suppression pool. The suppression pool temperature will continue to increase until the RHR heat exchanger heat removal rate is greater than the decay heat release rate.

6.2.1.1.3.3.5.3 Recovery Operations

The reactor operators will be alerted to the incident by the high drywell pressure signal and the reactor scram. For the purposes of evaluating the duration of the superheat condition in the drywell, it is assumed that their response is to shut the reactor down in an orderly manner using the main condenser while limiting the reactor cooldown rate to 100°F per hour. This will result in the reactor primary system being depressurized within six hours. At this time, the blowdown flow to the drywell will cease and the superheat condition will be terminated. If the plant operators elect to cool down and depressurize the reactor primary system more rapidly than 100°F per hour, then the drywell superheat condition will be shorter.

6.2.1.1.3.3.5.4 Drywell Design Temperature Considerations

For drywell design purposes, it is assumed that there is a blowdown of reactor steam for the six-hour cooldown period. The corresponding design temperature is determined by finding the combination of primary system pressure and drywell pressure that produces the maximum superheat temperature. This temperature is then assumed to exist for the entire six-hour period. The maximum drywell steam temperature occurs when the primary system is at approximately 450 psia and the drywell pressure is maximum. For design purposes, it is assumed that the drywell is at 35 psig; which results in a temperature of 340°F.

6.2.1.1.3.4 Accident Analysis Models

6.2.1.1.3.4.1 Short Term Pressurization Model

The analytical models, assumptions, and methods used by General Electric to evaluate the containment response during the reactor blowdown phase of a LOCA are described in Refs. 6.2-1, 6.2-23, and 6.2-26. For the recirculation line suction break, a detailed vessel blowdown model which determines the break mass and energy flows is based on Reference 6.2.23. For the main steam line break the vessel model in References 6.2.1 and 6.2.26 are used in the analysis.

References 6.2.1 and 6.2.26 provide the following additional models for use in the evaluation of the short term containment response to a postulated major pipe rupture:

1. The drywell model which determines the thermodynamic conditions as a result of the mass and energy flows into and out of the drywell.

2. The downcomer model which determines the clearing time and downcomer flow rate. The Mark III analytical model was made applicable to the Mark II containment by reducing the horizontal portion of the vent to zero length.

3. The suppression pool model for the temperature response by a mass and energy balance.

4. The suppression chamber airspace model which is used to calculate the airspace pressure and temperature response.

6.2.1.1.3.4.2 Long Term Cooling Mode

Once the RPV blowdown phase of the LOCA is over, the long term suppression pool temperature response was evaluated for the recirculation suction line break. The analysis was performed at 102% of the uprated power. A coupled reactor pressure vessel and containment model, based on the models provided in References 6.2.1 and 6.2.26, was used to calculate the containment transient response during long term events which add heat to the suppression pool. The model performs fluid mass and energy balances on the reactor primary system and the suppression pool, and calculates the reactor vessel water level, pressure and the long term suppression pool bulk temperature. During the long term, post-blowdown containment cooling transient, the ECCS flow path is a closed loop and the suppression pool mass will be constant. Schematically, the cooling model loop is shown on Figure 6.2-16. Since there is no change in mass storage in the system (the RPV is reflooded during the blowdown phase of the accident), the mass flow rates shown in the figure are equal, thus:

$$M_{D_o} = M_{s_o} = M_{eccs} \qquad \text{(Eq. 6.2-1)}$$

6.2.1.1.3.4.3 Analytical Assumptions

The key assumptions employed in the short term model are as follows:

(1) Fluid inventory depressurizes and a single-phase liquid blowdown to the drywell occurs maximizing the energy release to the containment.

(2) The initial suppression pool volume is at the maximum Technical Specification limit to maximize the drywell pressure response.

(3) Thermodynamic equilibrium exist between the liquid and gases in the drywell, and between the suppression pool and the suppression chamber airspace. Heat and mass transfer between the gases and the liquid in the drywell and suppression chamber airspace is calculated with containment spray operation.

(4) No credit is taken for passive heat sinks in the drywell, suppression chamber airspace, or in the suppression pool.

The key assumptions employed in the long term model are as follows:

(1) The drywell and suppression chamber atmosphere are both saturated (100 percent relative humidity).

(2) The drywell atmosphere temperature is equal to the temperature of the coolant spilling from the RPV, or to the spray temperature if the sprays are activated.

(3) The initial suppression pool volume is at the minimum Technical Specification limit to maximize the suppression pool temperature response.

(4) Thermodynamic equilibrium exist between the liquid and gases in the drywell, and between the suppression pool and the suppression chamber airspace. Heat and mass transfer between the gases and the liquid in the drywell and suppression chamber airspace is calculated without containment spray operation.

(5) Credit is taken for passive heat sinks in the drywell, suppression chamber airspace, and the suppression pool.

6.2.1.1.3.4.4 Energy Balance Considerations

The rate of change of energy in the suppression pool, E_p, is given by:

$$\frac{d}{dt}(E_p) = \frac{d}{dt}(M_{W_S} \bullet U_S)$$

$$= U_S \bullet \frac{d}{dt}(M_{W_S}) + M_{W_S} \bullet \frac{d}{dt}(U_S)$$

Since

$$\frac{d}{dt}\left(M_{W_S}\right) = 0$$

(because there is no change in mass storage, and at the conditions that will exist in the containment:

$$\frac{d}{dt}\left(U_s\right) = C_v \bullet \frac{d}{dt}\left(T_s\right)$$

where:

C_v	=	1.0 for the constant volume specific heat of water, Btu/lb-°F
T_s	=	pool temperature, °F

The pool energy balance yields:

$$M_{w_s} \bullet C_v \bullet \frac{d}{dt}(T_s) = \dot{M}_{D_o} \bullet h_D - \dot{M}_{s_o} \bullet h_s$$

This equation can be rearranged to yield:

$$\frac{d}{dt}(T_s) = \frac{\dot{M}_{D_o} \bullet h_D - \dot{M}_{s_o} \bullet h_s}{C_v \bullet M_{w_s}} \qquad \text{(Eq. 6.2-2)}$$

An energy balance on the RHR heat exchanger yields

$$hc = H_s - \frac{-q_{H_x}}{\dot{M}_{s_o}} \qquad \text{(Eq. 6.2-3)}$$

where,

h_c = enthalpy of ECCS flow entering the reactor, BTU/lb.

Similarly, an energy balance on the RPV will yield:

$$h_D = h_c + \frac{\dot{q}_D + \dot{q}_e}{\dot{M}_{eccs}} \qquad \text{(Eq. 6.2-4)}$$

Combining Equations 6.2-1, 6.2-2, 6.2-3, and 6.2-4 gives

$$\frac{d}{dt}(T_s) = \frac{\dot{q}_D + \dot{q}_e - q_{H_x}}{C_v \; M_{w_s}} \qquad \text{(Eq. 6.2-5)}$$

This differential equation is integrated by finite difference techniques to yield the suppression pool temperature transient.

6.2.1.1.3.4.5 Containment Thermodynamic Conditions

Once the energy equations are solved, the drywell and suppression chamber atmospheric temperatures can be calculated.

For the case in which no containment spray is operating, the suppression chamber temperature, T_w, at any time will be equal to the current temperature of the pool, T_s, and the drywell temperature, T_D, will be equal to the temperature of the fluid leaving the RPV. Thus:

$$T_D = T_s + \frac{\dot{q}_D + \dot{q}_e - \dot{q}_{H_x}}{C_p \; \dot{M}_{eccs}} \text{ and } T_w = T_s$$

Where C_p = Constant pressure specific heat of water, BTU/lb-°F.

For the case in which the containment spray is assumed to be operating, both the drywell and suppression chamber atmosphere will be at the spray temperature, T_{sp}, where:

$$T_{sp} = T_s - \frac{\dot{q}_{H_x}}{C_p \ \dot{M}_{eccs}} \text{ and } T_D = T_w = T_{sp}$$

Using the suppression chamber and drywell atmosphere temperatures, and assumption (1) of Subsection 6.2.1.1.3.4.3 (drywell and suppression chamber saturated), it is possible to solve for the containment total pressures, since:

$$P_D = P_{a_D} + P_{V_D} \qquad \text{(Eq. 6.2-6)}$$

$$P_S = P_{a_S} + P_{v_s} \qquad \text{(Eq. 6.2-7)}$$

Where:

P_D	=	drywell total pressure, psia
P_{a_D}	=	partial pressure of air in drywell, psia
P_{V_D}	=	partial pressure of water vapor in drywell, psia
P_S	=	suppression chamber total pressure, psia
P_{a_S}	=	partial pressure of air in the suppression chamber, psia
P_{V_S}	=	partial pressure of water vapor in the suppression chamber, psia

and from the Ideal Gas Law:

$$P_{a_D} = \frac{M_{a_D} \bullet RT_D}{V_D \bullet 144} \qquad \text{(Eq. 6.2-8)}$$

$$P_{a_S} = \frac{M_{a_S} \bullet RT_s}{V_s \bullet 144} \qquad \text{(Eq. 6.2-9)}$$

M_{a_D}	=	mass of air in the drywell, lb.
M_{a_S}	=	mass of air in the suppression chamber, lb.
R	=	gas constant for air, ft-lbf/lb-°R.
V_D	=	drywell free Volume, ft^3.
V_S	=	suppression chamber free volume, ft^3.

With known values of T_D and T_S, Equations 6.2-6, 6.2-7, 6.2-8 and 6.2-9 can be solved by transient analysis and iteration. This iteration procedure is also used to calculate the unknown quantities M_{a_D} and M_{a_s}.

6.2.1.1.3.4.6 Solution of Equations

The transient analysis is based on successive time step integration of the suppression pool temperature. When this integration has been performed and the value of T_s at the end of a time step has been calculated, a pressure balance is made. Using values of M_{a_D} and M_{a_s} from the end of the previous time step and the updated values of T_D and T_S, a check is made to see if P_S is greater than or equal to P_D using Equations 6.2-6, 6.2-7, 6.2-8 and 6.2-9. If P_S is greater than or equal to P_D, then the two values are made equal. The vacuum breakers between the drywell and suppression chamber ensure that P_S cannot be significantly greater than P_D .

Hence, with $P_D = P_s$ and knowing that: $M_{a_D} + M_{a_s}$ = constant where the constant is the known total initial mass of air in the suppression chamber and drywell prior to the accident, Equations 6.2-6, 6.2-7, 6.2-8 and 6.2-9 can be solved for M_{a_s}, M_{a_D}, and P_s/P_D. It is conservatively assumed that the total mass of air remains constant, which ignores any containment leakage that might occur during the transient.

If, as a result of the end-of-time-step pressure check,

$$P_s \leq P_D \leq P_s + \frac{H \bullet g}{\nu_w \bullet 144 \bullet g_c} \qquad \text{(Eq. 6.2-10)}$$

where:

g	=	acceleration of gravity, ft/sec^2
g_c	=	constant of proportionality in Newton's Second Law, ft-lb/lbf-sec^2
0	=	submergence of vents, ft
$]_w$	=	specific volume of fluid in vent ft^3;/lb

then the pressure in the drywell is higher than the pressure in the suppression chamber but not sufficiently so to depress the water to the bottom of the vents and thus permit air to flow from the drywell to the suppression chamber. Under these circumstances, no air transfer is assumed to have occurred during the time step, and Equations 6.2-6, 6.2-7, 6.2-8 and 6.2-9 are solved during the time step, and Equations 6.2-6, 6.2-7, 6.2-8 and 6.2-9 are solved using the updated temperatures with the same M_{a_s} and M_{a_D} values from the previous time step.

If the end-of-time-step pressure check shows:

$$P_D > P_s + \frac{H \bullet g}{\nu_w \bullet 144 \bullet g_c}$$

then the drywell pressure is set to the value:

$$P_D = P_s + \frac{H \bullet g}{\nu_w \bullet 144 \bullet g_c} \qquad \text{(Eq. 6.2-11)}$$

This requires that the drywell pressure can never exceed the suppression chamber pressure by more than the hydrostatic head associated with the submergence of the vents. To maintain this condition, some transfer of drywell air to the suppression chamber will be required. The amount of air transfer is calculated by using Equation 6.2-10 and combining Equations 6.2-6, 6.2-7, 6.2-8, 6.2-9, and 6.2-11 to give:

$$P_{v_D} + \frac{M_{a_D} \bullet RT_D}{144\ V_D} = P_{v_S} + \frac{M_{a_S} \bullet RT_W}{144\ V_s} + \frac{H \bullet g}{\nu_w \bullet 144 \bullet g_c}$$

which can be solved for the unknown air masses. The total pressures can then be determined.

6.2.1.1.4 Negative Pressure Design Evaluation

The primary containment has been designed for a pressure of -5 psi. The worst case for this consideration results from the inadvertent actuation of the drywell sprays. During such a transient, cold spray water is passed through the drywell atmosphere resulting in a drop in vapor region temperature and a corresponding drop in vapor region pressure. This condition has been analyzed for Susquehanna SES. A peak pressure of -4.72 psi was obtained.

To determine the temporal pressure and temperature of the primary containment, the conservation equation of mass and energy, along with the state equations for steam and nitrogen (noncondensable) are written for the drywell and wetwell regions. A schematic of these two regions is presented in Figure 6.2-61. The various terms for the mass and energy transfer mechanisms are also presented in this figure. The system of differential equations for each region are as follows (definition of nomenclature is provided in Subsection 6.2.1.1.4.1):

Drywell Region

As indicated in Figure 6.2-61, there are several mass transfer terms for this region. These are: drywell spray rate, M'_{spray}, drywell vapor region condensation rate (or rainout due to dripping saturation temperature), M'_{cond}, and wetwell-to-drywell vacuum breaker flow rate, M'_{VB}. A mass balance on the drywell vapor region yields,

$$\frac{dM_D}{dt} = \frac{dM_{NC}}{dt} + \frac{dM_{stm}}{dt} = [\dot{M}_{VB} + \dot{M}_{spray}]_{in} - [\dot{M}_{cond} + \dot{M}_{spray}]_{out} \qquad (1)$$

The spray water is assumed to be removed directly to the wetwell liquid region so as to disallow any potential for re-evaporation to the drywell, as well as maintain a larger drywell vapor region volume - both of which serve to induce conservations in the analysis. The requirement of maintaining saturation conditions for the steam component is imposed and results in the following relationship:

$$M_{stm} = \frac{V_D}{v_g(T_D)} \text{ or } \frac{dM_{stm}}{dt} = \frac{-V_D}{v_g^2(T_D)} \bullet \frac{d\,v_g}{dT_D} \bullet \frac{dT_D}{dt} \qquad (2)$$

The energy balance for this region is,

$$\frac{dE_D}{dt} = [\dot{M}_{spray} C_p (T_{out} - 32) + \dot{Q}_{VB}]_{in}$$
$$- [\dot{M}_{spray} C_p (T_f - 32)$$
$$+ \dot{M}_{cond} h_f(T_f)]_{out}$$
$$= \dot{M}_{spray} C_p (T_{out} - T_f) - \dot{M}_{cond} h_f(T_f) \bullet + \dot{Q}_{VB}$$

But,

$$\frac{dE_D}{dt} = \left[C_V^* T_D^* \frac{dM_{NC}}{dt} + u_g\ (T_D)\ \frac{dM_{stm}}{dt} \right] + \left[M_{NC} C_V^* + M_{stm} \frac{d\,u_g}{dT_D} \right] \frac{dT_D}{dt}$$

So,

$$\left[C_V^* T_D^* \frac{dM_{NC}}{dt} + u_g (T_D) \frac{dM_{stm}}{dt} \right] + \left[M_{NC} C_V^* + M_{stm} \frac{d\,u_g}{dT_D} \right] \frac{dT_D}{dt}$$
$$= \dot{M}_{spray} C_P (T_{out} - T_f) - \dot{M}_{cond}\, h_p (T_f) + \dot{Q}_{VB} \qquad (3)$$

The spray effectiveness, ς is defined as follows:

$$\xi = \frac{T_f - T_{out}}{T_D - T_{out}} = f(M_{stm} / M_{NC})$$

The functional relationship is determined in the work of Reference 6.2-14 and is illustrated in Figure 6.2-62.

<u>WETWELL REGION</u>

The wetwell region is modeled in much the same way as the drywell region except that, due to the presence of the suppression pool, two subregions are identified: one to represent the wetwell vapor region, and one to represent the wetwell liquid region (suppression pool). The vapor region is denoted by subscript sv. Mass and energy balances on this subregion yield the following:

$$\frac{dM_{SV}}{dt} = \frac{d(M_{NC})_{SV}}{dt} + \frac{d(M_{stm})_{SV}}{dt} \qquad (5)$$
$$= [\dot{M}_{evap}]_{in} - [\dot{M}_{VS} + (\dot{M}_{cond})_{SV} + \dot{M}_{drop}]_{out}$$

As was the case in the drywell region, the wetwell vapor region is assumed to maintain saturated conditions. Therefore,

$$(M_{stm})_{SV} = \frac{V_{SV}}{v_g(T_{SV})} \text{ or } \frac{d(M_{stm})_{SV}}{dt}$$
$$= \frac{1}{v_g(T_{SV})} \bullet \frac{dV_{SV}}{dt} - \frac{V_{SV}}{v_g^2(T_{SV})} \bullet \frac{d\,v_g}{dT_{SV}} \bullet \frac{dT_{SV}}{dt} \qquad (6)$$

From volume consideration, V_{SV} can change less than 2% and does so gradually throughout the transient. Therefore, the approximation is made that,

$$\frac{dV_{SV}}{dt} \sim 0 \qquad (7)$$

The suppression pool represents a large surface for condensation and evaporation thus resulting in a net mass transfer between the liquid and vapor subregions. This effect serves to maintain the wetwell vapor region in a saturated state and is therefore modeled with the terms in $\dot{M}_{evap}$ and M_{drop}. The kinetic theory of condensation (Reference 6.2-15) is used to determine these mass transfer rates. This results in the following expressions:

$$(\dot{M}_{cond})_{sv} = 144\,\Gamma\,A_{cond}\sqrt{\frac{g_c}{2\pi R_{stm}}} \bullet \frac{(P_{stm})_{sv}}{\sqrt{T^*_{sv}}}$$
$$\dot{M}_{evap} = 144\,A_{cond}\sqrt{\frac{g_c}{2\pi R_{stm}}} - \frac{P_g(T_\ell)}{\sqrt{T_{\ell^*}}} \qquad (8)$$

$$where, \Gamma = - w\sqrt{\pi}\,[1 + erf(w)] - e^{-w^2}$$

$$w = \frac{G_{net}}{G_{std}} = \frac{\sqrt{2\pi}\left(\dot{M}_{evap} + (\dot{M}_{cond})_{sv}\right)}{(144) - A_{cond}\,\rho_{stm}\sqrt{2\,g_c\,R_{stm}\,T^*_{sv}}} \qquad (9)$$
$$erf(w) = \frac{2}{\sqrt{\pi}}\int_o^w e^{-z^2}\,d_z$$

For the energy balance,

$$\frac{dE_{sv}}{dt} = C_v^* T_{sv}^* \frac{d(M_{NC})_{sv}}{dt} + d(M_{NC})_{sv} C_v^* \frac{dT_{sv}}{dt} + U_g(T_{sv}) \frac{d(M_{stm})_{sv}}{dt}$$

$$+ (M_{stm})_{sv} \frac{dU_g}{dT_{sv}} - \frac{dT_{sv}}{dt} \qquad (10)$$

$$= [\dot{M}_{evap} h_g(T_s)]_{in} - [\dot{Q}_{VB} + (\dot{M}_{cond_{sv}} h_f(T_{sv}) + \dot{M}_{drop} h_g(T_{sv})]_{out}$$

The suppression pool region is denoted by subscript s. Mass and energy balances on this subregion yield the following:

$$\frac{dM_s}{dt} = [\dot{M}_{drop} + \dot{M}_{cond} + (\dot{M}_{cond})_{sv}]_{in} - [\dot{M}_{evap}]_{out} \qquad (11)$$

$$\frac{dE_s}{dt} = C_v(T_s - 32) \frac{dM_s}{dt} + M_s C_v \frac{dT_s}{dt}$$

$$= [\dot{M}_{cond} h_f(T_v) + (\dot{M}_{cond})_{sv} h_f(T_{sv}) + \dot{M}_{drop} h_g(T_{sv}) \qquad (12)$$

$$+ \dot{M}_{spray} [h_f(T_f - T_s)]_{in} - [\dot{M}_{evap} h_g(T_s)]_{out}$$

Two additional mass and energy transfer mechanisms need further definition. These are:

<u>Vacuum Breaker Flows</u>

When sufficient differential pressure has built up across the diaphragm slab, the wetwell-to-drywell vacuum breaker assemblies will open allowing for transfer of mass and energy between these two regions. This transfer is described as follows:

(13)

$$\dot{M}_{VB} = C_{VB}^* A_{VB} \left[\frac{2g_c k_{sv}}{k_{sv} - 1} \rho_{sv} {}^{P_{sv}} \left\{ 1 - \left(\frac{P_D}{P_{sv}} \right)^{\frac{k_{sv}+1}{k_{sv}}} \right\} \right]^{1/2} \quad for \left(\frac{P_D}{P_{sv}} \right) > \left(\frac{2}{k_{sv}+1} \right)^{\frac{k_{sv}}{k_{sv}-1}}$$

Subcritical Flow

$$\dot{M}_{VB} = C_{VB}^* A_{VB} \left[g_c k_{sv} p_{sv} \rho_{sv} \left(\frac{2}{k_{sv}+1} \right)^{\frac{k_{sv}+1}{k_{sv}-1}} \right]^{1/2} \quad for \left(\frac{P_D}{P_{sv}} \right) \le \left(\frac{2}{k_{sv}+1} \right)^{\frac{k_{sv}}{k_{sv}-1}}$$

Critical Flow

$$(\dot{M}_{VB})_{stm} = \left(\frac{M_{stm}}{M_{stm} + M_{NC}}\right)_{sv} \dot{M}_{VB}$$

$$(\dot{M}_{VB})_{NC} = \left(\frac{M_{NC}}{M_{stm} + M_{NC}}\right)_{sv} \dot{M}_{VB} \qquad (14)$$

$$k_{sv} = \left(\frac{P_{NC}}{P_{tot}}\right)_{sv} k_{NC} + \left(\frac{P_{stm}}{P_{tot}}\right)_{sv} k_{stm}$$

and,

$$\dot{Q}_{VB} = (\dot{M}_{vs})_{stm} h_g(T_{sv}) + (\dot{M}_{VB})_{NC} C_P^* T_{sv}^* \qquad (15)$$

RHR Heat Exchangers

In the drywell spray mode, the RHR system draws water from the suppression pool, passes it through the RHR heat exchangers, and injects it into the drywell vapor region. As such, the RHR heat exchangers must be modeled to reflect this condition. Therefore,

where $\dot{Q}_{HX} = \dot{M}_{spray} C_p (T_s - T_{out} = \zeta E C_p (T_s - T_{sw})$

$$\zeta = \min(\dot{M}_{spray}, \dot{M}_{sw}) \qquad (16)$$

Combining yields, $T_{out} = T_s - \frac{\zeta E}{\dot{M}_{spray}} (T_s - T_{sw})$

These equations, combined with the state equations for steam and nitrogen, yield a set of coupled equations which, when reduced and solved simultaneously, determine the temporal response of the primary containment system to the postulated inadvertent drywell spray accident.

The inherent conservatisms of this model are: neglect transfer of sensible heat energy from equipment and structures to the drywell vapor region, disallow re-evaporation of the condensed drywell steam, maintain a large volume for the drywell region by transferring condensed steam mass directly to the suppression pool, and require saturated conditions in the primary containment vapor regions. Expanding on this last conservatism, for conditions during which a super heated environment is present initially, it is possible to get a low "short term" drop in vapor region pressure. This drop is associated with desuperheating the steam component; the energy for this process comes from the non-condensable component. This reduces the vapor region temperature--and hence pressure--and proceeds until the vapor region is saturated. For relatively hot spray water (e.g., 80°F), this short-term pressure drop can, in fact, give the maximum negative pressure. However, for cases wherein relatively cold spray water is used (e.g., 50°F) the maximum negative pressure is the "long-term" pressure. For this situation, a high relative humidity is conservative. This is the case for Susquehanna SES and, hence, justifies the assumption of saturated conditions for the primary containment vapor regions - both initially and throughout the transient.

In addition to the modeling conservatism, initial conditions for the primary containment are also chosen to induce conservatism in the analysis. The presence of any non-condensables $_{NC}$ in the drywell tends to "hold-up" the depressurization of this region following spray actuation. Thus, a condition is postulated wherein a small break occurs within the drywell serving to pressurize this region and drive all the non-condensables to the wetwell vapor space. This sets the initial pressure distribution (and, along with the assumptions regarding saturated conditions for the steam phase, the temperature distribution) for all three regions - drywell, wetwell vapor region, and suppression pool. These initial conditions are presented in Table 6.2-23.

The results of this analysis are illustrated in Figures 6.2-63 and 6.2-64. Again, these results indicate a maximum negative drywell pressure of -4.72 psig.

The differential pressure experienced across the diaphragm slab during this transient is illustrated in Figure 6.2-65. As indicated in this figure, a maximum –P of 4.6 psid results. This is well below the 28 psid design value for this slab.

6.2.1.1.4.1 Glossary of Terms Used in Subsection 6.2.1.1.4

A_{COND}	=	Suppression Pool Free Surface Area, ft^2
A_{VB}	=	Vent Area Through Vacuum Breakers, ft^2
C_{VB}	=	Vacuum Breaker Flow Coefficient
C_p	=	Specific Heat at Const. Press. for H_2O, 1 Btu/lb°F
C_p^*	=	Specific Heat at Const. Press. for N_2, 0.247 Btu/lb°R
C_v	=	Specific Heat at Const. Vol. for H_2O, 1 Btu/lb°F
C_v^*	=	Specific Heat at Const. Vol. for N_2, 0.176 Btu/lb°R
E	=	Energy Content, Btu
g_c	=	Gravitational Constant, 32.174 ft/sec^2
h	=	Specific Enthalpy, Btu/lb
k	=	Ratio of Specific Heats
M	=	Mass, lbs
M_{NC}	=	Non-Condensable Mass, lbs
M_{cond}	=	Condensate Mass, lbs
M_{drop}	=	Droplet Mass, lbs
M_{evap}	=	Evaporated Steam Mass, lbs
M_{stm}	=	Steam Mass, lbs
P	=	Pressure, psi
R	=	Gas Constant, ft-lbf/lb°R
Q	=	Transferred Energy, Btu
T	=	Temperature, °F
T*	=	Absolute Temperature, °R
t	=	Time, Sec
u_{stm}	=	Steam Specific Energy, Btu/lb
V	=	Volume, ft^3
ν	=	Specific volume, ft^3/lbm
w	=	Mass flux ratio, dimensionless
T_P	=	Liquid tempertaure, °R
u	=	Specific internal energy, BTU/lbm
P_g	=	Saturated pressure, psi

Greek Symbols

>	=	Spray Efficiency
γ	=	Hx Effectiveness
.	=	Minimum Hx Flowrate, lbs/sec
Δ	=	Density, lbs/ft^3

Subscripts

D	=	Drywell Region
f	=	Final; Saturated Liquid
g	=	Saturated Vapor
S	=	Suppression Pool Liquid Region, Sump
sat	=	Saturated Conditions
spray	=	Spray
SV	=	Suppression Pool Vapor Region
VB	=	Vacuum Breaker

6.2.1.1.5 Suppression Pool Bypass Effects

6.2.1.1.5.1 Protection Against Bypass Paths

The pressure boundary (diaphragm slab) between drywell and suppression chamber including the vent pipes, is fabricated, erected, and inspected by nondestructive examination methods in accordance with and to the acceptance standards of the ASME Code Section III, Subsection NC, 1971 Edition, including addenda through Summer 1972. This special construction, inspection and quality control ensures the integrity of this boundary. The design basis downward pressure differential and temperature for this boundary was established at 28 psid and 340°F which is substantially greater than conditions during a DBA. Actual peak accident differential pressure and temperature for this boundary (diaphragm slab) is provided in Table 6.2-6a.

All penetrations of this boundary except the vacuum breaker seats are welded. All penetrations are available for periodic visual inspection.

All potential bypass leakage paths (such as the purge and vent system) have been considered. Every path has at least two isolation valves in the leakage path. These valves are high quality leaktight containment isolation valves which are all normally closed. Other potential paths are discussed below:

1. Leakage through the diaphragm slab is minimized by the liner plate.

2. Leakage through the downcomers is prevented by the use of seamless pipe.

3. Leakage around the downcomers is minimized because each downcomer is attached to the liner plate by a continuously welded ring plate which is vacuum box tested after welding.

4. Leakage around the SRV discharge piping is minimized by the use of flued head connections.

6.2.1.1.5.2 Reactor Blowdown Conditions and Operator Response

In the event of a small break accident in the drywell, steam released will be collected in the drywell air space, and condensed in the suppression pool after passing through the downcomers. However, it is postulated that a portion of the steam can "bypass" the downcomers, passing directly to the suppression chamber air space via vacuum breaker leakage, diaphragm penetration seals leakage or cracks in the diaphragm concrete. The suppression chamber design pressure could be exceeded unless the blowdown is isolated or the wetwell sprays are actuated. To mitigate this accident, the wetwell sprays are manually operated. Procedures specify spray actuation at a suppression chamber pressure of 13 psig. Analysis shows that there is sufficient time for manual actuation of the sprays to prevent the suppression chamber atmosphere pressure from exceeding the design limit of 53 psig.

6.2.1.1.5.3 Analytical Assumptions

The transient was analyzed in three phases. During the first phase, the drywell is pressurized to the point needed to clear the downcomers. The second phase is the air clearing phase during which the drywell air moves to the suppression chamber. The third phase assumes steam only in the drywell, no further clearing of the downcomer vents, and only steam leaking to the suppression chamber atmosphere.

The drywell and suppression chamber were modelled using two single volume models with the "COPATTA" program. The drywell model was used during Phase I, with two bypass leak sizes of 0.05 and 0.0535 ft^2 studied. Credit was taken for the drywell walls as heat sinks, using the Uchida coefficient as the condensing coefficient. For the small break accident considered, 10 seconds were needed to pressurize the drywell sufficiently to clear the downcomers. The air and steam state points were used as initial conditions for Phase II, air clearing phase. All of the drywell air was assumed to be cleared in one second. In passing through the suppression pool, the air was cooled to the pool temperature before entering the suppression chamber air space. All steam entrained during clearing was assumed to be condensed in the suppression pool.

During Phase I, the air and steam leaked from the drywell model were added to the suppression chamber model. During Phase II, the air cleared was added to the suppression chamber model vapor region at the pool temperature, over a one-second period. During Phase III, the drywell would be filled with only steam. The team leakage into the suppression chamber was based on a 5.18 psid and calculated with the homogeneous frozen flow equation. The drywell steam properties ranged from saturated steam at 35.18 psig to 58.18 psig over a period of 1000 seconds. The upper limit, rather than reflecting the drywell design pressure, accounts for the 5 psig required to clear the downcomers. Credit was taken for suppression chamber walls being heat sinks, with Uchida condensing coefficient used. All 87 downcomers and 6 of 16 main steam relief valve discharge lines were treated as heat sources in the suppression chamber model. During Phase III, steam will be filling the downcomers and 6 SRV discharge lines, and thus a net transfer of heat from the tube surfaces to the suppression chamber atmosphere occurs. Table 6.2-24 lists drywell and suppression chamber initial and boundary conditions.

6.2.1.1.5.4 Analytical Results

For a 0.0535 ft^2 bypass leakage path, it takes 22.6 minutes for the suppression chamber to pressurize from 30 psig to 53 psig.

For a 0.05 ft^2 path, it takes 24.2 minutes to pressurize from 30 psig to 53 psig. Table 6.2-25 summarizes the blowdown data and calculated leakage.

6.2.1.1.6 Suppression Pool Dynamic Loads

Hydrodynamic loads due to main steam safety relief valve discharge and LOCA are described in Reference 6.2-28.

6.2.1.1.7 Asymmetric Loading Conditions

Asymmetric loads considered for the design of the containment structure include horizontal seismic and localized missile and 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 a description of the analytical methods used for missile and pipe rupture loads.

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 Subsection 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.

6.2.1.2 Containment Subcompartments

The containment subcompartments considered for SSES were the biological shield annulus and the drywell head region. The modeling procedures and considerations are presented in Appendix 6A.

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 reactor primary system to the containment system following a LOCA. Where the emergency core cooling systems enter into the determination of energy released to the containment, the single failure criteria has been applied to maximize the energy release to the containment following a LOCA.

6.2.1.3.1 Mass and Energy Release Data

Table 6.2-9 provides the mass and enthalpy release data for the recirculation line break. Figure 6.2-18 shows the blowdown flow rates for the recirculation line break graphically. This data was employed in the DBA containment pressure-temperature transient analyses reported in Subsection 6.2.1.1.3.3.1.

Table 6.2-10 provides the mass and enthalpy release data for the main steamline break. Figure 6.2-20 shows the vessel blowdown flow rates for the main steamline break as a function of time after the postulated rupture. This information has been employed in the containment response analyses presented in subsection 6.2.1.1.3.3.2.

Table 6.2-26 presents the long-term mass and energy release rates for the recirculation line break. This information is shown graphically in Figure 6.2-70.

6.2.1.3.2 Energy Sources

The reactor coolant system conditions prior to the line break are presented in Table 6.2-3a. Reactor blowdown calculations for containment response analyses are based upon these conditions during a LOCA.

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

a. Stored energy in the reactor system
b. Energy generated by fission product decay
c. Heat transfer from piping, vessel walls, and non-fuel hardware.
d. Sensible energy stored in the reactor structures
e. Energy being added by the ECCS pumps
f. Energy released from hydrogen generation and cladding oxidation.

All but the pump heat energy addition is discussed or referenced in this section. The pump heat rate used in evaluating the containment response to the LOCA is discussed in Table 6.2-5a.

Following each postulated accident event, the stored energy in the reactor system and the energy generated by fission product decay will be 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 reactor primary system metal will be transferred to the recirculating ECCS water and will thus contribute to the suppression pool and containment heatup.

6.2.1.3.3 Reactor Blowdown Model Description

The reactor primary system blowdown flow rates were evaluated with the models described in References 6.2-1, 6.2-23 and 6.2-26.

6.2.1.3.4 Effects of Metal-Water Reaction

The containment systems are designed to accommodate the effects of metal-water reactions and other chemical reactions which may occur following a LOCA. The amount of metal-water reaction which can be accommodated is consistent with the performance objectives of the ECCS. Subsection 6.2.5.3 provides a discussion on the generation of metal water hydrogen within the containment.

6.2.1.3.5 Thermal Hydraulic Data for Reactor Analysis

Sufficient data to perform confirming thermodynamic evaluations of the containment has been provided in Subsection 6.2.1.1.3.3 and associated tables.

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

Not Applicable to BWR.

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

Not Applicable to BWR.

6.2.1.6 Testing and Inspection

Preoperational containment testing and inspection programs are described in Section 3.8 and Chapter 14. Operational containment testing and inspection programs are described in Subsection 6.2.6. The requirements and bases for acceptability are described in the Technical Specifications.

6.2.1.7 Instrumentation Requirements

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

Containment airborne radioactivity monitoring is described in Subsection 12.3.4. Containment hydrogen monitoring is described in Subsection 6.2.5.

6.2.1.8 Response to NRC Generic Letter (GL) 96-06

GL 96-06 was issued on September 30, 1996, to address the following issues of concern:

1. Cooling water systems serving the containment air coolers may be exposed to the hydrodynamic effects of water hammer during either a loss-of-coolant accident (LOCA)

or a main steam line break (MSLB). These cooling water systems were not designed to withstand the hydrodynamic effects of water hammer.

2. Cooling water systems serving the containment air coolers may experience two-phase flow conditions during postulated LOCA and MSLB scenarios. The heat removal assumptions for design-basis accident scenarios are based on single-phase flow conditions.

3. Thermally induced overpressurization of isolated water-filled piping sections in containment could jeopardize the ability of accident-mitigating systems to perform their safety functions and could lead to a breach of containment integrity through bypass leakage.

PPL's response and NRC's acceptance are documented in Reference 6.2-31 through 6.2-42. The following sections are a summary of PPL's response to Generic Letter 96-06.

6.2.1.8.1 Drywell Cooling Water hammer and Two-Phase Flow

6.2.1.8.1.1 Containment Cooling

The SSES drywell cooling system is a non-safety-related system which is used to maintain containment temperature within acceptable limits during normal plant operations. The drywell cooling system automatically isolates on a Loss of Coolant Accident (LOCA) signal, and is not required to mitigate the consequences of a LOCA. Since the drywell cooling system is not credited in the SSES design bases, the potential for a drywell cooling water hammer or two-phase flow to affect containment cooling is not a concern.

6.2.1.8.1.2 Containment Integrity

Although the drywell cooling system is non-safety-related, it represents a viable form of containment heat removal during specific plant transients. The SSES Emergency Operating Procedure allow for its restoration and operation under transient conditions.

An evaluation of the restoration and operation of the drywell cooling system under transient conditions identified the possibility for a hydraulic transient during the restoration of drywell cooling. A calculation was performed, and concluded that the loads induced by the postulated hydraulic transient are relatively small and would not result in pipe or component stresses above allowable values. Therefore, the loads induced by a postulated water hammer will not impact containment integrity.

6.2.1.8.1.3 Closed Loop System Overpressurization

An evaluation of containment piping networks revealed that the only systems susceptible to this phenomenon are the non-safety related Reactor Building Closed Cooling Water (RBCCW) and Reactor Building Chilled Water (RBCW) systems, and the Drywell Floor Drain Sump discharge lines.

6.2.1.8.1.3.1 Reactor Building Closed Cooling Water/Reactor Building Cooling Water (RBCCW/RBCW)

The RBCCW and RBCW systems supply non-safety-related cooling loads. The potential for the rupture of these systems due to overpressurization does not threaten the availability of safety-related equipment needed to mitigate Design Basis Accidents. Further, this piping is assumed to be available during Design Basis Accidents, and is not credited in any SSES safety analyses.

6.2.1.8.1.3.2 Drywell Floor Drain Sump

The Drywell Floor Drain Sump system is a non-safety-related system and is not required for the accident mitigation. The pump discharge piping is subject to thermally induced pressurization between the pump discharge check valves and the inboard containment isolation valve. However, this piping will only pressurize if all four pump discharge check valves are leak tight. These check valves prevent gross leakage during sump pump operation and are not leak tight. Based on the valve not being leak tight, the failure of this piping due to excessive pressurization is not expected.

6.2.1.8.2 Containment Penetration Overpressurization

An evaluation of containment penetrations revealed that a total of twelve penetrations (per unit) are susceptible to the thermal pressurization phenomenon. These penetrations are:

1. X-23 & X-24 – the RBCCW supply and return lines to the recirculation pump seals and motor oil coolers;
2. X-53, X-54, X-55 & X-56 – the RBCW supply and return lines to the drywell coolers
3. X-85A, X-85B, X-86A, X-86B – the RBCW supply and return lines to the recirculation pump motor coolers;
4. X-61A – the Demineralization Water line to the drywell; and,
5. X-17 – the Residual Heat Removal (RHR) head spray line.

The RBCCW and RBCW containment penetrations support non-safety-related loads and automatically isolate on conditions indicative of a LOCA. The Demineralized Water system provides a source of clean water to the drywell for refueling outage maintenance activities, and is isolated prior to and during postulated accidents. Although the head spray line is part of the RHR system, it does not perform any safety-related function. Therefore, the potential for overpressurization of all susceptible penetrations does not affect the availability of safety-related equipment needed to mitigate Design Basis Accidents. The only safety-related function of these penetration assemblies (i.e., piping and valves) is to act as a containment barrier; in the post accident environment, these penetrations are not required to support any active safety-related function.

Since the RHR system will be operating during the post-accident time frame, the potential for overpressurization of the head spray penetration to impact the RHR systems, pressure boundary was also evaluated. Various failure modes were considered and it was determined that the worst case rupture induced by overpressurization of this penetration will not result in a breach of the operating system's pressure boundary. As such, RHR system operation, as well as primary containment integrity is unaffected.

The process piping located between the containment isolation valves associated with each penetration was evaluated using the criteria provided in the ASME Boiler & Pressure Vessel Code, Section III, Appendix F. Paragraph F-1430 has been used as a basis for calculating the allowable stresses. The results of the evaluation are:

- The predicted maximum pressures for all of the lines are within the allowable pressure limits
- All of the piping stresses are within allowable Appendix F limits
- For all of the penetrations, pressure relief will occur via a leakage path rather than through a catastrophic pressure boundary failure
- Gross failure of the valves is not expected

6.2.2 CONTAINMENT HEAT REMOVAL SYSTEM

6.2.2.1 Design Basis

The containment heat removal system, consisting of the containment cooling system, is an integral part of the RHR system. This system prevents excessive containment temperatures and pressures following a LOCA so that containment integrity is maintained. To fulfill this purpose, the containment cooling system meets the following safety design bases:

a. The system shall limit the long term bulk temperature of the suppression pool without spray operation when considering the energy additions to the containment following a LOCA. (See Reference 6.2-4.) These energy additions, as a function of time, are provided in the previous section.

b. The single failure criteria shall apply to the system.

c. The system shall be designed to safety grade requirements including the capability to perform its function following a Safe Shutdown Earthquake.

d. The system shall maintain operation during those environmental conditions imposed by the LOCA.

e. Each active component of the system shall be testable during normal operation of the nuclear power plant.

6.2.2.2 Containment Cooling System Design

Containment cooling is initiated in loop A or B by manually starting the RHR service water pump, opening the service water valve at the heat exchanger and opening the pool return valve. The containment cooling system is an integral part of the RHR system. Water is drawn from the suppression pool, pumped through one or both RHR heat exchangers and delivered to the suppression pool, to the containment spray header, or to the suppression pool vapor space spray header. Water from the RHR service water system is pumped through the heat exchanger tube side to exchange heat with the processed water. Two cooling loops are provided; each is mechanically and electrically separate from the other to achieve redundancy. P&ID is provided in Section 5.4. The process diagram, including the process data, is provided in Section 5.4 for all design operating modes and conditions.

All portions of the containment cooling system 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 Subsection 5.4.7.

The containment cooling function is aligned manually. There are no signals that automatically initiate the containment cooling function. LPCI mode is automatically initiated from ECCS signals and the RHR system aligned for containment cooling when directed by emergency procedures. As an alternative, with one LPCI injection pump in service in an RHR loop, an RHR heat exchanger may be manually aligned for long term containment cooling by limiting LPCI Injection flow to 10,000 gpm and directing flow through the RHR heat exchanger by closing the HV151F048A(B) valve. The RHRSW system must also be manually initiated to supply cooling water to the heat exchanger. Only one RHR heat exchanger is credited for long term cooling in the SSES containment analysis. If a single failure has occurred, and the action which the plant operator is taking does not result in system initiation, then the operator will place the other totally redundant system into operation by following the same initiation procedure. Containment spray is also manually aligned when directed by Emergency Procedures.

In addition to the post-accident heat removal function, the RHR system may be utilized in the suppression pool cooling mode for periods during normal plant operation. LOCA Analyses which account for a delayed LPCI injection due to the automatic realignment from suppression pool cooling indicate that acceptable peak cladding temperatures are maintained. Further, design and licensing basis analyses which address the system's response to design basis LOCA/LOOP events, while in the suppression pool cooling configuration, demonstrate that a usage of up to 10% (maximum allowed without management review) is acceptable.

Preoperational tests are performed to verify individual component operation, individual logic element operation, and system operation up to the drywell spray spargers. A similar sparger nozzle is bench-tested in the manufacturer's laboratory to substantiate the performance data established from hydraulic calculations. Finally, the spargers are tested by air, and some visible indication means is provided to verify that all nozzles are clear.

6.2.2.3 Design Evaluation of the Containment Cooling System

In the event of the postulated LOCA, the short term energy release from the reactor primary system will be dumped to the suppression pool. This will cause a pool temperature rise of approximately 35^{o}F. Subsequent to the accident, fission product decay heat will result in a continuing energy input to the pool. The containment cooling system will remove this energy, which is input to the primary containment system, thus resulting in acceptable suppression pool temperatures and containment pressures.

The insulation used within containment is predominantly all metal, reflective type. The other insulation types used in containment are phenolic foam insulation, fibrous insulation and Min-K insulation.

The reflective metallic insulation consists of large assemblies held in place by stainless steel latches. The latches are equipped with positive locking devices. The maximum weight for each assembly is 40 pounds. Each assembly consists of two half segments which overlap each other at longitudinal joints.

Phenolic foam insulation is a closed cell, low specific gravity material which, if transported to the suppression pool, would float. The phenolic foam is only used on the Reactor Building Chilled Water piping and is jacketed with stainless steel wherever practical.

Fibrous insulation is used in miscellaneous applications where the use of other insulation types is not practical. The total quantity of fibrous insulation is minimal.

Min-K insulation is used under pipe whip restraints and is significantly shielded from direct jet impact. All Min-K insulation is encapsulated in stainless steel cassettes.

For a representative large pipe break inside containment, it is difficult to estimate the actual amount of insulation that would be dislodged. But, assuming that several segments would be removed from the broken pipe and several more from the pipes in close proximity to the impingement jet, there would be a relatively small amount of insulation loose in the drywell area. This loose insulation could accumulate in many areas of the drywell including platforms, other piping and equipment. Another possible area would be the downcomer openings through the diaphragm floor. It would be unlikely that the relatively larger pieces of insulation would pass through the small openings at the top of the 87 downcomers. These openings are made smaller by the presence of jet deflectors as shown in Figure 6.2-56. Even so, the suction strainers on the CS and RHR pumps are sized assuming that conservative amounts of insulation transport to the suppression pool after a LOCA and that the insulation is filtered by the strainers.

Small pipe breaks are not expected to create significant debris. In addition, the drywell floor flood-up rate would be low for small breaks and the water height above the 87 downcomer weirs would be small. Therefore, the potential for any debris created by a small pipe break to be transported to the suppression pool is minimal. HPCI is designed to support small pipe breaks that do not cause rapid depressurization of the reactor vessel. The HPCI suppression pool suction strainers are conservatively designed for 50% plugging, even though small pipe breaks are not expected to result in significant debris in the suppression pool.

The RCIC suppression pool suction strainers are also designed for 50% plugging. RCIC is not an ECCS system. As such, accident analyses do not assume that RCIC will respond to any events (pipe breaks) that would result in the generation of debris or transport of debris to the suppression pool. Nonetheless, RCIC may be called upon to mitigate the effects of small pipe breaks. Such pipe breaks would not result in significant debris in the suppression pool as explained above.

The primary suction source for HPCI and RCIC is the Condensate Storage Tank (CST). This further reduces the probability that the HPCI and RCIC suppression pool suction strainers would be fouled even if the debris resulting from a small pipe break reached the suppression pool.

6.2.2.3.1 Summary of Containment Cooling Analysis

When calculating the long term, post LOCA pool temperature transient, it is assumed that the initial suppression pool temperature is at its maximum Technical Specification value. The containment analyses also assume RHR service water is at its peak design temperature of 97 F throughout the transient. Note however that a sensitivity analysis has been performed which credits a lower, yet conservative, RHR service water temperature for the first 2 hours of the containment analyses (91 F). This change justifies an increase in operator response time to initiate containment cooling during accident conditions from 10 minute to 20 minutes. Although the containment analyses were not rerun with an operator response time of 20 minutes at the reduced RHRSW temperature for the first two hours, the sensitivity analysis concludes that the peak suppression pool temperatures calculated in the long term DBA/LOCA containment analyses (which are based on an operator response time of 10 minutes) remain valid and bounding. These assumptions maximize 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 a fully fouled condition at the time the accident occurs. This conservatively minimizes the heat exchanger heat removal capacity. The resultant suppression pool temperature transient is described in Subsection 6.2.1.1.3.3.1 and is shown on Figure 6.2-8. Even with the degraded conditions outlined above, the maximum temperature is 211.2^{o}F. This peak occurs at approximately 9.6 hours after the accident.

When evaluating this long term suppression pool transient, all heat sources in the containment are considered. These heat sources are discussed in Subsection 6.2.1.3. Figure 6.2-9 shows the actual heat removal rate of the RHR heat exchanger.

The conservative evaluation procedure described above demonstrates that the RHR system in the suppression pool cooling mode limits the post-DBA containment temperature transient.

6.2.2.4 Tests and Inspections

The preoperational test program of the containment cooling system is described in Chapter 14.

Inservice testing of the pumps and valves in the containment heat removal systems will be in accordance with ASME Code as discussed in FSAR Section 3.9.6. An 18-inch line which is routed from the combined pump discharge back to the suppression pool is provided for RHR pump testing. Installed instrumentation is provided for measuring pump inlet and discharge pressure, and flow rate. Temperature of the pumped fluid at the pump inlet and combined discharge is recorded. All pump bearings are lubricated by the fluid being pumped; therefore, indication of bearing temperature is not required by the Code. Portable equipment will be required for testing vibration amplitude.

Leak rate testing of containment isolation valves is discussed in Section 6.2.6. All power-operated valves in the RHR system/containment cooling mode may be exercised during normal operation. The RHR pump discharge check valve has local disc position indicators on the valve hinge pin for verification of operability.

Inservice inspection will be in accordance with ASME Code Section XI, as discussed in FSAR Section 5.2.4.

6.2.2.5 Instrumentation Requirements

The details of the instrumentation are provided in Section 7.3. The suppression pool cooling mode of the RHR system is manually initiated from the control room.

6.2.3 SECONDARY CONTAINMENT FUNCTIONAL DESIGN

The secondary containment comprises the exterior structure of reactor building and the interior walls and floors that separate the three ventilation zones.

Zones I and II are the portions of the reactor building below elevation 779 ft. 1 in. surrounding the Unit 1 and Unit 2 primary containments, respectively.

Zone III consists of the portion of the reactor buildings above elevation 779 ft. 1 in. with the exception of the HVAC equipment rooms which are not part of the secondary containment.

The secondary containment houses the refueling and reactor servicing equipment, the new and spent fuel storage facilities, and other reactor auxiliary or service equipment, including the Reactor Core Isolation Cooling System, Reactor Water Cleanup System, Standby Liquid Control System, Control Rod Drive System equipment, the Emergency Core Cooling System, and electrical equipment components.

6.2.3.1 Design Bases

The functional capability of the ventilation system to maintain negative pressure in the secondary containment with respect to outdoors is discussed in Subsections 6.5.1.1 and 9.4.2.

The conditions that could exist following a LOCA require the establishment of a method of controlling the leakage from the primary into the secondary containment.

6.2.3.2 System Design

6.2.3.2.1 Secondary Containment Design

The reactor building is designed and constructed in accordance with the design criteria outlined in Chapter 3. The base mat, floor slabs and exterior walls below the refueling floor are constructed of reinforced concrete. Above the refueling floor at elevation 818 ft. 1 in., the building consists of a structural steel frame supporting an insulated metal roof deck and insulated siding wall panels.

Joints in the superstructure paneling are designed to ensure leaktightness. Penetrations of the reactor building are designed with leakage characteristics consistent with leakage requirements of the entire building. The reactor building is designed to limit the inleakage to 140 percent of the secondary containment free volume per day at -¼ in. wg, while operating the SGTS. The building structure above the refueling floor is also designed to contain a negative interior pressure of 0.25 in. wg.

Following a loss-of-coolant accident, all affected volumes of the secondary containment will be maintained at a negative pressure of 0.25 in. w.g. All these volumes are identified on Figures 6.2-24, 6.2-25, 6.2-26, 6.2-27, 6.2-28, 6.2-29, 6.2-30, 6.2-31, 6.2-32, 6.2-33, 6.2-34, 6.2-35, 6.2-36, 6.2-37, 6.2-38, 6.2-39, 6.2-40, 6.2-41, 6.2-42, and 6.2-43 as Ventilation Zones I, II and III.

An analysis of the post LOCA pressure transient in the secondary containment has been performed to determine the length of time following LOCA signal that the pressure in the secondary containment would exceed -¼ in. wg. The analysis assumed that the normal ventilation system was operating at the design pressure of -¼ in. w.g. until the E.S.F. signal isolated the system and initiated SGTS startup. An inleakage rate of 140% of secondary containment per day was used. A single failure of one SGTS train was assumed as well as a loss of offsite power to maximize the drawdown time. Heat loads from operating equipment and the heat transferred through the drywell head were considered. Each SGTS fan has a rated capacity of 10,500 CFM at a 17 in. w.g. pressure. Figure 6.2-60 shows the secondary containment pressure vs time for the drawdown under worst conditions. The secondary containment pressure recovers to -¼ in. w.g. within 5 minutes. The completion of the leakage path resulting from the activity release mechanisms inside the containment, leakage through the primary containment and possible leakage through the secondary containment would require a significantly greater period of time than would exist until the -¼ in. w.g. was restored.

Entrance to the reactor building is through the turbine building with air locks provided for separation. Access doors between building ventilation zones and into the control structure are provided with airlocks. Secondary containment access doors which are not provided with airlocks are administratively controlled to maintain secondary containment integrity.

The railroad access shaft, provided in Unit 1 only, is accessible to Zones I and III through access hatches that are normally kept closed and will not be opened without proper controls to maintain secondary containment integrity during normal plant operation. Ventilation supply and return ducting to the railroad access shaft is provided with manual isolation dampers to provide for opening the exterior railroad access door after closing the dampers, thus converting to an airlock and retaining secondary containment integrity. Operation of these dampers and the railroad access doors and hatches is administratively controlled. Doors within the secondary containment may be used for personnel ingress and egress during normal plant operation. The truck bay is part of Zone II. The truck bay access hatch will be normally closed. Opening of this hatch and the truck bay door (No. 102) will be administratively controlled.

The boundaries of the three zones of the secondary containment are shown on Figures 6.2-24, 6.2-25, 6.2-26, 6.2-27, 6.2-28, 6.2-29, 6.2-30, 6.2-31, 6.2-32, 6.2-33, 6.2-34, 6.2-35, 6.2-36, 6.2-37, 6.2-38, 6.2-39, 6.2-40, 6.2-41, 6.2-42 and 6.2-43.

The secondary containment design data can be found in Table 6.2-17.

A simplified air flow diagram for the secondary containment normal plant operation is shown on Figure 6.2-53. Figure 6.2-52 shows the simplified air flow diagram when Zone I or II and Zone III are isolated. An air flow diagram for Zone III isolation is shown on Figure 6.2-54.

6.2.3.2.2 Secondary Containment Isolation System

Isolation dampers and the plant protection signals that activate the secondary containment isolation system are described in Subsection 9.4.2.1.3.

6.2.3.2.3 Secondary Containment Bypass Leakage (SCBL)

The secondary containment structure completely encloses the primary containment structure such that a dual-containment design is utilized to limit the spread of radioactivity to the environment during a design basis LOCA. Following a LOCA, the secondary containment structure is maintained at a negative pressure, so that leakage from primary containment to secondary containment can be collected and filtered prior to release to the environment. SGTS performs the function of maintaining a negative pressure within secondary containment, as well as, collecting and filtering the leakage from primary containment, as described in Section 6.5.

The use of a dual-containment design results in the potential for Secondary Containment Bypass Leakage (SCBL). SCBL is defined as that leakage from primary containment which can bypass the leakage collection/filtration systems of secondary containment and escape directly to the environment. Similarly, a potential SCBL pathway is defined as any process line that penetrates both primary and secondary containment, or a process line that penetrates primary containment only, with a branch line connection that penetrates secondary containment. Consequently, a valid SCBL pathway is any process line or branch line that penetrates both primary and secondary containment which does not contain a barrier that eliminates bypass leakage from being released directly to the environment.

All potential SCBL pathways have been evaluated. It has been determined that the bypass leakage which could occur following the design basis LOCA results in a conservatively calculated dose within regulatory limits, as described in Section 15.6.5.

Table 6.2-15 identifies those lines penetrating primary containment which do not terminate inside Secondary Containment, as well as, those lines that penetrate primary containment with branch line connections that penetrate secondary containment. The potential SCBL pathways listed in Table 6.2-15 were evaluated to determine if the leakage barriers utilized in these act to eliminate or only limit SCBL. Leakage from those lines terminating in the secondary containment will be collected during the LOCA since the secondary containment is maintained at subatmospheric pressure and all exhaust is processed by the SGTS during these modes (Section 6.5). Therefore, lines terminating within the secondary containment are not considered potential bypass leakage paths and are not listed in Table 6.2-15.

The types of bypass leakage barriers employed by these lines are:

a. Isolation valve(s) inside and/or outside primary containment

b. Leakage collection system

c. Water seal in line

Leakage barriers of types B or C are considered to effectively eliminate any bypass leakage. Type C barriers have sufficient water volume available to maintain the seal for 30 days, as described in Section 6.2.3.2.3.1. Type B barriers insure that any leakage through containment isolation valves is routed through the SGTS filter train before being exhausted to the environment. Type A leakage barriers are considered to limit but not eliminate bypass leakage. Consequently, any potential SCBL pathways that contain only Type A leakage barriers are identified as valid SCBL pathways in Table 6.2-15. Closed systems with non-seismic piping are not relied upon as barriers to eliminate bypass leakage.

Leakage barriers in those lines confirmed to be valid SCBL pathways are periodically tested in a manner consistent with the guidance provided in Subsection 6.2.6 for performing 10CFR50, Appendix J Type B or C tests. The total combined leakage from all valid SCBL pathways is maintained less than or equal to the value specified for SCBL in the Technical Specifications and the DBA LOCA dose analysis value described in Section 15.6.5. Those penetrations for which credit is taken for water seals as a means of eliminating bypass leakage (Table 6.2-15) are tested as described in section 6.2.3.2.3.1.

As shown on Table 6.2-15, the only containment penetrations with lines penetrating both primary and secondary containment are:

- X-9A/B Feedwater Lines
- X-16A/B Core Spray Injection
- X-17 RHR Head Spray
- X-25 Drywell Purge & N_2 Supply*
- X-39A/B RHR Drywell Spray
- X-61A Demineralized Water Connection to Drywell
- X-88A N_2 Make-up to Drywell
- X-201A Wetwell Purge & N_2 Supply*
- X-220B N_2 Make-up to Wetwell

*(Only when the spectacle flange is not closed, see Table 6.2-15)

A valve maintenance and test program limits the total combined leakage through the primary containment isolation valves for these paths to less than that assumed for SCBL in the DBA LOCA Dose analysis described in Section 15.6.5. The test program and leakage limits are given in the Technical Specifications. All other lines listed in Table 6.2-15 were investigated as potential SCBL pathways but, for the reasons given in the table, were shown not to be valid SCBL paths.

6.2.3.2.3.1 Water Seals

Where water seals are used to eliminate the potential of secondary containment bypass leakage, the location of the water seal relative to the system isolation valves can be seen on the system P&IDs and also in Figures 6.2-66B, 6.2-66C, 6.2-66D, 6.2-66H, 6.2-66F, and 6.2-66G. In each case, either a loop seal is present or the water for the seal is replenished from a large reservoir; water seal maintenance is not dependent on a water sealing system.

Where maintenance of the water/loop seal is dependent upon the performance of the primary containment isolation valves, the penetrations have Technical Specification leakage rates for periodic testing given as water leak rates which meet the requirements for hydraulic testing in 10CFR50 Appendix J. Those penetrations for which credit is taken for water seals that do not meet the requirements of Appendix J for water sealing systems or do not rely upon containment isolation valves to maintain the water seal, are conservatively tested to meet pneumatic Technical Specification leakage rates for periodic testing.

A description of the water seals used to eliminate potential SCBL pathways is contained in the notes to Table 6.2-15.

6.2.3.3 Design Evaluation

The design evaluation of the secondary containment ventilation system is given in Subsections 6.5.1 and 9.4.2. The high energy lines within the secondary containment are identified and pipe ruptures analyzed in Section 3.6.

6.2.3.4 Tests and Inspections

The program for initial performance testing is described in Chapter 14. The program for periodic functional testing of the secondary containment isolation system and system components is described in the Technical Specifications.

6.2.3.5 Instrumentation Requirements

The control systems to be employed for the actuation of the reactor building Engineered Safety Feature air handling systems are described in Section 7.3.

The control and monitoring instrumentation for the above systems is discussed in Subsections 6.5.1 and 9.4.2.

6.2.4 CONTAINMENT ISOLATION SYSTEM

The containment isolation system consists of piping, valves and valve actuating means that provide capability for closing penetrations of the primary containment.

6.2.4.1 Design Bases

a. Containment isolation valves provide the necessary isolation of the containment in the event of accidents or other conditions. They limit the release of radioactive materials from the containment by maintaining leakage within the limits specified in the Leak Rate Test Program. For the DBA LOCA dose consequence analysis (see Section 15.6), the assumption is made that all containment isolation valves that are required to be closed (valves listed in Table 6.2-12 that are closed during LOCA) have completed their travel prior to the assumed release of gap activity from the fuel. The gap activity release is assumed to occur 2 minutes following the initiation of the event.

b. Nuclear steam supply system isolation valve closure speed limits radiological effects from exceeding guideline values established by 10CFR 50.67.

c. The design of isolation valving for lines penetrating the containment follows the requirements of General Design Criteria 55 through 56 as described in Subsection 6.2.4.3, Table 6.2-12, and Figures 6.2-44 through 6.2- 44M. Deviations from the explicit requirements of GDC 54 through 56 are discussed in Section 6.2.4.3 and Table 6.2-12, including the notes.

d. Isolation valving for instrument lines that penetrate the containment conforms to the requirements of Regulatory Guide 1.11 (3/71).

e. Containment isolation valves and associated piping including closed piping systems used as isolation barriers, meet the requirements of the ASME Boiler and Pressure Vessel Code Section III Classes 1 or 2, as applicable.

f. Design of the containment isolation valves and associated piping and penetrations shall be Seismic Category I.

g. The primary containment isolation systems have the capability to withstand the design pressure and temperature, which are derived from the design basis LOCA.

h. The primary containment can withstand both normal and accident metal/water reactions without degradation of capability below design limits.

i. Redundancy and physical separation are provided in the electrical and mechanical design. This ensures that no single failure in the Containment Isolation system (i.e. barriers or actuation systems) prevents the system from performing its intended functions.

j. Isolation valves, actuators, and controls are protected against loss of safety function from missiles, pipe whip, jet impingement and accident environments. See Subsection 3.6.2 for protection of containment penetration isolation valves and piping.

k. The containment isolation systems close those fluid penetrations that support systems not required for emergency operation. Fluid penetrations supporting engineered safety feature systems have remote manual isolation valves that may be closed from the control room. Appropriate isolation valves (other than check valves) are automatically closed by the signals listed in Table 6.2-12. The criteria for assigning isolation signals to their associated isolation valves are described in Subsection 7.3.1.1.2. Once the isolation function is initiated, it operates to completion.

6.2.4.2 System Design

The general criteria governing the design of the Containment isolation systems are provided in Subsections 6.2.4.1 with related criteria in Subsection 3.1.2. Table 6.2-12 lists the containment penetrations which are Type C tested and presents design information about each.
Table 6.2-12a lists those penetrations which contain instrument lines isolated by excess flow check valves.

Accompanying this table is Figure 6.2-44, which consists of diagrams for the various isolation valve arrangements. For the particular systems that penetrate the containment, listed in Table 6.2-12, a cross reference is provided to depict the respective isolation valve arrangement in Figures 6.2-44A, 6.2-44B, 6.4-44C, 6.2-44D, 6.4-44E, 6.2-44F, 6.4-44G, 6.2-44H, 6.4-44I, and 6.2-44J.

Isolation valves are designed to be operable under environmental conditions such as maximum differential pressures, extreme seismic occurrences, steam laden atmosphere, high temperature, and high humidity. The normal and accident environmental conditions are described in Section 3.11. Electrical redundancy is provided for power operated valves. Power for the actuation of two isolation valves in a line (inside and outside containment) is supplied by two redundant, independent power sources without cross ties. In general, outboard isolation valves receive power from the Division II power supply, while isolation valves within the containment or containment extensions receive power from the Division I power supply. ECCS penetrations are exceptions. In each case the supply may be ac and/or dc, depending upon the system under consideration.

All power-operated containment isolation valves are capable of being remote-manually operated from the main control room. Note #2 to Table 6.2-12 identifies all the automatic signals which effect containment isolation; these actuation signal codes are listed in the column in the table entitled "Actuation Signal." Therefore, where no actuation signal code is listed for a particular power-operated valve, reliance for effecting containment isolation is upon remote-manual operation.

Leakage detection is discussed in Section 5.2.5. In addition to the leak detection provisions discussed therein, ECCS and ESF pump rooms are provided with flooding alarms which annunciate in the control room. Floor drains in these rooms are normally isolated, such that any leakage is confined to the respective room. Certain power-operated valves which are not provided with automatic isolation signals are physically located within those rooms. Consequently, leakage to the reactor building from any of the corresponding lines can be identified by the control room operator, who can then remote-manually isolate the affected system.

The other category of power-operated valves which are not provided with automatic isolation signals are those in ECCS systems (other than the valves just described) which are required to operate after an accident. Each ECCS system is designed with two 100% redundant loops. Sometime after initiation of the ECCS systems, the control room operator can exercise his discretion to isolate unnecessary ECCS loops. Additionally, ECCS system return lines (including recirculation lines) are provided with check valves which afford short-term leakage control in event of a passive failure outside containment until positive closure of associated power operated containment isolated valves can be achieved by operator action. Some of these lines may also rely upon a closed system to provide a redundant long-term barrier in addition to or instead of a positive closure valve.

The third category of non-automatic power-operated valves are those in lines which, although not ECCS systems, provide a positive inflow of water to the reactor. These lines are equipped with check valves which will provide short-term leakage control until positive closure of associated power-operated containment isolation valves is achieved by operator action after the lines are no longer contributing water to the reactor.

All of the lines discussed above are designed as Class B, Seismic Category I, and missile protected outside primary containment. Thus, only one passive failure is postulated in all of these lines. The reactor building will contain any postulated leakage, and the standby gas treatment system will filter any airborne release.

The containment instrument gas supply to the MSS/RVs with auto depressurization function will be at a higher pressure than the post-accident containment atmosphere, thus, small leaks outside containment will not create a radioactive release. In the event of a passive failure outside containment, the check valve inside containment will provide short-term leakage control. When the instrument gas header pressure falls below the low pressure setpoint, an alarm will be actuated in the main control room to alert the operator to remote-manually isolate the affected line. The standby gas treatment system can filter any leakage until positive isolation is obtained by operator action.

Standby liquid system isolation provisions are discussed in Subsection 6.2.4.3.2.5. The RHR heat exchanger vent valves are discussed in Subsection 6.2.4.3.6.4.

The main steamline isolation valves 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 main steamline isolation valve has a gas accumulator to assist in its closure upon loss of air supply, loss of compressed gas supply, loss of electrical power to the pilot valves, and/or failure of the loading spring. The separate and independent action of either gas pressure or spring force is capable of closing an isolation valve.

Motor-operated isolation valves will remain in their last position upon failure of valve power, and air operated containment isolation valves will close upon loss of air or electrical power.

The design of the isolation valve system (i.e., valves and piping between the valves) gives consideration to the possible adverse effects of sudden isolation valve closure when the plant systems are functioning under normal operation.

6.2.4.3 Design Evaluation

6.2.4.3.1 Evaluation Against General Design Criterion 54

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

6.2.4.3.1.1 Operability and Leak Tests

Operability and leak rate testing of isolation valves is discussed in Subsection 6.2.4.4. Leak detection for piping between inboard and outboard isolation valves is discussed in Subsection 5.4.5.

6.2.4.3.1.2 Testing of Instrument Root Valves

The Instrument Isolation Valves associated with the Technical Specification Bases Section B 3.6.1.1 and TABLE B 3.6.1.1-1 shall be tested in accordance with Susquehanna's LEAKAGE RATE TEST PROGRAM. The Instrument Root Valves' leak rate are not added to the 10CFR50, Appendix J limits since the valves are only used during maintenance activities.

6.2.4.3.2 Evaluation against General Design Criterion 55

6.2.4.3.2.1 Feedwater Line

Each feedwater line forming a part of the reactor coolant pressure boundary is provided with three check valves for containment isolation. A nonslam type check valve is located inside the containment, while a simple swing check valve is located immediately outside containment, followed by a motor operated stop check valve which provides long term isolation capability. Three containment isolation valves are provided for each feedwater line since the operability of the check valve inside containment cannot be assured following a feedwater line break inside containment (see Subsection 3.6.1.2.2).

During a postulated LOCA, it is desirable to maintain reactor coolant makeup from all available sources. It would not improve safety to install a feedwater isolation valve that closed automatically on signals indicating a LOCA and thereby eliminate a source of reactor makeup. The provision of the check valve, however, ensures the prevention of a significant loss of reactor coolant inventory and offers immediate isolation if a break occurs in the feedwater line. For this reason, the outermost valve does not automatically isolate upon signal from the protection system. The valve is remote manually closed from the main control room to provide redundant isolation means and long term leakage protection. The operator will determine if make-up from the feedwater system is unavailable by use of the Feedwater Flow Indicator which will show high flow or no flow for feedwater pipe break or no flow for feedwater pump trip.

The operator will determine whether make-up from the feedwater system is unnecessary if the ECCS is functioning properly and reactor water is at normal level. ECCS operation signals are provided in the main control room and a level indicator continuously monitors the water level in the reactor vessel.

Since it is not necessary to isolate the feedwater, there is no need to alert the operator to initiate the isolation signal. However, for long-term isolation purposes, the operator may manually close the motor-operated check valve at any convenient time.

The RCIC, HPCI, and Reactor Water Cleanup System (RWCU) pump discharges connect to the feedwater system between the two outside containment isolation valves in each feedwater line. The HPCI and RCIC systems are provided with a remote manual motor operated stop valve for isolating the system from the feedwater system, and to provide positive long term containment isolation. RWCU is provided with a simple check valve to provide automatic short term containment isolation, and a manual motor operated valve for long term containment isolation. These valves also serve as the second isolation valve for a feedwater line break inside primary containment. Also, these lines connect to the feedwater lines within the reactor coolant pressure boundary (RCPB), which stops at, but includes the outermost stop check valve.

6.2.4.3.2.2 Recirculation Pump Seal Water Supply Line

The recirculation pump seal water line extends from the recirculation pump through the drywell and connects to the CRD supply line outside the primary containment.

The seal water line forms a part of the reactor coolant pressure boundary, therefore the consequences of failing this line have been evaluated. This evaluation shows that the consequences of breaking this line are less severe than those of failing an instrument line. The recirculation pump seal water line is I in, Class B from the recirculation pump through a check valve located inside the containment and an excess flow check valve outside the containment. From this valve to the CRD connection the line is Class D. Should this line be postulated to fail and either one of the check valves is assumed not to close (single active failure), the flow rate through the broken line would be substantially less than that permitted for a broken instrument line. Therefore, the two check valves in series provide sufficient isolation capability for postulated failure of this line.

6.2.4.3.2.3 Control Rod Drive Lines

The control rod drive system insert and withdraw lines penetrate the drywell.

The CRD insert and withdrawal lines are not part of the reactor coolant pressure boundary, since they do not directly communicate with the reactor coolant. The classification of these lines is quality group B, and they are designed in accordance with ASME Section III, Class 2. The basis on which the CRD insert and withdrawal lines are designed is commensurate with the safety importance of maintaining the pressure integrity of these lines.

It has been accepted practice not to provide automatic isolation valves for the CRD insert and withdrawal lines to preclude a possible failure mechanism of the scram function. The control rod drive insert and withdrawal lines can be isolated by the solenoid valves outside the primary containment. The lines that extend outside the primary containment are small and terminate in a system that is designed to prevent out-leakage. Solenoid valves normally are closed, but open on rod movement and during reactor scram. In addition, a ball check valve located in the control rod drive flange housing automatically seals the insert line in the event of a break. Finally, manual shutoff valves are provided. Potential water leakage from the CRD insert/withdrawal lines is measured by venting the non-seismic headers following an ILRT as discussed in note 20 to Table 6.2-22. To preclude the possibility of post-LOCA leakage entering the Turbine Building via the CRD lines, check valves have been installed near the Reactor/ Turbine Building Wall in a segment of CRD piping designed in accordance with ASME Section III, Class 3. These check valves maintain a 30 day water seal in the CRD pump discharge header and are tested as described in Section 6.2.3.2.3.1.

6.2.4.3.2.4 RCIC System Steamlines

The RCIC turbine steam supply line from main steamline C is provided with two motor-operated, normally-open gate valves - one inside and one outside the containment - and one normally-closed, air operated bypass valve inside containment. The RCIC turbine exhaust isolation is described in Subsection 6.2.4.3.3, and the pump discharge in Subsection 6.2.4.3.2.1.

6.2.4.3.2.5 Standby Liquid Control System Lines

The standby liquid control system line penetrates the drywell and connects to the reactor pressure vessel. In addition to a simple check valve inside the drywell, a motor operated normally open globe stop check valve is located outside the drywell. Because the standby liquid control line is a normally closed, nonflowing line, rupture of this line is extremely remote. A third valve provides an absolute seal for long term leakage control as well as preventing leakage of sodium pentaborate into the reactor pressure vessel during normal reactor operation.

6.2.4.3.2.6 Reactor Water Cleanup System

The RWCU system line from the recirculation loop and RPV drain to the RWCU pumps suction is provided with normally open motor operated gate valves, one inside and one outside the containment. The return line from the pumps discharge and the regenerative heat exchangers to the feedwater line is described in Subsection 6.2.4.3.2.1. An additional check valve is provided in the return line so that a break in the RWCU system will not cause a loss of coolant inventory.

6.2.4.3.2.7 HPCI System Steamlines

The HPCI system turbine steam supply line from main steamline B is provided with motor operated normally open gate valves, one inside and one outside containment. A normally-closed, air-operated globe valve is also provided in parallel with the inboard gate valve. These valves are closed on receipt of a HPCI isolation signal. The HPCI turbine exhaust isolation is described in Subsection 6.2.4.3.3.3, and the pump discharge in Subsection 6.2.4.2.1.

6.2.4.3.2.8 Main Steamlines

Each of the four main steam lines is provided with normally open air operated y-pattern globe valves, one inside and one outside containment. The isolation provisions for the main steamlines are further described in Subsection 5.2.5.

6.2.4.3.2.9 CS Influent Penetrations

The CS influent lines are each isolated by a normally closed remote manually operated, gate valve external to the containment and a testable check valve inside the containment. The check valve is provided with a bypass having a normally closed remote manually operated globe valve.

6.2.4.3.2.10 RHR Penetrations Connected to the RPV

The RHR shutdown supply line is provided with normally closed gate valves, one inside containment and one outside.

The piping between the isolation valves is provided with a relief valve with a relieving pressure setting greater than 1.5 times the maximum containment pressure.

The RHR Shutdown Cooling return line containment penetrations {X-13A(B)} are provided with a normally closed gate valve {HV-1(2)51F015A(B)} and a normally open globe valve {HV-1(2)51F017A(B)} outside containment and a testable check valve {HV-1(2)51F050A(B)} with a normally closed parallel air operated glove valve {HV-1(2)51F122A(B)} inside containment. The gate valve is manually opened and automatically isolates upon a containment isolation signal from the Nuclear Steam Supply Shutoff System or RPV low level 3 when the RHR System is operated in the Shutdown Cooling Mode only. The LPCI subsystem is an operational mode of the RHR System and uses the same injection lines to the RPV as the Shutdown Cooling Mode.

The design of these containment penetrations is unique in that some valves are containment isolation valves while other perform the function of pressure isolation valves. In order to meet to 10 CFR 50 Appendix J leakage testing requirements, the HV-1(2)51F015A(B) and the closed system outside containment are the only barriers tested in accordance with the Leakage Rate Test Program. Since these containment penetrations {X-13A and X-13B} include a containment isolation valve outside containment that is tested in accordance with 10CFR50 Appendix J requirements and a closed system outside containment that meets the requirements of USNRC Standard Review Plan 6.2.4 (September 1975), paragraph II.3.e, the containment isolation provisions for these penetrations provide an acceptable alternative to the explicit requirements of 10CFR50, Appendix A, GDC 55.

Containment penetrations X-13A(B are also high/low pressure system interfaces. In order to meet the requirements to have two (2) isolation valves between the high pressure and low pressure systems, the HV-1(2)51F050A(B), HV-1(2)51F122A(B), and HV-1(2)51F015A(B) valves are used to meet this requirement and are tested in accordance with the pressure test program.

A cross-tie line exists between the LPCI Injection lines and the RHR Shutdown Cooling suction line. This 1" line is installed to provide a positive pressure drop across the LPCI Injection Check Valves to hold the valves closed. The positive pressure drop is accomplished by relieving pressure from the upstream side of check valves HV151F050A and HV151F050B, and diverting the excess fluid to the RHR Shutdown Cooling suction line, which is at a lower pressure than at the point downstream of the check valves. A check valve is installed in the cross-tie line which functions as a pressure isolation valve, and normally open isolation valves are used for LPCI Injection Check Valve testing and isolation of either the 'A' or 'B' RHR loop.

The RPV spray line is provided with a normally-closed ac motor-operated gate valve inside containment and a normally-closed, dc motor-operated globe valve outside containment. Both valves close automatically upon receipt of a containment isolation signal.

6.2.4.3.3 Evaluation Against General Design Criterion 56

6.2.4.3.3.1 Containment Purge

The drywell and suppression chamber purge lines have isolation capabilities commensurate with the importance of safely isolating these lines. Each line has two normally closed, air opened, spring closed valves located outside the primary containment. Containment isolation requirements are met on the basis that the purge lines up to the outboard isolation valves are normally closed, low pressure lines, constructed to the same quality standards as the containment. The isolation valves for the purge lines are interlocked to preclude opening of the valves while a containment isolation signal exists as noted in Table 6.2-12 and fail closed on loss of electrical signal with the following exceptions:

1. Keylock handswitches are provided to override the containment isolation signal on valves HV-15703, HV-15705, HV-15711 and HV-15713 to allow emergency venting of the containment.

2. Key lock handswitches permit the 45 minute time delay and the LOCA isolation signal to be overridden on valves HV-15703, HV-15705, HV-15711, and HV-15713, to allow emergency venting or purging of the containment.

3. Key lock hand switches are provided to override the SGTS Exhaust High Radiation isolation signal on valves HV-15703, HV-15705, HV-15711, and HV-15713 to allow emergency venting or purging of the containment.

4. Target Rock valves, SV-15742A,B; SV-15740A,B; SV-15752A,B; SV-15750A,B; SV-15774A,B; SV-15776A,B; SV-15734A,B; SV-15736A,B; SV-15782A,B and SV-15780A,B can be opened 10 minutes after receipt of a LOCA isolation signal by using the valve hand switches.

Screens are provided on the drywell inlet and outlet purge lines. The purpose of the screens is to prevent debris generated by an accident, such as a pipe break, from entering the purge lines and preventing the containment isolation valves from closing. The screen is an expanded metal mesh with openings of .750 by 1.687 inches. The screens are safety-related components designed to withstand the design basis earthquake.

Purge line debris screens are not required in the wetwell since the wetwell contains no high energy lines or insulation. Additionally, there is no mechanism that would allow debris, such as insulation from the drywell, to reach the penetrations in the wetwell before the containment isolation valves close. Therefore, debris screens have been provided in the drywell only.

6.2.4.3.3.2 RCIC Turbine Exhaust, Vacuum Pump Discharge, and RCIC Pump Minimum Flow Bypass

These lines which penetrate the containment and discharge to the suppression pool, are each equipped with a motor-operated, remote manually actuated gate valve located as close to the containment as possible. There is a simple check valve upstream of the gate valve, which provides positive actuation for immediate isolation in the event of a break upstream of this valve. The gate valve in the RCIC turbine exhaust is designed to be key-locked open in the control room and interlocked to preclude opening of the inlet steam valve to the turbine while the turbine exhaust valve is not in a full open position. The RCIC vacuum pump discharge line is also normally key-locked open but has no requirement for interlocking with the steam inlet to the turbine. The RCIC pump minimum flow bypass line is isolated by a normally closed, remote manually actuated valve with a check valve installed upstream. The motor-operated valve will open only when the RCIC pump is running and flow rate at the pump discharge is below the low flow setpoint.

The justification taken for the approach for isolating these lines is that the check valves with the water seal provided by the suppression pool provide leakage control in the short term. Long-term leakage control is supplied by the control room operator closing the motor-operated valves remote-manually. This arrangement enhances the reliability of RCIC for those accident scenarios where high pressure coolant injection is required while still providing the required isolation capability.

6.2.4.3.3.3 HPCI Turbine Exhaust and HPCI Pump Minimum Flow Bypass

These lines penetrate the containment and discharge to the suppression pool. They are equipped with a motor operated, remote manually actuated gate valve located as close to the containment as possible. In addition, there is a simple check valve upstream of the gate valve, which provides positive actuation for immediate isolation in the event of a break upstream of this valve. The gate valve in the HPCI turbine exhaust is designed to be key-locked open in the control room and interlocked to preclude opening of the inlet steam valve to the turbine while the turbine exhaust valve is not in a full open position. The HPCI pump minimum flow bypass line is isolated by a normally closed, remote manually actuated valve with a check valve installed upstream. The motor-operated valve will open when the HPCI pump is running and the flow rate at the pump discharge is below the low flow setpoint.

The justification taken for the approach for isolating these lines is that the check valves with the water seal provided by the suppression pool provided leakage control in the short term. Long-term leakage control is supplied by the control room operator closing the motor-operated valves remote-manually. This arrangement enhances the reliability of HPCI for those accident scenarios where high pressure coolant injection is required while still providing the required isolation capability.

6.2.4.3.3.4 RCIC and HPCI Turbine Exhaust Vacuum Breaker Lines

These lines are provided with power operated isolation valves, outside containment. The valves close on a containment isolation signal.

6.2.4.3.3.5 Reactor Building Closed Cooling Water and Reactor Building Chilled Water Supplies and Returns

The influent lines and effluent lines are provided with two normally-open, power-operated valves. The valve inside containment is a butterfly valve, while the valve outside containment is a gate valve. The power operated valves are automatically closed on receipt of a containment isolation signal.

6.2.4.3.3.6 Post-LOCA Atmosphere Sampling Lines

The Post Accident Sampling System (PASS) shares the same containment penetrations with the H_2O_2 Analyzers. The lines that penetrate the containment and connect to the drywell and suppression chamber air volume are equipped with two normally open, failed closed solenoid operated valves in series. These valves are located outside and as close to the containment as possible. While two valves are provided in series for each penetration, both valves are powered from the same electrical division in order to prevent a single electrical failure from resulting in a loss of both divisions of H_2O_2 Analyzers. However, this results in the valves being susceptible to a single electrical failure, as described in Section 7.3.2a.2.2.3.1.2 (multiple hot shorts), which could result in both valves failing open or failing to remain closed. For all other conditions, the valves will provide redundant containment isolation barriers.

The susceptibility of the valves to a single electrical failure is offset by the fact that the external piping and components beyond the containment isolation valves up to and including the PASS/ H_2O_2 Analyzer System boundary valves are considered an extension of primary containment. Consequently, the design of the H_2O_2 Analyzer system outside primary containment meets the design and testing requirements for a closed system as specified in USNRC Standard Review Plan 6.2.4 (September 1975), Containment Isolation Provisions, paragraph II.3.e, except as clarified by Tables 3.2-1, 6.2-12, and 6.2-22. Therefore, the containment isolation barriers for these penetrations consist of two primary containment isolation valves and a closed system.

6.2.4.3.3.7 Liquid Radwaste System Equipment and Floor Drains

These lines are equipped with two normally-closed, solenoid-actuated, air-operated gate valves, both located outside containment. Inasmuch as the containment penetrations are just above the drywell floor slab, locating the inboard isolation valves inside containment would have been impractical, since the valves might have been underwater as a result of an accident. Thus, the inboard valves are attached directly to their respective containment penetration sleeves. In both cases, the piping between the isolation valves is designed as seismic Category I, ASME Section III, Class 2; the two valves are separated by only 1.5 feet of piping.

6.2.4.3.3.8 Suppression Pool Cleanup and Drain

The suppression pool cleanup and drain line is provided with two normally closed, motor operated remote manually actuated gate valves that are interlocked to close on receipt of a containment isolation signal. Since this line penetrates the suppression pool floor, locating a valve inside containment would be impractical; thus, both valves are outside containment. The piping between the isolation valves is designed as seismic Category I, ASME Section III, Class 2; the two valves are separated by one foot of piping. Inasmuch as these valves are located in the core spray pump room, flooding alarms will provide indication of gross leakage.

6.2.4.3.3.9 Containment Instrument Gas Supply To Containment Vacuum Relief Valves

The containment instrument gas supply line to the containment vacuum relief valve assemblies is provided with a check valve (inboard) and a normally-closed, solenoid-operated globe valve (outboard), both located outside containment. Another check valve is located inside the suppression chamber; however, credit for this check valve as a containment isolation valve is not taken, since its operability during a postulated pool swell due to LOCA cannot be assured. Both valves outside containment are located as close to the containment penetration as practicable.

6.2.4.3.3.10 Traversing Incore Probe (TIP) Guide Tubes

Isolation of the TIP drive guide tubes normally is accomplished by a solenoid-operated ball valve whenever the TIP cable and fission chamber are retracted. An explosive shear valve is also provided as a backup to ensure integrity of the containment in the unlikely event that the other isolation valve fails to close or the drive cable fails to retract if it should be extended in the guide tube during the time that containment isolation is required. This valve is designed to shear the cable and seal the guide tube upon a manual actuation signal. The valve is an explosive type valve, dc-operated, with monitoring of each actuating circuit provided. TIP drive cables are normally retracted except during an actual TIP mapping operation.

TIP System Guide Tube isolation valve controls (Figure 6.2-72) are non-Class 1E. This design provides a degree of confidence commensurate with the design requirement that the Guide Tube penetrations, of which there are five parallel lines, will isolate and remain isolated under normal and accident conditions. Should the Ball Valve be unable to isolate under accident conditions, the Shear Valve is provided to perform that function.

Because of their natural functional diversity, the pair of valves for each penetration provides an appropriate level of protection of the primary containment integrity. The existing design does not, however, provide the deterministic assurance of safety and defense in depth normally required of protective functions to ensure penetration integrity in accordance with GDC 56.

The existing isolation system is a standard GE BWR design, and has been evaluated by Licensing Topical Report NEDC-22253. This design has been reviewed for all standard GE BWRs, including those with Mark II Containment designs, as meeting the requirements of Regulatory Guide 1.11.

Because the Guide Tube isolation scheme has not been designed as a protective function, most of the provisions of 7.3.2a.2 do not apply to the isolation actuation circuits, their components or operation. Operator actions cannot override a valve OPEN signal from the local TIP probe position sensor.

Indications and controls required to assure timely operator actions to close the Guide Tubes are non-Class 1E and are located on back panels in the control room. A common indicator for the set of Guide Tube Valve Assemblies will indicate if any of the five parallel paths are not fully closed. Open ball valves are not annunciated. Leakage through open TIP Guide Tubes would create high radiation conditions that would be annunciated in the control room via the non-Class 1E Area Radiation Monitoring System.

6.2.4.3.3.11 Hardened Containment Vent System

The vent line has two spring-to-close, air-to-open butterfly valves located outside of the primary containment. The gas to the two valve actuators is normally isolated and power to the actuator solenoid valves is normally de-energized.

6.2.4.3.4 Evaluation Against General Design Criterion 57

This criteria was not used in the design of containment penetrations for Susquehanna SES.

6.2.4.3.5 Evaluation Against Regulatory Guide 1.11 (Rev. 1)

Instrument lines that penetrate the containment from the reactor coolant pressure boundary conform to Regulatory Guide 1.11. They are equipped with a restricting orifice except the reactor water level reference leg instrument lines which are restricted by a ½" pipe located inside the drywell and as close as practicable to the connection on the process pipe and with an excess flow check valve located outside as close as practicable to the containment. A manua isolation valve exists between each penetration and its associated excess flow check valve. These manual isolation valves serve no containment isolation function. Isolation valves 142002A&B and 242002A&B, in the instrument reference legs, which are backfilled by CRD water, are disabled in the open position by design, to preclude the possibility of pressurization of the reference legs to CRD pressure, resulting in false pressure and level signals. Should an instrument line which forms part of the RCPB develop a leak outside containment, a flow rate which results in a differential pressure across the excess flow check valve of 3 to 10 psi will cause the check valve to close automatically. Should an excess flow check valve fail to close when required, the main flow path through the valve has a resistance to flow at least the equivalent of a sharp-edged orifice of 0.375 inch diameter. Valve position indication and excess flow alarm are provided in the control room. Excess flow check valves in instrument lines penetrating reactor containment undergo periodic inservice testing as discussed in FSAR Subsection 3.9.6.

Instrument lines that do not connect to the reactor coolant pressure boundary conform to Regulatory Guide 1.11 through their qualification and installation in accordance with ASME Section III, Class 2 requirements. They are designated as "extensions of containment" as discussed in FSAR Subsection 3.13.1 and Tables 6.2-12a and 6.2-22. They are equipped with isolation and excess flow check valves whose status will be indicated in the control room.

6.2.4.3.6 GDC 56 Isolation Provisions with a Single Isolation Valve Outside Containment

Containment isolation provisions for certain lines in engineered safety feature or engineered safety feature-related systems may consist of a single isolation valve outside containment. A single isolation valve is considered acceptable if it can be shown that the system reliability is greater with only one isolation valve in the line, the system is closed outside containment, and a single active failure can be accommodated with only one isolation valve in the line.

When credit is taken for a single containment isolation valve, the closed system outside containment is protected from missiles, designed to seismic Category I standards, classified Safety Class 2 and has a design temperature and pressure rating of least equal to that for the containment. The closed system outside containment will be leak tested in accordance with the Leak Rate Test Program.

6.2.4.3.6.1 Core Spray (CS) Influent Penetrations

The CS pump minimum flow line valve is normally open and closes when pump flow is established or by a remote manual signal. For this reason, flow rate is appropriately the only parameter sensed for initiation of containment isolation. The pump test and flush line isolation valves are normally closed and remote manually operated. The piping external to the primary containment provides a second isolation barrier as a closed system. All piping in the core spray system is seismic Category I, ASME Section III, Class 2 from the first restraints inside the containment penetrations outward.

6.2.4.3.6.2 Containment Spray and RHR Pump Test and Minimum Flow Lines

The containment sprays (drywell and wetwell) and the RHR pump test lines are each provided with a normally-closed, remote-manually operated isolation valve outside containment. The RHR minimum flow line valve is normally open and closes when pump flow is established or by remote manual signal. For this reason, flow rate is appropriately the only parameter sensed for initiation of containment isolation. The external pipe provides the second isolation barrier as a closed system for all of these penetrations. Additionally, the containment spray and RHR pump test lines utilize the second valve outward from the containment instead of the valve closest to the containment wall as the isolation valve (see Figures 6.2-44B, detail (d) and Figure 6.2-44J, detail (x)).

6.2.4.3.6.3 HPCI, RCIC, CS, and RHR Pump Suction Lines

Although strictly speaking the HPCI, RCIC, CS, and RHR pump suction lines do not connect directly to the primary containment, they are nevertheless evaluated to GDC 56. These lines are each provided with one remote manually motor operated gate valve external to the containment and use the respective piping systems (i.e., closed system) as the second isolation barrier. For the RHR and CS valves the hand switches are key locked.

Inasmuch as the pump suction valves are located in their respective pump rooms, flooding alarms will provide indication of gross leakage.

6.2.4.3.6.4 RHR Combined Relief Valve Discharge and Heat Exchanger Vent Lines

The relief valve discharge lines are isolated by the relief valves themselves in a fashion similar to a check valve. The external piping provides the second barrier. The relief setting on these valves is more than 1.5 times the containment design pressure.

The RHR heat exchanger vent lines discharge to the suppression chamber via the relief valve discharge lines and are provided with two remotely controlled motor-operated globe valves. Credit for one of these two valves is taken for effecting containment isolation; the external piping provides the second barrier. Justification for this alternative method is as follows: The RHR heat exchanger vent valves will be opened only during system filling and venting. Therefore, the probability that an accident requiring isolation of the vent line will occur while the vent valves are open is small. Since the valve motors are controlled from separate switches, two operator errors or one operator error and a single active failure would be required in order for both valves to be opened during other operating modes. In any event, should isolation be required during filling and venting, potential leakage would be contained by the external piping.

6.2.4.3.7 Failure Mode and Effects Analyses for Containment Isolation

The following discussion pertains to the evaluation of single failure of those components and systems credited with performing a containment isolation function. It is not intended to be applied to components on systems performing any safety function other than containment isolation.

A single failure can be defined as a failure of a component in any safety system that results in a loss of, or degradation of the system's capability to perform its safety function. Active components are defined in Regulatory Guide 1.48 (Rev. 1) as components that must perform a mechanical motion while accomplishing a system safety function. Appendix A to 10CFR50 requires that electrical systems also are designed against passive single failures as well as active single failures.

In single failure analysis of electrical systems, no distinction is made between mechanically active or passive components; all fluid system components such as valves are considered "electrically active" whether or not "mechanical" action is required.

Electrical systems as well as mechanical systems are designed to meet the single failure criterion for both mechanically active and passive fluid system components, regardless of whether that component is required to perform a safety action in the nuclear safety operational analysis outline in Appendix 15A. Even though a component such as an electrically operated valve is not designed to receive a signal to change state (open or closed) in a safety scheme, it is assumed as a single failure that the system component changes state or fails. Electrically operated valves include valves that are electrically piloted but air operated as well as valves that are directly operated by an electrical device. In addition, all electrically operated valves that are automatically actuated can also be manually actuated from the main control room. A single failure in any electrical system is analyzed regardless of whether the loss of a safety function is caused by either component failing to perform a requisite mechanical motion, or component performing an unnecessary mechanical motion.

6.2.4.4 Tests and Inspections

The containment isolation system was preoperationally tested in accordance with the requirements of Chapter 14. The containment isolation system is periodically tested during reactor operation. The functional capabilities of power operated isolation valves are tested remote manually from the control room. By observing position indicators and changes in the affected system operation, the closing ability of a particular isolation valve is demonstrated.

A discussion of testing and inspection, including leak tightness testing, pertaining to isolation valves is provided in Subsection 6.2.6 and in the Technical Specifications. Table 6.2-12 lists all isolation valves in process lines required by GDC 55 or 56. Vents, drains and test connections are not listed in this table.

Instruments are periodically tested and inspected. Test and/or calibration points are supplied for each instrument.

Excess flow check valves which are in instrument sensing lines not considered an extension of containment shall be periodically tested by opening a test drain valve downstream of the excess flow check valves and verifying proper operation.

With the exception of the CRD insert and withdrawal lines and penetrations with Note# 34, the penetrations listed in Table 6.2-12 are Type C tested. The test methods and acceptance criteria are listed in Subsections 6.2.6 and 3.9.6.2. Table 6.2-22 identifies testing type for all penetrations.

6.2.5 COMBUSTIBLE GAS CONTROL IN CONTAINMENT

The combustible gas control system is provided, in accordance with the requirements of General Design Criterion 41 of Appendix A to 10CFR50, 10 CFR 50.44 “Combustible Gas Control for Nuclear Power Reactors” and regulatory Guide 1.7 Revision 3 “Control of Combustible Gas Concentrations in Containment” to control the concentration of hydrogen within the containment following a loss-of-coolant accident (LOCA).

A design basis LOCA hydrogen release is no longer defined in 10 CFR 50.44 or Regulatory Guide 1.7 Revision 3 and these documents establish the requirements for the hydrogen control systems to mitigate such a release.

To meet the regulatory requirements, systems to monitor and control the concentration of hydrogen are provided as follows:

a. A system to monitor the concentrations of hydrogen and oxygen within the containment

b. Containment mixing to prevent local hydrogen concentration buildup.

c. Inerted primary containment (less than 4% oxygen concentration) during power operation.

d. Limiting use of materials within the containment that would yield hydrogen gas by corrosion (mainly aluminum and zinc).

The following systems are not required by the regulations but are provided to ensure hydrogen levels remain below the level that could endanger containment integrity.

e. A hydrogen recombiner system to maintain the hydrogen concentration below combustible limits

f. A containment hydrogen purging subsystem to limit the concentration of hydrogen. This is a backup to the hydrogen recombiner system

6.2.5.1 Design Bases

The combustible gas control system has been designed based on the following criteria:

a. The hydrogen recombiner system is designed to maintain the hydrogen concentration below the combustible limit set by Regulatory Guide 1.7, Revision 1. Note that the current regulatory requirements do not require hydrogen recombiners.

b. The containment hydrogen and oxygen monitoring system is designed to monitor the hydrogen and oxygen concentrations in both the drywell and wetwell.

c. Containment mixing prevents buildup of local hydrogen gas concentrations within the drywell or wetwell during accident conditions.

d. The hydrogen recombiner and containment hydrogen monitoring systems are designed to Seismic Category I requirements, and meet the requirements of ASME Section III, where applicable.

e. There are four hydrogen recombiners in each unit, two in the drywell and two in the suppression chamber (wetwell). To provide defense in depth, one recombiner in the drywell and one in the wetwell will provide 100 percent of the required capacity; and one drywell and one wetwell recombiner are powered from each of the two separate essential power divisions. Note that the current regulatory requirements do not require hydrogen recombiners but the sizing of the installed recombiners was based on the hydrogen generation rates per Regulatory guide 1.7 Revision 1.

f. The components of the hydrogen monitoring system and the hydrogen recombiner system are separated or protected to ensure that missiles and pipe whip will not disable required functions.

g. The hydrogen monitoring system and the hydrogen recombiner system are testable during normal operation.

h. The recombiner system is remotely started from panels located in the control building.

i. The containment hydrogen purge system is designed, as a backup to the hydrogen recombiner system, to maintain the hydrogen concentration below the required limit.

j. The containment is inerted during operation, within operating mode limitations and concentration limits prescribed by Technical Specifications, to maintain a low level of oxygen.

6.2.5.2 System Design

Combustible gas control depends on the following functions and subsystems:

a. Hydrogen mixing

b. Hydrogen and oxygen monitoring system

c. Hydrogen recombiner system (not a safety related function)

d. Containment hydrogen purge system (not a safety related function)

e. Containment nitrogen inerting system

Hydrogen Mixing

A well mixed atmosphere in the drywell and wetwell ensures that local concentrations of hydrogen greater than four percent do not occur.

Post-LOCA mixing of the drywell atmosphere is accomplished by the safety-related portion of the containment ventilation system (see Subsection 9.4.5). Wetwell mixing will be accomplished by the blowdown to the wetwell and operation of the RHR system suppression chamber spray header (see Subsections 5.4.7 and 6.2.2.2).

Hydrogen and Oxygen Monitoring System

Primary Containment Atmosphere Monitoring System Hydrogen and Oxygen Analyzers

Two redundant systems are provided and are able to continuously monitor the gas concentration within the primary containment and the suppression chamber, to indicate, record, and alarm detection of excessive hydrogen or oxygen.

This system is part of the primary containment atmosphere monitoring system and is operated during normal operation during start up, and after a LOCA for post accident monitoring. Refer to Section 7.5 for safety-related display instrumentation.

Each redundant system is designed with independent, separate gas analyzers, located in panels outside the primary containment in the reactor building.

a. Operating principle of gas analyzers:

    The analyzer for each division has separate sample lines. Each analyzer can sample either of two points in the drywell or one point in the wetwell. The gas sample is pumped through the analyzer cells to determine the amount of hydrogen and oxygen.

    Reagent gas is added to the sample stream because of the wide variation in the composition of the containment atmosphere. For hydrogen analysis the reagent gas is 100% oxygen. A catalyst in the reference side of the analysis cell causes any hydrogen present in the sample gas to combine with the reagent oxygen to form water vapor before reaching the analysis filament. The cell temperature is maintained above saturation to prevent condensation. The thermal conductivity of the reacted sample in the reference side of the cell, with no hydrogen, is compared to the conductivity of the unreacted sample measured by the other side of the cell to yield an indication of volume percent hydrogen.

    The oxygen analyzer functions essentially the same as the hydrogen analyzer, except that it uses hydrogen as the reagent gas. This analysis technique is quite reliable and accurate. After analysis, the gas samples are returned to the drywell or wetwell.

    When the reactor is in startup or at power both of the redundant analyzer systems are either operating or maintained in standby. If in standby an analyzer will be activated from the control room after a LOCA. The analyzers are calibrated and tested periodically during normal operation in accordance with Technical Requirement Manual.

    The analyzer systems are designed for the following modes of operation:

    1. During startup.

    2. During normal reactor operation to monitor for excessive oxygen concentration.
    3. To monitor the containment atmosphere after a LOCA for excessive hydrogen or oxygen concentration.

b. Description of tests to demonstrate the performance capability of the analyzers.

    1. Seismic qualification test:

        The gas analyzer system panel was tested in accordance with IEEE 344-1975 to satisfy the requirements for Seismic Category I.

    2. Gas analyzer operational test:

        A preoperational test verified the performance of the analyzers in accordance with the technical specifications of the system. The analyzers are calibrated and tested periodically during normal operation in accordance with Technical Requirement Manual.

c. Location of sampling points within the primary containment:

The Division I (System A) drywell gas sampling points are located approximately at Elevation 790 feet, Azimuth 303°, 2 feet from the containment wall; and at elevation 714 feet, azimuth 292°, 5 feet from the containment wall. The Division II (System B) drywell sampling points are located approximately at elevation 750 feet, azimuth 155°, 2 feet from the containment wall; and at Elevation 728 feet, inside the reactor pedestal just under the RPV.

The wetwell (suppression chamber) sampling points are located at the containment wall approximately at elevation 688 feet; Division I System A at azimuth 287° and Division II System B at azimuth 109°.

d. System independence:

The primary containment monitoring system is a separate, independent gas analyzer system with the capability to monitor the combustible gas concentration independent of the operation of the combustible gas control system.

e. Failure modes and effect analysis:

The system level failure mode and effects analysis for the containment atmosphere monitoring system is provided in Table 6.2-14.

Hydrogen Recombiner System

There are four hydrogen recombiners in each unit, two in the drywell and two in the suppression chamber (wetwell). To provide defense in depth, one recombiner in the drywell and one in the wetwell will provide 100 percent of the required capacity. In each volume (drywell and wetwell), each of the two recombiners is powered from a separate essential power division, and each of the four recombiners is powered from a separate panel, from one of the four separate essential load groups. The two recombiners on each essential power division (one drywell, one wetwell) have individual controls on a single control panel. The two control panels are in separate locations in the control building outside containment.

Two hydrogen recombiners are located in the drywell, one (E440D) supported by the diaphragm slab at Elevation 704 feet, located at Azimuth 104° midway between the pedestal and the containment wall. The other hydrogen recombiner (E440C) is supported by the Elevation 719 foot steel and is located at Azimuth 339°, (6) feet from the containment wall. The only local equipment or structure located close to the suction or discharge of recombiner E440D is unit cooler V-416B, located approximately 4-1/2 feet from one of three discharges. All local equipment and structures are located six (6) feet or more from the suction and discharge of recombiner E440C.

Two hydrogen recombiners are located in the wetwell, supported above elevation 691 feet by platforms; one (E440A) at Azimuth 10° and the other (E440B) at Azimuth 190°. Both recombiners are located approximately midway between the pedestal and containment wall. These wetwell recombiners both have structures located close to the recombiner ports. Both recombiners have a 42 inch diameter diaphragm slab support column approximately 1-1/2 feet from the suction, and a 24 inch beam approximately 6 inches from the 26 inch high discharge.

Each hydrogen recombiner is a large electric heater. Natural convection draws a continuous stream of containment atmosphere through the recombiner, which heats it to a temperature sufficient for complete recombination of hydrogen with oxygen to form water. The heat-up time is approximately 4 hours.

The recombination unit consists of an inlet preheater section, a heater-recombination section, and a mixing chamber. The air is drawn into the unit by natural convection via the inlet louvers and passes through the preheater section, which consists of a shroud placed around the central heaters to take advantage of heat conduction through the walls. In this area the temperature of the inlet air is raised. This accomplishes the dual function of increasing the system efficiency and of evaporating any moisture droplets which may be entrained in the air. The warmed air then passes through an orifice plate whose perforations have been sized to regulate the airflow through the unit. After passing through the orifice plate, the air flows vertically upward through the heater section, where its temperature is raised to the range of 1150-1400°F, causing recombination of Hydrogen and Oxygen to occur. The recombination temperature is approximately 1135°F. The heater section consists of five banks of electric heaters stacked vertically. Each bank contains 60 individual U-type heating elements.

Next, the air rises from the top of the heater section and flows into the mixing chamber, which is at the top of the unit. Here, the hot air is mixed with the cooler containment air to discharge it back into the containment at a lower temperature. The cooler containment air enters the mixing chamber through the lower part of the upper louvers located on three sides of the unit.

Table 6.2-18 gives the design characteristics of the hydrogen recombiner.

Containment Hydrogen Purge System

The containment purge system is provided as a backup to the hydrogen recombiner system and would only be used post-LOCA on a high hydrogen concentration in containment, as indicated by the hydrogen analyzers or by sample analysis. This could only occur in the event of accidents or failures beyond the design basis, such as failure of both divisions of recombiners, or if hydrogen generation exceeded the recombiner capacity, or if inadequate containment mixing permitted a local high concentration at the sample point. The purge system controls the hydrogen concentration by dilution of the post-LOCA containment atmosphere. The containment atmosphere is purged through a two inch bypass valve. Nitrogen gas is added to containment as required to support the purge.

During normal operation the two inch purge exhaust line may be used intermittently for containment pressure control. The system design, however, prevents any purged gases from being exhausted directly to the environs. All purged gases are processed through the Standby Gas Treatment System (SGTS). Operating procedures require the SGTS to be operational before the inboard isolation valve and the two inch bypass valve are opened for the purge. The outboard isolation valve will remain shut. The purge valves are shown on Dwg. M-157, Sh. 1. M-157, Sh. 2, M-157, Sh. 3 and the SGTS System and its quality requirements are described in Section 6.5.1.1. Valve closure times are given in Table 6.2-12. Even in the very unlikely event of a LOCA occurring simultaneously with purge, the volume of air exhausted to the secondary containment before the redundant isolation valves close is only a small fraction of the capacity of the SGTS.

Containment Nitrogen Inerting System

An inerted containment was specified during the early design for Susquehanna, based on calculations using early Revision s of Regulatory Guide 1.7. When the post-LOCA hydrogen generation rate and hydrogen concentration within the containment were recalculated based on Regulatory Guide 1.7, Rev. 1, the worst case concentrations indicated that an inerted containment would not have been required. However, an inerted containment was retained:

a) To meet requirements of 10CFR50.44(c)(3)(i) for resolution of Unresolved Safety Issue A-48 (TMI-II Issues II.B.7 and II.B.8), which requires all BWR Mark I and Mark II containments to be inerted for combustible gas control, and

b) To meet 10CFR50 Appendix R fire suppression requirements. See the Fire Protection Review Report (FPRR).

Nitrogen gas will be used for primary containment atmosphere control. The Containment Nitrogen Inerting System and its quality requirements are shown on Dwg. M-157, Sh. 1. The oxygen concentration of the inerted atmosphere during reactor operation will not exceed four percent by volume. The oxygen concentration will be monitored by a portable gas analyzer, or by grab sample or by the hydrogen and oxygen analyzers. During normal operation the analysis frequency will be as required to maintain oxygen at less than four percent.

6.2.5.3 Design Evaluation

A design basis LOCA hydrogen release is no longer defined in 10 CFR 50.44 or Regulatory Guide 1.7 Revision 3 and these documents establish the requirements for the hydrogen control systems to mitigate such a release. Hydrogen recombiners are no longer required to mitigate a hydrogen release post-LOCA.

Start Historical

The analysis of the combustible gas in the containment following a LOCA assumed the following sources of hydrogen.

a. An assumed metal-water reaction with the zircalloy cladding surrounding the active portion of the fuel. The clad was assumed to react to a depth of .00023 in. in accordance with Regulatory Guide 1.7, because the ECCS analysis (Subsection 6.3.3) showed that five times the calculated metal water reaction would produce less hydrogen.

b. Radioloysis of the reactor coolant and injection water

c. Corrosion of the aluminum, zinc and zinc paint in the containment

d. The release of the free hydrogen already in the reactor coolant.

Reagent hydrogen returned to containment from the oxygen analyzers is a fraction of the least of these four sources and is not included in calculations. Hydrogen generated by radiolysis of sump water is distributed between the drywell and the wetwell in proportion to the volume of sump water present in each. Since almost all the sump water will be in the wetwell, it is assumed that 93.6% of the sump radiolysis hydrogen will be in the wetwell and 6.4% in the drywell.

Since no caustics will be added to the containment by the spray system, the pH of the water after a LOCA should be approximately 7.

Corrosion of zinc in contact with water at pH 7 with no additives is caused by two processes:

$$Zn + 2\,H_2O \rightarrow Zn\,(OH)_2 + H_2 \qquad (1)$$

$$2\,Zn + 2\,H_2O + O_2 \rightarrow 2\,Zn\,(OH)_2 \qquad (2)$$

Both reactions will be present in the post-LOCA atmosphere of the containment. The relative amount of corrosion due to Reaction (1) compared to Reaction (2) will depend on the availability of oxygen. Galvanized steel and zinc-based paint surfaces that are not submerged will be in contact with atmospheric oxygen along with the spray water; therefore, Reaction (2) should be a major contributor to the corrosion of zinc. For the submerged surfaces, the oxygen present will depend on the solubility of oxygen, which decreases with increasing temperature. Thus, Reaction (1) should dominate corrosion of submerged zinc surfaces at high temperature.

A search of the literature available on the subject of zinc corrosion at a pH of 7 gives data for corrosion as weight loss of zinc (References 6.2-6, 6.2-16, and 6.2-28) and also as hydrogen evolved (References 6.2-7 and 6.2-9). van Rooyen (Reference 6.2-8) surveyed the available literature and formulated a corrosion rate. The data given as weight loss of zinc should be viewed carefully to determine which corrosion reaction is seen. Other data is available for corrosion in water at higher pH levels or in water with Na OH additives. However, this data is not applicable to a BWR, which does not have borated reactor coolant, nor caustic or buffered containment sprays.

Baylis (Reference 6.2-7) determined the hydrogen generated from a sample of zinc submerged in distilled water for different time periods. This study was performed for temperatures of 100°F and lower. Therefore, the lower temperature corrosion domain can be inferred from this data.

Franklin Institute Research Laboratories performed a study of hydrogen evolution from zinc under simulated LOCA conditions and gave corrosion data for 2-hour and 24-hour periods (Reference 6.2-9). This data shows that corrosion is faster for the 2 hour period than for the 24-hour period for the same temperature, except at high temperatures (260°-300°F), where the corrosion rates are comparable. This effect is due to the build-up of a corrosion-resistant zinc hydroxide protective layer which inhibits corrosion after an extended period of time.

Burchell (Reference 6.2-6) and Cox (Reference 6.2-16) present corrosion as weight loss of zinc. In both cases, the corrosion rate is higher at the lower temperature domain, peaking at approximately 110°F and then decreasing with increasing temperature. Since the solubility of oxygen decreases with increasing temperature, the decrease in the corrosion rates can be attributed to the depletion of oxygen available. Thus, these corrosion rates show that reaction

(2) is dominant in the oxygen-rich lower temperature water, and reaction (1) becomes dominant with increasing temperature.

van Rooyen (Reference 6.2-8) determined the corrosion rate of zinc from the available data, but did not differentiate between reactions (1) and (2). van Rooyen's calculated corrosion rate therefore does not accurately represent hydrogen generated from zinc corrosion.
The data of References 6.2-7 and 6.2-9 on hydrogen generation from zinc corrosion were therefore used to develop the following bounding corrosion rate:

$$R_{Zn} = 3.76 \times 10^{-9}\, e_{(2.18x10-2T)}\ lb\text{-}moles/ft^2\text{-}hr \quad (T\ in\ {}^\circ F) \qquad (3)$$

Reaction (2) produces no free hydrogen. To obtain the most conservative hydrogen generation rate, all corrosion was therefore assumed to be Reaction (1), which produces one mole of free hydrogen per mole of zinc. The zinc reaction rate predicted by Equation (3) is therefore also the hydrogen generation rate from this process (i.e., $R(H_2)_{ZN}=R_{ZN}$). Equation (3) was therefore used to calculate the hydrogen released due to corrosion of both zinc and zinc-painted surfaces. See Table 6.2-13.

Hydrogen generated from corrosion of aluminum in containment was also included. A corrosion rate for aluminum at pH 7 was obtained from References 6.2-8, and the following rate equation was developed:

$$R_{Al} = 1.03 \times 10^{-4}\, e_{(-3491/T)}\ lb\text{-}moles/ft^2\text{-}hr \quad (T\ in\ {}^\circ K) \qquad (4)$$

Aluminum is assumed to corrode in water by the following reaction:

$$2\,A1 + 3\,H_2O \rightarrow A1_2O_3 + 3\,H_2 \qquad (5)$$

Reaction (5) shows that 3 moles of hydrogen are generated for every 2 moles of aluminum corroded. Therefore, multiplying Equation (4) by 3/2, the hydrogen generation rate due to aluminum corrosion will be:

$$R(H_2)A1 = 1.54 \times 10^{-4}\, e_{(-3491/T)}\ lb\text{-}moles/ft^2\text{-}hr \quad (T\ in\ {}^\circ K) \qquad (6)$$

As indicated in Figure 6.2-48, the quantity of hydrogen generated from corrosion of zinc and aluminum is small compared to that generated by radiolysis. Any uncertainties in hydrogen generation from zinc and aluminum which were not accounted for by the conservative assumption of Reaction (1) for zinc, and by the conservative methods of determining the corrosion rates, would not result in significantly larger quantities of hydrogen; and the four volume percent hydrogen criterion would not be exceeded.

The mass and area of zircalloy cladding surrounding the fuel, excluding the cladding surrounding the plenum volume, are given in Table 6.2-13.

During power operation, free hydrogen exists in the reactor water and steam as a consequence of the radiolytic decomposition of water. Additionally, hydrogen gas may be injected into the reactor coolant system with the feedwater to inhibit stress corrosion cracking. This process is known as Hydrogen Water Chemistry (HWC). The total quantity of free hydrogen that can be released to containment at the time of a LOCA would include the hydrogen inventory in the reactor coolant system as well as that of the feedwater and main steam lines inside containment. The normal operating hydrogen concentration for feedwater remains at 2.0 ppm. At this level, reactor water hydrogen concentration will be in the range of 320 to 400 ppb and steam hydrogen concentration will be 2.24 ppm. However, the total amount of hydrogen available for release to the containment from these sources under post LOCA conditions is negligible compared to the other sources such as metal water reaction, radiolysis of water and other corrosion reactions.

The total fission product adsorbed energy used to determine hydrogen generated by radiolysis is calculated based on Reference 6.2-17. The beta and gamma energy absorption rates and integrated energy releases are given in Figures 6.2-46 and 6.2-47. The assumptions used to calculate the energy releases are given in Table 6.2-13. The assumptions of Table 1 of Regulatory Guide 1.7 were followed.

The Figures 6.2-3, 6.2-7, and 6.2-8 curves of wetwell and drywell temperature versus time were used to calculate aluminum and zinc corrosion rates and thereby the hydrogen generation rates from these sources. The drywell and wetwell pressures at peak drywell pressure from Figure 6.2-2 were used to estimate the initial inventory of water vapor for determining the initial hydrogen concentrations, and thereby the recombination rates, at start of recombiners. Changes in these pressure and temperature profiles for power uprate were evaluated and found to have negligible effects on either hydrogen generation (Figure 6.2-48) or post-LOCA hydrogen concentration (Figures 6.2-49, 6.2-50, and 6.2-51).

The results of the analysis are given in the following figures:

a. The integrated production of hydrogen vs time - Figure 6.2-48.

b. The hydrogen concentrations vs time in the drywell with and without a recombiner operating - Figures 6.2-49 and 6.2-50.

c. The hydrogen concentrations vs time in the wetwell with and without a recombiner operating - Figure 6.2-51.

The recombiner system is activated when the hydrogen concentration reaches 3.5 vol percent. These times are given in Table 6.2-13.

The hydrogen recombiners have been designed to withstand the forces and pressures imposed during a LOCA. A system level failure modes and effects analysis for the recombiner system is given in Table 6.2-16.

End Historical

Purge Site Dose Analysis

For plants for which a notice of hearing on the application for a construction permit was published after November 5, 1970, an incremental post-LOCA purge dose calculation for the purge system is not required, as stated in Standard Review Plan, 15.6.5 Revision 1, Appendix C, "Radiological Consequences of a Design Basis Loss-of-Coolant Accident: Post-LOCA Purge Contribution."

6.2.5.4 Test and Inspections

Extensive tests have been performed on prototype and production recombiner systems of the type installed at Susquehanna SES. Initial development and prototype recombiner testing has been reported to the NRC in reports WCAP 7709-L, WCAP 7709-L Supplement 1, and WCAP 7709-L Supplement 2. The above reports have been accepted by the NRC.

Production recombiner testing has confirmed that the recombiners will perform satisfactorily under post-LOCA conditions. The production recombiner tests have been submitted to the NRC in reports WCAP 7709-L Supplements 3 through 7. All have been accepted by the NRC.

The conclusion from the above summarized tests is that the production recombiner with its associated equipment has been demonstrated to be qualified for the intended service conditions.

Each recombiner installed at Susquehanna SES underwent a post-installation test. This test demonstrated that the air flow through the recombiner meets the design requirements and that the recombiner reaches recombination temperature.

Periodically, the recombiners shall be energized and brought up to the required power level. If the recombiner temperature exceeds 1150°F, it shall be considered capable of performing its function. No hydrogen shall be present during the test since the production system tests and prototype tests indicate that recombination occurred solely because of the increased temperature.

6.2.5.5 Instrumentation Requirements

See Section 7.5 for descriptions of instrumentation and controls for other elements of the combustible gas control system.

6.2.5.5.1 Hydrogen Recombiner System

Divisionalized controls for operation of the hydrogen recombiners are provided in the control building relay room. Manual or automatic control is provided for each train to regulate power to the heaters in the associated recombiner. The controller maintains the correct power input to bring the recombiner above the threshold temperature for the recombination process. The controller setting is adjusted to accommodate variations in the containment temperature, pressure, and hydrogen concentration in the post-LOCA environment. The system is designed to conform to the applicable portions of IEEE 279 and is powered from a Class IE source.

The following instruments are provided for each recombiner unit:

a. Wattmeter - Provides a direct reading of the power in kilowatts being supplied to the recombiner unit.

b. Controller Potentiometer - Controls the power that is supplied to the recombiner unit, for manual operation.

c. On-Off MS Switch - Controls the power to energize/de-energize the main line contactor.

d. Power-Available Pilot Light - Indicates when power is available to the hydrogen recombiner power supply panel.

e. Temperature Readout - Provides a method of monitoring the temperature in the heater section of the recombination unit via the selector switch (see thermocouple selector switch, below) and the thermocouples. The unit is also equipped with an automatic temperature control circuit and controls the temperature of the unit when the temperature control selector switch is in AUTO.

f. Thermocouple Selector Switch - Used to select one of the three thermocouples in the recombiner unit; except for 1E440D, which has only two thermocouples that can be selected.

g. Temperature Control Selector Switch - Toggle switch which has an auto and a manual position.

Neither automatic temperature control nor temperature indication is required for post-LOCA operation. Proper post-LOCA recombiner operation is confirmed by reading the control panel wattmeter outside containment to confirm that enough power is being supplied to the heaters to maintain recombiner design temperature. Proper airflow through the recombiners is achieved by the orifice plate built into each unit.

6.2.5.5.2 Containment Hydrogen Purge Subsystem

Operation of the containment hydrogen purge subsystem is manually initiated from the control room. Refer to Section 7.6 for the description of the containment hydrogen purge subsystem controls and instrumentation.

The line penetrating the primary reactor containment is provided with power-operated isolation valves with controls in the control room to allow operator control during post-LOCA operation. A complete discussion of the isolation valve provisions is presented in Subsection 6.2.4.

Purge is exhausted through the Standby Gas Treatment System (SGTS). Differential pressure gages are provided across the SGTS vent filters to allow detection of filter clogging. Local temperature and pressure indicators are provided in the exhaust line to aid in the operation of the system. See the description of the SGTS in Section 6.5.1.1.

6.2.5.5.3 Instrumentation Requirements for Primary Containment Atmosphere Monitoring System (Hydrogen and Oxygen Analyzer)

The instrumentation and control of the primary containment monitoring system provides information of the performance of the hydrogen recombiner system and indicates the containment gas concentration during startup, during normal operation and after a LOCA. The unit will be manually placed into service following the 10 minute time delay resulting from the LOCA isolation (Table 6.2-12).

The two redundant systems are divisionalized and powered by respective Class IE power sources.

The analyzer units can be controlled locally or from the control room. Indicators for hydrogen and oxygen concentration of the containment are provided in the control room with system trouble annunciators to alert the operator. In addition a historical record is maintained by a two channel recorder. Refer to Section 7.5 for safety-related display instrumentation.

During normal operation the analyzers are tested periodically and calibrated against standard gases in accordance with Technical Requirement Manual. If possible each analyzer is also calibrated before being aligned for analysis.

The hydrogen and oxygen analyzer units are located outside the primary containment in the reactor building. These units are qualified to withstand the environmental conditions described in Section 3.11.

6.2.6 PRIMARY REACTOR CONTAINMENT LEAKAGE RATE TESTING

This section presents the testing program for the following leak rate tests:

- Type A Test, Primary containment integrated leak rate test (ILRT)
- Type B Test, Primary containment penetration leak rate test
- Type C Test, Primary containment isolation valve leak rate test

These leak rate tests comply with 10CFR50 Appendix A, General Design Criteria, and Appendix J, Primary Reactor Containment Leakage Rate Testing for Water Cooled Power Reactors.

Section 6.2.3.2.3 and Table 6.2-15 identifies the leak rate testing requirements for those penetrations that are Secondary Containment Bypass Leakage pathways.

Dwg. M-159, Sh. 1 shows the system used to perform the ILRT.

6.2.6.1 Primary Reactor Containment Integrated Leakage Rate Test

When the construction of the primary containment including all portions of systems that penetrate the containment was complete and the structural integrity test described in Subsection 3.8.1.7 was completed satisfactorily, the preoperational containment integrated leak rate test (ILRT) was performed. The preoperational ILRT was performed in accordance with the requirements of Chapter 14 to verify that the actual containment leak rate did not exceed the design limits. After the preoperational ILRT, periodic Type A tests are performed at the intervals specified in the plant Technical Specifications.

A general visual inspection of the accessible interior and exterior surfaces of the primary containment structure and components is performed. The inspection is performed prior to a periodic Type A test. In addition, when the Type A test is on a 10 year frequency, a general visual inspection is performed in 2 other refueling outages between Type A tests. If required, corrective action is taken and results are reported in accordance with 10CFR50 Appendix J Option B. Repairs and modifications to the containment structure shall meet the requirements of NEI 94-01, Rev. 0, Section 9.2.4 and ANSI/ANS-56.8-1994.

To ensure a successful ILRT, local leak rate tests, Type B and C tests, are performed on penetration boundaries and containment isolation valves. If necessary, repairs are made to Type B and C tested components between Type A tests. This ensures that the leakage through containment isolation barriers does not exceed design limits.

Periodic Type A tests are performed to ensure that the total leakage from containment does not exceed design limits. This is assured by limiting leakage to less than La when tested at Pa per the plant Technical Specifications. Table 6.2-19 contains the pertinent Type A test data including test pressures, test duration, and definitions of terms.

The Type A test acceptance criteria is in the plant Technical Specifications.

The absolute method described in ANSI/ANS-56.8-1994 or BN-TOP-1 is used to perform the Type A test. The leak rate and the associated 95% confidence limit are calculated in accordance with ANSI/ANS-56.8-1994 or BN-TOP-1. The calculated leak rate and the 95% confidence limit are to be contained in the post refuel outage report.

Prior to the start of any Type A test, the following pretest requirements must be met:

a. The containment isolation valves are closed by normal means and without adjustment (e.g., do not tighten a valve using the manual handwheel after the valve is closed by the motor operator). Identify in the Type A test final report any valve closure malfunctions or any valve adjustments made to reduce containment leakage.
b. The Appendix J pathways are vented and drained in accordance with NEI 94-01, Rev. 0, Section 8.0. Table 6.2-21 identifies the systems required for proper conduct of the Type A test and systems that are operable under post-accident conditions.

c. After test pressure is reached prior to the start of the Type A test, the containment atmosphere is stabilized in accordance with ANSI/ANS-56.8-1994 or BN-TOP-1. As necessary, the containment ventilation and cooling water systems are run prior to and during the Type A test to keep the containment atmosphere stabilized.

When the Type A test is complete, a verification test is performed in accordance with ANSI/ANS-56.8-1994 or BN-TOP-1. A known leak rate is imposed on containment through a calibrated flow measurement device. The verification test validates the Type A test results.

If during a Type A test or verification test, an unisolable leak is identified, the following steps are performed:

a. Stop the Type A test or verification test.
b. Depressurize, if needed, to fix the repair.
c. Repair the leak.
d. Start the Type A test over again.
e. Document the repairs in the post refuel outage report.

The Type A test frequency is in accordance with the Leakage Rate Test Program.

Table 6.2-22 (the Type Test column) identifies the penetrations that are Type A tested.

6.2.6.2 Primary Containment Penetration Leakage Rate Test

The following containment penetration designs are Type B tested:

- resilient seals, gaskets, or sealant compounds
- air locks and air lock door seals
- equipment and access hatch seals
- electrical canisters.

Preoperational Type B tests were performed and periodic Type B tests are performed in accordance with 10CFR50 Appendix J Option B. Table 6.2-22 identifies the penetrations that are Type B tested.

The air lock contains penetrations with threaded caps, penetrations with equalizing valves (described in Subsection 3.8.2.1.2), and electrical penetrations. The penetrations with threaded caps permit testing of the door seals and the entire air lock. Figures 6.2-57A-1, 6.2-57A-2, and 6.2-57A-3 show the locations of the penetrations in the air lock. Figures 6.2-58-1 and 6.2-58-2 show the details of the door seals and the pressure test connection. Table 6.2-22, Notes 2 and 3, specify the pressures used to test the air lock and the door seals. The air lock is periodically tested at Pa in accordance with the plant Technical Specifications. The door seals are tested at 10 psig at a frequency in accordance with the Leakage Rate Test Program.

The test pressure for all Type B tests, except the air lock door seals, is Pa, defined in Table 6.2-19. The Type B test acceptance criteria is in the plant Technical Specifications. The test methods are described in Subsection 6.2.6.3.

6.2.6.3 Primary Containment Isolation Valve Leakage Rate Tests

Table 6.2-22 identifies the containment isolation valves that are Type C tested in accordance with 10CFR50 Appendix J.

Some of the containment isolation valves are tested in a direction other than the accident direction. These valves are discussed below.

1. X-7A, B, C, D: Main Steam Line Penetrations, See Dwgs. M-141, Sh. 1 and Figure 5.4-8.

   The MSIVs can be tested by two methods. One of these methods applies pressure in between the MSIVs. In this test method, the pressure is applied to the inboard MSIVs, HV141F022A, B, C, D, in the reverse direction. This tends to unseat the inboard MSIV valve disc, making this a more conservative test for the inboard MSIVs. Since the y-globe valves are inside primary containment, any leakage through the valve packing and seals would not leave primary containment.

2. X-10, 11: HPCI and RCIC Turbine Steam Line Penetrations, See Dwgs. M-149, Sh. 1 and M-155, Sh. 1.

   Based on valve closure calculations, leakage through the HPCI gate valve, HV155F002, and the RCIC gate valve, HV149F007, in the reverse direction is equivalent to the leakage through the valves in the accident direction. The 1 in. bypass globe valves, HV155F100 and HV149F088, around the gate valves exhibit equivalent or more conservative leakage in the reverse direction. Since the gate and globe valves are inside primary containment, any leakage through the valve packing and seals that could leave primary containment is captured through reverse testing the valves.

3. X-12: RHR Shutdown Supply Penetration, See Dwg. M-151, Sh. 3.

   Test pressure is applied to PSV151F126 in the reverse direction. This tends to unseat the disc of the relief valve, making this a more conservative test. Since the relief valve is inside primary containment, any leakage through the valve packing and seals that could leave primary containment is captured through reverse testing the valve.

4. X-25, 26, 201A, 201B(U2), 202: Purge Supply and Exhaust Line Penetrations, See Dwgs. M-157, Sh. 1 and M-2157, Sh. 9.

   Test pressure is applied to CAC butterfly valves, HV15722, HV15713, HV15725, HV257113 and HV15703, in the reverse direction. Butterfly valves exhibit equivalent or more conservative leakage in the reverse direction. The valve packing is tested during the Type A test.

5. X-210, 215: HPCI and RCIC Turbine Exhaust Line Penetrations, See Dwgs. M-155, Sh. 1 and M-149, Sh. 1.

   Test pressure is applied to the HPCI gate valve, HV155F066, and the RCIC gate valve, HV149F059, in the reverse direction. The discs of gate valves are symmetrical and therefore testing in either direction produces similar results. The valve packing and seals are tested during the Type A test. In addition, these valves are tested with water. The valve leakage is not included in the Type B and C test acceptance criteria.

6. X-217: RCIC Pump Discharge Line Penetration, See Dwg. M-149, Sh. 1.

   Test pressure is applied to the RCIC globe valve, HV149F060, in the reverse direction. This tends to unseat the valve disc, making this a more conservative test for the valve. The valve packing and seals are tested during the Type A test. In addition, these valves are tested with water. The valve leakage is not included in the Type B and C test acceptance criteria.

7. X-243: Suppression Pool Cleanup and Drain, See Dwg. M-157, Sh. 1.

   Test pressure is applied to the gate valve, HV15766, in the reverse direction. The discs of gate valves are symmetrical and therefore testing in either direction produces similar results. The valve packing and seals are tested during the Type A test. In addition, these valves are tested with water. The valve leakage is not included in the Type B and C test acceptance criteria.

8. X-244, 245: HPCI and RCIC Vacuum Breaker Line Penetration. Refer to Dwgs. M-149, Sh. 1, M-150, Sh. 1, M-155, Sh. 1 and M-156, Sh. 1.

   The HPCI and RCIC vacuum breaker lines have symmetrical discs for the gate valves HV-2F079 and HV-2F084. Therefore, imposing the test pressure onto the valves from either direction procedures similar leakage rates.

8a. X-244: HPCI Breaker Penetration

   The HPCI inboard vacuum valve HV-1F079 is a flexwedge gate valve that is tested between the disc. Both disc and packing are exposed to the test pressure.

8b. X-245: RCIC Vacuum Breaker Penetration

   The RCIC inboard vacuum valve HV-1F084 is a flexwedge gate valve that is tested between the disc. Both disc and packing are exposed to the test pressure.

9. X-17: RPV Head Spray, See Dwg. M-151, Sh. 1.

   Based on valve closure calculations, leakage through the gate valve, HV151F022, in the reverse direction is equivalent to the leakage through the valves in the accident direction. Since the gate valve is inside primary containment, any leakage through the valve packing and seals that could leave primary containment is captured through reverse testing the valve.

The method by which these penetrations are tested and how the measured leakage is assigned is discussed below. The min path and max path leak rates are assigned to these penetrations in accordance with ANS-56.8-1994.

1. Penetrations X-7A, B, C, D: The MSIVs can be tested by two methods. The first method is by pressurizing between the MSL plugs and the MSIVs to Pa through test connection valves 141F017 and 141F018. This method determines the leak rate through each individual MSIV. The second method is to pressurize between the inboard and outboard MSIVs to 1/2 Pa through test connection valves 141F025A,B,C,D and 141F026A,B,C,D. This method determines the leak rate for the penetration and this leak rate is assigned to each MSIV in that penetration.

2a. Penetration X-10: Pressurize between HV149F007, HV149F088, and HV148F008 through test connection valves 149F036 and 149F037. This determines the leak rate for the penetration.

2b. Penetration X-11: Pressurize between HV155F002, HV155F100, and HV155F003 through test connection valves 155F014 and 155F015. This determines the leak rate for the penetration.

3. Penetration X-12: Pressurize between 151F067, PSV151F126, and HV151F008 through test connection valves 151061 and 151062. This determines the leak rate through PSV151F126 and HV151F008. Pressurize between 151F067 and HV151F009 through test connection valves 151061 and 151062. This determines the leak rate through HV151F009.

4a. Penetration X-25 and X-201A: Pressurize between HV15722, HV15725, HV15721, HV15723 and HV15724 through test connection valve 157018. This determines the leak rate for the penetration.

4b. Penetrations X-26: Pressurize between HV15713, HV15711 and HV15714 through test connection valve 157001. This determines the leak rate for the penetration.

4c. Penetration X-202: Pressurize between HV15703, HV15704 and HV15705 through test connection valve 157167. This determines the leak rate for the penetration.

4d. Penetration X-201B (U2): Pressurize between HV257113 and HV257114 through test connection valves 257320 and 257321. Pressurize the inlet flange of HV257113 between two sealing O-rings. These tests determine the leak rate for the penetration.

5a. Penetration X-210: Pressurize between HV155F066, HV155F075 and 155F049 through test connection valve 155F013. This determines the leak rate for the penetration.

5b. Penetration X-215: Pressurize between HV149F059, HV149F062 and 149F040 through test connection valve 149F041. This determines the leak rate for the penetration.

6. Penetration X-217: Pressurize between HV149F060 and 149F028 through test connection valve 149F055. This determines the leak rate for the penetration.

7. Penetration X-243: Pressurize between HV15766 and HV15768 through test connection valve 157122. This determines the leak rate for the penetration.

8a.2 Penetration X-244: Pressurize between HV-2F079 and HV-2F075 through Valve 2F092. Assign total leakage to that penetration.

8a.1 Penetration X-244: Pressurize between Disc for HV-1F079 through Valve 155802. Assign total leakage for that test to HV-1F079. Valve HV-1F075 is tested separately.

8b.2 Penetration X-245: Pressurize between HV-2F084 and HV-2F062 through Valve 2F065. Assign total leakage to that penetration.

8b.1 Penetration X-245: Pressurize between Disc for HV-1F084 (Unit1) and HV-2F084 (Unit 2) through Valve 149025 (Unit 1) and 249026 (Unit 2). Assign total leakage for that test to HV-1F084 (Unit 1) and HV-2F084 (Unit 2). Valve HV-1F062 (Unit 1) and HV-2F062 (Unit 2) is tested separately.

9. Penetration X-17: Pressurize between HV151F022 and HV151F023 through test connection valves 151F061 and 151F062. This determines the leak rate for the penetration.

Type B and C tests are performed by local pressurization. Use one of the following two methods: pressure decay or make-up flowrate. These methods of testing are described in ANSI/ANS-56.8-1994 Section 6.4. For most of the containment isolation valves, test pressure is applied in the accident direction. This means that pressure is applied in the same direction as the pressure experienced by the valve during a design basis accident. For a few containment isolation valves, test pressure is applied in a direction other than the accident direction (i.e., reverse testing). Due to generic BWR valve arrangements, reverse testing has been used for previously licensed plants. More details on reverse testing is provided above.

All containment isolation valve seats that are exposed to containment atmosphere following a LOCA are tested with air or nitrogen. The valves are to be tested at Pa as defined in Table 6.2-19.

Some penetrations contain lines that are designed to be water filled or sealed for at least 30 days following a LOCA, without a qualified seal water system. Table 6.2-22 identifies containment isolation valves that are in water filled or water sealed lines. The containment isolation valves in these lines are not required to be leak rate tested in accordance with 10CFR50, Appendix J. These valves are tested with water using the make-up flowrate method. These valves are tested at a pressure of 1.1 P_a. The leak rates are not included in the Type B and C running totals. The leak rates are included in the primary to secondary containment water leakage.

The Type C test acceptance criteria is in the plant Technical Specifications.

6.2.6.4 Scheduling and Reporting of Periodic Tests

The Leakage Rate Test Program specifies the periodic Type A, B, and C leak rate test frequencies.

Type B and C tests are conducted during normal plant operations or during plant shutdowns. However, the frequency between any individual Type B or C test shall not exceed the appropriate test interval specified in the Leakage Rate Test Program. Each time a Type B or C test is completed, the overall total leak rate for Type B and C tests is updated.

Post-refuel outage reports are prepared. The reports are available on-site for inspection.

6.2.6.5 Special Testing Requirements

6.2.6.5.1 Drywell to Pressure Suppression Chamber Atmosphere Bypass Area Test

6.2.6.5.1.1 High Pressure Leak Test

A Structural Integrity Test (SIT) was performed on the Unit 1 primary containment in January 1977. The SIT did not include a preoperational high pressure leak test to detect leakage from the drywell to the suppression chamber. Regulatory Guide 1.18 and 10CFR50 Appendix J do not require this high pressure leak test.

A SIT was performed on the Unit 2 primary containment in October 1983. The Unit 2 SIT was identical to the Unit 1 SIT with the following 3 exceptions:

1. It was performed during the ILRT.
2. Concrete strains were not measured.
3. A high pressure bypass test was performed.

6.2.6.5.1.2 Low Pressure Leak Test

Drywell to suppression chamber bypass tests are performed to determine the overall bypass area. The overall bypass area is the area that would allow drywell atmosphere to flow directly into the suppression chamber atmosphere without passing through the suppression pool water following a LOCA. The plant Technical Specifications specify the testing frequency for the bypass test.

At the start of the bypass test, the suppression chamber atmosphere is at atmospheric pressure. Based on the suppression pool water level, the drywell atmosphere is pressurized. The drywell pressure is maintained below a level that would force air through the downcomers and suppression pool water into the suppression chamber atmosphere. The bypass test then measures the pressure increase of the suppression chamber atmosphere. During the test, the suppression chamber atmosphere is isolated from the outside atmosphere. The drywell pressure is maintained at the desired differential pressure by adding or venting air to the drywell as required.

During refuel outages where a drywell to suppression chamber bypass test is not performed, a drywell to suppression chamber vacuum breaker leak test is performed on each set of vacuum breakers. This leak test is performed by pressurizing a downcomer with air to a pressure based on the suppression pool water level. The make-up flow required to maintain the test pressure is measured. The measured flow is the leak rate through the set of drywell to suppression chamber vacuum breakers.

The bypass test and vacuum breaker leak test acceptance criteria is in the plant Technical Specifications.

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TABLE 6.2-1

CONTAINMENT DESIGN PARAMETERS

	DRYWELL	SUPPRESSION CHAMBER
DRYWELL AND SUPPRESSION CHAMBER		
1. Internal Design Pressure, psig	53	53
2. External Design Pressure, psig	5	5
3. Drywell Deck Design Differential Pressure a. Download, psid b. Upload, psid	 28 5.5	
4. Design Temperature,°F	340	220
5. Drywell (including vents) Net Free Volume, ft^3	239,600	-
6. Design Leak Ratio, %/day	1.0	1.0
7. Maximum Allowable Leak Rate, %/day	1.0	1.0
8. Suppression Chamber Free Volume, ft^3		159,130 (low water) 148,590 (high water)
9. Suppression Chamber Water Volume. Minimum, ft^3 Maximum, ft^3		 122,410 131,550
10. Pool Free Cross-sectional Area, ft^2		5,277
11. Pool Depth (normal), ft		23
12. Drywell Free Volume/Pressure Suppression Chamber Free Volume		1.51 to 1.61
13. Primary System Volume/Pressure Suppression Pool Volume		.15
VENT SYSTEM		
1. No. of Active Downcomers		82
2. No. of Capped Downcomers		5
3. Nominal Downcomer Diameter, ft.		2
4. Total Downcomer Vent Area, ft^2		257
5. Downcomer Submergence, ft - high water level - normal water level - low water level		12 11 10
6. Downcomer Loss Factor		2.17

Table 6.2-2

ENGINEERED SAFETY SYSTEMS INPUTS AND ASSUMPTIONS FOR CONTAINMENT RESPONSE ANALYSES

	Analysis Value
	Case D[1]
ECCS Systems	
A. High Pressure Coolant Injection (HPCI)	
1. No. of Pumps	1
2. No. of Lines	1
3. Flowrate, gpm	0
B. Core Spray (CS)	
1. No. of Pumps	4
2. No. of Lines	2
3. Flowrate (runout), gpm/line	7,900
4. No. of Headers	2
C. Low Pressure Coolant Injection (LPCI)	
1. No. of Pumps	4
2. No. of Lines	2
3. Flowrate (runout), gpm/line	22,000
D. RHR Heat Exchangers	
1. Overall Heat Transfer Coefficient, Btu/sec.-°F/Unit	317.5

Notes:

1. Per Section 6.2.1.1.3.3.1.6, Case D produces the limiting results for the long-term containment analysis; therefore, only Case D values will be listed.

Table 6.2-3

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Table 6.2-4

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Table 6.2-5

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Table 6.2-6

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Table 6.2-7

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Table 6.2-8

This Table Has Been Deleted

TABLE 6.2-9

RPV BREAK FLOW DATA FOR
RECIRCULATION LINE BREAK
(102% P / 100% F)

TIME (sec)	TOTAL FLOW (lbm/sec)	FLOW ENTHALPY (Btu/lbm)
0.000	12210	525.0
0.003	52790	523.1
0.112	51280	523.3
0.300	50440	523.9
0.362	50150	524.1
0.456	49770	524.4
0.628	48920	525.0
0.756	48210	525.4
0.873	47520	525.8
0.951	47020	526.1
1.029	46500	526.3
1.123	45860	526.6
1.279	44770	527.1
1.435	43670	527.5
1.592	42570	527.9
1.779	41140	528.3
2.029	39620	529.0
2.310	38520	529.7
2.748	37820	530.6
3.060	37860	531.2
3.373	38270	531.9
3.685	38820	532.6
4.060	39430	533.5
4.498	39600	540.6
5.123	38090	547.5
6.123	37530	550.3
7.123	37390	545.9
8.029	33179	635.9
9.060	18430	726.3
10.029	18536	692.7

TABLE 6.2-9

RPV BREAK FLOW DATA FOR
RECIRCULATION LINE BREAK
(102% P / 100% F)

TIME (sec)	TOTAL FLOW (lbm/sec)	FLOW ENTHALPY (Btu/lbm)
12.498	17445	674.9
15.123	16650	647.0
17.623	14851	634.7
20.123	12901	626.5
25.123	8580	624.1
30.123	4858	616.7
35.002	2539	600.1
40.002	1189	613.7
45.010	522	677.2
50.017	188	759.8

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TABLE 6.2-10

RPV BREAK FLOW DATA FOR
MAIN STEAM LINE BREAK
(102% P / 100% F)

TIME (sec)	TOTAL FLOW (lbm/sec)	FLOW ENTHALPY (Btu/lbm)
0.001	9991	1191.0
0.007	11650	1191.0
0.011	11650	1191.0
0.065	11610	1191.0
0.112	11580	1191.0
0.215	8454	1191.0
0.309	8444	1192.0
0.402	8431	1192.0
0.512	8417	1192.0
0.605	8404	1192.0
0.715	8390	1192.0
0.809	8378	1192.0
0.875	8368	1192.0
1.000	29214	570.4
1.004	29215	570.4
1.262	29233	572.1
1.512	29239	573.6
1.731	29241	574.9
2.012	29233	576.6
2.481	29227	579.5
3.043	29199	583.0
3.481	29175	585.8
4.043	29117	589.5
4.543	29063	592.9
5.106	28963	597.1
6.043	28782	603.9
7.043	28493	611.7
8.043	28094	619.0

TABLE 6.2-10

RPV BREAK FLOW DATA FOR MAIN STEAM LINE BREAK (102% P / 100% F)

TIME (sec)	TOTAL FLOW (lbm/sec)	FLOW ENTHALPY (Btu/lbm)
9.043	27606	626.2
10.043	27028	633.1
13.543	19425	656.2
15.168	18573	666.4
17.418	17177	678.3
20.168	15251	688.6
25.168	11583	702.9
30.168	8203	715.7
35.168	5458	731.5
40.043	3512	758.0
45.043	2142	806.9
50.043	1255	894.2

TABLE 6.2-11
CORE DECAY HEAT FOLLOWING LOCA
FOR CONTAINMENT ANALYSIS

Time sec	+2 Sigma Decay Heat =SIL636	LOCA Fission Power	+2 Sigma Decay Heat +SIL636 +LOCA Fission Power	Time sec	+2 Sigma Decay Heat =SIL636	LOCA Fission Power	+2 Sigma Decay Heat +SIL636 +LOCA Fission Power
0	0.0722	0.9278	1.000	1000.0	0.0217	0	0.0217
0.5	0.0695	0.3334	0.4029	1.25E+03	0.0205	0	0.0205
1.0	0.0668	0.2042	0.2711	1.50E+03	0.0194	0	0.0194
1.5	0.0643	0.1781	0.2424	1.80E+03	0.0185	0	0.0185
2.0	0.0626	0.1911	0.2537	2.00E+03	0.0178	0	0.0178
2.5	0.0612	0.1828	0.2440	2.50E+03	0.0166	0	0.0166
3.0	0.0600	0.1885	0.2485	3.00E+03	0.0157	0	0.0157
3.6	0.0588	0.2207	0.2795	3.50E+03	0.0149	0	0.0149
4.0	0.0580	0.2437	0.3018	4.00E+03	0.0143	0	0.0143
4.4	0.0574	0.2491	0.3065	5.00E+03	0.0133	0	0.0133
5.0	0.0564	0.1990	0.2555	6.00E+03	0.0126	0	0.0126
6.0	0.0551	0.0300	0.0851	7.00E+03	0.0120	0	0.0120
7.0	0.0540	0.0183	0.0723	8.00E+03	0.0116	0	0.0116
8.0	0.0530	0.0166	0.0696	9.00E+03	0.0112	0	0.0112
9.0	0.0521	0.0149	0.0669	1.00E+04	0.0109	0	0.0109
10.0	0.0513	0.0127	0.0640	1.25E+04	0.0103	0	0.0103
12.5	0.0496	0.0102	0.0598	1.50E+04	9.79E-03	0	9.79E-03
15.0	0.0482	0.0099	0.0581	2.00E+04	9.10E-03	0	9.10E-03
20.0	0.0461	0.0072	0.0533	2.50E+04	8.61E-03	0	8.61E-03
25.0	0.0444	0.0054	0.0498	3.00E+04	8.24E-03	0	8.24E-03
30.0	0.0431	0.0044	0.0475	3.50E+04	7.95E-03	0	7.95E-03
35.0	0.0419	0.0037	0.0456	4.00E+04	7.68E-03	0	7.68E-03
40.0	0.0410	0.0032	0.0442	5.00E+04	7.27E-03	0	7.27E-03
50.0	0.0394	0.0025	0.0419	6.00E+04	6.95E-03	0	6.95E-03
60.0	0.0381	0.0021	0.0401	7.00E+04	6.69E-03	0	6.69E-03
70.0	0.0370	0.0018	0.0388	8.00E+04	6.48E-03	0	6.48E-03
80.0	0.0361	0.0016	0.0377	9.00E+04	6.30E-03	0	6.30E-03

TABLE 6.2-11
CORE DECAY HEAT FOLLOWING LOCA
FOR CONTAINMENT ANALYSIS

Time sec	+2 Sigma Decay Heat =SIL636	LOCA Fission Power	+2 Sigma Decay Heat +SIL636 +LOCA Fission Power	Time sec	+2 Sigma Decay Heat =SIL636	LOCA Fission Power	+2 Sigma Decay Heat +SIL636 +LOCA Fission Power
90.0	0.0353	0.0014	0.0367	1.00E+05	6.15E-03	0	6.15E-03
100.0	0.0346	0.0012	0.0358	1.25E+05	5.84E-03	0	5.84E-03
125.0	0.0331	0.0009	0.0340	1.50E+05	5.60E-03	0	5.60E-03
150.0	0.0320	0.0007	0.0327	2.00E+05	5.26E-03	0	5.26E-03
200.0	0.0303	0.0004	0.0307	2.50E+05	5.04E-03	0	5.04E-03
250.0	0.0291	0.0002	0.0293	3.00E+05	4.87E-03	0	4.87E-03
300.0	0.0281	0.0001	0.0282	3.50E+05	4.75E-03	0	4.75E-03
350.0	0.0273	0.0001	0.0273	4.00E+05	4.65E-03	0	4.65E-03
400.0	0.0266	0.0000	0.0266	5.00E+05	4.52E-03	0	4.52E-03
500.0	0.0254	0	0.0254	6.00E+05	4.44E-03	0	4.44E-03
600.0	0.0245	0	0.0245	7.00E+05	4.35E-03	0	4.35E-03
700.0	0.0237	0	0.0237	8.00E+05	4.19E-03	0	4.19E-03
800.0	0.0229	0	0.0229	9.00E+05	4.06E-03	0	4.06E-03
900.0	0.0223	0	0.0223	1.00E+06	3.89E-03	0	3.89E-03
Normalized Power = 3952 Mwt							

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TABLE 6.2-12

CONTAINMENT PENETRATION DATA

Penetration	Service	Fluid	Pipe Size (In.)	NRC Des. Crit.	E. S. F. (30)	Valve Number (36)	Primary Actuation Method	Second-ary Actuation Method	Power Source (17)	Valve Location (13)	Arrange ment (12)	Valve Type (1)	Valve Position				Closure Time (Secs)	Actuation Signal (2)	Length Pipe to Valve (Outer)	Remarks
													Normal	Shut-down	LOCA	Power Fails				
X-5 (Unit 1 Only)	Ctmt. Rad. Det., Supply Sample	Air/N_2	1	56	No	SV157100A	AC Coil	Spring	I	O(IB)	DD	GT	Open	Open	Closed	Closed	1	B,F	7'	(33)
						SV157101A	AC Coil	Spring	II	O		GT	Open	Open	Closed	Closed	1	B,F	8'	(33)
X-5 (Unit 1 Only)	Ctmt. Rad Det., Return Sample	Air/N_2	1	56	No	SV157102A	AC Coil	Spring	I	O(IB)	DD	GT	Open	Open	Closed	Closed	1	B,F	7'	(33)
						SV157103A	Ac Coil	Spring	II	O		GT	Open	Open	Closed	Closed	1	B,F	8'	(33)
X-5 (Unit 2 Only)	Ctmt. Rad. Det., Supply Sample	Air/N_2	1	56	No	SV257100A	AC Coil	Spring	I	O(IB)	DD	GT	Open	Open	Closed	Closed	1	B,F	8'	(33)
						SV257101A	AC Coil	Spring	II	O		GT	Open	Open	Closed	Closed	1	B,F	9.5'	(33)
X-5 (Unit 2 Only)	Ctmt. Rad. Det., Return Sample	Air/N_2	1	56	No	SV257102A	AC Coil	Spring	I	O(IB)	DD	GT	Open	Open	Closed	Closed	1	B,F	9'	(33)
						SV257103A	AC Coil	Spring	II	O		GT	Open	Open	Closed	Closed	1	B,F	10.5'	(33)
X-7A	Main Steam	Steam	26	55	Yes	1F028A	Compressed Air	Spring	II/RPSB	O	a	GB	Open	Closed	Closed	Closed	3-5	(a)		(3)(26)
			26			1F022A	Inst Gas	Spring	I/RPSA	I		GB	Open	Closed	Closed	Closed	3-5	(a)		(26)(37)
X-8	Main Steam Drain	Water	3	55	No	1F016	AC Mot	Manual	I	I	g	GT	Closed	Open	Closed	As Is	10	(a)	6'	(38)
			3			1F019	DC Mot	Manual	II	O		GT	Closed	Open	Closed	As Is	15	(a)	0	(38)
X-9A	Feed Water and HPCI, RCIC, and RWCU pump discharge	Water	24	55	Yes	1F032A	AC Mot	Manual	I	O	b	CK	Open	Closed	–	As Is	120	–	17	(14)(11)
			14			1F006	DC Mot	Manual	II	O		GT	Closed	Closed	Open	As Is	20	–		X-9B Only
						155038	Manual	–	–	O		GB	Closed	Closed	Closed	Closed	–	–		X-9B Only
			6			1F013	DC Mot	Manual	I	O		GT	Closed	Closed	Open	As Is	15	–		X-9A Only
						149020	Manual	–	–	O		GB	Closed	Closed	Closed	Closed	–	–		X-9A Only
			3			14182A	AC Mot	Manual	I	O		GT	Open	Open	Open	As Is	30	–		(11)(43)
			24			1F010A	Flow	–	–	I		CK	Open	Open	–	–	–	–		(11)(5)
			3			141F039A	Flow	–	–	O	b	CK	Open	Open	–	–	–			(11)(5)
			24			141818A	Flow	–	–	O	b	CK	Open	Open	–	–	–			(11)(5)
			3			241F039A	Flow	–	–	O	b	CK	Open	Open	–	–	–			(11)
X-10	Steam to RCIC	Steam	4	55	No	1F007	AC Mot	Manual	II	I	c	GT	Open	Closed	Open	As Is	20	(k)		(4)(15)
	Turbine		1			1F088	Inst Gas	Spring	II	I		GB	Closed	Closed	Open	Closed	20	(k)		(4)(15)
			4			1F008	DC Mot	Manual	I	O		GT	Open	Closed	Open	As Is	20	(k)	0'	(15)
X-11	Steam to	Steam	10	55	Yes	1F003	DC Mot	Manual	II	O	c	GT	Open	Closed	Open	As Is	50	(l)	0'	(15)
	HPCI		1			1F100	Inst Gas	Spring	I	I		GB	Closed	Closed	Closed	Closed	6	(l)		(15)(4)
	Turbine		10			1F002	AC Mot	Manual	I	I		GT	Open	Closed	Open	As Is	50	(l)		(15)(4)
X-12	RHR Shutdown Supply	Water	20	55	No	1F008	DC Mot	Manual	II	O	h	GT	Closed	Open	Closed	As Is	100	(b)	0	
			20			1F009	AC Mot	Manual	I	I		GT	Closed	Open	Closed	As Is	100	(b)		
			1			PSV1F126	Water	–	–	I		RLF	Closed	Closed	Closed	–	–	–		(4)
X-13A	RHR Shutdown Return	Water	24	55	Yes	1F015A	AC Mot	Manual	I	O	n	GT	Closed	Open	Open	As Is	24	–	0	(11)(6)(42)
			24			1F050A	Flow	Spring	I	I		TCK	Closed	Open	Open	–	–	–		(11)
			1			1F122A	Inst Gas	Spring	I	I		GB	closed	Closed	Closed	Closed	3	–		(11)

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Penetration	Service	Fluid	Pipe Size (In.)	NRC Des. Crit.	E. S. F. (30)	Valve Number (36)	Primary Actuation Method	Second-ary Actuation Method	Power Source (17)	Valve Location (13)	Arrange ment (12)	Valve Type (1)	Valve Position				Closure Time (Secs)	Actuation Signal (2)	Length Pipe to Valve (Outer)	Remarks
													Normal	Shut-down	LOCA	Power Fails				
X-14	Reactor Water Clean Up Supply	Water	6	55	No	1F001	AC Mot	Manual	I	I	g	GT	Open	Open	Closed	As Is	30	(c)	0	
			6			1F004	DC Mot	Manual	II	O		GT	Open	Open	Closed	As Is	30	(c), I		
X-16A	Core Spray	Water	12	55	Yes	1F005A	AC Mot	Manual	I	O	n	GT	Closed	Closed	Open	As Is	19	–	0	(11)
			12			1F006A	Flow	–	I	I		TCK	Closed	Closed	Open	–	–	–		(11)(5)
			1			1F037A	Inst Gas	Spring	I	I		GB	Closed	Closed	Closed	–	3	–		(11)
X-17	RPV Head Spray	Water	6	55	No	1F023	DC Mot	Manual	II	O	u	GB	Closed	Open	Closed	As Is	20	(d)	0	
(41)			6			1F022	AC Mot	Manual	I	I		GT	Closed	Open	Closed	As Is	30	(d)		(4)
X-19	Instrument Gas	N_2/Air Mix	3	56	No	SV12651	AC Coil	–	I	O	i	GB	Open	Open	Closed	Closed	2	F,G		(33)
						126074	Flow	–	–	I		CK	Open	Open	Closed	–	–	–		(5)
X-21	Instrument Gas	N_2/Air Mix	1	56	Yes	SV12654B	DC Coil	–	I	O	i	GB	Open	Open	Open	Open	1	–		(33)
						126152	Flow	–	–	I		CK	Open	Open	Open	–	–	–		(5)
X-23	Closed Cooling Water Supply	Water	4	56	No	HV11314	AC Mot	Manual	I	O	z	GT	Open	Closed	Closed	As Is	30	F,G		
(41)						HV11346	AC Mot	Manual	II	I		GT	Open	Closed	Closed	As Is	30	F,G		
X-24	Closed Cooling Water Return	Water	4	56	No	HV11313	AC Mot	Manual	I	O	z	GT	Open	Closed	Closed	As Is	30	F,G	0	
(41)						HV11345	AC Mot	Manual	II	I		GT	Open	Closed	Closed	As Is	30	F,G		
X-25	Drywell Purge Supply	Air/N_2	24	56	No	HV15722	Comp Air	Spring	I	O(IB)	Y	BF	Closed	Closed	Closed	Closed	15	B,F,R	0	(4)
			24			HV15723	Comp Air	Spring	II	O		BF	Closed	Closed	Closed	Closed	15	B,F,R	14	(8)
			6			HV15721	Comp Air	Spring	II	O		BF	Closed	Closed	Closed	Closed	15	B,F,R	10	(8)(32)
			18			HV15724	Comp Air	Spring	II	O		BF	Closed	Closed	Closed	Closed	15	B,F,R	10	(8)(32)
X-26	Drywell Purge Return	Air/N_2	24	56	No	HV15713	Comp Air	Spring	I	O(IB)	e	BF	Closed	Closed	Closed	Closed	15	B,F,R	0	(23) HS-17508AA (24) HS-15713A
			24			HV15714	Comp Air	Spring	II	O		BF	Closed	Closed	Closed	Closed	15	B,F,R		
			2			HV15711	Comp Air	Spring	II	O		GB	Closed	Closed	Closed	Closed	15	B,F,R		(23) HS-17508BA (24) HS-15711B
X-31B	Recirc Pump Seal Water Supply	Water	1	55	No	XV1F017B	Flow	-	-	O	BB	XFC	Open	Open	Open	-	-	-	0	(20)
						1F013B	Flow	-	-	I		CK	Open	Open	Open	-	-	-		(20)
X-31B (Unit 2 Only)	Ctmt. Rad. Det., Supply Sample	Air/N_2	1	56	No	SV257100B	AC Coil	Spring	I	O(IB)	DD	GT	Open	Open	Closed	Closed	1	B,F		(33)
						SV257101B	AC Coil	Spring	II	O		GT	Open	Open	Closed	Closed	1	B,F		(33)
X-31B (Unit 2 Only)	Ctmt. Rad. Det., Return Sample	Air/N_2	1	56	No	SV257102B	AC Coil	Spring	I	O(IB)	DD	GT	Open	Open	Closed	Closed	1	B,F		(33)
						SV257103B	AC Coil	Spring	II	O	DD	GT	Open	Open	Closed	Closed	1	B,F		(33)
X-35A and C thru F	TIP Drivers		3/8	56	No	J004	AC Coil	None		O(IB)	w	BL	Closed	Closed	Closed	Closed	5	A,F	2'	(21)
						J004	DC Explosion	None		O		Shear	Open	Open	Open	Open	1	–	2'	(21)

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Penetration	Service	Fluid	Pipe Size (In.)	NRC Des. Crit.	E. S. F. (30)	Valve Number (36)	Primary Actuation Method	Second-ary Actuation Method	Power Source (17)	Valve Location (13)	Arrangement (12)	Valve Type (1)	Valve Position: Normal	Valve Position: Shut-down	Valve Position: LOCA	Valve Position: Power Fails	Closure Time (Secs)	Actuation Signal (2)	Length Pipe to Valve (Outer)	Remarks
X-37A,B,C,D	CRD Insert	Water	1	55	Yes															(19)
X-38A,B,C,D	CRD Withdrawal	Water	3/4	55	Yes															(19)
X-39A	Drywell Spray	Water	12	56	No	1F016A	AC Mot	Manual	I	O	d	GB	Closed	Closed	Closed	As Is	90	F,G	7'	(6)(11)
X-41	Instrument Gas	N_2/Air	1	56	Yes	SV12654A	DC Coil	–	I	O	i	GB	Open	Open	Open	Open	1	–		(33)
		Mix				126154	Flow	–	–	I		CK	Open	Open	Open		–	–		(5)
X-42	Standby Liquid Control	Water	1-1/2	55	Yes	1F006	AC Mot	Manual	I	O	k	GCK	Open	Open	Open	As Is	34	–	6'	
						1F007	Flow	–	–	I		CK	Closed	Closed	Closed	–		–	16'	(5)
X-53 (41)	Chilled Water Supply "B"	Water	8	56	No	HV18781B1	Comp Air	Spring	II	O	I	GT	Open	Open	Closed	Closed	40	F,G	0	
						HV18782A1 (Unit 1)	Inst Gas	Spring	I	I		BF	Open	Open	Closed	Closed	12	F,G		
						HV28782A1 (Unit 2)		Spring	I	I		BF	Open	Open	Closed	Closed	12	F,G		
X-54 (41)	Chilled Water Return "B"	Water	8	56	No	HV18781B2	Comp Air	Spring	II	O	I	GT	Open	Open	Closed	Closed	40	F,G	0	
						HV18782A2 (Unit 1)	Inst Gas	Spring	I	I		BF	Open	Open	Closed	Closed	12	F,G		
						HV28782A2 (Unit 2)		Spring	I	I		BF	Open	Open	Closed	Closed	12	F,G		
X-55 (41)	Chilled Water Supply "A"	Water	8	56	No	HV18781A1	Comp Air	Spring	I	O	I	GT	Open	Open	Closed	Closed	40	F,G	0	
						HV18782B1 (Unit 1)	Inst Gas	Spring	II	I		BF	Open	Open	Closed	Closed	12	F,G		
						HV28782B1 (Unit 2)		Spring	II	I		BF	Open	Open	Closed	Closed	12	F,G		
X-56 (41)	Chilled Water Return "A"	Water	8	56	No	HV18781A2	Comp Air	Spring	I	O	I	GT	Open	Open	Closed	Closed	40	F,G	0	
						HV18782B2 (Unit 1)	Inst Gas	Spring	II	I		BF	Open	Open	Closed	Closed	12	F,G		
						HV28782B2 (Unit 2)		Spring	II	I		BF	Open	Open	Closed	Closed	12	F,G		
X-60A	Sample & Analyzer	Gas	1	56	Yes	SV15740A	AC Coil	Spring	I	O(1B)	q	GB	Closed	Open	Closed	Closed	1	B,F		(22)10 Min. (33) (40)
						SV15750A	AC Coil	Spring	I	O(1B)		GB	Closed	Open	Closed	Closed	1	B,F		(22)10 Min. (33) (40)
						SV15742A	AC Coil	Spring	I	O		GB	Closed	Open	Closed	Closed	1	B,F		(22)10 Min. (33) (40)
						SV15752A	AC Coil	Spring	I	O		GB	Closed	Open	Closed	Closed	1	B,F		(22)10 Min. (33) (40)
X-60A	Recirc Pump Seal Water Supply	Water	1	55	No	XV1F017A	Flow	–	–	O	BB	XFC	Open	Open	Open	–	–	–	0	(20)
						1F013A	Flow	–	–	I		CK	Open	Open	Open	–	–	–		(20)
X-60B	Sample & Analyzer	Water	3/4	55	No	1F019	Inst Gas	Spring	I	I	EE	GB	Open	Closed	Open	Closed	9	B,C		
			1			1F020	Comp Air	Spring	II	O		GB	Open	Closed	Open	Closed	2	B,C	2'	
X-61A (41)	Demin. Water	Water	1	56	No	141018	Manual	–	–	I	FF	GB	Closed	Closed	Closed	Closed	–	–		
						141017	Manual	–	–	O		GB	Closed	Closed	Closed	Closed	–	–		
X-61A	ILRT Leak Verification	Gas	1	56	No	157193 (Unit 1) 257200 (Unit 2)	Manual	–	–	I	FF	GB	Closed	Closed	Closed	Closed	–	–		
						157194 (Unit 1) 257199 (Unit 2)	Manual	–	–	0		GB	Closed	Closed	Closed	Closed	–	–		

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Penetration	Service	Fluid	Pipe Size (In.)	NRC Des. Crit.	E. S. F. (30)	Valve Number (36)	Primary Actuation Method	Second-ary Actuation Method	Power Source (17)	Valve Location (13)	Arrange ment (12)	Valve Type (1)	Valve Position				Closure Time (Secs)	Actuation Signal (2)	Length Pipe to Valve (Outer)	Remarks
													Normal	Shut-down	LOCA	Power Fails				
X-72A	Equipment Drain	Water	3	56	No	HV16116A1	Comp Air	Spring	I	O(IB)	f	GT	Closed	Closed	Closed	Closed	15	B,F	0	
						HV16116A2	Comp Air	Spring	II	O		GT	Closed	Closed	Closed	Closed	15	B,F		
X-72B	Floor Drain	Water	3	56	No	HV16108A1	Comp Air	Spring	I	O(IB)	f	GT	Closed	Closed	Closed	Closed	15	B,F	0	
						HV16108A2	Comp Air	Spring	II	O		GT	Closed	Closed	Closed	Closed	15	B,F	1	
X-80C	H_2O Analyzer	Gas	1	56	Yes	SV15750B	AC Coil	Spring	II	O(IB)	q	GB	Closed	Open	Closed	Closed	1	B,F		(22)10 Min. (33) (40)
						SV15740B	AC Coil	Spring	II	O(IB)		GB	Closed	Open	Closed	Closed	1	B,F		(22)10 Min. (33) (40)
						SV15776B	AC Coil	Spring	II	O(IB)		GB	Closed	Open	Closed	Closed	1	B,F		(22)10 Min. (33) (40)
						SV15742B	AC Coil	Spring	II	O		GB	Closed	Open	Closed	Closed	1	B,F		(22)10 Min. (33) (40)
						SV15752B	AC Coil	Spring	II	O		GB	Closed	Open	Closed	Closed	1	B,F		(22)10 Min. (33) (40)
						SV15774B	AC Coil	Spring	II	O		GB	Closed	Open	Closed	Closed	1	B,F		(22)10 Min. (33) (40)
X-85A	Chilled Water to Recirc Pump A	Water	3	56	No	HV18791A1	Comp Air	Spring	I	O	l	GT	Open	Closed	Closed	Closed	15	B,F	6	
(41)						HV18792B1 (Unit 1)	Inst Gas	Spring	II	I		BF	Open	Closed	Closed	Closed	8	B,F		
						HV28792B1 (Unit 2)		Spring	II	I		BF	Open	Closed	Closed	Closed	8	B,F		
X-85B	Chilled Water from Recirc Pump A	Water	3	56	No	HV18791A2	Comp Air	Spring	I	O	l	GT	Open	Closed	Closed	Closed	15	B,F	6	
(41)						HV18792B2 (Unit 1)	Inst Gas	Spring	II	I		BF	Open	Closed	Closed	Closed	8	B,F		
						HV28792B2 (Unit 2)		Spring	II	I		BF	Open	Closed	Closed	Closed	8	B,F		
X-86A	Chilled Water to Recirc Pump B	Water	3	56	No	HV18791B1	Comp Air	Spring	II	O	l	GT	Open	Closed	Closed	Closed	15	B,F	0	
(41)						HV18792A1 (Unit 1)	Inst Gas	Spring	I	I		BF	Open	Closed	Closed	Closed	8	B,F		
						HV28792A1 (Unit 2)		Spring	I	I		BF	Open	Closed	Closed	Closed	8	B,F		
X-86B	Chilled Water from Recirc Pump B	Water	3	56	No	HV18791B2	Comp Air	Spring	II	O	l	GT	Open	Closed	Closed	Closed	15	B,F	0	
(41)						HV18792A2 (Unit 1)	Inst Gas	Spring	I	I		BF	Open	Closed	Closed	Closed	8	B,F		
						HV28792A2 (Unit 2)		Spring	I	I		BF	Open	Closed	Closed	Closed	8	B,F		
X-87	Instrument Gas Return	N_2/Air Mix	2	56	No	SV12605	AC Coil	Spring	II	O	t	GB	Open	Closed	Closed	Closed	1	F,G	0	(33)
						HV12603	AC Mot	Manual	I	I		GB	Open	Closed	Closed	As Is	20	F,G	–	
X-88A	Drywell N_2 Makeup	N_2	1	56	No	SV15767	AC Coil	–	I	O(IB)	q	GB	Closed	Closed	Closed	Closed	1	B,F,R		(33)
						SV15789	AC Coil	–	II	O		GB	Closed	Closed	Closed	Closed	1	B,F,R	3	33)
X-88B	H_2O_2 Analyzer & Ctmt.Rad.Det Return	Gas	1	56	Yes	SV15776A	AC Coil	Spring	I	O(IB)	q	GB	Closed	Open	Closed	Closed	1	B,F	O	(22)10Min.(33) (40)
			1	56	Yes	SV15774A	AC Coil	Spring	I	O		GB	Closed	Open	Closed	Closed	1	B,F		(22)10Min.(33) (40)
X-91A (Unit 1 Only)	Ctmt. Rad. Det., Supply Sample	Air/N_2	1	56	No	SV157100B	AC Coil	Spring	I	O(IB)	DD	GT	Open	Open	Closed	Closed	1	B,F	11'	(33)
						SV157101B	AC Coil	Spring	II	O		GT	Open	Open	Closed	Closed	1	B,F	12'	(33)
X-91A (Unit 1 Only)	Ctmt. Rad. Det., Return Sample	Air/N_2	1	56	No	SV157102B	AC Coil	Spring	I	O(IB)	DD	GT	Open	Open	Closed	Closed	1	B,F	11'	(33)
						SV157103B	AC Coil	Spring	II	O		GT	Open	Open	Closed	Closed	1	B,F	12'	(33)
X-93	TIP Instruments	N_2/Air Mix	1	56	No	SV12661	Coil	Spring	I	O	i	GB	Open	Closed	Closed	Closed	1	B,F		(33)
						126072	Flow	–		I		CK	Open	Closed	–	–	–	–	–	

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CONTAINMENT PENETRATION DATA

Penetration	Service	Fluid	Pipe Size (In.)	NRC Des. Crit.	E. S. F. (30)	Valve Number (36)	Primary Actuation Method	Secondary Actuation Method	Power Source (17)	Valve Location (13)	Arrangement (12)	Valve Type (1)	Valve Position: Normal	Valve Position: Shut-down	Valve Position: LOCA	Valve Position: Power Fails	Closure Time (Secs)	Actuation Signal (2)	Length Pipe to Valve (Outer)	Remarks
X-201A	Suppression Chamber Purge Supply	Air/N_2	18	56	No	HV15725	Comp Air	Spring	I	O(IB)	Y	BF	Closed	Closed	Closed	Closed	15	B,F,R	0	(4)
			18			HV15724	Comp Air	Spring	II	O		BF	Closed	Closed	Closed	Closed	15	B,F,R	10	(8)
			6			HV15721	Comp Air	Spring	II	O		BF	Closed	Closed	Closed	Closed	15	B,F,R		(8)
			24			HV15723	Comp Air	Spring	II	O		BF	Closed	Closed	Closed	Closed	15	B,F,R	14	(8)
X-201B (Unit 2 only)	Hardened Containment Vent System	Steam/ H_2	12	56	No	HV257113	Compressed Gas (via SV)	Compressed Gas (via bypass to SV)	—	O(IB)	XX1	BF	Closed	Closed	Closed	Closed	—	—	9 Ft	
			12			HV257114			—	O		BF	Closed	Closed	Closed	Closed	—	—		
X-202	Suppression Chamber Purge Exhaust	Air/N_2	18	56	No	HV15703	Comp Air	Spring	I	O(IB)	e	BF	Closed	Closed	Closed	Closed	15	B,F,R	0	
																				(24)HS-15703A
																				(23)HS-17508AA
			18			HV15704	Comp Air	Spring	II	O		BF	Closed	Closed	Closed	Closed	15	B,F,R	15	
			2			HV15705	Comp Air	Spring	II	O		GB	Closed	Closed	Closed	Closed	15	B,F,R		
																				(23)HS-17508BA
																				(24)HS-15705B
X-203A	RHR Pump Suction	Water	24	56	Yes	1F004A	AC Mot	Manual	I	O	o	GT	Open	Closed	Open	As Is	200	–	0	(6)(29)(34)
X-204A	RHR Pump Test Line	Water	18	56	Yes	1F028A	AC Mot	Manual	I	O	X	GT	Closed	Closed	Closed	As Is	90	F,G	24	(8)(6)(11)(28)
			4		No	1F011A	Manual	-	I	O		GT	Closed	Closed	Closed	As Is			150	(8)(6)(11)
X-205A	Containment Spray	Water	18	56	Yes	1F028A	AC Mot	Manual	I	O	X	GT	Closed	Closed	Closed	As Is	90	F,G		(8)(6)(11)(28)
			4		No	1F011A	Manual	-	I	O		GT	Closed	Closed	Closed	As Is			137	(8)(6)(11)
X-206A	Core Spray Pump Suction	Water	16	56	Yes	1F001A	AC Mot	Manual	I	O	o	GT	Open	Open	Open	As Is	83	–	0	(6)(11)(34)
X-207A	Core Spray Pump Test & Flush	Water	10	56	Yes	1F015A	AC Mot	Manual	I	O	r	GB	Closed	Closed	Closed	As Is	80	F,G	0	(6)(11)(34)
X-208A	Core Spray Pump Min. Recirc.	Water	3	56	Yes	1F031A	AC Mot	Manual	I	O	r	GT	Open	Closed	Closed	As Is	20	–		(6)(11)(34)
X-209	HPCI Pump Suction	Water	16	56	Yes	1F042	DC Mot	Manual	II	O	o	GT	Closed	Closed	Open	As Is	115	(I)	0	(16)(34)
X-210	HPCI Turb Exhaust	Steam	20	56	Yes	1F066	DC Mot	Manual	II	O(IB)	m	GT	Open	Open	Open	As Is	111	–	0	(4)
						1F049	Flow	–		O		CK	Closed	Closed	Open	–				(5)
X-211	HPCI Pump Min. Recirc.	Water	4	56	Yes	1F012	DC Mot	Manual	II	O(IB)	m	GT	Closed	Closed	Closed	As Is	10	–	0	(34)
						1F046	Flow	–		O		CK	Closed	Closed	Closed	–				(5)(34)
X-212 (Unit 2 Only)	Ctmt. Rad. Det., Supply Sample	Air/N_2	1	56	No	SV257104	AC Coil	Spring	I	O(IB)	DD	GT	Closed	Closed	Closed	Closed	1	B,F		(33)
						SV257105	AC Coil	Spring	II	O		GT	Closed	Closed	Closed	Closed	1	B,F		(33)
X-214	RCIC Pump Suction	Water	6	56	No	1F031	DC Mot	Manual	I	O	o	GT	Closed	Closed	Open	As Is	35	–		(16)(34)

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CONTAINMENT PENETRATION DATA

Penetration	Service	Fluid	Pipe Size (In.)	NRC Des. Crit.	E. S. F. (30)	Valve Number (36)	Primary Actuation Method	Second-ary Actuation Method	Power Source (17)	Valve Location (13)	Arrangement (12)	Valve Type (1)	Valve Position: Normal	Valve Position: Shut-down	Valve Position: LOCA	Valve Position: Power Fails	Closure Time (Secs)	Actuation Signal (2)	Length Pipe to Valve (Outer)	Remarks
X-215	RCIC Turb Exhaust	Steam	10	56	No	1F059	DC Mot	Manual	I	O(IB)	m	GT	Open	Open	Open	As Is	60	–	0	(4)
						1F040	Flow	–	–	O		CK	Closed	Closed	Open	–		–		(5)
X-216	RCIC Pump Recirc.	Water	2	56	No	1F019	DC Mot	Manual	I	O(IB)	m	GB	Closed	Closed	Closed	As Is	5	–		(34)
						1F021	Flow	–	–	O		CK	Closed	Closed	Closed	–	–	–		(5)(34)
X-217 (Unit 1 Only)	RCIC Vacuum Pump Disch.	Air	2	56	No	1F060	DC Mot	Manual	I	O(IB)	m	GB	Open	Open	Open	As Is	32	–		(4)
						1F028	Flow	–		O		CK	Closed	Closed	Open	–	–	–		(5)
X-217 (Unit 2 Only)	RCIC Vacuum	Air	2	56	No	2F060	DC Mot	Manual	I	O(IB)	m	GB	Open	Open	Open	As Is	25	–		(4)
						2F028	Flow			O		CK	Closed	Closed	Open	–	–	–		(5)
X-218	Instrument Gas	N_2	1	56	No	SV12671	AC Coil	Spring	I	O	CC	GB	Closed	Closed	Closed	Closed	1	B,F		(33)
						126164	Flow	–	–	O(IB)		CK	Closed	Closed	Closed	–	–	–		(5)
X-220A (Unit 1 Only)	Ctmt. Rad. Det., Return Sample	Air/N_2	1	56	No	SV157106	AC Coil	Spring	I	O(IB)	DD	GT	Closed	Closed	Closed	Closed	1	B,F	8'	(33)
						SV157107	AC Coil	Spring	II	O		GT	Closed	Closed	Closed	Closed	1	B,F	9'	(33)
X-220B	Wetwell N_2 Makeup	N_2	1	56	No	SV15737	AC Coil	–	I	O(IB)	DD	GB	Closed	Closed	Closed	Closed	1	B,F,R		(33)
						SV15738	AC Coil	–	II	O		GB	Closed	Closed	Closed	Closed	1	B,F,R		(33)
X-221A	H_2O_2 Analyzer, Ctmt. Rad Det.,	N_2/Air	1	56	Yes	SV15780A	AC Coil	Spring	I	O(IB)	DD	GB	Closed	Open	Closed	Closed	1	B,F		(22)10Min.(33) (40) (11-Unit 2 Only)
	Sample Pts	Mix				SV15782A	AC Coil	Spring	I	O		GB	Closed	Open	Closed	Closed	1	B,F		(22)10Min.(33) (40) (11-Unit 2 Only)
X-221B (Unit 2 Only)	H_2O_2 Analyzer	N_2/Air	1	56	Yes	SV25780B	AC Coil	Spring	II	O(IB)	DD	GB	Closed	Open	Closed	Closed	1	B,F		(22)10Min.(33) (40)
	Ctmt. Rad. Det., Sample Pts.	Mix				SV25782B	AC Coil	Spring	II	O	DD	GB	Closed	Open	Closed	Closed	1	B,F		(22)10Min.(33) (40)
X-226A	RHR Min. Recirc	Water	6	56	Yes	1F007A	AC Mot	Manual	I	O	r	GT	Open	Closed	Closed	As Is	38	–	0	(6)(11)(34)
X-228A (Unit 1 Only)	Ctmt. Rad. Det., Supply Sample	Air/N_2	1	56	No	SV157104	AC Coil	Spring	I	O(IB)	DD	GT	Closed	Closed	Closed	Closed	1	B,F	8'	(33)
						SV157105	AC Coil	Spring	II	O		GT	Closed	Closed	Closed	Closed	1	B,F	9'	(33)
X-229B (Unit 2 Only)	Ctmt. Rad. Det., Return Sample	Air/N_2	1	56	No	SV257106	AC Coil	Spring	I	O(IB)	DD	GT	Closed	Closed	Closed	Closed	1	B,F		(33)
						SV257107	AC Coil	Spring	II	O		GT	Closed	Closed	Closed	Closed	1	B,F		(33)
X-233 (Unit 1 Only)	H_2O_2 Analyzer, Ctmt. Rad Det.,	N_2/Air	1	56	Yes	SV15782B	AC Coil	Spring	II	O	DD	GB	Closed	Open	Closed	Closed	1	B,F		(22)10Min.(33) (40)
	Sample Pts.	Mix				SV15780B	AC Coil	Spring	II	O(IB)		GB	Closed	Open	Closed	Closed	1	B,F		(22)10Min.(33) (40)
X-238A	H_2O_2 Analyzer Return, Ctmt.Rad. Det. &	N_2/Air	1	56	Yes	SV15736A	AC Coil	Spring	I	O(IB)	DD	GB	Closed	Open	Closed	Closed	1	B,F		(22)10Min.(33) (40)
	Post-Accident Sample	Mix				SV15734A	AC Coil	Spring	I	O		GB	Closed	Open	Closed	Closed	1	B,F		(22)10Min.(33) (40)
X-238B (Unit 1 Only)	H_2O_2 Analyzer & Ctmt.Rad.Det Return	N_2/Air	1	56	Yes	SV15734B	AC Coil	Spring	II	O	DD	GB	Closed	Open	Closed	Closed	1	B,F		(22)10Min.(33) (40)
		Mix				SV15736B	AC Coil	Spring	II	O(IB)		GB	Closed	Open	Closed	Closed	1	B,F		(22)10Min.(33) (40)

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TABLE 6.2-12

CONTAINMENT PENETRATION DATA

Penetration	Service	Fluid	Pipe Size (In.)	NRC Des. Crit.	E. S. F. (30)	Valve Number (36)	Primary Actuation Method	Second-ary Actuation Method	Power Source (17)	Valve Location (13)	Arrangement (12)	Valve Type (1)	Valve Position: Normal	Valve Position: Shut-down	Valve Position: LOCA	Valve Position: Power Fails	Closure Time (Secs)	Actuation Signal (2)	Length Pipe to Valve (Outer)	Remarks
X-238B (Unit 2 Only)	H_2O_2 Analyzer & Cont Rad Det.Return	N_2/Air Mix	1	56	Yes	SV25734B	AC Coil	Spring	I	O	DD	GB	Closed	Open	Closed	Closed	1	B,F		(22)10Min.(33) (40)
						SV25736B	AC Coil	Spring	II	O(IB)		GB	Closed	Open	Closed	Closed	1	B,F		(22)10Min.(33) (40)
X-243	Suppression Pool Cleanup & Drain	Water	6	56	No	HV15766	AC Mot	Manual	I	O(IB)	s	GT	Closed	Closed	Closed	As Is	35	B,F	0	(4)
						HV15768	DC Mot	Manual	II	O		GT	Closed	Closed	Closed	As Is	30	B,F	1	
X-244	HPCI Vacuum Breaker	N_2/Air Mix	3	56	Yes	1F079	DC Mot	Manual	I	O(IB)	pl	GT	Open	Open	Closed	As Is	15	F, LB	0	
						1F075	DC Mot	Manual	II	O	pl	GT	Open	Open	Closed	As Is	15	F, LB	7	(39)
X-245	RCIC Vacuum Breaker	Air/N_2	2	56	No	1F084	DC Mot	Manual	II	O(IB)	pl	GT	Open	Open	Closed	As Is	10	F, KB		(39)
						1F062	DC Mot	Manual	I	O	pl	GT	Open	Open	Closed	As Is	10	F, KB		
X-246A	RHR Relief Valve Discharge	Water/ Steam/ Air/ Gas	1	56	Yes	PSV15106A	Water Press	–		O	j	RLF	Closed	Closed	Closed	–		–		(6)(11)
			1			HV1F103A	AC Mot	Manual	I	O		GB	Closed	Closed	Closed	As Is		–		(6)(11)(31)

NOTES:

(1) Valve Type

Ball	BL
Butterfly	BF
Check	CK
Gate	GT
Globe	GB
Globe Stop Check	GCK
Pressure Relief	RLF
Testable Check	TCK
Excess Flow Check	XFC
Explosive (Shear)	SHEAR

(2) Isolation Signal Codes

All power-operated isolation valves are capable of being operated remote-manually from the control room.

Automatic isolation signals are listed and described below:

TABLE 6.2-12

CONTAINMENT PENETRATION DATA

Signal	Description
A	Reactor Vessel Water Level - Low Level 3
B	Reactor Vessel Water Level - Low, Low Level 2
C	Main Steam Line Radiation - High
D	Main Steam Line Flow - High
EA	Reactor Building Steam Line Tunnel Temperature - High
EC	Turbine Building Steam Line Tunnel Temperature - High
F	Drywell Pressure - High
G	Reactor Vessel Water Level - Low, Low, Low Level I
I	Standby Liquid Control System Manual Initiation
JA	RWCS Differential Flow - High
JB	RWCS Differential Pressure (Flow) - High
KA	RCIC Steam Line Differential Pressure (Flow) High
KB	RCIC Steam Supply Pressure - Low
KC	RCIC Turbine Exhaust Diaphragm Pressure - High
KD	RCIC Equipment Room Temperature - High
KF	RCIC Pipe Routing Area Temperature - High
KH	RCIC Emergency Area Cooler Temperature - High
LA	HPCI Steam Line Differential Pressure (Flow) High
LB	HPCI Steam Supply Pressure - Low
LC	HPCI Turbine Exhaust Diaphragm Pressure - High
LD	HPCI Equipment Room Temperature - High
LF	HPCI Emergency Area Cooler Temperature - High
LG	HPCI Pipe Routing Area Temperature – High

Signal	Description
MC	RHR System Flow - High
P	Main Steam Line Pressure - Low
R	SGTS Exhaust Radiation - High
UA	Main Condenser Vacuum - Low
UB	Reactor Vessel Pressure - High
WA	RWCS Area Temperature - High

TABLE 6.2-12

CONTAINMENT PENETRATION DATA

Isolation Actuation Groupings
(a) G, D, EA, EC, P, UA
(b) A, MC, UB
(c) B, JA, JB, WA
(d) A, F, MC, UB
(k) KA, KB, KC, KD, KF, KH
(l) LA, LB, LC, LD, LF, LG

(3) Test pressure is less than operating pressure - see Section 6.2.6.

(4) Test pressure is applied in reverse direction.

(5) Unassisted check valve is used as one containment boundary.

(6) External piping system provides one containment boundary.

(7) Intentionally deleted.

(8) Valve isolates two piping penetrations.

(9) Intentionally deleted.

(10) Intentionally deleted.

(11) 'B' penetration data is identical with 'A' penetration data but with 'B' suffix except that, where applicable, power for 'A' penetration isolation valves are supplied from Division I power and power for 'B' penetration isolation valves are supplied from Division II.

(12) See Figures 6.2-44 and 6.2-44A through 6.2-44L. Letters in this column refer to details in the figures.

(13) For valve location, I indicates a valve inside the primary containment; 0 indicates a valve outside the primary containment. (IB) indicates the inboard of two or more series isolation valves located outside the containment.

(14) Check valve closed on reverse flow if feedwater is not available. Closure may be assisted remote-manually with motor-operator.

(15) Valve does not receive a LOCA signal but does receive a closure signal (k or l) for a break in the steam line to the turbine.

(16) Opens on condensate storage tank low level or suppression pool high level, and system isolation signal is not present.

TABLE 6.2-12

CONTAINMENT PENETRATION DATA

(17) For air or gas operated valves, the power source listed is for the associated solenoid valve.

(18) These valves do not receive an isolation signal but they cannot be opened when a steam line break signal (k or l) is open.

(19) No containment isolation valves are provided. For explanation, refer to Subsections 4.6.1 and 6.2.4.3.2.3.

(20) The containment isolation scheme for this penetration has been analyzed "on some other defined basis" than GDC 55. See Subsection 6.2.4.3.2.

(21) Isolation of the Traversing Incore Probe (TIP) guide tube is normally accomplished by a solenoid-operated ball valve when the TIP cable is withdrawn. The explosive (shear) valve is fired only when the cable jams in the inserted position and a containment isolation is required. See Subsection 6.2.4.3.3.3.10.

(22) Interlock of the valve is designed to close upon LOCA signal but can be reopened after noted time (See 7.3.l.lb.1.3 and 6.2.4.3.3.1).

(23) Interlock of the valve is designed to close upon LOCA signal, but that signal can be bypassed and the valve can be reopened by noted handswitch (HS). LOCA bypass has no effect on High High Radiation closure and High High Radiation override has no effect on LOCA closure.

(24) Interlock of the valve is designed to close upon high radiation signal from the Standby Gas Treatment System exhaust, but that signal can be overridden and the valve reopened by noted handswitch (HS). LOCA bypass has no effect on High High Radiation closure and High High Radiation Override has no effect on LOCA closure.

(25) Intentionally deleted.

(26) Data in table for A penetration and valve also applies to B, C, and D penetrations and valves.

(27) Intentionally deleted.

(28) These valves can be opened post-LOCA if LPCI injection valve E11-F015 is closed or by manual isolation signal bypass, E11A-S18.

(29) 'C' penetration data is identical to 'A' penetration data but with 'C' suffix. 'B' and 'D' penetration data is identical to 'A' penetration data but with 'B' and 'D' suffixes and power supplied by Div. II.

(30) Engineered safety features systems are defined in Section 6.0. This column lists engineered safety features (ESF) systems. ESF systems are defined in Section 6.0. All containment isolation valves in this table have an ESF function whether or not their respective systems are ESF.

(31) Valve HV-F103A must be remote-manually opened when taking liquid samples post-accident.

(32) For these valves the first closure time is for Unit 1 valves and second is for the Unit 2 valves.

TABLE 6.2-12

CONTAINMENT PENETRATION DATA

(33) For purposes of Inservice Inspection per the ASME Code, such valves are classified as Rapid-Acting Valves (RAV) or valves which operate in an extremely short period of time. The specified FSAR values are representative of valve design limits rather than the installed stroke times. Specific acceptance criteria for these valves are specified in the Inservice Inspection Program Plan.

(34) This penetration is not Type C tested. This line terminates below the minimum water level in the Suppression Pool.

(35) These valves will be opened for collecting samples during normal and shutdown conditions.

(36) Valves in vents, drains and test connections that represent containment boundary are not listed in this table. Such valves are identified on the appropriate system P&ID with a “CB” designation.

(37) When testing in between MSIVs, test pressure is applied in the reverse direction.

(38) Deleted

(39) Test pressure is applied between the valve disc.

(40) External piping system provides redundant containment boundary as described in Note 31 to Table 6.2-22.

(41) Protection is susceptible to the thermal pressurization phenomenon as discussed in NRC Generic Letter 96-06.

(42) The containment isolation scheme for this penetration has been analyzed “on some other defined basis” than GDC 55. See Section 6.2.4.3.2.10 for details.

(43) Valves HV-14182A&B and HV-24182A&B are not relied upon for short-term containment isolation. See Section 6.2.4.3.2.1 for details. The closure times listed for these valves are nominal closure times. These times are neither stroke time limits nor design requirements that are relied upon in any analyses.

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Start Historical

TABLE 6.2-13

PARAMETERS USED FOR THE EVALUATION OF COMBUSTIBLE GASES IN THE CONTAINMENT AFTER A LOCA

ITEM	VALUE	
Zinc Corrosion Rate $\frac{\text{(lb-mole)}}{\text{ft}^2 - \text{hr}}$		
90°F	2.67×10^{-8}	
300°F	2.60×10^{-6}	
Zinc Corrosion Rate $\frac{\text{(lb-mole)}}{\text{ft}^2 - \text{hr}}$		
90°F	2.67×10^{-8}	
300°F	2.60×10^{-6}	
Aluminum Corrosion Rate $\frac{\text{(lb-mole)}}{\text{ft}^2 - \text{hr}}$		
100°F	1.36×10^{-9}	
200°F	7.49×10^{-9}	
300°F	2.63×10^{-8}	
	Drywell	Wetwell
Mass of zinc in galvanized steel (lb.)	9500	2770
Area of zinc in galvanized steel (sq ft.)	103,258	29,898
Mass of zinc paint (lb)*	5690	1004
Area of zinc paint (sq ft.)*	82,439	23,819
Percentage of zinc paint which is zinc	86	87.2
Mass of Aluminum (lb.)	1269	100
Mass of zircalloy cladding surrounding the fuel (lb)	69,325	
Reactant Mass of Zircalloy (lb.)	683.03	
Volume of free hydrogen normally in the coolant (scf @ 60°F)	Negligible	

* Surrounding active fuel only, not including plenum volumes.

TABLE 6.2-13

PARAMETERS USED FOR THE EVALUATION OF COMBUSTIBLE GASES IN THE CONTAINMENT AFTER A LOCA

ITEM	VALUE	
Reactor Operating Thermal Power	4031 Mwt*	
Fraction of fission product radiation energy absorbed by the coolant:		
Betas from fission products in the fuel	0.0	
Betas from fission products mixed with the coolant	1.0	
Gammas from fission products in the fuel	0.1	
Gammas from fission products mixed with the coolant	1.0	
Hydrogen yield rate G (H_2) molecules/100 ev	0.50	
Oxygen yield rate G (O_2) molecules/100 ev	0.25	
Fission product distribution:		
Coolant	1% solids + 50% halogens	
Air	100% noble gases	
Core	All others	
Drywell volume (cu ft.)	239,600	
Wetwell volume (cu ft.)	148,600	
Time to reach 3.5 vol. percent hydrogen in the drywell (days)	0.8	
Time to reach 3.5 vol. percent hydrogen in the wetwell (days)	0.5	

* 102% Rated Reactor operating thermal power

End Historical

TABLE 6.2-14

PRIMARY CONTAINMENT ATMOSPHERE MONITORING SYSTEM
(HYDROGEN/OXYGEN ANALYZER)
SYSTEM LEVEL

FAILURE MODE AND EFFECT ANALYSIS

Failure Mode	Effect on System	Detection	Remarks
Loss of one division of Class 1E power source	Loss of one analyzer unit. Loss of redundancy.	Annunciation in control room	Redundant analyzer available. Manual initiation by operator.
Loss of one division of instrument power	Loss of control room display instrumentation. Loss of redundancy.	Annunciation in control room	Manual initiation of redundant analyzer.
Analyzer failure (line break, etc)	Loss of one analyzer unit. Loss of redundancy.	Annunciation in control room	Manual initiation of redundant analyzer.

Table 6.2-15

Evaluation Of Potential Secondary Containment Bypass Leakage Pathways

Pen. No.	Pathway Description[(1)]	Leakage Barriers[(2)]	Valid Path
X-7A-D	Main Steam Lines: 24”-GBB-102	B (See Note 3)	NO
X-8	Main Steam Line Drain: 3”-EBD-114	B (See Note 12)	NO
X-9A/B	Feedwater Line: 30”-DBD-101 to Feedpumps	A	YES
	HPCI / RCIC Injection to ECCS keepfill CST and HPCI / RCIC Injection to ECCS keepfill to RHR fire protection connection: 2”-DBB-120 & 2”-DBB-121 to 2”-HCD-110 to 6”-HCD-105 and ; 10”-DBB-117 & 4”-DBB-112 to 10”-HCD-110 and; 2”-DBB-120 & 2”-DBB-121 to 2” -HCD-110 to 4”-HCD-111 to 4”-HCD-112 to 3”-HBD-174 to 3”-KBF-102 to 6”-KBF-102	A C (See Note 6)	YES NO
	RWCU Return Line via blowdown to condenser and other branch lines: 4”-EBC-104 to 4”-HBD-127 & 4”-HBD-131; 4”-EBC-101 to 2”-HBD-163 3”-EBC-103 to 4”-HBD-160 & 6”-HCD-105		
X-10	RCIC Steam Supply via Steam Line Drain to condenser: 1”-DBD-113 to 1”-EAD-114 to 3”-EBD-114	B (See Note 12)	NO

Table 6.2-15

Evaluation Of Potential Secondary Containment Bypass Leakage Pathways

Pen. No.	Pathway Description(1)	Leakage Barriers(2)	Valid Path
X-11	HPCI Steam Supply via Steam Line Drain to condenser: 1”-DBD-107 to 1”-EAD-114 to 3”-EBD-114	B (See Note 12)	NO
X-12	RHR Shutdown Cooling via keepfill and RHR Shutdown Cooling to keepfill to fire protection piping: 4”-HCD-112 & 2”-HBD-174 to 6”-HCD-105 and; 4”-HCD-112 & 2”-HBD-174 to 3” –HBD-174 to 3” KBF-102 to 6”-KBF-102	C (See Note 7)	NO
X-13A/B	RHR LPCI Injection via ECCS keepfill and RHR LPCI Injection to ECCS keepfill to fire protection piping: 2”-DBB-107 to 2”-HBD-174 to 4”-HCD-112 to 6”-HCD-105 and; 2”-DBB-107 to 2”-HBD-174 to 3”-HBD-174 to 3”-KBF-102 to 6”-KBF-102	C (See Note 4)	NO
X-14	RWCU Supply via blowdown to condenser and other branch lines: From pen X-14 to same paths as X-9A/B	C (See Note 8)	NO
X-16A/B	Core Spray Injection via keepfill, Core Spray Injection to keepfill to fire protection piping and keepfill tank to demineralizer water supply: 2” GBB-101 to 2”-HCD-111 to 4”-HCD-111 to 6” HCD-105 and; 2”-GBB-101 to 2”-HCD-111 to 4”-HCD-111 to 4”-HCD-112 to 3”-HBD-174 to 3”-KBF-102 to 6”-KBF-102 and; 2”-GBB-101 to 1”-HCD-111 to tank 1T274 to 1”-JCD-107	A	YES

Table 6.2-15

Evaluation Of Potential Secondary Containment Bypass Leakage Pathways

Pen. No.	Pathway Description[1]	Leakage Barriers[2]	Valid Path
X-17	RHR Head Spray via keepfill and RHR Head Spray to keepfill to fire protection piping: 2"-GBB-117 to 3"-HBD-174 to 4"-HCD-112 to 6"-HCD-105 and; 2"-GBB-117 to 3"-HBD-174 to 3"-KBF-102 to 6"-KBF-102	A (See Note 15)	YES
	RHR Head Spray via ESW: 12"-GBB-118 to 18"-GBB-109 to 12"-GBB-113 to 12" & 8"-GBC-105 to 2"-HCC-103 to 2" & 10"-HRC-108 to 12" & 14"-HRC-102 and 2"-HCC-103 to 2" & 10"-HRC-110 to 12" & 14"-HRC-101	C (See Note 16)	NO
	RHR Head Spray via RHRSW: 6"-GBB-117 to 6"-GBB-108 to 18"-GBB-109 to 24" & 20"-GBB-106 to 6"-GBB-119 to 6"-HRC-113 to 20"-HRC-112	C (See Note 16)	NO
X-23	RBCCW Supply via connection to Offgas system & air compressors: 4"-JBD-141 to 8"-JBD-139 to 3"-JBD-108	C (See Note 5)	NO
X-24	RBCCW Return via connection to Offgas system & air compressors: 4"-JBD-137 to 8"-JBD-137 to 3"-JBD-109	C (See Note 5)	NO
X-25 X-201A	Drywell Purge Supply N_2 Supply (6"): 24"& 18"-HBB-118 to 6"-HBD-182	B or A (See Note 9)	NO Except when inerting
X-26 X-202	Drywell Purge Return: 24"-HBB-117 to 24"-HBD-1111	B (See Note 9)	NO

Table 6.2-15

Evaluation Of Potential Secondary Containment Bypass Leakage Pathways

Pen. No.	Pathway Description(1)	Leakage Barriers(2)	Valid Path
X-31B X-60A	Recirc Pump Seal Mini-Purge: 1”-DCD-101 to 3”-DBD-108 to 3”-DBC-108	C (See Note 10)	NO
X-37A-D X-38A-D	CRD Insert & Withdrawal lines: CRD I/W lines to 3”-DBC-108	C (See Note 10)	NO
X-39A/B	RHR Drywell Spray via keepfill and RHR Drywell Spray to keepfill to fire protection piping: 12”-GBB-118 to 24”-GBB-115 to 4”-GBB-114 to 4” - HBD-184 and; 12”-GBB-118 to 6” –GBB-108 to 2” GBB-117 to 2”-HBD-174 to 3” –HBD-174 to 4”-HCD-112 to 6”-HCD-105 and; 6”-GBB-108 to 2”-GBB-117 to 2”-HBD-174 to 3”-HBD-174 to 3”-KBF-102 to 6”-NBF-102	A (See Note 15)	YES
	RHR Drywell Spray via ESW: 12”-GBB-118 to 18”-GBB-109 to 12”-GBB-113 to 12” & 8”-GBC-105 to 2”-HCC-103 to 2” & 10”-HRC-108 to 12” & 14”-HRC-102 and 2”-HCC-103 to 2” & 10”-HRC-110 to 12” & 14”-HRC-101	C (See Note 16)	NO
	RHR Drywell Spray via RHRSW: 6”-GBB-117 to 6”-GBB-108 to 18”-GBB-109 to 24” & 20”-GBB-106 to 6”-GBB-119 to 6”-HRC-113 to 20”-HRC-112	C (See Note 16)	NO
X-42	Standby Liquid Control: 1½”-DCA-106 to 1½”-DCB-101 to 3”-HCB-105 to 2”-JCD-107	C (See Note 13)	NO
X-53	RBCW Supply to “B Loop” DW Coolers via connection to RBCCW: 8”-JBD-114 to RBCCW supply (see X-23)	C (See Note 5)	NO

Table 6.2-15

Evaluation Of Potential Secondary Containment Bypass Leakage Pathways

Pen. No.	Pathway Description[1]	Leakage Barriers[2]	Valid Path
X-54	RBCW Return from “B Loop” DW Coolers via connection to RBCCW: 8”-JBD-119 to RBCCW return (see X-24)	C (See Note 5)	NO
X-55	RBCW Supply to “A Loop” DW Coolers via connection to RBCCW: 8”-JBD-114 to RBCCW supply (see X-23)	C (See Note 5)	NO
X-56	RBCW Return from “A Loop” DW Coolers via connection to RBCCW: 8”-JBD-119 to RBCCW return (see X-24)	C (See Note 5)	NO
X-60A X-80C X-88B X-221A X-221B(U2) X-233(U1) X-238A,B X-17 X-39A,B	Post Accident Sampling System (PASS) via connections to the H_2O_2 Analyzer System: 1”-HCB-106 1”-HCB-108 1”-HCB-109 1”-HCB-122 1”-HCB-127 PASS via connections to RHR: 1”-GBB-106	B (See Note 14) B (See Note 14)	NO NO
X-61A	Demineralized Water connection to Drywell: 1”-HCB -145 to 1”-JCD-107	A	YES
X-85A	RBCW Supply to Recirc Pump A via connection to RBCCW: 8”-JBD-114 to RBCCW supply (see X-23)	C (See Note 5)	NO
X-85B	RBCW Return from Recirc Pump A via connection to RBCCW: 8”-JBD-119 to RBCCW return (see X-24)	C (See Note 5)	NO

Table 6.2-15

Evaluation Of Potential Secondary Containment Bypass Leakage Pathways

Pen. No.	Pathway Description[1]	Leakage Barriers[2]	Valid Path
X-86A	RBCW Supply to Recirc Pump B via connection to RBCCW: 8"-JBD-114 to RBCCW supply (see X-23)	C (see Note 5)	NO
X-86B	RBCW Return from Recirc Pump B via connection to RBCCW: 8"-JBD-119 to RBCCW return (see X-24)	C (See Note 5)	NO
X-88A	N_2 Make-up to Drywell: 1"-HCB-156 to 1"-HBD-195 to 2"-HBD-57	A	YES
X-201B (U2)	Wetwell vent pipe to rupture disc PSE25701. This pathway applies to Unit 2 only. 18"-HBB-259 to 12"-HBD-2571	A and B (See Note 17)	NO
X-205A/B	RHR Wetwell Spray via keepfill: 6" to 18" GBB-109 to Drywell Spray line (see X-39A/B)	C (See Note 4)	NO
X-204A/B	RHR Suppression Pool Cooling: 18"-GBB-109 to Drywell Spray Line (see X-39A/B)	C (See Note 4)	NO
X-206A/B	Core Spray Pump Suction via connection to CST: 16"-HBB-104 to 16"-HCD-115 to 16"-HCB-102	C (See Note 11)	NO
X-209	HPCI Pump Suction via connection to CST: 16"-HBB-109 to 16"-HBB-107 to 16"-HCB-103	C (See Note 11)	NO

Table 6.2-15

Evaluation Of Potential Secondary Containment Bypass Leakage Pathways

Pen. No.	Pathway Description(1)	Leakage Barriers(2)	Valid Path
X-214	RCIC Pump Suction via connection to CST: 6"-HBB-102 to 6"-HBB-103 to 6"-HCB-104	C (See Note 11)	NO
X-220B	N_2 Make-up to Wetwell: 1"-HCB-157 to 1"-HBD-195 to 2"-HBD-57	A	YES
X-243	Suppression Pool C/U: 6"-HBB-121 to 4"-HBD-172 to 4"-HBD-173	C (See Note 11)	NO

Notes:

1. Unit 1 line numbers are provided, however, pathway applies to both units. Unit 2 line numbers begin with 2, e.g. if the Unit 1 line number is 24"-GBB-102, then the Unit 2 line number is 24"-GBB-202.

2. The following isolation barriers are used to limit or eliminate SCBL as discussed in Section 6.2.3.2.3. Details regarding how the barriers eliminate SCBL for specific penetrations is discussed in the referenced Note.

   A. Isolation valve(s) inside and/or outside primary containment.
   B. Leakage is collected and filtered prior to release.
   C. Water seal in line.

3. Leakage is routed to condenser where "scrubbing" is credited as part of MSIVLCS elimination. Valves are leak rate tested to be less than 300 scfh in accordance with Technical Specifications, and the radiological impact of this leakage is considered in the DBA LOCA dose analysis. Since the leakage is not released directly to the environment, and is considered separately from SCBL in the DBA LOCA dose analysis, these lines are eliminated as SCBL pathways.

4. Refer to Dwgs. M-151, Sh. 1, M-151, Sh. 2, M-151, Sh. 3, M-151, Sh. 4, M-155, Sh. 1, M-152, Sh. 1, M-149, Sh. 1 and M-150, Sh. 1.

   The SCBL pathway for penetrations X-13A/B RHR LPCI Injection, X-204A/B RHR Wetwell Spray, and X-205 RHR Suppression Pool, Cooling is via the ECCS keepfill connection to condensate transfer.

   The piping configuration for these RHR penetrations is such that they will remain filled with water following a LOCA, and/or a loop seal will be maintained between the drywell

Table 6.2-15

Evaluation Of Potential Secondary Containment Bypass Leakage Pathways

atmosphere the ECCS keepfill connections. For the LPCI Injection penetrations, a loop seal will be maintained inside primary containment. For Wetwell Spray and Suppression Pool Cooling lines, the piping configurations creates a loop seal which spans the penetrations and creates a water seal between the penetrations and the keepfill connections. Therefore, SCBL via these penetrations is precluded.

Table 6.2-15

Evaluation Of Potential Secondary Containment Bypass Leakage Pathways

5. Refer to Dwgs. M-113, Sh.1, M-187, Sh. 1, M-187, Sh. 2, and Figures 6.2-66H, and 6.2-66F.

The potential SCBL pathway for the RBCCW penetrations (X-23 & 24) is via the RBCCW supply and return lines through the turbine/radwaste buildings to the Offgas system (Charcoal Treatment System). The potential SCBL pathway for the RBCW penetrations (X-53, -54, -55, -56, -85A/B & -86A/B) is through these same lines via the RBCCW cross-tie to RBCW. The RBCCW and RBCW piping inside primary containment, while not designed to ASME Section III, is designed to Seismic Category I standards and therefore, is likely to remain intact following a large break LOCA. Furthermore, in the case of RBCCW and RBCW penetrations X-85A/B & 86A/B, all of the components served are also designed to Seismic Category I Standards.

For RBCCW, the pipe routing both inside and outside primary containment is such that a loop seal will be formed at the penetration, thereby sealing both sides of the valves with water such the valve discs will not be exposed to containment atmosphere. Consequently, SCBL through the RBCCW penetrations is precluded by the loop seal at the primary containment boundary (see FSAR Figure 6.2-66F). For RBCW, only 6 of the 14 drywell coolers served by the other RBCW penetrations are seismically qualified. This, coupled with an unfavorable pipe routing at the penetration, results in the inability to credit a loop seal at the penetrations similar to RBCCW.

An assessment of the RBCCW supply/return lines at the reactor to turbine building interface concluded that the piping will remain intact following a DBA LOCA. Consequently, the RBCCW supply/return lines to the turbine building will not be subject to a rapid draindown, thus preserving the water volume within secondary containment for both RBCCW and RBCW (see FSAR Figure 6.2-66E). This coupled with the presence of a head tank in the RBCCW system will ensure that the piping of concern in both RBCCW and RBCW will remain full of water, even if a small leak were to develop in the piping outside of secondary containment. Additionally, the pipe routing of the RBCW system within secondary containment is such that a loop seal capable of resisting long term containment pressure will exist, thereby precluding the potential for SCBL through the RBCW system. For RBCCW, SCBL is precluded by the loop seal at the containment penetration, as well as, the presence of water in the remainder of the system located within secondary containment discussed above. Therefore, SCBL via the RBCCW and RBCW penetration is precluded and the leakage from these penetrations need not be compared to the SCBL limit.

Table 6.2-15

Evaluation Of Potential Secondary Containment Bypass Leakage Pathways

6. Refer to Dwgs. M-144, Sh. 1, M-144, Sh. 2, M-145, Sh. 1 and Figures 3.6-17-1, 3.6-17-2, and 3.6-17-3.

   The water between the RWCU heat exchangers and secondary containment is sufficiently cold (120°F) such that it will maintain water in the various pathways identified. Based on the large water volume available and the pipe routing, a water seal will be maintained between the feedwater penetrations and the secondary containment boundary.

7. Refer to Dwgs. M-151, Sh. 1, M-151, Sh. 2, M-151, Sh. 3, and M-151, Sh. 4.

   RHR Shutdown cooling line to RHR pump suction will remaining water filled post-LOCA. This is due to the pipe routing from the containment penetration to the Reactor Recirculation piping inside primary containment and the water volume contained within this line. Additionally, the leakage through this penetration will be eliminated based on the water seal described in Note 4.

8. Refer to Dwgs. M-144, Sh. 1, M-144, Sh. 2 and Figures 3.6-17-1, 3.6-17-2, 3.6-17-3, and 6.2-66B.

   Eliminated by a loop seal inside primary containment with an inexhaustible source of water. CIV testing is not required based on the loop seal and the supply of water available. Water is maintained in the line DBA-101 by having minimum piping heights at elev. 720' and 704', the penetration of primary containment at elev. 751' and the RPV penetrations at elev. 732', 746', and 747'. The minimum water level in the reactor vessel, post-LOCA, is 10 feet below Bottom of Active Fuel (BAF). BAF is at elevation 750'. Water level will be restored to elevation 762' at 200 seconds, post-LOCA. Thus, a loop seal sufficient to resist long-term containment pressure is maintained.

9. The drywell purge supply pipe connects to non-Seismic Category I ductwork in secondary containment. This ductwork becomes the recirculation supply post-accident, thereby preventing leakage out of secondary containment via these lines from the subject penetrations. SCBL via the N_2 supply line is eliminated by the spectacle flange, which prevents through-pipe leakage. Therefore, a pathway through secondary containment does not exist when the flange is in the closed position.

   Primary containment inerting can be performed during power operations via the 6” N_2 supply line. This requires the spectacle flange to be in the open position and in this configuration SCBL is no longer eliminated. Thus a SCBL pathway will exist via the 6” N_2 supply line under these circumstances. The leakage through this pathway, when combined with that for the other SCBL pathways identified in this table, must be maintained within the SCBL limit assumed in the DBA LOCA Dose Analysis described in Section 15.6.5. Consequently, if the spectacle flange is placed in a position other than closed during power operation, the SCBL criteria must be met when the maximum

Table 6.2-15

Evaluation Of Potential Secondary Containment Bypass Leakage Pathways

pathway 10CFR50, Appendix J leakage for valves HV-1(2)5721, HV-1(2)5722, HV-1(2)5723, HV-1(2)5724 & HV-1(2)5725 is added to the total minimum pathway leakage for the other SCBL pathways identified in this table. Alternatively, an acceptable testing configuration is to use the lesser leakage from either valve HV-1(2)5721 or the combination of valves HV1(2)5722 and HV1(2)5725 and add this minimum pathway leakage to the running minimum pathway leakage (as-found) for the other SCBL pathways and to use the greater leakage from either valve HV-1(2)5721 or the combination of valves HV1(2)5722 and HV1(2)5725 and add this maximum pathway leakage to the running maximum pathway leakage (as-left) for the other SCBL pathways identified in this table. This is an acceptable configuration for the following reason. Valves HV-1(2)5723 and HV-1(2)5724 provide isolation to the Reactor Building recirculation plenum. These valves do not isolate a potential Secondary Containment Bypass Leakage pathway since the Reactor Building recirculation plenum is part of Secondary Containment. Since the valves do not isolate a SCBL pathway, leakage testing of these valves represents unnecessary conservatism with respect to SCBL. This configuration will still accommodate a single failure since either valve HV-1(2)5721 or the combination of valves HV(1)5722 and HV1(2)5725 will provide the appropriate SCBL leakage protection. Valve HV(1)5721 is a divison II valve and HV-1(2)5722 and HV-1(2)5725 are division I valves. This divisional separation accommodates a single failure. Note that including the leakage from either HV-1(2)5723 and/or HV-1(2)5724 is conservative and therefore acceptable.

10. Refer to Dwgs. M-146, Sh. 1 M-143, Sh. 1, M-143, Sh. 2, and Figure 6.2-66G.

A potential water bypass leakage path exists due to the CRD insert/withdrawal lines penetrating primary containment and the CRD supply line penetrating secondary containment. In this case, post-LOCA water from the reactor vessel could escape by draining out the bottom of the reactor at elevation 732'-04" into the insert/withdrawal lines; through the hydraulic control units (HCU's), supply headers and master control station on elevation 719'-0"; down the CRD supply piping and through secondary containment into the Turbine Building at elevation 662'-9".

In addition to the potential for water bypass leakage from the CRD supply line, pneumatic SCBL is possible from penetrations X-31B and 60A (Recirculation Pump seal Mini-Purge lines). These lines are supplied with water from the CRD pump, and have the potential to leak into secondary containment via the CRD supply line.

These pathways are eliminated by a "Seismic Island" consisting of ASME Section III, Class 3 piping, two (2) ASME Section III check valves and the necessary test connections and block valves (see figure 6.2-66G). The island is located just inside of secondary containment so as to prevent bypass leakage from reaching the Turbine Building. This is accomplished by using the clean water trapped between the Seismic

Table 6.2-15

Evaluation Of Potential Secondary Containment Bypass Leakage Pathways

Island and the reactor vessel as a 30-day water seal against the post-LOCA water reaching the Turbine Building. The Seismic Island check valves are periodically tested to ensure leakage is limited to less than 508 ml/hr to ensure a 30 day water seal is maintained. This leakrate was determined by dividing the volume of water in the CRD piping between the seismic island and the HCU's by 30 days.

Therefore, the water seal maintained in the CRD piping by the CRD Seismic Island precludes SCBL from occurring via the CRD supply line penetrating secondary containment.

11. Refer to Dwgs. M-157, Sh. 1, M-157, Sh. 2, M-157, Sh. 3, M-152, Sh. 1, M-155, Sh. 1, M-149, Sh. 1, M-150, Sh. 4, and Figure 6.2-66C.

    SCBL is eliminated for penetrations X-206A/B (Core Spray Pump Suction), X-209 (HPCI Pump Suction), X-214 (RCIC Pump Suction) and X-246 (Suppression Pool Purification line) based on a water seal provided by the suppression pool. The suction piping for these penetrations is located sufficiently below the minimum suppression pool water level so as to prevent the lines from being exposed to drywell atmosphere.

12. Leakage is routed to condenser where "scrubbing" is credited as part of MSIVLCS elimination. Valves are leak rate tested and maintained such that the combined leakage from these valves and the MSIV's is less than the 300 scfh limit specified for the MSIV's in Technical Specifications. The radiological impact of leakage scrubbed via the condenser is considered in the DBA LOCA Dose analysis. Since this leakage is not released directly to the environment, these lines are eliminated as SCBL pathways.

13. The Standby Liquid Control (SLC) line terminates inside the reactor vessel below the post-accident water level. Therefore, an inexhaustible water seal is provided to prevent containment atmosphere from reaching the SLC containment penetrations. Additionally, the SLC explosive valves provide an impenetrable barrier with regard to leakage through the valves.

14. The affected lines penetrate the reactor building, but terminate within a panel mounted on the turbine building side of the reactor/turbine building wall. However, the panel is vented to the reactor building. Consequently, any leakage from these lines is collected and treated by SGTS (ref. FSAR Section 18.1.21.5.3 & Dwg. M-123, Sh. 12).

Table 6.2-15

Evaluation Of Potential Secondary Containment Bypass Leakage Pathways

15. The following two (2) isolation barriers are used to limit SCBL from these valid pathways:

    a. Isolation valves HV151F040 and HV151F049 are outside of primary containment that will limit SCBL through the RHR line to LRW. The valves have an automatic isolation signal for low water level or high drywell pressure. The valves have separate power supplies, one is AC and the other is DC. The valves and associated piping are designed in accordance with ASME Section III, Class 2. The valves will be tested per 10CFR50 Appendix J requirements, and

    b. A "Seismic Island" consisting of ASME Section III, Class 3 piping, two (2) ASME Section III check valves, will limit SCBL from RHR through the Condensate System and the Fire Protection System. The check valves will close if there is no flow from the Condensate or Fire Protection water supply to RHR. The valves will be tested per 10CFR50 Appendix J requirements.

16. These lines are eliminated by loop seals established by RHR operation or ESW/RHRSW loop operation. Single failure does not eliminate the water seal.

17. The vent pipe pathway penetrates secondary containment in two locations:

    a. Rupture disc PSE25701 is a barrier for SCBL and prevents leakage from line HBD-2571 to the Reactor Building roof. Therefore, a pathway through secondary containment does not exist when disc PSE25701 has not ruptured.

    b. The tubing leading to the ROS is vented to secondary containment. Consequently, primary containment leakage is vented to secondary containment where it is collected and treated by SGTS.

TABLE 6.2-16

CONTAINMENT HYDROGEN RECOMBINER SYSTEM

SYSTEM LEVEL
FAILURE MODE AND EFFECT ANALYSIS

COMPONENT FAILURE MODE	EFFECT OF FAILURE ON THE SYSTEM	FAILURE MODE DETECTION	EFFECT OF FAILURE ON PLANT OPERATION
Loss of power (normal and preferred source)	None. The hydrogen recombiner will be powered from the standby diesel generators.	Alarm in the control room	No loss of safety function (Note: The hydrogen recombiners do not perform a safety related function.)
Loss of standby power from one diesel generator	None. The hydrogen recombiner system is redundant	Alarm in the control room	No loss of safety function (Note: The hydrogen recombiners do not perform a safety related function.)
Loss of one hydrogen recombiner	No loss of hydrogen control capacity. A second hydrogen recombiner is available. The hydrogen vent system is also available.	Alarm in the control room.	No loss of safety function (Note: The hydrogen recombiners do not perform a safety related function.)

TABLE 6.2-17

INFORMATION FOR THE SSES SECONDARY CONTAINMENT	
I.	Secondary Containment Ventilation Zones I, II and III
A.	Approximate Free Volume, ft^3 – Zone I 1,488,600 Zone II 1,598,600 Zone III 2,668,400
B.	Pressure, inches of water, gage 1. Normal Operation – ¼ 2. Post-accident – ¼
C.	Leak Rate at Post-Accident Pressure – 140% per day
D.	Exhaust Fans – common 1. Number – 2 2. Type – Centrifugal, SISW
E.	Filters – common 1. Number – 2 2. Type – prefilter, HEPA, charcoal, HEPA
II.	Transient Analysis
A.	Initial Conditions 1. Pressure, - ¼ in. wq 2. Temperature - 104°F 3. Outside Air Temperature - 92°F 4. Thickness of Secondary Containment Wall - 36 in. 5. Thickness of Primary Containment Wall – 72 in.
B.	Thermal Characteristics 1. Primary Containment Wall a. Thermal Conductivity, Btu/hr-ft-°F - .5 b. Thermal Capacitance, Btu/ft^3 - °F – 25 2. Secondary Containment Wall a. Thermal Conductivity, Btu/hr-ft-°F - .5 b. Thermal Capacitance, Btu/ft^3-°F – 25 3. Heat Transfer Coefficients a. Primary Containment Atmosphere to Primary Containment Wall, Btu/hr-ft^2 - °F – 1.46 b. Primary Containment Wall to Secondary Containment Atmosphere, Btu/hr-ft^2 - °F – 1.46 c. Secondary Containment Wall to Secondary Containment Atmosphere, Btu/hr-ft^2 - °F – 1.46 d. Primary Containment Emissivity, Btu/hr-ft^2 - °F – .9 e. Secondary Containment Emissivity, Btu/hr-ft^2 - °F – .9

TABLE 6.2-18

HYDROGEN RECOMBINER DESIGN CHARACTERISTICS		
	CONTAINMENT CONDITIONS	POST-LOCA CONDITIONS
Temperature (°F)	150	340
Pressure (psia)	16.2	63.3
Pressure Transient in 10 sec. (psia)		63.3
Relative Humidity (%)	0-100	100
Radiation – Total Dose (rads)	(1)	8.93×10^8
Life (yr)	40(2)	40(2)
Capacity (min) (SCFM) At 1 atm	100	100
Heaters Electrical Requirements Heater Power (Max)	75 kw, 3-phase, 60 Hz, 480 V ac	
Control Panel Instruments Electrical Requirements: Single-Phase, 60 Hz, 120 V ac (Supplied from power supply panel)	Operating Environment	
Temperature (°F)	70-90	
Pressure (psia)	15	
Relative Humidity (%)	0-100	
Life (yr)	40	

(1) The total dose for normal conditions plus Post-LOCA condition is included in the 8.93×10^8 rads

(2) Life will be 60 years to the end of the period of extended operation. A monitoring program ensures proper equipment performance.

TABLE 6.2-19

TYPE A TEST DATA		
A	Peak Test Pressure The calculated peak containment pressure related to the design basis loss of coolant accident.	Pa = 48.6 psig
B	Maximum Allowable Leakage Rate The maximum allowable leakage rate at peak accident pressure from the drywell and pressure suppression chamber.	La = 1.0 /day
C.	Measured Leakage Rate Overall measured leakage rate during Type A test from drywell and suppression chamber.	Lam
D.	Imposed Leakage Rate The leakage rate imposed on the containment during the verification test. Li is 75% to 125% of La.	Li
E.	Verification Test Leakage Rate The total containment leakage, including Li, measured during the verification test.	Lvm
F.	Test Duration 1) After the containment atmosphere has stabilized, the integrated leakage rate test period begins. 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 can be accurately determined. 2) The Type A test shall last a minimum of 8 hrs after stabilization and shall have a total of not less than 30 sets of data points at approximately equal time intervals. 3) The Type A test cannot be successfully terminated until the acceptance criteria of the plant Technical Specifications are met.	
G.	Drywell Temperature Limits During Type A Test	40-120°F
H.	Free Air Volume Drywell Suppression Chamber	239,600 ft^3 159,130 ft^3 (low water level) 148,590 ft^3 (high water level)

TABLE 6.2-20

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Table 6.2-21

SYSTEM VENTING AND DRAINING FOR PRIMARY CONTAINMENT INTEGRATED LEAKAGE RATE TEST

	The Reactor Building Chilled Water System (RBCWS) located inside primary containment does not meet the criteria for a closed system for purposes of containment isolation. The RBCWS is not vented during the Type A test and may be operated in its normal mode to maintain the containment atmosphere in a stabilized condition.
	Systems that are normally filled with water and operating under post-LOCA conditions are not specifically vented to the containment atmosphere or to the outside atmosphere. They remain water filled during the Type A test. These systems are listed below. (Note: Venting to the primary containment atmosphere does not 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). <u>System</u> Reactor Core Isolation Cooling * Residual Heat Removal Core Spray High Pressure Coolant Injection * * HPCI and RCIC will initially operate post DBA LOCA, but will subsequently be shutdown due to RPV depressurization. They are listed here since the penetrations within these systems terminate below the suppression pool minimum water level and therefore, do not communicate with post-accident containment atmosphere. This only applies to the water side of HPCI and RCIC.

TABLE 6.2-22

LEAKAGE RATE TEST LIST

Penetration	Description	Type Test	Inboard Isolation Barrier: Barrier Description/ Valve No. (28)	Inboard Isolation Barrier: Notes	Outboard Isolation Barrier: Barrier Description/ Valve No.	Outboard Isolation Barrier: Notes	Exemption to 10CFR50 Appendix J Required
X-1	Equip. Access Hatch	B	Double O-ring	1	-	-	
X-2	Equip. Access Hatch With Personnel Lock	B	Double O-ring	1	-	-	
X-2	Personnel Lock Barrel	B	Inner Door/Barrel	1, 2	Outer Door/Barrel	1, 2	
X-2	Personnel Lock Inner Door	B	Double O-ring	1, 3	-	-	
X-2	Personnel Lock Outer Door	B	-	-	Double O-ring	1, 3	
X-3A	Spare	A	Cap (3)	-	-	-	
X-3B	Primary Containment Pressure Inst.	A	Cap (1) Instrument Line (2)	- 10, 11, 30	-	-	
X-3C	Spare	A	Cap (3)	-	-	-	
X-3D	Spare	A	Cap (3)	-	-	-	
X-4	Drywell Head Access Manhole	B	Double O-ring	1	-	-	
-	Drywell Head	B	Double O-ring	1	-	-	
X-5	Ctmt. Rad. Det. Supply Sample	C	SV-157100A	11	SV-157101A	11	
X-5	Ctmt. Rad. Det. Return Sample	C	SV-157102A	11	SV-157103A	11	
X-6	CRD Removal Hatch	B	Double O-ring	1	-	-	
X-7A	Main Steam	C	HV-1F022A	4, 5, 16	HV-1F028A	4, 16	Yes
X-7B	Main Steam	C	HV-1F022B	4, 5, 16	HV-1F028B	4, 16	Yes
X-7C	Main Steam	C	HV-1F022C	4, 5, 16	HV-1F028C	4, 16	Yes
X-7D	Main Steam	C	HV-1F022D	4, 5, 16	HV-1F028D	4, 16	Yes
X-8	Main Steam Line Drain	C	HV-1F016	16	HV-1F019	16	
X-9A	Feedwater	C	1F010A	16	HV-1F032A, HV-1F013, HV-14182A, 1-49-020, 141F039A, 141818A, 241F039A	16	
X-9B	Feedwater	C	1F010B	16	HV-1F032B, HV-1F006, HV-14182B, 1-55-038, 141F039B, 141818B, 241F039B	16	

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LEAKAGE RATE TEST LIST

Penetration	Description	Type Test	Inboard Isolation Barrier		Outboard Isolation Barrier		Exemption to 10CFR50 Appendix J Required
			Barrier Description/ Valve No. (28)	Notes	Barrier Description/ Valve No.	Notes	
X-10	Steam To RCIC Turbine	C	HV-1F007, HV-1F088	6, 7, 16, 22	HV-1F008	16	Yes
X-11	Steam To HPCI Turbine	C	HV-1F002, HV-1F100	6, 7, 16, 22	HV-1F003	16	Yes
X-12	RHR Shutdown Supply	C	HV-1F009, PSV-1F126	16, 17	HV-1F008	16, 17	
X-13A	RHR Shutdown Return	C	HV-1F015A	9,11	Closed System	16, 17	
X-13B	RHR Shutdown Return	C	HV-1F015B	9,11	Closed System	16, 17	
X-14	Reactor Water Cleanup Supply	C	HV-1F001	14, 18	HV-1F004	14, 18	
X-15	Spare	A	Cap	-	-	-	
X-16A	Core Spray	C	HV-1F037A, HV-1F006A	16, 17	HV-1F005A	16,17	
X-16B	Core Spray	C	HV-1F037B, HV-1F006B	16, 17	HV-1F005B	16, 17	
X-17	RPV Head Spray	C	HV-1F022	16, 22	HV-1F023	16	
X-18	Spare	A	Cap	-	-	-	
X-19	Instrument Gas	C	1-26-074	-	SV-12651	-	
X-20	Spare	A	Cap	-	-	-	
X-21	Instrument Gas	C	1-26-152	-	SV-12654B	-	
X-22	Spare	A	Cap	-	-	-	
X-23	Closed Cooling Water Supply	C	HV-11346	16	HV-11314	16	
X-24	Closed Cooling Water Return	C	HV-11345	16	HV-11313	16	
X-25,201A	Purge Supply	C	HV-15722, HV-15725	8, 11	HV-15724, HV-15721, HV-15723	11	
X-26	Drywell Purge Exhaust	C	HV-15713	8, 11	HV-15714, HV-15711	11	
X-27A	Jet Pump Inst.	A	Cap (1) Excess Flow Check Vlv. (3)	10, 11, 27	-	-	
X-27B	Main Steam C Inst.	A	Cap (2) Excess Flow Check Vlv. (2)	10, 11, 27	-	-	
X-28A	Spare	A	Cap (4)	-	-	-	
X-28B	Jet Pump Inst.	A	Cap (3) Excess Flow Check Vlv (1)	10, 11, 27	-	-	

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LEAKAGE RATE TEST LIST

Penetration	Description	Type Test	Inboard Isolation Barrier: Barrier Description/ Valve No. (28)	Inboard Isolation Barrier: Notes	Outboard Isolation Barrier: Barrier Description/ Valve No.	Outboard Isolation Barrier: Notes	Exemption to 10CFR50 Appendix J Required
X-29A	Spare	A	Cap (4)	-	-	-	
X-29B	RWCU Inst.	A	Cap (2) Excess Flow Check Vlv. (2)	10, 11, 27	-	-	
X-30A (Unit 1)	Recirc Loop Inst.	A	Exess Flow Check Vlv (1)	10, 11, 27	-	-	
X-30A (Unit 2)	Recirc Loop Inst.	A	Cap (3) Excess Flow Check Vlv (1)	10, 11, 27	-	-	
X-30B	Spare	A	Cap	-	-		
X-31A (Unit 1)	Main Steam Inst.	A	Cap (2) Excess Flow Check Vlv (2)	10, 11, 27	-	-	
X-31A (Unit 2)	Main Steam Inst.	A	Cap (1) Excess Flow Check Vlv (3)	10, 11, 27	-	-	
X-31B	Recirculation Pump Seal Water Supply Line	C	1F013B	16	XV-1F0I7B	10, 16, 23	Yes
X-31B (Unit 1)	Spare	A	Cap (2)				
X-31B (Unit 2)	Ctmt. Rad. Det. Supply Sample	C	SV257100B	11	SV257101B	11	
X-31B (Unit 2)	Ctmt. Rad. Det. Return Sample	C	SV257102B	11	SV257103B	11	
X-32A	RHR Suction From R.P.V. Leak Det. Inst	A	Cap (2) Instrument Line	10, 11, 30	-	-	
X-32B	Spare	A	Cap (3)	-	-	-	
X-33A (Unit 1)	RHR Pump Inst.	A	Excess Flow Check Vlv. (2)	10, 11, 27	-	-	
X-33A (Unit 2)	RHR Pump Inst.	A	Cap (2) Excess Flow Check Vlv. (2)	10, 11, 27	-	-	
X-33B	RHR Pump Inst.	A	Cap (2) Excess Flow Check Vlv. (2)	10, 11, 27	-	-	
X-34A	Main Steam Inst.	A	Cap (2) Excess Flow Check Vlv. (2)	10, 11, 27	-	-	
X-34B	Main Steam Inst.	A	Cap (2) Excess Flow Check Vlv. (2)	10, 11, 27	-	-	
X-35A	TIP Drive	B,C	Double "O" Ring, Ball Valve	11	Shear Valve	11, 19	Yes
X-35B	Spare	A	Cap	-	-	-	

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LEAKAGE RATE TEST LIST

Penetration	Description	Type Test	Inboard Isolation Barrier: Barrier Description/ Valve No. (28)	Inboard Isolation Barrier: Notes	Outboard Isolation Barrier: Barrier Description/ Valve No.	Outboard Isolation Barrier: Notes	Exemption to 10CFR50 Appendix J Required
X-35C	TIP Drive	B,C	Double "O" Ring, Ball Valve	11	Shear Valve	11, 19	Yes
X-35D	TIP Drive	B,C	Double "O" Ring, Ball Valve	11	Shear Valve	11,19	Yes
X-35E	TIP Drive	B,C	Double "O" Ring, Ball Valve	11	Shear Valve	11, 19	Yes
X-35F	TIP Drive	B,C	Double "O" Ring, Ball Valve	11	Shear Valve	11, 19	Yes
X-36	Spare	A	Cap	-	-	-	-
X-37A	CRD Insert	A	-	20	-	-	Yes
X-37B	CRD Insert	A	-	20	-	-	Yes
X-37C	CRD Insert	A	-	20	-	-	Yes
X-37D	CRD Insert	A	-	20	-	-	Yes
X-38A	CRD Withdraw	A	-	20	-	-	Yes
X-38B	CRD Withdraw	A	-	20	-	-	Yes
X-38C	CRD Withdraw	A	-	20	-	-	Yes
X-38D	CRD Withdraw	A	-	20	-	-	Yes
X-39A	Containment Spray	C	HV-1F016A	9, 11, 16, 17	Closed System	9, 11, 17	
X-39B	Containment Spray	C	HV-1F016B	9, 11, 16, 17	Closed System	9, 11, 17	
X-40A	Jet Pump Inst.	A	Cap (1) Excess Flow Check Vlv. (3)	10, 11, 27	-	-	
X-40B	Main Steam Inst.	A	Cap (2) Excess Flow Check Vlv. (2)	10, 11, 27	-	-	
X-40C (Unit 1)	Jet Pump Inst.	A	Cap (1) Excess Flow Check Vlv. (3)	10, 11, 27	-	-	
X-40C (Unit 2)	Spare	A	Cap (4)	10, 11, 27	-	-	
X-40D	Jet Pump Inst.	A	Cap (1) Excess Flow Check Vlv. (3)	10, 11, 27	-	-	
X-40E	Jet Pump Inst.	A	Cap (1) Excess Flow Check Vlv. (3)	10, 11, 27	-	-	
X-40F	Jet Pump Inst.	A	Cap (1) Excess Flow Check Vlv. (3)	10, 11, 27	-		

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Penetration	Description	Type Test	Inboard Isolation Barrier		Outboard Isolation Barrier		Exemption to 10CFR50 Appendix J Required
			Barrier Description/ Valve No. (28)	Notes	Barrier Description/ Valve No.	Notes	
X-40G	Jet Pump Inst.	A	Cap (1) Excess Flow Check Vlv. (3)	10, 11, 27	-		
X-40H	Jet Pump Inst.	A	Cap (1) Excess Flow Check Vlv. (3)	10, 11, 27	-	-	
X-41	Instrument Gas	C	1-26-154	-	SV-12654A	-	
X-42	Stby. Liquid Control	C	1F007	14, 18	HV-1F006	14, 18	
X-43	Not Used	-	-	-	-	-	
X-44	Spare	A	Cap	-	-	-	
X-45	Spare	A	Cap	-	-	-	
X-46	Spare	A	Cap	-	-	-	
X-47	Spare	A	Cap	-	-	-	
X-48A (Unit 1)	Spare	A	Cap	-	-	-	
X-48A (Unit 2)	Spare	A	Cap (3)	-	-	-	
X-48B (Unit 1)	Spare	A	Cap (3)	-	-	-	
X-48B (Unit 2)	Main Steam Inst.	A	Cap (1) Excess Flow Check Vlv. (2)	10, 11, 27	-	-	
X-49A (Unit 1)	Recirc. Loop Inst.	A	Cap (1) Excess Flow Check Vlv. (2)	10, 11, 27	-	-	
X-49A (Unit 2)	Recirc. Loop Inst.	A	Cap (2) Excess Flow Check Vlv. (2)	10, 11, 27	-	-	
X-49B	Recirc. Loop Inst.	A	Cap (2) Excess Flow Check Vlv. (2)	10, 11, 27	-	-	
X-50A	Recirc. Loop Inst.	A	Cap (2) Excess Flow Check Vlv. (2)	10, 11, 27	-	-	
X-50B	Recirc. Loop Inst.	A	Cap (2) Excess Flow Check Vlv. (2)	10, 11, 27	-	-	
X-51A (Unit 1)	Recirc. Pump Inst.	A	Excess Flow Check Vlv. (2)	10, 11, 27	-	-	
X-51A (Unit 2)	Recirc. Pump Inst.	A	Cap (2) Excess Flow Check Vlv. (2)	10, 11, 27	-	-	

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Penetration	Description	Type Test	Inboard Isolation Barrier		Outboard Isolation Barrier		Exemption to 10CFR50 Appendix J Required
			Barrier Description/ Valve No. (28)	Notes	Barrier Description/ Valve No.	Notes	
X-51B	Recirc. Pump Inst.	A	Cap (2) Excess Flow Check Vlv. (2)	10, 11, 27	-	-	
X-52A (Unit 1)	Recirc. Pump Inst.	A	Excess Flow Check Vlv. (2)	10, 11, 27	-	-	
X-52A (Unit 2)	Recirc. Pump Inst.	A	Cap (2) Excess Flow Check Vlv. (2)	10, 11, 27	-	-	
X-52B	Recirc. Pump Inst.	A	Cap (1) Excess Flow Check Vlv. (3)	10, 11, 27	-	-	
X-53	Chilled Water Supply	C	HV-18782A1	16, 17	HV-18781B1	16, 17	
X-54	Chilled Water Return	C	HV-18782A2	16, 17	HV-18781B2	16, 17	
X-55	Chilled Water Supply	C	HV-18782B1	16, 17	HV-18781A1	16, 17	
X-56	Chilled Water Return	C	HV-18782B2	16, 17	HV-18781A2	16, 17	
X-57	Spare	A	Cap	-	-	-	
X-58A	RWCU Inst (2)	A	Cap (2) Excess Flow Check Vlv. (2)	10, 11, 27	-	-	
X-58B	Spare	A	Cap (4)	-	-	-	
X-59A	Reactor Level Inst	A	Cap (2) Excess Flow Check Vlv. (2)	10, 11, 27	-	-	
X-59B	Reactor Level Inst	A	Cap (2) Excess Flow Check Vlv. (2)	10, 11, 27	-	-	
X-60A	O_2 Sample	C	SV-15740A, SV-15742A	11	Closed System	31	
X-60A	Recirculation Pump Seal Water Supply Line	C	1F013A	16	XV-1F017A	10, 16, 23	Yes
X-60A	O_2 Sample	C	SV-15750A, SV-15752A	11	Closed System	31	
X-60B	Reactor Water Sample	C	HV-1F019	16	HV-1F020	16	
X-60B (Unit 1)	Spare	A	Cap (3)				
X-60B (Unit 2)	Spare	A	Cap (2)				
X-61A	Demin. Water	C	1-41-018	16	1-41-017	16	
X-61A (Unit 1)	ILRT Leak Verification	C	1-57-193	-	1-57-194	-	
X-61A (Unit 2)	ILRT Leak Verification	C	2-57-200	-	2-57-199	-	

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Penetration	Description	Type Test	Inboard Isolation Barrier		Outboard Isolation Barrier		Exemption to 10CFR50 Appendix J Required
			Barrier Description/ Valve No. (28)	Notes	Barrier Description/ Valve No.	Notes	
X-61A (Unit 1)	Spare	A	Cap (2)				
X61A (Unit 2)	Jet Pump Inst.	A	Cap (1) Excess Flow Check Vlv. (1)	10, 11, 27			
X-61B	Main Steam Inst	A	Cap (2) Excess Flow Check Vlv. (2)	10, 11, 27	-	-	
X-62A (Unit 1)	Main Steam Inst	A	Cap (1) Excess Flow Check Vlv. (3)	10, 11, 27	-	-	
X-62A (Unit 2)	Main Steam Inst	A	Cap (2) Excess Flow Check Vlv. (2)	10, 11, 27	-	-	
X-62B	Main Steam Inst	A	Cap (2) Excess Flow Check Vlv. (2)	10, 11, 27	-	-	
X-63A	Main Steam Inst	A	Cap (2) Excess Flow Check Vlv. (2)	10, 11, 27	-	-	
X-63B (Unit 1)	Main Steam, Core Spray Inst	A	Cap (1) Excess Flow Check Vlv. (3)	10, 11, 27	-	-	
X-63B (Unit 2)	Main Steam Inst	A	Cap (3) Excess Flow Check Vlv. (1)	10, 11, 27	-	-	
X-64A (Unit 1)	Main Steam Inst	A	Cap (2) Excess Flow Check Vlv. (2)	10, 11, 27	-	-	
X-64A (Unit 2)	Main Steam Inst	A	Cap (1) Excess Flow Check Vlv. (3)	10, 11, 27	-	-	
X-64B (Unit 1)	Pressure Inst	A	Cap (1) Excess Flow Check Vlv. (3)	10, 11, 27	-	-	
X-64B (Unit 2)	Spare	A	Cap (4)	10, 11, 27	-	-	
X-65A	Reactor Level Inst	A	Cap (3) Excess Flow Check Vlv. (1)	10, 11, 27	-	-	
X-65B (Unit 1)	Reactor Level Inst	A	Excess Flow Check Vlv. (1)	10, 11, 27	-	-	
X-65B (Unit 2)	Reactor Level Inst	A	Cap (3) Excess Flow Check Vlv. (1)	10, 11, 27	-	-	
X-66A	Reactor Level Inst	A	Cap (3) Excess Flow Check Vlv. (1)	10, 11, 27	-	-	

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Penetration	Description	Type Test	Inboard Isolation Barrier		Outboard Isolation Barrier		Exemption to 10CFR50 Appendix J Required
			Barrier Description/ Valve No. (28)	Notes	Barrier Description/ Valve No.	Notes	
X-66B	Reactor Level Inst	A	Cap (3) Excess Flow Check Vlv. (1)	10, 11, 27	-	-	
X-72A	Liquid Radwaste	C	HV-16116A1	11, 16	HV-16116A2	11, 16	
X-72B	Liquid Radwaste	C	HV-16108A1	11, 16	HV-16108A2	11, 16	
X-80A	Spare	A	Cap	-	-	-	
X-80B (Unit 1)	Main Steam Inst.	A	Excess Flow Check Vlv. (2)	10, 11, 27	-	-	
X-80B (Unit 2)	Main Steam Inst.	A	Cap (1) Excess Flow Check Vlv. (3)	10, 11, 27	-	-	
X-80C	H_20_2 Analyzer	C	SV-15750B, SV-15752B	11	Closed System	31	
X-80C	H_2O_2 Analyzer	C	SV-15740B, SV-15742B	11	Closed System	31	
X-80C	H_2O_2 Analyzer	C	SV-15776B, SV-15774B	11	Closed System	31	
X-81A	Spare	A	Cap (3)	-	-	-	
X-81B	Spare	A	Cap (3)	-	-	-	
X-82A	Spare	A	Cap (4)	-	-	-	
X-82B	Spare	A	Cap (3)	-	-	-	
X-83A	Spare	A	Cap (3)	-	-	-	
X-83B	Spare	A	Cap (3)	-	-	-	
X-84A	Vessel Leak Detect. Inst	A	Cap (3) Excess Flow Check Vlv (1)	10, 11, 27	-	-	
X-84B	Spare	A	Cap (3)	-	-	-	
X-85A	Chilled Water To Recirc Pumps	C	HV-18792B1	16	HV-18791A1	16	
X-85B	Chilled Water To Recirc Pumps	C	HV-18792B2	16	HV-18791A2	16	
X-86A	Chilled Water To Recirc Pumps	C	HV-18792A1	16	HV-18791B1	16	
X-86B	Chilled Water To Recirc Pumps	C	HV-18792A2	16	HV-18791B2	16	
X-87	Instrument Gas	C	HV-12603	-	SV-12605	-	
X-88A	Drywell N_2 Makeup	C	SV-15767	11	SV-15789	11	

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Penetration	Description	Type Test	Inboard Isolation Barrier: Barrier Description/ Valve No. (28)	Inboard Isolation Barrier: Notes	Outboard Isolation Barrier: Barrier Description/ Valve No.	Outboard Isolation Barrier: Notes	Exemption to 10CFR50 Appendix J Required
X-88B	H_2O_2 Sample	C	SV-15776A, SV-15774A	11	Closed System	31	
X-89	Not Used						
X-90A	Level Inst	A	Cap (1) Instrument Line (3)	10, 11, 30	-	-	
X-90B (Unit 1)	Spare	A	Cap (3)	-	-	-	
X-90B (Unit 2)	Spare	A	Cap (4)	-	-	-	
X-90C	Spare	A	Cap	-	-	-	
X-90D (Unit 1)	Press. Inst	A	Cap (1) Instrument Line (3)	10, 11, 30	-	-	
X-90D (Unit 2)	Press. Inst	A	Instrument Line (3)	10, 11, 30	-	-	
X-90E (Unit 1)	Spare	A	Cap (4)	-	-	-	
X-90E (Unit 2)	Spare	A	Cap (3)	-	-	-	
X-90F (Unit 1)	Spare	A	Cap	-	-	-	
X-90F (Unit 2)	Spare	A	Cap (4)	-	-	-	
X-91A (Unit 1)	Spare	A	Cap (2)	-	-	-	
X-91A (Unit 1)	Cmt. Rad. Det. Supply Sample	C	SV157100B	11	SV157101B	11	
X-91A (Unit 1)	Cmt. Rad. Det. Return Sample	C	SV157102B	11	SV157103B	11	
X-91A (Unit 2)	RWCU Inst., Main Steam Inst.	A	Cap (1) Excess Flow Check Vlv. (3)	10, 11, 27			
X-91B	Spare	A	Cap	-	-	-	
X-92	Spare	A	Cap (3)	-	-	-	
X-93	TIP Inst Gas	C	1-26-072	-	SV-12661	-	
X-94	Spare	A	Cap	-	-	-	
X-100A	Neut. Monitoring	B	Canister	12	-	-	
X-100B	Neut. Monitoring	B	Canister	12	-	-	
X-100C	Neut. Monitoring	B	Canister	12	-	-	

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Penetration	Description	Type Test	Inboard Isolation Barrier: Barrier Description/ Valve No. (28)	Inboard Isolation Barrier: Notes	Outboard Isolation Barrier: Barrier Description/ Valve No.	Outboard Isolation Barrier: Notes	Exemption to 10CFR50 Appendix J Required
X-100D	Neut. Monitoring	B	Canister	12	-	-	
X-100E (Unit 1)	Neut. Monitoring	B	Lead Shield/Support Plate	24	Double O-Ring Compression fitting	25	
X-100E (Unit 2)	Spare	A	Cap				
X-100F (Unit 1)	Communications	B	Lead Shield/Support Plate	24	Double O-Ring Compression fitting	25	
X-100F (Unit 2)	Spare	A	Cap				
X-100G	Spare	A	Cap	-	-	-	
X-100H (Unit 1)	Spare	A	Cap	-	-	-	
X-100H (Unit 2)	Communications	B	Lead Shield/Support Plate	24	Double O-Ring Compression Fitting	25	
X-101A	M.V. Power	B	Canister	13	Double O-ring	13	
X-101B	M.V. Power	B	Canister	13	Double O-ring	13	
X-101C	M.V. Power	B	Canister	13	Double O-ring	13	
X-101D	M.V. Power	B	Canister	13	Double O-ring	13	
X-101E	M.V. Power	B	Canister	13	Double O-ring	13	
X-101F	M.V. Power	B	Canister	13	Double O-ring	13	
X-102A	Low Level Signal/Temp.	B	Canister	13	Double O-ring	13	
X-102B	Low Level Signal/Temp.	B	Canister	13	Double O-ring	13	
X-103A	Low Level Signal/Temp.	B	Canister	13	Double O-ring	13	
X-103B	Low Level Signal/Temp.	B	Canister	13	Double O-ring	13	
X-104A	RPIS	B	Canister	13	Double O-ring	13	
X-104B	RPIS	B	Canister	13	Double O-ring	13	
X-104C	RPIS	B	Canister	13	Double O-ring	13	
X-104D	RPIS	B	Canister	13	Double O-ring	13	
X-104E (Unit 1)	Spare	A	Cap	-	-	-	

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Penetration	Description	Type Test	Inboard Isolation Barrier: Barrier Description/ Valve No. (28)	Inboard Isolation Barrier: Notes	Outboard Isolation Barrier: Barrier Description/ Valve No.	Outboard Isolation Barrier: Notes	Exemption to 10CFR50 Appendix J Required
X-104E (Unit 2)	Neut. Monitoring	B	Lead Shield/Support Plate	24	Double O-ring Compression Fitting	25	
X-104F	Spare	A	Cap	-	-	-	
X-104G	Spare	A	Cap	-	-	-	
X-104H	Spare	A	Cap	-	-	-	
X-105A	Low Volt. Power	B	Canister	13	Double O-ring	13	
X-105B	Low Volt. Power	B	Canister	13	Double O-ring	13	
X-105C	Low Volt. Power	B	Canister	13	Double O-ring	13	
X-105D	Low Volt. Power	B	Canister	13	Double O-ring	13	
X-106A	Low Volt. Control	B	Canister	13	Double O-ring	13	
X-106B	Low Volt. Control	B	Canister	13	Double O-ring	13	
X-106C	Low Volt. Control	B	Canister	13	Double O-ring	13	
X-106D	Low Volt. Control	B	Canister	13	Double O-ring	13	
X-107	Low Volt. Power	B	Canister	13	Double O-ring	13	
X-108	Low Volt. Power	B	Canister	13	Double O-ring	13	
X-200A	Access Hatch	B	Double O-ring	1	-	-	
X-200B	Access Hatch	B	Double O-ring	1	-	-	
X-201A	See Penetration X-25	-	-	-	-	-	
X-201B (U1)	Spare	---	Cap	---	---	---	
X-201B (U2)	Hardened Containment Vent System	B and C	HV-257113	8, 11, 32	HV-257114	11	
X-202	Purge Exhaust	C	HV-15703	8, 11	HV-15705, HV-15704	11	
X-203A	RHR Pump Suction	A	HV-1F004A	9, 11, 18	Closed System	9, 11, 18	
X-203B	RHR Pump Suction	A	HV-1F004B	9, 11, 18	Closed System	9, 11, 18	
X-203C	RHR Pump Suction	A	HV-1F004C	9, 11, 18	Closed System	9, 11, 18	
X-203D	RHR Pump Suction	A	HV-1F004D	9, 11, 18	Closed System	9, 11, 18	

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Penetration	Description	Type Test	Inboard Isolation Barrier		Outboard Isolation Barrier		Exemption to 10CFR50 Appendix J Required
			Barrier Description/ Valve No. (28)	Notes	Barrier Description/ Valve No.	Notes	
X-204A	RHR Pump Test Line	C	HV-1F028A, HV-1F011A	9, 11, 17	Closed System	9, 11, 18	
X-204B	RHR Pump Test Line	C	HV-1F028B, HV-1F011B	9, 11, 17	Closed System	9, 11, 18	
X-205A	Containment Spray	C	HV-1F028A, HV-1F011A	9, 11, 17	Closed System	9, 11, 18	
X-205B	Containment Spray	C	HV-1F028B, HV-1F011B	9, 11, 17	Closed System	9, 11, 18	
X-206A	Core Spray Pump Suction	A	HV-1F001A	9, 11, 18	Closed System	9, 11, 18	
X-206B	Core Spray Pump Suction	A	HV-1F001B	9, 11, 18	Closed System	9, 11, 18	
X-207A	Core Spray Pump Test	A	HV-1F015A	9, 11, 18	Closed System	9, 11, 18	
X-207B	Core Spray Pump Test	A	HV-1F015B	9, 11, 18	Closed System	9, 11, 18	
X-208A	Core Spray Pump Recirc	A	HV-1F031A	9, 11, 18	Closed System	9, 11, 18	
X-208B	Core Spray Pump Recirc	A	HV-1F031B	9, 11, 18	Closed System	9, 11, 18	
X-209	HPCI Pump Suction	A	HV-1F042	9, 11, 18	Closed System	9, 11, 18	
X-210	HPCI Turbine Exh.	C	HV-1F066	7, 11, 21	1F049	11, 21	Yes
X-211	HPCI Pump Recirc	A	HV-1F0l2	11, 18	1F046	11, 18	
X-212 (Unit 1)	Spare	A	Cap	-	-	-	
X-212 (Unit 2)	Ctmt. Rad. Det. Supply Sample	C	SV-257104	11	SV-257105	11	
X-213	Spare	A	Cap	-	-	-	
X-214	RCIC Pump Suction	A	HV-1F031	9, 11, 18	Closed system	9, 11, 18	
X-215	RCIC Turbine Exh.	C	HV-1F059	7, 11, 21	1F040	11, 21	Yes
X-216	RCIC Pump Recirc	A	FV-1F019	11, 18	1F021	11, 18	
X-217	RCIC Vac. Pump Disch.	C	HV-1F060	6, 11, 21	1F028	11, 21	
X-218	Instrument Gas	C	1-26-164	11	SV-12671	11	
X-219A	Level Inst.	A	Instrument Line (1)	10, 11, 30	-	-	
X-219B	Level Inst.	A	Instrument Line (1)	10, 11, 30	-	-	
X-220A (Unit 1)	Ctmt. Rad. Det. Return Sample	C	SV-157106	11	SV-157107	11	
X-220A (Unit 2)	Spare	A	Cap	-	-	-	

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Penetration	Description	Type Test	Inboard Isolation Barrier: Barrier Description/ Valve No. (28)	Inboard Isolation Barrier: Notes	Outboard Isolation Barrier: Barrier Description/ Valve No.	Outboard Isolation Barrier: Notes	Exemption to 10CFR50 Appendix J Required
X-220B	Wetwell N_2 Makeup	C	SV-15737	11	SV-15738	11	
X-221A	H_2O_2 Analyzer	C	SV-15780A, SV-15782A	11	Closed System	31	
X-221B (Unit 1)	Spare	A	Cap	-	-	-	
X-221B (Unit 2)	H_20_2 Analyzer	C	SV-25780B, SV-25782B	11	Closed System	31	
X-222	Spare	A	Cap	-	-	-	
X-223A	Suppression Pool Press Inst.	A	Instrument Line (1)	10, 11, 30	-	-	
X-223B	Spare	A	Cap	-	-	-	
X-224	Spare	A	Cap	-	-	-	
X-225	Spare/Sit Test Conn.	A	Cap	-	-	-	
X-226A	RHR Recirc	A	HV-1F007A	9, 11, 18	Closed System	9, 11, 18	
X-226B	RHR Recirc	A	HV-1F007B	9, 11, 18	Closed System	9, 11, 18	
X-227	Spare	A	Cap	-	-	-	
X-228A (Unit 1)	Ctmt. Rad. Det. Supply Sample	C	SV-157104	11	SV-157105	11	
X-228A (Unit 2)	Spare	A	Cap	-	-	-	
X-228B	Spare	A	Cap	-	-	-	
X-228C	Spare	A	Cap	-	-	-	
X-228D	Spare	A	Cap	-	-	-	
X-229A	Spare	A	Cap	-	-	-	
X-229B (Unit 1)	Spare	A	Cap	-	-	-	
X-229B (Unit 2)	Ctmt. Rad. Det. Return Sample	C	SV-257106	11	SV-257107	11	
X-230A	Spare	A	Cap	-	-	-	
X-231A	Spare	A	Cap	-	-	-	
X-231B	Spare	A	Cap	-	-	-	
X-232A	Level Inst.	A	Instrument Line (1)	10, 11, 30		-	
X-232B	Level Inst.	A	Instrument Line (1)	10, 11, 30	-	-	

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Penetration	Description	Type Test	Inboard Isolation Barrier		Outboard Isolation Barrier		Exemption to 10CFR50 Appendix J Required
			Barrier Description/ Valve No. (28)	Notes	Barrier Description/ Valve No.	Notes	
X-233 (Unit 1)	H_20_2 Analyzer	C	SV-15780B, SV-15782B	11	Closed System	31	
X-233 (Unit 2)	Spare	A	Cap	-	-	-	
X-234A	Level Inst.	A	Instrument Line (1)	10, 11, 30	-	-	
X-234B	Level Inst.	A	Instrument Line (1)	10, 11, 30	-	-	
X-235A	Level Inst.	A	Instrument Line (1)	10, 11, 30	-	-	
X-235B	Level Inst.	A	Instrument Line (1)	10, 11, 30	-	-	
X-236	Spare	A	Cap	-	-	-	
X-237	Spare	A	Cap	-	-	-	
X-238A	H_2O_2 Analyzer Return	C	SV-15736A, SV-15734A	11	Closed System	31	
X-238B	H_2O_2 Analyzer Return /	C	SV-15736B, SV-15734B	11	Closed System	31	
X-239	Not Used	-	-	-	-	-	
X-240	Not Used	-	-	-	-	-	
X-241	Not Used	-	-	-	-	-	
X-242	Not Used	-	-	-	-	-	
X-243	Supp. Pool Cleanup & Drain	C	HV-15766	7, 11, 14, 18,	HV-15768	11, 14, 18	Yes
X-244	HPCI Vac. Breaker	C	HV-1F079	11, 16, 29	HV-1F075	11, 16	Yes
X-245	RCIC Vac. Breaker	C	HV-1F084	11, 16, 29	HV-1F062	11, 16	Yes
X-246A	RHR Relief Valve Discharge	C B	Blind Flange, PSV-15106A HV-1F103A Spectacle Flange 1S299A	9, 11, 16 26	Closed System N/A	9, 11	Yes
X-246B	RHR Relief Valve Discharge.	C B	Blind Flange, HV-1F103B PSV-15106B Spectacle Flange 1S299B	9, 11, 16 32	Closed System N/A	9,11	Yes
X-247-299	Not Used	-	-	-	-	-	-
X-300	Low Voltage Control	B	Canister	13	Double O-ring	13	
X-301	Low Voltage Control	B	Canister	13	Double O-ring	13	

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TABLE 6.2-22

LEAKAGE RATE TEST LIST

Penetration	Description	Type Test	Inboard Isolation Barrier		Outboard Isolation Barrier		Exemption to 10CFR50 Appendix J Required
			Barrier Description/ Valve No. (28)	Notes	Barrier Description/ Valve No.	Notes	
X-330B	Inst. & Control	B	Canister	13	Double O-ring	13	

NOTES:

1. The penetration is sealed by a blind flange or door with double o-ring seals. The seals are leak rate tested by pressurizing between the o-rings.

2. The personnel air lock volume is pressurized to Pa. The air lock is tested periodically in accordance with the Leakage Rate Test Program. During the air lock test, tie downs are installed on the inner door. The normal locking mechanisms for the air lock doors are not designed to withstand a differential pressure greater than 5 psi across the door in the reverse direction. Figure 6.2-59 shows the details of the tie downs for the inner door. The tie downs are installed from within the air lock. The force exerted by the tie downs on the inner door is not mentioned. The mechanical and electrical penetrations in the air lock are tested by pressurizing the air lock barrel.

3. Double rubber seals are provided on both air lock doors. These seals are tested at 10 psig, a pressure less than the containment peak accident pressure. Testing at a pressure greater than 10 psig forces the gasket material out of the groove. The 10 psig test pressure is in accordance with the plant Technical Specifications. The test pressure is also permitted by NEI 94-01, Rev. 0, Section 10.2.2.1. Additionally, as mentioned in Note 2, the entire air lock, including the doors, is tested periodically at Pa.

4. If the MSIVs are tested together (i.e., between valves), they are tested at 1/2 Pa. Higher pressure will unseat the inboard MSIV. If the MSIVs are tested individually, they are tested at Pa.

5. If the MSIVs are tested together, the inboard globe valve is tested in the reverse direction. This is a conservative test since the test pressure tends to unseat the disc.

6. The globe valve is tested in the reverse direction.

7. The gate valve is tested in the reverse direction.

8. The butterfly valve is tested in the reverse direction. Butterfly valves exhibit equivalent or more conservative leakage in the reverse direction.

9. The containment isolation for this penetration consists of a containment isolation valve and a closed system outside containment. This is in compliance with 10CFR50 Appendix A GDC 54 and the US NRC Standard Review Plan 6.2.4, Containment Isolation Provisions, paragraph II.3.e.

TABLE 6.2-22

LEAKAGE RATE TEST LIST

The standard review plan allows the use of a single isolation valve outside containment in conjunction with a closed system outside containment. A single active failure can be accommodated. The closed system is missile/pipe whip protected, Seismic Category I, Safety Class 2, and has a temperature and pressure rating in excess of that for the containment. Closed system integrity is maintained and verified in accordance with the Leakage Rate Test Program.

10. The installation is in accordance with US NRC Regulatory Guide 1.11 (Safety Guide 11).

11. All containment isolation barriers and/or valves are outside the containment.

12. The electrical canister is Type B tested by pressurizing with dry nitrogen. The canister is welded to the penetration nozzle.

13. The electrical canister is bolted to the penetration nozzle. The bolted connection contains a double o-ring with a test connection. The electrical canister and double o-ring are Type B tested by pressurizing with dry nitrogen.

14. The isolation barrier remains water filled or a water seal remains in the line post-LOCA. The containment isolation valve is tested with water. The containment isolation valve leak rate is not included in the Type B and C test acceptance criteria. The acceptance criteria for water tested valves is in the plant Technical Specifications.

15. The relief valve is tested in the reverse direction. This is a conservative test since the test pressure tends to unseat the valve plug.

16. To expose the containment isolation valve seating surface to the containment atmosphere, the piping system is drained of fluid to the extent necessary.

17. The system remains water filled and operational during the ILRT. The penetration leak rate is added to the Type A test result. For RBCW, only 1 loop remains water filled.

18. The system is designed to remain water filled post-LOCA. The system remains water filled during the ILRT.

19. The TIP shear valves are not Type C tested. The shear valve isolates the TIP tubing by shearing the tube and drive cable and jamming the sheared ends of the tubing into a teflon coating on the shear valve disc. The shear valve cannot be Type C tested without destroying the drive tube. However, a valve from each lot of shear valves is leak rate tested prior to delivery. If the valve fails to meet the leakage criteria, the entire lot of shear valves is rejected. The explosive charges that operate the shear valves are in-service tested in accordance with the requirements of the ASME Code.

TABLE 6.2-22

LEAKAGE RATE TEST LIST

20. The CRD insert and withdraw line design does not facilitate Type C testing. Adequate leakage monitoring of the CRD lines is provided by measuring the water leakage from the headers while the containment is pressurized to Pa. This is done by venting the non-seismic CRD headers after the Type A test portion of the ILRT is complete and before the containment is depressurized. The allowable leakage for the CRD headers is controlled by the Leakage Rate Test Program to be within the DBA LOCA dose analysis for water leakage from ESF systems in Section 15.6.5.5.1.2.

    The lack of a Type C test is justified because there is not a credible failure mode that could cause air to be released through the subject containment penetrations. The insert and withdraw lines are connected to the CRDs that are located at the bottom of the reactor pressure vessel. Analyses have shown that the insert and withdraw lines will not fail as a result of a LOCA. The lines are always water filled.

21. The valve is required to operate post-accident. When the valve is closed, any leakage through the valve is into a seismically qualified, Class B system. The system does not communicate with the environment and is in an area served by the Standby Gas Treatment system. A water seal is maintained in the piping submerged in the suppression pool. The containment isolation valve is tested with water. The containment isolation valve leak rate is not included in the Type B and C test acceptance criteria. The acceptance criteria for water tested valves is in the plant Technical Specifications.

22. The inboard valve is tested in the reverse direction during the Type C test. The inboard valve is tested at Pa in the accident direction during the Type A test.

23. Refer to Table 6.2-12 Note 20 and Subsection 6.2.4.3.2.2. Installation of this penetration is justified under Regulatory Guide 1.11.

24. A lead radiation shield inside the penetration nozzle and an electrical feedthrough assembly support plate act as the non-pressure retaining barrier.

25. Electrical feedthrough assemblies are screwed/compression fitted into the penetration header plate. The header plate with a double o-ring seal is bolted to the containment nozzle. The electrical feedthrough assemblies and the double o-ring are Type B tested by pressurizing with dry nitrogen.

26. The spectacle flange is installed inboard of the containment isolation valves to provide a pressurization barrier. The spectacle is normally open. The spectacle is locally testable via dual o-ring seals with an intermediate pressure tap.

27. See Table 6.2-12a for the excess flow check valve number(s).

28. The number in parenthesis indicates the number of individual caps or excess flow check valves in the penetration.

TABLE 6.2-22

LEAKAGE RATE TEST LIST

29. Test pressure is applied between the valve disc.

30. For these penetrations, the instrument line outside the primary containment (including the associated instrument(s)) forms the isolation barrier as an “extension of primary containment.” The containment boundary includes the instrument line, the respective instrument(s), and any branch lines up to and including the first closed isolation valve designated as CB or ICB on the P&ID (also see Figure 6.2-44M, detail (ZZ)).

31. For each penetration, the H_2O_2 Analyzer lines outside primary containment (including the components within the analyzer panels) provide a redundant isolation barrier in the event of a single electrical failure of both Primary Containment Isolation Valves (PCIVs). These lines up to and including the first normally closed valve are an “extension of primary containment”, and are subject to the design and testing requirements for closed systems. The design of the H_2O_2 Analyzer Analyzer closed system outside primary containment is in accordance with the design requirements for such systems specified in USNRC Standard Review Plan 6.2.4 (September 1975), Containment Isolation Provisions, paragraph II.3.e, as clarified by Table 3.2-1. The integrity of the closed system and boundary valves are verified in accordance with the Leakage Rate Test Program. The closed system boundary for H_2O_2 Analyzer penetrations include the main process lines, branch connections up to the first normally closed isolation or check valve, and the analyzer panels (including the internal components and branch connections up to the first normally closed isolation or check valve). The closed system boundary between PASS and the H_2O_2 Analyzer System ends at the PASS solenoid operated isolation valves that form the Seismic Category I boundary between the systems (i.e.,SV-1(2)2361, SV-1(2)2365, SV-1(2)2366, SV-1(2)2368 & SV-1(2)2369).

32. The valve inlet flange is sealed with double o-ring seals. The flange is leak rate tested (Type B) by pressurizing between the o-rings.

TABLE 6.2-23

INITIAL AND BOUNDARY CONDITIONS FOR INADVERTENT SPRAY ACTUATION STUDY

	t_{-00}	Time Zero t_o
Drywell		
Volume (Ft^3)	239600	239600
Pressure (PSIA)	13.7	34.553
Temperature (F)	135	258.5
Relative Humidity (%)	90	100
Spray Rate (GPM/ TRAINS)	0/0	10700/1
Wetwell		
Volume - Vapor Region (Ft^3)	148590	145900
- Suppression Pool (Ft^3)	131550	131550
Pressure (PSIA)	13.7	30.06
Temperature (F)	50	50
Relative Humidity (%)	100	100
Suppression Pool Free Surface Area (Ft^2)	5277	5277
Wetwell-to-Drywell Vacuum Breakers		
Number of Valve Assemblies		4 of 5
Flow Area Per Assembly (Ft^2)		2.05
Flow Coefficient		0.495
Assumed Vacuum Breaker Lifting ΔP* (psid)		2.81
Assumed Vacuum Breaker Full Open ΔP* (psid)		4.48
RHR System - Drywell Spray Mode		
Service Water Flow Rate (GPM)		9000
Service Water Temperature (F)		32
Heat Exchange Effectiveness		0.245

*Δ P measured between wetwell and drywell.

TABLE 6.2-24

INITIAL AND BOUNDARY CONDITIONS FOR DRYWELL - WETWELL BYPASS LEAKAGE STUDY

DRYWELL	
VOLUME (ft^3)	239,337
PRESSURE (psia)	16.2
TEMPERATURE (°F)	135
RELATIVE HUMIDITY (%)	20
WALL SURFACE AREA (ft^2)	19,453
LINER THICKNESS (inch)	0.25
CONCRETE (ft)	6.0
CONDENSING COEFFICIENT	UCHIDA
BYPASS LEAKAGE AREA $A/\sqrt{k}$ (ft^2)	0.0535
(TWO CASES)	0.05
SUPPRESSION CHAMBER AIR SPACE	
VOLUME (ft^3)	148,589 (HIGH WATER LEVEL)
PRESSURE (psia)	16.2
TEMPERATURE (°F)	90
RELATIVE HUMIDITY (%)	100
DOWNCOMER SURFACE AREA ABOVE WATER LEVEL (ft^2)	15,902
MAIN STEAM RELIEF LINES SURFACE AREA (ft^2)	1,419.48
DOWNCOMER THICKNESS (INCH)	0.375
WALL SURFACE AREA (ft^2)	7,803
LINER THICKNESS (inch)	0.25
CONCRETE (ft)	6.0
CONDENSING COEFFICIENT	UCHIDA
CONVECTIVE COEFFICIENT	2.0
DOWNCOMER SUBMERGENCE (ft)	12
OUTSIDE AIR TEMPERATURE (°F)	105
SUPPRESSION POOL	
TEMPERATURE (°F)	90
MASS OF WATER (lbm)	8,171,315

TABLE 6.2-25

BLOWDOWN DATA AND BYPASS LEAKAGE

PHASE I (INTO DRYWELL MODEL)

MASS BLOWDOWN (lbm/sec)	212
ENTHALPY (Btu/lbm)	1,191.5

PHASE III

$A/\sqrt{k} = 0.0535\ ft^2$

Time (sec)	MASS RATE (lbm/sec)	ENTHALPY (Btu/lbm)
0	3.78	1,174.1
1000	4.61	1,181.4

$A/\sqrt{k} = 0.05\ ft^2$

Time (sec)	MASS RATE (lbm/sec)	ENTHALPY (Btu/lbm)
0	3.53	1,174.1
1000	4.31	1,181.4

TABLE 6.2-26

LONG-TERM BLOWDOWN DATA FOR A RECIRCULATION LINE BREAK (CASE D)

TIME (sec)	TOTAL FLOW (lbm/sec)	FLOW ENTHALPY (Btu/lbm)
0	34830	550.0
303	8346	128.4
607	8309	134.5
1204	8324	136.9
2426	8314	143.5
3612	8317	148.9
5424	8310	155.1
7236	8319	160.0
9047	8307	163.9
10797	8315	167.1
10859	8316	167.2
10922	8318	167.3
12609	8320	169.8
14416	8316	171.9
16229	8312	173.7
18041	8309	175.2
19791	8318	176.3
21603	8322	177.2
23416	8318	177.9
25228	8312	178.5
27041	8313	179.0
28791	8316	179.3
30603	8312	179.5
32478	8314	179.7
34228	8314	179.7
36041	8316	179.7
37853	8315	179.6
39603	8313	179.4
41415	8315	179.3

Table 6.2-27

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TABLE 6.2-3a

Initial Plant Conditions for
DBA-LOCA Containment Response

Parameter	Units	Value
Rated Power	MWt	3952
Rated Core Flow	Mlbm/hr	100
Rated Steam Dome Pressure	psig	1035
Rated Turbine Steam Flow	Mlbm/hr	16.532
Rated Feedwater Flow	Mlbm/hr	16.500
Final Feedwater Temperature	°F	399.3
Drywell Pressure	psig	2.0
Drywell Temperature	°F	135
Drywell Relative Humidity	percent	20
Wetwell Pressure	psig	2.0
Wetwell Temperature	°F	90
Wetwell Relative Humidity	percent	100
Suppression Pool Temperature	°F	90

TABLE 6.2-4a

Input and Assumptions for the Short Term DBA-LOCA Analysis

1. In the LAMB calculations of break flow rates and enthalpies, the Moody Slip flow model is used, consistent with Appendix K ECCS-LOCA modeling.

2. The power level for each power/flow point analysis includes an additional 2%, consistent with Regulatory Guide 1.49.

3. The recirculation suction line break area is 4.17 sq. ft. and the main steam line break area is 3.9 sq. ft.

4. The break is an instantaneous double-ended rupture of a recirculation suction line or main steam line. MSIVs are completely closed within 2 seconds into the event for an RSLB and within 12 seconds for an MSLB.

5. No credit is taken for the passive structural heat sinks in the containment.

6. The initial vent submergence and the suppression pool water volume are determined to the High Water Level (HWL).

7. Initial containment conditions are assumed that maximize the initial mass of noncondensable gases, which result in conservative peak drywell and wetwell pressures. For the MSLB event, initial containment conditions are assumed that minimize the initial mass of non-condensable gases, which result in conservative peak drywell temperatures. These include minimum drywell and wetwell initial pressure of –1.0 psig, maximum drywell initial temperature of 135°F, and maximum drywell relative humidity of 90%.

8. For analyses performed to provide containment results for input to the hydrodynamic loads assessment, nominal initial containment conditions are assumed.

9. The wetwell airspace is in thermal equilibrium with the suppression pool.

10. The decay heat values are based on the ANS 5.0 + 20%, as used in Appendix K ECCSLOCA evaluations.

11. Feedwater flow is assumed to continue at 100% rated flow and enthalpy for 10 seconds following initiation of the event, which results in conservative peak drywell and wetwell pressures.

12. In analyzing wetwell pressure results, a polytropic exponent for air of 1.4 is used. For these cases, bubble burst is assumed to occur when wetwell pressure exceeds drywell pressure by 2.5 psid, or at maximum wetwell airspace pressure if peak wetwell pressure never exceeds drywell pressure by this amount.

TABLE 6.2-5a

Input and Assumptions for the
Long Term DBA-LOCA Analysis

1. The DBA-LOCA is an instantaneous double-ended guillotine break of the recirculation suction line at the reactor vessel nozzle safe-end to pipe weld.

2. The reactor is operating at 102% of EPU power at rated steam dome pressure. A reactor scram occurs concurrent with the occurrence of the break.

3. The reactor core power following reactor scram includes fission energy, fuel stored energy, metal-water reaction energy, and ANS 5.1 + 2σ decay heat evaluated for ATRIUM – 10 fuel with 24-month fuel cycle.

4. Reactor blowdown flow rates are based on the Moody Slip model.

5. The reactor vessel control volume is assumed to include the fluid and structural masses of the primary system components including reactor vessel, recirculation loops, main steam lines to the inboard isolation valve, and other piping systems attached to the reactor vessel, such as ECCS lines up to the inboard isolation valves.

6. The portion of the feedwater (FW) inventory initially at a temperature higher than 198°F is injected into the vessel, after absorbing heat from the FW piping metal. This assumption is used to maximize the suppression pool (SP) temperature. Upstream FW, which is initially at lower temperature, will be heated up due to downstream pipe metal at higher temperature even if no steam flows to heaters from the turbine. This assumption is conservative because the coldest water injected into the vessel with this assumption is at a temperature higher than the peak SP temperature.

7. The wetwell airspace and suppression pool are assumed to be in thermal equilibrium and the wetwell airspace is saturated throughout the event.

8. The initial suppression pool water volume corresponds to the Low Water Level (LWL) to maximize the suppression pool temperature response.

9. All four CS and four LPCI pumps are assumed to provide reactor coolant makeup soon after low water level in the reactor vessel occurs. Operators are assumed to establish containment cooling with one heat exchanger no earlier than 10 minutes following initiation of the break.

10. A constant RHR heat exchanger K-value is conservatively assumed for containment cooling. The heat exchanger K-value would be expected to increase as the suppression pool (SP) temperature increases during the event due to changes in water properties with increasing temperature. The K-value assumed for this analysis corresponds to a value at the low end of the SP temperature excursion during operation of the heat exchanger.

11. The containment cooling heat exchanger service water temperature is assumed at the maximum value anticipated during a DBA-LOCA.

12. Credit is taken for passive heat sinks in the drywell, wetwell airspace and suppression pool.

13. All operating CS and RHR pumps have 100% of their motor horsepower rating converted to pump heat, which is added to the flow downstream of the pump.

14. Conservative values for MSIV closure are assumed. Rapid closure of the MSIV results in higher peak suppression pool temperature, since the shorter closure time would retain more water mass and energy in the vessel for blowdown to the containment.

15. Condensate Storage Tank (CST) water inventory is not available for vessel makeup.

Passive Containment Heat Sings		
Parameter	Units	Value
Drywell		
Steel Heat Capacity	BTU/°F	176,000
Steel Surface Area	sqft	71,000
Concrete Heat Capacity	BTU/°F	211,104
Concrete Surface Area	sqft	14,660
Wetwell Airspace		
Steel Heat Capacity	BTU/°F	97,932
Steel Surface Area	sqft	25,358
Concrete Heat Capacity	BTU/°F	0
Concrete Surface Area	sqft	0
Suppression Pool		
Steel Heat Capacity	BTU/°F	58,940
Steel Surface Area	sqft	15,557
Concrete Heat Capacity	BTU/°F	0
Concrete Surface Area	sqft	0

TABLE 6.2-6a

Containment Performance
For DBA-LOCA

Parameter	Units	Value
Peak Drywell Pressure	psig	48.6[1]
Peak Drywell Temperature	°F	337[2]
Peak Bulk Pool Temperature	°F	211.2[3]
Peak Wetwell Pressure	psig	36.5[1]
Peak Drywell-to-Wetwell (Down) Differential Pressure	psig	25.6[1]

Notes

1. Based on the Short-Term RSLB analysis
2. Based on the Short Term MSLB analysis
3. Based on the Case D Long-Term RSLB analysis

Table 6.2-9a

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TABLE 6.2-12a

DATA ON INSTRUMENT LINES PENETRATING CONTAINMENT(5)

PENETRATION NUMBER	SERVICE	VALVE NUMBER	VALVE ARRANGEMENT(1)	VALVE TYPE(2)	LENGTH PIPE TO VALVE(3)
X-3B	RHR	151085	VA	GB	0
		15110A	VA	XFC	ACAP
X-3B	RHR	151084	VA	GB	0
		15110C	VA	XFC	ACAP
X-27A	NUC. BLR. VESSEL INST.	142009R	V	GB	0
		1F059R	V	XFC	ACAP
		142009L	V	GB	0
		1F059L	V	XFC	ACAP
		142009N	V	GB	0
		1F059N	V	XFC	ACAP
X-27B	NUCLEAR BOILER	1F066C	V	GB	0
		1F070C	V	XFC	ACAP
		1F069C	V	GB	0
		1F073C	V	XFC	ACAP
X-28B	CORE SPRAY	1F017A	V	GB	0
		1F018A	V	XFC	ACAP
X-29B	RWCU	144001C	V	GB	0
		14411C	V	XFC	ACAP
		144001D	V	GB	0
		14411D	V	XFC	ACAP
X-30A	REACTOR RECIRC	1F058A	V	GB	0
		1F057A	V	XFC	ACAP
X-31A	RCIC	1F043A	V	GB	0
X-31A		1F044A	V	XFC	ACAP
X-31A		1F043C	V	GB	0
X-31A		1F044C	V	XFC	ACAP
X-31A (UNIT 2 ONLY)	NUC. BLR. VESSEL INST.	242009G	V	GB	0
X-31A (UNIT 2 ONLY)		2F059G	V	XFC	ACAP
X-31B	REACTOR RECIRC	1F016B	VB	GB	0
		1F017B	VB	XFC	ACAP
X-32A	RHR	151086	VA	GB	0
		15110B	VA	XFC	ACAP
		151087	VA	GB	0
		15110D	VA	XFC	ACAP
X-33A	RHR	151025	V	GB	0
		15109C	V	XFC	ACAP
		151022	V	GB	0
		15109D	V	XFC	ACAP
X-33B	RHR	151020	V	GB	0
		15109A	V	XFC	ACAP
		151021	V	GB	0
		15109B	V	XFC	ACAP

TABLE 6.2-12a

DATA ON INSTRUMENT LINES PENETRATING CONTAINMENT[5]

PENETRATION NUMBER	SERVICE	VALVE NUMBER	VALVE ARRANGEMENT[1]	VALVE TYPE[2]	LENGTH PIPE TO VALVE[3]
X-34A	HPCI	1F023A	V	GB	0
		1F024A	V	XFC	ACAP
		1F023C	V	GB	0
		1F024C	V	XFC	ACAP
X-34B	HPCI	1F023B	V	GB	0
		1F024B	V	XFC	ACAP
		1F023D	V	GB	0
		1F024D	V	XFC	ACAP
X-40A	NUC. BLR. VESSEL INST.	142005C	V	GB	0
		1F053C	V	XFC	ACAP
		142009T	V	GB	0
		1F059T	V	XFC	ACAP
		142006C	V	GB	0
		1F051C	V	XFC	ACAP
X-40B	NUCLEAR BOILER	1F067A	V	GB	0
		1F071A	V	XFC	ACAP
		1F068A	V	GB	0
		1F072A	V	XFC	ACAP
X-40C (UNIT 1 ONLY)	NUC. BLR. VESSEL INST.	142005A	V	GB	0
		1F053A	V	XFC	ACAP
		142009G	V	GB	0
		1F059G	V	XFC	ACAP
		142006A	V	GB	0
		1F051A	V	XFC	ACAP
X-40D	NUC. BLR.	142009E	V	GB	0
		1F059E	V	XFC	ACAP
		142009A	V	GB	0
		1F059A	V	XFC	ACAP
		142009C	V	GB	0
		1F059C	V	XFC	ACAP
X-40E	NUC. BLR. VESSEL INST.	142005D	V	GB	0
		1F053D	V	XFC	ACAP
		142009U	V	GB	0
		1F059U	V	XFC	ACAP
		142006D	V	GB	0
		1F051D	V	XFC	ACAP
X-40F	NUC. BLR. VESSEL INST.	142009M	V	GB	0
		1F059M	V	XFC	ACAP
		142009P	V	GB	0
		1F059P	V	XFC	ACAP
		142009S	V	GB	0
		1F059S	V	XFC	ACAP

TABLE 6.2-12a

DATA ON INSTRUMENT LINES PENETRATING CONTAINMENT[5]

PENETRATION NUMBER	SERVICE	VALVE NUMBER	VALVE ARRANGEMENT[1]	VALVE TYPE[2]	LENGTH PIPE TO VALVE[3]
X-40G	NUC. BLR. VESSEL INST.	142005B	V	GB	0
		1F053B	V	XFC	ACAP
		142009H	V	GB	0
		1F059H	V	XFC	ACAP
		142006B	V	GB	0
		1F051B	V	XFC	ACAP
X-40H	NUC. BLR. VESSEL INST.	142009B	V	GB	0
		1F059H	V	XFC	ACAP
		142009D	V	GB	0
		1F059D	V	XFC	ACAP
		142009F	V	GB	0
		1F059F	V	XFC	ACAP
X-48B (UNIT 2 ONLY)	NUCLEAR BOILER	2F066B	V	GB	0
		2F070B	V	XFC	ACAP
		2F069B	V	GB	0
		2F073B	V	XFC	ACAP
X-49A	REACTOR RECIRC	1F041A	V	GB	0
		1F009A	V	XFC	ACAP
		1F009B	V	XFC	ACAP
		1F042A	V	GB	0
		1F010A	V	XFC	ACAP
		1F010B	V	XFC	ACAP
X-49B	REACTOR RECIRC	1F041C	V	GB	0
		1F009C	V	XFC	ACAP
		1F009D	V	XFC	ACAP
		1F042C	V	GB	0
		1F010C	V	XFC	ACAP
		1F010D	V	XFC	ACAP
X-50A	REACTOR RECIRC	1F041B	V	GB	0
		1F011A	V	XFC	ACAP
		1F011B	V	XFC	ACAP
		1F042B	V	GB	0
		1F012A	V	XFC	ACAP
		1F012B	V	XFC	ACAP
X-50B	REACTOR RECIRC	1F041D	V	GB	0
		1F011C	V	XFC	ACAP
		1F011D	V	XFC	ACAP
		1F042D	V	GB	0
		1F012C	V	XFC	ACAP
		1F012D	V	XFC	ACAP

TABLE 6.2-12a

DATA ON INSTRUMENT LINES PENETRATING CONTAINMENT[5]

PENETRATION NUMBER	SERVICE	VALVE NUMBER	VALVE ARRANGEMENT[1]	VALVE TYPE[2]	LENGTH PIPE TO VALVE[3]
X-51A	REACTOR RECIRC	1F039A	V	GB	O
		1F040A	V	XFC	ACAP
		1F039C	V	GB	O
		1F040C	V	XFC	ACAP
X-51B	REACTOR RECIRC	1F039B	V	GB	O
		1F040B	V	XFC	ACAP
		1F039D	V	GB	O
		1F040D	V	XFC	ACAP
X-52A	REACTOR RECIRC	1F005A	VB	GB	O
		1F003A	VB	XFC	ACAP
		1F006A	VB	GB	O
		1F004A	VB	XFC	ACAP
X-52B	REACTOR RECIRC	1F005B	VB	GB	O
		1F003B	VB	XFC	ACAP
		1F006B	VB	GB	O
		1F004B	VB	XFC	ACAP
		1F058B	V	GB	O
		1F057B	V	XFC	ACAP
X-58A	RWCU	144001A	V	GB	O
		14411A	V	XFC	ACAP
		144001B	V	GB	O
		14411B	V	XFC	ACAP
X-59A	NUC. BLR. VESSEL INST.	142001	V	GB	O
X-59A		1F041	V	XFC	ACAP
X-59A		142002A	V	GB	O
X-59A (UNIT 2 ONLY)		242002A[4]	V	GB	O
X-59A		1F043A	V	XFC	ACAP
X-59B	NUC. BLR. VESSEL INST.	142002B	V	GB	O
X59B (UNIT 2 ONLY)		242002B[4]	V	GB	O
X-59B		1F043B	V	XFC	ACAP
X-59B		142011	V	GB	O
X-59B		14202	V	XFC	ACAP
X-60A	REACTOR RECIRC	1F016A	VB	GB	O
		1F017A	VB	XFC	ACAP
X-61A (UNIT 2 ONLY)	NUC. BLR. VESSEL INST.	242005A	V	GB	O
		2F053A	V	XFC	ACAP
X-61B	NUCLEAR BOILER	1F066D	V	GB	O
		1F070D	V	XFC	ACAP
		1F069D	V	GT	O
		1F073D	V	XFC	ACAP

TABLE 6.2-12a

DATA ON INSTRUMENT LINES PENETRATING CONTAINMENT[5]

PENETRATION NUMBER	SERVICE	VALVE NUMBER	VALVE ARRANGEMENT[1]	VALVE TYPE[2]	LENGTH PIPE TO VALVE[3]
X-62A (UNIT 1 ONLY)	NUC. BLR. VESSEL INST.	142010	V	GB	0
		1F061	V	XFC	ACAP
X-62A	NUCLEAR BOILER	1F067B	V	GB	0
		1F071B	V	XFC	ACAP
		1F068B	V	GB	0
		1F072B	V	XFC	ACAP
X-62B	NUCLEAR BOILER	1F066A	V	GB	0
		1F070A	V	XFC	ACAP
		1F069A	V	GB	0
		1F073A	V	XFC	ACAP
X-63A	NUCLEAR BOILER	1F067C	V	GB	0
		1F071C	V	XFC	ACAP
		1F068C	V	GB	0
		1F072C	V	XFC	ACAP
X-63B (UNIT 1 ONLY)	NUCLEAR BOILER	1F066B	V	GB	0
		1F070B	V	XFC	ACAP
		1F069B	V	GB	0
		1F073B	V	XFC	ACAP
X-63B	CORE SPRAY	1F017B	V	GB	0
		1F018B	V	XFC	ACAP
X-64A	NUCLEAR BOILER	1F067D	V	GB	0
		1F071D	V	XFC	ACAP
		1F068D	V	GB	0
		1F072D	V	XFC	ACAP
X-64A (UNIT 2 ONLY)	NUC. BLR. VESSEL INST.	242006A	V	GB	0
		2F051A	V	XFC	ACAP
X-64B (UNIT 1 ONLY)	NUC. BLR. VESSEL INST.	142007	V	GB	0
		1F055	V	XFC	ACAP
		14201	V	XFC	ACAP
		142008	V	GB	0
		1F057	V	XFC	ACAP
		1F045	V	GB	0
		1F046	V	XFC	ACAP
X-65A	NUC. BLR. VESSEL INST.	142003A	V	GB	0
		1F047A	V	XFC	ACAP
X-65B	NUC. BLR. VESSEL INST.	142003B	V	GB	0
		1F047B	V	XFC	ACAP
X-66A	NUC. BLR. VESSEL INST.	142004A	V	GB	0
		1F045A	V	XFC	ACAP
X-66B	NUC. BLR. VESSEL INST.	142004B	V	GB	0
		1F045B	V	XFC	ACAP

TABLE 6.2-12a

DATA ON INSTRUMENT LINES PENETRATING CONTAINMENT[5]

PENETRATION NUMBER	SERVICE	VALVE NUMBER	VALVE ARRANGEMENT[1]	VALVE TYPE[2]	LENGTH PIPE TO VALVE[3]
X-80B	RCIC	1F043B	V	GB	0
		1F044B	V	XFC	ACAP
		1F043D	V	GB	0
		1F044D	V	XFC	ACAP
X-80B (UNIT 2 ONLY)	NUCLEAR BOILER	242010	VB	GB	0
		2F061	VB	XFC	ACAP
X-84A	NUC. BLR. VESSEL INST.	141005	V	GB	ACAP
		1F009		XFC	0
X-90A	CNTMT. ATMOS.	157017	VA	GB	0
	CONTROL	15710A	VA	XFC	ACAP
		157209	VA	GB	0
		15709A	VA	XFC	ACAP
X-90A (UNIT 1 ONLY)		157210	VA	GB	0
	CNTMT. ATMOS.	15728A	VA	XFC	ACAP
	CONTROL	257210	VA	GB	0
		25728A1	VA	XFC	ACAP
X-90D	CNTMT. ATMOS.	157077	VA	GB	0
	CONTROL	15710B	V	XFC	ACAP
		157207	VA	GB	0
		15709B	VA	XFC	ACAP
		157208	VA	GB	0
		15728B	VA	XFC	ACAP
X-91A (UNIT 2 ONLY)	NUC. BLR. VESSEL INST.	242007	V	GB	0
		2F055	V	XFC	ACAP
		24201	V	XFC	ACAP
		242008	V	GB	0
		2F057	V	XFC	ACAP
X-91A (UNIT 2 ONLY)	RWCU	2F045	V	GB	0
		2F046	V	XFC	ACAP
X-219A	HPCI	155021	VA	GB	0
		15516	VA	XFC	ACAP
X-219B	HPCI	155022	VA	GB	0
		15517	VA	XFC	ACAP
X-223A	CNTMT. ATMOS.	157022	VA	GB	0
	CONTROL	15701A	VA	XFC	ACAP
X-232A	CNTMT. ATMOS.	157023	VA	GB	0
	CONTROL	15775A	VA	XFC	ACAP
X-232B	CNTMT. ATMOS.	157024	VA	GB	0
	CONTROL	15778A	VA	XFC	ACAP
X-234A	CNTMT. ATMOS.	157011	VA	GB	0
	CONTROL	15776	VA	XFC	ACAP

TABLE 6.2-12a

DATA ON INSTRUMENT LINES PENETRATING CONTAINMENT[5]

PENETRATION NUMBER	SERVICE	VALVE NUMBER	VALVE ARRANGEMENT[1]	VALVE TYPE[2]	LENGTH PIPE TO VALVE[3]
X-234B	CNTMT. ATMOS. CONTROL	157012 15777	VA VA	GB XFC	0 ACAP
X-235A	CNTMT. ATMOS. CONTROL	157010 15775B	VA VA	GB XFC	0 ACAP
X-235B	CNTMT. ATMOS. CONTROL	157013 15778B	VA VA	GB XFC	0 ACAP

NOTES

(1) Valve Arrangement

See Figure 6.2-44I, Detail (v). Valve arrangements designated as "VA" differ from the figure in that their associated pipes communicate directly with the containment atmosphere (or do not connect to the reactor coolant pressure boundary), and thus do not have an orifice inside containment. Furthermore, those instrument lines with "VA" valve designations are "extensions of primary containment", as designated by CB or ICB on the P&ID (see Figure 6.2-44M, Detail (22)). "VB" indicates a valve arrangement similar to the figure except that no orifice is provided.

(2) Valve Type

Globe GB
Excess Flow Check XFC

(3) Length Pipe to Valve

0: Globe valves are welded directly to the flued head at the containment penetration.
ACAP: "As close as possible" to the glove valve.

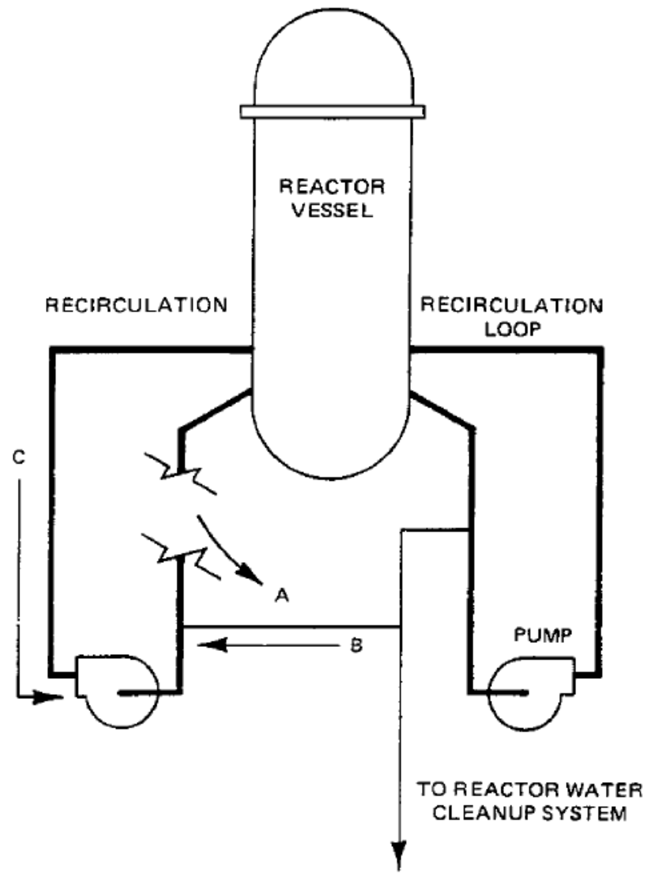
(4) These valves are disabled in the open position.

(5) All valves listed in this table are Type A tested with the exception of Penetrations X-31B and X-60A (See Table 6.2-22)

Table 6.2-15a Evaluation of Potential Bypass Leakage
This Table Has Been Deleted

POINT OF CRITICAL FLOW

A. RECIRCULATION LINE
B. CLEANUP LINE
C. COMBINED AREA OF ALL JET PUMP NOZZLES ASSOCIATED WITH THE BROKEN LOOP

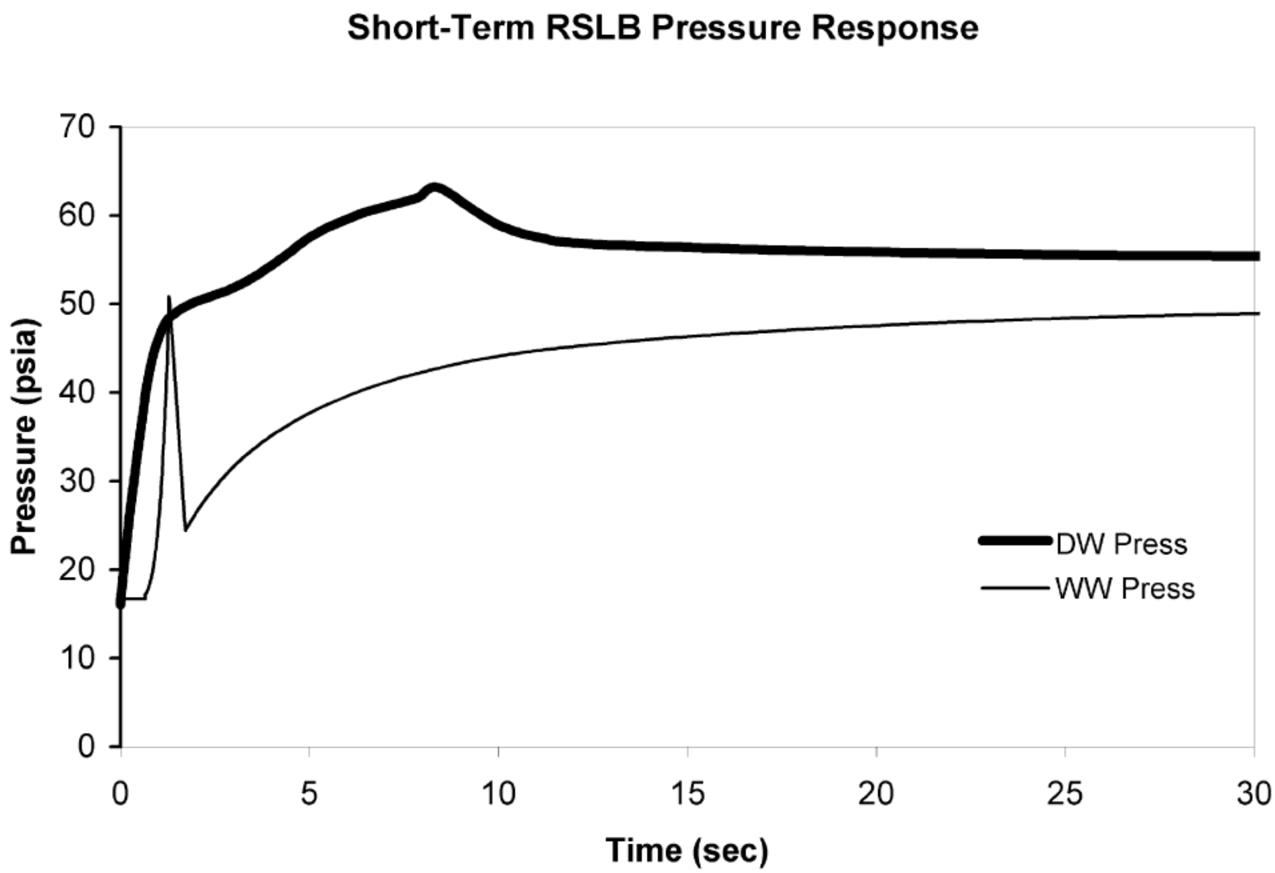


SCHEMATIC SHOWING COMPOSITION OF TOTAL RECIRCULATION LINE BREAK AREA

FSAR REV. 65

SUSQUEHANNA STEAM ELECTRIC STATION UNITS 1 AND 2 FINAL SAFETY ANALYSIS REPORT
DIAGRAM OF THE RECIRCULATION LINE BREAK LOCATION FIGURE 6.2-1, Rev. 49

Auto Cad: Figure Fsar 6_2_1.dwg



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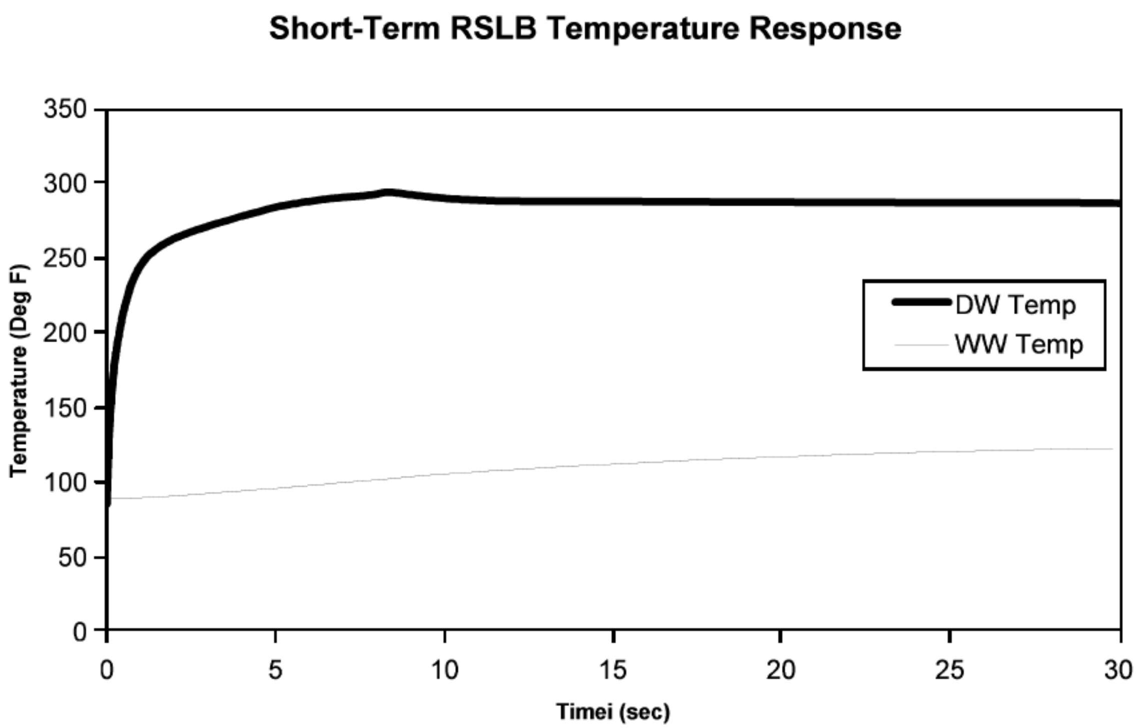
SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 AND 2
FINAL SAFETY ANALYSIS REPORT

PRESSURE RESPONSE FOR
RECIRCULATION LINE BREAK

FIGURE 6.2-2, Rev. 56

Auto Cad: Figure Fsar 6_2_2.dwg



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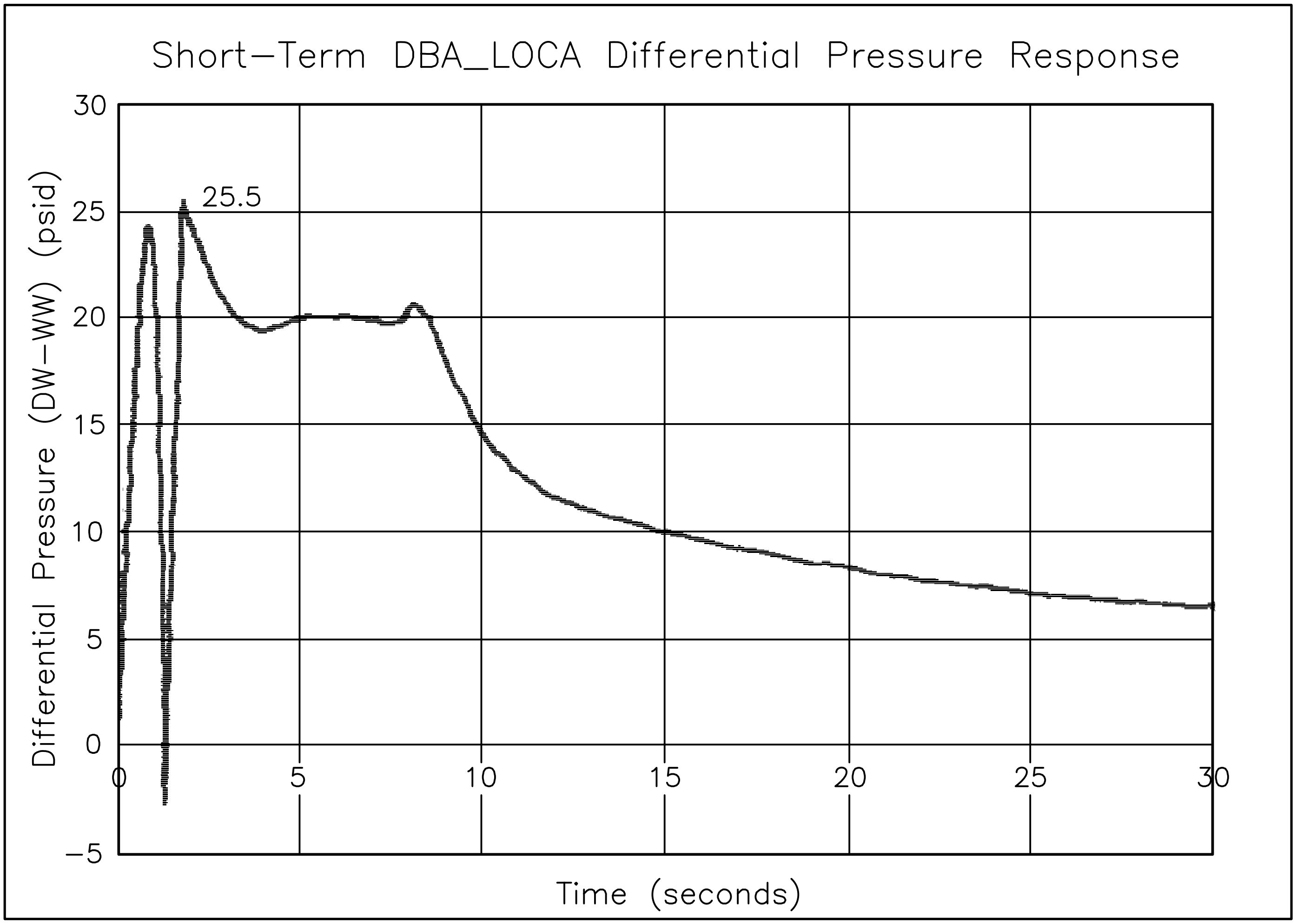
SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 AND 2
FINAL SAFETY ANALYSIS REPORT

TEMPERATURE RESPONSE FOR
RECIRCULATION LINE BREAK

FIGURE 6.2-3, Rev. 56

Auto Cad: Figure Fsar 6_2_3.dwg



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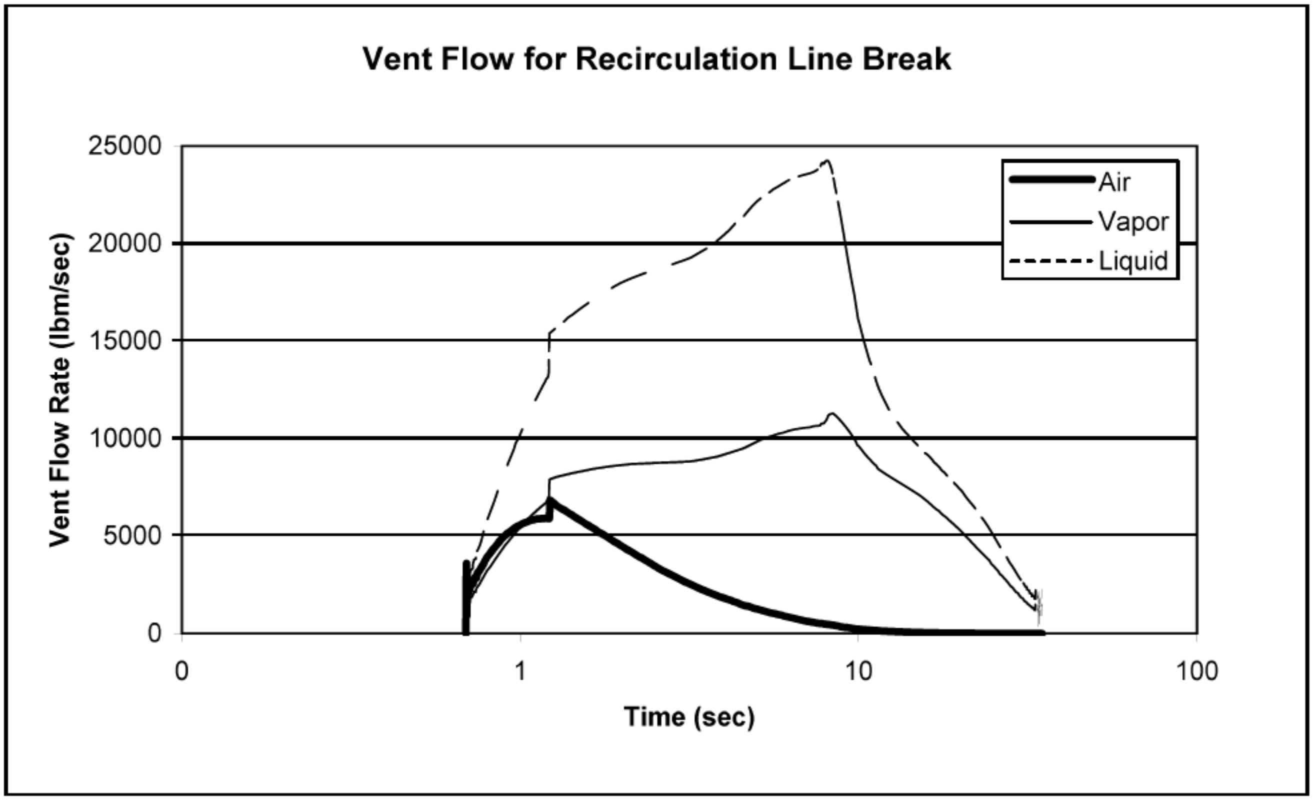
SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 AND 2
FINAL SAFETY ANALYSIS REPORT

SHORT-TERM DBA-LOCA DIFFERENTIAL PRESSURE RESPONSE

FIGURE 6.2-4, Rev. 56

Auto Cad: Figure Fsar 6_2_4.dwg



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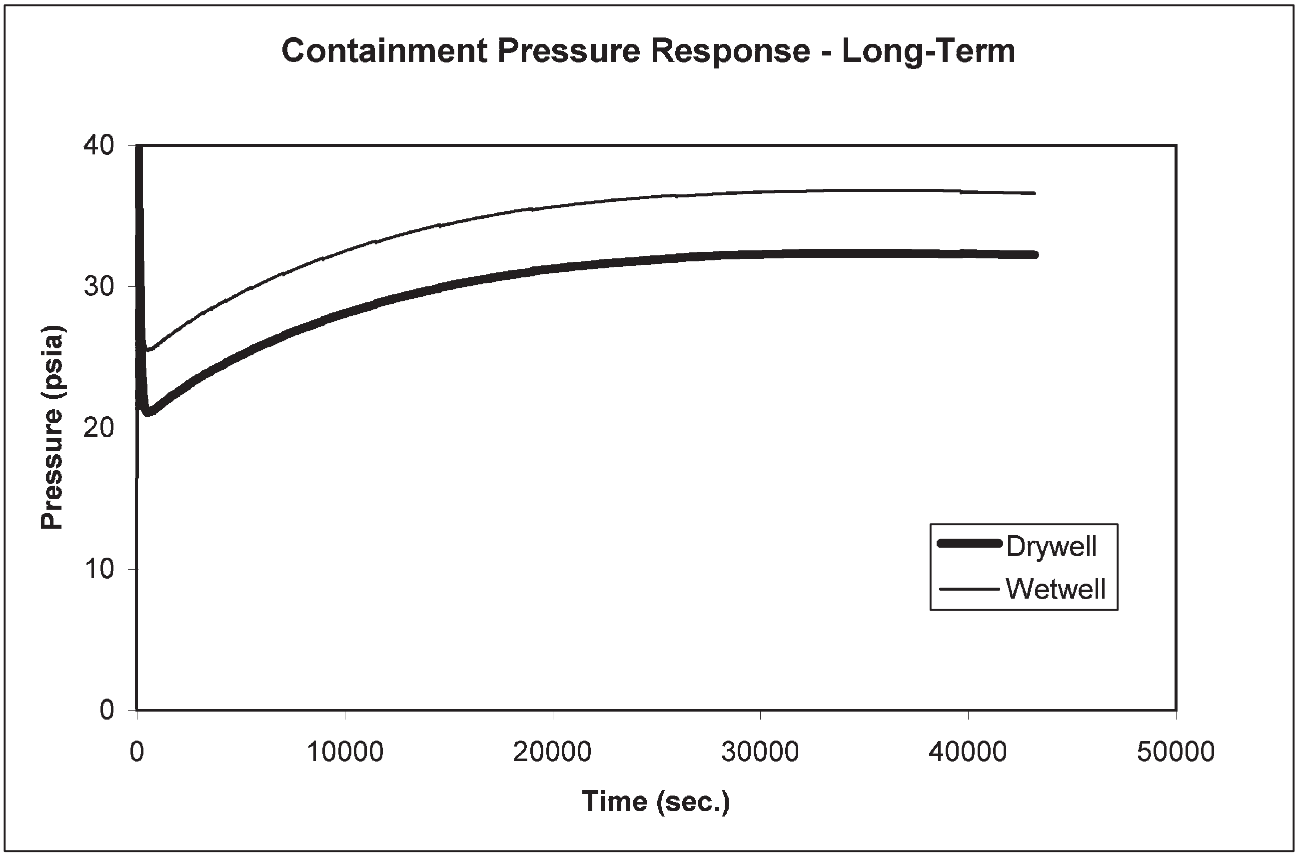
SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 AND 2
FINAL SAFETY ANALYSIS REPORT

VENT FLOW FOR RECIRCULATION
LINE BREAK

FIGURE 6.2-5, Rev. 56

Auto Cad: Figure Fsar 6_2_5.dwg



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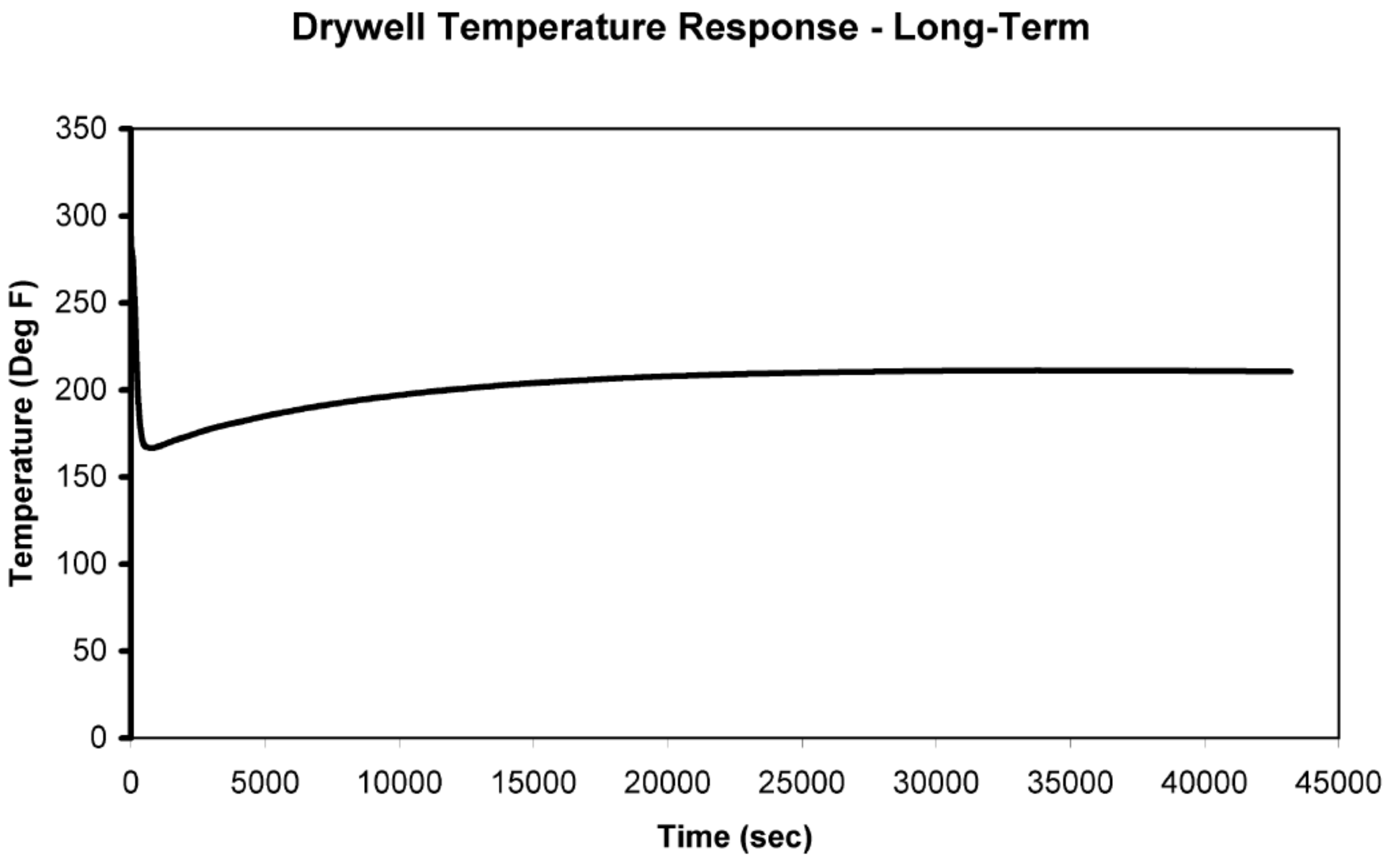
SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 AND 2
FINAL SAFETY ANALYSIS REPORT

CONTAINMENT PRESSURE RESPONSE
LONG-TERM

FIGURE 6.2-6, Rev. 52

Auto-Cad: Figure Fsar 6_2_6.dwg & .tif



THIS FIGURE REPLACES FIG.
6.2-7-1, 6.2-7-2 & 6.2-7-3

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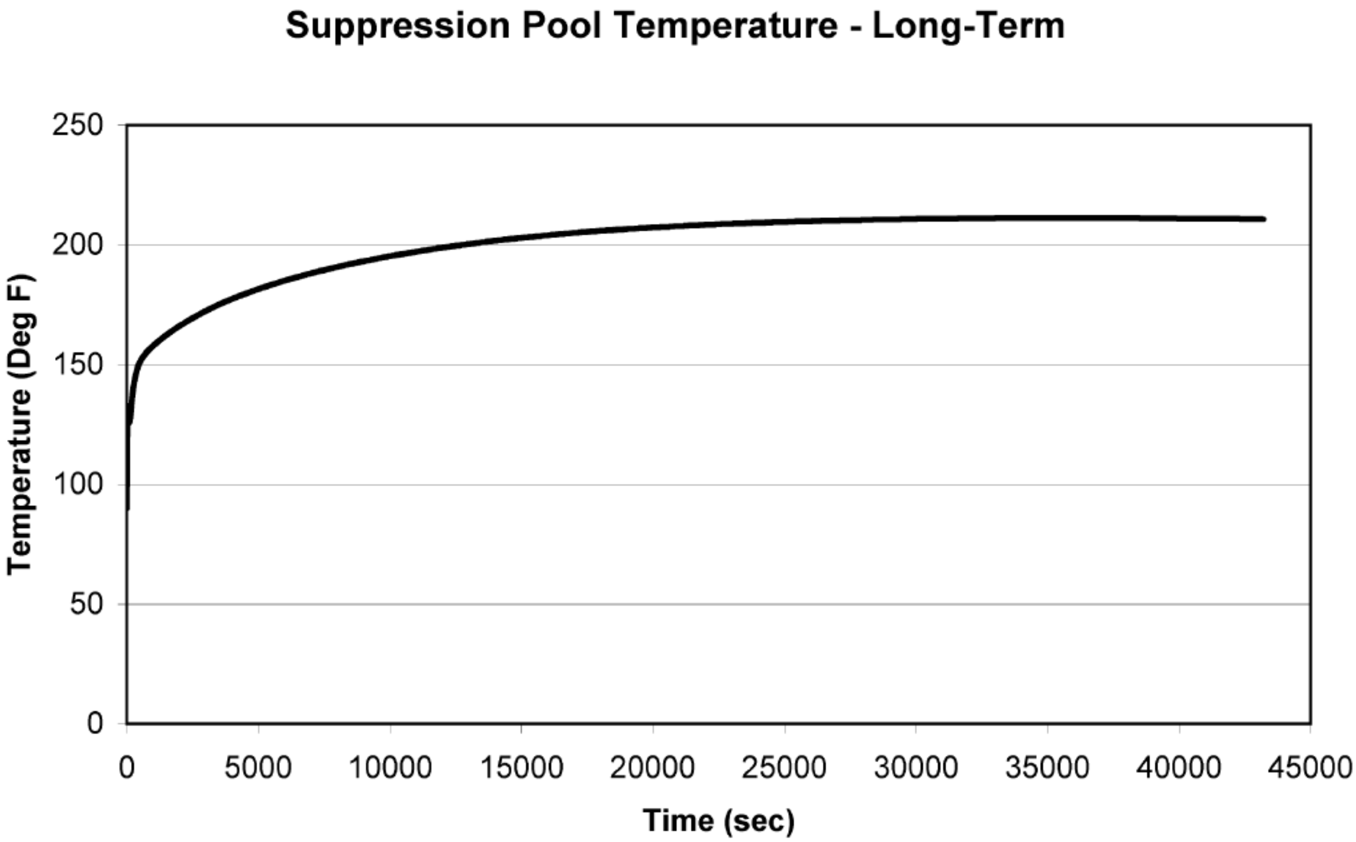
SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 AND 2
FINAL SAFETY ANALYSIS REPORT

DRYWELL TEMPERATURE RESPONSE
LONG-TERM

FIGURE 6.2-7, Rev. 56

Auto Cad: Figure Fsar 6_2_7.dwg



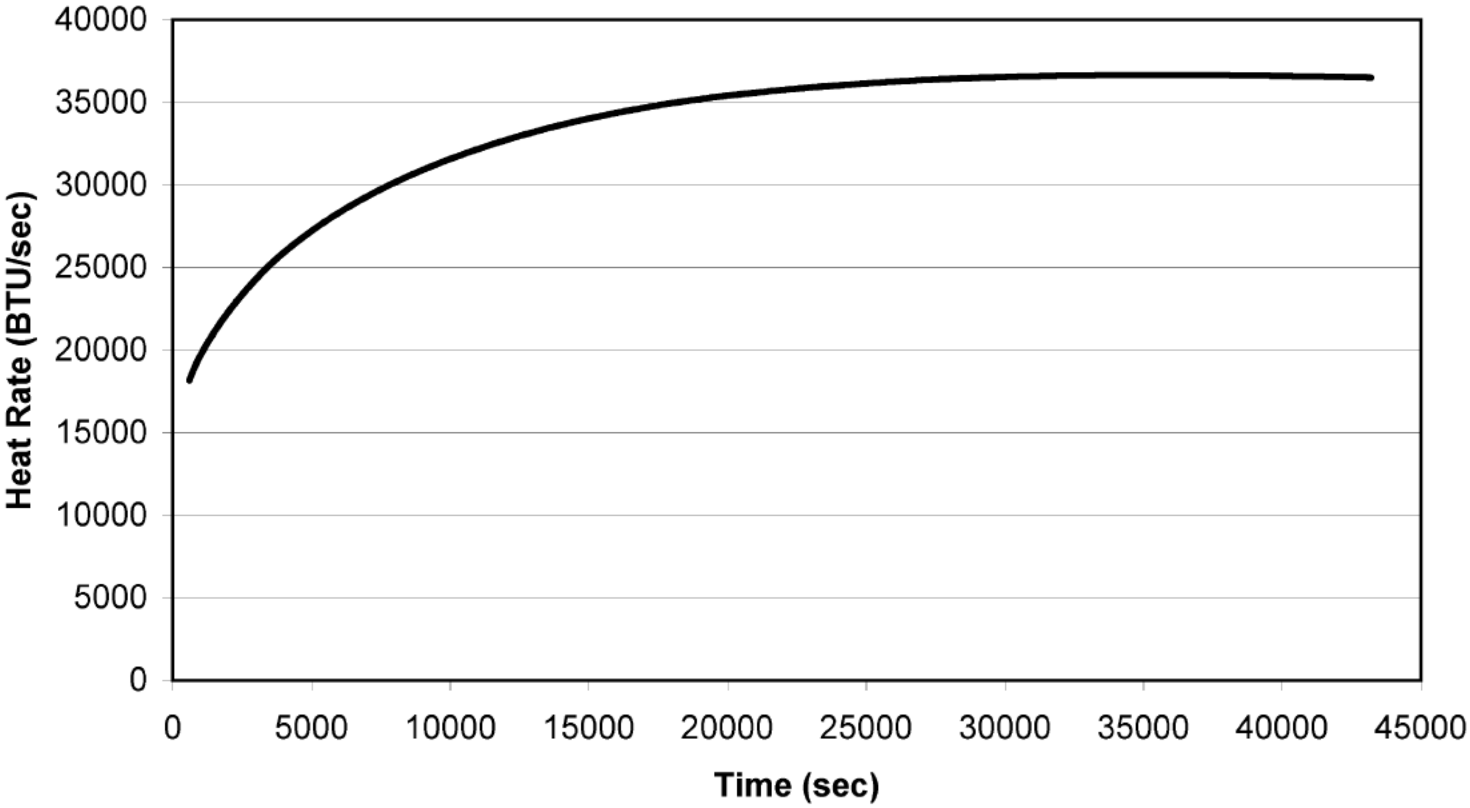
THIS FIGURE REPLACES FIGS.
6.2-8-1, 6.2-8-2 AND 6.2-8-3

FSAR REV. 65

SUSQUEHANNA STEAM ELECTRIC STATION UNITS 1 AND 2 FINAL SAFETY ANALYSIS REPORT
SUPPRESSION POOL TEMPERATURE RESPONSE LONG-TERM FIGURE 6.2-8, Rev. 52

Auto Cad: Figure Fsar 6_2_8.dwg

RHR Heat Removal Rate



THIS FIGURE REPLACES FIGS.
6.2-9-1, 6.2-9-2 AND 6.2-9-3

FSAR REV. 65

SUSQUEHANNA STEAM ELECTRIC STATION UNITS 1 AND 2 FINAL SAFETY ANALYSIS REPORT
RHR HEAT REMOVAL RATE FIGURE 6.2-9, Rev. 52

Auto Cad: Figure Fsar 6_2_9.dwg

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SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

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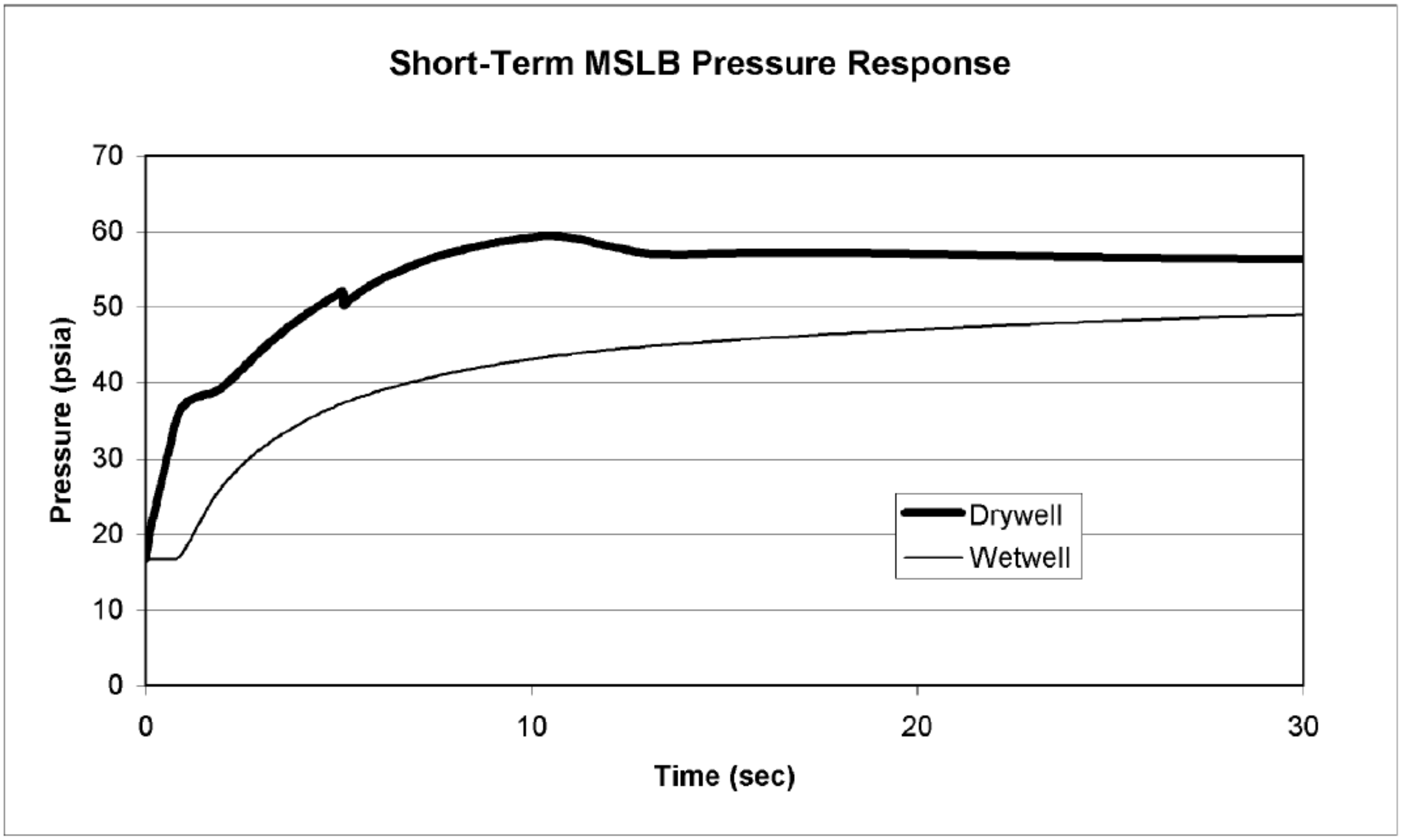
FIGURE 6.2-10, Rev. 51

AutoCAD Figure 6_2_10.doc



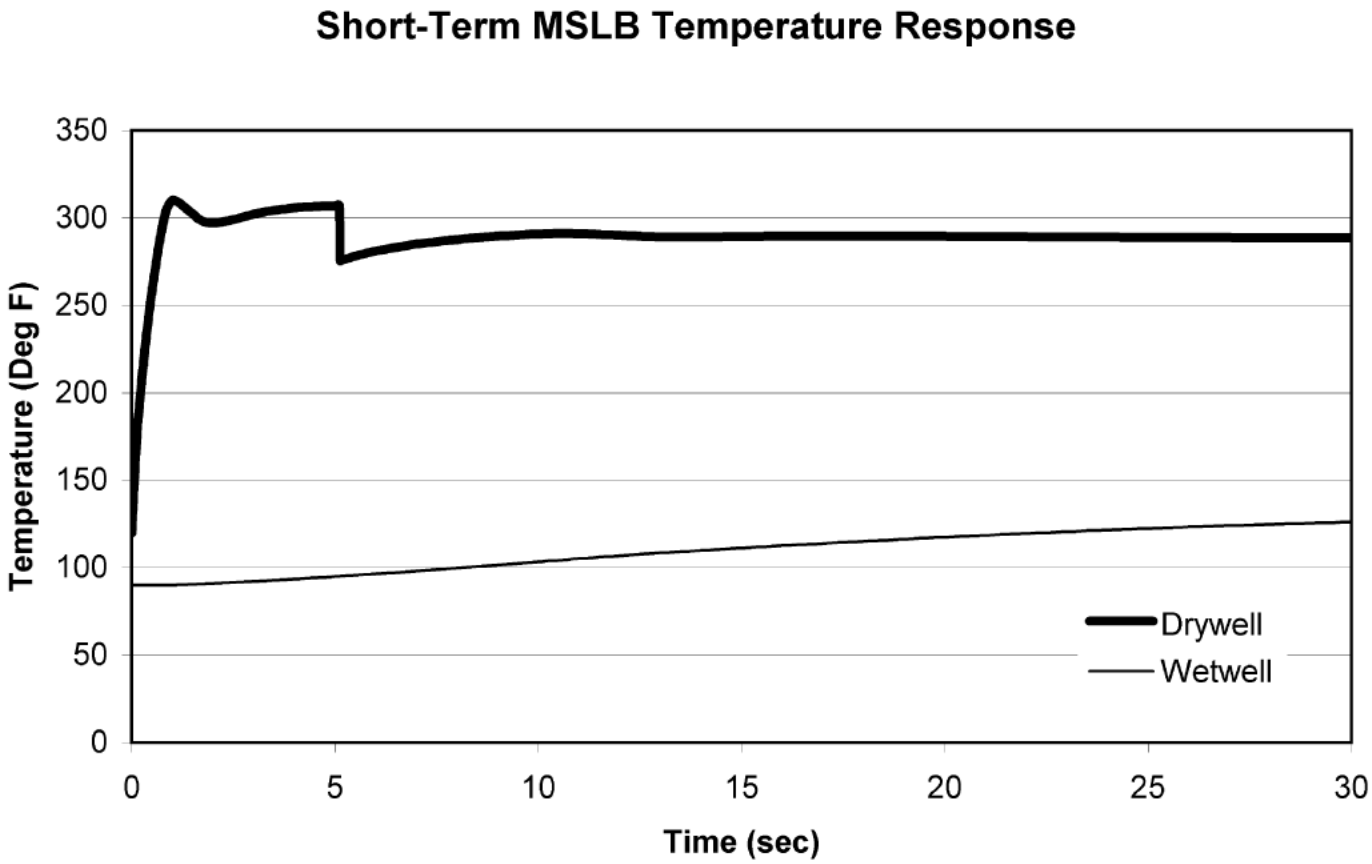
FSAR REV. 65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 AND 2
FINAL SAFETY ANALYSIS REPORT

PRESSURE RESPONSE FOR
STEAMLINE BREAK

FIGURE 6.2-11, Rev. 51

Auto Cad: Figure Fsar 6_2_11.dwg



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SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 AND 2
FINAL SAFETY ANALYSIS REPORT

TEMPERATURE RESPONSE FOR MAIN STEAMLINE BREAK

FIGURE 6.2-12, Rev. 51

Auto Cad: Figure Fsar 6_2_12.dwg

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FSAR REV. 65

SUSQUEHANNA STEAM ELECTRIC STATION UNITS 1 & 2 FINAL SAFETY ANALYSIS REPORT
Figure intentionally left blank FIGURE 6.2-13, Rev. 49

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SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

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FIGURE 6.2-14, Rev. 56

AutoCAD Figure 6_2_14.doc

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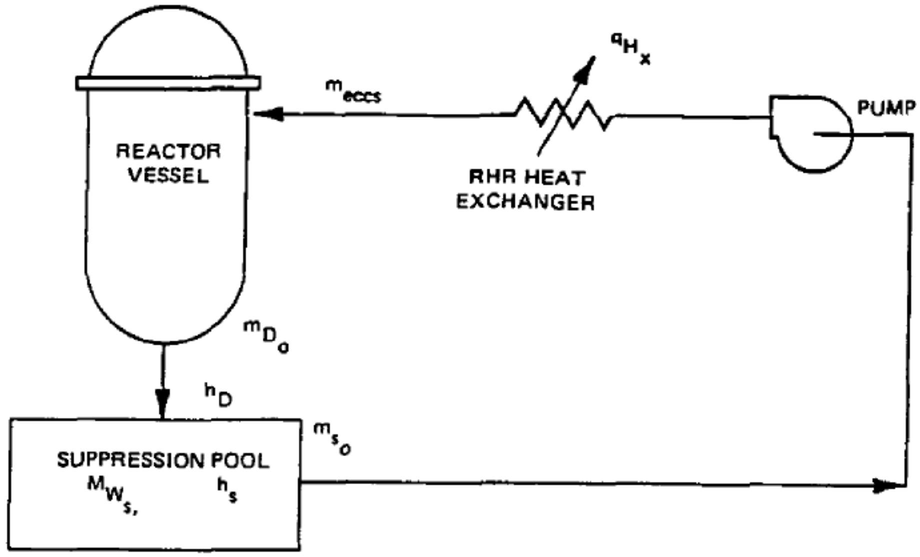
SUSQUEHANNA STEAM ELECTRIC STATION UNITS 1 & 2 FINAL SAFETY ANALYSIS REPORT
Figure Deleted FIGURE 6.2-15, Rev. 56

AutoCAD Figure 6_2_15.doc



h_D = ENTHALPY OF WATER LEAVING REACTOR, Btu/lb
m_{D_o} = FLOW RATE OUT OF REACTOR, lb/sec
h_s = ENTHALPY OF WATER IN SUPPRESSION POOL, Btu/lb
m_{s_o} = FLOW OUT OF SUPPRESSION POOL, lb/sec
q_{H_x} = HEAT REMOVAL RATE OF HEAT EXCHANGER, Btu/sec
M_{W_s} = MASS OF WATER IN SUPPRESSION POOL
q_D = CORE DECAY HEAT RATE, Btu/sec
q = STORED ENERGY RELEASE RATE, Btu/sec

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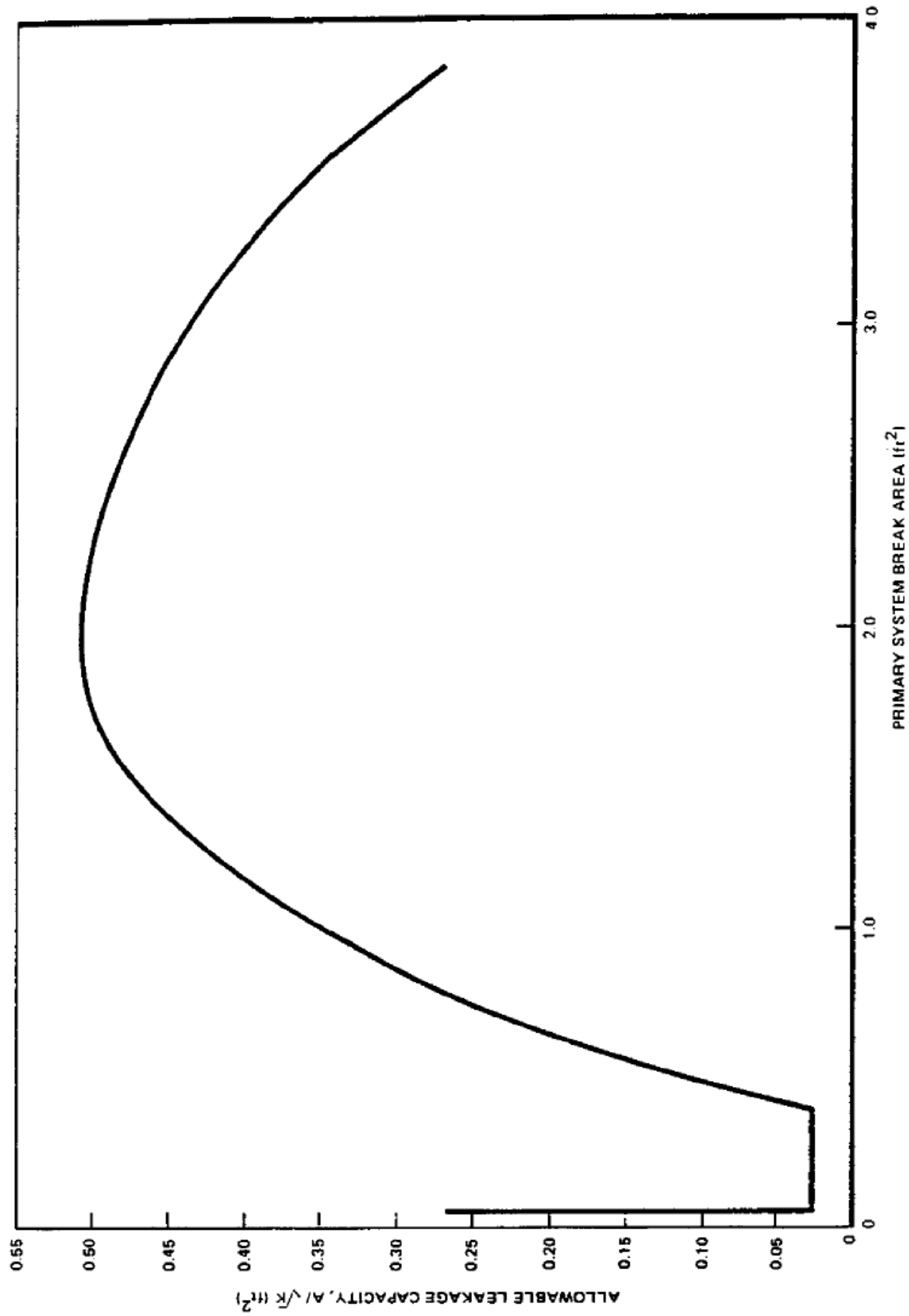
SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 AND 2
FINAL SAFETY ANALYSIS REPORT

SCHEMATIC OF ECCS LOOP

FIGURE 6.2-16, Rev. 49

Auto Cad: Figure Fsar 6_2_16.dwg



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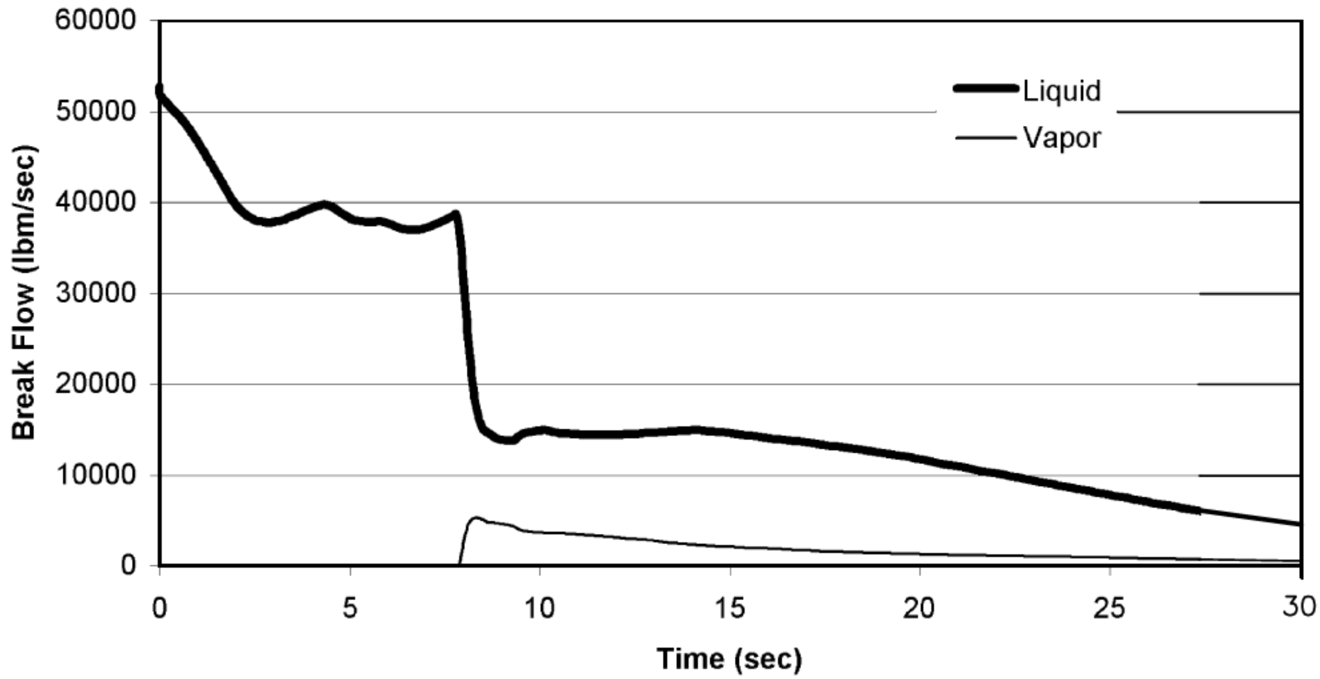
SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 AND 2
FINAL SAFETY ANALYSIS REPORT

ALLOWABLE LEAKAGE CAPACITY

FIGURE 6.2-17, Rev. 49

Auto Cad: Figure Fsar 6_2_17.dwg

Vessel Blowdown Rate for Recirculation Line Break



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SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 AND 2
FINAL SAFETY ANALYSIS REPORT

VESSEL BLOWDOWN RATE FOR
RECIRCULATION LINE BREAK

FIGURE 6.2-18, Rev. 51

Auto Cad: Figure Fsar 6_2_18.dwg

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SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

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FIGURE 6.2-19, Rev. 50

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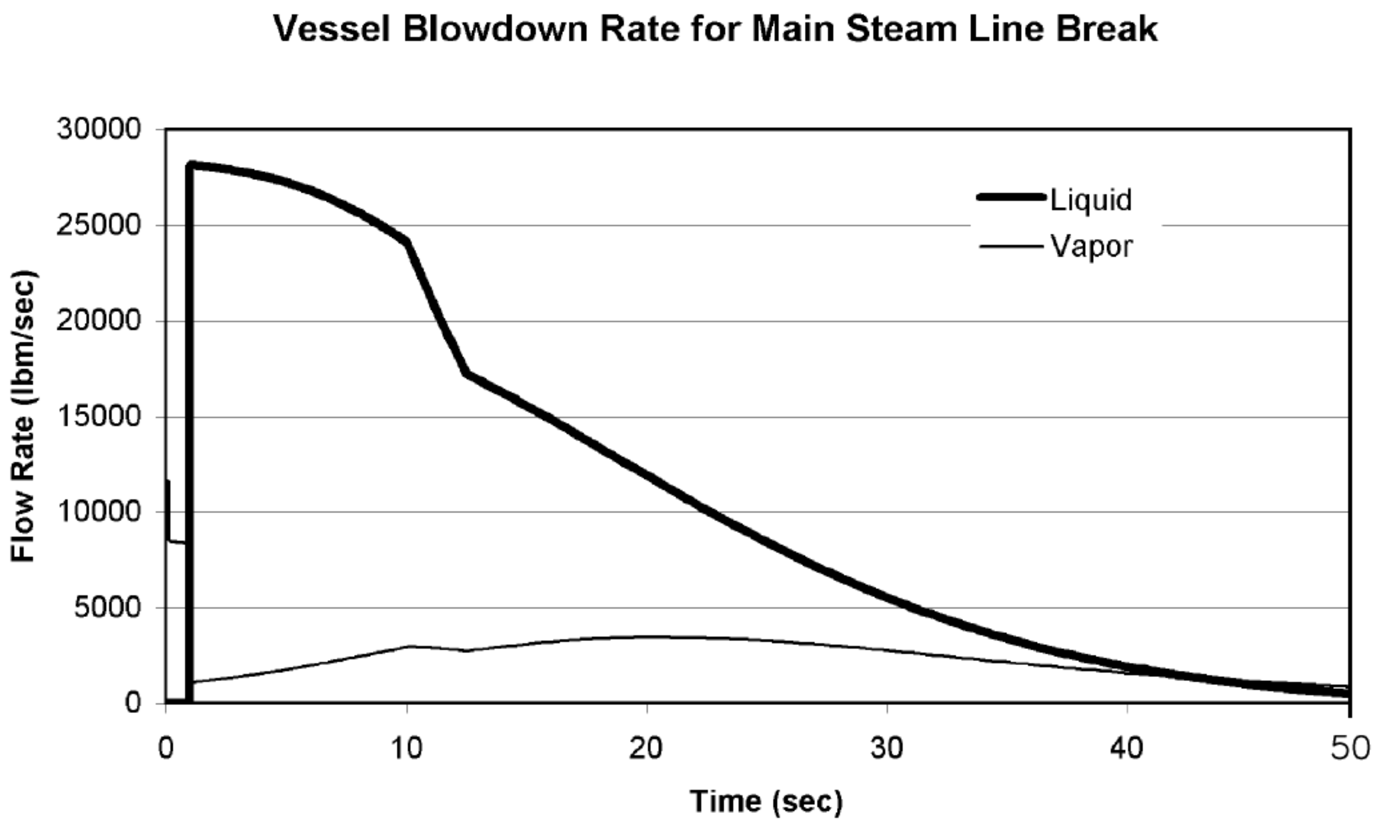

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SUSQUEHANNA STEAM ELECTRIC STATION UNITS 1 AND 2 FINAL SAFETY ANALYSIS REPORT
VESSEL BLOWDOWN RATE FOR MAIN STEAMLINE BREAK FIGURE 6.2-20, Rev. 51

Auto Cad: Figure Fsar 6_2_20.dwg

FIGURE DELETED

FIGURE DELETED

FIGURE 6.2-21, Rev. 50

FIGURE DELETED

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SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

FIGURE DELETED

FIGURE 6.2-22, Rev. 50

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SUSQUEHANNA STEAM ELECTRIC STATION UNITS 1 & 2 FINAL SAFETY ANALYSIS REPORT
THIS FIGURE INTENTIONALLY LEFT BLANK FIGURE 6.2-23, Rev. 49

AutoCAD Figure 6_2_23.doc

Security-Related Information Figure
Withheld Under 10 CFR 2.390

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SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 AND 2
FINAL SAFETY ANALYSIS REPORT

SECONDARY CONTAINMENT
BOUNDARY OUTLINE - UNIT 1
EL. 645'-0"

FIGURE 6.2-24, Rev. 55

Auto Cad: Figure Fsar 6_2_24.dwg

Security-Related Information
Figure Withheld Under 10 CFR 2.390

FSAR REV. 66

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 AND 2
FINAL SAFETY ANALYSIS REPORT

SECONDARY CONTAINMENT
BOUNDARY OUTLINE - UNIT 1
EL. 670'-0"

FIGURE 6.2-25, Rev. 56

Auto Cad: Figure Fsar 6_2_25.dwg

Security-Related Information
Figure Withheld Under 10 CFR 2.390

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SUSQUEHANNA STEAM ELECTRIC STATION UNITS 1 AND 2 FINAL SAFETY ANALYSIS REPORT
SECONDARY CONTAINMENT BOUNDARY OUTLINE - UNIT 1 EL. 683'-0" FIGURE 6.2-26, Rev. 55

Auto Cad: Figure Fsar 6_2_26.dwg

Security-Related Information
Figure Withheld Under 10 CFR 2.390

FSAR REV. 65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 AND 2
FINAL SAFETY ANALYSIS REPORT

SECONDARY CONTAINMENT
BOUNDARY OUTLINE - UNIT 1
EL. 719'-0"

FIGURE 6.2-27, Rev. 55

Auto Cad: Figure Fsar 6_2_27.dwg

Security-Related Information
Figure Withheld Under 10 CFR 2.390

FSAR REV. 65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 AND 2
FINAL SAFETY ANALYSIS REPORT

SECONDARY CONTAINMENT
BOUNDARY OUTLINE - UNIT 1
EL. 749'-1"

FIGURE 6.2-28, Rev. 55

Auto Cad: Figure Fsar 6_2_28.dwg

Security-Related Information
Figure Withheld Under 10 CFR 2.390

FSAR REV. 66

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 AND 2
FINAL SAFETY ANALYSIS REPORT

SECONDARY CONTAINMENT
BOUNDARY OUTLINE

FIGURE 6.2-29, Rev. 59

Auto Cad: Figure Fsar 6_2_29.dwg

Security-Related Information
Figure Withheld Under 10 CFR 2.390

FSAR REV. 66

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 AND 2
FINAL SAFETY ANALYSIS REPORT

SECONDARY CONTAINMENT BOUNDARY
OUTLINE - UNIT 1
EL. 818'-1"

FIGURE 6.2-30, Rev. 57

Auto Cad: Figure Fsar 6_2_30.dwg

Security-Related Information
Figure Withheld Under 10 CFR 2.390

FSAR REV. 65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 AND 2
FINAL SAFETY ANALYSIS REPORT

SECONDARY CONTAINMENT
BOUNDARY OUTLINE - UNIT 1
SECTION A-A

FIGURE 6.2-31, Rev. 55

Auto Cad: Figure Fsar 6_2_31.dwg

Security-Related Information
Figure Withheld Under 10 CFR 2.390

FSAR REV. 66

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 AND 2
FINAL SAFETY ANALYSIS REPORT

SECONDARY CONTAINMENT
BOUNDARY OUTLINE - UNIT 1
SECTION B-B

FIGURE 6.2-32, Rev. 59

Auto Cad: Figure Fsar 6_2_32.dwg

Security-Related Information
Figure Withheld Under 10 CFR 2.390

FSAR REV. 66

SUSQUEHANNA STEAM ELECTRIC STATION UNITS 1 AND 2 FINAL SAFETY ANALYSIS REPORT
SECONDARY CONTAINMENT BOUNDARY OUTLINE - UNIT 1 EL. 799'-1" FIGURE 6.2-33, Rev. 56

Auto Cad: Figure Fsar 6_2_33.dwg

Security-Related Information
Figure Withheld Under 10 CFR 2.390

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SUSQUEHANNA STEAM ELECTRIC STATION UNITS 1 AND 2 FINAL SAFETY ANALYSIS REPORT
SECONDARY CONTAINMENT BOUNDARY OUTLINE - UNIT 2 EL. 645'-0" FIGURE 6.2-34, Rev. 55

Auto Cad: Figure Fsar 6_2_34.dwg

Security-Related Information
Figure Withheld Under 10 CFR 2.390

FSAR REV. 65

SUSQUEHANNA STEAM ELECTRIC STATION UNITS 1 AND 2 FINAL SAFETY ANALYSIS REPORT
SECONDARY CONTAINMENT BOUNDARY OUTLINE - UNIT 2 EL. 670'-0" FIGURE 6.2-35, Rev. 55

Auto Cad: Figure Fsar 6_2_35.dwg

Security-Related Information
Figure Withheld Under 10 CFR 2.390

FSAR REV. 65

SUSQUEHANNA STEAM ELECTRIC STATION UNITS 1 AND 2 FINAL SAFETY ANALYSIS REPORT
SECONDARY CONTAINMENT BOUNDARY OUTLINE - UNIT 2 EL. 683'-0" FIGURE 6.2-36, Rev. 55

Auto Cad: Figure Fsar 6_2_36.dwg

Security-Related Information
Figure Withheld Under 10 CFR 2.390

FSAR REV. 65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 AND 2
FINAL SAFETY ANALYSIS REPORT

SECONDARY CONTAINMENT
BOUNDARY OUTLINE - UNIT 2
EL. 719'-1"

FIGURE 6.2-37, Rev. 55

Auto Cad: Figure Fsar 6_2_37.dwg

Security-Related Information
Figure Withheld Under 10 CFR 2.390

FSAR REV. 65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 AND 2
FINAL SAFETY ANALYSIS REPORT

SECONDARY CONTAINMENT
BOUNDARY OUTLINE - UNIT 2
EL. 749'-1"

FIGURE 6.2-38, Rev. 55

Auto Cad: Figure Fsar 6_2_38.dwg

Security-Related Information
Figure Withheld Under 10 CFR 2.390

FSAR REV. 66

SUSQUEHANNA STEAM ELECTRIC STATION UNITS 1 AND 2 FINAL SAFETY ANALYSIS REPORT
SECONDARY CONTAINMENT BOUNDARY OUTLINE - UNIT 2 EL. 779'-1" FIGURE 6.2-39, Rev. 57

Auto Cad: Figure Fsar 6_2_39.dwg

Security-Related Information
Figure Withheld Under 10 CFR 2.390

FSAR REV. 66

SUSQUEHANNA STEAM ELECTRIC STATION UNITS 1 AND 2 FINAL SAFETY ANALYSIS REPORT
SECONDARY CONTAINMENT BOUNDARY OUTLINE - UNIT 2 EL. 818'-1" FIGURE 6.2-40, Rev. 56

Auto Cad: Figure Fsar 6_2_40.dwg

Security-Related Information
Figure Withheld Under 10 CFR 2.390

FSAR REV. 65

SUSQUEHANNA STEAM ELECTRIC STATION UNITS 1 AND 2 FINAL SAFETY ANALYSIS REPORT
SECONDARY CONTAINMENT BOUNDARY OUTLINE - UNIT 2 SECTION A-A FIGURE 6.2-41, Rev. 55

Auto Cad: Figure Fsar 6_2_41.dwg

Security-Related Information
Figure Withheld Under 10 CFR 2.390

FSAR REV. 66

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 AND 2
FINAL SAFETY ANALYSIS REPORT

SECONDARY CONTAINMENT
BOUNDARY OUTLINE - UNIT 2
SECTION B-B

FIGURE 6.2-42, Rev. 57

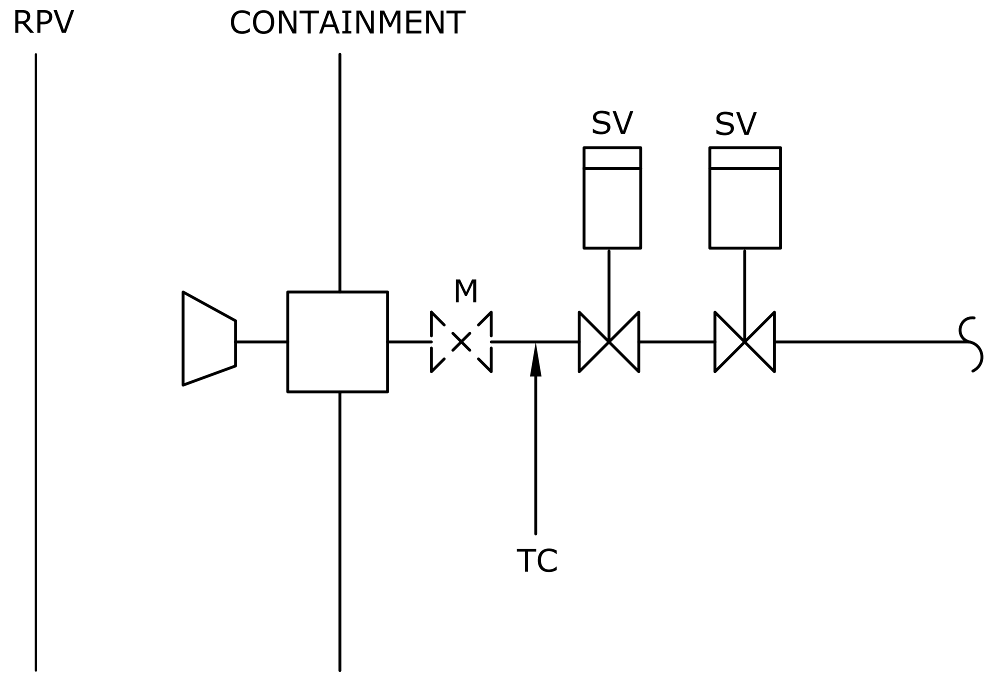
Auto Cad: Figure Fsar 6_2_42.dwg

Security-Related Information
Figure Withheld Under 10 CFR 2.390

FSAR REV. 66

SUSQUEHANNA STEAM ELECTRIC STATION UNITS 1 AND 2 FINAL SAFETY ANALYSIS REPORT
SECONDARY CONTAINMENT BOUNDARY OUTLINE - UNIT 2 EL. 799'-1" FIGURE 6.2-43, Rev. 56

Auto Cad: Figure Fsar 6_2_43.dwg



DETAIL (DD)

SV - Solenoid Valve
TC - Test Connection
M - Manual Valve

FSAR REV. 65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 AND 2
FINAL SAFETY ANALYSIS REPORT

CONTAINMENT PENETRATION
DETAILS

FIGURE 6.2-44, Rev. 54

Auto Cad: Figure Fsar 6_2_44.dwg

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FSAR REV. 65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

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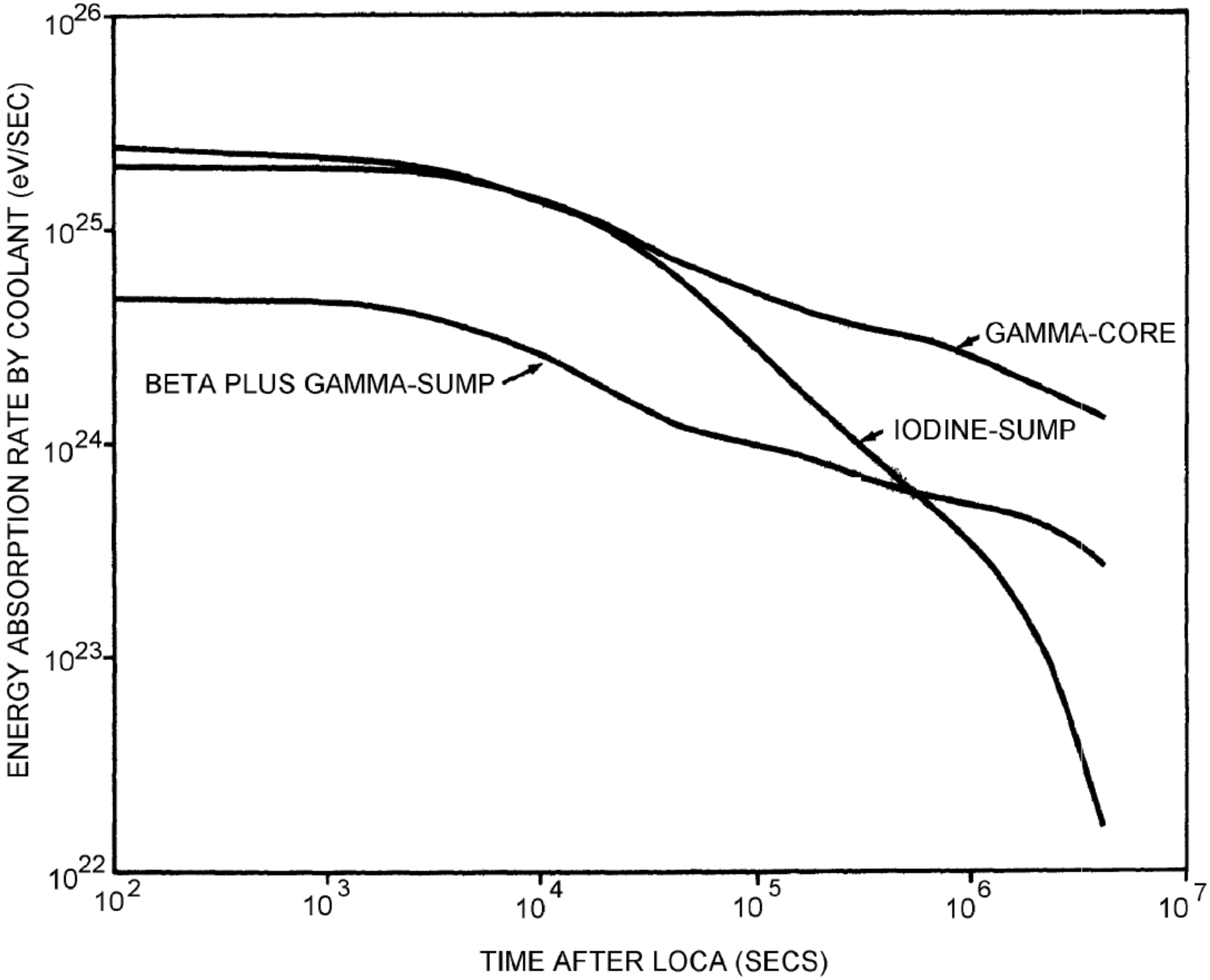
FIGURE 6.2-45, Rev. 49

AutoCAD Figure 6_2_45.doc



These curves are not maintained. Adsorbed energy for radiolytic hydrogen generation is now based on 102% of uprated power (101.5% of these curves).

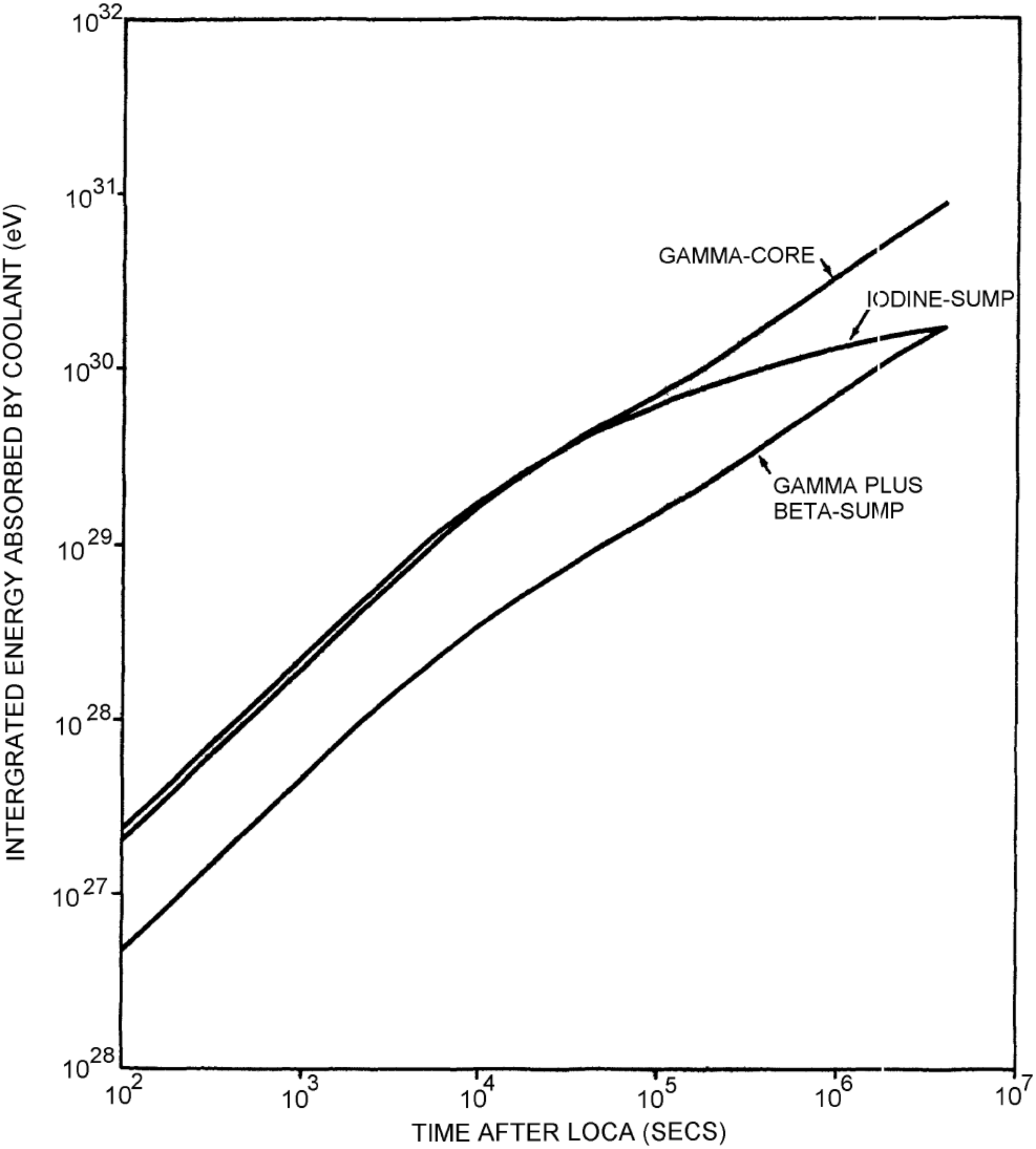
FSAR REV. 65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 AND 2
FINAL SAFETY ANALYSIS REPORT

ENERGY ABSORPTION RATE BY
THE COOLANT VS.
TIME AFTER LOCA

FIGURE 6.2-46, Rev. 55

Auto Cad: Figure Fsar 6_2_46.dwg



These curves are not maintained. Adsorbed energy for radiolytic hydrogen generation is now based on 102% of uprated power (101.5% of these curves).

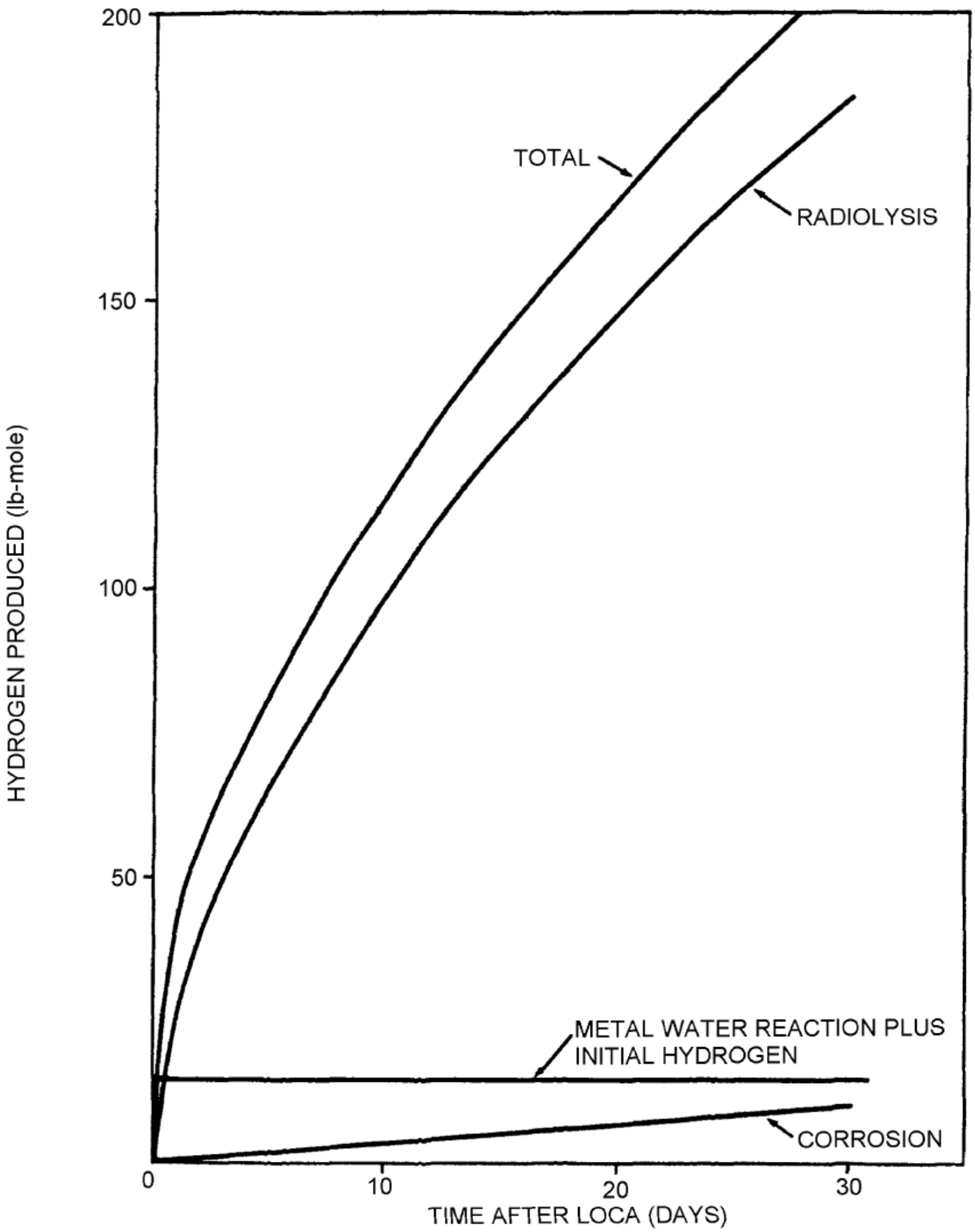
FSAR REV. 65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 AND 2
FINAL SAFETY ANALYSIS REPORT

INTEGRATED ENERGY ABSORBED
BY COOLANT VS.
TIME AFTER LOCA

FIGURE 6.2-47, Rev. 55

Auto Cad: Figure Fsar 6_2_47.dwg

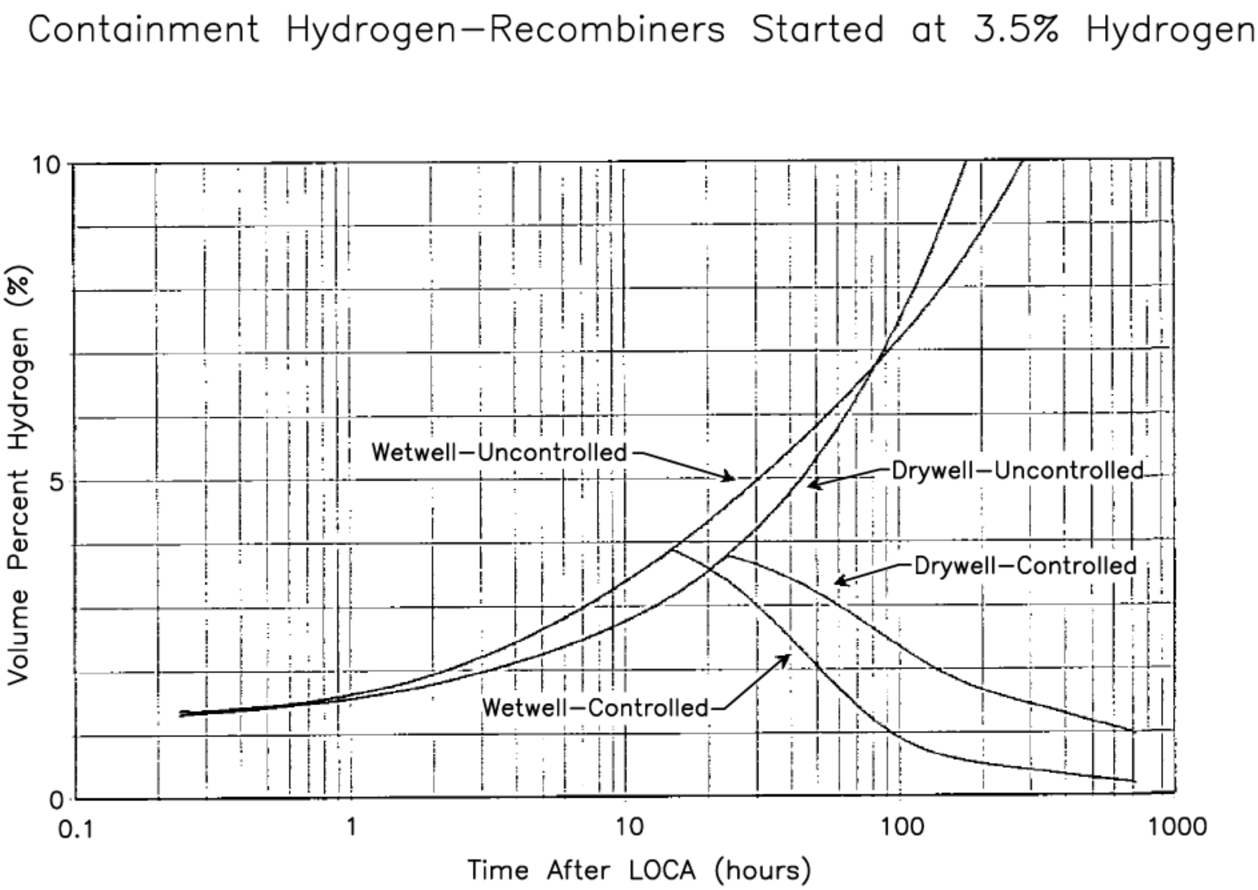


These curves are not maintained. hydrogen generation is now based on 102% of uprated power (101.5% of the radiolysis curve) plus very small effects of additional zinc and aluminum.

FSAR REV. 65

SUSQUEHANNA STEAM ELECTRIC STATION UNITS 1 AND 2 FINAL SAFETY ANALYSIS REPORT
INTERGRATED PRODUCTION OF HYDROGEN VS. TIME AFTER LOCA FIGURE 6.2-48, Rev. 55

Auto Cad: Figure Fsar 6_2_48.dwg



FSAR REV. 65

SUSQUEHANNA STEAM ELECTRIC STATION UNITS 1 AND 2 FINAL SAFETY ANALYSIS REPORT
HYDROGEN CONCENTRATION IN THE DRYWELL AND WETWELL VS. TIME AFTER LOCA (LONG AND SHORT TERM) FIGURE 6.2-49, Rev. 51

Auto Cad: Figure Fsar 6_2_49.dwg

FIGURE DELETED PER LDCN 4583

FSAR REV. 65

SUSQUEHANNA STEAM ELECTRIC STATION UNITS 1 & 2 FINAL SAFETY ANALYSIS REPORT
FIGURE DELETED PER LDCN 4583 FIGURE 6.2-50, Rev. 51

AutoCAD Figure 6_2_50.doc

FIGURE DELETED PER LDCN 4583

FSAR REV. 65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

FIGURE DELETED PER LDCN 4583

FIGURE 6.2-51, Rev. 51

AutoCAD Figure 6_2_51.doc

Security-Related Information
Figure Withheld Under 10 CFR 2.390

FSAR REV. 65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 AND 2
FINAL SAFETY ANALYSIS REPORT

REACTOR BUILDING VENTILATION
RECIRCULATION & STANDBY
GAS TREATMENT SYSTEMS
ZONE 1 & ZONE III ISOLATION

FIGURE 6.2-52, Rev. 49

Auto Cad: Figure Fsar 6_2_52.dwg

Security-Related Information
Figure Withheld Under 10 CFR 2.390

FSAR REV. 65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 AND 2
FINAL SAFETY ANALYSIS REPORT

REACTOR BUILDING VENTILATION
RECIRCULATION & STANDBY
GAS TREATMENT SYSTEMS
NORMAL PLANT OPERATION

FIGURE 6.2-53, Rev. 50

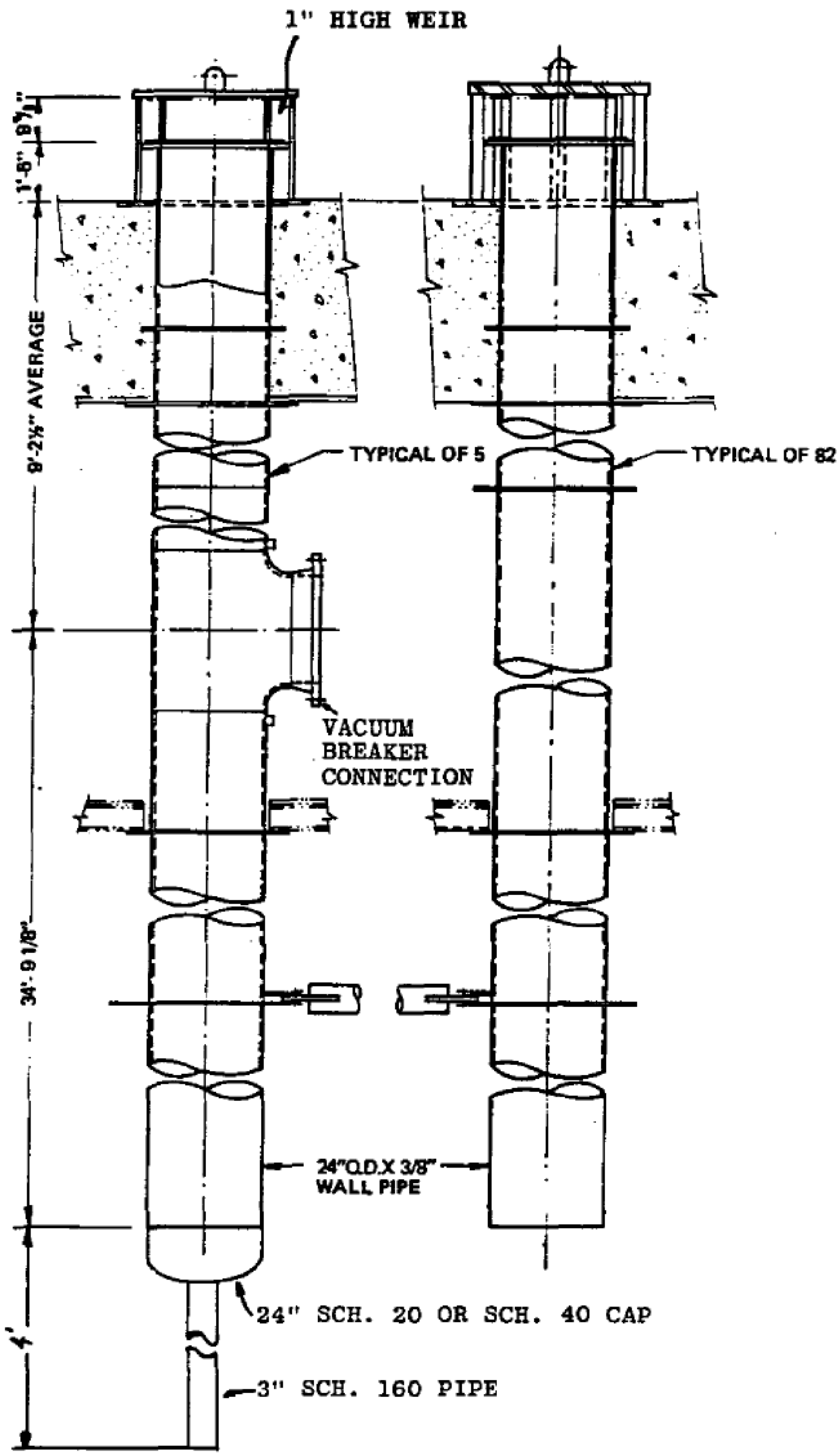
Auto Cad: Figure Fsar 6_2_53.dwg

Security-Related Information
Figure Withheld Under 10 CFR 2.390

FSAR REV. 65

SUSQUEHANNA STEAM ELECTRIC STATION UNITS 1 AND 2 FINAL SAFETY ANALYSIS REPORT
REACTOR BUILDING VENTILATION RECIRCULATION & STANDBY GAS TREATMENT SYSTEMS ZONE III ISOLATION
FIGURE 6.2-54, Rev. 49

Auto Cad: Figure Fsar 6_2_54.dwg



FSAR REV. 65

SUSQUEHANNA STEAM ELECTRIC STATION UNITS 1 AND 2 FINAL SAFETY ANALYSIS REPORT
DRYWELL TO WETWELL DOWNCOMERS FIGURE 6.2-56, Rev. 49

Auto Cad: Figure Fsar 6_2_56.dwg

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FSAR REV. 65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

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FIGURE 6.2-57, Rev. 48

AutoCAD Figure 6_2_57.doc

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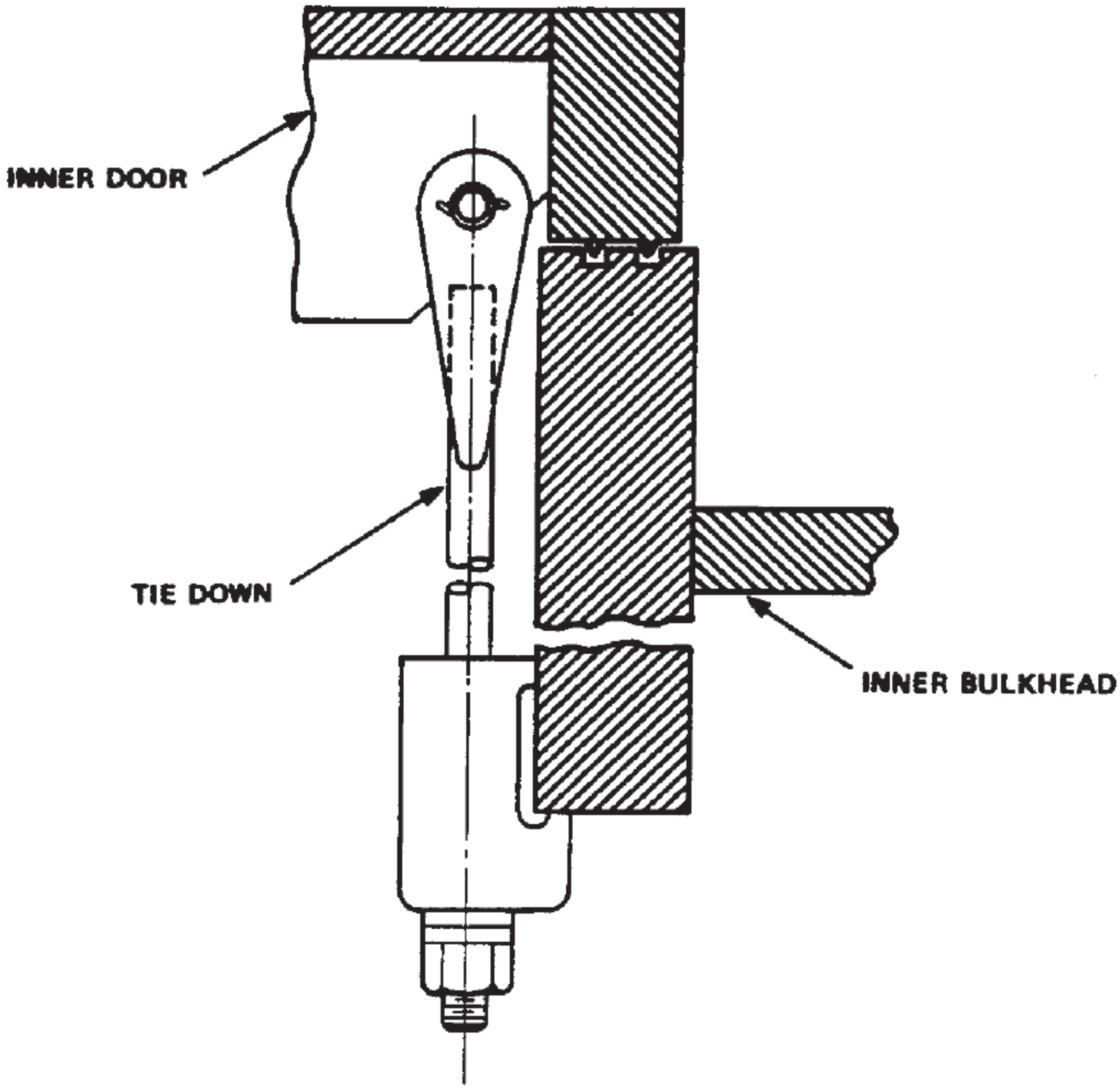
SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

THIS FIGURE HAS BEEN DELETED

FIGURE 6.2-58, Rev. 48



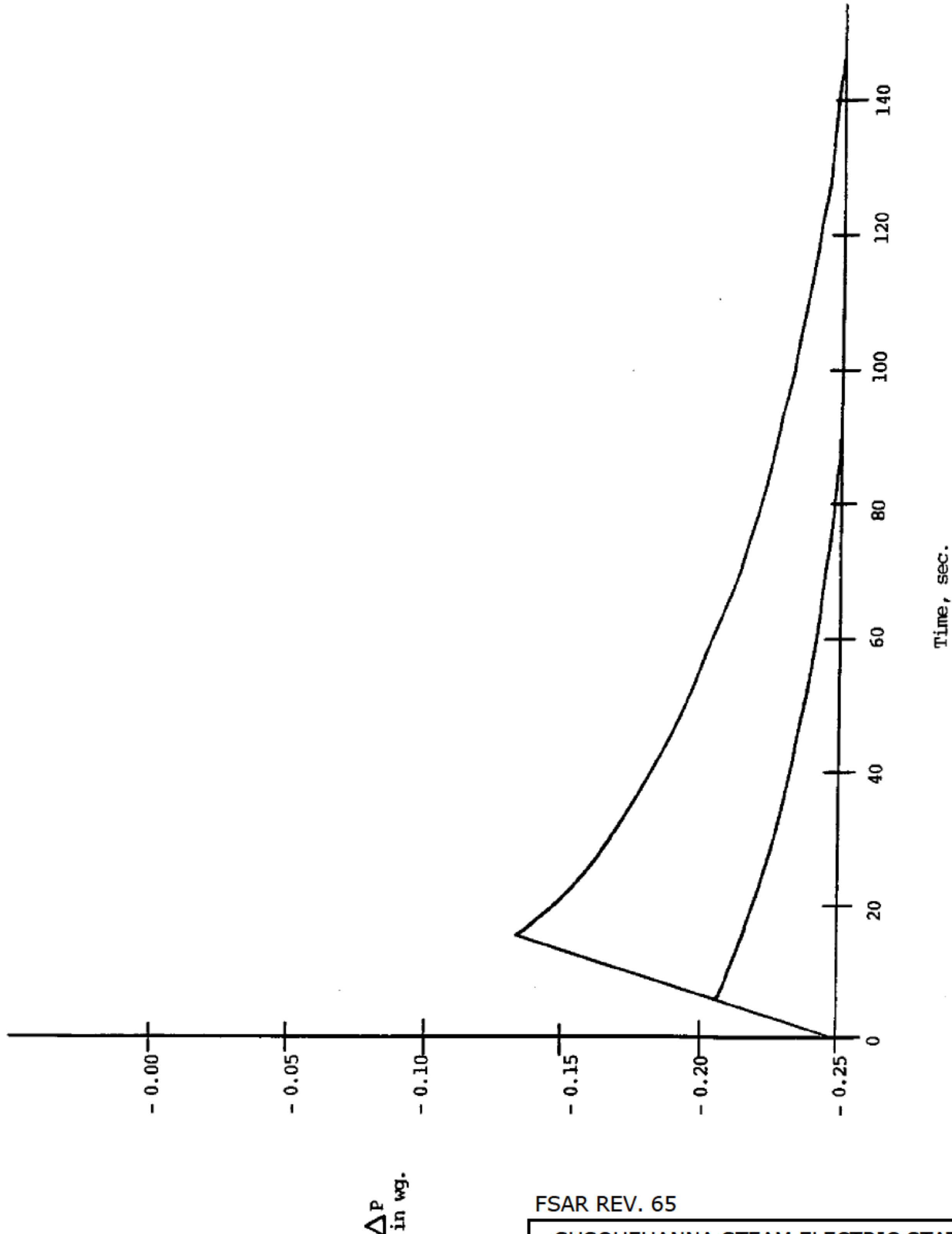
FSAR REV. 65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 AND 2
FINAL SAFETY ANALYSIS REPORT

PERSONNEL LOCK INNER
DOOR TIE DOWNS

FIGURE 6.2-59, Rev. 49

Auto Cad: Figure Fsar 6_2_59.dwg



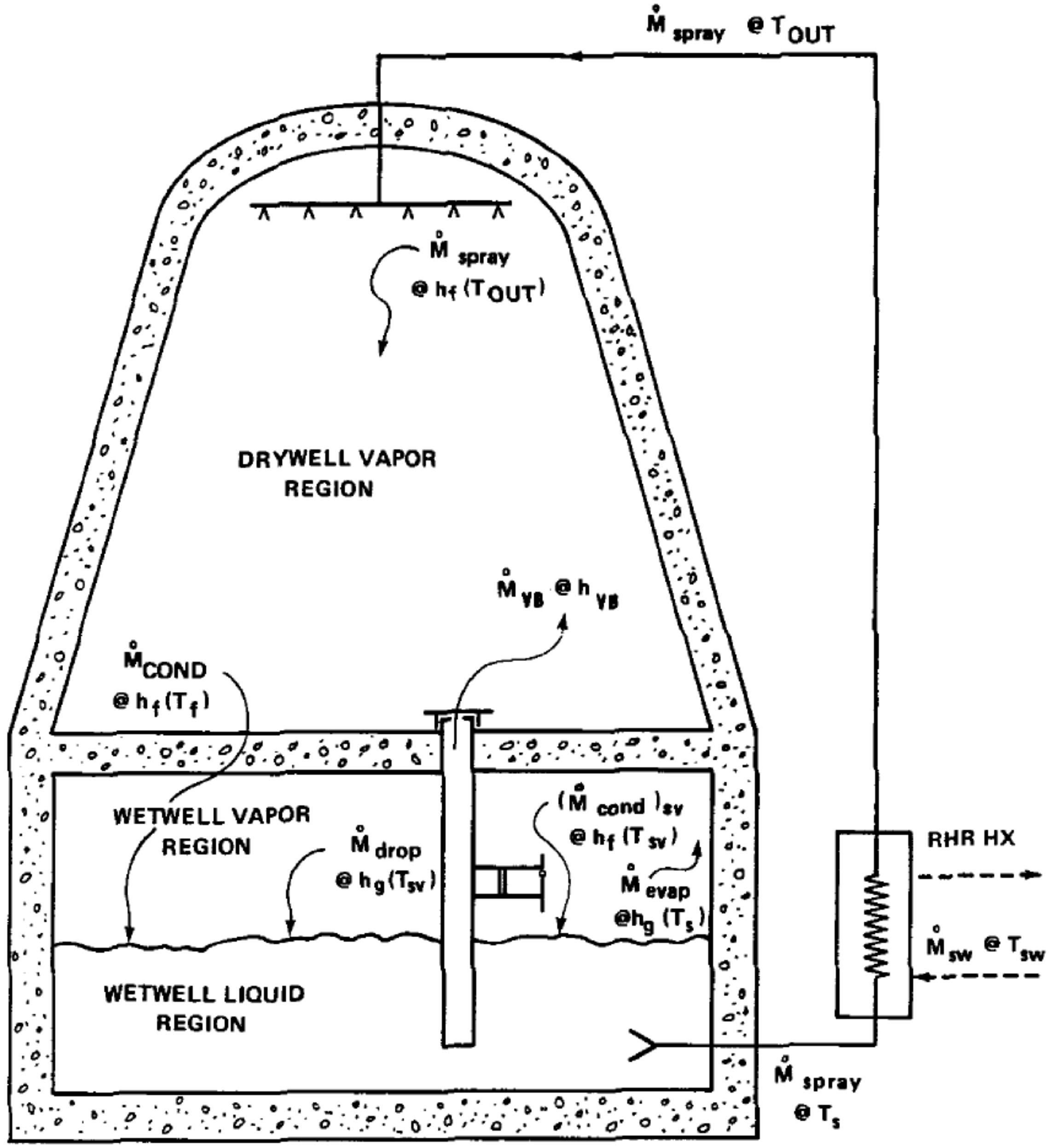
FSAR REV. 65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 AND 2
FINAL SAFETY ANALYSIS REPORT

SECONDARY CONTAINMENT
PRESSURE TRANSIENT
POST-LOCA

FIGURE 6.2-60, Rev. 49

Auto Cad: Figure Fsar 6_2_60.dwg



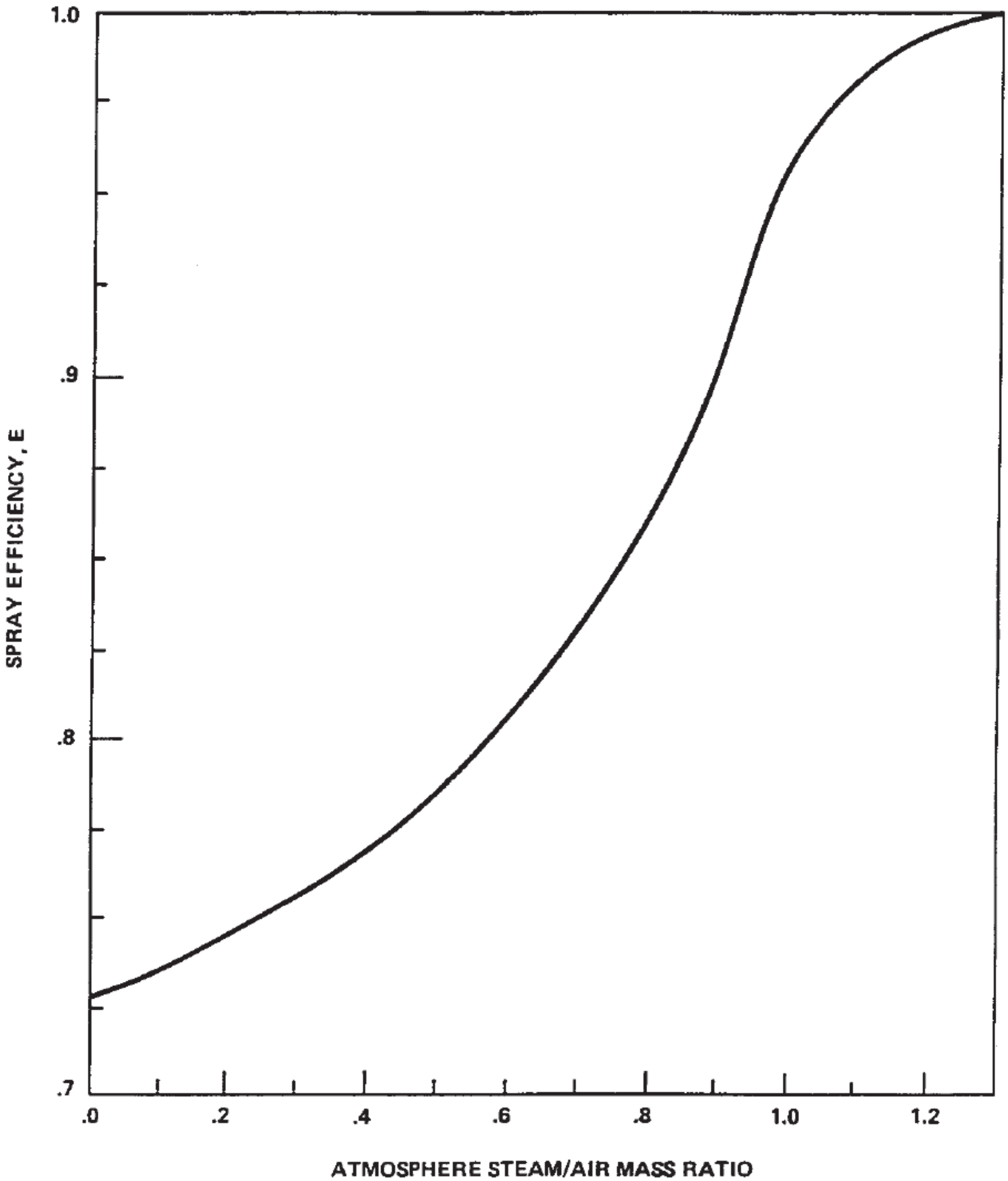
FSAR REV. 65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 AND 2
FINAL SAFETY ANALYSIS REPORT

MODEL FOR INADVERTENT
SPRAY ACTUATION

FIGURE 6.2-61, Rev. 49

Auto Cad: Figure Fsar 6_2_61.dwg



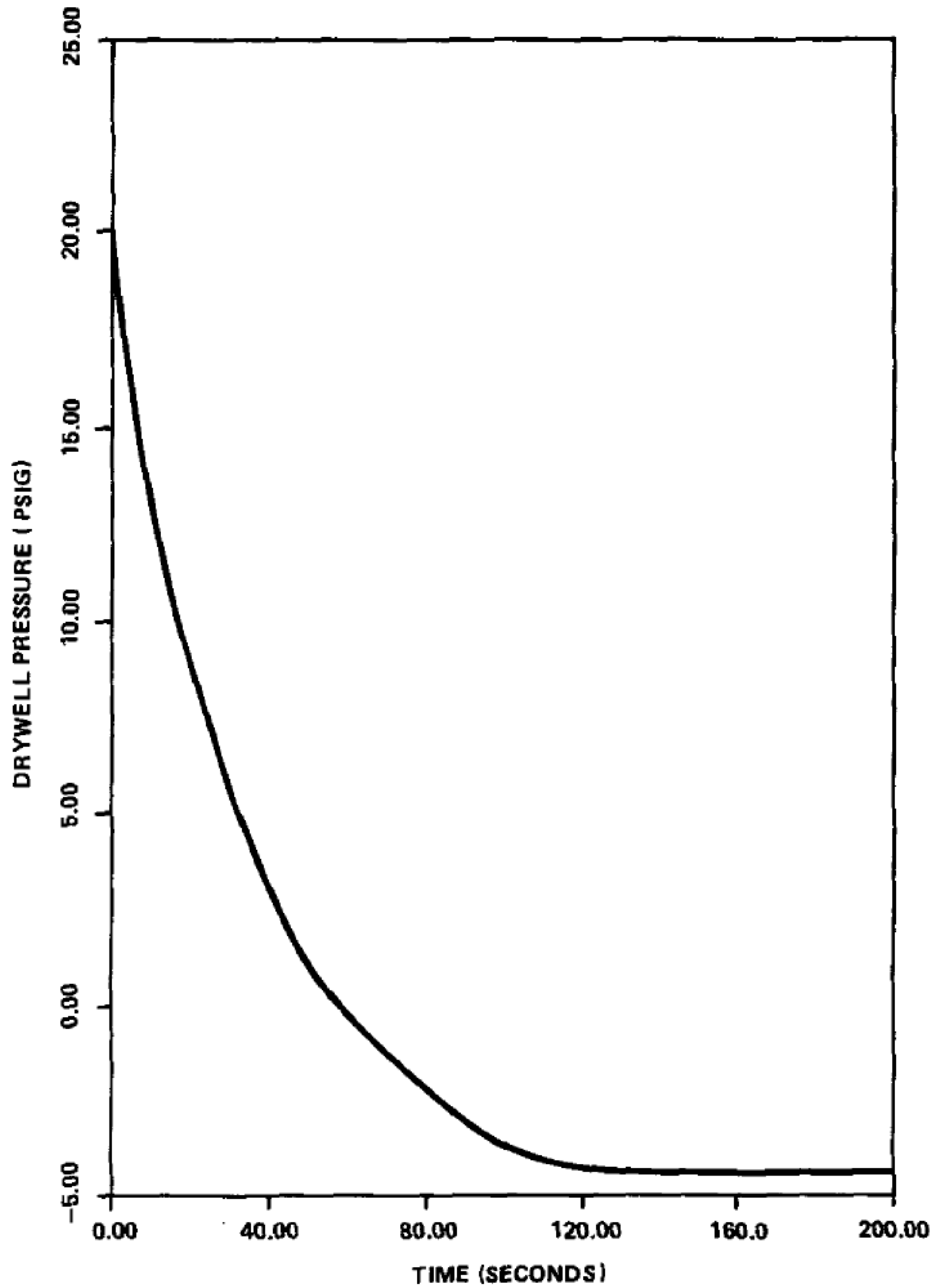
FSAR REV. 65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 AND 2
FINAL SAFETY ANALYSIS REPORT

THERMAL HEAT REMOVAL
EFFICIENCY OF CONTAINMENT
ATMOSPHERE SPRAY

FIGURE 6.2-62, Rev. 49

Auto Cad: Figure Fsar 6_2_62.dwg



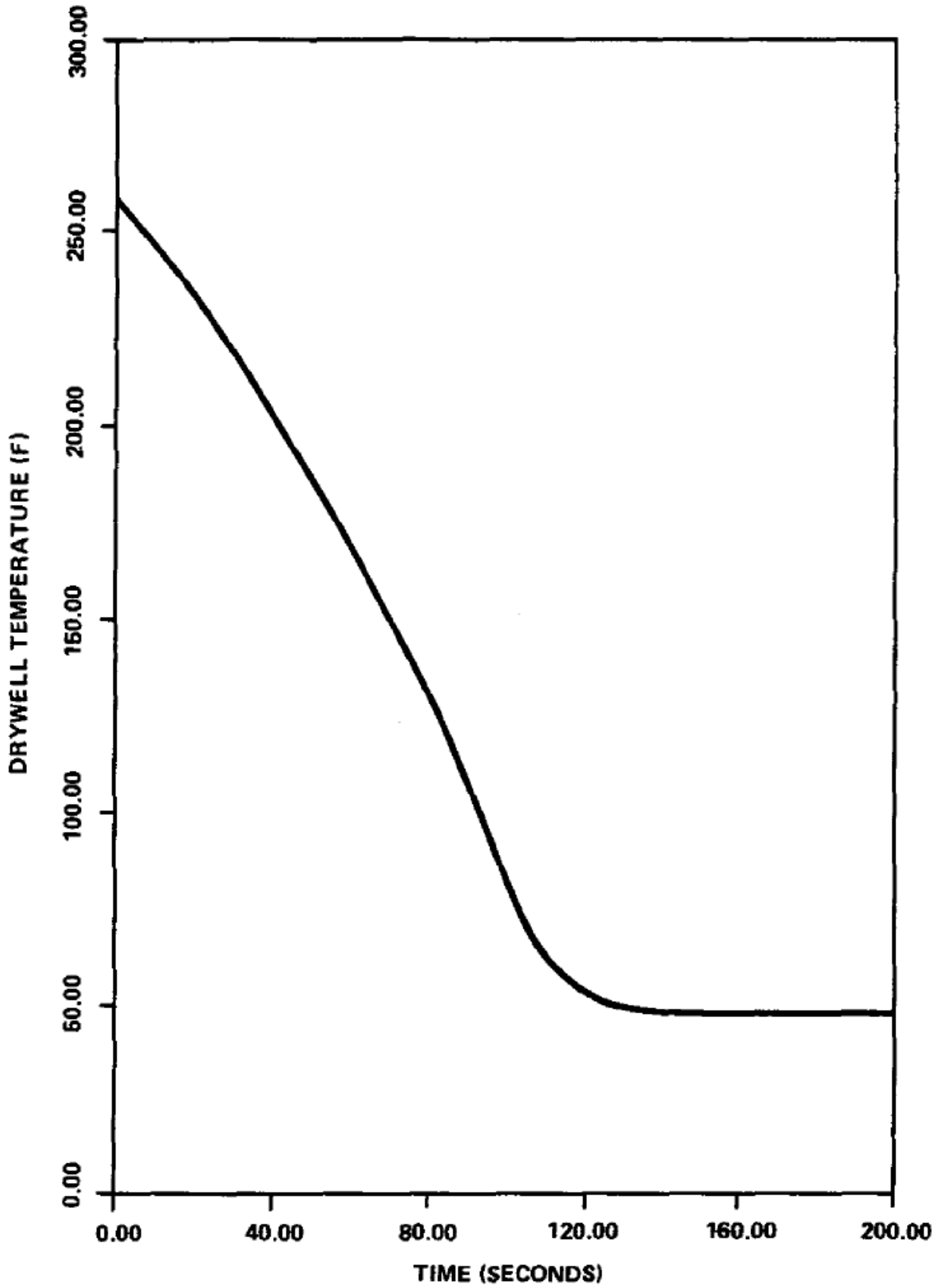
FSAR REV. 65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 AND 2
FINAL SAFETY ANALYSIS REPORT

DRYWELL PRESSURE RESPONSE
FOR INADVERTENT SPRAY
ACTUATION

FIGURE 6.2-63, Rev. 49

Auto Cad: Figure Fsar 6_2_63.dwg



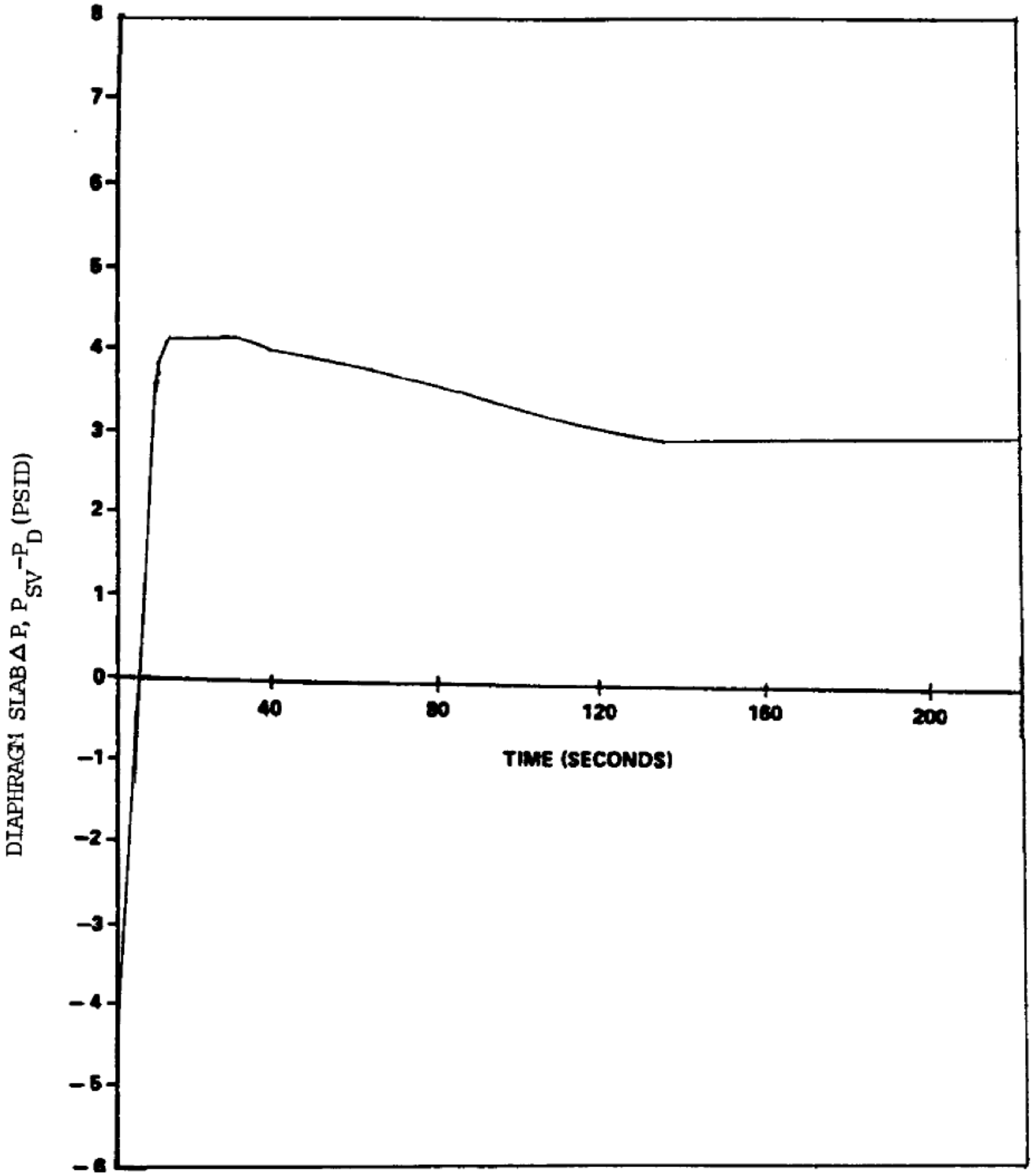
FSAR REV. 65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 AND 2
FINAL SAFETY ANALYSIS REPORT

DRYWELL TEMPERATURE
RESPONSE FOR
INADVERTENT SPRAY
ACTUATION

FIGURE 6.2-64, Rev. 49

Auto Cad: Figure Fsar 6_2_64.dwg



FSAR REV. 65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 AND 2
FINAL SAFETY ANALYSIS REPORT

DIFFERENTIAL PRESSURE EXPERIENCED ACROSS THE DIAPHRAGM SLAB DURING INADVERTENT ACTUATION OF THE DRYWELL SPRAY

FIGURE 6.2-65, Rev. 49

Auto Cad: Figure Fsar 6_2_65.dwg

FIGURE 6.2-67 REPLACED BY DWG. M-159, SH. 1

FSAR REV. 65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

FIGURE 6.2-67 REPLACED BY DWG. M-159, SH. 1

FIGURE 6.2-67, Rev. 55

AutoCAD Figure 6_2_67.doc

THIS FIGURE DELETED FOR POWER UPRATE

THIS FIGURE DELETED FOR POWER UPRATE

FIGURE 6.2-68, Rev. 50

THIS FIGURE DELETED FOR POWER UPRATE

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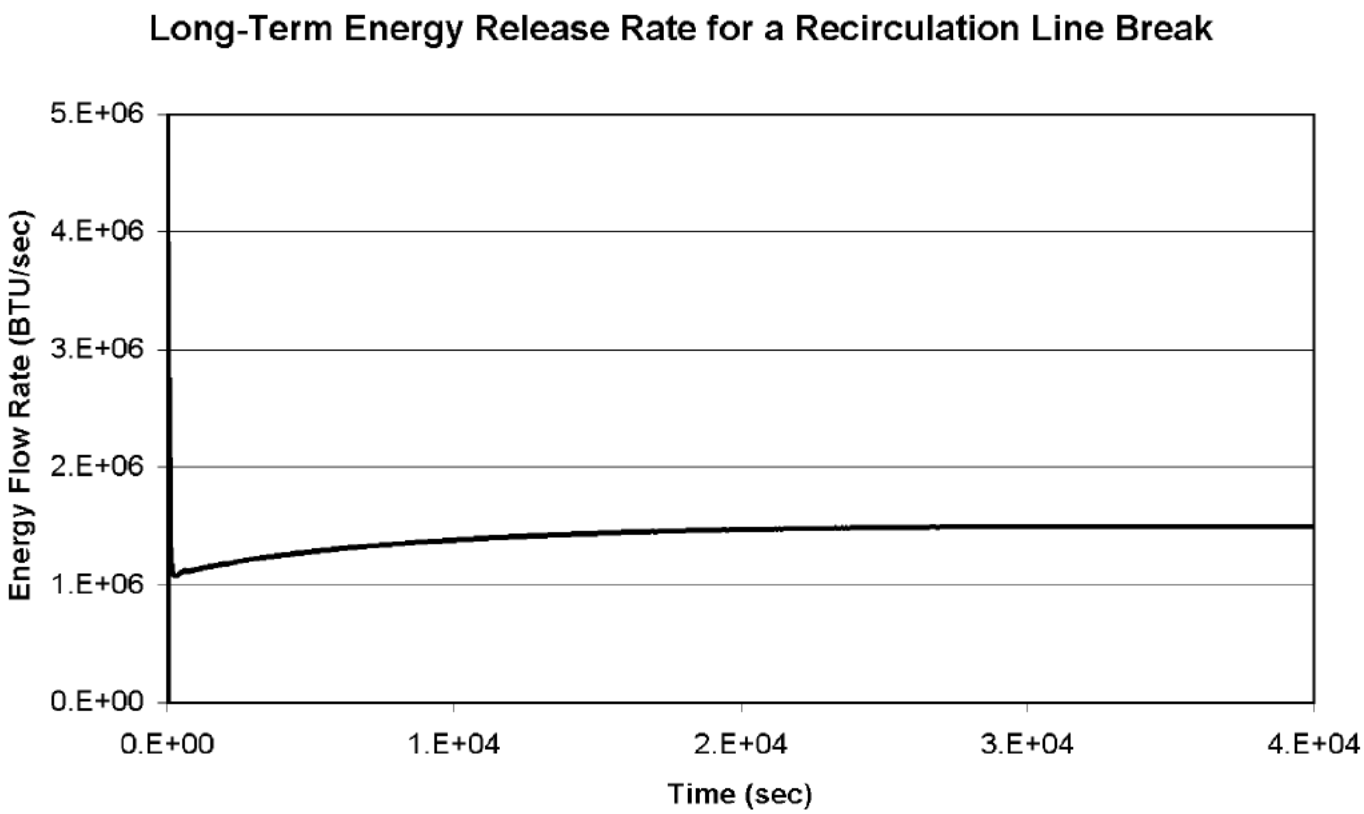
SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

THIS FIGURE DELETED FOR POWER UPRATE

FIGURE 6.2-69, Rev. 50

AutoCAD Figure 6_2_69.doc



FSAR REV. 65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 AND 2
FINAL SAFETY ANALYSIS REPORT

LONG-TERM ENERGY RELEASE RATE
FOR A RECIRCULATION LINE BREAK

FIGURE 6.2-70, Rev. 51

Auto Cad: Figure Fsar 6_2_70.dwg

FIGURE DELETED

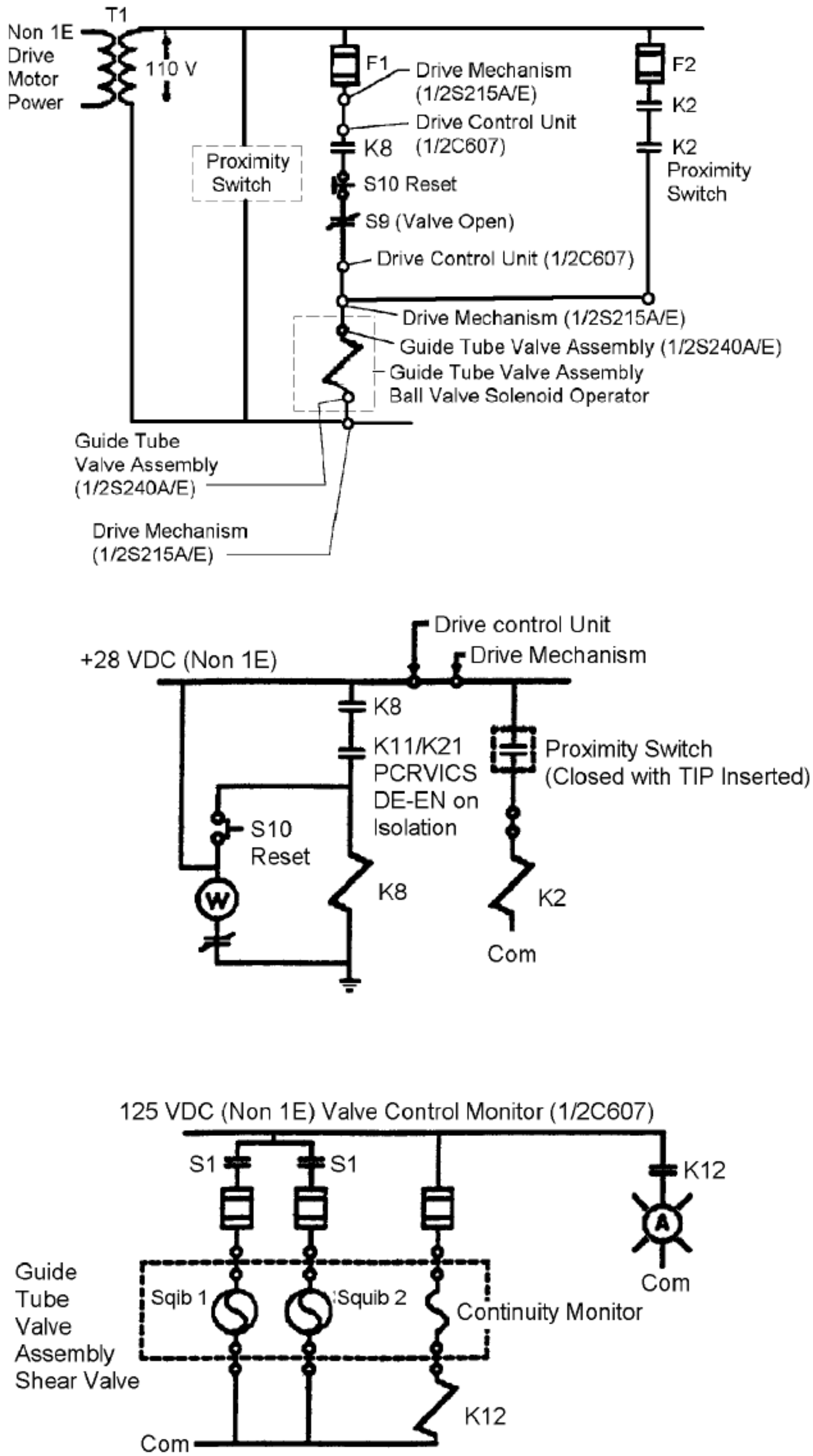
FSAR REV. 65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

FIGURE DELETED

FIGURE 6.2-71, Rev. 51

AutoCAD Figure 6_2_71.doc



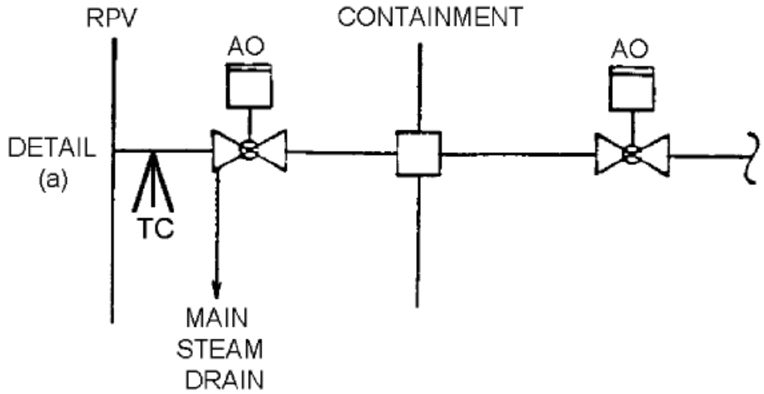
FSAR REV. 65

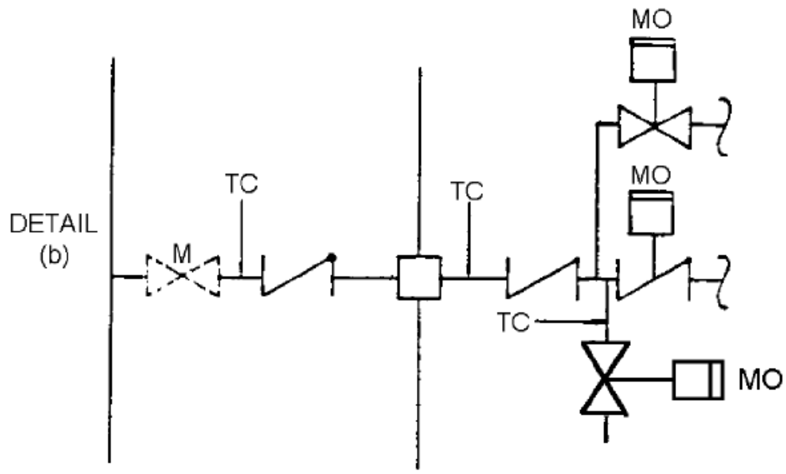
SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 AND 2
FINAL SAFETY ANALYSIS REPORT

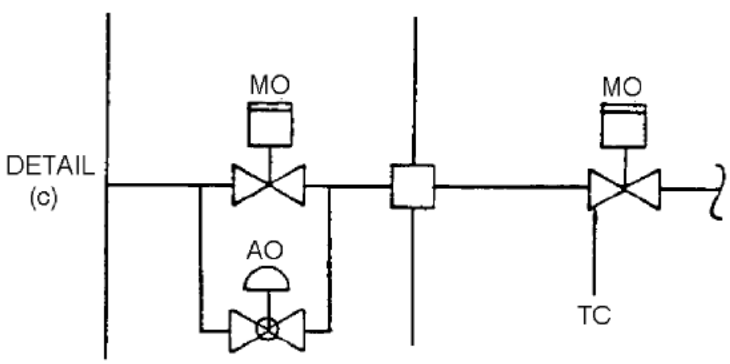
TIP GUIDE TUBE
ISOLATION CONTROL

FIGURE 6.2-72, Rev. 50

Auto Cad: Figure Fsar 6_2_72.dwg







MO– MOTOR OPERATED
AO– AIR OPERATED
M– MANUAL
TC– TEST CONNECTION

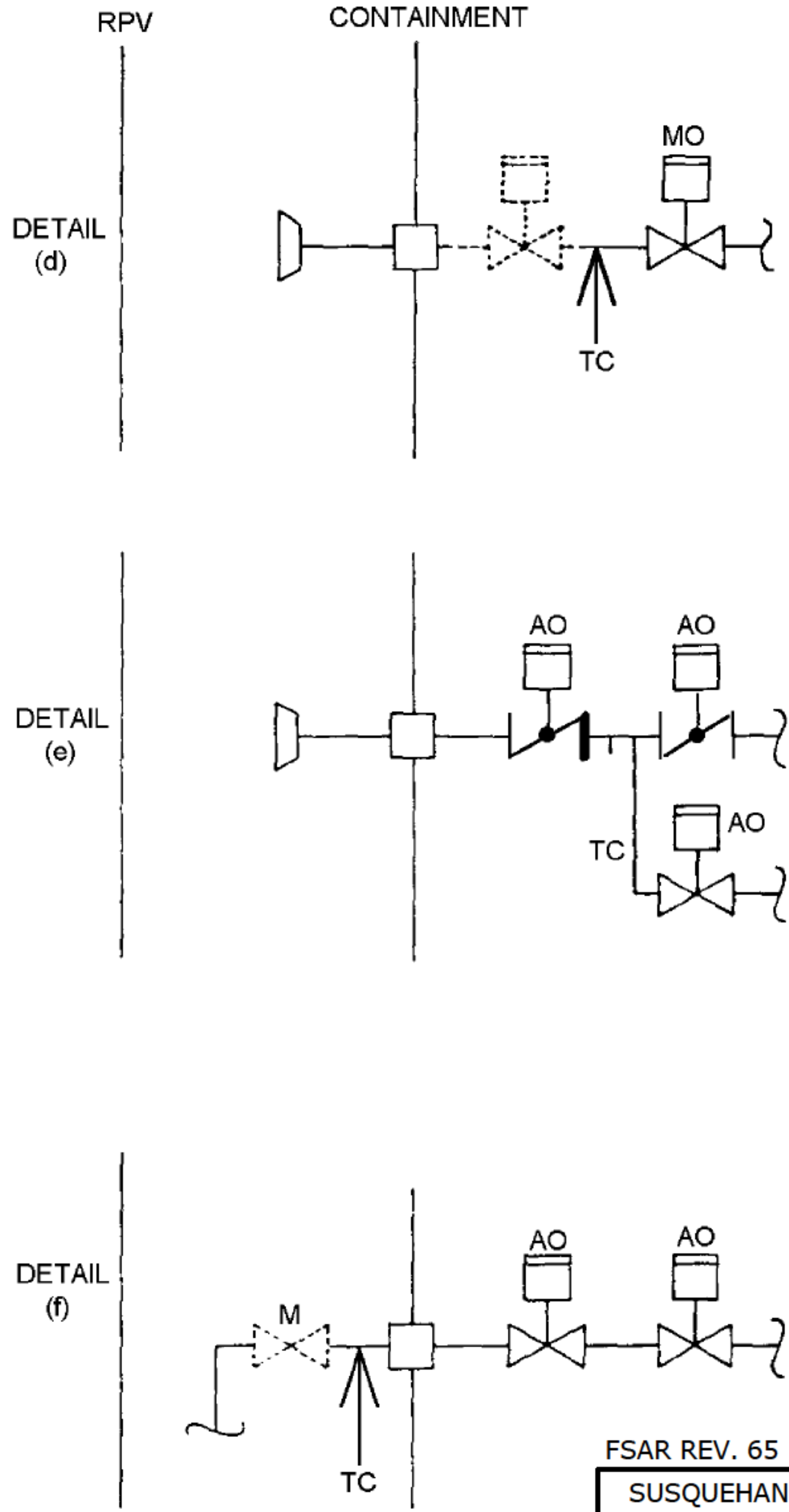
FSAR REV. 65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 AND 2
FINAL SAFETY ANALYSIS REPORT

CONTAINMENT PENETRATION
DETAILS

FIGURE 6.2-44A, Rev. 55

Auto Cad: Figure Fsar 6_2_44A.dwg



MO– MOTOR OPERATED
AO– AIR OPERATED
TC– TEST CONNECTION
M – MANUAL

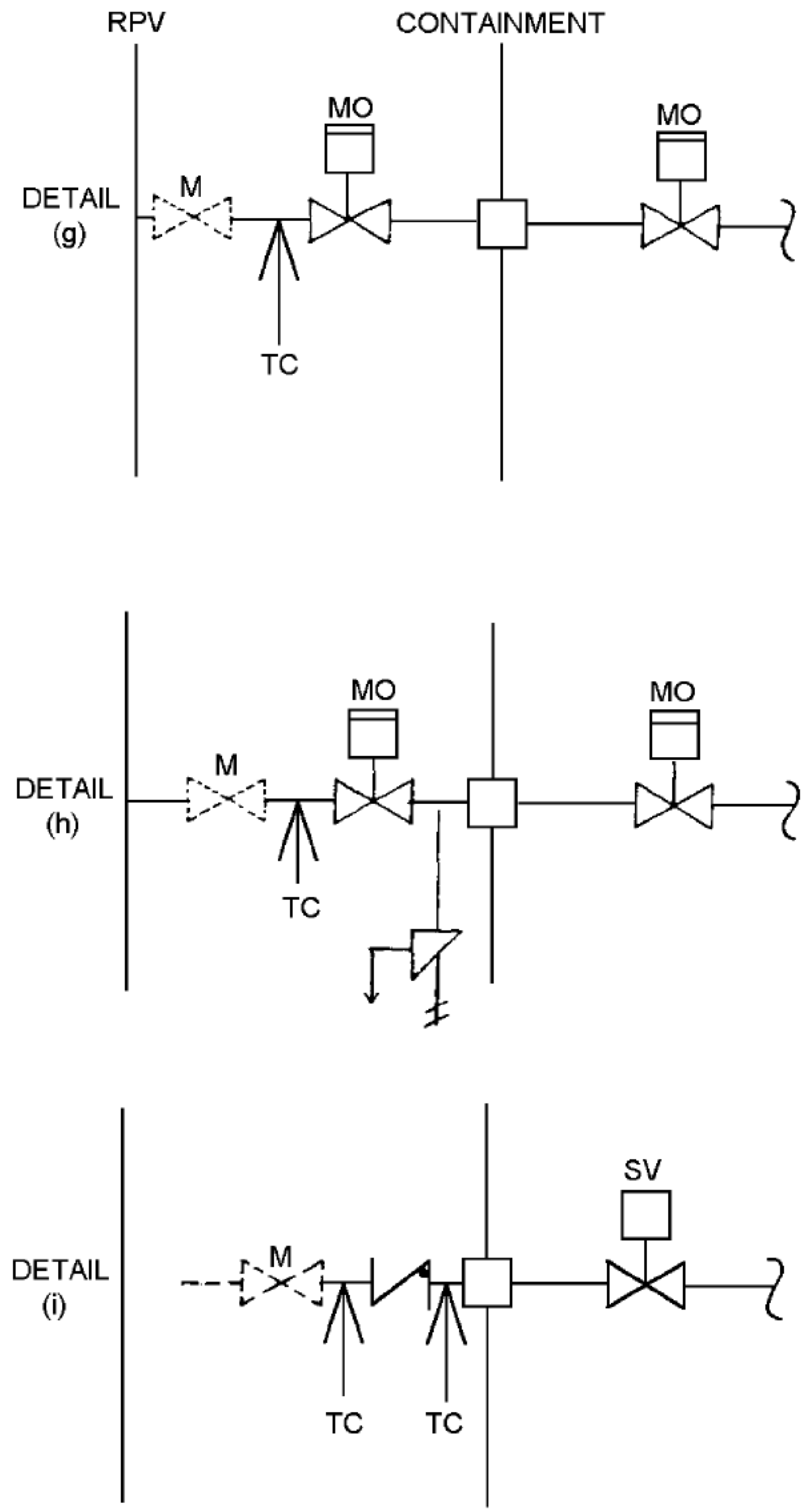
FSAR REV. 65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 AND 2
FINAL SAFETY ANALYSIS REPORT

CONTAINMENT PENETRATION
DETAILS

FIGURE 6.2-44B, Rev. 54

Auto Cad: Figure Fsar 6_2_44B.dwg



FSAR REV. 65

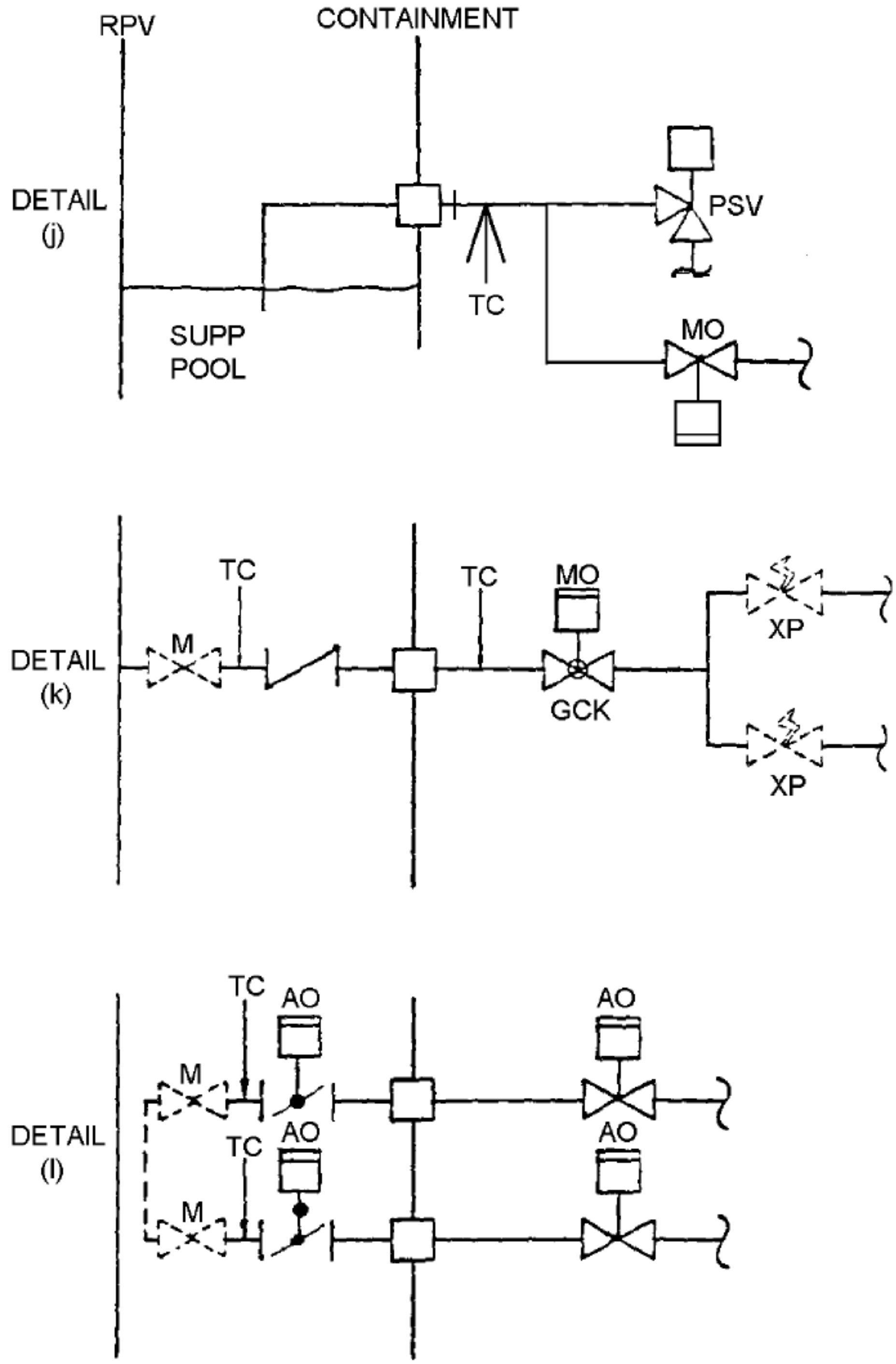
MO - MOTOR OPERATED
TC - TEST CONNECTION
SV - SOLENLID VALVE
M - MANUAL

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 AND 2
FINAL SAFETY ANALYSIS REPORT

CONTAINMENT PENETRATION
DETAILS

FIGURE 6.2-44C, Rev. 54

Auto Cad: Figure Fsar 6_2_44C.dwg

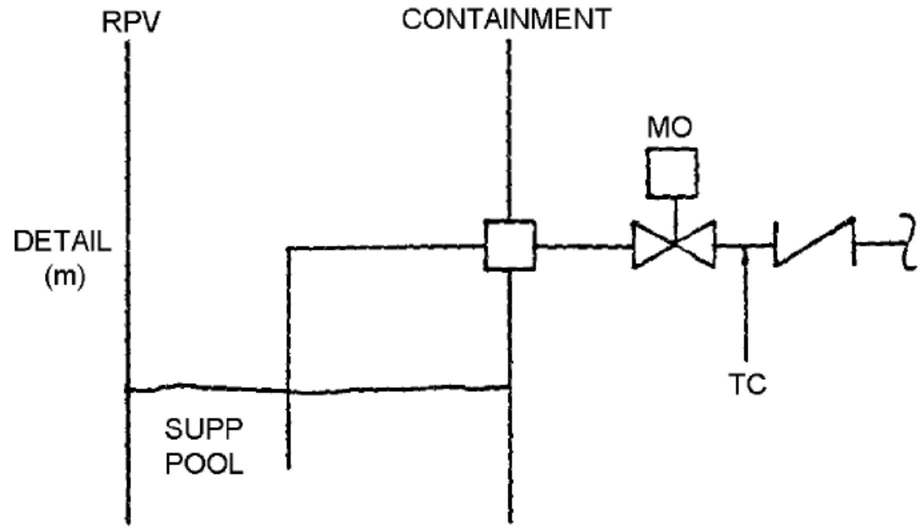


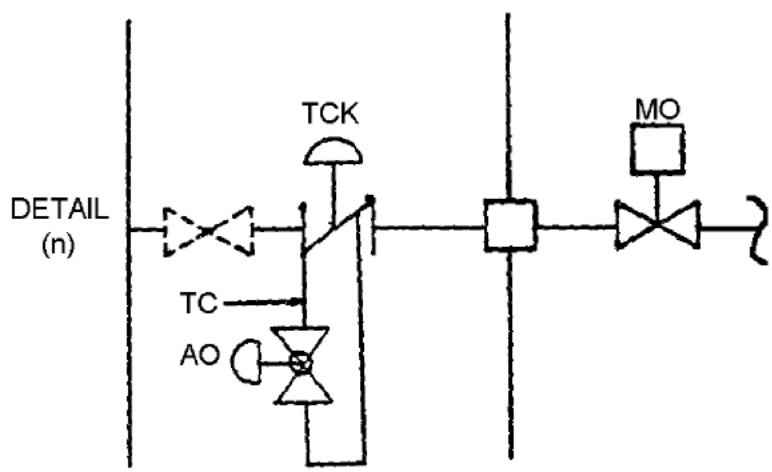
PSV - PRESSURE SAFETY VALVE
MO - MOTOR OPERATED
M - MANUAL
TC - TEST CONNECTION
GCK - GLOBE STOP-CHECK
XP - EXPLOSIVE VALVE
AO - AIR OPERATED

FSAR REV. 65

SUSQUEHANNA STEAM ELECTRIC STATION UNITS 1 AND 2 FINAL SAFETY ANALYSIS REPORT
CONTAINMENT PENETRATION DETAILS FIGURE 6.2-44D, Rev. 54

Auto Cad: Figure Fsar 6_2_44D.dwg





MO - MOTOR OPERATED
TC - TEST CONNECTION
TCK - TESTABLE CHECK
AO - AIR OPERATED
M - MANUAL

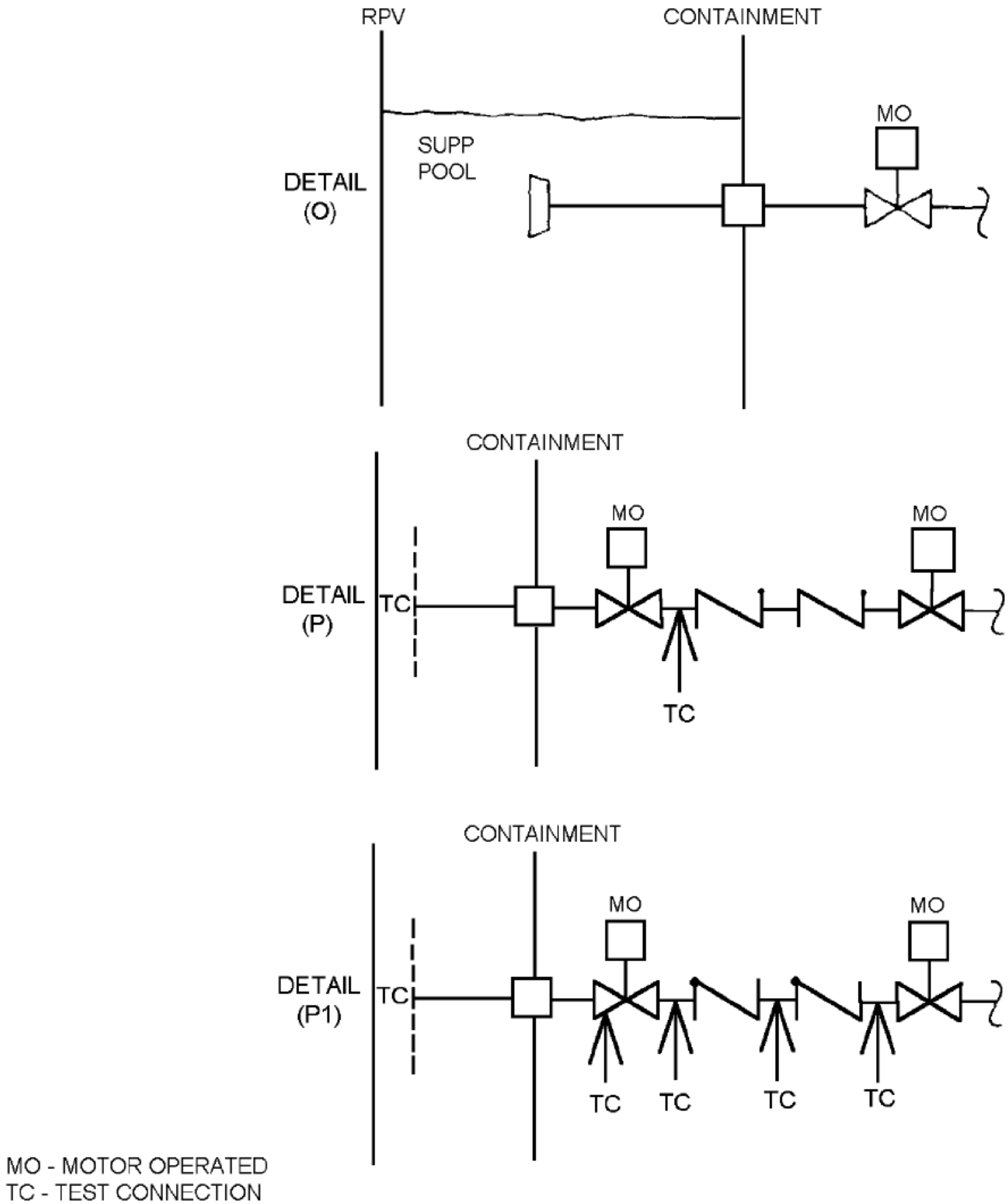
FSAR REV. 65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 AND 2
FINAL SAFETY ANALYSIS REPORT

CONTAINMENT PENETRATION
DETAILS

FIGURE 6.2-44E, Rev. 54

Auto Cad: Figure Fsar 6_2_44E.dwg



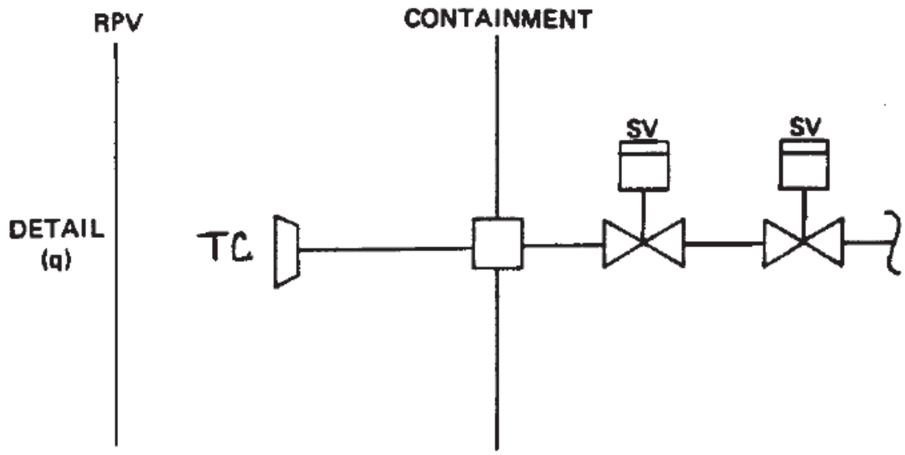
FSAR REV. 65

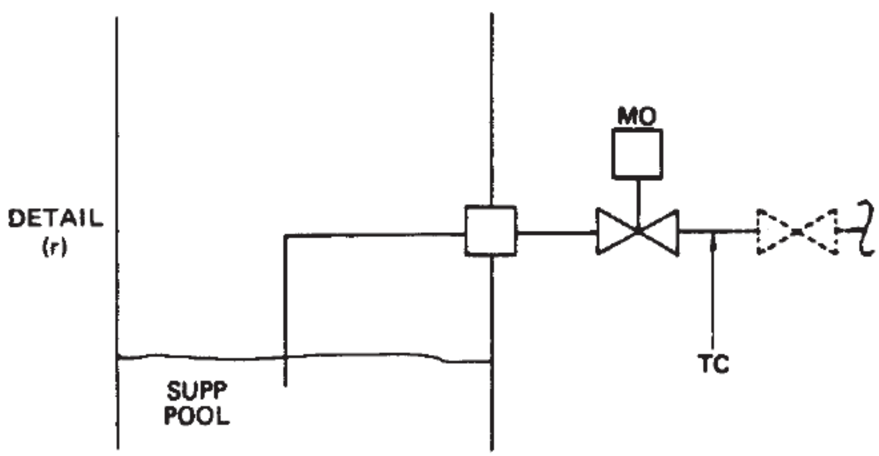
SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 AND 2
FINAL SAFETY ANALYSIS REPORT

CONTAINMENT PENETRATION
DETAILS

FIGURE 6.2-44F, Rev. 55

Auto Cad: Figure Fsar 6_2_44F.dwg





MO – MOTOR OPERATED
SV – SOLENOID VALVE
TC – TEST CONNECTION

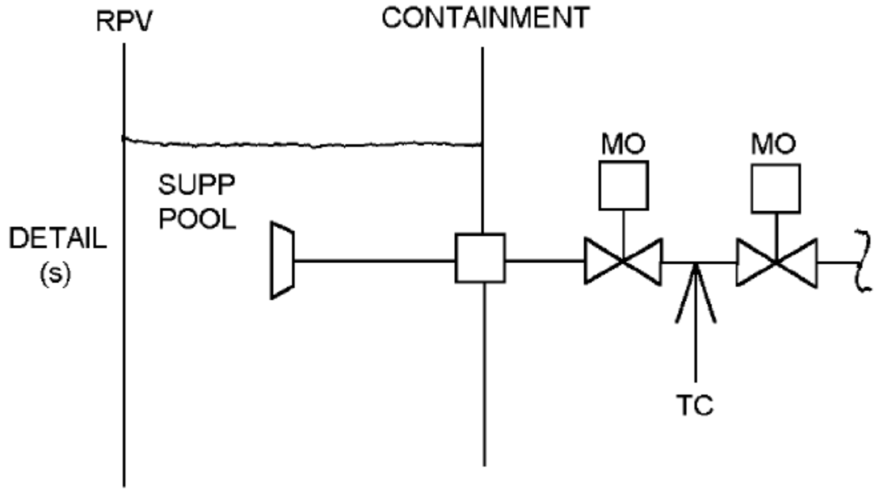
FSAR REV. 65

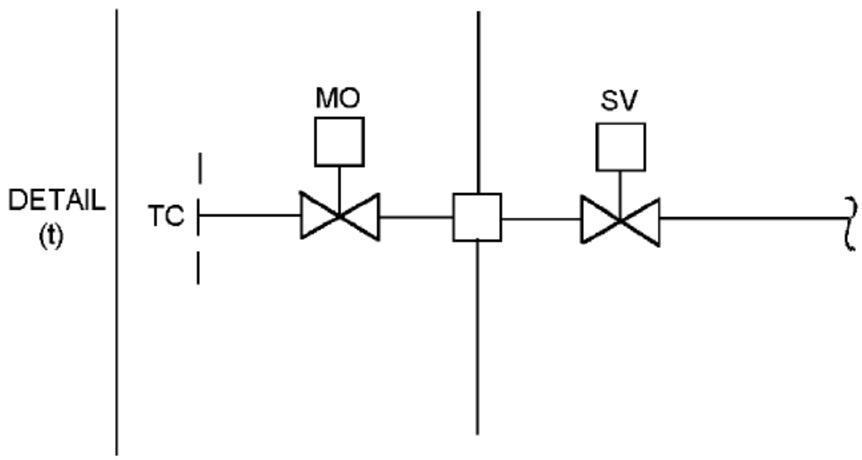
SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 AND 2
FINAL SAFETY ANALYSIS REPORT

CONTAINMENT PENETRATION
DETAILS

FIGURE 6.2-44G, Rev. 49

Auto Cad: Figure Fsar 6_2_44G.dwg



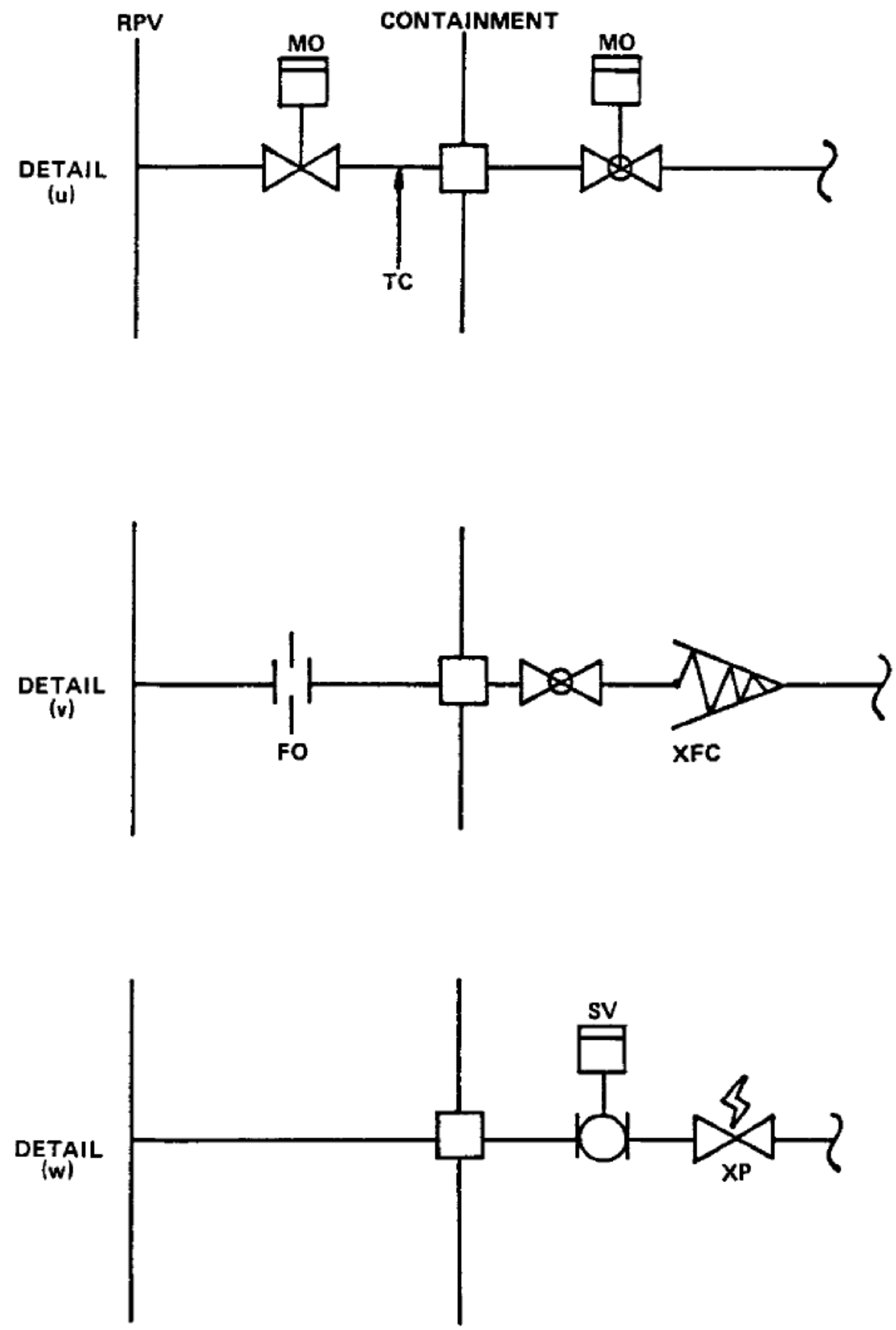


MO - MOTOR OPERATED
SV - SOLENOID VALVE
TC - TEST CONNECTION

FSAR REV. 65

SUSQUEHANNA STEAM ELECTRIC STATION UNITS 1 AND 2 FINAL SAFETY ANALYSIS REPORT
CONTAINMENT PENETRATION DETAILS FIGURE 6.2-44H, Rev. 54

Auto Cad: Figure Fsar 6_2_44H.dwg



MO – MOTOR OPERATED
SV – SOLENOID VALVE
TC – TEST CONNECTION
FO – FLOW ORIFICE
XFC – EXCESS FLOW CHECK VALVE
XP – EXPLOSIVE (SHEAR) VALVE

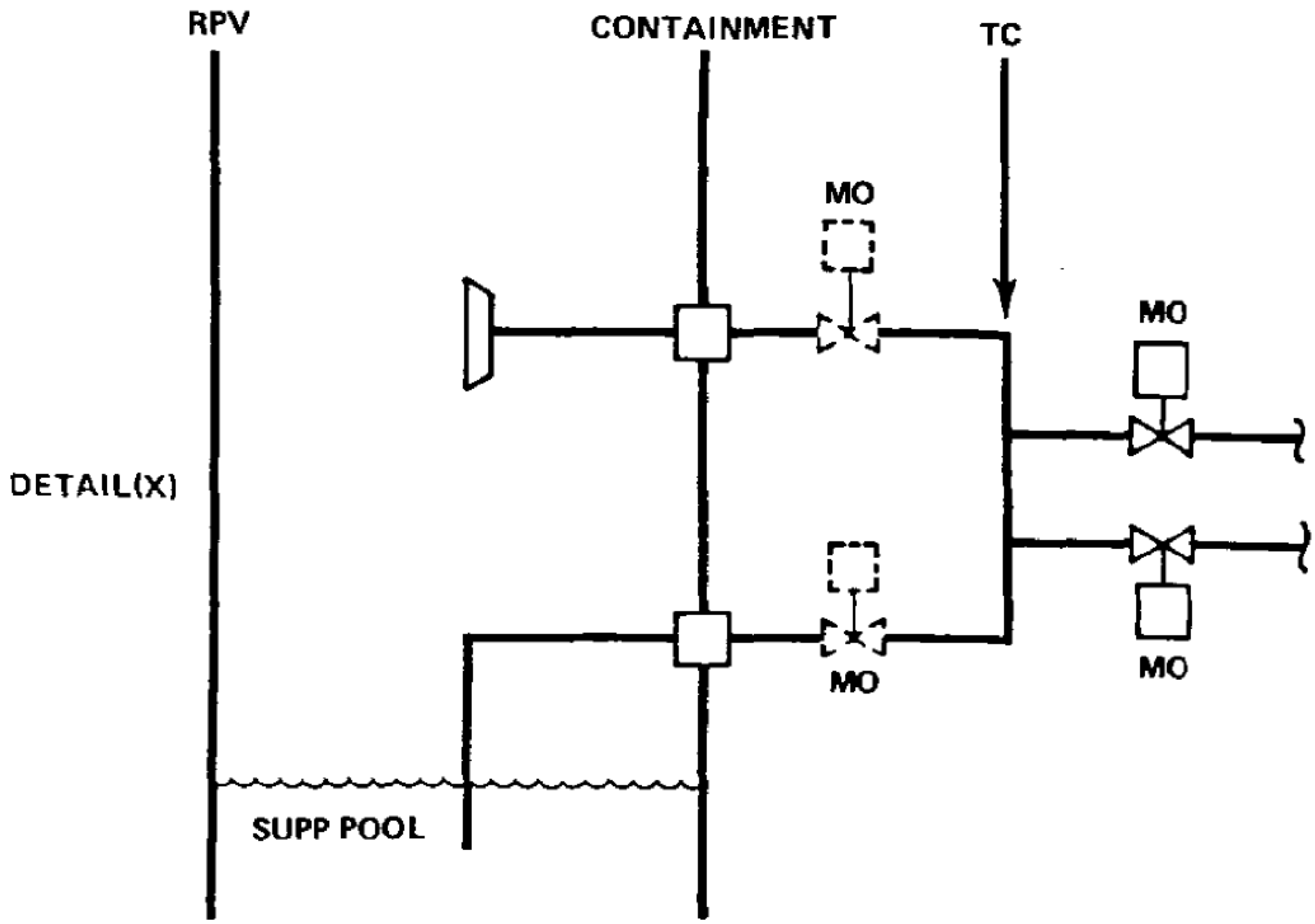
FSAR REV. 65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 AND 2
FINAL SAFETY ANALYSIS REPORT

CONTAINMENT PENETRATION DETAILS

FIGURE 6.2-44I, Rev. 49

Auto Cad: Figure Fsar 6_2_44I.dwg



MO - MOTOR OPERATED VALVE
TC - TEST CONNECTION

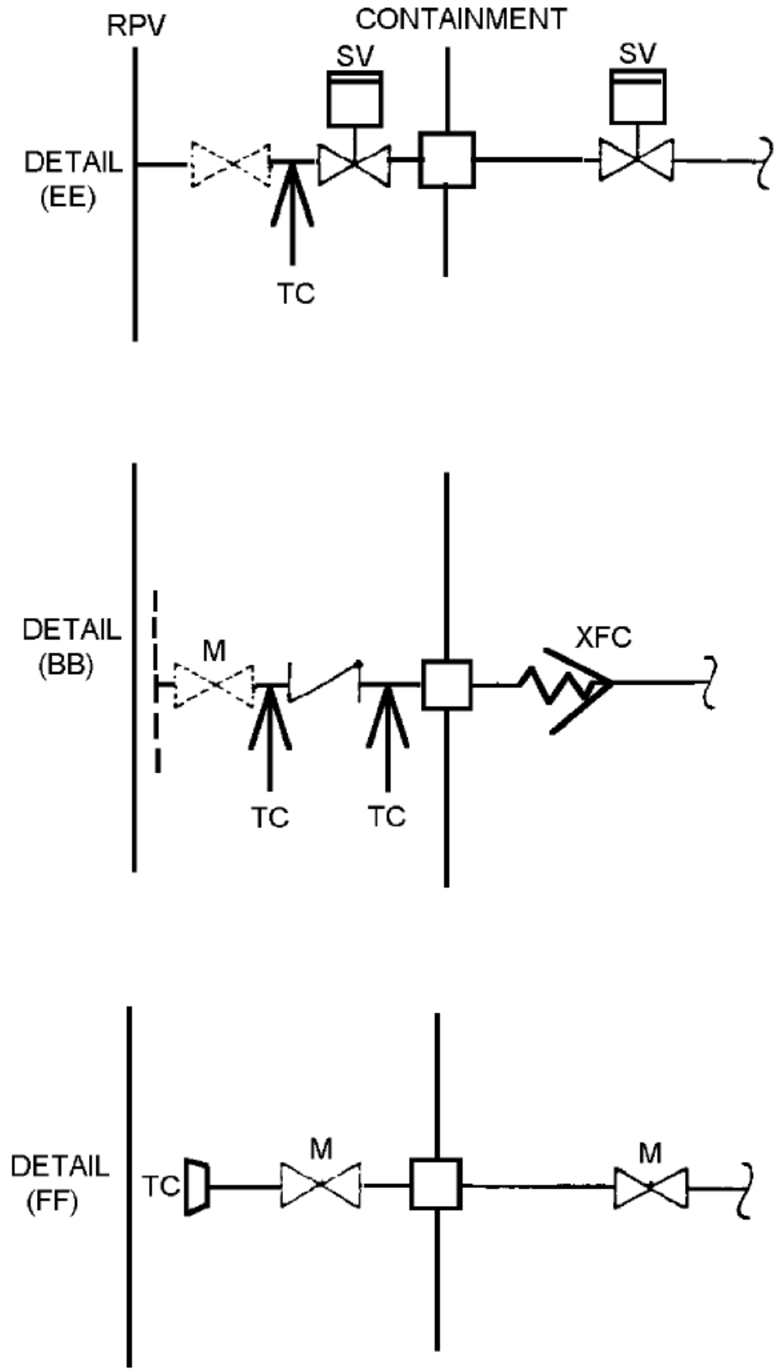
FSAR REV. 65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 AND 2
FINAL SAFETY ANALYSIS REPORT

CONTAINMENT PENETRATION
DETAILS

FIGURE 6.2-44J, Rev. 54

Auto Cad: Figure Fsar 6_2_44J.dwg



SV - SOLENOID VALVE
M - MANUAL
TC - TEST CONNECTION
XFC - EXCESS FLOW CHECK VALVE

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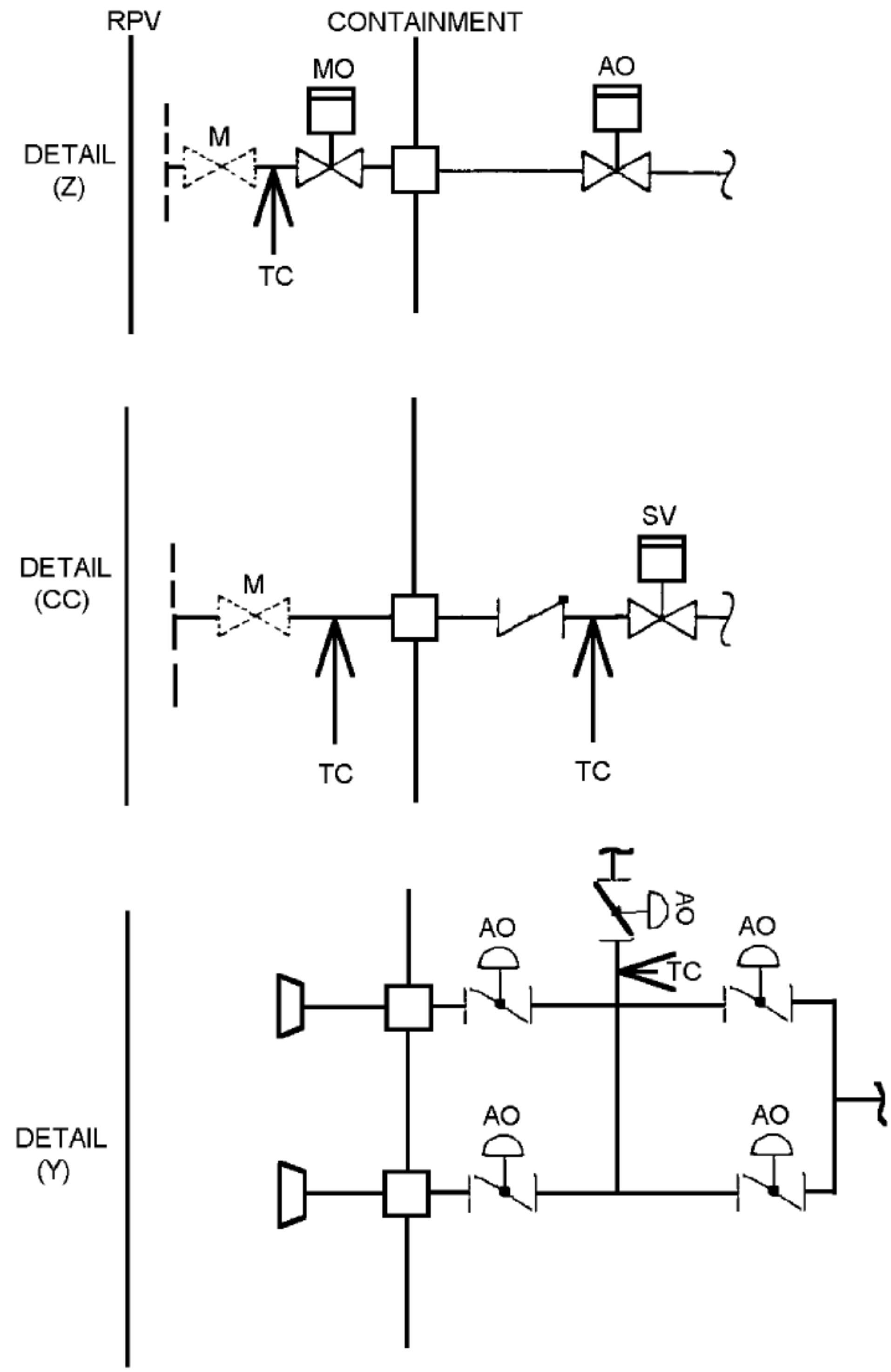
CONTAINMENT PENETRATION
DETAILS

FIGURE 6.2-44K, Rev. 54

Auto Cad: Figure Fsar 6_2_44K.dwg



MO - MOTOR OPERATED
M - MANUAL
TC - TEST CONNECTION
SV - SOLENOID VALVE
AO - AIR OPERATED

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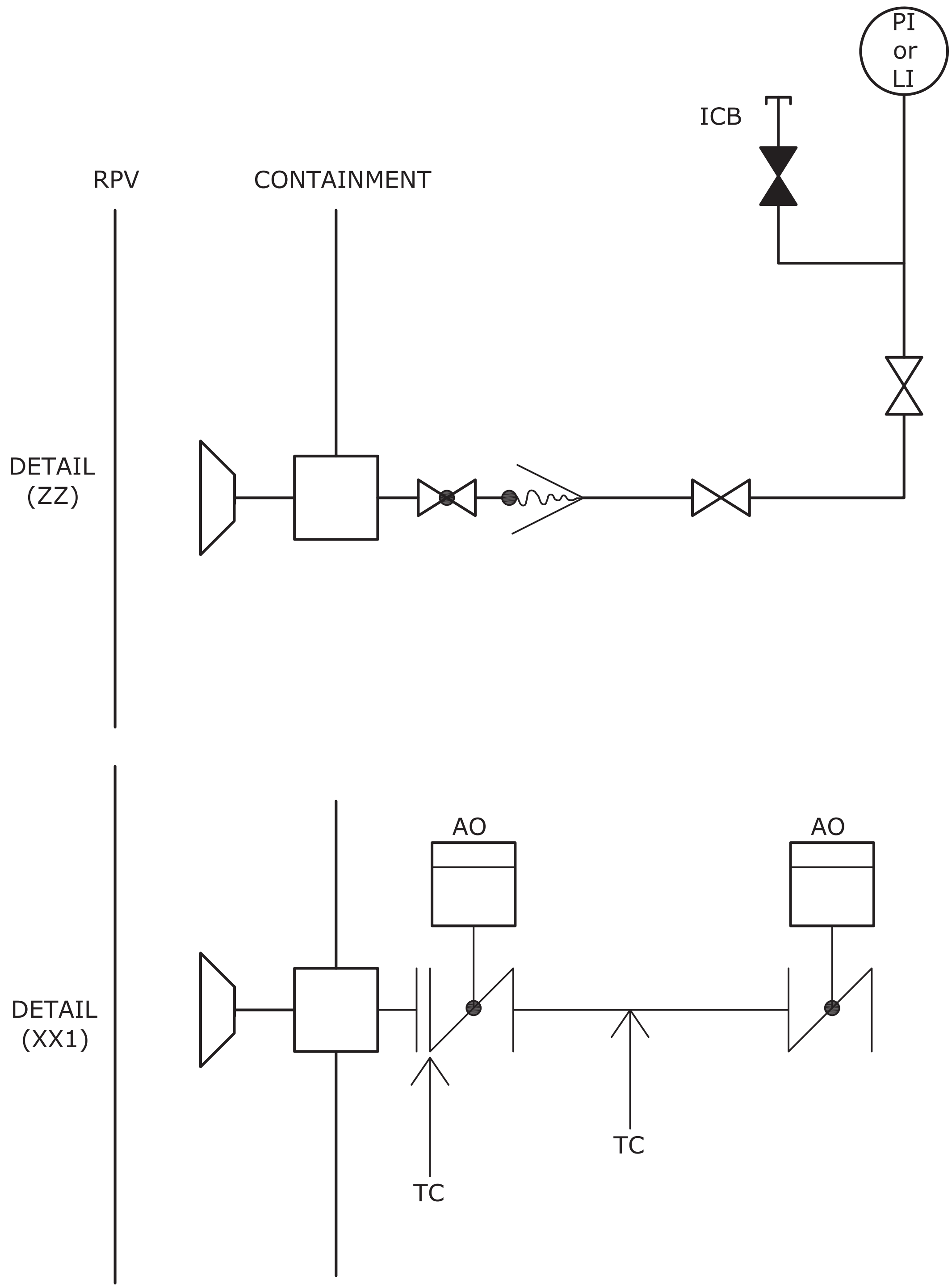
SUSQUEHANNA STEAM ELECTRIC STATION UNITS 1 AND 2 FINAL SAFETY ANALYSIS REPORT
CONTAINMENT PENETRATION DETAILS FIGURE 6.2-44L, Rev. 54

Auto Cad: Figure Fsar 6_2_44L.dwg



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SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 AND 2
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CONTAINMENT PENETRATION
DETAILS

FIGURE 6.2-44M, Rev. 56

Auto Cad: Figure Fsar 6_2_44M.dwg

FIGURE 6.2-55A REPLACED BY DWG. M-157, SH. 1

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FIGURE 6.2-55A REPLACED BY DWG. M-157, SH. 1

FIGURE 6.2-55A, Rev. 56

AutoCAD Figure 6_2_55A.doc

FIGURE 6.2-55B REPLACED BY DWG. M-157, SH. 2

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SUSQUEHANNA STEAM ELECTRIC STATION UNITS 1 & 2 FINAL SAFETY ANALYSIS REPORT
FIGURE 6.2-55B REPLACED BY DWG. M-157, SH. 2
FIGURE 6.2-55B, Rev. 55

AutoCAD Figure 6_2_55B.doc

FIGURE 6.2-55C REPLACED BY DWG. M-157, SH. 3

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FIGURE 6.2-55C REPLACED BY DWG. M-157, SH. 3

FIGURE 6.2-55C, Rev. 55

AutoCAD Figure 6_2_55C.doc

FIGURE DELETED PER LDCN 4582

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SUSQUEHANNA STEAM ELECTRIC STATION
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FINAL SAFETY ANALYSIS REPORT

FIGURE DELETED PER LDCN 4582

FIGURE 6.2-6-1, Rev. 57

AutoCAD Figure 6_2_6_1.doc

FIGURE DELETED PER LDCN 4582

FSAR REV. 65

SUSQUEHANNA STEAM ELECTRIC STATION UNITS 1 & 2 FINAL SAFETY ANALYSIS REPORT
FIGURE DELETED PER LDCN 4582 FIGURE 6.2-6-2, Rev. 57

AutoCAD Figure 6_2_6_2.doc

FIGURE DELETED PER LDCN 4582

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SUSQUEHANNA STEAM ELECTRIC STATION UNITS 1 & 2 FINAL SAFETY ANALYSIS REPORT
FIGURE DELETED PER LDCN 4582 FIGURE 6.2-6-3, Rev. 56

AutoCAD Figure 6_2_6_3.doc

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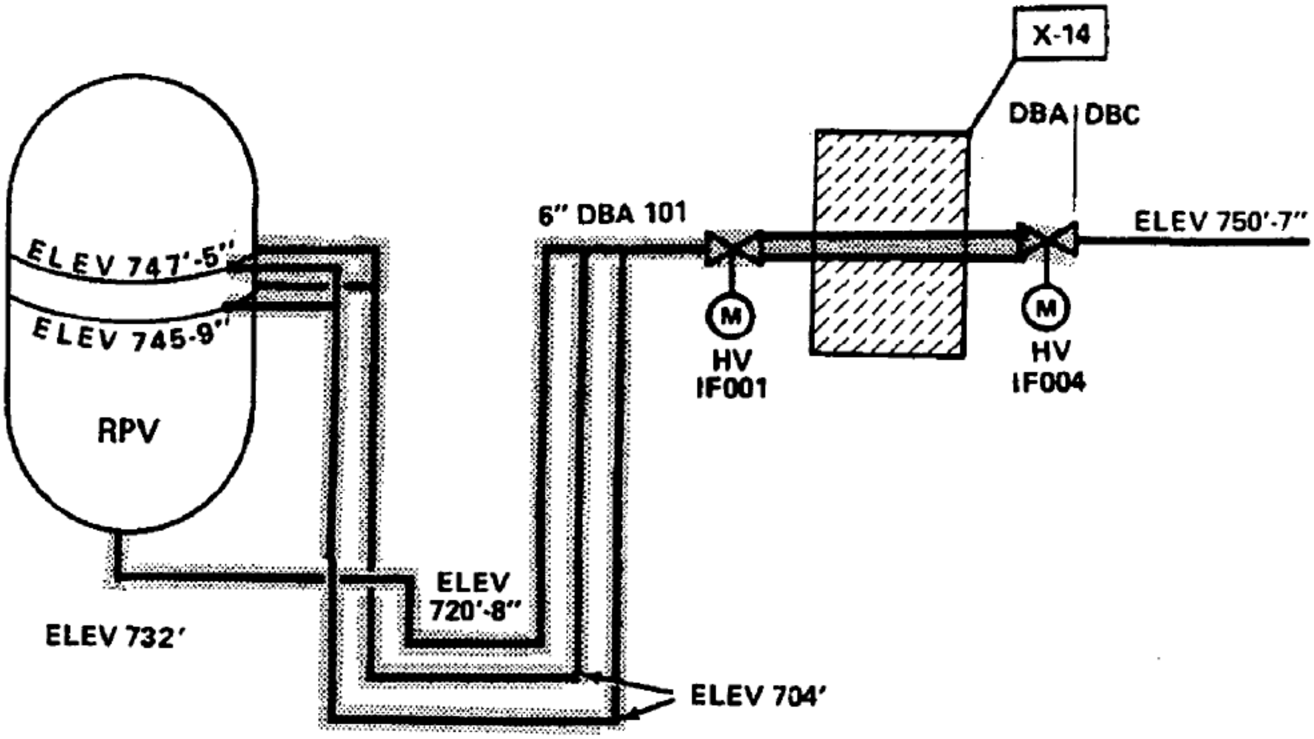
SUSQUEHANNA STEAM ELECTRIC STATION UNITS 1 & 2 FINAL SAFETY ANALYSIS REPORT
THIS FIGURE INTENTIONALLY LEFT BLANK FIGURE 6.2-66A, Rev. 49

AutoCAD Figure 6_2_66A.doc



NOTE 1: ALL PIPING SEISMIC CAT. 1

NOTE 2: DBA PIPING IS QUALITY GROUP A.

NOTE 3: WATER SEALED PIPING.

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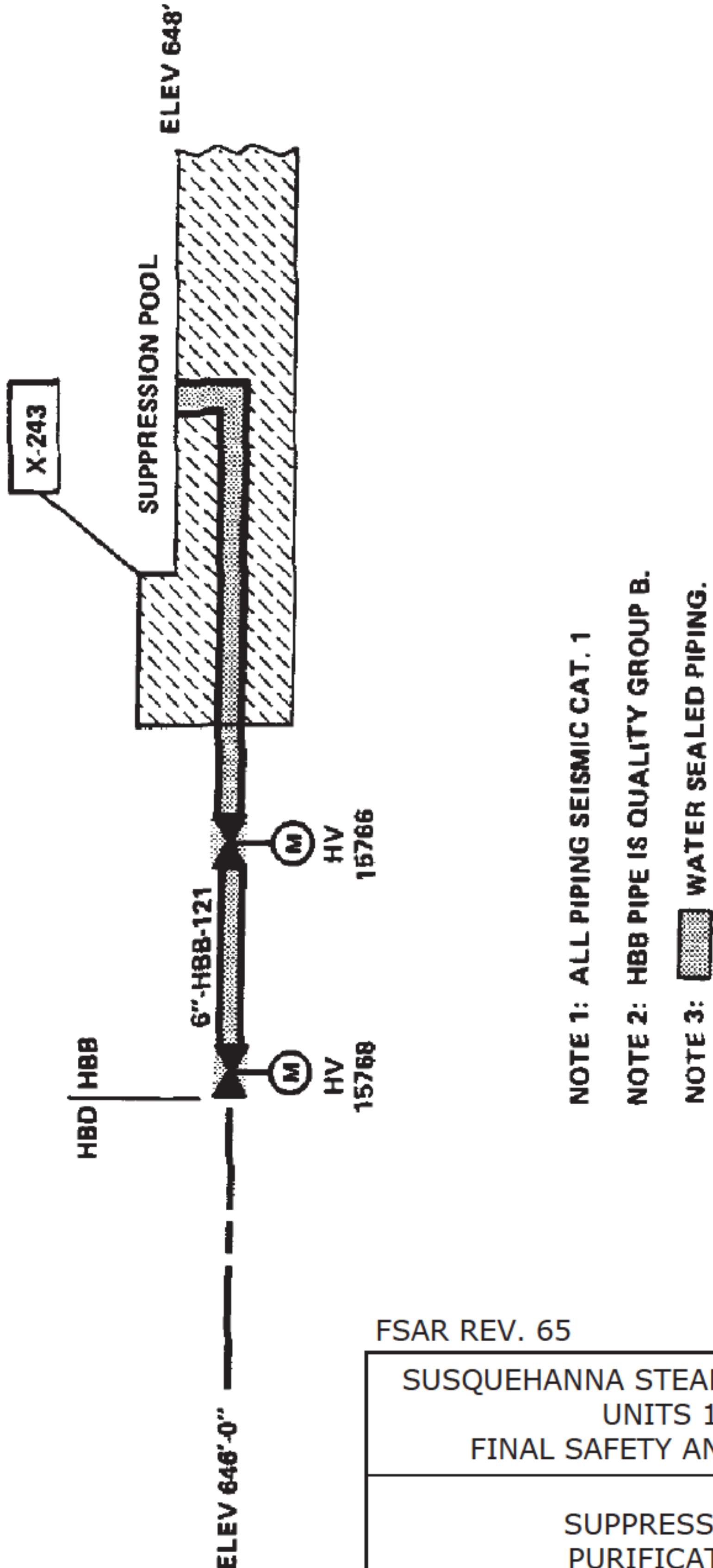
RWCU LINE PENETRATION

FIGURE 6.2-66B, Rev. 49

Auto Cad: Figure Fsar 6_2_66B.dwg



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SUSQUEHANNA STEAM ELECTRIC STATION
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SUPPRESSION POOL
PURIFICATION LINE
PENETRATION

FIGURE 6.2-66C, Rev. 49

Auto Cad: Figure Fsar 6_2_66C.dwg

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UNITS 1 & 2
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FIGURE 6.2-66D, Rev. 52

AutoCAD Figure 6_2_66D.doc

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UNITS 1 & 2
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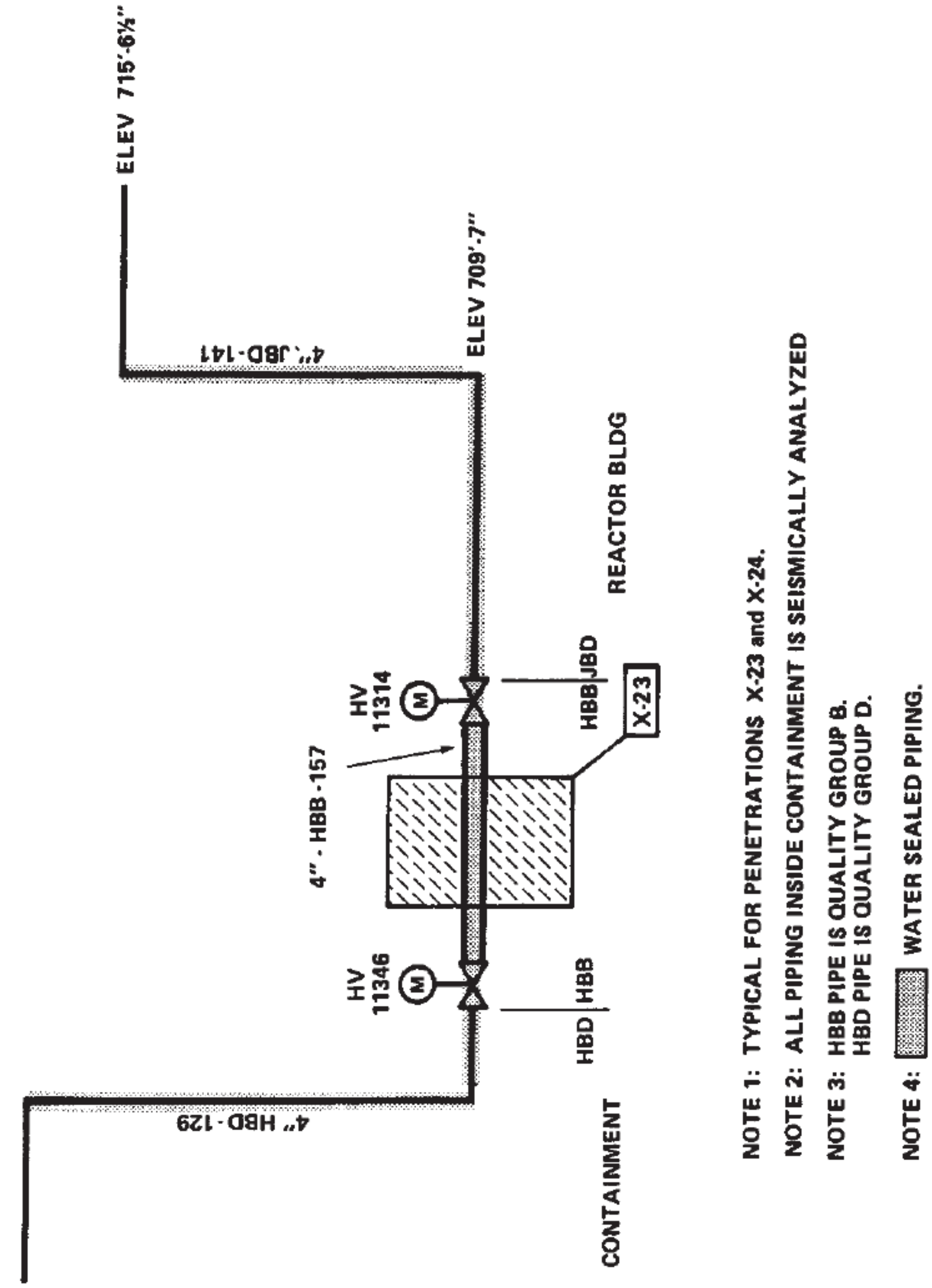
FIGURE 6.2-66E, Rev. 52

AutoCAD Figure 6_2_66E.doc



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SUSQUEHANNA STEAM ELECTRIC STATION
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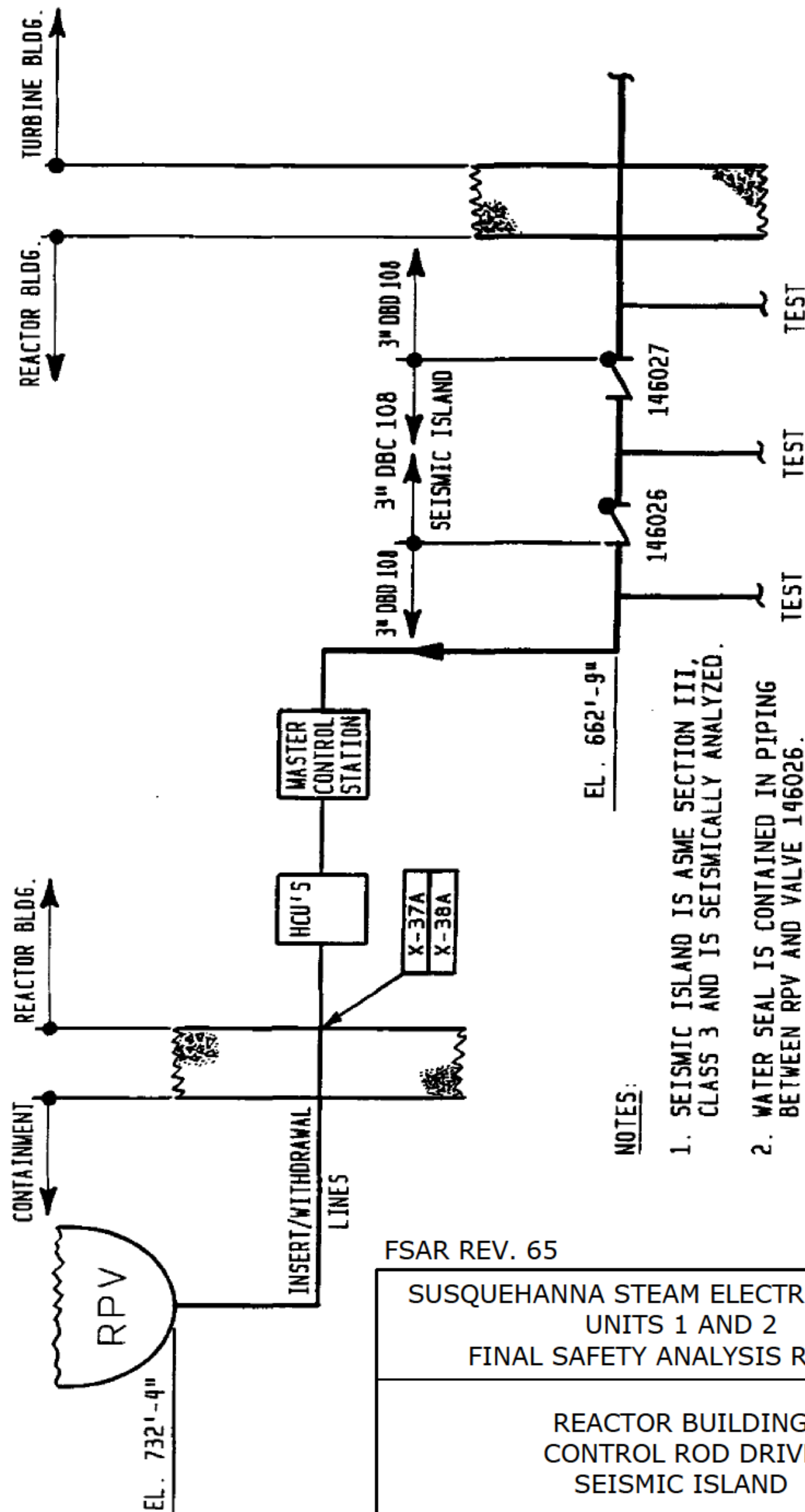
REACTOR BUILDING CLOSED
COOLING WATER LINE
PENETRATION

FIGURE 6.2-66F, Rev. 49

Auto Cad: Figure Fsar 6_2_66F.dwg



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SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 AND 2
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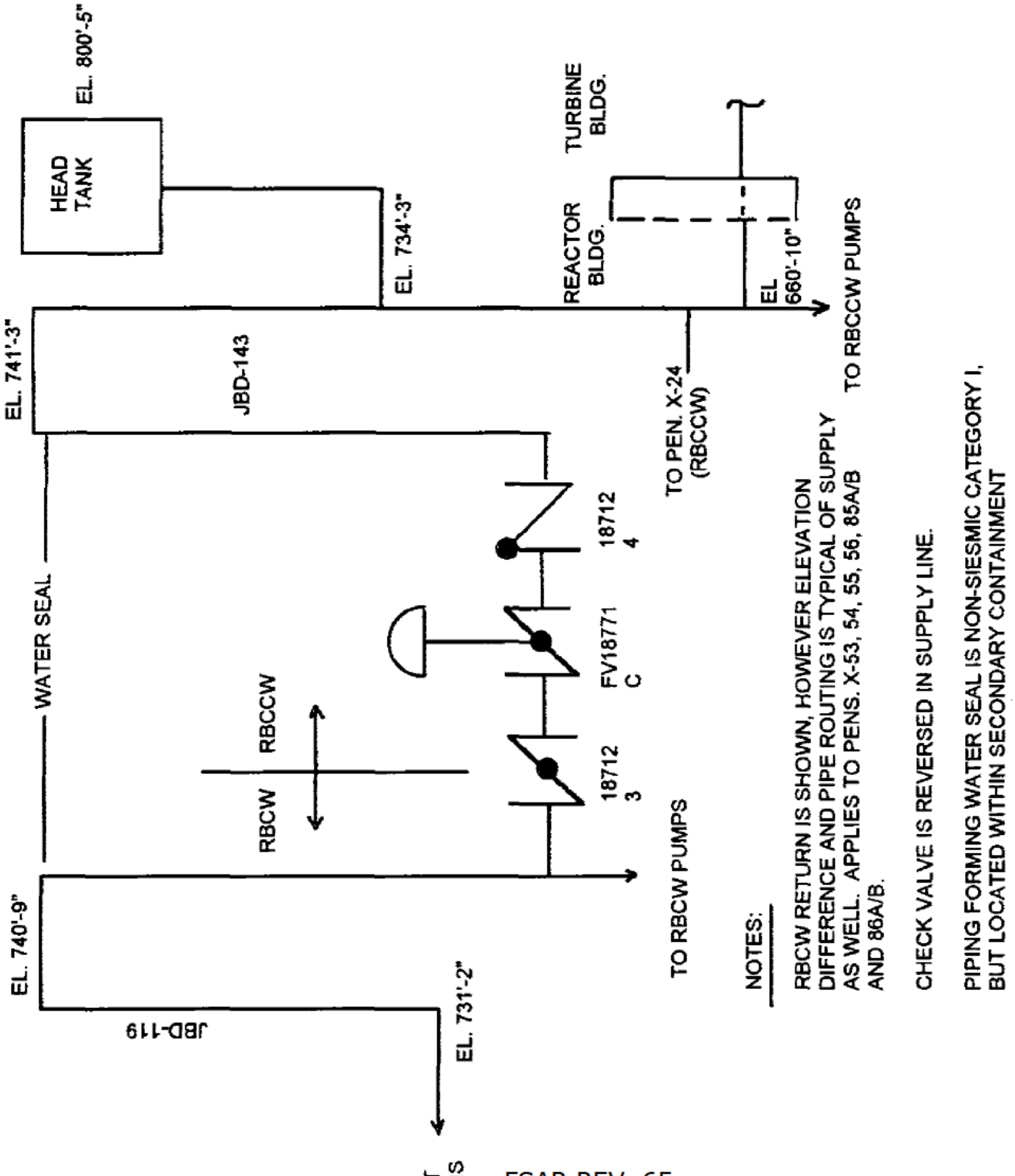
REACTOR BUILDING
CONTROL ROD DRIVE
SEISMIC ISLAND

FIGURE 6.2-66G, Rev. 49

Auto Cad: Figure Fsar 6_2_66G.dwg



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RBCCW SUPPLY/RETURN LINES
AT THE REACTOR BLDG. TO TURBINE
BLDG. INTERFACE

FIGURE 6.2-66H, Rev. 54

Auto Cad: Figure Fsar 6_2_66H.dwg

FIGURE DELETED

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FIGURE DELETED

FIGURE 6.2-7-1, Rev. 57

AutoCAD Figure 6_2_7_1.doc

FIGURE DELETED

FSAR REV. 65

FIGURE DELETED

FIGURE 6.2-7-2, Rev. 57

AutoCAD Figure 6_2_7_2.doc

FIGURE DELETED

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FIGURE DELETED

FIGURE 6.2-7-3, Rev. 56

AutoCAD Figure 6_2_7_3.doc

FIGURE DELETED

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SUSQUEHANNA STEAM ELECTRIC STATION
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FIGURE DELETED

FIGURE 6.2-8-1, Rev. 57

AutoCAD Figure 6_2_8_1.doc

FIGURE DELETED

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FIGURE DELETED

FIGURE 6.2-8-2, Rev. 57

AutoCAD Figure 6_2_8_2.doc

FIGURE DELETED

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FIGURE DELETED

FIGURE 6.2-8-3, Rev. 56

AutoCAD Figure 6_2_8_3.doc

FIGURE DELETED

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FIGURE DELETED
FIGURE 6.2-9-1, Rev. 52

AutoCAD Figure 6_2_9_1.doc

FIGURE DELETED

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SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
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FIGURE DELETED

FIGURE 6.2-9-2, Rev. 52

AutoCAD Figure 6_2_9_2.doc

FIGURE DELETED

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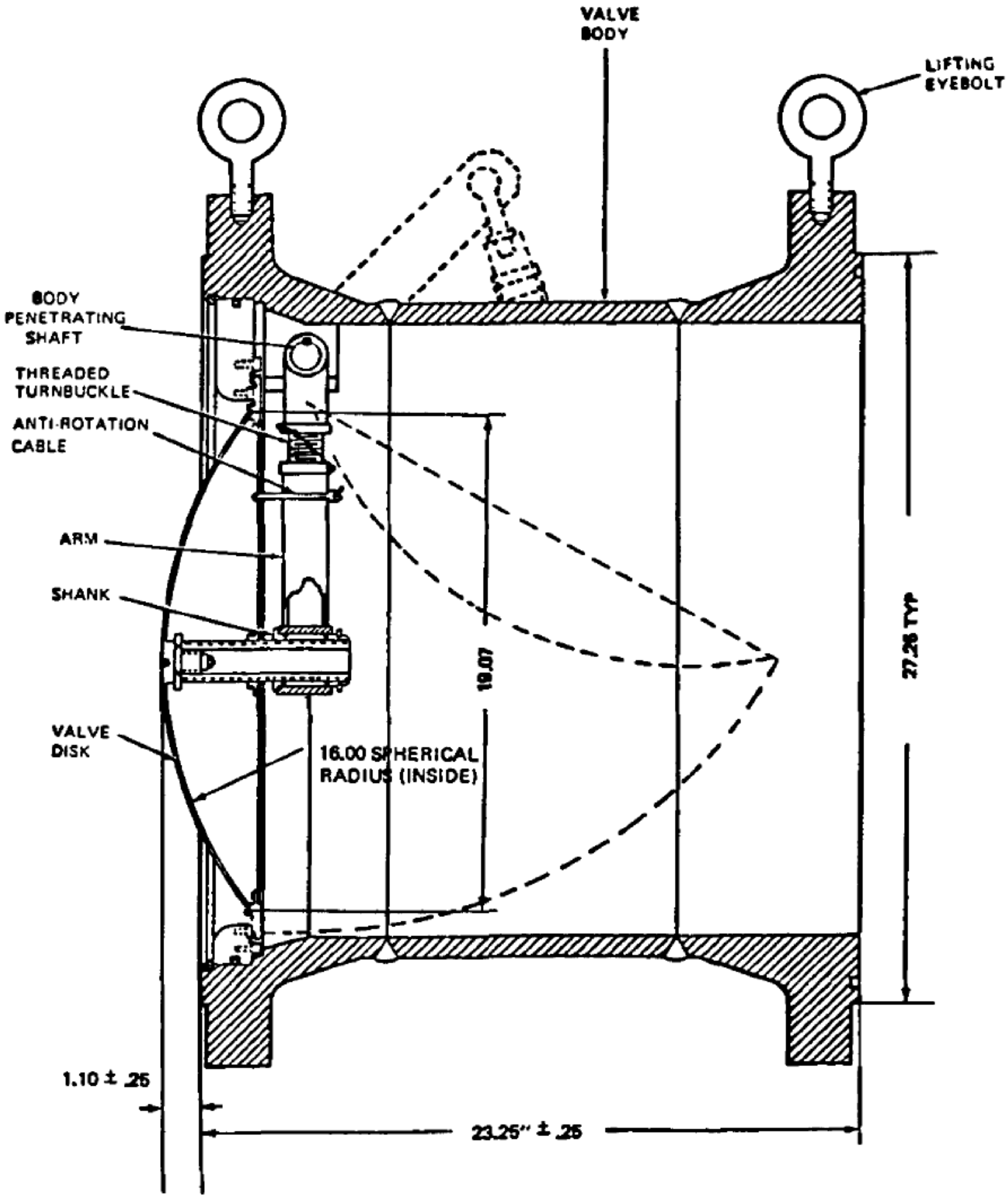
FIGURE DELETED

FIGURE 6.2-9-3, Rev. 51

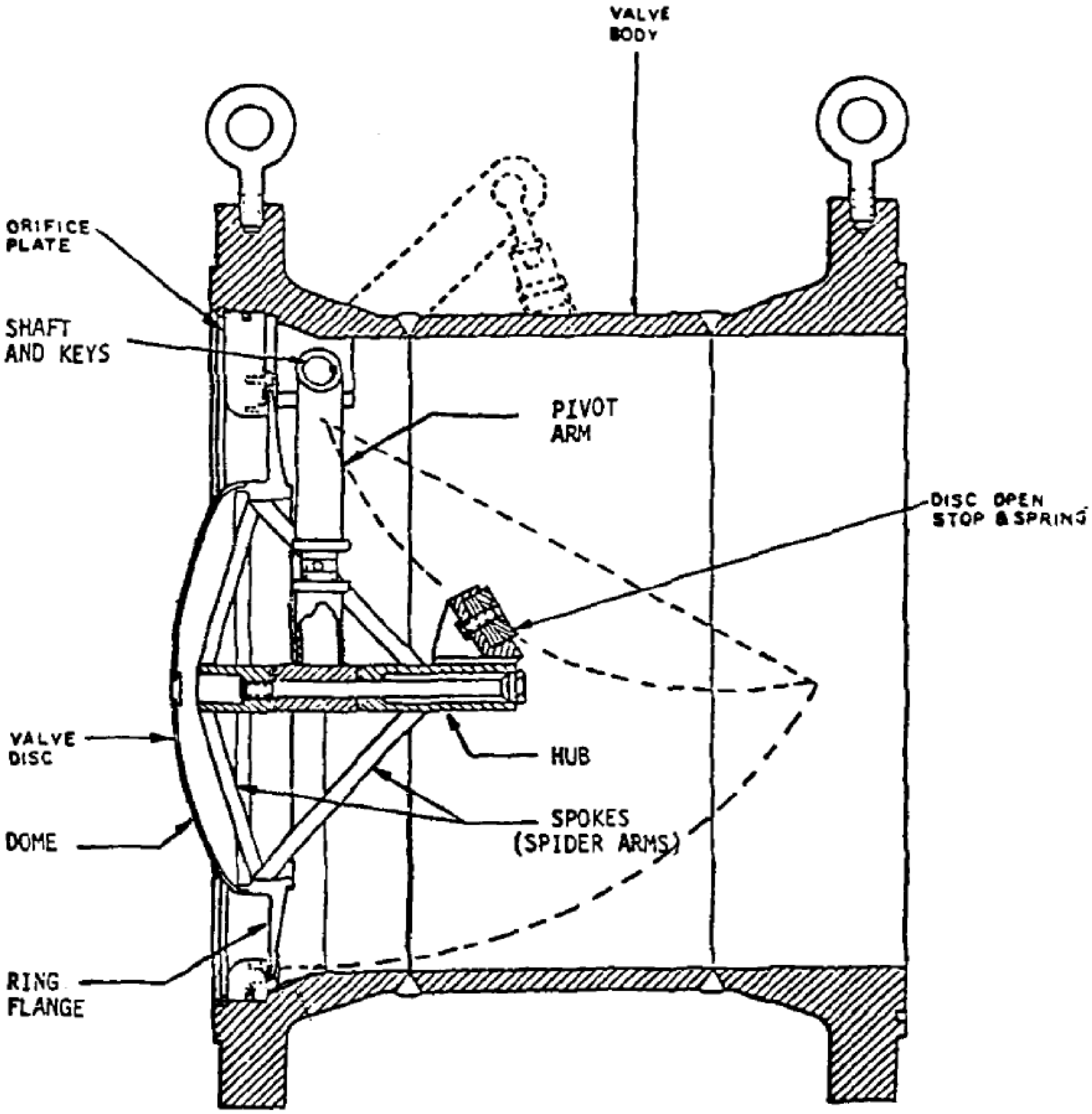
AutoCAD Figure 6_2_9_3.doc



FSAR REV. 65

SUSQUEHANNA STEAM ELECTRIC STATION UNITS 1 AND 2 FINAL SAFETY ANALYSIS REPORT
VACUUM BREAKER DISC/ARM ASSEMBLY UNIT 1 FIGURE 6.2-57-1, Rev. 48

Auto Cad: Figure Fsar 6_2_57_1.dwg



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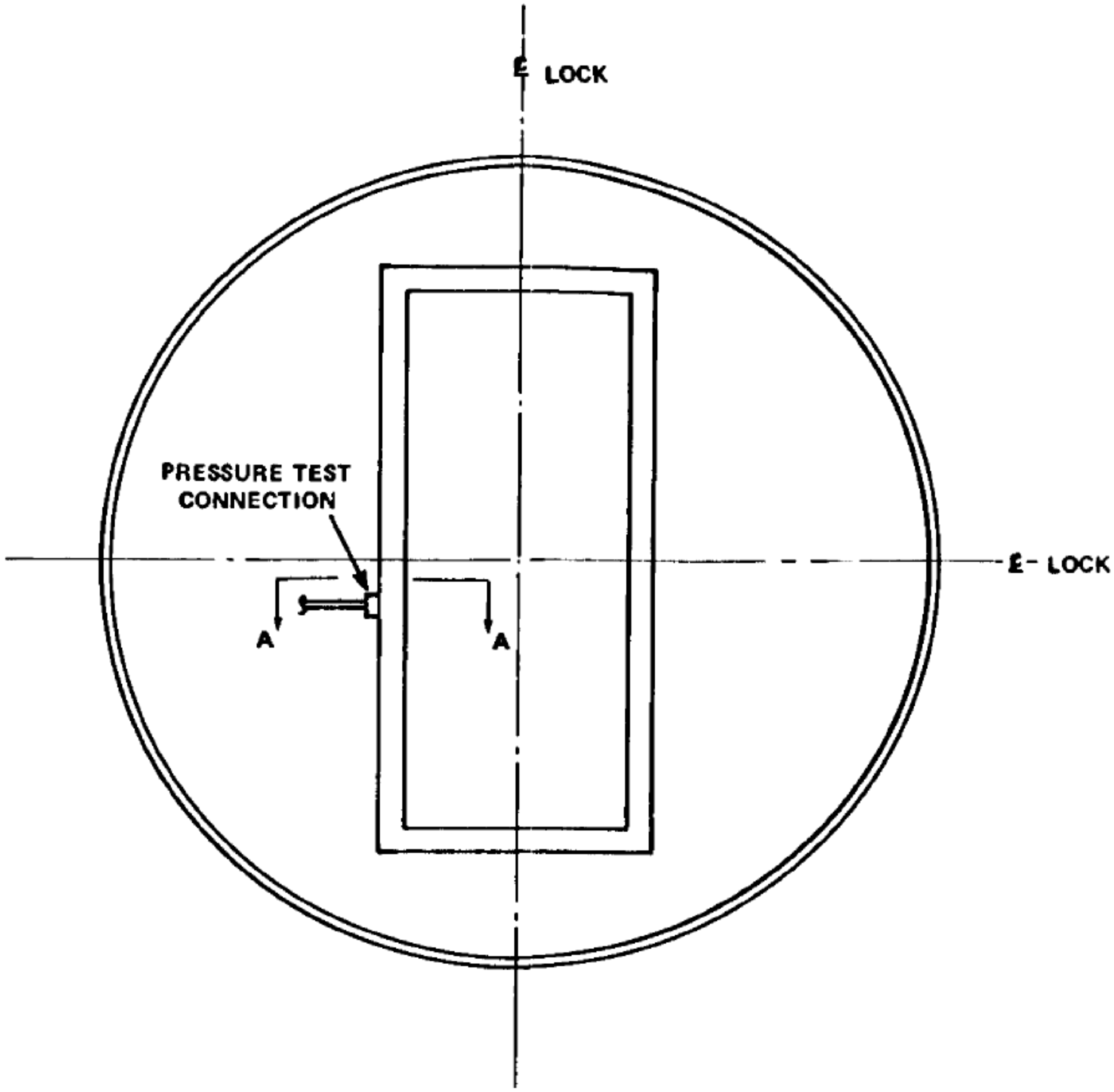
SUSQUEHANNA STEAM ELECTRIC STATION UNITS 1 AND 2 FINAL SAFETY ANALYSIS REPORT
VACUUM BREAKER DISC/ARM ASSEMBLY UNIT 2 FIGURE 6.2-57-2, Rev. 48

Auto Cad: Figure Fsar 6_2_57_2.dwg



ELEVATION VIEW OF
INTERIOR OR EXTERIOR BULKHEAD

FSAR REV. 65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 AND 2
FINAL SAFETY ANALYSIS REPORT

CONTAINMENT PERSONNEL
LOCK DOOR SEALS

FIGURE 6.2-58-1, Rev. 48

Auto Cad: Figure Fsar 6_2_58_1.dwg

FSAR REV. 65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 AND 2
FINAL SAFETY ANALYSIS REPORT

CONTAINMENT PERSONNEL
LOCK DOOR SEALS

FIGURE 6.2-58-2, Rev. 48

Auto Cad: Figure Fsar 6_2_58_2.dwg

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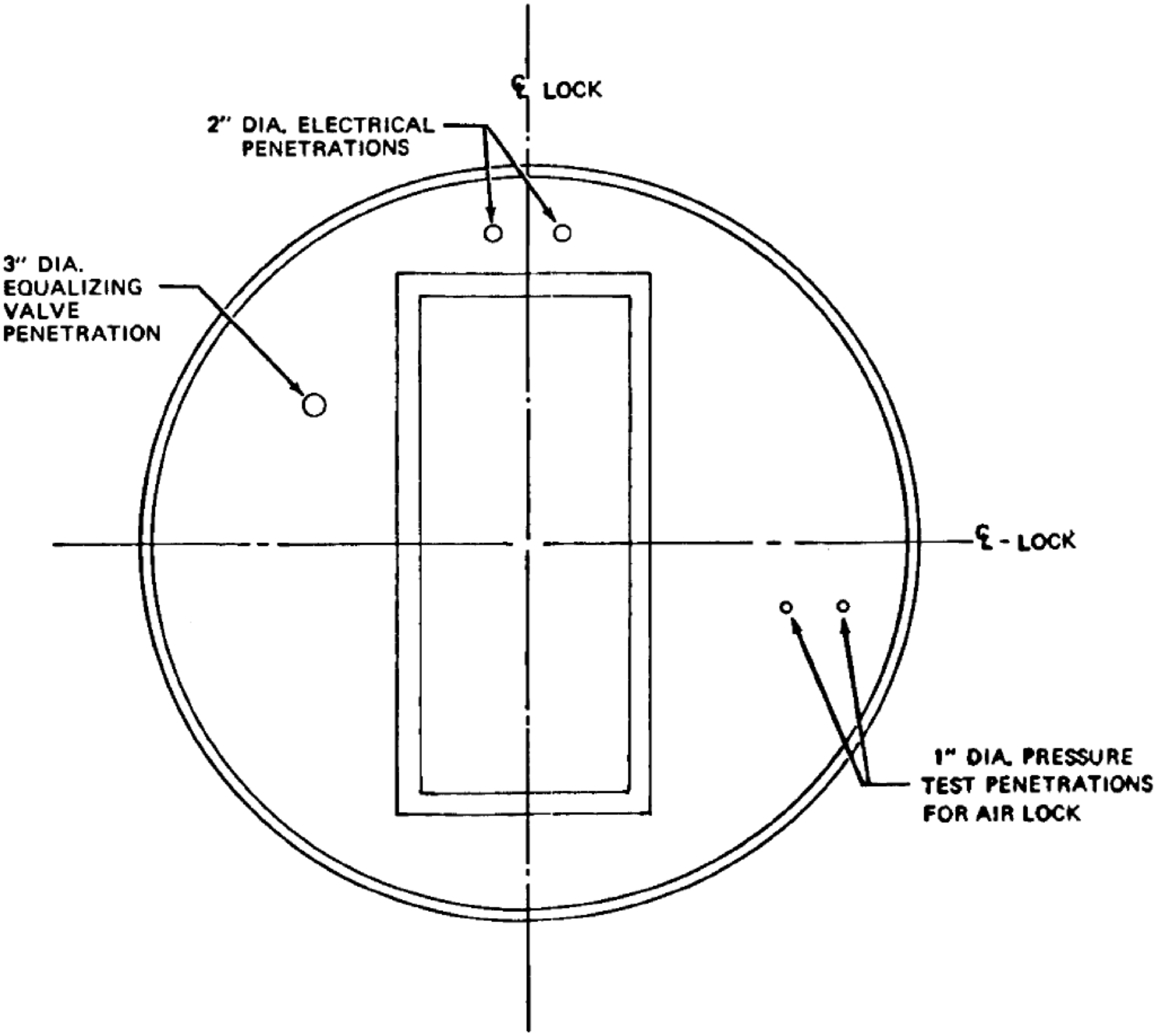
SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 AND 2
FINAL SAFETY ANALYSIS REPORT

CONTAINMENT PERSONNEL
LOCK DOOR PENETRATIONS

FIGURE 6.2-57A-1, Rev. 48

Auto Cad: Figure Fsar 6_2_57A_1.dwg



ELEVATION VIEW OF
EXTERIOR BULKHEAD

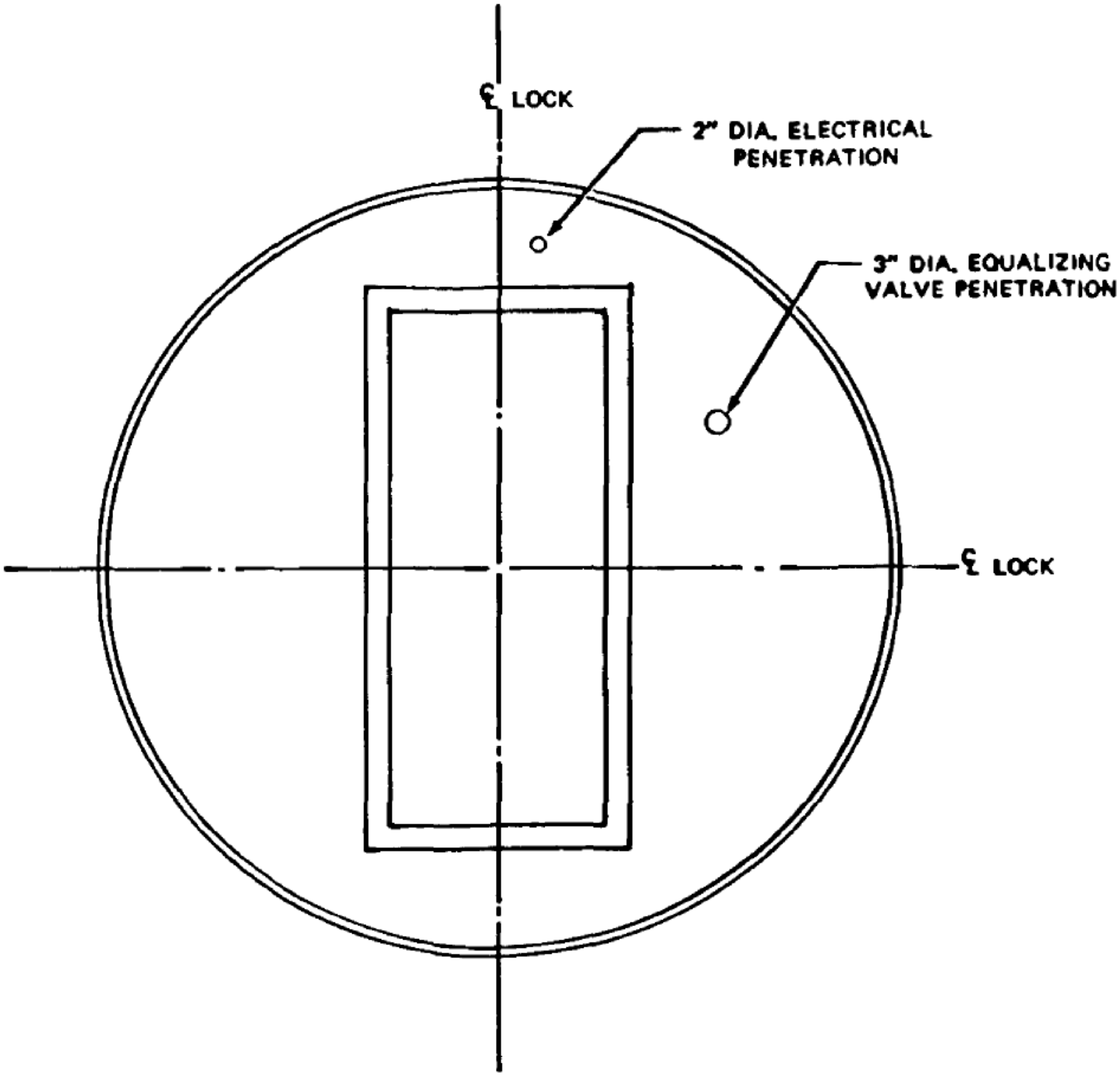
FSAR REV. 65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 AND 2
FINAL SAFETY ANALYSIS REPORT

CONTAINMENT PERSONNEL
LOCK DOOR PENETRATIONS

FIGURE 6.2-57A-2, Rev. 48

Auto Cad: Figure Fsar 6_2_57A_2.dwg



ELEVATION VIEW OF INTERIOR BULKHEAD

FSAR REV. 65

SUSQUEHANNA STEAM ELECTRIC STATION UNITS 1 AND 2 FINAL SAFETY ANALYSIS REPORT
CONTAINMENT PERSONNEL LOCK PENETRATIONS FIGURE 6.2-57A-3, Rev. 48

Auto Cad: Figure Fsar 6_2_57A_3.dwg

6.3 EMERGENCY CORE COOLING SYSTEMS

6.3.1 DESIGN BASES AND SUMMARY DESCRIPTION

Subsection 6.3.1 provides the design bases for the Emergency Core Cooling System (ECCS) and a summary description of the several systems as an introduction to the more detailed design descriptions provided in Subsection 6.3.2 and the performance analysis provided in Subsection 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 (LOCA) caused by ruptures in primary system piping. The functional requirements, (for example, coolant delivery rates) specified in detail in Table 6.3-2B for Unit 1 and Table 6.3-2C for Unit 2, are such that the system performance under all LOCA conditions postulated in the design satisfies the requirements of 10CFR50.46. These requirements, the most important of which is that the post-LOCA peak cladding temperature be limited to 2200^{o}F, are summarized in Subsection 6.3.3.2. In addition, the ECCS is designed to meet the following requirements:

1) Protection is provided for any primary line break up to and including the double-ended break of the largest line.

2) Two independent and diverse cooling methods (flooding and spraying) are provided to cool the core.

3) One high pressure cooling system is provided which is capable of maintaining water level above the top of the core and preventing ADS actuation for breaks of lines less than 1 inch nominal diameter.

4) With one exception, no operator action is required until 20 minutes after an accident to allow for operator assessment and decision. The only operator action assumed in the Section 6.3 ECCS analysis is that a RHR heat exchanger is placed in service within 20 minutes into the accident.

5) The ECCS is designed to satisfy all criteria specified in Section 6.3 for any normal mode of reactor operation.

6) A sufficient water source and the necessary piping, pumps and other hardware are provided so that the containment and reactor core can be flooded for possible core heat removal following a loss-of-coolant accident.

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) In order to meet the above requirements, the ECCS network has built-in redundancy so that adequate cooling can be provided, even in the event of specified failures. The following equipment makes up the ECCS:

   High Pressure Coolant Injection System (HPCI)
   Core Spray System (CS) (2 loops)
   Low Pressure Coolant Injection System (LPCI) (2 loops)
   Automatic Depressurization System (ADS)

3) The system is designed so that a single active or passive component failure, including power buses, electrical and mechanical parts, cabinets, and wiring will not disable the ADS.

4) In the event of a break in a pipe that is not a part of the ECCS, no single active component failure in the ECCS prevents automatic initiation and successful operation of less than the combination of ECCS equipment shown in Table 6.3-5 for a recirculation suction break (non-ECCS line break).

5) In the event of a break in a pipe that is a part of the ECCS, no single active component failure in the ECCS prevents automatic initiation and successful operation of less than the combination of ECCS equipment shown in Table 6.3-5 for a recirculation discharge break (ECCS line break).

   These are the minimum ECCS combinations which result after assuming the failures (from 4 above) and assuming that the ECCS line break disables a LPCI system loop.

6) Long-term cooling requires the removal of decay heat via the RHRSW system. In addition to the break which initiated the loss of coolant event, the system is able to sustain one failure, either active or passive, and still have at least one LPCI pump or one CS loop for makeup, and one RHR pump with a heat exchanger (including 100% RHRSW flow to the operating heat exchanger) for heat removal.

7) Off-site power is the preferred source of power for the ECCS network and every reasonable precaution is made to assure its high availability. However, on-site emergency power is provided with sufficient diversity and capacity so that all the above requirements are met even if off-site power is not available.

8) The on-site diesel fuel reserve is designed in accordance with IEEE-308 criteria as stated in Subsection 7.1.2.5.2.

9) Diesel-load configuration is 1 LPCI pump and 1 CS pump connected to a single diesel generator. (Typical for four aligned diesels in a one unit LOCA.)

10) Systems which 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.

11) Non-ECCS systems interfacing with the ECCS buses are automatically shed from and/or are initially inhibited from the ECCS buses of the affected unit when a LOCA signal exists and off-site AC power is not available.

12) No more than one storage battery is connectable to a DC power bus.

13) Each low pressure system 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.

14) Provisions for testing the ECCS network components (electronic, mechanical, hydraulic and pneumatic, as applicable) are installed in such a manner that they are an integral and non-separable part of the design.

6.3.1.1.3 ECCS Requirements for Protection from Physical Damage

The emergency core cooling system piping and components are protected against damage from movement, from thermal stresses, from the effects of the LOCA and the Safe Shutdown Earthquake. The ECCS is protected against the effects of pipe whip, which might result from piping failures up to and including the LOCA. This protection is provided by separation, pipe whip restraints, or energy absorbing materials if required. Any of these three methods will be applied to provide protection against damage to piping and components of the ECCS which otherwise could result in a reduction of ECCS effectiveness to an unacceptable level.

Mechanical separation outside the drywell is achieved as follows:

1) The ECCS shall be separated into three functional groups:

    a. HPCI

    b. CS(A&C) + LPCI(A&C)

    c. CS(B&D) + LPCI(B&D)

2) The equipment in each group shall be separated from that in the other two groups. In addition, the HPCI and the RCIC (which is not part of the ECCS) shall be separated.

3) Separation barriers shall be constructed between the functional groups as required to assure that environmental disturbances such as fire, pipe rupture, falling objects, etc., affecting one functional group will not adversely affect the remaining groups. In addition, separation barriers shall be provided as required to assure that such disturbances do not affect both RCIC and HPCI. For additional discussion, refer to Section 3.12.

6.3.1.1.4 ECCS Environmental Design Basis

The low pressure systems of the ECCS have testable check valves in the drywell portions of their respective piping runs. These safety-related, injection/isolation valves are designed for abnormal environmental requirements.

The ECCS equipment (e.g., pumps, motors) is qualified for abnormal environmental requirements.

Abnormal environmental conditions to which these components are qualified or designed are described in Section 3.11.

For a listing of all safety-related valves located in the drywell subject to spray impingement from the containment Spray System, see Table 6.3-10. No safety-related valves become submerged because of spray from the Containment Spray System.

6.3.1.2 Summary Descriptions of ECCS

The ECCS injection network comprises a high pressure coolant injection (HPCI) system, a low pressure core spray (CS) system and the low pressure coolant injection (LPCI) mode of the Residual Heat Removal System. These systems are briefly described here as an introduction to the more detailed system design descriptions provided in Subsection 6.3.2. The Automatic Depressurization System (ADS) which assists the injection network under certain conditions is also briefly described. Boiling water reactors which employ the same ECCS design are listed in Table 1.3-3.

6.3.1.2.1 High Pressure Coolant Injection

The HPCI pumps water through the feedwater sparger. The primary purpose of HPCI is to maintain reactor vessel inventory after small breaks which do not depressurize the reactor vessel.

6.3.1.2.2 Core Spray

The two loops pump water into peripheral ring spray spargers mounted above the reactor core. The primary purpose of CS is to provide inventory makeup and spray cooling during large breaks in which the core is calculated to uncover. When assisted by ADS, CS also provides protection for small breaks.

6.3.1.2.3 Low Pressure Coolant Injection

LPCI is an operating mode of the Residual Heat Removal System. Four pumps deliver water from the suppression pool to the recirculation lines. The primary purpose of LPCI is to provide vessel inventory makeup following large pipe breaks. When assisted by ADS, LPCI also provides protection for small breaks.

6.3.1.2.4 Automatic Depressurization System

ADS utilizes a number of the reactor safety/relief valves to reduce reactor pressure during small breaks in the event of HPCI failure. When the vessel pressure is reduced to within the capacity of the low pressure systems (CS and LPCI), these systems provide inventory makeup so that acceptable post accident temperatures are maintained.

6.3.2 SYSTEM DESIGN

More detailed descriptions of the individual systems including individual design characteristics are provided in Subsections 6.3.2.1 through 6.3.2.4. The following discussion will provide details of the combined systems; and in particular, those design features and characteristics which are common to all systems.

6.3.2.1 Schematic Piping and Instrumentation Diagrams

The P&IDs and process diagrams for the ECCS are identified in Subsection 6.3.2.2.

6.3.2.2 Equipment and Component Descriptions

The starting signal for the ECCS comes from at least two independent and redundant sensors of high drywell pressure, low RPV pressure, and low reactor water level. The ECCS is actuated automatically and with one exception requires no operator action during the first 20 minutes following the accident. The only operator action assumed in the Section 6.3 ECCS analysis is that a RHR heat exchanger is placed in service within 20 minutes into the accident. A time sequence for a Design Basis LOCA analysis showing starting of the systems is provided in Table 6.3-1B-2 for Unit 1 and Table 6.3-1B-3 for Unit 2.

Electric power for operation of the ECCS (except the dc powered HPCI system) is from the preferred offsite ac power supply. Upon loss of the preferred source, operation is from the onsite standby diesel generators. Four diesel generators supplying individual ac buses have sufficient diversity and capacity so that failure of one diesel satisfies ECCS requirements. Section 8.3 contains a more detailed description of the power supplies for the ECCS.

6.3.2.2.1 High Pressure Coolant Injection (HPCI) System

The high pressure coolant injection (HPCI) system consists of a steam turbine driven constant-flow pump assembly, associated system piping, valves, controls, and instrumentation. The P&ID for HPCI, Dwgs. M-155, Sh. 1 and M-156, Sh. 1, shows the system components and their arrangement. The HPCI system Process Diagram, Dwg. M1-E41-4, Sh. 1, shows the design operating modes of the system.

The HPCI system equipment is installed in the reactor building. Suction piping comes from both the condensate storage tank and the suppression pool. Injection water is piped to the reactor feedwater line. Steam supply for the turbine is piped from a main steamline in the primary containment. This piping is provided with an isolation valve on each side of the primary containment. Remote controls for valve and turbine operation are provided in the main control room. The controls and instrumentation of the HPCI system are described, illustrated, and evaluated in Section 7.3.

The HPCI system is provided to ensure that the reactor core is adequately cooled to meet the design bases in the event of a small break in the reactor coolant pressure boundary (RCPB) and loss of coolant that does not result in rapid depressurization of the reactor vessel. This permits the plant to be shut down while maintaining sufficient reactor vessel water inventory until the reactor vessel is depressurized. The HPCI system continues to operate until the reactor vessel pressure is below the pressure at which LPCI operation or core spray system operation can maintain core cooling.

The HPCI system is designed to pump water into the reactor vessel for a wide range of pressures in the reactor vessel. Initially, demineralized water from the condensate storage tank is used instead of injecting water from the suppression pool into the reactor. Water from either source is pumped into the reactor vessel through the feedwater spargers.

The level instrumentation on the condensate storage tank is used to automatically transfer the HPCI suction from the condensate storage tank to the suppression pool at a level determined by conservative NPSH calculations. The calculations ensure adequate NSPH during the transfer process and ensure there is no unacceptable vortex formation in the suction lines during the transfer process. This suction transfer can be remotely overridden to realign suction to the CST. The portion of the suction piping exposed to outside air temperatures is protected from cold weather effects both by heat tracing and by insulation.

The temperature of the level instrumentation is monitored by temperature instrumentation which alarms in the control room if the temperature falls below 40^{o}F.

The pump assembly is located below the level of the condensate storage tank and below the water level in the suppression pool 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 is calculated using the assumptions of Regulatory Guide 1.1 (12/70). The NPSH calculations are shown in Sections 6.3.2.2.1.1 and 6.3.2.2.1.2. The required NPSH is shown in Table 6.3-8. See also Figure 6.3-3a.

The HPCI turbine-pump assembly and piping are protected from detrimental physical effects of the DBA, 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 which is generated by decay and residual heat. The steam is extracted from a main steamline upstream of the main steamline isolation valves. The inboard and outboard HPCI isolation valves in the steamline 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 supply valve adjacent to the turbine.

A condensate drain pot is provided upstream of the turbine stop valve to prevent the HPCI steam supply line from filling with water. The drain pot normally routes the condensate to the main condenser, but upon receipt of a HPCI initiation signal or a loss of control air pressure, isolation valves on the condensate line automatically close.

The turbine power is controlled by a flow controller, sensing pump discharge flow and providing a variable signal (1-5 volts DC) 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 valve to indicate fully open and closed positions. Both lights shall be "on" 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 core cooling to prevent clad temperatures in excess of the limits (10CFR50.46) while the pressure in the reactor vessel is above the pressure at which core spray and LPCI become effective.

Exhaust steam from the HPCI turbine is discharged to 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 barometric condenser.

The HPCI turbine gland seals are routed to the barometric condenser for cooling and containment of radioactive steam. Noncondensable gases from the barometric condenser are pumped to the Standby Gas Treatment System.

The check valves and two isolation valves are provided in the vacuum breaker line which connects the air space in the suppression chamber with the HPCI turbine exhaust line. This eliminates any possibility of water from the suppression pool being drawn into the HPCI turbine exhaust line. The isolation valve in this vacuum breaker line operates automatically via a combination of low reactor pressure and high drywell pressure. Test connections are provided on either side of the two check valves.

Startup of the HPCI system is completely independent of ac power. Only dc power from the station battery and steam extracted from the nuclear system are necessary.

The various operations of the HPCI components are summarized as follows:

The HPCI controls automatically start the system and bring it to design flowrate within 30 seconds from receipt of a reactor pressure vessel (RPV) low water level signal or a primary containment (drywell) high pressure signal. Refer to Chapter 15 for more analysis details.

The HPCI turbine is shut down automatically by any of the following signals:

1) Turbine overspeed - This prevents damage to the turbine.

2) RPV high water level - This indicates that core cooling requirements are satisfied.

3) HPCI pump low suction pressure - This prevents damage to the pump due to loss of flow.

4) HPCI turbine exhaust high pressure - This indicates a turbine or turbine control malfunction.

If an initiation signal is received after the turbine is shut down, the system will restart automatically if no shutdown signals exists.

Additionally, because the steam supply line to the HPCI turbine is part of the RCPB, certain signals automatically isolate this line, causing shutdown of the HPCI turbine. The auto isolation signal will not clear until manually reset after the clearance of all isolation signals. Automatic shutoff of the steam supply is described in Section 7.3. However, automatic depressurization and the low pressure systems of the ECCS act as backup, and automatic shutoff of the steam supply does not negate the ability of the ECCS to satisfy the safety objective.

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) HPCI pump discharge shutoff valves
2) HPCI steam admission valve
3) HPCI turbine stop valve
4) HPCI turbine control valve
5) HPCI steamline drain isolation valves
6) HPCI test return valve to CST if open
7) Minimum flow bypass valve

Prior to startup, the turbine control system will be held at the low speed design condition. Upon receipt of an initiating signal a speed ramp generator module will automatically run the control system toward its high speed design point, thereby controlling the transient acceleration of the turbine. The flow controller will automatically over-ride the speed ramp generator and 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.

Startup of the auxiliary oil pump and proper functioning of the hydraulic control system is required to open the turbine stop and control valves. Operation of the barometric condenser components is required to prevent outleakage 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.

A minimum flow bypass is provided for pump protection. The bypass valve automatically opens on a low flow signal if the HPCI pump discharge pressure permissive is present, and automatically closes on a high flow signal. When the bypass is open, flow is directed to the suppression pool.

A line used for system testing leads from the HPCI pump discharge line to the condensate storage tank. The shutoff valves in this line are sequenced closed upon HPCI system initiation. To prevent pumping suppression pool water to the CST, these valves are also interlocked closed when the pump suction valve from the suppression pool is open. All automatically operated valves are equipped with a remote manual functional test feature.

The HPCI system initially injects water from the condensate storage tank. When the water level in the tank falls below some predetermined level, the pump suction is automatically transferred to the suppression pool. This level was determined by conservative calculations, which ensure that no unacceptable vortex formation would occur during the transfer process. In addition a vortex breaker is located at the suction nozzle of the CST to prevent vortex formation. Preoperational testing demonstrated that vortex formation did not occur. This test was performed with the condensate storage tank level at the transfer level, with the core spray pumps operating at 6000 gpm. This transfer may also be made from the main control room using remote controls. When the pump suction has been transferred to the suppression pool, a closed loop is established for recirculation of water escaping from a break. Suction can also be transferred to the CST if desired to access the remaining available volume.

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

The HPCI system incorporates a relief valve in the pump suction line to protect the components and piping from inadvertent overpressure conditions.

The HPCI pump and piping are positioned to avoid damage from the physical effects of design basis accidents, such as pipe whip, missiles, high temperature, pressure, and humidity.

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

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

1) A full flow test line is provided to route water to the condensate storage tank without entering the reactor pressure vessel.

2) A minimum flow bypass test line is provided to route water to the suppression pool without entering the reactor pressure vessel.

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

4) All motor-operated valves are capable of either local or remote manual operation for test purposes.

5) Drains are provided to leak test the major system valves.

The operating parameters for the components of the HPCI system, defined below, are shown on Dwg. M1-E41-4, Sh. 1.

1) One 100 percent capacity booster and main pump assembly and accessories

2) Piping, valves, and instrumentation for:

    a. Steam supply to the turbine

    b. Turbine exhaust to the suppression pool

    c. Supply from the condensate storage tank to the pump suction

    d. Supply from the suppression pool to the pump suction

e. Pump discharge to the feedwater line spargers, including a test line to the condensate storage tank, a minimum flow bypass line to the suppression pool, and a cooling water supply to accessory equipment.

The basis for the design conditions was the ASME Section III, Nuclear Power Plant Components. The design parameters for the HPCI system components are shown in Table 6.3-8.

6.3.2.2.1.1 NPSH Available with Suction from the Condensate Storage Tank

The available NPSH is calculated in accordance with Regulatory Guide 1.1. The following data was used in the calculation:

a. Condensate storage tank water level is conservatively assumed to be two feet below the transfer level.

b. Condensate storage tank water is at 100^{o}F.

c. Both HPCI and RCIC are in operation.

d. NPSHA = hs - hf + ha - hvpa

hs = static head
hf = friction head loss
ha = atmospheric pressure head
hvpa = vapor pressure

Unit I

hs = 673.75' - 650.25' = 23.5 ft.
hf = 7.1 ft.
ha = 33.16 ft.
hvpa = 2.2 ft.
NPSHA = 47.36 ft.

Unit II

hs = 673.75'-650.25' = 23.5 ft.
hf = 12.19 ft.
ha = 33.16 ft.
hvpa = 2.21 ft.
NPSHA = 42.26 ft.
NPSHR = 21 ft.

6.3.2.2.1.2 NPSH Available with Suction from the Suppression Pool

The available NPSH is calculated in accordance with Regulatory Guide 1.1. The following data was used in the calculation:

a. Suppression pool is at the minimum level of El. 668.5 feet. 668.5 El. is due to pool level drop for worst case passive failure in an ECCS pump room (Subsection 6.3-6).

b. Suppression pool water is at its maximum temperature for the given operating mode, 140°F.

c. Atmospheric pressure is assumed over the suppression pool.

d. NPSHA = hs - hf + ha - hvpa

hs = 668.5' - 650.25' = 18.25'
hf = 13.23 ft.
ha = 33.16 ft.
hvpa = 6.8 ft.
NPSHA = 31.4 ft. NPSHR = 21 ft.

6.3.2.2.2 Automatic Depressurization System (ADS)

If the RCIC and the HPCI cannot maintain the reactor water level, the automatic depressurization system, which is independent of any other system of the ECCS, reduces the reactor pressure so that flow from the LPCI and CS systems enters the reactor vessel in time to cool the core and limit any increase in fuel cladding temperature.

The automatic depressurization system 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 detail in Subsection 5.2.2. The operation of the ADS is discussed in Subsection 7.3.1.1a.1.4.

6.3.2.2.3 Core Spray (CS) System

Each of the two redundant core spray systems consists of: two 50% capacity centrifugal pumps that can be powered by normal auxiliary power or the standby ac power system; a spray sparger in the reactor vessel above the core (a separate sparger for each CS system); piping and valves to convey water from the suppression pool to the sparger; and associated controls and instrumentation. Dwg. M-152, Sh. 1, the CS system P&ID, presents the system components and their arrangement. The CS system Process Diagram, Dwg. M1-E21-15, Sh. 1, shows the design operating modes of the system. A simplified system flow diagram showing system injection into the reactor vessel is presented in Dwg. M1-E21-15, Sh. 1 for the CS system.

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

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

The core spray pump and all motor operated valves can be operated individually by manual switches located in the control room. Operating indication is provided in the control room by a flowmeter and valve indicator lights.

To assure continuity of core cooling, signals to isolate the containment do not operate any core spray system valves.

The discharge line to the reactor is provided with two isolation valves. One of these valves is a testable (with an air-operated solenoid valve) check valve located inside the drywell as close as practical to the reactor vessel. The check valve will move to the close position on loss of air and/or power. CS injection flow causes this valve to open during LOCA conditions (i.e., no power is required for valve actuation during LOCA). If the CS line should break outside the containment, the check valve in the line inside the drywell will prevent loss of reactor water outside the containment.

The other isolation valve (which is also referred to as the CS injection valve) is a motor operated gate valve located outside the primary containment as close as practical to the CS discharge line penetration into the containment. This valve is capable of opening with the maximum differential across the valve expected for any system operating mode. The valve stroke time is less than or equal to 19 seconds. This valve is normally closed to back up the inside testable check valve for containment integrity purposes.

The CS system components and piping are arranged to avoid unacceptable damage from the physical effect of design-basis accidents, such as pipe whip, missiles, high temperature, pressure and humidity.

All principal active CS equipment is located outside the primary containment.

A check valve (one per CS pump), and in each loop one flow element and restricting orifice are provided in the CS discharge line from the pump to the injection valve. The check valve is located below the minimum suppression pool water level and is provided so the piping downstream of the valve can be maintained full of water by the discharge line fill system (see Subsection 6.3.2.2.5). The flow element is provided to measure system flow rate during LOCA and test conditions and for automatic control of the minimum low flow bypass gate valve. The measured flow is indicated in the main control room. The restricting orifice was sized during pre-operational test of the system to limit system flow to acceptable values as described on the CS system Process Diagram. (Dwg. M1-E21-15, Sh. 1)

The CS pump (pump performance test results) characteristics, head, flow, horsepower, and required NPSH are shown in Figure 6.3-118.

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

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

The design pressure and temperature for various portions of the system were established in accordance with the ASME Section III Boiler and Pressure Vessel code and the required core spray system design specification written for this system. The original Core Spray System Process Diagram was used as input in the development of the design specification.

Each of the two redundant core spray systems takes suction from the suppression pool through a suction line that has two high capacity stacked disk strainers. The strainers have sufficient capacity to filter their design debris source term under worst case conditions while maintaining strainer pressure drop below the maximum value required to provide adequate NPSH and system flow. The design debris source term consists of conservative amounts of insulation, paint chips and other drywell debris that could reach the strainers after being destroyed by LOCA jet forces and transported to the suppression pool through the downcomers. This debris is assumed to be filtered by the strainers along with corrosion products that would exist in the suppression pool prior to a LOCA. Correlations between the amount of debris filtered by the strainers and strainer pressure drop are based on testing performed on one of the Susquehanna RHR strainers (which have a design similar to the CS strainers) and NRC approved methodology outlined in NEDO-32686, "Utility Resolution Guide for ECCS Suction Strainer Blockage". The suppression pools are cleaned and inspected periodically to maintain corrosion product amounts at acceptable levels and to confirm the absence of miscellaneous debris that would be a strainer blockage threat.

The CS pump is located in the reactor building below the water level in the suppression pool to assure positive pump suction. Pump NPSH requirements are met with the containment at atmospheric pressure. A pressure gage is provided to indicate the suction head. The available NPSH has been calculated in accordance with NRC Regulatory Guide 1.1. The CS pump characteristics are shown in Figure 6.3-118.

The CS system incorporates relief valves to prevent the components and piping from inadvertent overpressure conditions. One relief valve, located on the pump discharge, is set at 500 psig with a capacity of 100 gpm at 10% accumulation. The second relief valve is located on the suction side of the pump and is set for 100 psig at a capacity of 10 gpm at 10% accumulation.

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

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

1) All active CS components are testable during normal plant operation.

2) A full flow test line is provided to route water from and to the suppression pool without entering the reactor pressure vessel.

3) A suction test line supplying reactor grade water, is provided to test pump discharge into the reactor pressure vessel during normal plant shutdown.

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

5) All motor-operated valves and check valves are capable of operation for test purposes. The Core Spray pump discharge check valves (152/252 F003A,B,C,&D) have local disc position indication on the valve hinge pins.

6.3.2.2.3.1 NPSH Available for CS

The available NPSH is calculated in accordance with Regulatory Guide 1.1. The following data was used in the calculation:

a. The suppression pool is at the minimum post-accident level of El. 667.3 feet. 667-3' El. is due to suppression pool draw down assuming the worst case break (Main Steam Line break inside containment).

b. The centerline of the pump suction is at El. 646'-10 5/8".

c. The suction strainers (total of two strainers for each suction line) are filtering their design debris source term. The maximum pressure loss across the strainers at maximum runout flow of 7900 gpm is 4.3 psi. The pump vendor required NPSH at runout flow is 4.0 feet.

d. Atmospheric pressure head is assumed to be equal to the vapor pressure, $h_a - h_{vp}$

e. The suppression pool water is assumed to be at 220°F.

f. $NPSH_A = h_s - h_f + h_a - h_{vp}$

h_s = static head
h_f = friction head loss
h_a = atmospheric pressure head
h_{vp} = vapor pressure

Based on Section 6.3.2.2.3.1.d, NPSHA = $h_s - h_f$

with h_s = 20.41 feet
h_f = 14.66 feet

$NPSH_A$ = 20.41 – 14.66
$NPSH_A$ = 5.75 feet
$NPSH_r$ = 4.0 feet

6.3.2.2.4 Low Pressure Coolant Injection (LPCI) System

The low pressure coolant injection system is an operating mode of the RHR system. The LPCI system is automatically actuated by low water level in the reactor or high pressure in the drywell (high pressure in the drywell must be accompanied by a reactor vessel low pressure permissive signal) and uses four motor-driven RHR pumps to draw suction from the suppression pool and inject cooling water flow into the reactor core via the recirculation loop to accomplish cooling of the core by flooding.

The LPCI system, like the CS system, is designed to provide cooling to the reactor core only when the reactor vessel pressure is low, as is the case for large LOCA break sizes. However, when the LPCI operates in conjunction with the ADS, the effective core cooling capability of the LPCI is extended to all break sizes because the ADS will rapidly reduce the reactor vessel pressure to the LPCI operating range. NPSH for these flow conditions is shown in Figure 6.3-119.

Dwgs. M1-E11-3, Sh. 1 and M1-E11-3, Sh. 2, show a process diagram, (and process data) of the RHR system. The LPCI System P&ID is presented in Dwgs. M-151, Sh. 1, M-151, Sh. 2, M-151, Sh. 3, and M-151, Sh. 4.

LPCI operation includes using associated valves, control, instrumentation, and pump accessories. LPCI is normally powered from the preferred ac power source and from the standby ac power source upon a loss of preferred ac power.

In the event of a LOCA, the two halves of the LPCI system inject water into the discharge line in each recirculation loop. Since electrical power to each LPCI pump is separate, it is necessary to have a bus arrangement which permits the valves of a LPCI loop that has been disabled by a single failure of a divisional electrical supply to be energized by an alternate electrical supply. This feature preserves the ability of the LPCI to inject into the unbroken recirculation loop as well as the broken loop. See Table 6.3-5 for the LPCI pumps available during a LOCA and a limiting single failure.

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

The process diagram, Dwgs. M1-E11-3, Sh. 1 and M1-E11-3, Sh. 2, and the P&ID, Dwgs. M-151, Sh. 1, M-151, Sh. 2, M-151, Sh. 3, and M-151, Sh. 4, indicate a great many available flow paths other than the LPCI injection line. However, the low water level or high drywell pressure signal and RPV low pressure signals which automatically initiate the LPCI mode are also used to realign containment cooling and spray modes of operation and revert other associated valves to the LPCI lineup. Inlet and outlet valves from the heat exchangers receive no automatic signals as the system is designed to provide rated flow to the vessel whether they are open or not.

A check valve in the pump discharge line is used together with a discharge line fill system (see Subsection 6.3.2.2.5) to prevent water hammer resulting from a pump start with an empty discharge line. A flow element in the pump discharge line is used to provide a measure of system flow and to originate automatic signals for control of the pump minimum flow valve. The minimum 1flow valve permits a small flow to the suppression pool in the event no discharge valve is open or in case vessel pressure is higher than pump shutoff head.

Using the suppression pool as the source of water for the LPCI establishes a closed loop for recirculation of LPCI water escaping from the break.

The design pressure and temperature for various portions of the system were established in accordance with the ASME Section III Boiler and Pressure Vessel code and the required RHR system design specification written for this system. The RHR System Process Diagram (Dwgs. M1-E11-3, Sh. 1, and M1-E11-3, Sh. 2) was used as input in the development of the design specification.

LPCI pumps and equipment are described in detail in Subsection 5.4.7, which also describes the other functions served by the same pumps if 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 Subsection 6.2.2. The portions of the RHR required for accident protection including support structures are designed in accordance with Seismic Category I criteria (see Chapter 3). The LPCI pump characteristics are shown in Figure 6.3-119.

The LPCI system incorporates a relief valve on each pump suction line and the LPCI discharge header which protects the components and piping from inadvertent overpressure conditions. These valves are set to relieve pressure at 165 psig and 450 psig, respectively.

Provisions are included in the LPCI system to permit testing of the system. These provisions are:

1) All active LPCI components are designed to be testable during normal plant operation.

2) A discharge test line is provided for the four pumps to route suppression pool water back to the suppression pool without entering the reactor pressure vessel.

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

4) All motor-operated valves, air-operated valves and check valves are capable of operation for test purposes. The RHR Pump discharge check valves (151/251 F031A,B,C&D) have local disc position indication on the valve hinge pins.

5) Shutdown lines taking suction from the recirculation system are provided to permit testing of the pump discharge into the reactor pressure vessel after normal plant shutdown and to provide for shutdown cooling.

6) All relief valves are removable for bench testing during plant shutdown.

6.3.2.2.4.1 NPSH AVAILABLE FOR RHR

The available NPSH is calculated in accordance with Regulatory Guide 1.1. The following data is used for a typical NPSH calculation:

a. The suppression pool is at the minimum post-accident level of El. 667.3 feet. 667.3' El. is due to suppression pool draw down assuming the worst case break (Main Steam Line break inside containment).

b. The centerline of the pump suction is at El. 648'-1/2".

c. The suction strainers (total of two strainers for each suction line) are filtering their design debris source term. The maximum pressure loss across the strainers at maximum runout flow of 13,800 gpm is 2.5 psi. The pump vendor required NPSH at runout flow is 5.0 feet.

d. Atmospheric pressure head is assumed to be equal to the vapor pressure, $h_a – h_{vp}$

e. The suppression pool water is assumed to be at 220°F.

f. $NPSH_A = h_s - h_f + h_a - h_{vp}$

h_s = static head
h_f = friction head loss
h_a = atmospheric pressure head
h_{vp} = vapor pressure

Based on Section 6.3.2.2.4.1.d, $NPSHA = h_S - h_f$

with h_s = 19.26 feet
h_f = 11.09 feet

$NPSH_A = 19.26 – 11.09$
$NPSH_A$ = 8.17 feet
$NPSH_r$ = 5.0 feet

6.3.2.2.5 Discharge Line Fill System

The discharge line fill system, described in this section, serves the ECCS discharge lines (RHR, CS and HPCI) and the RCIC discharge line.

A requirement of the core cooling systems is that cooling water flow to the reactor vessel be initiated rapidly when the system is called on to perform its function. This quick-start system characteristic is provided by quick-opening valves, quick-start pumps, and a standby ac power source. The time lag between the signal to start the pump and the initiation of flow into the RPV is minimized by the ECCS and RCIC discharge line fill system which continuously keeps the core cooling pump discharge lines filled and simultaneously prevents water hammer during the rapid start transient of the ECCS and RCIC pumps.

The discharge line fill system consists of fill lines which provide a continuous supply of condensate from the condensate transfer system to the high points of the ECCS discharge piping. Following initial venting and system fill, a pressure above atmospheric pressure is maintained at the system's high points to prevent air accumulation. A minor, but continuous inflow into the discharge lines is required primarily to make up for leakage across the check or stop check valves provided near the ECCS and RCIC pumps. Past experience has shown that these valves will leak slightly, producing a small backflow. The estimated make-up for the pump discharge lines is less than 1 gpm. To ensure that the discharge lines are always filled, indication is provided in the Control Room as to whether the condensate transfer pumps are operating. An alarm will indicate low condensate transfer pump discharge pressure which can be verified on a pressure indicator in the control room.

A pressure switch is provided to initiate this low pressure alarm. Two pressure switches are provided to initiate auto start of the standby transfer pump. (Refer to FSAR Dwg. M-108, Sh. 1.) These pressure switches are primarily set to protect the condensate transfer pumps from operating at runout conditions. With one pump operation and approaching runout, tripping of the pressure switches will cause the second pump to start and thereby raise the pressure in the pump discharge header. The set point pressure for pump runout protection well exceeds the pump discharge pressure required for maintaining the injection lines pressurized. The fill lines for each system, therefore, are provided with pressure regulators to control the fill pressure to a few psi above atmospheric pressure at the systems high points so that entrapped air can be released through the high point vents during surveillance test. These pressure regulators have been permanently bypassed to allow the maximum available condensate transfer pressure to pass to the pump discharge headers. With the injection lines properly filled, vented, and pressurized, maintaining an adequate pump discharge header pressure will assure that the injection lines will remain filled with water.

A 2" fill line is provided for the discharge line of the HPCI train, the discharge line of the RCIC train, each of the two RHR trains, and each of the two core spray trains. The individual fill lines can be isolated to permit maintenance on the systems and on individual trains of a system without affecting the other train. Details are shown in the HPCI P&ID, Dwg. M-155, Sh. 1; the RHR P&ID, Dwgs. M-151, Sh. 1 and M-151, Sh. 3; the RCIC P&ID, Dwg. M-149, Sh. 1; and the CS P&ID, Dwg. M-152, Sh. 1. The condensate transfer pumps with associated instrumentation, including the low pressure alarm, are shown on the condensate and refueling water P&ID, Dwg. M-108, Sh. 1.

No level transmitters are provided to detect air bubbles upstream of injection valves.

Air pockets will be prevented by proper venting and filling and by maintaining the discharge lines continuously pressurized such that the pressure at the high points always exceeds atmospheric pressure. This will require a minor but continuous feed flow into the discharge lines to make up for valve leakage.

The presence of small, local air bubbles upstream of the injection valves will not be detrimental to the ECCS during the start transient.

Each RHR train has its own fill line and can be isolated from the other train. If one pump in an RHR train needs to be isolated for maintenance, the discharge line for the other pump will remain filled and pressurized to the isolation valve of that pump, allowing the pump to perform its function.

The condensate transfer pump discharge low pressure alarm instrumentation is tested in accordance with the Technical Requirements Manual. A channel functional test and a channel calibration are required.

A backup keepfill function is provided by the Demineralized Water System via a gravity feed system from an atmospheric tank (Refer to FSAR Section 9.2.9). The passive, backup keepfill capability provided for the ECCS & RCIC Systems assures that the systems are available for non-design basis accident events such as an Appendix R Fire (General Reference: PLA-4945). The tank contains a minimum volume of 2000 gallons. The tank level is monitored on a periodic basis and is refilled as necessary. The minimum volume allows for reasonable operator response time in the event of a loss of the primary keepfill system from the Condensate Transfer System.

Surveillance tests to determine if the discharge lines for the RHR, HPCI, RCIC and CS systems are full are required by the plant Technical Specifications. The tests are performed by momentarily opening the vents at the system's high points to confirm the water fill and flow. No special fill and vent procedures are required prior to surveillance testing of these pumps.

6.3.2.3 Applicable Codes and Classification

The applicable codes and classification of the ECCS are specified in Section 3.2. All piping systems and components (pumps, valves, etc.) for the ECCS comply with applicable codes, addenda, code cases, and errata in effect at the time the equipment is procured. The piping and components of each system of the ECCS within the containment and out to and including the pressure retaining injection valve are Safety Class 1. The remaining piping and components are Safety Class 2, 3, or non-code as indicated in Section 3.2, and as indicated on the individual system P&ID. The equipment and piping of the ECCS are designed to Seismic Category I requirements. This seismic designation applies to all structures and equipments essential to the core cooling function. IEEE codes applicable to the controls and power supplies are specified in Section 7.1.

6.3.2.4 Materials Specifications and Compatibility

Materials specifications and compatibility for the ECCS are presented in Sections 6.1 and 3.2. Nonmetallic materials such as lubricants, seals, packings, paints and primers, insulation, as well as metallic materials, etc., are selected as a result of an engineering review and evaluation for compatibility with other materials in the system and the surroundings with concern for chemical, radiolytic, mechanical and nuclear effects. Materials used are reviewed and evaluated with regard to radiolytic and pyrolytic decomposition and attendant effects on safe operation of the ECCS.

6.3.2.5 System Reliability

A single failure analysis shows that no single failure prevents the starting of the ECCS when required, or the delivery of coolant to the reactor vessel. No individual system of the ECCS is single failure proof with the exception of the ADS, hence it is expected that single failures will disable individual systems of the ECCS. The most severe effects of single failures with respect to loss of equipment occur if the loss of coolant accident occurs in combination with an ECCS pipe break coincident with a loss of off-site power. The consequences of the most severe single failures are shown in Table 6.3-5.

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 pump rooms layout and protection is covered in Subsection 6.2.3.

The ECCS is protected against the effects of pipe whip, which might result from piping failures up to and including the LOCA. This protection is provided by separation, pipe whip restraints, and energy absorbing materials. These three methods are applied to provide protection against damage to piping and components of the ECCS which otherwise could result in a reduction of ECCS effectiveness to an unacceptable level. See Section 3.6 for criteria on pipe whip.

The component supports which protect against damage from movement and from seismic events are discussed in Subsection 5.4.14. The methods used to provide assurance that thermal stresses do not cause damage to the ECCS are described in Subsection 3.9.3.

The discharge lines from RHR System relief valves PSV-15106 A&B (Unit 1) and PSV-25106 A&B (Unit 2) penetrate primary containment and discharge below the surface of the suppression pool. The corresponding line identification numbers for the discharge from these valves are 10"-HBB-120 (Unit 1) and 10"-HBB-220 (Unit 2). These lines have been designed and installed recognizing the full effect of the dynamic loads resulting from the normal water clearing of the submerged portion of the lines.

6.3.2.7 Provisions for Performance Testing

Periodic system and component testing provisions for the HPCI and Core Spray System are described in Subsection 6.3.2.2 as part of the individual system descriptions. These provisions for ADS are described in Subsection 6.3.4.2.2 and for LPCI in Subsection 6.3.4.2.4.

6.3.2.8 Manual Actions

With one exception, the ECCS is actuated automatically and requires no operator action during the first 20 minutes following the accident. The only operator action assumed in the Section 6.3 ECCS analysis is that a RHR heat exchanger is placed in service within 20 minutes into the accident.

The NPSH requirements of the CS pump and the LPCI (RHR) pump are shown in Figures 6.3-118 and 6.3-119, respectively.

During the long-term cooling period, the operator will take action as specified in Subsection 6.2.2.2 to place the containment cooling system into operation. Placing the containment cooling mode 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 control room to assist him in assessing the post-LOCA conditions. This instrumentation provides reactor vessel pressures and water levels, and 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 him in determining system operating status. The electrical and instrumentation complement to the ECCS is discussed in detail in Chapter 7.3. Other available instrumentation is listed in the P&IDs for the individual systems. Much of the monitoring instrumentation available to the operator is discussed in more detail in Chapter 5 and Section 6.2.

6.3.2.9 Position Verification for Manual Valves

Consideration has been given to the possibility that manual valves in the ECCS might be left in the wrong position when an accident occurs. Table 6.3-9 lists all the manually-operated valves in the ECCS (ADS, LPCI, Suppression Pool Cooling, Core Spray, and HPCI) and summarizes the methods for assuring correct valve position. The table lists only those manual valves which are related to the ECCS function of those systems. Thus, the only manual valves in the RHR system which were evaluated are those which comprise part of the LPCI and Suppression Pool Cooling modes. The boundaries of RHR for this purpose include sidestreams and connecting systems out to the first normally-closed remotely operated valve or to two check valves in series.

Many of the manual valves in these systems are vent, drain, or test connection valves which are normally closed and capped or have cam-locks where evaluated. These valves are identified in the "Function" column of Table 6.3-9. Such valves are not critical to the ECCS function; administrative controls, such as pre-startup valve lineup checks, should suffice to reasonably assure that such valves will not degrade ECCS performance.

Certain other valves are physically secured in their normal position to prevent inadvertent mispositioning. Valve manipulations are procedurally/administratively controlled in such a manner as to ensure accurate status control and proper restoration. In other cases, two isolation valves are provided in series to minimize the possibility of inter- or intra- system leakage. Again, such valves are identified in the "Function" column of Table 6.3-9.

Remote position indication of manual valves which are in the main flowpaths of the ECCS (except for makeup gas supply to the ADS valve accumulators) and which will be inaccessible during normal operation is provided in the control room. Proper administrative controls and/or surveillance testing are relied upon to assure the position of the remaining valves.

6.3.3 ECCS PERFORMANCE EVALUATION

ECCS performance is evaluated using approved 10CFR50 Appendix K models for demonstrating conformance to the acceptance criteria of 10CFR50.46. The ECCS performance is evaluated for the entire spectrum of break sizes for postulated loss of coolant accidents. The Section 15 accidents for which ECCS operation is required are:

- 15.2.8 Feedwater piping break
- 15.6.4 Spectrum of BWR steam system failures outside of containment
- 15.6.5 Loss-of-Coolant Accidents.

Section 15.6.5.5 provides radiological consequences of the DBA LOCA and the Main Steam Line Break events.

Evaluations for Susquehanna Units 1 and 2 with FANP ATRIUM™-10 fuel under uprated reactor power conditions have been performed. The results are used in analyses specific to the fuel neutronic design to demonstrate conformance to the acceptance criteria of 10CFR50.46. The analyses assumed an analytical power level of 4031 MWt which supports nominal rated powers as high as 3952 MWt. The analyses were performed using the NRC approved EXEM BWR LOCA methodology given in Reference 6.3.23.

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. Minimum ECCS functional requirements are specified in Subsections 6.3.3.4 and 6.3.3.5, and testing requirements are discussed in Subsection 6.3.4. Limits on minimum suppression pool water level are discussed in Section 6.2.

6.3.3.2 Acceptance Criteria for ECCS Performance

The applicable acceptance criteria, extracted from 10 CFR 50.46, are listed and for each criterion, applicable parts of Subsection 6.3.3 where conformance is demonstrated are indicated.

Criterion 1, Peak Cladding Temperature - "The calculated maximum fuel element cladding temperature shall not exceed 2200°F." Conformance to Criterion 1 is shown in Table 6.3-3B-2 for Unit 1 and Unit 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 6.3-3B-2 for Unit 1 and Unit 2.

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 6.3-3B-2 for Unit 1 and Unit 2.

Criterion 4, Coolable Geometry - "Calculated changes in core geometry shall be such that the core remains amenable to cooling." As described in Reference 6.3-14 conformance to Criterion 4 is demonstrated by conformance to Criteria 1, 2 and 3.

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 generically for General Electric BWRs in Reference 6.3-2, Section III.A as modified by Reference 6.3-20. Briefly summarized, the core remains covered to at least the jet pump suction elevation and the uncovered region is cooled by spray cooling and by steam generated in the covered part of the core.

6.3.3.3 Single Failure Considerations

The functional consequences of potential single failures in the ECCS are discussed in Subsection 6.3.2.5. There it is shown that all potential single failures are no more severe than one of the single failures identified in Table 6.3-5.

It is therefore only necessary to consider each of these single failures in the emergency core cooling system performance analyses.

Based on the EXEM BWR LOCA methodology (Reference 6.3-23) used for ATRIUM-10 fuel a large break in the recirculation suction piping with an LPCI single valve failure is the most severe failure.

A single failure in the ADS (one ADS valve) has no effect on large breaks. In calculations performed for the ATRIUM™-10 fuel, a single failure in the ADS (one ADS valve fails to open) is explicitly evaluated as a distinct failure. For all other single failure scenarios that were analyzed, it was assumed that one ADS valve does not open.

6.3.3.4 System Performance During the Accident

In general, the system response to an accident can be described as:

1) receiving an initiation signal,

2) a small lag time (to open all valves and have the pumps up to rated speed), and

3) finally the ECCS flow entering the vessel.

Key ECCS actuation set points and time delays for all the ECC systems are provided in Table 6.3-2B for Unit 1 and Unit 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 acceleration of the diesel-generators and pumps.

Simplified piping and instrumentation and functional control diagrams for the ECCS are provided in Subsection 6.3.2. The operational sequence of ECCS for the limiting LOCA event is shown in Table 6.3-1B-2 for Unit 1 and Unit 2.

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 will take action as specified in Subsection 6.2.2.2 to place the containment cooling system into operation. Long-term cooling capabilities are not impaired by a leak from the first isolation valve outside the suppression pool. Suppression pool water leakage can be made up by several methods. Leakage into the ECCS pump room will not flood high enough to communicate with other rooms. By maintaining water levels in the suppression pool, water level will eventually level out in the ECCS room stopping the leak. Making up suppression pool water can be done by either putting additional water directly into the suppression pool or into the vessel (assuming a LOCA).

6.3.3.5 Use of Dual Function Components for ECCS

With the exception of the 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 which have emergency core cooling functions, or vice versa. Because either the ADS initiating signal or the overpressure signal opens the safety relief valve, no conflict exists.

The LPCI system, however, uses the 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 subsystems for containment cooling or shutdown cooling. Immediately following a LOCA, the RHR system is directed to the LPCI mode. The LPCI system can be used to support long term containment cooling as well as its primary ECCS support function of cooling the reactor core following a loss of reactor coolant, as discussed in section 6.2.2.2 of the FSAR. The effects of this dual use for the LPCI system have been analyzed for ATRIUM™-10 fuel (Reference 6.3-14).

6.3.3.6 Limits on ECCS System Parameters

The limits on the ECCS system parameters are discussed in Subsections 6.3.3.1 and 6.3.3.7.1.

Any number of components in any given system may be out of service, up to and including the entire system. The maximum allowable out of service time is a function of the level of redundance and the specified test intervals as discussed in Section15A.

6.3.3.7 ECCS Analyses for LOCA

6.3.3.7.1 LOCA Analysis Procedures and Input Variables

AREVA ATRIUM™- 10 Fuel

The procedures approved for LOCA analysis conformance calculations are described in detail in References 6.3-14 and 6.3-15. These procedures were used in the calculations discussed in this Subsection 6.3.3 for ATRIUM™-10 fuel. The EXEM BWR LOCA application methodology (Reference 6.3-23) is used to demonstrate compliance with the first three 10CFR50.46 criteria. The methodology defines the plant-specific break spectrum using inputs and models as required by 10CRF50 Appendix K.

Three major AREVA computer codes are used to determine the LOCA response for the Susquehanna LOCA analysis. These codes are RODEX2, RELAX and HUXY. Together, these codes evaluate the reactor vessel blowdown response to a pipe rupture, the subsequent core flooding by ECCS, and the fuel cladding heatup. Figure 4.1 of Reference 6.3-14 is a flow diagram of these computer codes, indicating the major code functions and the transfer of major parameters. The purpose of each code is described below.

FUEL PARAMETERS ANALYSIS (RODEX2)

A complete analysis for a given break starts with the specification of fuel rod parameters as determined by RODEX2. RODEX2 is first used to determine the initial stored energy for both the blowdown analysis (RELAX) system and hot channel) and the heatup analysis (HUXY). RODEX2 is also used to calculate fuel parameters such as fuel to cladding gap sizes and heat transfer coefficients for use in HUXY calculations.

BLOWDOWN ANALYSIS (RELAX)

Relax is used to calculate the system thermal hydraulic response during the blowdown phase of the LOCA. The RELAX analysis is performed from the time of the break initiation to the time the ECCS low pressure core spray flow reaches its rated value and the intact recirculation loop isolation valve is fully closed. The RELAX system blowdown calculation provides the system thermal-hydraulic conditions during this time as boundary conditions for the RELAX hot channel model and at the end of this time for use in initialing the refill/reflood analysis.

The RELAX hot channel analysis is performed to analyze the maximum power assembly of the core. The hot channel is assumed to be operating on fuel thermal limits prior to the occurrence of the postulated LOCA. The results from the RELAX hot channel calculation are heat transfer coefficients and fluid conditions that are used for input to the HUXY heatup analysis.

REFILL/REFLOOD ANALYSIS (RELAX)

The RELAX code is also used to analyze the LOCA beginning with the time of both rated core spray flow and intact recirculation loop isolation valve closure. The RELAX code computes the system hydraulic response during the refill/reflood phase of a LOCA. The refill stage is the period when the lower plenum is filling due to ECCS injection. The reflood period is when the core is being reflooded with ECCS water. The principal result of a RELAX calculation is the time when the two-phase fluid reaches the hot node in the core by entrainment of the reflooding fluid, termed as the “time of hot node (or core) reflood.” The RELAX calculations provide HUXY with the time of hot node reflood and the time when the liquid has risen in the bypass to the height of the axial plane of interest (time of bypass reflood)

HEATUP ANALYSIS (HUXY)

The HUXY code is used to perform heatup calculations for the entire LOCA transient and yields peak cladding temperature and local cladding oxidation. The heat generated by metal-water reaction is included in the HUXY analysis. HUXY is used to calculate the thermal response of each fuel rod in one axial plane of the hot rod. The HUXY code implements the clad swelling and rupture models from NUREG-0630 and complies with the NRC criteria stated in 10CFR50 Appendix K for LOCA Evaluation Models.

The significant input variables used by the LOCA codes for analysis of FANP ATRIUM^{TM-}10 fuel are listed in Table 6.3-2B.

6.3.3.7.2 Accident Description

A detailed description of the LOCA calculation is provided in Reference 6.3-14.

The LOCA analyses covered a spectrum of break sizes in the suction and discharge piping of one of the recirculation loops. For the double-ended guillotine(DEG) break, the discharge coefficients, that characterize the rate at which coolant can escape from the break, were varied to span the condition at which the maximum PCT may occur. A discharge coefficient of 1.0 corresponds to full double-ended guillotine break with an area of 7.0 ft^2. For smaller pipe breaks, (longitudinal splits in the piping), areas of the opening were varied from 3.5 ft^2 to 0.2 ft^2. Two average axial power shapes (top peaked and mid peaked) were analyzed. Two single failure conditions were analyzed, battery failure (disabling the HPCI system) and a failure of a single injection valve in the LPCI.

The LOCA analyses for EPU rated conditions are described in References 6.3-14 and 6.3-15. Initial conditions were 4031 MWt with core flows of 80 Mlbs/hr and 108 Mlbs/hr.

A double ended guillotine break (1.0 DEG) of the recirculation suction line with a single LPCI valve failure using ECCS nominal delay times is the limiting break (highest PCT). System hot channel and hot node response curves for the analysis are shown in Figures 6.3-201 through 6.3-221.

For this analysis, the discharge valve in the broken recirculation loop is assumed to close when a suction side break occurs. This assumption allows credit to be taken for the LPCI flow in the failed recirculation loop.

A short description of the major events during the limiting design basis accident (DBA) is included.

At the beginning of the event the pipe break occurs, and offsite power is assumed to be unavailable. The core flow drops rapidly during the first 1 second, then pauses for the next 5 seconds before dropping to essentially zero between 10 and 20 seconds. The pause in the core flow reduction results from pressurization due to closure of MSIV. Loss of offsite power initiates the MSIV closure, which is delayed by 2 seconds. In response to the MSIV position at 85% open, a control rod scram signal is generated. The scram serves to shut down the reactor from full power operation.

During the early portion of the event, the recirculation drive flow in the broken loop ceases almost immediately. The flow in the drive line of the broken loop then reverses causing vessel inventory depletion through the jet pump nozzles and out the break. Also, at the beginning of the event, the intact loop recirculation pump is tripped due to the assumed loss of offsite power and begins to coast down. The remainder of the coastdown (after about 5 seconds) is then governed by natural circulation as the intact loop coastdown progresses, until the pressure in the lower plenum reaches the saturation pressure of the water in the lower plenum.

At around 8 seconds, the water level in the downcomer region outside the core shroud reaches the top of the jet pumps. Once the top of the jet pumps are uncovered, the core flow drops almost immediately to zero. Prior to this time, the core flow had been sustained primarily by natural circulation effects. However, once the top of the jet pumps uncover, the natural circulation flow from the downcomer region drop to zero, and the jet pumps are no longer capable of functioning in their intended manner. The result is an almost complete stagnation of core flow.

Liquid continues to be lost from the downcomer region until the break at the recirculation suction nozzle is uncovered (around 11 seconds). At this time the vessel depressurizes more rapidly as the break flow changes form primarily liquid flow to a liquid steam mixture. Shortly thereafter, the vessel pressure reaches the saturation point of the previously subcooled liquid in the lower plenum. At this time, around 14 seconds, a significant portion of the fluid in the lower plenum flashes (vaporizes) to steam. The lower plenum flashing causes a brief but significant increase in the core flow as the vaporization displaces the liquid, and the volume expansion pushes steam and liquid into the core.

The core flow decrease due to jet pump uncovery causes the liquid mass in the bundles to drop rapidly due to the combination of the lack of core flow and the ensuing vaporization of fluid in the bundles. The lower plenum flashing provides a source of liquid to the core which is vaporized to steam within a few seconds, causing the liquid mass in the bundles to once again drop rapidly.

This begins the period of core uncovery, which persists until the ECC systems begin injecting coolant into the reactor vessel.

The following discussion explains the interrelationship between the thermal hydraulic phenomena and the fuel response (primarily peak cladding temperature).

Figure 6.3-221 represents the temperature versus time for the fuel rod where the maximum PCT value is observed.

The first notable occurrence affecting the PCT response occurs near the time of jet pump uncovery. At this time, the heat transfer rates in the hot channel drop dramatically. This causes a heat up in the upper nodes in the bundle as the fuel rods are exposed to a predominantly vapor mixture. Shortly after the jet pump uncovery, the lower plenum flashed. This flashing provides a surge of core flow which replenishes the bundle inventory with a predominately liquid mixture. This causes a short term improvement in heat transfer. As a result, the cladding temperature decreases for the corresponding time.

Once the flashing in the lower plenum subsides and the steam-liquid mixture in the core begins to recede, all the fuel nodes uncover and begin to heat up. This condition continues until the ECC systems begin to inject coolant into the core.

At approximately 50 seconds, core spray injection begins and coolant is sprayed over the top of the core. Some of the core spray flow will penetrate down into the fuel channels, providing spray cooling to the bundles. In some locations, the fluid will be unable to penetrate into the fuel channels due to the high steam upflow. This phenomena, termed counter current flow limitation (CCFL), may cause a build up of accumulated core spray flow in the upper plenum if the injected flow exceeds that which can drain into the core region. A portion of the fluid which accumulates in the upper plenum will drain down into the core bypass region (inside the core but outside the fuel channels). This fluid may also drain into the fuel bundles located on the core periphery, or may drain into the CCFL limited bundles as the rate of steam upflow decreases through these bundles. The fluid which enters the core bypass region will either pass down into the lower plenum region through the leakage paths in the lower fuel support casting or lower tie plate, or may pass through the leakage paths in the channel directly into the lower portion of the fuel bundles.

The availability of coolant from the core spray system provides a direct heat transfer benefit after the end of system blowdown at about 66 seconds. Once rated core spray flow is attained credit for cooling due to core spray is taken in the ATRIUM^{TM-}-10 analysis. This approach is used since testing has demonstrated the applicability of the spray cooling coefficients provided in Appendix K of 10CFR50 to the ATRIUM^{TM-}-10 fuel design.

The LPCI system has a failed valve and is unavailable in the intact recirculation loop. However, the full LPCI flow is available in the broken loop when the discharge valve in that loop is fully closed at 84 seconds, (Figure 6.3-210). Water introduced into the upper plenum from the CS starts passing through the core by way of the passages between the fuel channels and through lower power fuel assemblies to the lower plenum at about 66 seconds. The lower plenum continues to fill providing a water-steam mixture to the core. At about 120 seconds, the cladding temperature reaches a peak when the flow of liquid to the hot node of the core is sufficient to maintain cooling.

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 Table 6.3-3C. These results are from Reference 6.3-14. Conformance to the acceptance criteria (PCT ≤ 2200°F, local oxidation ≤ 17% and core wide metal-water reaction ≤ 1%) is provided in Table 6.3-3B-2.

The peak clad temperature for the limiting break shown in Table 6.3-3B-2 differs slightly from those shown in Table 6.3-3C. Table 6.3-3B-2 results are from Reference 6.3-15, which is the analysis that establishes the MAPLHGR for the SSES Units. The results in Table 6.3-3C provide a relative comparison for the various conditions assumed for the break spectrum analyses.

For convenience in describing the LOCA phenomena, the break spectrum has been separated into two regions: small breaks and large breaks. The large breaks are those in the area range of 7.0 to 3.5 ft^2, while small breaks are those smaller than 3.5 ft^2.

The small break region provides a slower depressurization of the reactor vessel, delaying the time for low pressure ECC systems to become effective. As a result, failure of high pressure coolant injection (HPCI) is expected to be involved in the most limiting single failure scenario.

The large break region provides a rapid depressurization of the reactor vessel, making the HPCI and ADS systems relatively unimportant in determining the consequences of a LOCA. As a result, a failure involving the low pressure ECC systems is expected to be involved in the most limiting single failure scenario. As discussed in Section 6.3.3.7.4, the most limiting single failure in this region is the LPCI injection valve, disabling LPCI injection to the intact loop.

As demonstrated in Table 6.3-5, plants which incorporate the LPCI modification have a different complement of ECCS components available depending on break location (recirculation discharge or suction piping) and single failure assumptions. Analyses are performed for both locations to determine at which location the limiting DBA occurs.

6.3.3.7.4 Large Recirculation Line Break Calculations

In this region, the vessel depressurizes rapidly and the HPCI has an insignificant effect on the event. Consequently, failure of the core spray or LPCI is more severe.

Analyses have demonstrated that the LPCI injection valve failure is the most severe failure for large breaks. This failure disables the LPCI system from providing ECCS to the intact recirculation piping.

The highest calculated PCT for large breaks corresponds to a 1.0 DEG guillotine break with the break flow at each of the two ends of the recirculation suction piping unimpeded by the other (Tables 6.3-3B-2 and 6.3-3C). The limiting large break results are shown in Figures 6.3-201 through 6.3-221.

6.3.3.7.5 Transition Recirculation Line Break Calculations

The break sizes analyzed for the FANP ATRIUM™-10 fuel are characterized as large and small only.

6.3.3.7.6 Small Recirculation Line Break Calculations

As described in Section 6.3.3.7.2, analyses were performed for two initial flow conditions (80 Mlbs/hr and 108 Mlbs/hr), two average axial power shapes (top peaked and mid-peaked), and two single failure conditions (single LPCI valve failure and battery failure – disabling the HPCI system). Failures were assumed to occur in either the suction side or the discharge side of the recirculation loop piping.

The analyses showed that the most limiting break for all of these conditions was a large double-ended guillotine break and that small breaks were not limiting regardless of the single failure condition, (Reference 6.3-14). See Table 6.3-3C for results with different break sizes.

6.3.3.7.7 Calculations for Other Break Locations

General Electric performed analyses for non-recirculation line breaks as part of the original power uprate analysis (References 6.3-8 and 6.3-10). Events evaluated included: core spray line break, feedwater line break, steamline break inside containment, and steamline break outside containment. These analyses clearly demonstrated that these postulated events are significantly less limiting than the postulated recirculation line breaks.
AREVA analyzed the core spray line break at 4031 MWt in Reference 6.3-14 and confirmed that this break remains less limiting than the recirculation line breaks.

Thus, non-recirculation line breaks are not considered to be potentially limiting and are not specifically analyzed.

6.3.3.8 LOCA Analysis Conclusions

Having shown compliance with the applicable acceptance criteria of Subsection 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 as specified in the current cycle Core Operating Limit Report (COLR) for each unit (see FSAR Section 16.3, Technical Requirements Manuals).

6.3.4 TESTS AND INSPECTIONS

6.3.4.1 ECCS Performance Tests

All systems of the ECCS were tested for their operational ECCS function during the pre-operational and/or startup test program. Each component was tested for power source, range, direction of rotation, set point, limit switch setting, torque switch setting, etc. Each pump was tested for flow capacity for comparison with vendor data. (This test was also used to verify flow measuring capability.) The flow tests involved the same suction and discharge source; i.e., suppression pool or condensate storage tank.

All logic elements except sensors and relays were tested individually and then as a system to verify complete system response to emergency signals including the ability of valves to revert to the ECCS alignment from other positions.

Finally the entire system was 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 was performed with power supplied from both offsite power and onsite emergency power.

See Chapter 14 for a thorough discussion of pre-operational testing for these systems.

6.3.4.2 Reliability Tests and Inspections

The average reliability of a standby (non-operating) safety system is a function of the duration of the interval between periodic functional tests. The factors considered in determining the periodic test interval of the ECCS are: the desired system availability (average reliability), the number of redundant functional system success paths, the failure rates of the individual components in the system, and the schedule of periodic tests (simultaneous versus uniformly staggered versus randomly staggered). For the ECCS the above factors were used to determine safe test intervals utilizing the methods described in Reference 6.3-1.

All of the active components of the HPCI, CS, and LPCI systems are designed so that they may be tested during normal plant operation. Full flow test capability is provided by a test line back to the suction source. The full flow test is used to verify the capacity of each ECCS pump loop while the plant remains undisturbed (except for a slight disturbance during HPCI testing) in the power generation mode. In addition, each individual valve may be tested during normal plant operation. Input jacks are provided such that by opening the injection valve breaker, each ECCS loop can be tested for response time.

All of the active components of the ADS system are also designed so that they may be tested during normal plant operation. Tests performed every 24 months include a logic system functional test of the ADS system and manual operation of the ADS valves. ADS 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 initiating instrumentation and controls portion of the ECCS is discussed in Subsection 7.3.1. The emergency power system, which supplies electrical power to the ECCS in the event that offsite power is unavailable, is tested as described in Subsection 8.3.1. The frequency of testing is specified in the Technical Specifications. Visual inspections of all the ECCS components located outside the drywell can be made at any time during power operation subject to ALARA concerns. Components inside the drywell can be visually inspected only during periods of access to the drywell. When the reactor vessel is open, the spargers and other internals can be inspected.

6.3.4.2.1 HPCI Testing

The HPCI system can be tested at full flow with condensate storage tank water at any time during plant operation except when the reactor vessel water level is low, or when the condensate level in the condensate storage tank is below the reserve level, or when the valves from the suppression pool to the pump are open. If an initiation signal occurs while the HPCI system is being tested, the system returns automatically to the operating mode except as noted below. The following actions, which prevent the system from automatically returning to the operating mode, can be taken during HPCI system testing:

a) The F006 (injection valve) breaker may be opened to prevent inadvertent RPV injection.

b) The F008 and F011 test line valves may be prevented from automatic closure on a HPCI initiation. This is done to prevent possible system damage that could unnecessarily occur should the valves close during the test.

c) Additionally, some HPCI testing is required to be performed with the flow controller in manual.

For all configurations, manual actions can be taken to realign the system for vessel injection.

A design flow functional test of the HPCI system over the operating pressure and flow range is performed by pumping water from the condensate storage tank and back through the full flow test return line to the condensate storage tank. The HPCI system turbine pump is driven at its rated output by steam from the reactor. The suction valves from the suppression pool and the discharge valves to the feedwater lines remain closed. These two valves are tested separately to ensure their operability.

Inservice testing of pumps and valves in the HPCI system is discussed in Section 3.9.6. The HPCI pump discharge line, as well as its tributary filling line from the condensate transfer system, is normally protected from full reactor pressure by containment isolation valves which are designated as ASME Section XI-IWV category A. These valves will be leak-rate tested in accordance with the Code. Valves HV-E41-1(2)F006, 1(2)-55-038, and B21-1(2)F010B comprise the containment isolation arrangement for the HPCI discharge line. Valve F006 is a normally-closed, motor-operated gate valve which will open automatically only upon a HPCI initiation signal (coincidence of RPV low level and/or high drywell pressure). Valve 1(2)-55-038 is a normally locked-closed manual valve. Valve F010B is a quick-closing, tilting-disk check valve.

In addition, further isolation of the HPCI discharge line from the reactor coolant pressure boundary is provided by check valve 1(2)41818B, which is designated as ASME Category A. Therefore, adequate protection of the low pressure portions of the HPCI discharge line is provided by the aforementioned valves, and leakrate testing of check valves FOO5, 1(2)-55-012, and 1(2)-55-013 is unwarranted. The HPCI test conditions are tabulated on the HPCI process flow diagram, Dwg. M1-E41-4, Sh. 1.

6.3.4.2.2 ADS Testing

The ADS valves are tested every 24 months. This testing includes simulated automatic actuation of the system throughout its emergency operating sequence, but excludes actual valve actuation. Each individual ADS valve is manually actuated.

During plant operation the ADS system can be checked as discussed in Subsection 7.3.1.1a.1.4.

6.3.4.2.3 CS Testing

The CS pump and valves are tested periodically during reactor operation. With the injection valve closed and the return line open to the suppression pool, full flow pump capability is demonstrated. The injection valve and the check valve are tested in a manner similar to that used for the LPCI valves. The system test conditions during reactor shutdown are shown on the CS system process diagram, Dwg. M1-E21-15, Sh. 1. The portion of the CS outside the drywell may be inspected for leaks during tests.

Inservice testing of pumps and valves in the Core Spray system is discussed in Section 3.9.6. The core spray pump discharge lines are protected from full reactor pressure by containment isolation valves which are designated as ASME Category A. These valves will be leak-rate tested in accordance with the Code. Valves HV-E21-1(2) F005 A and B, 1(2) F006 A and B, and 1(2) F037A and B comprise the containment isolation arrangement for the core spray injection lines. Normally-closed, motor-operated valve F005A(B) is interlocked such that it will open automatically upon receipt of a LOCA signal only if reactor pressure is below core spray system design pressure. This design configuration is considered to conform with the criteria set forth in NRC Standard Review plan (NUREG 75-087) Section 6.3, Paragraph III.11.a.

6.3.4.2.4 LPCI Testing

Each LPCI loop can be tested during reactor operation. The test conditions are tabulated in Dwgs. M1-E11-3, Sh. 1 and M1-E11-3, Sh. 2. During plant operation, this test does not inject cold water into the reactor because the injection line check valve is held closed by the recirculation loop pressure, which is higher than the pump pressure, and because of the normally closed injection valve (F015). The injection line portion is verified not to be obstructed whenever the Shutdown Cooling (SDC) Mode of the RHR System is placed in service. Verification during operation in the SDC Mode in lieu of an additional test minimizes thermal stresses.

To test a LPCI pump at rated flow, the test line valve to the suppression pool is required to be open, the pump suction valve from the suppression pool is required to be open (this valve is normally open), and the pumps are started using the remote/manual switches in the control room. Correct operation is determined by observing the instruments in the control room.

If an initiation signal occurs during the test, the RHR system returns to the LPCI mode. The valves in the test bypass lines are closed automatically to assure that the LPCI pump discharge is correctly routed to the recirculation loop.

6.3.5 INSTRUMENTATION REQUIREMENTS

Design details including redundancy and logic of the ECCS instrumentation are discussed in Section 7.3.

All instrumentation required for automatic and manual initiation of the HPCI, CS, LPCI and ADS is discussed in Subsection 7.3.2 and is designed to meet the requirements of IEEE 279 and other applicable regulatory requirements. The HPCI, CS, LPCI and ADS can be manually initiated from the control room.

The HPCI System is automatically initiated on low reactor water level or high drywell pressure. CS and LPCI are automatically initiated on a low reactor water level or high drywell pressure initiation signal and the high drywell pressure initiation must be accomplished by a reactor vessel low pressure permissive signal. (See Table 6.3-2 for specific initiation levels for each system.) 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 LPCI pump or both CS pumps in the same loop are operating. The CS and LPCI automatically return from system flow test modes to the emergency core cooling mode of operation following receipt of an automatic initiation signal. HPCI will realign except for the conditions discussed in Section 6.3.4.2.1. The CS and LPCI system injection into the RPV begin when reactor pressure decreases to system discharge shutoff pressure.

HPCI injection begins as soon as the HPCI turbine pump is up to speed and the injection valve is opened since the HPCI is capable of injecting water into the RPV over a pressure range from 150 psig to 1210 psig.

6.3.6 NPSH MARGIN AND VORTEX FORMATION AFTER A PASSIVE FAILURE IN A WATER TIGHT ECCS PUMP ROOM

NPSH calculations for ECCS pumps have shown adequate margin to assure capability of proper pump operation after a pool level drop due to a worst case passive failure in an ECCS water tight pump room. This capability was initially verified during preoperational testing in SSES Units 1 and 2. The tests assumed a passive failure in the ECCS pump room resulting in the lowest pool level with subsequent operation of the ECCS pump with the smallest NPSH margin above NPSH required. Subsequent capability, due to regulatory driven changeout of strainers, was verified by full scale tests of the Unit 1 strainers at the EPRI Evaluation Center. These strainers were tested for vortexing potential and NPSH impact on existing margins and were shown to satisfy all system requirements, including a passive leak in an ECCS pump room. Even though the Unit 2 strainers were not tested, the effect of the changeout on Unit 2 margins is verifiable by hydraulic similitude through system and structure similarity between the two units. ECCS pump data is presented in Figures 6.3–118 and 6.3–119. Figures 6.3–120 and 6.3–121 are provided for reference information, actual performance is defined by Test Procedures.

The pool level drop has been determined assuming a passive failure in a ECCS water tight pump room with operator action 10 minutes after an alarm in the room indicating high water level. Vortex tests of ECCS pumps taking suction from the suppression pool (or condensate storage tank) were performed at the design basis minimum suppression pool (or condensate storage tank) water level during the Unit 1 preoperational testing. These tests showed no vortex formation, abnormal noise levels or signs of abnormal suction flow. However, as discussed above, new strainers replaced the original and these were tested for vortexing effect on the system by full scale tests at the EPRI Evaluation Center. The results of the tests indicated no visible vortexing. Since these tests were performed in a full scale test environment, only modified to observe vortex formation/air entrainment, similar performance results are expected with the equipment installed in the suppression pool. Also, since the tests were done only for Unit 1 strainers, differences are not expected in Unit 2 system margins due to hydraulic similitude through system and structure similarity between the two units as was the situation for NPSH.

6.3.7 REFERENCES

6.3-1 H. M. Hirsch, "Methods for Calculating Safe Test Intervals and Allowable Repair Times for Engineered Safeguard Systems," January 1973 (NEDO-10739).

6.3-2 "General Electric Company Analytical Model for Loss-of-Coolant Analysis in Accordance with 10 CFR 50, Appendix K," NEDO-20566A, September 1986.

6.3-3 Delete

6.3-4 Delete

6.3-5 Delete

6.3-6 Delete

6.3-7 Delete

6.3-8 Diefenderfer, S. B., and D. C. Pappone, "Susquehanna Steam Electric Station Units 1 and 2 SAFER/GESTR-LOCA Loss-of-Coolant Accident Analysis," NEDC-32071P, General Electric Nuclear Engineering Department.

6.3-9 Delete

6.3-10 "SAFER/GESTR-LOCA Analysis Basis Documentation for Susquehanna Steam Electric Station Units 1 and 2," NEDC-32281P, September 1993.

6.3-11 Delete

6.3-12 Delete

6.3-13 Delete

6.3-14 ”Susquehanna LOCA Break Spectrum Analysis for ATRIUM-10 Fuel and Extended Power Uprate” Framatome ANP EMF-3242(P), Rev. 1, March 2006.

6.3-15 ”Susquehanna LOCA MAPLHGR Analysis for ATRIUM–10 Fuel and Extended Power Uprate,” Framatome ANP EMF-3243 (P), Rev. 0, November 2005.

6.3-16 “System Analyses for Elimination of Selected Response Time Testing Requirements,” NEDO-32291, January 1994.

6.3-17 PL-NF-98-010, Rev. 0, Susquehanna SES Unit 1 Cycle 11 Core Operating Limits Report," July 1998.

6.3-18 SSES Unit 2 Cycle 9 Core Operating Limits Report, PL-NF-97-005, Rev. 0, April 1997.

6.3-19 NEDO-32686, "Utility Resolution Guide For ECCS Suction Strainer Blockage," GE Nuclear Energy, October 1998.

6.3-20 "GE Position Summary: Long-Term Post-LOCA Adequate Core Cooling Requirements," DRF-E22-00135-01, Revision 0, November 2000.

6.3-21 Delete

6.3-22 Delete

6.3-23 "Exem BWR-2000 ECCS Evaluation Model," EMF-2361 (P) (A) Framatome ANP, May 2001.

Table 6.3-1
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TABLE 6.3-2

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TABLE 6.3-3

SUMMARY OF RESULTS OF LOCA ANALYSIS

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TABLE 6.3-4

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TABLE 6.3-5

SINGLE FAILURES AND AVAILABLE SYSTEMS FOR SUSQUEHANNA

Assumed Failure")	Recirculation Suction Break Systems Remaining'"	Recirculation Discharge Break Systems Remaining
Opposite Unit False LOCA Signal	ADS[3], HPCI, 1 CS system (2 pumps), 2 LPCI pumps (one in each loop)	ADS, HPCI, 1 CS system (2 pumps), 1 LPCI pump
Battery[4]	ADS, 1 CS system (2 pumps), 3 LPCI pumps	ADS, 1 CS system (2 pumps), 1 LPCI pump
LPCI Injection Valve	ADS, HPCI, 2 CS systems (4 pumps), 2 LPCI pumps (in one loop)	ADS, HPCI, 2 CS systems (4 pumps)
Diesel-Generator[4]	ADS, HPCI, 1 CS system (2 pumps), 3 LPCI pumps	ADS, HPCI, 1 CS system (2 pumps), 1 LPCI pump
HPCI	ADS, 2 CS systems (4 pumps) 4 LPCI pumps (2 in each loop)	ADS, 2 CS systems (4 pumps), 2 LPCI pumps (in one loop)
ADS[3] (SPC ATRIUM™-I0 Fuel)	5 of 6 ADS valves, HPCI, 2 CS systems (4 pumps), 4 LPCI pumps (2 in each loop)	5 of 6 ADS valves; HPCI, 2 CS systems (4 pumps), 2 LPCI pumps (in one loop)

(1) Other postulated failures are not specifically considered because they all result in at least as much ECCS capacity as one of the above assumed failures.

(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 for the recirculation suction line break, less the ECCS in which the break is assumed.

(3) For FANP ATRIUM™-I0 fuel, a single failure in the ADS is modeled in separate calculations.

(4) One additional CS pump (50% flow) would also be available if DG failure was C or D diesel. Note, no additional CS pump would be available if DG failure was A or B diesel. The analyses assume no core spray cooling or inventory makeup credit for this pump.

TABLE 6.3-6

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TABLE 6.3-8 HPCI SYSTEM DESIGN PARAMETERS (values in parenthesis are those used for the original design analyses, before power uprate)		
HPCI PUMP		
Total Pump Design Flow	5070 GPM	
NPSHR	21 feet	
Developed Head, Maximum	3060 feet @ 1225 psia reactor pressure (2940 feet @ 1172 psia reactor pressure) 525 feet @ 165 psia reactor pressure	
Brake Horsepower	4800 HP @ 3060 feet developed head (not to exceed 4621 HP @ 2940 feet developed head) 1000 HP @ 525 feet developed head	
Design Pressure	1500 psig	
Water Temperature Range	40°F to 140°F	
HPCI TURBINE		
	High Pressure	**Low Pressure**
Reactor Pressure	1225 psia (1172 psia)	165 psia
Steam Inlet Pressure	1210 psia (1157 psia)	150 psia
Turbine Exhaust Pressure, Maximum	25 to 65 psia	25 to 65 psia
Design Inlet Pressure	1250 psig + Saturated Temperature	
Design Exhaust Pressure	200 psig + Saturated Temperature	
HPCI ORIFICE SIZING		
Coolant Loop orifices. Sized to obtain the required flow split between the lube oil cooler and the gland seal condenser.		
Minimum Flow Orifices. Sized to ensure a minimum flow or 500 gpm with the pump minimum flow bypass valve open.		
Test Return Orifice. Sized to simulate pump discharge pressure required when the HPCI System is injecting design glow with the reactor vessel pressure at 165 psia. A second orifice for normal system testing with the reactor vessel at 1015 psia may be provided to avoid a high pressure drop across the pump test return valve.		
Leak-off Orifices. Sized for 1/8 inch diameter minimum, 3/16 inch diameter maximum.		
Steam Exhaust Drain Pot Orifice. Sized for 1/8 inch diameter minimum, 3/16 inch diameter maximum.		

TABLE 6.3-8 HPCI SYSTEM DESIGN PARAMETERS (values in parenthesis are those used for the original design analyses, before power uprate)	
HPCI VALVES	
Steam Supply Valve – Open and/or close against full pressure within 20 seconds.	
Pump Discharge Valves – Open and/or close against full pressure within 20 seconds.	
Pump Minimum Flow Bypass Valve – Open and/or close against full pressure within 10 seconds.	
Steam Supply Isolation Valves – Close against full pressure at a minimum rate of 12 inches per minute.	
Cooling Water Pressure Control Valve – Self-contained downstream sensing control valve capable of maintaining constant downstream pressure of 75 psia.	
Pump Suction Relief Valve – 100 psig Relief Setting, 10 gpm @ 10% Accumulation.	
Cooling Water Relief Valve – Size to prevent over pressurizing piping, valves and equipment in the coolant loop in the event of failure of pressure control valves.	
Pump Test Return Valve – Capable of throttling against 1000 psi differential pressure.	
Relief Valve, Barometric Condenser – Capable of retaining 10 inches of mercury vacuum at 140°F ambient, with a set pressure of 5-7 psig and flow gpm at 10 percent accumulation.	
Turbine Exhaust Isolation Valve – Open and/or close against 50 psi differential pressure at a temperature of 360°F. Physically located at the highest point in the exhaust line on a horizontal run and as close to the containment as practicable.	
Check Valve – Located at the highest point in the line on a horizontal run, with adjacent piping arranged to provide a continuous downward slope from the upstream side of the check valve to the turbine exhaust drain pot and downstream of the check valve to the suppression pool.	
Isolation Valve, Steam Warmup/Drain Line – Open and/or close against differential pressure of 1210 psi with minimum travel of 12 inches per minute. The valve and valve associated equipment shall be capable of proper functional operation during maximum ambient conditions.	
Vacuum Breaker, Isolation Valves – Open and/or close against a differential pressure of 200 psi at a minimum rate of 12 inches per minute.	
Vacuum Breaker, Check Valves – Open with a minimum pressure drop (less than 0.5 psi) across the valve seat.	
Rupture Disk Assemblies – Utilized for turbine casing protection, shall include a mated vacuum support to prevent rupture disc reversing under vacuum conditions.	
Rupture Pressure: 175 psig ± 10 psig	
Flow Capacity: 750,000 lb/hr at 200 psig	
DC MOTOR POWER, MAXIMUM	
Hydraulic Oil Pump Motor:	7.5 Hp
Gland Seal Condenser Vacuum Pump Motor:	1.5 Hp
Gland Seal Condenser Drain Pump Motor:	3.0 Hp

TABLE 6.3-8 HPCI SYSTEM DESIGN PARAMETERS (values in parenthesis are those used for the original design analyses, before power uprate)		
CONDENSATE STORAGE		
135,000 Gallons Total reserve storage, per unit, for both HPCI and RCIC Systems.		
TURBINE EXHAUST VERTICAL REACTION FORCE		
Unbalanced pressure due to discharge under the suppression pool water level, which requires vertical hold down, is 20 psi.		
AMBIENT CONDITIONS		
	Temperature	**Relative Humidity**
Normal Plant Operation	60 to 100°F	95%
Accident Mode	148°F	100%

TABLE 6.3-9

MANUAL VALVES IN THE ECCS

SYSTEM	DWG./ FIGURE	VALVE NUMBER	SIZE/TYPE	FUNCTION	LOCATION	(UNIT 2)	METHOD OF ASSURING CORRECT POSITION
Containment Instrument Gas (ADS Valve Pneumatic Supply)	M-126, Sh.1	126015	1" GB	Maintenance	RB-749		Locked open.
	M-126, Sh.2	126017	1" GB	Maintenance	RB-749		Locked open.
	M-2126 Sh. 1	126020	1" GB	Test Vent	RB-749		If valve is left inadvertently open and the vent uncapped, an abnormal demand will be placed on the affected ADS supply header. Low header pressure will automatically open the supply valve from the high pressure nitrogen storage bottles and isolate the compressor from the header. Loss of nitrogen from the storage bottles will eventually result in actuation of the low pressure alarm in the control room. At that point, plant operating personnel will be alerted to take appropriate action.
		126021	1" GB	Test Conn.	DW-752		Locked closed. Also see 126020.
		126022	1" GB	Header isol.	DW-752		None
		126024G	1" GB	Isolation	DW-752		None
		126024J	1" GB	Isolation	DW-752		None
		126024M	1" GB	Isolation	DW-752		None
		126026	1" GB	Maintenance	RB-719	(749)	Locked open.
		126028	1" GB	Maintenance	RB-719	(749)	Locked open.
		126030	1" GB	Test Vent	RB-719		See 126020
		126031	1" GB	Test conn.	DW-719	(738)	Locked closed. Also see 126020
		126032	1" GB	Header isol.	DW-719	(738)	None
		126034K	1" GB	Isolation	DW-752		None
		126034L	1" GB	Isolation	DW-752		None
		126034N	1" GB	Isolation	DW-752		None
		126063	1" GB	Charging conn.	RB-749		Double isolation. Also see 126196.
		126064	1" GB	Charging conn.	RB-749		Double isolation. Also see 126196.
		126065	1" GB	Charging conn.	RB-719	(749)	Double isolation. Also see 126196.
		126066	1" GB	Charging conn.	RB-719	(749)	Double isolation. Also see 126196.
		126078 thru 090	1" GB	Maintenance	RB-749		None; only one of 26 high pressure nitrogen
		126091 thru 100	1" GB	Maintenance	RB-733	(749)	bottles would be lost if valve inadvertently closed.
		126153	1" GB	Test conn.	DW-719	(738)	See 126020.
		126155	1" GB	Test conn.	DW-752		See 126020.
		126159	1" GB	Maintenance	RB-719	(749)	See 126078.

TABLE 6.3-9

MANUAL VALVES IN THE ECCS

SYSTEM	DWG./ FIGURE	VALVE NUMBER	SIZE/TYPE	FUNCTION	LOCATION	(UNIT 2)	METHOD OF ASSURING CORRECT POSITION
Containment Instrument Gas (ADS Valve Pneumatic Supply) (continued)		126160	1" GB	Maintenance	RB-719	(749)	See 126078.
		126161	1" GB	Maintenance	RB-719	(749)	See 126078.
		126162	1" GB	Test vent	RB-749		See 126020.
		126163	1" GB	Test vent	RB-719	(749)	See 126020.
		126196	1" GB	Charging/Vent	RB-749	(226176)	Double isolation. If valves left inadvertently open, an abnormal demand will be placed on the affected ADS supply header. Loss of nitrogen from the storage bottles will eventually result in actuation of the low pressure alarm in the control room. At that point, plant operating personnel will be alerted to take appropriate action.
		126197	1" GB	Charging/Vent	RB-749	(226177)	See 126196.
		226175	1" GB	Charging/Vent	(U2 only)	RB-749	Administrative controls. (Normally open).
		226176	1" GB	Charging/Vent	(126196)	RB-779	See 126196.
		226177	1" GB	Charging/Vent	(126197)	RB-779	See 126196.
Nuclear Boiler – Automatic Depressurization System (ADS)	M-141, Sh.1	141007G, K,J,L,M & N	1" GB	Drain	DW-752		See 126020.
	M-141, Sh.2	141801, 807, 816, 811, 806, 817	1" GB	Vent	DW-739		None
RHR – Low Pressure Coolant Injection Mode (LPCI) and Suppression Pool Cooling Modes	M-151, Sh.1 M-151, Sh.2 M-151, Sh.3 M-151, Sh.4 M-2151, Sh. 1 M-2151 Sh. 3	151011	1" GB	Drain	RB-645		Administrative controls.
		151012	1" GB	Drain	RB-645		Administrative controls.
		151013	1" GB	Vent	RB-645		Administrative controls.
		151014	1" GB	Vent	RB-645		Administrative controls.
		151015	1" GB	Vent	RB-670		Administrative controls.
		151016	1" GB	Vent	RB-683		Administrative controls.
		151017	1" GB	Test conn.	RB-683		Administrative controls.
		151018	1" GB	Drain	RB-683		Administrative controls.
		151024	1" GB	Test conn.	DW-719		Double isolation.
		151026	1" GB	Test conn.	DW-719		Double isolation.
		151028	1" GB	Drain	RB-683		Administrative controls.
		151029	1" GB	Vent	RB-749		Administrative controls.
		151030	1" GB	Vent	RB-645		Administrative controls.
		151031	1" GB	Vent	RB-645		Administrative controls.
		151032	1" GB	Drain	RB-645		Administrative controls.
		151033	1" GB	Drain	RB-645		Administrative controls.

TABLE 6.3-9

MANUAL VALVES IN THE ECCS

SYSTEM	DWG./ FIGURE	VALVE NUMBER	SIZE/TYPE	FUNCTION	LOCATION	(UNIT 2)	METHOD OF ASSURING CORRECT POSITION
RHR – Low Pressure Coolant Injection Mode (LPCI) and Suppression Pool Cooling Modes (continued)		151034	1" GB	Vent	RB-670		Administrative controls.
		151035	1" GB	Vent	RB-683		Administrative controls.
		151036	1" GB	Test conn.	RB-683		Administrative controls.
		151037	1" GB	Drain	RB-683		Administrative controls.
		151048	1" GB	Drain	RB-645		Administrative controls.
		151049	1" GB	Vent	RB-683		Administrative controls.
		151051	1" GB	Test conn.	DW-719		Double isolation.
		151053	1" GB	Test conn.	DW-719		Double isolation.
		151056	1" GB	Vent	RB-683		Administrative controls.
		151058	1" GB	Drain	RB-683		Administrative controls.
		151065	1" GB	Vent	RB-683		Administrative controls.
		151070	12" GB	Isolation	RB-683		Locked closed; double isolation.
		151075	1" GB	Drain	RB-645		Administrative controls.
		151084	1" GB	Inst. Conn.	RB-749		Locked open.
		151085	1" GB	Inst. Conn.	RB-749		Locked open.
		151086	1" GB	Inst. Conn.	RB-749		Locked open.
		151087	1" GB	Inst. Conn.	RB-749		Locked open.
		151091 thru 92	1" GB	Vent	RB-683	(U1 only)	Administrative controls. Double isolation.
		151097	1" GB	Sample conn.	RB-683	(251101)	Administrative controls. (Normally open)
		151098	1" GB	Sample conn.	RB-683	(251102)	Administrative controls. (Normally open)
		151101	1" GB	Vent	DW-719	(251113)	Administrative controls. Double isolation.
		151102	1" GB	Vent	DW-719	(251114)	Closed capped. Double isolation.
		151103	1" GB	Drain	DW-704		Locked closed. Double isolation.
		151104	1" GB	Drain	DW-704		Closed capped. Double isolation.
		151105	1" GB	Drain	RB-683		Administrative controls. Double isolation.
		151106	1" GB	Drain	RB-683		Closed capped. Double isolation.
		151107	1" GB	Vent	DW-719		Administrative controls. Double isolation
		151108	1" GB	Vent	DW-719		Closed capped. Double isolation.
		151109	1" GB	Drain	DW-704		Locked closed. Double isolation.

TABLE 6.3-9

MANUAL VALVES IN THE ECCS

SYSTEM	DWG./ FIGURE	VALVE NUMBER	SIZE/TYPE	FUNCTION	LOCATION	(UNIT 2)	METHOD OF ASSURING CORRECT POSITION
RHR – Low Pressure Coolant Injection Mode (LPCI) and Suppression Pool Cooling Modes (continued)		151110	1" GB	Drain	DW-704		Closed capped. Double isolation.
		151111	1" GB	Drain	RB-683		Administrative controls. Double isolation.
		151112	1" GB	Drain	RB-683		Closed capped. Double isolation.
		151119A thru D	3/8" BV	Vent	RB-645		Administrative controls.
		151120A thru D	1" BV	Vent	RB-645		Administrative controls.
		151806	1" GB	Test Conn.	RB -683		Closed capped. Double isolation.
		151807	1" GB	Test Conn.	RB-683		Administrative controls. Double isolation.
		151808	1" GB	Test Conn.	RB-683		Administrative controls. Double isolation.
		151809	1" GB	Test Conn.	RB-683		Closed capped. Double isolation.
		151810	1" GB	Drain	RB-683		Administrative controls.
		151815	1" GB	Vent	RB-683		Administrative controls.
		151821	½" BV	Vent	RB-749		Administrative controls.
		1F018A thru 18D	4" GT	Maintenance	RB-645		Locked open.
		1F034A thru 034D	20" GT	Maintenance	RB-645		Locked open.
		1F045A thru 045D	1" GB	Drain	RB-645		Administrative controls.
		1F058A,B	1" GB	Vent & Test	RB-683		Administrative controls. Double isolation
		1F058B	1" GB	Vent & Test	RB-683		Administrative controls. Double isolation
		1F059A	1" GB	Vent & Test	RB-683		Administrative controls. Double isolation
		1F059B	1" GB	Vent & Test	RB-683		Administrative controls. Double isolation
		1F060A	24" GB	Block	DW-719		Locked open, position indication on 1C601.
		1F060B	24" GB	Block	DW-683		Locked open, position indication on 1C601.
		1F071A thru 071D	1" GB	Drain	RB-645		Administrative controls
		1F072A thru 072D	1" GB	Drain	RB-645		Administrative controls
		1F082	2" GB	Isolation	RB-683		Double isolation..
		1F102A thru 102D	1" GB	Vent	RB-645 & RB-670		Administrative controls.
		1F124A, B	1" GB	Drain	RB-645		Administrative controls.
		1F128A, B	1" GB	Drain	RB-670		Administrative controls.
		1F018A thru 018D	4" GT	Min. Flow	RB-645		Administrative controls
		RVPP15102A thru 102D	1" GB	Inst. Conn.	RB-645 & RB-683		Closed, plugged.
		251093	1" GB	Vent	(U2 only)	RB-683	Administrative controls. Double isolation.
		251094	1" GB	Vent	(U2 only)	RB-683	Administrative controls. Double isolation.
		251101	1" GB	Sample conn.	(151097)	RB-683	Administrative controls.
		251102	1" GB	Sample conn.	(151098)	RB-683	Administrative controls.
		251113	1" GB	Vent	(151101)	DW-719	Administrative controls. Double isolation.
		251114	1" GB	Vent	(151102)	DW-719	Closed capped. Double isolation.

TABLE 6.3-9

MANUAL VALVES IN THE ECCS

SYSTEM	DWG./ FIGURE	VALVE NUMBER	SIZE/TYPE	FUNCTION	LOCATION	(UNIT 2)	METHOD OF ASSURING CORRECT POSITION
RHR – Low Pressure Coolant Injection Mode (LPCI) and Suppression Pool Cooling Modes (continued)		151125	1" GB	Isolation	DW-704		Administrative controls.
		151126	1" GB	Isolation	DW-704		Administrative controls.
		151127	1" GB	Isolation	DW-704		Administrative controls.
		151128	1" GB	Isolation	DW-704		Administrative controls.
		151129	1" GB	Isolation	DW-704		Administrative controls.
		151131	1" GB	Drain	DW-704		Administrative controls.
		151132	1" GB	Drain	DW-704		Administrative controls.
Fuel Pool Cooling & Cleanup (crosstie to LPCI)	M-153, Sh. 1	153070A	8" GB	Isolation	RB-799		Double isolation (with 151070).
		153070B	8" GB	Isolation	RB-799		Double isolation (with 151070).
		153808	1" GB	Vent	RB-749		Closed plugged.
Core Spray	M-152, Sh.1	152001 thru 004	1" GB	Drain	RB-645		Administrative controls.
		152006	1" GB	Test conn.	RB-670		Administrative controls.
		152007	1" GB	Test conn.	RB-670		Administrative controls.
		152008	1" GB	Drain	RB-683		Administrative controls.
		152009	1" GB	Drain	RB-683		Administrative controls.
		152010	1" GB	Vent	RB-749		Administrative controls.
		152011	1" GB	Test conn.	DW-752		Double isolation.
		152012	1" GB	Test conn.	DW-752		Double isolation.
		152013	1" GB	Test conn.	DW-752		Double isolation.
		152014	1" GB	Test conn.	DW-752		Double isolation.
		152015	1" GB	Vent	RB-749		Administrative controls
		152016	1" GB	Vent	RB-645		Double isolation.
		152021	16" GT	Isolation	RB-645		Locked closed; double isolation
		152024	1" GB	Drain	RB-645		Administrative controls.
		152025	1" GB	Drain	RB-645		Administrative controls.
		152026	1" GB	Drain	RB-645		Administrative controls.
		152027	1" GB	Drain	RB-645		Administrative controls.
		152028	3" GB	Isolation	RB-670		Double Isolation (in combination with check valve 152005)
		152029	1" GB	Bypass	RB-749		Locked closed.
		152030	1" GB	Bypass	RB-749		Locked closed.
		1F002A	16" GT	Isolation	RB-645		Locked closed; double isolation
		1F002B	16" GT	Isolation	RB-645		Locked closed; double isolation
		1F007A	12" GT	Block	DW-752		Locked open; position indication on 1C601.
		1F007B	12" GT	Block	DW-752		Locked open; position indication on 1C601.
		1F008A	1" GB	Vent	RB-645		Administrative controls.

TABLE 6.3-9

MANUAL VALVES IN THE ECCS

SYSTEM	DWG./ FIGURE	VALVE NUMBER	SIZE/TYPE	FUNCTION	LOCATION	(UNIT 2)	METHOD OF ASSURING CORRECT POSITION
Core Spray (continued)		1F008B	1" GB	Vent	RB-645		Administrative controls.
		1F010A thru 010D	3" GB	Isolation	RB-645		Locked open.
		1F013A	1" GB	Test conn.	RB-749		Double isolation.
		1F013B	1" GB	Test conn.	RB-749		Double isolation.
		1F014A	1" GB	Test conn.	RB-749		Locked closed; double isolation.
		1F014B	1" GB	Test conn.	RB-749		Locked closed; double isolation.
		1F016A thru 016D	1" GB	Vent	RB-645		Locked closed.
		1F017A, B	1" GB	Maintenance	RB-719		If valve is inadvertently left closed, indication of reactor core differential pressure would be abnormally low.
		1F020A thru 020D	2" GB	Bypass Isolation	RB-645		Locked closed.
		1F046A thru 046D	1" GB	Drain	RB-645		Locked closed.
		1F025A, B	1" GB	Fill Sys.	RB-683		Administrative controls.
		1F027A, B	1" GB	Fill Sys.	RB-683		Administrative controls.
		1F028A, B	2" GB	Fill Sys.	RB-683		Locked open.
		RV-PP-15236A thru 236D	1" GB	Instr. Conn.	RB-645		Closed / plugged.
		252031 and 033	1" GB	Vent	(U2 only)	DW-752	Closed / capped; double isolation.
		252032 and 034	1" GB	Vent	(U2 only)	DW-752	Locked closed; double isolation
		252035 and 037	1" GB	Test Conn.	(U2 only)	RB-749	Locked closed /capped; double isolation
		252036 and 038	1" GB	Test Conn.	(U2 only)	RB-749	Closed / capped; double isolation.
High Pressure Coolant Injection (HPCI)	M-155, Sh.1	155001	1" GB	Drain	RB-645		Double isolation.
		155002	1" GB	Drain	RB-645		Double isolation.
		155003	1" GB	Test conn.	RB-645		Double isolation.
		155004	1" GB	Test conn.	RB-645		Double Isolation
		155007	2" GB	Maintenance	RB-645		Administrative controls.
		155008	2" GB	Maintenance	RB-645		Administrative controls.
		155009	1" GB	Vent	RB-645		Administrative controls.
		155010	1" GB	Vent	RB-670		Double isolation.
		155011	1" GB	Vent	RB-670		Double isolation.
		155014	1" GB	Test conn	RB-739		Double isolation.
		155015	1" GB	Test conn.	RB-739		Double isolation.
		155016	1" GB	Drain	RB-645		Double isolation.
		155017	2" GB	Fill sys.	RB-645		Locked open.
		155018	2" GB	Fill sys.	RB-719		Administrative controls.
		155019	1" GB	Drain	RB-645		Double isolation.

TABLE 6.3-9

MANUAL VALVES IN THE ECCS

SYSTEM	DWG./ FIGURE	VALVE NUMBER	SIZE/TYPE	FUNCTION	LOCATION	(UNIT 2)	METHOD OF ASSURING CORRECT POSITION
High Pressure Coolant Injection (HPCI) (continued)	M-155, Sh.1	155020	1" GB	Drain	RB-645		Double isolation.
		155021	1" GB	Maintenance	RB-670		Administrative controls.
		155022	1" GB	Maintenance	RB-670		Administrative controls.
		155023	1" GB	Maintenance	RB-670		Administrative controls.
		155025	1" GB	Vent	RB-670		Administrative controls.
		155026	1" GB	Vent	RB-670		Administrative controls.
		155027	1" GB	Maintenance	RB-670		Administrative controls.
		155028	1" GB	Vent	RB-670		Administrative controls.
		155029	1" GB	Maintenance	RB-670		Administrative controls.
		155030	1" GB	Vent	RB-670		Administrative controls.
		155031	1" GB	Maintenance	RB-670		Administrative controls.
		155032	1" GB	Drain	RB-670		Double isolation.
		155033	1" GB	Maintenance	RB-670		Administrative controls.
		155034	1" GB	Drain	RB-670		Double isolation.
		155035	1" GB	Maintenance	RB-670		Administrative controls.
		155036	1" GB	Drain	RB-645		Double isolation.
		155037	1" GB	Bypass Isolation	RB-645		Administrative controls.
		155038	1" GB	Bypass Isolation	RB-749		Locked closed.
		155039	1" GB	Vent	RB-670		Administrative controls.
		155040	1" GB	Drain	RB-670		Double isolation.
		155800	1" GB	Test conn.	RB-739		Double isolation.
		155801	1" GB	Test conn.	RB-739		Double isolation..
		155802	¼" BV	Test conn.	RB-670	(255052)	Locked closed / plugged
		1F010	16" GT	Isolation	RB-645		Locked open.
		1F013	1" GB	Test conn.	RB-670		Administrative controls.
		1F014	1" GB	Test conn.	RB-683		Double isolation.
		1F015	1" GB	Test conn.	RB-683		Double isolation.
		1F016	1" GB	Test conn.	RB-670		Double isolation.
	M-155,	1F017	1" GB	Test conn.	RB-670		Double isolation.
	Sh.1	1F023A thru 023D	1" GB	Maintenance	RB-683		Administrative controls. If valve is inadvertently left closed, a steam line high dP or "instrument line break signal" may be actuated, resulting in automatic closure of HPCI steam supply valve 1F002 or 1F003.
		1F036	1" GB	Drain	RB-645		Locked open.

TABLE 6.3-9

MANUAL VALVES IN THE ECCS

SYSTEM	DWG./ FIGURE	VALVE NUMBER	SIZE/TYPE	FUNCTION	LOCATION	(UNIT 2)	METHOD OF ASSURING CORRECT POSITION
High Pressure Coolant Injection (HPCI) (continued)	M-155, Sh.1	1F037	1” GB	Drain	RB-645		Locked open.
		1F044	1” GB	Test conn.	RB-645		Administrative controls.
		1F055	1” GB	Test conn.	RB-645		Double isolation.
		1F056	1” GB	Test conn.	RB-645		Double isolation.
		1F064	1” GB	Test conn.	RB-645		Double isolation.
		1F065	1” GB	Test conn.	RB-670		Double isolation.
		1F090	1” GB	Test conn.	RB-670		Administrative controls.
		1F091	1” GB	Test conn.	RB-670		Administrative controls.
		1F092	1” GB	Test conn.	RB-670		Administrative controls.
		255052	¼” BV	Test Conn.	RB-670	(155802)	Locked closed / capped
HPCI Turbine-Pump	M-156, Sh.1	156001	3/4” GB	Leakoff	RB-645		Administrative controls.
		156002	3/4” GB	Leakoff	RB-645		Administrative controls.
		156003	3/4” GB	Leakoff	RB-645		Administrative controls.
		156006	3/4” GB	Leakoff	RB-645		Administrative controls.
		156007	1” GB	Drain	RB-645		Administrative controls.
		156008	1” GB	Drain	RB-645		Double isolation.
		156009	1” GB	Drain	RB-645		Double isolation.
		156010A	1” GB	Vent	RB-645		Double isolation.
		156010B	1” GB	Vent	RB-645		Double isolation.
		156011	1” GB	Drain	RB-645		Administrative controls.
		156018	1” GB	Drain	RB-645		Administrative controls.
		156019	1” GB	Drain	RB-645		Administrative controls.
		15617	1” GB	Vent	RB-645		Administrative controls.
		1F043	1” GB	Test conn.	RB-645		Administrative controls.
		1F058	2” GB	Maintenance	RB-645		Administrative controls.
	M-156 Sh. 1	1F0161A thru O61C	1” GB	Vent	RB-645		Administrative controls.
		1F063A	1” GB	Vent	RB-645		Double Isolation.
		1F063B	1” GB	Vent	RB-645		Double Isolation.

TABLE 6.3-9

MANUAL VALVES IN THE ECCS

SYSTEM	DWG./ FIGURE	VALVE NUMBER	SIZE/TYPE	FUNCTION	LOCATION	(UNIT 2)	METHOD OF ASSURING CORRECT POSITION

LEGEND

TYPE: GB = Globe Valve
GT = Gate Valve
BV = Ball Valve

LOCATION: RB = Reactor Bldg.
DW = Drywell

The number represents the floor elevation.

TABLE 6.3-10

SAFETY-RELATED VALVES IN THE DRYWELL SUBJECT TO SPRAY IMPINGEMENT

P&ID(1)	OPR	TYPE	NUMBER
143	AO	HV	F019
143		TEST	F021
143		TEST	F022
143		MAN	F059
151		PSV	F126
141		TEST	F017
141		TEST	F018
141		DRN	F095A
141		DRN	F095B
141		DRN	F096A
141		DRN	F096B
141		ROOT	1RV-PP-14107A1
141		ROOT	2RV-PP-14107A1
141		ROOT	1RV-PP-14107B1
141		ROOT	2RV-PP-14107B1
141		ROOT	1RV-PP-14107A2
141		ROOT	2RV-PP-14107A2
141		ROOT	1RV-PP-14107B2
141		ROOT	2RV-PP-14107B2
141		ROOT	1RV-PP-14107A3
141		ROOT	2RV-PP-14107A3
141		ROOT	1RV-PP-14107B3
141		ROOT	2RV-PP-14107B3
144		TEST	F002
144		TEST	F003
149	AO	HV	F088
155	AO	HV	F100
126		CK	126072
126		CK	126152
126		CK	126154
143		CK	F013A
143		CK	F013B
126		TEST	126021
126		MAN	126022
126		MAN	126024G
126		MAN	126024J
126		MAN	126024M
126		TEST	126031
126		MAN	126032
126		MAN	126034K
126		MAN	126034L
126		MAN	126034N
126		TEST	126047

TABLE 6.3-10

SAFETY-RELATED VALVES IN THE DRYWELL SUBJECT TO SPRAY IMPINGEMENT

P&ID(1)	OPR	TYPE	NUMBER
126		TEST	126073
126		TEST	126075
126		TEST	126153
126		TEST	126155
141		DRN	141006A
141		DRN	141006B
141		DRN	141006C
141		DRN	141006D
141		DRN	141006E
141		DRN	141006F
141		DRN	141006G
141		DRN	141006H
141		DRN	141006J
141		DRN	141006K
141		DRN	141006L
141		DRN	141006M
141		DRN	141006N
141		DRN	141006P
141		DRN	141006R
141		DRN	141006S
141		DRN	141007G
141		DRN	141007J
141		DRN	141007K
141		DRN	141007L
141		DRN	141007M
141		DRN	141007N
141		DRN	141008A
141		DRN	141008B
141		DRN	141008C
141		DRN	141008D
141		DRN	141014
141		DRN	141015
143		VNT	F001A
143		VNT	F001B
143		VNT	F002A
143		VNT	F002B
143		MAN	F014A
143		MAN	F014B
141		VNT	141800
141		VNT	141801
141		VNT	141802
141		VNT	141803
141		VNT	141804

TABLE 6.3-10

SAFETY-RELATED VALVES IN THE DRYWELL SUBJECT TO SPRAY IMPINGEMENT

P&ID(1)	OPR	TYPE	NUMBER
141		VNT	141805
141		VNT	141806
141		VNT	141807
141		VNT	141810
141		VNT	141811
141		VNT	141812
141		VNT	141813
141		VNT	141814
141		VNT	141815
141		VNT	141816
141		VNT	141817
141	MO	HV	F001
141	MO	HV	F002
141	MO	HV	F005
141		ISO	141018
143		VNT	F025A
143		VNT	F025B
143		VNT	F026A
143		VNT	F026B
143		DRN	F027A
143		DRN	F028A (Unit 1 Only)
143		VNT	F034A
143		VNT	F034B (Unit 1 Only)
143		VNT	F035A
143		VNT	F035B (Unit 1 Only)
143		DRN	F036A
143		DRN	F036B
143		DRN	F038A
143		DRN	F038B
143		TEST	143027A
143		TEST	140327B
143		TEST	143028A
143		TEST	143028B
143		VNT	143030A
143		VNT	143030B
143		VNT	143029A
143		VNT	143029B
143		VNT	143015A
143		VNT	143015B
143		VNT	143016A
143		VNT	143016B
143		VNT	143017A
143		VNT	143017B

TABLE 6.3-10

SAFETY-RELATED VALVES IN THE DRYWELL SUBJECT TO SPRAY IMPINGEMENT

P&ID(1)	OPR	TYPE	NUMBER
143		VNT	143018A
143		VNT	140318B
143		VNT	143019A
143		VNT	143019B
143		VNT	143020A
143		VNT	143020B
143		VNT	143021A
143		VNT	143021B
143		VNT	143022A
143		VNT	143022B
143		VNT	143023A
143		VNT	143023B
143		VNT	143024A
143		VNT	143024B
143		VNT	143025A
143		VNT	143025B
143		VNT	143026A
143		VNT	143026B
144		DRN	144002A
144		DRN	144002B
151		TEST	F062
151		TEST	F061
151		DRN	151053
151		DRN	151051
151	AO	HV	F122A
151	AO	HV	F122B
151		TEST	F063
151		TEST	F064
151		VNT	151062
151		VNT	151061
151		TEST	151026
151		TEST	151024
151		VNT	151093 (Unit 1 Only)
151		VNT	151094 (Unit 1 Only)
151		DRN	151095
151		DRN	151096
2151		VNT	251097 (Unit 2 Only)
2151		VNT	251098 (Unit 2 Only)
2151		VNT	251099 (Unit 2 Only)
2151		VNT	251100 (Unit 2 Only)
152		TEST	152011
152		TEST	152012
152		TEST	152013

TABLE 6.3-10

SAFETY-RELATED VALVES IN THE DRYWELL SUBJECT TO SPRAY IMPINGEMENT

P&ID(1)	OPR	TYPE	NUMBER
152		TEST	152014
2152		VNT	252031 (Unit 2 Only)
2152		VNT	252032 (Unit 2 Only)
2152		VNT	252033 (Unit 2 Only)
2152		VNT	252034 (Unit 2 Only)
152	AO	HV	F037A
152	AO	HV	F037B
141		CK	F024A
141		CK	F024B
141		CK	F024C
141		CK	F024D
141		CK	F036A
141		CK	F036B
141		CK	F036C
141		CK	F036D
141		CK	F036E
141		CK	F036F
141		CK	F036G
141		CK	F036H
141		CK	F036J
141		CK	F036K
141		CK	F036L
141		CK	F036M
141		CK	F036N
141		CK	F036P
141		CK	F036R
141		CK	F036S
141		CK	F040G
141		CK	F040J
141		CK	F040K
141		CK	F040L
141		CK	F040M
141		CK	F040N
148		CK	F007
148		MAN	F008
144		MAN	F103
2155		VNT	255040 (Unit 2 Only)
2155		VNT	255041 (Unit 2 Only)
126	MO	HV	12603
143		DRN	F051A
143		DRN	F051B
144		DRN	F029
144		DRN	F030

TABLE 6.3-10

SAFETY-RELATED VALVES IN THE DRYWELL SUBJECT TO SPRAY IMPINGEMENT

P&ID(1)	OPR	TYPE	NUMBER
141		MAN	141016
141	MO	HV	F016
187	AO	HV	18792B2
187	AO	HV	18792B1
187	AO	HV	18792A2
187	AO	HV	18792A1
126		CK	126074
144	MO	HV	F106
144	MO	HV	F100
144	MO	HV	F101
149	MO	HV	F007
143	MO	HV	F032A
143	MO	HV	F032B
113	MO	HV	11345
113	MO	HV	11346
141		PSV	F037A
141		PSV	F037B
141		PSV	F037C
141		PSV	F037D
141		PSV	F037E
141		PSV	F037F
141		PSV	F037G
141		PSV	F037H
141		PSV	F037J
141		PSV	F037K
141		PSV	F037L
141		PSV	F037M
141		PSV	F037N
141		PSV	F037P
141		PSV	F037R
141		PSV	F037S
141		PSV	14137A
141		PSV	14137B
141		PSV	14137C
141		PSV	14137D
141		PSV	14137E
141		PSV	14137F
141		PSV	14137G
141		PSV	14137H
141		PSV	14137J
141		PSV	14137K
141		PSV	14137L
141		PSV	14137M

TABLE 6.3-10

SAFETY-RELATED VALVES IN THE DRYWELL SUBJECT TO SPRAY IMPINGEMENT

P&ID(1)	OPR	TYPE	NUMBER
141		PSV	14137N
141		PSV	14137P
141		PSV	14137R
141		PSV	14137S
151	MO	HV	F022
151		CK	F019
144	MO	HV	F102
144	MO	HV	F001
187	AO	HV	18782A2
187	AO	HV	18782A1
187	AO	HV	18782B2
187	AO	HV	18782B1
141		PSV	F013A
141		PSV	F013G
141		PSV	F013E
141		PSV	F013C
141		PSV	F013J
141		PSV	F013P
141		PSV	F013M
141		PSV	F013S
141		PSV	F013L
141		PSV	F013B
141		PSV	F013R
141		PSV	F013H
141		PSV	F013K
187		VNT	187828
187		DRN	187827
187		VNT	187830 (Unit 1 Only)
187		VNT	187817 (Unit 1 Only)
187		VNT	187816 (Unit 1 Only)
187		VNT	187826
187		VNT	187831 (Unit 1 Only)
187		VNT	187809 (Unit 1 Only)
187		VNT	187808 (Unit 1 Only)
2187		DRN	287824 (Unit 2 Only)
2187		VNT	287825 (Unit 2 Only)
2187		VNT	287823 (Unit 2 Only)
2187		VNT	287822 (Unit 2 Only)
2187		DRN – Unit 1 VNT – Unit 2	187829 287829
2187		VNT	287842 (Unit 2 Only)
2187		VNT	287843 (Unit 2 Only)
157#		PSV	15704A1, B1, C1, D1, E1

TABLE 6.3-10

SAFETY-RELATED VALVES IN THE DRYWELL SUBJECT TO SPRAY IMPINGEMENT

P&ID(1)	OPR	TYPE	NUMBER
157#		PSV	15704A2, B2, C2, D2, E2
141		PSV	F013F
141		PSV	F013D
141		PSV	F013N
155	MO	HV	F002
152	AO	CK	F006B
152	AO	CK	F006A
152		MAN	F007B
152		MAN	F007A
151	MO	HV	F009
151		MAN	F067
151	AO	CK	F050A
151	AO	CK	F050B
151		MAN	F060A
151		MAN	F060B
141		CK	F010A
141		CK	F010B
141	MO	HV	F011A
141	MO	HV	F011B
141	AO	HV	F022A
141	AO	HV	F022B
141	AO	HV	F022C
141	AO	HV	F022D
143	MO	HV	F023A
143	MO	HV	F023B
143	MO	HV	F031A
143	MO	HV	F031B
141		VNT	141022A
141		VNT	141022B
141		VNT	141023A
141		VNT	141023B
151		VNT	151101 (Unit 1 Only)
151		VNT	151102 (Unit 1 Only)
151		DRN	151103
151		DRN	151104
151		VNT	151107
151		VNT	151108
151		DRN	151109
151		DRN	151110
2151		VNT	251113 (Unit 2 Only)
2151		VNT	251114 (Unit 2 Only)
148		TEST	148003
148		TEST	148004

TABLE 6.3-10

SAFETY-RELATED VALVES IN THE DRYWELL SUBJECT TO SPRAY IMPINGEMENT

P&ID[1]	OPR	TYPE	NUMBER
151		ISO	151125
151		ISO	151126
151		ISO	151127
151		ISO	151128
151		ISO	151129
151		CK	151130
151		DRN	151131
151		DRN	151132

GENERAL NOTES:

1. See Table 1.8-4 for a cross-reference between P&ID and FSAR figures.

2. All above listed valves are subject to spray impingement.

3. Unit 2 valves are listed only if they are in addition to the corresponding Unit 1 valves.

4. # These items are located in the wetwell, but are subject to containment spray.

5. Tables do not include safety-related solenoid valves and associated air line valves to air operators since they do not perform any function required for safe shutdown.

TABLE 6.3-10

SAFETY-RELATED VALVES IN THE DRYWELL SUBJECT TO SPRAY IMPINGEMENT

P&ID(1)	OPR	TYPE	NUMBER
143	AO	HV	F019
143		TEST	F021
143		TEST	F022
143		MAN	F059
151		PSV	F126
141		TEST	F017
141		TEST	F018
141		DRN	F095A
141		DRN	F095B
141		DRN	F096A
141		DRN	F096B
141		ROOT	1RV-PP-14107A1
141		ROOT	2RV-PP-14107A1
141		ROOT	1RV-PP-14107B1
141		ROOT	2RV-PP-14107B1
141		ROOT	1RV-PP-14107A2
141		ROOT	2RV-PP-14107A2
141		ROOT	1RV-PP-14107B2
141		ROOT	2RV-PP-14107B2
141		ROOT	1RV-PP-14107A3
141		ROOT	2RV-PP-14107A3
141		ROOT	1RV-PP-14107B3
141		ROOT	2RV-PP-14107B3
144		TEST	F002
144		TEST	F003
149	AO	HV	F088
155	AO	HV	F100
126		CK	126072
126		CK	126152
126		CK	126154
143		CK	F013A
143		CK	F013B
126		TEST	126021
126		MAN	126022
126		MAN	126024G
126		MAN	126024J
126		MAN	126024M
126		TEST	126031
126		MAN	126032
126		MAN	126034K
126		MAN	126034L
126		MAN	126034N
126		TEST	126047

TABLE 6.3-10

SAFETY-RELATED VALVES IN THE DRYWELL SUBJECT TO SPRAY IMPINGEMENT

P&ID(1)	OPR	TYPE	NUMBER
126		TEST	126073
126		TEST	126075
126		TEST	126153
126		TEST	126155
141		DRN	141006A
141		DRN	141006B
141		DRN	141006C
141		DRN	141006D
141		DRN	141006E
141		DRN	141006F
141		DRN	141006G
141		DRN	141006H
141		DRN	141006J
141		DRN	141006K
141		DRN	141006L
141		DRN	141006M
141		DRN	141006N
141		DRN	141006P
141		DRN	141006R
141		DRN	141006S
141		DRN	141007G
141		DRN	141007J
141		DRN	141007K
141		DRN	141007L
141		DRN	141007M
141		DRN	141007N
141		DRN	141008A
141		DRN	141008B
141		DRN	141008C
141		DRN	141008D
141		DRN	141014
141		DRN	141015
143		VNT	F001A
143		VNT	F001B
143		VNT	F002A
143		VNT	F002B
143		MAN	F014A
143		MAN	F014B
141		VNT	141800
141		VNT	141801
141		VNT	141802
141		VNT	141803
141		VNT	141804

TABLE 6.3-10

SAFETY-RELATED VALVES IN THE DRYWELL SUBJECT TO SPRAY IMPINGEMENT

P&ID(1)	OPR	TYPE	NUMBER
141		VNT	141805
141		VNT	141806
141		VNT	141807
141		VNT	141810
141		VNT	141811
141		VNT	141812
141		VNT	141813
141		VNT	141814
141		VNT	141815
141		VNT	141816
141		VNT	141817
141	MO	HV	F001
141	MO	HV	F002
141	MO	HV	F005
141		ISO	141018
143		VNT	F025A
143		VNT	F025B
143		VNT	F026A
143		VNT	F026B
143		DRN	F027A
143		DRN	F028A (Unit 1 Only)
143		VNT	F034A
143		VNT	F034B (Unit 1 Only)
143		VNT	F035A
143		VNT	F035B (Unit 1 Only)
143		DRN	F036A
143		DRN	F036B
143		DRN	F038A
143		DRN	F038B
143		TEST	143027A
143		TEST	140327B
143		TEST	143028A
143		TEST	143028B
143		VNT	143030A
143		VNT	143030B
143		VNT	143029A
143		VNT	143029B
143		VNT	143015A
143		VNT	143015B
143		VNT	143016A
143		VNT	143016B
143		VNT	143017A
143		VNT	143017B

TABLE 6.3-10

SAFETY-RELATED VALVES IN THE DRYWELL SUBJECT TO SPRAY IMPINGEMENT

P&ID(1)	OPR	TYPE	NUMBER
143		VNT	143018A
143		VNT	140318B
143		VNT	143019A
143		VNT	143019B
143		VNT	143020A
143		VNT	143020B
143		VNT	143021A
143		VNT	143021B
143		VNT	143022A
143		VNT	143022B
143		VNT	143023A
143		VNT	143023B
143		VNT	143024A
143		VNT	143024B
143		VNT	143025A
143		VNT	143025B
143		VNT	143026A
143		VNT	143026B
144		DRN	144002A
144		DRN	144002B
151		TEST	F062
151		TEST	F061
151		DRN	151053
151		DRN	151051
151	AO	HV	F122A
151	AO	HV	F122B
151		TEST	F063
151		TEST	F064
151		VNT	151062
151		VNT	151061
151		TEST	151026
151		TEST	151024
151		VNT	151093 (Unit 1 Only)
151		VNT	151094 (Unit 1 Only)
151		DRN	151095
151		DRN	151096
2151		VNT	251097 (Unit 2 Only)
2151		VNT	251098 (Unit 2 Only)
2151		VNT	251099 (Unit 2 Only)
2151		VNT	251100 (Unit 2 Only)
152		TEST	152011
152		TEST	152012
152		TEST	152013

TABLE 6.3-10

SAFETY-RELATED VALVES IN THE DRYWELL SUBJECT TO SPRAY IMPINGEMENT

P&ID(1)	OPR	TYPE	NUMBER
152		TEST	152014
2152		VNT	252031 (Unit 2 Only)
2152		VNT	252032 (Unit 2 Only)
2152		VNT	252033 (Unit 2 Only)
2152		VNT	252034 (Unit 2 Only)
152	AO	HV	F037A
152	AO	HV	F037B
141		CK	F024A
141		CK	F024B
141		CK	F024C
141		CK	F024D
141		CK	F036A
141		CK	F036B
141		CK	F036C
141		CK	F036D
141		CK	F036E
141		CK	F036F
141		CK	F036G
141		CK	F036H
141		CK	F036J
141		CK	F036K
141		CK	F036L
141		CK	F036M
141		CK	F036N
141		CK	F036P
141		CK	F036R
141		CK	F036S
141		CK	F040G
141		CK	F040J
141		CK	F040K
141		CK	F040L
141		CK	F040M
141		CK	F040N
148		CK	F007
148		MAN	F008
144		MAN	F103
2155		VNT	255040 (Unit 2 Only)
2155		VNT	255041 (Unit 2 Only)
126	MO	HV	12603
143		DRN	F051A
143		DRN	F051B
144		DRN	F029
144		DRN	F030

TABLE 6.3-10

SAFETY-RELATED VALVES IN THE DRYWELL SUBJECT TO SPRAY IMPINGEMENT

P&ID(1)	OPR	TYPE	NUMBER
141		MAN	141016
141	MO	HV	F016
187	AO	HV	18792B2
187	AO	HV	18792B1
187	AO	HV	18792A2
187	AO	HV	18792A1
126		CK	126074
144	MO	HV	F106
144	MO	HV	F100
144	MO	HV	F101
149	MO	HV	F007
143	MO	HV	F032A
143	MO	HV	F032B
113	MO	HV	11345
113	MO	HV	11346
141		PSV	F037A
141		PSV	F037B
141		PSV	F037C
141		PSV	F037D
141		PSV	F037E
141		PSV	F037F
141		PSV	F037G
141		PSV	F037H
141		PSV	F037J
141		PSV	F037K
141		PSV	F037L
141		PSV	F037M
141		PSV	F037N
141		PSV	F037P
141		PSV	F037R
141		PSV	F037S
141		PSV	14137A
141		PSV	14137B
141		PSV	14137C
141		PSV	14137D
141		PSV	14137E
141		PSV	14137F
141		PSV	14137G
141		PSV	14137H
141		PSV	14137J
141		PSV	14137K
141		PSV	14137L
141		PSV	14137M

TABLE 6.3-10

SAFETY-RELATED VALVES IN THE DRYWELL SUBJECT TO SPRAY IMPINGEMENT

P&ID(1)	OPR	TYPE	NUMBER
141		PSV	14137N
141		PSV	14137P
141		PSV	14137R
141		PSV	14137S
151	MO	HV	F022
151		CK	F019
144	MO	HV	F102
144	MO	HV	F001
187	AO	HV	18782A2
187	AO	HV	18782A1
187	AO	HV	18782B2
187	AO	HV	18782B1
141		PSV	F013A
141		PSV	F013G
141		PSV	F013E
141		PSV	F013C
141		PSV	F013J
141		PSV	F013P
141		PSV	F013M
141		PSV	F013S
141		PSV	F013L
141		PSV	F013B
141		PSV	F013R
141		PSV	F013H
141		PSV	F013K
187		VNT	187828
187		DRN	187827
187		VNT	187830 (Unit 1 Only)
187		VNT	187817 (Unit 1 Only)
187		VNT	187816 (Unit 1 Only)
187		VNT	187826
187		VNT	187831 (Unit 1 Only)
187		VNT	187809 (Unit 1 Only)
187		VNT	187808 (Unit 1 Only)
2187		DRN	287824 (Unit 2 Only)
2187		VNT	287825 (Unit 2 Only)
2187		VNT	287823 (Unit 2 Only)
2187		VNT	287822 (Unit 2 Only)
2187		DRN – Unit 1 VNT – Unit 2	187829 287829
2187		VNT	287842 (Unit 2 Only)
2187		VNT	287843 (Unit 2 Only)
157#		PSV	15704A1, B1, C1, D1, E1

TABLE 6.3-10

SAFETY-RELATED VALVES IN THE DRYWELL SUBJECT TO SPRAY IMPINGEMENT

P&ID(1)	OPR	TYPE	NUMBER
157#		PSV	15704A2, B2, C2, D2, E2
141		PSV	F013F
141		PSV	F013D
141		PSV	F013N
155	MO	HV	F002
152	AO	CK	F006B
152	AO	CK	F006A
152		MAN	F007B
152		MAN	F007A
151	MO	HV	F009
151		MAN	F067
151	AO	CK	F050A
151	AO	CK	F050B
151		MAN	F060A
151		MAN	F060B
141		CK	F010A
141		CK	F010B
141	MO	HV	F011A
141	MO	HV	F011B
141	AO	HV	F022A
141	AO	HV	F022B
141	AO	HV	F022C
141	AO	HV	F022D
143	MO	HV	F023A
143	MO	HV	F023B
143	MO	HV	F031A
143	MO	HV	F031B
141		VNT	141022A
141		VNT	141022B
141		VNT	141023A
141		VNT	141023B
151		VNT	151101 (Unit 1 Only)
151		VNT	151102 (Unit 1 Only)
151		DRN	151103
151		DRN	151104
151		VNT	151107
151		VNT	151108
151		DRN	151109
151		DRN	151110
2151		VNT	251113 (Unit 2 Only)
2151		VNT	251114 (Unit 2 Only)
148		TEST	148003
148		TEST	148004

TABLE 6.3-10

SAFETY-RELATED VALVES IN THE DRYWELL SUBJECT TO SPRAY IMPINGEMENT

P&ID(1)	OPR	TYPE	NUMBER
151		ISO	151125
151		ISO	151126
151		ISO	151127
151		ISO	151128
151		ISO	151129
151		CK	151130
151		DRN	151131
151		DRN	151132

GENERAL NOTES:

1. See Table 1.8-4 for a cross-reference between P&ID and FSAR figures.

2. All above listed valves are subject to spray impingement.

3. Unit 2 valves are listed only if they are in addition to the corresponding Unit 1 valves.

4. # These items are located in the wetwell, but are subject to containment spray.

5. Tables do not include safety-related solenoid valves and associated air line valves to air operators since they do not perform any function required for safe shutdown.

Table 6.3-1A

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TABLE 6.3-1B

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TABLE 6.3-2A

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TABLE 6.3-2B
Unit 1 and Unit 2

SIGNIFICANT INPUT PARAMETERS TO THE LOSS-OF-COOLANT ACCIDENT ANALYSIS

PLANT PARAMETERS:	
Core Thermal Power	4031 MWt (FANP ATRIUM™-10 Fuel)
Vessel Steam Dome Pressure	1054 psia (FANP ATRIUM™-10 Fuel)
Maximum Recirculation Line Break Area (ft^2)	7.0(1) (FANP ATRIUM™-10 Fuel)
Recirculation Line Break Area for Small and Intermediate Breaks (ft^2)	3.5 to 0.05 (FANP ATRIUM™-10 Fuel)
FUEL PARAMETERS:	
Fuel Types	FANP ATRIUM™-10
Number of fuel rods	91 (8 are part length) (FANP ATRIUM™-10 Fuel)
Peak Technical Specification Linear Heat Generation Rate (kw/ft)	13.4 (FANP ATRIUM™-10 Fuel)

A more detailed list of input to the model and its source is presented for FANP ATRIUM™-10 fuel in References 6.3-14 and 6.3-15.

(1) Calculation of maximum line break area is based on maximum area at the break location. Break flow rate will be limited by the minimum flow area encountered in break path.

TABLE 6.3-2B
Unit 1 and UNIT 2

SIGNIFICANT INPUT PARAMETERS TO THE LOSS-OF-COOLANT ACCIDENT ANALYSIS

EMERGENCY CORE COOLING SYSTEM PARAMETERS:		
Low Pressure Coolant Injection System		
Vessel Pressure at which flow may commence	psid (vessel to drywell)	270
Minimum Rated Flow at Vessel Pressure	GPM/psid (vessel to drywell)	Fig. 6.3-80C (FANP ATRIUM™-10 Fuel)
Initiating signals low water level **or** high drywell pressure plus low reactor pressure permissive(6)	ft. above top of active fuel psig psig	≤ 0.06 FANP ATRIUM™-10 Fuel) ≥ 2.0 400
Maximum allowable time delay from initiating signal to pumps at rated speed	sec	36.6(2)
Pressure at which injection valve may open	psig (vessel pressure)	400
Pressure at which recirculation discharge valve signaled to close	psig	200
Maximum allowed recirculation discharge valve closing time	sec	33
Core Spray System		
Vessel pressure at which flow may commence	psid (vessel to drywell)	303
Minimum rated flow at Vessel Pressure	GPM/Core Spray Loop psid (vessel to drywell)	5585(3) Fig. 6.3-79C 105

(2) Analysis assumes a 24 second LPCI valve opening time.

(3) Accounts for 100 gpm leakage in the piping connection between the vessel nozzle and the shroud.

TABLE 6.3-2B
Unit 1 and Unit 2

SIGNIFICANT INPUT PARAMETERS TO THE LOSS-OF-COOLANT ACCIDENT ANALYSIS

Initiating signals low water level **or** high Drywell Pressure plus low reactor pressure permissive(6)	ft. above top of active fuel psig psig	≤ 0.06 (FANP ATRIUM™-10 Fuel) ≥2.0 400
Maximum allowed (runout) flow	GPM/ Core Spray Loop	6885 (FANP ATRIUM™-10 Fuel) Fig. 6.3-79C
Maximum allowed delay time from initiating signal to pump at rated speed	sec	40.1(4)
Pressure at which injection valve may open	psig (vessel pressure)	400
High Pressure Coolant Injection		
Vessel pressure at which flow may commence	psia	1225 to 165
Minimum rated flow available at vessel pressure	GPM psid (vessel to pump suction)	4500 1210 to 165 psid (FANP ATRIUM™-10 Fuel)
Initiating Signals low water level **or** high Drywell Pressure(6)	ft above top of active fuel psig	≤7.65 (FANP ATRIUM™-10 Fuel) ≥ 2.0
Maximum allowed delay time from initiating signal to rated flow available and injection valve wide open	sec	35

(4) Analysis assumes a 19 second CS valve opening time.

TABLE 6.3-2B
Unit 1 and Unit 2

SIGNIFICANT INPUT PARAMETERS TO THE LOSS-OF-COOLANT ACCIDENT ANALYSIS

Automatic Depressurization System		
Total number of valves installed		6
Number of valves used in analysis		6 (FANP ATRIUM™-10 Fuel)(5)
Minimum Flow Capacity of any 5 valves at vessel pressure	lbm/hr psig (vessel to suppression pool)	4.0×10^6 1125
Initiating Signals low water level **and** high Drywell Pressure **and** Signal that at least 1 LPCI pump or 1 CS loop (2 pumps per loop) are running (pump discharge pressure)	ft above top of active fuel psig (CS) psig (LPCI) psig	≤ 0.06 (FANP ATRIUM™-10 Fuel) ≥ 2.0 115 to 175 100 to 150
Delay time from all initiating signals completed to the time valves are open	sec	120 (FANP ATRIUM™-10 Fuel)

(5) For calculations in which the single failure of interest is the ADS, only 5 valves are operable.

(6) Calculations for ATRIUM™-10 fuel also performed to justify an additional 5 second of delay time. No credit is assumed for the start of HPCI, CS, or LPCI due to high drywell pressure.

Table 6.3-3A

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TABLE 6.3-3B

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TABLE 6.3-3C

Unit 1 and Unit 2

RECIRCULATION LINE BREAK RESULTS
HIGHEST PCT CASES
ATRIUM™ -10

Single Failure	Axial Power Shape			
	Mid-Peaked		Top-Peaked	
	Break Size and Location	PCT (ºF)	Break Size and Location	PCT (ºF)
108 Mlb/hr Flow 102% Power (4031 MWt)				
SF-BATT	0.6 DEG pump suction	1648	0.7 ft^2 pump discharge	1706
SF-LPCI	1.0 DEG pump suction	1698	0.8 DEG pump suction	1730
80 Mlb/hr Flow 102% Power (4031 MWt)				
SFF-BATT	0.6 DEG pump suction	1671	1.0 DEG pump discharge	1684
SF-LPCI	1.5 $ft.^2$ pump discharge	1728	1.0 DEG pump discharge	1803

Table Rev. 1

TABLE 6.3-1B-1

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TABLE 6.3-1B-2

Unit 1 and UNIT 2

EVENT TIMES FOR LIMITING RECIRCULATION LINE BREAK

(1.0) DEG PUMP SUCTION SINGLE-FAILURE LPCI VALVE

TOP-PEAKED AXIAL POWER DISTRIBUTION

102.% POWER (4031 MWt) 80 MLBS/HR FLOW

Event	Time (sec)
Initiate Break	0.0
Initiate Scram	2.5
MSIV closed	5.0
L2 low water level, HPCI signaled	5.7
L1 low water level, DG signaled	7.7
Jet pump suction uncovers	8.4
Recirc suction uncovers	11.5
Lower plenum flashes	14.5
DG power at ESS bus	32.8
LPCI pump starts	36.8
HPCI flow starts	39.8
CS pump starts	44.3
CS valve opens	44.4
Intact loop LPCI valve opens	NA
Intact loop LPCI flow starts	NA
Broken Loop valve opens	44.4
Broken Loop flow starts	44.5
CS flow starts	47.8
Recirc Discharge valve closure starts	51.3
End of Blowdown	65.5
Begin rated spray	65.5
Recirc Discharge valve closure complete	84.3
Core reflood	118.0
PCT	118.0
ADS valve opens	127.7
Bypass reflood	129.2

Table Rev. 1

TABLE 6.3-3B-1

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TABLE 6.3-3B-2

Unit 1 and UNIT 2

**RESULTS FOR LIMITING TWO LOOP OPERATION
RECIRCULATION LINE BREAK
1.0 DEG PUMP SUCTION SF-LPCI
TOP-PEAKED AXIAL 102% POWER (4031 MWt)
80 Mlbs/HR FLOW**

Peak Cladding Temperature, ºF	**1844ºF**
Local Cladding Oxidation (Max%)	**0.80%**
Total Hydrogen Generated (% of Total Hydrogen Possible)	**<0.2%**

FIGURE 6.3-2 REPLACED BY DWG. M1-E41-4, SH. 1

FSAR REV. 65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

FIGURE 6.3-2 REPLACED BY DWG. M1-E41-4, SH. 1

FIGURE 6.3-2, Rev. 52

AutoCAD Figure 6_3_2.doc

FIGURE DELETED

FSAR REV. 65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

FIGURE DELETED

FIGURE 6.3-3, Rev. 54

AutoCAD Figure 6_3_3.doc

FIGURE 6.3-4 REPLACED BY DWG. M-152, SH. 1

FSAR REV. 65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

FIGURE 6.3-4 REPLACED BY DWG. M-152, SH. 1

FIGURE 6.3-4, Rev. 55

AutoCAD Figure 6_3_4.doc

FIGURE 6.3-5 REPLACED BY DWG. M1-E21-15, SH. 1

FSAR REV. 65

SUSQUEHANNA STEAM ELECTRIC STATION UNITS 1 & 2 FINAL SAFETY ANALYSIS REPORT
FIGURE 6.3-5 REPLACED BY DWG. M1-E21-15, SH. 1
FIGURE 6.3-5, Rev. 51

AutoCAD Figure 6_3_5.doc

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FSAR REV. 65

SUSQUEHANNA STEAM ELECTRIC STATION UNITS 1 & 2 FINAL SAFETY ANALYSIS REPORT
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AutoCAD Figure 6_3_6.doc

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FSAR REV. 65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

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FIGURE 6.3-7, Rev. 51

AutoCAD Figure 6_3_7.doc

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SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

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FIGURE 6.3-8, Rev. 51

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FSAR REV. 65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

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FIGURE 6.3-9, Rev. 51

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SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

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FIGURE 6.3-10, Rev. 51

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SUSQUEHANNA STEAM ELECTRIC STATION UNITS 1 & 2 FINAL SAFETY ANALYSIS REPORT
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SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

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FIGURE 6.3-12, Rev. 51

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SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

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FIGURE 6.3-13, Rev. 51

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SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

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FIGURE 6.3-14, Rev. 51

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SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

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FIGURE 6.3-15, Rev. 51

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SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

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FIGURE 6.3-16, Rev. 51

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SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

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SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

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FIGURE 6.3-18, Rev. 51

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SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

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FIGURE 6.3-19, Rev. 51

AutoCAD Figure 6_3_19.doc

FIGURE 6.3-1A REPLACED BY DWG. M-155, SH. 1

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SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

FIGURE 6.3-1A REPLACED BY DWG. M-155, SH. 1

FIGURE 6.3-1A, Rev. 56

AutoCAD Figure 6_3_1A.doc

FIGURE 6.3-1B REPLACED BY DWG. M-156, SH. 1

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SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
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FIGURE 6.3-1B REPLACED BY DWG. M-156, SH. 1

FIGURE 6.3-1B, Rev. 55

AutoCAD Figure 6_3_1B.doc

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SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

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FIGURE 6.3-1C, Rev. 2

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SUSQUEHANNA STEAM ELECTRIC STATION UNITS 1 & 2 FINAL SAFETY ANALYSIS REPORT
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SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

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SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

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SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

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FIGURE 6.3-24, Rev. 51

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SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

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SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

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FIGURE 6.3-26, Rev. 51

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SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

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FIGURE 6.3-28, Rev. 51

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SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

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FIGURE 6.3-29, Rev. 51

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SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

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FIGURE 6.3-30, Rev. 51

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SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
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FIGURE 6.3-31, Rev. 51

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SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

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FIGURE 6.3-32, Rev. 51

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SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

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FIGURE 6.3-33, Rev. 51

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SUSQUEHANNA STEAM ELECTRIC STATION UNITS 1 & 2 FINAL SAFETY ANALYSIS REPORT
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SUSQUEHANNA STEAM ELECTRIC STATION UNITS 1 & 2 FINAL SAFETY ANALYSIS REPORT
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SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
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FIGURE 6.3-36, Rev. 51

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SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

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FIGURE 6.3-37, Rev. 51

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SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

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FIGURE 6.3-38, Rev. 51

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SUSQUEHANNA STEAM ELECTRIC STATION UNITS 1 & 2 FINAL SAFETY ANALYSIS REPORT
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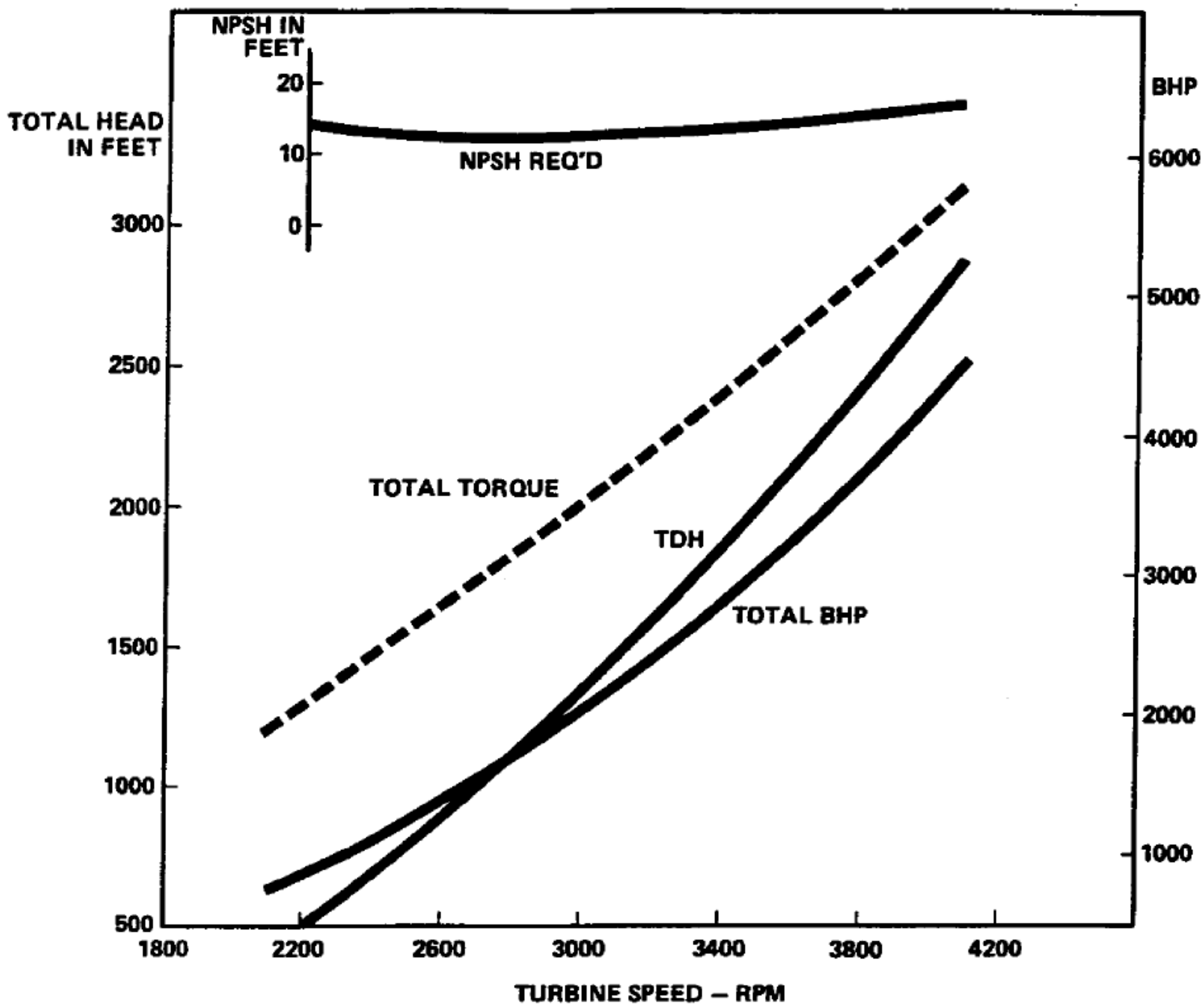
FIGURE 6.3-39, Rev. 51

AutoCAD Figure 6_3_39.doc



CONSTANT 5000 GPM WITH 100 GPM BOOSTER BY-PASS

Information Used for the Original, Pre-upate Design Analyses

FSAR REV.65

SUSQUEHANNA STEAM ELECTRIC STATION UNITS 1 & 2 FINAL SAFETY ANALYSIS REPORT
HIGH PRESSURE COOLANT INJECTION PUMP SPEED CHARACTERISTICS FIGURE 6.3-3A, Rev 50

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SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

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FIGURE 6.3-40, Rev. 51

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SUSQUEHANNA STEAM ELECTRIC STATION UNITS 1 & 2 FINAL SAFETY ANALYSIS REPORT
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SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

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FIGURE 6.3-42, Rev. 51

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SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

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FIGURE 6.3-43, Rev. 51

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SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

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FIGURE 6.3-44, Rev. 51

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SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

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FIGURE 6.3-45, Rev. 51

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SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

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FIGURE 6.3-46, Rev. 51

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SUSQUEHANNA STEAM ELECTRIC STATION UNITS 1 & 2 FINAL SAFETY ANALYSIS REPORT
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SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

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FIGURE 6.3-48, Rev. 51

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SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

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FIGURE 6.3-50, Rev. 55

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SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

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FIGURE 6.3-51, Rev. 55

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SUSQUEHANNA STEAM ELECTRIC STATION
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FINAL SAFETY ANALYSIS REPORT

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FIGURE 6.3-52, Rev. 55

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SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
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FIGURE 6.3-53, Rev. 55

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SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

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FIGURE 6.3-54, Rev. 55

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SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

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FIGURE 6.3-55, Rev. 55

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SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

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FIGURE 6.3-56, Rev. 55

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SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

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FIGURE 6.3-57, Rev. 55

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SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

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FIGURE 6.3-58, Rev. 55

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SUSQUEHANNA STEAM ELECTRIC STATION UNITS 1 & 2 FINAL SAFETY ANALYSIS REPORT
FIGURE DELETED FIGURE 6.3-59, Rev. 55

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SUSQUEHANNA STEAM ELECTRIC STATION
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FIGURE 6.3-60, Rev. 55

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SUSQUEHANNA STEAM ELECTRIC STATION
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FIGURE 6.3-61, Rev. 55

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SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
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FIGURE 6.3-62, Rev. 55

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SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

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FIGURE 6.3-63, Rev. 55

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SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

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FIGURE 6.3-64, Rev. 55

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SUSQUEHANNA STEAM ELECTRIC STATION
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FIGURE 6.3-65, Rev. 55

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SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

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FIGURE 6.3-66, Rev. 55

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SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
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FIGURE 6.3-67, Rev. 54

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SUSQUEHANNA STEAM ELECTRIC STATION
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FIGURE 6.3-68, Rev. 54

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SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

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FIGURE 6.3-69, Rev. 55

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SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

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FIGURE 6.3-6A, Rev. 51

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SUSQUEHANNA STEAM ELECTRIC STATION
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FIGURE 6.3-70, Rev. 55

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SUSQUEHANNA STEAM ELECTRIC STATION
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FINAL SAFETY ANALYSIS REPORT

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FIGURE 6.3-71, Rev. 55

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SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

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FIGURE 6.3-72, Rev. 55

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SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

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FIGURE 6.3-73, Rev. 55

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SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

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FIGURE 6.3-74, Rev. 55

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SUSQUEHANNA STEAM ELECTRIC STATION
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FINAL SAFETY ANALYSIS REPORT

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FIGURE 6.3-75, Rev. 55

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SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

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FIGURE 6.3-76, Rev. 55

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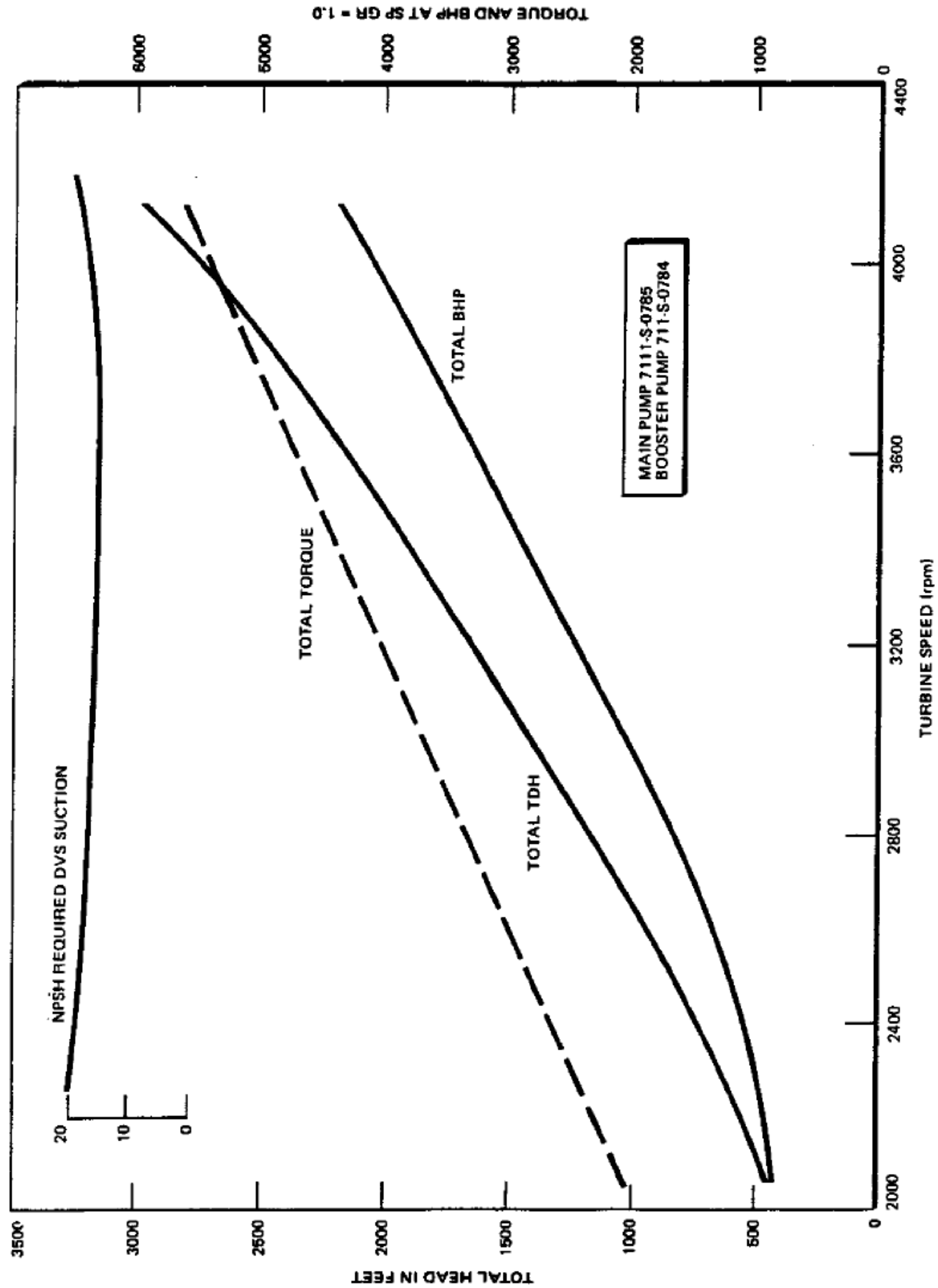

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SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

PUMP CHARACTERISTIC CURVES
FOR HPCI PUMPS

FIGURE 6.3-77, Rev 49

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SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

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FIGURE 6.3-78, Rev. 50

AutoCAD Figure 6_3_78.doc

FIGURE RENUMBERED FROM 6.3-79 TO 6.3-79A

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SUSQUEHANNA STEAM ELECTRIC STATION
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FIGURE RENUMBERED FROM 6.3-79 TO 6.3-79A

FIGURE 6.3-79, Rev. 54

AutoCAD Figure 6_3_79.doc

FIGURE RENUMBERED FROM 6.3-80 TO 6.3-80A

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SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

FIGURE RENUMBERED FROM 6.3-80 TO 6.3-80A

FIGURE 6.3-80, Rev. 54

AutoCAD Figure 6_3_80.doc

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SUSQUEHANNA STEAM ELECTRIC STATION
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FIGURE 6.3-81, Rev. 55

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SUSQUEHANNA STEAM ELECTRIC STATION
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FINAL SAFETY ANALYSIS REPORT

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FIGURE 6.3-82, Rev. 55

AutoCAD Figure 6_3_82.doc

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SUSQUEHANNA STEAM ELECTRIC STATION
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FINAL SAFETY ANALYSIS REPORT

FIGURE DELETED

FIGURE 6.3-83, Rev. 55

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SUSQUEHANNA STEAM ELECTRIC STATION
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FINAL SAFETY ANALYSIS REPORT

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FIGURE 6.3-84, Rev. 56

AutoCAD Figure 6_3_84.doc

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SUSQUEHANNA STEAM ELECTRIC STATION UNITS 1 & 2 FINAL SAFETY ANALYSIS REPORT
FIGURE DELETED FIGURE 6.3-85, Rev. 55

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SUSQUEHANNA STEAM ELECTRIC STATION
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FIGURE 6.3-86, Rev. 55

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SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

FIGURE DELETED

FIGURE 6.3-87, Rev. 55

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SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

FIGURE DELETED

FIGURE 6.3-88, Rev. 55

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SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

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FIGURE 6.3-89, Rev. 55

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SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

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FIGURE 6.3-8A, Rev. 50

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SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

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FIGURE 6.3-8B, Rev. 50

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FIGURE DELETED

FSAR REV. 65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

FIGURE DELETED

FIGURE 6.3-90, Rev. 55

AutoCAD Figure 6_3_90.doc

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FSAR REV. 65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

FIGURE DELETED

FIGURE 6.3-91, Rev. 55

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SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

FIGURE DELETED

FIGURE 6.3-92, Rev. 55

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SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

FIGURE DELETED

FIGURE 6.3-93, Rev. 55

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SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

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FIGURE 6.3-94, Rev. 55

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SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

FIGURE DELETED

FIGURE 6.3-95, Rev. 55

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SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

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FIGURE 6.3-96, Rev. 55

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FSAR REV. 65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

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FIGURE 6.3-97, Rev. 55

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FSAR REV. 65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

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FIGURE 6.3-98, Rev. 55

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SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

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FIGURE 6.3-99, Rev. 55

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FSAR REV. 65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

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FIGURE 6.3-100, Rev. 55

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SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

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FIGURE 6.3-101, Rev. 55

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SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

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FIGURE 6.3-102, Rev. 55

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SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

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FIGURE 6.3-103, Rev. 55

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SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

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FIGURE 6.3-104, Rev. 55

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SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

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FIGURE 6.3-105, Rev. 55

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FSAR REV. 65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

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FIGURE 6.3-106, Rev. 55

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FSAR REV. 65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

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FIGURE 6.3-107, Rev. 55

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FSAR REV. 65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

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FIGURE 6.3-108, Rev. 55

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FSAR REV. 65

SUSQUEHANNA STEAM ELECTRIC STATION UNITS 1 & 2 FINAL SAFETY ANALYSIS REPORT
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FIGURE 6.3-109, Rev. 55

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SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

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FIGURE 6.3-110, Rev. 55

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FSAR REV. 65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

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FIGURE 6.3-111, Rev. 55

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SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

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FIGURE 6.3-112, Rev. 55

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SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

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FIGURE 6.3-113, Rev. 55

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SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

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FIGURE 6.3-114, Rev. 55

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SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

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FIGURE 6.3-115, Rev. 55

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SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

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FIGURE 6.3-116, Rev. 55

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SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

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FIGURE 6.3-117, Rev. 54

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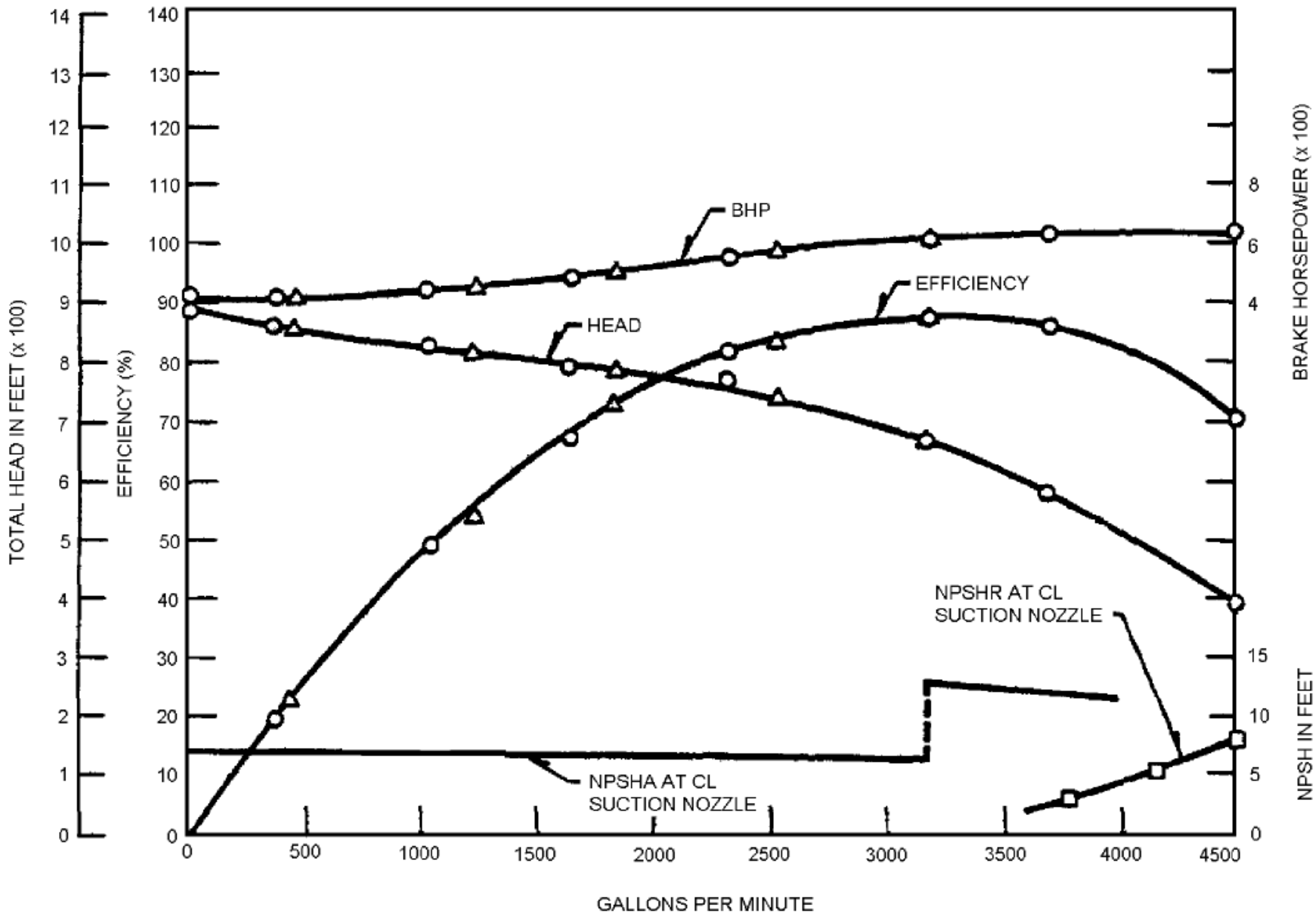

FSAR REV. 65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 AND 2
FINAL SAFETY ANALYSIS REPORT

CHARACTERISTIC CURVES FOR
CORE SPRAY PUMP

FIGURE 6.3-118, Rev. 52

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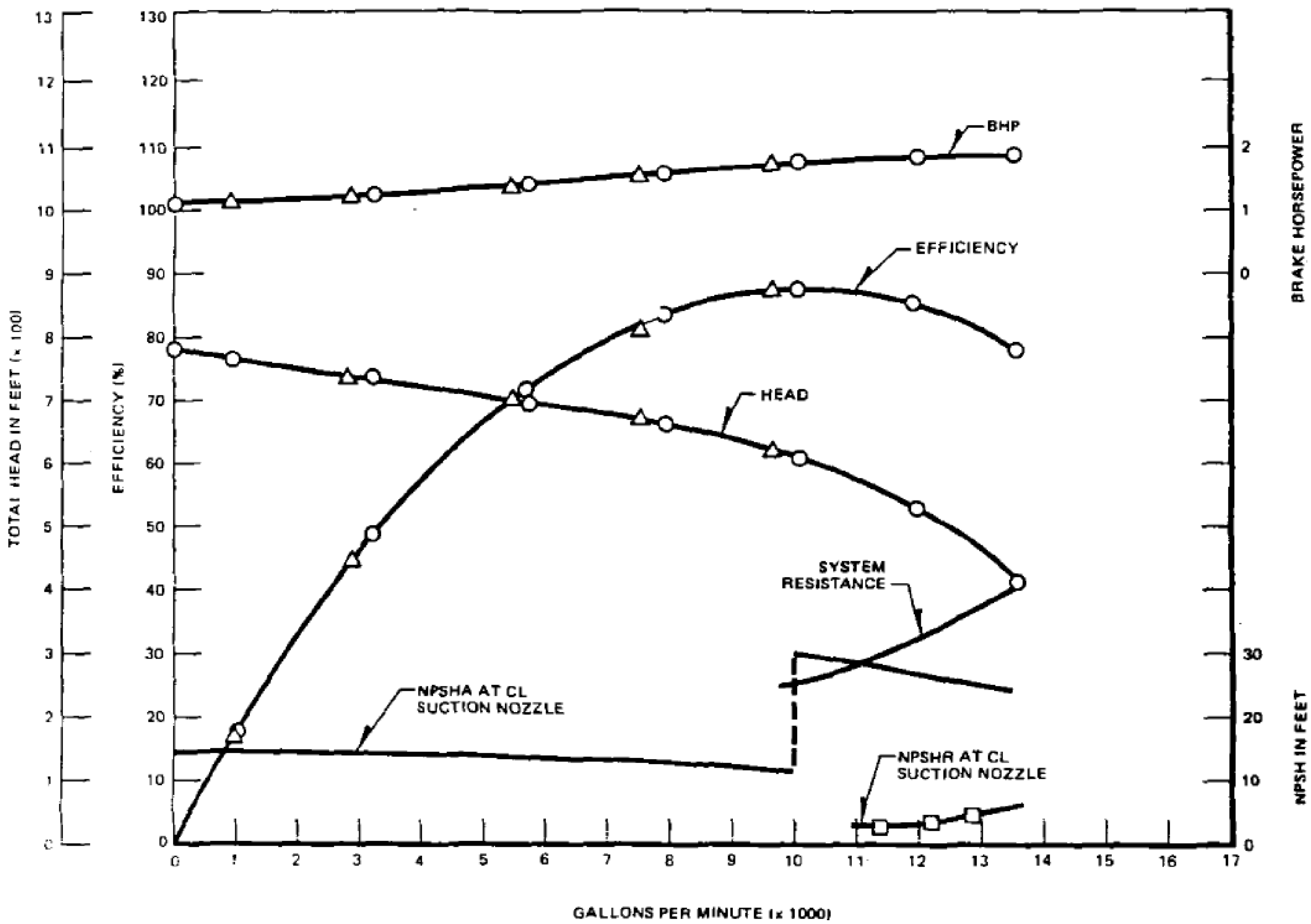


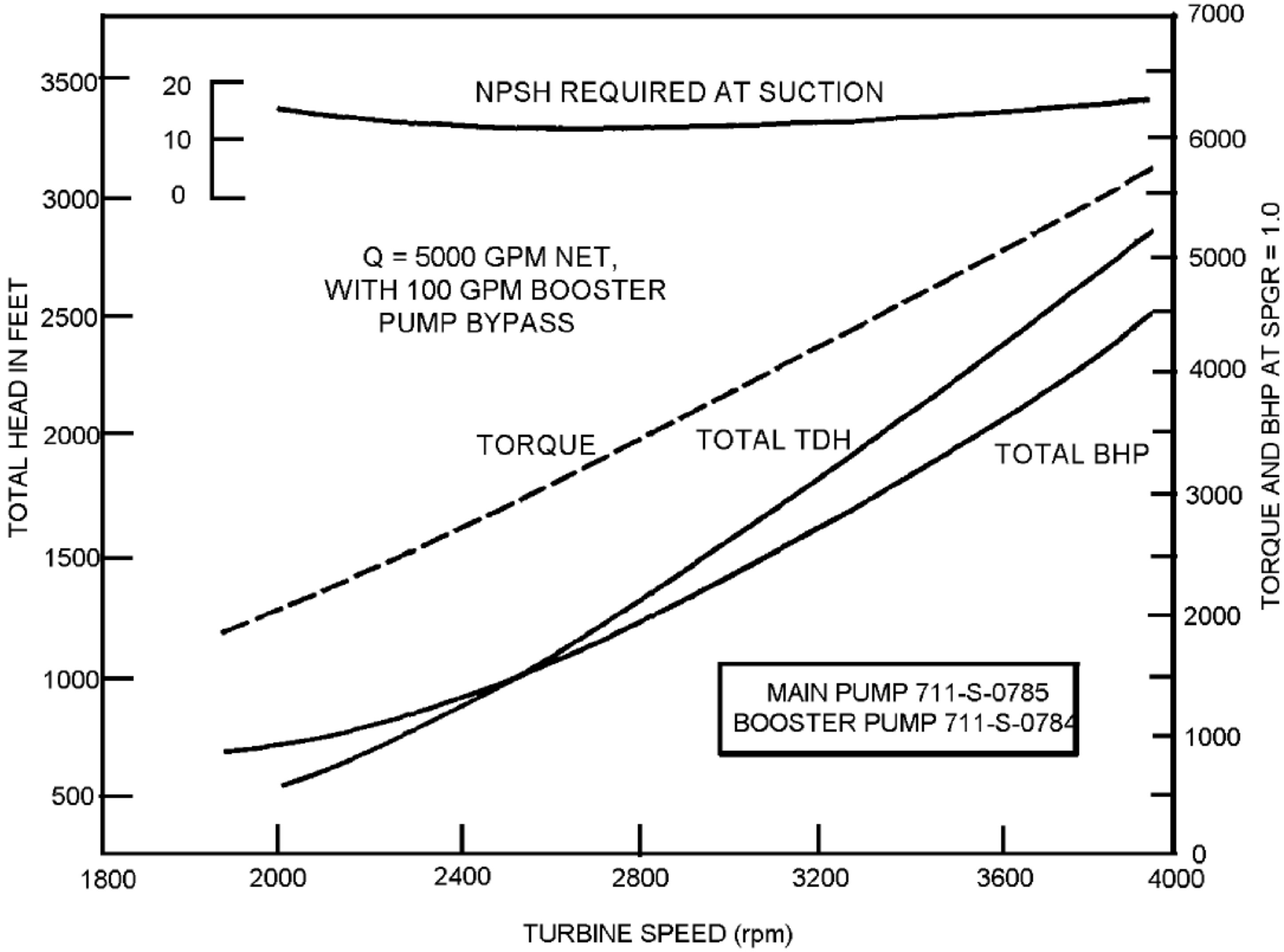
FSAR REV. 65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 AND 2
FINAL SAFETY ANALYSIS REPORT

CHARACTERISTIC CURVES FOR
LPCI PUMP

FIGURE 6.3-119, Rev. 51

Auto Cad: Figure Fsar 6_3_119.dwg



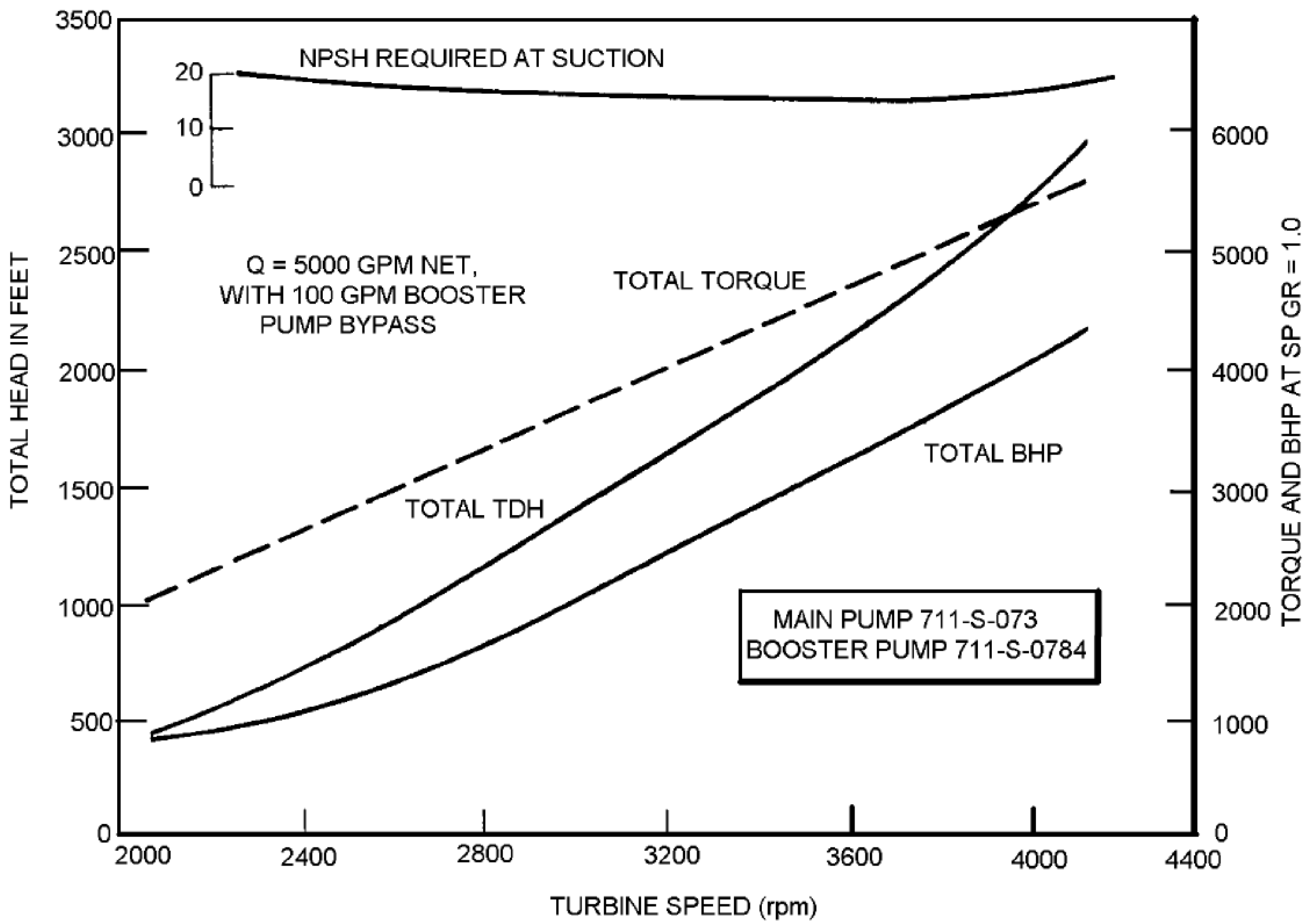
FSAR REV. 65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 AND 2
FINAL SAFETY ANALYSIS REPORT

SPEED CHARACTERISTIC CURVES FOR
HPCI PUMPS - UNIT 1

FIGURE 6.3-120, Rev. 54

Auto Cad: Figure Fsar 6_3_120.dwg



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SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 AND 2
FINAL SAFETY ANALYSIS REPORT

SPEED CHARACTERISTIC CURVES FOR
HPCI PUMPS - UNIT 2

FIGURE 6.3-121, Rev. 54

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SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

FIGURE DELETED

FIGURE 6.3-122, Rev. 56

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SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

FIGURE DELETED

FIGURE 6.3-123, Rev. 56

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SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

FIGURE DELETED

FIGURE 6.3-124, Rev. 56

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SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

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FIGURE 6.3-125, Rev. 56

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SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

FIGURE DELETED

FIGURE 6.3-126, Rev. 56

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SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

FIGURE DELETED

FIGURE 6.3-127, Rev. 56

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SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

FIGURE DELETED

FIGURE 6.3-128, Rev. 56

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SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

FIGURE DELETED

FIGURE 6.3-129, Rev. 56

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SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

FIGURE DELETED

FIGURE 6.3-130, Rev. 56

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SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

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FIGURE 6.3-131, Rev. 56

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SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

FIGURE DELETED

FIGURE 6.3-132, Rev. 56

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SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

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FIGURE 6.3-133, Rev. 56

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SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

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FIGURE 6.3-134, Rev. 56

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SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

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FIGURE 6.3-135, Rev. 56

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SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

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SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

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FIGURE 6.3-137, Rev. 56

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SUSQUEHANNA STEAM ELECTRIC STATION UNITS 1 & 2 FINAL SAFETY ANALYSIS REPORT
FIGURE DELETED FIGURE 6.3-138, Rev. 56

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SUSQUEHANNA STEAM ELECTRIC STATION UNITS 1 & 2 FINAL SAFETY ANALYSIS REPORT
FIGURE DELETED FIGURE 6.3-139, Rev. 56

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SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

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FIGURE 6.3-140, Rev. 56

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FSAR REV. 65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

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FIGURE 6.3-141, Rev. 56

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FSAR REV. 65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

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FIGURE 6.3-142, Rev. 56

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FSAR REV. 65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

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FIGURE 6.3-143, Rev. 56

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FSAR REV. 65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

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FIGURE 6.3-144, Rev. 56

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FSAR REV. 65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

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FIGURE 6.3-145, Rev. 56

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FSAR REV. 65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

FIGURE DELETED

FIGURE 6.3-146, Rev. 56

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FSAR REV. 65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

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FIGURE 6.3-147, Rev. 56

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FSAR REV. 65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

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FIGURE 6.3-148, Rev. 56

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FSAR REV. 65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

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FIGURE 6.3-149, Rev. 56

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SUSQUEHANNA STEAM ELECTRIC STATION UNITS 1 & 2 FINAL SAFETY ANALYSIS REPORT
FIGURE DELETED FIGURE 6.3-150, Rev. 56

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SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

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FIGURE 6.3-151, Rev. 56

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SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

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FIGURE 6.3-152, Rev. 56

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SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

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FIGURE 6.3-153, Rev. 56

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SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

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FIGURE 6.3-154, Rev. 56

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SUSQUEHANNA STEAM ELECTRIC STATION UNITS 1 & 2 FINAL SAFETY ANALYSIS REPORT
FIGURE DELETED FIGURE 6.3-155, Rev. 56

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SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

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FIGURE 6.3-156, Rev. 56

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FSAR REV. 65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

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FIGURE 6.3-157, Rev. 56

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FSAR REV. 65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

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FIGURE 6.3-158, Rev. 56

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FSAR REV. 65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

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FIGURE 6.3-159, Rev. 56

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FSAR REV. 65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

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FIGURE 6.3-160, Rev. 56

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FSAR REV. 65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

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FIGURE 6.3-161, Rev. 56

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FSAR REV. 65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

FIGURE DELETED

FIGURE 6.3-162, Rev. 56

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FSAR REV. 65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

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FIGURE 6.3-163, Rev. 56

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FSAR REV. 65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

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FIGURE 6.3-164, Rev. 56

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FSAR REV. 65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

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FIGURE 6.3-165, Rev. 56

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SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

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FIGURE 6.3-166, Rev. 56

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FSAR REV. 65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

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FIGURE 6.3-167, Rev. 56

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FSAR REV. 65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

FIGURE DELETED

FIGURE 6.3-168, Rev. 56

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FSAR REV. 65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

FIGURE DELETED

FIGURE 6.3-169, Rev. 56

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FSAR REV. 65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

FIGURE DELETED

FIGURE 6.3-170, Rev. 56

AutoCAD Figure 6_3_170.doc

FIGURE DELETED

FSAR REV. 65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

FIGURE DELETED

FIGURE 6.3-171, Rev. 56

AutoCAD Figure 6_3_171.doc

FIGURE DELETED

FSAR REV. 65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

FIGURE DELETED

FIGURE 6.3-200, Rev. 2

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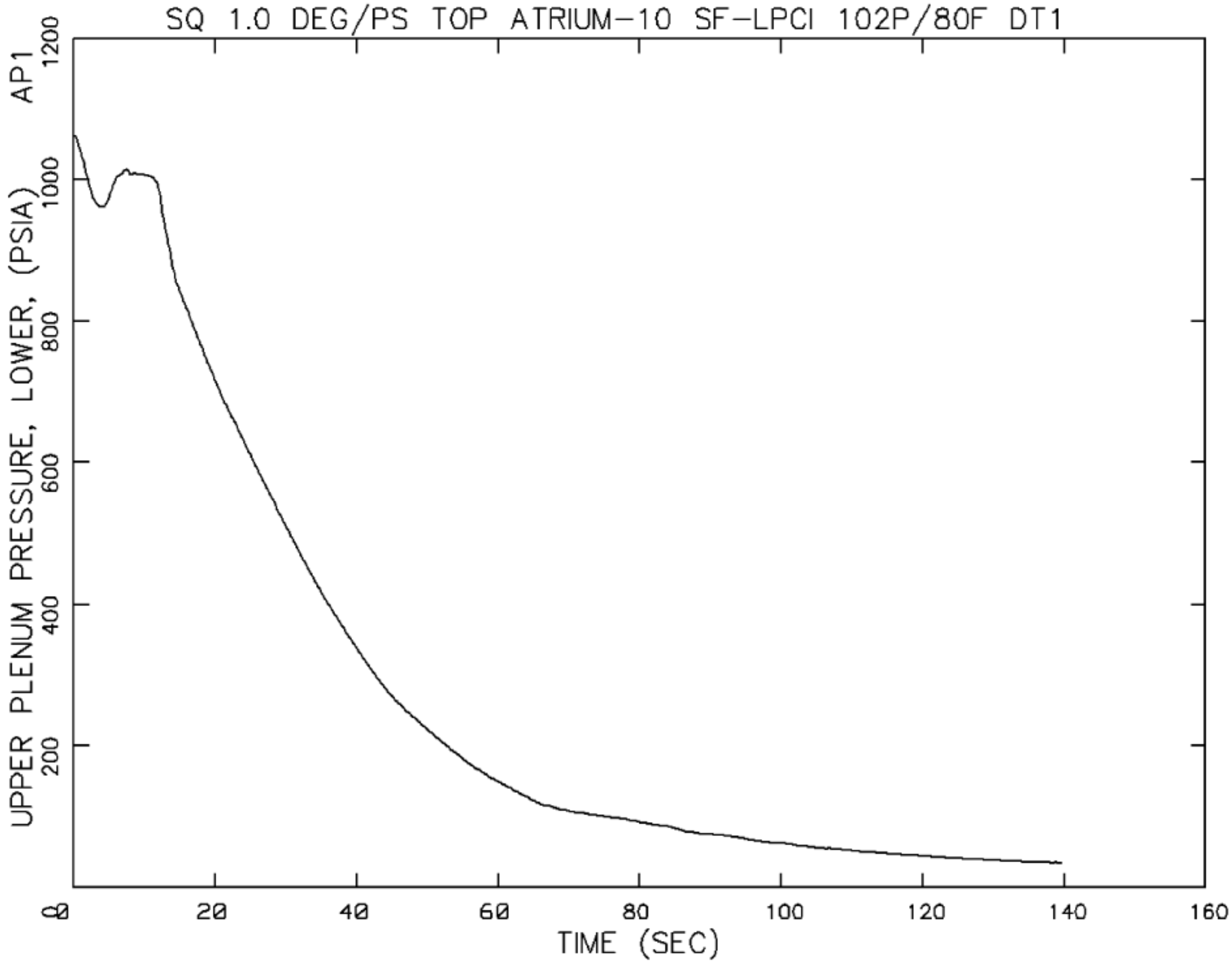

Limiting TLO Recirculation Line Break
Upper Plenum Pressure (Lower)

FSAR REV.65

SUSQUEHANNA STEAM ELECTRIC STATION UNITS 1 & 2 FINAL SAFETY ANALYSIS REPORT
LIMITING TLO RECIRCULATION LINE BREAK UPPER PLENUM PRESSURE (LOWER) **FIGURE 6.3-201, Rev 3**

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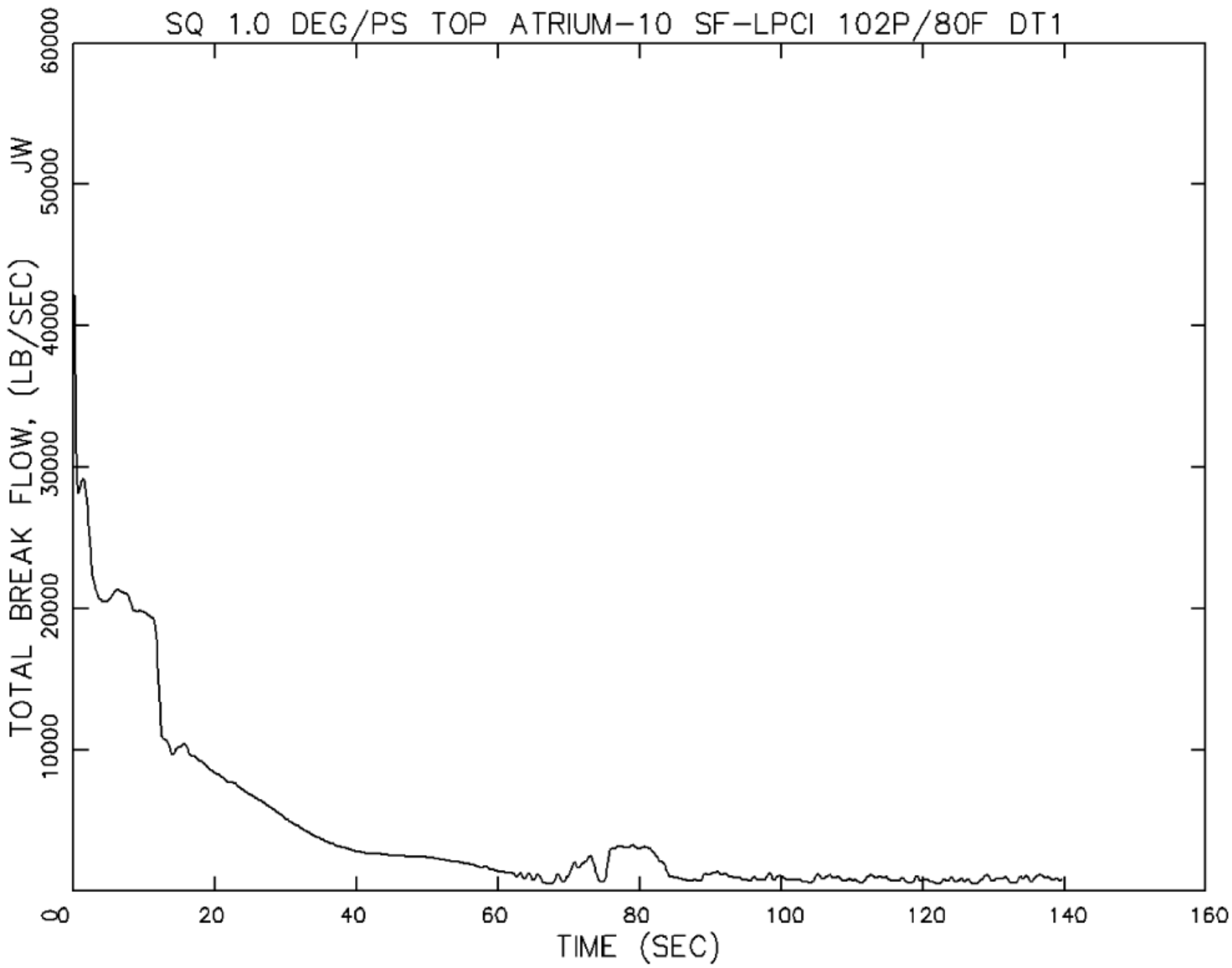


Limiting TLO Recirculation Line Break
Total Break Flow Rate

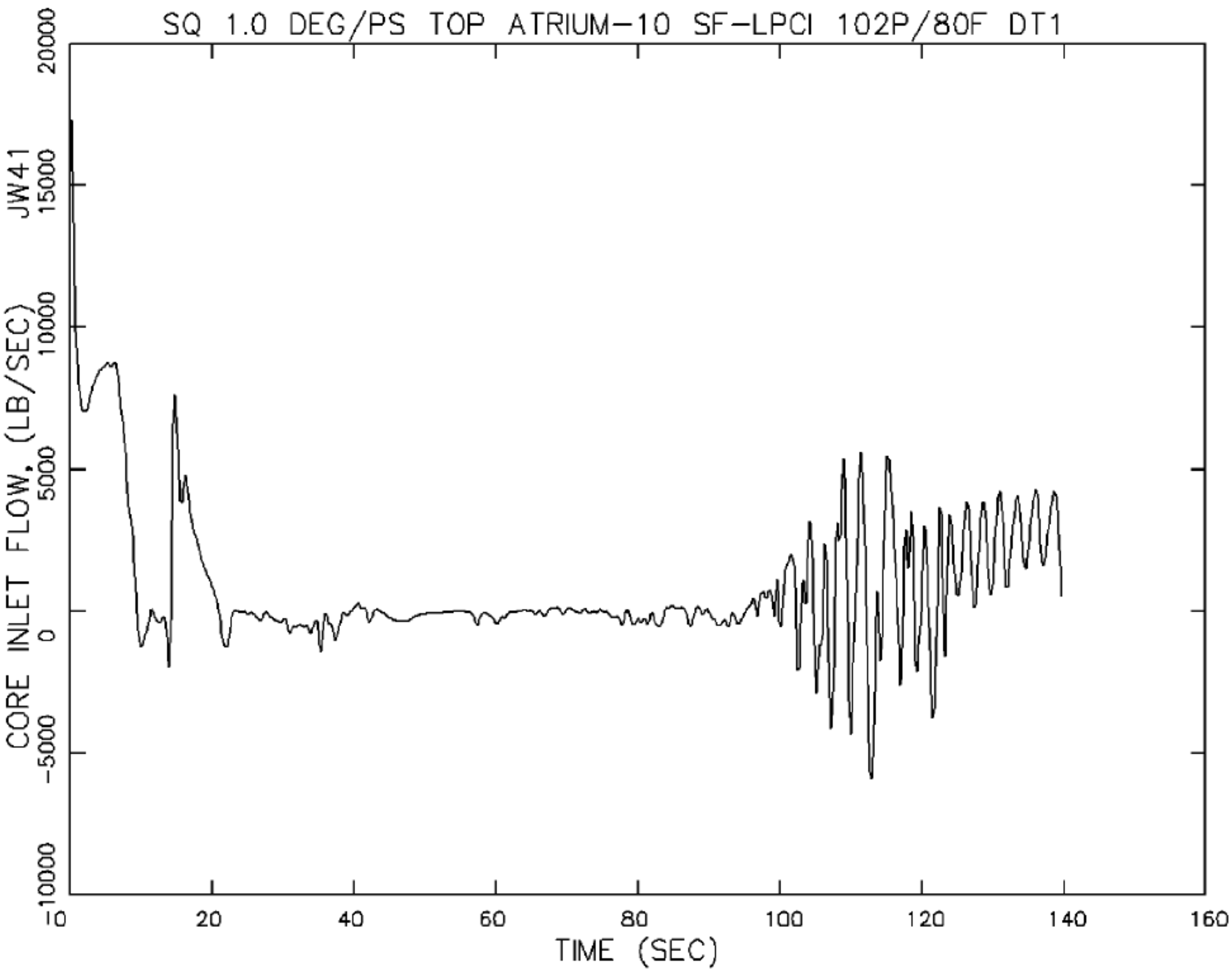
FSAR REV.65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

LIMITING TLO RECIRCULATION LINE BREAK
TOTAL BREAK FLOW RATE

FIGURE 6.3-202, Rev 3

AutoCAD: Figure Fsar 6_3_202.dwg

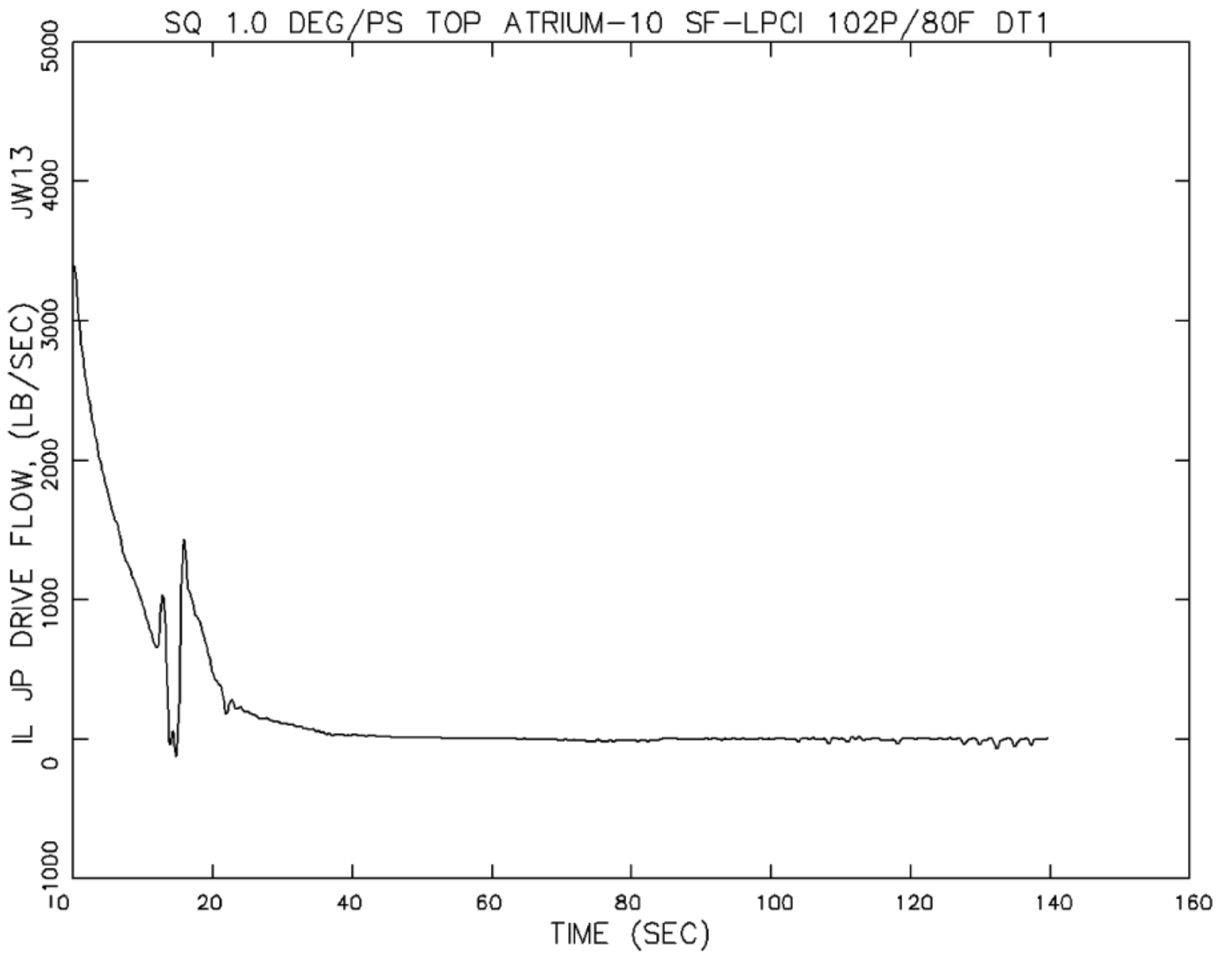


Limiting TLO Recirculation Line Break
Core Inlet Flow Rate

FSAR REV.65

SUSQUEHANNA STEAM ELECTRIC STATION UNITS 1 & 2 FINAL SAFETY ANALYSIS REPORT
LIMITING TLO RECIRCULATION LINE BREAK CORE INLET FLOW RATE FIGURE 6.3-203, Rev 3

AutoCAD: Figure Fsar 6_3_203.dwg



Limiting TLO Recirculation Line Break
Intact Loop Jet Pump Drive Flow Rate

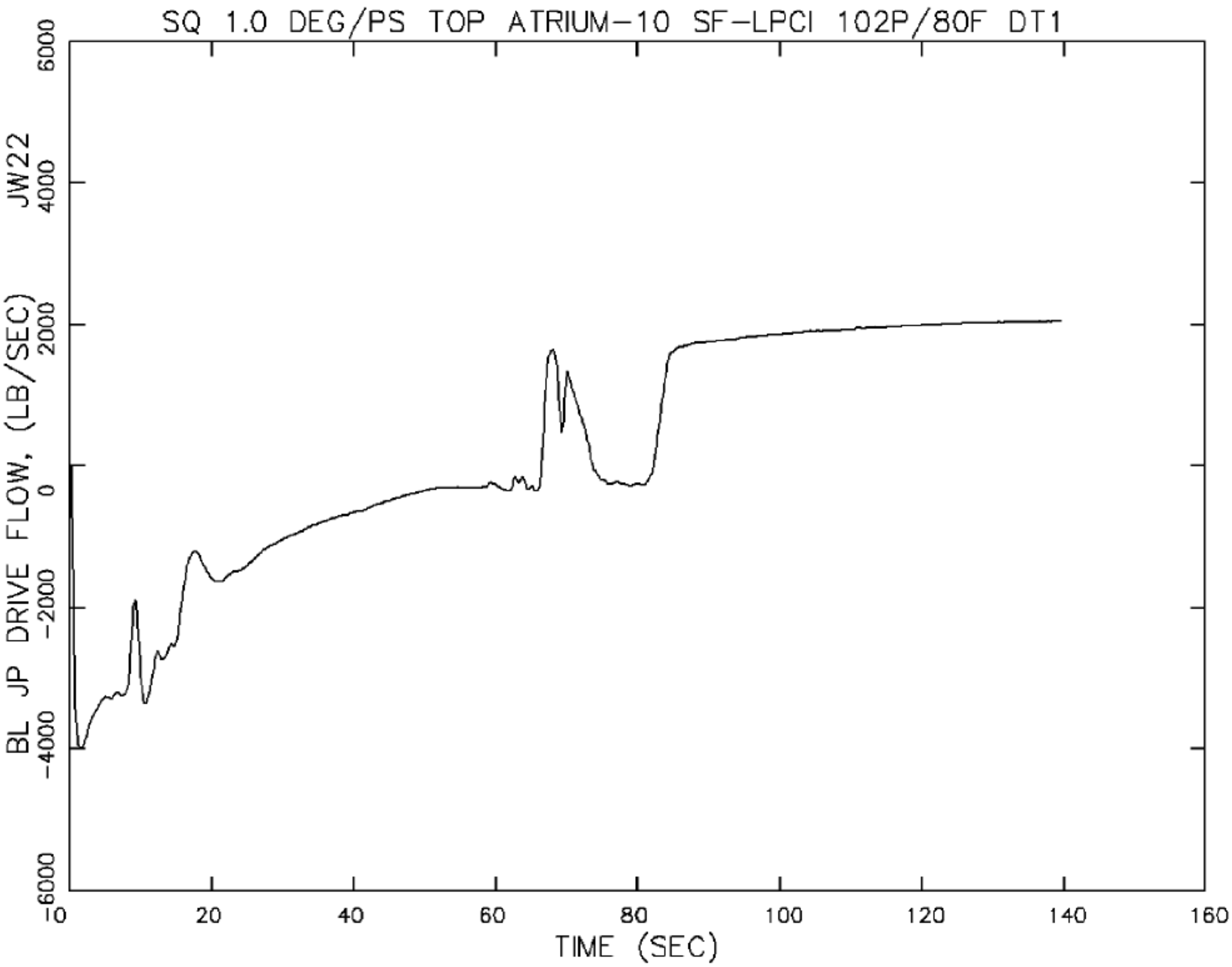
FSAR REV.65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

LIMITING TLO RECIRCULATION LINE BREAK
INTACT LOOP JET PUMP DRIVE FLOW RATE

FIGURE 6.3-204, Rev 3

AutoCAD: Figure Fsar 6_3_204.dwg



Limiting TLO Recirculation Line Break
Broken Loop Jet Pump Drive Flow Rate

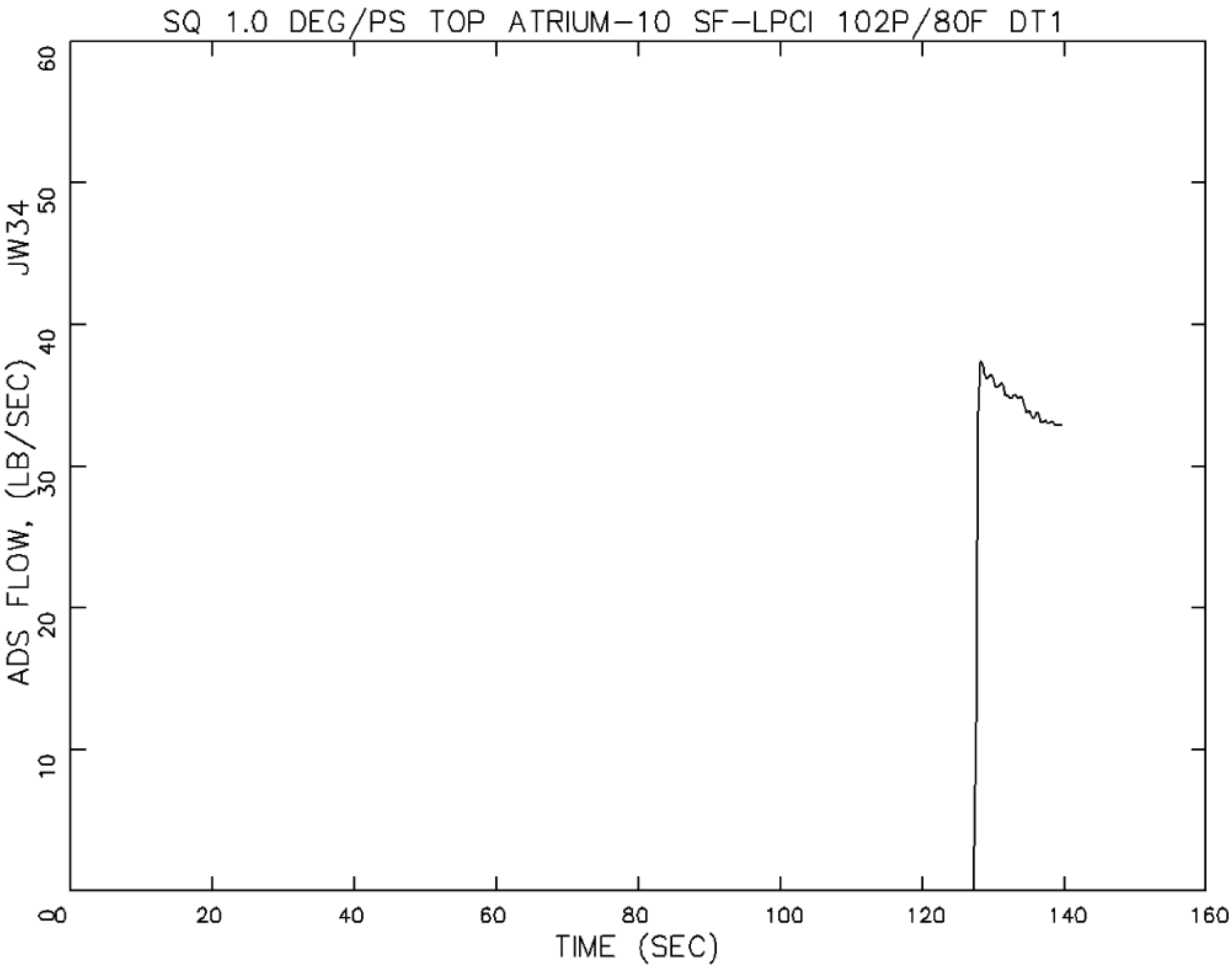
FSAR REV.65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

LIMITING TLO RECIRCULATION LINE BREAK
BROKEN LOOP JET PUMP DRIVE FLOW RATE

FIGURE 6.3-205, Rev 3

AutoCAD: Figure Fsar 6_3_205.dwg

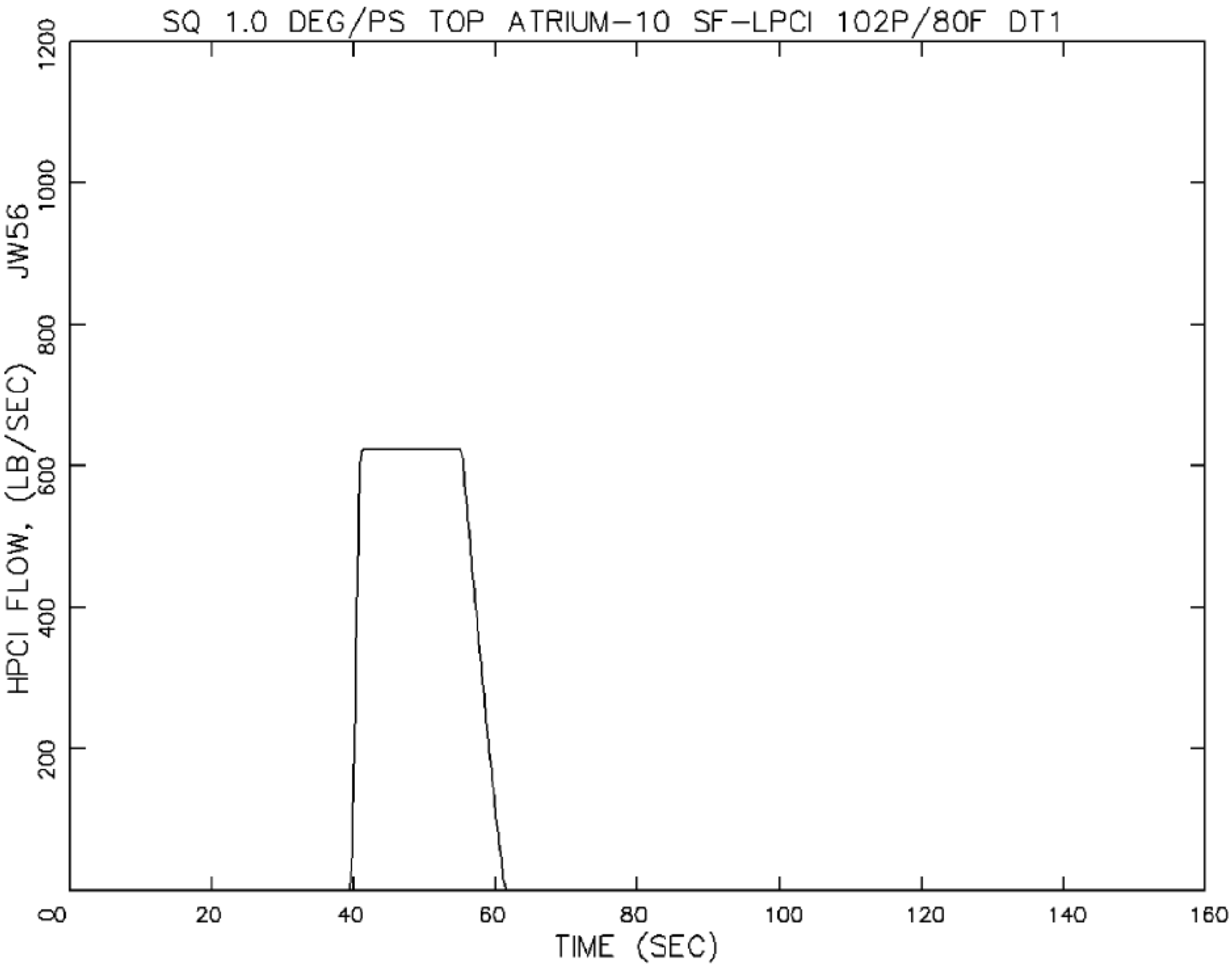


Limiting TLO Recirculation Line Break
ADS Flow Rate

FSAR REV.65

SUSQUEHANNA STEAM ELECTRIC STATION UNITS 1 & 2 FINAL SAFETY ANALYSIS REPORT
LIMITING TLO RECIRCULATION LINE BREAK ADS FLOW RATE FIGURE 6.3-206, Rev 3

AutoCAD: Figure Fsar 6_3_206.dwg

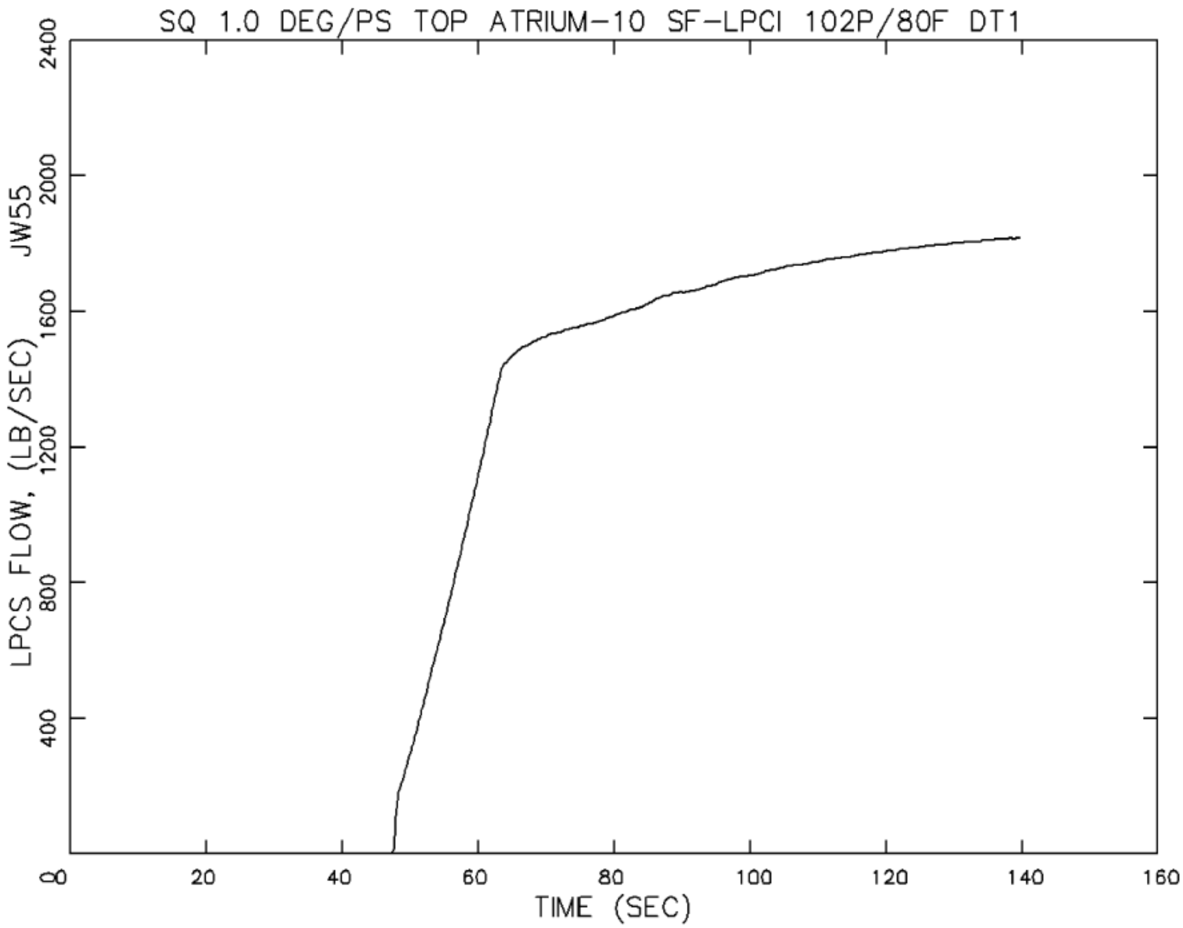


Limiting TLO Recirculation Line Break
HPCI Flow Rate

FSAR REV.65

SUSQUEHANNA STEAM ELECTRIC STATION UNITS 1 & 2 FINAL SAFETY ANALYSIS REPORT
LIMITING TLO RECIRCULATION LINE BREAK HPCI FLOW RATE FIGURE 6.3-207, Rev 3

AutoCAD: Figure Fsar 6_3_207.dwg



Limiting TLO Recirculation Line Break
LPCS Flow Rate

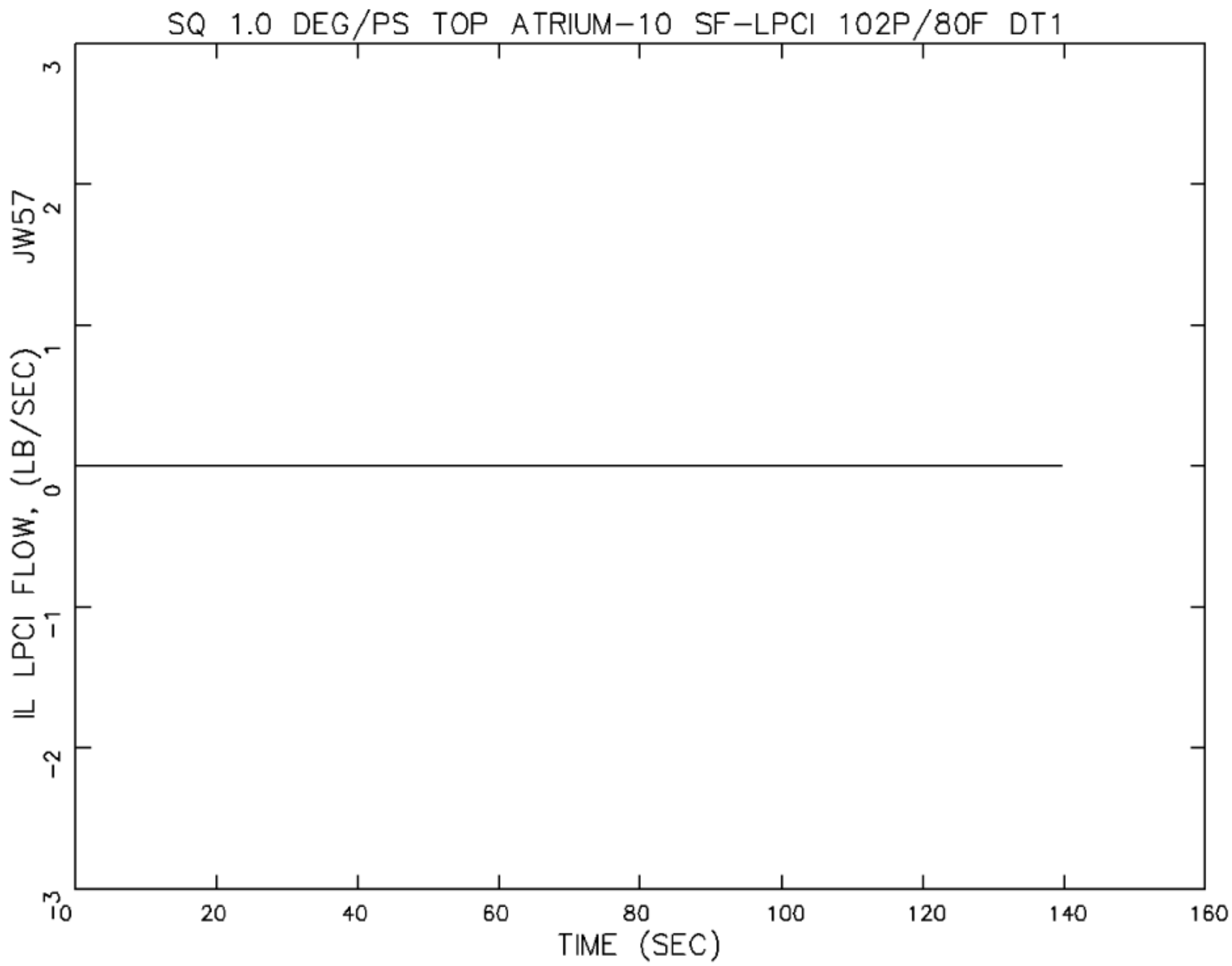
FSAR REV.65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

LIMITING TLO RECIRCULATION LINE BREAK
LPCS FLOW RATE

FIGURE 6.3-208, Rev 3

AutoCAD: Figure Fsar 6_3_208.dwg



Limiting TLO Recirculation Line Break
Intact Loop LPCI Flow Rate

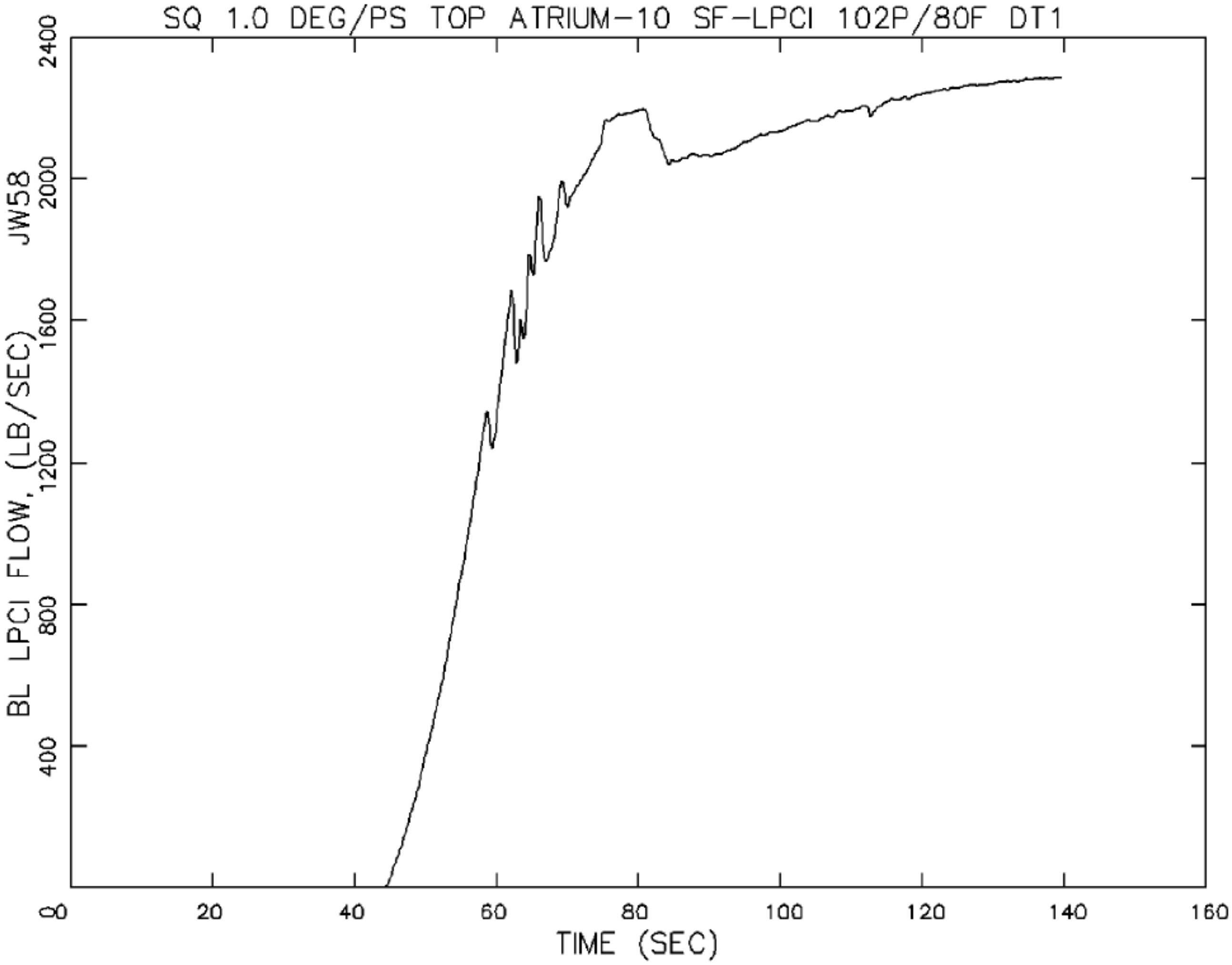
FSAR REV.65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

LIMITING TLO RECIRCULATION LINE BREAK
INTACT LOOP LPCI FLOW RATE

FIGURE 6.3-209, Rev 3

AutoCAD: Figure Fsar 6_3_209.dwg



Limiting TLO Recirculation Line Break
Broken Loop LPCI Flow Rate

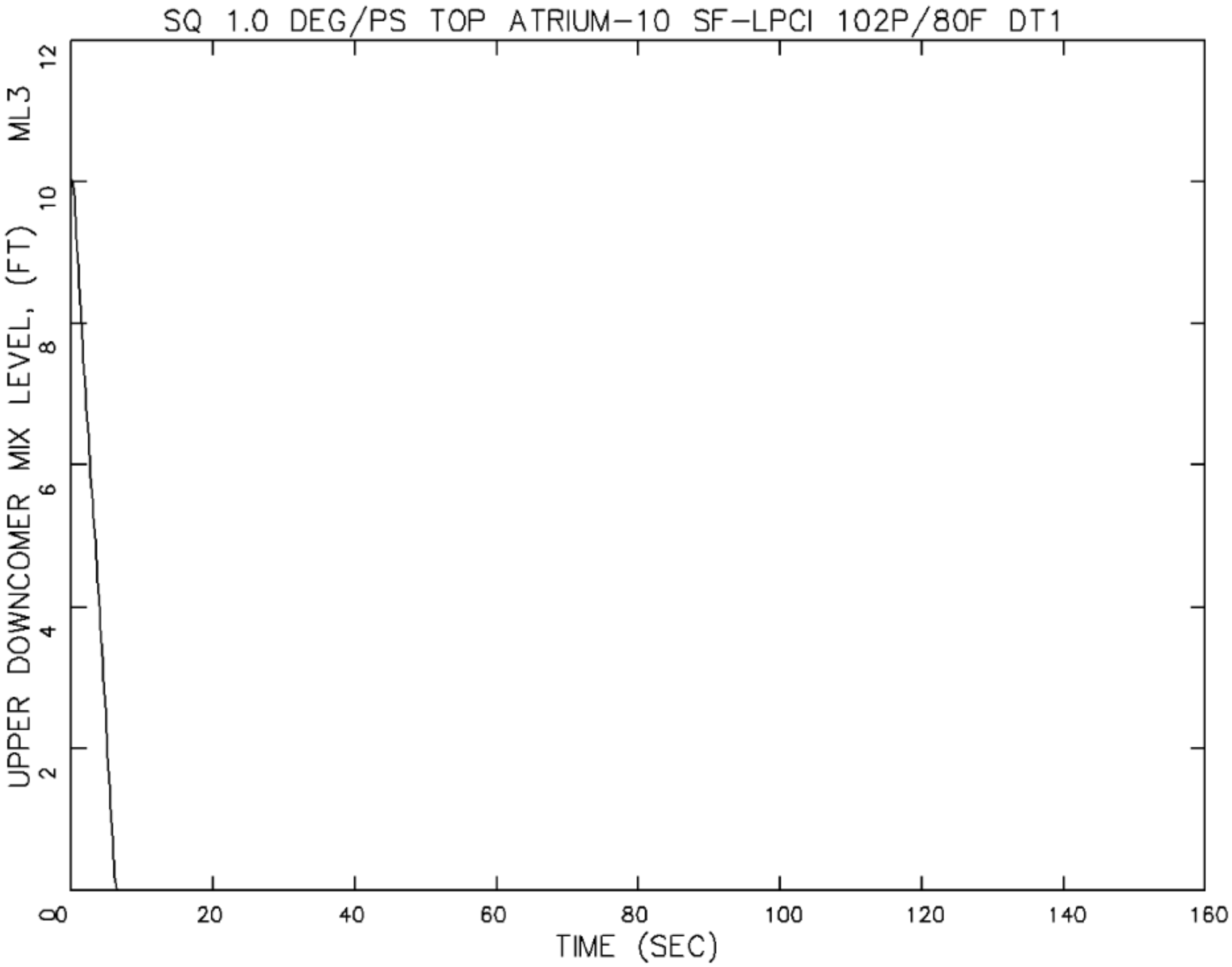
FSAR REV.65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

LIMITING TLO RECIRCULATION LINE BREAK
BROKEN LOOP LPCI FLOW RATE

FIGURE 6.3-210, Rev 3

AutoCAD: Figure Fsar 6_3_210.dwg



Limiting TLO Recirculation Line Break
Upper Downcomer Mixture Level

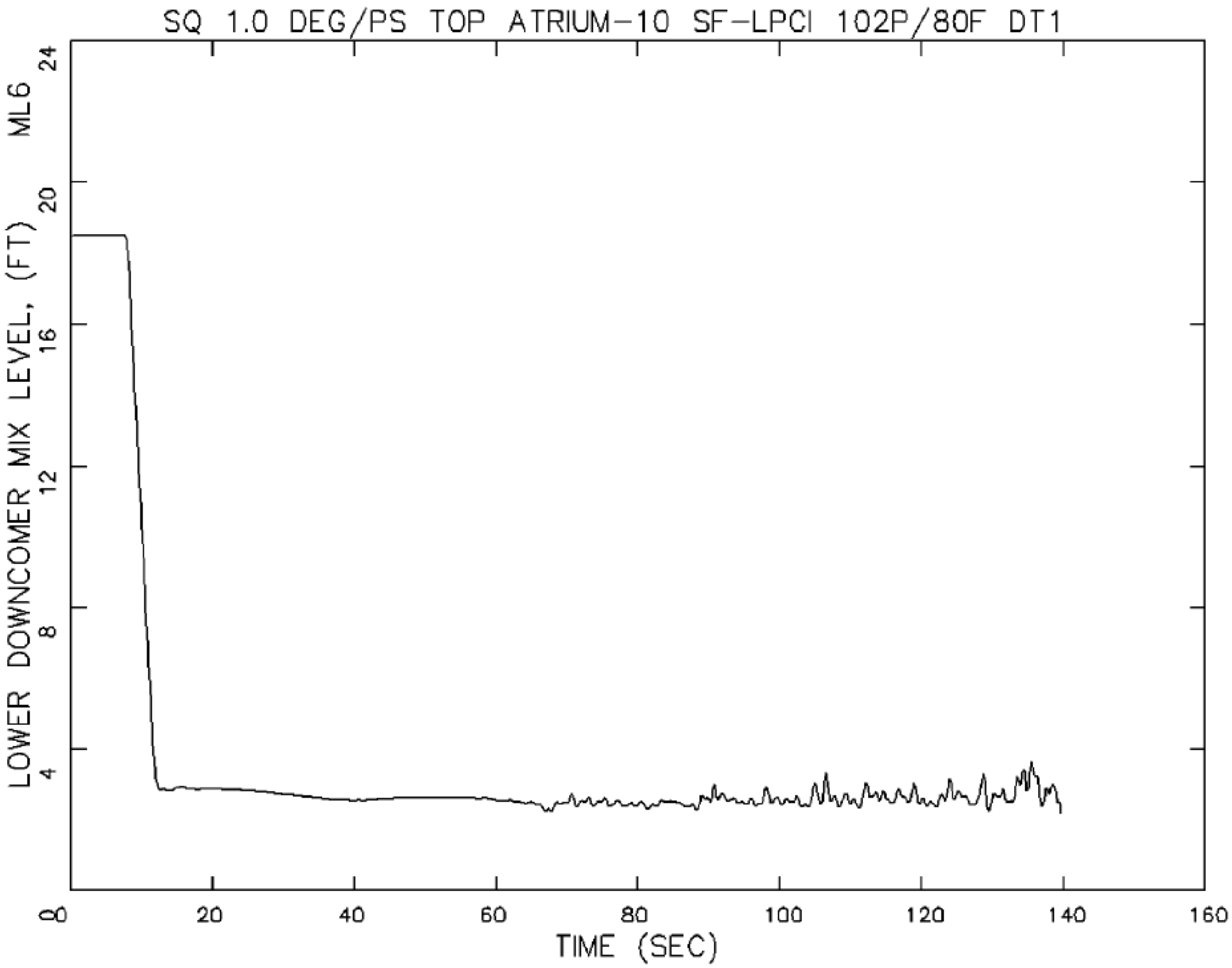
FSAR REV.65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

LIMITING TLO RECIRCULATION LINE BREAK
UPPER DOWNCOMER MIXTURE LEVEL

FIGURE 6.3-211, Rev 3

AutoCAD: Figure Fsar 6_3_211.dwg



Limiting TLO Recirculation Line Break
Lower Downcomer Mixture Level

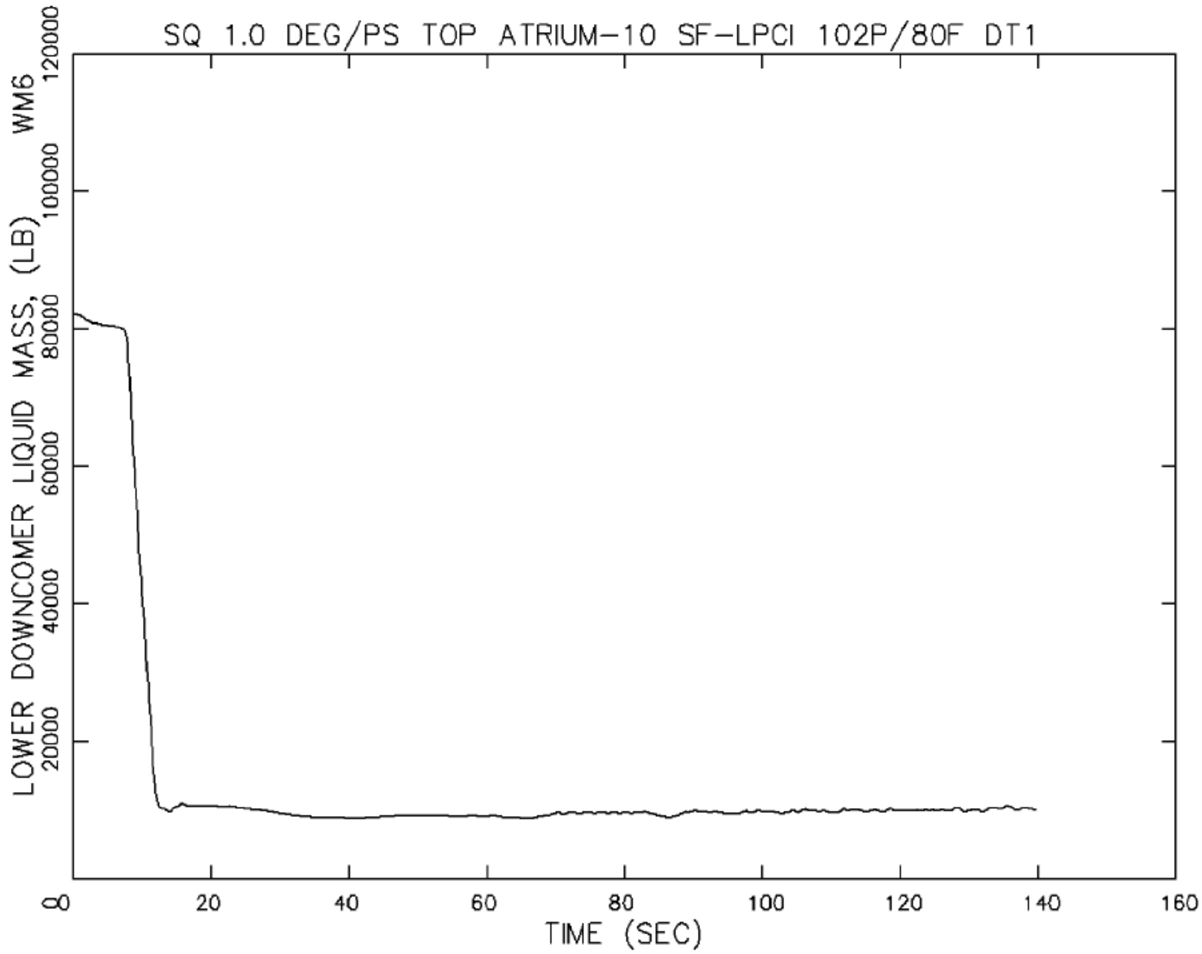
FSAR REV.65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

LIMITING TLO RECIRCULATION LINE BREAK
LOWER DOWNCOMER MIXTURE LEVEL

FIGURE 6.3-212, Rev 3

AutoCAD: Figure Fsar 6_3_212.dwg



Limiting TLO Recirculation Line Break
Lower Downcomer Liquid Mass

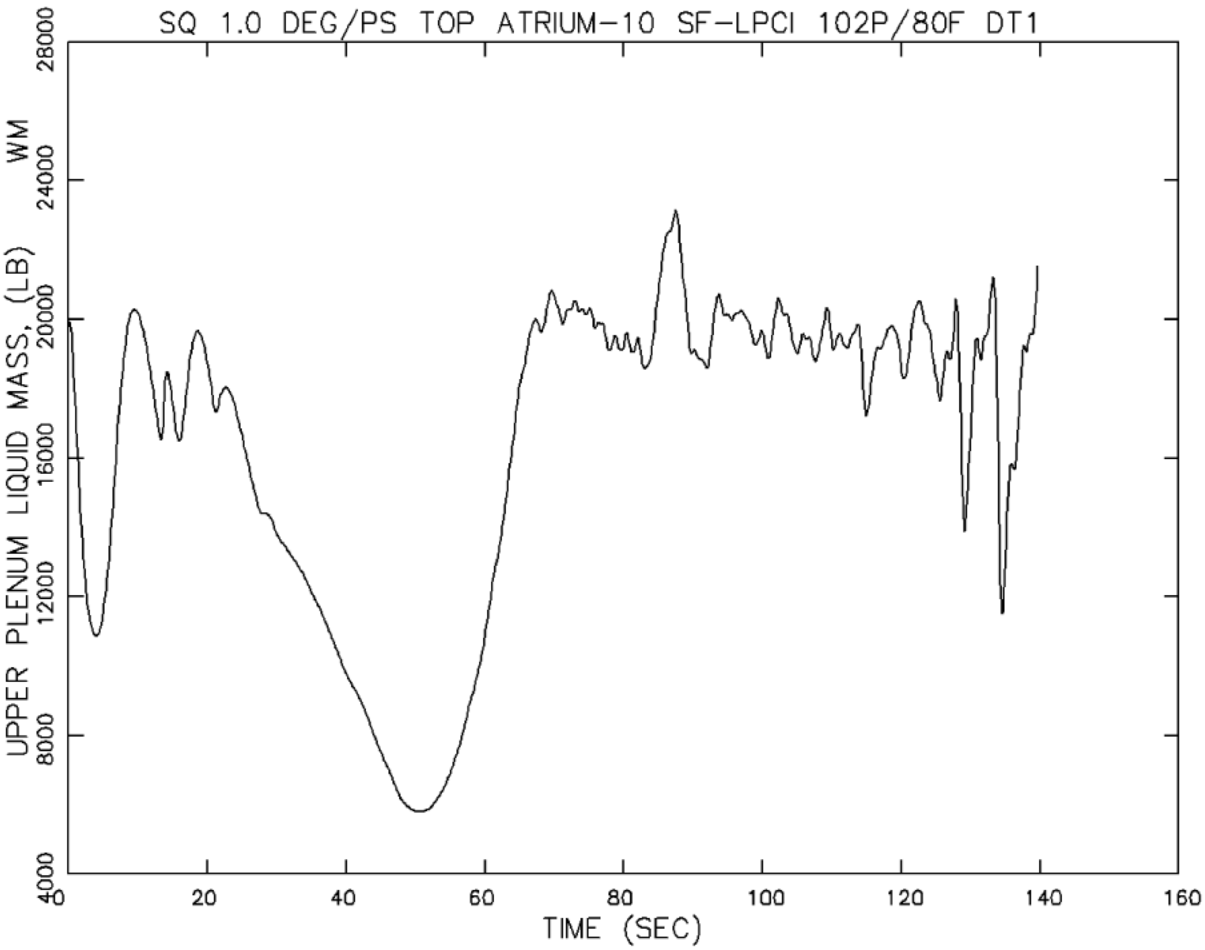
FSAR REV.65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

LIMITING TLO RECIRCULATION LINE BREAK
LOWER DOWNCOMER LIQUID MASS

FIGURE 6.3-213, Rev 3

AutoCAD: Figure Fsar 6_3_213.dwg

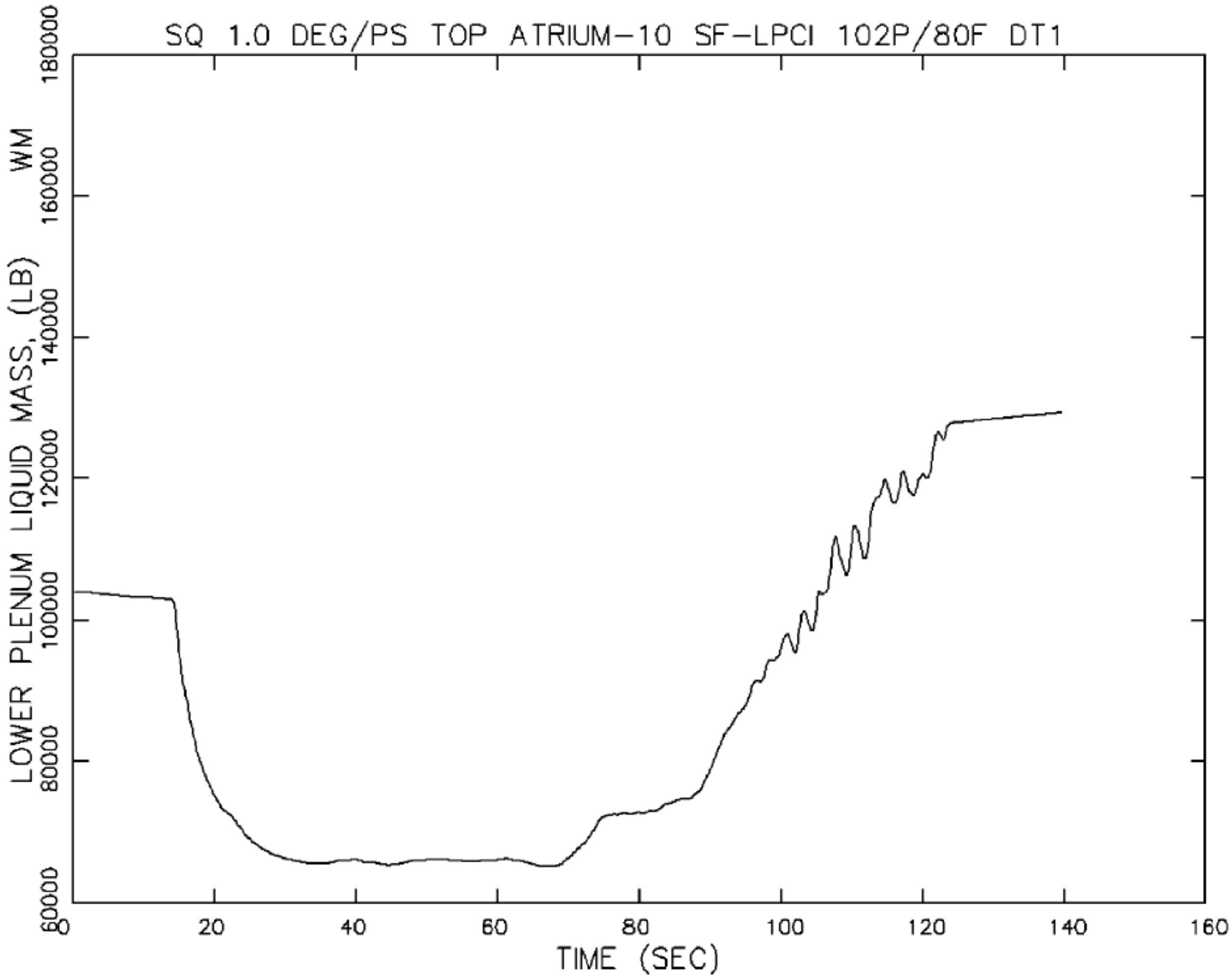


Limiting TLO Recirculation Line Break
Upper Plenum Liquid Mass

FSAR REV.65

SUSQUEHANNA STEAM ELECTRIC STATION UNITS 1 & 2 FINAL SAFETY ANALYSIS REPORT
LIMITING TLO RECIRCULATION LINE BREAK UPPER PLENUM LIQUID MASS FIGURE 6.3-214, Rev 3

AutoCAD: Figure Fsar 6_3_214.dwg



Limiting TLO Recirculation Line Break
Lower Plenum Liquid Mass

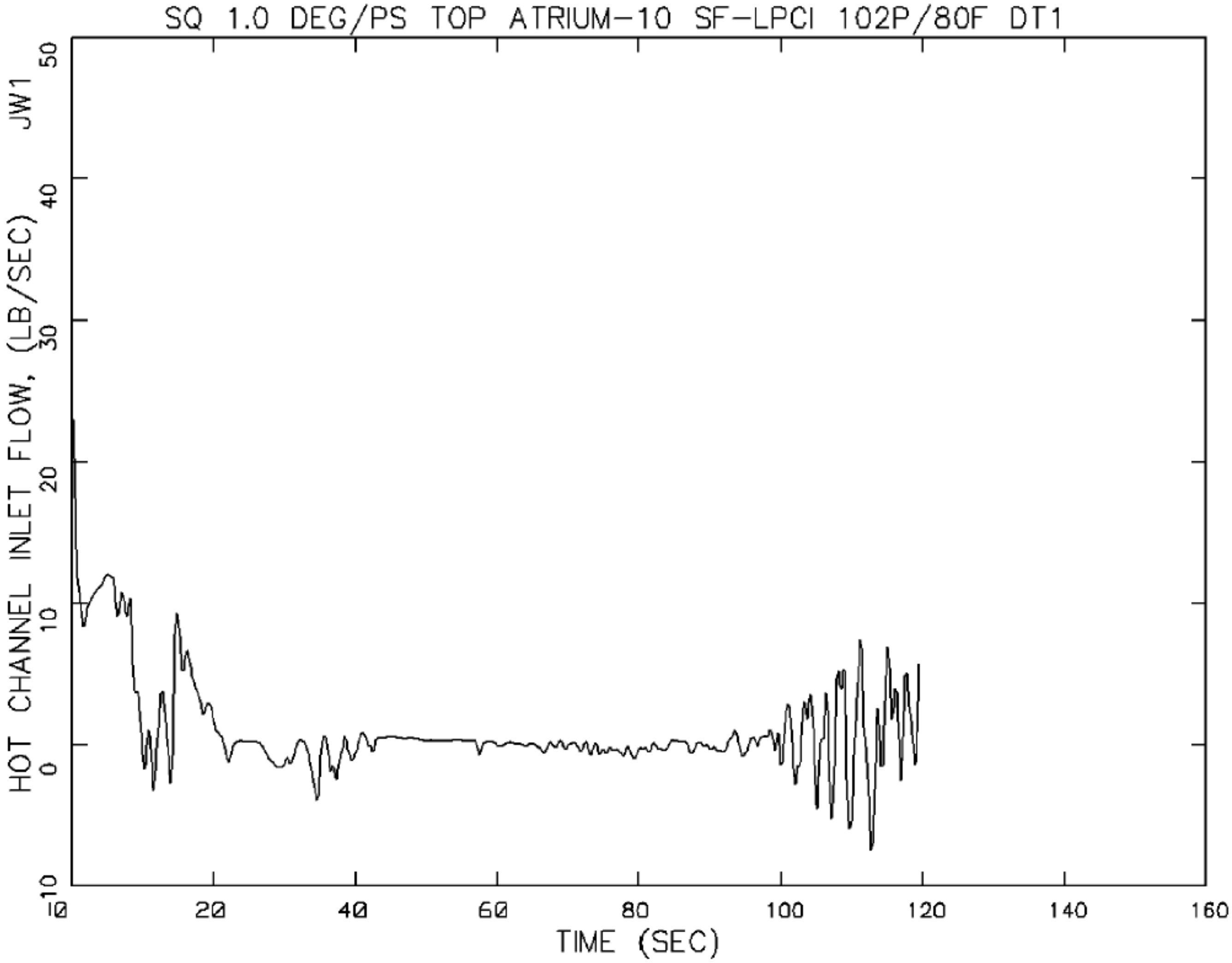
FSAR REV.65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

LIMITING TLO RECIRCULATION LINE BREAK
LOWER PLENUM LIQUID MASS

FIGURE 6.3-215, Rev 3

AutoCAD: Figure Fsar 6_3_215.dwg

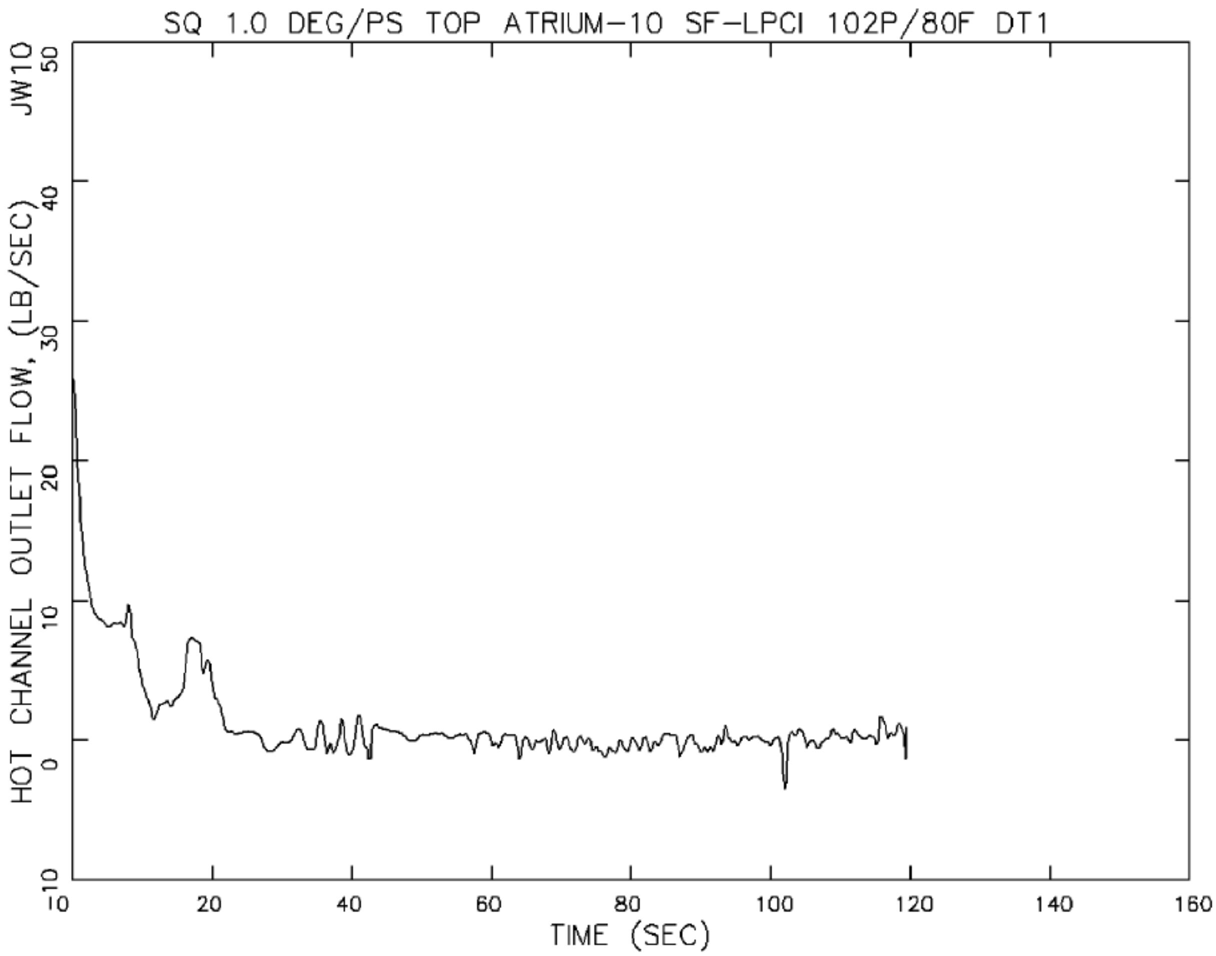


Limiting TLO Recirculation Line Break
Hot Channel Inlet Flow Rate

FSAR REV.65

SUSQUEHANNA STEAM ELECTRIC STATION UNITS 1 & 2 FINAL SAFETY ANALYSIS REPORT
LIMITING TLO RECIRCULATION LINE BREAK HOT CHANNEL INLET FLOW RATE FIGURE 6.3-216, Rev 3

AutoCAD: Figure Fsar 6_3_216.dwg



Limiting TLO Recirculation Line Break
Hot Channel Outlet Flow Rate

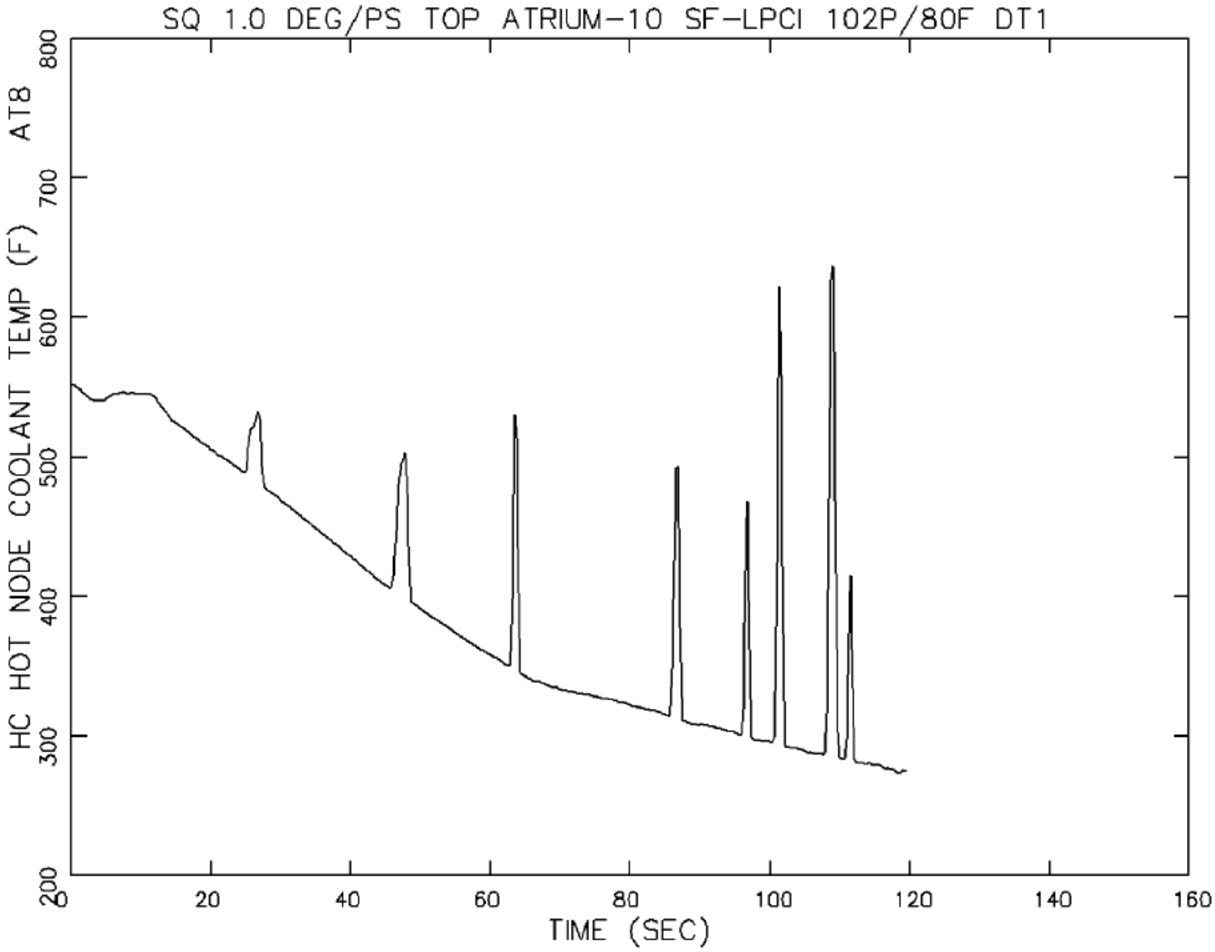
FSAR REV.65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

LIMITING TLO RECIRCULATION LINE BREAK
HOT CHANNEL OUTLET FLOW RATE

FIGURE 6.3-217, Rev 3

AutoCAD: Figure Fsar 6_3_217.dwg

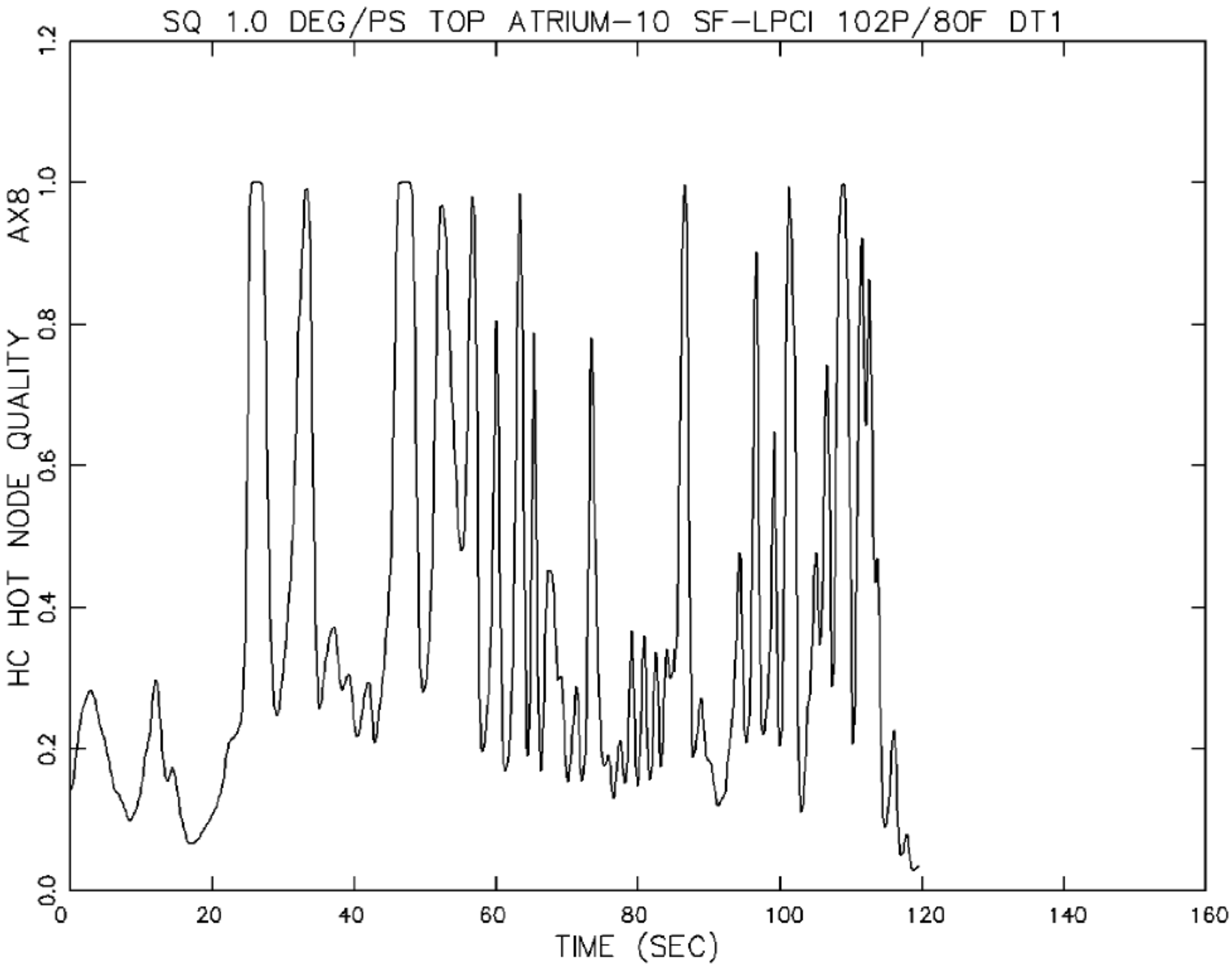


Limiting TLO Recirculation Line Break
Hot Channel Coolant Temperature
at the Limiting Node

FSAR REV.65

SUSQUEHANNA STEAM ELECTRIC STATION UNITS 1 & 2 FINAL SAFETY ANALYSIS REPORT
LIMITING TLO RECIRCULATION LINE BREAK HOT CHANNEL COOLANT TEMPERATURE AT THE LIMITING NODE FIGURE 6.3-218, Rev 3

AutoCAD: Figure Fsar 6_3_218.dwg



Limiting TLO Recirculation Line Break
Hot Channel Quality at the Limiting Node

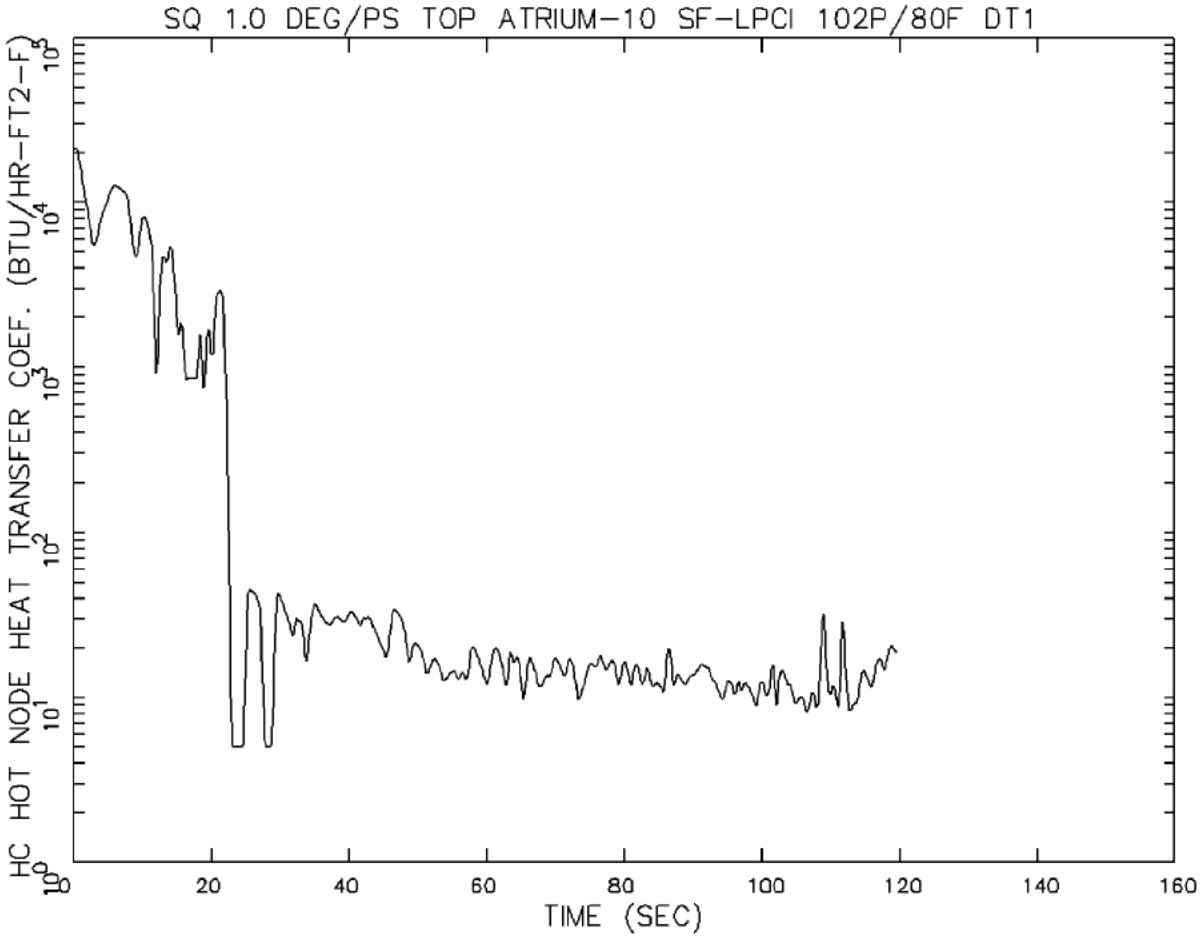
FSAR REV.65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

LIMITING TLO RECIRCULATION LINE BREAK
HOT CHANNEL QUALITY AT THE LIMITING NODE

FIGURE 6.3-219, Rev 3

AutoCAD: Figure Fsar 6_3_219.dwg



Limiting TLO Recirculation Line Break
Hot Channel Heat Transfer Coeff.
at the Limiting Node

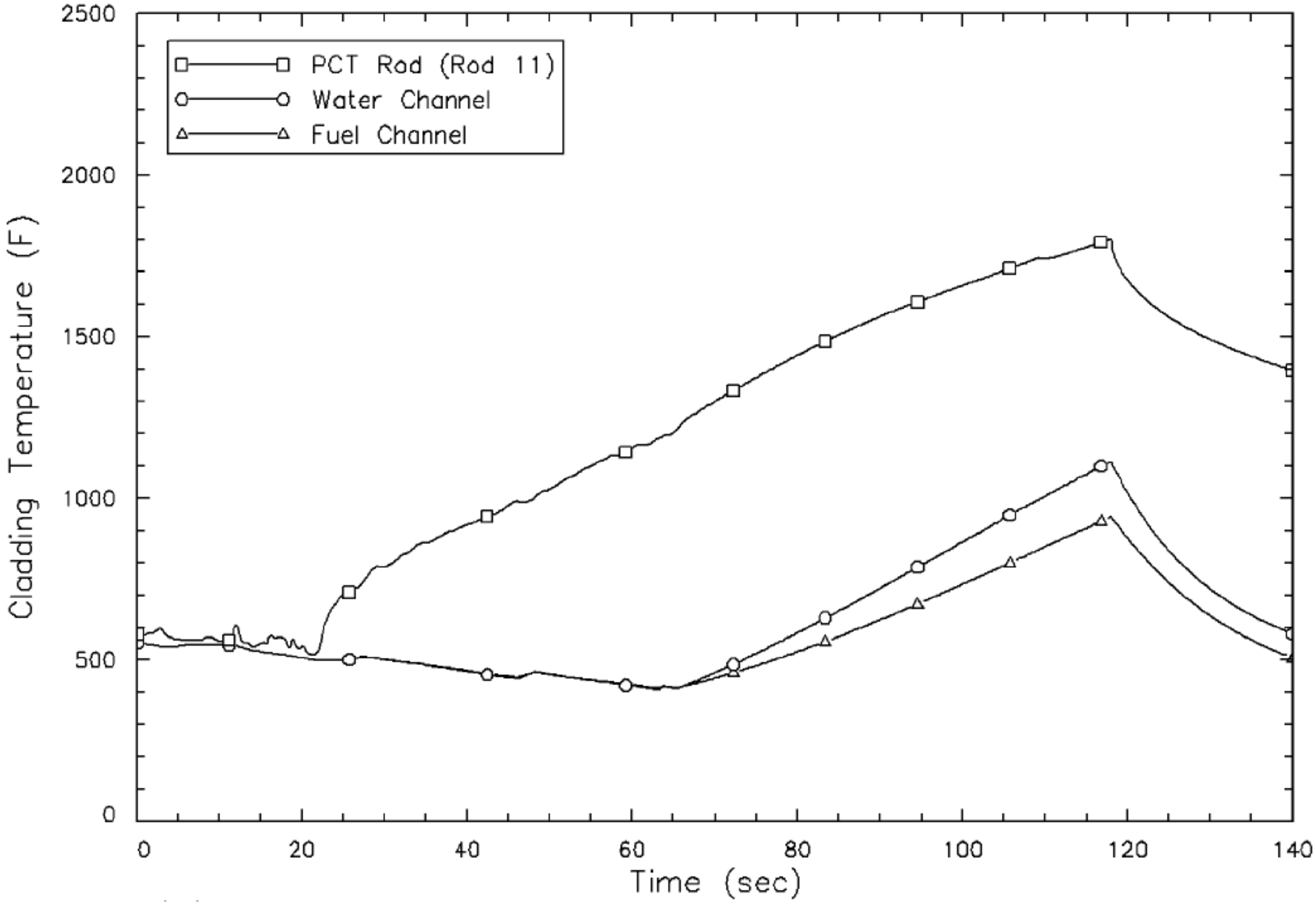
FSAR REV.65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

LIMITING TLO RECIRCULATION LINE BREAK
HOT CHANNEL HEAT TRANSFER COEFF.
AT THE LIMITING NODE

FIGURE 6.3-220, Rev 3

AutoCAD: Figure Fsar 6_3_220.dwg



Limiting TLO Recirculation Line Break
Cladding Temperatures

FSAR REV.65

SUSQUEHANNA STEAM ELECTRIC STATION UNITS 1 & 2 FINAL SAFETY ANALYSIS REPORT
LIMITING TLO RECIRCULATION LINE BREAK CLADDING TEMPERATURES FIGURE 6.3-221, Rev 3

AutoCAD: Figure Fsar 6_3_221.dwg

FIGURE DELETED PER LDCN 4547

FSAR REV. 65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

FIGURE DELETED PER LDCN 4547

FIGURE 6.3-222, Rev. 3

AutoCAD Figure 6_3_222.doc

FIGURE DELETED

FSAR REV. 65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

FIGURE DELETED

FIGURE 6.3-79A, Rev. 55

AutoCAD Figure 6_3_79A.doc

FIGURE DELETED

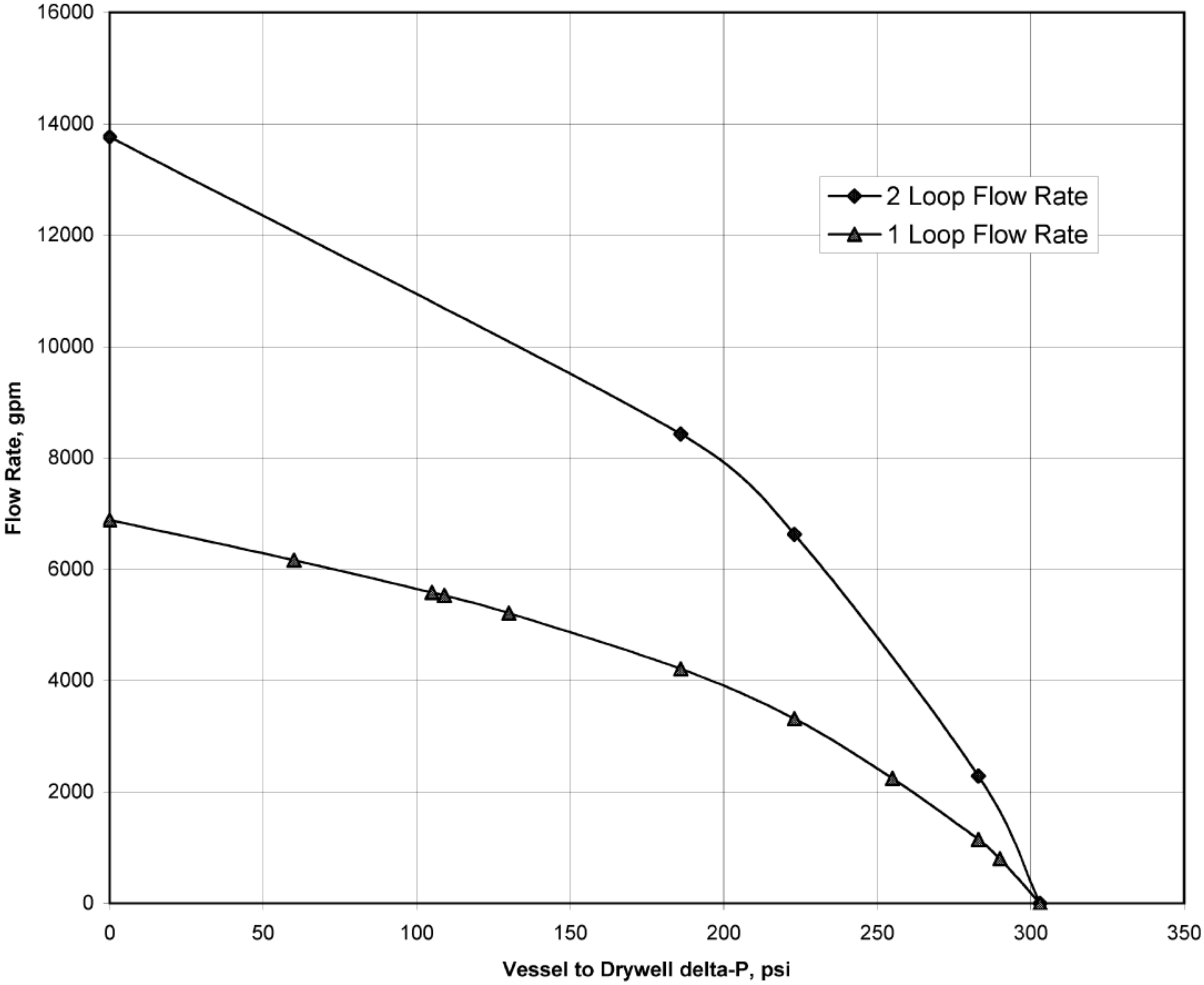
FSAR REV. 65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

FIGURE DELETED

FIGURE 6.3-79B, Rev. 57

AutoCAD Figure 6_3_79B.doc



FSAR REV.65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

LOW PRESSURE CORE SPRAY FLOW
VS. HEAD USED IN LOCA ANALYSIS
(FNAP ATRIUM™-10 FUEL)

FIGURE 6.3-79C, Rev 2

AutoCAD: Figure Fsar 6_3_79C.dwg

FIGURE DELETED

FSAR REV. 65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

FIGURE DELETED

FIGURE 6.3-80A, Rev. 55

AutoCAD Figure 6_3_80A.doc

FIGURE DELETED

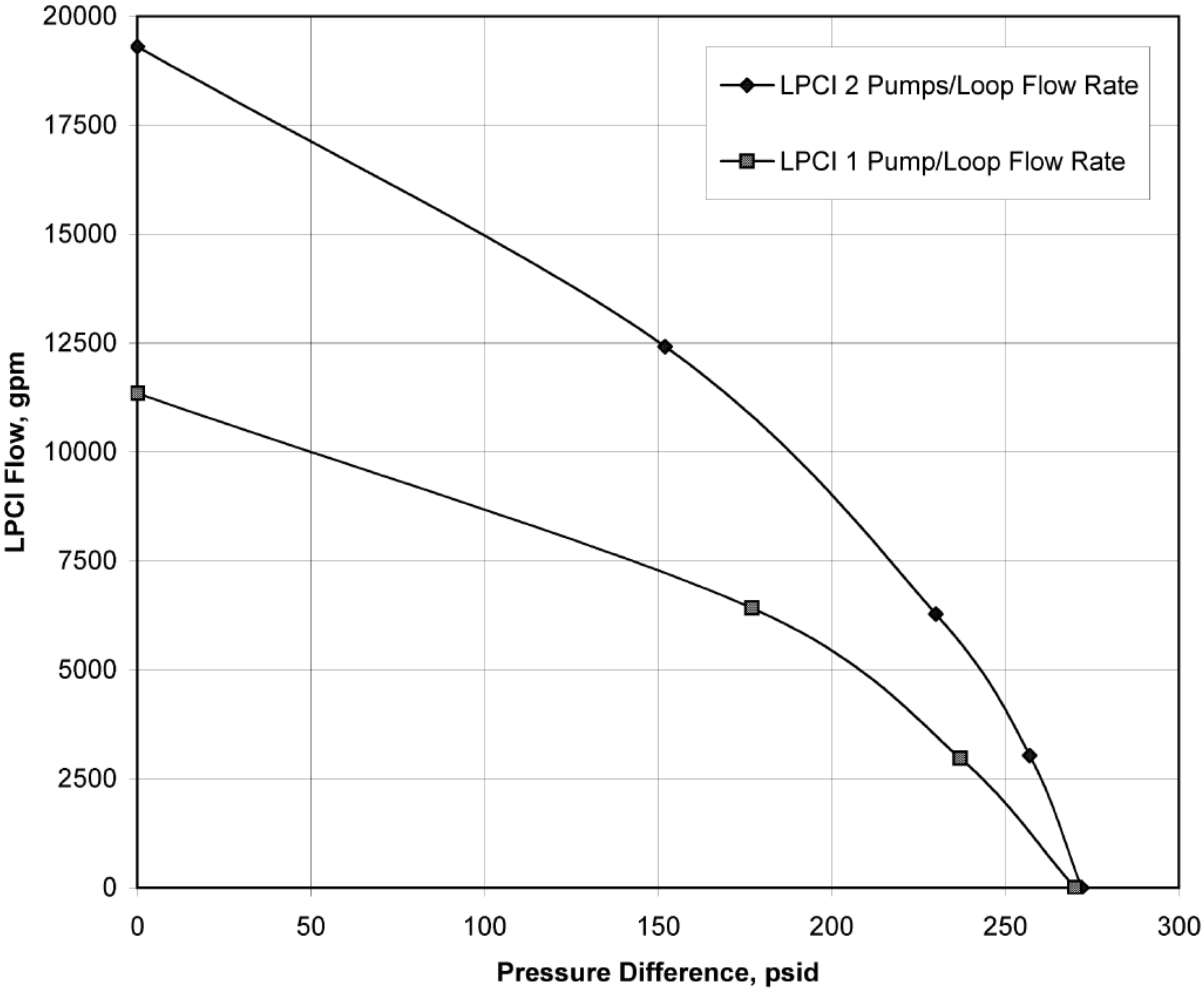
FSAR REV. 65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

FIGURE DELETED

FIGURE 6.3-80B, Rev. 57

AutoCAD Figure 6_3_80B.doc



FSAR REV.65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

RHR (LPCI) FLOW VS. HEAD
CHARACTERISTICS USE IN LOCA
ANALYSIS
(FNAP ATRIUM™-10 FUEL)

FIGURE 6.3-80C, Rev 2

AutoCAD: Figure Fsar 6_3_80C.dwg

6.4 HABITABILITY SYSTEMS

Habitability systems are designed to ensure habitability inside the control structure pressurization envelope during all normal and abnormal station operating conditions including the post LOCA requirements, in compliance with Design Criterion 19 of 10CFR50, Appendix A and 10CFR 50.67 for dose limits. Figures 6.4-1A, 6.4-1B, 6.4-1C, 6.4-1D and 6.4-1E show the control structure habitability zone. The areas covered include but not limited to the following rooms: Control Room, Technical Support Center (TSC), Operational Support Center (OSC), computer, relay, cable spreading, HVAC and battery rooms for both Units 1 and 2.

The habitability systems cover all the equipment, supplies, and procedures related to the control and auxiliary electrical equipment so that Control Room operators are safe against postulated releases of radioactive materials, noxious gases, smoke, and steam. Adequate water, sanitary facilities, and medical supplies are provided to meet the requirements of operating personnel during and after the accident. In addition, the environment of the Control Structure Envelope rooms are maintained to ensure the integrity of the contained safety related controls and equipment, during all the station operating conditions.

6.4.1 DESIGN BASES

The design bases of the habitability systems, upon which the functional design is established, are summarized as follows:

a) The control structure envelope is occupied continuously on a year-round basis. The occupancy of the operating personnel is ensured for a minimum of 5 days, after a design-basis accident (DBA).

b) HVAC systems for radiological habitability are designed to support personnel during normal and abnormal station operating conditions in the Control Structure Envelope.

c) Kitchen, sanitary facilities, and medical supplies for minor injuries are provided for the use of five Control Room personnel for five days during normal and accident conditions.

d) The radiological effects on the Control Structure Envelope that could exist as a consequence of any accident described in Chapter 15 will not exceed the guidelines set by 10CFR 50.67.

e) The design includes provisions to preclude the effects of smoke from inside or outside the plant from inhibiting the habitability of the Control Room, TSC and OSC.

f) Eye washes and emergency showers are located on the battery room floor. Respiratory and skin protection for emergencies are provided within the Control Room.

g) The habitability systems are designed to operate effectively during and after the DBA with the simultaneous loss of offsite power, Safe Shutdown Earthquake, and failure of any one of the HVAC system active components.

h) Radiation monitors, and smoke detectors continuously monitor the outside air at the control structure envelope outside air intakes. The detection of high radiation, smoke is alarmed in the Control Room and related protection functions are simultaneously initiated for high radiation. The operator may isolate the control structure on smoke alarm at his discretion.

i) In the event of a Control Room evacuation, an Alternate Control Structure HVAC Control Panel provides for manual operation of the required HVAC components from outside the Control Room.

6.4.2 SYSTEM DESIGN

6.4.2.1 Control Structure Envelope

Habitability system boundaries for Susquehanna SES is the control structure envelope.

a) An independent HVAC system is provided for the Control Room area. This includes: Control Room, TSC, OSC, kitchen, toilet and locker, office, conference room, document Control Room, electrical room, vestibule and storage space. All areas on plan floor EL 728'-0" and 741'-0" are served by this system. A detailed description of this redundant system is provided in Subsection 9.4.1.

b) Two independent HVAC systems are provided for the remaining areas. One system serves the computer room, lower relay rooms, computer maintenance room, office, and UPS rooms. The other system serves the lower cable spreading room, upper relay rooms, upper cable spreading rooms, electrician's office, battery rooms, cold instrument repair shop, equipment rooms, and HV equipment room. Each of these systems is described in Subsection 9.4.1.

There are eleven exterior doors in the control structure envelope. These doors are gasketed to minimize leakage and will be tested to 1/8" w.g. differential pressure to assure tightness.

Another leakage path across the ventilation barrier between the control structure envelope and outside environment is through the isolation damper blades. Isolation dampers are listed in Table 6.4-1.

Tests on the isolation dampers indicate a leakage rate as shown on Table 6.4-1 at test differential pressures ranging from 3 to 21 in. wg. The analysis for Control Room habitability given in Chapter 15 and Appendix 15B assumed a leakage of 10 cfm of outside air for ingress/egress and an additional 500 cfm of unidentified, unfiltered inleakage to the Control Structure Envelope. Makeup air to the envelope is also filtered, so the makeup air to the Control Structure Envelope would not be at outside air concentrations.

The environment of the Control Structure Envelope is maintained to ensure the integrity of the contained safety related controls and equipment during all operating conditions. Technical Specification 3.7.3 discusses maintaining a positive pressure of >0.125 inches water gauge relative to the outside atmosphere during the pressurization mode of operation.

6.4.2.2 Ventilation System Design

The detailed HVAC system design is presented in Subsection 9.4.1. These systems are shown on Dwgs. M-178, Sh. 1, M-178, Sh. 2, VC-178 Sh. 1, VC-178, Sh. 2, and VC-178, Sh. 3. Design parameters are listed in Table 9.4-2. A list of isolation dampers with their leakage characteristics and closure times is shown in Table 6.4-1.

All the components are designed to function during and after a SSE except for the outside air intake electric heating controls and humidification equipment, Control Room relief fan, reheat coils and their controls, which are supported to stay in position even though they may not function.

Components are protected from internally and externally generated missiles. See Section 3.5 for details. Layout diagrams of the control structure, showing doors, corridors, stairways, shield walls, equipment layout, and the Control Structure Envelope are shown on Figures 6.4-1A, 6.4-1B, 6.4-1C, 6.4-1D and 6.4-1E.

The description of controls, instruments, and radiation monitors for the control structure HVAC system is included in Subsections 9.4.1 and 7.3.1. The locations of outside air intakes and potential sources of radioactive and toxic gas releases are indicated on Figure 6.4-2.

A detailed description of the emergency makeup air filter trains is presented in Subsection 6.5.1.2.

6.4.2.3 Leaktightness

The entire Control Structure Envelope is of leaktight construction. The free air space volume is approximately 110,000 cubic feet in the Control Room floor, 80,000 cubic feet in the battery room floor, and 328,000 cubic feet in the remaining spaces of the envelope. All cable tray and duct penetrations are sealed. Approximately 5810 cfm of outside air is introduced in the pressurization emergency mode through charcoal filters into the envelope, to maintain approximately 1/8 in. w.g. positive pressure over atmosphere; this includes 3500 cfm to the battery rooms as make-up air. The battery rooms are exhausted through the SGTS exhaust vent. The air intake rates are the same for normal operation and for pressurization emergency modes radiation release. As discussed in FSAR Section 9.4.1, during normal operation, the control structure habitability envelope is maintained at a positive pressure over the outside air pressure.

6.4.2.4 Interaction with Other Zones and Pressure-Containing Equipment

The Control Structure Envelope is surrounded by the turbine building, reactor building, and central access control area. Each of these areas is separated from the control structure by shield walls and floors and served by independent HVAC systems.

All penetrations for conduits, pipes and ductwork penetrating the Control Structure Envelope will be completely sealed; all air outlet openings which continue to areas outside of the envelope will be isolated by a set of redundant isolation dampers (except for the smoke removal system) which has one normally closed isolation damper and one normally closed fire protection damper. The ductwork penetration is of welded construction.

The Control Structure Envelope is surrounded by the Turbine Building and Reactor Building. These areas are served by independent HVAC systems described in Section 9.4. The control structure is isolated by the ventilation barrier between the control structure and the other areas consisting of concrete wall and floor slab construction and leaktight doors.

Upper and lower cable spreading room floor drain discharge piping have rupture discs installed at their termination locations in the Turbine Building. These rupture discs support the Control Structure HVAC system in maintaining positive air pressure above atmosphere. In addition, these components provide a drainage path for firefighting water when a predetermined water head in the drain piping is reached based on actuation of automatic fire sprinkler systems or use of fire hoses in the cable spreading areas.

Except for fire protection halon bottles, fire extinguishers and self-containing breathing apparatus, there are no pressure-containing tanks in the Control Room area. Steam piping is excluded from the control structure.

6.4.2.5 Shielding Design

The Control Structure radiation shielding design is discussed in Section 12.3 which describes control structure shield wall thicknesses, the location of associated plant structures relative to the control structure, and provision to reduce radiation from external sources. A description of radiation sources used to design control structure shielding is presented in Section 12.2 and in Subsection 18.1.20 and includes source strength, geometry, and attenuation parameters.

Core Spray piping is located in the reactor building close to the reactor building/control structure wall. For the DBA LOCA dose consequence analysis (Chapter 15.6), the core spray piping is assumed to be filled with radioactive suppression pool water. For the DBA LOCA dose consequence analysis, the core spray piping creates a significant shine dose to the STA Office (C-401), Operational Support Center (C-402), Electrical Equipment Room (C-413) and NRC Conference Room (C-414). To reduce the dose from this source, ¾" steel plate was installed on portions of the core spray pipe and control structure wall.

6.4.3 SYSTEM OPERATIONAL PROCEDURES

During normal plant operation, the mixture of recirculated air and outside air for the control structure HVAC systems is filtered through UL Class 1 particulate filters with a rated efficiency of 90 percent by ASHRAE Standard 52-68 atmospheric dust spot method. The control structure HVAC systems are started through remote hand switches that are located in the Control Room HVAC control panel. The operation of the Control Room HVAC system is described in Subsection 9.4.1.2.1.

To remove any noxious gases and odors from the Control Room, the operator can manually isolate the Control Room HVAC system and place the emergency outside filter train in recirculating operation.

To remove smoke from the Control Room, the operator can manually operate the smoke exhaust fan and fire protection control damper from the fire protection control panel in the

Control Room. Smoke will be exhausted by the fans, through the duct system to the turbine building exhaust vent.

In the event of high radiation at the outside air intake of the control structure HVAC systems, the radiation monitoring system automatically shuts off normal outside air supply to the systems. The outside air is automatically routed through the emergency outside air filter train before entering the HVAC system.

In the event of a Reactor Building HVAC/Secondary Containment isolation signal, the control structure HVAC system will automatically transfer to the emergency outside air filter train as described in the high radiation mode.

Two emergency outside air filter trains and fans are provided. Each train consists of an electric heater, prefilter, upstream HEPA filter, charcoal adsorber, and downstream HEPA filter. The system is designed to handle the requirements of outside air for the HVAC systems. Each train is sized to process 6000 cfm ±10% (note that the fan is operationed at a flow rate ≤5810 cfm during surveillance test) of outside air, providing 500 cfm ±10% to the Control Room HVAC system, 400 cfm ±10% to the computer room HVAC system, and 5100 cfm ±10% to the control structure HVAC system. The emergency outside air filter train system is described in detail in Section 6.5.

In the event of an evacuation of the Control Room, operation of the control structure HVAC system can be manually controlled by an operator at the Alternate Control Structure HVAC Control Panel.

6.4.4 DESIGN EVALUATIONS

The control structure HVAC systems are designed to maintain a suitable environment for personnel and equipment in the control structure under all the station operating conditions. The systems are provided with redundant equipment to meet the single failure criteria. The redundant equipment is supplied with separate Class 1E power sources and is operable during loss of offsite power. The power supply and control and instrumentation meet IEEE-279 and IEEE-308 criteria. All the HVAC equipment, except the normal outside air intake heating, humidification, Control Room relief fan, reheat coils and their controls, and surrounding structure, are designed for Seismic Category I.

For the condition of a fire, as defined by 10CFR50, Appendix R, the need for the Control Structure HVAC system to provide cooling for the 72-hour coping period was evaluated. This evaluation concluded that the Control Structure HVAC system is not required to support safe shutdown.

The likelihood of an equipment fire affecting control structure habitability is minimized because early ionization detection is anticipated, fire fighting apparatus is available, and filtration and purging capabilities are provided. Refer to Subsection 9.5.1 for further description of the Fire Protection System.

The following provisions are made to minimize fire and smoke hazards inside the control structure and damage to nuclear safety related circuits:

a) Most electrical wiring and equipment are surrounded by, or mounted in, metal enclosures.

b) The nuclear safety related circuits for redundant divisions (including wiring) are physically segregated.

c) Cables used throughout the control structure are flame retardant.

d) Structural floors and interior walls are of reinforced concrete. Interior partitions are constructed of metal, masonry, or gypsum dry walls on metal joists. The Control Room ceiling is suspended type with non-combustible (maximum flame spread index, 25) acoustic tile, the door frames, and doors are metallic. Wood trim is not used.

The Control Room raised floor consists of steel plates and supports covered with carpet with a flame spread of less than 25.

A system is provided to detect high radiation at the outside air intake. These monitors alarm the Control Room upon detection of high radiation conditions. The emergency outside air filter trains, designed to remove radioactive particulates and adsorb radioactive iodine from the HVAC system outside air supply, are automatically started upon high radiation signals.

The emergency outside air filter trains and Control Room shielding are designed to limit the occupational dose levels required by 10CFR 50.67.

The introduction of sufficient outside air to maintain the Control Structure Envelope at a positive pressure with respect to surroundings, precludes infiltration of unfiltered air into the control structure at all the station operating conditions except when the system is in the recirculation mode.

6.4.4.1 Radiological Protection

The Control Room air purification system and shielding designs are based on the most limiting design basis assumptions, those of Regulatory Guide 1.183.

The CRHE radiation shielding is designed to reduce gamma radiation shine from both normal and post-accident radiation sources to levels consistent with the requirements of 10CFR20 or 10CFR50.67.

Under accident conditions, radiation doses to control room personnel may result from several sources. While in the control room, personnel are exposed to beta and gamma radiation from gaseous fission products that enter after an accident via the ventilation system or from unfiltered air entering the control structure habitability envelope (CSHE). In addition, personnel may be subject to gamma shine dose from fission products in the containment and reactor building, from contained system sources and from fission products in the atmosphere outside the CSHE.

To evaluate the capability of the control room ventilation system and radiation shielding to keep doses within the specified criteria, control room doses are evaluated for each of these dose contributors. This analysis includes control room doses from the following radiation sources:

- Contamination of the control room atmosphere by the pressurization of air flow or infiltration of the radioactive material contained in the radioactive plume released from the facility,

- Radiation shine from the external radioactive plume released from the facility,

- Radiation shine from radioactive material in buildings adjacent to the control structure; includes containment, reactor building and turbine building,

- Radiation shine from radioactive material in systems and components inside or external to the control room envelope, e.g., piping, components and radioactive material buildup in HVAC filters.

The concentration of radioactivity, which is postulated to surround the Control Room after the postulated accident, is dependent on, the containment leak rate, and the meteorology for each period of interest. The assessment of the amount of radioactivity within the Control Room considers the flow rate through the Control Room outside air intake, the effectiveness of the Control Room air purification system, the radiological decay of fission products, and the exfiltration rate from the Control Room.

The Control Room emergency filtration train draws the incoming air through an electric heating coil, moderate efficiency filter, HEPA filters, and a carbon adsorber to minimize the exposure of Control Room personnel to airborne radioactivity. In order to increase the effectiveness of the carbon adsorbers, incoming air is warmed by the heating coil to decrease its relative humidity. Air within the Control Room, TSC and OSC is recirculated continuously through the air handling unit, which controls room temperature 75°F $\pm$ 5°F and humidity 50% $\pm$ 5%.

The resulting calculated doses to personnel inside the control room for a postulated LOCA, taking into account the effects of control structure ingess and egress and occupancy of personnel on a rotating shift basis, are less then 5 rem TEDE. The doses are within the dose limits specified in 10CFR 50.67. A detailed discussion of the dose calculation model for control structure operators is discussed in Subsection 15.B.2.

Control structure shielding design, based on the most limiting design basis LOCA fission product release, is discussed in Section 12.3 and is evaluated in Subsection 15.B.2. The evaluations in Chapter 15 demonstrate that radiation exposures to control structure personnel originate from containment shine, external cloud shine, and containment airborne radioactivity sources. Total exposures resulting from design basis accidents are below the dose limits specified by 10CFR 50.67; the portion contributed by containment shine and external cloud shine is reduced to a small fraction of the total by means of shielding. Access control may also be used in areas of the Control Room Envelope that do not support critical safety functions, to maintain doses less than 10CFR 50.67 limits.

6.4.4.2 Toxic Gas Protection

The control structure HVAC systems are designed to satisfy the recommendation of revision 1 of Regulatory Guide 1.78. The HVAC systems are described in Subsection 9.4.1.

A detailed discussion of the toxic gas protection is in Subsection 2.2.3.

6.4.5 TESTING AND INSPECTION

The control structure HVAC systems and their components are thoroughly tested in a program consisting of the following:

a) Factory and component qualification tests (see Table 9.4-1)

b) Onsite preoperational testing (see Chapter 14)

c) Onsite subsequent periodic testing (see Chapter 16)

6.4.6 INSTRUMENTATION REQUIREMENTS

All safety-related instruments and controls for the control structure HVAC systems are electric or electronic, except for isolation damper actuators which are pneumatically operated. These dampers are designed to fail safe on loss of compressed air. The compressed air system is not safety-related.

a) Separate local HVAC panels are provided for redundant HVAC systems. Controls for the ‘A’ train of the HVAC systems are provided on ‘OC877A’ panel and the controls for the redundant ‘B’ train of the HVAC systems are provided on ‘OC877B’ panel. Important operating functions are controlled and monitored from the Control Room HVAC panel.

b) Instrumentation is provided to monitor important variables associated with normal operations. Instruments are provided to alarm in the Control Room if abnormal conditions are detected.

c) A radiation detection system (measurement range of .01 to 100 mR/hr.) is provided to monitor the radiation levels at the system outside air intakes. A high radiation signal is alarmed on the main control board.

d) Fire detection capability is provided in the outside air intake plenum. Fire detection is annunciated on the main control board via the fire protection control panel.

e) The control room and control structure HVAC systems are designed to provide automatic control of the environmental parameters such as temperature (normal and emergency plant operation) and humidity (normal plant operation only). These systems can be operated in manual or auto modes. The chilled water system can be started in manual or auto (standby) mode by placing the chilled water pump OP162A/B switch in start or auto mode.

f) A fire protection water spray system is provided for each charcoal adsorber bed in the emergency outside air filter train.

g) The emergency outside air filter train airflow rate and upstream HEPA filter differential pressure are recorded on the main control room HVAC panel. The upstream HEPA filter differential pressure high (indicated by CS EMERG OA HEPA FILTER DP HI), and the air flow low (indicated by CS EMERG OA SUP FAN FAILED) conditions are alarmed on this panel.

h) The control structure HVAC system Train A is designed for manual operation at the Alternate Control Structure HVAC Control Panel. Train A of the control structure chilled water system can also be manually operated at this panel. These systems have been evaluated for their need in supporting Appendix R safe shutdown in the event of a Control Room fire. The result of this evaluation is that these systems are not required to support Appendix R safe shutdown.

Table Rev. 51

TABLE 6.4-1 CONTROL STRUCTURE ISOLATION DAMPER CLOSURE TIMES				
DAMPER NO.	NOMINAL FLOW cfm	LEAKAGE cfm (Note)	CLOSURE TIME SECONDS (Note)	SIZE INCHES
HDO7802A/B	5810	5.05	3	26 x 28
HD07814A/B	5810	5.05	3	26 x 28
HD07812A/B	5810	5.05	3	28 x 26
HD07813A/B	5810	5.05	3	26 x 28
HD07833A/B	300	1.80	3	16 x 16
HD07824A1/B1	535	2.22	3	20 x 16
HD07871A1/A2	3500	2.80	3	20 x 20
HD07871B1/B2	3500	2.80	3	20 x 20
HD07872A/B	125	3.3	3	10 x 10
HD07873A/B	200	3.1	3	8 x 8

Note: Manufacturer's Suggested Operating Data

Security-Related Information
Figure Withheld Under 10 CFR 2.390

FSAR REV.65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

CONTROL ROOM LOCATION
INTAKE & EXHAUST LOCATION

FIGURE 6.4-2, Rev 51

AutoCAD: Figure Fsar 6_4_2.dwg

Security-Related Information
Figure Withheld Under 10 CFR 2.390

FSAR REV.65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

CONTROL STRUCTURE
ELEVATION

FIGURE 6.4-1A, Rev 55

AutoCAD: Figure Fsar 6_4_1A.dwg

Security-Related Information
Figure Withheld Under 10 CFR 2.390

FSAR REV.65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

CONTROL STRUCTURE
ENVELOPE PLAN
EL. 697'-0" & 714'-0"

FIGURE 6.4-1B, Rev 54

AutoCAD: Figure Fsar 6_4_1B.dwg

Security-Related Information
Figure Withheld Under 10 CFR 2.390

FSAR REV.65

SUSQUEHANNA STEAM ELECTRIC STATION UNITS 1 & 2 FINAL SAFETY ANALYSIS REPORT
CONTROL STRUCTURE ENVELOPE CONTROL ROOM FLOOR PLAN EL. 729'-0" TECHNICAL SUPPORT CENTER EL. 741'-1" FIGURE 6.4-1C, Rev 54

AutoCAD: Figure Fsar 6_4_1C.dwg

Security-Related Information
Figure Withheld Under 10 CFR 2.390

FSAR REV.65

SUSQUEHANNA STEAM ELECTRIC STATION UNITS 1 & 2 FINAL SAFETY ANALYSIS REPORT
CONTROL STRUCTURE ENVELOPE PLAN EL. 753'-0" & 771'-0"
FIGURE 6.4-1D, Rev 54

AutoCAD: Figure Fsar 6_4_1D.dwg

Security-Related Information
Figure Withheld Under 10 CFR 2.390

FSAR REV.65

SUSQUEHANNA STEAM ELECTRIC STATION UNITS 1 & 2 FINAL SAFETY ANALYSIS REPORT
CONTROL STRUCTURE ENVELOPE PLAN EL. 783'-0" FIGURE 6.4-1E, Rev 54

AutoCAD: Figure Fsar 6_4_1E.dwg

6.5 FISSION PRODUCT REMOVAL AND CONTROL SYSTEMS

6.5.1 ENGINEERED SAFETY FEATURE (ESF) FILTER SYSTEMS

6.5.1.1 Standby Gas Treatment System (SGTS)

6.5.1.1.1 Design Bases

The SGTS is designed to accomplish the following safety related objectives:

a) Exhaust sufficient filtered air from the reactor building to maintain a negative pressure of about 0.25 in. w.g. in the affected volumes following secondary containment isolation (see Subsection 9.4.2 for the secondary containment isolation signals) for the following design basis events:

   (1) spent fuel handling accident in the refueling floor area

   (2) LOCA

b) Filter the exhausted air to remove radioactive particulates and both radioactive and non-radioactive forms of iodine to limit the offsite dose to the guidelines of 10CFR50.67.

Non-safety-related objectives for design of the SGTS are as follows:

a) Filter and exhaust air from the primary containment for purging and ventilating.

b) Filter and exhaust discharge from the HPCI barometric condenser.

c) Filter and exhaust from the primary containment pressure relief line.

d) Filter and exhaust nitrogen from the primary containment for nitrogen purging.

The design bases employed for sizing the filters, fans, and associated ductwork are as follows:

a) Each train is sized and specified for treating incoming air mixture at a maximum of 125°F, and containing fission products and incoming particulates equivalent to 1.0 volume percent per day of the fission products available in the primary containment as determined in accordance with Regulatory Guide 1.183 using activity release assumptions for the design bases loss of coolant accident.

b) System capacity to match the maximum air flow rate required for the primary containment purge.

c) The system capacity to be maintained with all filters fully loaded (dirty).

d) For HEPA filters, maximum free velocity not to exceed 300 fpm, with maximum airflow resistance of 1 in. w.g. when clean and 3 in. w.g. when dirty, and minimum efficiency of 99.95 percent by DOP test method.

e) For prefilters, maximum face velocity not to exceed 300 fpm, with maximum airflow resistance of 0.5 in. w.g. when clean, and 1.0 in. w.g. when dirty.

f) Initial design including sizing of the associated ductwork was performed using the equal friction method.

g) Charcoal adsorber is rated for 99 percent trapping of radioactive iodine as elemental iodine (I_3), and 99 percent trapping of radioactive iodine as methyl iodide (CH_3I) when passing through charcoal at 70 percent relative humidity.

h) Each equipment train contains the amount of charcoal required to absorb the inventory of fission products leaking from the primary containment, based on a one unit LOCA.

i) Media cooling arrangement for each SGTS train is designed to remove heat generated by fission product decay on the HEPA filters and charcoal adsorbers during shutdown of the train.

j) Relative humidity at charcoal adsorber is limited to maximum of 70 percent by removing moisture entrained in the air stream and by preheating the air.

Failure of any component of the filtration train (i.e., from the SGTS filter inlet to the fan discharge), assuming loss of offsite power, cannot impair the ability of the system to perform its safety function. The system remains intact and functional in the event of a Safe Shutdown Earthquake (SSE).

6.5.1.1.2 System Design

Each of the two redundant SGTS trains consists of a mist eliminator, an electric air heater, a bank of prefilters, two banks of HEPA filters, upstream and downstream of charcoal adsorber, and a vertical 8 in deep charcoal adsorber bed with fire detection temperature sensors, water spray system for fire protection, and associated dampers, ducts, instruments, and controls. The airflow diagram for the SGTS is shown on Dwg. M-175, Sh. 2. The instruments and controls are shown on Dwg. VC-175, Sh. 3. The system design parameters are provided in Table 6.5-1.

The work, equipment and materials conform to the applicable requirements and recommendations of the guides, codes, and standards listed in Section 3.2.

Compliance of the system design with Regulatory Guide 1.52, is described in Section 3.13. Also see Table 6.5-2.

Each redundant SGTS train has a controllable capacity of 3,000 cfm to 10,500 cfm, and each is capable of treating required amount of air from both Unit 1 and Unit 2 reactor building volumes. (see Subsection 6.5.3). Components for each SGTS are designed as explained in the following paragraphs.

The fan performance and motor selection is based on the maximum air density and the maximum system pressure drop, that is, 70°F air temperature at the fan (55°F air at the inlet of the SGTS train plus approximately 15°F constant temperature pickup across the heater), and the pressure drop is based on maximum pressure drops across dirty filters.

The charcoal adsorber is a gasketless, welded seam type, filled with impregnated, activated carbon. The bank holds a total of approximately 6,920 lb carbon assuming a density of 28 lb/ft^3, having an ignition temperature of not less than 330°C. The charcoal adsorber is designed for a maximum loading capacity of 2.5 mg of total iodine (radioactive plus stable) per gram of activated carbon.

Six test canisters are provided for each adsorber. These canisters contain the same depth of the same charcoal that is in the adsorber. The canisters are mounted, so that a parallel flow path is created between each canister and the adsorber. Periodically one of the canisters is removed and laboratory tested to verify the adsorbent efficiency.

Thirty by fifty inch access doors into each filter compartment are provided in the equipment train housing. The doors have transparent portholes to allow inspection of components without violating the train integrity.

The housing is of all welded construction.

Gas tight interior lights with external light switches and fixture access are provided between all train filter banks to facilitate inspection of components.

Filter housings, including water drains, are in accordance with recommendations of Section 4.5 of Ref. 6.5-1.

Ductwork is designed in accordance with recommendations of Section 2.8 of Reference 6.5-1, except for sheet metal gauges that are slightly less, and the round duct reinforcements. The ductwork, however, has been seismically qualified by analysis and testing of duct specimens.

Outdoor makeup air supplements low exhaust airflow rates for most of the SGTS operational modes to satisfy the SGTS fan minimum airflow requirement. The outdoor makeup air is also used for charcoal bed cooling after a charcoal pre-ignition temperature is detected.

The purpose of the mist eliminator is to remove entrained water droplets from the inlet air stream, thereby protecting prefilters, HEPA filters and the charcoal adsorbers from water damage and plugging.

The electric heater reduces the relative humidity of the entering air to below 70 percent for charcoal adsorber operation, by maintaining a constant temperature rise across the heater. An analysis of heater capabilities for various entering saturated air conditions yields a peak heating requirement of 150,000 Btu/hr, at maximum 10,500 cfm airflow. In addition, approximately 36,000 Btu/hr heat loss is calculated from the section of SGTS housing between the heater and the charcoal bed. Overall required capacity is approximately 186,000 Btu/hr. A 90 kW heater is provided.

The charcoal bed is provided with an integral water spray system connected to the station fire protection system. A deluge valve and Seismic Category I backup valve are mounted in series adjacent to the charcoal adsorber. The backup valve is provided to prevent charcoal flooding if the deluge valve fails in an open position. Fire protection for the SGTS filter trains is also discussed in Subsection 9.5.1.

A continuous type thermistor is provided on the inlet and outlet of the charcoal bed.

The SGTS is actuated either automatically (safety related mode), or manually (non-safety related mode). The automatic actuation is originated by the reactor building isolation signal, or by detection of pre-ignition temperature in the charcoal adsorber bed, the latter for charcoal cooling purposes. The manual actuation is controlled by administrative procedures in such a way that the SGTS is started and airflow established (outdoor makeup air) prior to introduction of air or gas to be exhausted from a reactor building source.

Both SGTS fans are in lead; automatic actuation will result in the simultaneous start of both fans and manual actuation will result in the start of one fan. After actuation by either means, associated controls will be activated to open or modulate appropriate dampers, so that the system function is accomplished.

The SGTS inlet header pressure is monitored and controlled to a negative pressure to preclude the possibility of non-filtered gas or air bypassing the filtration train through the outdoor air makeup duct during system operation. The lead SGTS is started automatically and an alarm sounded in the control room, if this pressure rises to 1.5 in. w.g. positive when the system is not in operation, and the negative pressure will be established and maintained. The system will be stopped manually once the cause of the high inlet header pressure is identified and eliminated.

Outside air is used for either charcoal cooling or making up the total system flow. SGTS fans are operated at a constant air flow rate. The variable inlet vane dampers provided in the fan suction are modulated to compensate for filter pressure drop.

Any section of the charcoal bed inlet or outlet thermistors sensing a temperature higher than preset charcoal pre-ignition or ignition temperatures will result in the following:

a) The pre-ignition temperature will actuate an alarm in the control room, and will automatically initiate the affected SGTS train's charcoal cooling mode of operation by establishing a flow of outdoor makeup air across the charcoal bed.

b) The ignition temperature will actuate an alarm in the control room and open the deluge valve and the backup valve, thus introducing the fire protection water to the charcoal spray system. Four drain valves provided to drain the deluge water will be opened automatically by the ignition temperature signal. The operation of the deluge system will continue until the charcoal temperature falls below the ignition temperature. The deluge water flow will be controlled by the backup valve; the deluge valve will remain open after the initial actuation.

The SGTS is designed to Seismic Category I requirements.

The power supply meets IEEE-308 criteria and ensures uninterruptible operation in the event of loss of normal, onsite, ac power.

6.5.1.1.3 Design Evaluation

The SGTS is designed to preclude direct exfiltration of contaminated air from either reactor building, following an accident or abnormal occurrence which could have resulted in abnormally high airborne radiation in the secondary containment. Equipment is powered from essential buses and all power circuits will meet IEEE-308. Redundant components are provided where necessary to ensure that a single failure in the SGTS initiation signal or filter trains will not impair or preclude system operation. SGTS failure mode and effect analysis is presented in Table 6.5-3.

6.5.1.1.4 Tests and Inspections

Except for Items 5, 15, and 16, all tests and inspections described in Table 9.4-1 apply to the SGTS.

The system was preoperationally tested in accordance with the requirements of Chapter 14. Refer to the Technical Specifications for periodic test requirements for the SGTS.

6.5.1.1.5 Instrument Requirements

The SGTS can be actuated manually from the control room. Each SGTS train is designed to function automatically upon receipt of an ESF system actuation signal. The status of system equipment, which is an indication of pertinent system pressure drops and flow rates, is displayed in the control room during both normal and accident operation.

Table 6.5-2 addresses the extent to which the recommendations of NRC Regulatory Guide 1.52 are followed with respect to instrumentation.

All instrumentation is qualified to Seismic Category I requirements.

Redundancy and separation of the instrumentation is maintained, and it follows the redundancy and separation of the equipment.

The following conditions are annunciated in the control room:

a) Train failure

b) Heater failure (low temperature rise across the heater)

c) High or low pressure drop across the upstream HEPA – DIRTY HEPA, LOW FLOW

d) High pressure drop (DIFF PRESS) across any filter (a group alarm)

e) Pre-ignition charcoal temperature - Hi

f) Ignition charcoal temperature: Hi-Hi

g) Charcoal temperature detection system (HT DET SYS) failure (include the deluge valve solenoid circuit discontinuity)

h) Low pressure differential, referenced to the outdoor ambient pressure, in the reactor building ventilation zones being isolated – RB RECIRC ZONE(S) LO DIFF PRESS

i) High positive pressure or low negative pressure in the SGTS header – SGTS IN HDR LO DIFF PRESS, SGTS HDR HI PRESS

j) Outside makeup air damper failed open

k) Outside charcoal cooling air damper failed open

l) Instrument power failure

6.5.1.1.6 Materials

The materials of construction used in or on the filter systems are given in Tables 6.1-1a, 6.1-1b, and 6.5-5. Each of the materials is compatible with the normal and accident environmental conditions.

FSAR Dwg. C-1815, Sh. 3 shows the location of the SGTS filter trains is classified as harsh environment. The electrical components of the SGTS filter trains are environmentally qualified.

6.5.1.2 Control Structure Emergency Outside Air Supply System (OV-101) (CSEOASS) or (CREOASS)

6.5.1.2.1 Design Bases

The control structure emergency outside air supply system (CSEOASS) or (CREOASS) is designed to accomplish the following objectives:

a) Filter particulate matter which may be radioactive and remove gaseous iodine.

b) Recirculate and clean up room air.

c) Maintain ventilation air supply for the control structure envelope when radiation is detected in the outside air.

d) Maintain a positive pressure of 0.125 in. w.g. above atmospheric to inhibit outside air infiltration into the control structure during radiation filtration.

e) Operate during and after design basis accident without loss of function. The DBA initiation signal for this system is Reactor Building HVAC system isolation or secondary containment isolation.

f) Provide radiation monitoring of outside air supply.

The bases employed for sizing the filters, fans, heater, and associated ductwork are as follows:

a) System capacity (flow rate) to be based on required air changes for the control structure, and the air exhausted from the battery storage area. The required air change is calculated based on cfm required to slightly pressurize the control structure.

b) The system capacity to be maintained with all particulate filters fully loaded (dirty).

c) HEPA filters, maximum face velocity not to exceed 300 fpm with maximum airflow resistance of 1 in. w.g. when clean and 3 in. w.g. when dirty for upstream and 1.2 in. w.g. for downstream when dirty. A minimum efficiency to be 99.97 percent by DOP test method.

d) Prefilters, maximum face velocity not to exceed 300 fpm, with maximum airflow resistance 0.3 in. w.g. when clean and 0.9 in. w.g. when dirty.

e) Initial ductwork design including sizing of the ductwork was performed using equal friction method.

f) Charcoal adsorber is rated for 99 percent trapping of radioactive iodine as elemental iodine (I_3), and 99 percent trapping of radioactive iodine as methyl iodide (CH_3I) when passing through charcoal at 70 percent relative humidity.

g) Maximum relative humidity for air entering the charcoal adsorber to be limited to 70 percent by appropriate air heating.

h) The CSEOASS or CREOASS filter trains are designed to meet single failure criteria.

i) The CSEOASS or CREOASS is designed to Seismic Category I requirements, so that it remains operable during and after a Safe Shutdown Earthquake (SSE).

j) The power supply is designed to meet IEEE 308 criteria and ensure uninterrupted operation in the event of loss of normal AC power. The controls meet IEEE-279.

6.5.1.2.2 System Design

Each of the two redundant CSEOASS or CREOASS filter trains consists of an electric heater, a bank of prefilters, two banks of HEPA filters, one upstream and one downstream of the charcoal adsorber, and a vertical 4 in. deep charcoal adsorber bed with fire detector temperature sensors, associated dampers, instruments, controls, and water flooding system for fire protection. The CSEOASS or CREOASS is shown on Dwg. M-178, Sh. 1. The instrument and controls are shown on Dwg. VC-178, Sh. 1. The system design parameters are shown in Table 6.5-1.

The work, equipment and materials 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 NRC Regulatory Guide 1.52, as described in Section 3.13, and shown in Table 6.5-2.

Each CSEOASS or CREOASS filter train contains the following components listed in the direction of airflow:

a) A 30 KW electric heater to maintain relative humidity of the entering air below 70 percent. The heater is energized at the same time as the fan and provides approximately 15°F temperature rise across the coil, ensuring that entering outside air ranging from -5°F to 92°F will enter the filters with a relative humidity of less than 70 percent.

b) A charcoal adsorber designed with six gasketless welded 4 inch vertical beds, containing a total of 2336 lb. of impregnated, activated carbon, assuming a density of 30 lb/ft^3. Eight canisters are provided for each adsorber. The canisters contain the same depth of identical charcoal as the adsorber. The canisters are mounted, so that a parallel flow path is created between each canister and the adsorber. Periodically one of the canisters is removed and laboratory tested to verify the adsorbent efficiency.

c) The housing is constructed of carbon steel welded construction in accordance with Ref. 6.5-1. Stainless steel is used for filter support brackets. The housing is designed for -20 in. w.g. and a +5 psig. Each housing is provided with five 20x50 in. access doors for servicing the heater and filter banks.

The access doors are provided with transparent portholes to allow inspection of components without violating the trains' integrity.

Filter housings, including water drains, are in accordance with recommendations of Section 4.5 of Ref. 6.5-1.

Interior lights with external light switches and outside access for bulb replacement are provided to facilitate inspection, testing, and replacement of components.

d) A centrifugal fan designed for a flow rate of 6,000 cfm (note that the fan is operated at an air flow rate of 5810 cfm ±10%). The fan performance and motor selection is based on the maximum air density and the maximum system pressure drop.

e) Ductwork is designed in accordance with recommendations of Section 2.8 of Ref. 6.5-1, except for sheet metal gauges that are slightly less and round duct reinforcement. The ductwork, however, has been seismically qualified by analysis and testing of duct specimens.

A fire protection system, designed to extinguish a fire within the charcoal bed by flooding the housing, is provided. The fire protection system is designed to spray 36 gpm of water at 15 psi on the charcoal. A deluge valve and a backup valve are installed in series in the fire protection water connection adjacent to the housing. The back-up valve is installed downstream of the deluge valve to prevent charcoal flooding in the event of a malfunction of the deluge valve. One pre-ignition (190°F setting) and one ignition (450°F setting) temperature switch are located in the discharge duct connection. Six pre-ignition and six ignition switches are evenly spaced across the downstream face of the charcoal adsorber. A 190°F or greater leaving air temperature will trip any of the seven temperature switches, and alarm in the control room. A 450°F or greater leaving air temperature will trip any of the seven temperature switches, alarm in the control room, stop the fan, and energize the deluge valve and the back-up valve. An overflow is provided in the housing to allow water to drain once the housing is full. The water must be shut off manually. The housing is drained by opening five manual drain valves.

See Subsection 9.4.1.2.4 for additional details of the CSEOASS or CREOASS operation.

The CSEOASS or CREOASS is designed to Seismic Category I requirements.

The power supply meets the IEEE-308 criteria and ensures uninterruptible operation in the event of loss of normal, onsite, AC power.

6.5.1.2.3 Design Evaluation

The CSEOASS or CREOASS work in conjunction with the control structure HVAC systems to maintain habitability in the control structure. The design evaluation is given in Subsection 9.4.1 including failure mode and effect analysis presented in Table 9.4-19.

6.5.1.2.4 Tests and Inspections

With the exception of Items 5, 6, 7, 15, and 16, all tests and inspections described in Table 9.4-1 apply to the CSEOASS or CREOASS.

6.5.1.2.5 Instrumentation Requirements

The CSEOASS or CREOASS can be actuated manually from the control room. Each CSEOASS is designed to function automatically upon receipt of a radiation detection signal from detector elements located in the outside air intake plenum. In addition to starting the CSEOASS or CREOASS, high radiation is annunciated in the control room.

The CSEOASS or CREOASS can be started manually in the recirculation mode to clean up the air within the control room.

The reactor building HVAC system isolation signal (DBA initiation signal) will cause the CSEOASS or CREOASS to operate in exactly the same manner as a high radiation signal from the outside air intake.

The status of system equipment, indication of pertinent system pressure drops, and flow rates are displayed in the control room.

Table 6.5-2 addresses the extent to which the recommendations of NRC Regulatory Guide 1.52 are followed with respect to instrumentation.

All instrumentation is qualified to Seismic Category I requirements. Redundancy and separation of the instrumentation is maintained and follows the redundancy and separation of the equipment.

The following alarms are annunciated in the control room:

a) Fan failure

b) Heater failure (low temperature differential across the heater)

c) High pressure drop across the upstream HEPA

d) High charcoal temperature

e) High-high charcoal temperature.

6.5.1.2.6 Materials

The materials of construction used in or on the filter systems are given in Tables 6.1-1b, and 6.5-6. Each of the materials is compatible with the normal and accident environments postulated in the control structure where CSEOASS or CREOASS equipment is located.

FSAR Dwg. C-1815, Sh. 3, shows that EQ Zone CS8, which is CSEOASS or CREOASS filter trains, is classified as a harsh environment. The electrical components of the CSEOASS or CREOASS filter trains are environmentally qualified.

6.5.2 CONTAINMENT SPRAY SYSTEMS

The containment spray system is described in Subsection 6.2.2. The containment spray system is not required for fission product removal.

6.5.3 FISSION PRODUCT CONTROL SYSTEM

6.5.3.1 Primary Containment

The standby gas treatment system (SGTS) is used to control the release of fission products to the environment when purging the containment. This is described in detail in Subsection 6.5.1.1.

The Primary Containment is charged with nitrogen during plant start-up in accordance with the Technical Specifications. Gaseous nitrogen is used to reduce the concentration of oxygen, as discussed in Subsection 6.2.5.2. The containment is purged of nitrogen during reactor shutdown in accordance with the Technical Specifications with air from the Reactor Building Ventilation Supply Air System. The purge piping and valves are shown on Dwg. M-157, Sh. 1. The 24" diameter and 18" diameter piping can be used for purging during reactor power operation (as mentioned above), start-up and hot standby; otherwise, the purge supply and exhaust valves HV-15704, HV-15714, HV-15721, HV-15722, HV-15723, HV-15724 and HV-15725 remain closed. These valves cannot be manually overridden to open following containment isolation.

The 2" vent by-pass valves, HV-15711 and HV-15705, and the inner isolation valves, HV-15703 and HV-15713, on the purge exhaust lines will be used to relieve containment pressure increases caused by thermal expansion during normal operations. Keylock handswitches are provided to override the containment isolation signal on valves HV-15703, HV-15705, HV-15711 and HV-15713 to allow emergency venting of the containment. The containment make-up line valves SV-15737, SV-15738, SV-15767 and SV-15789 are not used in the operating procedures following containment isolation. SV-15776A and SV-15736A are isolated for a period of 10 minutes. After the isolation period has elapsed, these valves may be opened remote manually under administrative control for control of hydrogen, as discussed in Subsection 6.2.5.2.

Layout drawings of the primary containment are listed in Section 1.2.

Hydrogen recombiners and the hydrogen purge system are discussed in Subsection 6.2.5.

The primary containment leak rates are discussed in Section 6.2.

6.5.3.2 Secondary Containment

The following are provided to control fission products within the secondary containment following a design basis accident:

a) A secondary containment that completely surrounds each of the two primary containments.

b) The Standby Gas Treatment System (SGTS) discussed in Subsection 6.5.1.1.

c) A recirculation system.

The secondary containment consists of a reinforced concrete structure up to the refueling floor (El. 818 ft. 1 in.) and of a metal sided superstructure above el. 818 ft. 1 in., both discussed in Subsection 3.8.4.

The secondary containment isolation is discussed in Subsection 9.4.2.1. This section also defines three ventilation zones (I, II, and III).

The SGTS is used to maintain the affected zone(s) of the secondary containment at a negative pressure for the events and purposes described in Subsection 6.5.1.1.1.

A common recirculation system is provided for Units 1 and 2 to perform the following functions:

a) Mix the atmosphere in the reactor building to obtain a lesser and more uniform concentration of radioactivity following a design basis LOCA and refueling accident.

b) Prevent the spread of radioactivity by the heating-ventilating-cooling systems between Zone III and Zones I or II during and after a refueling accident.

c) Provide mixing of the atmosphere within the reactor building. This may involve mixing the atmosphere of all three zones; of Zone I or Zone II and the refueling area (Zone III); or of Zone III alone, particularly in case of the refueling accident described in b), above. See Subsection 9.4.2.1.3 for the secondary containment isolation modes. Also see Subsection 6.2.3 for the secondary containment analysis.

The recirculation system is shown on the Standby Gas Treatment System flow diagram, Dwg. M-175, Sh. 2. The instruments and controls are shown on Dwg. VC-175, Sh. 1.

Estimated respective zone(s) recirculation flow rates and their volumes are listed in Table 6.5-7.

The recirculation system consists of two 100 percent redundant, vane-axial fans connected to the emergency power supply, associated ductwork, dampers, and controls.

The recirculation air is distributed to all areas and rooms through the existing normal ventilation ductwork.

Both fans, ductwork used in the recirculation mode, supports, and instruments and controls meet the Seismic Category I requirements.

The recirculation system starts automatically on receiving the secondary containment isolation signal, which is defined in Subsection 9.4.2.1.3.

For the recirculation system failure mode and effect analysis see Table 6.5-4.

The tests and inspection described in items 1, 2, 3, 13 and 14 of Table 9.4-1 are applicable to the recirculation system.

6.5.4 ICE CONDENSER AS A FISSION PRODUCT CLEANUP SYSTEM

Not applicable.

6.5.5 REFERENCES

6.5-1 ORNL-NSIC-65

ENGINEERED SAFETY FEATURE FILTER SYSTEM DESIGN PARAMETERS

ITEM	SGTS	CSEOASS
Type	Built-up unit	Built-up unit
Number of units	2	2
Flow rate, each cfm	3,000 min to 10,500 max	6,000 (design) 5,810 (operation)
Fan		
Type	Centrifugal	Centrifugal
Drive	belt	belt
No. of fans per unit	1	1
No. of running fans	1	1
Total pressure, in wg	17 at max. flow; 1.5 at min. flow	10
Motor, hp, each	50	20
Mist Eliminator		
Quantity and size, in.	9-24x24x8	N/A
Eliminator media	304SS/Fiberglass Mash	N/A
Efficiency (1) gal 1000 cfm	1	N/A
Pressure drop, in. wg		
Initial	1	N/A
Maximum	2	N/A
Air Heater		
No of coils per unit	1	2
Heating capacity per unit, Btu/hr (kW)	307,000 (90)	102,000 (30)
Prefilters		
Quantity and size, in.	9-24x24x11-1/2	6-24x24x12
Pressure drop, in. wg		
Clean	0.5	0.3
Dirty	1.0	0.9
Efficiency (2), %	90	95
HEPA filter, upstream Quantity and size, in.	9-24x24x12	6-24x24x11-1/2
Pressure drop, in. wg		
Clean	1.0	1.0
Dirty	3.0	3.0
Efficiency (3), %	99.97	99.97

ITEM	SGTS	CSEOASS
Charcoal adsorber		
Type	Vertical bed	Vertical bed
Depth, in.	8	4
Filter media	Impregnated activated charcoal	Impregnated activated charcoal
Maximum Pressure drop, in. wg	4	2.2
Efficiency		
Removing inorganic iodine, %	99	99
Removing organic iodine, %	99	99
HEPA filter, downstream [4]		

(1) Prevent blinding of downstream HEPA filter when operated at 260°F with air-steam mixture containing 1 gal of water droplets (actively contained in the airstream) per 1000 cfm.

(2) Dust spot test on atmospheric dust.

(3) By MIL Standards 282 DOP test method on 0.3 micron particles.

(4) All design parameters same as HEPA, upstream except pressure drop dirty = 1.2 in wg. for downstream CSEOASS HEPA

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TABLE 6.5-2

ENGINEERED SAFETY FEATURE FILTER SYSTEMS
COMPLIANCE WITH RECOMMENDATIONS OF REGULATORY GUIDE 1.52

(See Section 3.13 For Further Information - Also See Note 1 At The End Of The Table)

REGULATORY POSITION	COMPLIED WITH Yes/No	DESCRIPTION OF REFERENCE		REMARKS
		SGTS	CSEOASS	
1. ENVIRONMENTAL DESIGN CRITERIA				
Position a	Yes	Dwg. C-1815, Sh. 3 SGTS Equipment Room Zone CS9	Dwg. C-1815, Sh. 3 SGTS Equipment Room Zone CS8	The ESF Filter Systems are designed for the max. environments, resulting from the postulated DBA, to which the systems will be exposed.
Position b	Yes	Dwg. C-1815, Sh. 3 SGTS Equipment Room Zone CS9	Dwg. C-1815, Sh. 3 CSEOASS Equipment Room Zone CS8	Source Assumptions are consistent with, TID 14844. Other ESF equipment and services are adequately shielded from the ESF filter systems
Position c	Yes	Dwg. C-1815, Sh. 3 SGTS Equipment Room Zone CS9	Dwg. C-1815, Sh. 3 CSEOASS Equipment Room Zone CS8	Assumptions are consistent with TID 14844.
Position d	Yes	See Remarks	See Remarks	The operation of the ESF filter systems is compatible with the operation of other ESF systems.
Position e	Yes	See Remarks	See Remarks	Components of ESF filter systems have been designed for temperatures in excess of the highest predicted outdoor temperature (92 F) and also suitable for use if exposed to the lowest predicted outdoor temperature (-5 F).
2. SYSTEM DESIGN CRITERIA				
Position a	Yes	Table 6.5-1 Dwg. M-175, Sh. 1 Dwg. M-175, Sh. 2	Table 6.5-1 Dwg. M-175, Sh. 1 Dwg. M-175, Sh. 2	Mist eliminators not provided on CSEOASS, no entrained water droplets in outdoor air entering the system
Position b	Yes	Drawing V-12-11	Drawing V-12-11	Missile protection walls separate the redundant units, from each other and from adjacent rotating equipment.
Position c	Yes	All components are Seismic Category 1	All components are Seismic Category 1	
Position d	N/A	N/A	N/A	Located outside both primary and secondary containment.
Position e	Yes	Tables 6.5-5 and 6.1-1	Tables 6.5-5 and 6.1-1	
Position f	Yes	10,500 cfm	6,000 cfm	Flow rates, each train.

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TABLE 6.5-2

ENGINEERED SAFETY FEATURE FILTER SYSTEMS COMPLIANCE WITH RECOMMENDATIONS OF REGULATORY GUIDE 1.52

(See Section 3.13 For Further Information - Also See Note 1 At The End Of The Table)

REGULATORY POSITION	COMPLIED WITH Yes/No	DESCRIPTION OF REFERENCE		REMARKS
		SGTS	CSEOASS	
Position g	Yes	Recorded: - System flow rate - PD across 1st HEPA filter Alarms: - See Subsection 6.5.1.1.5	Recorded: - System flow rate - PD across 1st HEPA filter Alarms: - See Subsection 6.5.1.2.5	
Position h	Yes	Section 7.3 and 6.5.1.2.5	Sections 7.3 and 6.5.1.1.5	
Position i	N/A	N/A	N/A	No permanent bypass arrangement installed.
Position j	Yes	Section 3.13, response to Regulatory Guide 1.52	Section 3.13, response to Regulatory Guide 1.52	
Position k	Yes	N/A	Subsection 6.5.1.2.2	
Position l	Yes	Subsection 6.5.1.1.4	Subsection 6.5.1.2.4	
Position m	N/A	-	-	
3. COMPONENT DESIGN CRITERIA AND QUALIFICATION TESTING				
Position a	Yes	Table 9.4-1 and Subsection 6.5.1.1.2	N/A	
Position b	Yes	Subsection 6.5.1.1.2	Subsection 6.5.1.2..2	Heater failure detected by loss of temperature differential across the heater will alarm in the control room. If this occurs during an engineered-safety feature actuation operator action will be necessary to shutdown the affected train. Total system effectiveness remains, since the SGTS filter trains are operated in Lead-Lead and CSEOASS filter trains are operated in Lead/Lag.
Position c	Yes Table 6.5-1	Table 9.4-1 Table 6.5-1	Table 9.4-1	

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TABLE 6.5-2

ENGINEERED SAFETY FEATURE FILTER SYSTEMS
COMPLIANCE WITH RECOMMENDATIONS OF REGULATORY GUIDE 1.52

(See Section 3.13 For Further Information - Also See Note 1 At The End Of The Table)

REGULATORY POSITION	COMPLIED WITH Yes/No	DESCRIPTION OF REFERENCE		REMARKS
		SGTS	CSEOASS	
Position d	Yes	Table 9.4-1	Table 9.4-1	
Position e	Yes	Subsection 6.5.1.1.2	Subsection 6.5.1.2..2	
Position f	Yes	Subsection 6.5.1.1.2	Subsection 6.5.1.2..2	
Position g	Yes	Subsection 6.5.1.1.2	Subsection 6.5.1.2..2	
Position h	N/A	N/A	N/A	Both systems are located on control structure.
Position i	Yes Table 6.5-1	Tables 9.4-1 and 6.5-1	Tables 9.4-1 and 6.5-1	Replace carbon meets qualification ans batch test results summarization Table 5-1 of ANSI N509-80 in place of Table 1 of Regulatory Guide 1.52, Revision 0.
Position j	Yes	Subsections 6.5.1.1.2	Subsection 6.5.1.2.2	
Position k	Yes	Subsections 6.5.1.1.2	Subsection 6.5.1.2.2	
Position l	Yes	Subsections 6.5.1.1.2	Subsection 6.5.1.2.2	
Position m	Yes	Subsections 6.5.1.1.2	Subsection 6.5.1.2.2	
Position n	Yes	See Remarks	See Remarks	Both systems are in compliance.
4. MAINTENANCE				
Position a	Yes	See Remarks	See Remarks	Charcoal will be removed by a carbon removal system which draws the charcoal out by a blower. Prefilter and HEPA filters can be easily unclamped.
Position b	Yes	Inside clear height approximately 8 ft. 0 in.	Inside clear height approximately 8 ft. 0 in.	
Position c	See Remarks	See Remarks	See Remarks	30 in. x 50 in. and 20 in. x 50 in. access doors provided with no vacuum breakers. Administrative controls will be used to preclude any work inside of the housing when the unit is in operation. Both systems are normally not used.

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TABLE 6.5-2

ENGINEERED SAFETY FEATURE FILTER SYSTEMS
COMPLIANCE WITH RECOMMENDATIONS OF REGULATORY GUIDE 1.52

(See Section 3.13 For Further Information - Also See Note 1 At The End Of The Table)

REGULATORY POSITION	COMPLIED WITH Yes/No	DESCRIPTION OF REFERENCE		REMARKS
		SGTS	CSEOASS	
Position d	See Remarks	See Remarks	See Remarks	The SGTS complies but CSEOASS is less than 5 ft. 0 in. frame to frame distance.
Position e	Yes	See Remarks	See Remarks	Both systems are in compliance.
Position f	Yes	See Remarks	See Remarks	Both systems are in compliance.
Position g	Yes	See Remarks	See Remarks	Both systems will be provided with appropriate material handling equipment for transfer of used filters to radwaste building for processing.
Position h	See Remarks	Table 9.4-1 and Section 3.13	Table 9.4-1 and Section 3.13	Section 3.13 takes exception to paragraph 4(h) of Regulatory Guide 1.52.
Position i	See Remarks	Section 3.13	Section 3.13	Section 3.13 takes exception to paragraph 3(i) of Regulatory Guide 1.52. A monthly schedule will provide for the unit to operate at least 15 minutes a month.
Position j	Yes	See Remarks	See Remarks	If construction needs filters prior to startup, they will purchase their own prefilters or glass pads.
Position k	Yes	See Remarks	See Remarks	Gas-tight light fixtures with exterior bulb replacement capabilities are provided.
Position l	Yes	See Remarks	See Remarks	Electrical, water, and compressed air services are provided in the areas of the filters.
Position m	Yes	See Remarks	See Remarks	No sharp corners or ledges exist in the housing construction.

Note 1: Positions identified in this table are per Revision 0, dated June 1973 of the Regulatory Guide 1.52. Conformance to positions of Revision 1, dated July 1976 and Revision 2, dated March 1978 are shown in Section 3.13.

TABLE 6.5-3

STANDBY GAS TREATMENT 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	Total loss of offsite power (Loop)	None. All units are powered from separate standby diesel generators.	Alarm in the control room	No loss of safety function
Emergency (LOCA or LOCA & LOOP)	Exhaust fans (OV109A&B)	Loss of one fan	The system is operated in the lead-lead mode, the alternate train is already in operation.	Alarm in the control room	No loss of safety function
Emergency (LOCA or LOCA & LOOP)	Electric heaters	Loss of electric heater	The system is operated in the lead-lead mode, the alternate train is already in operation.	Alarm in the control room	No loss of safety function
Emergency (LOCA or LOCA & LOOP)	Prefilters, mist eliminators, up-stream & down-stream HEPA filters	High differential pressure across any of these components	None. The fan inlet vanes and the outdoor makeup air damper will modulate in sequence to maintain air-flow. The filter trains are operated in LEAD-LEAD. Individual system low flow is detected and alarmed in the control room.	Alarm in the control room	No loss of safety function
Emergency (LOCA or LOCA & LOOP)	Charcoal adsorbers	High-high temperature (ignition temperature)	None. At ignition temperature the affected train exhaust fan is tripped, the whole train is isolated, the fire protection system is actuated. Since filter trains are operated in LEAD-LEAD, the tripping and isolation of one filter train will not prevent satisfactory operation.	Alarms in the control room at pre-ignition and ignition temperatures	No loss of safety function

TABLE 6.5-3

STANDBY GAS TREATMENT 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 (LOCA or LOCA & LOOP)	Recirc system to SGTS transfer dampers (PDD-07554A&B)	Damper failed closed	None. The building required pressure may not be maintained, for a short period of time. Both filter trains are operated in LEAD. The failure of one damper will not prevent satisfactory operation.	Alarm in the control room	No loss of safety function
Emergency (LOCA or LOCA & LOOP)	Outside air cooling air inlet dampers (HD-07555A&B)	Damper failed closed	None. These dampers are designed to fail safe in the closed position.	Damper position indication in the control room	No loss of safety function
Emergency (LOCA or LOCA & LOOP)	Outside air makeup dampers (FD-07551A2&B2)	Damper failed closed	None. These dampers are designed to fail safe in the closed position. The fan variable inlet vanes will continue to maintain minimum airflow and the inlet header static pressure at the set point. Filter train fans are operated in LEAD-LEAD. Failure of one outside air makeup damper will have no adverse effect on total system operation. If an individual train flow falls below a given setpoint an alarm is sounded in the control room.	Damper position indication in the control room	No loss of safety function

TABLE 6.5-3

STANDBY GAS TREATMENT 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 (LOCA or LOCA & LOOP)	Fans inlet dampers (FD-07552A&B)	Damper failed open	None. These dampers are normally open and are designed to fail safe in the open position.	Damper position indication in the control room	No loss of safety function
Emergency (LOCA or LOCA & LOOP)	Filter trains cross-tie dampers (TD-07560A&B)	Damper failed closed	None. These dampers are designed to fail safe in the closed position.	Damper position indication in the control room.	No loss of safety function
Emergency (LOCA or LOCA & LOOP)	Seismically analyzed fire protection backup deluge water valve (TV-07550A&B)	Valve failed closed	None. These valves are normally closed and are designed to fail safe in the closed position. These valves are backup to the regular nonseismic deluge valves	None. However, when the non-seismically qualified deluge valves open, an alarm sounds in the control room.	No loss of safety function
Emergency (LOCA or LOCA + LOOP)	Filter trains inlet dampers (HD-07553A&B)	Damper failed open	None. These dampers are normally open and are designed to fail safe in the open position.	Damper position indication in the control room	No loss of safety function

TABLE 6.5-3

STANDBY GAS TREATMENT 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 (LOCA or LOCA + LOOP)	Fans variable inlet vanes (FD-07551A1& B1)	Dampers fail	None. These dampers are designed to fail open. If the damper fails open, this will increase a demand for more makeup air. As a result, the outside air makeup damper will open and stay in fully open position, unless the inlet header controller starts to modulate it, if the building exhaust air-flow increases. The reactor building pressure control loop is independent of the SGTS flow control loop; therefore, the building pressure is not affected by this failure.	None	No loss of safety function
Emergency (LOCA or LOCA + LOOP)	Charcoal adsorbers temperature detection units	Failure of the temp. detection unit	The system is operated in the lead-lead mode, at high-high charcoal adsorber temperature the affected train may not be tripped automatically but the other train will continue to operate. Any of the SGTS redundant trains can be manually started from the control room.	Temperature detection unit trouble alarm in the control room. Also, SGTS exhaust high and high-high radiation alarms in the control room.	No loss of safety function

Table 6.5-4

RECIRCULATION SYSTEM FAILURE MODE AND EFFECT ANALYSIS(1)

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	Total loss of offsite power (LOOP)	None, each of the redundant fans and associated dampers are powered from separate standby diesel generations	Alarm in the control room	No loss of safety function
Emergency (LOCA or LOCA & LOOP)	Recirculation fans OV201A&B	Loss of one fan	None, the standby fan automatically starts.	Alarm in the control room	No loss of safety function
Emergency (LOCA or LOCA & LOOP)	Dampers on duct from recirculation system to SGTS HD-07543A&B	One damper failed closed	None, the other damper, installed in parallel, will remain open	Damper position indication in the control room	No loss of safety function
Emergency (LOCA or LOCA & LOOP)	Dampers on duct from Zone I equipment compartment exhaust system to supply plenum of recirculation system HD-17601A&B	One damper failed closed	None, the other damper, installed in parallel, will remain open.	Damper positon indication in the control room	No loss of safety function
Emergency (LOCA or LOCA & LOOP in Unit 1))	Dampers on duct from Zone II equipment compartment exhaust system to supply plenum of recirculation system HD-27601A&B	One damper failed open (2)	Possibility of limited transfer of Zone I recirculation air to Zone II reactor building exhaust vent	Flow alarm and flow indicating backup light in the control room	Possibility of some radioactive releases through Unit 2 Reactor Building vent. All releases will be monitored, and a Zone II isolation initiated, if required.

Table 6.5-4

RECIRCULATION SYSTEM FAILURE MODE AND EFFECT ANALYSIS[(1)]

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 & LOOP)	Dampers on duct from Zone I exhaust system to supply plenum of recirculation system HD-17602A&B	One damper failed closed	None, the other damper, installed in parallel will remain open.	Damper position indication in the control room	No loss of safety function
Emergency (LOCA or LOCA & LOOP in Unit 1)	Dampers on duct from Zone II exhaust system to supply plenum of recirculation system HD-27602A&B	One damper failed open [(2)]	Possibility of limited transfer of Zone I recirculation air to Zone II, exhaust vent	Flow alarm and flow indicating backup light in the control room	Possibility of some radioactive releases through Unit 2 Reactor Building vent. All releases will be monitored, and a Zone II isolation initiated, if required.
Emergency (LOCA or LOCA & LOOP)	Dampers on duct from exhaust plenum of recirculation system to Zone I supply system (Sys. No. V202) HD-17657A&B	One damper failed closed	None, the other damper, installed in parallel, will remain open	Damper position indication in the control room	No loss of safety function
Emergency (LOCA or LOCA & LOOP in Unit 1)	Dampers on duct from exhaust plenum of recirculation system to Zone II supply system HD-27657A&B	One damper failed open [(2)]	Possibility of limited transfer of Zone I recirculation air to Zone II supply system	Flow alarm and flow indicating backup light in the control room	Possibility of some radioactive releases through Unit 2 Reactor Building vent. All releases will be monitored, and a Zone II isolation initiated, if required.

(1) This table describes effects of single failures concurrent with design basis events in Unit 1. Effects of similar failures concurrent with design basis events in Unit 2 are similar.

(2) These dampers are designed to fail safe, that is, in closed position; however, for the purpose of these analyses, it is assumed that they may fail open.

TABLE 6.5-5

LIST OF MATERIALS USED IN THE STANDBY GAS TREATMENT SYSTEM

COMPONENTS	MATERIAL	CHEMICAL COMP.
Housing Plate & Angle Access Panel Plate Access Door Plate & Compression Frame Chromalox Heater Support Angle	ASTM A36 (Or Engineer Approved Equal)	
HECA [(1)] Plate Eclipse Valve-Shaft	ASTM A53	
Housing Pipe HECA [(1)] Pipe		
Housing Couplings Access Door Couplings & Plug		
Test Canister Plate HECA [(1)] Sheet		
Filter Frame Tubing	ASTM 554	
Prefilter	Glass Fibers w/Synthetic Resin, Particle board, Aluminum Separators, Fire Retardant Polyurethane Foam & Rubber Base Adhesive	
HEPA Filter	F-700 Glass, Chromized Steel Frame & Rubber Base Adhesive	

TABLE 6.5-5

LIST OF MATERIALS USED IN THE STANDBY GAS TREATMENT SYSTEM

COMPONENTS	MATERIAL		CHEMICAL COMP.
Moisture Separator Eclipse Valve-O-Ring	304 SST Frame W/Wire Mesh – 304 SST/Fiber Glass		
Neoprene Gasket	ASTM D105b & ASTM D2000 BC 516		
Paint	Mobil Zinc #7 With Zinc Pigment		$(C_2 H_3)_4\ Si_4$
	Ameron	Epoxy Primer	
		For Bare Metal	Amerlock 400
		For General Tie-Coat	Amercoat 149
		Waterborne Finish	
		Epoxy	Amerguard 335
		Acrylic	Amercoat 220
	Carboline	Epoxy Primer	
		For Bare Metal	No. 890
		For General Tie-Coat	Multi-Bond 120
		Waterborne Finish	
		Epoxy	Santile D250WB
		Acrylic	D3359
	Keeler & Long	Epoxy Primer	
		For Bare Metal	No. 1013
		For General Tie-Coat	No. 2001 Hydro-Poxy
		Waterborne Finish	
		Epoxy	H-1 Series

TABLE 6.5-5

LIST OF MATERIALS USED IN THE STANDBY GAS TREATMENT SYSTEM

COMPONENTS	MATERIAL	CHEMICAL COMP.
	Acrylic Wash Primer For Exterior Ductwork Only Acrylic Urethane Finish For Exterior Ductwork Only	W-1 Series KL9400 KLN-1 Series”
Glass	Holophane #540	Diffuser Lens SiO_3, AL_2O_3, CaO & Na_2O
Heaters	Model DH70 & Model #LU.H-15-21 W/#WUH-05	Chromalox Heater Elements – 80% Nickel Sheath, 20% Chromium Coiled Wire, Ceramic Coated Steel Flanges, Fins & Frame – A-36
Filter Frame Angle HECA(1)Clip, Angle, Spacer Rod	ASTM A276	
Weld Stud Nuts & Washers	ASTM A240	
Filter Frame Pipe & Elbow HECA (1) Pipe & Drain Nozzle	ASTM A312	

TABLE 6.5-5

LIST OF MATERIALS USED IN THE STANDBY GAS TREATMENT SYSTEM

COMPONENTS	MATERIAL	CHEMICAL COMP.
Best Canister Elbow	ASTM 403	
Alison Sensor 9090	ASTM 446	
Eclipse Valve-Body	Cast Iron	
Eclipse Valve Disc.	ASTM A569	
Test Canister Bar	ASTM A479-304	
Test Canister Tubing	ASTM A511-304	
Chromalox Heater Sheet	ASTM A569	
Test Canister Tubing	ASTM A213-304	
Nuts	Silicone Bronze	Manganese Copper Silicone
Bearings	Bronze	Manganese Copper
Alison 304 Junction Box	Model 2003-SS Junction Box	
Adsorbent	Impregnated, activated carbon	KI_3, or TEDA, or TEDA + KI - 5% by weight max. Carbon TEDA = Triethylenediamine

[(1)] High Efficiency Charcoal Adsorber (HECA) – Charcoal Adsorber

TABLE 6.5-6

LIST OF MATERIALS USED IN THE EMERGENCY
OUTSIDE AIR SUPPLY SYSTEM

COMPONENTS	MATERIAL	CHEMICAL COMP.
Structural Steel Base Channels	ASTM A36 (Or Engineer Approved Equal)	
Steel Plate Plenum Skin	ASTM A283	
SST Plate HEPA Filter Holding Cranes and Charcoal Bed Construction	ASTM A240	
Welded & Seamless Steel Pipe Water Drains	ASTM A53	
Seamless Steel Pipe Water Drains	ASTM A106	
Galvanized Pipe Water Spray System	ASTM A120	
Pipe Fittings Tank Flanges, ½ Couplings and Pipe Flanges	ASTM A234	
SST Welded Tubing Charcoal Bed Fittings (Test Canister Mounting Rings)	ASTM A269	
SST Bar & Shapes Structural Supports for Charcoal Bed	ASTM A276	
Welded Pipe Charcoal Bed Fittings	ASTM A312	
Cold Rolled Sheet Mounting Brackets for Electrical Components	ASTM A366	

TABLE 6.5-6

LIST OF MATERIALS USED IN THE EMERGENCY OUTSIDE AIR SUPPLY SYSTEM

COMPONENTS	MATERIAL	CHEMICAL COMP.
SST Bar & Shapes Structural Supports for Charcoal Bed	ASTM A479	
Structural Steel Tubing Rounds & Shapes Alternate for A-36 Rise Channels	ASTM A500	
Hot Formed Carbon Steel Stiffeners on Outside of Housing	ASTM A501	
SST Mechanical Tubing Test Canister Holding Plate	ASTM A511	
Galvanized Sheet Electrical Fittings Conduit, Junction Boxes	ASTM A526	
Miscellaneous Electrical Components Which are Part of the Electrical System, Such as Wire Covering, Relay Components, etc.		
	A Derivative of Phenol	Phenol C_6H_5OH
	Glass Polyester & Phenol Formaldehyde	HCHO and C_6H_5OH
	Bakelite & Formica (Same as Phenol)	

TABLE 6.5-6

LIST OF MATERIALS USED IN THE EMERGENCY
OUTSIDE AIR SUPPLY SYSTEM

COMPONENTS	MATERIAL	CHEMICAL COMP.
	Acrylic Resin Lucite (nameplates)	CH_2:C(CH_3)$COOCH_3$
	Copper Wire with Polyethylene Cover	
	Copper wire with Asbestos Cover (high temp. appl.)	
Adsorbent	Impregnated, activated carbon	KI_3, or TEDA, or TEDA + KI – 5% by weight max. Carbon TEDA = triethylenediamine
HEPA Filters	Glass Fibers with Resin Binder & Plastic Edge Seals	
Prefilter FARR HP-200	Glass Fibers with Phenolic Resin Binder	
Paint	Ameron — Epoxy Primer For Bare Metal For General Tie-Coat Waterborne Finish Epoxy Acrylic	 Amerlock 400 Amercoat 149 Amerguard 335 Amercoat 220

TABLE 6.5-6

LIST OF MATERIALS USED IN THE EMERGENCY OUTSIDE AIR SUPPLY SYSTEM

COMPONENTS	MATERIAL			CHEMICAL COMP.
	Carboline	Epoxy Primer		
			For Bare Metal	No. 890
			For General Tie-Coat	Multi-Bond 120
		Waterborne Finish		
			Epoxy	Santile D250WB
			Acrylic	D3359
	Keeler & Long	Epoxy Primer		
			For Bare Metal	No. 1013
			For General Tie-Coat	No. 2001 Hydro-Poxy
		Waterborne Finish		
			Epoxy	H-1 Series
			Acrylic	W-1 Series
		Wash Primer		
			For Exterior Ductwork Only	KL9400
		Acrylic Urethane Finish		KLN-1 Series
			For Exterior Ductwork Only	

TABLE 6.5-7

ZONE VOLUMES AND THEIR ESTIMATED RECIRCULATION AIRFLOW RATES

VENT ZONE NO.(1)	ZONE VOLUME FT^3	SUBSYSTEM FLOW PATH (ASSOCIATED FANS) (2)		ESTIMATED DESIGN AIR FLOW RATES (3)			
				MODE A (4)	MODE B (5)	MODE C (6)	MODE D (7)
I	1,488,600	Supply	(1V202)	28280	-	20020	-
		Return	(1V205,1V206)	29730	-	21470	-
II	1,598,600	Supply	(2V202)	-	29540	21500	-
		Return	(2V205,2V206)	-	31100	23060	-
III	2,668,400	Supply (8)		50680	49310	35890	80410
		Return	(1V217,2V217 1V213,2V213)	53280	51900	38480	83000

(1) Section 9.4.2.1 defines the boundaries of the ventilation system.

(2) Associated fans are listed to identify the zone supply and return subsystems but are assumed not to operate. Only a single OV201A or B recirculation fan plus a single OV109A or OV109B SGTS fan is assumed to operate in the recirculation modes.

(3) Differences between recirculation return air and supply air flows represent the maximum estimated design air flows exhausted through the SGTS system (OV109) in order to maintain negative pressure in the affected zone(s), assuming in leakage of 140% volume of the affected zone(s) per day.

(4) Isolation of Zone I and III

(5) Isolation of Zone II and III

(6) Isolation of Zone I, II and III

(7) Isolation of Zone III only

(8) Separate ducting is provided from the recirculation system (OV201) discharge plenum to the common refueling floor. It is not connected to the normal Zone III supply fan system (1V212 & 2V212).

6.6 IN-SERVICE INSPECTION OF CLASS 2 AND 3 COMPONENTS

The construction permit for Susquehanna SES was issued in November 1973.

Based on the conditions listed in 10CFR50.55a(g), the mandatory pre-service inspection requirements, including provisions for design and access, are stipulated to be Section XI of the ASME B&PV Code effective six months prior to the date of issuance of the construction permit. For Susquehanna SES the code in effect would be the 1971 Edition including the Summer 1972 Addenda, which required inspection of the reactor coolant pressure boundary only.

The actual pre-service inspection for Susquehanna SES will be conducted in accordance with the requirements of the 1974 Edition of the ASME Code, Section XI, including Addenda through Summer, 1975 as modified by Appendix III to Winter 1975 Addenda and IWA-2232 of the Summer 1976 Addenda to the extent practical within the limitations of design and access provisions and the geometry and materials of construction of the component. Pre-service inspection of Class 2 integrally welded supports, Category C-E-I and pressure retaining bolting, category C-D, will be in accordance with ASME Section XI, 1977 edition including addenda through Summer 1978. Subsequent in-service inspections will be conducted in accordance with the requirements of 10CFR50.55a(g), also, on an "as practical" basis.

The initial in-service examinations conducted during the first 120 months will comply, to the extent practical, with the requirements of the ASME B&PV Code Section XI Edition and Addenda incorporated by reference in 10CFR50.55a(b) on the date 12 months prior to the date of issuance of the operating license, subject to modifications listed by the reference sections.

The in-service examinations conducted throughout the service life of the Susquehanna SES will comply, to the extent practical, with the requirements of the ASME B&PV Code Section XI Edition and Addenda incorporated by reference in 10CFR50.55a(b) 12 months prior to the start of the inspection interval, subject to limitations listed by the reference sections.

Details of the in-service inspection program intervals are contained in the approved In-service Inspection Program; these documents will be updated to reflect program commitments for subsequent intervals.

6.6.1 COMPONENTS SUBJECT TO EXAMINATION

The inspection requirements of ASME Code Section XI, Articles IWC-2000 and IWD-2000, will be met within the limitations of design and access provisions and the geometry and materials of construction of the component, for all Class 2 and Class 3 pressure retaining components except for components excluded under IWC-1220. Class 2 and Class 3 supports are examined in accordance with IWF-2000. Note that the EPRI Topical Report TR-112657, Rev. B-A methodology, which was supplemented by Code Case N-578-1, will be utilized for implementing the risk-informed inservice inspection program. The risk-informed program scope will be implemented as an alternative to the ASME Section XI examination program for Class 2 Examination Categories C-F-1 and C-F-2 welds in accordance with 10CFR 50.55a(a)(3)(i). The risk-informed inservice inspection program has been expanded to include welds in the break exclusion region piping, also referred to as the high energy line break region, which includes several non-class welds that fall within the break exclusion region augmented inspection program.

Additional guidance for adaptation of the risk-informed inservice inspection evaluation process to break exclusion region piping is given in EPRI TR-1006937 Rev. 0-A.

6.6.2 ACCESSIBILITY

In-service inspection access to the ASME Code Class 2 and 3 components is provided in the design of the plant on an "as practical" basis. Pre-service inspections are provided to the "extent practical" within the limitations of design and access provisions for Code Class 2 and 3 components. Aside from providing normal access to components for installation, maintenance, and testing, the following provisions have been considered in the Susquehanna SES design:

6.6.2.1 Piping and Component Welds

Access envelopes have been considered for Class 2 components requiring volumetric and/or surface examinations. Weld contours and surfaces have been prepared for meaningful ultrasonic examination where required.

6.6.2.2 Insulation Removal

Class 2 piping or components requiring volumetric and/or surface examinations are equipped with removable insulation panels.

For Class 2 and Class 3 piping requiring a visual examination during system pressure tests that is not equipped with removable insulation, the visual examinations will be performed by inspecting the exposed surfaces and joints in component insulation to locate evidence of leakage and the floor areas (or equipment) directly underneath components for evidence of accumulated leakage that may drip from components.

For Class 2 and Class 3 piping requiring a visual examination during system pressure tests that is equipped with removable insulation, the visual examinations will be performed by inspecting the exposed surfaces for evidence of leakage.

6.6.2.3 Inaccessible Class 3 Piping

Piping located beneath the spray pond is embedded in concrete and is open-ended.

Piping of the ESW and RHRSW systems, running to and from the spray pond, is run underground.

Piping of the Fuel Pool Cooling Water system, running to the spent fuel pool, is embedded in the concrete of the reactor building refuel floor.

6.6.3 EXAMINATION TECHNIQUES AND PROCEDURES

In-service examination techniques and procedures used for Code Class 2 and 3 components will conform to the requirements of Subsection IWA-3100 of the governing Code edition and addenda.

6.6.4 INSPECTION INTERVALS

The ISI program schedule of required examinations to be completed in each inspection interval meets the requirements of IWC-2412 and IWD-2412 of Section XI.

6.6.5 EXAMINATION CATEGORIES AND REQUIREMENTS

ISI examination categories and requirements for ASME Class 2 and 3 components will be examined in accordance with IWC-2500, Table IWC-2500-1, IWD-2500, Table IWD-2500-1, and IWF-2500, and Table IWF-2500-1 of Section XI. Areas subject to examination and the extent of examination for Class 2 and Class 3 components comply with the requirements of Section XI on an "as practical" basis. Note that the EPRI Topical Report TR-112657, Rev. B-A methodology, which was supplemented by Code Case N-578-1, will be utilized for implementing the risk informed inservice inspection program. The risk-informed program scope will be implemented as an alternative to the ASME Section XI examination program for Class 2 Examination Categories C-F-1 and C-F-2 welds in accordance with 10CFR50.55a(a)(3)(i). The risk-informed inservice inspection program has been expanded to include welds in the break exclusion region piping, also referred to as the high energy line break region, which includes several non-class welds that fall within the break exclusion region augmented inspection program. Additional guidance for adaptation of the risk-informed inservice inspection evaluation process to break exclusion region piping is given in EPRI TR-1006937 Rev. 0-A.

6.6.6 EVALUATION OF EXAMINATION RESULTS

Evaluation of examination results will be in accordance with IWA-3000, IWC-3000, IWD-3000, and IWF-3000 for ASME Code Class 2 and 3 components.

Repairs to, or replacement of components containing unacceptable indications will be performed in accordance with the requirements of IWA-4000 of Section XI.

6.6.7 SYSTEM PRESSURE TESTS

System pressure tests will meet the requirements of IWC-5000 and IWD-5000 of Section XI.

6.6.8 AUGMENTED IN-SERVICE INSPECTION TO PROTECT AGAINST POSTULATED PIPING FAILURES

The augmented in-service inspection program to provide assurance against postulated piping failures of high energy systems between containment isolation valves will be reviewed and implemented as described below. There are no guard pipes used to enclose high energy piping on the Susquehanna SES.

The following augmented inspection program applies to piping between the containment isolation valves for which no breaks are postulated;

For ASME III, Class I and 2 piping, the requirements of the applicable Code apply, with the exception that the extent of examination will be augmented such that 100% of the circumferential welds within the containment isolation boundary will receive 100% volumetric examination during the first and second ten year inspection intervals. Commencing with the Third Ten Year Inspection Interval, the risk-informed break exclusion region program methodology, described in EPRI TR-1006937, Rev. 0-A, will be used to define the inspection scope in lieu of the 100% examination of all piping welds in the previous break exclusion region augmented program. Therefore, all welds in the original augmented program for the break exclusion region will be evaluated under the risk-informed inservice inspection program using an integrated risk-informed approach.

Volumetric examination of branch connections containing weldolets, half-couplings, and socket welds would not be meaningful due to the geometry of the branch connection and the small pipe sizes involved. Full coverage of the weld and required volume cannot be obtained. Therefore, surface examination will be performed on all branch to main run welds and all socket welds up to the first isolation valve on the branch line. All butt welds included in the branch piping up to the first isolation valve will receive full volumetric examination.

The inspection program will be performed, completely in accordance with ASME Section XI requirements, however, the extent of examination of ASME Section XI will be supplemented to comply with the augmented inspection program requirements outlined above.

Welds in piping 1" NPS and smaller are exempt from augmented in-service inspection as described above.

6.6.9 CONTAINMENT INSPECTIONS

On August 8, 1996, final rulemaking was published in the Federal Register (Volume 61, Number 154, Pages 41303-41312) to incorporate by reference Subsections IWE and IWL of the ASME Section XI Code into 10 CFR 50.55a. The effective date of this amendment was September 9, 1996. This rulemaking included several requirements in addition to those required in ASME Section XI and further required that a Containment Inspection Program be developed and implemented by September 9, 2001, five years following the effective date of the amendment.

This rulemaking specifies requirements to assure that the critical areas of the primary containment structure are inspected to detect degradation that could compromise its structural integrity and implement prescribed corrective actions accordingly.

ASME Section XI, Subsection IWE, defines the requirements for inservice inspection, repair, and replacement of Class MC (metal containment) pressure retaining components and their integral attachments, and of metallic shell and penetration liners of Class CC (concrete containment) pressure retaining components and their integral attachments. ASME Section XI, Subsection IWL, defines the requirements for inservice inspection and repair of reinforced concrete and replacement of post-tensioning systems of Class CC components. The amendment to 10 CFR 50.55a mandated the implementation of the 1992 Edition with the 1992 Addenda of Subsections IWE and IWL, including Subsection IWA for General Requirements, for the initial Containment Inspection Program interval.

Per 10CFR.50.55a(g), licensees are required to update their Containment Inservice Inspection Programs to meet the requirements of ASME Section XI once every ten years or inspection interval. The Containment Inservice Inspection Program is required to comply with the latest edition and addenda of the Code incorporated by reference in 10CFR50.55a twelve(12) months prior to the start of the interval per 10CFR50.55a(g)(4)(ii).

With the update to the Inservice Inspection Program for the Third Ten Year Inspection Interval for Class, 2 and 3 components, PPL has updated the Containment Inservice Inspection Program to its Second Interval. This update will enable all the Inservice Inspection Program components to be based on the same Edition and Addenda of ASME Section XI as well as share a common interval start date and end date.

APPENDIX 6A

SUBCOMPARTMENT DIFFERENTIAL PRESSURE CONSIDERATIONS

Differential pressure analyses were performed for the reactor vessel shield annulus and the drywell head region.

The RPV shield annulus, which is 48.95 ft high and 1.70 ft wide at the top, has the 28 in. recirculation pumps suction lines passing through it. The mass and energy release rates from a postulated recirculation outlet line break constitute the most severe transient in the reactor shield annulus. Therefore, it is selected as the pipe break when analyzing loading of the shield wall and the reactor pressure vessel support skirt for pipe breaks inside the annulus. Estimation of mass and energy release is based on the guidelines set forth in GE's letters to Bechtel; (GB 78-14 dated January 16, 1978 and GB 78-24 dated January 27, 1978) and "Technical Description Annulus Pressurization Load Adequacy Evaluation" (NEDO-24548/78 NED 302).

The subcompartment differential pressure analysis inputs and results presented in this section for the annulus pressurization analysis and the drywell head pressurization analysis are based on the original design basis conditions unless otherwise noted. The blowdown mass and energy release data for the recirculation outlet line break at power uprate conditions has been reanalyzed. The analyses performed for power uprate concluded that the original analyses were conservative and bound power uprate conditions. The original analysis for drywell head pressurization was judged to be overly conservative with respect to power uprate conditions and no reanalysis was performed. Therefore, the design of the shield wall and refueling seal plate is not affected by power uprate.

Recirculation Outlet Line Break

Table 6A-1(a) presents the mass and energy release data estimated by applying the NEDO 24548 method of combining blowdown data calculated from finite and instantaneous break opening time approaches. The blowdown from the supply side is assumed to be released into the annulus due to the break being located in the reactor shield wall penetration. The break is postulated to occur at the nozzle safe end attachment weld to the pipe. The blowdown from the vessel side is vented into the drywell atmosphere. Table 6A-1 (b) provides, as a function of time, the mass flux and areas used for each side of the break. Some physical parameters pertinent to the blowdown rate estimation are noted in the table.

Feedwater Line Break

In addition to the analyses for the recirculation outlet line break in the annulus, similar analyses using the same methodology for blowdown rate estimation are performed for a postulated feedwater line break in the annulus. Table 6A-1(c) presents the mass and energy release rates generated by only applying the very conservative instantaneous break opening time method. The blowdown from the supply side is assumed to enter the annulus due to the location of the postulated break being situated inside the reactor shield wall penetration. The blowdown from the vessel side is released into the drywell. The analysis conservatively assumes that the blowdown from both sides enters the annulus region. The mass flux as a function of time and areas used for each side of the break are presented in Table 6A-1(d). Some pertinent physical parameters are noted in the table.

In addition to the above mentioned lines, there are recirculation inlet lines inside the annulus. Since the recirculation inlet lines are much smaller than the outlet lines, the expected annulus pressurization would not be as severe as for the outlet lines, thus the inlet lines were not analyzed.

Note that the most restricted flow area on the feedwater supply pipe side is the break area itself. Full break area steady state blowdown from this side is conservatively assumed to be reached immediately after the pipe rupture. Note that only the very conservative instantaneous break opening time is used in the generation of Table 6A-1(c) and 6A-1(d) data.

Head Spray Line

In considering the drywell head region, the maximum blowdown rate stems from a break in the RHR head spray line. The blowdown mass and energy release rates for this line are calculated using Moody Critical Flow of 2700 lbm/sec-ft^2 and an enthalpy of 1198 Btu/lbm. Table 6A-2 shows the blowdown schedule for a 6 in. schedule 80S line break with an effective break area of 0.181 ft^2. Since this line could singularly pressurize the drywell head region, it is chosen for analysis in a postulated break.

The annulus pressurization and drywell head pressurization analyses were performed using Bechtel's COPDA computer code. These adjusted pressures are combined with the other appropriate loads (eg, seismic and jet impingement) to develop design loads for the affected structures and components. Subcompartment venting is used to ensure that the differential pressures developed will remain below the structural capability of compartment walls.

BIOLOGICAL SHIELD ANNULUS SUBCOMPARTMENT MODELING PROCEDURES AND ANALYSIS

Biological Shield Annulus

An analysis of the pressure distribution around the reactor pressure vessel after a recirculation outlet line break was performed. The general layout of the shield annulus is shown on Dwgs. C-331, Sh. 1, C-371, Sh. 2, C-1932, Sh. 3, C-1932, Sh. 4, and C-1932, Sh. 5, Figures 6A-1(a) and 6A-1(b). Figure 6A-2 is a schematic of the RPV shield annulus model. The model consists of six major levels. Each level is subdivided into twelve 30° segments to form a total of 72 nodes inside the annulus plus an additional node for the rest of the drywell.

In general, the arrangement of the pipes in the annulus determines the most representative level division, since they constitute the only significant flow restrictions. This 73 pressure node model is considered detailed enough to conservatively predict the maximum pressures on the compartment structure. Therefore, a nodalization sensitivity study is not needed.

For the purpose of determining peak pressure in the reactor vessel shield annulus, all insulation was assumed to move flush against the biological shield wall while still maintaining its original thickness. The volume of the insulation is excluded from the net volume of each subcompartment, and the projected area of the insulation which blocks the venting path is also excluded from the free venting area used in the analysis.

The major vent path to the drywell atmosphere is through the top of the biological shield annulus. Venting through the shield wall is allowed only through the ventilation duct openings at the lower section of the shield wall.

Initial conditions used in this analysis are 15.45 psia, 135°F, and 30 percent relative humidity.

Tables 6A-3 and 6A-4 give the subcompartment volumes, flow areas, L/A ratio, and flow coefficients (including origins) used in the analysis.

The resultant pressure distributions are shown on Figures 6A-3a, 6A-3b, 6A-3c, 6A-3d, 6A-3e, and 6A-3f for the recirculation outlet line break and Figures 6A-3g, 6A-3h, 6A-3i, 6A-3j, 6A-3k, and 6A-3l, for the feedwater line break. The subcompartment pressure existing in each subcompartment at the time of peak differential pressure across the RPV are also shown on these figures. The reactor shield wall is designed for a uniform internal pressure of 70 psig. See Section 3.8.3 for description of the design of the reactor shield wall. COPDA was used to calculate the pressures while the plots were generated using a pre-processor (ABS-PLOT) and TEKPLOT. Additionally, the load forcing functions which include both peak and transient loadings on the RPV and the reactor shield wall are presented on Figures 6A-7 and 6A-8 for the recirculation outlet line break and on Figures 6A-9 and 6A-10 for the feedwater line break. FORCE-GE was used to calculate the forces for the recirculation outlet line break and Bechtel Code NE698 for the feedwater line break while the plots were generated using a pre-processor (ABS-PLOT) and TEKPLOT. This forcing function represents the time-dependent resultant force on the structure and originates from the vector sum of the product of compartment pressure and area for each of the geometry nodes used to represent the surface.

For the recirculation outlet line break the 73 pressure node model is transformed into an 84 geometry node model for calculating the resultant forces. The geometry node model adds another level subdivision but uses the same arc segments. This allows better modeling near the recirculation line nozzle. The locations of the center of each node are given in Table 6A-5. For the feedwater line break the 73 pressure mode model is also used for the force model.

The components of these nodal areas are calculated in the following manner:

$$(A_x)_i = R_i H_i (\mathrm{Sin}\ \phi_{1_i} - \mathrm{Sin}\ \phi_{2_i})$$

$$(A_y)_i = R_i H_i (\mathrm{Cos}\ \phi_{2_i} - \mathrm{Cos}\ \phi_{1_i})$$

$(A_x)_i, (A_y)_i$ = x and y area components for node I

Where

R_i = Radius of the i h geometry node, in.

H_i = Height of the i^{th} geometry node, in.

ϕ_{1_i} = Starting angle (degrees) for i^{th} geometry node

ϕ_{2_i} = Ending angle (degrees) for i^{th} geometry node

For the recirculation outlet line break the resultant areas for each geometry node for the RPV are given in Table 6A-6. For the feedwater line break the resultant areas for each node are given in Table 6A-7. For the bio-shield the node areas are the ratio of the bio-shield radius divided by the RPV radius (12.7917/11.0937 = 1.1531) multiplied by the RPV nodal area.

Therefore, the force generated by a pressure, p_i, acting on a nodal area A_i has the following components:

$$(F_x)_i = P_i(A_x)i$$

$$(F_y)_i = P_i(A_y)i$$

Where

$(F_x)i, (F_y)i$ = x and y force components acting on node i

P_i = pressure acting on node i

The compartment pressure transients resulting from a break in the reactor shield annulus generate a nodal force distribution over exposed surfaces. The resultant of this nodal force distribution is presented in Figures 6A-7, 6A-8, 6A-9 and 6A-10. There are no external moments generated by this pressure response. However, any moments would result from the application of the external force distribution to a structural model. This would generate shear stresses (leading to internal moments) due to bending of the elements used to represent the structure as a result of the non-uniform load distribution. Further discussion of this result is contained in Section 3.8.3 where the application of these annulus pressurization results is described in detail.

Blowdown jet loads which include jet impingement and reaction forces against the reactor vessel are also analyzed for reference and comparison. Note that these analyses are based on the very conservative assumptions that the first pipe restraint nearest the nozzle fails. For the feedwater line break, approximately 9.5" pipe center line offset limited by the shield plug opening produces a net break area of 88.53 in², which, consequently, results into a total maximum jet load of 335,600 lbs. against the vessel. These blowdown jet loads are relatively small compared with the peak load contributed by the unbalanced reactor annulus pressurization due to the same breaks.

Subcomponent Annulus Pressurization Loads – Major Project Improvements

Initial Stretch Power Uprate (SPU) & Turbine Retrofit Project (TRP)

An evaluation was performed to analysis the impact on subcompartment annulus pressurization loads for the Stretch Power Uprate (SPU) and Turbine Retrofit Project (TRP) conditions.

A more realistic blowdown mass and energy release profile for RSLB was determined using the RELAP4 MODS computer code. The mass and energy release rates are provided in Table 6A-8. These release rates were calculated using the same physical model as previously described in the licensing analysis section. The results of the RELAP4 analysis yield peak forces on the reactor vessel that are approximately 90% of the original peak forces. Thus, is can be concluded that the original analysis for the reactor annulus differential pressures and resultant reactor vessel and biological shield wall load forcing functions is bounding.

For the FWLB, the blowdown from both sides of the break increases for SPU and TRP. As stated previously with regards to the FWLB, only the supply side blowdown enters the annulus region. Using the approach, the supply side blowdown for SPU/TRP is less than the total blowdown used in the original analysis; therefore, the previously analyzed loads were bounding.

Maximum Extended Lad Line Limit Analysis (MELLLA)

An evaluation was performed to analysis the impact on subcompartment annulus pressurization loads for operation in the Maximum Extended Load Line Limit Analysis (MELLLA) reactor operating domain.

A more realistic blowdown mass and energy release profile for RSLB was determined using the GE code LAMB for the AP load analysis. The LAMB code considers the pipe break separation time history, but ignores the fluid inertia effect, providing conservative results. This code analysis was accepted by the NRC during the licensing application. LAMB results at the minimum pump speed condition are bounded by the Susquehanna original analysis.

For the FWLB, the blowdown, as indicated by the flux of steam flashed from the mass blowdown, is bounded by that at the rated MELLLA power condition.

Extended Power Uprate (EPU)

An evaluation was performed to analyze the impact on subcompartment annulus pressurization loads with an increase in reactor thermal power at Extended Power Uprate (EPU) conditions.

For the RRLB, the analysis and conclusions reached for MELLLA domain remain valid.

For the FWLB, the blowdown from both side of the break increases for SPU and TRP. As stated previously with regards to the FWLB, only the supply side blowdown enters the annulus region. Using this approach, the supply side blowdown for SPU/TRP is less than the total blowdown used in the original analysis; therefore, the original analyzed loads are bounding.

DRYWELL HEAD REGION SUBCOMPARTMENT ANALYSIS

The design basis pressure differential between the drywell head and containment region is a structural requirement of the drywell head. A pressure analysis of the drywell head region for a postulated head spray line break was performed.

Figure 6A-4 illustrates the basic arrangement of the head region. Venting from the head region is accomplished through ventilation openings as shown on Figure 6A-4. These vent openings provide a total of 16.75 sq. ft. vent area with an equivalent orifice (slightly rounded) discharge coefficient of 0.67 to relieve pressure build-up caused by the postulated break.

Figure 6A-5 is the schematic flow diagram with vent flow areas and discharge coefficient used in the drywell head venting analysis.

To determine peak pressure in the drywell head, all insulation was assumed to remain in place. Initial conditions of 15.4 psia, 135°F, and 20 percent relative humidity were used in this analysis.

The pressure transient of this analysis is presented on Figure°6A-6. It can be seen that the maximum pressure in the drywell head region is 23.2 psia and occurs 0.83 seconds after the head spray line break. Considering the containment pressure to be atmospheric (no drywell air displaced into the containment), a drywell head to containment pressure differential of 8.5 psid is obtained. This pressure differential is well below the design pressure differential of 16.0 psid.

Table 6A-1

This Table Has Been Deleted

TABLE 6A-2

HEAD SPRAY LINE BREAK[1]

Time (sec)	Steam Flow (lbm/sec)	Steam Enthalpy (Btu/lbm)
0.0	490	1198
20.0	490	1198

[1] Head spray line break is based on 6 in. Schedule 80S pipe with Moody Blowdown corresponding to 2700 lbm/sec-sq ft. Overall containment response is that of a "small break accident".

TABLE 6A-3

SUSQUEHANNA-COMPARTMENT VOLUMES USED IN REACTOR VESSEL SHIELD ANNULUS SUBCOMPARTMENT ANALYSIS

COMPARTMENT NO.	DESIGNATION	VOLUME, ft^3
1	V1	54
2	V2	54
3	V3	54
4	V4	54
5	V5	54
6	V6	54
7	V7	54
8	V8	54
9	V9	54
10	V10	54
11	V11	54
12	V12	54
13	V13	69
14	V14	76
15	V15	75
16	V16	76
17	V17	76
18	V18	69
19	V19	69
20	V20	76
21	V21	75
22	V22	76
23	V23	76
24	V24	69
25	V25	59
26	V26	57
27	V27	57
28	V28	57
29	V29	57
30	V30	57
31	V31	57
32	V32	57
33	V33	57
34	V34	57
35	V35	57
36	V36	59
37	V37	60
38	V38	58
39	V39	60
40	V40	76
41	V41	58

TABLE 6A-3

SUSQUEHANNA-COMPARTMENT VOLUMES USED IN REACTOR VESSEL SHIELD ANNULUS SUBCOMPARTMENT ANALYSIS

COMPARTMENT NO.	DESIGNATION	VOLUME, ft^3
42	V42	60
43	V43	76
44	V44	58
45	V45	60
46	V46	76
47	V47	58
48	V48	60
49	V49	77
50	V50	71
51	V51	73
52	V52	77
53	V53	75
54	V54	77
55	V55	77
56	V56	74
57	V57	77
58	V58	73
59	V59	71
60	V60	77
61	V61	34
62	V62	34
63	V63	34
64	V64	34
65	V65	34
66	V66	34
67	V67	34
68	V68	34
69	V69	34
70	V70	34
71	V71	34
72	V72	34
73	V73	235200

TABLE 6A-4 (1 of 4)

SUSQUEHANNA - FLOW AREA AND COEFFICIENTS USED IN REACTOR VESSEL SHIELD ANNULUS SUBCOMPARTMENT ANALYSIS

Flow Paths	Flow Area (ft^2)	K Factor	Description	L/A (ft^{-1})	Flow Coefficient
1-2, 1-12, 2-3, 3-4, 4-5, 5-6, 6-7, 7-8, 8-9, 9-10, 10-11, 11-12	10	0.13 1.0	30° Turn Final Expansion	0.62	0.94
1-13, 2-14, 3-15, 4-16, 5-17, 6-18, 7-19, 8-20, 9-21, 10-22, 11-23, 12-24	8.5	0.05 1.0	Friction Final Expansion	1.01	0.97
2-73, 3-73, 5-73, 6-73, 8-73, 9-73, 11-73, 12-73	2	0.42 1.0	Contraction Final Expansion	0.73	0.83
13-24, 18-19	9.5	0.13 1.12 1.0	30° Turn Around Pipe Final Expansion	0.54	0.66
13-14, 15-16, 16-17, 17-18, 19-20, 20-21, 22-23, 23-24	13	0.13 0.1 1.0	30° Turn Around Pipe Final Expansion	0.43	0.9
14-15, 21-22	12	0.1 0.1 0.13 1.0	Around Pipe Around Instrument Pipe 30° Turn Final Expansion	0.43	0.86
13-25, 18-30, 19-31, 24-36	4.5	1.35 0.28 1.0	Around Pipe Around Pipe Final Expansion	1.57	0.61
14-26, 16-28, 17-29, 20-32, 22-34, 23-35,	5.5	0.28 0.28 1.0	Around Pipe Around Pipe Final Expansion	1.17	0.8
15-27, 21-33	4.5	0.28 0.28 0.31 1.0	Around Pipe Around Pipe Around Pipe Final Expansion	1.31	0.73

TABLE 6A-4 (Continued) (2 of 4)

Flow Paths	Flow Area (ft^2)	K Factor	Description	L/A (ft^{-1})	Flow Coefficient
25-36, 30-31	11	0.13 1.0	30° Turn Final Expansion	0.55	0.94
25-26,26-27, 27-28,28-29, 29-30,31-32, 32-33,33-34, 34-35,35-36,	9.5	0.13 0.16 1.0	30° Turn Around Pipe Final Expansion	0.58	0.88
25-37,26-38, 27-39,28-40, 29-41,30-42, 31-43,32-44, 33-45,34-46, 35-47,36-48	8.5	0.07 1.0	Friction Final Expansion	0.92	0.96
37-48,38-39 41-42,45-46	10.5	0.13 0.01 1.0	30° Turn Around Instrument Pipe Final Expansion	0.55	0.93
37-38,40-41, 44-45,47-48	9.5	0.13 0.16 1.0	30° Turn Around Pipe Final Expansion	0.57	0.88
39-40,42-43, 43-44,46-47	11	0.13 1.0	30° Turn Final Expansion	0.55	0.94
37-49, 48-60	8	0.01 0.07 1.0	Around Instrument Pipe Friction Final Expansion	1.07	0.96
38-50,41-53, 44-56,47-59	6	1.11 1.0	Around Pipe Final Expansion	1.14	0.68
39-51,42-54, 45-57	8	0.08 1.0	Around Instrument Pipe Final Expansion	1.07	0.96
40-52,43-55 46-58	8.5	0.07 1.0	Around Pipe Final Expansion	1.06	0.96
49-50 59-60	11.5	0.13 0.15 0.15 1.0	30° Turn Around Pipe Around Pipe Final Expansion	0.46	0.83

TABLE 6A-4 (Continued) (3 of 4)

Flow Paths	Flow Area (ft²)	K Factor	Description	L/A (ft⁻¹)	Flow Coefficient
		0.125	30° Turn		
		0.01	Around Instrument Pipe		
49-60	14	1.0	Final Expansion	0.42	0.93
		0.13	30° Turn		
		0.01	Around Instrument Pipe		
		0.47	Around Pipe		
50-51	10.5	1.0	Final Expansion	0.48	0.78
		0.13	30° Turn		
51-52,52-53,		0.15	Around Pipe		
56-57	13	1.0	Final Expansion	0.44	0.88
		0.13	30° Turn		
		0.01	Around		
		0.15	Around		
53-54,57-58	12.5	1.0	Final Expansion	0.45	0.88
		0.13	30° Turn		
54-55	14.5	1.0	Final Expansion	0.42	0.94
		0.13	30° Turn		
		0.15	Around Pipe		
		0.12	Around CRD		
		0.15	Around Pipe		
55-56	10.5	1.0	Final Expansion	0.5	0.8
		0.13	30° Turn		
		0.47	Around Pipe		
58-59	11	1.0	Final Expansion	0.47	0.79
49-61,52-64,					
53-65,55-67,		0.49	Around Pipe		
57-69	6.5	1.0	Final Expansion	0.96	0.81
		0.49	Around Pipe		
54-66,		0.08	Around Instrument Pipe		
60-72	6	1.0	Final Expansion	1.0	0.79
		0.49	Around Pipe		
		0.17	Around CRD		
56-68	5.5	1.0	Final Expansion	1.07	0.77
61-62,63-64		0.11	30° Turn		
67-68,69-70		0.96	Around Pipe		
71-72	5	1.0	Final Expansion	1.03	0.69

TABLE 6A-4 (Continued) (4 of 4)

Flow Paths	Flow Area (ft^2)	K Factor	Description	L/A (ft^{-1})	Flow Coefficient
61-72,62-63					
64,65,66-67		0.11	30° Turn		
68-69,70-71	6.5	1.0	Final Expansion	0.9	0.94
		0.11	30° Turn		
		0.96	Around Pipe		
65-66,		0.1	Around Instrument Pipe		
71-62	4.5	1.0	Final Expansion	1.1	0.67
61-73,63-73					
64-73,66-73					
67-73,69-73		0.12	Contraction		
70-73,72-73	6	1.0	Final Expansion	0.28	0.94
62-73,65-73		0.05	Contraction		
68-73,71-73	7.5	1.0	Final Expansion	0.28	0.97

TABLE 6A-5

Geometry Node Locations

Node Numbers	Elevation
1 - 12	733' - 4-13/16"
13 - 24	740' - 7"
25 - 36	745' - 9-1/2"
37 - 48	751' - 4-7/8"
49 - 60	759' - 4-5/8"
61 - 72	766' - 2-1/4"
73 - 84	773' - 10-1/2"

Node Angles	Node Numbers
345°	1, 13, 25, 37, 49, 61, 73
315°	2, 14, 26, 38, 50, 62, 74
285°	3, 15, 27, 39, 51, 63, 75
255°	4, 16, 28, 40, 52, 64, 76
225°	5, 17, 29, 41, 53, 65, 77
195°	6, 18, 30, 42, 54, 66, 78
165°	7, 19, 31, 43, 55, 67, 79
135°	8, 20, 32, 44, 56, 68, 80
105°	9, 21, 33, 45, 57, 69, 81
75°	10, 22, 34, 46, 58, 70, 82
45°	11, 23, 35, 47, 59, 71, 83
15°	12, 24, 36, 48, 60, 72, 84

Note: Elevations and node angles are for center of geometry nodes.

TABLE 6A-6

RPV GEOMETRY NODE AREAS FOR
RECIRCULATION OUTLET LINE BREAK

Geometry Node Number	Area (x) ($inch^2$) based on RPV (inside) radius	Area (y) ($inch^2$) based on RPV (inside) radius
1	5741	1541
2	4209	4209
3	1541	5749
4	1541	5749
5	4209	4209
6	5749	1540
7	5749	1541
8	4209	4209
9	1541	5749
10	1541	5749
11	4209	4209
12	5749	1541
13	5724	1534
14	4191	4191
15	1534	5724
16	1534	5724
17	4191	4190
18	5724	1534
19	5724	1534
20	4190	4191
21	1534	5724
22	1534	5724
23	4190	4190
24	5724	1534
25	2596	696

TABLE 6A-6

RPV GEOMETRY NODE AREAS FOR
RECIRCULATION OUTLET LINE BREAK

Geometry Node Number	Area (x) ($inch^2$) based on RPV (inside) radius	Area (y) ($inch^2$) based on RPV (inside) radius
26	1900	1900
27	696	2596
28	696	2596
29	1900	1870
30	2596	690
31	2596	690
32	1900	1900
33	696	2596
34	696	2596
35	1900	1900
36	2596	696
37	6373	1708
38	4666	4666
39	1708	6373
40	1708	6373
41	4665	4665
42	6373	1708
43	6373	1708
44	4666	4666

TABLE 6A-7

RPV GEOMETRY MODE AREAS
FOR FEEDWATER LINE BREAK

Geometry Mode Number	Area (x) ($inch^2$) based on RPV (inside) radius	Area (y) ($inch^2$) based on RPV (inside) radius
1	5749	1541
2	4209	4209
3	1541	5749
4	1541	5749
5	4209	4209
6	5749	1541
7	5749	1541
8	4209	4209
9	1541	5749
10	1541	5749
11	4209	4209
12	5749	1541
13	8320	2229
14	6091	6091
15	2229	8320
16	2229	8320
17	6091	6091
18	8320	2229
19	8320	2229
20	6091	6091
21	2229	8320
22	2229	8320
23	6091	6091
24	8320	2229
25	6373	1708

TABLE 6A-7

RPV GEOMETRY MODE AREAS
FOR FEEDWATER LINE BREAK

Geometry Mode Number	Area (x) (inch^2) based on RPV (inside) radius	Area (y) (inch^2) based on RPV (inside) radius
26	4666	4666
27	1708	6373
28	1708	6373
29	4666	4666
30	6373	1708
31	6373	1708
32	4666	4666
33	1708	6373
34	1708	6373
35	4666	4666
36	6373	1708
37	6373	1708
38	4666	4666
39	1708	6373
40	1708	6373
41	4666	4666
42	6373	1708
43	6373	1708
44	4666	4666

TABLE 6A-8

REACTOR PRIMARY SYSTEM BLOWDOWN FLOW RATES AND FLUID ENTHALPY - RECIRCULATION OUTLET LINE BREAK

POWER UPRATE VALUES

Time (sec)	Mass Flow (lbm/sec)	Enthalpy (Btu/lbm)
0	0.00	0.00
1.000-03	3.2400+02	526.8
2.170-03	9.9100+02	526.8
2.180-03	9.9800+02	526.8
4.600-03	3.3750+03	526.8
6.900-03	6.8700+03	526.8
8.600-03	1.0245+04	526.8
1.010-02	1.3741+04	526.8
1.260-02	2.0370+04	526.8
1.510-02	2.7481+04	526.8
1.760-02	3.4834+04	526.8
2.010-02	4.1945+04	526.8
2.260-02	4.8936+04	526.8
2.363-02	5.1640+04	526.8
2.771-02	5.1640+04	526.8
2.772-02	2.7786+04	526.8
3.010-02	3.0200+04	526.8
3.260-02	3.2523+04	526.8
3.510-02	3.4576+04	526.8
3.760-02	3.6359+04	526.8
4.010-02	3.7764+04	526.8
4.260-02	3.8898+04	526.8
4.780-02	4.0141+04	526.8
1.000+00	4.0141+04	526.8

TABLE 6A-1(a)

REACTOR PRIMARY SYSTEM BLOWDOWN FLOW RATES AND FLUID ENTHALPY - RECIRCULATION OUTLET LINE BREAK

Time (sec)	Mass Flow (lbm/sec)	Enthalpy (Btu/lbm)
0.000	0.0000	0.000
2.5500-03	1.3400+03	527.9
3.9000-03	2.6750+03	527.9
4.9600-03	4.0100+03	527.9
5.8600-03	5.3500+03	527.9
7.3700-03	8.0200+03	527.9
9.2400-03	1.2025+04	527.9
1.1800-02	1.9285+04	527.9
1.3800-02	2.6560+04	527.9
1.5800-02	3.2355+04	527.9
1.8000-02	4.5975+04	527.9
2.0800-02	4.5975+04	527.9
2.0800-02	2.2400+04	527.9
2.1800-02	2.4130+04	527.9
2.2800-02	2.5840+04	527.9
2.3800-02	2.7520+04	527.9
2.5800-02	3.0780+04	527.9
2.7800-02	3.3880+04	527.9
3.0800-02	3.8170+04	527.9
3.5800-02	4.4220+04	527.9
3.7000-02	4.5975+04	527.9
4.1400-01	4.5975+04	527.9
4.1400-01	3.4370+04	527.9
1.0000+00	3.4370+04	527.9

TABLE 6A-1(b)

RECIRC. OUTLET LINE BREAK BLOWDOWN MASS FLUX TIME HISTORY

Vessel Side

Time (seconds)	Mass Flux (lbm/sec/ft²)	Effective Break Area (ft²)
0.00255	21200	0.0316
0.00496	21200	0.0964
0.00737	21200	0.1892
0.01180	21200	0.4548
0.01580	21200	0.7631
0.02080	21200	1.0843
0.02081	8410	1.3317
0.02180	8410	1.4346
0.02380	8410	1.6361
0.02780	8410	2.0142
0.03580	8410	2.6290
0.03700	8410	2.7333
0.41400	8410	3.6440
0.41410	8410	3.6440
1.0	8410	3.6440

Pump Side

Time (seconds)	Mass Flux (lbm/sec/ft²)	Effective Break Area (ft²)
0.00255	21200	0.0316
0.00496	21200	0.0964
0.00737	21200	0.1892
0.01180	21200	0.4548
0.01580	21200	0.7631
0.02080	21200	1.0843
0.02081	8410	1.3317
0.02180	8410	1.4346
0.02380	8410	1.6361
0.02780	8410	2.0142
0.03580	8410	2.6290
0.03700	8410	2.7333
0.41400	8410	1.8220
0.41410	8410	0.4420
1.0	8410	0.4420

NOTE: Listed below are pertinent physical parameters used in the blowdown estimation.

$A = 3.644\ ft^2$	Minimum cross-sectional area between vessel and break
$D = 2.154\ ft$	Pipe I.D. at the break location
$h_o = 527.85\ Btu/Lbm$	Vessel enthalpy
$L_i = 2.917\ ft$	Inventory length
$P_o = 1031.2\ psia$	Vessel pressure
$P_{sat} = 908\ psia$	Saturation pressure
$V = 0.02127\ ft^3/lbm$	Specific volume of the fluid initially in the pipe
$V_i = 135\ ft^3$	Inventory volume

TABLE 6A-1(c)

REACTOR PRIMARY SYSTEM BLOWDOWN FLOW RATES
AND FLUID ENTHALPY - FEEDWATER LINE BREAK

Time (sec)	Mass Flow (lbm/sec)	Enthalpy (Btu/lbm)
0	0	361.1
0.0001	21830	361.1
0.0207	21830	361.1
0.0208	20075	361.1
1.0	20075	361.1

TABLE 6A-1(d)

FEEDWATER LINE BREAK BLOWDOWN MASS FLUX TIME HISTORY

Time (sec)	Mass Flux (lbm/sec/Ft^2)	Effective Break Area (Ft^2)
Vessel Side:		
0.0001	20625	0.3528
0.0207	20625	0.3528
0.0208	20625	0.2679
1.0	20625	0.2679
Supply Pipe Side (1) (3):		
0.0001	20625	0.7055
1.0	20625	0.7055

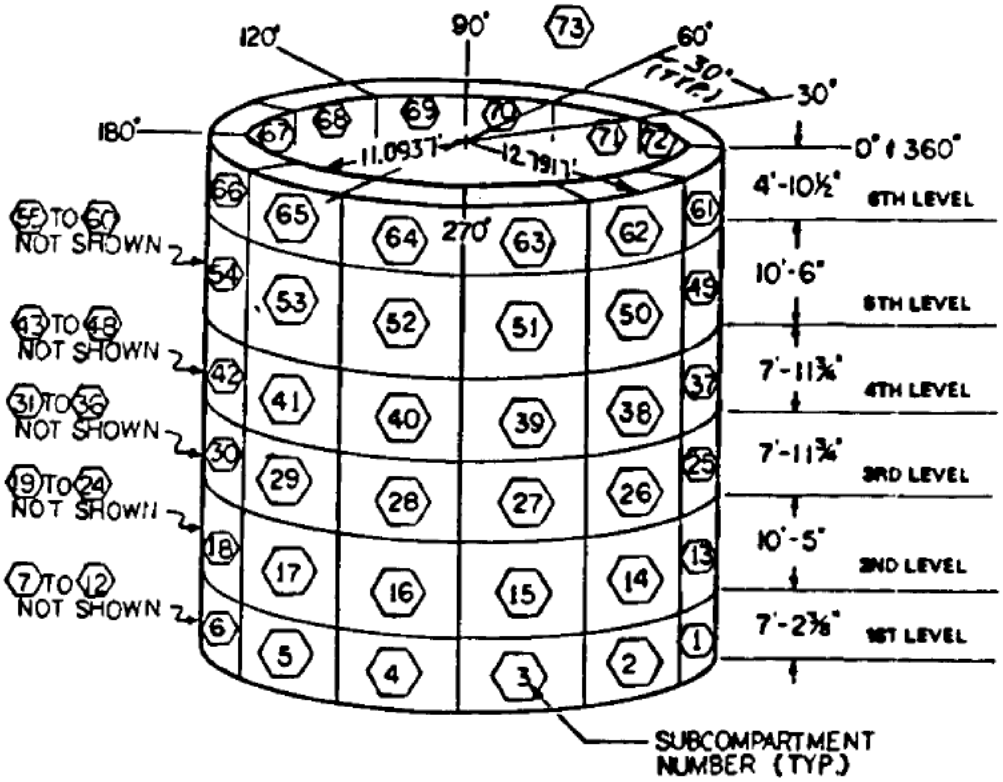
NOTES:

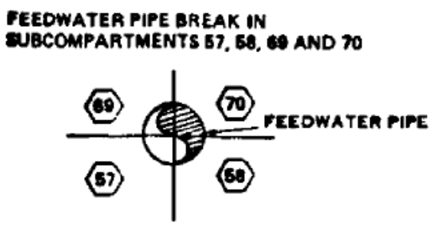
(1) The most restricted flow area on the feedwater supply pipe side is the break area itself. Full break area steady state blowdown from this side is conservatively assumed to be reached immediately after the pipe rupture.

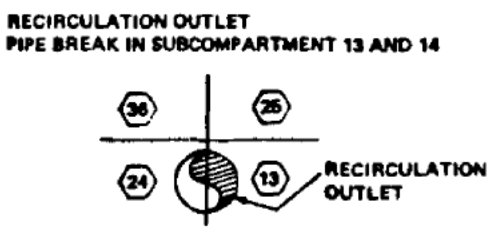
(2) Listed below are some pertinent physical parameters used in the blowdown estimation:

A_L = 0.7055 ft^2	Minimum cross-sectional area - supply pipe side
D = 0.9478	Pipe I.D. at the break location
ho = 361.1 Btu/Lbm	FW enthalpy
Po = 1053 PSIA	Vessel pressure
Psat = 213 PSIA	Saturation pressure
v = 0.01846 ft^3/Lbm	Specific volume of the feedwater
vi = 2.79 ft^3	Inventory volume

(3) Annulus pressurization is based on blowdown flow from the supply side only. Based on the break location, flow from the vessel side is expected to exit directly to the drywell.







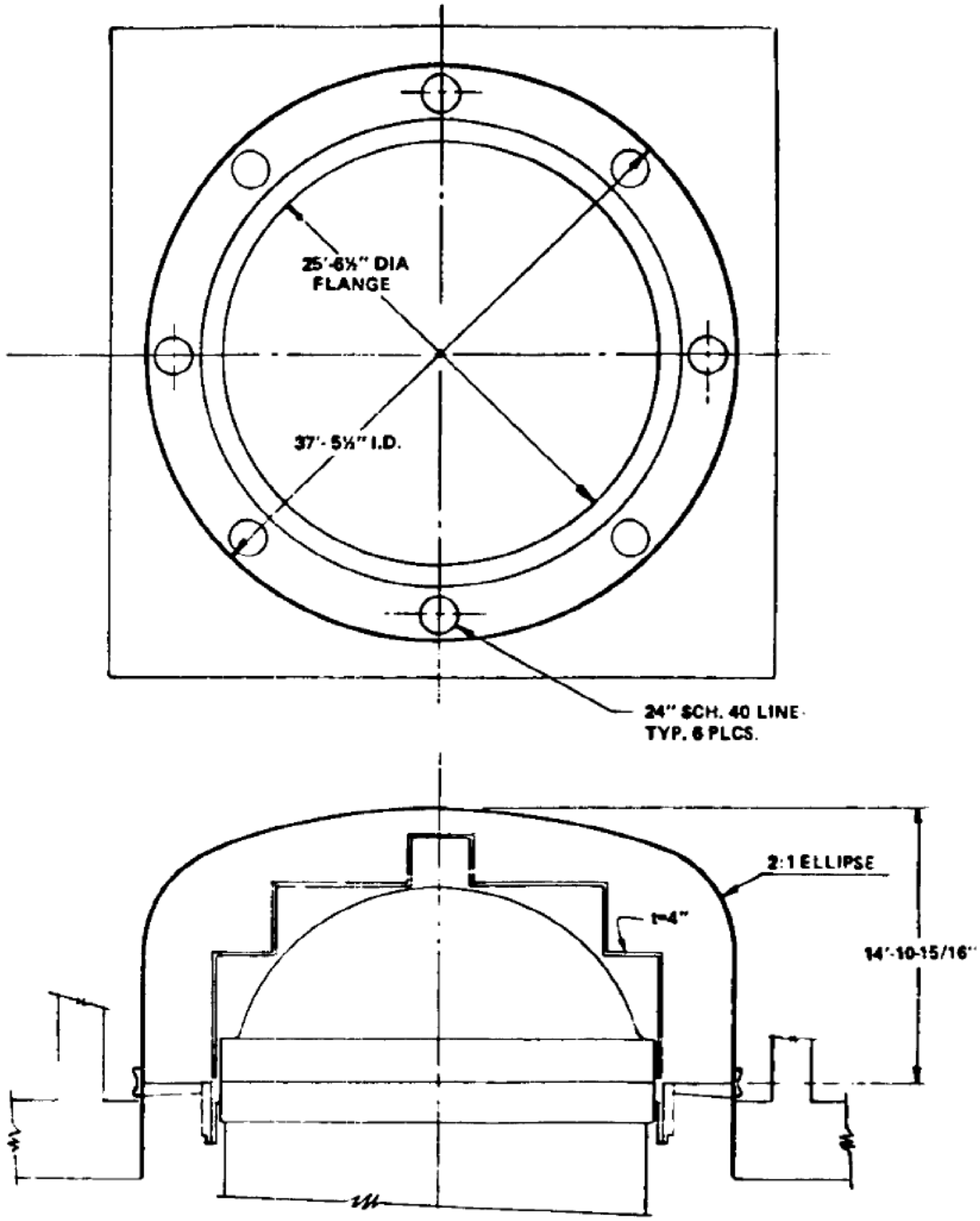
FSAR REV.65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

RPV SHIELD ANNULUS
SUBCOMPARTMENT
MODEL SCHEMATIC

FIGURE 6A-2, Rev. 47

AutoCAD: Figure Fsar 6A_2.dwg



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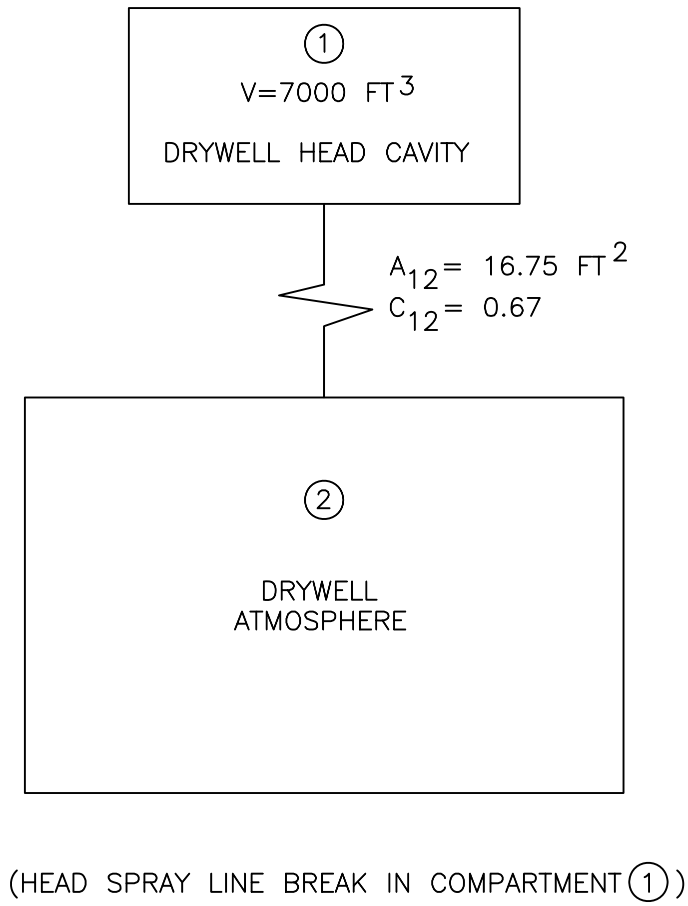
SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

DRYWELL HEAD ARRANGEMENT

FIGURE 6A-4, Rev. 47

AutoCAD: Figure Fsar 6A_4.dwg



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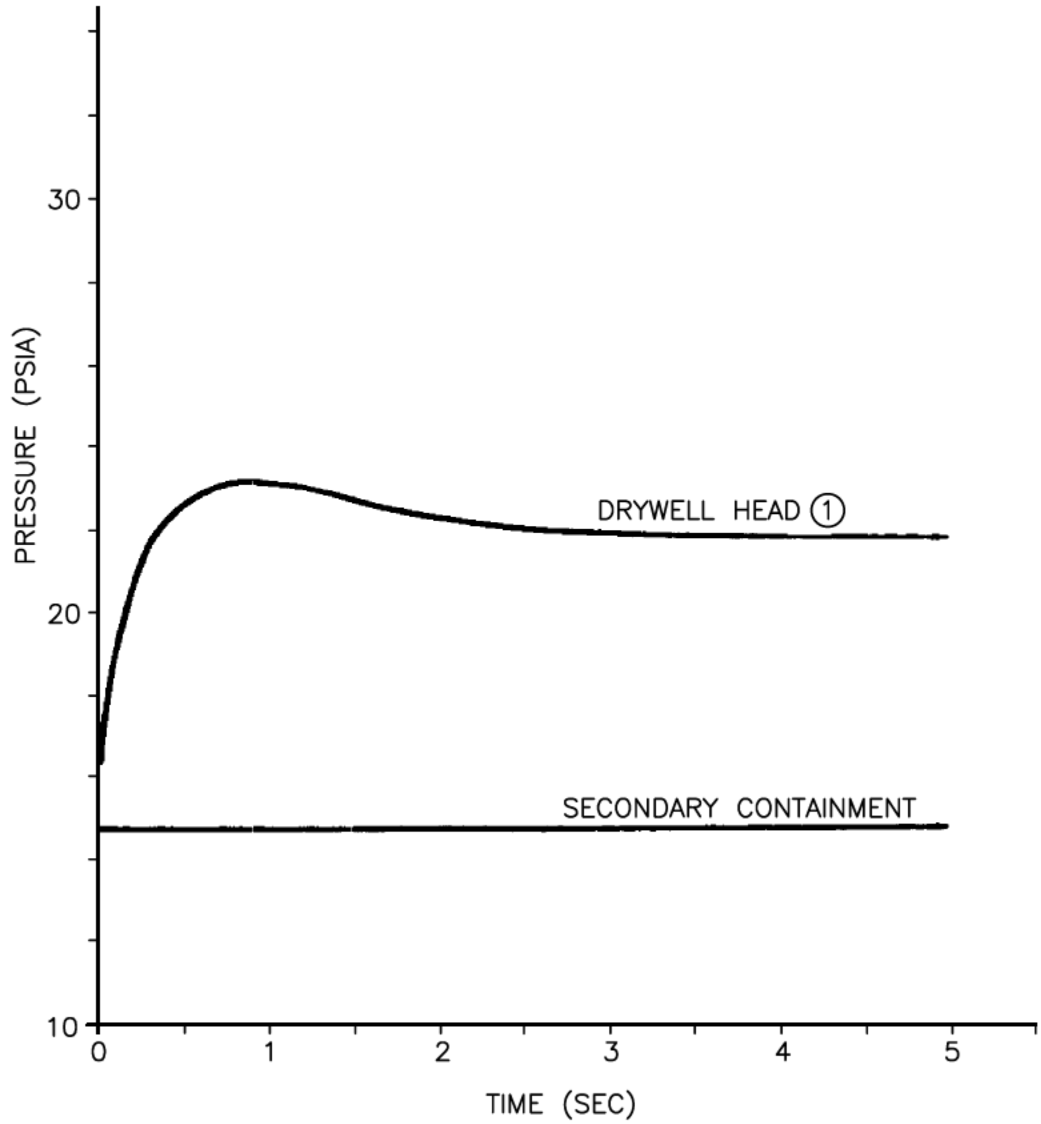
SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

HEAD SPRAY LINE
BREAK GEOMETRY

FIGURE 6A-5, Rev. 47

AutoCAD: Figure Fsar 6A_5.dwg



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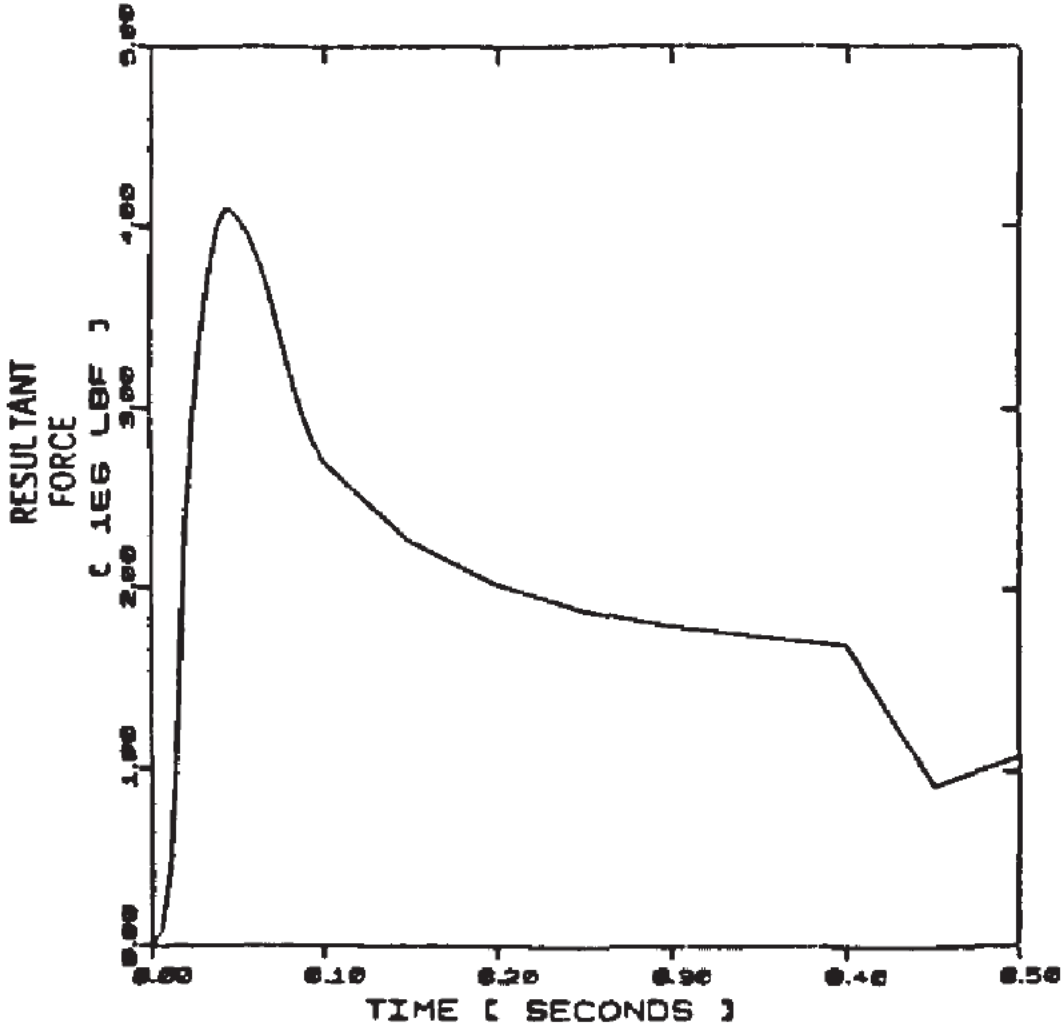
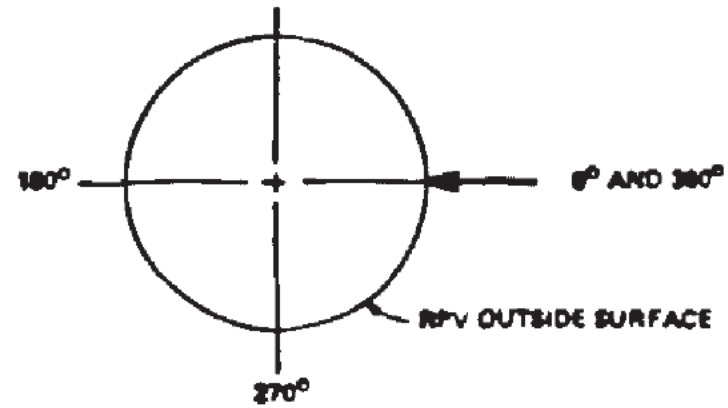
SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

PRESSURE RESPONSE IN THE
DRYWELL HEAD FOR A HEAD
SPRAY LINE BREAK

FIGURE 6A-6, Rev. 47

AutoCAD: Figure Fsar 6A_6.dwg





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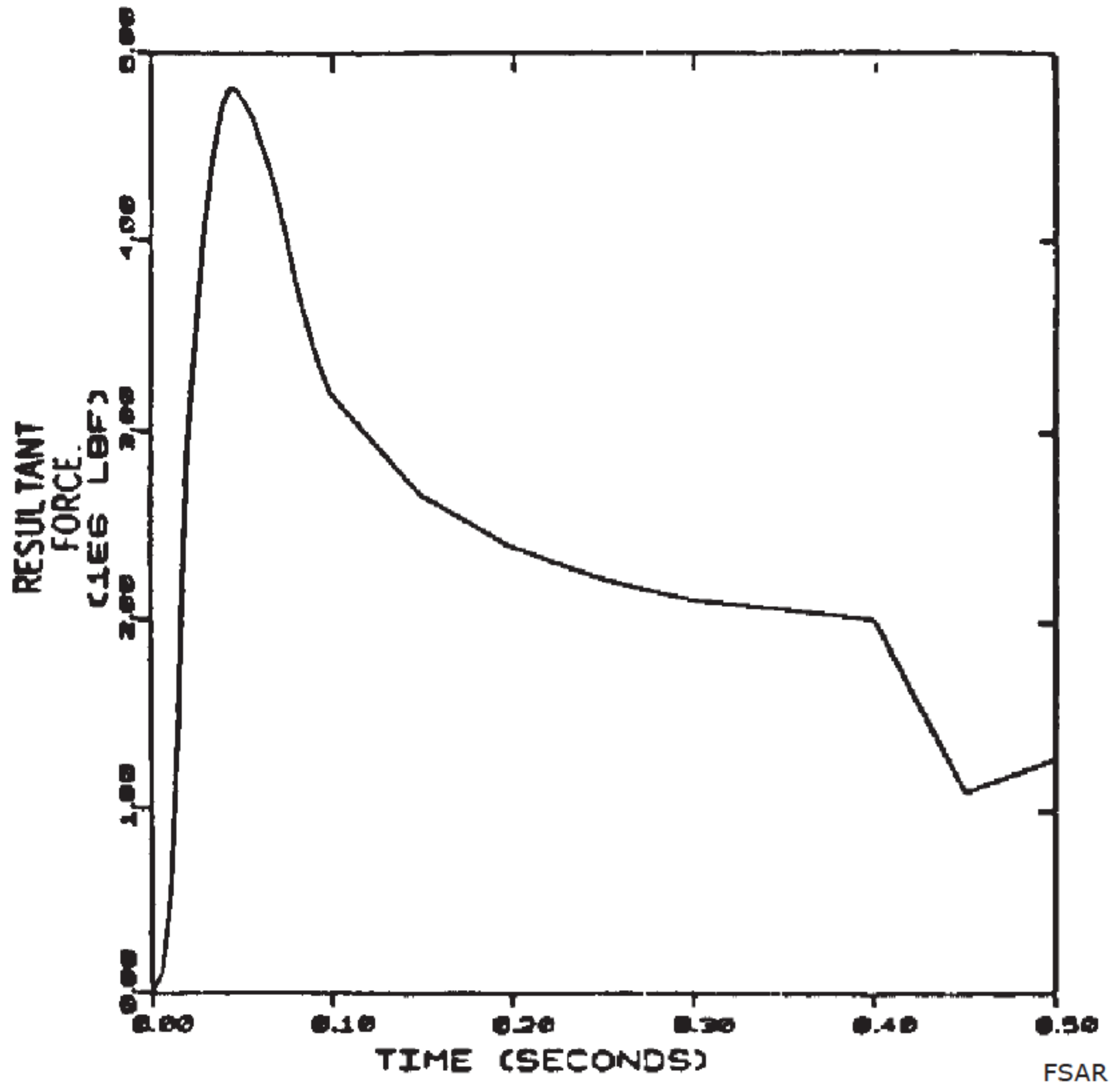
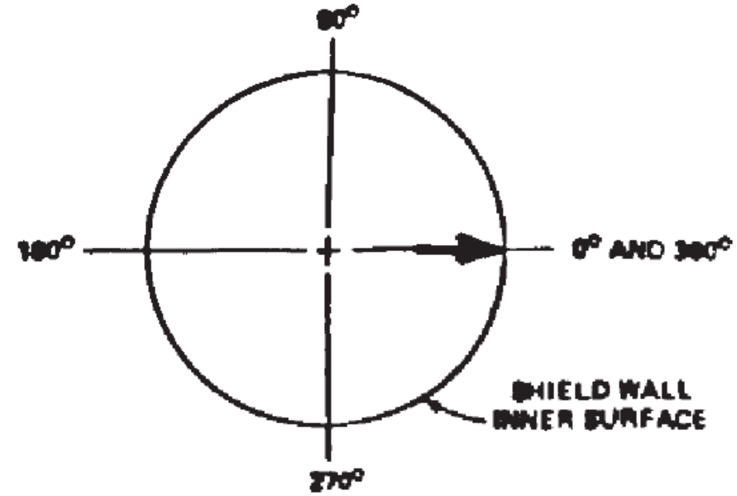
SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

FORCE TRANSIENT ON REACTOR
PRESSURE VESSEL FOLLOWING A
RECIRC. LINE BREAK AT THE
NOZZLE SAFE END

FIGURE 6A-7, Rev. 47

AutoCAD: Figure Fsar 6A_7.dwg

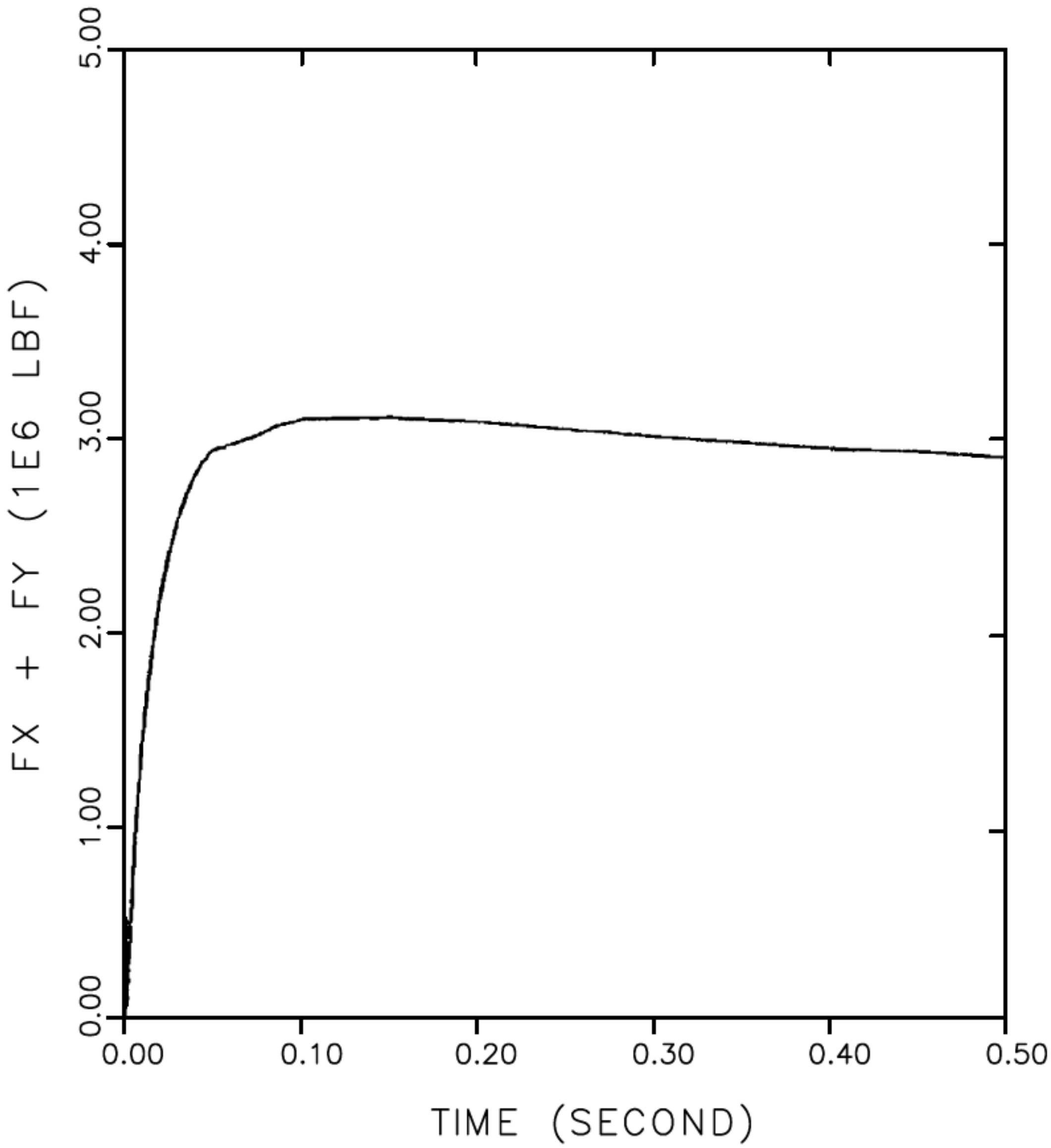




FSAR REV.65

SUSQUEHANNA STEAM ELECTRIC STATION UNITS 1 & 2 FINAL SAFETY ANALYSIS REPORT
FORCED TRANSIENT ON REACTOR SHIELD WALL FOLLOWING RECIRC. LINE BREAK AT THE NOZZLE SAFE END FIGURE 6A-8, Rev. 47

AutoCAD: Figure Fsar 6A_8.dwg



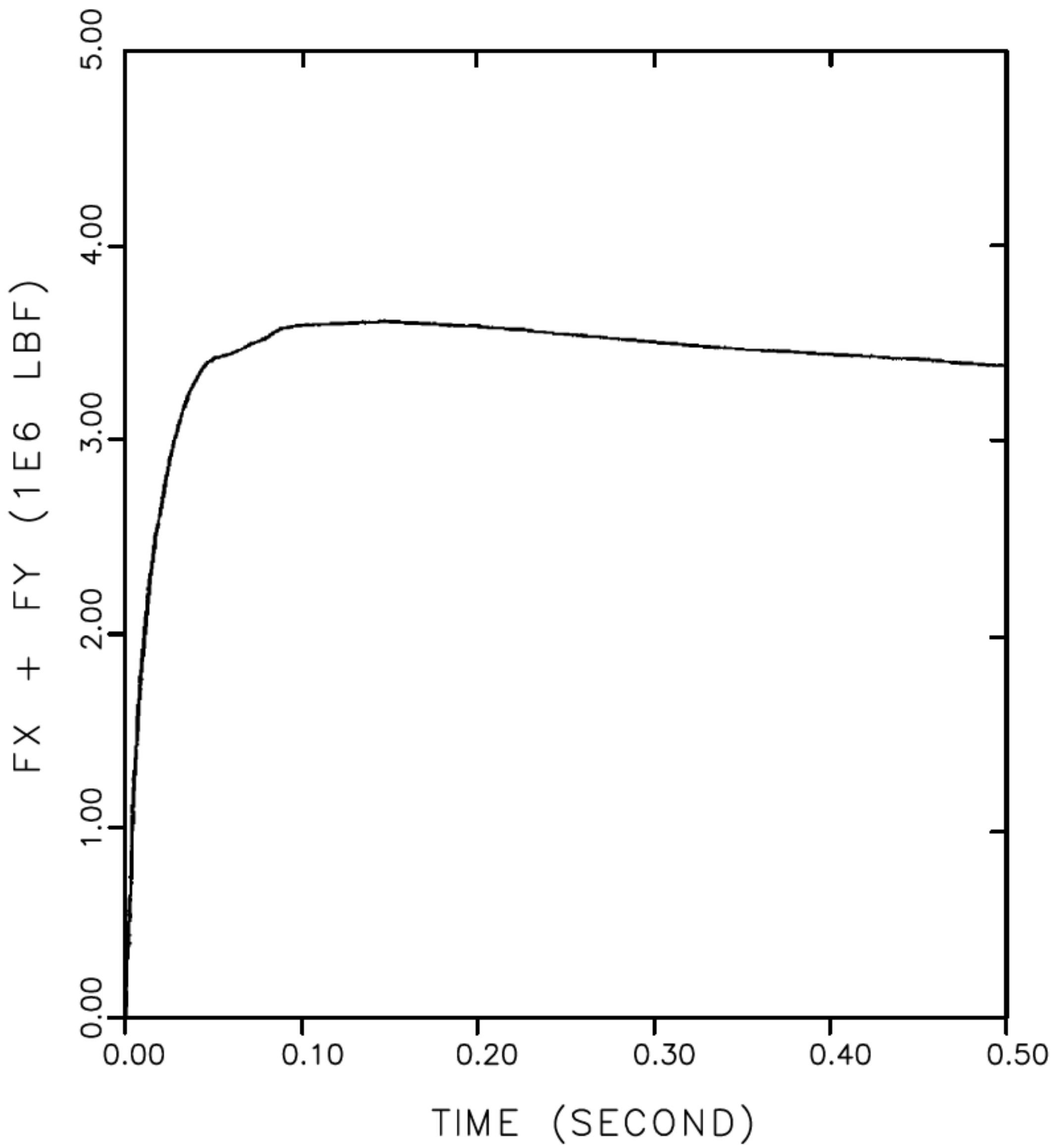
FSAR REV.65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

RESULTANT FORCE TRANSIENT ON
RPV FOLLOWING A FEEDWATER
LINE BREAK AT THE NOZZLE

FIGURE 6A-9, Rev. 48

AutoCAD: Figure Fsar 6A_9.dwg



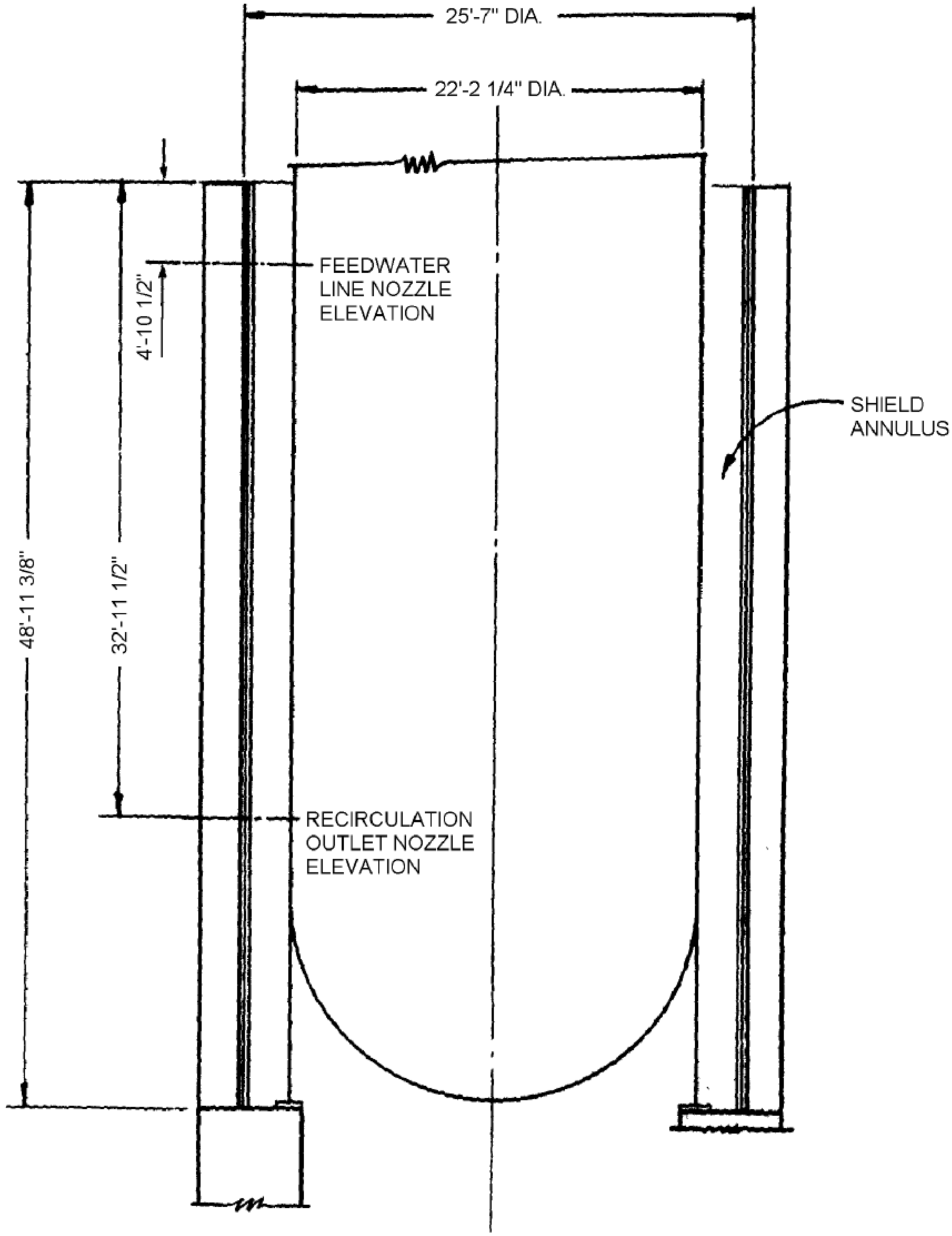
FSAR REV.65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

RESULTANT FORCE ON SHIELD WALL FOLLOWING A FEEDWATER LINE BREAK AT THE NOZZLE

FIGURE 6A-10, Rev. 48

AutoCAD: Figure Fsar 6A_10.dwg



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SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

REACTOR SHIELD ANNULUS
ARRANGEMENT

FIGURE 6A-1A, Rev. 55

AutoCAD: Figure Fsar 6A_1A.dwg

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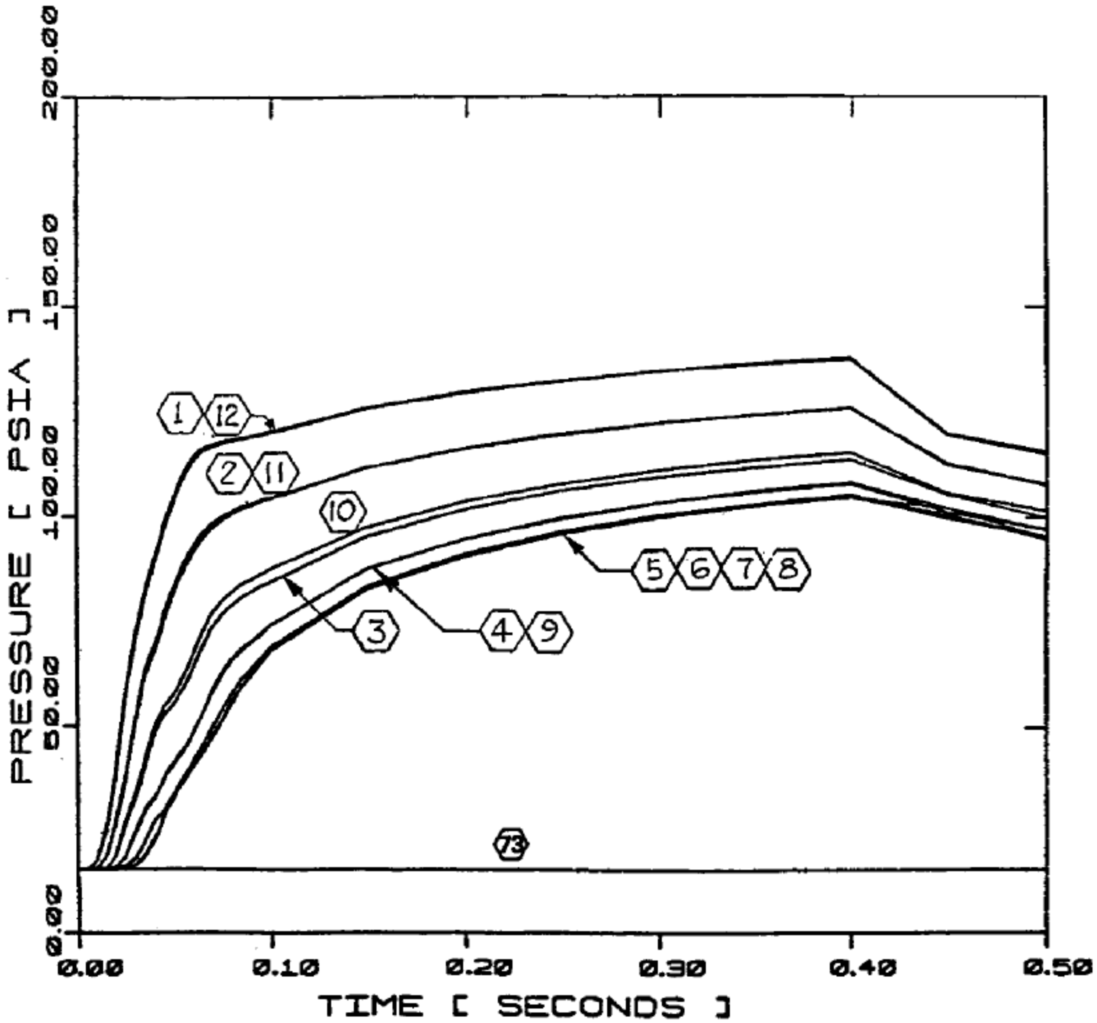
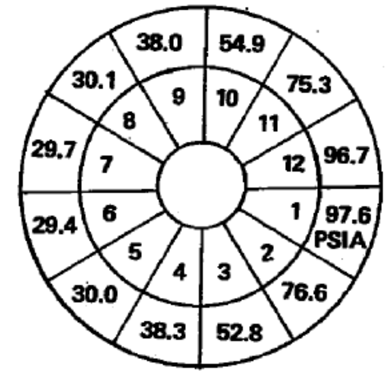
RPV SHIELD WALL
AND PEDESTAL

FIGURE 6A-1B, Rev. 47

AutoCAD: Figure Fsar 6A_1B.dwg





1ST LEVEL

THE ABOVE SPACIAL PRESSURE DISTRIBUTION OCCURS AT 0.046 SEC PRODUCING THE MAXIMUM DIFFERENTIAL PRESSURE ACROSS THE VESSEL

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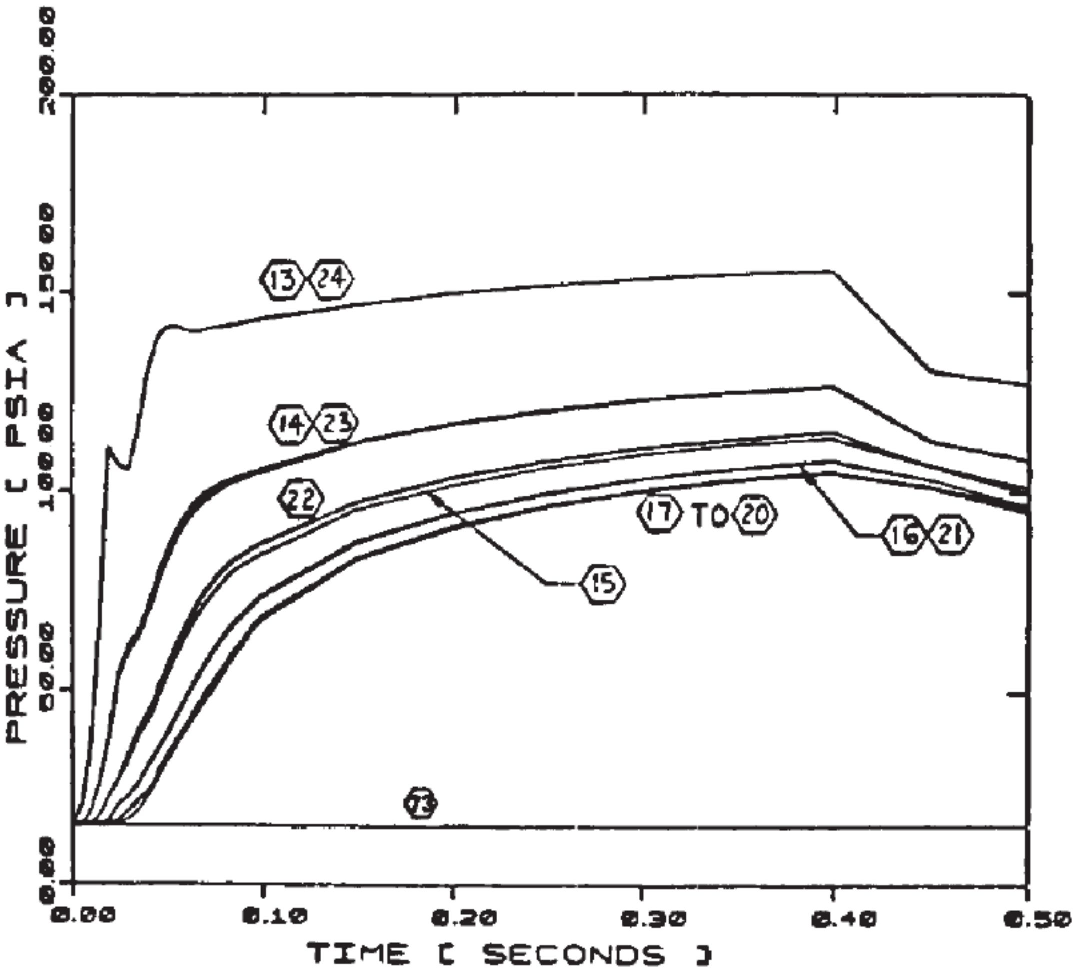
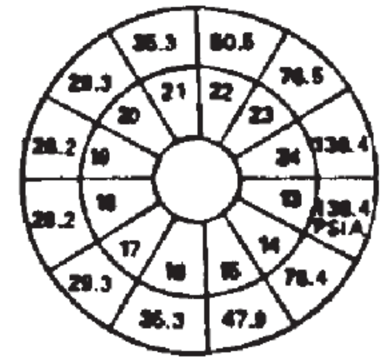
PRESSURE TRANSIENT IN
SHIELD ANNULUS FOLLOWING
A RECIRC. LINE BREAK AT
THE NOZZLE SAFE END

FIGURE 6A-3A, Rev. 47

AutoCAD: Figure Fsar 6A_3A.dwg





2ND LEVEL

THE ABOVE SPACIAL PRESSURE DISTRIBUTION OCCURS AT 0.048 SEC PRODUCING THE MAXIMUM DIFFERENTIAL PRESSURE ACROSS THE VESSEL

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SUSQUEHANNA STEAM ELECTRIC STATION
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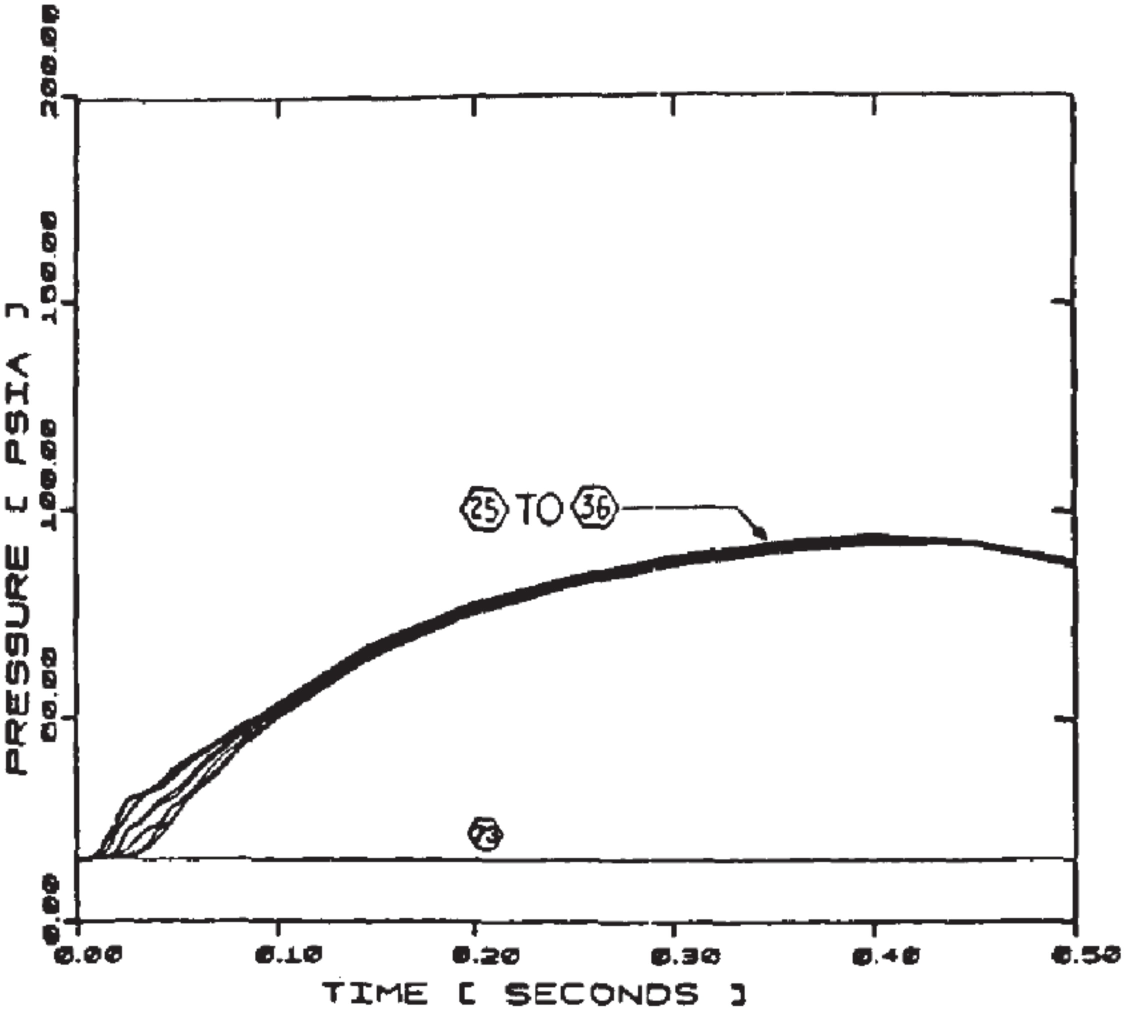
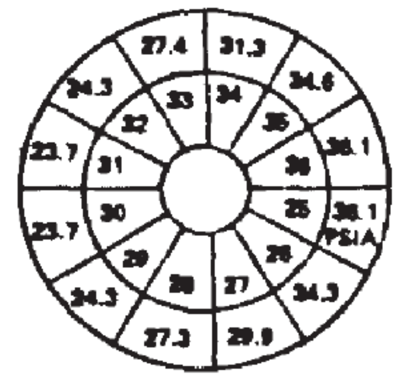
PRESSURE TRANSIENT IN SHIELD ANNULUS FOLLOWING A RECIRC. LINE BREAK AT THE NOZZLE SAFE END

FIGURE 6A-3B, Rev. 47

AutoCAD: Figure Fsar 6A_3B.dwg





3RD LEVEL

THE ABOVE SPACIAL PRESSURE DISTRIBUTION OCCURS AT 0.046 SEC PRODUCING THE MAXIMUM DIFFERENTIAL PRESSURE ACROSS THE VESSEL

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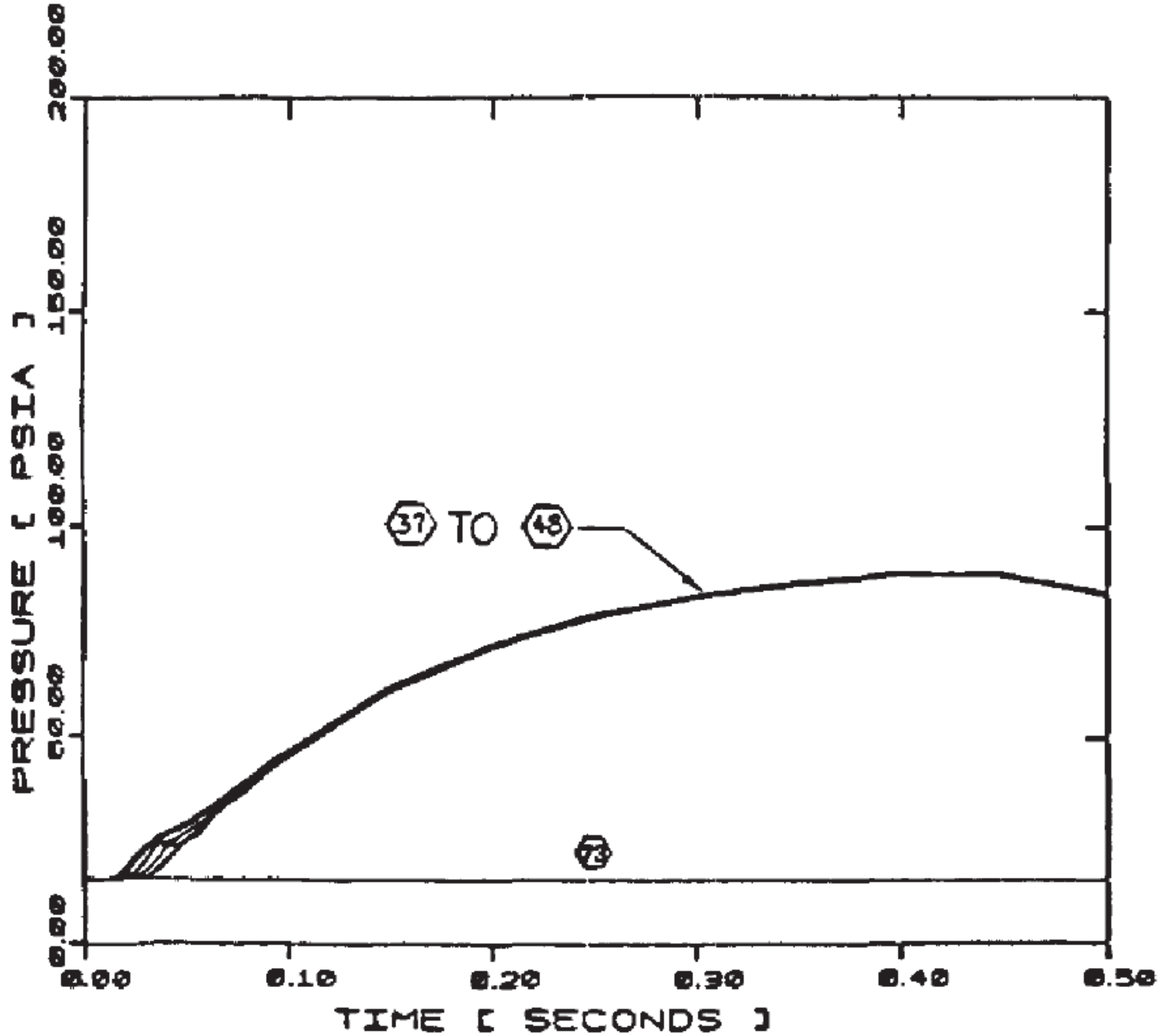
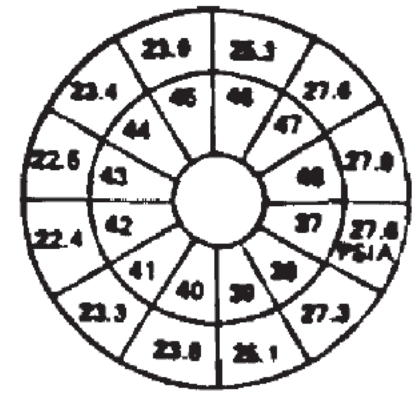
PRESSURE TRANSIENT IN SHIELD
ANNULUS FOLLOWING A RECIRC.
LINE BREAK AT THE NOZZLE
SAFE END

FIGURE 6A-3C, Rev. 47

AutoCAD: Figure Fsar 6A_3C.dwg





4TH LEVEL

THE ABOVE SPACIAL PRESSURE DISTRIBUTION OCCURS AT 0.046 SEC PRODUCING THE MAXIMUM DIFFERENTIAL PRESSURE ACROSS THE VESSEL

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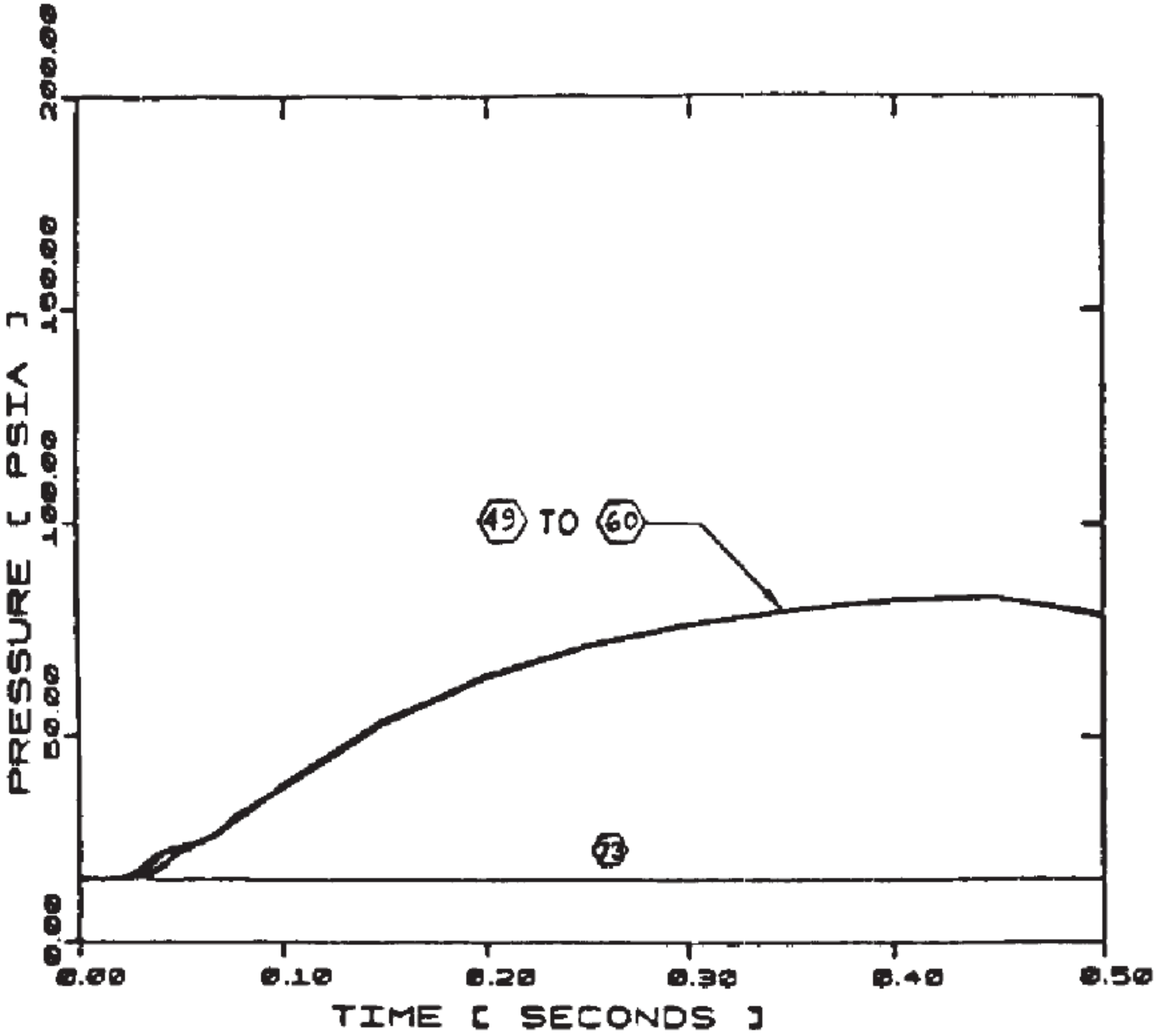
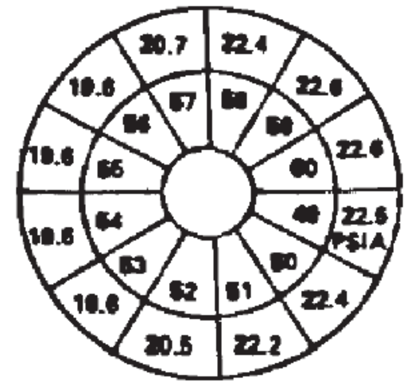
PRESSURE TRANSIENT IN SHIELD
ANNULUS FOLLOWING A RECIRC.
LINE BREAK AT THE NOZZLE
SAFE END

FIGURE 6A-3D, Rev. 47

AutoCAD: Figure Fsar 6A_3D.dwg





5TH LEVEL

THE ABOVE SPACIAL PRESSURE DISTRIBUTION OCCURS AT 0.048 SEC PRODUCING THE MAXIMUM DIFFERENTIAL PRESSURE ACROSS THE VESSEL

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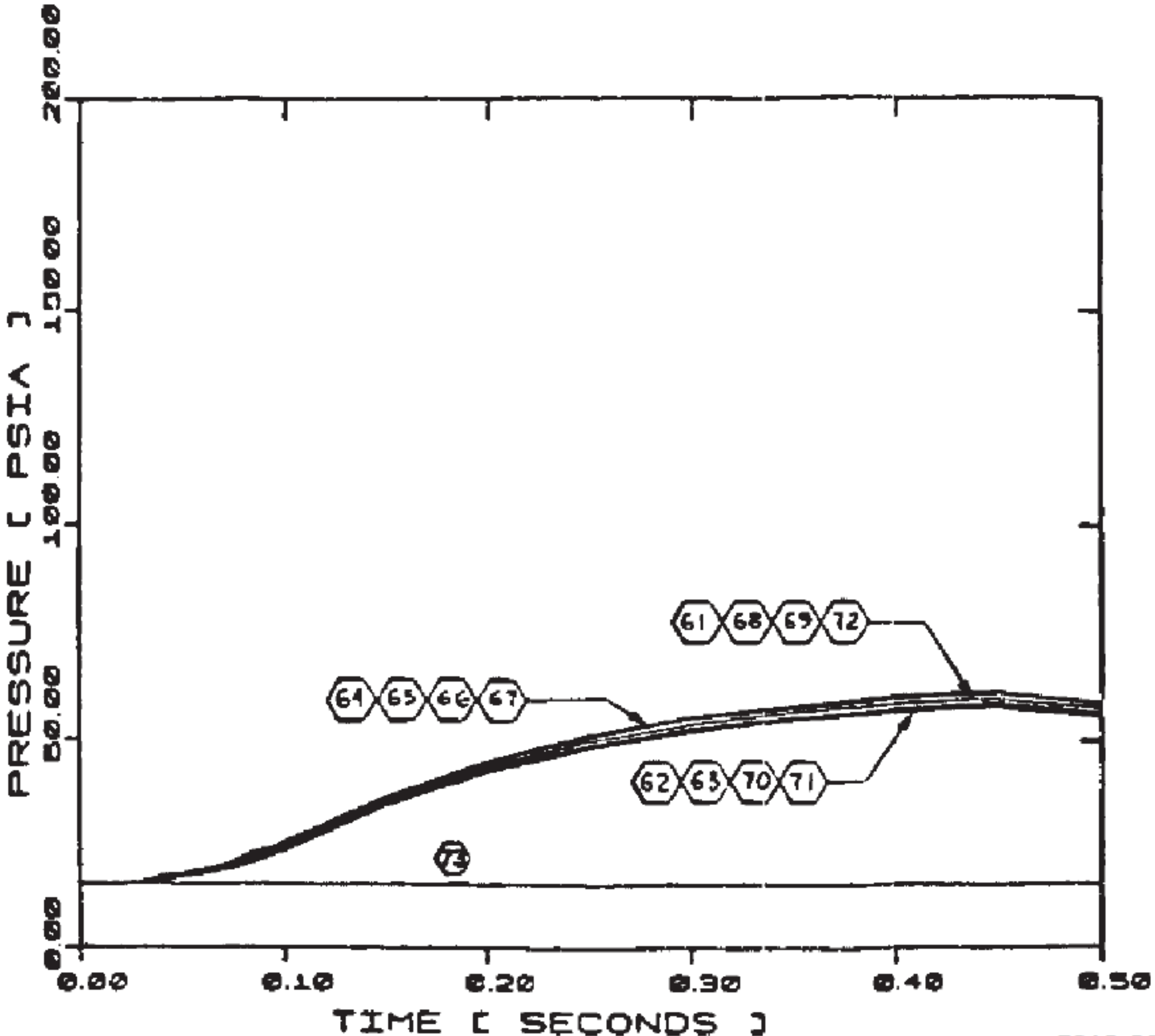
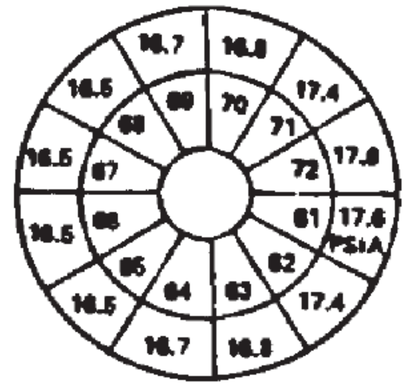
PRESSURE TRANSIENT IN SHIELD
ANNULUS FOLLOWING A RECIRC.
LINE BREAK AT THE NOZZLE
SAFE END

FIGURE 6A-3E, Rev. 47

AutoCAD: Figure Fsar 6A_3E.dwg





6TH LEVEL

THE ABOVE SPACIAL PRESSURE DISTRIBUTION OCCURS AT 0.046 SEC PRODUCING THE MAXIMUM DIFFERENTIAL PRESSURE ACROSS THE VESSEL.

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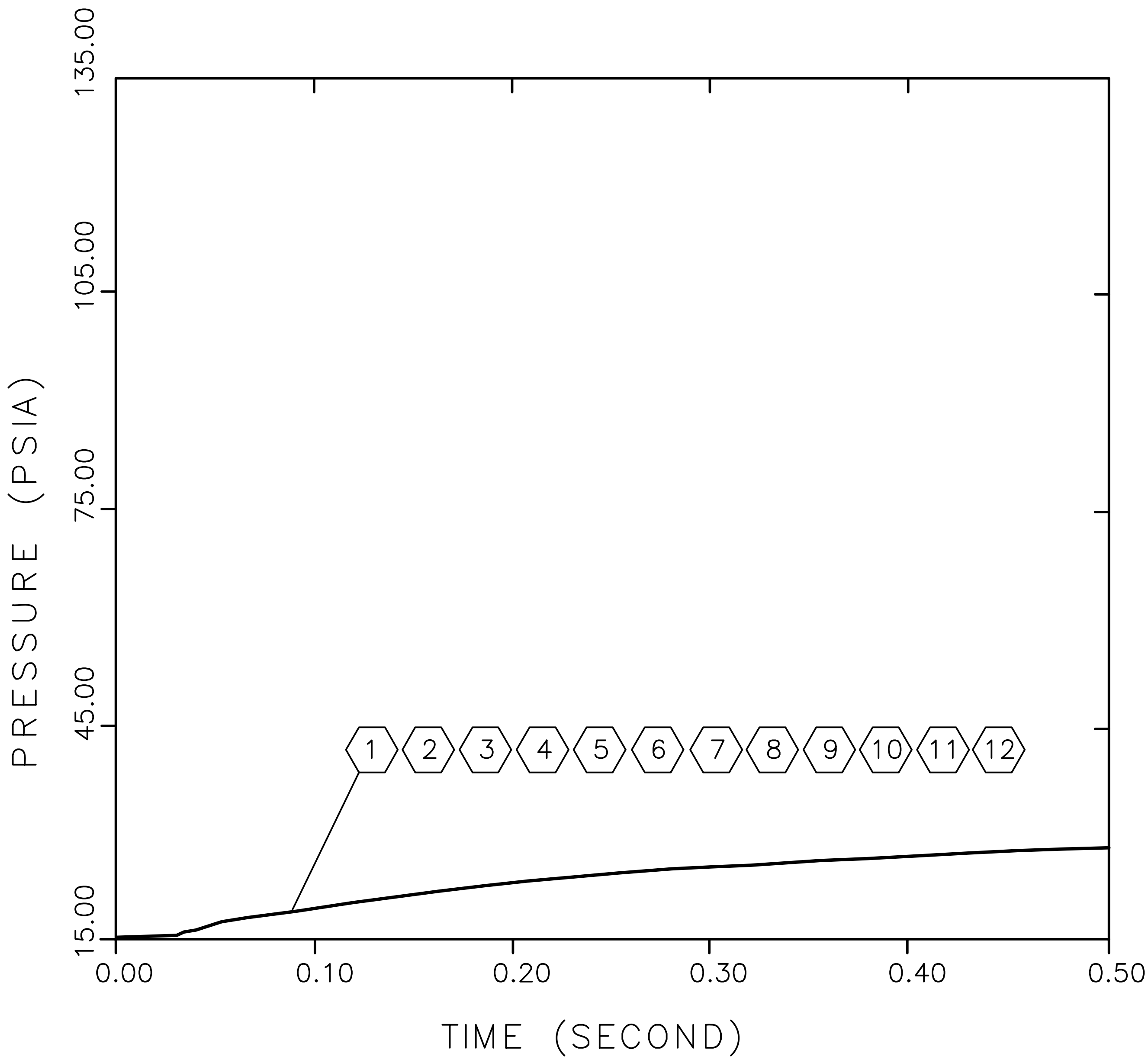
PRESSURE TRANSIENT IN SHIELD ANNULUS FOLLOWING A RECIRC. LINE BREAK AT THE NOZZLE SAFE END FIGURE 6A-3F, Rev. 47

AutoCAD: Figure Fsar 6A_3F.dwg



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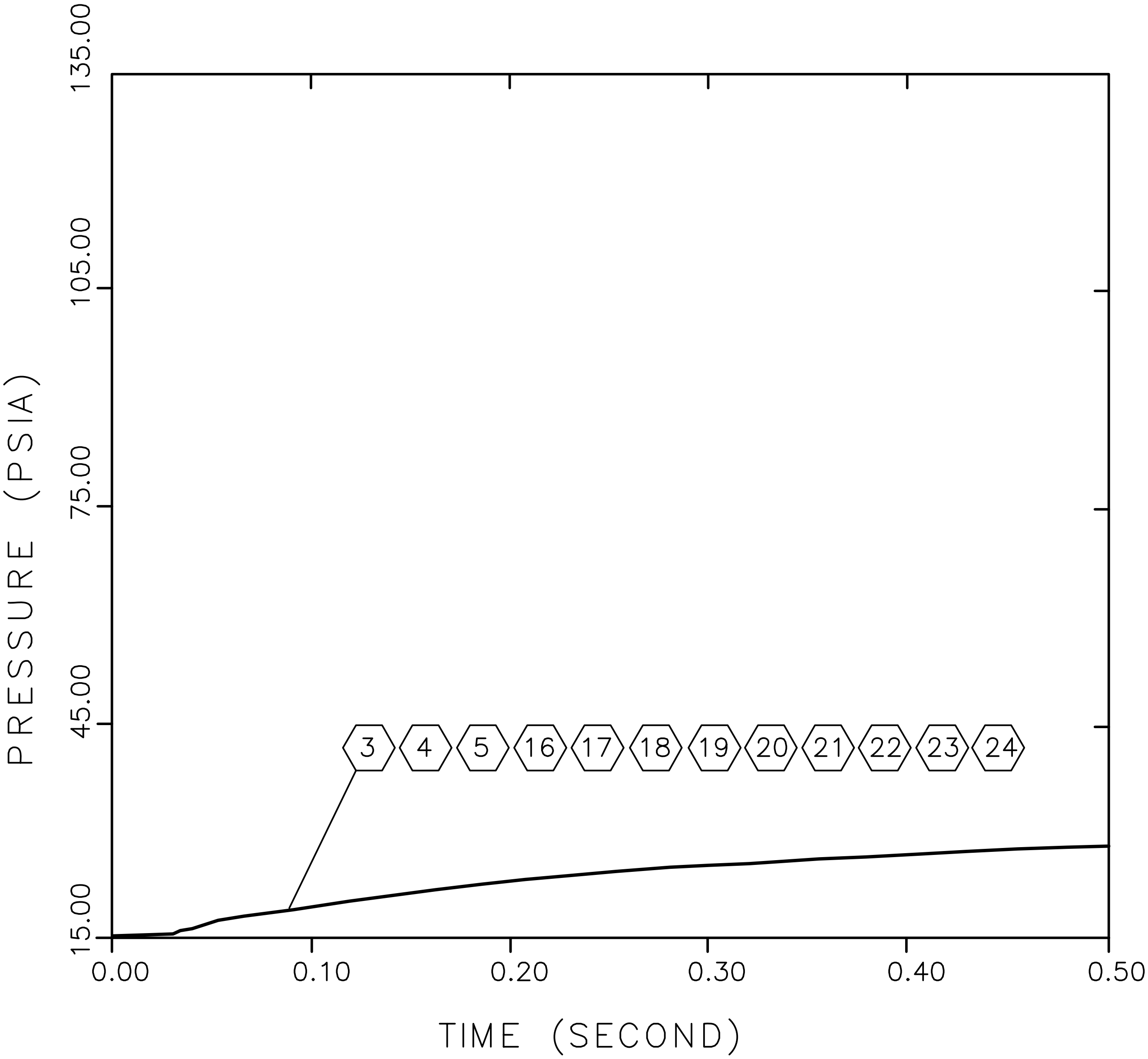
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

PRESSURE TRANSIENT IN SHIELD
ANNULUS FOLLOWING A FEEDWATER
LINE BREAK AT THE NOZZLE
SAFE END

FIGURE 6A-3G, Rev. 48

AutoCAD: Figure Fsar 6A_3G.dwg



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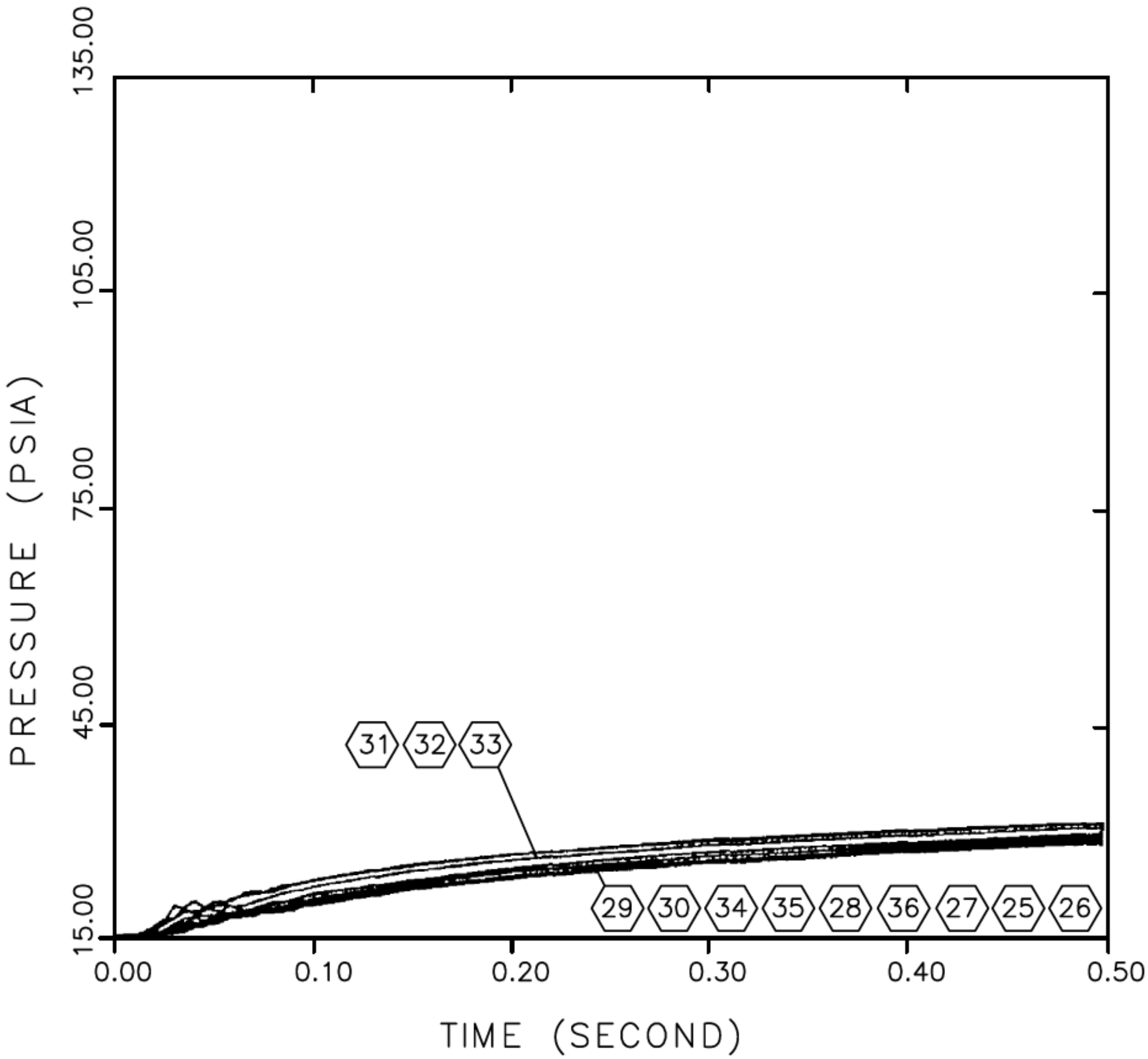
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

PRESSURE TRANSIENT IN SHIELD
ANNULUS FOLLOWING A FEEDWATER
LINE BREAK AT THE NOZZLE
SAFE END

FIGURE 6A-3H, Rev. 48

AutoCAD: Figure Fsar 6A_3H.dwg



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UNITS 1 & 2
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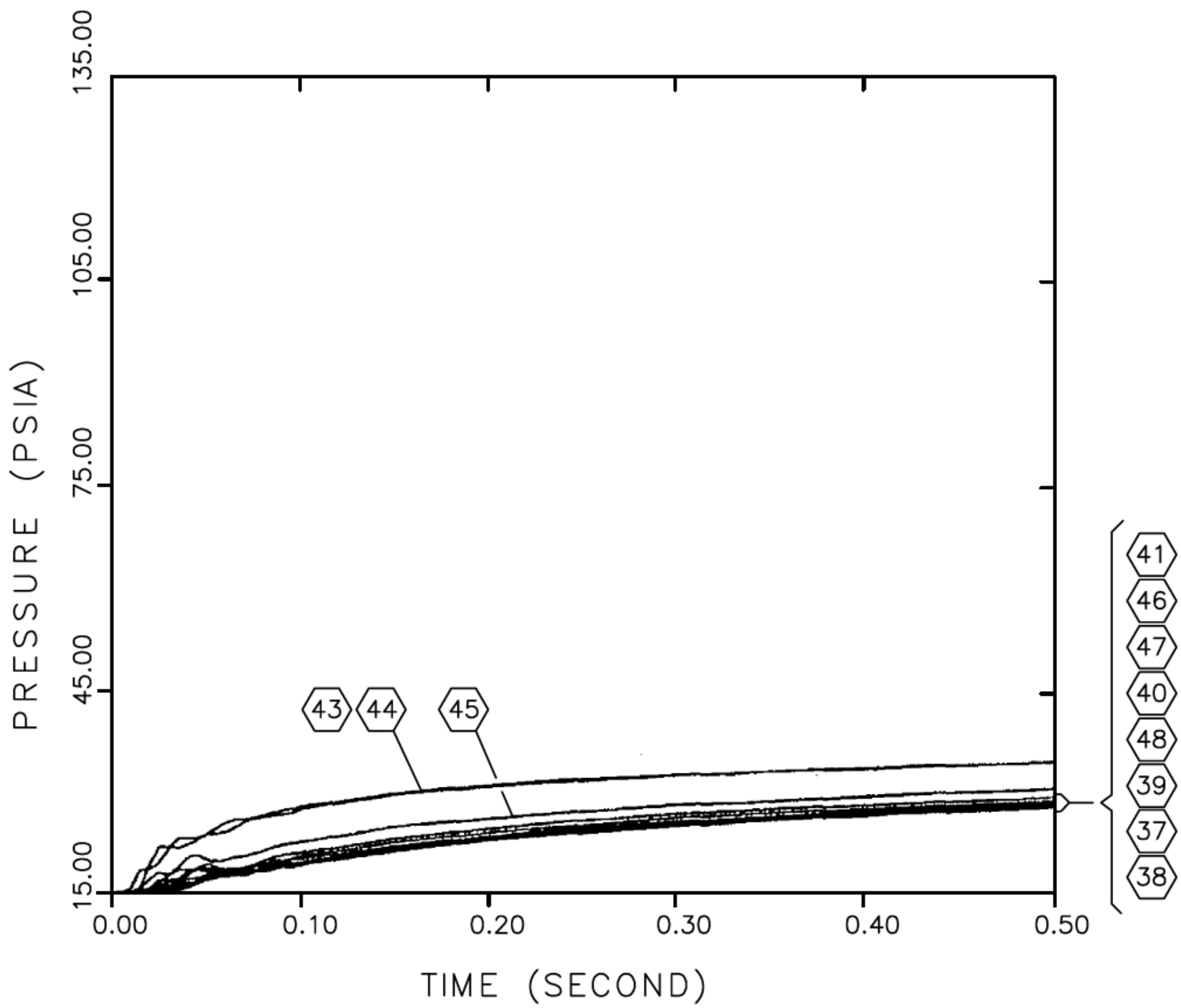
PRESSURE TRANSIENT IN SHIELD
ANNULUS FOLLOWING A FEEDWATER
LINE BREAK AT THE NOZZLE
SAFE END

FIGURE 6A-3I, Rev. 48

AutoCAD: Figure Fsar 6A_3I.dwg



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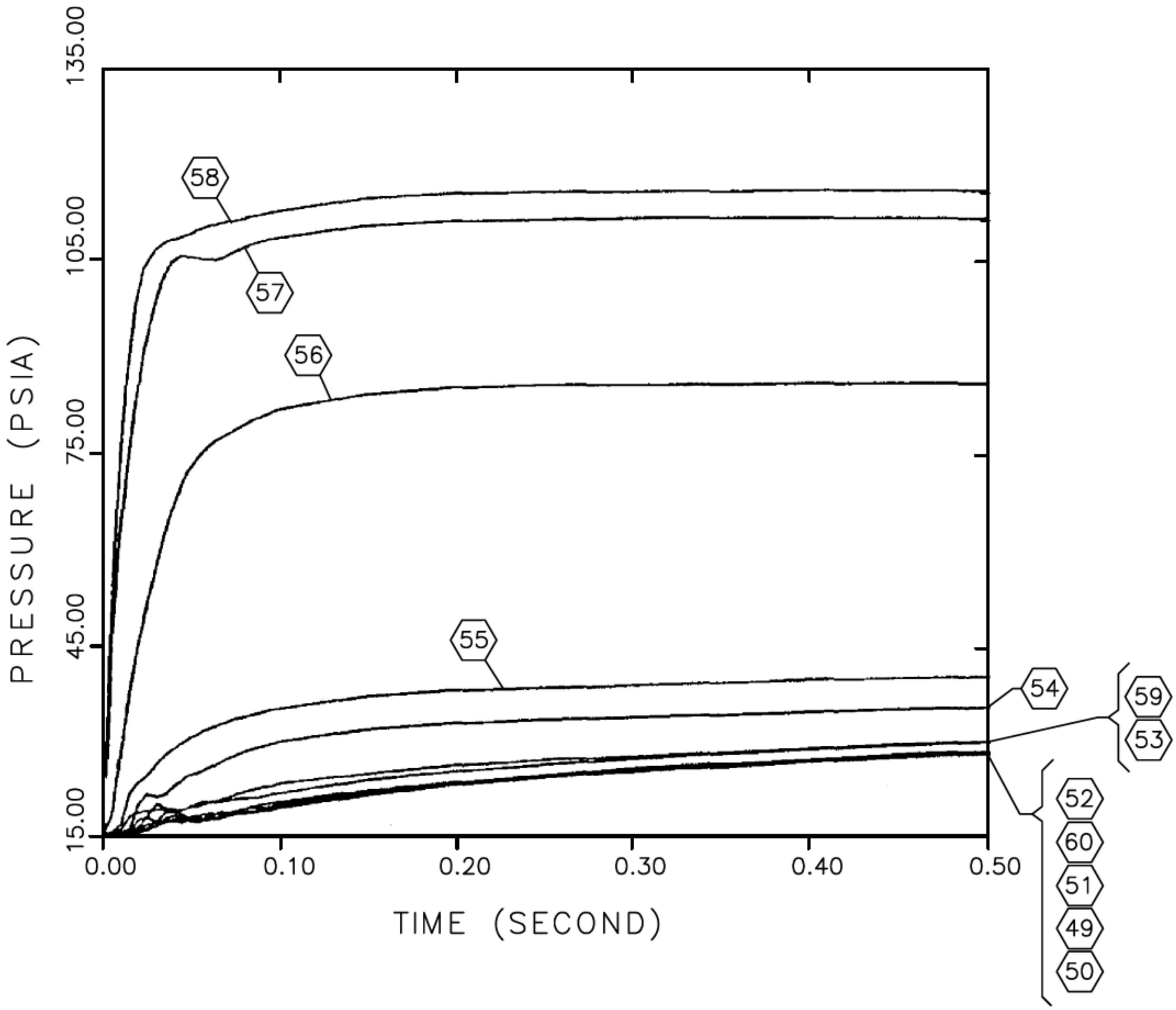
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

PRESSURE TRANSIENT IN SHIELD
ANNULUS FOLLOWING A FEEDWATER
LINE BREAK AT THE NOZZLE
SAFE END

FIGURE 6A-3J, Rev. 48

AutoCAD: Figure Fsar 6A_3J.dwg



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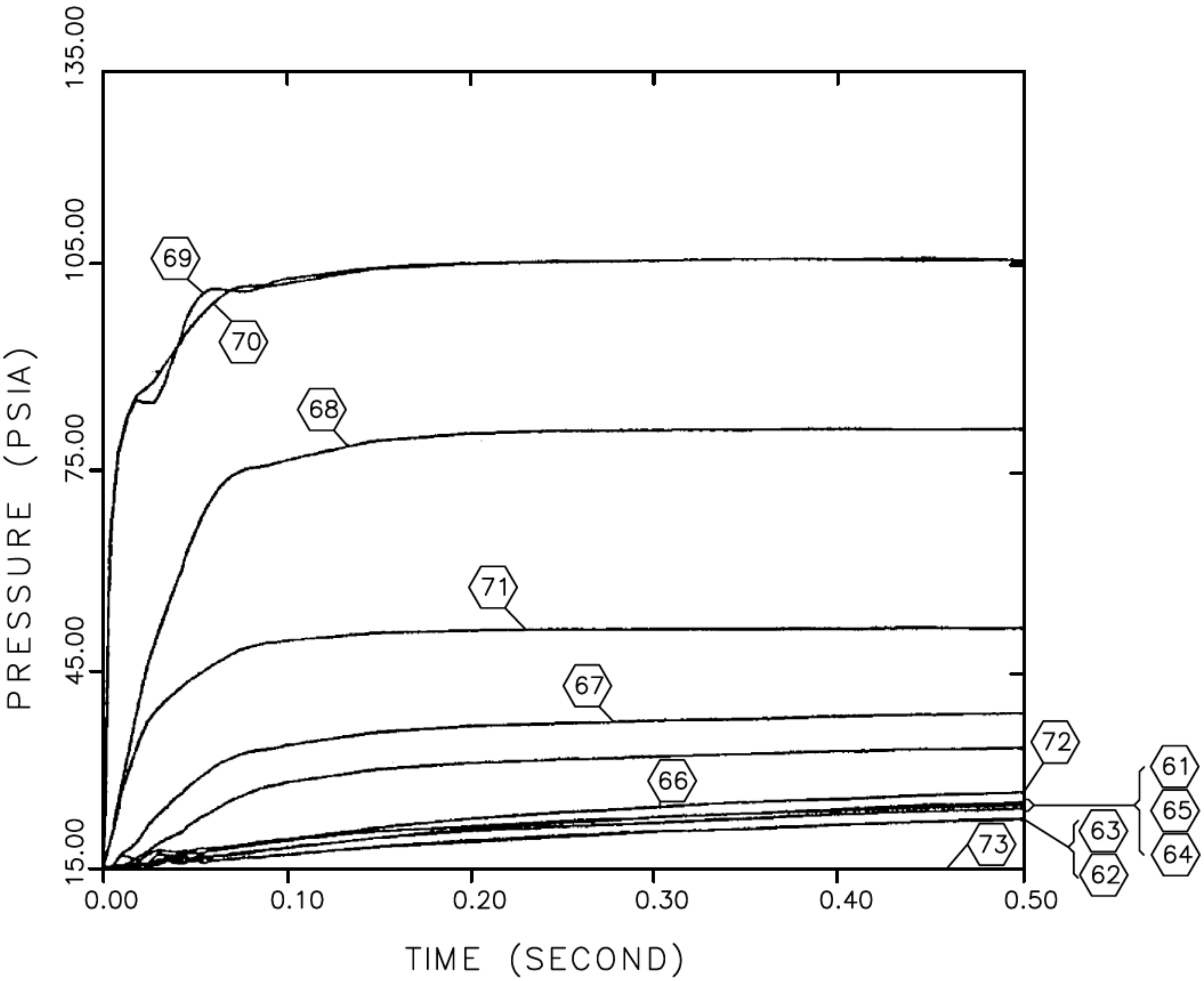
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

PRESSURE TRANSIENT IN SHIELD
ANNULUS FOLLOWING A FEEDWATER
LINE BREAK AT THE NOZZLE
SAFE END

FIGURE 6A-3K, Rev. 48

AutoCAD: Figure Fsar 6A_3K.dwg



FSAR REV.65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

PRESSURE TRANSIENT IN SHIELD
ANNULUS FOLLOWING A FEEDWATER
LINE BREAK AT THE NOZZLE
SAFE END

FIGURE 6A-3L, Rev. 48

AutoCAD: Figure Fsar 6A_3L.dwg

FIGURE DELETED PER LDCN 4547

FSAR REV. 65

SUSQUEHANNA STEAM ELECTRIC STATION UNITS 1 & 2 FINAL SAFETY ANALYSIS REPORT
FIGURE DELETED PER LDCN 4547 FIGURE 6A-3M, Rev. 48

AutoCAD Figure 6A_3M.doc

FIGURE DELETED PER LDCN 4547

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SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
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FIGURE DELETED PER LDCN 4547

FIGURE 6A-3N, Rev. 48

AutoCAD Figure 6A_3N.doc

FIGURE DELETED PER LDCN 4547

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SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

FIGURE DELETED PER LDCN 4547

FIGURE 6A-3O, Rev. 48

AutoCAD Figure 6A_3O.doc

APPENDIX B

COMPARTMENT DIFFERENTIAL PRESSURE ANALYSIS DESCRIPTION

The computer codes COPDA, FLUD and COTTAP4 were used to evaluate compartment differential pressure. This appendix describes the computational procedure and the analytical techniques used in FLUD. The analytical basis for COPDA is described in Reference 6B-4 and the analytical basis for COTTAP4 is described in Reference 3.6-10. The set-up of initial conditions, the determination of the thermodynamic state point at subsequent time increments, and computation of energy and mass transport between one time step is discussed in Sections 6B.1, 6B.2 and 6B.3 for FLUD. Selection was made of the control volume and flow path configuration that resulted in the best representation of the pressure transients in the compartments along the flow paths from the break.

6B.1 FLUD Calculational Procedure

The major differences between FLUD and COPDA (Ref. 6B-4) are the use of steam table curve fits (Section 6B.3) instead of table look-ups and the equation of state which is a first-order virial expansion (discussed in 6B.1.1). The fluid flow equations (compressible equations, HEM model and integrated momentum equation) used in COPDA have been reproduced in the FLUD Code. It may be observed from the FLUD flowchart in Fig. 6B-1 that the calculational procedures for FLUD and COPDA are very similar.

6B.1.1 Equation of State

In this section we describe how FLUD determines the thermodynamic state for each compartment in a system of interconnected compartments.

Our thermodynamic system (compartment) is assumed to be in equilibrium. The states assumed by the air-steam-water mixture can be described in terms of thermodynamic coordinates P, V, and T referring to the mixture as a whole. The equation of state is derived from a first order virial expansion as presented in Ref. 6B-1. Using the molecular theory of gases, the following equation of state for an air-steam mixture is obtained assuming negligible air-steam molecular interaction:

$$P = (M_a R_a + M_s R_s)\frac{T}{V} + \left(\frac{M_s}{V}\right)^2 R_s T B_s(T), \quad (1bf/ft^2) \qquad \text{(Eq. 6B-1)}$$

where the temperature dependence of the second virial coefficient for steam $B_s(T)$ is given by[2]

$$B_s(T) = 0.0330 - \frac{75.3137}{T} 10^{3.2659} / \left(T^2 x 10^{-5} + 1.1308\right) \qquad \text{(Eq. 6B - 2)}$$

Eq. 6B-1 can be rewritten as the sum of the partial pressure of air P_a and the partial pressure of steam P_s where

$$P_a = \frac{M_a}{V} R_a T, \left(1bf / ft^2\right) = 0.37043 \frac{T}{v_a}, (psia) \qquad \text{(Eq. 6B - 3)}$$

and

$$P_s = \frac{M_s}{V} R_s T \left[1 + \frac{M_s}{V} B_s(T)\right], \left(1bf / ft^2\right) \qquad \text{(Eq. 6B - 4)}$$

Eq. 6B-4 compares well with the steam tables.[2] For example, the relative error in Eq. 6B-4 is less than 1% for saturated steam at temperatures less than 570°F.

6B.1.2 Compartment Thermodynamic State

At any time, the total internal energy E, the air mass M_a, and the vapor mass M_v have know values for each compartment. Vapor is defined as a homogeneous mixture of steam and water in unknown proportions.

The internal energy is a function of as many thermodynamic coordinates as are necessary to specify the state of the system. Therefore, for known air and vapor masses and because the compartment volume is originally specified, the compartment internal energy can be expressed as a function of temperature only:

$$E = E(T) \qquad \text{(Eq. 6B-5)}$$

At the saturation temperature T_o, there is a discontinuous change in the slope of E(T) due to a phase change in the compartment atmosphere. Associated with T_o is the compartment saturation energy $E_o = E(T_o)$. Equation 6B-5 has two branches: (1) a two-phase branch were $E < E_o$ and $T < T_o$ and (2) a superheat branch where $E > E_o$ and $T > T_o$. Along the two-phase branch the vapor portion of the atmosphere has a non-zero water mass component, while along the superheat branch the vapor contains no water.

Having examined the behavior of E(T), we now proceed to solve EQ. 6B-5 for the compartment temperature, E being known. v_{sat}, e_{sat} and v_w, e_w represent the specific volumes and specific internal energies of saturated steam and water respectively. The dependence of these quantities on temperature is determined empirically from steam table curve fits described in Section 6B-3. E_o is calculated to determine on which branch of E(T) the compartment temperature lies. At compartment saturation, the steam mass M_s is identical to M_v and the specific volume of the steam is just $v_{sat}(T_o)$. Thus,

$$V = M_v v_{sat} \quad (T_o) \qquad \text{(Eq. 6B - 6)}$$

The above equation is easily solved to T_o by utilizing the inverse of the function $v_{sat}(T_o)$, which is also a steam table curve fit where $T_o = T_{sat}(V/M_v)$. The saturation internal energy for the compartment is then given by

$$E_o = M_a c_{va} T_o + M_v e_{sat}(T_o) \qquad \text{(Eq. 6B - 7)}$$

where c_{va} = 0.1725 Btu/lbm°R is the specific heat at constant volume for air averaged over the temperature range –109.7 to 440.3°F. For the case $E<E_o$ (the two-phase branch), the explicit dependence of E on M_a, M_s, M_w, and T is

$$E = M_a c_{va} T + M_s(T) e_{sat}(T) + M_w(T) e_w(T) \qquad \text{(Eq. 6B - 8)}$$

The functions $e_s(P_s,T)$ and $e_w(T)$ are the specific internal energies of steam and water respectively and are also discussed in Section 6B. 3. The steam and water masses are functions of temperature only and are given by

$$M_s(T) = x(T) M_v = \frac{V - M_v v_w(T)}{v_{sat}(T) - v_w(T)} \qquad \text{(Eq. 6B - 9)}$$

and

$$M_w(T)=M_v-M_s(T) \qquad \text{(Eq. 6B-9)}$$

where the steam quality x(T) is defined by the following:

$$x(T) = \frac{M_s(T)}{M_v} = \frac{V/M_v - v_w(T)}{v_{sat}(T) - v_w(T)} \qquad \text{(Eq. 6B - 10)}$$

For the case $E>E_o$ (the superheat branch), the explicit dependence of E is given by

$$E=M_a c_{va} T+M_s e_s(P_s,T) \qquad \text{(Eq. 6B-11)}$$

The steam mass M_s is not a function of temperature since it is equal to the vapor mass M_v, and of course the water mass is zero.

Because E is a complex function of T as seen by the above, EQ. 6B-5 does not readily lend itself to a strictly analytical solution. Instead, FLUD employs a one-pass iterative technique to solve for the temperature.

6B.1.3 Compartment Initial Conditions

The initial thermodynamic state is specified for each compartment by the total compartment pressure P, and the compartment volume V, temperature T, relative humidity ϕ, and vapor quality x.

If $\phi<1.0$, the compartment is superheated, the vapor consists entirely of steam, and the steam mass is given by definition as

$$M_s = \phi \frac{V}{v_{sat}(T)} \qquad \text{(Eq. 6B - 12)}$$

The steam partial pressure is obtained from Eq. 6B-4, and thus the air mass is given by Eq. 6B-3. The internal energy is calculated using Eq. 6B-11. If $\phi=1.0$ and $x=1.0$, the compartment is saturated. The steam partial pressure is given by the saturation pressure is given by the saturation pressure $P_s=P_{sat}(T)$. The saturation pressure of steam P_{sat} is obtained empirically from a curve fit to the steam tables. The steam mass is given by Eq. 6B-12 with $\phi=1.0$. The vapor mass is identically equal to the steam mass, and the internal energy is computed from Eq. 6B-7. For $\phi=1.0$ and $x<1.0$, the compartment is two-phase. The vapor and steam masses are given by Eq. 6B-9 and the water mass by Eq. 6B-9. The steam partial pressure is equal to the saturation pressure $P=P_{sat}(T)$. Therefore, the air mass can be calculated from Eq. 6B-3. However, because the compartment now contains water, the volume accessible to the air and steam V_g is just

$$V_g=V-M_w v_{sat}(T) \qquad \text{(Eq. 6B-13)}$$

This gas volume V_g must be used in place of V in Eq. 6B-3 in determining the air mass. The internal energy is obtained from Eq. 6B-8.

6B.1.4 Air and Vapor Component Flow Rates

The time-dependent partial pressure of steam is given by Eq. 6B-4 where v_s replace V/M_s. The time-dependent air specific volume v_a is then obtained from Eq. 6B-3. Time-dependent air and steam mass fractions are then calculated as follows:

$$f_a=v_s(v_s+v_a)^{-1} \qquad \text{(Eq. 6B-14)}$$

$$f_v=v_a(v_s+v_a)^{-1} \qquad \text{(Eq. 6B-14)}$$

The flow rates of the air and vapor components that comprise the gas are calculated from the total flow rate $\dot{M}_{ij}$ by using the mass fractions of air and vapor in the upstream compartment:

$$\dot{M}_{aij} = f_a \dot{M}_{ij} \qquad \text{(Eq. 6B-15)}$$

$$\dot{M}_{vij} = f_v \dot{M}_{ij} \qquad \text{(Eq. 6B-16)}$$

6B.2 Energy Transfer Mechanisms

There are several mechanisms by which FLUD transfers energy to and from the various compartments and the atmosphere. These mechanisms are:

(1) Blowdown energy
(2) Flow of energy between compartments
(3) Compartment heat loads
(4) Compartment unit coolers

All of these mechanisms add or subtract energy from the system. A continuous accounting of all energy contributors is kept by FLUD in the form of an overall energy balance to ensure energy conservation. The various energy transfer mechanisms are discussed and the energy balance are discussed below.

6B.2.1 Blowdown Energy

Blowdown energy is added to the system of compartments when FLUD is used to analyze a high-energy pipe break problem. The blowdown flow rate $\dot{M}_B$ specific enthalpy h_B, and the split among compartments are assumed to be given as input data. The rate of energy addition to the system by blowdown $\dot{H}_B$ is usually a time-varying quantity given by

$$\dot{H}_B = \dot{M}_B h_B \qquad \text{(Eq. 6B-17)}$$

This variable energy rate is used to calculate the amount of energy that is placed in one or in the various break compartments during each time step. The total amount of blowdown energy added to the system is the integral of $\dot{H}_B$.

$$\dot{H}_B(t) = \int_0^t \dot{H}_B dt \qquad \text{(Eq. 6B-18)}$$

The blowdown energy rate added to the ith compartment is calculated by multiplying the user-supplied split fraction for the ith compartment times the total blowdown energy rate in Eq. 6B-17.

6B.2.2 Enthalpy Flow

Whenever mass is transferred between compartments or between a compartment and the atmosphere, there is an associated transfer of energy based upon the enthalpy of the upstream compartment. The general relation used to calculate enthalpy flow between compartments is

$$\dot{H}_i = \sum_j \dot{M}_{ij} h^*_{ij} \qquad \text{(Eq. 6B-19)}$$

where h^*_{ij} represents the total specific enthalpy of the gas in the upstream compartment and $\overline{M}_{ij}$ is the flow rate between compartments i and j as discussed in 6B.1.4. The total enthalpy flow rate for the system is

$$\dot{H} = \sum \dot{H}_i \qquad \text{(Eq. 6B-20)}$$

When energy transfer occurs between a compartment and the atmosphere, the relation used to calculate this flow is

$$\dot{H}_{atm,i} = \dot{M}_{ii} h^*_{ii} \qquad \text{(Eq. 6B-21)}$$

Here $\dot{M}_{ii}$ represents the total flow from or to the atmosphere from component i and h^*_{ij} is the specific enthalpy of the upstream compartment (which may be either compartment i or the atmosphere depending upon the sign of $\dot{M}_{ii}$). The total enthalpy flow rate to the atmosphere is

$$\dot{H}_{atm} = \sum_i \dot{H}_{atm,i} \qquad \text{(Eq. 6B-22)}$$

and the total amount of energy transferred to the atmosphere is

$$H_{atm}(t) = \int_0^t \dot{H}_{atm} dt \qquad \text{(Eq. 6B-23)}$$

6B.2.3 Compartment Heat Loads

Heat is generated within a compartment in the case where pumps or equipment are operating in that compartment. These heat loads are given with the input data as a constant heat rate (Btu/sec) for each compartment $\dot{Q}_{load}$. These heat loads are assumed to be applicable throughout the problem under consideration.

6B.2.4 Unit Coolers

Unit coolers or room coolers are present in many situations, especially in compartments that have equipment capable of generating large heat loads. Room coolers can have a variable start temperature which is specified in the input data. The coolers are usually set to begin operating when the compartment temperature exceeds some prescribed limit.

The cooling heat transfer rate is given by

$$\dot{Q}_{cool} = \alpha(T - T_{cool}) \qquad \text{(Eq. 6B - 24)}$$

where T_{cool} is the cooler cold water inlet temperature, T is the temperature of the compartment, and $\propto$ is the cooler constant (Btu/sec-°R). The cooler constant can be calculated from room cooler specifications and is assumed to be constant throughout the temperature ranges of the room atmosphere and the cooling water temperature.

6B.2.5 Energy Balance

The energy balance given by the following equations is used to ensure that energy conservation is achieved.

$$E_{bal} = E_i + \dot{Q}dt + \dot{H}_{atm}dt - \dot{H}_B dt - E_i(0) \qquad \text{(Eq. 6B - 25)}$$

where E_i is the total energy in the ith compartment, E_i (0) is the initial compartment energy, and

$$\dot{Q} = \dot{Q}_c + \dot{Q}_{load} + \dot{Q}_{cool} \qquad \text{(Eq. 6B - 26)}$$

If an energy balance is achieved, then E_{bal} should be zero.

6B.2.6 Blowout Panel Activation

Blowout panels are treated as instantaneous one-way switches. Once a blowout panel set pressure is exceeded. the flowpath is open for the duration of the calculation. The actual activation of a blowout panel is made by setting the forward and reverse set pressures equal to zero once the forward set pressure has been exceeded.

6B.2.7 Energy and Mass Conservation

Energy and mass conservation is then checked by calculating the following quantities:

$$E_{bal} = \sum E_i + \int \dot{Q} dt + \int \dot{H}_{atm} dt - \int \dot{H}_B dt - E_{init} \qquad \text{(Eq. 6B - 27)}$$

and

$$M_{bal} = \sum M_i + \int \dot{M}_Q dt + \int \dot{M}_{atm} dt - \int \dot{M}_B dt - M_{init} \qquad \text{(Eq. 6B - 28)}$$

If all mass and energy transfer has been accounted for, then E_{bal} and M_{bal} should be zero (or a very small percentage of the total energy and mass due to computer round-off error).

6B.2.8 Eulerian Integration

The time-dependent quantities listed below are integrated according to the following general scheme:

$$X(T + \Delta t) = X(t) + \dot{X}(t)\Delta t \qquad \text{(Eq. 6B - 29)}$$

where X is any time dependent variable and $\dot{X}$ is its time rate of change. The variables intergrated by FLUD are:

$\dot{H}_B$ - blowdown enthalpy flow rate

$\dot{M}_B$ - blowdown mass flow rate

$\dot{E}$ - energy rate of change

$\dot{H}_{atm}$ - atmospheric enthalpy flow rate

$\dot{M}_a$ - air mass flow rate

$\dot{M}_v$ - vapor mass flow rate

$\dot{M}_{atm}$ - atmospheric mass flow rate

6B.3 Thermodynamic Properties of Steam, Water, and Air

FLUD uses steam, air, and water properties for various thermodynamic calculations which are performed during each time step. The thermodynamic variables needed in FLUD calculations are:

$e_a(T)$	specific internal energy of air
$P_{sat}(T)$	saturation pressure of steam
$v_{sat}(T)$	saturation specific volume of steam
$e_s(T,P)$	specific internal energy of steam
$v_w(T)$	specific volume of water
$e_w(T)$	specific internal energy of water
$T_{sat}(P)$	saturation temperature of steam
$T_{sat}(v)$	saturation temperature of steam
$e_{sat}(T)$	saturation specific internal energy of steam
$h_{sat}(T)$	saturation specific enthalpy of steam
$h_{fg}(P)$	enthalpy of vaporization of steam

The "known" quantities that can be used to calculate the above nine variables are the macroscopic compartment thermodynamic variables pressure, specific volume, and temperature, P, v, and T respectively.

The air and water properties $e_a(T)$, $v_w(T)$, and $e_w(T)$ are calculated by spline fitting polynomials to data in the steam and gas tables [2], [3]. The air property $e_a(T)$ was found to be adequately represented by a linear fit. This is no doubt due to the good "ideal gas" behavior of air. Thus,

$$e_a(T)=a_1T \qquad \text{(Eq. 6B-30)}$$

The water properties $v_w(T)$ and $e_w(T)$ and the steam properties $h_{sat}(T)$, $e_o(T)$, and $e_{sat}(T)$ are very nearly straight line functions, but small variations were accommodated by using third order spline polynomial fits of the general form:

$$\text{property } (T) = a_0 + a_1T + a_2T^2 + a_3T^3 \qquad \text{(Eq. 6B-31)}$$

For example, for $h_{fg}(P)$,

$$h_{fg}(P) = a_o + a_1P + a_2P^2 + a_3P^3 \quad \text{(Eq. 6B-32)}$$

The accuracy of he curve fits the range between 0.01% and 4%[3] for the various properties.

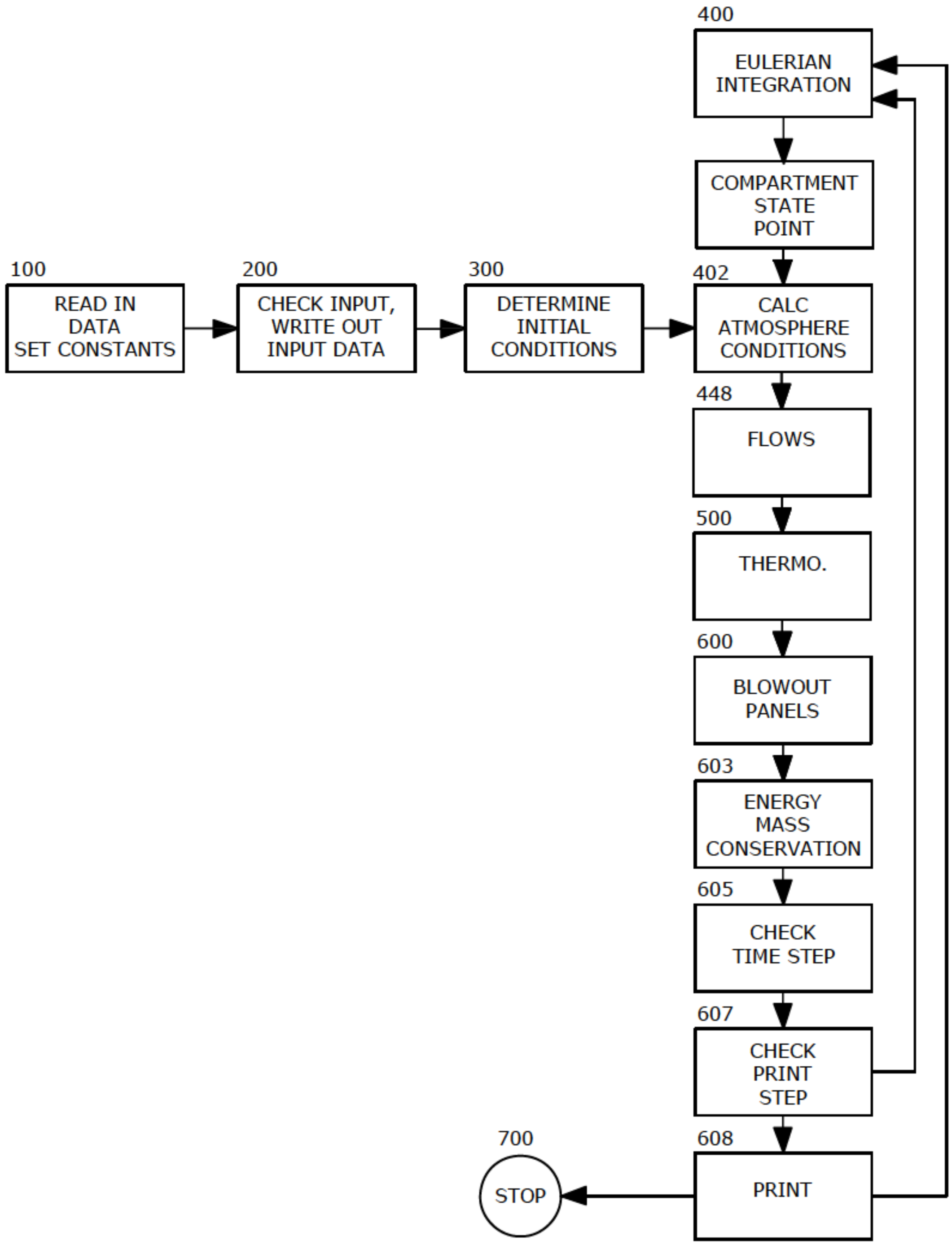
6B.4 References

6B-1 Reif, F. J. Fundamentals of Statistical and Thermal Physics, McGraw-Hill Book Co., p. 183.

6B-2 Kennan, J. H. et al, Steam Tables, John Wiley & Sons, Inc., New York, 1969.

6B-3 Kennan, J. H., and J. Kaye, Gas Tables, John Wiley & Sons, Inc., New York, 1948.

6B-4 Bechtel Topical Report BN-TOP-4 Rev. 1, October 1977, "Subcompartment Pressure and Temperature Transient Analysis." This report was approved by the NRC in February, 1979.



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BASICE FLUD CALCULATION
FLOWCHART

FIGURE 6B-1, Rev. 47

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6.7 MAIN STEAM ISOLATION VALVE LEAKAGE ISOLATED CONDENSER TREATMENT METHOD

The MSIV leakage Isolated Condenser Treatment Method (ICTM) controls and minimizes the release of fission products which could leak through the closed main steam isolation valves (MSIVs) after a LOCA. The treatment method provides this control by processing MSIV leakage prior to release to the atmosphere. This is accomplished by directing the leakage through the main steam drain line to the condenser.

The ICTM takes advantage of the large volume and surface area in the main steam lines and main condenser to provide hold-up and plate-out of fission products that may leak from the closed MSIVs. In this approach, the main steam piping, the bypass/drain piping, and the main condenser are used to mitigate the consequences of an accident which could result in potential offsite exposures comparable to 10CFR50.67 limits. Therefore, as required by Appendix A to Part 100, the components and piping systems used in the ICTM must be capable of performing their function during and following a safe shutdown earthquake (SSE). The technical justification for the seismic capability of the ICTM is based on plant specific analyses of a sample set of anchors, the main condensers, and the turbine buildings. In addition, a plant specific walkdown was completed to compare the plant with an experience data base developed for this application.

A plant specific dose calculation shows that the ICTM is effective to reduce dose consequences of MSIV leakage over an expanded operating range. The ICTM also resolves the safety concern (Generic Issue C-8) that the original MSIV Leakage Control System (LCS) would not function at MSIV leakage rates higher than the LCS design capacity. Except for the requirement to establish a proper flow path from the MSIVs to the condenser, the ICTM is passive and does not have any logic controls and interlocks. The method is consistent with the philosophy of protection by multiple leak-tight barriers used in containment design for limiting fission product release to the environment. The ICTM is reliable and effective for MSIV leakage treatment.

6.7.1 Design Bases

6.7.1.1 Safety Criteria

The following criteria represent the design, safety and performance requirements imposed upon the MSIV leakage ICTM:

1. The ICTM has sufficient capacity and capability to treat any leakage from the MSIVs consistent with the containment leakage limits imposed for the conditions associated with a postulated design-basis LOCA. Specifically, a complete severance of a recirculation line shall not permit an offsite dose to exceed the guidelines of 10CFR50.67.

2. The ICTM is capable of performing its function during the postulated accident conditions and following a coincident loss of offsite power (LOOP).

3. Post Accident containment atmosphere from the ICTM shall be directed such that it will not affect functioning of structures, systems, or components important to safety.

4. The ICTM is capable of manual initiation and is designed to permit actuation about 20 minutes following the postulated design-basis LOCA. This time period is considered to be consistent with loading requirements of the emergency electrical buses and with reasonable times for operator action.

5. The ICTM is designed to permit testing of the main steam drain line motor operated valve during power operation to the extent practical; and testing of the boundary motor operated valves during plant shutdowns.

6. The ICTM piping and condenser are designed and constructed to standard industrial practices (e.g., ANSI B31.1 and Heat Exchanger Institute (HEI) Standards, respectively). They are seismically rugged and not susceptible to a primary collapse mode of failure as a result of seismic vibratory motion.

6.7.1.2 Regulatory Acceptance Criteria

All piping and motor operated valves included in the ICTM comply with the applicable codes, addenda, code cases, and errata in effect at the time the equipment was procured. There is no change in quality classification of components used in the ICTM. The original design requirements are considered to be capable of mitigating the consequences of a LOCA. The technical justification for the seismic capability of the ICTM is based on plant specific analyses of a sample set of anchors, the main condensers, and the turbine buildings. In addition, a plant specific walkdown was completed to compare the plant with an experience data base developed for this application.

A plant specific dose calculation shows that the ICTM is effective to reduce dose consequences of MSIV leakage over an expanded operating range. The ICTM also resolves the safety concern (Generic Issue C-8) that the original MSIV Leakage Control System (LCS) would not function at MSIV leakage rates higher than the LCS design capacity.

6.7.1.3 Leakage Rate Requirements

The features of the ICTM are established to reduce the leakage rate of radioactive materials to the environment during the postulated LOCA. The leakage requirements are imposed upon the ICTM, in order to:

1. include all plant effluents in the filtered, elevated release dose calculations,

2. allow for realistically attainable MSIV leakage limits (limits which are operationally and statistically assured), and

3. assure reasonable leakage verification test frequencies.

The design and operational requirements imposed upon the MSIV leakage ICTM relative to the foregoing criteria are established to:

1. allow MSIV leakage rates up to 100 scfh for each MSIV in each line, but not to exceed 300 scfh total combined leakage for the four main steam lines,

2. allow a MSIV leakage rate verification testing frequency compatible with the requirements of SSES Technical Specifications, and

3. assure and restrict total plant offsite dose impacts below 10CFR50.67.

6.7.2 System Description

6.7.2.1 General Description

The MSIV leakage ICTM shall minimize the release of fission products to the environment after the postulated LOCA. This is accomplished by directing the MSIV leakage through the main steam drain line to the condenser. In addition, there are alternate pathways that can direct leakage to the condenser. The ICTM takes advantage of the large volume and surface area in the condenser to provide hold-up and plate-out of fission products that may leak from the MSIVs. This method provides effective fission product attenuation in the condenser such that the consequences of MSIV leakage can be significantly reduced. The MSIV leakage that enters the condenser is subsequently released to the atmosphere from the low-pressure turbine seals.

6.7.2.1.1 Primary Pathway

The primary pathway to the condenser is the main steam drain line through the HV-1(2)41F020 and HV-1(2)41F021 motor operated valves. The HV-1(2)41F020 valve is normally open and will not need to be operated. The HV-1(2)41F021 valve is normally closed and will need to be opened by an operator. The handswitch for the HV-1(2)41F021 valve is in the control room. The following criteria represent the design, safety and performance requirements imposed upon the HV-1(2)41F021 valve:

1. The valve shall be capable of performing its function following a coincident loss of offsite power (LOOP).

2. The valve shall be capable of manual initiation and is designed to permit actuation about 20 minutes following the postulated design-basis LOCA. This time period is considered to be consistent with loading requirements of the emergency electrical buses and with reasonable times for operator action.

3. The valve shall be tested in accordance with the SSES In-Service Test program.

These criteria assure, with a high degree of certainty, that the primary flow path can be established.

In addition to the valves required to establish the primary flowpath, there are three normally open motor operated valves that shall be closed by an operator to prevent leakage to other areas of the turbine building. The boundary valves are: HV-1(2)0107, to Steam Jet Air Ejector; HV-1(2)0109, to Steam Seal Evaporator; and HV-1(2)0111, to Reactor Feed Pump Turbines. The handswitches for these valves are in the control room. The following criteria represent the design, safety and performance requirements imposed upon these valves:

1. The valve shall be capable of performing its function following a coincident loss of offsite power (LOOP).

2. The valve shall be capable of manual initiation and is designed to permit actuation about 20 minutes following the postulated design-basis LOCA. This time period is considered to be consistent with loading requirements of the emergency electrical buses and with reasonable times for operator action.

3. The valve shall be tested in accordance with the SSES In-Service Test program.

These criteria assure, with a high degree of certainty, that the boundary can be established.

6.7.2.1.2 Alternate Pathways

In addition to the primary pathway, alternate orificed pathways (which do not require the opening of any valves) exist as a backup to direct MSIV leakage to the condenser should the HV-1(2)41F021 valve not open as expected. These pathways include:

1. The orificed bypass line around the HV-1(2)41F021 valve.

2. The four (4) orificed drain lines from the main steam line eight (8) inch drip legs.

3. The one (1) orificed drain line from the main steam line twelve (12) inch drip leg.

These pathways enter the condenser at or below the same elevation of the primary pathway.

6.7.2.2 System Operation

The ICTM primary pathway is established manually by the operator after it has been ascertained that:

1. MSIV leakage rates warrant processing by ICTM.

The ICTM primary pathway is established manually by the operator from control room panels by performing the following activities:

1. confirm the HV-1(2)41F020 valve is open,

2. open the HV-1(2)41F021 valve, and

3. close the boundary valves (HV-1(2)0107, HV-1(2)0109, and HV-1(2)0111).

Except for establishing the flowpath to the condenser, the ICTM is passive and does not require additional operator action. The alternate pathways do not require any operator action.

6.7.2.3 Equipment Required

The following equipment components are required for the ICTM:

1. Piping - the main steam drain piping or erosion resistant alloy. The piping provides the flowpath from the main steam lines, down stream of the outboard MSIVs, to the main condenser.

2. Valves - motor operated. One of the valves is normally closed and will be opened to establish an unrestricted flowpath to the condenser. Three of the valves are normally opened and will be closed to prevent MSIV leakage from flowing to other areas in the plant.

3. Condenser - anchored to prevent excessive movement during a SSE. The condenser volume and surface area provide hold-up and plate-out of fission products

6.7.3 System Evaluation

An evaluation of the capability of the ICTM to prevent or control the release of the radioactivity from the main steamlines following a design-basis LOCA has been conducted. The results of this evaluation are presented in the following subsections.

6.7.3.1 Functional Protection Features

The ICTM is designed to operate under the expected conditions following a design-basis LOCA. The main steam piping and main condenser designs are seismically rugged, and the design requirements applied to SSES main steam piping and main condenser contain adequate margin, based on the original design requirements. The valves' operating conditions (pressure drop across the valve) will be less severe following a LOCA than the valves' normal operating conditions. The valves will be capable of performing their function following a coincident loss of offsite power (LOOP).

6.7.3.2 Effects of Single Active Failures

The ICTM will function following an active component failure of the HV-1(2)41F021 to open by virtue of the alternate pathways to the condenser. The alternate pathways are passive and do not require any equipment to be operated.

6.7.3.3 Effects of Seismic Induced Failures

The ICTM is capable of its function based on the plant specific analyses of a sample set of anchors, the main condensers, and the turbine buildings. In addition, a plant specific walkdown was completed to compare the plant with an experience data base developed for this application. The walkdown and analyses confirmed that other plant systems would not adversely affect the ICTM. The main steam piping and main condenser designs are seismically rugged, and the design requirements applied to SSES main steam piping and main condenser contain adequate margin, based on the original design requirements.

6.7.3.4 Isolation Provisions

The ICTM does not contain any valves required to maintain containment integrity.

6.7.3.5 Leakage Protection Evaluation

The ICTM will limit the release of radioactive materials to the environment during a postulated LOCA. The ICTM will accomplish this function through the use of components described in Subsection 6.7.2. The ICTM could be manual initiated following the LOCA. The dose contribution from activity processed by the ICTM is evaluated in Subsection 6.7.3.8.

6.7.3.6 Failure Mode and Effects Analysis

The ICTM is considered to be reliable based on the few components needed to implement the method. Except for the requirement to establish a proper flow path from the MSIVs to the condenser, the ICTM is passive and does not have any logic controls and interlocks.

6.7.3.7 Influence on Other Safety Features

The ICTM motor operated valves are powered from the engineered safeguard power sources. The load is estimated to be about 4 kw per unit. These non-class 1E loads are connected through an approved isolation system to Diesel Generator backed Class 1E sources.

The ICTM does not introduce or expose the steam piping or valves to thermal or mass loadings different from that experienced in normal isolation valve service; therefore cannot affect or degrade the sealing ability of the MSIVs.

6.7.3.8 Radiological Evaluation

A plant specific radiological analysis has been performed to assess the effects of the ICTM on the Control Room and off-site doses following a postulated design basis LOCA. The analysis used standard conservative assumptions for the radiological source term consistent with Regulatory Guide (RG) 1.183, “Alternative Radiological Source Terms for Evaluating Design Basis Accidents at Nuclear Power Reactors,” (dated July 2000). The analysis results show that the ICTM is effective. The off-site doses and Control Room doses will not exceed the regulatory limits contained in 10CFR50.67.

The off-site and Control Room doses resulting from a LOCA are discussed in Subsection 15.6.5 of the FSAR. The off-site and Control Room doses associated with the ICTM are the sum of containment leakage LOCA doses evaluated in the power uprate revision to the design-basis LOCA calculation and the additional doses calculated for the ICTM.

6.7.4 Instrumentation Requirements

Except for the requirement to establish a proper flow path from the MSIVs to the condenser, the ICTM is passive and does not have any logic controls and interlocks.

6.7.5 Inspection and Testing

The ICTM valves (HV-1(2)41F021, HV-1(2)0107, HV-1(2)109, and HV-1(2)0111) shall be tested in accordance with the SSES In-Service Test program. The valves will be stroke tested at least every refueling outage.

Table 6.7-1

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FIGURE 6.7-2, Rev. 54

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