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SECTION 1.2

CONTENTS (Continued)

SECTION 1.2

ILLUSTRATIONS

SECTION 1.2

ILLUSTRATIONS

SECTION 1.2

ILLUSTRATIONS (Continued)

(6) Monitoring of essential generators, transformers, and circuits is provided in the main control room.

1.2.1.2.5.3 Power Conversion Systems Process Control Criteria

(1) Control equipment is provided to control the reactor pressure throughout its operating range.

(2) The turbine is able to respond automatically to minor changes in load.

(3) Control equipment in the feedwater system maintains the water level in the reactor vessel at the optimum level required by steam separators.

(4) Control of the power conversion equipment is possible from a central location.

1.2.1.2.6 Power conversion Systems Criteria

Components of the power conversion systems shall be designed to perform the following basic objectives:

(1) produce electrical power from the steam coming from the reactor, condense the steam into water, and return the water to the reactor as heated feedwater with a major portion of its gases and particulate impurities removed; and

(2) assure that any fission products or radioactivity associated with the steam and condensate during normal operation are safely contained inside the system or are released under controlled conditions in accordance with waste disposal procedures.

1.2.2 Plant Description

1.2.2.1 Site Characteristics

1.2.2.1.1 Site Location

The plant is located on a site adjacent to or close to a body of water with sufficient capacity for either once-through or recirculated cooling or a combination of both methods.

1.2.2.1.2 Description of Plant Environs

1.2.2.1.2.1 Meteorology

The safety-related structures and equipment are designed to retain required functions for the loads resulting from any tornado with characteristics not exceeding the values provided in Table 2.0-1.

Tornado missiles are discussed in Section 3.5.

1.2.2.1.2.2 Hydrology

The safety design basis of the plant provides that structures of safety significance will be unaffected by the hydrologic parameter envelope defined in Chapter 2.

1.2.2.1.2.3 Geology and Seismology

The structures of safety significance for the plant are designed to withstand a safe shutdown earthquake (SSE) which results in a freefield peak acceleration of 0.3g.

1.2.2.1.2.4 Shielding

Shielding is provided throughout the plant, as required to maintain radiation levels to operating personnel and to general public within the applicable limits set forth in 10CFR20 and 10CFR100. It is also designed to protect certain plant components from radiation exposure resulting in unacceptable alterations of material properties or activation.

1.2.2.1.3 Site Arrangements

The containment and building arrangements including equipment locations are shown in Figures 1.2-2 through 1.2-31.

1.2.2.2 Nuclear Steam Supply Systems

The nuclear steam supply system includes a direct-cycle forced-circulation boiling water reactor that produces steam for direct use in the steam turbine. A heat balance showing the major parameters of the nuclear steam supply system for the rated power conditions is shown in Figure 1.1-2.

1.2.2.2.1 Reactor Pressure Vessel System

The reactor pressure vessel system (RPVS) contains the reactor pressure vessel with the reactor internal pump (RIP) casings; core and supporting structures; the steam separators and dryers; the control rod guide tubes; the spargers for the feedwater, RHR and core flooder system; the control rod drive housing; the in-core instrumentation guide tubes and housings; and other components. The main connections to the vessel include steamlines, feedwater lines, reactor internal pumps, control rod drives and in-core nuclear instrument detectors, core flooder lines, residual heat removal lines, head spray and vent lines, core plate differential pressure lines, internal pump differential pressure lines, and water level instrumentation.

A venturi-type flow restrictor is a part of the reactor pressure vessel nozzle configuration for each steamline. These restrictors limit the flow of steam from the reactor vessel before the main steamline isolation valves are closed in case of a main steamline break outside the containment

Control rod drive housing supports are located internal to the reactor vessel and the control rod drive. The supports limit the travel of a control rod in the event that a control rod housing is ruptured.

The reactor vessel is designed and fabricated in accordance with applicable codes for a pressure of 1250 psig. The nominal operating pressure in the steam space above the separators is 1040 psia. The vessel is fabricated of low alloy steel and is clad internally with stainless steel or Ni-Cr-Fe Alloy (except for the top head, RIP motor casing, nozzles other than the steam outlet nozzle, and nozzle weld zones which are unclad).

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

1.2.2.2.2 Nuclear Boiler System

1.2.2.2.2.1 Main Steamline Isolation Valves

All pipelines that both penetrate the containment and offer a potential release path for radioactive material are provided with redundant isolation capabilities. Automatic isolation valves are provided in each main steamline. Each is powered by both steam pressure and spring force. These valves fulfill the following objectives:

(1) prevent excessive damage to the fuel barrier by limiting the loss of reactor coolant from the reactor vessel resulting from either a major leak from the steam piping outside the containment or a malfunction of the pressure control system resulting in excessive steam flow from the reactor vessel;

(2) limit the release of radioactive materials by isolating the reactor coolant pressure boundary in case of the detection of high steam line radiation.

1.2.2.2.2.2 Main Steamline Flow Instrumentation

The steam flow instrumentation is connected to the venturi type steam nozzle of the RPV. The instrumentation provides high nozzle flow isolation signals in case of a main steam line break.

1.2.2.2.2.3 Nuclear System Pressure Relief System

A pressure relief system consisting of safety/relief valves mounted on the main steamlines is provided to prevent excessive pressure inside the nuclear system as a result of operational transients or accidents.

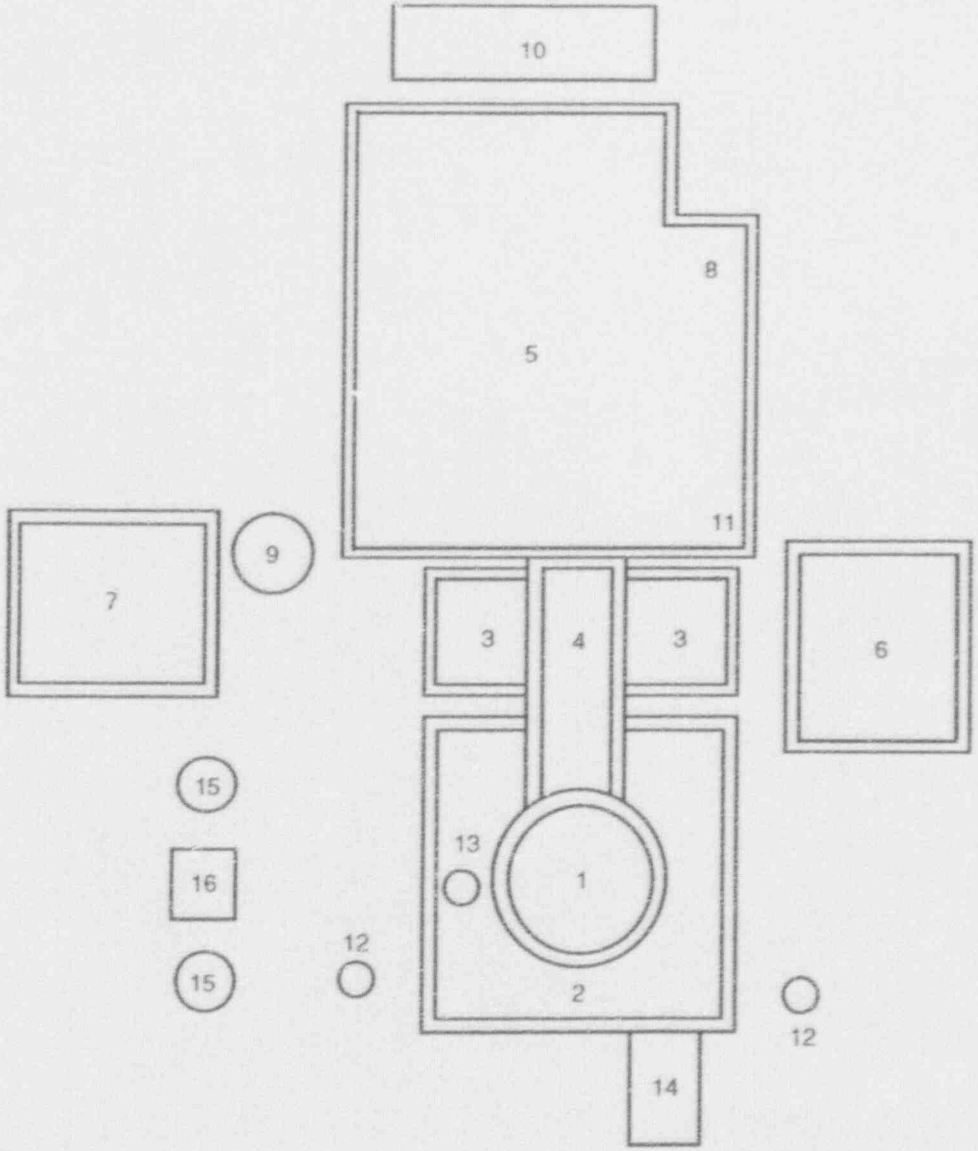
1.2.2.2.2.4 Automatic Depressurization System

The ADS rapidly reduces reactor vessel pressure in a loss-of-coolant accident, enabling the low-pressure RHR to deliver cooling water to the reactor vessel.

The ADS uses some of the safety relief valves that are part of the nuclear system pressure relief system. The safety relief valves used for ADS are set to open on detection of appropriate low reactor water level and high drywell pressure signals. The ADS will not be activated unless either RHR/low pressure flooding loop pump are operating. This is to ensure that adequate coolant will be available to maintain reactor water level after depressurization.

1.2.2.2.2.5 Reactor Vessel Instrumentation

In addition to instrumentation for the nuclear



NO.	FACILITY
1	REACTOR CONTAINMENT
2	REACTOR BUILDING
3	CONTROL BUILDING
4	MAIN STEAM/FEEDWATER TUNNEL
5	TURBINE BUILDING
6	SERVICE BUILDING
7	RADWASTE BUILDING
8	HOUSE BOILER
9	CONDENSATE STORAGE TANK
10	MAIN TRANSFORMER
11	NORMAL SWITCHGEAR
12	DIESEL OIL STORAGE TANK (3)
13	STACK
14	EQUIPMENT ENTRY LOCK
15	FIRE PROTECTION WATER STORAGE TANK (2)
16	FIRE PROTECTION PUMPHOUSE

FIGURE 1.2-1 SITE PLAN

GE PROPRIETARY INFORMATION - provided under separate cover
(Figures 1.2-23a through 1.2-23g, pages 1.2-39 through 1.2-45)

Figure	Page	Amendment
1.2-23a	1.2-39	21
1.2-23b	1.2-40	21
1.2-23c	1.2-41	21
1.2-23d	1.2-42	21
1.2-23e	1.2-43	21
1.2-23f	1.2-44	6
1.2-23g	1.2-45	6

TABLE 1.3-1

COMPARISON OF NUCLEAR STEAM SUPPLY SYSTEM DESIGN CHARACTERISTICS (Continued)

Design	This Plant* ABWR 278-872	GESSAR BWR/6 238-748	NMP-2 BWR/5 251-764	Grand Gulf BWR/6 251-800
Thermal and Hydraulic (Continued)				
Design power peaking factor				
Maximum relative assemble power	1.40	1.40	1.40	1.40
Local peaking factor	1.25	1.13	1.24	1.13
Axial peaking factor	1.40	1.40	1.40	1.40
Total peaking factor	2.43	2.26	2.43	2.26
Nuclear (first core) (Section 4.3)				
Water/UO_2 volume ratio (cold)	2.95	2.70	2.55	2.70
Reactivity with strongest control rod out (k_{eff})	<0.99	<0.99	<0.99	<0.99
Dynamic void coefficient (c/%) at core	-5.20c @ 102% rated output	-7.16	-8.57	-7.14
average voids (%) (EOC-rated output)	39.2	40.95	40.54	41.31
Fuel temperature doppler coefficient (c/^oC) (EOC-rated output)	-0.360	-0.412	-0.419	-0.396

Parameters for the core loading in Figure 4.3-1 used in the sensitivity analysis.

TABLE 1.3-1

COMPARISON OF NUCLEAR STEAM SUPPLY SYSTEM DESIGN CHARACTERISTICS (Continued)

Design	This Plant* ABWR 278-872	GESSAR BWR/6 238-748	NMP-2 BWR/5 251-764	Grand Gulf BWR/6 251-800
Core Assembly (Continued)				
Core diameter (equivalent) (in.)	203.3	185.2	160.2	191.5
Core height (active fuel) (in.)	146	150	146	150
Reactor Control System (Chapters 4 and 7)				
Method of variation of reactor power	Movable control rods and variable forced coolant flow	Movable control rods and variable forced coolant flow	Movable control rods and variable forced coolant flow	Movable control rods and variable forced coolant flow
Number of movable control rods	205	177	185	193
Shape of movable control rods	Cruciform	Cruciform	Cruciform	Cruciform
Pitch of movable control rods	12.2	12.0	12.0	12.0
Control material in movable rods	B_4C granules compacted in SS tubes	B_4C granules compacted in SS tubes	B_4C granules compacted in SS tubes	B_4C granules compacted in SS tubes

**Parameters for the core loading in Figure 4.3-1 used in the sensitivity analysis.*

Table 1.7-1

PIPING AND INSTRUMENTATION AND PROCESS FLOW DIAGRAMS

SSAR Fig. No.	Page No.	Title	Type
4.6-8	4.6-24	CRD System	P&ID
4.6-9	4.6-26	CRD System	PFD
5.1-3	5.1-5	Nuclear Boiler System	P&ID
5.4-4	5.4-47	Reactor Recirculation System	P&ID
5.4-5	5.4-48	Reactor Recirculation System	PFD
5.4-8	5.4-51	Reactor Core Isolation Cooling System	P&ID
5.4-9	5.4-53	Reactor Core Isolation Cooling System	PFD
5.4-10	5.4-55	Residual Heat Removal System	P&ID
5.4-11	5.4-59	Residual Heat Removal System	PFD
5.4-12	5.4-61	Reactor Water Clean-Up System	P&ID
5.4-13	5.4-63	Reactor Water Clean-Up System	PFD
6.2-39	6.2-90	Atmospheric Control System	P&ID
6.2-40	6.2-92	Flamibility Control System	P&ID
6.3-1	6.3-25	High Pressure Core Flooder System	PFD
6.3-7	6.3-33	High Pressure Core Flooder System	P&ID
6.5-1	6.5-13	Standby Gas Treatment System	P&ID
6.7-1	6.7-4	High Pressure Nitrogen Gas Supply System	P&ID
9.1-1	9.1-23	Fuel Pool Cooling and Cleanup System	P&ID
9.1-2	9.1-25	Fuel Pool Cooling and Cleanup System	PFD
9.2-1	9.2-26	Reactor Building Cooling Water System	P&ID
9.2-1A	9.2-34a	Reactor Building Cooling Water System	PFD

Table 1.7-1

PIPING AND INSTRUMENTATION AND PROCESS FLOW DIAGRAMS (Continued)

SSAR Fig. No.	Page No.	Title	Type
9.2-2	9.2-35	HVAC Normal Cooling Water System	P&ID
9.2-3	9.2-37	HVAC Emergency Cooling Water System	P&ID
9.2-4	9.2-39	Makeup Water System (Condensate)	P&ID
9.2-5	9.2-40	Makeup Water System (Purified)	P&ID
9.3-1	9.3-16	Standby Liquid Control System	P&ID
9.3-1A	9.3-16.1	Standby Liquid Control System	PFD
9.3-6	9.3-21	Instrument Air System	P&ID
9.3-7	9.3-22	Service Air System	P&ID
9.4-8	9.4-8	Drywell Cooling System	P&ID
9.5-1	9.5-11	Suppression Pool Cleanup System	P&ID

Table 1.7-4

CONVERSION TABLES-METRIC TO ASME STANDARD UNITS

Flow-Volume Per Unit Time

M^3/HR	GAL/MIN	M^3/HR	GAL/MIN	M^3/HR	GAL/MIN	M^3/HR	GAL/MIN
1	4.4	10	44	100	440	1000	4402
2	8.8	20	88	200	881	2000	8805
3	13.2	30	132	300	1321	3000	13207
4	17.6	40	176	400	1761	4000	17610
5	22.0	50	220	500	2201	5000	22012
6	26.4	60	264	600	2641	6000	26414
7	30.8	70	308	700	3082	7000	30817
8	35.2	80	352	800	3522	8000	35219
9	39.6	90	396	900	3962	9000	39621

Temperature

°C	°F	°C	°F	°C	°F	°C	°F
0.1	32.18	1	33.8	10	50	100	212
0.2	32.36	2	35.6	20	68	200	392
0.3	32.54	3	37.4	30	86	300	572
0.4	32.72	4	39.2	40	104	400	752
0.5	32.90	5	41.0	50	122	500	932
0.6	33.08	6	42.8	60	140	600	1112
0.7	33.26	7	44.6	70	158	700	1292
0.8	33.44	8	46.4	80	176	800	1472
0.9	33.62	9	48.2	90	194	900	1652

Pressure

Kg/Cm^2	PSI	Kg/Cm^2	PSI	Kg/Cm^2	PSI	Kg/Cm^2	PSI
0.01	0.142	0.1	1.422	1	14.22	10	142.2
0.02	0.285	0.2	2.845	2	28.45	20	284.5
0.03	0.427	0.3	4.267	3	42.67	30	426.7
0.04	0.569	0.4	5.689	4	56.89	40	568.9
0.05	0.711	0.5	7.11	5	71.11	50	711.1
0.06	0.853	0.6	8.534	6	85.34	80	853.4
0.07	0.996	0.7	9.956	7	99.56	70	995.6
0.08	1.138	0.8	11.378	8	113.78	80	1137.8
0.09	1.280	0.9	12.800	9	128.00	90	1280.0

Table 1.7-4

CONVERSION TABLES-METRIC TO ASME STANDARD UNITS (Continued)

Length

M	inch	M	Inch	M	Inch	M	Inch
0.001	0.004	0.1	0.039	1	3.28	10	32.81
0.002	0.008	0.2	0.079	2	6.56	20	65.62
0.003	0.012	0 3	0.118	3	9.84	30	98.43
0.004	0.016	0.4	0.157	4	13.12	40	131.2
0.005	0.020	0.5	0.197	5	16.40	50	164.0
0.006	0.024	0.6	0.236	6	19.69	60	196.9
0.007	0.028	0.7	0.276	7	22.97	70	229.7
0.008	0.032	0.8	0.315	8	26.25	80	262.5
0.009	0.035	0.9	0.354	9	29.53	90	295.3

TABLE 1.8-19

SRPs and BTPs Applicable To ABWR (Continued)

SRP No.		Appl. Rev.	Issued Date	ABWR Applicable?	Comments
10.4.4	Turbine Bypass System	2	7/81	Yes	
10.4.5	Circulating Water System	2	7/81	Yes	
10.4.6	Condensate Cleanup System	2	7/81	Yes	
10.4.7	Condensate and Feedwater System	3	4/84	Yes	
	BTP ASB 10-2	3	4/84	Yes	
10.4.8	Steam Generator Blowdown System (PWR)	2	7/81	No	PWR only
10.4.9	Auxiliary Feedwater System (PWR)	2	7/81	No	PWR only
	BTP ASB 10-1	2	7/81	No	PWR only
	Chapter 11 Radioactive Waste Management				
11.1	Source Terms	2	7/81	Yes	
11.2	Liquid Waste Management Systems	2	7/81	Yes	
11.3	Gaseous Waste Management Systems	2	7/81	Yes	
	BTP ETSB 11-5	0	7/81	No	
11.4	Solid Waste Management Systems	2	7/81	Yes	
	BTP ETSB 11-3	2	7/81	Yes	
	Appendix 11.4-A	0	7/81	Yes	
11.5	Process and Effluent Radiological Monitoring Instrumentation and Sampling Systems	3	7/81	Yes	
	Appendix 11.5-A	1	7/81	Yes	
	Chapter 12 Radiation Protection				
12.1	Assuring That Occupational Radiation Exposures are As Low As Is Reasonably Achievable	2	7/81	Yes	

TABLE 1.8-19

SRPs and BTPs Applicable To ABWR
(Continued)

SRP No.		Appl. Rev.	Issued Date	ABWR Applicable?	Comments
12.2	Radiation Sources	2	7/81	Yes	
12.3 -- 12.4	Radiation Protection Design Features	2	7/81	Yes	
12.5	Operational Radiation Protection Program	2	7/81	--	Interface
	Chapter 13 Conduct of Operations				
13.1.1	Management and Technical Support Organization	2	7/81	--	Interface
13.1.2 - 13.1.3	Operating Organization	2	7/81	--	Interface
13.2	Training (Replaced by SRP Sections 13.2.1 and 13.2.2)				
13.2.1	Reactor Operator Training	0	7/81	--	Interface
13.2.2	Training For Non-Licensed Plant Staff	0	7/81	--	Interface
13.3	Emergency Planning	2	7/81	--	Interface
13.4	Operational Review	2	7/81	--	Interface
13.5	Plant Procedures (Replaced by SRP Sections 13.5.1 and 13.5.2)				
13.5.1	Administration Procedures	0	7/81	--	Interface
13.5.2	Operating and Maintenance Procedures	1	7/85	--	Interface
	Appendix A	0	7/85	--	Interface
13.6	Physical Security	2	7/81	Yes	ABWR and Interface
	Chapter 14 Initial Test Program				
14.1	Initial Plant Test Programs - PSAR (Deleted)				
14.2	Initial Plant Test Programs - FSAR	2	7/81	Yes	
14.3	Standard Plant Design, Initial Test Program - Final Design Approval (FDA) (Deleted)				

TABLE 1.8-20

RGs Applicable to ABWR (Continued)

RG No.	Regulatory Guide Title	Appl. Rev.	Issued Date	ABWR Appli-cable?	Comments
1.60	Design Response Spectra for Seismic Design of Nuclear Power Plants.	1	12/73	Yes	
1.61	Damping Values for Seismic Design of Nuclear Power Plants.	0	10/73	Yes	
1.62	Manual Initiation of Protective Actions.	0	10/73	Yes	
1.63	Electric Penetration Assemblies in Containment Structures of Nuclear Power Plants.	3	2/87	Yes	
1.64	Quality Assurance Requirements for the Design of Nuclear Power Plants.		Superceded		See Table 17.0-1
1.65	Materials and Inspections for Reactor Vessel Closure Studs.	0	10/73	Yes	
1.68	Initial Test Programs for Water-Cooled Reactor Power Plants.	2	8/78	Yes	
1.68.1	Preoperational and Initial Startup Testing of Feedwater and Condensate Systems for Boiling Water Reactor Power Plants.	1	1/77	Yes	
1.68.2	Initial Startup Test Program to Demonstrate Remote Shutdown Capability for Water-Cooled Nuclear Power Plants.	1	7/78	Yes	
1.68.3	Preoperational Testing of Instrument and Control Air Systems.	0	4/82	Yes	
1.69	Concrete Radiation Shields for Nuclear Power Plants.	0	12/73	Yes	
1.70	Standard Format and Content of Safety Analysis Reports for Nuclear Power Plants.	3	11/78	Yes	
1.71	Welder Qualifications for Areas of Limited Accessibility.	0	12/73	---	Interface
1.72	Spray Pond Piping Made From Fiberglass-Reinforced Thermosetting Resin.	2	11/78	Yes	

TABLE 1.8-20

RGs Applicable to ABWR (Continued)

RG No.	Regulatory Guide Title	Appl. Rev.	Issued Date	ABWR Appli-cable?	Comments
1.73	Qualification Tests of Electric Valve Operators Installed Inside the Containment of Nuclear Power Plants.	0	1/74	Yes	
1.74	Quality Assurance Terms and Definitions.		Superceded		See Table 17.0-1
1.75	Physical Independence of Electric Systems.	2	9/78	Yes	
1.76	Design Basis Tornado for Nuclear Power Plants	0	4/74	Yes	
1.77	Assumptions Used for Evaluating a Control Rod Ejection Accident for Pressurized Water Reactors.	0	5/74	No	PWR only
1.78	Assumptions for Evaluating the Habitability of a Nuclear Power Plant Control Room During a Postulated Hazardous Chemical Release.	0	6/74	Yes	
1.79	Preoperational Testing of Emergency Core Cooling Systems for Pressurized Water Reactors.	1	9/75	No	PWR only
1.81	Shared Emergency and Shutdown Electric Systems for Multi-Unit Power Plants.	1	1/75	Yes	
1.82	Water Sources for Long-Term Recirculation Cooling Following Loss-of-Coolant Accident.	1	11/85	Yes	
1.83	In-Service Inspection of Pressurized Water Reactor Steam Generator Tubes.	1	7/75	No	PWR only
1.84	Design and Fabrication Code Case Acceptability, ASME Section III, Division 1.	27	11/90	Yes	
1.85	Materials Code Case Acceptability, ASME Section III, Division 1.	27	11/90	Yes	
1.86	Termination of Operating Licenses for Nuclear Reactors.	0	6/74	----	Interface

TABLE 1.8-21 (Continued)

INDUSTRIAL CODES AND STANDARDS APPLICABLE TO ABWR

Code or Standard Number	Year	Title
N45.2.5	1974	Supplementary Quality Assurance Requirements for Installation, Inspection, and Testing of Structural Concrete and Structural Steel During the Construction Phase of Nuclear Power Plants
N45.2.8* (RG 1.116)	1976	Quality Assurance Requirements for Installation, Inspection, and Testing of Mechanical Equipment and Systems
N509	1980	Nuclear Power Plant Air Cleaning Units and Components
N510	1980	Testing of Nuclear Air-Cleaning Systems
N101.2	1972	Protective Coatings (Paints) for Light Water Nuclear Containment Facilities
N101.4	1972	QA for Protective Coatings Applied to Nuclear Facilities
N195		(See ANS 59.51)
N237		(See ANS 18.1

* As modified by NRC accepted alternate positions to the related Regulatory Guide and identified in Table 2-1 of Reference 1 to Chapter 17.

1A.2.25 Report on Outages of Emergency Core-Cooling Systems Licensee Report and Proposed Technical Specification Changes [II.K.3(17)]

NRC Position

Several components of the emergency core cooling (ECC) systems are permitted by technical specifications to have substantial outage times (e.g., 72 hours for one diesel-generator; 14 days for the HPCI system). In addition, there are no cumulative outage time limitations for ECC systems. Licensees should submit a report detailing outage dates and lengths of outages for all ECC systems for the last 5 years of operation. The report should also include the causes of the outages (i.e., controller failure, spurious isolation).

Clarification

The present technical specifications contain limits on allowable outage times for ECC systems and components. However, there are no culative outage time limitations on these same systems. It is possible that ECC equipment could meet present technical specification requirements but have a high unavailability because of frequent outages within the allowable technical specifications.

The licensees should submit a report detailing outage dates and length of outages for all ECC systems for the last 5 years of operation, including causes of the outages. This report will provide the staff with a quantification of historical unreliability due to test and maintenance outages, which will be requirements in the technical specifications.

Based on the above guidance and clarification, a detailed report should be submitted. The report should contain (1) outage dates and duration of outages; (2) causes of the outage; (3) ECC systems or components involved in the outage; and (4) corrective action taken. Tests and maintenance outages should be included in the above listings which are to cover the last 5 years of operation. The licensee should propose changes to improve the availability of ECC equipment, if needed.

Applicants for an operating license shall establish a plan to meet these requirements.

Response

See Subsection 1A.3.5 for Interface Requirements

1A.2.26 Modification of Automatic De-Pressurization System Logic - Feasibility for Increased Diversity for Some Event Sequences [II.K.3(18)]

NRC Position

The automatic depressurization system (ADS) actuation logic should be modified to eliminate the need for manual actuation to assure adequate core cooling. A feasibility and risk assessment study is required to determine the optimum approach. One possible scheme that should be considered is ADS actuation on low reactor-vessel water level provided no high-pressure coolant injection (HPCI) or high-pressure coolant system (HPCS) flow exists and a low-pressure emergency core cooling (ECC) system is running. This logic would complement, not replace, the existing ADS actuation logic.

Response

An 8 minute high drywell pressure bypass timer has been added to the ADS initiation logic to address TMI action item II.K.3.18. This timer will initiate on a Low Water Level 1 signal. When it times out, it bypasses the need for a high drywell signal to initiate the standard ADS initiation logic.

For all LOCAs inside the containment, a high drywell signal will be present and ADS will actaute 29 seconds after a Low Water Level 1 signal is reached. All LOCAs outside the containment become rapidly isolated and any one of the three high pressure ECCS can control the water level. The high drywell pressure bypass timer in the ADS initiation logic will only affect the LOCA response if all high pressure ECCs fail following a break outside the containment. For this case the ADS will automatically initaite within 509 seconds (8 minute timer plus 29 second standard ADS logic delay) following a Low Water Level 1 signal.

TABLE 2.0-1

ENVELOPE OF ABWR STANDARD PLANT SITE DESIGN PARAMETERS

Maximum Ground Water Level:
2 feet below grade

Maximum Flood (or Tsunami) Level:[(3)]
1 foot below grade

Precipitation (for Roof Design):
- Maximum rainfall rate: 19.4 in/hr[(8)]
- Maximum snow load: 50 lb/sq. ft.

Design Temperatures:
- Ambient

  1% Exceedance Values
  - Maximum: 100^{O}F dry bulb/77^{O}F coincident wet bulb
  - Minimum: -10^{O}F

  0% Exceedance Values (Historical limit)
  - Maximum: 115^{O}F dry bulb/82^{O}F coincident wet bulb
  - Minimum: -40^{O}F
- Emergency Cooling Water Inlet: 95^{O}F
- Condenser Cooling Water Inlet : ≤100OF

Extreme Wind: Basic Wind Speed:
110mph[(1)]/130mph[(2)]

Tornado:[(4)]
- Maximum tornado wind speed: 300mph
- Translational velocity: 60mph
- Radius: 150 ft
- Maximum atm VP: 2.0 psid
- Missile Spectra: Per SRP 3.5.1.4 Spectrum 1

Soil Properties:
- Minimum Bearing Capacity (demand): 15ksf
- Minimum Shear Wave Velocity: 1000fps[(9)]
- Liquification Potential:
  None at plant site resulting from OBE and SSE[(7)] 421.1c

Seismology:
- OBE Peak Ground Acceleration (PGA): 0.10g[(5) (6)]
- SSE PGA : 0.30g[(5)]
- SSE Response Spectra: per Reg.Guide 1.60
- SSE Time History: Envelope SSE Response Spectra

---

(1) *50-year recurrence interval; value to be utilized for design of non-safety-related structures only.*

(2) *100-year recurrence interval; value to be utilized for design for safety-related structures only.*

(3) *Probable maximum flood level (PMF), as defined in ANSI/ANS-2.8, "Determining Design Basis Flooding at Power Reactor Sites."*

(4) *10,000,000-year tornado recurrence interval.*

(5) *Free-field, at plant grade elevation.*

(6) *For conservatism, a value of 0.15g is employed to evaluate structural and component responses in Chapter 3.*

(7) *See item 3 in Section 3A.1 for additional information.* 241.1c

(8) *Maximum value for 1 hour 1 sq. mile PMP with ratio of 5 minutes to 1 hour PMP as found in National Weather Source Publication HMR No. 52. Maximum short term rate; 6.2in/5min.*

(9) *This is the minimum shear wave velocity at low storms after the soil property uncertainties have been applied.*

CHAPTER 3

TABLE OF CONTENTS (Continued)

TABLE 3.2-1

CLASSIFICATION SUMMARY

The classification information is presented by System *** in the following order:

Table 3.2-1 Item No.	MPL Number**	Title
B		Nuclear Boiler Supply System
B1	B11	Reactor Pressure Vessel System*
B2	B21	Nuclear Boiler System*
B3	B31	Reactor Recirculation System
C		Control and Instrument Systems
C1	C11	Rod Control and Information System
C2	C12	Control Rod Drive System
C3	C31	Feedwater Control System
C4	C41	Standby Liquid Control System
C5	C51	Neutron Monitoring System*
C6	C61	Remote Shutdown System
C7	C71	Reactor Protection System*
C8	C81	Recirculation Flow Control System
C9	C82	Automatic Power Regulator System
C10	C85	Steam Bypass and Pressure Control System
C11	C91	Process Computer (Includes PMCS and PGCS)
C12	C93	Refueling Platform Control Computer
C13	C94	CRD Removal Machine Control Computer
D		Radiation Monitoring Systems
D1	D11	Process Radiation Monitoring* System
D2	D21	Area Radiation Monitoring System
D3	D23	Containment Atmospheric Monitoring System*
E		Core Cooling Systems
E1	E11	Residual Heat Removal System*
E2	E22	High Pressure Core Flooder System*

* *These systems or subsystems thereof, have a primary function that is safety-related. As shown in the balance of this Table, some of these systems contain non-safety related components and, conversely, some systems whose primary functions are non-safety related contain components that have been designated safety-related.*

** *Master Parts List Number designated for the system*

*** *Only those systems that are in the ABWR Standard Plant scope are included in this table.*

TABLE 3.2-1

CLASSIFICATION SUMMARY (Continued)

Table 3.2-1 Item No.	MPL Number**	Title
E		Core Cooling Systems (Continued)
E3	E31	Leak Detection and Isolation System*
E4	E51	Reactor Core Isolation Cooling System*
F		Reactor Servicing Equipment
F1	F11	Fuel Servicing Equipment
F2	F12	Miscellaneous Servicing Equipment
F3	F13	RPV Servicing Equipment
F4	F14	RPV Internal Servicing Equipment
F5	F15	Refueling Equipment
F6	F16	Fuel Storage Facility
F7	F17	Under-Vessel Servicing Equipment
F8	F21	CRD Maintenance Facility
F9	F22	Internal Pump Maintenance Facility
F10	F32	Fuel Cask Cleaning Facility
F11	F41	Plant Start-up Test Facility
F12	F51	Inservice Inspection Equipment
G		Reactor Auxiliary Systems
G1	G31	Reactor Water Cleanup System
G2	G41	Fuel Pool Cooling and Cleanup System
G3	G51	Suppression Pool Cleanup System
H		Control Panels
H1	H11	Main Control Room Panels*
H2	H12	Control Room Back Panels*
H3	H14	Radioactive Waste Control Panels
H4	H21	Local Control Panels*
H5	H22	Instrument Racks
H6	H23	Mutiplexing System
H7	H25	Local Control Boxes

* *These systems or subsystems thereof have a primary function that is safety-related. As shown in the balance of this Table, some of these systems contain non-safety related components and, conversely, some systems whose primary functions are non-safety related contain components that have been designated safety-related.*

** *Master Parts List Number designated for the system*

TABLE 3.2-1

CLASSIFICATION SUMMARY (Continued)

Table 3.2-1 Item No.	MPL Number**	Title
J	**Nuclear Fuel**	
J1	J11	Nuclear Fuel
J2	J12	Fuel Channel
K	**Radioactive Waste System**	
K1	K17	Radwaste System
N	**Power Cycle Systems**	
N1	N11	Turbine Main Steam System
N2	N21	Condensate, Feedwater and Condensate Air Extraction System
N3	N22	Heater, Drain and Vent System
N4	N25	Condensate Purification System
N5	N26	Condensate Filter Facility
N6	N27	Condensate Demineralizer
N7	N31	Main Turbine
N8	N32	Turbine Control Syste
N9	N33	Turbine Gland Steam System
N10	N34	Turbine Lubricating Oil System
N11	N35	Moisture Separator Heater
N12	N36	Extraction System
N13	N37	Turbine Bypass System
N14	N38	Reactor Feedwater Pump Driver
N15	N39	Turbine Auxiliary Steam System
N16	N41	Generator
N17	N42	Hydrogen Gas Cooling System
N18	N43	Generator Cooling System
N19	N44	Generator Sealing Oil System
N20	N51	Exciter
N21	N61	Main Condenser
N22	N62	Offgas System
N23	N71	Circulating Water System
N24	N72	Condenser Cleanup System
P	**Station Auxilairy Systems**	
P1	P11	Make Water System (Purified)
P2	P13	Makeup Water System (Condensate)

* *These systems or subsystems thereof, have a primary function that is safety-related. As shown in the balance of this Table, some of these systems contain non-safety related components and, conversely, some systems whose primary functions are non-safety related contain components that have been designated safety-related.*

** *Master Parts List Number designated for the system*

TABLE 3.2-1

CLASSIFICATION SUMMARY (Continued)

Table 3.2-1 Item No.	MPL Number**	Title
P	Station Auxiliary Systems (Continued)	
P3	P21	Reactor Building Cooling Water System*
P4	P22	Turbine Building Cooling Water System
P5	P24	HVAC Normal Cooling Water System
P6	P25	HVAC Emergency Cooling Water System
P7	P32	Oxygen Injection System
P8	P40	Ultimate Heat Sink
P9	P41	Reactor Service Water System
P10	P42	Turbine Service Water System
P11	P51	Station Instrument Air System
P12	P52	Instrument Air System
P13	P54	High Pressure Nitrogen Gas Supply System
P14	P61	Heating Steam and Condensate Water Return System
P15	P62	House Boiler
P16	P63	Hot Water Heating System
P17	P73	Hydrogen Water Chemistry System
P18	P74	Zinc Injection System
P19	P81	Breathing Air System
P20	P91	Sampling System (Includes PASS)
P21	P92	Freeze Protection System
P22	P95	Iron Injection System
R	Station Electrical Systems	
R1	R10	Electrical Power Distribution System
R2	R11	Unit Auxiliary Transformer
R3	R13	Isolated Phase Bus
R4	R21	Non-Segreated Phase Bus
R5	R22	Metalclad Switchgear
R6	R23	Power Center
R7	R24	Motor Control Center
R8	R31	Raceway System
R9	R34	Grounding Wire
R10	R35	Electrical Wiring Penetration

* *These systems or subsystems thereof, have a primary function that is safety-related. As shown in the balance of this Table, some of these systems contain non-safety related components and, conversely, some systems whose primary functions are non-safety related contain components that have been designated safety-related.*

** *Master Parts List Number designated for the system*

TABLE 3.2-1

CLASSIFICATION SUMMARY (Continued)

Table 3.2-1 Item No.	MPL Number**	Title
R		Station Electrical Systems (Continued)
R11	R40	Combustion Turbine Gnererator
R12	R42	Direct Current Power Supply*
R13	R43	Emeregncy Diesel Generator System*
R14	R46	Vital AC Power Supply
R15	R47	Instrument and Controol Power Supply
R16	R51	Communication System
R17	R52	Lighting and Servicing Power Supply
S		Power Transmission Systems
S1	S12	Reserve Transformer
T		Containment and Environmental Control Systems
T1	T11	Primary Containment System
T2	T12	Containment Internal Structures
T3	T13	Reactor Pressure Vessel Pedestal
T4	T22	Standby Gas Treatment System*
T5	T25	PCV Pressure and Leak Testing Facility
T6	T31	Atmospheric Control System
T7	T41	Drywell Cooling System
T8	T49	Flammability Control System
T9	T53	Suppression Pool Temperature Monitoring System*
U		Structures and Servicing Systems
U1	U21	Foundation Work
U2	U24	Turbine Pedestal
U3	U31	Cranes and Hoists
U4	U32	Elevator
U5	U41	Heating, Ventilating and Air Conditioning*
U6	U43	Fire Protection System
U7	U46	Floor Leakage Detection System
U8	U47	Vacuum Sweep System

* *These systems or subsystems thereof, have a primary function that is safety-related. As shown in the balance of this Table, some of these systems contain non-safety related components and, conversely, some systems whose primary functions are non-safety related contain components that have been designated safety-related.*

** *Master Parts List Number designated for the system*

TABLE 3.2-1

CLASSIFICATION SUMMARY (Continued)

Table 3.2-1 Item No.	MPL Number**	Title
U	Structures and Servicing Systems (Continued)	
U9	U48	Decontamination System
U10	U71	Reactor Building*
U11	U72	Turbine Building*
U12	U73	Control Building*
U13	U74	Radwaste Building
U14	U75	Service Building
Y	Yard Structures and Equipment	
Y1	Y31	Stack
Y2	Y52	Oil Storage and Transfer System
Y3	Y86	Site Security

* *These systems or subsystems thereof, have a primary function that is safety-related. As shown in the balance of this Table, some of these systems contain non-safety related components and, conversely, some systems whose primary functions are non-safety related contain components that have been designated safety-related.*

** *Master Parts List Number designated for the system*

TABLE 3.2-1

CLASSIFICATION SUMMARY (Continued)

Principal Component[a]	Safety Class[b]	Location[c]	Quality Group Classification[d]	Quality Assurance Requirement[e]	Seismic Category[f]	Notes	
B2 Nuclear Boiler System (Continued)							
4. Piping including supports main steamline (MSL) and feedwater (FW) line up to and including the outermost isolation valve	1	C,SC	A	B	I		210.20
5. Piping including supports-MSL from outermost isolation valve to and including seismic interface restraint and FW from outermost isolation valve to the shutoff valve	2	SC	B	B	I		210.20
6. Piping including supports-MSL from the seismic interface restraint to the turbine stop valve	N	SC,T	B	B	---	(r)	210.20; 210.6 210.7 260.4
7. Piping from FW shutoff valve to seismic interface restraint	3	SC	C	B	I		210.20; 260.4
8. Deleted							210.20
9. Deleted							
10. Pipe whip restraint - MSL/FW if needed	3	SC,C	---	B	---	(dd)	
11. Piping including supports-other within outermost isolation valves							210.20
a. RPV head vent	1	C	A	B	I	(g)	
b. Main steam drains	1	C,SC	A	B	I	(g)	
12. Piping including supports-other beyond outermost isolation or shutoff valves							210.20
a. RPV head vent beyond shutoff valves	N	C	C	E	---		260.4
b. Main steam drains	N	SC	B/D	B	I/---	(r)	260.4

TABLE 3.2-1

CLASSIFICATION SUMMARY (Continued)

Principal Component[a]	Safety Class[b]	Location[c]	Quality Group Classification[d]	Quality Assurance Requirement[e]	Seismic Category[f]	Notes
B2 Nuclear Boiler System (Continued)						
13. Piping including supports-instrumentation up to and beyond outermost isolation valves	2/N	C,SC	B/D	B/E	I/---	(g)
14. Safety/relief valves	1	C	A	B	I	
15. Valves - MSL and FW isolation valves, and other FW valves within containment	1	C,M	A	B	I	
16. Valves - FW, other beyond outermost isolation valves up to and including shutoff valves	2	SC	B	B	I	
17. Valves - within outermost isolation valves						
a. RPV head vent	1	C	A	B	I	(g)
b. Main steam drains	1	C,SC	A	B	I	(g)
18. Valves, other						
a. RPV head vent	3	C	C	B	I	
b. Main steam drain	N	SC	C	B	---	
19. Deleted						
20. Mechanical modules-instrumentation with safety-related function	3	C,SC	---	B	I	
21. Electrical modules with safety-related function	3	C,SC,X	---	B	I	(i)
22. Cable with safety-related function	3	C,SC,X	---	B	I	

210.20
260.4

TABLE 3.2-1

CLASSIFICATION SUMMARY (Continued)

Principal Component[a]	Safety Class[b]	Location[c]	Quality Group Classification[d]	Quality Assurance Requirement[e]	Seismic Category[f]	Notes	
B3 Reactor Recirculation System							
1. Piping-Purge System, heat exchanger and primary side of recirculation motor cooling system (RMCS)	3	C	C	B	I	(s)	210.8 210.19
2. Pipe Supports	3	C	C	B	I		
3. Pump motor cover and hardware	2	C	B	B	I		
4. Pump non-pressure retaining parts including motor, instruments, electrical cables and seals	N	C	---	E	---		260.4
5. Valves	3	C	C	B	I	(g)	
6. ATWS equipment associated with the pump trip function	N	C	---	E	---	(cc)	260.4
C1 Rod Control and Information System							
1. Electrical Modules	N	RZ,X	D	E	---		
2. Cable	N	SC,RZ,X	D	E	---		
C2 CRD System							
1. Valves with no safety related function (not part of HCU)	N	SC	D	E	---		
210.20 2. Piping including supports-insert line	2	C,SC	B	B	I	(j)	
3. Piping-other (pump suction, pump discharge, drive header)	N	SC	D	E	---	(g)	260.4
4. Hydraulic control unit	2	SC	---	B	I	(k)	
5. Fine motion drive motor	N	C	--	E	---		260.4

TABLE 3.2-1

CLASSIFICATION SUMMARY (Continued)

		Principal Component[a]	Safety Class[b]	Location[c]	Quality Group Classification[d]	Quality Assurance Requirement[e]	Seismic Category[f]	Notes
	E4	RCIC System (Continued)						
260.4		4. RCIC Pump and piping including support, CST suction line from the first RCIC motorized valve, S/P suction line to the pump, discharge line up to the FW line "B" thermal sleeve	2	SC	B	B	I	(g)
260.4		5. Pump motors	N	SC	---	E	I	
		6. Valves - outer isolation and within	1/2	C,SC	A/B	B	I	(g)
260.4		7. Valves - outside the PCV*	2	SC	B	B	I	(g)
		8. Valves - beyond turbine inlet second shutoff	3	SC	C	B	I	(g)
260.4		9. Turbine including supports	2	SC	---	B	I	(m)
		10. Electrical modules with safety-related function	3	C,SC,X	---	B	I	
		11. Cable with safety function	3	C,SC,X	---	B	I	
		12. Other mechanical and electrical modules	N	SC,X	---	E	---	
260.4	F1	**Fuel Servicing Equipment**	N/2	SC	---	E	---	
	F2	**Miscellaneous Servicing Equipment**	N	SC,RZ	---	E	---	

* *Except item 8.*

TABLE 3.2-1

CLASSIFICATION SUMMARY (Continued)

	Principal Component[a]	Safety Class[b]	Location[c]	Quality Group Classification[d]	Quality Assurance Requirement[e]	Seismic Category[f]	Notes	
F3	**RPV Servicing Equipment**	N/2	SC	---	E	---		
F4	**RPV Internal Servicing Equipment**	N	SC	---	E	---		
F5	**Refueling Equipment**							
	1. Refueling equipment platform assembly	N	SC	---	E	I	(bb)	260.4 210.13 430.198a
	2. Refueling bellows	N	SC	---	E	---		
F6	**Fuel Storage Equipment**							
	1. Fuel storage racks - new and spent	N	SC	---	E	I	(bb)	210.15
	2. Defective fuel storage	N	SC	---	E	---	(bb)	
	3. Spent fuel pool liner	N	SC	---	E	I		
F7	**Under-Vessel Servicing Equipment**	N	SC	---	E	---	(bb)	
F8	**CRD Maintenance Facility**	N	SC	---	E	---		
F9	**Internal Pump Maintenance Facility**	N	SC	---	E	---		
F10	**Fuel Cask Cleaning Facility**	N	SC	---	E	---		
F11	**Plant Start-up Test Equipment**	N	M	---	E	---		

TABLE 3.2-1

CLASSIFICATION SUMMARY (Continued)

	Principal Component[a]	Safety Class[b]	Location[c]	Quality Group Classification[d]	Quality Assurance Requirement[e]	Seismic Category[f]	Notes
K1	**Radwaste System**						
	1. Drain piping including supports and valves - radioactive	N	ALL (except RZ,X)	D	E	--	(p)
	2. Drain piping including supports and valves - nonradioactive	N	ALL	D	E	---	(p)
	3. Piping and valves - containment isolation	2	C,SC	B	B	I	
	4. Piping including supports and valves forming part of containment boundary	N	C,SC	B	B	I	
	5. Pressure vessels including supports	N	W	---	E	---	(p)
	6. Atmospheric tanks including supports	N	C,SC,H, T,W	---	E	---	(p)
	7. 0-15 PSIG Tanks and supports	N	W	---	E	---	(p)
	8. Heat exchangers and supports	N	C,SC,W	---	E	---	(p)
	9. Piping including supports and valves	N	C,SC,H, T,W	---	E	---	(p)
	10. Other mechanical and electrical modules	N	ALL	--- E	---	(p)	
	11. ECCS equipment room sump backflow protection check valves	3	SC	C	B	I	
N1	**Turbine Main Steam System**						
	1. Deleted						

TABLE 3.2-1

CLASSIFICATION SUMMARY (Continued)

	Principal Component[a]	Safety Class[b]	Location[c]	Quality Group Classification[d]	Quality Assurance Requirement[e]	Seismic Category[f]	Notes
N1	**Turbine Main Steam System** (Continued)						
	2. Branch line of MSL including supports between the second isolation valve and the turbine stop valve from branch point at MSL to and including the first valve in the branch line	N	SC,T	B	B	---	(r)
N2	**Condensate, Feedwater and Condensate Air Extraction System**						
	1. Main feedwater line (MFL) including supports from second isolation valve branch lines and components beyond up to outboard shutoff valves	N	SC	B	B	I	
260.4	2. Feedwater system components beyond outboard shutoff valve	N	T	D	E	---	
N3	**Heater, Drain and Vent System**	N	T	---	E	---	
N4	**Condensate Purification System**	N	T	---	E	---	
N5	**Condensate Filter Facility**	N	T	---	E	---	
N6	**Condensate Demineralizer**	N	T	---	E	---	
N7	**Main Turbine**	N	T	---	E	---	
N8	**Turbine Control System**						
	1. Turbine stop valve, turbine bypass valves, and the main steam leads from the turbine control valve to the turbine casing	N	T	D	E	---	(1)(n)(o)

TABLE 3.2-1

CLASSIFICATION SUMMARY (Continued)

Principal Component[a]	Safety Class[b]	Location[c]	Quality Group Classification[d]	Quality Assurance Requirement[e]	Seismic Category[f]	Notes
N9 Turbine Gland Steam System	N	T	D	E	---	
N10 Turbine Lubricating Oil System	N	T	---	E	---	
N11 Moisture Separator Heater	N	T	---	E	---	
N12 Extraction System	N	T	---	E	---	
N13 Turbine Bypass System						
1. Turbine bypass piping including supports up to the turbine bypass valve	N	T	D	E	---	
N14 Reactor Feedwater Pump Driver	N	T	---	E	---	
N15 Turbine Auxiliary Steam System	N	T	---	E	----	
N16 Generator	N	T	---	E	---	
N17 Hydrogen Gas Cooling System	N	T	---	E	---	
N18 Generator Cooling System	N	T	---	E	---	
N19 Generator Sealing Oil System	N	T	---	E	---	
N20 Exciter	N	T	---	E	---	
N21 Main Condenser	N	T	---	E	---	
N22 Offgas System	N	T	---	E	---	
N23 Circulating Water System	N	T	D	E	---	
N24 Condenser Cleanup Facility	N	T	---	E	---	

TABLE 3.2-1

CLASSIFICATION SUMMARY (Continued)

	Principal Component[a]	Safety Class[b]	Location[c]	Quality Group Classification[d]	Quality Assurance Requirement[e]	Seismic Category[f]	Notes	
	P1 Makeup Water System (Purified)							
	1. Piping including supports and valves forming part of thew containment boundary	2	C	B	B	I		
	2. Demineralizer water storage tank including supports	N	O	D	E	---		260.4
	3. Demineralizer water header-piping including supports and valves	2	SC	B	B	I		
	4. Piping including supports and valves	N	O	D	E	---		
	5. Other components	N	O	D	E	---		260.4
	P2 Makeup Water System (Condensate)							
	1. Condensate storage tank including supports	N	O	D	E	---	(w)	
210.20	2. Condensate header - piping including supports, level instrumentation and valves	2	SC	B	B	I		
	3. Piping including supports and valves and other components	N	O	D	E	---		260.4
	P3 Reactor Building Cooling Water System							
210.20	1. Piping and valves forming part of primary containment boundary	2	SC,C	B	B	I	(g)	
	2. Other safety-related piping, including supports, pumps and valves	3	SC,C	C	B	I		

TABLE 3.2-1

CLASSIFICATION SUMMARY (Continued)

Principal Component[a]	Safety Class[b]	Location[c]	Quality Group Classification[d]	Quality Assurance Requirement[e]	Seismic Category[f]	Notes
U5 Heating, Ventilating, and Air Conditioning Systems* (Continued)						
g. Valves and Dampers-secondary containment isolation	2	SC,RZ	---	B	I	
h. Other safety-related valves and dampers	3	H,Z	---	B	I	
i. Electrical modules with safety-related function	3	SC,RZ H,X	---	B	I	
j. Cable with safety-related function	3	SC,RZ H,X	---	B	I	
2. Non-safety related equipment**						
a. HVAC mechanical or electrical components with non-safety related functions	N	SC,RZ,H X,W,T	---	E	---	260.4
U6 Fire Protection System						
210.20 1. Piping including supports and valves forming part of the primary containment boundary	2	C	B	B	I	
2. Other piping including supports and valves	N	SC,C,X RZ,H,T, W,O	D	E	---	(t) (u) 260.4
3. Pumps	N	F	D	E	---	(t) (u)
4. Pump motors	N	F	---	E	---	(t) (u)

* *Includes thermal and radiological environmental control functions within the ABWR Standard Plant scope.*

** *Controls environment in rooms or areas containing non-safety related equipment within the ABWR Standard Plant.*

TABLE 3.2-1

CLASSIFICATION SUMMARY (Continued)

Principal Component[a]	Safety Class[b]	Location[c]	Quality Group Classification[d]	Quality Assurance Requirement[e]	Seismic Category[f]	Notes	
U6 Fire Protection System (Continued)							
5. Electrical Modules	N	C,SC,X RZ,H, T,W	---	E	---	(t) (u)	
6. CO_2 actuation modules	N	RZ	---	E	---	(t) (u)	260.4
7. Cables	N	SC,C,X	---	E	---	(t) (u)	
8. Sprinklers or deluge water	N	H,W,SC, X,RZ,T	D	E	---	(t) (u)	
9. Foam, preaction or deluge	N	RZ,T	---	E	---	(t) (u)	
U7 Floor Leakage Detection System	N	SC,RZ	---	E	---		
U8 Vacuum Sweep System	N	C,SC	---	E	---		
U9 Decontamination System	N	C,SC,RZ T,W,S,X	---	E	---		
U10 Reactor Building	3	SC,RZ	---	B	I		
U11 Turbine Building	N	T	---	E	---	(v)(ee)	260.4
U12 Control Building	3	X	---	B	I		
U13 Radwaste Building	N	W	---	E	---		260.4
1. Radwaste Building Substructure	3	W	---	B	I		
U14 Service Building	N	H	---	E	---		260.4
Y1 Stack	3	RZ	---	E	I		
Y2 Oil Storage and Transfer System	2/N	O	---	B/E	I/---		
Y3 Site Security	N	ALL	---	E	---		

NOTES (Continued)

s. The recirculation motor cooling system (RMCS) is classified Quality Group C and Safety Class 3 which is consistent with the requirements of 10CFR50.55a. The RMCS, which is part of the reactor coolant pressure boundary (RCPB) meets 10CFR50.55a (c)(2). Postulated failure of the RMCS piping cannot cause a loss of reactor coolant in excess of normal makeup (CRD return or RCIC flow), and the RMCS is not an engineered safety feature. Thus, in the event of a postulated failure of the RMCS piping during normal operation, the reactor can be shutdown and cooled down in an orderly manner, and reactor coolant makeup can be provided by a normal make up system (e.g., CRD return or RCIC system). Thus, per 10CFR50.55a(c)(2), the RMCS need not be classified Quality Group A or Safety Class 3, however, the system is designed and constructed in accordance with ASME Boiler and Pressure Vessel Code, Section III, Class 1 criteria as specified in Subsection 3.9.3.1.4 and Figure 5.4-4.

260.4 t. A quality assurance program for the Fire Protection System meeting the guidance of Branch Technical Position CMEB 9.5-1 (NUREG-0800), is applied.

u. Special seismic qualification and quality assurance requirements are applied.

v. See Reg Guide 1.143, paragraph C.5 for the offgas vault seismic requirements.

w. The condensate storage tank will be designed, fabricated, and tested to meet the intent of API Standard API 650. In addition, the specification for this tank will require: (1) 100% surface examination of the side wall to bottom joint and (2) 100% volumetric examination of the side wall weld joints.

x. The cranes are designed to hold up their loads and to maintain their positions over the units under conditions of SSE.

y. All off-engine components are constructed to the extent possible to the ASME Code, Section III, Class 3.

z. Components associated with safety-related function (e.g., isolation) are safety-related.

aa. Structures which support or house safety-related mechanical or electrical components are safety-related.

bb. All quality assurance requirements shall be applied to ensure that the design, construction and testing requirements are met.

260.4 cc. A quality assurance program, which meets or exceeds the guidance of Generic Letter 85-06, is applied to all non-safety related ATWS equipment.

dd. The need for pipe whip restraints on the MSL/FW piping will be determined by a "leak-before-break" evaluation.

ee. The condenser anchorage and turbine procedure is given in Subsection 3.7.3.16 and the codes, load combinations, and structural acceptance criteria are given in Table 3.2-4.

3.3 WIND AND TORNADO LOADINGS

ABWR Standard Plant structures which are Seismic Category I are designed for tornado and extreme wind phenomena.

3.3.1 Wind Loadings

3.3.1.1 Design Wind Velocity

Seismic Category I structures are designed to withstand a design wind velocity of 130 mph at an elevation of 33 feet above grade with a recurrence interval of 100 years. See Subsection 3.3.3.1 for interface requirement.

3.3.1.2 Determination of Applied Forces

The design wind velocity is converted to velocity pressure in accordance with Reference 1 using the formula:

$$q_z = 0.00256\,K_z\,(IV)^2$$

where K_z = the velocity pressure exposure coefficient which depends upon the type of exposure and height (z) above ground per Table 6 of Reference 1.

I = the importance factor which depends on the type of exposure; appropriate values of I are listed in Table 3.3-1,

V = design wind velocity of 130 mph, and

q_z = velocity pressure in psf

The velocity pressure (q_z) distribution with height for exposure types C and D of Reference 1 are given in Table 3.3-2.

The design wind pressures and forces for buildings, components and cladding, and other structures at various heights above the ground are obtained, in accordance with Table 4 of Reference 1 by multiplying the velocity pressure by the appropriate pressure coefficients and gust factors. Gust factors are in accordance with Table 8 of Reference 1. Appropriate pressure coefficients are in accordance with Figures 2, 3a, 3b, 4, and Tables 9 and 11 through 16 of Reference 1. Reference 2 is used to obtain the effective wind pressures for cases which Reference 1 does not cover. Since the Seismic Category I structures are not slender or flexible, vortex-shedding analysis is not required and the above wind loading is applied as a static load.

3.3.2 Tornado Loadings

3.3.2.1 Applicable Design Parameters

The design basis tornado is described by the following parameters:

(1) A maximum tornado wind speed of 300 mph at a radius of 150 feet from the center of the tornado;

(2) A maximum translational velocity of 60 mph;

(3) A maximum tangential velocity of 240 mph, based on the translational velocity of 60 mph;

(4) A maximum atmospheric pressure drop of 2.00 psi with a rate of the pressure change of 1.2 psi per second; and

(5) The spectrum of tornado-generated missiles and their pertinent characteristics as given in Subsection 3.5.1.4.

See Subsection 3.3.3.2 for interface requirement.

3.3.2.2 Determination of Forces on Structures

The procedures of transforming the tornado loading into effective loads and the distribution across the structures are in accordance with Reference 4. The procedure for transforming the tornado-generated missile impact into an effective or equivalent static load on structures is given in Subsection 3.5.3.1. The loading combinations of the individual tornado loading components and the load factors are in accordance with Reference 4.

The reactor building and control building are not vented structures. The exposed exterior roofs and walls of these structures are designed for the 2.00 psi pressure drop. Tornado dampers are provided on all air intake and exhaust openings. These dampers are designed to withstand a negative 1.46 psi pressure.

3.3.2.3 Effect of Failure of Structures or Components Not Designed for Tornado Loads

All safety-related system and components are protected within tornado-resistant structures.

See Subsection 3.3.3.3 for interface requirement.

3.3.3 Interfaces

3.3.3.1 Site-Specific Design Basis Wind

The site-specific design basis wind shall not exceed the design basis wind given in Table 2.0-1 (See Subsection 2.2.1).

3.3.3.2 Site-Specific Design Basis Tornado

The site-specific design basis tornado shall not exceed the design basis tornado given in Table 2.0-1 (See Subsection 2.2.1).

3.3.3.3 Effect of Remainder of Plant Structures, Systems, and Components not Designed for Tornado Loads

All remainder of plant structures, systems, and components not designed for tornado loads shall be analyzed for the site-specific loadings to ensure that their mode of failure will not effect the ability of the Seismic Category I ABWR Standard Plant structures, systems, and components to perform their intended safety functions. (See Subsection 3.3.2.3)

3.3.4 References

1. ANSI Standard A58.1, *Minimum Design Loads for Buildings and Other Structures*, Committee A. 58.1, American National Standards Institute.

2. ASCE Paper No. 3269, *Wind Forces on Structures*, Transactions of the American Society of Civil Engineers, Vol. 126, Part II.

3. ANSI/ANS 2.3, American National Standard, Estimating Tornado and Extreme Wind Characteristics at Nuclear Power Sites,Standards Committee Working Group ANS--2.3, American Nuclear Society.

4. Bechtel Topical Report BC-TOP-3-A, Revision 3, *Tornado and Extreme Wind Design Criteria for Nuclear Power Plants*.

generated from other natural phenomena. The design basis tornado for the ABWR Standard Plant is the maximum tornado windspeed corresponding to a probability of 10E-7 per year (300 mph). The other characteristics of this tornado, summarized in Subsection 3.3.2.1. The design basis tornado missiles are per SRP 3.5.1.4, Spectrum 1.

Using the design basis tornado and missile spectrum as defined above with the design of the Seismic Category I buildings, compliance with all of the positions of Regulatory Guide 1.117, "Tornado Design Classification," Positions C.1 and C.2 is assured.

The SGTS charcoal absorber beds are housed in the tornado resistant reactor building and therefore are protected from the design basis tornado missiles. The offgas system charcoal absorber beds are located deep within the turbine building and it is considered very unlikely that these beds could be ruptured as a result of a design basis tornado missile. These features assure compliance with Position C.3 of Regulatory Guide 1.117.

An evaluation of all non safety-related structures, systems, and components (not housed in a tornado structure) whose failure due to a design basis tornado missile that could adversely impact the safety function of safety-related systems and components will be provided to the NRC by the applicant referencing the ABWR design. See Subsection 3.5.4.2 for interface requirements.

3.5.1.5 Site Proximity Missiles Except Aircraft

External missiles other than those generated by tornados are not considered as a design basis (i.e. $\leq 10^{-7}$ per year).

3.5.1.6 Aircraft Hazards

Aircraft hazards are not a design basis event for the Nuclear Island (i.e. $\leq 10^{-7}$ per year).

3.5.2 Structures, Systems, and Components to be Protected from Externally Generated Missiles

The sources of external missiles which could affect the safety of the plant are identified in Subsection 3.5.1. Certain items in the plant are required to safely shut down the reactor and maintain it in a safe condition assuming an additional single failure. These items, whether they be structures, systems, or components, must therefore all be protected from externally generated missiles.

These items are the safety-related items listed in Table 3.2-1. Appropriate safety classes and equipment locations are given in this table. All of the safety-related systems listed are located in buildings which are designed as tornado resistant. Since the tornado missiles are the design basis missiles, the systems, structures, and components listed are considered to be adequately protected. Provisions are made to protect the charcoal delay tanks against tornado missiles.

See Subsection 3.5.4.1 for interface requirement.

3.5.3 Barrier Design Procedures

The procedures by which structures and barriers are designed to resist the missiles described in Subsection 3.5.1 are presented in this section. The following procedures are in accordance with Section 3.5.3 of NUREG-0800 (Standard Review Plan).

3.5.3.1 Local Damage Prediction

The prediction of local damage in the impact area depends on the basic material of construction of the structure or barrier (i.e., concrete or steel). The corresponding procedures are presented separately. Composite barriers are not utilized in the ABWR Standard Plant for missile protection.

3.5.3.1.1 Concrete Structures and Barriers

The modified Petry formula (Reference 3) is applied analytically for missile penetration in concrete. To prevent perforation, a minimum concrete thickness of 2.2 times the penetration thickness determined for an infinitely thick concrete slab is employed. In the event that spalling or scabbing is unacceptable, a minimum concrete thickness of 3 times the penetration thickness determined for an infinitely thick concrete slab is provided. These design procedures have been substantiated by full-scale impact tets in which reinforced concrete panels (12 to 24 inches thick, 3000-psi design strength) were impacted by poles, pipes, and rods simulating tornado-borne debris (Reference 4).

3.5.3.1.2 Steel Structure and Barriers

The Stanford equation (Reference 5) is applied for steel structures and barriers.

3.5.3.2 Overall Damage Prediction

The overall response of a structure or barrier to missile impact depends largely upon the location of impact (e.g., near mid-span or near a support), dynamic properties of the steucture/barrier and missile, and on the kinetic energy of the missile. In general, it has been assumed that the impact is plastic with all of the initial momentum of the missile transferred to the structure or barrier and only a portion of the kenetic energy absorbed as strain energy within the structure or barrier.

After demonstrating that the missile does not perforate the structure or barrier, an equi-

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TABLES

ILLUSTRATIONS

3.6 PROTECTION AGAINST DYNAMIC EFFECTS ASSOCIATED WITH THE POSTULATED RUPTURE OF PIPING

This Section deals with the structures, systems, components and equipment in the ABWR Standard Plant.

Subsections 3.6.1 and 3.6.2 describe the design bases and protective measures which ensure that the containment; essential systems, components and equipment; and other essential structures are adequately protected from the consequences associated with a postulated rupture of high-energy piping or crack of moderate-energy piping both inside and outside the containment.

Before delineating the criteria and assumptions used to evaluate the consequences of piping failures inside and outside of containment, it is necessary to define a pipe break event and a postulated piping failure:

Pipe break event: Any single postulated piping failure occurring during normal plant operation and any subsequent piping failure and/or equipment failure that occurs as a direct consequence of the postulated piping failure.

Postulated Piping Failure: Longitudinal or circumferential break or rupture postulated in high-energy fluid system piping or throughwall leakage crack postulated in moderate-energy fluid system piping. The terms used in this definition are explained in Subsection 3.6.2.

Structures, systems, components and equipment that are required to shut down the reactor and mitigate the consequences of a postulated piping failure, without offsite power, are defined as essential and are designed to Seismic Category I requirements.

The dynamic effects that may result from a postulated rupture of high-energy piping include missile generation; pipe whipping; pipe break reaction forces; jet impingement forces; compartment, subcompartment and cavity pressurizations; decompression waves within the ruptured pipes and seven types of loads identified with loss of coolant accident (LOCA) on Table 3.9-2.

Subsection 3.6.3 and Appendix 3E describe the implementation of the leak-before-break (LBB) evaluation procedures as permitted by the broad scope amendment to General Electric Criterion 4 (GDC-4) published in Reference 1. It is anticipated, as mentioned in Subsection 3.6.4.2, that a COL applicant will apply to the NRC for approval of LBB qualification of selected piping by submitting a technical justification report. The approved piping, referred to in this SSAR as the LBB piping, will be excluded from pipe breaks, which are required to be postulated by Subsection 3.6.1 and 3.6.2, for design against their potential dynamic effects. However, such piping are included in postulation of pipe cracks for their effects as described in Subsections 3.6.1.3.1, 3.6.1.2.1.5 and 3.6.2.1.6.2. It is emphasized that an LBB qualification submittal is not a mandatory requirement; a COL applicant has an option to select from none to all technically feasible piping systems for the benefits of the LBB approach. The decision may be made based upon a cost-benefit evaluation (Reference 6).

3.6.1 Postulated Piping Failures In Fluid Systems Inside and Outside of Containment

This subsection sets forth the design bases, description, and safety evaluation for determining the effects of postulated piping failures in fluid systems both inside and outside the containment, and for including necessary protective measures.

3.6.1.1 Design Bases

3.6.1.1.1 Criteria

Pipe break event protection conforms to 10CFR50 Appendix A, General Design Criterion 4, *Environmental and Missile Design Bases*. The design bases for this protection is in compliance with NRC Branch Technical Positions (BTP) ASB 3-1 and MEB 3-1 included in Subsections 3.6.1 and 3.6.2, respectively, of NUREG-0800 (Standard Review Plan).

MEB 3-1 describes an acceptable basis for selecting the design locations and orientations of postulated breaks and cracks in fluid systems piping. Standard Review Plan Sections 3.6.1 and 3.6.2 describe acceptable measures that could be taken for protection against the breaks and cracks and for restraint against pipe whip that may result from breaks.

The design of the containment structure, component arrangement, pipe runs, pipe whip restraints and compartmentalization are done in consonance with the acknowledgment of protection against dynamic effects associated with a pipe break event. Analytically sized and positioned pipe whip restraints are engineered to preclude damage based on the pipe break evaluation.

3.6.1.1.2 Objectives

Protection against pipe break event dynamic effects is provided to fulfill the following objectives:

(1) Assure that the reactor can be shut down safely and maintained in a safe cold shutdown condition and that the consequences of the postulated piping failure are mitigated to acceptable limits without offsite power.

(2) Assure that containment integrity is maintained.

(3) Assure that the radiological doses of a postulated piping failure remain below the limits of 10CFR100.

3.6.1.1.3 Assumptions

The following assumptions are used to determine the protection requirements.

(1) Pipe break events may occur during normal plant conditions (i.e., reactor startup, operation at power, normal hot standby* or reactor cooldown to a cold shutdown conditions but excluding test modes).

210.23 (2) A pipe break event may occur simultaneously with a seismic event, however, a seismic event does not initiate a pipe break event. This applies to Seismic Category I and non-Seismic Category I piping.

(3) A single active component failure (SACF) is assumed in systems used to mitigate consequences of the postulated piping failure and to shut down the reactor, except as noted in item (4) below. A SACF is malfunction or loss of function of a component of electrical or fluid systems. The failure of an active component of a fluid system is considered to be a loss of component function as a result of mechanical, hydraulic, or electrical malfunction but not the loss of component structural integrity. The direct consequences of a SACF are considered to be a part of the single active failure. The single active component failure is assumed to occur in addition to the postulated piping failure and any direct consequences of the piping failure.

(4) Where the postulated piping failure is assumed to occur in one of two or more redundant trains of a dual-purpose moderate-energy essential system (i.e., one required to operate during normal plant conditions as well as to shut down the reactor and mitigate the consequences of the piping failure), single active failure of components in the other train or trains of that system only are not assumed, provided the system is designed to Seismic Category I standards, is powered from both offsite and onsite sources, and is constructed, operated, and inspected to quality assurance, testing and inservice inspection standards appropriate for nuclear safety-related systems. The residual heat removal system is an example of such a system.

(5) If a pipe break event involves a failure of non-Seismic Category I piping, the pipe break event must not result in failure of essential systems, components and equipment to shut down the reactor and mitigate the consequences of the pipe break event considering a SACF in accordance with items (3) and (4) above.

(6) If loss of offsite power is a direct consequence of the pipe break event (e.g., trip of the turbine-generator producing a power

* *Normal hot standby is a normally attained zero power plant operating state (as opposed to a hot standby initiated by a plant upset condition) where both feedwater and main condenser are available and in use.*

surge which in turn trips the main breaker), then a loss of offsite power occurs in a mechanistic time sequence with a SACF. Otherwise, offsite power is assumed available with a SACF.

(7) A whipping pipe is not capable of rupturing impacted pipes of equal or greater nominal pipe diameter, but may develop throughwall cracks in equal or larger nominal pipe sizes with thinner wall thickness.

(8) All available systems, including those actuated by operator actions, are available to mitigate the consequences of a postulated piping failure. In judging the availability of systems, account is taken of the postulated failure and its direct consequences such as unit trip and loss of offsite power, and of the assumed SACF and its direct consequences. The feasibility of carrying out operator actions are judged on the basis of ample time and adequate access to equipment being available for the proposed actions.

Although a pipe break event outside the containment may require a cold shutdown, up to eight hours in hot standby is allowed in order for plant personnel to assess the situation and make repairs.

(10) Pipe whip occurs in the plane defined by the piping geometry and causes movement in the direction of the jet reaction. If unrestrained, a whipping pipe with a constant energy source forms a plastic hinge and rotates about the nearest rigid restraint, anchor, or wall penetration. If unrestrained, a whipping pipe without a constant energy source (i.e., a break at a closed valve with only one side subject to pressure) is not capable of forming a plastic hinge and rotating provided its movement can be defined and evaluated.

(11) The fluid internal energy associated with the pipe break reaction can take into account any line restrictions (e.g., flow limiter) between the pressure source and break location and absence of energy reservoirs, as applicable.

3.6.1.1.4 Approach

To comply with the objectives previously described, the essential systems, components, and equipment are identified. The essential systems, components, and equipment, or portions thereof, are identified in Table 3.6-1 for piping failures postulated inside the containment and in Table 3.6-2 for outside the containment.

3.6.1.2 Description

The lines identified as high-energy per Subsection 3.6.2.1.1 are listed in Table 3.6-3 for inside the containment and in Table 3.6-4 for outside the containment. Moderate-energy piping defined in Subsection 3.6.2.1.2 is listed in Table 3.6-5 for outside the containment. Pressure response analyses are performed for the subcompartments containing high-energy piping. A detailed discussion of the line breaks selected, vent paths, room volumes, analytical methods, pressure results, etc., is provided in Section 6.2 for primary containment subcompartments.

The effects of pipe whip, jet impingement, spraying, and flooding on required function of essential systems, components, and equipment, or portions thereof, inside and outside the containment are considered.

In particular, there are no high-energy lines near the control room. As such, there are no effects upon the habitability of the control room by a piping failure in the control building or elsewhere either from pipe whip, jet impingement, or transport of steam. Further discussion on control room habitability systems is provided in Section 6.4.

3.6.1.3 Safety Evaluation

3.6.1.3.1 General

An analysis of pipe break events is performed to identify those essential systems, components, and equipment that provide protective actions required to mitigate, to acceptable limits, the consequences of the pipe break event.

Pipe break events involving high-energy fluid systems are evaluated for the effects of pipe whip, jet impingement, flooding, room pressurization, and other environmental effects such as temperature. Pipe break events involving moderate-energy fluid systems are evaluated for wetting from spray, flooding, and other environmental effects.

By means of the design features such as separation, barriers, and pipe whip restraints, a discussion of which follows, adequate protection is provided against the effects of pipe break events for essential items to an extent that their ability to shut down the plant safely or mitigate the consequences of the postulated pipe failure would not be impaired.

3.6.1.3.2 Protection Methods

3.6.1.3.2.1 General

The direct effects associated with a particular postulated break or crack must be mechanistically consistent with the failure. Thus, actual pipe dimensions, piping layouts, material properties, and equipment arrangements are considered in defining the following specific measure for protection against actual pipe movement and other associated consequences of postulated failures.

(1) Protection against the dynamic effects of pipe failures is provided in the form of pipe whip restraints, equipment shields, and physical separation of piping, equipment, and instrumentation.

(2) The precise method chosen depends largely upon limitations placed on the designer such as accessibility, maintenance, and proximity to other pipes.

3.6.1.3.2.2 Separation

The plant arrangement provides physical separation to the extent practicable to maintain the independence of redundant essential systems (including their auxiliaries) in order to prevent the loss of safety function due to any single postulated event. Redundant trains (e.g., A and B trains) and divisions are located in separate compartments to the extent possible. Physical separation between redundant essential systems with their related auxiliary supporting features, therefore, is the basic protective measure incorporated in the design to protect against the dynamic effects of postulated pipe failures.

Due to the complexities of several divisions being adjacent to high-energy lines in the drywell and reactor building steam tunnel, specific break locations are determined in accordance with Subsection 3.6.2.1.4.3 for possible spatial separation. Care is taken to avoid concentrating essential equipment in the break exclusion zone allowed per Subsection 3.6.2.1.4.2. If spatial separation requirements (distance and/or arrangement to prevent damage) cannot be met based on the postulation of specific breaks, barriers, enclosures, shields, or restraints are provided. These methods of protection are discussed on Subsections 3.6.1.3.2.3 and 3.6.1.3.2.4.

For other areas where physical separation is not practical, the following high-energy line-separation analysis (HELSA) evaluation is done to determine which high- energy lines meet the spatial separation requirement and which lines require further protection:

(1) For the HELSA evaluation, no particular break points are identified. Cubicles or areas through which the high-energy lines pass are examined in total. Breaks are postulated at any point in the piping system.

(2) Essential systems, components, and equipment at a distance greater than thirty feet from any high energy piping are considered as meeting spatial separation requirements. No damage is assumed to occur due to jet impingement since the impingement force becomes negligible beyond 30 feet. Likewise, a 30-ft evaluation zone is established for pipe breaks to assure protection against potential damage from a whipping pipe. Assurance that 30 feet represents the maximum free length is made in the piping layout.

(3) Essential systems, components, and equipment at a distance less than 30 feet from any high-energy piping are evaluated to see if damage could occur to more than one essential division, preventing safe shutdown of the plant. If damage occurred to only one division of a redundant system, the

which are required to function following a pipe rupture, are protected.

(4) High-energy fluid system pipe whip restraints and protective measures are designed so that a postulated break in one pipe could not, in turn, lead to a rupture of other nearby pipes or components if the secondary rupture could result in consequences that would be considered unacceptable for the initial postulated break.

(5) For any postulated pipe rupture, the structural integrity of the containment structure is maintained. In addition, for those postulated ruptures classified as a loss of reactor coolant, the design leak tightness of the containment fission product barrier is maintained.

(6) Safety/relief valves (SRV) and the reactor core isolation cooling (RCIC) system steamline are located and restrained so that a pipe failure would not prevent depressurization.

not result in whipping of the cracked pipe. High-energy fluid systems are also postulated to have cracks for conservative environmental conditions in a confined area where high- and moderate-energy fluid systems are located.

The following high-energy piping systems (or portions of systems) are considered as potential candidates for a postulated pipe break during normal plant conditions and are analyzed for potential damage resulting from dynamic effects:

(1) All piping which is part of the reactor coolant pressure boundary and subject to reactor pressure continuously during station operation;

(2) All piping which is beyond the second isolation valve but subject to reactor pressure continuously during station operation; and

(3) All other piping systems or portions of piping systems considered high-energy systems.

Portions of piping systems that are isolated from the source of the high-energy fluid during normal plant conditions are exempted from consideration of postulated pipe breaks. This includes portions of piping systems beyond a normally closed valve. Pump and valve bodies are also exempted from consideration of pipe break because of their greater wall thickness.

3.6.2.1.4 Locations of Postulated Pipe Breaks

Postulated pipe break locations are selected as follows:

3.6.2.1.4.1 Piping Meeting Separation Requirements

Based on the HELSA evaluation described in Subsection 3.6.1.3.2.2, the high-energy lines which meet the spatial separation requirements are generally not identified with particular break points. Breaks are postulated at all possible points in such high-energy piping systems. However, in some systems break points are particularly specified per the following subsections if special protection devices such as barriers or restraints are provided.

3.6.2.1.4.2 Piping in Containment Penetration Areas

No pipe breaks or cracks are postulated in those portions of piping from containment wall to and including the inboard or outboard isolation valves which meet the following requirement in addition to the requirement of the ASME Code, Section III, Subarticle NE-1120:

(1) The following design stress and fatigue limits are not exceeded:

<u>For ASME Code, Section III, Class 1 Piping</u>

(a) The maximum stress range between any two loads sets (including the zero load set) does not exceed 2.4 S_m, and is calculated* by Eq. (10) in NB-3653, ASME Code, Section III.

If the calculated maximum stress range of Eq. (10) exceeds 2.4 S_m, the stress ranges calculated by both Eq. (12) and Eq. (13) in Paragraph NB-3653 meet the limit of 2.4 S_m.

(b) The cumulative usage factor is less than 0.1

(c) The maximum stress, as calculated by Eq. (9) in NB-3652 under the loadings resulting from a postulated piping failure beyond these portions of piping does not exceed the lesser of 2.25 S_m and 1.8 S_y except that following a failure outside containment, the pipe between the outboard isolation valve and

* *For those loads and conditions in which Level A and Level B stress limits have been specified in the Design Specification.*

the first restraint may be permitted higher stresses provided a plastic hinge is not formed and operability of the valves with such stresses is assured in accordance with the requirement specified in Section 3.9.3. Primary loads include those which are deflection limited by whip restraints.

For ASME Code, Section III, Class 2 Piping

(d) The maximum stress as calculated by the sum of Eqs. (9) and (10) in Paragraph NC-3652, ASME Code, Section III, considering those loads and conditions thereof for which level A and level B stress limits are specified in the system's Design Specification (i.e., sustained loads, occasional loads, and thermal expansion) including an OBE event does not exceed $0.8(1.8\ S_h + S_A)$. The S_h and S_A are allowable stresses at maximum (hot) temperature and allowable stress range for thermal expansion, respectively, as defined in Article NC-3600 of the ASME Code, Section III.

(e) The maximum stress, as calculated by Eq. (9) in NC-3653 under the loadings resulting from a postulated piping failure of fluid system piping beyond these portions of piping does not exceed the lesser of $2.25\ S_h$ and $1.8\ S_y$.

Primary loads include those which are deflection limited by whip restraints. The exceptions permitted in (c) above may also be applied provided that when the piping between the outboard isolation valve and the restraint is constructed in accordance with the Power Piping Code ANSI B31.1, the piping is either of seamless construction with full radiography of all circumferential welds, or all longitudinal and circumferential welds are fully radiographed.

(2) Welded attachments, for pipe supports or other purposes, to these portions of piping are avoided except where detailed stress analyses, or tests, are performed to demonstrate compliance with the limits of item (1).

(3) The number of circumferential and longitudinal piping welds and branch connections are minimized. Where penetration sleeves are used, the enclosed portion of fluid system piping is seamless construction and without circumferential welds unless specific access provisions are made to permit inservice volumetric examination of longitudinal and circumferential welds.

(4) The length of these portions of piping are reduced to the minimum length practical.

(5) The design of pipe anchors or restraints (e.g., connections to containment penetrations and pipe whip restraints) do not require welding directly to the outer surface of the piping (e.g., flued integrally forged pipe fittings may be used) except where such welds are 100 percent volumetrically examinable in service and a detailed stress analysis is performed to demonstrate compliance with the limits of item (1).

(6) Sleeves provided for those portions of piping in the containment penetration areas are constructed in accordance with the rules of Class MC, Subsection NE of the ASME Code, Section III, where the sleeve is part of the containment boundary. In addition, the entire sleeve assembly is designed to meet the following requirements and tests:

(a) The design pressure and temperature are not less than the maximum operating pressure and temperature of the enclosed pipe under normal plant conditions.

(b) The Level C stress limits in NE-3220, ASME Code, Section III, are not exceeded under the loadings associated with containment design pressure and temperature in combination with the safe shutdown earthquake.

(c) The assemblies are subjected to a single pressure test at a pressure not less than its design pressure.

(d) The assemblies do not prevent the access required to conduct the inservice examination specified in item (7).

(7) A 100% volumetric inservice examination of all pipe welds would be conducted during each inspection interval as defined in IWA-2400, ASME Code, Section XI.

3.6.2.1.4.3 ASME Code Section III Class 1 Piping In Areas Other Than Containment Penetration

With the exception of those portions of piping identified in Subsection 3.6.2.1.4.2, breaks in ASME Code, Section III, Class 1 piping are postulated at the following locations in each piping and branch run:

(a) At terminal ends*

(b) At intermediate locations where the maximum stress range (see Subsection 3.6.2.1.4.2, Paragraph (1)(a)) as calculated by Eq. (10) in NB-3653, ASME Code, Section III.

If the calculated maximum stress range of Eq.(10) exceeds the stress range calculated by both Eq.(12) and Eq.(13) in Paragraph NB-3653 should meet the limit of 2.4 Sm.

(c) At intermediate locations where the cumulative usage factor exceeds 0.1.

* *Extremities of piping runs that connect to structures, components (e.g., vessels, pumps, valves), or pipe anchors that act as rigid constraints to piping motion and thermal expansion. A branch connection to a main piping run is a terminal end of the branch run, except where the branch run is classified as part of a main run in the stress analysis and is shown to have a significant effect on the main run behavior. In piping runs which are maintained pressurized during normal plant conditions for only a portion of the run (i.e., up to the first normally closed valve) a terminal end of such runs is the piping connection to this closed valve*

As a result of piping re-analysis due to differences between the design configuration and the as-built configuration, the highest stress or cumulative usage factor locations may be shifted; however, the initially determined intermediate break locations need not be changed unless one of the following conditions exists:

(i) The dynamic effects from the new (as-built) intermediate break locations are not mitigated by the original pipe whip restraints and jet shields.

(ii) A change is required in pipe parameters such as major differences in pipe size, wall thickness, and routing.

3.6.2.1.4.4 ASME Code Section III Class 2 and 3 Piping in Areas Other Than Containment Penetration

With the exceptions of those portions of piping identified in Subsection 3.6.2.1.4.2, breaks in ASME Codes, Section III, Class 2 and 3 piping are postulated at the following locations in those portions of each piping and branch run:

(a) At terminal ends (see Subsection 3.6.2.1.4.3, Paragraph (a))

(b) At intermediate locations selected by one of the following criteria:

(i) At each pipe fitting (e.g., elbow, tee, cross, flange, and nonstandard fitting), welded attachment, and valve. Where the piping contains no fittings, welded attachments, or valves, at one location at each extreme of the piping run adjacent to the protective structure.

(ii) At each location where stresses calculated (see Subsection 3.6.2.1.4.2, Paragraph (1)(d)) by the sum of Eqs. (9) and (10) in NC/ND-3653, ASME Code, Section III, exceed 0.8 times the sum of the stress limits given in NC/ND-3653.

As a result of piping re-analysis due to differences between the design configuration and the as-built configuration, the highest stress locations may be shifted; however, the initially determined intermediate break locations may be used unless a redesign of the piping resulting in a change in the pipe parameters (diameter, wall thickness, routing) is required, or the dynamic effects from the new (as-built) intermediate break location are not mitigated by the original pipe whip restraints and jet shields.

3.6.2.1.4.5 Non-ASME Class Piping

Breaks in seismically analyzed non-ASME Class (not ASME Class 1, 2 or 3) piping are postulated according to the same requirements for ASME Class 2 and 3 piping above. Separation and interaction requirements between Seismically analyzed and non-seismically analyzed piping are met as described in Subsection 3.7.3.13.

3.6.2.1.4.6 Separating Structure With High-Energy Lines

If a structure separates a high energy line from an essential component, the separating structure is designed to withstand the consequences of the pipe break in the high-energy line at locations that the aforementioned criteria require to be postulated. However, as noted in Subsection 3.6.1.3.2.3, some structures that are identified as necessary by the HELSA evaluation (i.e., based on no specific break locations), are designed for worst-case loads.

3.6.2.1.5 Locations of Postulated Pipe Cracks

Postulated pipe crack locations are selected as follows:

3.6.2.1.5.1 Piping Meeting Separation Requirements

Based on the HELSA evaluation described in Subsection 3.6.1.3.2.2, the high- or moderate-energy lines which meet the separation requirements are not identified with particular crack locations. Cracks are postulated at all possible points that are necessary to demonstrate adequacy of separation or other means of protections provided for essential structures, systems and components.

3.6.2.1.5.2 High-Energy Piping

With the exception of those portions of piping identified in Subsection 3.6.2.1.4.2, leakage cracks are postulated for the most severe environmental effects as follows:

(1) For ASME Code, Section III Class 1 piping, at axial locations where the calculated stress range (see Subsection 3.6.2.1.4.2, Paragraph (1)(a)) by Eq. (10) and either Eq. (12) or Eq. (13) in NB-3653 exceeds 1.2 S_m.

(2) For ASME Code, Section III Class 2 and 3 or non-ASME class piping, at axial locations where the calculated stress (see Subsection 3.6.2.1.4.4, Paragraph (b)(ii)) by the sum of Eqs. (9) and (10) in NC/ND-3653 exceeds 0.4 times the sum of the stress limits given in NC/ND-3653.

(3) Non-ASME class piping which has not been evaluated to obtain stress information have leakage cracks postulated at axial locations that produce the most severe environmental effects.

3.6.2.1.5.3 Moderate-Energy Piping

3.6.2.1.5.3.1 Piping In Containment Penetration Areas

Leakage cracks are not postulated in those portions of piping from containment wall to and including the inboard or outboard isolation valves provided they meet the requirements of the ASME Code, Section III, NE-1120, and the stresses calculated (See Subsection 3.6.2.1.4.4, Paragraph (b)(ii)) by the sum of Eqs. (9) and (10) in ASME Code, Section III, NC-3653 do not exceed 0.4 times the sum of the stress limits given in NC-3653.

3.6.2.1.5.3.2 Piping In Areas Other Than Containment Penetration

(1) Leakage cracks are postulated in piping located adjacent to essential structures, systems or components, except:

(a) Where exempted by Subsections 3.6.2.1.5.3.1 and 3.6.2.1.5.4,

(b) For ASME Code, Section III, Class 1 piping the stress range calculated (see Subsection 3.6.2.1.4.2, Paragraph (1)

3.6.2.2 Analytic Methods to Define Blowdown Forcing Functions and Response Models.

3.6.2.2.1 Analytic Methods to Define Blowdown Forcing Functions.

The rupture of a pressurized pipe causes the flow characteristics of the system to change creating reaction forces which can dynamically excite the piping system. The reaction forces are a function of time and space and depend upon fluid state within the pipe prior to rupture, break flow area, frictional losses, plant system characteristics, piping system, and other factors. The methods used to calculate the reaction forces for various piping systems are presented in the following subsections.

The criteria that are used for calculation of fluid blowdown forcing functions include:

(1) Circumferential breaks are assumed to result in pipe severance and separation amounting to at least a one-diameter lateral displacement of the ruptured piping sections unless physically limited by piping restraints, structural members, or piping stiffness as may be demonstrated by inelastic limit analysis (e.g., a plastic hinge in the piping is not developed under loading).

(2) The dynamic force of the jet discharge at the break location is based on the cross-sectional flow area of the pipe and on a calculated fluid pressure as modified by analytically- or experimentally-determined thrust coefficient. Line restrictions, flow limiters, positive pump-controlled flow, and the absence of energy reservoirs are taken into accounts, as applicable, in the reduction of jet discharge.

(3) All breaks are assumed to attain full size within one millisecond after break initiation.

The forcing functions due to the postulated pipe breaks near the reactor at a branch connection are calculated by the solution of one-dimensional, compressible unsteady steam flow in the gas system. The numerical analysis is performed by the method of characteristics. The flow starts with steady flow from the RPV to the turbine. A pipe break causes the steam flow to reverse its direction and to flow from the turbine to the break location. The pipe segment force time histories are determined by calculating the momentum change in the pipe segments of a closed system. The broken pipe segment force time history is calculated in accordance with Appendix B of ANSI/ANS-58.2.

210.24

(5) Piping within the broken loop is no longer considered part of the RCPB. Plastic deformation in the pipe is considered as a potential energy absorber. Limits of strain are imposed which are similar to strain levels allowed in restraint plastic members. Piping systems are designed so that plastic instability does not occur in the pipe at the design dynamic and static loads unless damage studies are performed which show the consequences do not result in direct damage to any essential system or component.

(6) Components such as vessel safe ends and valves which are attached to the broken piping system, do not serve a safety-related function, or failure of which would not further escalate the consequences of the accident are not designed to meet ASME Code-imposed limits for essential components under faulted loading. However, if these components are required for safe shutdown or serve to protect the structural integrity of an essential component, limits to meet the Code requirements for faulted conditions and limits to ensure required operability will be met.

(7) The piping stresses in the containment penetration areas due to loads resulting from a postulated piping failure can not exceed the limits specified in Subsection 3.6.2.1.4.2(1)(c).

An analysis for pipewhip restraint selection PDA computer program; and a pipe break modeling program ANSYS are performed as described in Appendix 3D, which predicts the response of a pipe subjected to the thrust force occurring after a pipe break. The program treats the situation in terms of generic pipe break configuration which involves a straight, uniform pipe fixed at one end and subjected to a time--dependent thrust force at the other end. A typical restraint used to reduce the resulting deformation is also included at a location between the two ends. Nonlinear and time-independent stress-strain relationships are used to model the pipe and the restraint. Using a plastic-hinge concept, bending of the pipe is assumed to occur only at

3.6.2.2.2 Pipe Whip Dynamic Response Analyses

The prediction of time-dependent and steady-thrust reaction loads caused by blowdown of subcooled, saturated, and two-phase fluid from ruptured pipe is used in design and evaluation of dynamic effects of pipe breaks. A discussion of the analytical methods employed to compute these blowdown loads is given in Subsection 3.6.2.2.1. Following is a discussion of analytical methods used to account for this loading.

The criteria used for performing the pipe whip dynamic response analyses include:

(1) A pipe whip analysis is performed for each postulated pipe break. However, a given analysis can be used for more than one postulated break location if the blowdown forcing function, piping and restraint system geometry, and piping and restraint system properties are conservative for other break locations.

(2) The analysis includes the dynamic response of the pipe in question and the pipe whip restraints which transmit loading to the support structures.

(3) The analytical model adequately represents the mass/inertia and stiffness properties of the system.

(4) Pipe whipping is assumed to occur in the plane defined by the piping geometry and configuration and to cause pipe movement in the direction of the jet reaction.

the fixed end and at the location supported by the restraint.

Effects of pipe shear deflection are considered negligible. The pipe-bending moment-deflection (or rotation) relation used for these locations is obtained from a static nonlinear cantilever-beam analysis. Using the moment-rotation relation, nonlinear equations of motion of the pipe are formulated using energy considerations and the equations are numerically integrated in small time steps to yield time-history of the pipe motion.

The piping stresses in the containment penetration areas are calculated by the ANSYS computer program, a program as described in Appendix 3D. The program is used to perform the non-linear analysis of a piping system for time varying displacements and forces due to postulated pipe breaks.

3.6.2.3 Dynamic Analysis Methods to Verify Integrity and Operability

3.6.2.3.1 Jet Impingement Analyses and Effects on Safety-Related Components

The methods used to evaluate the jet effects resulting from the postulated breaks of high-energy piping are described in Appendices C and D of ANSI/ANS 58.2 and presented in this subsection.

The criteria used for evaluating the effects of fluid jets on essential structures, systems, and components are as follows:

(1) Essential structures, systems, and components are not impaired so as to preclude essential functions. For any given postulated pipe break and consequent jet, those essential structures, systems, and components need to safely shut down the plant are identified.

(2) Essential structures, systems, and components which are not necessary to safely shut down the plant for a given break are not protected from the consequences of the fluid jet.

(3) Safe shutdown of the plant due to postulated pipe ruptures within the RCPB is not aggravated by sequential failures of safety-related piping and the required emergency cooling system performance is maintained.

(4) Offsite dose limits specified in 10CFR100 are complied with.

(5) Postulated breaks resulting in jet impingement loads are assumed to occur in high-energy lines at full (102%) power operation of the plant.

(6) Throughwall leakage cracks are postulated in moderate energy lines and are assumed to

result in wetting and spraying of essential structures, systems, and components.

(7) Reflected jets are considered only when there is an obvious reflecting surface (such as a flat plate) which directs the jet onto an essential equipment. Only the first reflection is considered in evaluating potential targets.

(8) Potential targets in the jet path are considered at the calculated final position of the broken end of the ruptured pipe. This selection of potential targets is considered adequate due to the large number of breaks analyzed and the protection provided from the effects of these postulated breaks.

The analytical methods used to determine which targets will be impinged upon by a fluid jet and the corresponding jet impingement load include:

(1) The direction of the fluid jet is based on the arrested position of the pipe during steady-state blowdown.

(2) The impinging jet proceeds along a straight path.

(3) The total impingement force acting on any cross-sectional area of the jet is time and distance invariant with a total magnitude equivalent to the steady-state fluid blowdown force given in Subsection 3.6.2.2.1 and with jet characteristics shown in Figure 3.6-3.

(4) The jet impingement force is uniformly distributed across the cross-sectional area of the jet and only the portion intercepted by the target is considered.

(5) The break opening is assumed to be a circular orifice of cross-sectional flow area equal to the effective flow area of the break.

(6) The jet impingement force is equal to the steady-state value of the fluid blowdown force calculated by the methods described in Subsection 3.6.2.2.1.

(7) The distance of jet travel is divided into two or three regions. Region 1 (Figure 3.6-3) extends from the break to the asymptotic area. Within this region the discharging fluid flashes and undergoes expansion from the break area pressure to the atmospheric pressure. In Region 2 the jet expands further. For partial-separation circumferential breaks, the area increases as the jet expands. In Region 3 jet expands at a half angle of 10^{o}. (Figures 3.6-3a and c.)

(8) The analytical model for estimating the asymptotic jet area for subcooled water and saturated water assumes a constant jet area. For fluids discharging from a break which are below the saturation temperature at the corresponding room pressure or have a pressure at the break area equal to the room pressure, the free expansion does not occur.

(9) The distance downstream from the break where the asymptotic area is reached (Region 2) is calculted for circumferential and longitudinal breaks.

(10) Both longitudinal and fully separated circumferential breaks are treated similarly. The value of fL/D used in the blowdown calculation is used for jet impingement also.

(11) Circumferential breaks with partial (i.e., h<D/2) separation between the two ends of the broken pipe not significantly offset (i.e., no more than one pipe wall thickness lateral displacement) are more difficult to

quantify. For these cases, the following assumptions are made.

(a) The jet is uniformly distributed around the periphery.

(b) The jet cross section at any cut through the pipe axis has the configuration depicted in Figure 3.6-3b and the jet regions are as therein delineated.

(c) The jet force F_j = total blowdown F.

(d) The pressure at any point intersected by the jet is:

$$P_j = \frac{F_s}{A_R}$$

where

A_R = the total 360^o area of the jet at a radius equal to the distance from the pipe centerline to the target.

(e) The pressure of the jet is then multiplied by the area of the target submerged within the jet.

(12) Target loads are determined using the following procedures.

(a) For both the fully separated circumferential break and the longitudinal break, the jet is studied by determining target locations vs. asymptomatic distance and applying ANSI/ANS-58.2, Appendices C and D.

(b) For circumferential break limited separation, the jet is analyzed by using different equations of ANSI/ANS 58.2, Appendices C and D and determing respective target and asymptomatic locations

c) After determination of the total area of the jet at the target, the jet pressure is calculated by:

$$P_1 = \frac{F_j}{A_x}$$

where

P_1 = incident pressure

A_x = area of the expanded jet at the target intersection.

If the effective target area (A_{te}) is less than expanded jet area ($A_{te} \le A_x$), the target is fully submerged in the jet and the impingement load is equal to (P_1) (A_{te}). If the effective target area is greater than expanded jet area ($A_{te} > A_x$), the target intercepts the entire jet and the impingement load is equal to (P_1) (A_x) = F_j. The effective target area (A_{te}) for various geometries follows:

(1) Flat surface - F-- a case where a target with physical ar. A_t is oriented at angle d with respect to the jet axis and with no flow reversal, the effective target area A_{te} is:

$$A_{te} = (A_t)\ (\sin\phi).$$

(2) Pipe Surface - As the jet hits the convex surface of the pipe, its forward momentum is decreased rather than stopped; therefore, the jet impingement load on the impacted area is expected to be reduced. For conservatism, no credit is taken for this reduction and the pipe is assumed to be impacted with the full impingement load. However, where shape factors are justifiable, they may be used. The effective target area A_{te} is:

$$A_{te} = (D_A)\ (D)$$

where

D_A = diameter of the jet at the target interface, and

D = pipe OD of target pipe for a fully submerged pipe.

When the target (pipe) is larger than the area of the jet, the effective target area equals the expanded jet area

$$A_{te} = A_x$$

(3) For all cases, the jet area (A_x) is assumed to be uniform and the load is uniformly distributed on the impinged target area A_{te}.

3.6.2.3.2 Pipe Whip Effects on Essential Components

This subsection provides the criteria and methods used to evaluate the effects of pipe displacements on essential structures, systems, and components following a postulated pipe rupture.

Pipe whip (displacement) effects on essential structures, systems, and components can be placed in two categories: (1) pipe displacement effects on components (nozzles, valves, tees, etc.) which are in the same piping run that the break occurs in; and (2) pipe whip or controlled displacements onto external components such as building structure, other piping systems, cable trays, and conduits, etc.

3.6.2.3.2.1 Pipe Displacement Effects on Components in the Same Piping Run

The criteria for determining the effects of pipe displacements on inline components are as follows:

(1) Components such as vessel safe ends and valves which are attached to the broken piping system and do not serve a safety function or failure of which would not further escalate the consequences of the accident need not be designed to meet ASME

Code Section III-imposed limits for essential components under faulted loading.

(2) If these components are required for safe shutdown or serve to protect the structural integrity of an essential component, limits to meet the ASME Code requirements for faulted conditions and limits to ensure required operability are met.

The methods used to calculate the pipe whip loads on piping components in the same run as the postulated break are described in Section 3.6.2.2.2.

3.6.2.3.2.2 Pipe Displacement Effects on Essential Structures, Other Systems, and Components

The criteria and methods used to calculate the effects of pipe whip on external components consists of the following:

(1) The effects on essential structures and barriers are evaluated in accordance with the barrier design procedures given in Subsection 3.5.3

(2) If the whipping pipe impacts a pipe of equal or greater nominal pipe diameter and equal or greater wall thickness, the whipping pipe does not rupture the impacted pipe. Otherwise, the impacted pipe is assumed to be ruptured.

(3) If the whipping pipe impacts other components (valve actuators, cable trays, conduits, etc.), it is assumed that the impacted component is unavailable to mitigate the consequences of the pipe break event.

(4) Damage of unrestrained whipping pipe on essential structures, components, and systems other than the ruptured one is prevented by either separating high energy systems from the essential systems or providing pipe whip restraints.

3.6.2.3.3 Loading Combinations and Design Criteria for Pipe Whip Restraint

Pipe whip restraints, as differentiated from piping supports, are designed to function and carry load for an extremely low-probability gross failure in a piping system carrying high-energy fluid. In the ABWR plant, the piping integrity does not depend on the pipe whip restraints for any piping design loading combination including earthquake but shall remain functional following an earthquake up to and including the SSE (See Subsection 3.2.1). When the piping integrity is lost because of a postulated break, the pipe whip restraint acts to limit the movement of the broken pipe to an acceptable distance. The pipe whip restraints (i.e., those devices which serve only to control the movement of a ruptured pipe following gross failure) will be subjected to once-in-a-lifetime loading. For the purpose of the pipe whip restraint design, the pipe break is considered to be a faulted condition (See Subsection 3.9.3.1.1.4) and the structure to which the restraint is attached is also analyzed and designed accordingly. The pipe whip restraints are non-ASME Code components; however, the ASME Code requirements may be used in the design selectively to assure its safety-related function if ever needed. Other methods, i.e. testing, with reliable data base for design and sizing of pipe whip restraints can also be used.

The pipe whip restraints utilize energy absorbing U-rods to attenuate the kinetic energy of a ruptured pipe. A typical pipe whip restraint is shown in Figure 3.6-6. The principal feature of these restraints is that they are installed with several inches of annular clearance between them and the process pipe. This allows for installation of normal piping insulation and for unrestricted pipe thermal movements during plant operation. Select critical locations inside primary containment are also monitored during hot functional testing to provide verification of adequate clearances prior to plant operation. The specific design objectives for the restraints are:

(1) The restraints shall in no way increase the reactor coolant pressure boundary stresses by their presence during any normal mode of reactor operation or condition;

(2) The restraint system shall function to stop the movement of a pipe failure (gross loss of piping integrity) without allowing damage to critical components or missile development; and

(3) The restraints should provide minimum hindrance to inservice inspection of the process piping.

For the purpose of design, the pipe whip restraints are designed for the following dynamic loads:

(1) Blowdown thrust of the pipe section that impacts the restraint;

(2) Dynamic inertia loads of the moving pipe section which is accelerated by the blowdown thrust and subsequent impact on the restraint;

(3) Design characteristics of the pipe whip restraints are included and verified by the pipe whip dynamic analysis described in Subsection 3.6.2.2.2; and

(4) Since the pipe whip restraints are not contacted during normal plant operation, the postulated pipe rupture event is the only design loading condition.

Strain rate effects and other material property variations have been considered in the design of the pipe whip restraints. The material properties utilized in the design have included one or more of the following methods:

(1) Code minimum or specification yield and ultimate strength values for the affected components and structures are used for both the dynamic and steady-state events;

(2) Not more than a 10% increase in minimum code or specification strength values is used when designing components or structures for the dynamic event, and code minimum or specification yield and ultimate strength values are used for the steady-state loads:

(3) Representative or actual test data values are used in the design of components and structures including justifiably elevated strain rate-affected stress limits in excess of 10%; or

(4) Representative or actual test data are used for any affected component(s) and the minimum code or specification values are used for the structures for the dynamic and the steady-state events

3.6.2.4 Guard Pipe Assembly Design

The ABWR primary containment does not require guard pipes.

3.6.2.5 Material to be Supplied for the Operating License Review

See Subsection 3.6.4.1

3.6.3 Leak-Before-Break Evaluation Procedures

Per Regulatory Guide 1.70, Revision 3, November 1978, the safety analysis Section 3.6 has traditionally addressed the protection measures against dynamic effects associated with the non- mechanistic or postulated ruptures of piping. The dynamic effects are defined in introduction to Section 3.6. Three forms of piping failure (full flow area circumferential and longitudinal breaks, and throughwall leakage crack) are postulated in accordance with Subsection 3.6.2 and Branch Technical Position MEB 3-1 of NUREG - 0800 (Standard Review Plan) for their dynamic as well as environmental effects.

However, in accordance with the modified General Electric Criterion 4 (GDC-4), effective November 27, 1987, (Reference 1), the mechanistic leak-before-break (LBB) approach, justified by appropriate fracture mechanics techniques, is recognized as an acceptable procedure under certain conditions to exclude design against the dynamic effects from postulation of breaks in high energy piping. The LBB approach is not used to exclude postulation of cracks and associated effects as required in Subsection 3.6.2.1.5 and 3.6.2.1.6.2. It is anticipated, as mentioned in Subsection 3.6.4.2, that a COL applicant will apply to the NRC for approval of LBB qualification of selected piping. These approved piping, referred to in this SSAR as the LBB-qualified piping, will be excluded from pipe breaks, which are required to be postulated by Subsections 3.6.1 and 3.6.2, for design against their potential dynamic effects.

The following subsections describe (1) certain design bases where the LBB approach is not recognized by the NRC as applicable for exclusion of pipe breaks, and (2) certain conditions which limit the LBB applicability. Appendix 3E provides guidelines for LBB applications describing in detail the following necessary elements of an LBB report to be submitted by a COL applicant for NRC approval: fracture mechanics methods, leak rate prediction methods, leak detection capabilities and typical special considerations for LBB applicability. Also included in Appendix 3E is a list of candidate piping systems for LBB qualification. The LBB application approach described in this subsection and Appendix 3E is consistent with that documented in Draft SRP 3.6.3 (Reference 4) and NUREG-1061 (Reference 5).

The LBB approach is not used to exclude postulation of cracks and associated effects in

3.6.4 COL License Information

3.6.4.1 Details of Pipe Break Analysis Results and Protection Methods

The following shall be provided by the COL applicant (See Subsection 3.6.2.5):

(1) A summary of the dynamic analyses applicable to high-energy piping systems in accordance with Subsection 3.6.2.5 of Regulatory Guide 1.70. This shall include:

  (a) Sketches of applicable piping systems showing the location, size and orientation of postulated pipe breaks and the location of pipe whip restraints and jet impingement barriers.

  (b) A summary of the data developed to select postulated break locations including calculated stress intensities, cumulative usage factors and stress ranges as delineated in BTP MEB 3-1.

(2) For failure in the moderate-energy piping systems listed in Table 3.6-5, descriptions showing how safety-related systems are protected from the resulting jets, flooding and other adverse environmental effects. 410.21

(3) Identification of protective measures provided against the effects of postulated pipe failures for protection of each of the systems listed in Tables 3.6-1 and 3.6-2. 410.22

(4) The details of how the MSIV functional capability is protected against the effects of postulated pipe failures. 410.26

(5) Typical examples, if any, where protection for safety-related systems and components against the dynamic effects of pipe failures include their enclosure in suitably designed structures or compartments (including any additional drainage system or equipment environmental qualification needs). 410.28

(6) The details of how the feedwater line check and feedwater isolation valves functional capabilities are protected against the effects of postulated pipe failures.

3.6.4.2 Leak-Before-Break Analysis Report

As required by Reference 1, and LBB analysis report shall be prepared for the piping systems proposed for exclusion from analysis for the dynamic effects due to failure of piping failure. The report shall be prepared in accrodance with the guidelines presented in Appendix 3E and Submitted by the COL applicant to the NRC for approval

3.6.5 References

1. *Modification of General Design Criterion 4 Requirements for Protection Against Dynamic Effects of Postulated Pipe Rupture*, Federal Register, Volume 52, No. 207, Rules and Regulations, Pages 41288 to 41295, October 27, 1987

2. *RELAP 3, A Computer Program for Reactor Blowdown Analysis*, IN-1321, issued June 1970, Reactor Technology TID-4500.

3. ANSI/ANS-58.2, *Design Basis for Protection of Light Water Nuclear Power Plants Against the Effects of Postulated Pipe Rupture*.

4. *Standard Review Plan; Public Comments Solicited*, Federal Register, Volume 52, No. 167, Notices, Pages 32626 to 32633, August 28, 1987.

5. NUREG-1061, Volume3, *Evaluation of Potential for Pipe Breaks, Report of the U.S. NRC Piping Review Committee*, November 1984.

6. Mehta, H. S., Patel, N.T. and Ranganath, S., *Application of the Leak-Before-Break Approach to BWR Piping*, Report NP-4991, Electric Power Research Institute, Palo Alto, CA, December 1986.

Table 3.6-4

HIGH ENERGY PIPING OUTSIDE CONTAINMENT

Piping System*

Main Steam

Main Steam Drains

Steam supply to RCIC Turbine

CRD(to and from HCU)

RHR(injection to feedwater from nearest check valves in the RHR lines)

Reactor Water Cleanup (to Feedwater via RHR and to first inlet valve to RPV head spray)

Reactor Water Cleanup (pumps suction and discharge)

* *Fluid systems operating at high-energy levels less than 2 percent of the total time are not included. These systems are classified moderate-energy systems, (i.e., HPCF, RCIC, SAM and SLCS).*

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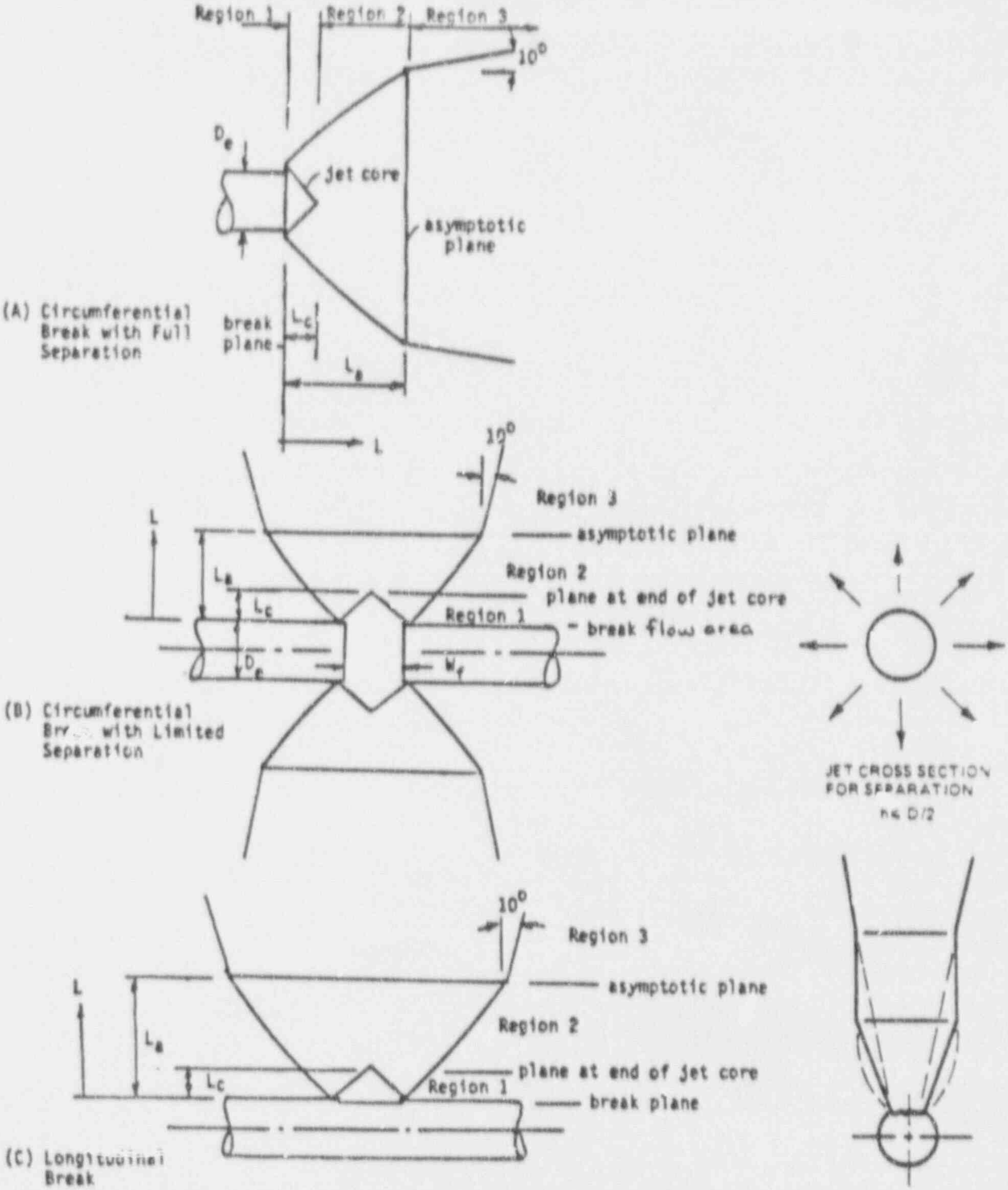

Figure 3.6-8 JET CHARACTERISTICS

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SECTION 3.7

CONTENTS (Continued)

SECTION 3.7

TABLES

3.7 SEISMIC DESIGN

All structures, systems, and equipment of the facility are defined as either Seismic Category I or non-Seismic Category I. The requirements for Seismic Category I identification are given in Section 3.2 along with a list of systems, components, and equipment which are so identified.

All structures, systems, components, and equipment that are safety-related, as defined in Section 3.2, are designed to withstand earthquakes as defined herein and other dynamic loads including those due to reactor building vibration (RBV) caused by suppression pool dynamics. Although this section addresses seismic aspects of design and analysis in accordance with Regulatory Guide 1.70, the methods of this section are also applicable to other dynamic loading aspects, except for the range of frequencies considered. The cutoff frequency for dynamic analysis is 33 Hz for seismic loads and 60 Hz for suppression pool dynamic loads. The definition of rigid system used in this section is applicable to seismic design only.

The safe shutdown earthquake (SSE) is that earthquake which is based upon an evaluation of the maximum earthquake potential considering the regional and local geology, seismology, and specific characteristics of local subsurface material. It is that earthquake which produces the maximum vibratory ground motion for which Seismic Category I systems and components are designed to remain functional. These systems and components are those necessary to ensure:

(1) the integrity of the reactor coolant pressure boundary;

(2) the capability to shut down the reactor and maintain it in a safe shutdown condition; and

(3) the capability to prevent or mitigate the consequences of accidents that could result in potential offsite exposures comparable to the guideline exposures of 10CFR100.

The operating basis earthquake (OBE) is that earthquake which, considering the regional and local geology, seismology, and specific characteristics of local subsurface material, could reasonably be expected to affect the plant site during the operating life of the plant. It is that earthquake which produce vibratory ground motion for which those features of the nuclear power plant necessary for continued operation without undue risk to the health and safety of the public are designed to remain functional. During the OBE loading condition, the safety-related systems are designed to be capable of continued safe operation. Therefore, for this loading condition, safety-related structures, and equipment are required to operate within design limits.

The seismic design for the SSE is intended to provide a margin in design that assures capability to shut down and maintain the nuclear facility in a safe condition. In this case, it is only necessary to ensure that the required systems and components do not lose their capability to perform their safety-related function. This is referred to as the no-loss-of-function criterion and the loading condition as the SSE loading condition.

Not all safety-related components have the same functional requirements. For example, the reactor containment must retain capability to restrict leakage to an acceptable level. Therefore, based on present practice, elastic behavior of this structure under the SSE loading condition is ensured. On the other hand, there are certain structures, components, and systems that can suffer permanent deformation without loss of function. Piping and vessels are examples of the latter where the principal requirement is that they retain contents and allow fluid flow.

Table 3.2-1 identifies the equipment in various systems as Seismic Category I or non-Seismic Category I.

3.7.1 Seismic Input

3.7.1.1 Design Response Spectra

The design earthquake loading is specified in terms of a set of idealized, smooth curves called the design response spectra in accordance with Regulatory Guide 1.60.

Figure 3.7-1 shows the standard ABWR design values of the horizontal SSE spectra applied at the ground surface in the free field for damping ratios of 2.0, 5.0, 7.0 and 10.0% of critical values of the vertical SSE spectra applied at the ground surface in the free field for damping ratios of 2.0, 5.0, 7.0, and 10.0% of critical damping where the maximum vertical ground acceleration is 0.30 g at 33Hz, same as the maximum horizontal ground acceleration.

The design values of the OBE response spectra are one-half* of the spectra shown in Figures 3.7-1 and 3.7-2. These spectra are shown in Figures 3.7-3 through 3.7-20.

The design spectra are constructed in accordance with Regulatory Guide 1.60. The normalization factors for the maximum values in two horizontal directions are 1.0 and 1.0 as applied to Figure 3.7-1. For vertical direction, the normalization factor is 1.0 as applied to Figure 3.7-2.

3.7.1.2 Design Time History

The design time histories are synthetic acceleration time histories generated to match the design response spectra defined in Subsection 3.7.1.1.

The design time histories considered in GESSAR (Reference 1) are used. They are developed based on the method proposed by Vanmarcke and Cornell (Reference 2) because of its intrinsic capability of imposing statistical independence among the synthesized acceleration time history components. The earthquake acceleration time history components are identified as H1, H2, and V. The H1 and H2 are the two horizontal components mutually perpendicular to each other. Both H1 and H2 are based on the design horizontal ground spectra shown in Figure 3.7-1. The V is the vertical component and it is based on the design vertical ground spectra shown in Figure 3.7-2.

* *The OBE given in Chapter 2 is one-third of the SSE, i.e., 0.10 g, for the ABWR Standard Nuclear Island design. However, as discussed in Chapter 2, a more conservative value of one-half of the SSE, i.e., 0.15 g, was employed to evaluate the structural and component response.*

The magnitude of the SSE design time history is equal to twice the magnitude of the design OBE time history. The OBE time histories and response spectra are used for dynamic analysis and evaluation of the structural Seismic System; the OBE results are doubled for evaluating the structural adequacy for SSE. For development of floor response spectra for Seismic Subsystem analysis and evaluation, see Subsection 3.7.2.5.

The response spectra produced from the OBE design time histories are shown in Figures 3.7-3 through 3.7-20 along with the design OBE response spectra. The closeness of the two spectra in all cases indicates that the synthetic time histories are acceptable.

The response spectra from the synthetic time histories for the damping values of 1, 2, 3 and 4 percent conform to the requirement for an enveloping procedure provided in Item II.1.b of Section 3.7.1 of NUREG-0800 (Standard Review Plan, SRP). However, the response spectra for the higher damping values of 7 and 10 percent show that there are some deviations from the SRP requirement. This deviation is considered inconsequential, because (1) generating an artificial time history whose response spectra would envelop design spectra for five different damping values would result in very conservative time histories for use as design basis input, and (2) the response spectra from the synthetic time histories do envelop the design spectra for the lower damping values. This is very important because the loads due to SSE on structures should use 7 percent damping for concrete components, but are obtained by ratioing up the response from the OBE analysis involving the lower damping. The OBE analysis uses only the lower damping values (up to 4%), which are consistent with the SRP requirements (See Subsection 3.7.1.3).

(3) actual testing of equipment in accordance with one of the methods described in Subsection 3.9.2.2 and Section 3.10.

3.7.3.2 Determination of Number of Earthquake Cycles

3.7.3.2.1 Piping

Fifty (50) peak OBE cycles are postulated for fatigue evaluation.

3.7.3.2.2 Other Equipment and Components

Criterion II.2.b of SRP Section 3.7.3 recommends that at least one safe shutdown earthquake (SSE) and five operating basis earthquakes (OBEs) should be assumed during the plant life. It also recommends that a minimum of 10 maximum stress cycles per earthquake should be assumed (i.e., 10 cycles for SSE and 50 cycles for OBE). For equipment and components other than piping, 10 peak OBE stress cycles are postulated for fatigue evaluation based on the following justification.

To evaluate the number of cycles engendered by a given earthquake, a typical Boiling Water Reactor Building reactor dynamic model was excited by three different recorded time histories: May 18, 1940, El Centro NS component, 29.4 sec; 1952, Taft N69^0 W component, 30 sec; and March 1957, Golden Gates 89^{0}E component, 13.2 sec. The modal response was truncated so that the response of three different frequency bandwidths could be studied, 0^+-to-10 Hz, 10-to-20 Hz, and 20-to-50 Hz. This was done to give a good approximation to the cyclic behavior expected from structures with different frequency content.

Enveloping the results from the three earthquakes and averaging the results from several different points of the dynamic model, the cyclic behavior given in Table 3.7-6 was formed.

Independent of earthquake or component frequency, 99.5% of the stress reversals occur below 75% of the maximum stress level, and 95% of the reversals lie below 50% of the maximum stress level.

In summary, the cyclic behavior number of fatigue cycles of a component during a earthquake is found in the following manner:

(1) the fundamental frequency and peak seismic loads are found by a standard seismic analysis (i.e., from eigen extraction and forced response analysis);

(2) the number of cycles which the component experiences are found from Table 3.7-6 according to the frequency range within which the fundamental frequency lies; and

(3) for fatigue evaluation, one-half percent (0.005) of these cycles is conservatively assumed to be at the peak load, and 4.5% (0.045) at the three-quarter peak. The remainder of the cycles have negligible contribution to fatigue usage.

The SSE has the highest level of response. However, the encounter probability of the SSE is so small that it is not necessary to postulate the possibility of more than one SSE during the 60-year life of a plant. Fatigue evaluation due to the SSE is not necessary since it is a faulted condition and thus not required by ASME Code Section III.

The OBE is an upset condition and is included in fatigue evaluations according to ASME Code Section III. Investigation of seismic histories for many plants show that during a 60-year life it is probable that five earthquakes with intensities one-tenth of the SSE intensity, and one earthquake approximately 20% of the proposed SSE intensity, will occur. The 60-year life corresponds to 40 years of actual plant operation divided by a 67% usage factor. To cover the combined effects of these earthquakes and the cumulative effects of even lesser earthquakes, 10 peak OBE stress cycles are postulated for fatigue evaluation.

3.7.3.3 Procedure Used for Modeling

3.7.3.3.1 Modeling of Piping Systems

3.7.3.3.1.1 Summary

To predict the dynamic response of a piping system to the specified forcing function, the dynamic model must adequately account for all significant modes. Careful selection must be made of the proper response spectrum curves and proper location of anchors in order to separate Seismic Category I from non-Category I piping systems.

3.7.3.3.1.2 Selection of Mass Points

When performing a dynamic analysis, a piping system is idealized either as a mathematical model consisting of lumped masses connected by weightless elastic members or as a consistent mass model. The elastic members are given the properties of the piping system being analyzed. The mass points are carefully located to adequately represent the dynamic properties of the piping system. A mass point is located at the beginning and end of every elbow or valve, at the extended valve operator, and at the intersection of every tee. On straight runs, mass points are located at spacings no greater than the span length corresponding to 33 Hz. A mass point is located at every extended mass to account for torsional effects on the piping system. In addition, the increased stiffness and mass of valves are considered in the modeling of a piping system.

3.7.3.3.1.3 Selection of Spectrum Curves

In selecting the spectrum curve to be used for dynamic analysis of a particular piping system, a curve is chosen which most closely describes the accelerations existing at the end points and restraints of the system. The procedure for decoupling small branch lines from the main run of Seismic Category I piping systems when establishing the analytical models to perform seismic analysis are as follows:

(1) The small branch lines are decoupled from the main runs if they have a diameter less than one-third the diameter of the main run.

(2) The stiffness of all the anchors and its supporting steel is large enough to effectively decouple the piping on either side of the anchor for analytic and code jurisdictional boundary purposes. The RPV is very stiff compared to the piping system and therefore, it is modeled as an anchor. Penetration assemblies (head fittings and penetration sleeve pipe) are very stiff compared to the piping system and are modeled as anchors.

The stiffness matrix at the attachment location of the process pipe (i.e., main steam, RHR supply and return, RCIC, etc.) head fitting is sufficiently high to decouple the penetration assembly from the process pipe. Previous analysis indicates that a satisfactory minimum stiffness for this attachment point is equal to the stiffness in bending and torsion of a cantilevered pipe section of the same size as the process pipe and equal in length to three times the process pipe outer diameter.

For a piping system supported at more than two points located at different elevations in the building, the response spectrum analysis is performed using the envelope response spectrum of all attachment points. Alternatively, the multiple support excitation analysis methods may be used where acceleration time histories or response spectra are applied at all the piping attachment points. Finally, the worst single floor response spectrum selected from a set of floor response spectra obtained at various floors may be applied identically to all floors provided it envelops the other floor response spectra in the set.

3.7.3.3.2 Modeling of Equipment

For dynamic analysis, Seismic Category I equipment is represented by lumped-mass systems which consist of discrete masses connected by weightless springs. The criteria used to lump masses are:

(1) The number of modes of a dynamic system is controlled by the number of masses used; therefore, the number of masses is chosen so that all significant modes are included. The modes are considered as significant if the corresponding natural frequencies are less than 33 Hz and the stresses calculated from these modes are greater than 10% of the total stresses obtained from lower modes. This approach is acceptable provided at least 90% of the loading/inertia is contained in the modes used. Alternately,

where

R = combined response;

R_i = response to the i^{th} mode; and

N = number of modes considered in the analysis.

3.7.3.7.2.2 Double Sum Method

This method, as defined in Regulatory Guide 1.92, is mathematically:

$$R = \left(\sum_{k=1}^{N} \sum_{s=1}^{N} | R_k R_s | \epsilon_{ks} \right)^{1/2} \quad (3.7\text{-}18)$$

where

R = representative maximum value of a particular response of a given element to a given component of excitation;

R_k = peak value of the response of the element due to the k^{th} mode;

N = number of significant modes considered in the modal response combination; and

R_s = peak value of the response of the element attributed to s^{th} mode

where

$$\epsilon_{ks} = \left[1 + \left\{ \frac{(\omega'_k - \omega'_s)}{(\beta'_k \ \omega_k + \beta'_s \ \omega_s)} \right\}^2 \right]^{-1} \quad (3.7\text{-}19)$$

in which

$$\omega'_k = \omega_k \left[1 - \beta_k^2 \right]^{1/2}$$

$$\beta'_k = \beta_k + \frac{2}{t_d \, \omega_k}$$

where ω_k and β_k are the modal frequency and th. damping ratio in the kth mode, respectively, and t_d is the duration of the earthquake.

3.7.3.8 Analytical Procedure for Piping

3.7.3.8.1 Piping Subsystems Other Than NSSS

3.7.3.8.1.1 Qualification by Analysis

The methods used in seismic analysis vary according to the type of subsystems and supporting structure involved. The following possible cases are defined along with the associated analytical methods used.

3.7.3.8.1.2 Rigid Subsystems with Rigid Supports

If all natural frequencies of the subsystem are greater than 33 Hz, the subsystem is considered rigid and analyzed statically as such. In the static analysis, the seismic forces on each component of the subsystem are obtained by concentrating the mass at the center of gravity and multiplying the mass by the appropriate maximum floor acceleration.

3.7.3.8.1.3 Rigid Subsystems with Flexible Supports

If it can be shown that the subsystem itself is a rigid body (e.g., piping supported at only two points) while its supports are flexible, the overall subsystem is modeled as a single-degree-of-freedom subsystem consisting of an effective mass and spring.

The natural frequency of the subsystem is computed and the acceleration determined from the floor response spectrum curve using the appropriate damping value. A static analysis is performed using 1.5 times the acceleration value. In lieu of calculating the natural frequency, the peak acceleration from the spectrum curve may be used.

If the subsystem has no definite orientation, the excitation along each of three mutually perpendicular axes is aligned with respect to the system to produce maximum loading. The excitation in each of the three axes is considered to act simultaneously. The excitations are combined by the SRSS method.

3.7.3.8.1.4 Flexible Subsystems

If the piping subsystem has more than two supports, it cannot be considered a rigid body and must be modeled as a multi-degree-of-freedom subsystem.

The subsystem is modeled as discussed in Subsection 3.7.3.3.1 in sufficient detail (i.e., number of mass points) to ensure that the lowest natural frequency between mass points is greater than 33 Hz. The mathematical model is analyzed using a time-history analysis technique or a response spectrum analysis approach. After the natural frequencies of the subsystem are obtained, a stress analysis is performed using the inertia forces and equivalent static loads obtained from the dynamic analysis for each mode.

For a response spectrum analysis based on a modal superposition method, the modal response accelerations are taken directly from the spectrum. The total seismic stress is normally obtained by combining the modal stress using the SRSS method. The seismic stress of closely spaced modes (i.e., within 10% of the adjacent mode) are combined by absolute summation. The resulting total is treated as a pseudomode and is then combined with the remaining modal stresses by the SRSS method.

The approach is simple and straightforward in all cases where the group of modes with closely spaced frequencies is tightly bundled (i.e., the lowest and the highest modes of the group are within 10% of each other). However, when the group of closely spaced modes is spaced widely over the frequency range of interest while the frequencies of the adjacent modes are closely spaced, the absolute sum method of combining response tends to yield over-conservative results. To prevent this problem, a general approach applicable to all modes is considered appropriate. The following equation is merely a mathematical representation of this approach.

The most probable system response, R, is given by:

$$R = \left(\sum_{i=1}^{N} R_i^2 + 2\Sigma \left| R_\ell R_m \right| \right)^{1/2} \quad (3.7\text{-}20)$$

where the second summation is to be done on all ℓ and m modes whose frequencies are closely spaced to each other,

and where

R_i = response to the i^{th} mode

N = number of significant modes considered in the modal response combinations.

The excitation in each of the three major orthogonal directions is considered to act simultaneously with their effect combined by the SRSS method.

3.7.3.8.1.5 Static Analysis

A static analysis is performed in lieu of a dynamic analysis by applying the following forces at the concentrated mass locations (nodes) of the analytical model of the piping system:

(1) horizontal static load, $F_h = C_h W$, in one of the horizontal principal directions;

(2) equal static load, F_h, in the other horizontal principal direction; and

(3) vertical static load, $F_v = C_v W$;

where

C_h, C_v = multipliers of the gravity acceleration, g, determined from the horizontal and vertical floor response spectrum curves, respectively. (They are functions of the period and the appropriate damping of the piping system); and

W = weight at node points of the analytical model.

Magnetic tape recording and playback units are provided for multiple channel recording and playback of the THA accelerometer signals. The data recordings include an additional recorded channel for the timing reference signal generated in the control unit. The recording and playback systems have a special cabinet furnished for those instruments and devices necessary for system testing, annunciating, calibration, and control. This cabinet is located in the control equipment room.

3.7.4.2.2 Peak Recording Accelerographs

Each sensor unit contains three peak-recording accelerographs mounted in a mutually orthogonal array. The units are unpowered and record peak accelerations triaxially by proportional scratches on record plates. The PRAs that are mounted directly on equipment have one axis coincident with the principal equipment axis. All other PRAs have their principal axes oriented identically with one horizontal axis parallel to the major horizontal axis assumed in the seismic analysis.

One PRA is located on a reactor water cleanup unit (RWCU) regenerative heat exchanger support. A second PRA is located on an RHR pipe support. A third PRA is located on a diesel generator support.

Data from PRAs must be manually retrieved following an earthquake and is used in the detailed investigations for particular structures, systems, and equipment.

3.7.4.2.3 Seismic Switches

One triaxial seismic switch (SS) is installed on the reactor building foundation. This device actuates a visual and audible annunciator in the main control room when the OBE acceleration on at least one of the axes has been exceeded. When the threshold acceleration is sensed, the relay closes and remains closed for an adjustable period after the threshold is no longer exceeded.

3.7.4.2.4 Response Spectrum Recorders

The response spectrum recorders measure both horizontal and vertical peak acceleration for a series of frequencies pertinent to specific structures and equipment. Response spectra are recorded for three mutually orthogonal directions at the sensor location by inscribing steel reed deflections upon record plates. One recorder is located on the reactor building foundation in a clean zone. Another recorder is located on the control building foundation. If the OBE design response spectra values for specific frequencies are exceeded during an earthquake, specific switches mounted in the recorders annunciate the specific frequencies in the control equipment room.

Two other recorders do not contain alarm contacts. One is mounted in the reactor building pipe tunnel on a 20-inch RHR line and another is on a FMCRD control panel support.

3.7.4.2.5 Recording and Playback Equipment

A cabinet located in the control equipment room houses the recording, playback, and calibration units that are used in conjunction with the THA sensors to produce a time-history record of the earthquake. It also contains audible and visual annunciators wired to display initiation of the THA recorder and the power supply components for all equipment contained within the cabinet.

3.7.4.3 Control Room Operator Notification

Activation of the seismic triggers causes an audible and visual annunciation in the main control room to alert the plant operator that an earthquake has occurred. The annunciation is set to occur at 0.01g vertical acceleration on the free field.

The triggers cause initiation of the THA recording system at horizontal or vertical acceleration levels slightly higher than the expected background level including induced vibrations from sources such as traffic, elevators, people, and machinery. The initial set points may be changed once significant plant operating data have been obtained which indicate that a different setpoint would provide better THA system operation.

Audible and visual annunciators are provided in the main control room to indicate whether the OBE floor accelerations have been exceeded for the seismic switch location.

The peak acceleration level experienced by the reactor building basemat is available immediately following the earthquake. This is obtained by playing back the recorded THA data from the basemat location and reading the peak value from a strip chart recorder.

Significant response spectra from the reactor building basemat are available immediately following an earthquake for comparison with the OBE and SSE response spectra.

3.7.4.4 Comparison of Measured and Predicted Responses

Initial determination of the earthquake level is performed immediately after the earthquake by comparing the measured response spectra from the reactor building basemat with the OBE and SSE response spectra for the corresponding location. If the measured spectra exceed the OBE response spectra, the plant is shut down and a detailed analysis of the earthquake motion is undertaken.

After any earthquake, the data from all seismic recorders and recording instruments are retrieved. When the OBE has been exceeded, the data from these instruments are analyzed to obtain the seismic accelerations experienced at the location of major Seismic Category I structures and equipment. The measured response from the time-history accelerographs, peak-recording accelerographs, and response spectrum recorders are used to determine the response spectra at the location of each Seismic Category I structure and system. These spectra are compared with those used in the design to determine whether the structure or system is still adequate for future use. Peak-recording accelerographs mounted on equipment are used to determine whether the design limitation of that specific equipment has been exceeded.

The theoretical structural response and measured structural responses are compared to assess the degree of conservatism in the analytical predictions. Seismic levels are established to determine whether the plant can be brought back on line. The criteria consider system design and dynamic analysis in establishing the acceptable levels for continued operation.

3.7.4.5 In-Service Surveillance

Each of the seismic instruments will be demonstrated operable by the performance of the channel check, channel calibration, and channel functional test operations at the intervals specified in Table 3.7-9.

3.7.5 COL License Information

3.7.5.1 Seismic Parameters

The design basis horizontal g value is 0.3g for SSE and 0.15g for OBE. These are maximum free-field ground accelerations at the site as measured at the existing grade level near the ABWR. The response spectra are presented in Subsection 3.7.1. The range of site parameters used to establish the design basis seismic parameters is presented in Appendix 3A.

3.7.6 References

1. General Electric Company BWR/6-238 *Standard Safety Analysis Report (GESSAR)*, Docket No. STN 50-447, November 7, 1975.

2. E. H. Vanmarcke and C. A. Cornell, *Seismic Risk and Design Response Spectra*, ASCE Specialty Conference on Safety and Reliability of Metal Structures, Pittsburgh, Pennsylvania, November 1972.

3. NUREG-0800, *Standard Review Plan*, Section 3.7.1.

4. L. K. Liu, *Seismic Analysis of the Boiling Water Reactor*, symposium on seismic analysis of pressure vessel and piping components, First National Congress on Pressure Vessel and Piping, San Francisco, California, May 1971.

SECTION 3.9

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TABLES

pletion of preoperational testing, the reactor vessel head and the shroud head are removed, the vessel is drained, and major components are inspected on a selected basis. The inspections cover the shroud, shroud head, core support structures, recirculation internal pumps, the peripheral control rod drive, and incore guide tubes. Access is provided to the reactor lower plenum for these inspections.

The analysis, design and/or equipment that are to be utilized in a facility will comply with Regulatory Guide 1.20 as explained below.

Regulatory Guide 1.20 describes a comprehensive vibration assessment program for reactor internals during preoperational and initial startup testing. The vibration assessment program meets the requirements of Criterion 1, Quality Standards and Record, Appendix A to 10CFR50 and Section 50.34, Contents of Applications; Technical Information, of 10CFR50. This Regulatory Guide is applicable to the core support structures and other reactor internals.

Vibration testing of reactor internals is performed on all GE-BWR plants. At the time of original issue of Regulatory Guide 1.20, test programs for compliance were instituted for the then designed reactors. The first ABWR plant is considered a prototype and is instrumented and subjected to preoperation and startup flow testing to demonstrate that flow-induced vibrations similar to those expected during operation will not cause damage. Subsequent plants which have internals similar to those of the prototypes are also tested in compliance with the requirements of Regulatory Guide 1.20. GE is committed to confirm satisfactory vibration performance of internals in these plants through preoperational flow testing followed by inspection for evidence of excessive vibration. Extensive vibration measurements in prototype plants together with satisfactory operating experience in all BWR plants have established the adequacy of reactor internal designs. GE continues these test programs for the generic plants to verify structural integrity and to establish the margin of safety.

See Subsection 3.9.7.1 for COL license information pertaining to the reactor internals vibration testing program.

3.9.2.5 Dynamic System Analysis of Reactor Internals Under Faulted Conditions

The faulted events that are evaluated are defined in Subsection 3.9.5.2.1. The loads that occur as a result of these events and the analysis performed to determine the response of the reactor internals are as follows:

(1) **Reactor Internal Pressures** - The reactor internal pressure differentials (Figure 3.9-1a) due to assumed break of main steam or feedwater line are determined by analysis as described in Subsection 3.9.5.2.2. In order to assure that no significant dynamic amplification of load occurs as a result of the oscillatory nature of the blowdown forces during an accident, a comparison is made of the periods of the applied forces and the natural periods of the core support structures being acted upon by the applied forces. These periods are determined from a comprehensive vertical dynamic model of the RPV and internals with 12 degrees of freedom. Besides the real masses of the RPV and core support structures, account is made for the water inside the RPV.

(2) **External Pressure and Forces on the Reactor Vessel**-An assumed break of the main steam line, the feedwater line or the RHR line at the reactor vessel nozzle results in jet reaction and impingement forces on the vessel and asymmetrical pressurization of the annulus between the reactor vessel and the shield wall. These time-varying pressures are applied to the dynamic model of the reactor vessel system. Except for the nature and locations of the forcing functions the dynamic model and the dynamic analysis method are identical to those for seismic analysis as described below. The resulting loads on the reactor internals, defined as LOCA loads, are considered as shown in Table 3.9.2.

(3) **Safety/Relief Valve Loads (SRV Loads)**-The discharge of the SRVs result in reactor building vibration (RBV) due to suppression pool dynamics as described in Appendix 3B. The response of the reactor

210.33

internals to the RBV is also determined with dynamic model and dynamic analysis method described below for seismic analysis.

(4) **LOCA Loads**-The Assumed LOCA also results in RBV due to suppression pool dynamics as described in Appendix 3B and the response of the reactor internals are again determined with the dynamic model and dynamic analysis method used for seismic analysis. Various types of LOCA loads are identified on Table 3.9-2.

(5) **Seismic Loads**-The theory, methods, and computer codes used for dynamic analysis of the reactor vessel, internals, attached piping and adjoining structures are described in Section 3.7 and Subsection 3.9.1.2. Dynamic analysis is performed by coupling the lumped-mass model of the reactor vessel and internals with the building model to determine the system natural frequencies and mode shapes. The
210.33 relative displacement, acceleration, and load response is then determined by either the time-history method or the resonse-spectrum method. The load on the reactor internals due to faulted event SSE are obtained from this analysis.

The above loads are considered in combination as defined in Table 3.9-2. The SRV, LOCA (SBL, IBL or LBL) and SSE loads as defined in Table 3.9-2 are all assumed to act in the same direction. The peak colinear responses of the reactor internals to each of these loads are added by the square root of the sum of the squares (SRSS) method. The resultant stresses in the reactor internal structures are directly added with stress resulting from the static and steady state loads in the faulted load combination, including the stress due to peak reactor internal pressure differential during the LOCA. The reactor internals satisfy the stress deformation and fatigue limits as defined in Subsection 3.9.5.3.

3.9.2.6 Correlations of Reactor Internals Vibration Tests With the Analytical Results

Prior to initiation of the instrumented vibration measurement program for the prototype plant, extensive dynamic analyses of the reactor and internals are performed. The results of these analyses are used to generate the allowable vibration levels during the vibration test. The vibration data obtained during the test will be analyzed in detail.

The results of the data analyses, vibration amplitudes, natural frequencies, and mode shapes are then compared to those obtained from the theoretical analysis.

Such comparisons provide the analysts with added insight into the dynamic behavior of the reactor internals. The additional knowledge gained from previous vibration tests has been utilized in the generation of the dynamic models for seismic and loss of coolant accident (LOCA) analyses for this plant. The models used for this plant are similar to those used for the vibration analysis of earlier prototype BWR plants.

3.9.3 ASME Code Class 1, 2, and 3 Components, Component Supports, and Core Support Structures

3.9.3.1 Loading Combinations, Design Transients, and Stress Limits

This section delineates the criteria for selection and definition of design limits and loading combination associated with normal operation, postulated accidents, and specified seismic and other reactor building vibration (RBV) events for the design of safety-related ASME Code components (except containment components which are discussed in Section 3.8).

This section discusses the ASME Class 1, 2, and 3 equipment and associated pressure retaining parts and identifies the applicable loadings, calculation methods, calculated stresses, and allowable stresses. A discussion of major equipment is included on a component-by-component basis to provide examples. Design transients and dynamic loading for ASME Class 1, 2, and 3 equipment are covered in Subsection 3.9.1.1. Seismic-related loads and dynamic analyses are discussed in Section 3.7. The suppression pool-related RBV loads are described in Appendix 3B. Table 3.9-2 presents the combinations of dynamic events to be considered for the design and analysis of all ABWR ASME Code Class 1, 2, and 3 components, component supports, core support structures and equipment. Specific loading combinations considered for evaluation of each specific equipment are derived from Table 3.9-2 and are contained in the design specifications and/or design reports of the respective equipment. (See Subsection 3.9.7.4 for COL license information)

Table 3.9-2 also presents the evaluation models and criteria. The predicted loads or stresses and the design or allowable values for the most critical areas of each component are compared in accordance with the applicable code criteria or other limiting criteria. The calculated results meet the limits.

The design life for the ABWR Standard Plant is 60 years. A 60 year design life is a requirement for all major plant components with reasonable expection of meeting this design life. However, all plant operational components and equipment except the reactor vessel are designed to be replaceable, design life not withstanding. The design life requirement allows for refurbishment and repair, as appropriate, to assure the design life of the overall plant is achieved. In effect, essentially all piping systems, components and equipment are designed for a 60 year design life. Many of these components are classified as ASME Class 2 or 3 or Quality Group D. Applicants referencing the ABWR design will identify these ASME Class 2, 3 amd Quality Group D components and provide the analyses required by the ASME Code, Subsection NB. These analysis will include the appropriate operating vibration loads and for the effects of mixing hot and cold fluids.

3.9.3.1.1 Plant Conditions

All events that the plant will or might credibly experience during a reactor year are evaluated to establish design basis for plant equipment. These events are divided into four plant conditions. The plant conditions described in the following paragraphs are based on event probability (i.e., frequency of occurrence as discussed in Subsection 3.9.3.1.1.5) and correlated to service levels for design limits defined in the ASME Boiler and Pressure Vessel Code Section III as shown in Tables 3.9-1 and 3.9-2.

3.9.3.1.1.1 Normal Condition

Normal conditions are any conditions in the course of system startup, operation in the design power range, normal hot standby (with condenser available), and system shutdown other than upset, emergency, faulted, or testing.

3.9.3.1.1.2 Upset Condition

An upset condition is any deviation from normal conditions anticipated to occur often enough that design should include a capability to withstand the conditions without operational impairment. The upset conditions include system operational transients (SOT) which result from any single operator error or control malfunction, from a fault in a system component requiring its isolation from the system, from a loss of load or power, or from an operating basis earthquake. Hot standby with the main condenser isolated is an upset condition.

3.9.3.1.1.3 Emergency Condition

An emergency condition includes deviations from normal conditions which require shutdown for correction of the condition(s) or repair of damage in the reactor coolant pressure boundary (RCPB). Such conditions have a low probability of occurrence but are included to provide assurance that no gross loss of structural integrity will result as a concomitant effect of any damage developed in the system. Emergency condition events include but are not limited to infrequent operational transients (IOT) caused by one of the following: (a) a multiple valve blowdown of the reactor vessel; (b) LOCA from a small break or crack (SBL) which does not depressurize the reactor systems, does not actuate automatically the ECCS operation, nor results in leakage beyond normal makeup system capacity, but which requires the safety functions of isolation of containment and shutdown and may involve inadvertent actuation of automatic depressurization system (ADS); (c) improper assembly of the core during refueling; or (d) improper or sudden start of one recirculation pump. Anticipated transient without scram (ATWS) or reactor overpressure with delayed scam (see Tables 3.9-1 and 3.9-2) is an IOT classified as an emergency condition.

3.9.3.1.1.4 Faulted Condition

A faulted condition is any of those combinations of conditions associated with extremely low-probability postulated events whose consequences are such that the integrity and operability of the system may be impaired to the extent that considerations of public health and safety are involved. Faulted conditions encompass events, such as LOCA, that are postulated because their consequences would include the potential for the release of significant amounts of radioactive material. These events are the most drastic that must be considered in the design and thus represent limiting design bases. Faulted condition events include but are not limited to one of the following: (a) a control rod drop accident; (b) a fuel-handling accident; (c) a main steam line or feedwater line break; (d) the combination of any small/intermediate break LOCA (SBL or IBL) with the safe shutdown earthquake, and a loss of offsite power; or (e) the safe shutdown earthquake plus large break LOCA (LBL) plus a loss of offsite power.

The IBL classification covers those breaks for which the ECCS system operation will occur during the blowdown, and which results in reactor depressurization. The LBL classification covers the sudden, double ended severance of a main steam line inside or outside the containment that results in transient reactor depressurization, or any pipe rupture of equivalent flow cross sectional area with similar effects.

3.9.3.1.1.5 Correlation of Plant Condition with Event Probability

The probability of an event occurring per reactor year associated with the plant conditions is listed below. This correlation identifies the appropriate plant conditions and assigns the appropriate ASME Section III service levels for any hypothesized event or sequence of events.

Plant Condition	ASME Code Service Level	Event Encounter Probability per Reactor Year
Normal (planned)	A	1.0
Upset (moderate probability)	B	$1.0 > P \geq 10^{-2}$
Emergency (low probability)	C	$10^{-2} > P \geq 10^{-4}$
Faulted (extremely low probability)	D	$10^{-4} > P > 10^{-6}$

3.9.3.1.1.6 Safety Class Functional Criteria

For any normal or upset design condition event Safety Class 1, 2, and 3 equipment and piping (see Subsection 3.2.3) shall be capable of accomplishing its safety functions as required by the event and shall incur no permanent changes that could deteriorate its ability to accomplish its safety functions as required by any subsequent design condition event.

For any emergency or faulted design condition event, Safety Class 1, 2, and 3 equipment and piping shall be capable of accomplishing its safety functions as required by the event but repairs could be required to ensure its ability to accomplish its safety functions as required by any subsequent design condition event.

Specific stress criteria to meet the functional requirements are identified in a footnote to Table 3.9-2.

3.9.3.1.2 Reactor Pressure Vessel Assembly

The reactor vessel assembly consists of the reactor pressure vessel, vessel support skirt, and shroud support.

The reactor pressure vessel, vessel support skirt, and shroud support are constructed in accordance with the ASME Boiler and Pressure Vessel Code Section III. The shroud support consists of the shroud support plate and the shroud support cylinder and its legs. The reactor pressure vessel assembly components are classified as an ASME Class 1. Complete stress reports on these components are prepared in accordance with ASME Code requirements. NUREG-0619 (Reference 5) is also considered for feedwater nozzle and other such RPV inlet nozzle design.

The stress analysis is performed on the reactor pressure vessel, vessel support skirt, and shroud support for various plant operating conditions (including faulted conditions) by using the elastic methods except as noted in Subsection 3.9.1.4.2. Loading conditions, design stress limits, and methods of stress analysis for the core support structures and other reactor internals are discussed in Subsection 3.9.5.

3.9.3.1.3 Main Steam (MS) System Piping

210.6 210.36 The piping systems extending from the reactor pressure vessel to and including the outboard main steam isolation valve are constructed in accordance with the ASME Boiler and Pressure Vessel Code Section III, Class 1 criteria. The rules contained in Appendix F of ASME Code Section III are used in evaluating faulted loading conditions independently of other design and operating conditions. Stresses calculated on an elastic basis are evaluated in accordance with F-1360.

The MS system piping extending from the outboard main steam isolation valve to the turbine stop valve is constructed in accordance with the ASME Boiler and Pressure Vessel Code Section III, Class 2 Criteria. 210.36

3.9.3.1.4 Recirculation Motor Cooling (RMC) Subsystem

The RMC system piping loop between the recirculation motor casing and the heat exchanger is constructed in accordance with the ASME Boiler and Pressure Vessel Code Section III, Subsection NB-3600. The rules contained in Appendix F of ASME Code Section III are used in evaluating faulted loading conditions independently of all other design and operating conditions. Stresses calculated on an elastic basis are evaluated in accordance with F-1360. 210.36

3.9.3.1.5 Recirculation Pump Motor Pressure Boundary

The motor casing of the recirculation internal pump is a part of and welded into an RPV nozzle and is constructed in accordance with the requirements of an ASME Boiler and Pressure Vessel Code Section III, Class 1 component. The motor cover is a part of the pump/motor assembly and is constructed as an ASME Class 1 component. These pumps are not required to operate during the safe shutdown earthquake or after an accident. 210.36

3.9.3.1.6 Standby Liquid Control (SLC) Tank

The standby liquid control tank is constructed in accordance with the requirements of an ASME Boiler and Pressure Vessel Code Section III, Class 2 component. 210.76

3.9.3.1.7 RRS and RHR Heat Exchangers

The primary and secondary sides of the RRS (reactor recirculation system) are constructed in accordance with the requirements of an ASME Boiler and Pressure Vessel Code Section III, Class 1 and Class 2 component, respectively. The primary and secondary side of the RHR system heat exchanger is constructed as an ASME Class 2 and Class 3 component respectively. 210.36

3.9.3.1.8 RCIC Turbine

Although not under the jurisdiction of the ASME Code, the RCIC turbine is designed and evaluated and fabricated following the basic guidelines of ASME Code Section III for Class 2 components.

3.9.3.1.9 ECCS Pumps

210.36 The RHR, RCIC, and HPCF pumps are constructed in accordance with the requirements of an ASME Code Section III, Class 2 component.

3.9.3.1.10 Standby Liquid Control (SLC) Pump

210.36 The SLC system pump is constructed in accordance with the requirements for ASME Code Section III, Class 2 component.

3.9.3.1.11 Standby Liquid Control (SLC) Valve (Injection Valve)

210.36 The SLC system injection valve is constructed in accordance with the requirements for ASME Code Section III, Class 1 component.

3.9.3.1.12 Main Steam Isolation and Safety/Relief Valves

210.36 The main steam isolation valves and SRVs are constructed in accordance with ASME Boiler and Pressure Vessel Code Section III, Subsection NB-3500, requirements for Class 1 component.

3.9.3.1.13 Safety/Relief Valve Piping

The relief valve discharge piping extending from the relief valve discharge flange to the diaphram floor penetration is constructed in accordance with ASME Boiler and Pressure Vessel Code Section III, requirements for Class 3 components. The relief valve discharge piping extending from the diaphram floor penetration to the quenchers is constructed in accordance with ASME Boiler and Pressure Vessel Code, Section III, requirements for Class 2 components.

3.9.3.1.14 Reactor Water Cleanup (RWCU) System Pump and Heat Exchangers

The RWCU pump and heat exchangers (regenerative and nonregenerative) are not part of a safety system and are non-Seismic Category I equipment. ASME Boiler and Pressure Vessel Code Section III for Class 3 components is used as a guide in constructing the RWCU System pump and heat exchanger components. 210.36

3.9.3.1.15 Fuel Pool Cooling and Cleanup System Pumps and Heat Exchangers

The pumps and heat exchangers are constructed in accordance with the requirements for ASME Boiler and Pressure Vessel Code Section III, Class 3 component. 210.36

3.9.3.1.16 ASME Class 2 and 3 Vessels

The Class 2 and 3 vessels (all vessels not previously discussed) are constructed in accordance with the ASME Boiler and Pressure Vessel Code Section III. The stress analysis of these vessels is performed using elastic methods. 210.36

3.9.3.1.17 ASME Class 2 and 3 Pumps

The Class 2 and 3 pumps (all pumps not previously discussed) are designed and evaluated in accordance with the ASME Boiler and Pressure Vessel Code Section III. The stress analysis of these pumps is performed using elastic methods. See Subsection 3.9.3.2 for additional information on pump operability. 210.36

3.9.3.1.18 ASME Class 1, 2 and 3 Valves

The Class 1, 2, and 3 valves (all valves not previously discussed) are constructed in accordance with the ASME Boiler and Pressure Vessel Code Section III. 210.36

All valves and their extended structures are designed to withstand the accelerations due to seismic and other RBV loads. The attached piping is supported so that these accelerations are not exceeded. The stress analysis of these valves is performed using elastic methods. See Subsection 3.9.3.2 for additional information on valve operability.

3.9.3.1.19 ASME Class 1, 2 and 3 Piping

The Class 1, 2 and 3 piping (all piping not previously discussed) is constructed in accord- 210.36

ance with the ASME Boiler and Pressure Vessel Code Section III. For Class 1 piping, for the faulted plant condition, stresses are calculated on an elastic basis and evaluated in accordance with Appendix F of the Code. For Class 2 and 3 piping, stresses are calculated on an elastic basis and evaluated in accordance with NC/ND-3600 of the Code.

3.9.3.2 Pump and Valve Operability Assurance

Active mechanical (with or without electrical operation) equipment are Seismic Category I and each is designed to perform a mechanical motion for its safety-related function during the life of the plant under postulated plant conditions. Equipment with faulted condition functional requirements include active pumps and valves in fluid systems such as the residual heat removal system, emergency core cooling system, and main steam system.

This Subsection discusses operability assurance of active ASME Code Section III pumps and valves, including motor, turbine or operator that is a part of the pump or valve (See Subsection 3.9.2.2).

Safety-related valves and pumps are qualified by testing and analysis and by satisfying the stress and deformation criteria at the critical locations within the pumps and valves. Operability is assured by meeting the requirements of the programs defined in Subsection 3.9.2.2, Section 3.10, Section 3.11 and the following subsections.

Section 4.4 of GE's Environmental Qualification Program (Reference 6) applies to this subsection, and the seismic qualification methodology presented therein is applicable to mechanical as well as electrical equipment.

3.9.3.2.1 ECCS Pumps, Motors and Turbine

Dynamic qualification of the ECCS (RHR, RCIC and HPCF) pumps with motor or turbine assembly is also described in Subsections 3.9.2.2.2.6 and 3.9.2.2.2.7.

3.9.3.2.1.1 Consideration of Loading, Stress, and Acceleration Conditions in the Analysis

In order to avoid damage to the ECCS pumps during the faulted plant condition, the stresses caused by the combination of normal operating loads, SSE, other RBV loads, and dynamic system loads are limited to the material elastic limit. A three dimensional finite-element model of the pump and associated motor (see Subsections 3.9.3.2.2 and 3.9.3.2.1.5 for RCIC pump and turbine, respectively) and its support is developed and analyzed using the response spectrum and the dynamic analysis method. The same is analyzed due to static nozzle loads, pump thrust loads, and dead weight. Critical location stresses are compared with the allowable stresses and the critical location deflections with the allowables; and accelerations are checked to evaluate operability. The average membrane stress σm for the faulted condition loads is limited to 1.2S or approximately 0.75 σ_y (σ_y = yield stress), and the maximum stress in local fibers (σm + bending stress σb) is limited to 1.8S or approximately 1.1 σ_y. The max- imum faulted event nozzle loads are also con- sidered in an analysis of the pump supports to assure that a system misalignment cannot occur.

Performing these analyses with the conservative loads stated and with the restrictive stress limits as allowables assures that critical parts of the pump and associated motor or turbine will not be damaged during the faulted condition and that the operability of the pump for post-faulted condition operation will not be impaired.

3.9.3.2.1.2 Pump/Motor Operation During and Following Dynamic Loading

Active ECCS pump/motor rotor combinations are designed to rotate at a constant speed under all conditions. Motors are designed to withstand short periods of severe overload. The high rotary inertia in the operating pump

3.9.3.4 Component Supports

The design of bolts for component supports is specified in the ASME Code Section III, Subsection NF. Stress limits for bolts are given in NF-3225. The rules and stress limits which must be satisfied are those given in NF-3324.6 multiplied by the appropriate stress limit factor for the particular service loading level and stress category specified in Table NF-3225.2-1.

Moreover, on equipment which is to be, or may be, mounted on a concrete support, sufficient holes for anchor bolts are provided to limit the anchor bolt stress to less than 10,000 psi on the nominal bolt area in shear or tension.

Concrete anchor bolts which are used for pipe support base plates will be designed to the applicable factors of safety which are defined in I&E Bulletin 79-02, "Pipe Support Base Plate Designs Using Concrete Expansion Anchor Bolts," Revision 1 dated June 21,1979.

3.9.3.4.1 Piping

Supports and their attachments for essential ASME Code Section III, Class 1,2, and 3 piping are designed in accordance with Subsection NF* up to the interface of the building structure. The building structure component supports are designed in accordance with ANSI/AISC N690, Nuclear Facilities-Steel Safety-Related Structures for Design, Fabrication and Erection or AISC specification for the Design, Fabrication, and Erection of Structural Steel for buildings.

*Augmented by the following: (1) application of Code Case N-476, Supplement 89.1 which governs the design of single angle members of ASME Class 1,2,3 and MC linear component supports; and (2) when eccentric loads or other torsional loads are not accommodated by designing the load to act through the shear center or meet "Standard for Steel Support Design", analyses will be performed in accordance with torsional analysis methods such as: "Torsional Analysis of Steel Members, USS Steel Manual", Publication T114-2/83.

correspond to those used for design of the supported pipe. The component loading combinations are discussed in Subsection 3.9.3.1. The stress limits are per ASME III, Subsection NF and Appendix F. Supports are generally designed either by load rating method per paragraph NF-3260 or by the stress limits for linear supports per paragraph NF-3231. The critical buckling loads for the Class 1 piping supports subjected to faulted loads that are more severe than normal, upset and emergency loads, are determined by using the methods discussed in Appendices F and XVII of the Code. To avoid buckling in the piping supports, the allowable loads are limited to two thirds of the determined critical buckling loads.

The design of all supports for non-nuclear piping satisfies the requirements of ANSI B31.1, Paragraphs 120 and 121.

For the major active valves identified in Subsection 3.9.3.2.4, the valve operators are not used as attachment points for piping supports.

The design criteria and dynamic testing requirements for the ASME III piping supports are as follows:

(1) Piping Supports - All piping supports are designed, fabricated, and assembled so that they cannot become disengaged by the movement of the supported pipe or equipment after they have been installed. All piping supports are designed in accordance with the rules of Subsection NF of the ASME Code up to the building structure interface as defined in the project design specifications.

(2) Spring Hangers - The operating load on spring hangers is the load caused by dead weight. The hangers are calibrated to ensure that they support the operating load at both their hot and cold load settings. Spring hangers provide a specified down travel and up travel in excess of the specified thermal movement.

(3) Snubbers - The operating loads on snubbers are the loads caused by dynamic events (e.g., seismic, RBV due to LOCA and SRV discharge, discharge through a relief valve line or valve closure) during various operating conditions. Snubbers restrain piping against response to the vibratory excitation and to the associated differential movement of the piping system support anchor points. The criteria for locating snubbers and ensuring adequate load capacity, the structural and mechanical performance parameters used for snubbers and the installation and inspection considerations for the snubbers are as follows:

(a) Required Load Capacity and Snubber Location

The entire piping system including valves and support system between anchor points is mathematically modeled for complete piping structural analysis. In the dynamic analysis, the snubbers are modeled as a spring with a given spring stiffness depending on the snubber size. The analysis determines the forces and moments acting on each piping components and the forces acting on the snubbers due to all dynamic loading and operating conditions defined in the piping design specification. The forces on snubbers are operating loads for various operating conditions. The calculated loads cannot exceed the snubber design load capacity for various operating conditions, i.e., design, normal, upset, emergency and faulted.

Subsection 3.9.2.5. Dynamic analysis is performed by coupling the lumped-mass model of the reactor vessel and internals with the building model to determine the system natural frequencies and node shapes. The relative displacement, acceleration, and load response is then determined by either the time-history method or the response-spectrum method.

3.9.5.3 Design Bases

3.9.5.3.1 Safety Design Bases

The reactor internals including core support structures shall meet the following safety design bases:

(1) The reactor vessel nozzles and internals shall be so arranged as to provide a floodable volume in which the core can be adequately cooled in the event of a breach in the nuclear system process barrier external to the reactor vessel;

(2) Deformation of internals shall be limited to assure that the control rods and core standby cooling systems can perform their safety-related functions; and

(3) Mechanical design of applicable structures shall assure that safety design bases (1) and (2) are satisfied so that the safe shutdown of the plant and removal of decay heat are not impaired.

3.9.5.3.2 Power Generation Design Bases

The reactor internals including core support structures shall be designed to the following power generation design bases:

(1) The internals shall provide the proper coolant distribution during all anticipated normal operating conditions to allow power operation of the core without fuel damage;

(2) The internals shall be arranged to facilitate refueling operations; and

(3) The internals shall be designed to facilitate inspection.

3.9.5.3.3 Design Loading Categories

The basis for determining faulted dynamic event loads on the reactor internals is shown in Sections 3.7, 3.8 and Subsections 3.9.2.5, 3.9.5.2.3 and 3.9.5.2.4. Table 3.9-2 shows the load combinations used in the analysis.

Core support structures and safety class internals stress limits are consistent with ASME Code Section III, Subsection NG. For these components, Level A, B, C, and D service limits are applied to the normal, upset, emergency, and faulted loading conditions, respectively, as defined in the design specification. Stress intensity and other design limits are discussed in Subsections 3.9.5.3.5 and 3.9.5.3.6

3.9.5.3.4 Response of Internals Due to Steam Line Break Accident

As described in Subsection 3.9.5.2.3.2, the maximum pressure loads acting on the reactor internal components result from steam line break upstream of the main steam isolation valve and, on some components, the loads are greatest with operation at the minimum power associated with the maximum core flow (Table 3.9-3, Case 2). This has been substantiated by the analytical comparison of liquid versus steam line breaks and by the investigation of the effects of core power and core flow.

It has also been pointed out that, although possible, it is not probable that the reactor would be operating at the rather abnormal condition of minimum power and maximum core flow. More realistically, the reactor would be at or near a full power condition and thus the maximum pressure loads acting on the internal components would be as listed under Case 1 in Table 3.9-3.

3.9.5.3.5 Stress and Fatigue Limits for Core Support Structures

The design and construction of the core support structures are in accordance with ASME Code Section III, Subsection NG.

3.9.5.3.6 Stress, Deformation, and Fatigue Limits for Safety Class and Other Reactor Internals (Except Core Support Structures)

For safety class reactor internals, the stress deformation and fatigue criteria listed in Tables 3.9-4 through 3.9-7 are based on the criteria established in applicable codes and standards for similar equipment, by manufacturers standards, or by empirical methods based on field experience and testing. For the quantity SF_{min} (minimum safety factor) appearing in those tables, the following values are used:

Service Level	Service Condition	SF_{min}
A	Normal	2.25
B	Upset	2.25
C	Emergency	1.5
D	Faulted	1.125

Components inside the reactor pressure vessel such as control rods which must move during accident condition have been examined to determine if adequate clearances exist during emergency and faulted conditions. No mechanical clearance problems have been identified. The forcing functions applicable to the reactor internals are discussed in Subsection 3.9.2.5.

The design criteria, loading conditions, and analyses that provide the basis for the design of the safety class reactor internals other than the core support structures meet the guidelines of NG-3000 and are constructed so as not to adversely affect the integrity of the core support structures (NG-3122).

The design requirements for equipment classified as non-safety (other) class internals (e.g., steam dryers and shroud heads) are specified with appropriate consideration of the intended service of the equipment and expected plant and environmental conditions under which it will operate. Where Code design requirements are not applicable, accepted industry or engineering practices are used.

3.9.6 Inservice Testing of Pumps and Valves

Inservice testing of safety-related pumps and valves will be performed in accordance with the requirements of Section XI, Subsection IWP and IWV, of the ASME Code. Table 3.9-8 lists the inservice testing parameters and frequencies for the safety-related pumps and valves. Valves having a containment isolation function are also noted in the listing. Code testing flexibility in the ASME/ANSI O&M Part 6 for pumps and Part 10 for valves produced no need for relief requests. A review of field experience for typical BWR testing problems also showed the Code encompassed common relief requests. Inservice inspection is discussed in Subsection 5.2.4 and Section 6.6. 210.47

Details of the inservice testing program, including test schedules and frequencies will be reported in the inservice inspection and testing plan which will be provided by the applicant referencing the ABWR design. The plan will integrate the applicable test requirements for safety-related pumps and valves including those listed in the technical specifications, Chapter 16, and the containment isolation valves, Subsection 6.2.4. An example is the periodic leak testing of the reactor coolant pressure isolation valves in Table 3.9-9 will be performed in accordance with Chapter 16 Surveillance Requirement 3.6.1.5.10. This plan will include baseline pre-service testing to support the periodic in-service testing of the components. Depending on the test results, the plan will provide a commitment to disassemble and inspect the safety related pumps and valves when limits of Subsection IWP or IWV are exceeded, as described in the following paragraphs. The primary elements of this plan, including the requirements of Generic Letter 89-10 for motor operated valves, are delineated in the subsections to follow. (See Subsection 3.9.7.3 for COL license information requirements). 210.49 210.50

3.9.6.1 Inservice Testing of Safety-Related Pumps

The ABWR safety-related pumps and piping configurations accommodate inservice testing at a flow rate at least as large as the maximum design flow for the pump. In addition, the 210.47

sizing of each minimum recirculation flow path is evaluated to assure that its use under all analyzed conditions will not result in degradation of the pump. The flow rate through minimum recirculation flow paths can also be periodically measured to verify that flow is in accordance with the design specification.

The safety-related pumps are provided with instrumentation to verify that the net positive suction head (NPSH) is greater than or equal to the NPSH required during all modes of pump operation. These pumps can be disassembled for evaluation when the Code Section XI testing results in a deviation which falls within the "required action range." The Code provides criteria limits for the test parameters identified in Table 3.9-8. A program will be developed by the applicant referencing the ABWR design to establish the frequency and the extent of disassembly and inspection based on suspected degradation of all safety related pumps, including the basis for the frequency and the extent of each disassembly. The program may be revised throughout the plant life to minimize disassembly based on past disassembly experience. (See Subsection 3.9.7.3(1) for COL license information requirements.)

3.9.6.2 Inservice Testing of Safety-Related Valves

3.9.6.2.1 Check Valves

All ABWR safety-related piping systems incorporate provisions for testing to demonstrate the operability of the check valves under design conditions. In-service testing will incorporate the use of advance non-intrusive techniques to periodically assess degradation and the performance characteristics of the check valves. The Code Section XI tests will be performed, and check valves that fail to exhibit the required performance can be disassembled for evaluation. The Code provides criteria limits for the test parameters identified in Table 3.9-8. A program will be developed by the applicant referencing the ABWR design to establish the frequency and the extent of disassembly and inspection based on suspected degradation of all safety related pumps, including the basis for the frequency and the extent of each disassembly. The program may be revised throughout the plant life to minimize disassembly based on past disassembly experience. (See Subsection 3.9.7.3(1) for COL license information requirements.)

3.9.6.2.2 Motor Operated Valves

The motor operated valve (MOV) equipment specifications require the incorporation of the results of either in-situ or prototype testing with full flow and pressure or full differential pressure to verify the proper sizing and correct switch settings of the valves. Guidelines to justify prototype testing are contained in Generic Letter 89-10, Supplement 1, Questions 22 and 24 through 28. The applicant referencing the ABWR design will provide a study to determine the optimal frequency for valve stroking during in-service testing such that unnecessary testing and damage is not done to the valve as a result of the testing. (See Subsection 3.9.7.3 for COL license information requirements).

The concerns and issues identified in Generic Letter 89-10 for MOVs will be addressed prior to plant startup. The method of assessing the loads, the method of sizing the actuators, and the setting of the torque and limit switches will be specifically addressed. (See Subsection 3.9.7.3 for COL license information requirements).

The in-service testing of MOVs will rely on diagnostic techniques that are consistent with the state of the art and which will permit an assessment of the performance of the valve under actual loading. Periodic testing will be conducted under adequate differential pressure and flow conditions that allow a justifiable demonstration of continuing MOV capability for design basis conditions, including recovery from inadvertent valve positioning. MOVs that fail the acceptance criteria, and are "declared inoperable," for stroke tests and leakage rate can be disassembled for evaluation. The Code provides criteria limits for the test parameters identified in Table 3.9-8. A program will be developed by the applicant referencing the ABWR design to establish the frequency and the extent of disassembly and inspection based on suspected degradation of all safety related "MOV's", including the basis for the frequency and the extent of each disassembly. The program may be revised throughout the plant life to minimize disassembly based on past disassembly experience. (See Subsection 3.9.7.3(1) for COL license information requirements.)

3.9.6.2.3 Isolation Valve Leak Tests

The leak-tight integrity will be verified for each valve relied upon to provide a leak-tight function. These valves include:

(1) pressure isolation valves - valves that provide isolation of pressure differential from one part of a system from another or between systems;

(2) temperature isolation valves - valves whose leakage may cause unacceptable thermal loading on supports or stratification in the piping and thermal loading on supports or whose leakage may cause steam binding of pumps; and

(3) containment isolation valves - valves that perform a containment isolation function in accordance with the Evaluation Against Criterion 54, Subsection 3.1.2.5.5.2, including valves that may be exempted from Appendix J, Type C, testing but whose leakage may cause loss of suppression pool water inventory.

Leakage rate testing of valves will be in accordance with the Code Section XI. An example is the fusible plug valves that provide a lower drywell flood for severe accidents described in Subsection 9.5.12. The valves are safety-related due to the function of retaining suppression pool water as shown in Figure 9.5-3. These special valves are noted here and not in Table 3.9-8. The fusible plug valve is a nonreclosing pressure relief device and the Code requires replacement of each at a maximum of 5 year intervals.

3.9.7 COL License Information

3.9.7.1 Reactor Internals Vibration Analysis, Measurement and Inspection Program

The first COL applicant will provide, at the time of application, the results of the vibration assessment program for the ABWR prototype internals. These results will include the following information specified in Regulatory Guide 1.20.

R. G. 1.20	Subject
C.2.1	Vibration Analysis Program
C.2.2	Vibration Measurement Program
C.2.3	Inspection Program
C.2.4	Documentation of Results

NRC review and approval of the above information on the first COL applicants docket will complete the vibration assessment program requirements for prototype reactor internals.

In addition to the information tabulated above, the first COL applicant will provide the information on the schedules in accordance with the applicable portions of position C.3 of Regulatory Guide 1.20 for non-prototype internals.

Subsequent COL applicants need only provide the information on the schedules in accordance with the applicable portions of position C.3 of Regulatory Guide 1.20 for non-prototype internals. (See Subsection 3.9.2.4 for interface requirements).

3.9.7.2 ASME Class 2 or 3 or Quality Group Components with 60 Year Design Life

COL applicants will identify ASME Class 2 or 3 or Quality Group D components that are subjected to loadings which could result in thermal or dynamic fatigue and provide the analyses required by the ASME Code, Subsection NB. These analyses will include the appropriate operating vibration loads and for the effects of mixing hot and cold fluids. (See Subsection 3.9.3.1.

3.9.7.3 Pump and Valve Inservice Testing Program

COL applicants will provide a plan for the detailed pump and valve inservice testing and inspection program. This plan will

(1) Include baseline pre-service testing to support the periodic in-service testing of the components required by technical specifications. Provisions are included to disassemble and inspect the pump, check valves, and MOVs within the Code and safety-related classification as necessary, depending on test results. (See Subsections 3.9.6, 3.9.6.1, 3.9.6.2.1 and 3.9.6.2.2)

(2) Provide a study to determine the optimal frequency for valve stroking during inservice testing. (See Subsection 3.9.6.2.2)

(3) Address the concerns and issues identified in Generic Letter 89-10; specifically the method of assessment of the loads, the method of sizing the actuators, and the setting of the torque and limit switches. (See Subsection 3.9.6.2.2)

3.9.7.4 Audit of Design Specification and Design Reports

COL applicants will make available to the NRC staff design specification and design reports required by ASME Code for vessels, pumps, valves and piping systems for the purpose of audit. (See Subsection 3.9.3.1)

3.9.8 References

1. *BWR Fuel Channel Mechanical Design and Deflection,* NEDE-21354-P, September 1976.

2. *BWR/6 Fuel Assembly Evaluation of Combined Safe Shutdown Earthquake (SSE) and Loss-of-Coolant Accident (LOCA) Loadings,* NEDE-21175-P, November 1976.

3. NEDE-24057-P (Class III) and NEDE-24057 (Class I) Assessment of Reactor Internals. Vibration in BWR/4 and BWR/5 Plants,

Table 3.9-1

PLANT EVENTS

A. Plant Operating Events

		ASME Code Service Limit(10)	No. of Events(1)
1.	Boltup (1)	A	68
2.	Hydrostatic Test (two test cycles for each boltup cycle)	Testing	135
3.	Startup (100^{O}F/hr Heatup Rate)(2)	A	390
4.	Daily and Weekly Reduction to 50% Power (1)	A	18,000
5.	Control Rod Pattern Change (1)	A	600
6.	Loss of Feedwater Heaters	B	120
7.	Scram:		
	a. Turbine Generator Trip, Feedwater On, and Other Scrams	B	188
	b. Loss of Feedwater Flow, Loss of Auxiliary Power	B	209
	c. Turbine Bypass, Single Safety or Relief Valve Blowdown	B	12
8.	Reduction to 0% Power, Hot Standby, Shutdown (100^{O}F/hr Cooldown Rate) (2)	A	378
9.	Refueling Shutdown with Head Spray and Unbolt (1)	A	68
10.	Scram:		
	a. Reactor Overpressure with Delayed Scram (Anticipated Transient Without Scram, ATWS)	C	1(3)
	b. Automatic Blowdown	C	1(3)
11.	Improper or Sudden Start of Recirculation Pump with Cold Bottom Head or Hot Standby - Drain Shut Off - Pump Restart	C	1(3)

Table 3.9-1

PLANT EVENTS

B. Dynamic Loading Events(8)

		ASME Code Service Limit(10)	No. of Cycles/ Events(1)
12.	Operating Basis Earthquake (OBE) Event at Rated Power Operating Conditions	B	10 Cycles (4)
13.	Safe Shutdown Earthquake (SSE) (5) at Rated Power Operating Conditions	D(9)	1(3) Cycle
14.	Turbine Stop Valve Full Closure (TSVC)(6) During Event 7a and Testing	B	990 Cycles
15.	Safety Relief Valve (SRV) Actuation (One, Two Adjacent, All or Automatic Depressurization System) During Event 7a and 7b	B	396 Events(7)
16.	Loss of Coolant Accident (LOCA)		
	Small Break LOCA (SBL)	D(9)	1(3)
	Intermediate Break LOCA (IBL)	D(9)	1(3)
	Large Break LOCA (LBL)	D(9)	1(3)

NOTES:

(1) Some events apply to reactor pressure vessel (RPV) only. The number of events/cycles applies to RPV as an example.

(2) Bulk average vessel coolant temperature change in any one hour period.

(3) The annual encounter probability of a single event is $<10^{-2}$ for a Level C event and $<10^{-4}$ for a Level D event. See Subsection 3.9.3.1.1.5.

(4) 50 peak OBE cycles for piping, 10 peak OBE cycles for other equipment and components.

(5) One stress or load reversal cycle of maximum amplitude.

Table 3.9-1

PLANT EVENTS

B. Dynamic Loading Events

(Continued)

NOTES:

(6) Applicable to main steam piping system only.

(7) The number of reactor building vibratory load cycles on the reactor vessel and internal components is 29,400 cycles of varying amplitude during the 396 events of safety/relief valve actuation.

(8) Table 3.9-2 shows the evaluation basis combination of these dynamic loadings.

(9) Appendix F or other appropriate requirements of the ASME Code are used to determine the service Level D limits, as described in Subsection 3.9.1.4.

(10) These ASME Code Service Limits apply to ASME Code Class 1, 2 and 3 components, component supports and Class CS structures. Different limits apply to Class MC and CC containment vessels and components, as discussed in Section 3.8.

Table 3.9-2

LOAD COMBINATIONS AND ACCEPTANCE CRITERIA FOR SAFETY-RELATED, ASME CODE CLASS 1, 2 AND 3 COMPONENTS, COMPONENT SUPPORTS, AND CLASS CS STRUCTURES

	Plant Event	Service Loading Combination(1),(3),(4)	ASME Service Level(2)
1.	Normal Operation (NO)	N	A
2.	Plant/System Operating Transients (SOT)	(a) N + TSVC (b) N + SRV(8)	B(5) B(5)
3.	NO + OBE	N + OBE	B(5)
4.	SOT + OBE	(a) N + TSVC + OBE (b) N + SRV(8) + OBE	B(5) B(5)
5.	Infrequent Operating Transient (IOT), ATWS	N(10) + SRV(8)	C(5),(6),(10)
6.	SBL	N + SRV (9) + SBL(11)	C(5),(6)
7.	SBL or IBL + SSE	N + SBL (or IBL)(11) + SSE + SRV(9)	D(5),(6),(7)
8.	LBL + SSE	N + LBL (11) + SSE	D(5),(6),(7)
9.	NLF	N + SRV (8) + TSVC (12)	D(5)

210.34

NOTES:

(1) See Legend on the following pages for definition of terms. See Table 3.9-1 for plant events and cycles information.

The service loading combination also applies to Seismic Category I Instrumentation and electrical equipment (See Section 3.10).

(2) The service levels are as defined in appropriate subsection of ASME Section III, Division 1.

(3) For vessels and pumps, loads induced by the attached piping are included as identified in their design specification.

For piping systems, water (steam) hammer loads are included as identified in their design specification.

(4) The method of combination of the loads is in accordance with NUREG-0484, Revision 1.

(5) For active Class 1, 2 or 3 valves, the design pressure is specified equal to or greater than the pressure for which the valve must operate (open or close).

Table 3.9-2

LOAD COMBINATIONS AND ACCEPTANCE CRITERIA FOR SAFETY-RELATED, ASME CODE CLASS 1, 2 AND 3 COMPONENTS, COMPONENT SUPPORTS, AND CLASS CS STRUCTURES (Continued)

LOAD DEFINITION LEGEND:

$LOCA_7$ - Annulus pressurization (AP) loads due to a postulated line break in the annulus region between the RPV and shieldwall. Vessel depressurization loads on reactor internals (see Subsection 3.9.2.5) and other loads due to reactor blowdown reaction and jet impingement and pipe whip restraint reaction from the broken pipe are included with the AP loads.

SBL - Loads induced by small break LOCA (see Subsections 3.9.3.1.1.3 and 3.9.3.1.1.4); the loads are: $LOCA_3$(a), $LOCA_4$ and $LOCA_6$. See Note (11).

IBL - Loads induced by intermediate break LOCA (see Subsection 3.9.3.1.1.4); the loads are: $LOCA_3$(a) or $LOCA_3$(b), $LOCA_4$, $LOCA_5$ and $LOCA_6$. See Note (11).

LBL - Loads induced by large break LOCA (see Subsection 3.9.3.1.1.4); the loads are: $LOCA_1$ through $LOCA_7$. See Note (11).

Table 3.9-3

PRESSURE DIFFERENTIALS ACROSS REACTOR VESSEL INTERNALS

Reactor Component(3)		Maximum Pressure Differences Occurring During a Steam Line Break (psid)	
		Case 1(1)	Case 2(2)
1.	Core plate and guide tube	26.7	23.5
2.	Shroud support ring and lower shroud (beneath the core plate)	35.1	37.8
3.	Shroud head (at marked elevation)	11.3	21.7
4.	Upper shroud (just below top guide)	13.1	22.1
5.	Core averaged power fuel bundle (bulge at bottom of bundle)	14.2	13.0
5.	Core averaged power fuel bundle (collapse at bottom of top guide)	11.8	11.5
6.	Maximum power fuel bundle (bulge at bottom of bundle)	16.2	14.0
7.	Top guide	6.2	9.4
8.	Steam Dryer	6.9	10.8
-	Shroud head to water level, from points (a) to (b), irreversible pressure drop	13.4	23.2
-	Shroud head to water level, from points (a) to (b), elevation pressure drop	1.5	2.2

NOTES:

(1) Instantaneous break initiated at 102% rated core power, 102.4% rated steam flow, and 111.1% rated recirculation flow.

(2) Instantaneous break initiated at 54.5% rated core power, 49.8% rated steam flow, and 114.8% rated recirculation flow.

(3) Item numbers in this column correspond to the location (node) numbers identified in Figure 3.9-5.

SECTION 3.11

CONTENTS

3.11 ENVIRONMENTAL QUALIFICATION OF SAFETY-RELATED MECHANICAL AND ELECTRICAL EQUIPMENT

This section defines the environmental conditions with respect to limiting design conditions for all the safety-related mechanical and electrical equipment, and documents the qualification methods and procedures employed to demonstrate the capability of this equipment to perform safety-related functions when exposed to the environmental conditions in their respective locations. The safety-related equipment within the scope of this section are defined in Subsection 3.11.1. Dynamic qualification is addressed in Sections 3.9 and 3.10 for Seismic Category I mechanical and electrical equipment, respectively.

Limiting design conditions include the following:

(1) Normal Operating Conditions - planned, purposeful, unrestricted reactor operating modes including startup, power range, hot standby (condenser available), shutdown, and refueling modes;

(2) Abnormal Operating Conditions - any deviation from normal conditions anticipated to occur often enough that the design should include a capability to withstand the conditions without operational impairment;

(3) Test Conditions - planned testing including pre-operational tests;

(4) Accident Conditions - a single event not reasonably expected during the course of plant operation that has been hypothesized for analysis purposes or postulated from unlikely but possible situations or that has the potential to cause a release of radioactive material (a reactor coolant pressure boundary rupture may qualify as an accident; a fuel cladding defect does not); and

(5) Post-Accident Conditions - during the length of time the equipment must perform its safety-related function and must remain in a safe mode after the safety-related function is performed.

3.11.1 Equipment Identification and Environmental Conditions

Safety related electrical equipment within the scope of this section includes all three categories of 10CFR50.49(b) (Reference 1). Safety-related mechanical equipment (e.g., pumps, motor-operated valves, safety-relief valves, and check valves) are as defined and identified in Section 3.2. Electrical and mechanical equipment safety classifications are further defined on the system design drawings.

Safety related equipment located in a harsh environment must perform its proper safety function during normal, abnormal, test, design basis accident and post accident environments as applicable. A list of all safety-related electrical and mechanical equipment that is located in a harsh environment area will be included in the En- vironmental Qualification Document (EQD) to be prepared as mentioned in Subsection 3.11.6.

Environmental conditions for the zones where safety-related equipment is located are calculated for normal, abnormal, test, accident and post-accident conditions and are documented in Appendix 3I, Equipment Qualification Environmental Design Criteria (EQEDC). Environmental conditions are tabulated by zones, contained in the referenced building arrangements. Typical equipment in the noted zones is shown in the referenced system P&ID and IED design drawings.

Occurences of anticipated abnormal operating conditions are similar to test conditions and their significant environments are comparable.

Environmental parameters include temperature, pressure, relative humidity, and neutron dose rate and integrated dose. Radiation dose for gamma and beta data for both normal and accident conditions will be provided by applicant referencing the ABWR design in accordance with the interface requirements in Subsection 12.2.3.1 The radiation requirements are site specific documentation owing to the need to model specific equipment which is applicant determined, the HVAC detailed medeling and the evolving considerations in the area of accident source terms are expected to generate significantly differing radiation requirments Where applicable, these parameters are given in terms of a time-based profile.

The magnitude and 60-year frequency of occurrence of significant deviations from normal plant environments in the zones have insignif- icant effects on equipment total thermal normal aging or accident aging. Abnormal conditions are overshadowed by the normal or accident conditions in the Appendix 3I tables.

Margin is defined as the difference between the most severe specified service conditions of the plant and the conditions used for qualification. Margins shall be included in the qualification parameters to account for normal variations in commercial production of equipment and reasonable errors in defining satisfactory performance. The environmental conditions shown in the Appendix 3I tables do not include margins.

Some mechanical and electrical equipment may be required by the design to perform an intended safety function between munutes of the occurrence of the event but less than 10 hours into the event. Such equipement shall be shown to remain functional in the accident environment for a period of at least 1 houre in exces of the time assumed in the accident anylysis unless a time margin of less than 1 hour can be justified. Such justification will include for each piece of equipment: (1) consideration of a spectrum of breaks; (2) the potential need for the equipment later in the event or during recovery operations; (3) detemination that failure of the equipment after performance of its safety function will not be detrimental to plant safety or mislead the operator; and (5) determination that the margin applied to the minimum operability time, when combined with other test margins, will account for the uncertainties accociated with the use of analytical techniques in the derivation of environmental parameters, the number of units tested, production tolerances, and test equipment inaccuracies

The environmental conditions shown in the Appendix 3I tables are upper-bound envelopes used to establish the environmental design and qualification bases of safety-related equipment. The upper bound envelopes indicate that the zone data reflects the worse case expected environment produced by a compendium of accident conditions.

Estimated chemical environmental conditions are also reported is Appendix 3I.

3.11.2 Qualification Tests and Analyses

Safety-related electrical equipment that is located in a harsh environment is qualified by test or other methods as described in IEEE 323 and permitted by 10CFR50.49(f) (Reference 1). Equipment type test is the preferred method of qualification.

Safety-related mechanical equipment that is located in a harsh environment is qualified by analysis of materials data which are generally based on test and operating experience.

The qualification methodology is described in detail in the NRC approved licensing Topical Report on GE's environmental qualification program (Reference 2). This report also addresses compliance with the applicable portions of the General Design Criteria of 10CFR50, Appendix A, and the Quality Assurance Criteria of 10CFR50, Appendix B. Additionally, the report describes conformance to NUREG-0588 (Reference 3), and Regulatory Guides and IEEE Standards referenced in Section 3.11 of NUREG-0800 (Standard Review Plan).

Mild environment is that which, during or after a design basis event (DBE, as defined in Reference 2), would at no time be significantly more severe than that which exists during normal, test and abnormal events.

The vendors of equipment located in a mild environment are required to submit a certificate of compliance certifying that the equipment has been qualified to assure its required safety-related function in its applicable environment. This equipment is qualified for dynamic loads as addressed in Sections 3.9 and 3.10. Further, a surveillance and maintenance program will be developed to ensure equipment operability during its designed life.

3.11.3 Qualification Test Results

The results of qualification tests for safety-related equipment will be documented, maintained, and reported as mentioned in Subsection 3.11.6.

3.11.4 Loss of Heating, Ventilating and Air Conditioning

To ensure that loss of heating, ventilating, and air conditioning (HVAC) system does not adversely affect the operability of safety-related controls and electrical equipment in buildings and areas served by safety-related HVAC systems, the HVAC systems serving these areas meet the single-failure criterion. Section 9.4 describes the safety-related HVAC systems including the detailed safety evaluations. The loss of ventilation calculations are based on maximum heat loads and consider operation of all operable equipment regardless of safety classification.

3.11.5 Estimated Chemical and Radiation Environment

3.11.5.1 Chemical Environment

Equipment located in the containment drywell and wetwell is potentially subject to water spray modes of the RHR system. In addition, equipment in the lower portions of the containment is potentially subject to submergence. The chemical composition and resulting pH to which safety-related equipment is exposed during normal operation and design basis accident conditions is reported in Appendix 3I.

Sampling stations are provided for periodic analysis of reactor water, refueling and fuel storage pool water, and suppression pool water to assure compliance with operational limits of the plant technical specifications.

3.11.5.2 Radiation Environment

Safety-related systems and components are designed to perform their safety-related function when exposed to the normal operational radiation levels and accident radiation levels.

The normal operational exposure is based on the radiation sources provided in Chapter 12.

Radiation sources associated with the DBA and developed in accordance with NUREG-0588 (Reference 3) are provided in Chapter 15.

Integrated doses associated with normal plant operation and the design basis accident condition for various plant compartments are described in Appendix 3I.

3.11.6 COL License Information

3.11.6.1 Environmental Qualification Document

The EQD shall be prepared summarizing the qualification results for all safety-related equipment. The EOD shall include the following:

(1) The test environmental parameters and the methodology used to qualify the equipment located in harsh environments shall be identified.

(2) A summary of environmental conditions and qualified conditions for the safety-related equipment located in a harsh environment zone shall be presented in the system component evaluation work (SCEW) sheets as described in Table I-1 of GE's environmental qualification program (Reference 2). The SCEW sheets shall be compiled in the EQD.

3.11.6.2 Environmental Qualification Records

The results of the qualification tests shall be recorded and maintained in an auditable file.

3.11.7 References

(1) Code of Federal Regulations, Title 10, Chapter I, Part 50, Paragraph 50.49, Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plant.

(2) General Electric Environmental Qualification Program,NEDE-24326-1-P, Proprietary Document, January 1983.

(3) Interim Staff Position on Environmental Qualification of Safety-Related Electrical Equipment, NUREG-0588.

APPENDIX 3D

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SECTION 3D.4

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3D.4 PIPING

3D.4.1 Piping Analysis Program--PISYS

PISYS is a computer code for analyzing piping systems subjected to both static and dynamic piping loads. Stiffness matrices representing standard piping components are assembled by the program to form a finite element model of a piping system. The piping elements are connected to each other via nodes called pipe joints. It is through these joints that the model interacts with the environment, and loading of the piping system becomes possible. PISYS is based on the linear elastic analysis in which the resultant deformations, forces, moments and accelerations at each joint are proportional to the loading and the superposition of loading is valid.

PISYS has a full range of static dynamic load analysis options. Static analysis includes dead weight, uniformly-distributed weight, thermal expansion, externally-applied forces, moments, imposed displacements and differential support movement (pseudo-static load case). Dynamic analysis includes mode shape extraction, response spectrum analysis, and time-history analysis by modal combination or direct integration. In the response spectrum analysis, i.e. uniform support motion response spectrum analysis (USMA) or independent support motion response spectrum analysis (ISMA), the user may request modal response combination in accordance with NRC Regulatory Guide 1.92. In the ground motion (uniform motion) or independent support time-history analysis, the normal mode solution procedure is selected. In analysis involving time-varying nodal loads, the step by step direct integration method is used.

The PISYS program has been benchmarked against Nuclear Regulatory Commission piping models. The results are documented in a report to the Commission, "PISYS Analysis of NRC Benchmark Problems", NEDO-24210, August 1979, for mode shapes and USMA options. The ISMA option has been validated against NUREG/CR-1677, "Piping Benchmark Problems Dynamic Analysis Independent Support Motion Response Spectrum Method," published in August 1985.

3D.4.2 Component Analysis--ANSI7

ANSI7 is a computer code for calculating stresses and cumulative usage factors for Class 1, 2 and 3 piping components in accordance with articles NB, NC and ND-3650 of the ASME Code, Section III. ANSI7 is also used to combine loads and calculate combined service level A, B, C and D loads on piping supports and pipe mounted equipment.

3D.4.3 Area Reinforcement--NOZAR

The computer program NOZAR (Nozzle Area Reinforcement Program) performs an analysis of the required reinforcement area for openings. The calculations performed by NOZAR are in accordance with the rules of the ASME Code, Section III, 1974 edition.

3D.4.4 Dynamic Forcing Functions

3D.4.4.1 Relief Valve Discharge Pipe Forces Computer Program--RVFOR

The relief valve discharge pipe connects the pressure-relief valve to the suppression pool. When the valve is opened, the transient fluid flow causes time dependent forces to develop on the pipe wall. This computer program computes the transients fluid mechanics and the resultant pipe forces using the method of characteristics.

3D.4.4.2 Turbine Stop Valve Closure--TSFOR

TSFOR program computes the time-history forcing function in the main steam piping due to turbine stop valve closure. The program utilizes the method of characteristics to compute fluid momentum and pressure loads at each change in pipe section or direction.

3D.4.5 Response Spectra Generation

3D.4.5.1 ERSIN Computer Program

ERSIN is a computer code used to generate response spectra for pipe mounted equipment and for floor mounted equipment. ERSIN provides direct generation of local or global acceleration response spectra.

3D.4.5.2 RINEX Computer Program

RINEX is a computer code used to interpolate and extrapolate amplified response spectra used in the response spectrum method of dynamic analysis. RINEX is also used to generate response spectra with nonconstant model damping. The nonconstant model damping analysis option can calculate spectral acceleration at the discrete eigenvalues of a dynamic system using either the strain energy weighted modal damping or the ASME Code Class N-411-1 damping values.

3D.4.6 Piping Dynamic Analysis Program--PDA

The pipe whip dynamic analysis is performed using the PDA computer program, as described in Subsection 3.6.2.2.2. PDA is a computer program used to determine the response of a pipe subjected to the thrust force occurring after a pipe break. It also is used to determine the pipe whip restraint design and capacity.

The program treats the situation in terms of generic pipe break configuration, which involves a straight, uniform pipe fixed at one end and subjected to a time-dependent thrust force at the other end. A typical restraint used to reduce the resulting deformation is also included at a location between the two ends. Nonlinear and time-independent stress-strain relations are used to model the pipe and the restraint. Using a plastic hinge concept, bending of the pipe is assumed to occur only at the fixed end and at the location supported by the restraint.

Effects of pipe shear deflection are considered negligible. The pipe-bending moment-deflection (or rotation) relation used for these locations is obtained from a static nonlinear cantilever beam analysis. Using moment-angular rotation relations, nonlinear equations of motion are formulated using energy considerations and the equations are numerically integrated in small time steps to yield the time-history of the pipe motion.

3D.4.7 Deleted

3D.4.8 Thermal Transient Program--LION

The LION program is used to compute radial and axial thermal gradients in piping. The program calculates a time-history of ΔT_1, ΔT_2, Ta, and Tb (defined in the ASME Code, Section III, Subsection NB) for uniform and tapered pipe wall thickness.

3D.4.9 Deleted

3D.4.10 Engineering Analysis System--ANSYS

The ANSYS computer program is a large scale general purpose program for the solution of several classes of Engineering Analysis problems. Analysis capabilities include static and dynamic; plastic, creep and swelling; small and large deflections; and other applications.

This program will accommodate a complete model and an enhanced capacities in input, output and graphic interface. Locations of interest for stresses and displacements can be obtained by this nonlinear analysis. It is served as a verification work for the PDA program.

Other program of the same capacities with periodical improvement is also applicable to this analysis.

APPENDIX 3E

GUIDELINES FOR LBB APPLICATIONS

APPENDIX 3E

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APPENDIX 3E

GUIDELINES FOR LBB APPLICATION

3E.1 INTRODUCTION

As discussed in Subsection 3.6.3, this appendix provides detailed guidelines for the COL applicant's use in applying for NRC's approval of LBB for specific piping systems. Also included in this appendix are the fracture mechanics properties of ABWR piping materials and analysis methods, including the leak rate calculation methods. Table 3E.1-1 gives a list of piping systems inside and outside the containment that are preliminary candidates for LBB application. As noted on Table 3E.1-1, most candidate piping systems are carbon steel piping. Therefore, this appendix deals extensively with the evaluation of carbon steel piping.

Piping qualified by LBB would be excluded from the non-mechanistic postulation requirements of double-ended guillotine break (DEGB) specified in Subsection 3.6.3. The LBB qualification means that the through-wall flaw lengths that are detectable by leakage monitoring systems (see Subsection 5.2.5) are significantly smaller than the flaw lengths that could lead to pipe rupture or instability.

Section 3E.2 addresses the fracture mechanics properties aspects required for evaluation in accordance with Subsection 3.6.3. Section 3E.3 describes the fracture mechanics techniques and methods for the determination of critical flaw lengths and evaluation of flaw stability. Explained in Section 3E.4 is the determination of flaw lengths for detectable leakages with margin. A brief discussion on the leak detection capabilities is presented in Section 3E.5. Finally, Section 3E.6 provides general guidelines for the preparation of LBB justification reports by providing two examples.

Material selection and the deterministic LBB evaluation procedure are discussed in this section.

3E.1.1 Material Selection Guidelines

The LBB approach is applicable to piping systems for which the materials meet the following criteria: (1) low probability of failure from the effects of corrosion (e.g., intergrannular stress corrosion cracking) and (2) adequate margin before susceptibility to cleavage type fracture over the full range of consequences.

The ABWR plant design specifies use of austenitic stainless steel piping made of material (e.g., nuclear grade or low carbon type) that is recognized as resistant to IGSCC. The carbon steel or ferritic steels specified for the reactor pressure boundary are described in 3E.2.2. These steels are assured to have adequate toughness to preclude a fracture at operating temperatures. A COL applicant is expected to supply a detailed justification in the LBB evaluation report considering system temperature, fluid velocity and environmental conditions.

3E.1.2 Deterministic Evaluation Procedure

The following deterministic analysis and evaluation are performed as an NRC-approved method to justify applicability of the LBB concept.

(1) Use the fracture mechanics and the leak rate computational methods that are accepted by the NRC staff, or are demonstrated accurate with respect to other acceptable computational procedures or with experimental data.

(2) Identify the types of materials and materials specifications used for base metal, weldments and safe ends, and provide the materials properties including toughness and tensile data, long-term effects such as thermal aging, and other limitations.

(3) Specify the type and magnitude of the loads applied (forces, bending and torsional moments), their source(s) and method of combination. For each pipe size in the functional system, identify the location(s) which have the least favorable combination of stress and material properties for base metal, weldments and safe ends.

(4) Postulate a throughwall flaw at the location(s) specified in (3) above. The size of the flaw should be large enough so that the leakage is assured detection with sufficient margin using the installed leak detection capability when pipes are subjected to normal operating loads. If auxiliary leak detection systems are relied on, they should be described. For the estimation of leakage, the normal operating loads (i.e., deadweight, thermal expansion, and pressure) are to be combined based on the algebraic sum of individual values.

Using fracture mechanics stability analysis or limit load analysis based on (11) below, and normal plus SSE loads, determine the critical crack size for the postulated throughwall crack. Determine crack size margin by comparing the selected leakage size crack to the critical crack size. Demonstrate that there is a margin of 2 between the leakage and critical crack sizes. The same load combination method selected in (5) below is used to determine the critical crack size.

(5) Determine margin in terms of applied loads by a crack stability analysis. Demonstrate that the leakage size cracks will not experience unstable crack growth if 1.4 times the normal plus SSE loads are applied. Demonstrate that crack growth is stable and the final crack is limited such that a double-ended pipe break will not occur. The dead-weight, thermal expansion, pressure, SSE (inertial), and seismic anchor motion (SAM) loads are combined based on the same method used for the primary stress evaluation by the ASME Code. The SSE (inertial) and SAM loads are combined by square-root-of-the-sum-of-the-squares (SRSS) method.

(6) The piping material toughness (J-R curves) and tensile (stress-strain curves) properties are determined at temperatures near the upper range of normal plant operation.

(7) The specimen used to generate J-R curves is assured large enough to provide crack extensions up to an amount consistent with J/T condition determined by analysis for the application. Because practical specimen size limitations exist, the ability to obtain the desired amount of experimental crack extension may be restricted. In this case, extrapolation techniques is used as described in NUREG-1601, Volume 3, or in NUREG/CR-4575. Other techniques can be used if adequately justified.

(8) The stress-strain curves are obtained over the range from the preoperational limit to maximum load.

(9) Preferably, the materials tests should be conducted using archival materials for the pipe being evaluated. If archival material is not available, plant specific or industry wide generic material data bases are assembled and used to define the required material tensile and toughness properties. Test material includes base and weld metals.

(10) To provide an acceptable level of reliability, generic data bases are reasonable lower bounds for compatible sets of material tensile and toughness properties associated with materials at the plant. To assure that the plant specific generic data base is adequate, a determination is made to demonstrate that the generic data base represents the range of plant materials to be evaluated. This determination is based on a comparison of the plant material properties identified in (2) above with those of the materials used to develop the generic data base. The number of material heats and weld procedures tested are adequate to cover the strength and toughness range of the actual plant materials. Reasonable lower bound tensile and toughness properties from the plant specific generic data base are to be used for the stability analysis of individual materials, unless otherwise justified.

Industry generic data bases are reviewed to provide a reasonable lower bound for the population of material tensile and toughness properties associated with any individual specification (e.g., A106, Grade B), material type (e.g., austenitic steel) or welding procedures.

The number of material heats and weld procedures tested should be adequate to cover the range of the strength ar tensile properties expected for specific aterial specifications or types. Reasonable lower bound tensile and toughness properties from the industry generic data base are used fro the stability analysis of individual materials.

If the data are being developed from an archival heat of material three stress-strain curves and three J-resistance curves from that one heat of material is sufficient. The tests should be conducted at temperatures near the upper range of normal plant operation. Tests should also be conducted at a lower temperature, which may represent a plant condition (e.g., hot standby) where pipe break would present safety concerns similar to normal operation. These tests are intended only to determine if there is any significant dependence of toughness on temperature over the temperature range of interest. The lower toughness should be used in the fracture mechanics evaluation. One J-R curve and one stress-strain curve for one base metal and weld metal are considered adequate to determine temperature dependence.

(11) There are certain limitations that currently preclude generic use of limit load analyses to evaluate leak-before-break conditions deterministically. However, a modified limit-load analysis can be used for austenitic stainless steel piping to demonstrate acceptable margins as described in Subsection 3E.3.3.

Table 3E.1-1

LEAK BEFORE BREAK CANDIDATE PIPING SYSTEM

System	Location	Description	Diameter (mm)
Main Steam (4 lines)	PC	RPV to RCCV	700
Feedwater (2 lines/6 risers)	PC	RPV to RCCV	550/300
RCIC Steam	PC	MS line to RCCV	150
HPCF	PC	RPV to first check valve	200
RHR/LPFL	PC	RPV to first check valve	250
RHR/Suction	PC	RPV to first closed gate valve	350
CUW	PC	RHR suction to RCCV	200
Main Steam (4 lines)	Steam Tunnel	RCCV to turbine building	700
Feedwater (2 lines)	Steam Tunnel	RCCV to turbine building	550
RHR Div. A Suction	Steam Tunnel	FW line A to check valve	250
RCIC Steam	SC	RCCV to turbine shutoff valve	150
RCIC Supply	SC	FW line to first check valve	200
CUW Suction	SC	RCCV to heat exchanger discharge	200
CUW Discharge	SC	Heat exchanger discharge to FW suction	200/150

Note: All piping in primary and secondary containment (including steam tunnel) are carbon steel piping, except the in-containment CUW piping which is stainless steel.

Legend: PC: Primary Containment
SC: Secondary Containment
FW: Feedwater
MS: Main Steam

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SECTION 3E.2

ILLUSTRATIONS

3E.2 MATERIAL FRACTURE TOUGHNESS CHARACTERIZATION

This subsection describes the fracture toughness properties and flow stress evaluation fc. the ferritic and austenitic steel materials used in ABWR plant piping, as required for evaluation according to Section 3E.1.2.

3E.2.1 Fracture Toughness Characterization

When the elastic-plastic fracture mechanics (EPFM) methodology or the J-T methodology is used to evaluate the leak-before-break conditions with postulated through-wall flaws, the material toughness property is characterized in the form of J-integral resistance curve (or J-R curve) [1, 2, 3]. The J-R curve, schematically shown in Figure 3E.2-1a, represents the material's resistance to crack extension. The onset of crack extension is assumed to occur at a critical value of J. Where the plane strain conditions are satisfied, initiation J is denoted by J_{IC}. Plane strain crack conditions, achieved in test specimen by side grooving, generally provide a lower bound behavior for material resistance to stable crack growth.

Once the crack begins to extend, the increase of J with crack growth is measured in terms of slope or the nondimensional tearing modulus, T, expressed as:

$$T = \frac{E}{\sigma_f^2} \cdot \frac{dJ}{da} \qquad \text{(E.2-1)}$$

The flow stress, σ_f, is a function of the yield and ultimate strength, and E is the elastic modulus. Generally, σ_f is assumed as the average of the yield and ultimate strength. The slope $\frac{dJ}{da}$ of the material J-R curve is a function of crack extension a. Generally, $\frac{dJ}{da}$ decreases with crack extension thereby giving a convex upward appearance to the material J-R curve in Figure 3E.2-1a.

To evaluate the stability of crack growth, it is convenient to represent the material J-R curve in the J-T space as shown in Figure 3E.2-1b. The resulting curve is labeled as J-T material. Crack instability is predicted at the intersection point of the J/T material and J/T applied curves.

The crack growth invariably involves some elastic unloading and distinctly nonproportional plastic deformation near the crack tip. J-integral is based on the deformation theory of plasticity [4, 5] which inadequately models both of these aspects of plastic behavior. In order to use J-integral to characterize crack growth (i.e. to assure J-controlled crack growth), the following sufficiency condition in terms of a nondimensional parameter proposed by Hutchinson and Paris [6], is used:

$$\omega = \frac{b}{J} \cdot \frac{dJ}{da} >> 1 \qquad \text{(E.2-2)}$$

Where b is the remaining ligament. Reference 7 suggests that $\omega > 10$ would satisfy the J-controlled growth requirements. However, if the requirements of this criteria are strictly followed, the amount of crack growth allowed would be very small in most test specimen geometries. Use of such a material J-R curve in J/T evaluation would result in grossly underpredicting the instability loads for large diameter pipes where considerable stable crack growth is expected to occur before reaching the instability point. To overcome this difficulty, Ernst [8] proposed a modified J-integral, J_{mod}, which was shown to be effective even when limits on 1 were grossly violated. The Ernst correction essentially factors-in the effect of crack extension in the calculated value of J. This correction can be determined experimentally by measuring the usual parameters: load, displacement and crack length.

The definition of J_{mod} is:

$$J_{mod} = J - \int_{a_o}^{a} \left|\frac{\partial(J-G)}{\partial a}\right|_{\delta_{pl}} da \qquad \text{(E.2-3)}$$

Where

- J is based on deformation theory of plasticity
- G is the linear elastic Griffith energy release rate or elastic J, J_{el}.
- δ_{pl} is the nonlinear part of the load-point displacement, (or simply the total minus the elastic

displacement).

a_o, a are the initial and current crack lengths respectively.

For the particular case of the compact tension specimen geometry, the preceding Equation and the corresponding rate take the form

$$J_{mod} = J + \int_{a_o}^{a} \frac{\gamma \cdot J_{pl}}{b} \, da \qquad (E.2\text{-}4)$$

where J_{pl} is the nonlinear part of the deformation theory J, b is the remaining ligament and is

$$= (1+0.76\, b/W) \qquad (E.2\text{-}5)$$

Consequently the modified material tearing modulus T_{mod} can be defined as:

$$T_{mod} = T_{mat} + \frac{E}{\sigma_f^2} \frac{\gamma}{b} \cdot J_{pl} \qquad (E.2\text{-}6)$$

Since in most of the test J-R curves the $\omega > 10$ limit was violated, all of the material J-T data were recalculated in the J_{mod}, T_{mod} format. The J_{mod}, T_{mod} calculations were performed up to crack extension of a = 10% of the original ligament in the test specimen. The J-T curves were then extrapolated to larger J values using the method recommended in NUREG 1061, Vol. 3 [9].

The J_{mod} - T_{mod} approach is used in this appendix for illustrative purposes. It should be adopted if justified based on its acceptability by the technical literature. A J_D - approach is another more justifiable approach.

3E.2.2 Carbon Steels and Associated Welds

The carbon steels used in the ABWR reactor coolant pressure boundary piping are: SA 106 Gr B, SA 333 Gr. 6 and SA 672, Gr. C70. The first specification covers seamless pipe and the second one pertains to both seamless and seam-welded pipe. The last one pertains to seam-welded pipe for which plate stock is specified as SA 516. Gr. 70. The corresponding material specifications used for carbon steel flanges, fittings and forgings are equivalent to the piping specifications.

While the chemical composition requirements for a pipe per SA 106 Gr. B and SA 333 Gr. 6 are identical, the latter is subjected to two additional requirements: (1) a normalizing heat treatment which refines the grain structure and, (2) a charpy test at -50°F with a specified minimum absorbed energy of 13 ft-lbs. The electrodes and filler metal requirements for welding carbon steel to carbon or low alloy steel are as specified in Table 3E.2-1.

A comprehensive test program was undertaken at GE to characterize the carbon steel base and weld material toughness properties. The next section describes the scope and the results of this program. The purpose of the test program was to generate the necessary data for application in Section 3E.6 and to illustrate a general procedure of conducting the tests per requirements of Item (10) in Section 3E.1.2. The extent of the test program for NRC's approval of an application will depend upon the identified requirements.

3E.2.2.1 Fracture Toughness Test Program

The test program consisted of generating true stress-true strain curves, J-Resistance curves and the charpy V-notch tests. Two materials were selected : (1) SA333 Gr. 6, 16-inch diameter, Schedule 80 pipe and (2) SA516, Gr. 70, 1-inch thick plate. Table 3E.2-2 shows the chemical composition and mechanical property test information provided by the material supplier. The materials were purchased to the same specifications as those to be used in the ABWR applications.

To produce a circumferential butt weld, the pipe was cut in two pieces along a circumferential plane and welded back using the shielded metal arc process. The weld prep was of single V design with a backing ring. The preheat temperature was 200°F.

The plate material was cut along the longitudinal axis and welded back using the SAW process. The weld prep was of a single V type with one side as vertical and the other side at 45°. A backing plate was used during the welding with a clearance of 1/4 inch at the bottom of the V. The interpass temperature was maintained at less than 500°F.

Both the plate and the pipe welds were X-rayed according to Code [11] requirements and were found to be satisfactory.

It is well-known that carbon steel base materials show considerable anisotropy in fracture toughness properties. The toughness depends on the orientation and direction of propagation of the crack in relation to the principal direction of mechanical working or gain flow. Thus, the selection of proper orientation of charpy and J-R curve test specimen is important. Figure 3E.2-2 shows the orientation code for rolled plate and pipe specimen as given in ASTM Standard E399 [12]. Since a through-wall circumferential crack configuration is of most interest from the DEGB point of view, the L-T specimen in a plate and the L-C specimen in a pipe provide the appropriate toughness properties for that case. On the other hand, T-L and C-L specimen are appropriate for the axial flaw case.

Charpy test data are reviewed first since they provide a qualitative measure of the fracture toughness.

3E.2.2.1.1 Charpy Tests

The absorbed energy or its complement, the lateral expansion measured during a Charpy V-notch test provides a qualitative measure of the material toughness. For example, in the case of austenitic stainless steel flux weldments, the observed lower Charpy energy relative to the base metal was consistent with the similar trend observed in the J-Resistance curves. The Charpy tests in this program were used as preliminary indicators of relative toughness of welds, HAZs and the base metal.

The carbon steel base materials exhibit considerable anisotropy in the Charpy energy as illustrated by Figure 3E.2-3 from Reference 13. This anisotropy is associated with development of grain flow due to mechanical working. The Charpy orientation C in Figure 3E.2-3 (orientations LC and LT in Figure 3E.2-2) is the appropriate one for evaluating the fracture resistance to the extension of a through-wall circumferential flaw. The upper shelf Charpy energy associated with axial flaw extension (orientation A in Figure 3E.2-3) is considerably lower than that for the circumferential crack extension.

A similar trend in the base metal charpy energies was also noted in this test program. Figures 3E.2-4a and b show the pipe and plate material Charpy energies for the two orientations as a function of temperature. The tests were conducted at six temperatures ranging from room temperature to 550°F. From the trend of the Charpy energies as a function of temperature in Figures 3E.2-4a and b it is clear that even at room temperature the upper shelf conditions have been reached for both the materials.

No such anisotropy is expected in the weld metal since it does not undergo any mechanical working after its deposition. This conclusion is also supported by the available data in the technical literature. The weld metal charpy specimen in this test program were oriented the [illegible] way [illegible] the LC or LT orientations in Figure [illegible] H[illegible] charpy specimens were also [illegible]

[illegible] 2-5 shows a comparison of the charpy energies from the 333 Gr. 6 base metal, the weld metal and the HAZ. In most cases two specimens were used. Considerable scatter in the weld and HAZ charpy energy values is seen. Nevertheless, the average energies fro the weld metal and the HAZ seem to fall at or above the average base metal values. This indicates that, unlike the stainless steel flux weldments, the fracture toughness of carbon steel weld and HAZ, as measured by the charpy tests, is at least equal to the carbon steel base metal.

The preceding results and the results of the stress-strain tests discussed in the next section or other similar data are used as a basis to choose between the base and the weld metal properties for use in the J-T methodology evaluation.

3E.2.2.1.2 Stress-Strain Tests

The stress-strain tests were performed at three temperatures: Room temperature, 350°F and 550°F. Base and weld metal from both the pipe and the plate were tested. The weld specimens were in the as-welded condition. The standard test data obtained from these tests are summarized in Table 3E.2-3.

An examination of Table 3E.2-3 shows that the measured yield strength of the weld metal, as expected, is considerably higher than that of the base metal. For example, the 550°F yield strength of the weld metal in Table 3E.2-3 ranges from 53 to 59 ksi, whereas the base metal yield strength is only 34 ksi. The impact of this observation in the selection of appropriate material (J/T) curve is discussed in later sections.

Figures 3E.2-6 a through d show the plots of the 550°F and 350°F stress-strain curves for both the pipe and the plate used in the test. As expected, the weld metal stress-strain curve in every case is higher than the corresponding base metal curve. The Ramberg-Osgood format characterization of these stress-strain curves is given in Section 3E.3.2 where appropriate values of and is also provided.

3E.2.2.1.3 J-R Curve Tests

The test temperatures selected for the J-R curve tests were: room temperature, 350°F and 550°F. Both the weld and the base metal were included. Due to the curvature, only the 1T plan compact tension (CT) specimens were obtained from the 16 inch diameter test pipe. Both 1T and 2T plan test specimens were prepared from the test plate. All of the CT specimens were side-grooved to produce plane strain conditions.

Table 3E.2-4 shows some details of the J-R curve tests performed in this test program. The J-R curve in the LC orientation of the pipe base metal and in the LT orientation of the plate base metal represent the material's resistance to crack extension in the circumferential direction. Thus, the test results of these orientations were used in the LBB evaluations. The orientation effects are not present in the weld metal. As an example of the J-R curve obtained in the test program, Figure 3E.2-7 shows the plot of J-R curve obtained from specimen OWLC-A.

3E.2.2.2 Material (J/T) Curve Selection

The normal operating temperatures for most of the carbon steel piping in the reactor coolant pressure boundary in the ABWR generally fall into two categories: 528-550°F and 420°F. The latter temperature corresponds to the operating temperature of the feedwater piping system. The selections of the appropriate material (J/T) curves for these two categories are discussed next.

3E.2.2.2.1 Material J/T Curve for 550°F

A review shows that 5 tests were conducted at 550°F. Two tests were on the weld metal, two were on the base metal and one was on the heat-affected zone. Figure 3E.2-8 shows the plot of material J_{mod}, T_{mod} values calculated from the J-Δa values obtained from the 550°F tests. The value of flow stress, σ_f used in the tearing modulus calculation (Equation E.2-1) was 52.0 ksi based on data shown in Table 3E.2-3. To convert the deformation J and $\frac{dJ}{da}$ values obtained from the J-R into J_{mod}, T_{mod}, Equations E.2-4 and E.2-6 were used. Only the data from the pipe weld (Specimen ID OWLC-A) and the plate base metal (Specimen ID BMLI-12) are shown in Figure 3E.2-8. A few unreliable data points were obtained in the pipe base metal (Specimen ID OBLC-2) J-R curve test due to a malfunction in the instrumentation. Therefore, the data from this test were not included in the evaluation. The J-R curves from the other two 550°F tests were evaluated as described in the next paragraph. For comparison purposes, Figure 3E.2-8 also shows the SA106 carbon steel J-T data obtained from the J-R curve reported by Gudas [14]. The curve also includes extrapolation to higher J values based on the method recommended in NUREG 1061, Vol. 3[9].

The J_{mod}-T_{mod} data for the plate weld metal and the plate HAZ were evaluated. A comparison shows that these data fall slightly below those for the plate base metal shown in Figure 3E.2-8. On the other hand, as noted in Subsection 3E.2.2.1.2, the yield strength of the weld metal and the HAZ is considerably higher than that of the base metal. The material stress-strain and J-T curves are the two key inputs in determining the instability load and flaw values by the (J/T) methodology. Calculations performed for representative through-wall flaw sizes showed that the higher yield strength of the weld metal more than compensates for the slightly lower J-R curve and, consequently, the instability load and flaw predictions based on base metal properties are smaller (i.e., conservative). Accordingly, it was concluded that the material (J-T) curve shown in Figure 3E.2-8 is the appropriate one to use in the LBB evaluations for carbon steel piping at 550°F.

3E.2.2.2.2 Material J/T Curve For 420°F

Since the test temperature of 350°F can be considered reasonably close to the 420°F, the test J-R curves for 350°F were used in this case. A review of the test matrix in Table 3E.2-4 shows that three tests were conducted at 350°F. The J_{mod}, T_{mod} data for all three tests were reviewed. The flow stress value used in the tearing modulus calculation was 54 ksi based on Table 3E.2-3. Also reviewed were the data on SA106 carbon steel at 300°F reported by Gudas [14].

Consistent with the trend of the 550°F data, the 350°F weld metal (J-T) data fell below the plate and pipe base metal data. This probably reflects the slightly lower toughness of the SAW weld in the plate. The (J/T) data for the pipe base metal fell between the plate base metal and the plate weld metal. Based on the considerations similar to those presented in the previous section, the pipe base metal J-T data, although they may lie above the weld J-T data, were used for selecting the appropriate (J-T) curve. Accordingly, the curve shown in Figure 3E.2-9 was developed for using the (J-T) methodology in evaluations at 420°F.

3E.2.3 Stainless Steels and Associated Welds

The stainless steels used in the ABWR reactor coolant pressure boundary piping are either Nuclear grade or low carbon Type 304 or 316. These materials and the associated welds are highly ductile and therefore, undergo considerable plastic deformation before failure can occur. Toughness properties of Type 304 and 316 stainless steels have been extensively reported in the open technical literature and are, thus, not discussed in detail in this section. Due to high ductility and toughness, modified limit load methods can be used to determine critical crack lengths and instability loads (see Subsection 3E.3.3).

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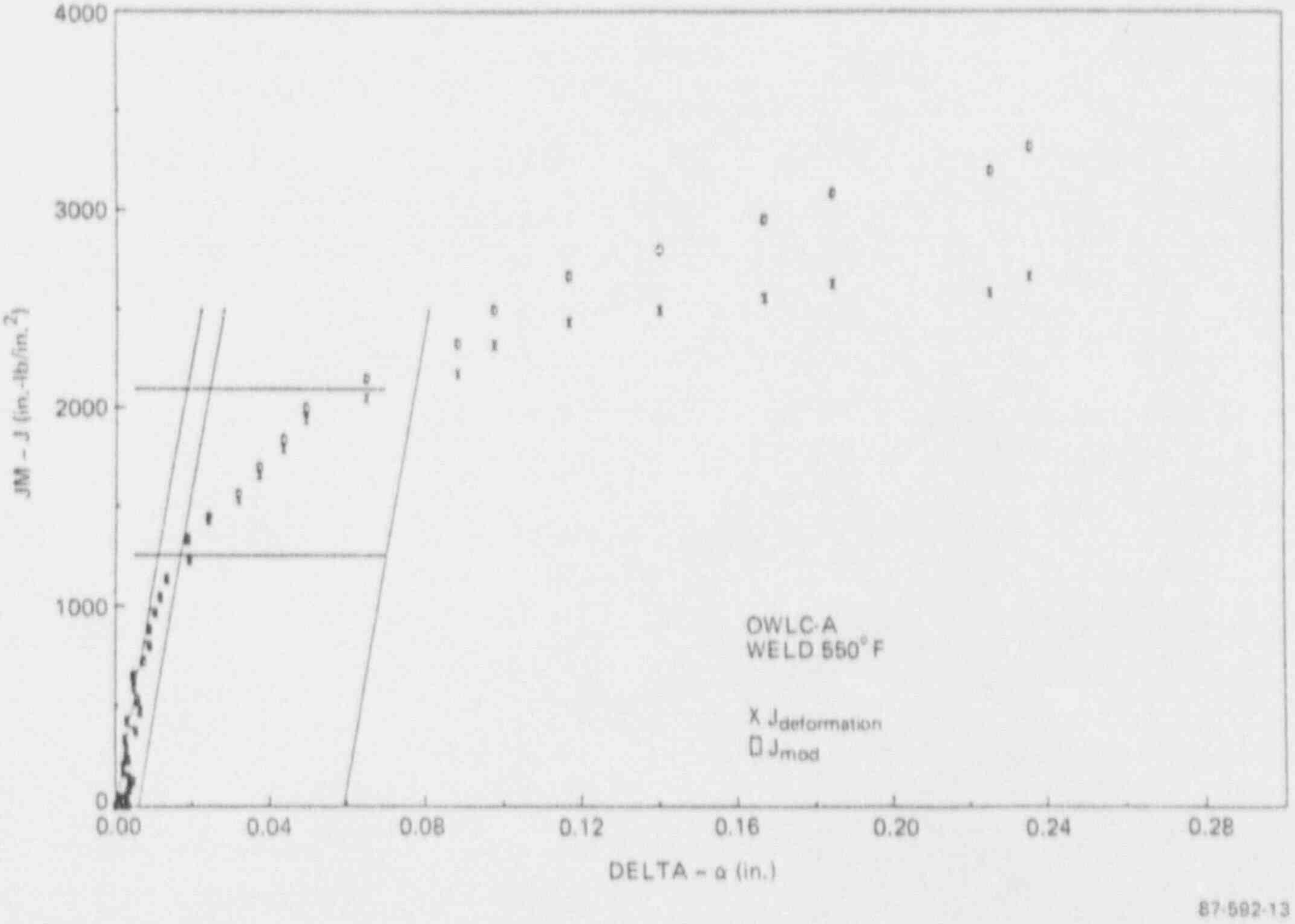

Figure 3E.2-7 PLOT OF 550° F TEST J-R CURVE FOR PIPE WELD

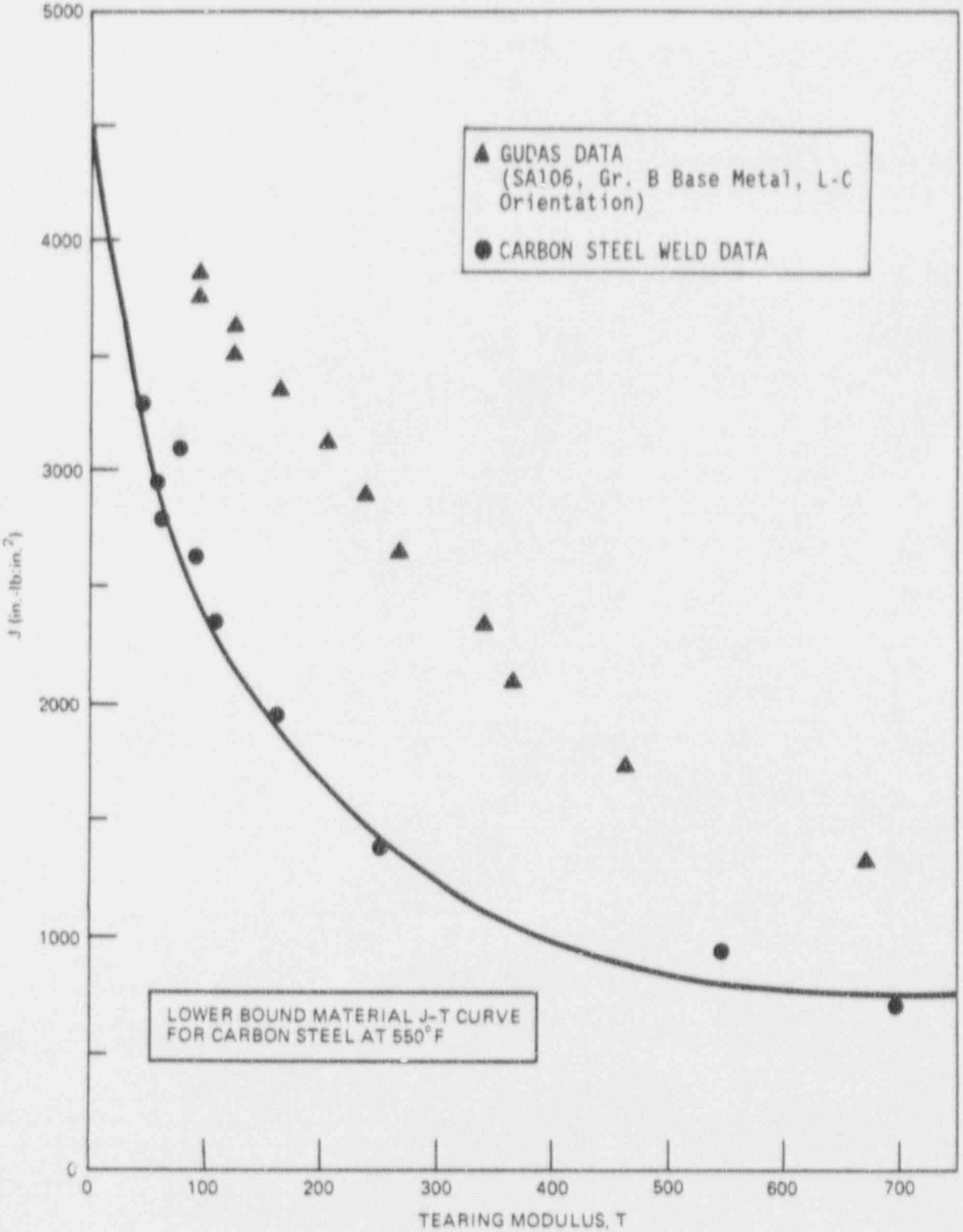

Figure 3E.2-8 PLOT OF 550°F J_{mod}, T_{mod} DATA FROM TEST J-R CURVE

SECTION 3E.3

CONTENTS

SECTION 3E.3

ILLUSTRATIONS

3E.3 FRACTURE MECHANICS METHODS

This subsection deals with the fracture mechanics techniques and methods for the determination of critical flaw lengths and instability loads for materials used in ABWR. These techniques and methods comply with Criteria (5) through (11) described in Section 3E.1.2.

3E.3.1 Elastic-Plastic Fracture Mechanics or (J/T) Methodology

Failure in ductile materials such as highly tough ferritic materials is characterized by considerable plastic deformation and significant amount of stable crack growth. The EPFM approach outlined in this subsection considers these aspects. Two key concepts in this approach are: (1) J-integral [1, 2] which characterizes the intensity of the plastic stress-strain field surrounding the crack tip and (2) the tearing instability theory [3, 4] which examines the stability of ductile crack growth. A key advantage of this approach is that the material fracture toughness characteristic is explicitly factored into the evaluation.

3E.3.1.1 Basic (J/T) Methodology

Figure 3E.3-1 schematically illustrates the J/T methodology for stability evaluation. The material (J/T) curve in Figure 3E.3-1 represents the material's resistance to ductile crack extension. Any value of J falling on the material R-curve is denoted as J_{mat} and is a function solely of the increase in crack length Δa. Also defined in Figure 3E.3-1 is the 'applied' J, which for given stress-strain properties and overall component geometry, is a function of the applied load P and the current crack length, a. Hutchinson and Paris [4] also define the following two nondimensional parameters:

$$T_{applied} = \frac{E}{\sigma_f^2} \cdot \frac{\partial J_{applied}}{\partial a}$$

$$T_{mat} = \frac{E}{\sigma_f^2} \cdot \frac{dJ_{mat}}{da} \qquad (3E.3\text{-}1)$$

where E is Young' modulus and σ_f is an appropriate flow stress.

Intersection point of the material and applied (J/T) curves denotes the instability point. This is mathematically stated as follows:

$$J_{applied}\ (a,P) = J_{mat}\ (a) \qquad (3E.3\text{-}2)$$

$$T_{applied} < T_{mat}\ \text{(stable)} \qquad (3E.3\text{-}3)$$

$$T_{applied} > T_{mat}\ \text{(unstable)}$$

The load at instability is determined from the J versus load plot also shown schematically in Figure 3E.3-1. Thus, the three key curves in the tearing stability evaluation are: $J_{applied}$ versus $T_{applied}$, J_{mat} versus T_{mat} and $J_{applied}$ versus load. The determination of appropriate J_{mat} versus T_{mat} or the material (J/T) curve has been already discussed in subsection 3E.2.1. The $J_{applied}$ - $T_{applied}$ or the (J/T) applied curve can be easily generated through perturbation in the crack length once the $J_{applied}$ versus load information is available for different crack lengths. Therefore, only the methodology for the generation of $J_{applied}$ versus load information is discussed in detail.

3E.3.1.2 J Estimation Scheme Procedure

The $J_{applied}$ or J as a function of load was calculated using the GE/EPRI estimation scheme procedure [5, 6]. The J in this scheme is obtained as sum of the elastic and fully plastic contributions:

$$J = J_e + J_p \qquad (3E.3\text{-}4)$$

The material true stress-strain curve in the estimation scheme is assumed to be in the Ramberg-Osgood format:

$$\left(\frac{\varepsilon}{\epsilon_0}\right) = \left(\frac{\sigma}{\sigma_0}\right) + \alpha \left(\frac{\sigma}{\sigma_0}\right)^n \qquad (3E.3\text{-}5)$$

where, σ_0 is the material yield stress, $\epsilon_0 = \frac{\sigma_0}{E}$, and α and n are obtained by fitting the preceding equation to the material true stress-strain curve.

The estimation scheme formulas to evaluate the J-integral for a pipe with a through-wall circumferential flaw subjected to pure tension or pure bending are as follows

Tension

$$J = f_1(a_e, \frac{R}{t})\frac{P^2}{E} + \alpha\sigma_0\epsilon_0 c(\frac{a}{b})h_1(\frac{a}{b}, n, \frac{R}{t})\left[\frac{P}{P_0}\right]^{n+1} \quad (3E.3\text{-}6)$$

where,

$$f_1(\frac{a}{b}, n, \frac{R}{t}) = \frac{a F^2(\frac{a}{b}, n, \frac{R}{t})}{4\pi R^2 t^2}$$

$$P_0 = 2\sigma_0 Rt\,[\pi - \gamma - 2 \arcsin(\frac{1}{2}\sin\gamma)]$$

Bending

$$J = f_1(a_e, \frac{R}{t})\frac{M^2}{E} + \alpha\sigma_0\epsilon_0 c(\frac{a}{b})h_1(\frac{a}{b}, n, \frac{R}{t})\left[\frac{M}{M_0}\right]^{n+1} \quad (3E.3\text{-}7)$$

where,

$$f_1(\frac{a}{b}, n, \frac{R}{t}) = \pi a(\frac{R}{I})^2 F^2(\frac{a}{b}, n, \frac{R}{t})$$

$$M_0 = M_0\,[\cos(\frac{\gamma}{2}) - \frac{1}{2}\sin(\gamma)]$$

The nondimensional functions F and h are given in Reference 6

While the calculation of J for given α, n, σ_0 and load type is reasonably straight-forward, one issue that needs to be addressed is the tearing instability evaluation when the loading includes both the membrane and the bending stresses. The estimation scheme is capable of evaluating only one type of stress at a time. This aspect is addressed next.

3E.3.1.3 Tearing Instability Evaluation Considering Both the Membrane and Bending Stresses

Based on the estimation scheme formulas and the tearing instability methodology just outlined, the instability bending and tension stresses can be calculated for various through-wall circumferential flaw lengths. Figure 3E.3-2 shows a schematic plot of the instability stresses as a function of flaw length. For the same stress level, the allowable flaw length for the bending is expected to be larger than the tension case.

When the applied stress is a combination of the tension and bending, a linear interaction rule is used to determine the instability stress or conversely the critical flaw length. The application of linear interaction rule is certainly conservative when the instability load is close to the limit load. The applicability of this proposed rule should be justified by providing a comparision of the predictions by the proposed approach (or an alternate approach) with those available for cases where the combination is treated together.

The interaction formulas are following: (See Figure 3E.3-2)

Critical Flaw Length

$$a_c = \left(\frac{\sigma_t}{\sigma_t+\sigma_b}\right) a_{c,t} + \left(\frac{\sigma_b}{\sigma_t+\sigma_b}\right) a_{c,b} \quad (3E.3\text{-}8)$$

where:

σ_t = applied membrane stress

σ_b = applied bending stress

$a_{c,t}$ = critical flaw length for a tension stress of $(\sigma_t+\sigma_b)$

$a_{c,b}$ = critical flaw length for a bending stress of $(\sigma_t+\sigma_b)$

Instability Bending Stress

$$S_b = (1 - \frac{\sigma_t}{\sigma_t'})\,\sigma'_b \quad (3E.3\text{-}9a)$$

where:

S_b = instability bending stress for flaw length, a, in the presence of membrane stress, σ_t.

σ_t = applied membrane stress

σ_t = instability tension stress for flaw length, a.

σ_b' = instability bending stress for flaw length, a.

Once the instability bending stress, S_b, in the presence of membrane stress, $_t$, is determined, the instability load margin corresponding to the detectable leak-size crack (as required by LBB criterion in Section 3.6.3) can be calculated as follows:

Instability Load Margin (3E.3-9b) $\dfrac{\sigma_t + S_b}{\sigma_t + \sigma_b}$

It is assumed in the preceding equation that the uncertainty in the calculated applied stress is essentially associated with the stress due to applied bending loads and that the membrane stress, which is generally due to the pressure loading, is known with greater certainty. This method of calculating the margin against loads is also consistent with the definition of load margin employed in Paragraph IWB-3640 of Section XI [7].

3E.3.2 Application of (J/T) Methodology to Carbon Steel Piping

From Figure 3E.2-3, it is evident that carbon steels exhibit transition temperature behavior marked by three distinct stages: lower shelf, transition and upper shelf. The carbon steels generally exhibit ductile failure mode at or above upper shelf temperatures. This would suggest that a net-section collapse approach may be feasible for the evaluation of postulated flaws in carbon steel piping. Such a suggestion was also made in a review report prepared by the Naval Research Lab [8]. Low temperature (i.e. less than 125^{0}F) pipe tests conducted by GE [9] and by Vassilaros [10] which involved circumferentially cracked pipes subjected to bending and/or pressure loading, also indicate that a limit load approach is feasible. However, test data at high temperatures specially involving large diameter pipes are currently not available. Therefore, a (J/T) based approach is used in the evaluation.

3E.3.2.1 Determination of Ramberg-Osgood Parameters for 550^{0}F Evaluation

Figure 3E.2-6a shows the true stress-true strain curves for the carbon steels at 550^{0}F. The same data is plotted here in Figure 3E.3-3 in the Ramberg-Osgood format. It is seen that, unlike the stainless steel case, each set for stress-strain data (i.e. data derived from one stress-strain curve) follow approximately a single slope line. Based on the visual observation, a line representing α = 2, n = 5 in Figure 3E.3-3 was drawn as representing a reasonable upper bound to the data shown.

The third parameter in the Ramberg-Osgood format stress-stain curve is σ_o, the yield stress. Based on the several internal GE data on carbon steels such as SA 333 Gr.6, and SA 106 Gr.B, a reasonable value of 550^{0}F yield strength was judged as 34600 psi. To summarize, the following values are used in this appendix for the (J/T) methodology evaluation of carbon steels as 550^{0}F:

α = 2.0

n = 5.0

σ_0 = 34600 psi

E = 26×10^6 psi

3E.3.2.2 Determination of Ramberg-Osgood Parameters for 420^{0}F Evaluation

Figure 3E.3-4 shows the Ramberg-Osgood (R-O) format plot of the 350^{0}F true stress-stain data on the carbon steel base metal. Also shown in Figure 3E.3-4 are the CE data a SA 106 Grade B at 400^{0}F. Since the difference between the ASME Code Specified minimum yield strength at 350^{0}F and 420^{0}F is small, the 350^{0}F stress-strain data were considered applicable in the determination of R-O parameters for evaluation at 420^{0}F.

A review of Figure 3E.3-4 indicates that the majority of the data associated with any one test can be approximated by one straight line.

It is seen that some of the data points associated with the yield point behavior fall along the y-axis. However, these data points at low stain level were not considered significant and, therefore, were not included in the R-O fit.

The 350°F yield stress for the base material is given in Table 3E.2-3 as 37.9 ksi. Since the difference between the ASME Code specified minimum yield strengths of pipe and plate carbon steels at 420°F and 350°F is roughly 0.9 ksi, the σ_o value for use at 420°F are chosen as (37.9^{0} - 0.9) or 37 ksi. In summary, the following values of R-O parameters are used for evaluation of 420°F:

σ_o = 37,000 psi

α = 5.0

n = 4.0

3E.3.3 Modified Limit Load Methodology for Austenitic Stainless Steel Piping

Reference 16 describes a modified limit load methodology that may be used to calculate the critical flaw lengths and instability loads for austenitic stainless steel piping and associated welds. If appropriate, this or an equivalent methodology may be used in lieu of the (J/T) methodology described in 3E.3.1.

3E.3.4 Bimetallic Welds

For joining austenitic steel to ferritic steel, the Ni-Cr-Fe Alloys 82 or 182 are generally used for weld metals. The procedures recommended in Section 3E.3.3 for the austenitic welds are applicable to these weld metals. This is justified based on the common procedures adopted for flaw acceptance in the ASME Code Section XI, Article IWB-3600 and Appendix C, for both types of the welds. If other types of bimetallic weld metals are used, proper procedures should be used with generally acceptable justification.

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SECTION 3E.4

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SECTION 3E.4

ILLUSTRATIONS

3E.4 LEAK RATE CALCULATION METHODS

Leak rates of high pressure fluids through cracks in pipes are a complex function of crack geometry, crack surface roughness, applied stresses, and inlet fluid thermodynamic state. Analytical predictions of leak rates essentially consist of two separate tasks: calculation of the crack opening area, and the estimation of the fluid flow rate per unit area. The first task requires the fracture mechanics evaluations based on the piping system stress state. The second task involves the fluid mechanics considerations in addition to the crack geometry and its surface roughness information. Each of these tasks are now discussed separately considering the type of fluid state in BWR piping.

3E.4.1 Leak Rate Estimation for Pipes Carrying Water

EPRI-developed computer code PICEP [1] may be used in the leak rate calculations. The basis for this code and comparison of its leak rate predictions with the experimental data is described in References 2 and 3. This code was has been used in the successful application of LBB to primary piping system of a PWR. The basis for flow rate and crack opening area calculations in PICEP is briefly described first. A comparison with experimental data is shown next.

Other methods (e.g., Reference 4) may be used for leak rate estimation at the descretion of the applicant.

3E.4.1.1 Description of Basis for Flow Rate Calculation

The thermodynamic model implemented in PICEP computer program assumes the leakage flow through pipe cracks to be isenthalpic and homogeneous, but it accounts for non-equilibrium "flashing" transfer process between the liquid and vapor phases.

Fluid friction due to surface roughness of the walls and curved flow paths has been incorporated in the model. Flows through both parallel and convergent cracks can be treated. Due to the complicated geometry within the flow path, the model uses some approximations and empirical factors which were confirmed by comparison against test data.

For given stagnation conditions and crack geometries, the leak rate and exit pressure are calculated using an iterative search for the exit pressure starting from the saturation pressure corresponding to the upstream temperature and allowing for friction, gravitational, acceleration and area change pressure drops. The initial flow calculation is performed when the critical pressure is lowered to the back pressure without finding a solution for the critical mass flux.

A conservative methodology was developed to handle the phase transformation into a two-phase mixture or superheated steam through a crack. To make the model continuous, a correction factor was applied to adjust the mass flow rate of a saturated mixture to be equal to that of a slightly subcooled liquid. Similarly, a correction factor was developed to ensure continuity as the steam became superheated. The superheated model was developed by applying thermodynamic principles to an isentropic expansion of the single phase steam.

The code can calculate flow rates through fatigue or IGSCC cracks and has been verified against data from both types. The crack surface roughness and the number of bends account for the difference in geometry of the two types of cracks. The guideline for predicting leak rates through IGSCCs when using this model was based on obtaining the number of turns that give the best agreement for Battelle Phase II test data of Collier et al. [5]. For fatigue cracks, it is assumed that the crack path has no bends.

3E.4.1.2 Basis for Crack Opening Area Calculation

The crack opening area in PICEP code is calculated using the estimation scheme formulas. The plastic contribution to the displacent is computed by summing the contributions of bending and tension alone, a procedure that underestimates the displacent from combined tension and bending. However, the plastic contribution is expected to be insignificant because the applied stresses at normal operation are generally such that they do not produce significant plasticity at the cracked location.

3E.4.1.3 Comparison Verification with Experimental Data

Figure 3E.4-1 from Reference 3 shows a comparison PICEP prediction with measured leak rate data. It is seen that PICEP predictions are virtually always conservative (i.e., the leak flow rate is underpredicted).

3E.4.2 Flow Rate Estimation for Saturated Steam

3E.4.2.1 Evaluation Method

The calculations for this case were based on the maximum two-phase flow model developed by Moody [Reference 6]. However, in an LBB-report, a justification should be provided by comparing the predictions of this method with the available experimental data, or a generally accepted method, if available, should be used.

The Moody predicts the flow rate of steam-water mixtures in vessel blowdown from pipes (see Figure 3E.4-2). A key parameter that characterized the flow passage in the Moody analysis is fL/D_h, where, f is the coefficient of friction, L, the length of the flow passage and D_h, the hydraulic diameter. The hydraulic diameter for the case of flow through a crack is 2δ where δ is the crack opening displacement and the length of the flow passage is t, the thickness of the pipe. Thus, the parameter fL/D_h in the Moody analysis was interpreted as $ft/2\delta$ for the purpose of this evaluation.

Figure 3E.4-3 shows the predicted mass flow rates by Moody for fL/D_h of 0 and 1. Similar plots are given in Reference 6 for additional fL/D_h values of 2 through 100. Since the steam in the ABWR main steam lines would be essentially saturated, the mass flow rate corresponding to the upper saturation envelope line is the appropriate one to use. Table 3E.4-1 shows the mass flow rates for a range of fL/D_h values for a stagnation pressure of 1000 psi which is roughly equal to the pressure in an ABWR piping system carrying steam.

A major uncertainty in calculating the leakage rate is the value of f. This is discussed next.

3E.4.2.2 Selection of Appropriate Friction Factor

Typical relationships between Reynolds' Number and relative roughness ϵ/D_h, the ratio of effective surface protrusion height to hydraulic diameter, were relied upon in this case. Figure 3E.4-4, from Reference 7, graphically shows such a relationship for pipes. The ϵ/D_h ratio for pipes generally ranges from 0 to 0.50. However, for a fatigue crack consisting of rough fracture surfaces represented by a few mils, the roughness height ϵ at some location may be almost as much as δ. In such cases, ϵ/D_h would seem to approach 1/2. There are no data or any analytical model for such cases, but a crude estimate based on the extrapolation of the results in Figure 3E.4-4 would indicate that f may be of the order of 0.1 to 0.2. For this evaluation an average value of 0.15 was used with the modification as discussed next.

For blowdown of saturated vapor, with no liquid present, Moody states that the friction factor should be modified according to

$$f_g = f_{GSP}\left[\frac{\nu f}{\nu g}\right]^{1/3} \quad (3E.4\text{-}1)$$

where

f_g = modified friction factor

f_{GSP} = factor for single phase

$\frac{\nu f}{\nu g}$ = liquid/vapor specific volume ratio evaluated at an average static pressure in the flow path

This correction is necessary because the absence of a liquid film on the walls of the flow channel at high quality makes the two-phase flow model invalid as it stands. The average static pressure in the flow path is going to be something in excess of 500 psia if the initial pressure is 1000 psia; this depends on the amount of flow choking and can be determined from Reference 6. However, a fair estimate of $(\nu f/\nu g)^{1/3}$ is 0.3, so the friction factor for saturated steam blowdown may be taken as 0.3 of that for mixed flow.

Based on this discussion, a coefficient of friction of 0.15 x 0.3 = 0.045 was used in the flow rate estimation. Currently experimental data are unavailable to validate this assumed value of coefficient of friction.

3E.4.2.3 Crack Opening Area Formulation

The crack opening areas were calculated using LEFM procedures with the customary plastic zone correction. The loadings included in the crack opening area calculations were: pressure weight and thermal expansion.

The mathematical expressions given by Paris and Tada [8] are used in this case. The crack opening areas for pressure (A_p) and bending stresses (A_b) were separately calculated and then added together to obtain the total area, A_c.

For simplicity, the calculated membrane stresses from weight and thermal expansion loads were combined with the axial membrane stress, σ_p, due to the pressure.

The formulas are summarized below:

$$A_p = \frac{\sigma_p}{E} (2\pi Rt) G_p (\lambda) \quad (3E.4\text{-}2)$$

where,

σ_p = axial membrane stress due to pressure, weight and thermal expansion loads.

E = Young's modulus

R = pipe radius

t = pipe thickness

λ = shell parameter = $a/\sqrt{Rt}$

a = half crack length

(3E.4-3)

$$G_p(\lambda) = \lambda^2 + 0.16\lambda^4 \quad (0 \leq \lambda \leq 1)$$

$$= 0.02 + 0.81\lambda^2 + 0.30\lambda^3 + 0.03\lambda^4 \quad (1 \leq \lambda \leq 5)$$

$$A_b = \frac{\sigma_b}{E} \cdot \pi \cdot R^2 \cdot \frac{(3 + \cos\theta)}{4} I_t^{(\theta)} \quad (3E.4\text{-}4)$$

where,

σ_b = bending stress due to weight and thermal expansion loads

θ is half crack angle

(3E.4-5)

$$I_t(\theta) = 2\theta^2 \left[1 + \left(\frac{\theta}{\pi}\right)^{3/2} \left\{ 8.6 - 13.3\left(\frac{\theta}{\pi}\right) + 24\left(\frac{\theta}{\pi}\right)^2 \right\} + \left(\frac{\theta}{\pi}\right)^3 \left\{ 22.5 - 75\left(\frac{\theta}{\pi}\right) + 205.7\left(\frac{\theta}{\pi}\right)^2 - 247.5\left(\frac{\theta}{\pi}\right)^3 + 242\left(\frac{\theta}{\pi}\right)^4 \right\} \right]$$

$(0 < \theta < 100^0)$

The plastic zone correction was incorporated by replacing a and θ in these formulas by a_e and θ_e which are given by

$$\theta_{eff} = \theta + \frac{K_{total}^2}{2\pi R \sigma_Y^2} \quad (3E.4\text{-}6)$$

$$a_e = \theta_e \cdot R$$

The yield stress, σ_y, was conservatively assumed as the average of the code specified yield and ultimate strength. The stress intensity factor, K_{total}, includes contribution due to both the membrane and bending stress and is determined as follows:

$$K_{total} = K_m + K_b \quad (3E.4\text{-}7)$$

where,

$$K_m = \sigma_p \sqrt{a} \cdot F_p(\lambda)$$

$$F_p(\lambda) = (1 + 0.3225\lambda^2)^{\frac{1}{2}}$$

$$= 0.9 + 0.25\lambda \qquad (0 \leq \lambda \leq 1)$$
$$(1 \leq \lambda \leq 5)$$

$$K_b = \sigma_b \cdot \sqrt{\pi a} \cdot F_b(\theta)$$

$$F_b(\theta) = 1 + 6.8\left(\frac{\theta}{\pi}\right)^{3/2}$$
$$- 13.6\left(\frac{\theta}{\pi}\right)^{5/2} + 20\left(\frac{\theta}{\pi}\right)^{7/2}$$
$$(0 \leq \theta \leq 100^0)$$

The steam mass flow rate, M, shown in Table 3E.4-1 is a function of parameter, $ft/2\delta$. Once the mas. flow rate is determined corresponding to the calculated value of this parameter, the leak rate in gpm can then be calculated.

3E.4.3 References

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3E.5 LEAK DETECTION CAPABILITIES

A complete description of various leak detection systems is provided in Subsection 5.2.5. The leakage detection system gives separate considerations to: leakage within the drywell and leakage external to the drywell. The limits for reactor coolant leakage are described in Subsection 5.2.5.4.

The total leakage in the drywell consists of the identified leakage and the unidentified leakage. The identified leakage is that from pumps, valve stem packings, reactor vessel head seal and other seals, which all discharge to the equipment drain sump. The technical specification limit on the identified leak rate is expected to be 25 gpm.

The unidentified leak rate in the drywell is the portion of the total leakage received in the drywell sumps that is not identified as previously described. The licensing (technical specification) limit on unidentified leak rate is 1 gpm. To cover uncertainties in leak detection capability, although it meets Regulatory Guide 1.45 requirements, a margin factor of 10 is required per Reference 16 of Subsection 3E.3.4 to determine a reference leak rate. A reduced margin factor may be used if accounts can be made of effects of sources of uncertainties such as plugging of the leakage crack with particulate material over time, leakage prediction, measurement techniques, personnel and frequency of monitoring. For the piping in drywell, a reference leak rate of 10 gpm may be used, unless a smaller rate can be justified.

The sensitivity and reliability of leakage detection systems used outside the drywell must be demonstrated to be equivalent to Regulatory Guide 1.45 systems. Methods that have been shown to be acceptable include local leak detection, for example, visual observation or instrumentation. Outside the drywell, the leakage rate detection and the margin factor depend upon the design of the leakage detection systems.

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TABLES (Continued)

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3E.6 GUIDELINES FOR PREPARATION OF AN LBB REPORT

Some of the key elements of an LBB evaluation report for a high energy piping system are: system description, evaluation of susceptibility to water hammer and thermal fatigue, material specification, piping geometry, stresses and the LBB margin in evaluation results. Two examples are presented in the following subsections to provide guidelines and illustrations for preparing an LBB evaluation report.

3E.6.1 Main Steam Piping

3E.6.1.1 System Description

The four 28-inch (700 mm) main steam (MS) lines carry steam from the reactor to the turbine and auxiliary systems. The reactor coolant pressure boundary portion of each line being evaluated in this section connects to a flow restrictor which is a part of the reactor pressure vessel nozzle and is designed to limit the rate of escaping steam from the postulated break in the downstream steam line. The restrictor is also used for flow measurements during plant operation. The safety relief valves (SRVs) discharge into the pressure suppression pool through SRV discharge piping. The SRV safety function includes protection against overpressure of the reactor primary system. The main steam line A has a branch connection to supply steam to the reactor core isolation cooling (RCIC) system turbine.

This section addresses the MS piping system in the reactor building which is designed and constructed to the requirements of the ASME Code, Section III, Class 1 piping (within outermost isolation valve) and Class 2 piping. It is classified as Seismic Category I. It is inspected according to ASME Code Section XI.

3E.6.1.2 Susceptibility to Water Hammer

Significant pressure pulsation of water hammer effect in the pipe may occur as a result of opening of SRVs or closing of the turbine stop valve. A brief description of these phenomena follows. These two transients are considered in the main steam piping system design and fatigue analysis. These events are more severe than the opening or closing of a main steam isolation valve or water carry over through main steam and SRV piping. Moreover, the probability of water carry over during core flooding in case of an accident is low.

Safety Relief Valve Lift Transient Description

SRV produces momentary unbalanced forces acting on the discharge piping system for the period from the opening of the SRV until a steady discharge flow from the reactor pressure vessel to the suppression pool is established. This period includes clearing of the water slug at the end of the discharge piping submerged in the suppression pool. Pressure waves traveling through the discharge piping following the relatively rapid opening of the SRVs causes the discharge piping to vibrate. This in turn produces time dependent forces that act on the main steam piping segments.

There are a number of events/transients/postulated accidents that result in SRV lift:

a. Automatic opening signal when main steam system pressure exceeds the set point for a given valve (there are different set points for different valves in a given plant).

b. Automatic opening signal for all valves assigned to the automatic depressurization system function on receipt of proper actuation signal.

c. Manual opening signal to valve selected by plant operator.

The SRVs close when the main steam system pressure reaches the relief mode reseat pressure or when the plant operator manually releases the opening signals.

It is assumed (for conservatism) that all SRVs are activated at the same time, which produces simultaneous forces on the main steam piping system.

Turbine Stop Valve Closure Transient Description

Prior to turbine stop valve closure, saturated steam flows through each main steam line at nuclear boiler rated pressure and mass flow rate. Upon signal, the turbine stop valves close rapidly and the steam flow stops at the upstream side of these valves. A pressure wave is created and travels at sonic velocity toward the reactor vessel through each main stream line. The flow of steam into each main steam line from the reactor vessel continues until the fluid compression wave reaches the reactor vessel nozzle. Repeated reflection of the pressure wave at the reactor vessel and stop valve ends of the main steam lines produces time varying pressures and velocities at each point along the main steam lines. The combination of fluid momentum changes, shear forces, and pressure differences cause forcing functions which vary with position and time to act on the main steam piping system. The fluid transient loads due to turbine stop valve closure is considered as design load for upset condition.

Basic Fluid Transient Concept

Despite the fact that the SRV discharge and the turbine stop valve closure are flow-starting and flow-stopping processes, respectively, the concepts of mass, momentum, and energy conservation and the differential equations which represent these concepts are similar for both problems. The particular solution for either of the problems is obtained by incorporating the appropriate initial conditions and boundary conditions into the basic equations. Thus, relief valve discharge and turbine stop valve closure are seen to be specific solutions of the more general problem of compressible, non-steady fluid flow in a pipe.

The basic fluid dynamic equations which are applicable to both relief valve discharge and turbine stop valve closure are used with the particular fluid boundary conditions of these occurrences. Step-wise solution of these equations generates a time-history of fluid properties at numerous locations along the pipe. Simultaneously, reaction loads on the pipe are determined at each location corresponding to the position of an elbow.

The computer programs RVFOR and TSFOR described in Appendix 3D are used to calculate the fluid transient forces on the piping system due to safety relief valve discharge and turbine stop valve closure. Both of the programs use method of characteristics to calculate the fluid transients.

The results from the RVFOR program have been verified with various inplant test measurements such as from the Monticello tests and Caoroso tests and the test sponsored by BWR owner for NUREG-0737 at Wyle Test facilities, Huntsville, Alabama. Various data from the strain gages on the pipes and the load cells on the supports were compared with the analytical data and found to be in good correlation.

Evaluation of the ensuing effects are considered as a normal design process for the main steam piping system. The peak pressure pulses are within the design capability of a typical piping design and the piping stresses and support loads remain within the ASME Code allowables.

It is concluded that, during these water hammer type events, the peak pressures and segment loads would not cause overstressed conditions for the main steam piping system.

3E.6.1.3 Thermal Fatigue

No thermal stratification and thermal fatigue are expected in the main steam piping since there is no large source of cold water in these lines. A small amount of water may collect in the near horizontal leg of the main steam line due to steam condensation. However, a slope of 1/8 inch per foot of main steam piping is provided in each main steam line. Water drain lines are provided at the end of slope to drain out the condensate. Thus, in this case no significant thermal cycling effects on the main steam piping are expected.

3E.6.1.4 Piping, Fittings and Safe End Materials

The material specified for the 28-inch main steam pipe is SA672 Grade C70. The corresponding specification for the piping fittings and forgings are given as SA420, WPL6 and SA350, LF2, respectively. The material for the safe end forging welded between the main steam piping and the steam nozzle is SA508 Class 3.

3E.6.1.5 LBB Margin Evaluation

The Code stress analysis of the piping is reviewed to obtain representative stress magnitudes. Table 3E.6-1 shows, for example purposes, the stress magnitudes due to pressure, weight, thermal expansion and SSE loads.

The leak rate calculations are performed assuming saturated steam conditions at 1050 psi. The leak rate model for saturated steam developed in Section 3E.4.2 is be used in this evaluation. Pressure, weight and thermal expansion stresses are included in calculating the crack opening area. A plot of leak rate as a function of crack size is developed as is shown in Figure 3E.6-1. The leakage flaw length corresponding to the reference leak rate (see Section 3E.5) is determined from this figure.

The calculations for the critical flaw size and instability load corresponding to leakage-size crack are performed using the J-T methodology. Specifically, the 550°F J-R curve shown in Figure 3E.2-8 and the Ramberg-Osgood parameters given in Subsection 3E.3.2.1 are used. A plot of instability tension and bending stresses as a function of crack length is developed. Table 3E.6-2 shows the example presentation of calculated critical crack size and the margin along with the instability load margin for the leakage size crack. It is noted that the critical crack size margin is greater than 2 and the instability load margin also exceeds $\sqrt{2}$.

3E.6.1.6 Conclusion

For all example main steam lines, based upon the reference leakage rates and assumed stress magnitudes, leakage flaw lengths are calculated and compared against the critical flaw length. The margin is shown to be greater than 2 for the leakage rates. Also, the leak-size crack stability evaluation is shown to have a margin of at least $\sqrt{2}$.

It is also shown that the conditions required for applicability of LBB (see Subsection 3.6.3.2), such as high resistance to failure from effects of IGSCC, water hammer and thermal fatigue, are satisfied. Therefore, all four of the main steam lines qualify for LBB behavior.

3E.6.2 Feedwater Piping Example

3E.6.2.1 System Description

The function of the feedwater (FW) system is to conduct water to the reactor vessel over the full range of the reactor power operation. The feedwater piping consists of two 22-inch (550 mm) diameter lines from the high-pressure feedwater heaters, connecting to the reactor vessel through three 12-inch (300 mm) risers on each line. Each line has one check valve inside the containment drywell and one positive closing check valve outside containment. During shutdown cooling mode, reactor water pumped through the RHR heat exchanger in one loop is returned to the vessel by way of one feedwater line.

This section addresses the feedwater piping in the reactor building, extending from the vessel to the outboard isolation valve (ASME Class 1) and further through the shutoff valve to and including the seismic interface restraint (ASME Class 2). This section of the feedwater piping is classified as Seismic Category I.

3E.6.2.2 Susceptibility to Water Hammer

There is no record of feedwater piping failure due to water hammer. Although there are several check valves in the feedwater system, operating procedure and the control systems have been designed to limit the magnitude of water hammer load to the extent that a formal design is not required.

3E.6.2.3 Thermal Fatigue

Thermal fatigue is not a concern in ABWR feedwater piping. The ASME Code evaluation includes operating temperature transients, cold and hot water mixing and thermal stratification.

3E.6.2.4 Piping. Fittings and Safe End Material

The material for piping is either SA333, Gr. 6 or SA-672, Gr. C70.

3E.6.2.5 Piping Sizes, Geometries and Stresses

Table 3E.6-3 shows the normal operating temperatures, pressures and thickness for representative pipe sizes in the example feedwater system. The nominal thickness for both pipe sizes correspond to schedule 80. Table 3E.6-4 shows, for example purposes, the stress magnitudes for each pipe size due to pressure, weight, thermal expansion and SSE loads. Only the pressure weight and thermal expansion stresses are used in the leak rate evaluation, where a sum of all stresses is used in the instability load and critical flaw evaluation.

3E.6.2.6 LBB Margin Evaluation

The incoming water of the feedwater system is in a subcooled state. Accordingly, the leakage flaw length calculations are based on the procedure outlined in Section 3E.4.1. The saturation pressure, P_{sat}, for each pipe size is calculated from the normal operation temperatures given in Table 3E.6-3. The leak rates are calculated as a function of crack length. The leakage flaw lengths corresponding to the reference leak rate (see Section 3E.5) are then determined.

The calculations for the critical flaw size and the instability load corresponding to leakage size cracks is performed using the J-T methodology. Specifically, the J-T curve shown in Figure 3E.2-9 and the Ramberg-Osgood parameters given in Subsection 3E.3.2.2 are used. Table 3E.6-5 shows the example presentation of calculated critical crack sizes, and the margins along with the instability load margins for the leakage size cracks. Results are shown for both the 22-inch and 12-inch lines. It is noted that the critical crack size margin is greater than 2 and the instability load margin also exceeds $\sqrt{2}$.

3E.6.2.7 Conclusion

For the example feedwater piping, based upon the reference leakage rate and assumed stress magnitudes, leakage flaw lengths are calculated for 22-inch and 12-inch lines. Comparison with critical crack lengths shows margin to be greater than 2. Also, the leak-size crack stability evaluation shows a margin of at least $\sqrt{2}$.

It is also demonstrated that the feedwater line meets other LBB criteria of Subsection 3.6.3.2 including immunity to failure from effects of IGSCC, water hammer and thermal fatigue. Therefore, the feedwater lines qualify for LBB behavior.

Table 3E.6-1

STRESSES IN THE MAIN STEAM LINES
(Assumed for example)

Nominal Pipe Size (in)	Pipe O.D. (in)	Nominal Thickness (in)	Long. Pressure Stress (ksi)	Weight + Thermal Expansion Stress (ksi)	SSE Stress (ksi)
28	28.0	1.32	5.17	3.0	5.0

Table 3E.6-2

CRITICAL CRACK LENGTH AND INSTABILITY LOAD MARGIN EVALUATIONS FOR MAIN STEAM LINES (Example)

Pipe Size (in)	Reference Leak Rate (gpm)	Reference Leakage Crack Length (in)	Critical Crack Length (in)	Instability[1] Bending Stress, S_b (ksi)	Margins on Critical Crack	Margins on Load[2] at Leakage Crack
28	10[3]	13.45	30.7	24.2	2.3	2.2

Notes:

1. Based on Equation 3E.3-9a
2. Based on Equation 3E-9b.
3. See Section 3E.5.

Table 3E.6-3

DATA FOR FEEDWATER SYSTEM PIPING (EXAMPLE)

Nominal Pipe Size (in)	Pipe O.D. (in)	Nominal Thickness (in)	Nominal Temperature (°F)	Operating Pressure (psig)
12	12.75	0.687	420	1100
22	22.0	1.031	420	1100

Table 3E.6-4

STRESSES IN FEEDWATER LINES (ASSUMED FOR EXAMPLE)

Nominal Pipe Size (in)	Logitudinal Pressure Stress (ksi)	Weight + Thermal Expansion Stress (ksi)	Safe Shut-down Earthquake (SSE) Stress (ksi)
12	5.1	4.0	5.0
22	5.4	4.0	5.0

Table 3E.6-5

CRITICAL CRACK LENGTH AND INSTABILITY LOAD MARGIN EVALUATIONS FOR FEEDWATER LINES (EXAMPLE)

Pipe Size (in)	Reference Leak Rate (gpm)	Reference Leakage Crack Length (in)	Critical Crack Length (in)	Instability[1] Bending Stress, S_b (ksi)	Margins on Critical Crack	Margins on Load[2] at Leakage Crack
12	10^3	5.7	13.1	24.0	2.3	2.1
22	10^3	6.7	20.4	25.6	3.1	2.2

Notes:

1. Based on Equation 3E.3-9a
2. Based on Equation 3E-9b.
3. See Section 3E.5.

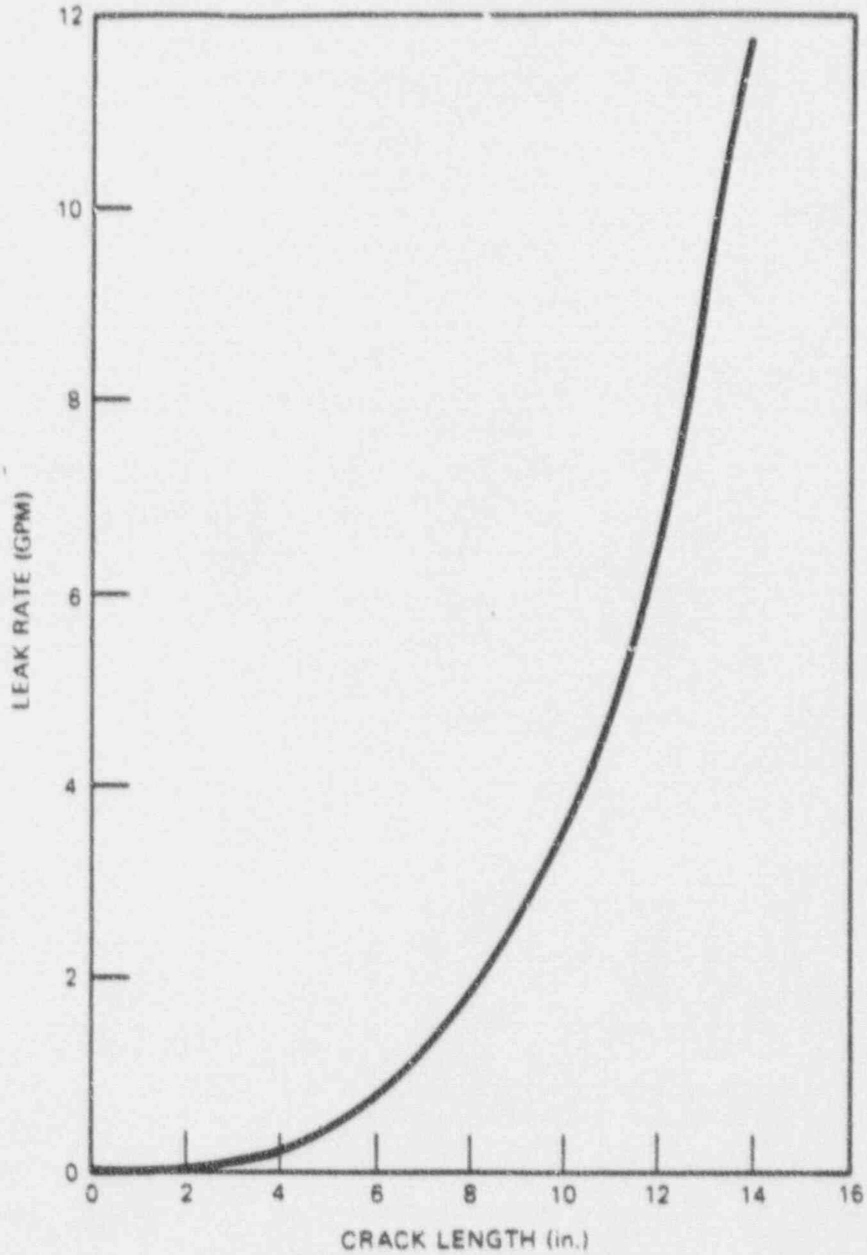

Figure 3E.6-1 LEAK RATE AS A FUNCTION OF CRACK LENGTH IN MAIN STEAM PIPE (EXAMPLE)

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DELETED

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31.3 ENVIRONMENTAL CONDITIONS PARAMETERS

GE PROPRIETARY-provided under separate cover

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CHAPTER 4

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4.4.2.3.3 Regions of the Power Flow Map

Region I — This region defines the system operational capability with the reactor internal pumps running at their minimum speed (30%). Power changes, during normal startup and shutdown, will be in this region. The normal operating procedure is to start up along curve 1.

Region II — This is the low power area of the operating map where the carryover through steam separators is expected to exceed the acceptable value. Operation within this region is precluded by system interlocks.

Region III — This is the high power/low flow area of the operating map which the system is the least damped. Operation within this region is precluded by SCRRI (Selected Control Rods Run-In).

Region IV — This represents the normal operating zone of the map where power changes can be made, by either control rod movement or by core flow changes, through the change of the pump speeds.

4.4.2.3.4 Design Features for Power-Flow Control

The following limits and design features are employed to maintain power-flow conditions shown in Figure 4.4-1:

(1) Minimum Power Limits at Intermediate and High Core Flows: To prevent unacceptable separator performance, the recirculation system is provided with an interlock to reduce the RIP speed.

(2) Pump Minimum Speed Limit: The Reactor Internal Pumps (RIPs) are equipped with Anti-Rotation Devices (ARD) which prevent a tripped RIP from rotating backwards. The ARD begins operating at 300 rpm decreasing speed. In order to prevent mechanical wear in the ARD, minimum speed is specified at 300 rpm. However, to provide a stable operation, the minimum pump speed is set at 450 rpm (30% of required).

4.4.2.3.5 Flow Control

The normal plant startup procedure requires the startup of all RIPs first and maintain at their minimum pump speed (30% of rated), at which point reactor heatup and pressurization can commence. When operating pressure has been established, reactor power can be increased. This power-flow increase will follow a line within Region I of the flow control map shown in Figure 4.4-1. The system is then brought to the desired power-flow level within the normal operating area of the map (Region IV) by increasing the RIP speeds and by withdrawing control rods.

Control rod withdrawal with constant pump speed will result in power/flow changes along lines of constant pump speed (Curves 1 through 8). Change of pump speeds with constant control rod position will result in power/flow changes along, or nearly parallel to, the rated flow control line (curves A through F).

4.4.2.4 Thermal and Hydraulic Characteristics Summary Table

The thermal-hydraulic characteristics are provided in Table 4.4-1 for the core and tables of Section 5.4 for other portions of the reactor coolant system.

4.4.3 Loose-Parts Monitoring System

The loose parts monitoring system (LPMS) is designed to provide detection of loose metallic parts within the reactor pressure vessel. Detection of loose parts can provide the time required to avoid or mitigate safety-related damage to or malfunctions of primary system components. PMS detect structure borne sound that can indicate the presence of loose parts impacting against the reactor pressure vessel internals. The LPMS detection system can evaluate some aspects of selected signals. However, the system by itself will not diagnose the presence and location of a loose part. Expert diagnostic by an experie ced LPM engineer is required to confirm the presence of a loose part.

4.4.3.1 Power Generation Design Bases

The LPMS is designed to provide detection and operator warning of loose parts in the reactor pressure vessel to avoid or mitigate safety-related damage to or malfunctions of primary system components. The LPMS is not classified as a safety-related system, although it is designed in conformance with Regulatory Guide 1.133.

Additional design considerations provide for the inclusion of electronic features to minimize operator interfacing requirements during normal operation and to enhance the analysis function when operator action is required to investigate potential loose parts.

4.4.3.2 System Description

The LPMS continuously monitors the reactor pressure vessel and appurtenances for indications of loose parts. The LPMS consists of sensors, cables, signal conditioning equipment, alarming monitor, signal analysis and data acquisition equipment, and calibration equipment. The alarm setting for each sensor is determined after system installation is complete. The alarm setting is set low enough to meet the sensitivity requirements, yet is designed to discriminate between normal background noises and the loose part impact signal to minimize spurious alarms. Each sensor channel is isolated to reduce the possibility of signal ground loop problems and to minimize by use of tuned filters. A disable signal is provided during control rod movement and other plant maneuvers that may initiate a spurious alert-level alarm.

LPMS sensors are usually accelerometers. The array of LPMS accelerometers typically consist of twelve to twenty sensors that are strategically mounted on the external surface of the primary pressure boundary at various elevations and azimuths at natural collection regions for potential loose parts. General mounting locations are at the a) main steam outlet nozzle, b) feedwater inlet nozzle, c) core spray nozzles, and d) control rod drive housings. The sensors will be mounted in such a fashion as to provide high frequency response and sensitivity.

The online system sensitivity is such that the system can detect a metallic loose part that weighs between 0.25 lb to 30 lbs and impacts with kinetic energy of 0.5 ft-lb on the inside surface of the reactor pressure vessel within 3 feet of a sensor. The LPMS frequency range of interest is typically from 1 to 10 kHz. Frequencies lower than 1 kHz are generally associated with flow induced vibration signals or flow noise.

Physical separation is maintained from the sensors at each natural collection region to an area where they are combined and routed through the cable penetration to a termination point. The termination point is at a point in the plant that is accessible for maintenance during full power operation.

The LPPMS includes provisions for both automatic and manual start-up of data acquisition equipment with automatic activation in the event the preset alert level is reached or exceeded. The system also initiates an alarm to the control room personnel when an alert condition is reached. The data acquisition system will automatically select the alarmed channel plus additional channels for simultaneous recording. The signal analysis equipment will allow immediate visual and audio monitoring of all signals.

Provisions exists for periodic online channel check and functional tests and for offline channel calibration during periods of cold shutdown or refueling. The LPMS electronics are designed to facilitate the recognition, location, replacement, repair, and adjustment of malfunctioning LPMS components. The LPMS components located inside the containment have been designed and installed to perform their function following all seismic events that do not require plant shutdown, up to and including the Operation Basis Earthquake. The LPMS components selected for this application are rated to meet the normal operating radiation, vibration, temperature, and humidity environments in which the components are installed.

All LPMS components within the containment are designed for a 60 year design life. In those instances where a 60 year design life is not practicable, a replacement program will be established for those parts that are anticipated to have limited service life.

4.4.3.3 Normal System Operation

The LPMS will be set to alarm for detected signals having characteristics of metal-to-metal impacts.

After installation of the sensor array, the LPMS overall and individual channels can be characterized at plant start-up before operation monitoring. Each accelerometer channels will exhibit its own particular and unique frequency spectrum. This frequency signature, or normal background noise, results from a combination of both internal and external sources due to normal and transient conditions.

Calibration is an important part of LPMS operation. The LPMS is calibrated to detect a loose part with minimum impact energy of 0.5 ft-lb within 3 feet of a sensor. Alarm level setpoint is determined by using a manual calibration device to simulate the presence of a loose part impact near each sensor. The setpoint is typically based on a percentage of the calibration signal magnitude, and is a function of actual background noise. Additionally, calibrated impacts at various locations near the senors assist in diagnosing the source of the signal.

Discrimination logic is typically incorporated in the LPMS to avoid spurious alarms. Discrimination logic rejects events that do not have the characteristics of an impact signal of a loose part. Typical discrimination functions are based on the length of time the signal is above the setpoint, the number of channels alarming, the time between alarms, the repetition of the signal, and the waveform and frequency content. False alert signals due to plant maneuvers are avoided by the use of administrative procedures by control room personnel.

Usually the plant operator makes the preliminary evaluation based on the available information. If the presence of unusual metal impact sound is indicated, then the station engineers perform additional evaluation. LPM experts are required to correctly diagnose the presence and location of a loose part. In order to reach proper conclusions, various factors must be considered such as: plant operating conditions; location of the channels that alarmed; and comparison of the amplitude and frequency contents of the signals with known normal operation data.

4.4.3.4 Safety Evaluation

The LPMS is intended to be used for information purposes only by the plant operator. The plant operators do not rely on the information provided by the LPMS for the performance of any safety-related action. Although the LPMS is not classified as a safety-related system, it is designed to meet the seismic and environmental operability recommendations of Regulatory Guide 1.133.

4.4.3.5 Test and Inspection

The LPMS will be calibrated to detect a metallic loose part that weighs from 0.25 lb to 30 lbs and impacts with kinetic energy of 0.5 ft-lb within 3 feet of each sensor. Provisions will be made to verify the calibration of the LPMS at each refueling. The system will be recalibrated as necessary when found to be out of calibration. A test and reset capability will be included for functional test capability.

The manufacturer will provide services of qualified personnel to provide technical guidance for installation, start-up, and acceptance testing of the system. In addition, the manufacturer will provide the necessary training of plant personnel for proper system operation and maintenance and planned operating and record keeping procedures.

4.4.3.6 Instrumentation Application

The LPMS consists of sensors, cables, signal conditioning equipment, alarming monitor, signal analysis and data acquisition equipment, and calibration equipment.

4.4.4 COL License Information

4.4.4.1 Power Flow Operating Map

The specific power flow operating map to be used at the plant will be provided by the utility to the USNRC for information.

4.4.4.2 Thermal Limits

The thermal limits for the core loading at the plant will be provided by the utility to the USNRC for information.

years in BWR applications. Extensive laboratory tests have demonstrated that XM-19 is a suitable material and that it is resistant to stress corrosion in a BWR environment.

4.5.3 Interfaces

4.5.3.1 CRD Inspection Program

The CRD inspection program shall include provisions to detect incipient defects before they could become serious enough to cause operating problems. [See Subsection 4.5.1.2(2)] The CRD nozzle and CRD bolting are included in the inservice inspection program. [See Table 5.2-8, System Number B11/B12] CRD bolting is available for inservice examinations during normally scheduled CRD maintenance.

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ILLUSTRATIONS (Continued)

(2) the primary side of the auxiliary or emergency systems interconnected with the primary system; and

(3) any blowdown or heat dissipation system connected to the discharge side of the pressure relieving devices.

The schematic arrangements of the SRVs are shown in Figures 5.2-3 and 5.2-4.

5.2.2.4 Equipment and Component Description

5.2.2.4.1 Description

The nuclear pressure relief system consists of SRVs located on the main steamlines between the reactor vessel and the first isolation valve within the drywell. These valves protect against overpressure of the nuclear system.

The SRVs provide three main protection functions:

(1) overpressure relief operation (the valves are opened using a pnuematic actuator upon receipt of an automatic or manually-initiated signal to reduce pressure or to limit a pressure rise);

(2) overpressure safety operation (the valves function as safety valves and open to prevent nuclear system overpressurization - they are self-actuated by inlet steam pressure if not already signaled open for relief operation);

(3) depressurization operation (the ADS valves open automatically as part of the emergency core cooling system (ECCS) for events involving small breaks in the nuclear system process barrier. The location and number of the ADS valves can be determined from Figure 5.1-3).

Chapter 15 discusses the events which are expected to activate the primary system SRVs. The section also summarizes the number of valves expected to operate in safety (steam pressure) mode of operation during the initial blowdown of the valves and the expected duration of this first blowdown. For several of the events it is expected that the lowest set SRV will reopen and reclose as generated heat decays. The pressure increase and relief cycle will continue with lower frequency and shorter relief discharges as the decay heat drops off.

Remote manual actuation of the valves from the control room is recommended to minimize the total number of these discharges with the intent of achieving extended valve seat life.

The SRV is opened by either of the following two modes of operation:

(1) The safety (steam pressure) mode of operation is initiated when the direct and increasing static inlet steam pressure overcomes the restraining spring and the frictional forces acting against the inlet steam pressure at the main disc or pilot disc and the main disc moves in the opening direction at a faster rate than corresponding disc movements at higher or lower inlet steam pressures. The condition at which this action is initiated is termed the "popping pressure" and corresponds to the set-pressure value stamped on the nameplate of the SRV.

(2) The relief (power) mode of operation is initiated when an electrical signal is received at any of the solenoid valves located on the pneumatic actuator assembly. The solenoid valve(s) will open, allowing pressurized air to enter the lower side of the pneumatic cylinder piston which pushes the piston and the rod upwards. This action pulls the lifting mechanism of the main or pilot disc thereby opening the valve to allow inlet steam to discharge through the SRV until the inlet pressure is near or equal to zero.

The pneumatic operator is so arranged that if it malfunctions it will not prevent the valve from opening when steam inlet pressure reaches the spring lift set pressure.

For overpressure SRV operation (self-actuated or spring lift mode), the spring load establishes the safety valve opening setpoint pressure and is set to open at setpoint

5.2.3.4.1.3 Cold-Worked Austenitic Stainless Steels

Cold work controls are applied for components made of austenitic stainless steel. During fabrication cold work is controlled by applying limits in hardness, bend radii and surface finish on ground surfaces.

5.2.3.4.2 Control of Welding

5.2.3.4.2.1 Avoidance of Hot Cracking

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

Written welding procedures which are approved by GE are required for all primary pressure boundary welds. These procedures comply with the requirements of Sections III and IX of the ASME Boiler Pressure Vessel Code and applicable NRC Regulatory Guides.

All austenitic stainless steel weld filler materials were required by specification to have a minimum delta ferrite content of 8 FN (ferrite number) determined on undiluted weld pads by magnetic measuring instruments calibrated in accordance with AWS specification A4.2-74.

Delta ferrite measurements are not made on qualification welds. Both the ASME Boiler and Pressure Vessel Code and Regulatory Guide 1.31 specify that ferrite measurements be performed on undiluted weld filler material pads when magnetic instruments are used. There are no requirements for ferrite measurement on qualification welds.

5.2.3.4.2.2 Regulatory Guide 1.34: Electroslag Welds

See Subsection 5.2.3.3.2.2.

5.2.3.4.2.3 Regulatory Guide 1.71: Welder Qualification or Areas of Limited Accessibility

Regulatory Guide 1.71 requires that weld fabrication and repair for wrought low-alloy and high-alloy steels or other materials such as static and centrifugal castings and bimetallic joints should comply with fabrication requirements of Sections III and IX of the ASME Boiler and Pressure Vessel Code. It also requires additional performance qualifications for welding in areas of limited access.

All ASME Section III welds are fabricated in accordance with the requirements of Sections III and IX of the ASME Boiler and Pressure Vessel Code. There are few restrictive welds involved in the fabrication of BWR components. Welder qualification for welds with the most restrictive access is accomplished by mockup welding. Mock-up is examined by sectioning and radiography (or UT). 252.11

The Acceptance Criterion II.3.b.(3) of SRP Section 5.2.3 is based on Regulatory Guide 1.71. The ABWR design meets the intent of this regulatory guide by utilizing the alternate approach as follows:

When access to a non-volumetrically examined ASME Section III production weld (1) is less than 305 mm in any direction and (2) allows welding from one access direction only, such weld and repairs to welds in wrought and cast low alloy steels, austenitic stainless steels and high nickel alloys and in any combination of these materials shall comply with the fabrication requirements specified in ASME Boiler and Pressure Vessel Code Section III and with the requirements of Section IX invoked by Section III, supplemented by the following requirements: 252.11

(1) The welder performance qualification test assembly required by ASME Section IX shall be welded under simulated access conditions. An acceptable test assembly will provide both a Section IX welder performance qualification required by this Regulatory guide.

    If the test assembly weld is to be judged by bend tests, a test specimen shall be removed from the location least favorable for the welder. If this test specimen cannot be removed from a location prescribed by Section IX, an additional bend test specimen will be required. If the test assembly weld is to be judged by radiography or UT, the length of the weld to be examined shall include the location least favorable for the welder.

Records of the results obtained in welder accessibility qualification shall be as certified by the manufacturer or installer, shall be maintained and shall be made accessible to authorized personnel.

Socket weld with a 50A nominal pipe size and under are excluded from the above requirements.

252.11

(2) (a) For accessibility, when more restricted access conditions than qualified will obscure the welder's line of sight to the extent that production welding will require the use of visual aids such as mirrors. The qualification test assembly shall be welded under the more restricted access conditions using the visual aid required for production welding.

(b) GE complies with ASME Section IX.

(3) Surveillance of accessibility qualification requirements will be performed along with normal surveillance of ASME Section IX performance qualification requirements.

5.2.3.4.3 Regulatory Guide 1.66: Nondestructive Examination of Tubular Products

For discussion of compliance with Regulatory Guide 1.66, see Subsection 5.2.3.3.3.

5.2.4 Preservice and Inservice Inspection and Testing of Reactor Coolant Pressure Boundary

This subsection describes the preservice and inservice inspection and system pressure test programs for NRC Quality Group A, ASME Boiler and Pressure Vessel Code, Class 1, items.* It describes those programs implementing the requirements of Subsection IWB of the ASME Boiler and Pressure Vessel (ASME Code) Code Section III and XI of the ASME B&PV Code Section XI.

The design to perform preservice inspection is based on the requirements of the ASME Code, Section XI, 1989 Edition. The development of the preservice and inservice inspection program plans will be the responsibility of the COL applicant and will be based on the ASME Code, Section XI, Edition and Addenda specified in accordance with 10CFR50, Section 50.55a. For design certification, General Electric is responsible for designing the reactor pressure vessel for accessibility to perform preservice and inservice inspection. Responsibility for designing other components for preservice and inservice inspection is the responsibility of the COL applicant. The COL applicant will be responsible for specifying the Edition of the ASME Code, Section XI, to be used, based on the procurement date of the component per 10CFR50, Section 50.55a. The ASME Code requirements discussed in this section are provided for information and are based on the 1989 Edition of ASME Section XI.

5.2.4.1 Class 1 System Boundary

5.2.4.1.1 Definition

The class 1 system boundary for both preservice and inservice inspection programs and the system pressure test program includes all those items within the Class 1 and Quality Group A boundary on the piping and instrumentation drawings (P&IDs). Based on 10 CFR (1-1-90 Edition) and Regulatory Guide 1.26, Revision 3, that boundary includes the following:

(1) Reactor pressure vessel
(2) Portions of the main steam system
(3) Portions of the feedwater system
(4) Portions of the standby liquid control system
(5) Portions of reactor water cleanup system
(6) Portions of the residual heat removal system
(7) Portions of the reactor core isolation cooling system
(8) Portions of the high pressure core flooder system

Those portions of the above systems within the Class 1 boundary are those items which are part of the reactor coolant system up to and

** Items as used in this subsection are products constructed under a Certificate of Authorization (NCA-3120) and material (NCA-1220). See Section III, NCA-1000, footnote 2.*

including any and all of the following:

(1) the outermost containment isolation valve in the system piping which penetrates primary reactor containment.

(2) the second of two valves normally closed during normal reactor operation in system piping which does not penetrate primary reactor containment.

(3) the reactor coolant system safety and relief valves,

(4) the main steam and feedwater system up to and including the outermost containment isolation valve.

5.2.4.1.2 Exclusions

Portions of systems within the reactor coolant pressure boundary, as defined in Subsection 5.2.4.1.1, that are excluded from the Class 1 boundary in accordance with 10CFR50, Section 50.55a, are as follows:

(1) those components where, in the event of postulated failure of the component during normal reactor operation, the reactor can be shut down and cooled down in an orderly manner, assuming makeup is provided by the reactor coolant makeup system only; and

(2) components which are or can be isolated from the reactor coolant system by two valves (both closed, both open, or one closed and one open). Each such open valve is capable of automatic actuation and if the other valve is open its closure time is such that, in the event of postulated failure of the component during normal reactor operation, each valve remains operable and the reactor can be shut down and cooled down in an orderly manner assuming makeup is provided by the reactor coolant makeup system only.

The description of portions of systems excluded from the reactor coolant pressure boundary does not address Class 1 components exempt from inservice examinations under ASME Code, Section XI, rules. The Class 1 components exempt from inservice examinations are described in ASME Code, Section XI, IWB-1220.

5.2.4.2 Accessibility

All items within the Class 1 boundary are designed to provide access for the examinations required by ASME Section XI, IWB-2500. Items such as nozzle-to-vessel welds often have inherent access restrictions when vessel internals are installed therefore for preservice examination shall be performed on these items prior to installation of internals which would interfere with examination.

5.2.4.2.1 Reactor Pressure Vessel Access

Access for examinations of the reactor pressure vessel (RPV) is incorporated into the design of the vessel, biological shield wall and vessel insulation as follows:

(1) RPV Welds Below the Top Biological Shield Wall

The shield wall and vessel insulation behind the shield wall are spaced away from the RPV outside surface to provide access for remotely operated ultrasonic examination devices as described in Subsection 5.2.4.3.2.1. Access for the insertion of automated devices is provided through removable insulation panels at the top of the shield wall and at access ports at reactor vessel nozzles. Platforms are attached to the bioshield wall to provide access for installation of remotely operated nozzle examination devices.

(2) RPV Welds Above Top of the Biological Shield Wall

Access to the reactor pressure vessel welds above the top of the biological shield wall is provided by removable insulation panels. This design provides reasonable access for both automated as well as manual ultrasonic examination.

(3) Closure Head, RPV Studs, Nuts and Washers

The closure head is dry stored during refueling. Removable insulation is designed to provide access for manual ultrasonic examinations of closure head welds. RPV nuts and washers are dry stored and are accessible for surface and visual (VT-1) examination. RPV studs may be volumetrically examined in place or when removed.

(4) Bottom Head Welds

Access to the bottom head to shell weld and bottom head seam welds is provided through openings in the RPV support pedestal and removable insulation panels around the cylindrical lower portion of the vessel. This design provides access for manual or automated ultrasonic examination equipment. Sufficient access is provided to partial penetration nozzle welds i.e., CRD penetrations, instrumentation nozzles and recirculation internal pump penetration welds, for performance of the visual, VT-2, examination during the system leakage and system hydrostatic examinations.

(5) Reactor Vessel Support Skirt

The integral attachment weld from the number four shell course forging to the RPV skirt will be examined ultrasonically. Sufficient access is provided for either manual or automated ultrasonic examination. Access is provided to the balance of the support skirt for performance of visual, VT-3, examination.

5.2.4.2.2 Piping, Pumps, Valves and Supports

Physical arrangement of piping pumps and valves provide personnel access to each weld location for performance of ultrasonic and surface (magnetic particle or liquid penetrant) examinations and sufficient access to supports for performance of visual, VT-3, examination. Working platforms are provided in some areas to facilitate servicing of pumps and valves. Platforms and ladders are provided for access to piping welds including the pipe-to-reactor vessel nozzle welds. Removable thermal insulation is provided on welds and components which require frequent access for examination or are located in high radiation areas. Welds are located to permit ultrasonic examination from at least one side, but where component geometries permit, access from both sides is provided.

Restrictions: For piping systems and portions of piping systems subject to volumetric and surface examination, the following piping designs are not used:

(1) Valve to valve
(2) Valve to reducer
(3) Valve to tee
(4) Elbow to elbow
(5) Elbow to tee
(6) Nozzle to elbow
(7) Reducer to elbow
(8) Tee to tee
(9) Pump to valve

Straight sections of pipe and spool pieces shall be added between fittings. The minimum length of the spool piece has been determined by using the formulate $L = 2T + 152mm$, where L equals the length of the spool piece (not including weld preparation) and T equals the pipe wall thickness.

5.2.4.3 Examination Categories and Methods

5.2.4.3.1 Examination Categories

The examination category of each item is listed in Table 5.2-8 which is provided as an example for the preparation of the preservice and inservice inspection program plans. The items are listed by system and line number where applicable. Table 5.2-8 also states the method of examination for each item. The preservice and inservice examination plans will be supplemented with detailed drawings showing the examination areas, such as Figures 5.2-7a and 5.2-7b.

For the preservice examination, all of the items selected for inservice examination shall be performed once in accordance with ASME Section XI, IWB-2200 with the exception of the examinations specifically excluded by ASME Section XI from preservice requirements, such as VT-3 examination of valve body and pump casing internal surfaces (B-L-2 and B-M-2 examination categories, respectively) and the visual VT-2 examinations for categories B-E and B-P.

Supplemental examinations recommended in GE Service Information Letters (SILs) and Rapid Communication Service Information Letters (RICSILs) for previous BWR designs are not applicable to the ABWR. The ABWR design has either eliminated the components addressed by the SIL or RICSIL, e.g., jet pumps, or has eliminated the need for the examination by eliminating creviced designs and using materials resistant to the known degradation mechanisms, such as intergrannular stress corrosion cracking, upon which the SIL and RICSIL examinations were based.

5.2.4.3.2 Examination Methods

5.2.4.3.2.1 Ultrasonic Examination of the Reactor Vessel

Ultrasonic examination for the RPV will be conducted in accordance with the ASME Code, Section XI. The design to perform preservice inspection on the reactor vessel shall be based on the requirements of the ASME Code, Section XI, 1989 Edition. For the required preservice examinations, the reactor vessel shall meet the acceptance standards of Section XI, IWB-3510. The RPV shell welds are designed for 100% accessibility for both preservice and inservice inspection. The RPV nozzle-to-shell welds will be 100% accessible for preservice inspection but might have limited areas that will not be accessible from the outer surface for inservice examination techniques. However, the inservice inspection program for the reactor vessel is the responsibility of the COL applicant and any inservice inspection program relief request will be reviewed by the NRC staff based on the Code Edition and Addenda in effect and inservice inspection techniques available at the time of COL application.

The GE reactor vessel inspection system (GERIS) meets the detection and sizing requirements of Regulatory Guide 1.150, as cited in Table 5.2-9. Inner radius examinations are performed from the outside of the nozzle using several compound angle transducer wedges to obtain complete coverage of the required examination volume. Electronic gating used in GERIS system records up to 8 different reflectors simultaneously to assure that all relevant indications are recorded. Appendix 5A demonstrated compliance with Regulatory Guide 1.150.

5.2.4.3.2.2 Visual Examination

Visual examination methods, VT-1, VT-2 and VT-3, shall be conducted in accordance with ASME Section XI, IWA-2210. In addition, VT-2 examinations shall meet the requirements of IWA-5240.

Direct visual, VT-1, examinations shall be conducted with sufficient lighting to resolve a 0.8mm black line on an 18% neutral grey card. Where direct visual, VT-1, examinations are conducted without the use of mirrors or with other viewing aids, clearance (of at least 610mm of clear space) is provided where feasible for the head and shoulders of a man within a working arm's length (508mm) of the surface to be examined.

At locations where leakages are normally expected and leakage collection systems are located, (e.g., valve stems and pump seals), the visual, VT-2, examination shall verify that the leakage collection system is operative.

Piping runs shall be clearly identified and laid out such that insulation damage, leaks and structural distress will be evident to a trained visual examiner.

5.2.4.3.2.3 Surface Examination

Magnetic particle and liquid penetrant examination techniques shall be performed in accordance with ASME Section XI, IWA-2221 and IWA-2222, respectively. Direct examination access for magnetic particle (MT) and penetrant (PT) examination is the same as that required for direct visual (VT-1) examination (Subsection 5.2.4.3.2.3), except that additional access shall be provided as necessary to enable physical contact with the item in order to perform the examination. Remote MT and PT generally are not appropriate as a standard examination process, however, boroscopes and mirrors can be used at close range to improve the angle of vision. As a minimum, insulation removal shall expose the area of each weld plus at least 152mm from the toe of the weld on each side. Insulation will generally be removed 406mm on each side of the weld.

5.2.4.3.2.4 Volumetric Ultrasonic Direct Examination

Volumetric ultrasonic direct examination shall be performed in accordance with ASME Section XI, IWA-2232. In order to perform the examination, visual access to place the head and shoulders within 508mm of the area of interest shall be provided where feasible. Nine inches between adjacent pipes is sufficient spacing if there is free access on each side of the pipes. The transducer dimension has been considered: a 38mm diameter cylinder, 76mm long placed with access at a right angle to the surface to be examined. The ultrasonic examination instrument has been considered as a rectangular box 305 x 305 x 508mm located within 12m from the transducer. Space for a second examiner to monitor the instrument shall be provided if necessary.

Insulation removal for inspection is to allow sufficient room for the ultrasonic transducer to scan the examination area. A distance of 2T plus 152mm where T is pipe thickness, is the minimum required on each side of the examination area. The insulation design generally leaves 406mm on each side of the weld, which exceeds minimum requirements.

5.2.4.3.2.5 Alternative Examination Techniques

As provided by ASME Section XI, IWA-2240, alternative examination methods, a combination of methods, or newly developed techniques may be substituted for the methods specified for a given item in this section, provided that they are demonstrated to be equivalent or superior to the specified method. This provision allows for the use of newly developed examination methods, techniques, etc., which may result in improvements in examination reliability and reductions in personnel exposure.

5.2.4.3.3 Data Recording

Manual data recording will be performed where manual ultrasonic examinations are performed. Electronic data recording and comparison analysis are to be employed with automated ultrasonic examination equipment. Signals form each ultrasonic transducer will be fed into a data acquisition system in which the key parameters of any reflectors will be recorded. The data to be recorded for manual and automated methods are:

(1) Location
(2) Position
(3) Depth below the scanning surface
(4) Length of the reflector

(5) Transdu.. data including angle and frequency
(6) Calibration data

The data so recorded shall be compared with the results of subsequent examinations to determine the behavior of the reflector.

5.2.4.3.4 Qualification of Personnel and Examination Systems for Ultrasonic Examination

Personnel performing exa... shall be qualified in accordance with A... Section XI, Appendix VII. Ultrasonic examination systems shall be qualified in accordance with industry accepted program for implementation of ASME Section XI, Appendix VIII.

5.2.4.4 Inspection Intervals

The inservice inspection intervals for the ABWR will conform to Inspection Program B as described in Section XI, IWB-2412. Except where deferral is permitted by Table IWB-2500-1, the percentages of examinations completed within each period of the interval shall correspond to Table IWB- 2412-1. An example of the selection of items and examinations to be conducted within the 10-year intervals are described in Table 5.2-8.

Supplemental examinations recommended in GE Service Information Letters (SILS) and Rapid Communication Service Information Letters (RICSILS) for previous BWR designs are not applicable to the ABWR. The ABWR design has either eliminated the components addressed by the SIL or RICSIL, e.g., jet pumps, or has eliminated the need for the materials resistant to the known degradation mechanisms, such as intergrannular stress corrision cracking, upon which the SIL and RICSIL examinations were based.

5.2.4.5 Evaluation of Examination Results

Examination results will be evaluated in accordance with ASME Section XI, IWB-3000 with repairs based on the requirements of IWA-4000 and IWB-4000. Re-examination shall be conducted in accordance with the requirements of IWA-2200. The recorded results shall meet the acceptance standards specified in IWB-3400-1.

5.2.4.6 System Leakage and Hydrostatic Pressure Tests

5.2.4.6.1 System Leakage Tests

As required by Section XI, IWB-2500 for Category B-P, a system leakage test shall be performed in accordance with IWB-5221 on all Class 1 components and piping within the pressure retaining boundary following each refueling outage. For the purposes of the system leakage test, the pressure retaining boundary is defined in Table IWB-2500-1, Category B-P, Note 1. The system leakage test shall include a VT-2 examination in accordance with IWA-5240. The system leakage test will be conducted approximately at the maximum operating pressure and temperature indicated in the applicable process flow diagram for the system as indicated in Table 1.7-1. The system hydrostatic test (Subsection 5.2.4.6.2), when performed is acceptable in lieu of the system leakage test.

5.2.4.6.2 Hydrostatic Pressure Tests

As required by Section XI, IWB-2500 for Category B-P, the hydrostatic pressure test shall be performed in accordance with ASME Section IWB-5222 on all Class 1 components and piping within the pressure retaining boundary once during each 10 year inspection interval. For purposes of the hydrostatic pressure test the pressure retaining boundary is defined in Table IWB-2500-1, Category B-P, Note 1. The system hydrostatic test shall include a VT-2 examination in accordance with IWA-5240. For the purposes of determining the test pressure for the system hydrostatic test in accordance with IWB-5222 (a), the nominal operating pressure shall be the maximum operating pressure indicated in the process flow diagram for the nuclear boiler system, Figure 5.1-3.

5.2.4.7 Code Exemptions

As provided in ASME Section XI, IWB-1220, certain portions of Class 1 systems are exempt from the volumetric and surface examination requirements of IWB-2500. These portions of systems are specifically identified in Table 5.2-8.

NUREG/CR-4287, ANL-85-33, June 1985.

8. D.A. Hale, et al, *BWR Coolant Impurities Program*, EPRI, Palo Alto, CA, Final Report on RP2293-2.

281.4,281.7,281.10
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9. K.S. Brown and G.M. Gordon, *Effects of BWR Coolant Chemistry on the Propensity of IGSCC Initiation and Growth in Creviced Reactor Internals Components*, paper presented at the Third International Symposium of Environmental Degadation of Materials in Nuclear Power Systems, ANS-NACE-TMS/AIME, Traverse City, Michigan, September 1987.

10. B.M. Gordon et al, *EAC Resistance of BWR Materials in HWC*, Predeeding of Second International Symposium Environmental Degration of Materials in Nuclear Power Systems, ANS, LaGrange Park, ILL 1986.

281.3

10a. BWR Hydrogen Water Chemistry Guidelines: 1987 Revision EPRI NP-4947-SR, December 1988.

10b. Guidline for Permanent BWR Hydrogen Water Chemistry Installations: 1987 Revision, EPRI NP-5203-SR-A.

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11. B.M. Gordon, *Corrosion and Corrosion Control in BWR's*, NEDE-30637, December 1984.

12. B.M. Gordon et al, *Hydrogen Water Chemistry for BWR's- Materials Behavior*, EPRI NP-5080, Palo Alto, CA, March 1987.

Table 5.2-8

EXAMINATION CATEGORIES

Quality Group	System Number	System Title	System Description	P&ID Diagram	Sec. XI Exam Cat.	Items Examined	Exam Method
A	B11/B21	Reactor Pressure Vessel/ Nuclear Boiler	Reactor Pressure Vessel	Figure 5.1-3			
			Vessel Shell Welds		B-A	Welds	UT (Note 7)
			Vessel Head Welds		B-A	Welds	UT (Note 7)
			Shell-to-Flange Weld		B-A	Weld	UT
			Head-to-Flange Weld		B-A	Weld	UT, MT
			Nozzles for: Main Steam, Feedwater, SD Outlet, CCS(Fldg.) & SD Inlet, SD - RWCU SD Outlet, CCS(Spray) & SD Inlet		B-D	Welds, Inner Radius	UT
			CRD Housing to Middle Flange and Middle Flange to Spool Piece Bolting		B-G-2	Bolts	VT-1
			Nozzles for CRD, RIP & Instrumentation		B-E	External Surfaces	VT-2 (Note 8)
			Closure Head Nuts		B-G-1	Nuts	MT
			Closure Studs		B-G-1	Studs	UT, MT (Note 9)
			Threads in Flange		B-G-1	Threads	UT
			Closure Washers, Bushings		B-G-1		VT-1

Table 5.2-8

EXAMINATION CATEGORIES (Con't)

Quality Group	System Number	System Title	System Description	P&ID Diagram	Sec. XI Exam Cat.	Items Examined	Exam Method
A	B11/B21	Reactor Pressure Vessel/ Nuclear Boiler (Cont.)	Reactor Pressure Vessel	Figure 5.1-3			
			Integral Attachments		B-H	Welds	UT or MT (Note 10)
			Vessel Interior		B-N-1	Vessel	VT-3 (Note 11)
			Interior Attachment Welds Within Beltline Region		B-N-2	Welds	VT-1 (Note 12)
			Interior Attachment Welds Beyond Beltline Region		B-N-2	Welds	VT-3 (Note 12)

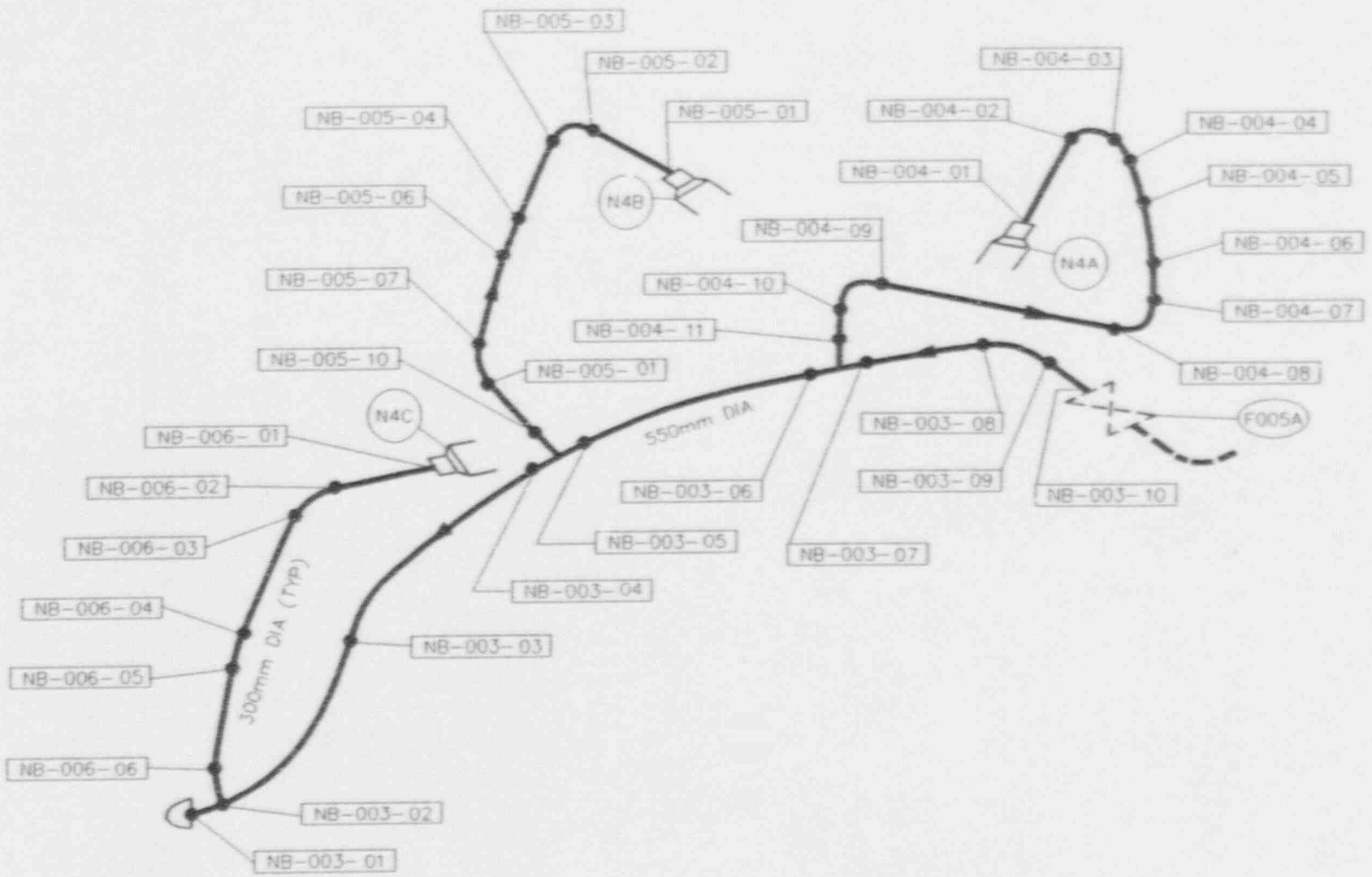

Figure 5.2-7b TYPICAL PIPING SYSTEM ISOMETRIC (Feedwater line from RPV to valve F005A)

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SECTION 5.3

CONTENTS (Continued)

SECTION 5.3

CONTENTS (Continued)

ILLUSTRATIONS

ment of 593°C minimum was applied to all low-alloy steel welds.

All previous BWR pressure vessels have employed similar fabrication methods. These vessels have operated for an extensive number of years and their service history is rated excellent.

5.3.3.4 Inspection Requirements

All plates, forgings, and bolting were 100% ultrasonically tested and surface examined by magnetic-particle methods or liquid-penetrant methods in accordance with ASME Code, Section III. Welds on the reactor pressure vessel were examined in accordance with methods prescribed and meet the acceptance requirements specified by ASME Code, Section III. In addition, the pressure retaining welds were ultrasonically examined using acceptance standards which are required by ASME Code, Section XI.

5.3.3.5 Shipment and Installation

The completed reactor vessel is given a thorough cleaning and examination prior to shipment. The vessel is tightly sealed for shipment to prevent entry of dirt or moisture. Preparations for shipment are in accordance with detailed written procedures.

On arrival at the reactor site the reactor vessel is examined for evidence of any contamination as a result of damage to shipping covers. Measures are taken during installation to assure that vessel integrity is maintained; for example, access controls are applied to personnel entering the vessel, weather protection is provided, and periodic cleanings are performed.

5.3.3.6 Operating Conditions

Procedural controls on plant operation are implemented to hold thermal stresses within acceptable ranges and to meet the pressure/temperature limits of Subsection 5.3.2. The restrictions on coolant temperature are as follows:

(1) the average rate of change of reactor coolant temperature during normal heatup and cooldown shall not exceed 55 °C during any one hour period;

(2) if the coolant temperature difference between the dome (inferred from P (sat)) and the bottom head drain exceeds 55°C, neither reactor power level nor recirculation pump flow shall be increased.

The limit regarding the normal rate of heatup and cooldown (Item 1) assures that the vessel closure, closure studs, vessel support skirt, control rod drive housing, and stub tube stresses and usage remain within acceptable limits. Vessel temperature limit on recirculating pump operation and power level increase restriction (Item 2) augments the Item 1 limit in further detail by assuring that the vessel bottom head region will not be warmed at an excessive rate caused by rapid sweep-out of cold coolant in the vessel lower head region by recirculating pump operation or natural circulation (cold coolant can accumulate as a result of control drive inleakage and/or low recirculation flow rate during startup or hot standby).

These operational limits when maintained ensure that the stress limits within the reactor vessel and its components are within the thermal limits to which the vessel was designed for normal operating conditions. To maintain the integrity of the vessel in the event that these operational limits are exceeded, the reactor vessel has been designed to withstand a limited number of transients caused by operator error. Also, for abnormal operating conditions where safety systems or controls provide an automatic temperature and pressure response in the reactor vessel, the reactor vessel integrity is maintained since the severest anticipated transients have been included in the design conditions. Therefore, it is concluded that the vessel integrity will be maintained during the most severe postulated transients since all such transients are evaluated in the design of the reactor vessel.

5.3.3.7 Inservice Surveillance

Inservice inspection of the reactor pressure vessel will be in accordance with the requirements of the ASME Boiler and Pressure Vessel Code, Section XI. The vessel will be examined once prior to startup to satisfy the preoperational requirements of IWB-2000 of ASME Code, Section XI. Subsequent inservice inspection monitor changes in the fracture toughness properties of ferritic materials in the reactor vessel beltline region resulting from exposure to neutron irradiation and thermal environment. Specimens of actual reactor beltline material will be exposed in the reactor vessel and periodically withdrawn for impact testing. Operating procedures will be modified in accordance with test results to assure adequate brittle-fracture control.

Material surveillance programs and inservice inspection programs are in accordance with applicable ASME Code requirements and provide assurance that brittle-fracture control and pressure vessel integrity will be maintained throughout the service lifetime of the reactor pressure vessel.

5.3.4 COL License Information

5.3.4.1 Fracture Toughness Data

Fracture toughness data based on the limiting reactor vessel materials will be provided (See Subsection 5.3.1.5.1).

5.3.4.2 Materials and Surveillance Capsule

The following will be identified: the specific materials in each surveillance capsule; the capsule lead factors; the withdrawal schedule for each surveillance capsule; the neutron fluence to be received by each capsule at the time of its withdrawal; and, the vessel end-of-life peak neutron fluence (See Subsection 5.3.1.6.4).

5.3.5 References

1. *An Analytical Study on Brittle Fracture of GE-BWR Vessel Subject to the Design Basis Accident*, (NEDO-10029).

2. *Transient Pressure Rises Affecting Fracture Toughness Requirements for Boiling Water Reactors*, January 1979, (NEDO-21778-A).

the main condenser, and the feedwater system will supply the makeup water required to maintain reactor vessel inventory.

In the event the reactor vessel is isolated and the feedwater supply unavailable, relief valves are provided to automatically (or remote manually) maintain vessel pressure within desirable limits. The water level in the reactor vessel will drop due to continued steam generation by decay heat. Upon reaching a predetermined low level, the RCIC system will be initiated automatically. The turbine-driven pump will supply demineralized make-up water from (1) the condensate storage tank (CST) to the reactor vessel and (2) the suppression pool. Seismically installed level instrumentation is provided for automatic transfer of the water source with manual override from CST to suppression pool on receipt of either a low CST water level or high suppression pool level signals (CST water is primary source). The turbine will be driven with a portion of the decay heat steam from the reactor vessel and will exhaust to the suppression pool. Suppression pool water is not usually demineralized and hence should only be used in the event all sources of demineralized water have been exhausted.

During RCIC operation, the suppression pool shall act as the heat sink for steam generated by reactor decay heat. This will result in a rise in pool water temperature. RHR heat exchangers are used to maintain pool water temperature within acceptable limits by cooling the pool water.

5.4.6.1.1 Residual Heat and Isolation

5.4.6.1.1.1 Residual Heat

The RCIC system shall initiate and discharge, within 30 seconds, a specified constant flow into the reactor vessel over a specified pressure range. The RCIC water discharge into the reactor vessel varies between a temperature of 4.5°C up to and including a temperature of 77°C. The mixture of the cool RCIC water and the hot steam does the following:

(1) quenches steam,

(2) removes reactor residual heat, and

(3) replenishes reactor vessel inventory.

Redundantly the HPCF system performs a similar function, hence providing single failure protection. Both systems use different reliable electrical power sources which permit operation with either onsite or offsite power. Additionally, the RHR system performs a residual heat removal function.

5.4.6.1.1.2 Isolation

Isolation valve arrangements include the following:

(1) Two RCIC lines penetrate the reactor coolant pressure boundary. The first is the RCIC steamline which branches off one of the main steamlines between the reactor vessel and the main steam isolation valves. This line has two automatic motor-operated isolation valves, one is located inside and the other outside the drywell. An automatic motor-operated inboard RCIC isolation bypass valve is used. The isolation signals noted earlier close these valves.

(2) The RCIC pump discharge line is the other line that penetrates the reactor coolant pressure boundary, which directs flow into a feedwater line just outboard of the primary containment. This line has a testable check valve and an automatic motor-operated valve located outside primary containment.

(3) The RCIC turbine exhaust line also penetrates the containment. Containment penetration is located about a meter above the suppression pool maximum water level. A vacuum breaking line with two vacuum breakers in series runs in the suppression pool air space and connects to the RCIC turbine exhaust line inside the containment. Located outside the containment in the turbine exhaust line is a remote-manually controlled motor operated isolation valve.

(4) The RCIC pump suction line, minimum flow pump discharge line, and turbine exhaust line penetrate the containment and are sub-

merged in the suppression pool. The isolation valves for these lines are outside the containment and require automatic isolation operation, except for the turbine exhaust line which has remote manual operation.

The RCIC system design includes interfaces with redundnat leak detection devices, monitoring:

(1) a high pressure drop across a flow device in the steam supply line equivalent to 300 percent of the steady state steam flow at 83.8 kg/cm^2abs pressure;

(2) a high area temperature utilizing temperature switches as described in the leak detection system (high area temperature shall be alarmed in the control room);

(3) a low reactor pressure of 3.5 kg/cm^2g minimum: and

(4) a high pressure between the RCIC turbine exhaust rupture diaphragms.

These devices, activated by the redundant power supplies, automatically isolate the steam supply to the RCIC turbine and trip the turbine. HPCF provides redundancy for RCIC should RCIC become isolated.

5.4.6.1.2 Reliability, Operability, and Manual Operation

5.4.6.1.2.1 Reliability and Operability

The RCIC system (Table 3.2-1) is designed commensurate with the safety importance of the system and its equipment. Each component is individually tested to confirm compliance with system requirements. The system as a whole is tested during both the start-up and pre-operational phases of the plant to set a base mark for system reliability. To confirm that the system maintains this mark, functional and operability testing is performed at predetermined intervals throughout the life of the plant.

A design flow functional test of the RCIC system may be performed during normal plant operation by drawing suction from the suppression pool and discharging through a full flow test return line to the suppression pool. All components of the RCIC system are capable of individual functional testing during normal plant operation. System control provides automatic return from test to operating mode if system initiation is required, and the flow is automatically directed to the vessel.

Also, see Subsection 5.4.6.2.4.

5.4.6.1.2.2 Manual Operation

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

5.4.6.1.3 Loss of Offsite Power

The RCIC system power is derived from a reliable source that is maintained by either onsite or offsite power.

5.4.6.1.4 Physical Damage

The system is designed to the requirements presented in Table 3.2-1 commensurate with the safety importance of the system and its equipment. The RCIC is physically located in a different quadrant of the reactor building and utilizes different divisional power and seperate electrical routings than its redundant system as discussed in Subsection 5.4.6.1.1.1 and 5.4.6.2.4.

5.4.6.1.5 Environment

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

5.4.6.2 System Design

5.4.6.2.1 General

5.4.8.1

The CUW system:

(1) removes solid and dissolved impurities from the reactor coolant and measures the reactor water conductivity in accordance with Regulatory Guide 1.56, "Maintenance of Water Purity in Boiling Water Reactors";

(2) provides containment isolation that places the major portion of the CUW system outside the RCPB, limiting the potential for significant release of radioactivity from the primary system to the secondary containment;

(3) discharge excess reactor water during startup, shutdown, and hot standby conditions to the main condenser or radwaste or suppression pool;

(4) provides full system flow to the RPV head spray as required for rapid RPV cooldown and rapid refueling; and

(5) minimizes RPV temperature gradients by maintaining circulation in the bottom head of the RPV during periods when the reactor internal pumps are unavailable.

The CUW system is automatically removed from service upon SLCS actuation. This isolation prevents the standby liquid reactivity control material from being removed from the reactor water by the cleanup system. The design of the CUW system is in accordance with Regulatory Guide 1.26 and Regulatory Guide 1.29.

5.4.8.2 System Description

The CUW is a closed-loop system of piping, circulation pumps, a regenerative heat exchanger, non-regenerative heat exchangers, reactor water pressure boundary isolation valves, a reactor water sampling station, (part of the sampling system) and two precoated filter-demineralizers. During blowdown of reactor water swell, the loop is open to the radwaste or suppression pool. The single loop has two parallel pumps taking common suction through a regenerative heat exchanger (RHX) and two parallel non-regenerative heat exchangers (NRHX) from both the single bottom head drain line and the shutdown cooling suction line of the RHR loop "B". The cooled effluent of the NRHXs goes through the CUW pumps to the two filter-demineralizers for cleanup. CUW system discharge is split to feedwater lines "A" and "B". The system P&ID is provided in Figure 5.4-12.

The total capacity of the system, as shown on the process flow diagram in Figure 5.7-13 is equivalent to 2% of rated feedwater flow. Each pump, NRHX, and filter-demineralizer is capable of 50% system capacity operation, with the one RHX capable 100% system capacity operation.

The operating temperature of the filter-demineralizer units is limited by the ion exchange resins; therefore, the reactor coolant must be cooled before being processed in the filter-demineralizer units. The regenerative heat exchanger transfers heat from the tubeside (hot process inlet) to the shellside (cold process return). The shellside flow returns to the reactor. The non-regenerative heat exchanger cools the process further by transferring heat to the reactor building cooling water system.

The filter-demineralizer units are pressure precoat-type filters using powdered ion-exchange resins. Spent resins are not regenerated and are sluiced from the filter-demineralizer unit to a backwash receiving tank from which they are transferred to the radwaste system for processing and disposal. To prevent resins from entering the reactor in the event of failure of a filter demineralizer resin support, a strainer is installed on the filter-demineralizer unit. Each strainer and filter-demineralizer vessel has a control room alarm that is energized by high differential pressure. Upon further increase in differential pressure from the alarm point, the filter demineralizer will automatically isolate.

The backwash and precoat cycle for a filter-demineralizer unit is automatic to minimize the need for operator intervention. The filter-demineralizer piping configuration is complete and crud traps are eliminated. A bypass line is provided around the filter-demineralizer units.

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The backwash and precoat cycle for a filter-demineralizer unit is automatic to minimize the need for operator intervention. The filter-demineralizer piping configuration is complete and crud traps are eliminated. A bypass line is provided around the filter-demineralizer units.

In the event of low flow or loss of flow in the system, the precoat is maintained on the septa by a holding pump. Sample points are provided in the common influent header and in each effluent line of the filter-demineralizer units for continuous indication and recording of system conductivity. High conductivity is annunciated in the control room. The influent sample point is also used as the normal source of reactor coolant grab samples. Sample analysis also indicates the effectiveness of the filter-demineralizer units.

The suction line (RCPB portion) of the CUW system contains two motor-operated isolation valves which automatically close in response to signals from the leak detection and isolation system, actuation of the standby liquid control system, and high-filter demineralizer inlet temperature. Subsection 7.3.1.1.2 describes the leak detection and isolation system setpoints that are summarized in Tables 5.2-6 and 5.2-7. This isolation prevents loss of reactor coolant and release of radioactive material from the reactor, prevents removal of liquid reactivity control material by the cleanup system should the SLCS be in operation, and prevents exceeding the design temperature of the CUW and the filter-demineralizer resins. The RCPB isolation valves may be remote manually operated to isolate the system equipment for maintenance or servicing. Discussion of the RCPB is provided in Section 5.2.

Each filter-demineralizer vessel shall be installed in an individual shielded compartment. The compartments shall not require accessibility during operation of the filter-demineralizer unit. Shielding is required due to the concentration of radioactive products in the filter-demineralizer process system. Service space shall be provided the filter-demineralizer for septa removal. All inlet, outlet, vent, drain, and other process valves shall be located outside the filter-demineralizer compartment in a separate shielded area together with the necessary piping, strainers, holding pumps and instrument elements. Process equipment and controls shall be arranged so that all normal operations are conducted at the panel from outside the vessel or valve and pump compartment shielding walls. Access to the filter-demineralizer compartment is normally permitted only after removal of the precoat. Penetrations through compartment walls shall be located so as not to compromise radiation shielding requirements. Primarily, this affects nozzle locations on tanks so that wall penetrations do not "see" the tanks. Generally, this means piping through compartment walls should be above, below, or to the side of filter-demineralizer units. The local control panel shall be outside the vessel compartment and process valve cell, located convenient to the CUW system. The tank which receives backwash shall be located in a separate shielded room below the filter-demineralizer units.

The filter-demineralizer vents are piped to the backwash receiving tank. Piping vents and drains are directed to low conductivity collection in radwaste. System pressure relief valves are piped to radwaste. Refer to Figure 5.4-12 for the exact configuration.

A remote, manually-operated gate valve on the return line to the feedwater lines in the steam tunnel provides long term leakage control. Instantaneous reverse flow isolation is provided by check valves in the CUW piping.

CUW system operation is controlled from the main control room. Filter demineralizing operations, which include backwashing and precoating, are controlled automatically from a process controller or manually from a local panel.

5.4.8.3 System Evaluation

The CUW system, in conjunction with the condensate treatment system and the fuel pool cooling and cleanup system, maintains reactor water quality during all reactor operating modes (normal, hot standby, startup, shutdown, and refueling).

The CUW system has process interfaces with the RHR, control rod drive, nuclear boiler, radwaste, fuel pool cooling and cleanup (FPC), reactor building cooling water systems, RPV, and suppression pool. The CUW suction is from the RHR "B" shutdown suction line and the RPV bottom head drain. The CUW system main process pump

(2) The feedwater lines are designed to conduct water to the reactor vessel over the full range of reactor power operation.

5.4.9.3 Description

The main steam piping is described in Section 10.3. The main steam and feedwater piping from the reactor through the containment isolation interfaces is diagrammed in Figure 5.1-3.

As discussed in Table 3.2-1 and shown in Figure 5.1-3, the main steamlines are Quality Group A from the reactor vessel out to and including the outboard MSIV and Quality Group B from the outboard MSIVs to the turbine stop valve. They are also Seismic Category I only from the reactor pressure vessel out to the seismic interface restraint.

The feedwater piping consists of two 550 A diameter lines from the feedwater supply header to the reactor. Isolation of each line is accomplished by two containment isolation valves consisting of one check valve inside the drywell and one positive closing check valve outside containment (Figure 5.1-3). Also included in this portion of the line is a manual maintenance valve (F005) between the inboard isolation valve and the reactor nozzle. The design temperature and pressure of the feedwater line is the same as that of the reactor inlet nozzle (i.e., 87.9 kg/cm^2g and 302^oC).

210.7 The feedwater piping upstream of the second isolation valve contains a remote, manual, motor-operated gate valve and upstream of the gate valve, a seismic interface restraint. The outboard isolation valve and the seismic interface restraint provide a quality group transitional point in the feedwater lines.

210.7 As discussed in Table 3.2-1 and shown in Figure 5.1-3 the feedwater piping is Quality Group A from the reactor pressure vessel out to and including the outboard isolation valve, Quality Group B from the outboard isolation valve to and including the seismic interface restraint, and Quality Group D beyond the shutoff valve. The feedwater piping and all connected piping of 65A or larger nominal size is Seismic Category I only from the reactor pressure vessel out to and including the seismic inter face restraint.

The materials used in the piping are in accordance with the applicable design code and supplementary requirements described in Section 3.2. The valve between the outboard isolation valve and the shutoff valve upstream of the RHR entry to the feedwater line is to effect a closed loop outside containment (CLOC) for containment bypass leakage control (Subsections 6.2.6 and 6.5.3).

The general requirements of the feedwater system are described in Subsections 7.1.1.7, 7.7.1.4, 7.7.2.4, and 10.4.7.

5.4.9.4 Safety Evaluation

Differential pressure on reactor internals under the assumed accident condition of a ruptured steamline is limited by the use of flow restrictors and by the use of four main steamlines. All main steam and feedwater piping will be designed in accordance with the requirements defined in Section 3.2. Design of the piping in accordance with these requirements ensures meeting the safety design bases.

5.4.9.5 Inspection and Testing

Testing is carried out in accordance with Subsection 3.9.6 and Chapter 14. Inservice inspection is considered in the design of the main steam and feedwater piping. This consideration assures adequate working space and access for the inspection of selected components.

5.4.10 Pressurizer

Not Applicable to BWR

5.4.11 Pressurizer Relief Discharge System

Not Applicable to BWR

5.4.12 Valves

5.4.12.1 Safety Design Bases

Line valves, such as gate, globe, and check valves, are located in the fluid systems to perform a mechanical function. Valves are components of the system pressure boundary and, having moving parts, are designed to operate efficiently to maintain the integrity of this boundary.

The valves operate under the internal pressure/temperature loading as well as the external loading experienced during the various system transient operating conditions. The design criteria, the design loading, and acceptability criteria are as specified in Subsection 3.9.3 for ASME Class 1, 2, and 3 valves. Compliance with ASME Code is discussed in Subsection 5.2.1.

5.4.12.2 Description

Line valves are manufactured standard types designed and constructed in accordance with the requirements of ASME Code Section III for Class 1, 2, and 3 valves. All materials, exclusive of seals, packing, and wearing components, shall endure the 60-year plant life under the environmental conditions applicable to the particular system when appropriate maintenance is periodically performed.

Power operators will be sized to operate successfully under the maximum differential pressure determined in the design specification.

5.4.12.3 Safety Evaluation

Line valves will be shop tested by the manufacturer for performability. Pressure retaining parts are subject to the testing and examination requirements of Section III of the ASME Code. To minimize internal and external leakage past seating surfaces, maximum allowable leakage rates are stated in the design specifications for both back seat as well as the main seat for gate and globe valves.

Valve construction materials are compatible with the maximum anticipated radiation dosage for the service life of the valves.

5.4.12.4 Inspection and Testing

Valves serving as containment isolation valves which must remain closed or open during normal plant operation may be partially exercised during this period to assure their operability at the time of an emergency or faulted condition. Other valves, serving as a system block or throttling valves, may be exercised when appropriate.

Leakage from critical valves steam is monitored by use of double-packed stuffing boxes with an intermediate lantern leakoff connection for detection and measurement of leakage rates.

Motors used with valve actuators will be furnished in accordance with applicable industry standards. Each motor actuator will be assembled, factory tested, and adjusted on the valve for proper operation, position, torque switch setting, position transmitter function (where applicable), and speed requirements. Valves will be to demonstrate adequate stem thrust (or torque) capability to open or close the valve within the specified time at specified differential pressure. Tests will verify no mechanical damage to valve components during full stroking of the valve. Suppliers will be required to furnish assurance of acceptability of equipment for the intended service based on any combination of:

(1) test stand data,

(2) prior field performance,

(3) prototype testing, and

(4) engineering analysis.

Pre-operational and operational testing performed on the installed valves consists of total circuit checkout and performance tests to verify speed requirements at specified differential pressure.

5.4.13 Safety/Relief Valves

The reactor component and subsystem SRVs are listed in Table 5.4-5. The RHR relief valves are discussed separately in Subsection 5.4.7.1.3.

5.4.13.1 Safety Design Bases

Overpressure protection is provided at

isolatable portions of the following systems: SLC, RHR, HPCF, and RCIC. The relief valves will be selected in accordance with the rules set forth in the ASME Code Section III, Class 1, 2, and 3 components. Other applicable sections of the ASME Code, as well as ANSI, API, and ASTM Codes, will be followed.

5.4.13.2 Description

Pressure relief valves have been designed and constructed in accordance with the same code class as that of the line valves in the system.

Table 3.2-1 lists the applicable code classes for valves. The design criteria, design loading, and design procedure are described in Subsection 3.9.3.

5.4.13.3 Safety Evaluation

The use of pressure-relieving devices will assure that over-pressure will not exceed 10% above the design pressure of the system. The number of pressure-relieving devices on a system or portion of a system has been determined on this basis.

5.4.13.4 Deleted

5.4.14 Component Supports

Support elements are provided for those components included in the RCPB and the connected systems.

5.4.14.1 Safety Design Bases

Design loading combinations, design procedures, and acceptability criteria are as described in Subsection 3.9.3. Flexibility calculations and seismic analysis for Class 1, 2, and 3 components are to be confirmed with the appropriate requirements of ASME Code Section III.

Support types and materials used for fabricated support elements are to conform with Sections NF-2000 and NF-3000 of ASME Code Section III. Pipe support spacing guidelines of Table 121.1.4 of ANSI B31.1, Power Piping Code, are to be followed.

5.4.14.2 Description

The use and the location of rigid-type supports, variable or constant spring-type supports, snubbers, and anchors or guides are to be determined by flexibility and seismic/dynamic stress analyses. Component support elements are manufacturer standard items. Direct weldment to thin wall pipe is to be avoided where possible.

5.4.14.3 Safety Evaluation

The flexibility and seismic/dynamic analyses are to be performed for the design of adequate component support systems included all transient loading conditions expected by each component. Provisions are to be made to provide spring-type supports for the initial dead weight loading due to hydrostatic testing of steam systems to prevent damage to this type support.

5.4.14.4 Inspection and Testing

After completion of the installation of a support system, all hanger elements are to be visually examined to assure that they are in correct adjustment to their cold setting position. Upon hot start-up operations, as discussed in Subsection 3.9.2.1.2, thermal growth will be observed to confirm that spring-type hangers will function properly between their hot and cold setting positions. Final adjustment capability is provided on all hanger or support types. Weld inspections and standards are to be in accordance with ASME Code Section III. Welder qualifications and welding procedures are in accordance with ASME Code Section IX and NF-4300 of ASME Code Section III.

5.4.15 References

1. *Design and Performance of General Electric Boiling Water Reactor Main Steam Line Isolation Valves*, General Electric Co., Atomic Power Equipment Department, March 1969 (APED-5750).

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Table 6.1-1

ENGINEERED SAFETY FEATURES COMPONENT MATERIALS (Continued)

Component	Form	Material	Specification (ASTM/ASME)
HPCF			
Same as RHR-A above.			
RCIC			
Same as RHR-A above.			
Standby Liquid Control Pump (No welding)			
Fluid Cylinder	Forging	Stainless Steel	SA182 F304
Cylinder Head, Valve Cover, and Stuffing Box Flange Plate	Plate	Stainless Steel	SA240 Type 304
Cylinder Head Extension, Valve Stop, and Stuffing Box	Bar	Stainless Steel	SA479 Type 304
Stuffing Box Gland and Plungers	Forging	Stainless Steel	SA564 Type 630 (H 1100)
Studs	Bar	Alloy Steel	SA193 Grade B7
Nuts	Forging	Alloy Steel	SA194 Grade 7
Standby Liquid Storage Tank			
Tank	Plate	Stainless Steel	SA240 Type 304
Fittings	Forgings	Stainless Steel	SA183 Gr F304
Pipe	Pipe	Stainless Steel	SA312 Type 304
Welds	Electrodes	Stainless Steel	FA 5.4 & 5.9, Types 308, 308L, 316L
Containment Vessel	Plate	Carbon Steel	SA516 Gr 70
	Plate	Stainless Steel	SA240 Type 304L
Penetrations	Forging	Carbon Steel	SA350 Gr LF 1 or 2
	Forging	Stainless Steel	SA182/F304L
Structural Steel	Shapes	Carbon Steel	A-36

Table 6.1-1

ENGINEERED SAFETY FEATURES COMPONENT MATERIALS (Continued)

Component	Form	Material	Specification (ASTM/ASME)
HVAC Emergency Cooling Water System			
Heat Exchanger	Plate	Carbon Steel	SA283 Gr A
	Tube	Copper Alloy	SB75-C12200
Pump	Casting	Carbon Steel	SA216 Gr WCB
	Casting	Stainless Steel	SA351 Gr CF8
Valves	Casting	Carbon Steel	SA216 Gr WCB
	Forging	Carbon Steel	SA105
Piping	Seamless Pipe	Carbon Steel	SA106 Gr A
	Welded Pipe	Carbon Steel	SA672 Gr B60
Reactor Building Cooling Water System			
Heat Exchanger (Note 1)	Plate		SA283 Gr B
	Tubes		Note 1
Pump	Casting	Carbon Steel	SA216 Gr WCC
	Casting	Stainless Steel	SA351 Gr CF8
Valves	Casting	Carbon Steel	SA216 Gr WCB
	Forging	Carbon Steel	SA105
Piping	Seamless Pipe	Carbon Steel	SA106 Gr A
	Welded Pipe	Carbon Steel	SA672 Gr B60
Reactor Service Water System (Note 1)			
Pump	Casting		
Valves	Casting		
	Casting		
	Casting		
	Forging		
Piping	Seamless Pipe		
	Welded Pipe		

Note 1: Materials are site dependent

Influent and effluent lines of this group are isolated by automatic or remote-manual isolation valves located as close as possible to the containment boundary.

6.2.4.3.2.4 Evaluation Against Regulatory Guide 1.11

Instrument lines that connect to the RCPB and penetrated the containment have 1/4-inch orifices and manual isolation valves, in compliance with Regulatory Guide 1.11 requirements.

6.2.4.3.3 Evaluation of Single Failure

A single failure can be defined as a failure of a component (e.g., a pump, valve, or a utility such as offsite power) to perform its intended safety functions as a part of a safety system. The purpose of the evaluation is to demonstrate that the safety function of the system will be completed even with that single failure. Appendix A to 10CFR50 requires that electrical systems be designed specifically against a single passive or active failure. Section 3.1 describes the implementation of these standards as well as General Design Criteria 17, 21, 35, 38, 41, 44, 54, 55 and 56.

Electrical as well as mechanical systems are designed to meet the single-failure criterion, regardless of whether the component is required to perform a safety action. 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 if 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. Therefore, a single failure in any electrical system is analyzed, regardless of whether the loss of a safety function is caused by a component failing to perform a requisite mechanical motion or a component performing an unnecessary mechanical motion.

6.2.4.4 Test and Inspections

The containment isolation system is scheduled to undergo periodic testing 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.

Air-testable check valves are provided on influent emergency core cooling lines of the HPCF and RHR systems whose operability is relied upon to perform a safety function.

A discussion of testing and inspection of isolation valves is provided in Subsection 6.2.1.6. Instruments are periodically tested and inspected. Test and/or calibration points are supplied with each instrument. Leakage integrity tests shall be performed on the containment isolation valves with resilient material seals at least once every 3 months.

6.2.5 Combustible Gas Control in Containment

The atmospheric control system (ACS-T31) is provided to establish and maintain an inert atmosphere within the primary containment during all plant operating modes except during shutdown for refueling or equipment maintenance and during limited periods of time to permit access for inspection at low reactor power. The flammability control system (FCS-T49) is provided to control the potential buildup of oxygen from design-basis radiolysis of water. The objective of these systems is to preclude combustion of hydrogen and damage to essential equipment and structures.

6.2.5.1 Design Bases

Following are criteria that serve as the bases for design:

(1) Since there is no design requirement for the ACS or FCS in the absence of a LOCA and there is no design-basis accident in the ABWR that results in core uncovery or fuel failures, the following requirements mechanistically assume that a LOCA

producing the design-basis hydrogen and oxygen has occurred.

(2) The hydrogen generation from metal-water reaction is defined in Regulatory Guide 1.7.

(3) The hydrogen and oxygen generation from radiolysis is defined in Regulatory Guide 1.7.

(4) The ACS establishes an inert atmosphere throughout the primary containment following an outage or other occasions when the containment has been purged with air to an oxygen concentration greater than 3.5 percent.

(5) The ACS maintains the primary containment oxygen concentration below the maximum permissible limit per Regulatory Guide 1.7 during normal, abnormal, and accident conditions in order to assure an inert atmosphere.

(6) The ACS also maintains a slightly positive pressure in the primary containment during normal, abnormal and accident conditions to prevent air (oxygen) leakage into the inerted volumes from the secondary containment, and provides non-essential monitoring of the oxygen concentration in the primary containment to assure a breathable mixture for safe personnel access or an inert atmosphere, as required. Essential monitoring is provided by the containment atmospheric monitoring system (CAMS) as described in Chapter 7.

(7) The drywell and the suppression chamber will be mixed uniformly after the design-basis LOCA due to natural convection and molecular diffusion. Mixing will be further promoted by operation of the containment sprays.

(8) The system is capable of controlling combustible gas concentrations in the containment atmosphere for the design bases LOCA without relying on purging and without releasing radioactive material to the environment.

(9) The system is designed to maintain an inert primary containment after the design-bases LOCA assuming a single-active failure. The backup purge function need not meet this criterion.

(10) Components of the AC system inside the reactor building are protected from postulated missiles and from pipe whip, as required to assure proper action as well as other dynamic effects such as tornado missiles and flooding. 430.209a

(11) The AC system isolation function has the capability to withstand the dynamic effects associated with the safe shutdown earthquake without loss of function. 430.209a

(12) The system is designed so that all components subjected to the primary containment atmosphere (i.e., inboard isolation valves) are capable of withstanding the temperature and pressure transients resulting from a LOCA. These components will withstand the humidity and radiation conditions in the wetwell or drywell following a LOCA.

(13) The ACS is nonsafety class except as necessary to assure primary containment integrity (penetrations, isolation valves). The ACS and FCS are designed and built to the requirements specified in Section 3.2.

(14) The ACS includes the valves and piping carrying nitrogen to the containment, valves and piping from the containment to the SGTS and HVAC (U41) exhaust line, non-safety oxygen monitoring, and all related instruments and controls. The ACS does not include any structures housing or supporting the aforementioned equipment or any ducting in the primary containment.

The nitrogen supplied from the AC system shall be oil-free with a moisture content of less than 2.5 ppm. Filters are provided to remove particulates larger than 5 microns.

(15) The system is designed to facilitate periodic inspections and tests. The ACS can be inspected or tested during normal plant conditions.

6.2.6.3 Containment Isolation Valve Leakage Rate Test (Type C)

6.2.6.3.1 General

430.50a Type C tests will be performed on all containment isolation valves required to be tested per 10CFR50 Appendix J. All testing is performed pneumatically, except hydraulic testing may be performed on isolation valve Type C tests using water as a sealant provided that the system line for the valve is not a potential containment atmosphere leak path.

Type C tests (like Type B test) are performed by local pressurization using either pressure decay or flowmeter method. The test pressure is applied in the same direction as when the valve is required to perform its safety function, unless it can be shown that results from tests with pressure applied in a different direction are equivalent or conservative. For the pressure decay method, test volume is pressurized with air or nitrogen to at least P_a. The rate of decay of pressure of the known test volume is monitored to calculate leakage rate. For the flowmeter method, required pressure is maintained in the test volume by making up air, nitrogen or water (if applicable) through a calibrated flowmeter. The flowmeter fluid flow rate is the isolation valve (or Type B test volume) leakage rate.

All isolation valve seats which are exposed to containment atmosphere subsequent to a LOCA are tested with air or nitrogen at containment peak accident pressure, P_a.

430.50e MSIVs and isolation valves isolated from a sealing system will use a test pressure of at least P_a.

Those valves which are in lines designed to be, or remain, filled with a liquid for at least 30 days subsequent to a loss-of-coolant accident are leakage rate tested with that liquid. The liquid leakage measured is not converted to equivalent air leakage nor added to the Type B and C test total.

All test connections, vent lines, or drain lines consisting of double barrier (e.g. 2-valves in series, one valve and a cap, or one valve and a flange), that are connected between isolation valves and form a part of the primary containment boundary need not be Type-C tested due to their infrequent use and multiple barriers as long as the barrier configurations are maintained using an administrative control program.

For Type C testing of containment penetrations, all testing will be done in the correct direction unless it can be shown that testing in the reverse direction is equivalent, or more conservative. The correct direction for this design is defined as flow from inside the containment to outside the containment.

6.2.6.3.2 Acceptance Criteria

The combined leakage rate of all components subject to Type B and Type C (Subsection 6.2.6.3) tests shall not exceed 60% of L_a. If repairs are required to meet this limit, the results shall be reported in a separate summary to the NRC, to include the structural conditions of the components which contributed to the failure.

6.2.6.4 Scheduling and Reporting of Periodic Tests

The periodic leakage rate test schedules for Type A, B and C tests are described in Chapter 16.

Type B and C tests may be conducted at any time during normal plant operations or during shutdown periods, as long as the time interval between tests for any individual Type B or C tests does not exceed 2 years. 430.50g Each time a Type B or C test is completed, the overall total leakage rate for all required Type B and C tests is updated to reflect the most recent test results. In addition to the periodic tests, any major modification, replacement of component which is part of the primary reactor containment boundary, or resealing a seal welded door, performed after the preopertional leakage rate test will be followed by either a Type A, Type B, or Type C test as applicable for the area effected by the modification. 430.51 Type A, B and C test results shall be submitted to the NRC in the summary report approximately three months after each test.

Included in the leak rate test summary report will be, a report detailing the containment inspection, a report detailing any repairs necessary to pass the tests, and the leak rate test results.

6.2.6.5 Special Testing Requirements

The maximum allowable leakage rate into the secondary containment and the means to verify that the inleakage rate has not been exceeded, as well as the containment leakage rate to the environment, are discussed in Subsections 6.2.3 and 6.5.1.3.

TABLE 6.2-2b

NET POSITIVE SUCTION HEAD (NPSH) AVAILABLE TO RHR PUMPS

A. Suppression pool is at its minimum depth, El. -3740mm (-12.27 Ft).

B. Centerline of pump suction is at El. -7200mm (23.62 Ft).

C. Suppression pool water is at its maximum temperatue for the given operating mode, 100°C (212°F).

D. Pressure is atmospheric above the suppression pool.

E. Maximum suction strainer losses are 0.21m (0.69 Ft).

$$NPSH = H_{ATM} + H_S - H_{VAP} - H_F$$

where:

H_{ATM} = atmospheric head

H_S = static head

H_{VAP} = vapor pressure head

H_F = Frictional head including strainer

<u>Minimum Expected NPSH</u>

RHR Pump Runout is 1130 m^3/h (4975 gpm).

Maximum suppression pool temperature is 100°C (212°F)

H_{ATM} = 10.78m (35.38 Ft)

H_S = 3.46m (11.35 Ft)

H_{VAP} = 10.78m (35.38 Ft)

H_F = 0.80m (2.62 Ft)

NPSH available = 10.78 + 3.46 - 10.78 - 0.80 = 2.66m (8.73 Ft)

NPSH required = 2.4m (7.87 Ft)

430.28

TABLE 6.2-2c

NET POSITIVE SUCTION HEAD (NPSH) AVAILABLE TO HPCF PUMPS

A. Suppression pool is at its minimum depth, El. -3740mm (-12.27 Ft).

B. Centerline of pump suction is at El. -7200mm (23.62 Ft).

C. Suppression pool water is at its maximum temperatue for the given operating mode, 100°C (212°F).

D. Pressure is atmospheric above the suppression pool.

E. Maximum suction strainer losses are 0.5m (1.67 Ft).

$$NPSH = H_{ATM} + H_S - H_{VAP} - H_F$$

where:

H_{ATM} = atmospheric head

H_S = static head

H_{VAP} = vapor pressure head

H_F = Frictional head including strainer

440.77

<u>Minimum Expected NPSH</u>

HPCF Pump Runout is 890 m^3/h (3918 gpm).

Maximum suppression pool temperature is 100°C (212°F)

H_{ATM} = 10.78m (35.38 Ft)

H_S = 3.46m (11.35 Ft)

H_{VAP} = 10.78m (35.38 Ft)

H_F = 1.02m (3.35 Ft)

NPSH available = 10.78 + 3.46 - 10.78 - 1.02 = 2.44m (8.01 Ft)

NPSH required = 2.2m (7.22 Ft)

Table 6.2-9 Secondary Containment Penetration List[1]

Penetration Number	Name	Elevation (mm)	Diameter (mm)
1	RCW (B)	-8200	600
2	RCW (B)	-8200	600
3	HPCF	-8200	600
4	SS	-8200	50
5	RD (LCW)	-8200	80
6	RD (SD)	-8200	65
7	RD (HCW)	-8200	150
8	TV	-8200	250
9	RCW (A)	-8200	600
10	RCW (A)	-8200	600
11	RCW (C)	-8200	550
12	RCW (C)	-8200	550
13	HPCF	-8200	600
14	MUWC	-8200	250
15	CRD	-8200	150
16	CRD	-8200	50
17	SPH	-8200	150
18	RCW (B)	-1700	150
19	RCW (B)	-1700	150
20	RCW (B)	-1700	200
21	RCW (B)	-1700	200
22	MS	-1700	80
23	SA	-1700	65
24	IA	-1700	50
25	FP	-1700	150
26	RCW (A)	-1700	150
27	RCW (A)	-1700	150
28	RCW (A)	-1700	200
29	RCW (A)	-1700	200
30	HSR	-1700	150
31	RCW (C)	-1700	100
32	RCW (C)	-1700	100
33	RCW (C)	-1700	200
34	RCW (C)	-1700	200
35	HS	4800	150
36	MS	4800	80
37	LCW (FPC)	4800	150
38	LCW (CUW)	4800	150
39	RCIC	4800	50
40	MS (4)	16191	700
41	FDW (?)	13810	600
42	HVAC Exhaust	27200	*
43	HVAC Supply	31700	*
44	Controlled Access(2)	12300	**
45	Equipment Lock	12300	**
46	Railroad Car Door	12300	**
47	HS	12300	150
48	HWH	12300	150

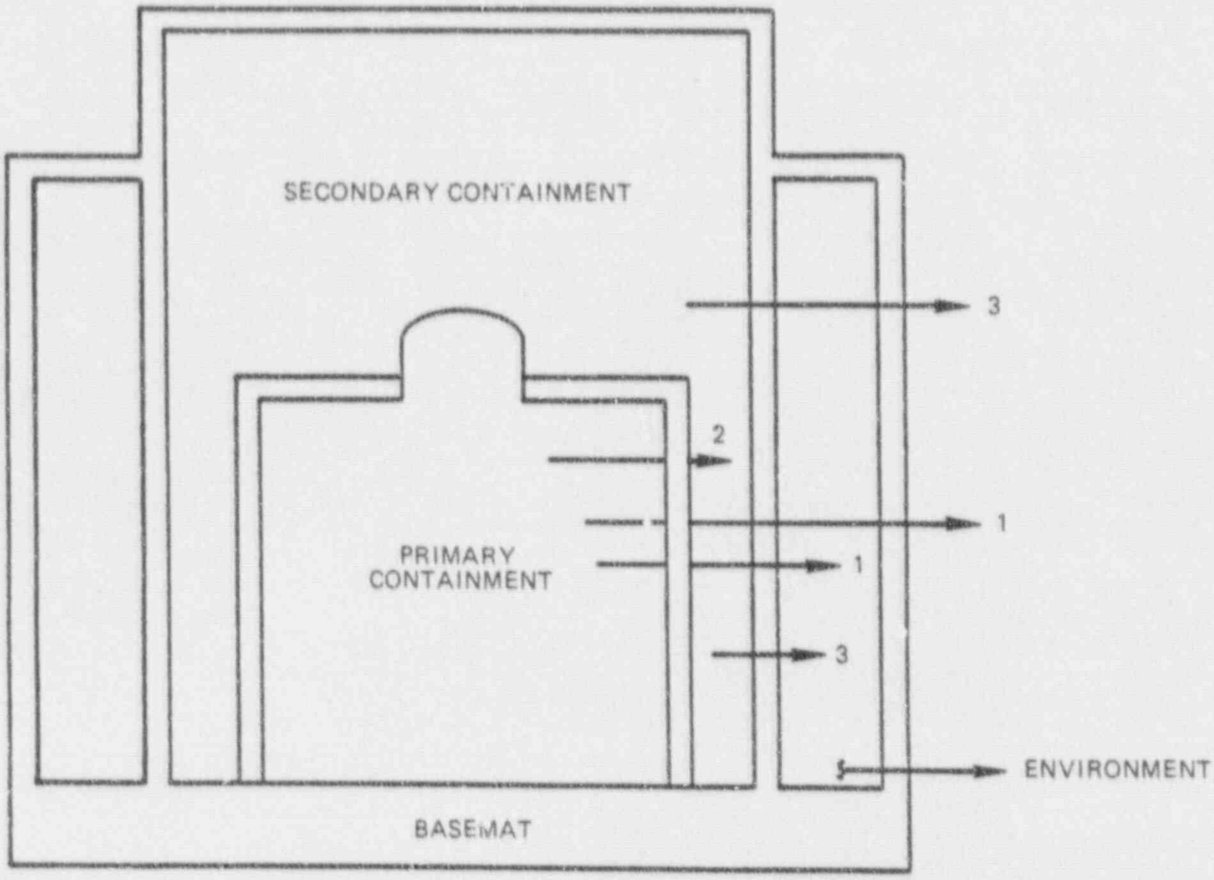
Table 6.2-9 Secondary Containment Penetration List[1] (Continued)

Penetration Number	Name	Elevation (mm)	Diameter (mm)
49	HWH	12300	150
50	HNCW	12300	200
51	HNCW	12300	200
52	MUWP	4800	150
53	AC	4800	50
54	AC	4800	250
55	HWH	4800	50
56	HWH	4800	50
57	Cabletrays	23500	
58	Cabletrays	12300	
59	Cabletrays	4800	

Note: 1. This Table provided in response to Question 430.34

* These HVAC openings have safety-related isolation valves with both local monitoring and remote (in control room) monitoring.

** These doors are monitored in the control room as per Subsection 13.6.3.4.



LEAKAGE FROM:

1. PRIMARY CONTAINMENT TO ENVIRONMENT OR CLEAN ZONE
2. PRIMARY CONTAINMENT TO SECONDARY CONTAINMENT
3. SECONDARY CONTAINMENT TO CLEAN ZONE OR THE ENVIRONMENT

87-245-29

Figure 6.2–27 THREE BASIC TYPES OF LEAKAGE PATHS

Refer to Figures 1.2-2 through 1.2-12

Figure 6.2-28 CONTAINMENT BOUNDARIES IN THE REACTOR BUILDING - PLAN SECTION A-A (0^{0} - 180^{0})

Refer to Figures 1.2-2 through 1.2-12

Figure 6.2-29 CONTAINMENT BOUNDARIES IN THE REACTOR BUILDING - PLAN SECTION B-B (90^{0} - 270^{0})

Refer to Figures 1.2-2 through 1.2-12

Figure 6.2-30 CONTAINMENT BOUNDARIES IN THE REACTOR BUILDING - PLAN AT ELEV (-) 13200mm

Refer to Figures 1.2-2 through 1.2-12

Figure 6.2-31 CONTAINMENT BOUNDARIES IN THE REACTOR BUILDING - PLAN AT ELEV (-)6700mm

Refer to Figures 1.2-2 through 1.2-12

Figure 6.2-32 CONTAINMENT BOUNDARIES IN THE REACTOR BUILDING - PLAN AT ELEV (-)200mm

Refer to Figures 1.2-2 through 1.2-12

Figure 6.2-33 CONTAINMENT BOUNDARIES IN THE REACTOR BUILDING - PLAN AT ELEV 7300mm

Refer to Figures 1.2-2 through 1.2-12

Figure 6.2-34 CONTAINMENT BOUNDARIES IN THE REACTOR BUILDING - PLAN AT ELEV 13100mm

Refer to Figures 1.2-2 through 1.2-12

Figure 6.2-35 CONTAINMENT BOUNDARIES IN THE REACTOR BUILDING - PLAN AT ELEV 18500mm

Refer to Figures 1.2-2 through 1.2-12

Figure 6.2-36 CONTAINMENT BOUNDARIES IN THE REACTOR BUILDING - PLAN AT ELEV 26700mm

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Figure 6.3-8 DELETED

(See Figure 5.4-8)

SECTION 6.4

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SECTION 6.4

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TABLES

ILLUSTRATIONS

Food storage space is provided as a part of the kitchen-lunchroom adjacent to the control equipment room. Water and food storage adequate for 12 people for 5 days is stored in this area. The storage cabinets have a net volume of 28 ft^3 useable for food storage. In addition, the refrigerator has a net volume of 10 ft^3 available. Potable water is stored in sealed sanitary containers in the kitchen-lunchroom.

All foodstuffs and water intended for emergency use must be so labeled and not be used for normal conditions, thus ensuring and adequate supply at all times for emergency use.

The sanitary facilities are located across the hall from the control room.

6.4.5 Testing and Inspection

The system is designed to permit periodic inspection of important components (e.g., fans, motors, belts, coils, filters, ductwork, piping, dampers, control instrumentation and valves), to assure the integrity and efficiency of the system. Local display and indicating devices are provided for periodic inspection of vital parameters such as air temperature upstream and downstream of the heating and cooling coils, cooling water inlet temperatures, filter pressure drop, duct static pressures, and water pressures at the inlet and outlet of coils.

Test connections are provided in the duct work and piping for periodic checking of air and water flows for conformance to design requirements. All features are periodically tested by initiating all dampers during normal operation. The operating system is proven operable by its performance during normal plant operations. The HEPA filters are periodically tested with DOP smoke per ANSI N510. The charcoal filters are to be periodically tested with a freon gas for adsorption efficiency. Inspection and sampling connections are provided for on site filter testing.

Filter pressure drop is to be routinely monitored and a high differential alarm alerts the operator to switch over to standby system.

The systems are to be tested periodically by initiating the changeover sequence during normal operation. All equipment is designed to facilitate the above discussed test and inspection functions.

Failure of any system or component to properly perform its assigned function during any test or inspection is grounds for repair or replacement.

6.4.6 Instrumentation Requirements

A complete description of the required instrumentation is given in Subsection 7.3.1.1.8.

6.4.7 COL License Information

The control room habitability system design was based on the following environmental conditions.

6.4.7.1 External Temperature

The maximum external air temperature is 115°F and the minimum external air temperature is -40°F.

6.4.7.2 Meterology (X/Q's)

The X/Q's used for evaluation of the control room operator dose to meet General Design Criterion 19 were derived from Regulatory Guide 1.3 for ground level release. Specific values and assumptions are presented in Subsection 15.6.5.

6.4.7.3 Toxic Gases

General Design Criterion 19, as related to providing adequate protection to permit access and occupancy of the control room under accident conditions. Acceptance is based upon the meeting the guidance of Regulatory Guide 1.78 relating to instrumentation to detect and alarm any hazardous chemical release in the plant vicinity and relating to the systems capability to isolate the control room from such releases; and Regulatory Guide 1.95 relating to the systems capability to limit the accumulation of chlorine within the control room. The ABWR is not designed for any hazardous chemical release. The control room is provided with an isolation system for radioactivity release which can be easily modified to handle additional sensors. Chemical accidents (including chlorine) require site specific information such as frequency, distance from control room, and size of container. None of which is available for a generic site.

SECTION 6.5

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TABLES

ILLUSTRATIONS

6.5 FISSION PRODUCTS REMOVAL AND CONTROL SYSTEMS

6.5.1 Engineered Safety Features Filter Systems

The filter systems required to perform safety-related functions following a design basis accident are:

(1) Standby gas treatment system (T22-SGTS).

(2) Control room portion of the HVAC system. (U41-HVAC)

The control room portion of the HVAC system is discussed in Section 6.4 and Subsection 9.4.1. The SGTS is discussed in this Subsection (6.5.1).

6.5.1.1 Design Basis

6.5.1.1.1 Power Generation Design Basis

The SGTS has the capability to filter the gaseous effluent from the primary containment or from the secondary containment when required to limit the discharge of radioactivity to the environment to meet 10CFR100 requirements.

6.5.1.1.2 Safety Design Basis

The SGTS is designed to accomplish the following:

(1) Maintain a negative pressure in the secondary containment, relative to the outdoor atmosphere, to control the release of fission products to the environment.

(2) Filter airborne radioactivity (halogen and air particulates) in the effluent to reduce offsite doses to within the limits specified in 10CFR100.

(3) Ensure that failure of any active component, assuming loss of offsite power, cannot impair the ability of the system to perform its safety function.

(4) Remain intact and functional in the event of a safe shutdown earthquake (SSE).

(5) Meet environmental qualification requirements established for system operation.

6.5.1.2 System Design

6.5.1.2.1. General

The SGTS P&ID is provided as Figure 6.5-1.

6.5.1.2.2 Component Description

Table 6.5-1 provides a summary of the major SGTS components. The SGTS consists of two parallel and redundant trains of active equipment which share a single filter train. Suction is taken from above the refueling area or from the primary containment via the atmospheric control system (T31-ACS). The discharge goes to the main plant stack.

The SGTS consists of the following principal components:

(1) Two independent dryer trains consisting of a moisture separator and an electric process heater.

(2) Two independent process fans located upstream of the filter train.

(3) A filter train consisting of a prefilter, a high efficiency particulate air (HEPA) filter, a charcoal adsorber, a second HEPA filter, and space heaters.

6.5.1.2.3 SGTS Operation

6.5.1.2.3.1 Automatic

Upon the receipt of a high drywell pressure signal or a low reactor water level signal, or when high radioactivity is detected in the secondary containment or refueling floor ventilation exhaust, the SGTS is automatically actuated. If system operation is not confirmed, the redundant process fan and dryer train are automatically placed into service. In the event a malfunction disables an operating process fan or dryer train, the standby process fan and dryer train are manually initiated.

6.5.1.2.3.2 Manual

The SGTS is on standby during normal plant operation and may be manually initiated before or during primary containment purging (de-inerting) when required to limit the discharge of contaminants to the environment. It may be manually initiated whenever its use may be needed to avoid exceeding radiation monitor setpoints.

6.5.1.2.3.3 Decay Heat Removal

Cooling of the SGTS filters may be required to prevent the gradual accumulation of decay heat in the charcoal. This heat is generated by the decay of radioactive iodine adsorbed on the SGTS charcoal. The charcoal is typically cooled by the air from the process fan.

A water deluge capability is also provided, but primarily for fire protection since redundant process fans are provided for air cooling. Since the deluge is available, it may also be used to remove decay heat for sequences outside the normal design basis. Temperature instrumentation is provided for control of the SGTS process and space electric heaters. This instrumentation may also be used by the operator to [re-]establish a cooling air flow post-accident, if required.

Water is supplied from the fire protection system and is connected to the SGTS via a spool piece.

6.5.1.3 Design Evaluation

6.5.1.3.1 General

(1) A slight negative pressure is normally maintained in the secondary containment by the reactor building HVAC system (Subsection 9.4.5). On SGTS initiation per Subsection 6.5.1.2.3.1, the secondary containment is automatically isolated from the HVAC system.

(2) The SGTS filter particulate and charcoal efficiencies are outlined in Table 6.5-1. Dose analyses of events requiring SGTS operation, described in Subsections 15.6.5 and 15.7.4, indicate that offsite doses are within the limits established by 10 CFR 100.

(3) The SGTS is designated as an engineered safety feature since it mitigates the consequences of a postulated accident by controlling and reducing the release of radioactivity to the environment. The SGTS, except for the deluge, is designed and built to the requirements for Safety Class 3 equipment as defined in Section 3.2, and 10 CFR 50, Appendix B.

The SGTS has independent, redundant active components. Should any active component fail, SGTS functions can be performed by the redundant component. The electrical devices of independent components are powered from separate Class 1E electrical buses.

(4) The SGTS is designed to Seismic Category I requirements as specified in Section 3.2. The SGTS is housed in a Category I structure. All surrounding equipment, components, and supports are designed to appropriate safety class and seismic requirements.

(5) The SGTS design is based on the maximum pressure and differential pressure, maximum integrated dose rate, maximum relative humidity, and maximum temperature expected in secondary containment for the LOCA event.

A secondary containment draw-down analysis will be performed by the COL applicant to demonstrate the capability of the SGTS to maintain the design negative pressure following a LOCA including inleakage from the open, non-isolated penetration lines identified during construction engineering and the event of the worst single failure of a secondary containment isolation valve to close. (See Subsection 6.5.5.1 for interface requirements).

6.5.1.3.2 Sizing Basis

Figure 6.5-2 provides an assessment of the secondary containment pressure after the design-basis LOCA assuming an SGTS fan capacity of 4000 scfm (70°F, 1 atmosphere) per fan and the leakage rates shown in Table 6.5-2. Credit for secondary containment as a fission product control system is only taken if the secondary containment is actually at a negative pressure by considering the potential effect of wind on the ambient pressure in the vicinity of the reactor building. For the ABWR dose analysis, direct transport of containment leakage to the environment was assumed for the first 20 minutes after LOCA event initiation (in addition to the leakage through the MSIVs to the main turbine condenser). Each SGTS fan was sized to

6.5.2 Containment Spray Systems

Credit is not taken for any fission product removal provided by the drywell and wetwell spray portions of the RHR system.

6.5.3 Fission Product Control Systems

Fission product control systems are provided in conjunction with other ESF systems to limit the release of radioactive material from the containment to the environment following postulated design basis events. Dose analyses are provided in Chapter 15. The fission product control systems consist of the primary containment and the secondary containment. The following is a discussion of each fission product control system.

6.5.3.1 Primary Containment

The primary containment is a cylindrical steel-lined reinforced concrete structure forming a limited leakage boundary for fission products released to the containment atmosphere following a LOCA or other event. The containment is divided into the upper and lower drywells and the suppression chamber (wetwell) by the reinforced concrete diaphragm floor and the reactor vessel pedestal. The diaphragm floor is rigidly attached to the reactor pedestal and the containment wall. A liner is also provided as part of the diaphragm floor to prevent bypass of steam from the upper drywell to the suppression chamber air space during an accident. The primary containment is totally within the secondary containment. A test program confirm the integrity of the leakage boundary. The assumed leak rate from primary containment is 0.5% of the free containment volume per day measured at the containment design pressure.

Containment leak rate testing is described in Subsection 6.2.6. The primary containment walls, liner plate, mechanical penetrations, isolation valves, hatches, and locks function to limit release of radioactive materials, subsequent to postulated accidents, such that the resulting offsite doses are less than the guideline values of 10CFR100.

The structural design details of the primary containment are discussed in Subsection 3.8.2. Primary containment isolation valves are discussed in Subsection 6.2.4. The conditions in the containment during and after the design basis events are given in Section 6.2.

Layouts of the primary containment structure are given in the building arrangement drawings in Section 1.2.

The primary containment atmosphere is inerted with nitrogen by the atmospheric control system (ACS). The ACS is described in Subsection 6.2.5. Following the design-basis LOCA, the flammability control system (FCS) controls the concentration of oxygen in containment. Oxygen is generated by the radiolytic decomposition of water.

On appropriate signals, containment isolation valves close as required. The primary containment provides a passive barrier to limit the leakage of airborne radioactive material. Systems required to accomplish ECCS or other ESF functions are not isolated. See Subsection 6.2.3 for further details of isolation valve closure signals.

6.5.3.2 Secondary Containment

The secondary containment is provided so that leakage from the primary containment is collected and treated and monitored by the SGTS prior to release to the environment. Refer to Subsection 6.2.3 for a description of the secondary containment boundary and Subsection 6.5.1 for a description of the SGTS.

6.5.4 Ice Condenser as a Fission Product Control System

The GE ABWR does not utilize any kind of an ice condenser feature as a fission product control system.

6.5.5 COL License Information

6.5.5.1 SGTS Performance

The COL applicant will perform a SGTS draw-down analysis in accordance with Subsection 6.5.1.3.1(5).

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TABLES

6.6 PRESERVICE AND INSERVICE INSPECTION AND TESTING OF CLASS 2 AND 3 COMPONENTS AND PIPING

This subsection describes the preservice and inservice inspection and system pressure test programs for Quality Groups B and C, i.e., ASME Code Class 2 and 3 items*, respectively. It describes those programs implementing the requirements of ASME B&PV Code, Section XI, Subsections IWB and IWC. The requirements for subsequent inservice inspection intervals are addressed in Subsection 5.3.3.7.

The development of the preservice and inservice inspection program plans will be the responsibility of the COL applicant and will be based on the ASME Code, Section XI, Edition and Addenda specified in accordance with 10CFR50, Section 50.55a. Responsibility for designing components for preservice and inservice inspection is the responsibility of the COL applicant. The COL applicant will be responsible for specifying the Edition of the ASME Code, Section XI, to be used, based on the procurement date of the component per 10CFR50, Section 50.55a. The ASME Code requirements discussed in this section are provided for information and are based on the 1989 Edition of the ASME Section XI.

6.6.1 Class 2 and 3 System Boundaries

The Class 2 and 3 system boundaries for both preservice and inservice inspection programs and the system pressure test program includes applicable items within the 3 boundary and the 4 boundary on the piping and instrumentation drawings (P&IDs). Those items boundaries include all or part of the following:

(1) Main steam system
(2) Feedwater system
(3) Reactor core isolation cooling system
(4) High pressure core flooder system
(5) Standby liquid control system
(6) Residual heat removal system.
(7) Reactor water clean up system
(8) Control rod drive system
(9) Deleted
(10) Purified make up water system
(11) Atmospheric control system
(12) Deleted
(13) HVAC normal cooling water system
(14) Deleted
(15) Deleted
(16) Deleted
(17) Reactor building cooling water system
(18) Deleted
(19) Fuel pool cooling and clean-up system
(20) Reactor service water system

6.6.1.1 Class 2 System Boundary Description

Those portions of the systems listed in Subsection 6.6.1 within the Class 2 boundary, based on Regulatory Guide 1.26, Revision 3, for Quality Group B, are as follows:

(1) Portions of the reactor coolant pressure boundary as defined in Subsection 5.2.4.1.1, but which are excluded from the Class 1 boundary pursuant to Subsection 5.2.4.1.2.

(2) Systems or portions of systems important to safety that are designed for reactor shutdown or residual heat removal.

(3) Portions of the steam systems extending from the outermost containment isolation valve up to but not including the turbine stop and bypass valves and connected piping up to and including the first valve that is either normally closed or capable of automatic closure during all modes of normal reactor operation.

(4) Systems or portions of systems that are connected to the reactor coolant pressure boundary and are not capable of being isolated from the boundary during all modes of normal reactor operation by two valves, each of which is normally closed or capable of automatic closure.

(5) Systems or portions of systems important to safety that are designed for (1) emergency core cooling, (2) post accident containment heat removal, or (3) post accident fission product removal.

Items (1) through (5) above describe the Class 2 boundary only and are not related to exemptions

* *Items as used in this Section are products constructed under a Certificate of Authorization (NCA-3120) and material (NCA-1220). See Section III, NCA-1000, footnote 2*

from inservice examinations under ASME Code, Section XI rules. The Class 2 components exempt from inservice examinations are described in ASME Code, Section XI, IWC-1220.

6.6.1.2 Class 3 System Boundary Description

Those portions of the systems listed in Subsection 6.6.1 within the Class 3 boundary, based on Regulatory Guide 1.26, Revision 3, for Quality Group C, are not part of the reactor coolant pressure boundary but are as follows:

(1) Cooling water systems or portions of cooling water systems important to safety that are designed for emergency core cooling, post-accident containment heat removal, post-accident containment atmosphere cleanup, or residual heat removal from the reactor and from the spent fuel storage pool (including

primary and secondary cooling systems). Portions of these systems that are required for their safety functions and that do not operate during any mode of normal operation and cannot be tested adequately, however, are included in Class 2.

(2) Cooling water and seal water systems or portions of these systems important to safety that are designed for functioning of components and systems important to safety.

(3) Systems or portions of systems that are connected to the rector coolant pressure boundary and are capable of being isolated from that boundary during all modes of normal reactor operation by two valves each of which is normally closed or capable of automatic closure.

(4) Systems, other than radioactive waste management systems, not covered by items a, b and c above, that contain or may contain radioactive material and whose postulated failure would result in conservatively calculated potential offsite doses (ref. Regulatory Guides 1.3 and 1.4), that exceed 0.5 rem to the whole body or its equivalent to any part of the body.

Items (1) through (4) above describe the Class 3 boundary only and are not exemptions from inservice examinations under ASME Code, Section XI rules. The Class 3 components exempt from inservice examinations are described in the ASME Code, Section XI, IWD-1220.

6.6.2 Accessibility

All items within the Class 2 and 3 boundaries are designed to provide access for the examinations required by IWC-2500 and IWD-2500. Responsibility for designing components for accessibility for preservice and inservice inspection is the responsibility of the COL applicant

6.6.2.1 Class 2 RHR Heat Exchangers

The physical arrangement of the residual heat removal (RHR) heat exchangers shall, be conducive to the performance of the required ultrasonic and surface examinations. The RHR heat exchanger nozzle-to-shell welds will be 100% accessible for preservice inspection during fabrication but might have limited areas that will not be accessible from the outer surface for inservice examination techniques. However, the inservice inspection program for the RHR heat exchanger is the responsibility of the COL applicant and any inservice inspection program relief request will be reviewed by the NRC staff based on the Code Edition and Addenda in effect and inservice inspection techniques available at the time of COL application. Removable thermal insulation is provided or those welds and nozzles selected for frequent examination during the inservice inspection. Platforms and ladders are provided as necessary to facilitate examination.

6.6.2.2 Class 2 Piping, Pumps, Valves and Supports

Physical arrangement of piping pumps and valves provide personnel access to each weld location for performance of ultrasonic and surface (magnetic particle or liquid penetrant) examinations and sufficient access to supports for performance of visual, VT-3, examination. Working platforms are provided in some areas to facilitate servicing of pumps and valves. Removable thermal insulation is provided on welds and components which require frequent access for examination or are located in high radiation areas. Welds are located to permit ultrasonic examination from at least one side, but where component geometries permit, access from both sides is provided.

Restrictions: For piping systems and portions of piping systems subject to volumetric and surface examination, the following piping designs are not used:

(1) Valve to valve
(2) Valve to reducer
(3) Valve to tee
(4) Elbow to elbow
(5) Elbow to tee
(6) Nozzle to elbow
(7) Reducer to elbow
(8) Tee to tee
(9) Pump to valve

Straight sections of pipe and spool pieces shall be added between fittings. The minimum length of the spool piece has been determined by using the formulate $L = 2T + 6$ inches, where L equals the length of the spool piece (not including weld preparation) and T equals the pipe wall thickness.

6.6.3 Examination Categories and Methods

6.6.3.1 Examination Categories

The examination category of each item is listed in Table 6.6-1 which is provided as an example for the preparation of preservice and inservice program plans. The items are listed by system and line number where applicable. Table 6.6-1 also states the method of examination for each item.

For preservice examination, all of the items selected for inservice examination shall be performed once in accordance with ASME Section XI, IWC-2200 and IWD-2200, with the exception of the examinations specifically excluded by ASME Section XI from preservice requirements, such as the visual VT-2 examinations for Category C-H, D-A, D-B and D-C.

6.6.3.2 Examination Methods

6.6.3.2.1 Visual Examination

Visual Examination Methods, VT-2 and VT-3, shall be conducted in accordance with ASME Section XI, IWA-2210. In addition, VT-2 examinations shall also meet the requirements of IWA-5240.

At locations where leakages are normally expected and leakage collection systems are located, (e.g., valve stems and pump seals), the visual, VT-2, examination shall verify that the leakage collection system is operative.

Piping runs shall be clearly identified and laid out such that insulation damage, leaks and structural distress will be evident to a trained visual examiner.

6.6.3.2.2 Surface Examination

Magnetic Particle and Liquid Penetrant examination techniques shall be performed in accordance with ASME Section XI, IWA-2221 and IWA-2222, respectively. For direct examination access for magnetic particle (MT) and penetrant (PT) examination, a clearance (of at least 24 inches of clear space) is provided where feasible for the head and shoulders of a man within a working arm's length (20 inches) of the surface to be examined. In addition, access shall be provided as necessary to enable physical contact with the item as necessary to perform the examination. Remote MT and PT generally are not appropriate as a standard examination process, however, borescopes and mirrors can be used at close range to improve the angle of vision. As a minimum, insulation removal shall expose the area of each weld plus at least six inches from the toe of the weld on each side. Insulation will generally be removed 16 inches on each side of the weld.

6.6.3.2.3 Volumetric Ultrasonic Direct Examination

Volumetric ultrasonic direct examination shall be performed in accordance with ASME Section XI, IWA-2232. In order to perform the examination, visual access to place the head and shoulder within 20 inches of the area of interest shall be provided where feasible. Nine inches between adjacent pipes is sufficient spacing if there is free access on each side of the pipes. The transducer dimension has been considered: a 1 1/2 inch diameter cylinder, 3 inches long placed with the access at a right angle to the surface to be examined. The ultrasonic examination instrument has been considered as a rectangular box 12 x 12 x 20 inches located within 40 feet from the transducer. Space for a second examiner to monitor the instrument shall be provided if necessary.

Insulation removal for inspection is to allow sufficient room for the ultrasonic transducer to scan the examination area. A distance of 2T plus 6 inches, where T is the pipe thickness, is the minimum required on each side of the examination area. The insulation design generally leaves 16 inches on each side of the weld, which exceeds minimum requirements.

6.6.3.2.4 Alternative Examination Techniques

As provided by ASME Section XI, IWA-2240, alternative examination methods, a combination of methods, or newly developed techniques may be substituted for the methods specified for a given item in this section, provided that they are demonstrated to be equivalent or superior to the specified method. This provision allows for the use of newly developed examination methods, techniques, etc., which may result in improvements in examination reliability and reductions in personnel exposure.

6.6.3.2.5 Data Recording

Manual data recording will be performed where manual ultrasonic examinations are performed. If automated systems are used, electronic data recording and comparison analysis are to be employed with automated ultrasonic examination equipment. Signals from each ultrasonic transducer would be fed into a data acquisition system in which the key parameters of any reflectors will be recorded. The data to be recorded for manual and automated methods are:

(1) location;
(2) position;
(3) depth below the scanning surface;
(4) length of the reflector;
(5) transducer data including angle and frequency; and
(6) calibration data.

The data so recorded shall be compared with the results of subsequent examinations to determine the behavior of the reflector.

6.6.3.2.6 Qualification of Personnel and Examination Systems for Ultrasonic Examination

Personnel performing examinations shall be qualified in accordance with ASME Section XI, Appendix VII. Ultrasonic examination systems shall be qualified in accordance with an industry accepted program for implementation of ASME Section XI, Appendix VIII.

6.6.4 Inspection Intervals

6.6.4.1 Class 2 Systems

The inservice inspection intervals for Class 2 systems will conform to Inspection Program B as described in Section XI, IWC-2412. Except where deferral is permitted by Table IWC-2500-1, the percentages of examinations completed within each period of the interval shall correspond to Table IWC-2412-1. An example of the selection of Code Class 2 items and examinations to be conducted within the 10-year intervals are described in Table 6.6-1.

6.6.4.2 Class 3 Systems

The inservice inspection intervals for Class 3 systems will conform to Inspection Program B as described in Section XI, IWD-2412. Except where deferral is permitted by Table IWD-2500-1, the percentages of examinations completed within each period of the interval shall correspond to Table IWD-2412-1. An example of the selection of Code Class 3 items and examinations to be conducted within the 10-year intervals are described in Table 6.6-1.

6.6.5 Evaluation of Examination Results

Examination results will be evaluated in accordance with ASME Section XI, IWC-3000 for Class 2 components, with repairs based on the requirements of IWA-4000 and IWC-4000. Examination results will be evaluated in accordance with ASME Section XI, IWD-3000 for Class 3 components, with repairs based on the requirements of IWA-4000 and IWD-4000.

6.6.6 System Pressure Tests

6.6.6.1 System Inservice Test

As required by Section XI, IWC-2500 for category C-H and by IWD-2500 for categories D-A, D-B and D-C, a system inservice test shall be performed in accordance with IWC-5221 on Class 2 systems, and IWD-5221 on Class 3 systems, which are required to operate during normal operation. The system inservice test shall include all Class 2 or 3 components and piping within the pressure retaining boundary and shall be performed once during each inspection period as defined in Tables IWC-2412-1 and IWD-2412-1 for Program B. For the purposes of the system inservice test of Class 2 systems, the pressure retaining boundary is defined in Table IWC-2500-1, Category C-H, Note 7. For the purposes of the system inservice test for Class 3 systems, the system boundary is defined in Note 1 of Table IWD-2500-1, for categories D-A, D-B and D-C. The system inservice test shall include a VT-2 examination in accordance with IWA-5240, except that, where portions of a system are subject to system pressure tests associated with two different functions, the VT-2 examination shall only be performed during the test conducted at the higher of the test pressures. The system inservice test will be conducted at approximately the maximum operating pressure and temperature indicated in the applicable process flow diagram for the system as indicated in Table 1.7-1. The system hydrostatic test (Subsection 5.2.4.6.2), when performed is acceptable in lieu of the system inservice test.

6.6.6.2 System Functional Test

As required by Section XI, IWC-2500 for category C-H and by IWD-2500 for categories D-A, D-B and D-C, a system functional test shall be performed in accordance with IWC-5221 on Class 2 systems, and IWD-5221 on Class 3 systems, which are not required to operate during normal operation but for which a periodic system functional test is performed. The system functional test shall include all Class 2 or 3 components and piping within the pressure retaining boundary and shall be performed once during each inspection period as defined in Tables IWC-2412-1 and IWD-2412-1 for Program B. For the purposes of the system functional test of Class 2 systems, the pressure retaining boundary is defined in Table IWC-2500-1, Category C-H, Note 7. For the purposes of the system functional test for Class 3 systems, the system boundary is defined in Note 1 of Table IWD-2500-1, categories D-A, D-B and D-C. The system inservice test shall include a VT-2 examination in accordance with IWA-5240, except that, where portions of a system are subject to system pressure tests associated with two different functions, the VT-2 examination shall only be performed during the test conducted at the higher of the test pressures. The system functional test will be conducted at the nominal operating pressure and temperature indicated in the applicable process flow diagram for the functional test for each system as indicated in Table 1.7-1. The system hydrostatic test (Subsection 5.2.4.6.2), when performed is acceptable in lieu of the system inservice test.

6.6.6.3 Hydrostatic Pressure Tests

As required by Section XI, IWC-2500 for Category B-P, the hydrostatic pressure test shall be performed in accordance with ASME Section IWC-5222 on all Class 2 components and piping within the pressure retaining boundary once during each 10 year inspection interval. For purposes of the hydrostatic pressure test, the pressure retaining boundary is defined in Table IWB-2500-1, Category B-P, Note 1. The system hydrostatic test shall include a VT-2 examination in accordance with IWA-5240. For the purposes of determining the test pressure for the system hydrostatic test in accordance with IWB-5222 (a), the system design pressure as indicated on the applicable piping and instrumentation diagram for the system, as shown in Table 1.7-1, shall be used for P_{sv} in all cases.

6.6.7 Augmented Inservice Inspection

6.6.7.1 High Energy Piping

All high energy piping between the containment isolation valves are subject to the following additional inspection requirements:

All circumferential welds shall be 100 percent volumetrically examined each inspection interval as defined in Subsection 6.6.3.2.3. Further, accessibility, examination requirements and procedures shall be as discussed in Subsections 6.6.2, 6.6.3 and 6.6.5, respectively. Piping in these areas shall be seamless, thereby eliminating all longitudinal welds.

6.6.7.2 Erosion-Corrosion

Piping systems determined to be susceptible to single-phase erosion-corrosion shall be subject to a program of nondestructive examinations to verify the system structural integrity. The examination schedule and examination methods shall be determined in accordance with applicable regulations and regulatory documents, such as NRC Bulletin 87-01, and applicable rules of Section XI of the ASME Boiler and Pressure Vessel Code.

6.6.8 Code Exemptions

As provided in ASME Section XI, IWC-1220 and IWD-1220, certain portions of Class 2 and 3 systems are exempt from the volumetric and surface and visual examination requirements of IWC-2500 and IWD-2500. These portions of systems are specifically identified in Table 6.6-1

Table 6.6-1

EXAMINATION CATEGORIES AND METHODS (Con.t)

Quality Group	System Number	System Title	System Description	P&ID Diagram	Sec. XI Exam Cat.	Items Examined	Exam Method
B	G31	RWCU	50A equipment drain sump line from RPV head	Figure 5.4-12a	Exempted per IWC-1222 (a),(b)		
			All pressure retaining components and piping		C-H	External surfaces (Note 5)	VT-2

Table 6.6-1

EXAMINATION CATEGORIES AND METHODS (Cont)

Quality Group	System Number	System Title	System Description	P&ID Diagram	Sec XI Exam Cat.	Items Examined	Exam Method

Table 6.6-1

EXAMINATION CATEGORIES AND METHODS (Cont)

Quality Group	System Number	System Title	System Description	P&ID Diagram	Sec XI Exam Cat.	Items Examined	Exam Method

Table 6.6-1

EXAMINATION CATEGORIES AND METHODS (Cont)

Quality Group	System Number	System Title	System Description	P&ID Diagram	Sec XI Exam Cat.	Items Examined	Exam Method

Table 6.6-1

EXAMINATION CATEGORIES AND METHODS (Cont)

Quality Group	System Number	System Title	System Description	P&ID Diagram	Sec XI Exam Cat.	Items Examined	Exam Method

Table 6.6-1

EXAMINATION CATEGORIES AND METHODS (Cont.)

Quality Group	System Number	System Title	System Description	P&ID Diagram	Sec. XI Exam Cat.	Items Examined	Exam Method
B	P11	Purified Make-up Water	50A piping penetrating primary containment from outermost valve F141 up to and including inboard check valve F142.	Figure 5.2-5b	Exempted per IWC-1222 (a) , (b)		
			All pressure retaining components and piping		C-H	External Surfaces (Note 5)	VT-2

Table 6.6-1

EXAMINATION CATEGORIES AND METHODS (Cont.)

Quality Group	System Number	System Title	System Description	P&ID Diagram	Sec. XI Exam Cat.	Items Examined	Exam Method
B	P24	HVAC Normal Cooling Water	Piping penetrating primary containment from valve F142 up to and including valve F141; and from valve F053 up to and including valve F054	Figure-9.2-25	Exempted per IWC-1222 (a), (b)		
			All pressure retaining components and piping		C-H	External surfaces (Note 5)	VT-2

Table 6.6-1

EXAMINATION CATEGORIES AND METHODS (Cont)

Quality Group	System Number	System Title	System Description	P&ID Diagram	Sec XI Exam Cat.	Items Examined	Exam Method

Table 6.6-1

EXAMINATION CATEGORIES AND METHODS (Cont)

Quality Group	System Number	System Title	System Description	P&ID Diagram	Sec XI Exam Cat.	Items Examined	Exam Method

Table 6.6-1

EXAMINATION CATEGORIES AND METHODS (Cont)

Quality Group	System Number	System Title	System Description	P&ID Diagram	Sec XI Exam Cat.	Items Examined	Exam Method

Table 6.6-1

EXAMINATION CATEGORIES AND METHODS (Cont.)

Quality Group	System Number	System Title	System Description	P&ID Diagram	Sec. XI Exam Cat.	Items Examined	Exam Method
B	T39	Atmos-pheric Control	Drywell / Wetwell purge supply lines from primary containment penetrations through valves F002 and F003, through Flow Elements FE001 and FE003	Figure 6.2-39g			
			Piping		C-F-2	Welds (Note 1)	UT, MT
			Integral attachments		C-C	Welds (Note 3)	MT
			All pressure retaining components		C-H	External surfaces (Note 5)	VT-2
			Piping and component supports		F-A	Supports (Note 6)	VT-3

Table 6.6-1

EXAMINATION CATEGORIES AND METHODS (Cont)

Quality Group	System Number	System Title	System Description	P&ID Diagram	Sec XI Exam Cat.	Items Examined	Exam Method

Table 6.6-1

EXAMINATION CATEGORIES AND METHODS (Cont)

Quality Group	System Number	System Title	System Description	P&ID Diagram	Sec XI Exam Cat.	Items Examined	Exam Method

Table 6.6-1

EXAMINATION CATEGORIES AND METHODS (Cont.)

Quali Group	System Number	System Title	System Description	P&ID Diagram	Sec. XI Exam Cat.	Items Examined	Exam Method
C	B21	Nuclear Boiler	Main Steam SRV discharge lines	Fig.5.1-3b			
			All pressure retaining components and piping		D-A	External Surfaces (Note 7)	VT-2
			Integral Attachments		D-A	Welds (Note 8)	VT-3
			Piping and Component Supports		F-A	Supports (Note 6)	VT-3

6.7 HIGH PRESSURE NITROGEN GAS SUPPLY SYSTEM

6.7.1 Functions

The high pressure nitrogen gas supply system is divided into two independent divisions, with each division containing a safety-related emergency stored nitrogen supply. The essential stored nitrogen supply is Safety Class 3, Seismic Category I, designed for operation of the main steam S/R valve ADS function accumulators.

The function of the nonsafety-related, makeup nitrogen gas supply system is:

(1) relief function accumulators of main steam S/R valves,

(2) pneumatically operated valves and instruments inside the PCV,

(3) leak detection system radiation monitor calibration

(4) ADS function accumulators to compensate for the leakage from main steam S/R solenoid valves during normal operation

6.7.2 System Description

Nitrogen gas for the essential system is supplied from high pressure nitrogen gas storage bottles. Nitrogen gas for the nonessential makeup system is supplied from the nitrogen gas evaporator via the makeup line to the atmospheric control (AC) system. The nitrogen supply system shall supply nitrogen which is oil-free with a moisture content of less than 2.5 ppm. The essential system is separated into two divisions. There are tielines between the nonessential and each division of the essential system. Each tieline has a motor operated shutoff valve. For details, see Figure 6.7-1 and Table 6.7-1.

Each division of the essential system has ten bottles. Normally, outlet valves from five of the ten bottles are kept open. Each division has a pressure control valve to depressurize the nitrogen gas from the bottles.

The bottles are mechanically restrained to preclude generation of high-pressure missiles during an SSE. The bottles are also covered by a heavy steel plate, which serves as a barrier to potential missiles.

Flow rate and capacity requirements are divided into an initial requirement and a continuous supply. An initial requirement for each ADS SRV provides for actuations of the valve against drywell pressure. Fifty gallon accumulators supplied for each main steam ADS SRV actuator fulfill the steam valve requirement. The continuous supply is divided into safety and nonsafety portions.

Compressed nitrogen at a rate adequate to make up the nitrogen leakage of each serviced valve is provided by the safety portion. This assumes an air leakage rate for each valve of 1 scfh for a period of at least seven days. The essential system with associated lines, valves and fittings are classified as Safety Class 3, Seismic Category I.

The nonsafety portion provides compressed nitrogen at a rate adequate to recharge the ADS SRV accumulators. The nonessential system has two pressure control valves to depressurize the nitrogen gas from the AC system. One is to depressurize to 200 psi for the SRV accumulators and the other is to depressurize to 100 psi for other pneumatic uses.

The continuous supply portion of the pneumatic system, extending from the AC system to the isolation valve prior to the essential system is not safety related.

Nonsafety piping and valves of the system are designed to ANSI B31.1, Power Piping Code, and the requirements of Quality Group D of Regulatory Guide 1.26. Pressure vessels and heat exchangers are designed to ASME Section VIII, Division I.

System design pressure is 200 psig with the system design temperature at 150°F.

6.7.3 System Evaluation

Vessels, piping and fittings of the safety portion of the system are designed to Seismic

Category I, ASME Code III, Class 3, Quality Group C and Quality Assurance B requirements, except for the piping and valves for the containment and drywell penetrations which are designed to Seismic Category I, ASME Code III, Class 2, Quality Group B and Quality Assurance B requirements.

The essential high pressure nitrogen gas supply is separated into two independent divisions, with each division capable of supplying 100% of the requirements of the division being serviced. Each division is mechanically and electrically separated from the other. The system satisfies the components' nitrogen demands during all plant operation conditions (normal through faulted).

Safety grade portions of the high pressure nitrogen gas supply system are capable of being isolated from the nonsafety parts and retaining their function during LOCA and/or seismic events under which any nonsafety parts may be damaged.

Pipe routing of Division 1 and Division 2 nitrogen gas is kept separated by enough space so that a single fire, equipment dropping accident, strike from a single high energy whipping pipe, jet force from a single broken pipe, internally generated missile or wetting equipment with spraying water cannot prevent the other division from accomplishing its safety function. Separation is accomplished by spatial separation or by a reinforced concrete barrier, to ensure separation of each pneumatic air division from any systems and components which belong to the other pneumatic air division.

6.7.4 Inspection and Testing Requirements

Periodic inservice inspection of components, in accordance with ASME Section XI, to ensure the capability and integrity of the system is mandatory. Nitrogen quality shall be tested periodically to assure compliance with ANSI MC11.1.

The nitrogen isolation valves are capable of being tested to assure their operational integrity by manual actuation of a switch located in the control room and by observation of associated position indication lights. Test and vent connections are provided at the containment isolation valves in order to verify their leaktightness. Operation of valves and associated equipment used to switch from the nonsafety to safety nitrogen supply can be tested to assure operational integrity by manual actuation of a switch located in the control room and by observation of associated position indication lights. Periodic tests of the check valves and accumulators shall be conducted to assure valve operability

6.7.5 Instrumentation Requirements

A pressure sensor is provided for the safety nitrogen supply, and an alarm signals low nitrogen pressure.

A remote manual switch and open-closed position lights are provided in the control room for valve operation and position indication.

7.1 INTRODUCTION

This chapter presents the specific detailed design and performance information relative to the instrumentation and control aspects of the safety-related systems utilized throughout the plant. The design and performance considerations relative to these systems' safety function and their mechanical aspects are described in other chapters.

7.1.1 Identification of Safety-Related Systems

7.1.1.1 General

Instrumentation and control systems are designated as either nonsafety-related systems or safety systems depending on their function. Some portions of a system may have a safety function while other portions of the same system may be classified nonsafety-related. A description of the system of classification can be found in Chapter 15, Appendix A.

The systems presented in Chapter 7 are also classified according to NRC Regulatory Guide 1.70, Revision 3 (i.e., reactor protection (trip) system (RPS), engineered safety feature (ESF) systems, systems required for safe shutdown, safety-related display instrumentation, all other instrumentation systems required for safety, and control systems not required for safety). Table 7.1-1 compares instrumentation and control systems of the ABWR with those of the GESSAR II 238 Nuclear Island. Differences and their effect on safety-related systems are also identified in Table 7.1-1.

Each individual safety-related system utilizes redundant channels of safety-related instruments for initiating safety action. The automatic decision making and trip logic functions associated with the safety action of several safety-related nuclear steam supply systems (NSSS) are accomplished by a four-division correlated and separated protection logic complex called the safety system logic and control (SSLC). The SSLC multidivisional complex includes divisionally separate control room and other panels which house the SSLC equipment for controlling the various safety function actuation devices. The SSLC receives input signals from the redundant channels of instrumentation in the safety-related system, and uses the input information to perform logic functions in making decisions for safety actions.

Divisional separation is also applied to the essential multiplexing system (EMS), which provides data highways for the sensor input to the logic units and for the logic output to the system actuators (actuated devices such as pump motors and motor operated valves). Systems which utilize the SSLC are the reactor protection (trip) system, the high pressure core flooder system, the residual heat removal system, the automatic depressurization system, the leak detection and isolation system and the reactor core isolation cooling system which are defined in the following subsections and discussed in other sections of this chapter.

7.1.1.2 Reactor Protection (Trip) System (RPS)

The reactor protection (trip) system instrumentation and controls initiated an automatic reactor shutdown via insertion of control rods (scram) if monitored system variables exceed preestablished limits. This action avoids fuel damage, limits system pressure and thus restricts the release of radioactive material.

7.1.1.3 Engineered Safety Features (ESF) Systems

7.1.1.3.1 Emergency Core Cooling Systems (ECCS)

Instrumentation and controls provide automatic initiation and control of specific 420.29
core cooling systems such as high-pressure core flooder (HPCF) system, automatic depressurization system (ADS), reactor core isolation cooling system (RCIC) and the low-pressure coolant injection flooders of the residual heat removal system provided to cool the core fuel cladding following a design basis accident.

7.1.1.3.2 Leak Detection and Isolation System

Instrumentation and controls monitor selected potential sources of steam and water leakage or other conditions and automatically initiate closure of various isolation valves if monitored 420.29
system variables exceed preestablished limits. This action limits the loss of coolant from the

reactor coolant pressure boundary and the release of radioactive materials from either the reactor coolant pressure boundary or from the fuel and equipment storage pools.

7.1.1.3.3 Wetwell and Drywell Spray Mode of RHR

Instrumentation and control provides manual initiation of wetwell spray and manual initiation of drywell spray (when high drywell pressure signal is present) to condenses steam in the containment and remove heat from the containment. The drywell spray has an interlock such that drywell spray is possible only in the presence of a high drywell pressure condition.

7.1.1.3.4 Suppression Pool Cooling Mode of RHR (SPC-RHR)

Instrumentation and control is provided to manually initiate portions of the RHR system to effect cooling of the suppression pool water.

7.1.1.3.5 Standby Gas Treatment System

Instrumentation and Control is provided to maintain negative pressure in the secondary
420.29 containment and for automatically limiting airborne radioactivity release from containment if required.

7.1.1.3.6 Emergency Diesel Generator Support Systems

Instrumentation and control is provided to assure availability of electric control and motive power under all design basis conditions. The function of the diesel generator is to provide
420.29 automatic emergency AC power supply for the safety-related loads (required for the safe shutdown of the reactor) when the offsite source of power is not available.

7.1.1.3.7 Reactor Building Cooling Water System

Instrumentation and control is provided to assure availability of cooling water for heat removal from the nuclear system as required. Safety-related portions of this system start
420.29 automatically on receipt of a LOCA and/or LOPP signal.

7.1.1.3.8 Essential HVAC Systems

Instrumentation and control is provided to
automatically maintain an acceptable thermal 420.29
environment for safety equipment and operating personnel.

7.1.1.3.9 HVAC Emergency Cooling Water System

Automatic instrumentation and control is 420.29
provided to assure that adequate cooling is provided for the main control room, the control building essential electrical equipment rooms, and the diesel generator cooling coils.

7.1.1.3.10 High Pressure Nitrogen Gas Supply System

Automatic instrumentation and control is 420.29
provided to assure adequate instrument high pressure nitrogen is available for ESF equipment operational support.

7.1.1.4 Safe Shutdown Systems

7.1.1.4.1 Alternate Rod Insertion Function (ARI)

Though not required for safety, instrumentation and controls for the ARI provide a function for mitigation of the consequences of anticipated transient without scram (ATWS) events. Upon receipt of an initiation signal (high reactor dome pressure or low reactor water level), the fine-motion control rod drive (FMCRD) motor
shall automatically drive all rods full-in. 420.29
This provides a method, diverse from the hydraulic control units (HCUs) for scramming the reactor.

7.1.1.4.2 Standby Liquid Control System (SLCS)

Instrumentation and controls are provided for the manual initiation of an independent backup system which can shut the reactor down from rated power to the cold condition in the event that all withdrawn control rods cannot be inserted to achieve reactor shutdown.

7.1.1.4.3 Residual Heat Removal (RHR) System / Shutdown Cooling Mode

Instrumentation and controls provide manual initiation of cooling systems to remove the decay and sensible heat from the reactor vessel.

FIGURE 7.3-5 LEAK DETECTION & ISOLATION SYSTEM IBD

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7.3-104.8	20	7.3-104.47	20
7.3-104.9	20	7.3-104.48	20
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7.3-104.12	20	7.3-104.51	20
7.3-104.13	20	7.3-104.52	20
7.3-104.14	20	7.3-104.53	20
7.3-104.15	20	7.3-104.54	20
7.3-104.16	20	7.3-104.55	20
7.3-104.17	20	7.3-104.56	20
7.3-104.18	20	7.3-104.57	20
7.3-104.19	20	7.3-104.58	20
7.3-104.20	20	7.3-104.59	20
7.3-104.21	20	7.3-104.60	20
7.3-104.22	20	7.3-104.61	20
7.3-104.23	20	7.3-104.62	20
7.3-104.24	20	7.3-104.63	21
7.3-104.25	20	7.3-104.64	21
7.3-104.26	20	7.3-104.65	20
7.3-104.27	20	7.3-104.66	20
7.3-104.28	20	7.3-104.67	20
7.3-104.29	20	7.3-104.68	20
7.3-104.30	2[illegible]	7.3-104.69	20
7.3-104.31	[illegible]	7.3-104.70	20
7.3-104.32	2[illegible]	7.3-104.71	20
7.3-104.33	[illegible]	7.3-104.72	20
7.3-104.34	20	7.3-104.73	20
7.3-104.35	20	7.3-104.74	20
7.3-104.36	20	7.3-104.75	20
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(b) The following nuclear boiler instrumentation is provided on the remote shutdown control panels as indicated:

(i) reactor water level wide range indication (A, B)

(ii) reactor water level shutdown range indication (A, B)

(iii) reactor pressure indication (A,B)

(5) Reactor Building Cooling Water (RCW) System

(a) The following functions have transfer and control switches located on the remote shutdown panels as indicated:

(i) RCW Pumps (A,E and B,D)

(ii) RCW heat exchanger cooling water outlet valves (A,E and B,D)

(iii) RCW RHR heat exchanger outlet valve (A,B)

(iv) RCW diesel generator outlet valve (A,E and B,D)

(v) RCW supply side separator valve (A,B)

(b) RCW loop flow A,B indication is provided on the RSS panels.

(6) Reactor Service Water System (RSW)

(a) The following functions have transfer and control switches located on the remote shutdown panels as indicated:

(i) RSW Pumps (A,E and B,D)

(ii) RCW heat exchanger sea water inlet valve (A,E and B,D)

(iii) RCW RHR heat exchanger strainer inlet valve (A,E and B,D)

(iv) RCW heat exchanger sea water outlet valve (A,E and B,D)

(7) Electrical Power Distribution System (EPDS)

(a) The following functions have transfer and control switches located on the Division I remote shutdown panel:

(i) 6.9Kv M/C diesel generator (A) incoming breaker

(ii) 6.9Kv M/C C bus tie to S(A,B)-2 breakers

(iii) 6.9Kv M/C C power train C-1,2 feeder breakers

(iv) 480V P/C C-1,2 incoming breakers

(v) 480V P/C C-1 bus tie to D-1 breaker

(b) The following functions have transfer and control switches located on the Division II remote shutdown panel:

(i) 6.9Kv M/C diesel generator (B) incoming breaker

(ii) 6.9Kv M/C D bus tie to S(A,B)-2 breakers

(iii) 6.9Kv M/C D power train D-1,2 feeder breakers

(iv) 480V P/C D-1,2 incoming breakers

(v) 480V P/C D-1 bus tie to C-1 breaker

(c) A 6.9Kv M/C (C,D) voltmeter is provided on RSS panels A,B, respectively.

(8) Flammability Control System (FCS)

(a) The following FCS system equipment function has transfer and control switches located on both remote shutdown panels as indicated:

(i) valve (cooling water inlet) A, B

(9) Atmospheric Control (AC) System

(a) The following AC system equipment functions have transfer and control switches located on both remote shutdown panels as indicated:

(i) suppression pool temperature (A, B)

(ii) suppression pool level (A,B)

(10) Makeup Water Condensate System (MUWC)

(a) The following MUWC system equipment function has transfer and control switches located on the Division II remote shutdown panel as indicated:

(i) condensate storage pool level (B)

(11) Emergency Diesel Generator (DG) System

(a) The following DG system equipment functions have transfer and control switches located on corresponding remote shutdown panels as indicated:

(i) diesel generator run/stop (A)

(ii) diesel generator run/stop (B)

7.4.2 Analysis

7.4.2.1 Alternate Rod Insertion Function

7.4.2.1.1 General Functional Requirements Conformance

The alternate rod insertion (ARI) function is accomplished by the rod control and information system (RC&IS) and the fine-motion control rod drive (FMCRD) subsystem. This function provides an alternate method of driving control rods into the core which is diverse from the hydraulic scram system.

The RC&IS and the active run-in function of the FMCRD motors are not required for safety, nor are these components qualified in accordance with safety-related criteria. However, the FMCRD components associated with hydraulic scram are qualified in accordance with safety criteria.

The subsystem's inherent diversity provides mitigation of the consequences of ATWS (anticipated transient without scram) events. This capability is discussed in Subsection 7.7.1.2.2.

7.4.2.1.2 Specific Regulatory Requirements Conformance

Table 7.1-2 identifies the alternate rod insertion (ARI) function and the associated codes and standards applied. In addition to GDCs 13 and 19 (applied to non-safety-related system/functions in accordance with the SRP, Section 7.7), GDC 25 and Reg Guide 1.75 are also addressed relative to the shutdown characteristics of the subsystem and its interface with the essential power buses. The following analysis lists the applicable criteria in order of the listing on the table, and discusses the degree of conformance for each. Any exceptions or clarifications are so noted.

(1) 10CFR50.55a (IEEE 279)

Although the ARI is not Class 1E, the portions of the FMCRD used for the hydraulic scram function are qualified as Class 1E. These functions are analyzed along with the reactor protection (trip) system discussed in Section 7.2.

With regard to IEEE 279, Section 4.7, signals which interface between ARI and RPS are optically isolated such that postulated failures within the ARI controls cannot affect the safety-related scram function.

The RC&IS logic has been designed such that no single failure results in failure to insert more than one operable control rod when the ARI function is activated. Also, two manual actions are required at the dedicated operators panel to manually initiate ARI.

(2) General Design Criteria (GDC)

(a) Criteria: GDCs 13, 19, and 25.

(b) Conformance: The ARI is in compliance

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Figure 7.7-12 STEAM BYPASS AND PRESSURE CONTROL SYSTEM IED, SHEET 3

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CHAPTER 8

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SECTION 8.1

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8.1 INTRODUCTION

8.1.1 Utility Grid Description

The description of the utility grid system is out of the ABWR Standard Plant scope, however there are interface requirements contained in Section 8.2.3.1 which must be complied with by the Utility.

8.1.2 Electric Power Distribution System

8.1.2.1 Description of Offsite Electrical Power System

The scope of the offsite electrical power system includes the entire system from the termination of the transmission lines coming into the switchyard to the termination of the bus duct at the terminals of the main generator and at the input terminals of the circuit breakers for the 7.2KV switchgear. The applicant has design responsibility for portions of the offsite power system. The scope split is as defined in the detailed description of the offsite power system in Section 8.2.1.1.

The 1500MVA main power transformer is a bank of three single phase transformers. One single phase installed spare transformer is provided.

A generator breaker capable of interrupting the maximum available fault current is provided. This allows the generator to be taken off line and the main grid to be utilized as a power source for the unit auxiliary transformers and their loads, both Class 1E and non-Class 1E. This is also the start-up power source for the unit.

There are three unit auxiliary transformers, connected to supply power to three approximately equal load groups of equipment. The "Normal Preferred" power feed is from the unit auxiliary transformers so that there normally are no bus transfers required when the unit is tripped off the line.

One, three-winding 37.5 MVA unit reserve auxiliary transformer is supplied to provide power via one winding for the emergency buses as an alternate to the "Normal Preferred" power. The other secondary winding supplies reserve power to the non-safety-related buses in the turbine building. This is truly a reserve transformer because unit startup is accomplished from the normal preferred power, which is backfed from the offsite power grid over the main power circuit to the unit auxiliary transformers. The two low voltage windings of the reserve transformer are rated 18.75 MVA each.

8.1.2.2 Description of Onsite AC Power Distribution System

Three turbine building non-safety-related buses per load group and one reactor building safety-related bus per division receive power from the single unit auxiliary transformer assigned to each load group. Load groups A, B and C line up with Divisions I, II and III, respectively. One winding of the reserve auxiliary transformer may be utilized to supply reserve power to each of the non-safety-related buses either directly or indirectly through bus tie breakers. The three safety-related buses may be supplied power from the other winding of the reserve auxiliary transformer.

A combustion turbine generator supplies standby power to permanent non-safety-related loads in the turbine building. These loads are grouped on one of the 6.9KV buses per load group. A power supply bus is also provided from the combustion turbine to the three Class 1E medium voltage buses in the reactor building via breakers that are normally racked out for Divisions I and III and remote manually closed under administrative control for Division II.

In general, motors larger than 300 KW are supplied from the 6.9Kv bus. Motors 300KW or smaller but larger than 100KW are supplied power from 480V power center switchgear. Motors 100KW or smaller are supplied power from 480V motor control centers. The 6.9KV and 480V single line diagrams are shown in Figure 8.3-1.

During normal plant operation all of the non-Class 1E buses and two of the Class 1E buses are supplied with power from the turbine generator through the unit auxiliary transformers. The third Class 1E bus is supplied from the reserve transformer. This third division is immediately available, without a bus transfer, if the normal preferred power is lost to the other two divisions.

Three diesel generator standby ac power supplies provide a separate onsite source of power for each Class 1E load group when normal or alternate preferred power supplies are not available. The transfer from the normal preferred or alternate preferred power supplies to the diesel generator is automatic. The transfer back to the normal preferred or the alternate preferred power source is a manual transfer.

The Division I, II, and III standby ac power supplies consist of an independent 6.9Kv Class 1E diesel generator, one for each division. Each DG may be connected to its respective 6.9Kv Class 1E switchgear bus through a main circuit breaker located in the switchgear.

The standby ac power system is capable of providing the required power to safely shutdown the reactor after loss of preferred power (LOPP) and/or loss of coolant accident (LOCA) or to maintain the safe shutdown condition and operate the Class 1E auxiliaries necessary for plant safety during and after shutdown with any one of the three power load groups.

The plant 480 VAC auxiliary power system distributes sufficient power for normal auxiliary and Class 1E 480 volt plant loads. All Class 1E elements of the auxiliary power distribution system are supplied via the 6.9Kv Class 1E switchgear and, therefore, are capable of being fed by the normal preferred, alternate preferred, standby or combustion turbine generator power supplies.

The 120 VAC non-Class 1E instrumentation power system, Figure 8.3-4, provides power for non-Class 1E control and instrumentation loads.

The Class 1E 120 VAC instrument power system, Figure 8.3-4, provides for Class 1E plant controls and instrumentation. The system is separated into Divisions I, II and III with distribution panels fed from their respective divisional sources.

The 125V dc power distribution system provides four independent and redundant onsite battery sources of power for operation of Class 1E dc loads. The 125V dc non-Class 1E power is supplied from three 125V dc batteries located in the turbine building. A separate non-Class 1E 250V battery is provided to supply uninterruptible power to the plant computers and non-Class 1E dc motors.

The safety system and logic control (SSLC) for RPS and MSIV derives its power from four uninterruptible 120 VAC buses. The SSLC for the ECCS derives its power from the four divisions of 125V dc buses. The four buses provide the redundancy for various instrumentation, logic and trip circuits and solenoid valves. The SSLC power supply is further described in Subsection 8.1.3.1.1.2.

8.1.2.3 Safety Loads

The safety loads utilize various Class 1E ac and/or dc sources for instrumentation and motive or control power or both for all systems required for safety. Combinations of power sources may be involved in performing a single safety function. For example, low voltage dc power in the control logic may provide an actuation signal to control a 6.9kV circuit breaker to drive a large ac-powered pump motor. The systems required for safety are listed below:

(1) Safety System Logic and Control Power Supplies including the Reactor Protection System

(2) Core and Containment Cooling Systems

(a) Residual Heat Removal System (RHR)

(b) High Pressure Core Flooder (HPCF) System

(c) Automatic Depressurization System (ADS)

(d) Leak Detection and Isolation System (LDS)

(e) Reactor Core Isolation Cooling System (RCIC)

(3) ESF Support Systems

(a) Diesel generator Sets and Class 1E ac/dc power distribution systems.

(b) HVAC Emergency Cooling Water System (HECW)

(c) Reactor Building Cooling Water (RCW) System

(d) Spent Fuel Pool Cooling System

(e) Standby Gas Treatment System (SGTS)

(f) Reactor Building Emergency HVAC System

(g) Control Building HVAC System

(h) High Pressure Nitrogen Gas Supply System

(4) Safe Shutdown Systems

(a) Standby Liquid Control System (SLCS)

(b) Nuclear Boiler System

(i) Safety/Relief Valves (SRVs)
(ii) Steam Supply Shutoff Portion

(c) Residual Heat Removal (RHR) system decay heat removal

(5) Essential Monitoring Systems

(a) Neutron Monitoring System

(b) Process Radiation Monitoring System

(c) Containment Atmosphere Monitoring System

(d) Suppression Pool Temperature Monitoring System

For detailed listings of Division I, II and III loads, see Tables 8.3-1 and 8.3-2.

8.1.3 Design Bases

8.1.3.1 Safety Design Bases--Onsite Power

8.1.3.1.1 General Functional Requirements

8.1.3.1.1.1 Onsite Power Systems--General

The unit's total safety-related load is divided into three divisions of load groups. Each load group is fed by an independent 6.9Kv Class 1E bus, and each load group has access to one onsite and two offsite power sources. An additional onsite power source is provided by the combustion turbine generator (CTG).

Each of the two normally energized power feeders are provided for the Divisions I, II and III Class 1E systems. Normally two load groups are fed from the normal preferred power source and the third load group is fed from the alternate preferred power source. Both feeders are used during normal plant operation to prevent simultaneous deenergization of all divisional buses on the loss of only one of the offsite power supplies. The transfer to the alternate preferred feeder is manual. During the interim, power is automatically supplied by the diesel generators.

The redundant Class 1E electrical load groups (Divisions I, II, and III) are provided with separate onsite standby ac power supplies, electric buses, distribution cables, controls, relays and other electrical devices. Redundant parts of the system are physically separated and independent to the extent that in any design basis event with any resulting loss of equipment, the plant can still be shut down with either of the remaining two divisions. Independent raceway systems are provided to meet load group cable separation requirements for Divisions I, II, and III.

Divisions I, II, and III standby ac power supplies have sufficient capacity to provide power to all their respective loads. Loss of the normal preferred power supply, as detected by 6.9Kv Class 1E bus under-voltage relays, will cause the standby power supplies to start and connect automatically, in sufficient time to maintain the reactor in a safe condition, safely shut down the reactor or limit the consequences of a design basis accident (DBA) to acceptable limits. The standby power supplies are capable of being started and stopped manually and are not to be stopped automatically during emergency operation unless required to preserve integrity. Automatic start will also occur on receipt of a level 1 1/2 signal (HPCF initiate), level 1.0 signal (RHR initiate) and high drywell pressure.

The Class 1E 6.9Kv Divisions I, II, and III switchgear buses, and associated 6.9Kv diesel generators, 480 VAC distribution systems, 120 VAC and 125 VDC power and control systems conform to Seismic Category I requirements and are housed in Seismic Category I structures. Seismic Qualification is in accordance with IEEE Standard 344. (See Section 3.10)

8.1.3.1.1.2 SSLC (Safety System Logic and Control) Power Supply System Design Bases

In order to provide redundant, reliable power of acceptable quality and availability to support the safety logic and control functions during normal, upset and accident conditions, the following design bases apply:

(1) SSLC power has four separate and independent Class 1E inverter constant voltage constant frequency (CVCF) power supplies each backed by separate Class 1E batteries.

(2) Provision is made for automatic switching to the alternate bypass supply from its division in case of a failure of the inverter power supply. The inverter power supply is synchronized in both frequency and phase with the alternate bypass supply, so that unacceptable voltage spikes will be avoided in case of an automatic transfer from normal to alternate supply. The SSLC uninterruptible power supply complies with IEEE Std. 944.

8.1.3.1.2 Regulatory Requirements

The following list of criteria is addressed in accordance with Table 8.1-1 which is based on Table 8-1 of the Standard Review Plan. In general, the ABWR is designed in accordance with all criteria. Any exceptions or clarifications are so noted.

8.1.3.1.2.1 General Design Criteria

(1) GDC 2 - Design Bases for Protection against Natural Phenomena;

(2) GDC 4 - Environmental and Missile Design Bases;

(3) GDC 5 - Sharing of Structures, Systems and Components;

The ABWR is a single-unit plant design. Therefore, this GDC is not applicable.

(4) GDC 17 - Electric Power Systems;

(5) GDC 18 - Inspection and Testing of Electrical Power Systems;

(6) GDC 50 - Containment Design Base .

8.1.3.1.2.2 NRC Regulatory Guides

(1) RG 1.6 - Independence Between Redundant Standby (Onsite) Power Sources and Between Their Distribution Systems;

(2) RG 1.9 - Selection, Design and Qualification of Diesel generator Units Used as Standby (Onsite) Electric Power Systems at Nuclear Power Plants;

(3) RG 1.32 - Criteria for Safety-Related Electric Power Systems for Nuclear Power Plants;

(4) RG 1.47 - Bypassed and Inoperable Status Indication for Nuclear Power Plant Safety Systems;

(5) RG 1.63 - Electric Penetration Assemblies in Containment Structures for Light-Water-Cooled Nuclear Power Plants;

(6) RG 1.75 - Physical Independence of Electric Systems;

Isolation between Class 1E power supplies and non-Class 1E loads is discussed in Subsection 8.3.1.1.1.

(7) RG 1.81 - Shared Emergency and Shutdown Electric Systems for Multi-Unit Nuclear Power Plants;

The ABWR is designed as a single-unit plant. Therefore, this Regulatory Guide is not applicable.

(8) RG 1.106 - Thermal Overload Protection for Electric Motors on Motor-Operated Valves;

(9) RG 1.108 - Periodic Testing of Diesel Generator Units Used as Onsite Electric Power Systems at Nuclear Power Plants;

(10) RG 1.118- Periodic Testing of Electric Power and Protection Systems;

(11) RG 1.153- Criteria for Power, Instrumentation, and Control Portions of Safety Systems;

(12) RG 1.155- Station Blackout

8.1.3.1.2.3 Branch Technical Positions

(1) BTP ICSB 4 (PSB) - Requirements on Motor-Operated Valves in the ECCS Accumulator Lines;

This BTP is written for Pressurized Water Reactor (PWR) plants only and is therefore not applicable to the ABWR.

(2) BTP ICSB 8 (PSB) - Use of Diesel generator Sets for Peaking;

The diesel generator sets are not used for peaking in the ABWR design. Therefore, this criteria is satisfied.

(3) BTP ICSB 11 (PSB) - Stability of Offsite Power Systems;

(4) BTP ICSB 18 (PSB) - Application of the Single Failure Criterion to Manually-Controlled Electrically-Operated Valves;

(5) BTP ICSB 21 - Guidance for Application of Regulatory Guide 1.47;

(6) BTP PSB 1 - Adequacy of Station Electric Distribution System Voltages;
[See Subsection 8.3.1.1.7 (8)]

(7) BTP PSB 2 - Criteria for Alarms and Indications Associated with Diesel- Generator Unit Bypassed and Inoperable Status;

8.1.3.1.2.4 Other SRP Criteria

(1) NUREG/CR 0660 - Enhancement of Onsite Diesel Generator Reliability;

Operating procedures and the training of personnel are outside the scope of the ABWR Standard Plant. NUREG/CR 0660 is therefore imposed as an interface requirement for the applicant. See Subsection 8.1.4.2 for interface requirement.

(2) TMI Action Item II.E.3.1. - Emergency Power Supply for Pressurizer Heater;

This criteria is applicable only to PWRs and does not apply to the ABWR.

(3) TMI Action Item II.G.1-Emergency Power for Pressurizer Equipment;

This criteria is applicable only to PWRs and does not apply to the ABWR.

8.1.4 COL License Information

8.1.4.1 Diesel Generator Reliability

NUREG/CR 0660 pertaining to the enhancement of onsite diesel generator reliability through operating procedures and training of personnel will be addressed by the applicant (see Subsection 8.1.3.1.2.4(1)).

8.1.5 References

IEEE Std 944, Recommended Practice for the Application and Testing of Uninterruptible Power Supplies for Power Generating Stations.

TABLE 8.1-1

ON SITE POWER SYSTEM SRP CRITERIA APPLICABLE MATRIX

APPLICABLE CRITERIA	REF. IEEE STD	Offsite Power System	AC PowerSystems (Onsite)	DC Power Systems (Onsite)
GDC 2			X	X
GDC 4			X	X
GDC 5**				
GDC 17		X	X	X
GDC 18		X	X	X
GDC 50			X	X
RG 1.6			X	X
RG 1.9	387		X	
RG 1.32	308	X	X	X
RG 1.47		X	X	X
RG 1.63	317		X	X
RG 1.75	384		X	X
RG 1.81**				
RG 1.106			X	X
RG 1.108			X	
RG 1.118	338		X	X
RG 1.128	484			X
RG 1.129	450			X
RG 1.153	603		X	X
RG 1.155***	NUMARK 8700		X	X
BTP ICSB 4*	279			
BTP ICSB 8	308		X	
BTP ICSB 11		X		
BTP ICSB 18			X	
BTP ICSB 21		X	X	X
BTP PSB 1			X	
BTP PSB 2			X	
NUREG CR0660			X	
II. E. 3.1*				
II. G. 1*				

* PWR only; not applicable to ABWR

** Multi-unit plants only; not applicable to single-unit ABWR

*** See Subsection 19E.2.1.2.2

SECTION 8.2

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8.2 OFFSITE POWER SYSTEMS

8.2.1. Description

8.2.1.1 Scope

This section provides a description of the system design and the performance requirements for the offsite power system. The offsite power system consists of the electrical circuits and associated equipment for interconnection to the offsite transmission system, the plant main generator, and the onsite power distribution systems. Included are the plant switchyards, the main step-up transformers, the unit auxiliary transformers, the reserve transformer, the high voltage tie lines from the switchyards to the transformers, the isolated phase buses with their auxiliary systems including relays and local instrumentation and controls, and the non-segregated phase bus ducts from the unit auxiliary and reserve transformers to the medium voltage switchgear.

The offsite power system includes the transmission system and the switchyard. It ends at the terminals of the plant main generator and at the circuit breaker input terminals of the medium voltage (7.2kV) switchgear. The design scope for the standard plant ends at the low voltage terminals of the main power transformer and the high voltage terminals of the reserve auxiliary transformer. Although the transmission system and switchyard are not in the scope of the standard plant design, the standard plant design is based on a transmission system and switchyard which meet certain design concepts. Design bases (10CFR Part 52 interface requirements) consistent with these concepts are included in Section 8.2.3 for COL applicant. Meeting the stated design bases will ensure that the total power system design is consistent and meets all regulatory requirements.

The portions of the offsite power system which fall under the design responsibility of the COL applicant will be unique to each COL application. It is the responsibility of all concerned parties to insure that the total completed design of equipment and systems falling within the scope of this SSAR section be in line with the description and requirements stated in this SSAR, however. See Section 8.2.3 for a detailed listing and description of the design bases requirements.

8.2.1.2 Description of Offsite Power System

The offsite electrical power system within the scope of the ABWR standard design consists of the isolated phase bus duct up to the low voltage terminals of the main power transformer, isolated phase bus duct to the unit auxiliary transformers, a low voltage generator breaker, three unit auxiliary transformers, a reserve auxiliary transformer, and 6.9kV connections from the unit auxiliary and reserve transformers to the input terminals of the medium voltage (7.2kV, 500MVA) switchgear, as indicated on the single line diagram, Figure 8.3-1. The main power transformer, the high voltage leads to the switchyards, the switchyards and the auxiliary equipment for those portions of the system are in the scope of the applicant.

Air cooled isolated phase bus duct rated 36kA is provided for a power feed to the main power transformer.

A generator breaker is provided in the isolated phase bus duct at an intermediate location between the main generator and the main power transformer. The generator breaker provided is capable of interrupting a maximum fault current of 275kA symmetrical and 340kA asymmetrical at 5 cycles after initiation of the fault. This corresponds to the maximum allowable interface fault current specified in Section 8.2.3. The low voltage generator breaker allows the generator to be taken off line and the main grid to be utilized as a power source by backfeeding to the unit auxiliary transformers and their loads, both Class 1E and non-Class 1E. This is also the start-up power source for the unit.

Unit sychronization will normally be through the low voltage generator breaker. A coincidental three-out-of-three logic scheme and synchrocheck relays are used to prevent faulty synchronizations. Dual trip coils are provided on the breaker and control power is supplied from redundant load groups of the non-safety-related onsite 125V DC power.

It is a design bases requirement that synchronization be possible through the switching station's circuit breakers (See Section 8.2.3).

There are three unit auxiliary transformers. The transformers have three windings and each transformer feeds one Class 1E bus directly, two non-Class 1E buses directly, and one non-Class 1E bus indirectly through a non 1E to non 1E bus tie. The medium voltage buses are in a three load group arrangement with three non-safety-related buses and one safety-related bus per load group. Each unit auxiliary transformer has an oil/air rating at 65 degrees centigrade of 37.5Mva for the primary winding and 18.75Mva for each secondary winding. The forced air/forced oil rating is 62.5 and 31.25/31.25Mva respectively. The normal loading of the six transformers is balanced with the heaviest loaded winding carrying a load of 17.7Mva The heaviest transformer loading occurs when one of the three unit auxiliary transformers is out of service with the plant operating at full power. Under these conditions the heaviest loaded winding experiences a load of 21.6Kva, which is about two thirds of its forced air/forced oil rating. See Table 8.2-1 for a more detailed summary of the loads.

Disconnect links are provided in the isolated phase bus duct feeding the unit auxiliary transformers so that any single failed transformer may be taken out of service and operation continued on the other two unit auxiliary transformers. One of the buses normally fed by the failed transformer would have to be picked up on the reserve auxiliary transformer in order to keep all reactor internal pumps operating so as to attain full power. The reserve auxiliary transformer is sized for this type of service.

One, three-winding 37.5MVA unit reserve transformer is supplied to provide power as an alternate to the "Normal Preferred" power. One of the equally rated secondary windings supplies reserve power to the nine (three through cross-ties) non-safety-related buses and the other winding supplies reserve power to the three safety-related buses. The combined load of the three safety-related buses is equal to the oil/air the rating of the transformer winding serving them. This is equal to 60% of the forced air/forced oil rating of the transformer winding. The transformer is truly a reserve transformer because unit startup is accomplished from the normal preferred power, which is backfed over the main power circuit to the unit auxiliary transformers. The reserve auxiliary transformer serves no startup function.

8.2.1.3 Separation

The location of the main transformer, unit auxiliary transformers, and reserve auxiliary transformer are shown on Figure 8.2-1. The reserve auxiliary transformer is separated from the unit auxiliary transformers by a minimum distance of 50 feet. It is a requirement that the 50 foot minimum separation be maintained by the incoming tie lines, also. The transformers are provided with oil collection pits and drains to a safe disposal area.

Reference is made to Figures 8.3-1 for the single line diagrams showing the method of feeding the loads. Separation of the normal preferred and alternate preferred power feeds is accomplished by floors and walls over their routes through the turbine, control and reactor buildings except within the switchgear rooms where they must be routed to the same switchgear lineups. The normal preferred feeds are routed around the outside of the turbine building in an electrical tunnel from the unit auxiliary transformers to the turbine building switchgear rooms as shown on Figure 8.2-1. (An underground duct bank is an acceptable alternate.) From there the feeds to the reactor building exit the turbine building and continue across the roof on the Divisions 1 and 3 side of the control building (Figure 8.3-1). They drop down the side of the control building in the space between the control and reactor buildings where they enter the reactor building and continue on through the Divisions I and III side of the reactor building to the respective safety-related switchgear rooms in the reactor building.

The alternate preferred feeds from the reserve auxiliary transformer are routed inside the turbine building. The turbine building switchgear feed from the reserve auxiliary transformer is routed directly to the turbine building switchgear rooms. The feed to the control building is routed in corridors outside of the turbine building switchgear rooms. It exits the turbine building and crosses the control building roof on the opposite side of the control building from the route for the normal preferred power feeds. The steam tunnel is located between the normal preferred feeds and the alternate preferred feeds across the stepped roof of the control building. The alternate preferred power feed turns down between the control and reactor building and enters the reactor building on the Division II side of the reactor building. From there it continues on to the respective switchgear rooms in the reactor building.

Instrument and control cables for the unit auxiliary transformer are to be routed in solid metal raceways and separate from the normal preferred power cable raceways by a separation that is equivalent to that provided for the power feeds. The reserve auxiliary cables may not share raceways with any other cables, however. The instrumentation and controls for the unit auxiliary transformers and generator breaker may be routed in the raceways corresponding to the load group of their power source.

A combustion turbine supplies standby power to the non-safety-related turbine building buses which supply the permanent non-safety-related loads. It is a 9MW rated self-contained unit which is capable of operation without external auxiliary systems. Although it is located on site, it is treated as an additional offsite source in that it supplies power to multiple load groups of electrical buses.

Manually controlled breakers provide the capability of connecting the combustion turbine generator to any one of the emergency buses if all other power sources are lost.

The location of the combustion turbine generator (CTG) is shown on Figure 8.2-1. The CTG standby power feed for the turbine building is routed directly to the switchgear rooms in the turbine building. The branch to the reactor building is routed adjacent to the alternate preferred feeds across the control and reactor buildings.

8.2.2 Analysis

In accordance with the NRC Standard Review Plan (NUREG 0800), Table 8-1 and Section 8.2, the offsite power distribution system is designed consistent with the following criteria, so far as it applies to the non-Class 1E equipment. Any exceptions or clarifications are so noted.

8.2.2.1 General Design Criteria

(1) GDC 5 and RG 1.81 - Sharing of Structures, Systems and Components;

The ABWR is a single unit plant design. Therefore, these criteria are not applicable.

(2) GDC 17 - Electric Power Systems;

As shown in Figure 8.3-1, each of the Class 1E divisional 6.9 kV M/C buses can receive power from multiple sources. There are separate utility feeds from the station grid (via the main transformer), and the offsite line (via the reserve auxiliary transformer). The unit auxiliary transformer output power feeds and the reserve auxiliary transformer output power feeds are routed by two completely separate paths through the turbine building, control building and reactor building to their destinations in the emergency electrical rooms. Although these load groups are non-Class 1E, such separation assures the physical independence requirements of GDC 17 are preserved.

The transformers are provided with oil collection pits and drains to a safe disposal area. This separation meets the requirements of BTP CMEB 9.5-1 and is therefore deemed adequate.

(3) GDC 18 - Inspection and Testing of Electrical Power Systems;

The low voltage generator breaker must open on a turbine trip to maintain the normal preferred power supply to the safety buses. This breaker cannot be tested during normal operation of the plant. Generator breakers are extremely reliable. There are published test results showing a reliability number of 0.9967 for 50 close operations per year. This compares favorably with the probability of failure from other causes of the normal preferred power supply.

All other equipment can either be tested during normal plant operation or it is continually tested by virtue of its operation during normal plant operation and it remaining in the same state to supply normal preferred power to the safety buses following a turbine trip.

(4) RG's 1.32, 1.47, and BTP ICSB 21;

These distribution load groups are non-Class 1E and non-safety related. Therefore, this criteria is not applicable.

(5) RG 1.153--Criteria For Power, Instrumentation and Control Portions of Safety Systems

(6) RG 1.155--Station Blackout

(7) BTP ICSB 11 (PSB) - Stability of Offsite Power Systems;

(8) Appendix A to SRP Section 8.2

It is a requirement that the design, testing and installation of the low voltage generator breaker meet the specific guidelines of this appendix, therefore compliance with the appendix is assured.

(9) IEEE Std 765, IEEE Standard for Preferred Power Supply for Nuclear Powered Generating Stations

It is a requirement that the total design provided by GE and the applicant meet the requirements of this IEEE standard as modified by the following specific additional requirements and explanatory statements in Table 8.2-2. The additional requirements are more restrictive than the requirements which they replace or modify from the IEEE standard. Any stated requirements in the SSAR which are in conflict with the requirements stated in this standard take precedence over the requirements of the standard.

8.2.3 Design Bases (Interface Requirements)

The standard design of the ABWR is based on certain assumptions concerning the design bases which will be met by the COL applicant in designing the portion of the offsite power system in his scope, as defined in Section 8.2.1.1. Those design bases assumptions are listed here which the COL applicant should meet.

(1) In case of failure of the normal preferred power supply circuit, alternate preferred power should normally remain available to the reserve auxiliary transformer.

(2) Voltage variations shall be no more than plus or minus 10 percent of their nominal value during normal steady state operation. Their should be a voltage dip of no more than 20 percent during motor starting. It is expected that the sizing of the unit auxiliary and reserve auxiliary transformers, (see Section 8.2.1.2) will insure that this voltage dip requirement is met.

(3) Maintain the normal steady state frequency of the power system within plus or minus 2 cycles per second of 60 cycles per second during recoverable periods of system instability.

(4) Analyze the site specific configuration of the incoming power lines to assure that the expected availability of the offsite power is as good as the assumptions made in performing the plant probability risk analysis. If, during this analysis, it is determined that the availability of the power from the alternate preferred power source is significantly less reliable than the normal preferred power, normal operation of all plant buses from the normal preferred power source is acceptable and recommended.

(5) The main and reserve offsite power circuits shall be electrically independent and physically separated. They shall be connected to switching stations which are independent and separate. They shall be connected to different transmission systems.

(6) The switching station to which the main offsite power circuit is connected shall have at least two full capacity main buses arranged such that:

(a) Any incoming or outgoing transmission line can be switched without affecting another line;

(b) Any single circuit breaker can be isolated for maintenance without interrupting service to any circuit;

(c) Faults of a single main bus are isolated without interrupting service to any circuit.

(7) The main power transformer shall be three normally energized single-phase transformers with an additional installed spare. Provisions shall be made to permit connecting and energizing the spare transformer in no more than 12 hours following a failure of one of the normally energized transformers.

(8) The main transformer shall be designed to meet the requirements of ANSI Standard C57.12.00, General Requirements for Liquid-Immersed Distribution, Power and Regulating Transformers.

(9) Physical separation between transformers and oil collection shall be provided as stated for fire protection in Section 9A.4.6.

(10) Circuit breakers and disconnect switches shall be sized and designed in accordance with the latest revision of ANSI Standard C37.06, Preferred Ratings and Related Capabilities for AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis.

(11) Although unit synchronization is normally through the low voltage generator circuit breaker, provisions shall be made to synchronize the unit through the switching station's circuit breakers. This makes it possible to re-synchronize with the system following a load rejection within the steam bypass capability of the generating unit.

(12) All relay schemes used for protection of the offsite power circuits and of the switching station's equipment shall be redundant and include backup protection features. All breakers shall be equipped with dual trip coils. Each redundant protection circuit which supplies a trip signal shall be connected to a separate trip coil. All equipment and cabling associated with each redundant system shall be physically separated.

(13) The dc power needed to operate redundant protection and control equipment of the offsite power system shall be supplied from two separate, dedicated switchyard batteries, each with a battery charger fed from a separate ac bus. Each battery shall be capable of supplying the dc power required for normal operation of the switching station's equipment.

(14) Two redundant low voltage ac power supply systems shall be provided to supply ac power to the switching station's auxiliary loads. Each system shall be supplied from separate, independent ac buses. The capacity of each system shall be adequate to meet the ac power requirements for normal operation of the switching station's equipment.

(15) Each transformer shall have primary and backup protective devices. DC power to the primary and backup devices shall be supplied from separate dc sources.

(16) The requirements of IEEE Std 765, Preferred Power Supply for Nuclear Generating Stations, as modified by Section 8.2.2.1(9) of this SSAR shall be met.

8.2.4 Scope Split (Interfaces Requirements)

The interface point between the ABWR design and the COL applicant design for the main generator output is at the connection of the isolated phase bus to the main power transformer low voltage terminals. The rated conditions for this interface is 1500 MVA at a power factor of 0.9 and a voltage of 26.325 kV plus or minus 10 per cent. It is a requirement that the COL applicant provide sufficient impedance in the main power transformer and the high voltage circuit to limit the primary side maximum available fault current contribution from the system to no more than 275 kA symmetrical and 340 kA asymmetrical at 5 cycles from inception of the fault. These values should be acceptable to most COL applicants. When all equipment and system parameters are known, a refined calculation based on the known values with a fault located at the generator side of the generator breaker may be made. This may allow a lower impedance for the main power transformer, if desired.

The second power scope split interface occurs at the high voltage terminals of the reserve auxiliary transformer. The rated load is 37.5 MVA at a 0.9 power factor. The voltage and frequency will be the COL applicants standard with the actual values to be determined at contract award. Tolerances are plus or minus 10 per cent of nominal for voltage and plus or minus 2 per cent of nominal for frequency. Frequency may vary plus or minus 2 cycles per second during periods of recoverable system instability. The maximum allowable voltage dip during the starting of large motors is 20 %.

Protective relaying scope split interfaces for the two power system interfaces are to be defined during the detail design phase following contract award.

8.2.5 References

(1) ANSI Std C37.06, Preferred Ratings and Related Capabilities for AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis.

(2) ANSI Std C57.12.00, General Requirements for Liquid-Immersed Distribution, Power and Regulating Transformers.

Table 8.2-1
ADDITIONAL REQUIREMENTS
IEEE STD 765

IEEE STD765 Reference	Requirement or Explanatory Note
4.1 General	SSAR Figure 8.3-1 should be used as the reference single line instead of the IEEE Std example, Figures 2, (a), (b) and (c).
4.2 Safety Classification	The redundancy, independence, separation and application of single failure criteria called for in this chapter of the SSAR must be met.
4.3 Function	The ABWR design utilizes direct connection of the two preferred power circuits to the Class 1E buses. One circuit automatically supplies power to the Class 1E buses following an accident.
5.1.2 Transmission System Reliability	Additional analysis is required per Section 8.2.3.1.
5.1.3 Transmission System Independence	
5.1.3.2	Specific requirements for tolerance to equipment failures are stated in the SSAR and must be met.
5.1.3.3	Since a separation of at least 50 feet is required for the exposed circuits, it is not likely that a common takeoff structure will be used.
5.3.2 Class 1E Power System Interface Independence	See 5.1.3.3 comments.
5.3.3 Connections with Class 1E Systems	
5.3.3.2	Manual and automatic dead-bus transfers are used. Automatic live-bus transfers are not required and are not used.
5.3.3.3	Only standby power sources may be paralleled with the preferred power sources for load testing. The available fault current must be less than the rating of the breakers. It is not required and not allowed for the normal and alternate preferred power supply breakers for a bus to be closed simultaneously so there is no time that the available fualt current at a bus exceeds the equipment rating.
7.0 Multi-Unit Considerations	The ABWR is a single unit design, therefore there is no sharing of preferred power supplies between units.

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8.3 ONSITE POWER SYSTEMS

8.3.1 AC Power Systems

The onsite power system interfaces with the offsite power system at the input terminals to the supply breakers for the normal and alternate power feeds to the medium voltage (7.2kV) switchgear. It is a three load group system with each load group consisting of a non-safety-related and a safety-related portion. The three load groups of the Class 1E power system are independent of each other. The principal elements of the auxiliary ac electric power systems are shown on the single line diagrams (SLD) in Figure 8.3-1, 4, 5 and 7.

Each Class 1E division has a dedicated diesel generator, which automatically starts on high drywell pressure, low reactor vessel level or loss of voltage on the division's 6.9 kV bus. Each 6.9-kV Class 1E bus feeds it's associated 480V unit substation through a 6.9-kV/480/277V power center transformer.

Standby power is provided to permanent non-safety-related loads in all three load groups by a combustion turbine generator located in the turbine building.

AC power is supplied at 6.9KV for motor loads larger than 300KW and transformed to 480 V for smaller loads. The 480V system is further transformed into lower voltages as required for instruments, lighting, and controls. In general, motors larger than 300KW are supplied from the 6.9KV buses. Motors 300KW or smaller but larger than 100KW are supplied power form 480V switchgear. Motors 100KW or smaller are supplied power from 480V motor control centers.

See Subsection 8.3.4.9 for COL license information.

8.3.1.0 Non-Safety-Related AC Power System

8.3.1.0.1 Non-Safety-Related Medium Voltage Power Distribution System

The non-safety-related medium voltage power distribution system consists of nine 6.9KV buses divided into three load groups. The three load group configuration was chosen to match the mechanical systems which are mostly three trains (Three feedwater pumps, three circulating water pumps, three turbine building supply and exhaust fans).

Within each load group there is one bus which supplies power production loads which do not provide water to the pressure vessel. Each one of these buses has access to power from one winding of its assigned unit auxiliary transformer. It also has access to the reserve auxiliary transformer as an alternate source if its unit auxiliary transformer fails or during maintenance outages for the normal feed. Bus transfer is manual dead bus transfer and not automatic.

Another bus within each load group supplies power to pumps which are capable of supplying water to the pressure vessel during normal power operation (i.e., the condensate and feedwater pumps). These buses normally receive power from the unit auxiliary transformer and supply power to the third bus (plant investment protection (PIP)) in the load group through a cross-tie. The cross-tie automatically opens on loss of power but may be manually reclosed if it is desired to operate a condensate or feedwater pump from the combustion turbine or the reserve auxiliary transformer which are connectable to the PIP buses. This cross-tie arrangement allows advantage to be taken of the fact that the feedwater pumps are motor driven through an adjustable speed drive so that they have low starting currents and can be started and run at low power. The combustion turbine and reserve auxiliary transformer have sufficient capacity to start either or both of the reactor feedwater and condensate pumps in a load group. This provides three load groups of non-safety grade equipment in addition to the divisional 1E load groups which may be used to supply water to the reactor vessel in emergencies.

A third bus supplies power to permanent non-safety loads such as the turbine building HVAC, the turbine building service water and the turbine building closed cooling water systems. On loss of normal preferred power the cross-tie to the power production bus is automatically tripped open and the permanent non-safety related bus is automatically transferred (two out of the three buses in the load groups transfer) via a dead bus transfer to the combustion turbine which automatically starts on loss of power. The permanent service systems for each load group automatically restart to support their load groups.

The buses are comprised of 7.2KV 500MVA metal clad switchgear with a bus full load rating of 2000A. Maximum calculated full load short time current is 1700A. Bus ratings of 3000 amperes are available for the switchgear as insurance against future load growth, if necessary. The required interrupting capacity is 41,000 amperes.

The 6.9kV buses supply power to adjustable speed drives for the feedwater and reactor internal pumps. These adjustable speed drives are designed to the requirements of IEEE Std 519, Guide for Harmonic Control and Reactive Compensation of Static Power Converters. Voltage distortion limits are as stated in Table 4 of the IEEE Std.

8.3.1 0.2 Non-Safety-Related Low Voltage Power Distribution System

Power for the 480V auxiliaries is supplied from power centers consisting of 6.9KV/480 volt transformers and associated metalclad switchgear, Figure 8.3-1. There are six non-safety-related, two per load group, power centers. One power center per load group is supplied power from the permanent non-safety bus for the load group.

8.3.1.0.3 Non-Class 1E Vital AC Power Supply System

The function of the non-Class 1E Vital ac Power Supply System is to provide reliable 120V uninterruptible ac power for important non-safety related loads that are required for continuity of power plant operation. The system consists of three 120V ac uninterruptible constant voltage, constant frequency (CVCF) power supplies, each including a static inverter, ac and dc static transfer switches, a regulating stepdown transformer (as an alternate ac power supply), and a distribution panel (Figure 8.3-5). The primary source of power comes from the non-Class 1E ac motor control centers. The secondary source is the non-Class 1E 125 VDC central distribution panels.

There are three automatic switching modes for the CVCF power supplies, any of which may be initiated manually. First, the frequency of the output of the inverter is normally synchronized with the input ac power. If the frequency of the input power goes out of range, the power supply switches over to internal synchronization to restore the frequency of its output. Switching back to external synchronization is automatic and occurs if the frequency of the ac power has been restored and maintained for approximately 60 seconds.

The second switching mode is from ac to dc for the power source. If the voltage of the input ac power is less than 88% of the rated voltage, the input is switched to the dc power supply. The input is switched back to the ac power after a confirmation period of approximately 60 seconds.

The third switching mode is between the inverter and the voltage regulating transformer. If any of the conditions listed below occur, the power supply is switched to the voltage regulating transformer.

(a) Output voltage out of rating by more than plus or minus 10 per cent

(b) Output frequency out of rating by more than plus or minus 3 per cent

(c) High temperature inside of panel

(d) Loss of control power supply

(e) Commutation failure

(f) Overcurrent of smoothing condenser

(g) Loss of control power for gate circuit

(h) Incoming MCCB trip

(i) Cooling fan trip

Following correction of any of the above events transfer back is by manual initiation only.

8.3.1.0.4 Computer Vital AC Power Supply System (Non-Safety-Related)

Two constant voltage and constant frequency power supplies are provided to power the process computers. Each of the power supplies consists of an ac to dc rectifier, and a dc to ac inverter, a bypass transformer and dc and ac solid state transfer switches (Figure 8.3-5). The normal feed for the power supplies is from non-Class 1E power center supplied from the permanent non-safety- related buses which receive power from the combustion turbine if offsite power is lost. The backup for the normal feeds is from the 250VDC battery. Each power supply is provided with a backup ac feed though isolation transformers and a static transfer switch. The backup feed is provided for alternate use during maintenance periods. Switching of the power supply is similar to that described for the non-vital ac power supply system, above. See Subsection 8.3.1.0.3.

8.3.1.1 Safety-Related A′ Power Distribution System

8.3.1.1.1 Medium Voltage Safety-Related Power Distribution System

Class 1E ac power loads are divided into three divisions (Divisions I, II, and III), each fed from an independent 6.9-kV Class 1E bus. During normal operation (which includes all modes of plant operation; i.e., shutdown, refueling, startup, and run.), two of the three divisions are fed from an offsite normal preferred power supply. The remaining division shall be fed from the alternate power source (See Subsection 8.3.4.9).

Each 6.9 kV bus has a safety grounding circuit breaker designed to protect personnel during maintenance operations (see Figure 8.3-1). During periods when the buses are energized, these breakers are racked out (i.e., in the disconnect position). A control room annunciator sounds whenever any of these breakers are racked in for service.

The interlocks for the bus grounding devices are as follows:

(1) Undervoltage relays must be actuated.

(2) Bus Feeder breakers must be in the disconnect position.

(3) Voltage for bus instrumentation available.

Conversely, the bus feeder breakers are interlocked such that they cannot close unless their associated grounding breakers are in their disconnect positions.

Standby AC power for Class 1E buses is supplied by diesel generators at 6.9 kV and distributed by the Class 1E power distribution system. Division I, II and III buses are automatically transferred to the diesel generators when the normal preferred power supply to these buses is lost.

The Division I safety-related bus has one non-safety-related load on it. The load is a power center which supplies power to the fine motion control rod drive (FMCRD) motors. Although these motors are not safety-related, the drives may be inserted as a backup to scram and are of special importance because of this. It is important that the first available standby power be available for the motors, therefore, a diesel supplied bus was chosen as the first source of standby ac power and the combustion turbine as the second backup source. Division I was chosen because it was the most lightly loaded diesel generator.

The load breaker in the Division I switchgear is part of the isolation scheme between the safety-related power and the non-safety-related load. In addition to the normal overcurrent tripping of this isolation breaker, zone selective interlocking is provided between it and its upstream Class 1E bus feed breaker.

If fault current flows in the non-Class 1E load, it is sensed by the Class 1E current device for the isolation breaker and a trip blocking signal is sent to the upstream Class 1E feed breaker. This blocking lasts for about 75 milliseconds. This allows the isolation breaker to trip in its normal instantaneous tripping time of 35 to 50 milliseconds, if the magnitude of the fault current is high enough. This assures that the fault current has been terminated before the Class 1E upstream breaker is free to trip. For fault currents of lesser magnitude, the blocking delay will time out without either breaker tripping, but the isolation breaker will eventually trip and always before the upstream breaker. This order of tripping is assured by the coordination between the two breakers provided by long-time pickup, long-time delay and instantaneous pickup trip device characteristics. Tripping of the Class 1E feed breaker is normal for faults which occur on the Class 1E bus it feeds. Coordination is provided between the bus main feed breakers and the load breakers.

The zone selective interlock is a feature of the trip unit for the breaker and is tested when the other features such as current setting and long-time delay are tested.

A pair of interlocked breakers are provided at the input to the power center transformer to supply power to the transformer from either the safety-related diesel generator backed bus or the non-safety-related combustion turbine backed bus.

Switchover to the diesel generator is automatic on loss of power from the safety-related source. Switching back to the safety-related power is by manual action only. The breaker in the safety-related leg of the power supply is Division I associated. The breaker in the non-safety-related leg is non-safety-related on the basis of the electrical isolation of its controls, the fact that there are two breakers between it and the Class 1E 6.9kV bus and that the transfer breakers are interlocked such that only one can be in the closed condition.

The circuits on the output side of the power center transformer are non-safety-related on the basis of the isolation provided by the two upstream breakers and the power center transformer. It is also a requirement that they cannot be classified anything other than non-safety-related so that they can never be routed as associated with cables of any safety-related division.

8.3.1.1.2 Low Voltage Safety-Related Power Distribution System

8.3.1.1.2.1 Power Centers

Power for 480V auxiliaries is supplied from power centers consisting of 6.9-kV/480V transformers and associated metal clad switchgear, Figure 8.3-1.

Class 1E 480V power centers supplying Class 1E loads are arranged as independent radial systems, with each 480V bus fed by its own power transformer. Each 480V Class 1E bus in a division is physically and electrically independent of the other 480V buses in other divisions.

The 480V unit substation breakers supply motor control centers and motor loads up to and including 300KW. Switchgear for the 480V load centers is of indoor, metal-enclosed type with drawout circuit breakers. Control power is from the Class 1E 125 VDC power system of the same division.

8.3.1.1.2.2 Motor Control Centers

The 480V MCCs feed motors 100kW or smaller, control power transformers, process heaters, motor-operated valves and other small electrically operated auxiliaries, including 480-120V and 480-240V transformers. Class 1E motor control centers are isolated in separate load groups corresponding to divisions established by the 480V unit substations.

Starters for the control of 460v motors 100kW or smaller are MCC-mounted, across-the-line magnetically operated, air break type. Power circuits leading from the electrical penetration assemblies into the containment area have a fuse in series with the circuit breakers as a backup protection for a fault current in the penetration in the event of circuit breaker overcurrent or fault protection failure.

8.3.1.1.3 120/240V Distribution System

Individual transformers and distribution panels are located in the vicinity of the loads requiring 120/240V power. This power is used for lighting, 120V receptacles and other 120V loads.

8.3.1.1.4 Instrument Power Supply Systems

8.3.1.1.4.1 120V AC Safety-Related Instrument Power System

Individual transformers supply 120V ac instrument power (Figure 8.3-4). Each Class 1E divisional transformer is supplied from a 480V MCC in the same division. There are three divisions, each backed up by its divisional diesel generator as the source when the offsite source is lost. Power is distributed to the individual loads from distribution panels, and to logic level circuits through the control room logic panels.

8.3.1.1.4.2 120V AC Safety Related Vital AC Power Supply System

8.3.1.1.4.2.1 Constant Voltage, Constant Frequency (CVCF) Power Supply for the Safety System Logic and Control (SSLC)

The power supply for the SSLC is shown in Figure 8.3-5, with each of the four buses supplying power for the independent trip systems of the SSLC system. Four constant voltage, constant frequency (CVCF) control power buses (Divisions I, II, III, and IV) have been established. They are each normally supplied independently from inverters which, in turn, are normally supplied power via a static switch from a rectifier which receives 480V divisional power. A 125V dc battery provides an alternate source of power through the static switch.

For Divisions I, II, and III, the AC supply is from a 480 V MCC for each division. The backup dc supply is via a static switch and a dc/ac inverter from the 125VDC central/distribution board for the division. A second static switch also is capable of transferring from the inverter to a direct feed through a voltage regulating transformer from a 480V motor control center for each of the three divisions.

Since there is no 480V ac Division IV power, Division IV is fed from a Division I motor control center. Otherwise, the ac supply for the Division IV CVCF power supply is similar to the other three divisions. The dc supply for Division IV is backed up by a separate Division IV battery.

The CVCF power supply buses are designed to provide logic and control power to the four division SSLC system that operates the RPS. [The SSLC for the ECCS derives its power from the 125 VDC power system (Figure 8.3-7)]. The ac buses also supply power to the neutron monitoring system and parts of the process radiation monitoring system and MSIV function in the leak detection system. Power distribution is arranged to prevent inadvertent operation of the reactor scram initiation or MSIV isolation upon loss of any single power supply.

Routine maintenance can be conducted on equipment associated with the CVCF power supply. Inverters and solid state switches can be inspected, serviced and tested channel by channel without tripping the RPS logic.

8.3.1.1.4.2.2 Components

Each of the four Class 1E CVCF power supplies includes the following components:

(1) a power distribution cabinet, including the CVCF 120 VAC bus and circuit breakers for the SSLC loads;

(2) a solid-state inverter, to convert 125 VDC power to 120 VAC uninterruptible power supply;

(3) a solid-state transfer switch to sense inverter failure and automatically switch to alternate 120 VAC power;

(4) a 480V/120V bypass transformer for the alternate power supply;

(5) a solid-state transfer switch to sense ac input power failure and automatically switch to alternate 125 VDC power.

(6) a manual transfer switch for maintenance.

(7) an output power monitor which monitors the 120 VAC power from the CVCF power supply to its output power distribution cabinet. If the voltage or frequency of the ac power gets out of its design range, the power monitor trips and interrupts the power supply to the distribution cabinet. The purpose of the power monitor is to protect the scram solenoids from voltage levels and frequencies which could result in their damage.

8.3.1.1.4.2.3 Operating Configuration

The four 120 VAC essential power supplies operate independently, providing four divisions of CVCF power supplies for the SSLC. The normal lineup for each division is through an essential 480 VAC power supply, the ac/dc rectifier, the inverter and the static transfer switch. The bus for the RPS A solenoids is supplied by the Division II CVCF power supply. The RPS B solenoids bus is supplied from the Division III CVCF power supply. The #3 soleniods for the MSIVs are powered from the Division I CVCF; and the #2 soleniods, from the Division II CVCF power supply.

8.3.1.1.5 Class 1E Electric Equipment Considerations

The following guidelines are utilized for Class 1E equipment.

8.3.1.1.5.1 Physical Separation and Independence

All electrical equipment is separated in accordance with IEEE Std 384, Regulatory Guide 1.75 and General Design Criterion 17, with the following clarifying interpretations of IEEE Std 384:

(1) Enclosed solid metal raceways are required for separation between safety-related or associated cables of different safety divisions or between safety-related or associated cables and non-safety-related cables if the vertical separation distance is less than five feet, the horizontal separation distance is less than three feet and the cables are in the same fire area;

(2) Both groupings of cables requiring separation per item one must be enclosed in solid metal raceways.

To meet the provisions of Policy Issue SECY-89-013, which relates to fire tolerance, three hour rated fire barriers are provided between areas of different safety divisions throughout the plant except in the primary containment and the control room complex. See Section 9.5.1.0 for a detailed description of how the provisions of the Policy Issue are met.

The overall design objective is to locate the divisional equipment and its associated control, instrumentation, electrical supporting systems and interconnecting cabling such that separation is maintained among all divisions. Redundant divisions of electric equipment and cabling are located in separate rooms or fire areas wherever possible.

Electric equipment and wiring for the Class 1E systems which are segregated into separate divisions are separated so that no design basis event is capable of disabling more than one division of any ESF total function.

The safety-related divisional ac switchgear, power centers, battery rooms and dc distribution panels and MCCs are located to provide separation and electrical isolation among the divisions. Separation is provided among divisional cables being routed between the equipment rooms, the Main Control Room, containment and other processing areas. Equipment in these areas is divided into Divisions I, II, III and IV and separated by barriers formed by walls, floors, and ceilings. The equipment is located to facilitate divisional separation of cable trays and to provide access to electrical penetration assemblies. Exceptions to this separation objective are identified and analyzed as to equivalency and acceptability in the fire hazard analysis. (See Appendix 9A.5)

The penetration assemblies are located around the periphery of the containment and at different elevations to facilitate reasonably direct routing to and from the equipment. No penetration carries cables of more than one division.

Separation within the main control room is designed in accordance with IEEE 384, and is discussed in Subsection 8.3.1.4.1.

Wiring for all Class 1E equipment indicating lights is an integral part of the Class 1E cables used for control of the same equipment and are considered to be Class 1E circuits.

Associated cables, if any, are treated as Class 1E circuits and routed in their corresponding divisional raceways. Separation requirements are the same as for Class 1E circuits. Associated cables are required to meet all of the requirements for Class 1E cables.

The careful placing of equipment is important to the necessary segregation of circuits by division. Deliberate routing in separate fire areas on different floor levels, and in embedded ducts is employed to achieve physical independence.

8.3.1.1.5.2 Class 1E Electric Equipment Design Bases and Criteria

(1) Motors are sized in accordance with NEMA standards. The manufacturers' ratings are at least large enough to produce the starting, pull-in and driving torque needed for the particular application, with due consideration for capabilities of the power sources. Plant design specifications for electrical equipment require such equipment be capable of continuous operation for voltage fluctuations of +/- 10%. In addition, Class 1E motors must be able to withstand voltage drops to 70% rated during starting transients.

(2) Power sources, distribution systems and branch circuits are designed to maintain voltage and frequency within acceptable limits.

(3) The selection of motor insulation such as Class F, H or B is a design consideration based on service requirements and environment. The Class 1E motors are qualified by tests in accordance with IEEE Std 334.

(4) Interrupting capacity of switchgear, power centers, motor control centers, and distribution panels is equal to or greater than the maximum available fault current to which it is exposed under all modes of operation.

    Interrupting capacity requirements of the 7.2kV Class 1E switchgear is selected to accommodate the available short-circuit current at the switchgear terminals. Circuit breaker and applications are in accordance with ANSI Standards. (See Subsection 8.3.4.1 for COL license information)

Unit substation transformers are sized and impedances chosen to facilitate the selection of low-voltage switchgear, MCCs and distribution panels, which are optimized within the manufacturer's recommended ratings for interrupting capacity and coordination of overcurrent devices. Impedance of connecting upstream cable is factored in for a specific physical layout.

8.3.1.1.5.3 Testing

The design provides for periodically testing the chain of system elements from sensing devices through driven equipment to assure that Class 1E equipment is functioning in accordance with design requirements. Such on-line testing is greatly enhanced by the design, which utilizes three independent divisions, any one of which can safely shut down the plant. The requirements of IEEE Std 379 Regulatory Guide 1.118 and IEEE 338 are met.

8.3.1.1.6 Circuit Protection

8.3.1.1.6.1 Philosophy of Protection

Simplicity of load grouping facilitates the use of conventional, protective relaying practices for isolation of faults. Emphasis has been placed on preserving function and limiting loss of Class 1E equipment function in situations of power loss or equipment failure.

Circuit protection of the Class 1E buses contained within the nuclear island is interfaced with the design of the overall protection system outside the nuclear island.

8.3.1.1.6.2 Grounding Methods

The medium voltage (6900V) system is low resistance grounded except that each diesel generator is high resistance grounded to maximize availability.

8.3.1.1.6.3 Bus Protection

Bus protection is as follows:

(1) 6.9kV bus incoming circuits have inverse time overcurrent, ground fault, bus differential and undervoltage protection.

(2) 6.9kV feeders for power centers have instantaneous, inverse time overcurrent and ground fault protection.

(3) 6.9kV feeders for heat exchanger building substations have inverse time overcurrent and ground fault protection.

(4) 6.9kV feeders used for motor starters have instantaneous, inverse time overcurrent, ground fault and motor protection.

(5) 480V bus incoming line and feeder circuits have inverse time overcurrent and ground fault protection.

8.3.1.1.6.4 Protection Requirements

When the diesel-generators are called upon to operate during LOCA conditions, the only protective devices which shut down, the diesel are the generator differential relays, and the engine overspeed trip. These protection devices are retained under accident conditions to protect against possible, significant damage. Other protective relays, such as loss of excitation, antimotoring (reverse power) overcurrent voltage restraint, low jacket water pressure high jacket water temperature and low lube oil pressure, are used to protect the machine when operating in parallel with the normal power system, during periodic tests. The relays are automatically isolated from the tripping circuits during LOCA conditions. However, all bypassed parameters are annunciated in the main control room (see Subsection 8.3.1.1.8.5). The bypasses are testable and are manually reset as required by Position 7 of Reg. Guide 1.9 No trips are bypassed during LOPP or testing.

8.3.1.1.7 Load Shedding and Sequencing on Class 1E Buses

This subsection addresses Class 1E Divisions I, II, and III. Load shedding, bus transfer and sequencing on a 6.9kV Class 1E bus is initiated on loss of bus voltage. Only LOPP signals are used to trip the loads. However, the presence of a LOCA during LOPP reduces the time delay for initiation of bus transfer from 3 seconds to 0.4 seconds. The load sequencing for the diesels is given on Table 8.3-4.

Load shedding and buses ready to load signals are generated by the control system for the electrical power distribution system. Individual timers for each major load are reset and started by their electrical power distribution systems signals.

(1) **Loss of Preferred Power (LOPP)** : The 6.9kV Class 1E buses are normally energized from the

normal or alternate preferred power supplies. Should the bus voltage decay to below 70% of its nominal rated value for a predetermined time a bus transfer is initiated and the signal will trip the supply breaker, and start the diesel generator. When the bus voltage decays to 30%, large pump motor breakers are tripped. The transfer proceeds to the diesel generator. If the standby diesel generator is ready to accept load (i.e., voltage and frequency are within normal limits and no lockout exists, and the normal and alternate preferred supply breakers are open), then the diesel-generator breaker is signalled to close, accomplishing automatic transfer of the Class 1E bus to the diesel generator. Large motor loads will be sequence started as required and shown on Table 8.3-4.

(2) **Loss of Coolant Accident (LOCA)**: When a LOCA occurs, with or without a LOPP, the load sequence timers are started if the 6.9 KV emergency bus voltage is greater than 70% and loads are applied to the bus at the end of preset times.

Each load has an individual load sequence timer which will start if a LOCA occurs and the 6.9 KV emergency bus voltage is greater than 70%, regardless of whether the bus voltage source is normal or alternate preferred power or the diesel generator. The load sequence timers are part of the low level circuit logic for each LOCA load and do not provide a means of common mode failure that would render both onsite and offsite power unavailable. If a timer failed, the LOCA load could be applied manually provided the bus voltage is greater than 70%.

(3) **LOPP following LOCA**: If the bus voltage (normal or alternate preferred power) is lost during post-accident operation, transfer to diesel generator power occurs as described in (1) above.

(4) **LOCA following LOPP**: If a LOCA occurs following loss of the normal or alternate preferred power supplies, the LOCA signal starts ESF equipment as required. Running loads are not tripped. Automatic (LOCA + LOPP) time delayed load sequencing assures that the diesel-generator will not be overloaded.

(5) **LOCA when diesel generator is parallel with preferred power source during test**: If a LOCA occurs when the diesel generator is paralled with either the normal preferred power or the alternate preferred power source, the D/G will automatically be disconnected from the 6.9 KV emergency bus regradless of whether the test is being conducted from the local control panel or the main control room.

(6) **LOPP during diesel generator paralleling test**: If the normal preferred power supply is lost during the diesel-generator paralleling test, the diesel-generator circuit breaker is automatically tripped. Transfer to the diesel generator then proceeds as described in (1).

If the alternate preferred source is used for load testing the diesel generator, and the alternate preferred source is lost (and no LOCA signal exists), the diesel-generator breaker will trip on overcurrent, and LOPP condition will exist. Load shedding and bus transfer will proceed as described in (1).

(7) **Restoration of offsite power**: Upon restoration of offsite power, the Class 1E bus(es) can be transferred back to the offsite source by manual operation only.

(8) **Protection against degraded voltage**: For protection of the Division I, II and III electrical equipment against the effects of a sustained degraded voltage, the 6.9 kV ESF bus voltages are monitored. When the bus voltage degrades to 90% or below of its rated value and after a time delay (to prevent triggering by transients), undervoltage will be annunciated in the control room. Simultaneously a 5-minute timer is started, to allow the operator to take corrective action. After 5 minutes, the respective feeder breaker with the undervoltage is tripped. Should a LOCA occur during the 5-minute time delay, the feeder breaker with the undervoltage will be tripped instantly. Subsequent bus transfer will be as desribed above.

8.3.1.1.8 Standby AC Power System

The diesel generators comprising the Divisions I, II and III standby ac power supplies are designed to quickly restore power to their respective Class 1E distribution system divisions as required to achieve safe shutdown of the plant and/or to mitigate the consequences of a LOCA in the event of a coincident LOPP. Figure 8.3-1 shows the interconnections between the preferred power supplies and the Divisions I, II and III diesel-generator standby power supplies.

8.3.1.1.8.1 Redundant Standby AC Power Supplies

Each standby power system division, including the diesel generator, its auxiliary systems and the distribution of power to various Class 1E loads through the 6.9kV and 480V systems, is segregated and separated from the other divisions. No automatic interconnection is provided between the Class 1E divisions. Each diesel generator set is operated independently of the other sets and is connected to the utility power system by manual control, only during testing or for bus transfer.

8.3.1.1.8.2 Ratings and Capability

The size of each of the diesel-generators serving Divisions I, II and III satisfies the requirements of NRC Regulatory Guide 1.9 and IEEE Std 387 and conforms to the following criteria:

(1) Each diesel generator is capable of starting, accelerating and supplying its loads in the sequence shown in Table 8.3-4.

(2) Each diesel generator is capable of starting, accelerating and supplying its loads in their proper sequence without exceeding a 25% voltage drop at its terminals.

(3) Each diesel generator is capable of starting, accelerating and running its largest motor at any time after the automatic loading sequence is completed, assuming that the motor had failed to start initially.

(4) The criteria is for each diesel generator to be capable of reaching full speed and voltage within 20 seconds after receiving a signal to start, and capable of being fully loaded within the next 65 seconds as shown in Table 8.3-4. The limiting condition is for the RHR and HPCF injection valves to be open 36 seconds after the receipt of a high drywell or low reactor vessel level signal. Since the motor operated valves are not tripped off the buses, they start to open, if requested to do so by their controls, when power is restored to the bus at 20 seconds. This gives them an allowable travel time of 16 seconds, which is attainable for the valves.

(5) Each diesel generator has a continuous load rating of 6.25 MVA @ 0.8 power factor (see Figure 8.3-1). The overload rating is 110% of the rated output for a two-hour period out of a 24-hour period.

See Subsection 8.3.4.2 for COL license information.

8.3.1.1.8.3 Starting Circuits and Systems

Diesel generators I, II and III start automatically on loss of bus voltage. Under-voltage relays are used to start each diesel engine in the event of a drop in bus volatge below preset values for a predetermined period of time. Low-water-level switches and drywell high-pressure switches in each division are used to initiate diesel start under accident conditions. Manual start capability (without need of dc power) is also provided. The transfer of the Class 1E buses to standby power supply is automatic should this become necessary on loss of all preferred power. After the breakers connecting the buses to the preferred power supplies are open the diesel-generator breaker is closed when required generator voltage and frquency are established.

Disel generators I, II and III are designed to start and attain rated voltage and frequency within 20 seconds. The generator, and voltage regulator are designed to permit the set to accept the load and to accelerate the motors in the sequence within the time requirements. The voltage drop caused by starting the large motors does not exceed the requirements set forth in Regulatory Guide 1.9, and proper acceleration of these motors is ensured. Control and timing circuits are provided, as appropriate, to ensure that each load is applied automatically at the correct time. Each diesel generator set is provided with two independent starting air systems.

8.3.1.1.8.4 Automatic Shedding, Loading and Isolation

The diesel generator is connected to its Class 1E bus only when the incoming preferred source breakers have been tripped (Subsection 8.3.1.1.7). Under this condition, major loads are tripped from the Class 1E bus, except for the Class 1E 480V unit substation feeders, before closing the diesel generator breaker.

The large motor loads are later reapplied sequentially and automatically to the bus after closing of the diesel-generator breaker.

8.3.1.1.8.5 Protection Systems

The diesel generator is shut down and the generator breaker tripped under the following conditions during all modes of operation and testing operation:

(1) engine overspeed trip; and

(2) generator differential relay trip.

These and other protective functions (alarms and trips) of the engine or the generator breaker and other off-normal conditions are annunciated in the main control room and/or locally as shown in Table 8.3-5. Local alarm/annunciation points have auxiliary isolated switch outputs which provide inputs to alarm/annunciator refresh units in the main control room which identifies the diesel generator and general anomaly concerned. Those anomalies which cause the respective D/G to become inoperitive are so indicated in accordance with Regulatory Guide 1.47 and BTP PSB-2.

8.3.1.1.8.6 Local and Remote Control

Each diesel generator is capable of being started or stopped manually from the main control room. Start/stop control and bus transfer control may be transferred to a local control station in the diesel generator area by operating key switches at that station.

8.3.1.1.8.7 Engine Mechanical Systems and Accessories

Descriptions of these systems and accessories are given in Section 9.5.

8.3.1.1.8.8 Interlocks and Testability

Each diesel generator, when operating other than in test mode, is totally independent of the preferred power supply. Additional interlocks to the LOCA and LOPP sensing circuits terminate parallel operation test and cause the diesel generator to automatically revert and reset to its standby mode if either signal appears during a test. A lockout or maintenance mode removes the diesel generator from service. The inoperable status is indicated in the control room.

8.3.1.1.8.9 Reliability Qualification Testing

The qualification tests are performed on the diesel generator per IEEE Std. 387 as modified by Regulatory Guide 1.9 requirements.

See Subsection 8.3.4.10 for interface requirements.

8.3.1.2 Analysis

8.3.1.2.1 General AC Power Systems

The general ac power systems are illustrated in Figure 8.3-1. The analysis demonstrates compliance of the Class 1E ac power system to NRC General Design Criteria (GDC), NRC Regulatory Guides and other criteria consistent with the Standard Review Plan (SRP).

Table 8.1-1 identifies the onsite power system and the associated codes and standards applied in accordance with Table 8-1 of the SRP. Criteria are listed in order of the listing on the table, and the degree of conformance is discussed for each. Any exceptions or clarifications are so noted.

(1) General Design Criteria (GDC):

   (a) Criteria: GDCs 2, 4, 17, 18 and 50.

   (b) Conformance: The ac power system is in compliance with these GDCs. The GDCs are generically addressed in Subsection 3.1.2.

(2) Regulatory Guides (RGs):

   (a) RG 1.6 - Independence Between Redundant Standby (Onsite) Power Sources and Between Their Distribution Systems

   (b) RG 1.9 - Selection, Design, and Qualification of Diesel-Generator Units Used as Standby (Onsite) Electric Power Systems at Nuclear Power Plants

   (c) RG 1.32 - Criteria for Safety-Related Electric Power Systems for Nuclear Power Plants

(d) RG 1.47 - Bypassed and Inoperable Status Indication for Nuclear Power Plant Safety Systems

(e) RG 1.63 - Electric Penetration Assemblies in Containment Structures for Light-Water-Cooled Nuclear Power Plants

(f) RG 1.75 - Physical Independence of Electric Systems

(g) RG 1.106 - Thermal Overload Protection for Electric Motors on Motor-Operated Valves

Safety functions which are required to go to completion for safety have their thermal overload protection devices in force during normal plant operation but the overloads are bypassed under accident conditions per Regulatory Postion 1.(b) of the guide.

(h) RG 1.108 - Periodic Testing of Diesel Generator Units Used as Onsite Electric Power Systems at Nuclear Power Plants

(i) RG 1.118 - Periodic Testing of Electric power and Protection Systems

(j) RG 1.153 - Criteria for Power, Instrumentation, and Control Portions of Safety Systems

(k) RG 1.155 - Station Blackout

Regarding Position C-1 of Regulatory Guide 1.75 (see Section 8.3.1.1.1), the non-safety related FMCRD motors and brakes are supplied power from the Division 1 Class 1E safety-related bus through a dedicated power center transformer. The Class 1E load breaker for the bus is tripped by fault current for faults in the non-safety load. There is also a zone selective interlock provided from the load breaker to the Class 1E bus supply breaker so that the supply breaker is blocked from tripping while fault current is flowing in the non-safety load feeder. This meets the intent of the Regulatory Guide position in that the main supply breaker is prevented from tripping on faults in the non-safety-related loads. A second isolation device is provided by the power center transformer, which is associated and meets 1E requirements.

There are three 6.9 KV electrical divisions which are independent load groups backed by individual diesel-generator sets. The low voltage ac systems consists of four divisions which are backed by independent dc battery, charger and inverter systems.

The standby power system redundancy is based on the capability of any one of the Divisions 1, 2 or 3 load groups to provide the minimum safety functions necessary to manually shut down the unit from the control room in case of an accident and maintain it in the safe shutdown condition. Two of the four instrument and control divisions are required to be functional to accomplish an automatic safe shutdown.

There is no sharing of standby power system components between load groups, and there is no sharing of diesel-generator power sources between units, since the ABWR is a single-plant design.

Each standby power supply for each of the three load groups is composed of a single generator driven by a diesel engine having faststart characteristics and sized in accordance with Regulatory Guide 1.9.

Table 8.3-1 and 8.3-2 show the rating of each of the Divisions I, II and III diesel generators, respectively, and the maximum coincidental load for each.

(3) Branch Technical Positions (BTPs):

(a) BTP ICSB 8 (PSB) - Use of Diesel-Generator Sets for Peaking

(b) BTP ICSB 18 (PSB) - Application of the Single Failure Criterion to Manually-Controlled Electrically-Operated Valves.

(c) BTP ICSB 21 - Guidance for Application of Regulatory Guide 1.47

(d) BTP PSB 1 - Adequacy of Station Electric Distribution System Voltages

(e) BTP PSB 2 - Criteria for Alarms and indications Associated with Diesel-Generator Unit Bypassed and Inoperable Status

The onsite ac power system is designed consistent with these positions.

(4) Other SRP Criteria:

(a) NUREG/CR 0660 - Enhancement of Onsite Diesel Generator Reliability

As indicated in Subsection 8.1.3.1.2.4, the operating procedures and training of personnel are outside of the Nuclear Island scope of supply. NUREG/CR 0660 is therefore imposed as an interface requirement for the applicant.(See Subsection 8.1.4.2)

(b) NRC Policy Issue On Alternate Power for Non-safety Loads

This policy issue states that "An evolutionary ALWR design should include an alternate power source to the non-safety loads unless the design can demonstrate that the design margins in the evolutionary ALWR will result in transients for a loss of non-safety power event that are no more severe than those associated with the turbine-trip-only event in current existing plant designs." A subsequent clarification stated that the transfer should be an automatic slow bus transfer to pickup at least one of the non MG set driven RIPs for an ABWR.

An automatic transfer has not been provided for two reasons:

(1) The coast down provided by the MG sets is equivalent to the coastdown provided by the recirculation pump inertia on the current plants.

(2) The manner in which the ABWR functions on the loss of offsite power does not require a bus transfer. The four RIPs which are not supplied from the high inertia MG sets receive a trip command immediately on tripping of the unit. This trip command originates from turbine/load rejection trip, low vessel water level (level 3) trip or high vessel dome pressure trip. The supply breakers to the high inertia MG sets are also tripped to prevent power being drawn from the flywheels by the other large motors on the buses. The remaining six RIPs continue to operate to optimize the rate of recirculation flow reduction until the MG sets have coasted down to the ASD cut off point, at which time the remaining RIPs are tripped.

The only need to restart a RIP is in preparation for restart of the plant, at which time normal power must have been restored to the non-safety buses. The operator may then restart any of the RIPs, providing that the temperature difference between the vessel dome (as indicated by the dome pressure indicator) and the bottom head is within allowable limits. A start inhibit interlock is provided to insure that the temperature limits are satisfied before a RIP is started.

Any non-safety loads which should be restarted immediately are on the plant investment protection (PIP) buses. These buses are picked up automatically by the combustion turbine. For the remaining non-safety buses there is no requirement to immediately restore power and for simplicity considerations automatic transfers are not provided.

8.3.1.2.2 Deleted

8.3.1.2.3 Quality Assurance Requirements

A planned quality assurance program is provided in Chapter 17. This program includes a comprehensive system to ensure that the purchased material, manufacture, fabrication, testing and quality control of the equipment in the emergency electric power system conforms to the evaluation of the emergency electric power system equipment vendor quality assurance programs and preparation of procurement specifications incorporating quality assurance requirements. The administrative responsibility and control provided are also described in Chapter 17.

These quality assurance requirements include an appropriate vendor quality assurance program and organization, purchaser surveillance as required, vendor preparation and maintenance of appropriate test and inspection records, certificates and other quality assurance documentation, and vendor submittal of quality control records considered necessary for purchaser retention to verify quality of completed work.

A necessary condition for receipt, installation and placing of equipment in service has been the signing and auditing of QA/QC verification data and the placing of this data in permanent onsite storage files.

8.3.1.2.4 Environmental Considerations

In addition to the effects of operation in normal service environment, all Class 1E equipment is designed to operate during and after any design basis event, in the accident environment expected in the area in which it is located. All Class 1E electric equipment is qualified to IEEE 323 (see Section 3.11)

8.3.1.3 Physical Identification of Safety-Related Equipment

8.3.1.3.1 Power, Instrumentation and Control Systems

Electrical and control equipment, assemblies, devices, and cables grouped into separate divisions shall be identified so that their electrical divisional assignment is apparent and so that an observer can visually differentiate between Class 1E equipment and wiring of different divisions, and between Class 1E and non-Class 1E equipment and wires. The identification method shall be placed on color coding. All markers within a division shall have the same color. For associated cables (if any) treated as Class 1E (see Note 1), there shall be an "A" appended to the divisional designation (e.g., "A1"). The latter "A" stands for associated. "N" shall be used for nondivisional cables. Associated cables are uniquely identified by a longitudinal stripe or other color coded method and the data on the label. The color of the cable marker for associated cables shall be the same as the related Class 1E cable. Divisional separation requirements of individual pieces of hardware are shown in the system elementary diagrams. Identification of raceways, cables, etc., shall be compatible with the identification of the Class 1E equipment with which it interfaces. Location of identification shall be such that points of change of circuit classification (at isolation devices, etc.) are readily identifiable.

Note 1 Associated circuits added beyond the certified design must be specifically identified and justified per Subsection 8.3.4.13. Associated circuits are defined in Section 5.5.1 of IEEE 384-1981, with the clarification for Items (3) and (4) that non-Class 1E circuits being in an enclosed raceway without the required physical separation or barriers between the enclosed raceway and the Class 1E or associated cables makes the circuits (related to the non-Class 1E cable in the enclosed raceway) associated circuits.

8.3.1.3.1.1 Equipment Identification

Equipment (Panels, racks, junction or pull boxes) of each division of the Class 1E electric system and various CVCF power supply divisions are identified as follows:

(1) The background of the name-plate for the equipment of a division has the same color as the cable jacket markers and the raceway markers associated with that division.

(2) Power system distribution equipment (e.g., motor control centers, switchgear, transformers, distribution panels, batteries, chargers) is tagged with an equipment number the same as indicated on the single-line diagrams.

(3) The nameplates are laminated black and white plastic, arranged to show black engraving on a white background for non-Class 1E equipment. For Class 1E equipment, the name-plates have color coded background with black engraving.

8.3.1.3.1.2 Cable Identification

All cables for Class 1E systems and associated circuits (except those routed in conduits) are tagged every 5 ft prior to (or during) installation. All cables are tagged at their terminations with a unique identifying number (cable number), in addition to the marking characteristics shown below.

Cables shall be marked in a manner of sufficient durability to be legible throughout the life of the plant, and to facilitate initial verification that the installation is in conformance with the separation criteria.

Such markings shall be colored to uniquely identify the division (or non-division) of the cable. Generally, individual conductors exposed by stripping the jacket are also color coded or color tagged (at intervals not to exceed 1 foot) such that their division is still discernable. Exceptions are permitted for individual conductors within cabinets or panels where all wiring is unique to a single division. Any non-divisional cable within such cabinets shall be appropriately marked to distinguish it from the divisional cables.

8.3.1.3.1.3 Raceway Identifcation

All conduit is similarly tagged with a unique conduit number, in addition to the marking characteristics shown below, at 15 ft intervals, at discontinuities, at pull boxes, at points of entrance and exit of rooms and at origin and destination of equipment. Conduits containing cables operating at above 600V (i.e., 6.9kV) are also tagged to indicate the operating voltage. These markings are applied prior to the installation of the cables.

All Class 1E cable raceways are marked with the division color, and with their proper raceway identification at 15 ft intervals on straight sections, at turning points and at points of entry and exit from enclosed areas. Cable trays are marked prior to installation of their cables.

To help distinguish the neutron-monitoring and scram solenoid cables from other type cables, the following unique voltage class designations and markings are used:

Type of Special Cables	Unique Voltage Class
Neutron-monitoring	VN
Scram solenoid cables	VS

Neutron-monitoring cables are run in their own divisional conduits and cable trays, separately from all other power, instrumentation and control cables. Scram solenoid cables are run in a separate conduit for each rod scram group.

The redundant Class 1E, equipment and circuits, assigned to redundant Class 1E divisions and non-Class 1E system equipment and circuits are readily distinguishable from each other without the necessity for consulting reference materials. This is accomplished by color coding of equipment, name-plates, cables and raceways, as described above.

8.3.1.3.1.4 Sensory Equipment Grouping and Designation Letters

Redundant sensory logic/control and actuation equipment for safety-related systems shall be identified by suffix letters. Sensing lines are discussed in Section 7.7.1.1.

8.3.1.4 Independence of Redundant Systems

8.3.1.4.1 Power Systems

The Class 1E onsite electric power systems and major components of the separate power divisions is shown on Figure 8.3-1.

Independence of the electric equipment and raceway systems between the different divisions is maintained primarily by firewall-type separation as decribed in Subsection 8.3.1.4.2. Any exceptions are justified in Appendix 9A, Subsection 9A.5.5.5.

The physical independence of electric power systems complies with the requirements of IEEE Standards 308, 379, 384, General Design Criteria 17, 18 and 21 and NRC Regulatory Guides 1.6 and 1.75.

8.3.1.4.1.1 Class 1E Electric Equipment Arrangement

(1) Class 1E electric equipment and wiring is segregated into separate divisions so that no single credible event is capable of disabling enough equipment to hinder reactor shutdown and removal of decay heat by either of two unaffected divisional load groups or prevent isolation of the containment in the event of an accident. Separation requirements are applied to control power and motive power for all systems involved.

(2) Equipment arrangement and/or protective barriers are provided such that no locally generated force or missile can destroy any redundant RPS, NSSS, ECCS, or ESF functions. In addition, arrangement and/or separation barriers are provided to ensure that such disturbances do not affect both HPCF and RCIC systems.

(3) Routing of wiring/cabling is arranged such as to eliminate, insofar as practical, all potential for fire damage to cables and to separate the redundant divisions so that fire in one division will not propagate to another division. Class 1E and non-Class 1E cables are separated in accordance with IEEE 384 and R.G. 1.75 (see Figures 9A.4-1 through 9A.4-16).

(4) An independent raceway system is provided for each division of the Class 1E electric system. The raceways are arranged, physically, top to bottom, as follows (based on the function and the voltage class of the cables):

(a) V4 = Medium voltage power, 6.9kV (8kv insulation class).

(b) V3 = Low voltage power including 480 VAC, 120 VAC, 125 VDC power and all instrumentation and control power supply feeders (600V insulation class).

(c) V2 = High level signal and control, including 125 VDC and 120 VAC controls which carry less than 20A of current and 250 VDC or ac for relay contactor control.

(d) V1 = Low level signal and control, including fiber-optic cables and metallic cables with analog signals up to 55 VDC and digital signal up to 12 VDC.

Power cables (V3) are routed in flexible metallic conduit under the raised floor of the control room.

8.3.1.4.1.2 Electric Cable Installation

(1) **Cable Derating and cable tray fill**--Base ampacity rating of cables is established as described in Subsection 8.3.3.1. Electric cables of a discrete Class 1E electric system division are installed in a cable tray system provided for the same division. Cables are installed in trays in accordance with their voltage ratings and as described in Subsection 8.3.1.4.1. Tray fill is as established in Subsection 8.3.3.1.

(2) **Cable routing in potentially hostile areas**--Circuits of different safety divisions are not routed through the same potentially hostile area, with the exception of main steam line instrumentation and control circuits and main steam line isolation valves circuits which are exposed to possible steam line break and turbine missiles, respectively. Cable routing in the drywell is discussed in association with the equipment it serves in the "Special Cases" Section 9A.5.

(3) **Sharing of cable trays**--All divisions of Class 1E ac and dc systems are provided with independent raceway systems.

(4) **Cable fire protection and detection**--For details of cable fire protection and detection, refer to Subsections 8.3.3 and 9.5.1.

(5) **Cable and raceway markings**--All cables (except lighting and nonvital communications) are tagged at their terminations with a unique identifying number. [illegible]lors used for identification of cables and [illegible]ways are covered in Subsection 8.3.1.3.

(6) **Spacing of wiring and components in control boards, panels and relay racks**--Separation is accomplished by mounting the redundant devices or other components on physically separated control boards if, from a plant operational point of view, this is feasible. When operational design dictates that redundant equipment be in close proximity, separation is achieved by a barrier or enclosure to retard internal-fire or by a maintained air space in accordance with criteria given in Subsection 8.3.1.4.2.

In this case, redundant circuits which serve the same safety-related function enter the control panel through separated apertures and terminate on separate and separated terminal blocks. Where redundant circuits unavoidably terminate on the same device, barriers are provided between the device terminations to ensure circuit separation approved isolators (generally optical) are used.

(7) **Electric penetration assembly**--Electric penetration assemblies of different Class 1E divisions are separated by three hour fire rated barriers, i.e., separate rooms and/or locations on separate floor levels). Separation by distance (without barriers) is allowed only within the inerted containment. (See Section 20.3, RAI8, Response 435.31). Separation between division and non-divisional penetrations [illegible]ll be in accordance with IEEE 384. Grouping of circuits in penetration assemblies follows the same raceway voltage groupings as described in Subsection 8.3.1.4.1.

Redundant overcurrent interrupting devices are provided for all electrical circuits (including all instrumentation and control devices, as well as power circuits) going through containment penetrations, if the maximum available fault current (including failure of upstream devices) is greater than the continuous current rating of the penetration. This avoids penetration damage in the event of failure of any single overcurrent device to clear a fault within the penetration or beyond it. (See Subsection 8.3.4.4 for COL license information.

8.3.1.4.1.3 Control of Compliance with Separation Criteria During Design and Installation

Compliance with the criteria which insures independence of redundant systems is a supervisory responsibility during both the design and installation phases. The responsibility is discharged by:

(1) identifying applicable criteria;

(2) issuing working procedure to implement these criteria;

(3) modifying procedures to keep them current and workable;

(4) checking the manufacturer's drawings and specifications to ensure compliance with procedures; and

(5) controlling installation and procurement to assure compliance with approved and issued drawings and specifications.

The equipment nomenclature used on the ABWR standard design is one of the primary mechanisms for ensuring proper separation. Each equipment and/or assembly of equipment carries a single number, (e.g., the item numbers for motor drivers are the same as the machinery driven). Based on these identification numbers, each item can be identified as essential or nonessential, and each essential item can further be identified to its safety separation division. This is carried through and dictates appropriate treatment at the design level during preparation of the manufacturer's drawings.

Non-Class 1E equipment is separated where desired to enhance power generation reliability, although such separation is not a safety consideration.

Once the safety-related equipment has been identified with a Class 1E safety division, the divisional assignment dictates a characteristic color (Subsection 8.3.1.3) for positive visual identification. Likewise, the divisional identification of all ancillary equipment, cable and raceways match the divisional assignment of the system it supports.

8.3.1.4.2 Independence of Redundant Safety-Related Instrumentation and Control Systems

This subsection defines independence criteria applied to safety-related electrical systems and instrumentation and control equipment. Safety-related systems to which the criteria apply are those necessary to mitigate the effects of anticipated and abnormal operational transients or design basis accidents. This includes all those systems and functions enumerated in Subsections 7.1.1.3, 7.1.1.4, 7.1.1.5, and 7.1.1.6. The term "systems" includes the overall complex of actuated equipment, actuation devices (actuators), logic, instrument channels, controls, and interconnecting cables which are required to perform system safety functions. The criteria outlines the separation requirements necessary to achieve independence of safety-related functions compatible with the redundant and/or diverse equipment provided and postulated events.

8.3.1.4.2.1 General

Separation of the equipment for the systems referred to in Subsections 7.1.1.3, 7.1.1.4, 7.1.1.5, and 7.1.1.6 is accomplished so that they are in compliance with 10CFR50 Appendix A, General Design Criteria 3, 17, 21 and 22, and NRC Regulatory Guides 1.75 (IEEE 384) and 1.53 (IEEE 379).

Independence of mutually redundant and/or diverse Class 1E equipment, devices, and cables is achieved by three-hour fire-rated barriers and electrical isolation. This protection is provided to maintain the independence of nuclear safety-related circuits and equipment so that the protective function required during and following a design basis event including a single fire anywhere in the plant or a single failure in any circuit or equipment can be accomplished. The exceptional cases where it is not possible to install such barriers have been analyzed and justified in Appendix 9A.5.

8.3.1.4.2.2 Separation Techniques

The methods used to protect redundant safety systems from results of single failures or events are utilization of safety class structures, three-hour fire-rated protective barriers, and isolation devices.

8.3.1.4.2.2.1 Safety Class Structure

The basic design consideration of plant layout is such that redundant circuits and equipment are located in separate safety class areas (i.e., separate fire zones) insofar as possible. The separation of Class 1E circuits and equipment is such that the required independence will not be compromised by the failure of mechanical systems served by the Class 1E electrical system. For example, Class 1E circuits are routed or protected so that failure of related mechanical equipment of one system cannot disable Class 1E circuits or equipment essential to the operation of a redundant system. This separation of Class 1E circuits and equipments make effective use of features inherent in the plant design such as using different rooms or floors.

8.3.1.4.2.2.2 Three-Hour Fire Rated Protective Barriers

Three-hour fire rated protective barriers shall be such that no locally generated fire, or missile resulting from a design basis event (DBE) or from random failure of Seismic Category I equipment can disable a safety-related function. The exceptional cases where it is not possible to install such barriers have been analzed and justified in Appendix 9A.5.

Separation in all safety equipment or cable areas shall equal or exceed the requirements of IEEE 384.

8.3.1.4.2.2.3 Main Control Room and Relay Room Panels

The protection system and ESF control, logic, and instrument panels/racks shall be located in a safety class structure in which there are no potential sources of missiles or pipe breaks that could jeopardize redundant cabinets and raceways.

Control, relay, and instrument panels/racks will be designed in accordance with the following general criteria to preclude failure of non-safety circuits from causing failure of any safety circuit and to preclude failure of one safety circuit from causing failure of any other redundant safety circuit. Single panels or instrument racks will not contain circuits or devices of the redundant protection system or ESF systems except:

(1) Certain operator interface control panels may have operational considerations which dictate that redundant protection system or ESF system circuits or devices be located in a single panel. These circuits and devices are separated horizontally and vertically by a minimum distance of 6 inches or by steel barriers or enclosures.

(2) Class 1E circuits and devices will also be separated from the non-Class 1E circuits and from each other horizontally and vertically by a minimum distance of 6 inches or by steel barriers or enclosures.

(3) Where electrical interfaces between Class 1E and non-Class 1E circuits or between Class 1E circuits of different divisions cannot be avoided, Class 1E isolation devices are used (Subsection 8.3.1.4.2.2.4).

(4) If two panels containing circuits of different separation divisions are less than 3 feet apart, there shall be a steel barrier between the two panels. Panel ends closed by steel end plates are considered to be acceptable barriers provided that terminal boards and wireways are spaced a minimum of 1 inch from the end plate.

(5) Penetration of separation barriers within a subdivided panel is permitted , provided that such penetrations are sealed or otherwise treated so that fire generated by an electrical fault could not reasonably propagate from one section to the other and disable a protective function.

8.3.1.4.2.2.4 Isolation Devices

Where electrical interfaces between Class 1E and non-Class 1E circuits or between Class 1E circuits of different divisions cannot be avoided, Class 1E isolation devices will be used. AC isolation (The FMCRD drives on Division 1 is the only case.) is provided by interlocked circuit breaker coordination and an isolation transformer as described in Subsection 8.3.1.1.1.

Wiring from Class 1E equipment or circuits which interface with non-Class 1E equipment circuits (i.e., 8.3.1.4.2.2.4 Isolation Devices

Where electrical interfaces between Class 1E and non-Class 1E circuits or between Class 1E circuits of different divisions cannot be avoided, Class 1E isolation devices will be used. AC isolation (the FMCRD drives on Division 1 is the only case) is provided by interlocked circuit breaker coordination and an isolation transformer as described in Subsection 8.3.1.1.1.

Wiring from Class 1E equipment or circuits which interface with non-Class 1E equipment circuits (i.e., annunciators or data loggers) is treated as Class 1E and retain its divisional identification up to and including its isolation device. The output circuits from this isolation device are classified as non-divisional and shall be physically separated from the divisional wiring.

8.3.1.4.2.3 System Separation Requirements

Specific divisional assignment of safety-related systems and equipment is given in Table 8.3-1. Other separation requirements pertaining to the RPS and other ESF systems are given in the following subsections.

8.3.1.4.2.3.1 Reactor Protection (Trip) System (RPS)

The following separation requirements apply to the RPS wiring:

(1) RPS sensors, sensor input circuit wiring, trip channels and trip logic equipment will be arranged in four functionally independent and divisionally separate groups designated Divisions I, II, II and IV. The trip channel wiring associated with the sensor input signals for each of the four divisions provides inputs to divisional logic cabinets which are in the same divisional group as the sensors and trip channels and which are functionally independent and physically separated from the logic cabinets of the redundant divisions.

(2) Where trip channel data originating from sensors of one division are required for coincident trip logic circuits in other divisions, Class 1E isolation devices (i.e., fiber optic medium) will be used as interface elements for signals sent from one division to another such as to maintain electrical isolation between divisions.

(3) Sensor wiring for several trip variables associated with the trip channels of one division may be run together in the same conduits or in the same raceways of that same and only division. Sensor wiring associated with one division will not be routed with, or in close proximity to, any wiring or cabling associated with a redundant division.

(4) The scram solenoid circuits, from the actuation devices to the solenoids of the scram pilot valves of the CRD hydraulic control units, will be run in grounded steel conduits, with no other wiring contained within the conduits, so that each scram group is protected against a hot short to any other wiring by a grounded enclosure. Short sections (less than one meter) of flexible metallic conduit will be permitted for making connections within panels and the connections to the solenoids.

(5) Separate grounded steel conduits will be provided for the scram solenoid wiring for each of four scram groups. Separate grounded steel conduits will also be provided for both the A solenoid wiring circuits and for the B solenoid wiring circuits of the same scram group.

(6) Scram group conduits will have unique identification and will be separately routed as Division II and III conduits for the A and B solenoids of the scram pilot valves, respectively. This corresponds to the divisional assignment of their power sources. The conduits containing the scram solenoid group wiring of any one scram group will also be physically separated by a minimum separation distance of 1 inch from the conduit of any other scram group, and from metal enclosed raceways which contain either divisional or non-safety-related (non-divisional) circuits. The scram group conduits may not be routed within the confines of any other tray or raceway system. The RPS conduits containing the scram group wiring for the A and B solenoids of the scram pilot valves (associated with Divisions II and III, respectively), shall be separated from non-enclosed raceways associated with any of the four electrical divisions or non-divisional cables in accordance with IEEE 384 and Regulatory Guide 1.75.

(7) Any scram group conduit may be routed alongside of any cable or raceway containing either safety-related circuits (of any division), or any cable or raceway containing non-safety-related circuits, as long as the conduit itself is not within the boundary of any raceway which contains either the divisional or the non-safety-related circuits and is physically separated from said cables and raceway boundaries as stated in (6) above. Any one scram group conduit may also be routed along with scram group conduits of the same scram group or with conduits of any of the three other scram groups as long as the minimum separation distance of one inch (2.5 cm) is maintained.

(8) The standby liquid control system redundant Class 1E controls will be run as Division I and Division II so that no failure of standby liquid control (SLC) function will result from a single electrical failure in a RPS circuit.

(9) The startup range monitoring (SRNM) subsystem cabling of the NMS cabling under the vessel is treated as divisional. The SRNM cables will be assigned to Division I, II, III and IV. Under the vessel, cables will be enclosed and separated as defined in Appendix 9A.5.5.5.

8.3.1.4.2.3.2 Other Safety-Related Systems

(1) Separation of redundant systems or portions of a system shall be such that no single failure can prevent initiation and completion of an engineered safeguard function.

(2) The inboard and outboard isolation valves are redundant to each other so they are made independent of and protected from each other to the extent that no single failure can prevent the operation of at least one of an inboard/outboard pair.

(3) Isolation valve circuits require special attention because of their function in limiting the consequences of a pipe break outside the primary containment. Isolation valve control and power circuits are required to be protected from the pipe lines that they are responsible for isolating.

Essential isolation valve wiring in the vicinity of the outboard valve (or downstream of the valve) shall be installed in conduits and routed to take advantage of the mechanical protection afforded by the valve operator or other available structural barriers not susceptible to disabling damage from the pipe line break. Additional mechanical protection (barriers) shall be interposed as necessary between wiring and potential sources of disabling mechanical damage consequential to a break downstream of the outboard valve.

(4) The several systems comprising the ECCS have their various sensors, logics, actuating devices and power supplies assigned to divisions in accordance with Table 8.3-1 so that no single failure can disable a redundant ECCS function. This is accomplished by limiting consequences of a single failure to equipment listed in any one division of Table 8.3-1. The wiring to the ADS solenoid valves within the drywell shall run in rigid conduit. ADS conduit for solenoid A shall be divisionally separated from solenoid B conduit. Short pieces (less than 2 feet) of flexible conduit may be used in the vicinity of the valve solenoids.

(5) Electrical equipment and raceways for systems listed in Table 8.3-1 shall not be located in close proximity to primary steam piping (steam leakage zone), or be designed for short term exposure to the high temperature leak.

(6) Class 1E electrical equipment located in the suppression pool level swell zone is limited to suppression pool temperature monitors, which have their terminations sealed such that operation would not be impaired by submersion due to pool swell or LOCA. Consistent with their Class 1E status, these devices are also qualified to the requirements of IEEE 323 for the environment in which they are located.

(7) Containment penetrations are so arranged that no design basis event can disable cabling in more than one division. Penetrations do not contain cables of more than one divisional assignment.

(8) Annunciator and computer inputs from Class 1E equipment or circuits are treated as Class 1E and retain their divisional identification up to a Class 1E isolation device. The output circuit from this isolation device is classified as nondivisional.

Annunciator and computer inputs from non-Class 1E equipment or circuits do not require isolation devices.

8.3.2 DC Power Systems

8.3.2.1 Description

8.3.2.1.1 General Systems

A DC power system is provided for switchgear control, control power, instrumentation, critical motors and emergency lighting in control rooms, switchgear rooms and fuel handling areas. Four independent Class 1E 125VDC divisions, three independent non-safety-related 125VDC load groups and one non-safety-related 250VDC computer and motor power supply are provided. See Figures 8.3-7 for the single lines.

Each battery is separately housed in a ventilated room apart from its charger and distribution panels. Each battery feeds a dc distribution switchgear panel which in turn feeds local distribution panels and dc motor control centers. An emergency eye wash is supplied in each battery room.

All batteries are sized so that required loads will not exceed warranted capacity at end-of-installed-life with 100% design demand.

All chargers are sized to supply the continuous load demand to their bus while restoring batteries to a fully charged state.

8.3.2.1.1.1 Class 1E 125 VDC System

The 125 VDC system provides a reliable control and switching power source for the Class 1E systems.

Each 125 VDC battery is provided with a charger, and a standby charger shared by two divisions, each of which is capable of recharging its battery from a discharged state to a fully charged state while handling the normal, steady-state dc load.

Batteries are sized for the dc load in accordance with IEEE Standard 485.

8.3.2.1.2 Class 1E DC Loads

The 125 VDC Class 1E power is required for emergency lighting, diesel-generator field flashing, control and switching functions such as the control of 6.9-kV and 480V switchgear, control relays, meters and indicators, multiplexers, vital ac power supplies, as well as dc components used in the reactor core isolation cooling system.

The four divisions that are essential to the safe shutdown of the reactor are supplied from four independent 125 VDC buses.

8.3.2.1.3 Station Batteries and Battery Chargers, General Considerations

The four ESF load groups are supplied from the four Class 1E 125 VDC systems (See Figure 8.3-7). Each of the Class 1E 125 VDC systems has a 125 VDC battery, a battery charger and a distribution panel. One standby battery charger can be connected to either of two divisions and another standby battery charger can be connected to either of two other divisions. Kirk key interlocks prevent cross connection between divisions. The main dc distribution buses include distribution panels, drawout-type breakers and molded case circuit breakers.

The Class 1E 125 VDC systems supply dc power to Divisions I, II, III and IV, respectively, and are designed as Class 1E equipment in accordance with IEEE Std 308. They are designed so that no single failure in any 125 VDC system will result in conditions that prevent safe shutdown of the plant with either of the two remaining ac power divisions. The plant design and circuit layout from these dc systems provide physical separation of the equipment, cabling and instrumentation essential to plant safety.

Each division of the system is located in an area separated physically from other divisions. All the components of Class 1E 125 VDC systems are housed in Seismic Category I structures.

8.3.2.1.3.1 125 VDC Systems Configuration

Figure 8.3-7 shows the overall 125 VDC system provided for Class 1E Divisions I, II, III and IV. One divisional battery charger is used to supply each divisional dc distribution panel bus and its associated battery. The divisional battery charger is normally fed from its divisional 480V MCC bus.

Each Class 1E 125 VDC battery is provided with a charger, and a standby charger shared by two divisions, each of which is capable of recharging its battery from a discharged state to a fully charged state while handling the normal, steady-state dc load. Cross connection between two divisions through a standby charger is prevented by at least two interlocked breakers in series in each potential cross-connect path.

The maximum equalizing charge voltage for Class 1E batteries is 140 VDC. The dc system minimum discharge voltage at the end of the discharge period is 1.75 VDC per cell (105 volts for the battery). The operating voltage range of Class 1E dc loads is 100 to 140V.

As a general requirement, the batteries have sufficient stored energy to operate connected essential loads continuously for at least two hours without recharging. The Division I battery, which controls the RCIC system, is sufficient for eight hours of coping during station blackout. During this event scenario, the load reductions on Divisions II, III, and IV also extend the times these batteries are available (See Appendix Subsection 19E.2.1.2.2). Each distribution circuit is capable of transmitting sufficient energy to start and operate all required loads in that circuit.

A load capacity analysis has been performed, based on IEEE 485-1978, for estimated Class 1E dc battery loads as of September, 1989.

An initial composite test of onsite ac and dc power systems is called for as a prerequisite to initial fuel loading. This test will verify that each battery capacity is sufficient to satisfy a safety load demand profile under the conditions of a LOCA and loss of preferred power.

Thereafter, periodic capacity tests may be conducted in accordance with IEEE Std 450. These tests will ensure that the battery has the capacity to continue to meet safety load demands.

See Subsection 8.3.4.6 for COL license informations.

8.3.2.1.3.2 Non-Class 1E 125V DC Power Supply

A non-class 1E 125VDC power supply, Figure 8.3-7, is provided for non-safety-related switchgear, valves, converters, transducers, controls and instrumentation. The system has three load groups with one battery, charger and bus per load group. There are bus tie breakers between buses. Normal operation is with bus tie breakers open and interlocks prevent paralleling batteries. Each load group's battery and charger may be removed from service as a unit for maintenance or testing. A battery can be recharged by its charger prior to being placed back into service.

One backup charger is provided and is connectable to any of the three buses, one bus at a time, under control of Kirk key interlocks to:

(a) Perform extended maintenance on the normal charger for the load group.

(b) To make a live transfer of a bus to supply power from the bus of another load group without paralleling the two batteries.

The chargers are load limiting battery replacement type chargers capable of operation without a battery connected to the bus. The backup charger may be supplied from the ac supply of any one of the three load groups. It may be used to charge any one battery at a given time. For example the load group B battery may be charged from load group A or B or C ac power via the backup charger.

Each bus is connectable to either of the other two buses via Kirk key interlocked tie breakers. The Kirk key interlock system allows paralleling of chargers. Since the chargers are self load limiting, parallel operation is acceptable. The Kirk key interlock system prevents parallel operation of batteries. This is to prevent the possibility of paralleling batteries which have different terminal voltages and experiencing a large circulating current as a result.

The battery output breaker has an overcurrent trip and interrupts fault current flow from the battery to a bus fault. A combination disconnect switch and fuse is an acceptable alternate for the battery output breaker. The charger output breaker and the bus input breaker do not have overcurrent trips as the charger is load limiting and therefore protects itself. They are used as disconnect switches only. Bus load breakers have overcurrent trips coordinated with the battery output breaker. Tripping current for the load breakers is supplied by the battery.

8.3.2.1.3.3 Non-Class 1E 250V DC Power Supply

A non-class 1E 250VDC power supply, Figure 8.3-7, is provided for the computers and the turbine turning gear motor. The power supply consists of one 250VDC battery and two chargers. The normal charger is fed by 480VAC from either the load Group A or load Group C turbine building load centers. Selection of the desired ac supply is by a mechanically interlocked transfer switch. The standby charger is fed from a load Group A control building motor control center. Selection of the normal or the standby charger is controlled by key interlocked breakers. A 250VDC central distribution board is provided for connection of the loads, all of which are non-class 1E.

8.3.2.1.3.4 Ventilation

Battery rooms are ventilated to remove the minor amounts of gas produced during the charging of batteries.

8.3.2.1.3.5 Station Blackout

Station blackout performance is discussed in Subsection 19E.2.1.2.2.

8.3.2.2 Analysis

8.3.2.2.1 General DC Power Systems

The 480 VAC power supplies for the divisional battery chargers are from the individual class 1E MCC to which the particular 125 VDC system belongs (Figure 8.3-7). In this way, separation between the independent systems is maintained and the ac power provided to the chargers can be from either preferred or standby ac power sources. The dc system is so arranged that the probability of an internal system failure resulting in loss of that dc power system is extremely low. Important system components are either self-alarming on failure or capable of clearing faults or being tested during service to detect faults. Each battery set is located in its own ventilated battery room. All abnormal conditions of important system parameters such as charger failure or low bus voltage are annunciated in the main control room and/or locally.

AC and dc switchgear power circuit breakers in each division receive control power from the batteries in the respective load groups ensuring the following:

(1) The unlikely loss of one 125 VDC system does not jeopardize the Class 1E feed supply to the Class 1E buses.

(2) The differential relays in one division and all the interlocks associated with these relays are from one 125 VDC system only, thereby eliminating any cross connections between the redundant dc systems.

8.3.2.2.2 Regulatory Requirements

The following analyses demonstrate compliance of the Class 1E Divisions I, II, III and IV dc power systems to NRC General Design Criteria, NRC Regulatory Guides and other criteria consistent with the standard review plan. The analyses establish the ability of the system to sustain credible single failures and retain their capacity to function.

The following list of criteria is addressed in accordance with Table 8.1-1 which is based on Table 8-1 of the Standard Review Plan (SRP). In general, the ABWR is designed in accordance with all criteria. Any exceptions or clarifications are so noted.

(1) General Design Criteria (GDC):

  (a) Criteria: GDCs 2, 4, 17, and 18.

  (b) Conformance: The DC power system is in compliance with these GDCs. The GDCs are generically addressed in Subsection 3.1.2.

(2) Regulatory Guides (RGs):

  (a) RG 1.6 - Independence Between Redundant Standby (Onsite) Power Sources and Between Their Distribution Systems

  (b) RG 1.32 - Criteria for Safety-Related Electric Power Systems for Nuclear Power Plants

  (c) RG 1.47 - Bypassed and Inoperable Status Indication for Nuclear Power Plant Safety Systems

  (d) RG 1.63 - Electric Penetration Assemblies in Containment Structures for Light-Water-Cooled Nuclear Power Plants

  (e) RG 1.75 - Physical Independence of Electric Systems

The dc safety-related standby lighting system circuits up to the lighting fixtures are Class 1E and are routed in seismic Category I raceways. However, the lighting fixtures themselves are not seismically qualified, but are seismically supported. The cables and circuits from the power source to the lighting fixtures are Class 1E. The bulbs cannot be seismically qualified. This is an exception to the requirement that all Class 1E equipment be seismically qualified. The bulbs can only fail open and therefore do not represent a hazard to the Class 1E power sources.

Associated circuits added beyond the certified design must be specifically identified and justified per Subsection 8.3.4.13. Associated circuits are defined in Section 5.5.1 of IEEE 384-1981, with the clarification for Items (3) and (4) that non-Class 1E circuits being in an enclosed raceway without the required physical separation or barriers between the enclosed raceway and the Class 1E or associated cables makes the circuits (related to the non-Class 1E cable in the enclosed raceway) associated circuits.

(f) RG 1.106 - Thermal Overload Protection for Electric Motors on Motor-Operated Valves

Safety functions which are required to go to completion for safety have their thermal overload protection devices in force during normal plant operation but the overloads are bypassed under accident conditions per Regulatory Postion 1.(b) of the guide.

(g) RG 1.118 - Periodic Testing of Electric Power and Protection Systems

(h) RG 1.128 - Installation Designs and Installation of Large Lead Storage Batteries for Nuclear Power Plants

(i) RG 1.129 - Maintenance, Testing, and Replacement of Large Lead Storage Batteries for Nuclear Power Plants

(j) RG 1.153 - Criteria for Power, Instrumentation, and Control Portions of Safety Systems

(k) RG 1.155 - Station Blackout

The Class 1E dc power system is designed in accordance with the listed Regulatory Guides. It is designed with sufficient capacity, independence and redundancy to assure that the required power support for core cooling, containment integrity and other vital functions is maintained in the event of a postulated accident, assuming a single failure.

The batteries consist of industrial-type storage cells, designed for the type of service in which they are used. Ample capacity is available to serve the loads connected to the system for the duration of the time that alternating current is not available to the battery charger. Each division of Class 1E equipment is provided with a separate and independent 125 VDC system.

The DC power system is designed to permit inspection and testing of all important areas and features, especially those which have a standby function and whose operation is not normally demonstrated.

(i) RG 1.153 Criteria For Power, Instrumentation, and Control Portions of Safety Systems

(j) RG 1.155 Station Blackout

Credit is not taken for the CTG as an alternate AC source (AAC) so Section 3.3.5 of RG 1.155 is not required to be met. (The CTG does meet the requirements of Section 3.3.5, however.) See Section 19E.2.1.2.2 for a discussion of compliance with RG 1.155.

(3) Branch Technical Positions (BTPs):

BTP ICSB 21 - Guidance for Application of Regulatory Guide 1.47.

The dc power system is designed consistent with this criteria.

(4) Other SRP Criteria:

According to Table 8-1 of the SRP, there are no other criteria applicable to dc power systems.

8.3.3 Fire Protection of Cable Systems

The basic concept of fire protection for the cable system in the ABWR design is that it is incorporated into the design and installation rather than added onto the systems. By use of fire resistant and nonpropagating cables, conservative application in regard to ampacity ratings and raceway fill, and by separation, fire protection is built into the system. Fire suppression systems (e.g.; automatic sprinkler systems) are provided as listed in Table 9.5.1-1.

8.3.3.1 Resistance of Cables to Combustion

The electrical cable insulation is designed to resist the onset of combustion by limiting cable ampacity to levels which prevent overheating and insulation failures (and resultant possibility of fire) and by choice of insulation and jacket materials which have flame-resistive and self-extinguishing characteristics. Polyvinyl chloride or neoprene cable insulation is not used in the ABWR. All cable trays are fabricated from noncombustible material. Base ampacity rating of the cables was established as published in IPCEA-46-426/IEEE S-135 and IPCEA-54-440/ NEMA WC-51. Each coaxial cable, each single conductor cable and each conductor in multiconductor cable is specified to pass the vertical flame test in accordance with UL-44.

In addition, each power, control and instrumentation cable is specified to pass the vertical tray flame test in accordance with IEEE 383.

Power and control cables are specified to continue to operate at a conductor temperature not exceeding 90°C and to withstand an emergency overload temperature of up to 130°C in accordance with IPCEA S-66-524/NEMA WC-7 Appendix D. Each power cable has stranded conductor and flame-resistive and radiation-resistant covering. Conductors are specified to continue to operate at 100% relative humidity with a service life expectancy of 60 years. Also, Class 1E cables are designed and qualified to survive the LOCA ambient condition at the end of the 60-yr life span. The cable installation (i.e., redundant divisions separated by fire barriers) is such that direct impingement of fire suppressant will not prevent safe reactor shutdown, even if failure of the cable occurs. Cables are specified to be submersible, however (See the fourth requirement/ compliance in Subsection 9.5.1.0).

8.3.3.2 Localization of Fires

In the event of a fire, the installation design will localize the physical effects of the fire by preventing its spread to adjacent areas or to adjacent raceways of different divisions. Localization of the effect of fires on the electric system is accomplished by separation of redundant cable systems and equipment as described in Subsection 8.3.1.4. Floors and walls are effectively used to provide vertical and horizontal fire-resistive separations between redundant cable divisions.

In any given fire area an attempt is made to insure that there is equipment from only one safety-related division. This design objective is not always met due to other over-riding design requirements. IEEE Std 384 and Regulatory Guide 1.75 are always complied with, however. In addition an analysis is made and documented in Section 9A.5.5 to ascertain that the requirement of being able to safely shut the plant down with complete burnout of the fire area without recovery of the equipment is met. The fire detection, fire suppression and fire containment systems provided should assure that a fire of this magnitude does not occur, however.

Maximum separation of equipment is provided through location of redundant equipment in separate fire areas. The safety-related divisional ac unit substations, motor control centers, and dc distribution panels are located to provide separation and electrical isolation between the divisions. Clear access to and from the main switchgear rooms is also provided. Cable chases are ventilated and smoke removal capability is provided. Local instrument panels and racks are separated by safety division and located to facilitate required separation of cabling.

8.3.3.3 Fire Detection and Protection Systems

All areas of the plant are covered by a fire detection and alarm system. Double manual hose coverage is provided throughout the buildings. Sprinkler systems are provided as listed on Table 9.5.1-1. The diesel generator rooms and day tank rooms are protected by foam sprinkler systems. The foam sprinkler systems are dry pipe systems with pre-action valves which are actuated by compensated rate of heat rise and ultraviolet flame detectors. Individual sprinkler heads are opened by their thermal links.

8.3.4 COL License Information

8.3.4.1 Interrupting Capacity of Electrical Distribution Equipment

The interrupting capacity of the switchgear and circuit interrupting devices must be shown to be compatible with the magnitude of the available fault current based on final selection of the transformer impedence, etc. (See Subsection 8.3.1.1.5.2(4)).

8.3.4.2 Diesel Generator Design Details

Subsection 8.3.1.1.8.2 (4) requires the diesel generators be capable of reaching full speed and voltage within 20 seconds after the signal to start. Demonstrate the reliability of the diesel generator start-up circuitry designed to accomplish this.

8.3.4.3 Certified Proof Tests on Cable Samples

Subsection 8.3.1.2.4 requires certified proof tests on cables to demonstrate 60-year life, and resistance to radiation, flame and the environment. Demonstrate the testing methodology to assure such attributes are acceptable for the 60-year life.

8.3.4.4 Electrical Penetration Assemblies

Subsection 8.3.1.4.1.2. (7) specifies design requirements for electrical penetration assemblies. Provide fault current clearing-time curves of the electrical penetrations' primary and secondary current interrupting devices plotted against the thermal capability (I^2t) curve of the penetration (to maintain mechanical integrity). Provide an analysis showing proper coordination of these curves. Also, provide a simplified one-line diagram showing the location of the protective devices in the penetration circuit, and indicate the maximum available fault current of the circuit.

Provide specific identification and location of power supplies used to provide external control power for tripping primary and backup electrical penetration breakers (if utilized).

Provide an analysis demonstrating the thermal capability of all electrical conductors within penetrations is perserved and protected by one of the following:

(1) Show that maximum available fault current (including failure of upstream devices) is less than the maximum continuous current capacity (based on no damage to the penetration) of the conductor within the penetration; or

(2) Show that redundant circuit protection devices are provided, and are adequately designed and set to interrupt current, in spite of single failure, at a value below the maximum continuous current capacity (based on no damage to the penetration) of the conductor within the penetration. Such devices must be located in separate panels or be separated by barriers and must be independent such that failure of one will not adversly affect the other. Furthermore, they must not be dependent on the same power supply.

8.3.4.5 (deleted)

8.3.4.6 DC Voltage Analysis

Provide a dc voltage analysis showing battery terminal voltage and worst case dc load terminal voltage at each step of the Class 1E battery loading profile. (See Subsection 8.3.2.1)

Provide the manufactuer's ampere-hour rating of the batteries at the two hour rate and at the eight hour rate, and provide the one minute ampere rating of the batteries (see Subsection 8.3.2.1.3.2).

8.3.4.7 (deleted

8.3.4.8 (deleted)

8.3.4.9 Offsite Power Supply Arrangement

Operating procedures shall require one of the three divisional buses of Figure 8.3-1 be fed by the alternate power source during normal operation; in order to prevent simultaneous deenergization of all divisional buses on the loss of only one of the offsite power supplies. (See Subsection 8.2.3.1(4))

8.3.4.10 Diesel Generator Qualification Tests

The schedule for qualification testing of the diesel generators, and the subsequent results of those tests, must be provided. The tests shall be in accordance with IEEE 387 and Regulatory Guide 1.9. (See Susbsection 8.3.1.8.9)

8.3.4.11 (deleted)

8.3.4.12 Minimum Starting Voltages for Class 1E Motors

Provide the minimum required starting voltages for Class 1E motors. Compare these minimum required voltages to the voltages that will be supplied at the motor terminals during the starting transient when operating on offsite power and when operating on the diesel generators.

8.3.4.13 Identification and Justification of Associated Circuits

Prior to the implementation stage of the design, the only "associated circuits" (as defined by IEEE 384) known to exist in the ABWR Standard Plant design are for the FMCRD drive power feed taken from the division 1 6.9Kv safety-related bus (see Subsection 8.3.1.1.1). In the implementation design, provide 1) assurance that this is still a true statement, or 2) specifically identifiy and justify any other such circuits in the ABWR SSAR; and show they meet the requirements of Regulatory Guide 1.75, position C.4.

8.3.4.14 Administrative Controls for Bus Grounding Circuit Breakers

Figure 8.3-1 shows bus grounding circuit breakers, which are intended to provide safety grounds during maintenance operations. Administrative controls shall be provided to keep these circuit breakers racked out (i.e., in the disconnect position) whenever corresponding buses are energized. Furthermore, annunciation shall be provided to alarm in the control room whenever the breakers are racked in for service.

8.3.4.15 Testing of Thermal Overload Bypass Contacts for MOVs

Thermal overlaod protection for Class 1E MOVs is bypassed only during LOCA events. A means for testing the bypass function shall be implemented, in accordance with the requirements of Regulatory Guide 1.106.

8.3.4.16 Emergency Operating Procedures for Station Blackout

COL applicants should provide instructions in their plant Emergency Operating Procedures for operator actions during a postulated station blackout event. Specifically, if Division 1 instrumentation is functioning properly, the redundant Divisions II, III, and IV should be shut down in order to 1) reduce heat dissipation in the control room while HVAC is lost, and 2) conserve battery energy for additional SRV capacity, or other specific functions, as needed, throughout the event.

8.3.4.17 Common Industrial Standards Referenced in Purchase Specifications

In addition to the regulatory codes and standards required for licensing, purchase specifications shall contain a list of common industrail standards, as appropriate, for the assurance of quality manufacturing of both safety and non-safety related equipment. Such standards would include ANSI, ASTM, IEEE, NEMA, UL, etc.

8.3.5 References

In addition to those codes and standards required by the SRP the following codes and standards will be used and have been referenced in the text of this chapter of the SSAR.

IEEE Std 323	Qualifying Class 1E Equipment for Nuclear Power Generating Stations
IEEE Std 334	Standard for Type Test of Continuous Duty Class 1E Motors for Nuclear Power Generating Stations
IEEE Std 379	Standard Applications of the Single-Failure Criterion to Nuclear Power Generating Stations
IEEE Std 382	Standard for Qualification of Safety-Related Valve Actuators
IEEE Std 383	Standard for Type Test of Class 1E Electrical Cables, Field Splices, and Connecting for Nuclear Power Generating Stations

IEEE Std 387	Standard Criteria for Diesel-Generator Units Applied as Standby Power Supplies for Nuclear Power Generating Stations
IEEE Std 450	Recommended Practice for Large Lead Storage Batteries for Generating Stations and Substations
IEEE Std 485	Recommended Practice for Sizing Large Lead Storage Batteries for Generating Stations and Substations
[illegible]19	Guide for Harmonic Control and Reactive Compensation of Static Power Converters
[illegible] S-66-402	Thermoplastic Insulated Wire & Cable for the Transmission and Distribution of Electrical Energy
IPCEA-54-440/ NEMA WC-51	Ampacities Cables in Open-top Cable Trays
IPCEA S-66-524/ NEMA WC-7	Cross-Linked-Thermosetting Polyethlene Insulated Wire and Cable for the Transmission and Distribution of Electrical Energy
SECY-89-013	[illegible] Victor, Jr., *Design Requirements Related To The Evolutionary Advanced Light Water Reactors (ALWRS)*, Policy Issue, SECY-89-013, The Commissioners, United State Nuclear Regulatory Commission, January 19, 1989.

A partial listing of other common industry standards which may be used as applicable is given below. There are many more standards referenced in the standards which are listed below:

Motor Control Centers

NEMA ICS-2	Standards for Industrial Control Devices, Controllers and Assemblies

Underwriter's Laboratories Standard No. 845

Low Voltage Circuit Breakers

ANSI C37.13	Low Voltage Power Circuit Breakers
ANSI C37.16	Preferred Ratings and Related Requirements for Low Voltage AC Power Circuit Breakers and AC Power Service Protectors
ANSI C37.17	trip Devices for AC and General-Purpose DC Low-Voltage Power Circuit Breakers
ANSI C37.50	Test Procedures for Low Voltage AC Power Circuit Breakers Used in Enclosures

Molded Case Circuit Breakers

UL 489	Branch Circuit and Service Circuit Breakers
NEMA AB-1	Molded Case Circuit Breakers

7.2Kv metalclad Switchgear

ANSI C37.01	Application Guide for Power Circuit Breakers
ANSI C37.04	AC Power Circuit Breaker Rating Structure
ANSI C37.06	Preferred Ratings of Power Circuit Breakers
ANSI C37.09	Test Procedure for Power Circuit Breakers
ANSI C37.[illegible]	Power Circuit Breaker Control Requirements
ANSI C37.20	Switchgear Assemblies and Metal-Enclosed Bus
ANSI C37.100	Definitions for Power Switchgear

Transformers

ANSI C57.12	General Requirements for Distribution, Power, and Regulating Transformers
ANSI C57.12.11	Guide for Installation of Oil-immersed Transformers (10MVA and Larger, 69-287 kV rating)
ANSI C57.12.80	Terminology for Power and Distribution Transformers
ANSI C57.12.90	Test Code for Distribution, Power, and Regulating Transformers

TABLE 8.3-1

D/G LOAD TABLE -LOCA + LOPP

SYS. NO.	LOAD DESCRIPTION	RATING (kW)	GENERATOR OUTPUT (kW) A	B	C	NOTE*
--	MOTOR opc VALVES	231x3	X	X	X	(2)
C12	FMCRD (@ 0.25pf)	210x1 (840 KVA)	X	X	X	(4)
C41	SLC PUMP	45x2	45	45	--	
E11	RHR PUMP	540x3	540	540	540	
	Fill Pump*	3.7x3				
E12	HPCF PUMP	1400x2	--	1400	1400	
G31						
G41	FPC PUMP	75x2	78.9	78.9	--	
P13						
P21	RCW PUMP	320x4	640	640	--	
		260x2	--	--	520	
P25	HECW PUMP	22x5	44	44	44	
	HECW REFRIGERATOR	135x5	135	270	270	
P41	RSW PUMP**	270x6	540	540	540	
R23	P/C TRANSF. LOSS	40x6	84.2	84.2	84.2	
R42	DC 125V CHGR div. I	70x1	70.0	--	--	
	div. II, III, IV	34x3	34	34	34	(11)
	125V DC stby charger		70	--	34	

* See Table 8.3-3 for Notes
** Part of Turbine Island

TABLE 8.3-1

D/G LOAD TABLE -LOCA + LOPP (Continued)

SYS. NO.	LOAD DESCRIPTION	RATING (kW)	GENERATOR OUTPUT (kW) A	B	C	NOTE*
R46	VITAL CVCF		--	--	--	
	(Div. 1,2,3)	20x3	20	20	20	
	(Div. 4)	20	20			
R47	TRANSF. C/R INST	20x6	40	40	40	
R52	LIGHTING	100x3	100	100	100	
T22	SGTS FAN	18.5x2	18.5	18.5	--	
	SGTS HEATER	10x6	30	30	--	
T49	FCS HEATER	108x2		108	108	
	FCS BLOWER	11x2		11.0	11.0	
U41	MCR HVAC FANS A-B	74.5X4	--	149	149	(13)
	MCR RECIRC FANS A-B	14X4	--	28	28	(13)
	C/B ELEC EQUIP AREA HVAC FANS A-C	14X6	28	28	28	(13)
	R/B DG/ELEC EQUIP AREA HVAC FANS A-C	84X6	168	168	168	(13)
	R/B DG ROOM EMERGENCY SUPPLY FANS A-C	46.5X6	93	93	93	(13)
	R/B EQUIP AREA ROOM COOLERS A-C		89	107	84	(13)
	OTHER LOADS		62.5	62.5	60.5	
	TOTAL CONNECTED LOADS		3368.9	4884.9	4564.4	
	TOTAL STANDBY LOADS AND SHORT TIME LOADS		933.0*	633.0*	633.5*	
	TOTAL OPERATING LOADS		2435.9	4251.9	3930.9	

* *See Table 8.3-3 for Notes*

TABLE 8.3-2

D/G LOAD TABLE -LOPP (W/O LOCA)

SYS. NO.	LOAD DESCRIPTION	RATING (kW)	DIESEL ENGINE OUTPUT (kW) A	B	C	NOTE*

(Since there are no LOPP only loads on the diesel generators the LOCA load table envelopes the LOPP loading. See Table 8.3-1)

* *See Table 8.3-3 for Notes*
** *Part of Turbine Island*

TABLE 8.3-2

D/G LOAD TABLE -LOPP (W/O LOCA) (Continued)

SYS. NO.	LOAD DESCRIPTION	RATING (kW)	DIESEL ENGINE OUTPUT (kW) A	B	C	NOTE*

Deleted

* *See Table 8.3-3 for Notes*

TABLE 8.3-3

NOTES FOR TABLES 8.3-1 AND 8.3-2

(1) --: shows that the load is not connected to the switchgear of this division.
X: shows that the load is not counted for D/G continuous output calculation by the reasons shown on other notes.

(2) "Motor operated valves" are operated only 30-60 seconds. Therefore they are not counted for the DG continuous output calculation.

(3) Deleted

(4) FMCRD operating time (about 2 minutes) is not counted for the DG continuous output calculation.

(5) Deleted

(6) Deleted

(7) Deleted

(8) Deleted

(9) Deleted

(10) Deleted

(11) Div. IV battery charger is fed from Div. I motor control center.

(12) Load description acronyms are interpeted as follows:

C/B	- Control Building	HX	- Heat Exchanger
COMP	- Computer	IA	- Instrument Air
CRD	- Control Rod Drive	MCR	- Main Control Room
CUW	- Clean Up Water	MUWC	- Make Up Water System (condensed)
CVCF	- Constant Voltage Constant Frequency	NPSS	- Nuclear Protection Safety System
DG	- Diesel Generator	R/B	- Reactor Building
FCS	- Flammability Control System	RCW	- Reactor Cooling Water (building)
FPC	- Fuel Pool Cooling	RHR	- Residual Heat Removal
FMCRD	- Fine Motion Cotrol Rod Drive	RSW	- Reactor Sea Water
HECW	- Emergency Cooling Water	SBGT	- Standby Gas Treatment
HPCF	- High Pressure Core Flooder	SLC	- Standby Liquid Control

(13) Redundant units, one unit of a division and one unit is in standby in case the operating unit shuts down. Total connected load is shown on the table.

Table 8.3-4

D/G LOAD SEQUENCE DIAGRAM
MAJOR LOADS
(Response to Questions 435.14 & 435.15)

Mode	Block Time Div.	BLOCK 1 (20 SEC)	BLOCK 2 (30 SEC)	BLOCK 3 (35 SEC)	BLOCK 4 (40 SEC)	BLOCK 5 (45 SEC)	BLOCK 6 (50 SEC)	BLOCK 7 (55 SEC)	BLOCK 8 (60 SEC) Auto	BLOCK 9 AFTER 65 SEC Manual	
LOPP	I	MOV Inst. Tr Lighting FMCRD	DG HVAC	RCW Pump HECW Pump	RCW Pump	RSW Pump R/B Emer. HVAC C/B Emer. HVAC	RSW Pump	SGTS	Chargers CVCFs	SLC Pump HECW Refrig	RHR Pump CUW Pump FPC Pump
LOPP	II	MOV Inst. Tr Lighting	DG HVAC	RCW Pump HECW Pump	RCW Pump MCR HVAC	RSW Pump R/B Emer. HVAC C/B Emer. HVAC	RSW Pump	SGTS	Chargers CVCFs	SLC Pump HECW Refrig	RHR Pump CUW Pump FPC Pump
LOPP	III	MOV Inst. Tr Lighting	DG HVAC	RCW Pump HECW Pump	RCW Pump MCR HVAC	RSW Pump R/B Emer. HVAC C/B Emer. HVAC	RSW Pump		Chargers CVCFs	HECW Refrig	RHR Pump
LOCA & LOPP	I	MOV Inst. Tr Lighting FMCRD*	RHR Pump DG HVAC	RCW Pump HECW Pump	RCW Pump	RSW Pump R/B Emer. HVAC C/B Emer. HVAC	RSW Pump	SGTS	Chargers CVCFs	SLC Pump HECW refrig	FCS FPC Pump
LOCA & LOPP	II	MOV HPCF Pump Inst. Tr Lighting	RHR Pump DG HVAC	RCW Pump HECW Pump	RCW Pump MCR HVAC	RSW Pump R/B Emer. HVAC C/B Emer. HVAC	RSW Pump	SGTS	Chargers CVCFs	SLC Pump HECW Refrig	FCS FPC Pump
LOCA & LOPP	III	MOV HPCF Pump Inst. Tr Lighting	RHR Pump DG HVAC	RCW Pump HECW Pump	RCW Pump MCR HVAC	RSW Pump R/B Emer. HVAC C/B Emer. HVAC	RSW Pump		Chargers CVCFs	HECW Refrig	

Note* FMCRDs are the only Non Class 1E loads on the DG buses.

TABLE 8.3-5

DIESEL GENERATOR ALARMS*

Annunciation	DOS	DTS	DTT	GDT	GCB	GTT	LBP
Engine Overspeed Trip	X	X	X		X		
Generator Differential Relay Trip		X		X	X	X	
Generator Ground Overcurrent					X	X	X
Generator Voltage Restraint Overcurrent					X	X	X
Generator Bus Underfrequency					X	X	X
Generator Reverse Power		X			X	X	X
Generator Loss of Field		X			X	X	X
Generator Bus Differential Relay Trip					X		
High-High Jacket Water Temperature		X	X		X		X
D/G Bearing High Temperature		X			X	X	X
Low-Low Lube Oil Temperature		X	X		X		X
D/G Bearings High Vibration		X	X		X		X
High-High Lube Oil Temperature		X	X		X		X
Low-Low Lube Oil Pressure		X	X		X		X
High Crankcase Pressure		X	X		X		X
Low-Low Jacket Water Pressure		X	X		X		X
Low Level -- Jacket Water			X				
Low Pressure -- Jacket Water			X				
Low Temperature -- Jacket Water In			X				
High Temperature -- Jacket Water Out			X				
Low Level -- Lube Oil Mark			X				
Low Temperature -- Lube Oil In			X				
High Temperature -- Lube Oil Out			X				
High Diff. Pressure -- Lube Oil Filter			X				
Low Pressure -- Turbo Oil Right/Left Bank				X			
Low Pressure -- Lube Oil			X				
Control Circuit Fuse Failure			X				
Diesel Generator Overvoltage						X	
Low Pressure -- Strating Air			X				
In Maintenance Mode			X			X	
D/G Unit Fails to Start			X				
D/G Phase Overcurrent						X	
Out of Service		X			X		
Lockout Relay Operated		X			X	X	
Low-High Level -- Fuel Day Tank			X				
Low Level -- Fuel Storage Tank			X				
Low Pressure -- Fuel Oil			X				
High Diff. Pressure -- Fuel Filter			X				
In Local control Only			X				

TABLE 8.3-5

DIESEL GENERATOR ALARMS* (Continued)

Legend:

DOS	=	Diesel OverSpeed
DTS	=	Diesel Trip or Inoperative
DTT	=	Diesel Trouble or in Test
GDT	=	Generator Differential Trip
GCB	=	Generator Circuit Breaker Trip
GTT	=	Generator Trouble or in Test
LBP	=	LOCA ByPass (i.e., trip bypassed during LOCA) (Not an annunciator window)

* This list may vary depending on unique characteristics of specific diesel generator selected.

APPENDIX 8A
MISCELLANEOUS ELECTRICAL SYSTEMS

SECTION 8A

CONTENTS

SECTION 8A.1

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ILLUSTRATIONS

8A MISCELLANEOUS ELECTRICAL SYSTEMS

8A.1 Station Grounding and Surge Protection

8A.1.1 Description

The electrical grounding system is comprised of:

(1) an instrument grounding network,

(2) an equipment grounding network for grounding electrical equipment (e.g. switchgear, motors, distribution panels, cables, etc.) and selected mechanical components (e.g. fuel tanks, chemical tanks, etc.),

(3) a plant grounding grid, and

(4) a lightning protection network for protection of structures, transformers and equipment located outside buildings.

The plant instrumentation is grounded through a separate insulated radial grounding system comprised of buses and insulated cables. There is a single point connection to the station grounding grid.

The equipment grounding network is such that all major equipment, structures and tanks are grounded with two diagonally opposite ground connections. The ground bus of all switchgear assemblies, motor control centers and control cabinets are connected to the station ground grid through at least two parallel paths. One bare copper cable is installed with each underground electrical duct run, and all metallic hardware in each manhole is connected to the cable.

A plant grounding grid consisting of bare copper cables is provided to limit step and touch potentials to safe values under all fault conditions. The buried grid is located at the switchyard and connected to systems within the buildings by a 500 MCM bare copper loop which encircles all buildings (See Figure 8A.1-1).

The target value of ground resistance is 0.05 ohms or less for the reactor, turbine, control, service and radwaste buildings. If the target grounding resistance is not achieved by the ground grid, auxiliary ground grids, shallow buried ground rods or deep buried ground rods will be used in combination as necessary to meet the target ground resistance value.

The lightning protection system covers all major plant structures and is designed to prevent direct lightning strikes to the buildings, electric power equipment and instruments. It consists of air terminals, bare downcomers and buried grounding electrodes which are separate from the normal grounding system. Lightning arresters are provided for each phase of all tie lines connecting the plant electrical systems to the switchyard and offsite line. Plant instrumentation located outdoors or connected to cabling running outdoors is provided with surge suppression devices to protect the equipment from lightning induced surges.

8A.1.2 Analysis

There are no SRP or regulatory requirements for the grounding and lightning protection system. It is designed and required to be installed to the applicable sections of the following codes and standards.

(1) IEEE Std 80, Guide for Safety in AC Substation Grounding

(2) IEEE Std 81, Guide for Measuring Earth Resistivity, Ground Impedance, and Earth Surface Potentials of a Ground System

(3) IEEE Std 665, Guide for Generation Station Grounding

(4) NFPA-78, National Fire Protection Association's Lightning Protection Code

This code is utilized as recommended practices only. It does not apply to electrical generating plants.

8A.1.3 COL License Information

It is the responsibility of the COL applicant to perform ground resistance measurements to determine that the required value of 0.05 ohms or less has been met and to make additions to the system if necessary to meet the target resistance.

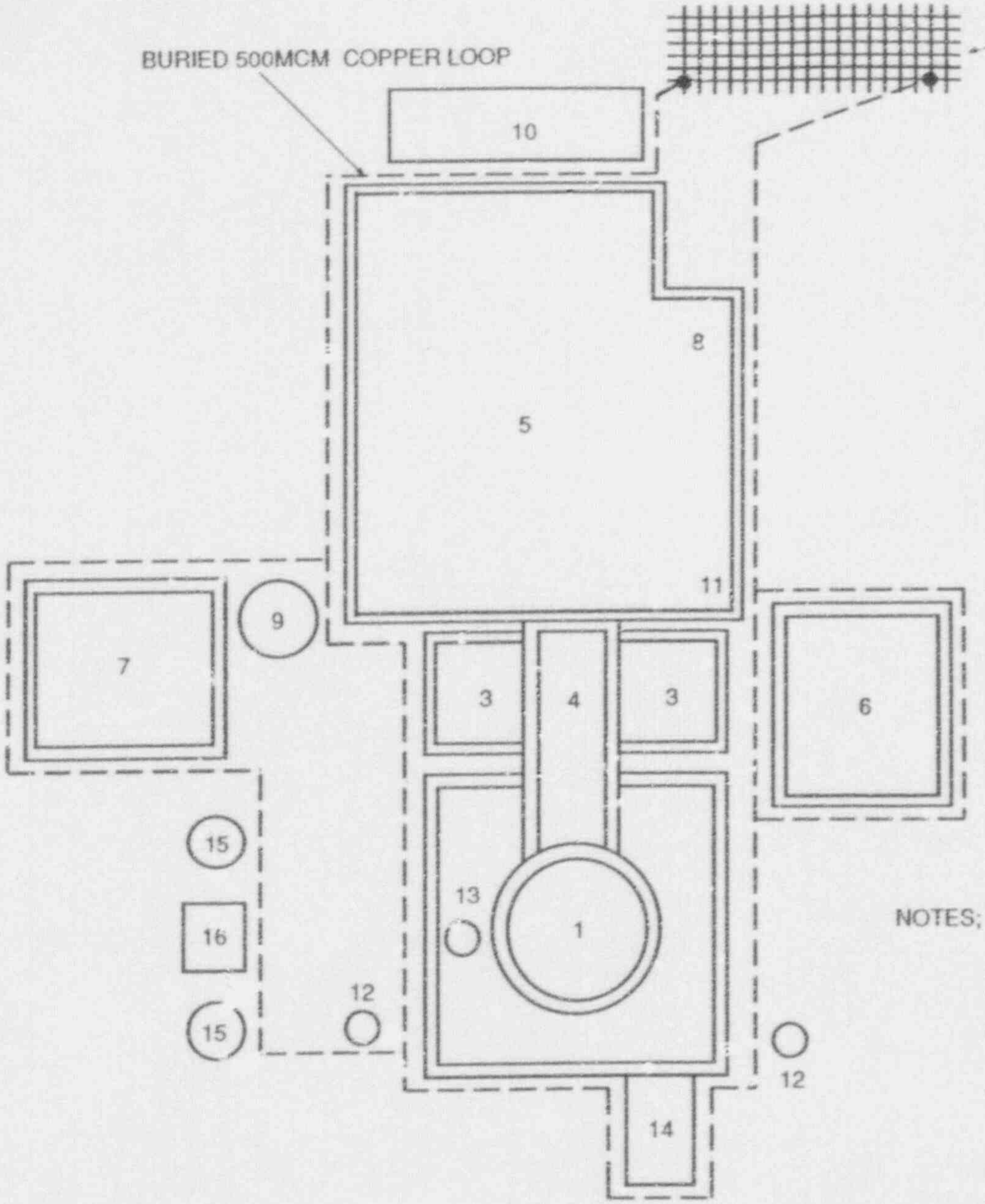
8A.1.4 References

(1) IEEE Std 80, Guide for Safety in AC Substation Grounding

(2) IEEE Std 81, Guide for Measuring Earth Resistivity, Ground Impedance, and Earth Surface Potentials of a Ground System

(3) IEEE Std 665, Guide for Generation Station Grounding

(4) NFPA-78, National Fire Protection Association's Lightning Protection Code



NO.	FACILITY
1	REACTOR CONTAINMENT
2	REACTOR BUILDING
3	CONTROL BUILDING
4	MAIN STEAM/FEEDWATER TUNNEL
5	TURBINE BUILDING
6	SERVICE BUILDING
7	RADWASTE BUILDING
8	HOUSE BOILER
9	CONDENSATE STORAGE TANK
10	MAIN TRANSFORMER
11	NORMAL SWITCHGEAR
12	DIESEL OIL STORAGE TANK (3)
13	STACK
14	EQUIPMENT ENTRY LOCK
15	FIRE PROTECTION WATER STORAGE TANK (2)
16	FIRE PROTECTION PUMPHOUSE

NOTES;

STRUCTURES AND BUILDINGS TO BE GROUNDED TO THE YARD LOOP PER THE FOLLOWING SPECIFICATIONS:

A. ELECTRICAL GROUNDING REQUIREMENTS SPECIFICATIONS

B. LIGHTING PROTECTION SPECIFICATION

FIGURE 8A.1-1 SITE PLAN (GROUNDING)

SECTION 8A.2

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8A.2 Cathodic Protection

8A.2.1 Description

A cathodic protection system is provided. Its design is plant unique as it must be tailored to the site conditions. The COL license applicant must provide a design meeting the requirements listed in Subsection 8A.2.3.

8A.2.2 Analysis

There are no SRP or regulatory requirements nor any national standards for cathodic protection systems. The system is designed to the requirements listed in Subsection 8A.2.3.

8A.2.3 COL License Information

The COL applicant is required to meet the following minimum requirements for the design of the cathodic protection systems. These requirements are the same as those called for in Chapter 11, Section 9.4 of the Utility Requirements Document issued by the Electric Power Research Institute.

(1) The need for cathodic protection on the entire site, portions of the site, or not at all shall be determined by analyses. The analyses shall be based on soil resistivity readings, water chemistry data, and historical data from the site gathered from before commencement of site preparation to the completion of construction and startup.

(2) Where large protective currents are required, a shallow interconnected impressed current system consisting of packaged high silicon alloy anodes and transformer-rectifiers, shall normally be used. The rectifiers shall be approximately 50 percent oversized in anticipation of system growth and possible higher current consumption.

(3) The protected structures of the impressed current cathodic protection system shall be connected to the station grounding grid.

(4) Localized sacrificial anode cathodic protection systems shall be used where required to supplement the impressed current cathodic protection system and protect surfaces which are not connected to the station grounding grid or are located in outlying areas.

(5) Prepackaged zinc type reference electrodes shall be permanently installed near poorly accessible protected surfaces to provide a means of monitoring protection level by measuring potentials.

(6) Test stations above grade shall be installed throughout the station adjacent to the areas being protected for termination of test leads from protected structures and permanent reference electrodes.

8A.2.4 References

(1) Utility Requirements Document, Advanced Light Water Reactor, Volume II, ALWR Evolutionary Plant, Electric Power Institute

SECTION 8A.3

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8A.3 Electric Heat Tracing

8A.3.1 Description

The electric heat tracing system provides freeze protection where required for outdoor service components and fluid warming of process fluids if required, either in or out doors. If the operation of the heat tracing is required for proper operation of a safety-related system, the heat tracing for the safety-related system is required to be safety-related, also. Power for heat tracing is supplied from buses backed by the onsite standby generators. Non safety-related heat tracing has access to the combustion turbine generator through the same load group as the components protected. Safety-related heat tracing is assigned to the appropriate division for a source of safety-related power.

8A.3.2 Analysis

There are no SRP or regulatory requirements for cathodic protection systems. They are required to be designed and installed to the applicable sections of the following codes and standards.

(1) IEEE Std 622, Recommended Practice for the Design and Installation of Electric Heat Tracing Systems in Nuclear Power Generating Stations

(2) IEEE Std 622A, Recommended Practice for the Design and Installation of Electric Pipe Heating Control and Alarm Systems in Nuclear Power Generating Stations

8A.3.3 COL License Information

No COL applicant information is required.

8A.3.4 References

The following codes and standards have been referenced in this section of the SSAR.

(1) IEEE Std 622, Recommended Practice for the Design and Installation of Electric Heat Tracing Systems in Nuclear Power Generating Stations

(2) IEEE Std 622A, Recommended Practice for the Design and Installation of Electric Pipe Heating Control and Alarm Systems in Nuclear Power Generating Stations

SECTION 9.1

CONTENTS (Continued)

SECTION 9.1

CONTENTS (Continued)

9.1.2 Spent Fuel Storage

9.1.2.1 Design Bases

9.1.2.1.1 Nuclear Design

(1) A full array in the loaded spent fuel rack is designed to be subcritical, by at least 5% Δk. Neutron-absorbing material, as an integral part of the design, is employed to assure that the calculated k_{eff}, including biases and uncertainties, will not exceed 0.95 under all normal and abnormal conditions.

(a) Monte Carlo techniques are employed in the calculations performed to assure that k_{eff} does not exceed 0.95 under all normal and abnormal conditions.

(b) The assumption is made that the storage array is infinite in all directions. Since no credit is taken for neutron leakage, the values reported as effective neutron multiplication factors are, in reality, infinite neutron multiplication factors.

(c) The biases between the calculated results and experimental results, as well as the uncertainty involved in the calculations, are taken into account as part of the calculational procedure to assure that the specific k_{eff} limit is met.

9.1.2.1.2 Storage Design

The fuel storage racks provided in the spent fuel storage pool provide storage for 270% of one full core fuel load.

The fuel storage pool liner seismic classification is provided in Table 3.2-1.

9.1.2.1.3 Mechanical and Structural Design

The spent fuel storage racks in the reactor building contain storage space for fuel assemblies (with channels) or bundles (without channels). They are designed to withstand all credible static and seismic loadings. The racks are designed to protect the fuel assemblies and bundles from excessive physical damage which may cause the release of radioactive materials in excess of 10CFR20 and 10CFR100 requirements, under normal and abnormal conditions caused by impacting from either fuel assemblies, bundles or other equipment.

The spent fuel pool is a reinforced concrete structure with a stainless steel liner. The bottoms of all pool gates are sufficiently high to maintain the water level over the spent fuel storage racks form adequate shielding and cooling. All pool fill and drain lines enter the pool above the safe shielding water level. Redundant anti-siphon vacuum breakers are located at the high point of the pool circulation lines to preclude a pipe break from siphoning the water from the pool and jeopardizing the safe water level.

The racks include individual solid tube storage compartments, which provide lateral restraints over the entire length of the fuel assembly or bundle. The weight of the fuel assembly or bundle is supported axially by the rack fuel support. Lead-in guides at the top of the storage spaces provide guidance of the fuel during insertion.

The racks are fabricated from materials used for construction are specified in accordance with the latest issue of applicable ASTM specifications. The racks are constructed in accordance with a quality assurance program that ensures the design, construction and testing requirements are met.

The racks are designed to withstand, while maintaining the nuclear safety design basis, the impact force generated by the vertical free-fall drop of a fuel assembly from a height of 6 feet. The rack is designed to withstand a pullup force of 4000 pounds and a horizontal force of 1000 pounds. There are no readily definable horizontal forces in excess of 1000 pounds, and in the event a fuel assembly should jam, the maximum lifting force of the fuelhandling platform grapple (assumes limit switches fail) is 3000 pounds.

The fuel storage racks are designed to handle irradiated fuel assemblies. The expected radiation levels are well below the design levels.

In accordance with Regulatory Guide 1.29, the fuel storage racks are designated Safety Class 2 and Seismic Category I. The structural integrity of the rack has been demonstrated for the load combinations described below using linear elastic design methods.

The applied loads to the rack are:

(1) dead loads, which are weight of rack and fuel assemblies, and hydrostatic loads;

(2) live loads - effect of lifting an empty rack during installation;

(3) thermal loads - the uniform thermal expansion due to pool temperature changes;

(4) seismic forces of OBE and SSE;

(5) accidental drop of fuel assembly from maximum possible height 6 feet above rack; and

(6) postulated stuck fuel assembly causing an upward force of 3000 pounds.

The load combinations considered in the rack design are:

(1) live loads

(2) dead loads plus OBE

(3) dead loads plus SSE; and

(4) dead loads plus fuel drop.

Thermal loads were not included in the above combinations because they were negligible due to the design of the rack (i.e., the rack is attached only at its base and is free to expand/contract under pool temperature changes).

The loads experienced under a stuck fuel assembly condition are less than those calculated for the seismic conditions and, therefore, have not been included as a load combination.

The storage racks are attached to the support structure by bolting, sufficient to counteract the tendency to overturn from horizontal loads and to lift from vertical loads. The analysis of the rack assumed an adequate supporting structure, and loads were generated accordingly.

Stress analyses were performed by classical methods based upon shears and moments developed by the dynamic method. Using the given loads, load conditions and analytical methods, stresses were calculated at critical sections of the rack and compared to acceptance criteria referenced in ASME Section III subsection NF. Compressive stability was calculated according to the AISI code for light gage structures.

The loads in the three orthogonal directions were considered to be acting simultaneously and were combined using the SRSS method suggested in Regulatory Guide 1.92. The loads due to the OBE event are approximately 90% of those due to an SSE event, and allowable stress levels for OBE are 50% of SSE, therefore making the OBE event the limiting load condition except for stability, where SSE acceptance criteria of 67% of critical buckling strength is limiting.

Under fuel drop loading conditions, the acceptance criterion is that, although deformation may occur, K_{eff} must remain <0.95. The rack is designed such that, should the drop of a fuel assembly damage the tubes and dislodge a plate of poison material, the K_{eff} would still be <0.95 as required.

The effect of the gap between the fuel and the storage tube has been taken into account on a local effect basis. Dynamic response analysis shows that the fuel contacts the tube over a large portion of its length, thus preventing an overloaded condition of both fuel and tube.

The vertical impact load of the fuel onto its seat has been considered conservatively as being slowly applied without any benefit for strain rate effects.

9.1.2.1.4 Thermal-Hydraulic Design

The fuel storage rack is designed to provide sufficient natural convection coolant flow to remove 68,000 Btu/hr/bundle of decay heat.

The support structure must be designed to provide an adequate flow rate to prevent water reaching excessive temperatures 212°F. The flow rate is dependent on the decay heat load, the ΔP losses through the structure and the losses through the rack and bundle.

In the spent fuel storage pool, the bundle decay heat is removed by recirculation flow to the fuel pool cooling heat exchanger to maintain the pool temperature. Although the design pool exit temperature within the rack is high depending on the naturally induced bundle flow which carries away the decay heat generated by the spent fuel. The rate of naturally circulated flow and maximum rack exit temperature have been evaluated.

The parameters which will affect the water flow

(9) Replace vessel studs.

(10) Install reactor vessel head.

(11) Install vessel head piping and insulation.

(12) Hydro test vessel if required.

(13) Install drywell head; leak check.

(14) Install shield plugs.

(15) Stow gates.

(16) Startup tests - the reactor is returned to full power operation. Power is increased gradually in a series of steps unit the reactor is operating at rated power. At specific steps during the approach to power, the incore flux monitors are calibrated.

9.1.4.2.10.3 Departure of Fuel From Site

The empty cask arrives at the plant on the special flatbed railcar or truck. The personnel shipping barrier and transfer impact structure are removed from the large casks and stored outside the rail entry door. Health physics personnel check the cask exterior to determine if decontamination is necessary. Decontamination, if required, and washdown to remove road dirt, is performed before removal of the cask from the transport vehicle. The R/B equipment entry airlock door is opened and the cask with its transport device moved into the building. The rail car or truck is blocked in position.

The airlock door is closed and the cask is inspected for shipping damage.

The cask cooling system of the transport vehicle is disconnected. The cask yoke is removed from its storage position on the flatbed and attached to the cask trunnions. The yoke engagement, car brakes and wheel blocks and clearances for cask tilt and lift are checked. The cask is tilted to the vertical position with combined main hoist lift and trolley movement. With the cask in a vertical position, the cask is lifted approximately 5 ft off the transport device skid mounting trunnions to clear the upper coolant duct. The cask is moved up to the refueling floor and then into the cask washdown pit and slowly lowered to the floor of the pit. Closure head lifting cables on the yoke are attached to the head and secured and the closure nuts are disengaged. The cask is next raised and transferred into the cask pit.

The cask is moved to a position over the center of the cask pit and slowly lowered into the cask pit until it rests on the cask pit floor.

The cask lifting yoke is lowered until disengaged from the cask trunnions and the closure head lifted off the cask. The closure head and yoke are moved into the cask washdown pit for storage. The canal gates between the cask pit and the spent fuel pool are removed and spent fuel transfer from the storage racks to the cask is started.

Spent fuel is transferred underwater from storage in the spent fuel pool to the cask using the telescoping fuel grapple mounted on the refueling platform. When the cask is filled with spent fuel, the gate between the cask pit and the spent fuel pool is replaced. The closure head is replaced on the cask and the lift yoke engaged with the cask trunnions. The loaded cask is raised, transferred to the cask washdown pit, and slowly lowered to the pit floor.

The cask is checked by health physics personnel and decontamination is performed in the cask washdown pit with high pressure water sprays, chemicals and hand scrubbing as required to clean the cask to the level required for transport. Cooling connections are available in the cask washdown pit in the event cooling is required during decontamination activities. The remaining closure nuts are replaced and tightened. Smear tests are performed to verify cleaning to offsite transportation requirements.

The cleaned cask is lowered from the refueling floor to the reactor building entry lock onto cask skids with the reactor building crane and mounted on the transport vehicle. The cask cooling system of the transport vehicle is connected to the cask and the cask internal pressure and temperature are monitored. When they are at equilibrium conditions, the cask is ready for shipment. The personnel barrier and impact structure are replaced. The reactor building airlock facility doors are opened and the cask and transport device are moved out of the reactor building.

9.1.4.3 Safety Evaluation of Fuel Handling System

Safety aspects (evaluation) of the fuel servicing equipment are discussed in Subsection 9.1.4.2.3 and safety aspects of the refueling equipment are discussed throughout Subsection 9.1.4.2.7. In addition, a following summary safety evaluation of the fuel-handling system is provided below.

The fuel prep machine removes and installs channels with all parts remaining underwater. Mechanical stops prevent the carriage from lifting the fuel bundle or assembly to height where water shielding is not sufficient. Irradiated channels, as well as small parts such as bolts and springs, are stored underwater. The spaces in the channel storage rack have center posts which prevent the loading of fuel bundles into this rack.

There are no nuclear safety problems associated with the handling of new fuel bundles, singly or in pairs. Equipment and procedures prevent an accumulation of more than two bundles in any location.

The refueling platform is designed to prevent it form toppling into the pools during a SSE. Redundant safety interlocks, as well as limit switches, are provided to prevent accidentally running the grapple into the pool walls. The grapple utilized for fuel movement is on the end of a telescoping mast. At full retraction of the mast, the grapple is sufficiently below water surface, so there is no chance of raising a fuel assembly to the point where it is inadequately shielded by water. The grapple is hoisted by redundant cables inside the mast, and is lowered by gravity. A digital readout is displayed to the operator, showing him the exact coordinates of the grapple over the core.

The mast is suspended and gimbaled from the trolley, near its top, so that the mast can be swung about the axis of platform travel, in order to remove the grapple from the water for servicing and for storage.

The grapple has two independent hooks, each operated by an air cylinder. Engagement is indicated to the operator. Interlocks prevent grapple disengagement until a "slack cable" signal from the lifting cables indicates that the fuel assembly is seated. The slack cable indication is also used to determine if a fuel bundle is lodged in a position other than its normal, seated position in the core.

430.193 In addition to the slack cable signal, the elevation of the grapple is continuously indicated. Also, after the grapple is disengaged, the position of the upper part of the fuel bundle can be observed using television.

In addition to the main hoist on the trolley, there are two auxiliary hoist on the trolley. These three hoists are precluded from operating simultaneously because control power is available to only one of them at a time. The two auxiliary hoists have load cells with interlocks which prevent the hoists form moving anything as heavy as a fuel bundle.

The two auxiliary hoists have electrical interlocks which prevent the lifting of their loads higher than a specified limit. Adjustable mechanical jam-stops on the cables back up these interlocks.

The cask is moved by the reactor building crane to the cask pit and gated off and the cask pit filled with water. Only then is the spent fuel pool connected to the cask pit and the fuel transfer begun. When the cask is loaded, the spent fuel pool is gated closed and the cask removal procedure reversed. A cask decontamination pit area is provided.

Light loads such as the blade guide, fuel support casting, control rod or control rod guide tube weigh considerably less than a fuel bundle and are administratively controlled to eliminate the movement of any light load over the spent fuel pool above the elevation required for fuel assembly handling. Thus, the kinetic energy of any light load would be less than a fuel bundle and would have less damage induced. Secondly, to satisfy NUREG 0554, the equipment handling components over the spent fuel pool are designed to meet the single failure proof criteria.

The spent fuel storage racks are purchased equipment. The purchase specification for these racks will require the vendor to provide the 430.193
information requested in Question 430.192 pertaining to load drop analysis. See Subsection 9.1.4.3 for interface requirements.

In summary, the fuel-handling system complies with General Design Criteria 2, 3, 4, 5, 61, and 63, and applicable portions of 10CFR50.

9.1.5 Overhead Heavy Load Handling Systems (OHLH)

9.1.5.1 Design Bases

The equipment covered by this subsection handle items considered as heavy loads that are handled under conditions that mandate critical handling compliance.

Critical load handling conditions include loads, equipment, and operations, which if inadvertent operations or equipment malfunctions either separately or in combination, could cause; (1) a release of radioactivity, (2) a criticality accident, (3) the inability to cool fuel within reactor vessel or spent fuel pool or (4) prevent safe shutdown of the reactor. This includes risk assessments to spent fuel and storage pool water levels, cooling of fuel pool water, new fuel criticality. This includes all components and equipment used in moving any load weighing more than one fuel assembly including the weight of its associated handling devices (i.e., one ton).

The reactor building crane as designed shall provide a safe and effective means for transporting heavy loads including the handling of new and spent fuel, plant equipment and service tools. Safe handling includes design considerations for maintaining occupational radiation exposure as low as practicable during transportation and handling.

Where applicable, the appropriate seismic category, safety class quality group, ASME, ANSI, industrial and electrical codes have been identified (see Tables 3.2-1 and 9.1-6). The designs will conform to the relevant requirements of General Design Criterion 2, 4 and 61 of 10CFR Part 50, Appendix A.

The lifting capacity of each crane or hoist is designed to at least the maximum actual or anticipated weight of equipment and handling devices in a given area serviced. The hoists, cranes, or other lifting devices shall comply with the requirements of ANSI N14.6, ANSI B30.9, ANSI B30.10 and NUREG-0612 Subsection 5.1.1(4) or 5.1.1(5). Cranes and hoists are also designed to criteria and guidelines of NUREG-0612 Subsection 5.1.1(7), ANSI B30.2 and CMAA-70 specifications for electrical overhead traveling cranes, including ANSI B30.11, ANSI B30.16, and NUREG-0554 as applicable.

9.1.5.2 System Description

9.1.5.2.1 Reactor Building Crane

The reactor building (RB) is a reinforced concrete structure which encloses the reinforced concrete containment vessel, the refueling floor, new fuel storage vault, the storage pools for spent-fuel and the dryer and separator and other equipment. The reactor building crane provides heavy load lifting capability for the refueling floor. The main hook (150 ton capacity) will be used to lift the concrete shield blocks, drywell head, reactor pressure vessel (RPV) head insulation, RPV head, dryer, separator strong back, RPV head strongback carousel, new fuel shipping containers, and spent fuel shipping cask. The orderly placement and movement paths of these components by the reactor building crane precludes transport of these heavy loads over the spent fuel storage pool or over the new fuel storage vault.

The RB crane will be used during refueling/servicing as well as when the plant is online. During refueling/servicing, the crane handles the shield plugs, drywell and reactor vessel heads, steam dryer and separators, etc. (see Table 9.1-7). Minimum crane coverage include RB refueling floor laydown areas, and RB equipment storage pit. During normal plant operation the crane will be used to handle new fuel shipping containers and the spent fuel shipping casks. Minimum crane coverage must include the new fuel vault, the RB equipment hatches, and the spent fuel cask loading and washdown pits. A description of the refueling procedure can be found in Section 9.1.4.

The RB crane will be interlocked to prevent movement of heavy loads over the spent fuel storage portion of the spent fuel storage pool. Since the crane is used for handling large heavy objects over the open reactor the crane is of type I design. The reactor building crane shall be designed to meet the single-failure-proof requirements of NUREG-0554.

9.1.5.2.2 Other Overhead Load Handling System

9.1.5.2.2.1 Upper Drywell Servicing Equipment

The upper drywell arrangement provides servicing access for the main steam isolation valves (MSIVs), feedwater isolation valves, safety relief valves (SRVs), emergency core cooling systems (ECCSs) isolation valves, and drywell cooling coils, fans and motors. Access to the space is via the RB through either the upper drywell personnel lock or equipment hatch. All equipment is removed through the upper drywell equipment hatch. Platforms are provided for servicing the feedwater and mainsteam isolation valves, safety relief valves, and drywell cooling equipment with the object of reducing maintenance time and operator exposure. The MSIVs, SRVs, and feedwater isolation valves all weigh in excess of 200 kg. Thus they are considered heavy loads.

With maintenance activity only being performed during a refueling outage, only safe shutdown ECCS piping and valves need be protected from any inadvertent load drops. Since only one division of ECCS is required to maintain the safe shutdown condition and the ECCS divisions are spatially separated, an inadvertent load drop that breaks more than one division of ECCS is not credible. In addition, two levels of piping support structures and equipment platforms separate and shield the ECCS piping from heavy loads transport path.

This protection is adequate such that no credible load drop can cause either (1) a release of radioactivity, (2) a criticality accident, or (3) the inability to cool fuel within reactor vessel or spent fuel pool; therefore, the upper drywell servicing equipment is not subject to the requirements of Subsection 9.1.5.

9.1.5.2.2.2 Lower Drywell Servicing Equipment

The lower drywell (L/D) arrangement provides for servicing, handling and transportation operations for RIP, and FMCRD. The lower drywell OHLHS consists of a rotating equipment service platform, chain hoists, FMCRD removal machine, a RIP removal machine, and other special purpose tools.

The rotating equipment platform provides a work surface under the reactor vessel to support the weight of personnel, tools, and equipment and to facilitate transportation moves and heavy load handling operations. The platform rotates 360° in either direction from its stored or "idle" position. The platform is designed to accommodate the maximum weight of the accumulation of tools and equipment plus a maximum sized crew. Weights of tools and equipment are specified in the interface control drawings for the equipment used in the lower drywell. Special hoists are provided in the lower drywell and reactor building to facilitate handling of these loads.

(1) Reactor Internal Pump Servicing

There are 10 RIPs and their supporting instrumentation and heat exchangers in the L/D that require servicing. The facilities provided for servicing the RIPs include:

(a) L/D equipment platform with facilities to rotate the motor from vertical to horizontal and place it on a cart for direct pull out to the RB. The equipment platform rotates to facilitate alignment with the installed pump locations.

(b) Attachment points for rigging the RIP heat exchanger into place. The RIP heat exchanger can be lowered straight down to the equipment platform.

(c) Access to the RIP equipment platform is via stairs. There is a ladder access to the RIP heat exchanger maintenance platform.

(d) The L/D equipment tunnel and hatch are utilized to remove the RIP motors from the lower drywell.

(e) The RIP motor servicing area is directly outside the L/D equipment hatch.

The 10 RIPs have wet induction motors in housings which protrude into the lower drywell from the RPV bottom head. These are in a circle at a radius of 3162.5 mm from the RPV centerline. For service, the motor is removed from below and outside, whereas the diffuser, impeller and shaft are removed from above and inside the RPV.

The motor, with its lower flange attached, weighs approximately 3300 kg, is 830 mm in diameter and 1925 mm high. The flange has "ears" that extend from two sides, 180° apart. These ears, which are used to handle the motor, increase the flange diameter to 1200 mm for a width of 270 mm.

The motor, suspended from jack screws, is lowered straight down out of its housing onto

9.1.6 COL License Information

9.1.6.1 New Fuel Storage Racks Criticality Analysis

The COL applicant referencing the ABWR design shall provide the NRC confirmatory criticality analysis as required by Subsection 9.1.1.1.1.

9.1.6.2 Dynamic and Impact Analyses of New Fuel Storage Racks

The COL applicant referencing the ABWR design shall provide the NRC confirmatory dynamic and impact analyses of the new fuel storage racks. See Subsection 9.1.1.1.6.

9.1.6.3 Spent Fuel Storage Racks Criticality Analysis

The COL applicant referencing the ABWR design shall provide the NRC confirmatory critically analysis as required by Subsection 9.1.2.3.1.

9.1.6.4 Spent Fuel Racks Load Drop Analysis

The COL applicant referencing the ABWR design shall provide the NRC confirmatory load drop analysis as required by Subsection 9.1.4.3.

9.1.6.6 Overhead Load Handling System Information

The COL applicant shall provide the NRC for confirmatory review: (1) heavy load handling system and equipment maintenance procedures, (2) heavy load handling system and equipment maintenance procedures and/or manuals, (3) heavy load handling system and equipment inspection and test plans; NDE, Visual, etc., (4) heavy load handling safe load paths and routing plans, (5) QA program to monitor and assure implementation and compliance of heavy load handling operations and controls, (6) operator qualifications, training and control program.

9.1.6.5 New Fuel Inspection Stand Seismic Capability

The COL applicant referencing the ABWR design will install the new fuel inspection stand firmly to the wall so that it does not fall into or dump personnel into the spent fuel pool during an SSE. (See Subsection 9.1.4.2.3.2.)

9.1.7 References

1. *General Electric Standard Application for Reactor Fuel*, (NEDE-24011-P-A, latest approved revision).

Table 9.1-1

DEFINITION OF TERMS

A_b	Flow area through bundles = 15.353 in.^{2}).
A_k	Arbitrary area used in bundle friction correlation = 10 in.^{2}
C_p	Specific heat of water = 1.0 Btu/lb- ^oF.
g	Gravitational constant 32.2 ft/sec^2.
H_b	Head loss through bundle (ft H_2O).
h_c	Effective depth of cold water over entrance point into bundle = 13.5 ft in this example
ℓ	Intercept in ρ versus t correlation = 63.45 lb/ft^3.
M	Slope of ρ versus t correlation = -0.0145 lb/ft^3 -^oF.
ρ_c	Density of water = 62.00 lb/ft^3 (at 100^{o}F).
Q	Heat evolution rate from bundle = 68,000/3,600 Btu/sec.
t	Inlet water temperature (100^{o}F).
V_b	Velocity of water through bundle (ft/sec).

Table 9.1-2

FUEL SERVICING EQUIPMENT

No.	Component Identification	Essential Classification (a)	Safety Classification (b)	Quality Group (c)	Seismic Category (d)
1	Fuel Prep Machine	NE	N	E	N/A
2	New Fuel Inspection Stand	PE	2	E	O
3	Channel Bolt Wrench	NE	N	E	NA
4	Channel-Handling Tool	NE	N	E	NA
5	Fuel Pool Vacuum Sipper	NE	N	E	NA
6	General-Purpose Grapple	NE	N	E	NA
430.196 7	Deleted				
8	Refueling Platform	PE	2	E	O
9	Channel-Handling Machine	NE	N	E	NA

Notes:

(a) NE = Non Essential
PE = Passive Essential

(b) N = Non-nuclear safety-related
2 = Safety Class

(c) E = Elements of 10CFR50, Appendix B are generally applied, commensurate with the importance of the requirement function.

(d) NA = No Seismic Requirements
I = Seismic Category I
O = Designed for OBE, and to hold its load in a SSE

Table 9.1-3

REACTOR VESSEL SERVICING EQUIPMENT

No.	Essential Component Identification (a) (b)	Safety Classification (c)	Classification (d)	Quality Group	Seismic Category
1	Reactor Vessel Service Tools	NE	N	E	NA
2	Steamline Plug	NE	N	E	NA
3	Shroud Head Bolt Wrench	NE	N	E	NA
4	Head Holding Pedestal	NE	N	E	I
7	Head Stud Rack	NE	N	E	NA
6	Dryer and Separator Strongback	NE	N	E	NA*
7	Head Strongback Carousel	PE	2	E	NA
8	RIP Impeller Shaft	PE	N	E	NA
9	RIP Impeller Rack	NE	N	E	NA
10	Fuel Assembly Sampler	NE	N	E	NA

Notes:

(a) NE = Non Essential
PE = Passive Essential

(b) N = Non-nuclear Safety-related
2 = Safety Class

(c) E = Elements of 10CFR50, Appendix B are generally applied, commensurate with the importance of the requirement function.

(d) NA = No Seismic Requirements
I = Seismic Category I

* *Dynamic analysis methods for seismic loading are not applicable, as this equipment is supported by the reactor service crane. Lifting devices have been designed with a minimum safety factor of 5 and undergo proof testing.*

Table 9.1-4

UNDER-REACTOR VESSEL SERVICING EQUIPMENT AND TOOLS

No.	Equipment/Tool	Classification	Safety Class	Seismic Category
1	FMCRD Handling Equipment	NE	N	NA
	FMCRD Motor/Seal Assembly	NE	N	NA
2	Equipment Handling Platform	NE	N	NA
3	Water Seal Cap	NE	N	NA
4	In-Core Flange Seal Test Plug	NE	N	NA
5	Key Bender	NE	N	NA
6	RIP Motor Servicing Equipment	NE	N	NA

Notes:

NA = No Seismic Requirements
N = Non-nuclear safety-related
NE = Non Essential

Table 9.1-5

TOOLS AND SERVICING EQUIPMENT

Fuel Servicing Equipment

Channel Handling Boom
Fuel Preparation Machines
New Fuel Inspection Stand
Channel Bolt Wrenches
Channel Handling Tool
Fuel Pool Vacuum Sipper
Jib Crane
General Purpose Grapples
Refueling Platform

Servicing Aids

Pool Tool Accessories
Actuating Poles
General Area Underwater Lights
Local Area Underwater Lights
Drop Lights
Underwater TV Monitoring System
Underwater Vacuum Cleaner
Viewing Aids
Light Support Brackets
Underwater Viewing Tube

Reactor Vessel Servicing Equipment

Reactor Vessel Servicing Tools
Steam Line Plugs and Installation Tools
Shroud Head Bolt Wrenches
Head Holding Pedestals
Head Stud Rack
Dryer-Separator Strongback
Head Strongback/Carousel
(including Stud Tensioners)

In-Vessel Servicing Equipment

Instrument Strongback
Control Rod Grapple
Control Rod Guide Tube Grapple
Fuel Support Grapple
Grid Guide

In-Vessel Servicing Equipment (Continued)

Control Rod Latch Tool
Instrument Handling Tool
Control Rod Guide Tube Seal
In-Core Guide Tube Seals
Blade Guides
Fuel Assembly Sampler
Peripheral orifice Grapple
Orifice Holder
Peripheral Fuel Support Plug
Fuel Support Plug Tool
RIP Handling Tools

Refueling Equipment

Refueling Platform

Storage Equipment

Fuel Storage Racks
Channel Storage Racks
Defective Fuel Storage Containers
In-Vessel Racks
CR Guide Tube Storage Rack
CR Storage Rack
Defective Fuel Storage Rack

Under-Reactor Vessel Servicing Equipment

Line Motion
Control Rod Drive Servicing Tools
CRD Hydraulic System Tools
Water Seal Cap
FMCRD Handling Equipment
Handling Platform
Thermal Sleeve Installation Tool
In-Core Flange Seal Test Plug
Key Bender
Spring Reel
Radiation Shield
RIP Handling Equipment

Table 9.1-6

REFERENCE CODES AND STANDARDS

Number	Title
ANS--N14.6	Standard for Special Lifting Devices for Shipping Containers Weighing (5 ton) or More for Nuclear Materials
ANSI B30.9	"Slings"
ANSI B30.10	"Hooks"
ANSI B30.2	Performance Standards for Overhead Electric Wire Rope Hoists
ANSI B30.16	Performance Standards for Air Wire Rope Hoists
ANSI B30.11	Overhead and Gantry Crane
CMAA70	Specifications for Electric Overhead Travelling Cranes"
NUREG--0554	Single-failure-proof Cranes for Nuclear Power plants
NUREG--0612	Control of Heavy Loads at Nuclear Power Plants

Table 9.1-7

HEAVY LOAD EQUIPMENT USED TO HANDLE LIGHT LOADS AND RELATED REFUELING HANDLING TASKS

HANDLING OPERATIONS/EQUIPMENT	APPLICABLE LIGHT LOAD HANDLING SUBSECTIONS
Overhead Bridge Cranes	9.1.4.2.2
Reactor Building Crane	9.1.4.2.2
Fuel Servicing Equipment	9.1.4.2.3
Servicing Aids	9.1.4.2.4
Reactor Vessel Servicing Equipment	9.1.4.2.5
Steamline Plug	
Head Stud Rack	
Dryer/Separator Strongback	
Head Strongback/Carousel	
In-Vessel Servicing Equipment	9.1.4.2.6
Refueling Equipment	9.1.4.2.7 thru 9.1.4.10
Refueling Platform	
Vessel Platform	
Storage Equipment	
Under Reactor Vessel Servicing Equipment	
Fuel Handling Service Tasks	
Reactor Shutdown Handling Tasks	
Drywell Head Removal	
Reactor Well Servicing	
Reactor Vessel Head Removal	
Dryer Removal	
Separator Removal	
Fuel Bundle Sampling	
Refueling	
Vessel Closure	

Table 9.1-8

HEAVY LOAD OPERATIONS

Hardware Handling Tasks	Handling Systems*	Handling Equipment	In plant Location Elevation*
RPV OPENING/CLOSING OPERATIONS:			
Dry Well--Shield Blocks: Remove, store and reinstall	RBS	RB Crane Main hoist	RB 26700 RF 26700
D/S Pool, Spend Fuel Pool Fuel Cask Pit, Shield Plugs and Pool Seal Gates Removal, reinstallation and storage on the refueling floor or in D/S Pool.	RBS	RB Crane Main or Auxiliary Hoist, Slings & strongbacks	RF 26700 D/S P 18700
Drywell Head Removal, storage and reinstallation	RBS	RB Crane Main Hoist, Drywell Head Strongback	RF 26700 R/W 23700
Reactor Vessel Head Insulation Removal, storage and reinstallation	RBS	RB Crane Main Hoist Lifting Sling	RF 26700 R/W 18700
Reactor Vessel Head Removal, storage and reinstallation, includes handling stud tensioner studs, nuts, Head Strong-back/carousel	RBS	RB Crane Main Hoist Auxiliary Hoist Head Strongback/ Carousel RPV Head support Pedestal	RF 26700 RW 18700
Steam Dryer Removal, storage and reinstallation	RBS	RB Crane Main Hoist Dryer/Separator Strongback	RW 18700 D/SP 18700 IRV 14500

* See Table 9.1-9 for Legend.

Table 9.1-8

HEAVY LOAD OPERATIONS
(Continued)

Hardware Handling Tasks	Handling Systems*	Handling Equipment	In plant Location Elevation*
RPV OPENING/CLOSING OPERATIONS: (Continued)			
D/SP Cover plates Removal, storage and reinstallation.	RBS	RB Crane Auxiliary Hoist Lifing slings	RF 26700
RPV Service Platform Removal, storage and reinstallation.	RBS	RB Crane Auxiliary Hoist Lifing slings	RF 26700 IRV 14500
Steam Plugs Temporary tool Installation and removal	RBS	RB Crane Auxiliary Hoist 1/2 ton Chain Hoist Service Platform Refueling Platform	RF 26700 IRV 15500
Steam Separator/Shroud Head Removal, storage and reinstallation. Include unbolting shroud head bolts from Refueling Platform	RBS	RB Crane Main Hoist Dryer/Separator Refueling Platform	RW 18700 IRV 9500 D/SP 18700
Fuel Bundle Sampler Tool Positioning, sampling and removal, storage	RBS	Refueling Platform or RB Crane Auxiliary Hoists	RW 18700 IRV 9100
REFUELING OPERATIONS:			
New Fuel:			
Receive at G/F. & lift to RF. Receiving inspection remove outer container	RBS	RB Crane Auxiliary Hoist	RE 7300 RF 26700

* See Table 9.1-9 for Legend.

Table 9.1-8

HEAVY LOAD OPERATIONS
(Continued)

Hardware Handling Tasks	Handling Systems*	Handling Equipment	In plant Location Elevation*
REFUELING OPERATIONS: (Continued)			
Remove inner container and store fuel bundle in new fuel vault rack. Move fuel to new fuel inspection stand, inspect and return to storage.	RBS	RB Crane Auxiliary Hoist	RF 26700 NFS 18700 NFI 18700
Move new fuel from vault to fuel pool, storage of fuel channel fixtures. Channel new fuel and store. Move channeled fuel and load into reactor core.	RBS	RB Crane Auxiliary Hoist Refueling Platform Auxiliary Hoist Fuel Grapple	NFS 18700 FSP 14800 FCF 14800 RF 26700 RVC 9500
Spent Fuel:			
Remove spent fuel from RPV core. Transport spent fuel to storage racks and/or fuel channel fixture remove channels and store spent fuel bundles	RBS	Refueling Platform Auxiliary Hoists Fuel Grapple Channel Handling Boom	RW 18700 FSP 14880 FCF 14800 RVC 9500
Fuel Cask:			
Receive, lift to refueling floor. Lower into cask washdown pit, washdown & move to load pit. Move spent fuel to cask load pit. Move loaded cask to cask washdown pit. Move cask to G/F for shipment.	RBS	RB Crane Main Hoist Auxiliary Hoist Refueling Platform Auxiliary Hoists Fuel Grapple	G/F 7300 RF 26700 FWP 18700 FLP 14800

* See Table 9.1-9 for Legend.

Table 9.1-8

HEAVY LOAD OPERATIONS
(Continued)

Hardware Handling Tasks	Handling Systems*	Handling Equipment	In plant Location Elevation*
REACTOR SERVICE OPERATIONS:			
Control Rod Blades Replacement including adjacent fuel bundles moving and storage in in-vessel rack and blade guide removal /. installation. Fuel support removal and reinstallation.	RBS	Refueling Platform Auxiliary Hoists Fuel Grapple Fuel Support Grapple Control Rod Grapple	RVC 9500 RV 5300
Control Rod Guide Tube (CRGT) (Nonroutine) Removal & Replacement. Prior removal of control rod, fuel, fuel support and blade guide see above.	RBS	Refueling Platform Auxiliary Hoists CRGT Grapple	RVC 5300
Internal Recirculation Pump Servicing: Removal of pump impeller, diffuser and the wear ring and piston ring through annulus between shroud and RPV I.D. wall. Move impeller to fuel storage pool.	RBS	RB Crane Auxiliary Hoist Service Platform Pump Impeller Grapple	FSP 18700 IRV 3000
UPPER DRYWELL SERVICING			
MSIVs and SRVs Servicing: removal, installation, and transportation for repair and calibrations from installed location to RCCV entrance and up to special service room area and return.	UDS SRM(C)	Monorail for servicing MSIVs and SRVs Monorail Hoist Transportation Cart Hatchway Hoist Wall Mount	UDW 12500 RB 12500 RB 18700 SRM 18700(c)
	MSS	Steam Tunnel Crane Hoist Transportation Cart Hatchway Hoist Wall Mount	MST 12500 SRM 18700(c)

* See Table 9.1-9 for Legend.

Table 9.1-8

HEAVY LOAD OPERATIONS
(Continued)

Hardware Handling Tasks	Handling Systems*	Handling Equipment	In plant Location Elevation*
LOWER DRYWELL SERVICING:			
RIPs Motors Removal and installation and transport to service area and return during maintenance.	LDS SRM(B)	Jack Screws Transportation Cart Equipment Platform Turntable L/D RIP Hoist	L/D(-)2500 L/D(-)6700 SRM(-)6700 (C)
RIP Heat Exchangers Removal and installation for replacement or servicing	LDS RBS	Special Rigging Transportation Cart Equipment Platform L/D RIP Hoist	L/D(-)2500 L/D(-)6700 R/B(-)6700 R/B(-)7300
FMCRD Control Rod Drives Removal and installation from/to RPV for maintenance	LDS SRM(A)	FMCRD Remote handling machine	LDW/URV (-)6700
(1) Motor and seal replacement			
(2) FMCRD drive mechanism replacement	SRM(A)	FMCRD motor servicing machine	SRM(-)6700(A)
(3) Move CRD hardware to service room area for service	LDS	Lifting/handling device to move CRD hardware to service room area for service	LDW(-)6700 SRM(-)6700(A)
Neutron Monitor Sensor Replacement and servicing	LDS RBS	Refueling Platform Auxiliary Hoist Special Tools cask onto tunnel track.	RVC 5300

* See Table 9.1-9 for Legend.

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TABLES

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ILLUSTRATIONS

SECTION 9.2

ILLUSTRATIONS (Continued)

9.2 WATER SYSTEMS

9.2.1 Station Service Water System

The functions normally performed by the station service water system are performed by the systems discussed in Subsection 9.2.11.

9.2.2 Closed Cooling Water System

The functions normally performed by the closed cooling water system are performed by the systems discussed in Subsections 9.2.11, 9.2.12, 9.2.13, and 9.2.14.

9.2.3 Demineralized Water Makeup System

The functions normally performed by the demineralized water makeup system are performed by the systems discussed in Subsections 9.2.8,9.2.9 and 9.2.10.

9.2.4 Potable and Sanitary Water System (PSW)

This subsection provides a conceptual design of the potable and sanitary water (PSW) as required by 10CFR52. The interface requirements for this system are part of the design certification.

9.2.4.1 Safety Design Bases (Interface Requirements)

The PSW system has no safety-related function. Failure of the system does not compromise any safety-related system or component, nor does it prevent a safe shutdown of the plant.

9.2.4.2 Power Generation Design Bases (Interface Requirements)

(1) The PSW system is designed to provide a minimum of 200 gpm of potable water during peak demand periods.

(2) Potable water is filtered and treated to prevent harmful physiological effects on plant personnel.

(3) The PSW includes a sanitary drainage system which is designed to collect liquid wastes and entrained solids discharged by all plumbing fixtures located in areas with no sources of potentially radioactive wastes and conveys them to a sewage treatment facility.

(4) The PSW includes a sewage treatment system which treats sanitary waste using the activated sludge biological treatment process. The aeration tanks are capable of receiving waste at a rate between 12,000 gpd and 48,800 gpd.

(5) The PSW system shall be designed with no interconnections with systems having the potential for containing radioactive materials. Protection shall be provided through the use of air gaps, where necessary.

9.2.4.3 System Description (Conceptual Design)

The PSW system is composed of a potable water system, a sanitary drainage system and a sewage treatment system.

9.2.4.3.1 Potable Water System

Filtered water flows by gravity from the filtered water storage tank of the MWP system into a potable water storage tank. A hypochlorite addition pump and tank are provided which adds sodium hypochlorite to the water entering the potable water storage tank. Two potable water pumps send water from the potable water storage tank to a hydropneumatic pressure tank. A hydropneumatic pressure tank and air compressor are provided to maintain adequate pressure within a potable water distribution piping system. Potable water is sent to a heater where it is heated and distributed throughout the plant.

9.2.4.3.2 Sanitary Drainage System

The sanitary drainage system collects liquid wastes and conveys them to the sewage treatment system. This system is installed in accordance with ANSI A40.8, National Plumbing Code, and applicable local or state codes.

9.2.4.3.3 Sewage Treatment System

The sewage treatment system is a concrete structure containing several compartments. The sewage treatment systems uses the activated sludge biological treatment process. The system includes a comminutor with a bypass screen channel, two aeration tanks, three final clarifiers, one chlorine contact tank, two aerobic digesters, three air blowers, a froth spray pump, a hypochlorite pump and related equipment. The system can be operated in two modes: extended aeration and contact stabilization.

9.2.4.4 System Operation (Conceptual Design)

9.2.4.4.1 Normal Operation

The potable water pumps take water from the potable water storage tank and discharges it into the potable water hydropneumatic pressure tank. Under automatic control, a low pressure switch starts one of the two potable water pumps when the hydropneumatic pressure tank water pressure falls below a specified limit. A pressure switch automatically starts the second potable water pump when a single pump is unable to maintain the tank pressure above a specified limit. When water level reaches a specified high level in the hydropneumatic pressure tank, a level switch automatically stops the potable water pumps. If high water level in the pressure tank is reached and the tank pressure is low, the air compressor is automatically started and is stopped at a specified pressure by a high pressure switch.

The air compressor controls are interlocked with the potable water pump controls so that the air compressor may operate only when the pumps are stopped and the hydropneumatic pressure tank water level is at the specified high limit.

Downstream of the hydropneumatic pressure tank, a branch sends potable water to a heater and a hot water distribution system.

Potable water is used to flush the service water sides of the RSW and TSW heat exchangers whenever they are put into a wet standby condition.

Normally, the sewage treatment system is operated in the extended aeration mode. The sanitary wastes enter the sewage treatment system via the comminutor, in which any solids are shredded, and flows into the aeration tanks. In the aeration tanks, the waste liquids are continuously aerated. Occasionally, foaming occurs in the aeration tanks. A froth spray system is provided which uses processed sewage to control any froth which is present. The aeration tank contents are then transferred to the clarifier where the sludge is allowed to settle. The clarified sewage passes into the chlorine contact tank for chlorination prior to being discharged via the cooling tower blowdown line. The settled sludge is sent to the aerobic digesters and disposed of off-site.

9.2.4.4.2 Abnormal Operation

The components of the PSW system are designed to meet the increased needs during refueling operations when additional people are on-site.

The sewage treatment system may be operated in the contact stabilization mode to process the substantially higher waste water flow rates during outages. In this mode, a portion of the settled sludge from the final clarifiers is aerated, sent to the aeration tanks and mixed with incoming sewage.

9.2.4.5 Evaluation of Potable and Sanitary Water System Performance (Interface Requirements)

The COL applicant shall analyze the PSW system to assure that the system meets all applicable regulatory requirements and is compatible with site conditions.

9.2.4.6 Safety Evaluation (Interface Requirements)

There are no safety requirements.

9.2.4.7 Instrumentation and Alarms (Interface Requirements

The subsystems of the PSW system are provided with control panels located in the control building which are designed for remote manual and automatic control of the processes.

A flow proportioning controller is used to operate the hypochlorinator pump as water enters the PSW system. Pressure and level switches are provided to start and stop the potable water pumps and the air compressor. Low hydropneumatic tank pressure is alarmed. Low level in the hypochlorite feed tank is alarmed.

The minimum instrumentation requirements for the sewage treatment system are a treated effluent sewage flow meter and a common air blower discharge pressure gage.

9.2.4.8 Tests and Inspections (Interface Requirements)

Drainage piping is hydrostatically tested to the equivalent of a 10 foot head of water for a minimum of 15 minutes.

The operability of all other parts of the PSW system is demonstrated by use during normal system operation.

9.2.5 Ultimate Heat Sink

This subsection provides a conceptual design of the ultimate heat sink (UHS) as required by 10CFR52. The interface requirements for the UHS are part of the design certification.

9.2.5.1 Safety Design Bases (Interface Requirements)

430.204 (1) The UHS is designed to provide sufficient cooling water to the reactor service water (RSW) system to permit safe shutdown and cooldown of the unit and maintain the unit in a safe shutdown condition. The UHS temperature is provided in Table 2.0-1.

(2) In the event of an accident, the UHS is designed to provide sufficient cooling water to the RSW system to safely dissipate the heat for that accident. The amount of heat to be removed is provided in Tables 9.2-4a, -4b and -4c.

430.202.3 430.204 (3) The UHS is sized so that makeup water is not required for at least 30 days following an accident and design basis temperature and chemistry limits for safety-related equipment are not exceeded.

(4) The UHS is designed to perform its safety function during periods of adverse site conditions, resulting in maximum water consumption and minimum cooling capability.

430.204 (5) The UHS is designed to withstand the most severe natural phenomenon or site-related event (e. g., SSE, tornado, hurricane, flood, freezing, spraying, pipe whip, jet force missiles, fire, failure of non-Seismic Category I equipment, flooding as a result of pipe failures or transportation accident), and reasonably probable combinations of less severe phenomena and/or events, without impairing its safety function.

(6) The safety related portion of the UHS shall be designed to perform their required cooling function assuming a single active failure in any mechanical or electrical system.

(7) The UHS is designed to withstand any credible single failure of man-made structural features without impairing its safety function.

(8) All safety-related heat rejection systems shall be redundant so that the essential cooling function can be performed even with the complete loss of one division. Single failures of passive components in electrical systems may lead to the loss of the affected pump, valve or other components and the partial or complete loss of cooling capability of that division but not of other divisions. 430.204

(9) The UHS and any pumps, valves, structures or other components that remove heat from safety systems shall be designed to Seismic Category I and ASME Code, Section III, Class 3, Quality Assurance B, Quality Group C, IEEE-279 and IEEE-308 requirements.

(10) The safety-related portions of the UHS shall be mechanically and electrically separated.

(11) The UHS is designed to include the capability for full operational testing.

9.2.5.2 Power Generation Design Bases (Interface Requirements)

The UHS is designed to remove the heat load of the RSW system during all phases of normal plant operation. These heat loads are provided in Tables 9.2-4a, -4b and 4c. However, it is not a requirement that the UHS temperature be assumed to be the maximum temperature for all operating modes during normal plant operations. 430.203 430.202.2

9.2.5.3 System Description (Conceptual Design)

The UHS is a spray pond which serves the safety-related functions of providing cooling water and acting as a heat sink for the RSW system during accident conditions. The spray pond also serves as a heat sink during normal operation by accepting the heat load of the RSW system.

There are no other heat loads associated with the spray pond in addition to the RSW system. 430.204 430.203

9.2.5.3.1 General Description

The UHS is a highly reliable, Seismic Category I spray pond that provides that an adequate source of cooling water is available at all times for reactor operation, shutdown cooldown and for accident mitigation. The RSW system (Subsection 9.2.15) receives cooling water from the UHS and returns the water to the spray pond via the spray networks.

9.2.5.3.2 Spray Pond Description

The spray pond is of Seismic Category I design, excavated below grade and sized for a water volume adequate for 30 days of cooling under design basis conditions.

The pond is lined to minimize seepage. The pond is provided with a Seismic Category I overflow weir to accommodate normal water level fluctuations and an emergency spillway to limit the maximum water level in the pond during maximum precipitation conditions.

430.204 Four spray networks are arranged in the pond to provide cooling for the RSW return water. The networks and their supply piping are suspended above the pond surface on reinforced concrete columns.

9.2.5.3.3 Spray Pond Pump Structure

The spray pond pump structure houses the RSW pumps and associated piping and valves. See Subsection 9.2.15. The pump structure is located on the edge of the spray pond. Openings are provided in front of the pump structure to allow pond water to flow into the wet pits where the pump suctions are located. Each pump is located in its own bay. A removable screen is placed at the entrance of each bay.

The pump structure is designed to provide adequate net positive suction head for the pumps.

HVAC equipment maintains necessary conditions for proper operation of the equipment in the pump structure.

9.2.5.3.4 System Components

Four spray networks are provided. During normal plant operation, two of the networks are in operation. When the heat load is increased during cooldown, shutdown or accident, the RSW return water will be sent to all four networks. Network header piping is sized for proper flow rates to all nozzles in the network. Piping is sloped to allow complete drainage of the networks and network supply piping to minimize corrosion and prevent freezing.

The spray nozzles are of corrosion resistant materials and designed to provide good thermal performance while minimizing drift loss. The system is designed so that the pressure drop across the nozzles for proper spray performance is achieved for all anticipated modes of RSW system operation. The nozzles are designed to be resistant to clogging.

A cold weather bypass line is provided for the RSW return line to allow bypassing the spray networks and returning the heated water directly to the pond.

Makeup water to the spray pond is supplied via the power cycle heat sink makeup line. A makeup water valve is provided which is controlled by a level 430.204 detector in the spray pond to maintain proper water level. The makeup water valve can also be operated remotely when desired to maintain desired water level or quality.

A blowdown weir and line are provided which conducts blowdown to the power cycle heat sink blowdown line. Blowdown from the spray pond occurs to remove excess water from precipitation and to maintain water quality control.

9.2.5.4 System Operation (Conceptual Design)

9.2.5.4.1 Normal Operation

Normally, the RSW has one pump per division in operation. The RSW return water from each division is collected into a header and sent to the UHS where it is sent to two of the four networks. The operators may change the operating RSW pumps and the UHS networks when desired.

During operation without spray pond blowdown, the concentration of scale-forming constituents in the water would increase due to evaporation impairing heat exchanger performance. Also, biofouling may occur under some conditions. To prevent these adverse conditions from occurring, chemical addition equipment is provided and blowdown may be increased by increasing the makeup rate. Sufficient spray pond water inventory is provided such that scale-producing agents, such as calcium sulfate, do not reach concentrations that might cause scaling during the 30 day post accident period when no makeup or blowdown is assumed.

9.2.5.4.2 Cold Weather Operation

The spray pond is designed to perform its safety function with an initial ice layer on the pond surface. During icing conditions, RSW system return flow to the pond is initially sent to the cold weather bypasses. These bypasses direct the warm water toward the ends of the pond under any ice that may be present to allow the return water to circulate and mix with the water in the pond. Any ice layer present on the pond surface will melt. Once a hole is formed in the ice layer, a return path for spray water is available and the spray networks may be used if needed.

430.204

9.2.5.5 Spray Pond Thermal Performance (Conceptual Design)

9.2.5.5.1 Design Meteorology

The COL applicant shall obtain and use conservative site-specific design meteorological data in the detailed design of the spray pond.

9.2.5.5.2 Spray Pond Water Requirements

The COL applicant shall determine the water requirements used in selecting spray pond design volume and used in the pond thermal performance analysis. These requirements include:

(1) Evaporation Due to Plant Heat Load

(2) Natural Evaporation

(3) Drift Loss

(4) Seepage

(5) Sedimentation

(6) Water Quality

(7) Minimum Water Level for Operation

9.2.5.6 Evaluation of UHS Performance (Interface Requirements)

The COL applicant shall analyze the UHS performance to assure that UHS is adequate for 30 days of cooling without makeup or blowdown and that the cooling water temperature does not exceed the design limit for design basis heat input and site conditions.

9.2.5.7 Safety Evaluation (Interface Requirements)

9.2.5.7.1 Thermal Performance

The COL applicant shall demonstrate by analysis that the UHS is capable of providing cooling water within the design temperature limit for at least 30 days for the design basis event using conservative meteorology and assumptions.

9.2.5.7.2 Effects of Severe Natural Events or Site-Related Events

The COL applicant shall demonstrate by analysis that the UHS is capable of fulfilling its safety function concurrent with any of the following events: SSE, tornado, flood, drought, transportation accident, or fire. 430.204

9.2.5.7.3 Freezing Considerations

The COL applicant shall demonstrate by analysis that the UHS is designed for operations under any freezing conditions that may occur.

9.2.5.8 Conformance to Regulatory Guide 1.27 and 1.72 (Interface Requirement)

The COL applicant shall demonstrate that the UHS meets all applicable requirements of Regulatory Guide 1.27.

If any spray pond piping is made from fiberglass-reinforced thermosetting resin, the COL applicant shall provide information to show that all applicable requirements of Regulatory Guide 1.72 are met.

9.2.5.9 Instrumentation and Alarms (Interface Requirement)

UHS low water level (if applicable) and high water temperature are provided and alarmed in the control room. UHS surface water temperature indication is provided (if it can differ appreciably from the bulk temperature) in the control room.

UHS makeup and blowdown volumes (if applicable) are indicated by flow totalizers located in the makeup and blowdown lines.

430.204 **9.2.5.10 Tests and Inspections**

The COL applicant shall prepare and perform a preoperational test program and tests during normal operations in accordance with the requirements of Chapter 14.

9.2.6 Condensate Storage Facilities and Distribution System

The functions of the storing and distribution of condensate are described in Subsection 9.2.9.

9.2.7 Plant Chilled Water Systems

The functions of the plant chilled water system are performed by the systems described in Subsections 9.2.12 and 9.2.13.

9.2.8 Makeup Water (MWP) System (Preparation)

This subsection provides a conceptual design of the makeup water preparation system as required by 10CFR52. The interface requirements for this system are part of the design certification.

9.2.8.1 Safety Design Bases (Interface Requirements)

The MWP system has no safety-related function. Failure of the system does not compromise any safety-related system or component, nor does it prevent a safe shutdown of the plant.

9.2.8.2 Power Generation Design Bases (Interface Requirements)

(1) The MWP system consists of two divisions capable of producing at least 200 gpm of demineralized water each.

(2) Storage of demineralized water shall be at least 200,000 gallons.

(3) The quality of the demineralized water shall meet the requirements in Table 9.2-2a.

(4) Demineralized water shall be provided at a minimum flow rate of approximately 600 gpm at a temperature between 50 to 100°F.

(5) The MWP system is not connected to any systems having the potential for containing radioactive material.

(6) The MWP system provides 200 gpm of filtered water to meet maximum anticipated peak demand periods for the Potable and Sanitary Water System.

9.2.8.3 System Description (Conceptual Design)

The MWP system consists of both mobile and permanently installed water treatment systems.

The permanently installed system consists of a well, filters, reverse osmosis modules and demineralizers which prepare demineralized water from well water. The demineralized water is sent to storage tanks until it is needed. Pumps are provided to keep the makeup water distribution system (MUWP) pressurized at all times. The components of the MWP system are listed in Table 9.2-15 and the system block flow diagram is in Figure 9.2-10.

While it is planned to install both permanent divisions, only one division may be installed if plant water requirements and economic conditions indicate that the second division will not be needed.

Mobile water treatment systems will be used before the permanent system is installed and later if water requirements exceed the capacity of the permanent system or if economic condition make use of mobile equipment attractive compared to operating and maintaining the permanent system.

9.2.8.3.1 Well System

A well, well water storage tank and two well water forwarding pumps are provided which can produce sufficient water to meet the concurrent needs of the makeup water preparation system and the potable and sanitary water system.

9.2.8.3.2 Pretreatment System

Two dual media filters are provided in parallel which are backwashed when needed using one of two backwash pumps and water from a filtered water storage tank. This tank is provided with a heater to maintain a water temperature of at least 50°F at all times. Water may be sent from the filtered water storage tank to the Potable and Sanitary Water System or to the next components of the MWP system.

9.2.8.3.3 Reverse Osmosis Modules

Chemical addition tanks, pumps and controls are provided to add sodium hexametaphosphate and sodium hydroxide to the filtered water.

Four high pressure, horizontal multistage reverse osmosis (RO) feed pumps provide a feed pressure of approximately 440 psig. Reverse osmosis membranes are arranged in two parallel divisions of two passes each with the permeate of the first passes going to the inlet of the second passes. The reject or brine from the first passes are sent to the cooling tower blowdown by gravity. A chemical addition tank, two pumps and controls are provided to add sodium hydroxide to the permeate of the first pass. The reject from the second passes is recycled to the RO feed pump suction line. The permeate from the second pass is sent to a RO permeate storage tank.

9.2.8.3.4 Demineralizer System

Two demineralizer feed pumps are provided in each parallel division. Three mixed bed demineralizers are provided in parallel in each division with two normally in operation with the third in standby. The demineralized water is monitored and sent to the demineralized water storage tanks.

9.2.8.3.5 Demineralized Water Storage System

Two demineralized water storage tanks are provided with a heater to maintain a water temperature of at least 50°F at all times. Three demineralized water forwarding pumps are provided to send water to the MUWP system.

9.2.8.3.6 Makeup Water Preparation Building

A building is provided for all of the subsystems listed above except for the well water storage tank and the demineralized water storage tanks which are located outdoors. The building is provided with a heating system capable of maintaining a temperature of at least 50°F at all times.

The building does not contain any safety-related structures, systems or components. The MWP system shall be designed so that any failure in the system, including any that cause flooding, shall not result in the failure of any safety-related structure, system or component.

The building has a large open area about 25 feet by 40 feet with truck access doors and services for mobile water processing systems. These services include electric power, service air, connections to the water storage tanks and a waste connection. This area will be used for mobile water treatment systems or storage.

9.2.8.4 System Operation (Conceptual Design)

9.2.8.4.1 Normal Operation

During normal operation, the well pump is controlled by a water level controller to keep the well water storage tank full. The well water forwarding pumps are controlled by a water level controller to keep the filtered water storage tank full. Normally, one filter will be operating with the other filter in standby. The second filter is started from the control building or is automatically started by a low water level in the filtered water storage tank. When any filter develops a high pressure drop, it is isolated and any standby filter is put into operation. One of the two backwash pumps is operated to backwash the filter. The backwash is sent to the cooling tower blowdown by gravity.

Sodium hexametaphosphate is added to control calcium sulfate or other fouling in the RO membranes and sodium hydroxide is added to adjust the pH for RO treatment.

The RO feed pumps are controlled by a water level controller which keeps the RO permeate storage tank full. These pumps feed the water through both RO passes. The RO membranes are of the thin film composite type. The first pass permeate which becomes feed for the second pass has a pressure of about 200 to 250 psig. Sodium hydroxide is added to the first pass permeate to adjust the pH to improve dissolved solids rejection in the second pass.

The demineralizer feed pumps are controlled by a water level controller in the demineralized water storage tanks. Each demineralizer contains [illegible] cubic feet of ion exchange resin in a cation/anion ratio of 1 to 2. When the effluent quality of a demineralizer becomes unsatisfactory, it is automatically removed from operation and the standby demineralizer is automatically put into operation. The exhausted resins are regenerated offsite.

The demineralized water forwarding pumps are controlled by a pressure switch in their discharge piping. Normally, one pump is operated to maintain a specified system pressure. When the pressure drops below a specified pressure, the second pump is automatically put into operation until system pressure returns to the normal range. If this does not occur, the third pump is automatically put into operation.

9.2.8.4.2 Abnormal Operation

During the early construction period and at certain times later, the makeup water preparation system may either not be installed or may not be in operation. Also, there may be times when demineralized water requirements exceed the production capacity. During these periods, mobile water treating systems will be used. They will be transported to the site by truck and will enter the makeup water preparation building through large doors. When no longer required they will be removed.

9.2.8.5 Evaluation of Makeup Water System Preparation Performance (Interface Requirements)

The COL applicant shall analyze the raw water quality and availability and the required makeup water quality and amounts to assure that these requirements can be met. Any deficiencies in either quality or production capability shall be met with mobile water treating systems.

9.2.8.6 Safety Evaluation (Interface Requirements)

There are no safety requirements.

9.2.8.7 Instrumentation and Alarms (Interface Requirements)

One division of MWP components is normally in operation. The components of the standby division are automatically placed into operation upon receiving a low level signal from their downstream water storage tank.

The following shall be displayed and alarmed locally and in the control building:

- Water level in all water storage tanks
- Running status of all pumps
- System pressures and differential pressures associated with the filters and RO modules
- Water quality monitors, including conductivity, pH, turbidity and silica analyzers

All water storage tanks are provided with low-low water level switches which stop the forwarding pumps for that tank.

9.2.8.8 Tests and Inspections (Interface Requirements)

The COL applicant shall prepare and perform a preoperational test program and tests in accordance with the requirements of Chapter 14.

9.2.9 Makeup Water System (Condensate)

9.2.9.1 Design Bases

(1) The makeup water-condensate system (MUWC) shall provide condensate quality water for both normal and emergency operations when required.

(2) The MUWC system shall provide a required water quality as follows:

Conductivity (μS/cm)	≤ 0.5 at 25°C
Chlorides, as Cl (ppm)	≤ 0.02
pH	5.9 to 8.3 at 25°C

Conductivity and pH limits shall be applied after correction for dissolved CO_2. (The above limits shall be met at least 90% of the time.)

(3) The MUWC system shall supply water for the uses shown in Table 9.2-1.

(4) The MUWC system is not safety related.

(5) The condensate storage tank shall have a capacity of 2,110 m^3. This capacity was determined by the capacity required by the uses shown in Table 9.2-2.

(6) All tanks, piping and other equipment shall be made of corrosion-resistant materials.

(7) The HPCF and RCIC instrumentation, which initiates the automatic switchover of HPCF and RCIC suction from the CST header to the suppression pool, shall be designed to safety-grade requirements (including installation with necessary seismic support).

(8) The instrumentation is mounted in a safety grade standpipe located in the reactor building secondary containment. With no condensate flowing, the water level is the same in both the CST and the standpipe. A suitable correction will be made for the effect of flow upon water level in the standpipe.

9.2.9.2 System Description

The MUWC P&ID is shown in Figure 9.2-4 This system includes the following:

(1) A condensate storage tank (CST) is provided. It is of concrete construction with a stainless steel lining. The volume is shown in Table 9.2-3.

(2) The following pumps take suction from the CST:

(a) RCIC pumps

(b) CRD pumps

(c) HPCF pumps

(d) SPCU pumps

(3) The system shall be designed and constructed in accordance with Seismic Category I, ASME code, Section III, Class 3 requirements.

(4) The system shall be powered from Class 1E buses.

(5) The HECW system shall be protected from missiles in accordance with Subsection 3.5.1.

(6) Design features to preclude the adverse effects of water hammer are in accordance with the SRP section addressing the resolution of USI A-1 discussed in NUREG-0927.

These features shall include:

(a) an elevated surge tank to keep the system filled;

(b) vents provided at all high points in the system;

(c) after any system drainage, venting is assured by personnel training and procedures; and

(d) system valves are slow acting.

(7) The HECW system shall be protected from failures of high and medium energy lines as discussed in Section 3.6.

9.2.13.2 System Description

The HVAC emergency cooling water system consists of subsystems in three divisions. Division A has one refrigerator and pump and Division B and C have two refrigerator units, two pumps, instrumentation and distribution piping and valves to corresponding cooling coils. A chemical addition tank is shared by all HECW divisions. Each HECW division shares a surge tank with the corresponding division of the RCW system. The refrigerator capacity is designed to cool the diesel generator zone and electrical equipment room in its division.

The system is shown in Figgure 9.2-3. The refrigerators are located in the control building as shown in Figures 1.2-20 and 1.2-21. This system shares the RCW surge tanks which are in the reactor building as shown in Figure 1.2-12. Equipment is listed in Table 9.2-9. Each cooling coil has a three-way valve controlled by a room thermostat. Alternately, flow may be controlled by a temperature control valve. Condenser cooling is from the corresponding division of RCW.

Piping and valves for the HECW system, as well as the cooling water lines from the RCW system, designed entirely to ASME Code, Section III, Class 3, Quality Group C, Quality Assurance B requirements. The extent of this classification is up to and including drainage block valves. There are no primary or secondary containment penetrations within the system. The HECW system is not expected to contain radioactivity.

High temperature of the returned cooling water causes the standby refrigerator unit to start automatically. Makeup water is supplied from the MUWP system, at the surge tank. Each surge tank has the capacity to replace system water losses for more than 100 days during an emergency. The only non-safety-related portions of the HECW divisions are the chemical addition tank and the piping from the tank to the safety related valves which isolate the safety related portions of the system.

Also, see Subsection 9.2.17.5 for COL license information requirements.

9.2.13.3 Safety Evaluation

The HECW system is a Seismic Category I system, protected from flooding and tornado missiles. All components of the system are designed to be operable during a loss of normal power by connection to the ESF buses. See Tables 8.3-1 and 8.3-2. Redundant components are provided to ensure that any single component failure does not preclude system operation in Divisions B and C. The system is designed to meet the requirements of Criterion 19 of 10CFR50. Each chiller is isolated in a separate room.

9.2.13.4 Tests and Inspection

Initial testing of the system includes performance testing of the refrigerators, pumps and coils for conformance with design capacity water flows and heat transfer capabilities. An integrity test is performed on the system upon completion.

The HECW system is designed to permit periodic in-service inspection of all system components to assure the integrity and capability of the system.

The HECW system is designed for periodic pressure and functional testing to assure: (1) the structural and leaktight integrity by visual inspection of the components; (2) the operability and the performance of the active components of the system; and (3) the operability of the system as a whole.

Local display devices are provided to indicate all vital parameters required in testing and inspections. Standby features are periodically tested by initiating the transfer sequence during normal operation.

The refrigerators are tested in accordance with ASHRAE Standard 30. The pumps are tested in accordance with standards of the Hydraulic Institute. ASME Section VIII and TEMA C standards apply to the heat exchangers. The cooling coils are tested in accordance with ASHRAE Standard 33.

9.2.13.5 Instrumentation and Alarms

A regulated supply of makeup water is provided to add purified water to the surge tanks by water level controls.

The chilled water pumps are controlled from the main control panel. The standby refrigerator with an interlock which automatically starts the standby refrigerator and pump upon failure of the operating unit in Divisions B and C.

The refrigerator units can be controlled individually from the main control room by a remote manual switch. Chilled water temperature is controlled by inlet guide vanes on each chiller refrigerant circuit. Condenser water flow is controlled by a three-way valve to provide constant inlet condensate water temperature.

A temperature controller and flow switch continuously monitor the discharge of each evaporator. If the temperature of the chilled water drops below a specified level, the controller automatically adjusts the position of the compressor inlet guide vanes. Flow switches prohibit the chiller from operating unless there is water flow through both evaporator and condenser.

9.2.14 Turbine Building Cooling Water System

9.2.14.1 Design Bases

9.2.14.1.1 Safety Design Bases

The turbine building cooling water (TCW) system serves no safety function and has no safety design basis

There are no connections between the TCW system and any other safety-related systems.

9.2.14.1.2 Power Generation Design Bases

(1) The TCW system provides corrosion-inhibited, demineralized cooling water to all turbine island auxiliary equipment listed in Table 9.2-11.

(2) During power operation, the TCW system operates to provide a continuous supply of cooling water, at a maximum temperature of 105°F, to the turbine island auxiliary equipment, with a service water inlet temperature not exceeding 95°F.

(3) The TCW system is designed to permit the maintenance of any single active component without interruption of the cooling function.

(4) Makeup to the TCW system is designed to permit continuous system operation with design failure leakage and to permit expeditious post-maintenance system refill.

(5) The TCW system is designed to have an atmospheric surge tank located at the highest point in the system.

(6) The TCW system is designed to have a higher pressure than the power cycle heat sink water to ensure leakage is from the TCW system to the power cycle heat sink in the event a tube leak occurs in the TCW system heat exchanger.

9.2.14.2 System Description

9.2.14.2.1 General Description

The TCW system is illustrated on Figure 9.2-6. The system is a single loop system and consists of one surge tank, one chemical addition tank, three pumps with a capacity of 15,000 gpm each, three heat exchangers with heat removal capacity of 65 x 10^6 Btu/h each. (connected in parallel), and associated coolers, piping, valves, controls, and instrumentation. Heat is removed from the TCW system and transferred to the non-safety-related turbine service water system (Subsection 9.2.16).

A TCW system sample is periodically taken for analysis to assure that the water quality meets the chemical specifications.

9.2.14.2.2 Component Description

Codes and standards applicable to the TCW system are listed in Table 3.2-1. The system is designed in accordance with quality Group D specifications.

The chemical addition tank is located in the turbine building in close proximity to the TCW system surge tank.

The TCW pumps are 50% capacity each and are constant speed electric motor driven, horizontal centrifugal pumps. The two pumps are connected in parallel with common suction and discharge lines.

The TCW heat exchangers are 50% capacity each and are designed to have the TCW water circulated on the shell side and the power cycle heat sink water circulated on the tube side. The surface area is based on normal heat load.

The surge tank, which is shared between the HNCW and TCW systems, is an atmospheric carbon steel tank located at the highest point in the TCW system. The surge tank is provided with a level control valve that controls makeup water addition.

The surge tank is located above the TCW pumps and heat exchangers in the turbine building in a location away from any safety-related components. Failure of the surge tank will not affect any safety-related systems.

Those parts of the TCW system in the turbine building are located in areas that do not contain any safety-related systems. All safety-related systems in the turbine building are located in special areas to prevent any damage from non-safety-related systems during seismic events. Those parts of the TCW system outside the turbine building are located away from any safety-related systems.

9.2.14.2.3 System Operation

During normal operation, two of the three 50% capacity TCW system pumps circulate corrosion-inhibited demineralized water through the shell side of two of the three 50% capacity TCW heat exchangers in service. The heat from the TCW system is rejected to the turbine service water system which circulates water on the tube side of the TCW system heat exchangers.

The standby TCW system pump is automatically started on detection of low TCW system pump discharge pressure. The standby TCW system heat exchanger is placed in service manually.

The cooling water flow rate to the electro-hydraulic control (EHC) coolers, the turbine lube oil coolers and aftercoolers, and generator exciter air cooler is regulated by control valves. Control valves in the cooling water outlet from these units are throttled in response to temperature signals from the fluid being cooled.

The flow rate of cooling water to all of the other coolers is manually regulated by individual throttling valves located on the cooling water outlet from each unit.

The minimum system cooling water temperature is maintained by adjusting the TCW system heat exchanger bypass valve.

The surge tank provides a reservoir for small amounts of leakage from the system and for the expansion and contraction of the cooling fluid with changes in the system temperature and is connected to the pump suction.

Demineralized makeup water to the TCW system is controlled automatically by a level control valve which is actuated by sensing surge tank level. A corrosion inhibiter is manually added to the system.

9.2.14.3 Safety Evaluation

The TCW system has no safety design bases and serves no safety function.

9.2.14.4 Tests and Inspections

All major components are tested and inspected as separate components prior to installation, and as an integrated system after installation to ensure design performance. The systems are preoperationally tested in accordance with the requirements of Chapter 14.

The components of the TCW system and associated instrumentation are accessible during plant operation for visual examination. Periodic inspections during normal operation are made to ensure operability and integrity of the system. Inspections include measurements of cooling water flows, temperatures, pressures, water quality, corrosion-erosion rate, control positions, and set points to verify the system condition.

9.2.14.5 Instrumentation and Alarms

Pressure and temperature indicators are provided where required for testing and balancing the system. Flow indicator taps are provided at strategic points in the system for initial balancing of the flows and verifying flows during plant operation.

Surge tank high and low level and TCW pump discharge pressure alarms are retransmitted to the main control room from the TCW local control panels.

Makeup flow to the TCW system surge tank is initiated automatically by low surge tank water level and is continued until the normal level is reestablished.

Provisions for taking TCW system water samples are included.

9.2.15 Reactor Service Water System

9.2.15.1 Portions Within Scope of ABWR Standard Plant

Those portions of the reactor service water (RSW) system that are within the control building are in the scope of the ABWR Standard Plant and are described in Subsections 9.2.15.1.1 through 9.2.15.1.6.

All portions of the RSW system which are outside the control building are not in the scope of the ABWR Standard Plant.

9.2.15.1.1 Safety Design Bases

(1) The reactor service water (RSW) system shall be designed in three divisions to remove heat from the three divisions of the reactor cooling water system which is required for safe reactor shutdown, and which also cools those auxiliaries whose operation is desired following a LOCA, but not essential to safe shutdown.

(2) The RSW system shall be designed to

Seismic Category I and ASME Code, Section III, Class 3, Quality Assurance B, Quality Group C, IEEE-279 and IEEE-308 requirements.

(3) The RSW system shall be protected from flooding, spraying, steam impingement, pipe whip, jet forces, missiles, fire and the effect of failure of any non-Seismic Category I equipment, as required.

(4) The RSW system shall be designed to meet the foregoing design bases during a loss of preferred power.

9.2.15.1.2 Power Generation Design Bases

The RSW system shall be designed to cool the reactor building cooling water (RCW) as required during: (a) normal operation; (b) emergency shutdown; (c) normal shutdown; and (d) testing.

9.2.15.1.3 System Description

The RSW system provides cooling water during various operating modes, during shutdown and post-LOCA operations. The system removes heat from the RCW system and transfers it to the ultimate heat sink. Figure 9.2-7 shows the RSW system diagram. Component descriptions are provided in Table 9.2-13.

9.2.15.1.4 Safety Evaluation

The components of the RSW system are separated and protected to the extent necessary to assure that sufficient equipment remains operating to permit shutdown of the unit in the event of any of the following (Separation is applied to electrical equipment and instrumentation and controls as well as to mechanical equipment and piping.):

(1) flooding, spraying or steam release due to pipe rupture or equipment failure;

(2) pipe whip and jet forces resulting from postulated pipe rupture of nearby high energy pipes;

(3 missiles which result from equipment failure; and

(4) fire.

Liquid radiation monitors are provided in the RCW system. Upon detection of radiation leakage in a division of the RCW system, that system is isolated by operator action from the control room, and the cooling load is met by another division of the RCW system. Consequently, radioactive contamination released by the RSW system to the environment does not exceed allowable limits defined by 10CFR100.

System low point drains and high point vents are provided as required.

During all plant operating modes each division shall have at least one service water pump operating. Therefore, if a LOCA occurs, the system is already in operation. If a loss of offsite power occurs during a LOCA, the pumps momentarily stop until transfer to standby diesel-generator power is completed. The pumps are restarted automatically according to the diesel loading sequence. No operator action is required, following a LOCA, to start the RSW system in its LOCA operating mode.

9.2.15.1.5 Instrumentation and Alarms

Locally mounted temperature indicators or test wells are furnished on the equipment cooling water discharge lines to enable verification of specified heat removal during plant operation.

9.2.15.1.6 Tests and Inspections

The RSW system is designed for periodic pressure and functional testing to assure:

(1) the structural and leaktight integrity by visible inspection of the components;

(2) the operability and the performance of active components of the system; and

(3) the operability of the system as a whole.

9.2.15.2 Portions Outside the Scope of ABWR Standard Plant

All Portions of the RSW system which are outside the control building are not in the scope of the ABWR Standard Plant. Subsections 9.2.15.2.1 through 9.2.15.2.6 provide conceptual design of these portions of the RSW system as required by 10CFR52. The interface requirements for this system are part of the design certification.

The site dependent portions of the RSW system shall meet all requirements in Subsections 9.2.15.1.1 through 9.2.15.1.6 and all following requirements. This subsection provides a conceptual design and interface requirements for those portions of the RSW system which are site dependent and are a part of the design certification.

9.2.15.2.1 Safety Design Bases (Interface Requirements)

The COL applicant shall provide the following system design features and additional information which are site dependent:

(1) the temperature increase and pressure drop across the heat exchangers

(2) the required and available net positive suction head for the RSW pumps at pump suction locations considering anticipated low water levels

(3) the location of the RSW pump house

(4) the design features to assure that the requirements in Subsection 9.2.15.1.1(3) are met

(5) an analysis of a pipeline break and a single active component failure shall show that flooding shall not affect the main control room or more than one division of the RSW system.

9.2.15.2.2 Power Generation Design Bases (Interface Requirement)

There are none.

9.2.15.2.3 System Description (Conceptual Design)

The RSW pump house is located at the ultimate heat sink (UHS) which is described in Section 9.2.5.

The RSW system is able to function during abnormally high or low water levels and steps are taken to prevent organic fouling that may degrade system performance. These steps include trash racks and provisions for biocide treatment (where discharge is allowed). Where discharge of biocide is not allowed, non-biocide treatment will be provided. Thermal backwashing capability will be provided at any site where infestations of macrobial growth can occur.

9.2.15.2.4 Safety Evaluation (Interface Requirement)

System components and piping materials are provided to be compatible with the site cooling water to minimize corrosion. Adequate corrosion safety factors are used to assure the integrity of the system during the life of the plant.

An analysis shall show that the requirements in Subsections 9.2.15.1.1(3) and 9.2.15.2.1(5) are met.

9.2.15.2.5 Instrumentation and Alarms (Interface Requirement)

There are none.

9.2.15.2.6 Tests and Inspections (Interface Requirements)

The tests shall assure, under conditions as close to design as practical, the performance of the full operational sequence that brings the system into operation for reactor shutdown and for LOCA, including operating of applicable portions of the reactor protection system and the transfer between normal and standby power sources.

9.2.16 Turbine Service Water System

The turbine service water (TSW) system supplies cooling water to the turbine cooling water (TCW) system heat exchangers to transfer heat from the TCW system to the power cycle heat sink.

9.2.16.1 Portions Within Scope of ABWR Standard Plant

Those portions of the turbine service water (TSW) system that are within the turbine building are in the scope of the ABWR Standard Plant and are described in Subsections 9.2.16.1.1 through 9.2.16.1.5.

All portions of the TSW system that are outside the turbine building are not in the scope of the ABWR Standard Plant.

9.2.16.1.1 Safety Design Bases

The TSW system does not serve or support any safety function and has no safety design basis.

9.2.16.1.2 Power Generation Design Bases

(1) The TSW system is designed to remove heat from the turbine cooling water (TCW) system heat exchangers and reject this heat to the power cycle heat sink during normal and shutdown conditions.

(2) During normal power operation the TSW system supplies cooling water to the TCW system heat exchangers at a temperature not exceeding 100°F.

(3) The TSW system is designed to permit the maintenance of any single active component without interruption of the cooling function.

9.2.16.1.3 System Description

9.2.16.1.3.1 General Description

The TSW system is illustrated on Figure 9.2-8.

The TSW pumps take suction from the power cycle heat sink and supply cooling water to the tube side of the TCW heat exchangers. The heat rejected to the TSW system is discharged to the power cycle heat sink.

9.2.16.1.3.2 Component Description

The TSW system consists of three 50% capacity vertical wet pit pumps located at the intake structure. One pump is in operation during normal operation with one pump on standby.

The TSW pumps supply cooling water to the three TCW heat exchangers (two are normally in service and one is on standby).

A summary of the TCW heat exchangers is provided in Table 9.2-12.

9.2.16.1.3.3 System Operation

The system normally is started manually from the main control room and one pump is operated continuously during normal power operation conditions.

The standby pump is started automatically in the event the normally operating pump trips or the discharge header pressure drops below a preset limit.

9.2.16.1.4 Safety Evaluation

The TSW system does not serve or support any safety function and has no safety design bases. The TSW system is not interconnected with any safety-related systems. See Subsection 9.2.17.5 for interface requirements.

9.2.16.1.5 Instrumentation Application

Pressure and temperature indicators are provided where required for testing the system.

TSW system pump status is indicated in the main control room.

TSW system trip is alarmed and the automatic startup of the standby pump is annunciated in the main control room.

High differential pressure across the duplex filters is alarmed in the main control room.

9.2.16.1.6 Tests and Inspections

All major components are tested and inspected as separate components prior to installation, and as an integrated system after installation to ensure design performance. The systems are preoperationally tested in accordance with the requirements of Chapter 14.

The components of the TSW system and associated instrumentation are accessible during plant operation for visual examination. Periodic inspections during normal operation are made to ensure operability and integrity of the system. Inspections include measurement of the TSW system flow, temperatures, pressures, differential pressures and valve positions to verify the system condition.

9.2.16.2 Portions Outside Scope of ABWR Standard Plant

All portions of the TSW system that are outside the turbine building are not in the scope of the ABWR Standard Plant. Subsections 9.2.16.2.1 through 9.2.16.2.6 provide a conceptual design of these portions of the TSW system as required by 10CFR52. The interface requirements for this system are part of the design certification.

The site dependent portions of the TSW system shall meet all requirements in Subsections 9.2.16.1.1 through 9.2.16.1.5 and following requirements. This subsection provides a conceptual design and interface requirements for those portions of the TSW system which are site dependent and are a part of the design certification.

9.2.16.2.1 Safety Design Bases (Interface Requirement)

There are none

9.2.16.2.2 Power Generation Design Bases (Interface Requirements)

The COL applicant shall provide the following system design features and additional information which are site dependent.

(1) the temperature increase and pressure drop across the heat exchangers

(2) the required and available net positive suction head for the TSW pumps at pump suction locations considering anticipated low water levels

(3) the location of the TSW pump house

9.2.16.3 System Description

9.2.16.3.1 General Description (Conceptual Design)

Piping and valves in the TSW system are carbon or low alloy steel and are protected from interior corrosion with suitable corrosion resistant material as required by site specific soil and water conditions.

9.2.16.3.2 Component Description (Conceptual Design)

Three strainers are provided (one for each TSW pump). Debris collected in the strainer is automatically sluiced to a disposal collection area.

9.2.16.3.3 Safety Evaluation (Interface Requirements)

The COL applicant shall demonstrate that all safety-related components, systems and structures are protected from flooding in the event of a pipeline break in the TSW system.

9.2.16.3.4 Instrumentation and Alarms (Interface Requirements)

There are none.

9.2.16.3.5 Tests and Inspections (Interface Requirements)

There are none.

9.2.17 COL License Information

9.2.17.1 Ultimate Heat Sink

Interface requirements pertaining to the ultimate heat sink are delineated in Subsection 9.2.5 as follows:

Subsection	Title
9.2.5.1	Safety Design Bases
9.2.5.2	Power Generation Design Bases
9.2.5.6	Evaluation of UHS Performance
9.2.5.7	Safety Evaluation
9.2.5.8	Conformance to Regulatory Guide 1.27
9.2.5.9	Instrumentation and Alarms
9.2.5.10	Tests and Inspections

9.2.17.2 Makeup Water System (Preparation)

Interface requirements pertaining to the makeup water system (Preparation) are delineated in Subsection 9.2.8 as follows:

Subsection	Title
9.2.8.1	Safety Design Bases
9.2.8.2	Power Generation Design Bases
9.2.8.5	Evaluation of Makeup Water System (Preparation) Perfromance
9.2.8.6	Safety Evaluation
9.2.8.7	Instrumentation and Alarms
9.2.8.8	Tests and Inspections

9.2.17.3 Potable and Sanitary Water System

Interface requirements pertaining to the potable and sanitary water system are delineated in Subsection 9.2.4 as follows:

Subsection	Title
9.2.4.1	Safety, Design Bases
9.2.4.2	Power Generation Design Bases
9.2.4.5	Evaluation of Potable and Sanitary Water System
9.2.4.6	Performance Safety Evaluation
9.2.4.7	Instrument and Alarms
9.2.4.8	Tests and Inspections

9.2.17.4 Reactor Service Water System (Portions Outside the Scope of ABWR Standard Plant)

Interface requirements pertaining to the reactor service water system) portions outside the scope of ABWR standard plant) are delineated in Subsection 9.2.15.2 as follows:

Subsection	Title
9.2.15.2.1	Safety Design Bases
9.2.15.2.2	Power Generation Design Bases
9.2.15.2.4	Safety Evaluation
9.2.15.2.5	Instrumentation and Alarms
9.2.15.2.6	Tests and Inspections

9.2.17.5 Turbine Service Water System (Portions Outside the Scope of ABWR Standard Plant)

Interface requirements pertaining to the turbine service water system (portions outside scope of ABWR standard plant) are delineated in Subsection 9.2.16.2) as follows:

Subsection	Title
9.2.16.2.1	Safety Design Bases
9.2.16.2.2	Power Generation Design Bases
9.2.16.2.4	Safety Evaluation
9.2.16.2.5	Instrumentation and Alarms
9.2.16.2.6	Tests and Inspections

9.2.17.6 HECW System COL License Information

The COL applicant shall provide for the following after the refrigerators have been procured.

(a) Means shall be provided for adjusting refrigerator capacity to chilled water outlet temperature.

(b) Means shall be provided for starting and stopping the pump and refrigerator on proper sequence.

(c) Means shall be provided for reacting to a loss of electrical power and for automatically restarting of pumps and refrigerators when electrical power is restored.

TABLE 9.2-3

CAPACITY REQUIREMENTS FOR CONDENSATE STORAGE TANK

Function	Capacity Required
dead space-top of pool	7,900g (Note 1)
normal operation variation and receiving volume for plant startup return water	264,000g
minimum storage volume	66,000g
dead space-middle of pool	34,320g (Note 1)
water source for station blackout	150,480g (Note 2)
dead space-bottom of pool	34,320g (Note 1)
Total	557,020g

NOTE

(1) These values are based on a bottom area of 1,400 ft^2.

(2) Water for operation of RCIC is taken from the condensate storage tank and the suppression pool as described in the EPGs of Appendix 18A.

TABLE 9.2-4a

REACTOR BUILDING COOLING WATER DIVISION A

Operating Mode/ Components	Normal Operating Conditions		Shutdown at 4 hours		Shutdown at 20 hours		Hot Standby (no loss of AC)		Hot Standby (loss of AC)		Emergency (LOCA) (Suppression Pool at 97°C	
ESSENTIAL	Heat (Note 1)	Flow	Heat	Flow	Heat	Flow	Heat	Flow	Heat	Flow	Heat	Flow
Emergency Diesel Generator A	---	---	---	---	---	---	---	---	12.5	1.010	12.5	1,010
RHR Heat Exchanger A	---	---	102.4	5,280	32.8	5,280	---	---	24.0	5,280	84.7	5,280
FPC Heat Exchanger A	6.6	1,230	6.6	1,230	6.6	1,230	6.6	1,230	6.6	1,230	9.1	1,230
Others (essential) (Note 2)	3.1	640	3.4	640	3.6	640	3.2	640	3.9	640	4.0	640
NON-ESSENTIAL												
RWCU Heat Exchanger	19.1	700	---	700	---	700	19.1	700	19.7	700	---	---
Inside Drywell (Note 3)	5.7	1,410	5.7	1,410	5.7	1,410	5.7	1,410	3.2	1,410	---	---
Others (non-essential) (Note 4)	2.5	440	2.5	440	2.5	440	2.5	440	0.8	260	0.7	260
Total Load	37.0	4,420	120.6	9,700	51.2	9,700	37.1	4,420	70.7	10,530	111.0	8,420

NOTES:

(1) Heat x 10^6 Btu/h; flow x g/m, sums may not be equal due to rounding.

(2) HECW refrigerator, room coolers (FPC pump, RHR, RCIC, SGTS, FCS, CAMS), RHR motor and seal coolers.

(3) Drywell (A & C) and RIP coolers.

(4) Instruments and service air coolers: RWCU pump cooler, CRD pump oil, and RIP Mg sets.

TABLE 9.2-4b

REACTOR BUILDING COOLING WATER DIVISION B

Operating Mode/ Components	Normal Operating Conditions		Shutdown at 4 hours		Shutdown at 20 hours		Hot Standby (no loss of AC)		Hot Standby (loss of AC)		Emergency (LOCA) (Suppression Pool at 97°C	
ESSENTIAL	Heat (Note 1)	Flow	Heat	Flow	Heat	Flow	Heat	Flow	Heat	Flow	Heat	Flow
Emergency Diesel Generator B	—	—	—	—	—		—	—	12.5	1,010	12,5	1,013
RHR Heat Exchanger B	—	—	102.4	5,280	32.8	5,280	—	—	24.0	5.280	84.7	5,280
FPC Heat Exchanger B	6.6	1,230	6.6	1,230	6.6	1,230	6.6	1,230	6.6	1,230	9.1	1,230
Others (essential)(Note 2)	4.9	1860	5.4	1860	5.4	1860	4.9	1860	5.5	1860	6.3	1860
NON-ESSENTIAL												
RWCU Heat Exchanger	19.1	700	—	700	—	700	19.1	700	19.1	700	—	—
Inside Drywell (Note 3)	5.1	1,230	5.8	1,230	5.1	1,230	5.1	1,230	2.3	1,230	—	—
Others (non-essential) (Note 4)	2.6	700	1.4	700	1.4	700	1.4	700	0.3	40	—	40
Total Load	38.3	5,720	121.6	11,000	51.3	11,000	37.1	5,720	70.3	11,350	112.6	9,530

NOTES:

(1) Heat x 10^6 Btu/h; flow x g/m, sums may not be equal due to rounding.

(2) HECW refrigerator, room coolers (FPC pump, RHR, HPCS, SGTS, FCS, CAMS), HPCS and RHR motor and mechanical seal coolers.

(3) Drywell (B) and RIP coolers.

(4) Reactor Building sampling coolers; LCW sump coolers (in drywell and reactor building), RIP MG sets and RWCU pump coolers.

TABLE 9.2-4c

REACTOR BUILDING COOLING WATER

DIVISION C

Operating Mode/ Components	Normal Operating Conditions		Shutdown at 4 hours		Shutdown at 20 hours		Hot Standby (no loss of AC)		Hot Standby (loss of AC)		Emergency (LOCA) (Suppression Pool at 97°C	
ESSENTIAL	Heat (Note 1)	Flow	Heat	Flow	Heat	Flow	Heat	Flow	Heat	Flow	Heat	Flow
Emergency Diesel Generator B	----	----	----	----	----		----	----	12.5	1,010	[illegible]	1,010
RHR Heat Exchanger B	----	----	102.4	5,280	32.8	5,280	----	----	24.0	5,280	84.7	5,280
Others (essential)(Note 2)	5.8	2,780	6.3	2.780	6.3	2,780	5.8	2,780	5.8	2,780	6.9	2,780
NON-ESSENTIAL												
Others (non-essential) (Note 4)	19.4	1,860	18.2	1,860	7.0	1,860	19.4	1,860	0.5	220	0.7	220
Total Load	25.2	4,640	126.9	9,920	46.1	9,920	25.2	4,640	42.8	9,290	104.8	9,290

NOTES:

(1) Heat x 10^6 Btu/h; flow x g/m, sums may not be equal due to rounding.

(2) HECW refrigerator, room coolers motor coolers, and mechanical seal coolers for RHR and HPCF.

(3) Instrument and service air coolers, CRD pump oil cooler, radwaste components, HSCR condenser, and turbine building sampling coolers.

TABLE 9.2-4d

DESIGN CHARACTERISTICS FOR REACTOR BUILDING COOLING WATER SYSTEM COMPONENTS

RCW Pumps (Two per division)	RCW (A)/(B)	RCW (C)
Discharge Flow Rate	6,250 gpm/pump	5,450 gpm/pump
Pump Total Head	82 psig	75 psig
Design Pressure	200 psig	200 psig
Design Temperature	$158^{o}F$	$158^{o}F$

RCW Heat Exchangers (Three per division)	RCW (A)/(B)	RCW (C)
Capacity (for each heat exchanger)	$45x10^6$ BTU/h	$42x10^6$BTU/h

RCW Surge Tanks	
Capacity	Equal to 30 days of normal leakage
Design Pressure	Static Head
Design Temperature	$158^{o}F$

RCW Chemical Addition Tanks	
Design Pressure	200 psig
Design Temperature	$158^{o}F$

RCW Piping	
Design Pressure	200 psig
Design Temperature	$158^{o}F$

TABLE 9.2-6

HVAC NORMAL COOLING WATER SYSTEM COMPONENT DESCRIPTION

HNCW Chillers

Type	Centrifugal hermetic
Quantity	5 (including one standby unit)
Cooling Capacity	8.93×10^6 BTU [illegible] each
Chilled water flow per unit	1,980 g/m
Supply temperature	44.6°F
Condenser water flow per unit	1,840 g/m
Supply temperature	95°F
Control	Inlet guide vane
Condenser	Shell and tube
Evaporator	Shell and tube

HNCW Water Pumps

Quantity	5 (including one standby unit)
Type	Centrifugal, horizontal
Capacity (gpm) each	1,980
Total discharge head	71 psi

TABLE 9.2-7

HVAC NORMAL COOLING WATER LOADS

Name of Area or Unit	During Normal Operation		During Refueling Shutdown	
	Capacity BTU/h x 10^{-6}	Flow gpm	Capacity BTU/h x 10^{-6}	Flow gpm
Reactor Building				
Drywell Coolers (2 of 3)	0.92	306	0.75	306
RIP Coolers	1.66	9[illegible]	2.90	459
Others (Note 1)	10.40	577	17.69	2,801
Turbine Building (Note 2)	2.14	192	1.08	172
Radwaste Building (Note 4)	5.42	358	6.45	1,023
Service Building	3.47	770	3.47	770
Others (Note 5)	4.37	633	3.38	633
Total	28.4	2,928	35.7 (Note 6)	6,164

NOTES:

(1) Loads include reactor/turbine building supply units.

(2) Loads are the offgas cooler condenser (normal operation only) and the electrical equipment supply unit.

(3) Deleted

(4) Loads included are the radwaste building supply unit and the radwaste building electrical equipment room supply unit.

(5) Loads include HVH units not previously included.

(6) The HNCW chillers are 8.93 x 10^{6} BTU/h each and the pumps 1,980 gpm each. Thus, four HNCW pumps have total capacity in excess of the amount required as shown in the last column of the table

TABLE 9.2-8

HECW SYSTEM COMPONENT DESCRIPTION

HECW Chillers

Type		Centrifugal hermetic
Quantity		5
Capacity (refrigeration)	five	2.3×10^6 BTU/h each
Chilled water pump flow	five	250 gpm each
Supply temperature	44.6°F	
Condenser water flow	five	564 gpm each
Supply temperature (max.)		95°F
Condenser	Shell and tube	
Evaporator	Shell and tube	

HECW Water Pumps

Quantity	5 - 256 gpm each
Type	Centrifugal, horizontal

TABLE 9.2-9

HVAC EMERGENCY COOLING WATER SYSTEM HEAT LOADS

		NORMAL		EMERGENCY	
DIVISION	SYSTEM	Heat Load ($x10^6$ BTU/h)	Chilled Water Flow (gpm)	Heat Load ($x10^6$ BTU/h	Chilled Water Flow (gpm)
A	diesel generator zone (A)	0.83	62	0.83	62
	control building elect. eq. room (A)	1.19	88	1.19	88
	Total	2.02	150	2.02	150
B	main control room	1.35	113	1.25	104
	diesel generator zone (B)	0.86	64	0.86	64
	control bldg. elect. eq. room (B)	1.19	88	1.19	88
	Total	3.4	265	3.3	256
C	main control room	1.35	113	1.25	104
	diesel generator zone (c)	0.86	64	0.86	64
	control bldg. elect. eq. room (C)	1.19	88	1.19	88
	Total	3.40	265	3.30	256

Table 9.2-10

HVAC EMERGENCY COOLING WATER SYSTEM ACTIVE FAILURE ANALYSIS

Failure of diesel generator to start or failure of all power to a single Class 1E power system bus	Loss of one refrigerator and pump in Division B or C would not permit sending chilled water to the main control room from the affected division. The other HECW division would send chilled water to the main control room which would maintain adequate cooling. In Division A, loss of either the refrigerator or the pump would result in loss of cooling water flow to Division A essential electrical equipment room and diesel generator Zone A. Cooling of main control room not affected.
Failure of auto pump or refrigerator signal	Same analysis as above
Failure of a single HECW refrigerator	Same analysis as above
Failure of a single HECW pump	Same analysis as above
Failure of HECW pump and refrigerator room cooling	Same analysis as above

TABLE 9.2-11

TURBINE BUILDING COOLING WATER SYSTEM HEAT LOADS

The TCW system removes heat from the following components:

- HVAC normal cooling water chillers
- generator stator coolers, hydrogen coolers, seal oil coolers, exciter coolers and breaker coolers
- turbine lube coolers
- mechanical vacuum pump coolers
- iso phase bus coolers
- electro-hydraulic control coolers
- reactor feed pump variable speed motor coolers and motor thyristor coolers
- standby reactor feed pump motor coolers
- condensate pump motor coolers
- heater drain pump motor coolers

Table 9.2-12

SUMMARY OF TURBINE COOLING WATER SYSTEM HEAT EXCHANGERS

Equipment Description	Number /In Use
Plant Chillers	5/4
Gen stators coolers	2/1
Gen H2 coolers	2/2
Gen H2 seal oil cooler	4/2
Gen exciter cooler	1/1
Gen breaker cooler	1/1
Turbine lube oil coolers	2/1
Mech vacuum pump cooler	1/1
Isolated phase bus cooler	1/1
Air compress & aftercooler	3/3
EHC coolers	2/1
RFP variable speed motor coolers	2/2
RFP motor thyrister coolers	2/2
Standby RFP motor coolers	1/0
Condensate pump motor coolers	4/3
Heater drain pumpo coolers	2/2

Table 9.2-13

REACTOR SERVICE WATER SYSTEM

RSW Pumps (Two per division)

Discharge Flow Rate, per pump	7,920 gpm
Pump Total Head	50 psi
Design Pressure	115 psi
Design Temperature	122° F

RSW Piping and Valves

Design Pressure	155 psi
Design Temperature	122° F

Table 9.2-14

POTABLE AND SANITARY WATER SYSTEM COMPONENTS

(Interface Requirements)

All Tanks are vertical, cylindrical type except where noted. All water pumps are horizontal, centrifugal and single stage. All chemical feed pumps are positive displacement diaphram type.

Component	Major Design Features
Potable Water Storage Tank	
Capacity	6,000 gallons
Potable Water Pump	
Quantity	two
Capacity	100 gpm each
Head	250 feet
Hypochlorinator Pump	
Capacity	2.5 gph
Head	125 psi
Hypochlorite Tank	
Capacity	50 gallons
Hydropneumatic Pressure Tank	
Type	Horizontal, cylindrical
Capacity	4,000 gallons
Design pressure	150 psig
Air Compressor	
Type	Piston, single-stage
Capacity	6 scfm
Discharge pressure	120 psig
Comminutor	
Type	Revolving vertically-slooted drum
Aeration Tank	
Quantity	two
Volume	900 cub. feet each
Clarifier	
Quantity	one large, two small
Volume	675 cubic feet, 240 cubic feet each

Table 9.2-14

POTABLE AND SANITARY WATER SYSTEM COMPONENTS (Continued)

(Interface Requirements)

Component	Major Design Features
Hypochlorite Contact Tank	
Volume	150 cubic feet
Aerobic Digester	
Quantity	two
Volume	900 cubic feet each
Air Blower	
Quantity	three
Capacity	12 scfm each
Froth Spray Pump	
Capacity	25 gpm
Head	100 feet
Hypochlorite Feed Pump	
Capacity	6 gph
Head	100 feet
Hypochlorite Tank	
Capacity	100 gallons

Table 9.2-15

MAKEUP WATER PREPARATION SYSTEM COMPONENT

(Interface Requirements)

All Tanks are vertical, cylindrical type. All water pumps are horizontal, centrifugal and single stage except the RO feed pumps. All chemical feed pumps are positive displacement, diaphram type.

Component	Major Design Features
Well	
Capacity	at least 2,000 gpm
Well Water Tank	
Capacity	10,000 gallons
Well Water Pumps	
Quantity	two
Capacity	1,000 gpm
Filters	
Quantity	two
Capacity	1,000 gpm each
Type	Pressure type, dual media
Filtered Water Storage Tank	
Capacity	40,000 gallons
Backwash Pumps	
Quantity	two
Capacity	2,000 gpm each
Head	90 feet
RO Feed Pumps	
Quantity	four
Type	Horizontal, multistage
Capacity	200 gpm
Head	400 to 500 psig
RO First Pass	
Quantity	two
Type	2 to 1 array of thin film composite membranes
Capacity	300 gpm permeate each with 25% rejection
RO Second Pass	
Quantity	two
Type	1 to 1 array of thin film composite membranes
Capacity	200 gpm permeate each with 33% rejection

Table 9.2-15

MAKEUP WATER PREPARATION SYSTEM COMPONENT (Continued)

(Interface Requirements)

Component	Major Design Features
RO Permeate Storage Tank	
Capacity	5,000 gallons
RO Permeate Feed Pumps	
Capacity	5,000 gallons
Demineralizer Feed Pumps	
Quanitity	four
Capacity	100 gpm each
Head	230 feet
Demineralizers	
Quanitity	six
Capacity	100 gpm each
Resin	40 cubic feet of 1:2 cation/anion resin each
Demineralized Water Storage Tanks	
Quanitiy	two
Capacity	100,000 gallons each
Demineralized Water Forwarding Pumps	
Quanitity	three
Capacity	200 gpm each
Chemical Feed Tank (NaHMP)	
Capacity	200 gallons
Chemical Feed Pump (NaHMP)	
Quanitity	two
Capacity	10 gph each
Chemical Feed Tank (NaOH)	
Capacity	400 gallons
Chemical Feed Pump (NaOH)	
Quanitity	four (three normally operating with one spare)
Capacity	10 gph each

Table 9.2-16

TURBINE SERVICE WATER SYSTEM

(Interface Requirement)

TSW Pumps (Three 50% pumps)	
Discharge Flow Rate	15,000 gpm per pump
Pump Total Head	28 psig
Design Pressure	85 psig
Design Temperature	$104^{\circ}F$
TSW Piping and Valves	
Design Pressure	85 psig
Design Temperature	$104^{\circ}F$

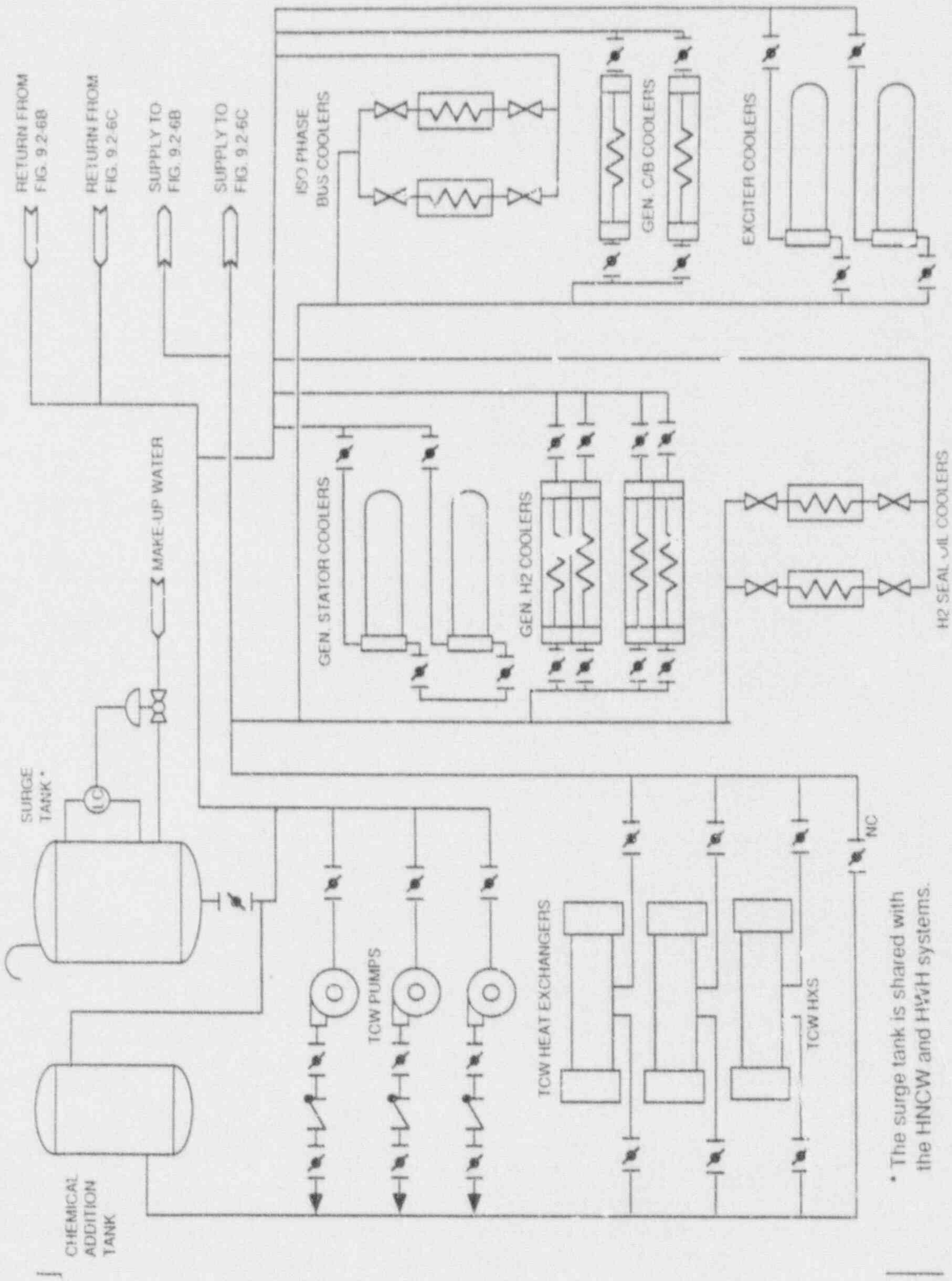


Figure 9.2-6a TURBINE COOLING WATER SYSTEM DIAGRAM

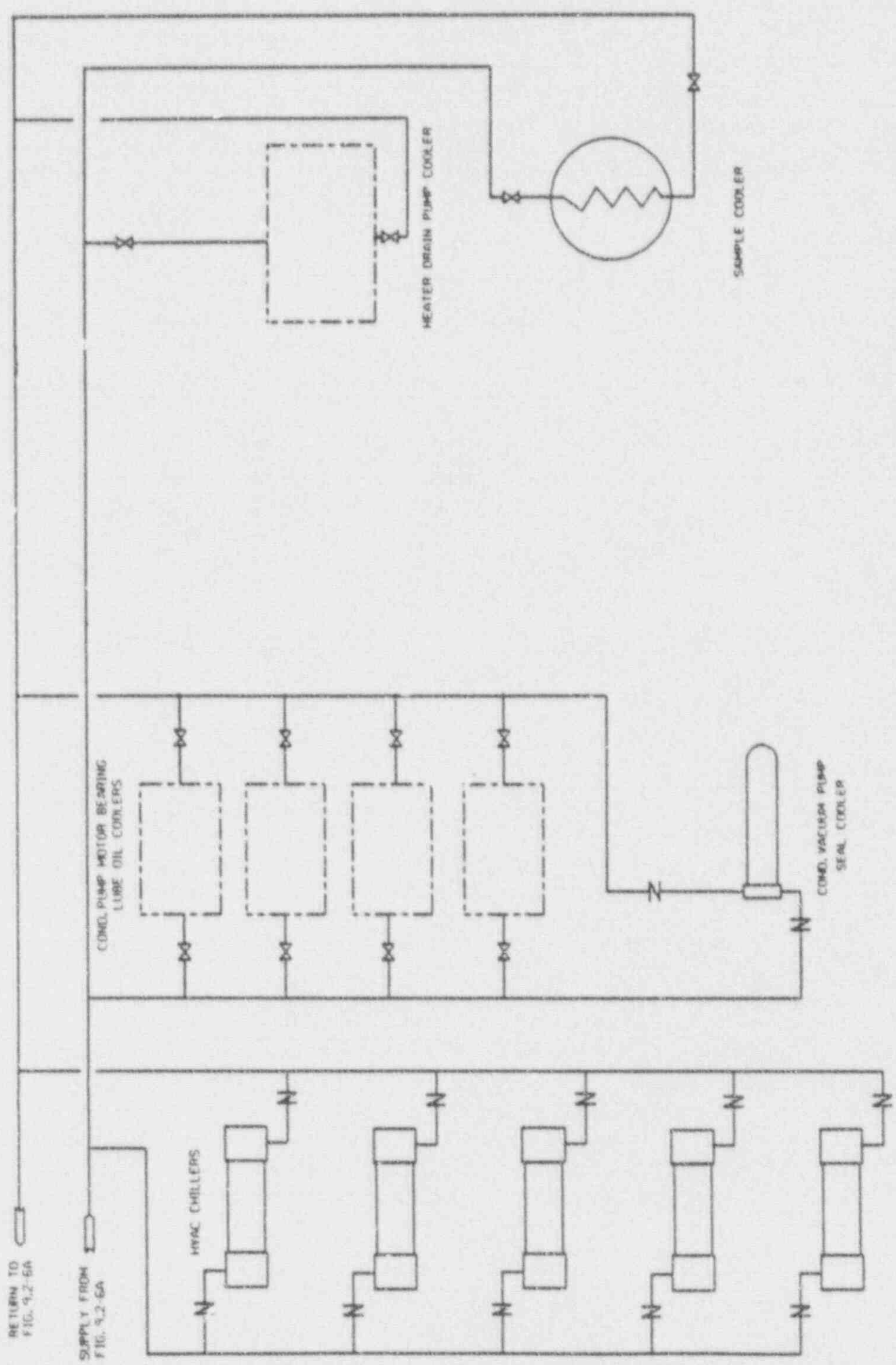


Figure 9.2-6b TURBINE COOLING WATER SYSTEM DIAGRAM

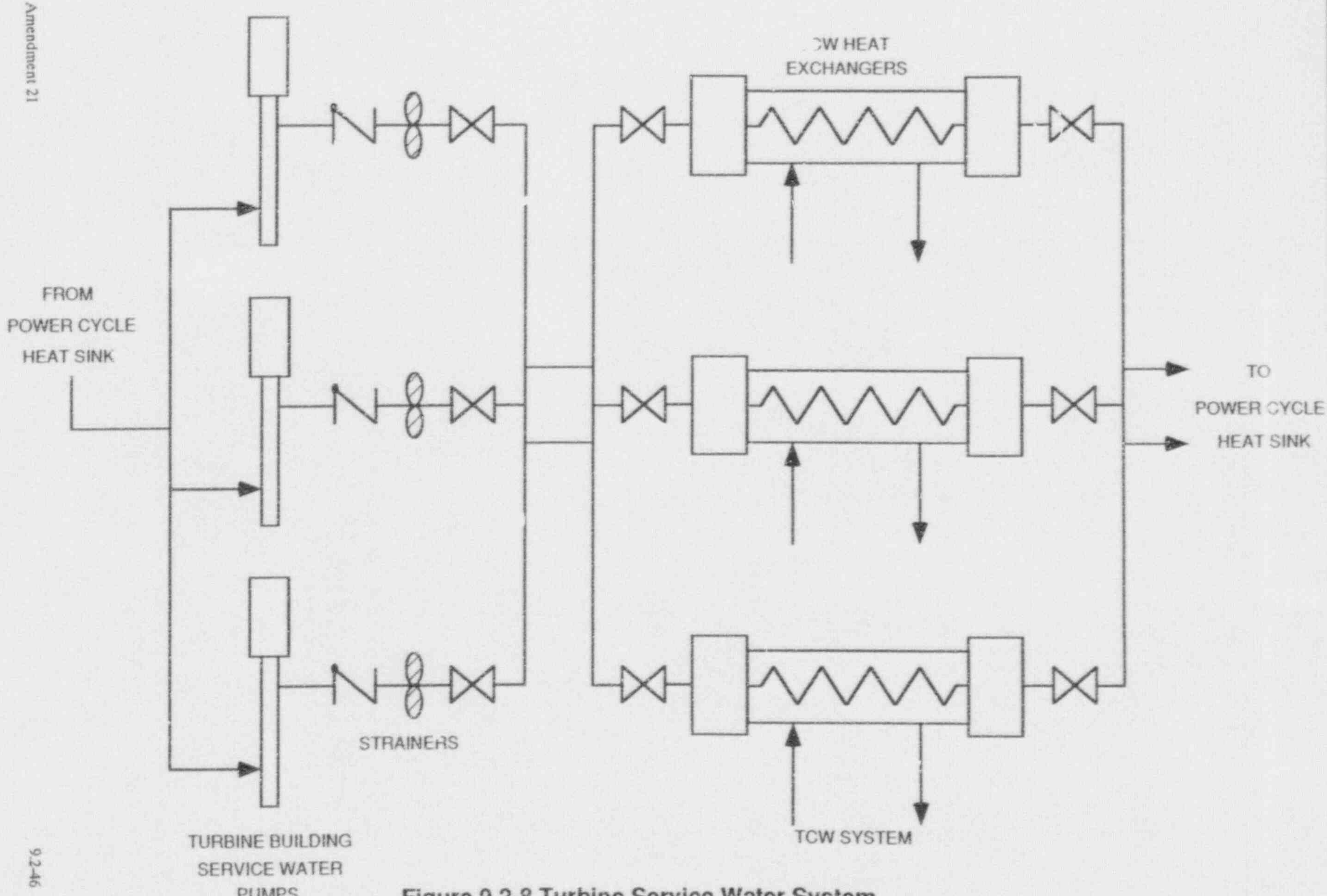
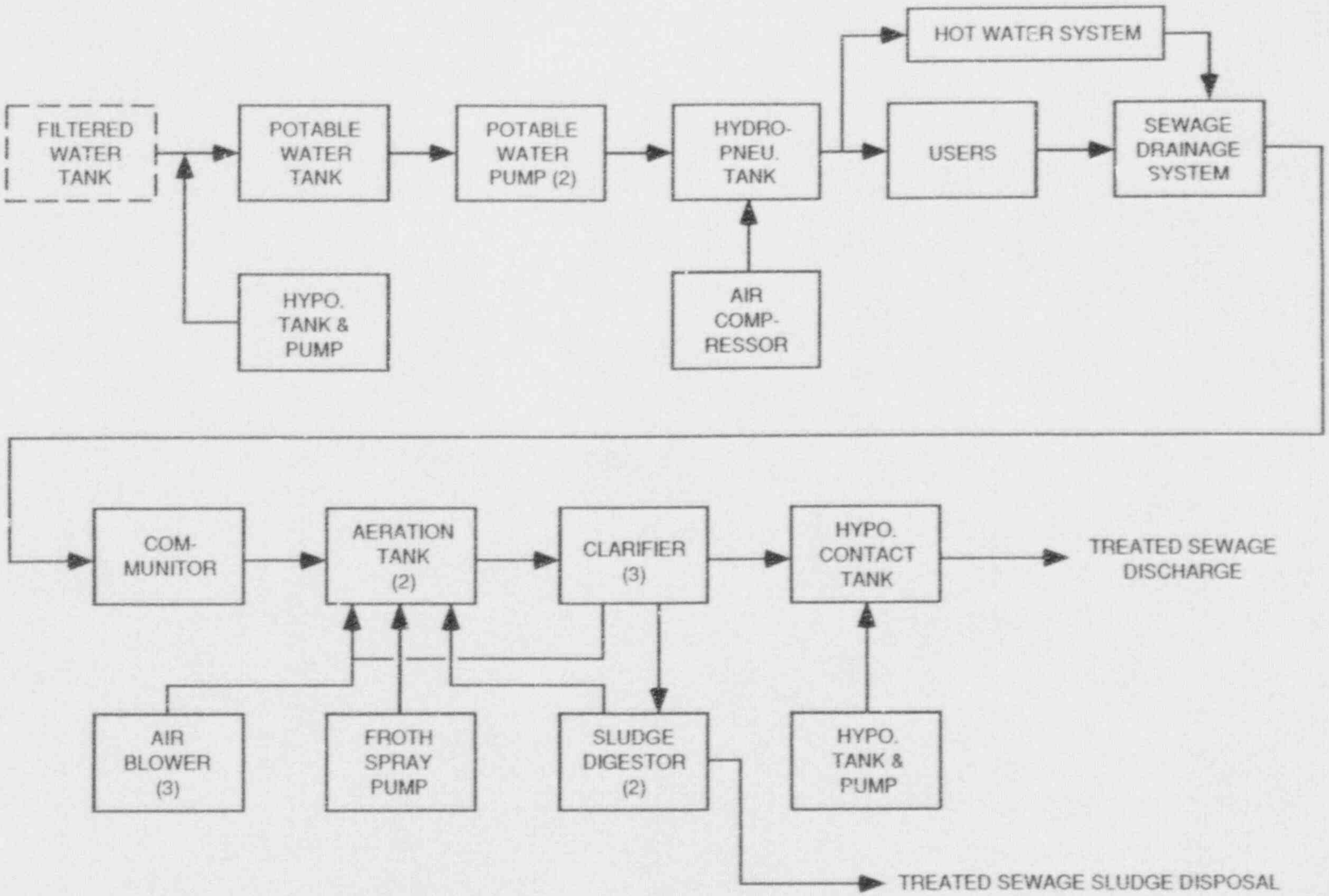
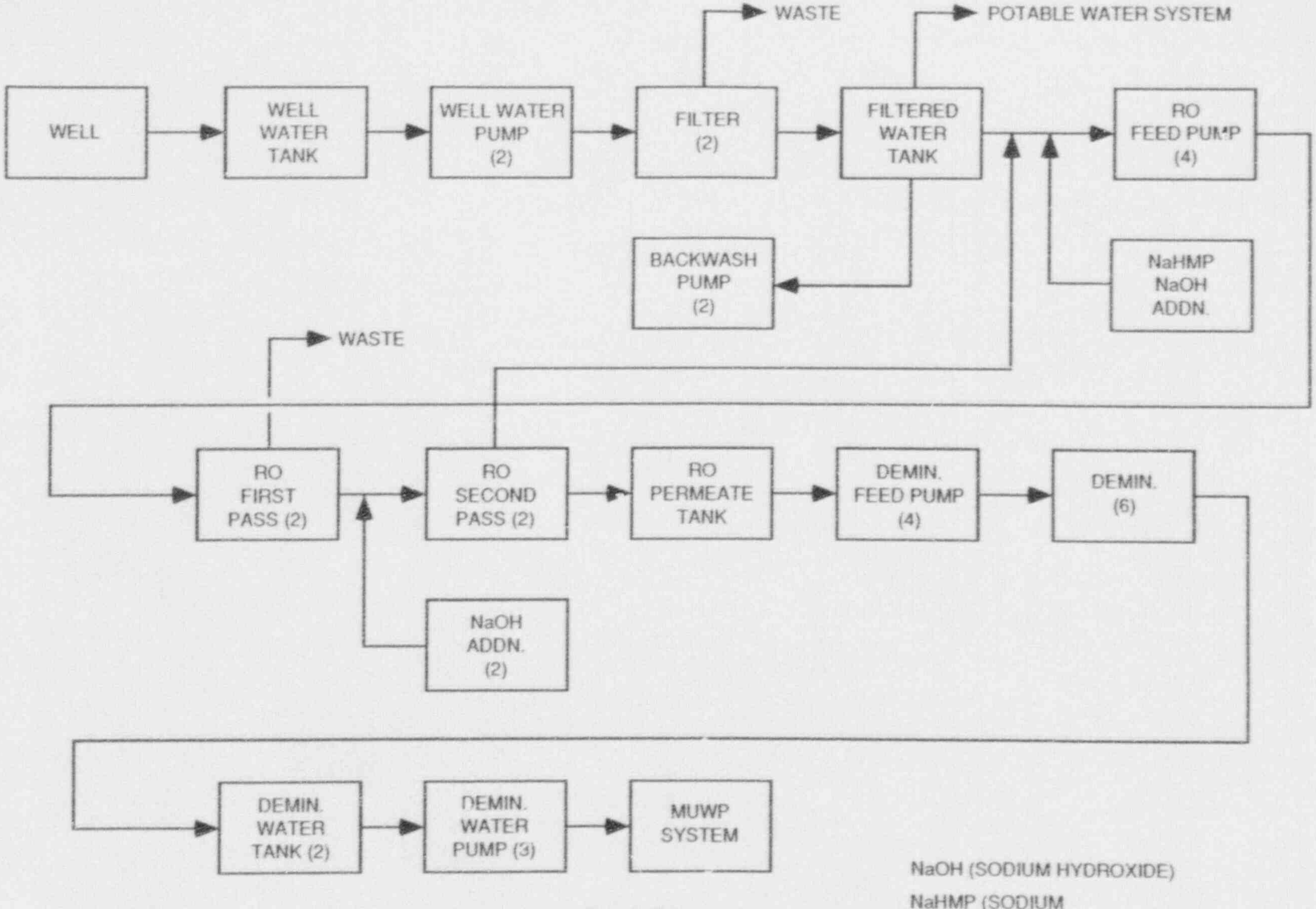


Figure 9.2-8 Turbine Service Water System



Block Flow Diagram
(Interface Requirements)

Figure 9.2-9 Potable and Sanitary Water System



Block Diagram
(Interface Requirements)

Figure 9.2-10 Makeup Water Preparation System

SECTION 9.3

TABLES

ILLUSTRATIONS

9.3 PROCESS AUXILIARIES

9.3.2 Process and Post Accident Sampling

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9.3 PROCESS AUXILIARIES

9.3.6 Instrument Air System

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9.3 PROCESS AUXILIARIES

9.3.8 Radioactive Drain Transfer System

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9.3.9 Hydrogen Water Chemistry System

9.3.9.1 Design Bases

9.3.9.1.2 Safety Design Basis

The hydrogen water chemistry (HWC) system is non-nuclear, non-safety-related and is required to be safe and reliable, consistent with the requirement of using hydrogen gas. The hydrogen piping in the turbine building shall be designed to Seismic Category I requirements to comply with BTP 9.5-1.

9.3.9.1.2 Power Generation Design Basis

BWR reactor coolant is demineralized water, typically containing 100 to 200 parts per billion (ppb) dissolved oxygen from the radiolytic decomposition of water. To mitigate the potential for intergranular stress corrosion cracking (IGSCC) of sensitized austenitic stainless steels, the dissolved oxygen in the reactor water can be reduced to less than 20 ppb by the addition of hydrogen to the feedwater. The amount of hydrogen required is in the range of 1.0 to 1.5 ppm. The exact amount required depends on many factors including incore recirculation rates. The amount required will be determined by tests performed during the initial operation of the plant.

The concentration of hydrogen and oxygen in the main steam line and eventually in the main condenser is altered in this process. This leaves an excess of hydrogen in the main condenser that would not have equivalent oxygen to combine with in the offgas system. To maintain the offgas system near its normal operating characteristics, a flow rate of oxygen equal to approximately one-half the injected hydrogen flow rate is injected in the offgas system upstream of the recombiner.

The HWC system utilizes the guidelines given in EPRI report NP-5283-SR-A, "Guidelines for Permanent BWR Hydrogen Water Chemistry Installation" and EPRI report NP-4947-SR, "BWR Hydrogen Water Chemistry Guidelines: 1987 Revision," October 1988.

9.3.9.2 System Description

The HWC system, illustrated in Figure 9.3-8, is composed of hydrogen and oxygen supply systems, systems to inject hydrogen in the feedwater and oxygen in the offgas and subsystems to monitor the effectiveness of the HWCS system. These systems monitor the oxygen levels in the offgas system, the feedwater system, the lower plenum region and the CUW inlet, hydrogen and pH levels in the feedwater system, the lower plenum region and the CUW inlet, and crack growth of pre-cracked samples in water from the lower plenum region.

The hydrogen supply system will be site dependent. Hydrogen can be supplied either as a high pressure gas or as a cryogenic liquid. Hydrogen and oxygen can also be generated on site by the dissociation of water by electrolysis. The HWC hydrogen supply system is integrated with the generator hydrogen supply system to save the cost of having separate gas storage facilities for both systems.

The oxygen supply system will be site dependent. A single oxygen supply system could be provided to meet the requirements of HWC system and the condensate oxygen injection system described in Subsection 9.3.10.

9.3.9.3 Safety Evaluation

The operation of the HCS is not necessary to assure:

(1) The integrity of the reactor coolant pressure boundary,

(2) The capability to shut down the reactor; or

(3) The capability to prevent or mitigate the consequences of events which could result in potential offsite exposures.

The HWC system is used, along with other measures, to reduce the likelihood of corrosion failures which would adversely affect plant availability. The means of storing and handling hydrogen and oxygen shall utilize the guidelines in EPRI NP-5283-SR-A, "Guidelines for Permanent BWR Hydrogen Water Chemistry Installations".

9.3.9.4 Inspection and Testing Requirements

The HWC system is proved operable during the initial operation of the plant. During a refueling or maintenance outage, hydrogen injection is not required. System maintenance or testing can be performed during such periods.

9.3.9.5 Instrumentation and Controls

Automatic control features in the HWC system minimize the need for operator attention and improve performance. These are:

(1) Automatic variation of hydrogen and oxygen flow rates with reactor power level.

(2) Automatic oxygen injection rate change delay. This function is also augmented as a function of reactor power level.

(3) Automatic shutdown on several alarms.

(4) Isolation on system power loss, operator restart.

(5) Reprogrammable alarms and controller electronics.

(6) Hydrogen and oxygen flow monitor correction function to compensate for nonlinearities.

The recommended trips of the oxygen and hydrogen injection systems include:

(1) Reactor scram

(2) Low or high residual oxygen in the off-gas

(3) High area hydrogen concentration

(4) Low oxygen injection system supply pressure

(5) High hydrogen flow

The instrumentation provided includes:

(1) Flow monitors for measurement of hydrogen and oxygen flow rates.

(2) Hydrogen area monitor sensors to detect any hydrogen to the atmosphere.

(3) Pressure gages for measurement of hydrogen and oxygen supply pressures and instrument air pressure.

(4) An oxygen analyzer for measuring the percent oxygen leaving the offgas recombiner.

(5) Sensors for measuring dissolved oxygen content.

(6) Sensors for measuring pH and dissolved hydrogen.

(7) A system for verifying the effectiveness of HWC by measuring electrochemical potential (ECP) and crack growth rate.

9.3.10 Oxygen Injection System

9.3.10.1 Design Bases

The oxygen injection system is designed to add sufficient oxygen to the Condensate System to suppress corrosion and corrosion product release in the condensate and feedwater systems. Experience has shown that the preferred feedwater oxygen concentration is 20 to 50 ppb. During shutdown and startup operation the feedwater oxygen concentration is usually much above the 20 to 50 ppb range. However, during power operation, deaeration in the main condenser may reduce the condensate oxygen concentration below 20 ppb, thus, requiring that some oxygen be added. The amount required is up to approximately 5 cubic feet per hour. 281.17

9.3.10.2 System Description

The oxygen supply consists of high pressure gas cylinders. The oxygen injection system shall use the guidelines for gaseous oxygen injection systems in EPRI report NP-5283-SR-A, "Guidelines for Permenent Hydrogen Water Chemistry Installations - 1987 Revision," September 1987. A condensate oxygen injection module is provided with pressure regulators and associated piping, valves, and controls to depressurize the gaseous oxygen and route it to the condensate injection modules. There are check valves and isolation valves between the condensate injection modules and the condensate lines upstream of the filters.

The flow regulating valves in this system are operated from the main control room. The oxygen concentration in the condensate/feedwater system is monitored by analyzers in the sampling system (Subsection 9.3.2). An operator will make changes in the oxygen injection rate in response to changes in the condensate/feedwater concentration. An automatic control system is not required because instantaneous changes in oxygen injection rate are not required.

9.3.10.3 Safety Evaluation

The oxygen injection system is not required to assure any of the following conditions.

(1) integrity of the reactor coolant pressure boundary;

(2) capability to shut down the reactor and maintain it in a safe shutdown condition, or

(3) ability to prevent or mitigate the consequences of events which could result in potential offsite exposures.

Consequently, the injection system itself is not safety-related. The high pressure oxygen storage bottles are located in an area in which large amounts of burnable materials are not present. Usual safe practices for handling high pressure gases are followed.

281.17 9.3.10.4 Tests and Inspections

The oxygen injection system is proved operable by its use during normal operation. The system valves may be tested to ensure operability from the main control room.

9.3.10.5 Instrumentation Application

The oxygen storage bottles have pressure gages which will indicate to the operators when a new bottle is required. A flow element will indicate the oxygen gas flow rate at all times. The gas flow regulating valves will have position indication in the main control room.

The oxygen monitors are discussed in Subsection 9.3.2.

9.3.11 Zinc Injection System

9.3.11.1 Design Bases

Provisions are made to permit installation of a system for adding a zinc solution to the feedwater. 281.15 Piping connections (Figure 10.4-7) for a bypass loop around the feedwater pumps and space (Figure 1.2-25) for the zinc addition equipment are provided. If experience shows it to be necessary, a zinc injection system may be added later in plant life. The amount of zinc in the reactor water will be less than 10 ppb during nornal opereation.

9.3.11.2 Safety Evaluation

The injection system is not necessary to ensure:

(1) the integrity of the reactor coolant pressure boundary;

(2) the capability to shut down the reactor; or

(3) the capability to prevent or mitigate the consequences of events which could result in potential offsite exposures.

9.3.11.3 Test and Inspections

The zinc injection system is proved operable after installation. Zinc injection would not be performed when the plant is in cold shutdown. During these periods, the system could have maintenance or testing performed.

9.3.11.4 Instrumentation

Instrumentation would be provided so that the injection of zinc solution would be stopped automatically if feedwater flow stops. The zinc injection rate would be manually adjusted based on zinc concentration data in the reactor water.

9.3.12 Interfaces

9.3.12.1 Radioactive Drain Transfer System Collection Piping

The applicant referencing the ABWR design will provide equipment and floor drain piping P&IDs as a part of the radioactive drain transfer system. This piping will be provided with the following features:

(1) These piping systems shall be non-nuclear safety class and quality Group D with the exception of any containment penetrations or piping within the drywell which shall be Seismic Category I and quality Group B.

(2) The floor drain piping system shall be arranged with a separate piping system for each quadrant. The piping shall be arranged so that flooding or backflow in one quadrant cannot adversely affect the other quadrants.

(3) There shall be no interconnection between any portion of the radioactive drain transfer system and any non-radioactive waste system.

(4) Effluent from non-radioactive systems shall be monitored prior to discharge to assure that there are no unacceptable discharges.

See Subsection 9.3.8.2 for information concerning the remainder of the radioactive drain transfer system.

9.3 PROCESS AUXILIARIES

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SECTION 9.4

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SECTION 9.4

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9.4 AIR CONDITIONING HEATING, COOLING AND VENTILATION SYSTEMS

9.4.1 Control Building HVAC

The control building heating, ventilating and air-conditioning (HVAC) system is divided into two separate systems. A HVAC system for the control room equipment on the top two floors. Plus a HVAC system for essential electrical and heat exchanger equipment.

9.4.1.1 Control Room Equipment HVAC

9.4.1.1.1 Design Basis

(1) The control room (HVAC) system is designed with sufficient redundancy to ensure operation under emergency conditions assuming the single failure of any one active component.

(2) Provisions are made in the system to detect and limit the introduction of airborne radioactive material in the control room.

(3) Provisions is made in the system to detect and remove smoke and radioactive material from the control room.

(4) The HVAC system is designed to provide a controlled temperature environment to ensure the continued operation of safety-related equipment under accident conditions.

(5) The HVAC system and components are located in the Seismic Category I control building structure that is tornado-missile and flood protected.

430.241 (6) Tornado missle barriers are provided for intake and exhaust structures.

9.4.1.1.2 Power Generation Design Basis

(1) The HVAC system is designed to provide an environment with controlled temperature and humidity to ensure both the comfort and safety of the operators. The nominal design conditions for the control room environment are 75°F and 50% relative humidity.

(2) The system is designed to permit periodic inspection of the principal system components.

(3) The outside design conditions for the control room HVAC system are 115°F during the summer and -40°F during the winter.

9.4.1.1.3 System Description

The control room is heated, cooled and pressurized by a recirculated air system with filtered outdoor air for ventilation and pressurization purposes. The recirculated air and the outdoor air will be mixed and drawn through a filter section, a heating coil section, and a cooling coil section. Under normal conditions, sufficient air is supplied to pressurize the control room and exfiltrate to pressurize the control building.

The control building HVAC P&ID is shown in Figure 9.4-1. The control room flow rate is given in Table 9.4-3, and the system component descriptions are given in Table 9.4-4. The control building recirculation unit consists of a medium grade bag filter, a heating coil, cooling coil, two 100% capacity supply fans. 430.237

Two 100% capacity return exhaust fans draw air from the electrical area, corridors, control room, computer room, office areas, and the HVAC equipment room. This air is returned to the air conditioning unit during normal operations. Modulating dampers in the return duct work to the fans are controlled by a pressure controller to maintain the required positive pressure. The controller is located in the electrical equipment area.

An emergency recirculation system consisting of an electrical heating coil, a prefilter, HEPA filter, charcoal adsorber, a HEPA filter, and two 100% capacity booster fans which are provided in parallel to the normal mixed outdoor and return air path to the supply conditioning units. The charcoal adsorber will be 2 inches deep as a minimum. The system is normally on standby for use only during high radiation. A radioactivity monitoring system monitors the building intakes for radiation. The radiation monitor allows the control room operator to select the safest intake. The makeup air for pressurization can be diverted through the HEPA and charcoal adsorbing system before distribution in the control room areas.

Smoke detectors in the control room and the control equipment room exhaust systems actuate an alarm on indication of smoke.

The HVAC equipment space is physically separated into divisional rooms. Each divisional room consists of an air intake room and an air exhaust room.

9.4.1.1.4 Safety Evaluation

The control building HVAC system is designed to maintain a habitable environment and to ensure the operability of components in the control room. All control room HVAC equipment and surrounding structures are of Seismic Category I design and operable during loss of the offsite power supply.

The ductwork which services these safety functions is termed ESF ductwork, and is of Seismic Category I design. ESF ducting is high pressure safety grade ductwork designed to withstand the maximum positive and/or negative pressure to which it can be subjected under normal or abnormal conditions. Galvanized steel ASTM A526 or ASTM A527 is used for outdoor air intake and exhaust ducts. All other ducts are welded black steel ASTM A570, Grade A or Grade D. Ductwork and hangers are Seismic Category I. Bolted flange and welded joints are qualified per ERDA 76-21.

430.228 Redundant and independent components are provided where necessary to ensure that a single failure will not preclude adequate control room ventilation.

A radiation monitoring system is provided to detect high radiation in the outside air intake ducts. A radiation monitor is provided in the control room to monitor control room area radiation levels. These monitors alarm in the control room upon detection of high radiation conditions. Isolation of the control room and initiation of the outdoor air cleanup unit fans are accomplished by the following signals:

(1) high radiation in the inside air intake duct, and

(2) manual isolation.

Under normal conditions, sufficient air is supplied to pressurize the control room and exfiltrate to pressurize the control building.

The safety-related isolation valves at the outside air intakes are protected from becoming inoperable due to freezing, icing, or other environmental conditions.

On smoke in a division of the MCR HVAC, that division of the HVAC system is put into smoke removal mode. For smoke removal, the exhaust fan is stopped, the recirculation duct valve is closed, and the fan bypass valve is opened. Either division of MCR HVAC can be used as a smoke removal system.

9.4.1.1.5 Inspection and Testing Requirements

Provisions are made for periodic tests of the outdoor air cleanup fans and filters. These tests include determinations of differential pressure across the filter and of filter efficiency. Connections for testing, such as injection, sampling and monitoring are properly located so that test results are indicative of performance.

The high-efficiency particulate air (HEPA) filters may be tested periodically with dioctyl phthalate smoke (DOP). The charcoal filters may be periodically tested with freon for bypasses.

The balance of the system is proven operable by its use during normal plant operation. Portions of the system normally closed to flow can be tested to ensure operability and integrity of the system.

9.4.1.1.6 Instrumentation Application

The area exhaust fan is started manually and the fan discharges the air to atmosphere.

A high radiation signal automatically starts the outdoor air cleanup system, closes the normal air inlet damper and closes the exhaust air dampers.

A temperature indicating controller senses the temperature of the air leaving the air cleanup system. The controller then modulates an electric heating coil to maintain the leaving air temperature at a preset limit. A limit switch will cause an alarm to be actu- ated on high air temperature. A moisture-sensing element, working in conjunction with the temperature controller measures the relative humidity of the air entering the charcoal absorber.

Differential pressure indicators show the pressure drop across the prefilters and the HEPA filters. A differential pressure indicating switch also measures the pressure drop across the entire filter train. The switch causes an alarm to be actuated if the pressure drop exceeds a preset limit. A flow switch in the outdoor air cleanup system fan discharge duct automatically starts the standby system and initiates an alarm on operating fan failure.

The electrical equipment area and the control room area return exhaust fans start automatically when the air-conditioning unit is started. Each fan inlet damper is open automatically. The exhaust dampers to the conditioning unit are opened automatically.

Differential pressure-indicating controllers modulate dampers in the return air ducts to maintain space positive pressure requirements.

The cooling unit starts automatically on a signal from the temperature-indicating controller installed in the HVAC room. The controller modulates a three-way chilled water valve to maintain the space conditions.

During winter, the electric unit heaters are cycled by temperature-indicating controller switches, located within the filter rooms and the air-handler rooms.

The supply and return air duct work has manual balancing dampers provided in the branch ducts for balancing purposes. The dampers are locked in place after the system is balanced.

9.4.1.1.7 Regulatory Guide 1.52 Compliance Status

The control room ESF filter trains comply with all applicable provisions of Regulatory Guide 1.52, Section C except as noted below.

The revisions of ANSI N509 and N510 listed in Table 1.8-21 are used for ABWR ESF fliter train design; the Regulatory Guide references older revisions of these standards.

The control room ESF filter trains are in compliance with the system design criteria except for the heater and demisters. The heaters and demisters are put into systems to regulate the relative humidity of the air as it enters the ESF filter train. Since the control room air-handling units are designed to maintain the control room temperature and humidity within limits, additional controls are not necessary for the ESF filter train.

9.4.1.1.8 Standard Review Plan 6.5.1 Compliance Status

The control room ESF system complies with SRP 6.5.1, Table 6.5.1-1. The only exceptions are for heater and moisture separator instrumentation requirements. Since these components are not necessary for the ABWR design, no instrumentation has been supplied to monitor their operation. Relative humidity and temperature of the inlet air is maintained by the control room air-handling system.

9.4.1.2 Essential Electrical and Reactor Building Cooling Water Equipment HVAC

9.4.1.2.1 Design Basis

(1) The HVAC system is designed with sufficient redundancy to ensure operation under emergency conditions assuming the failure of any one active component.

(2) The HVAC system is designed to provide a controlled temperature environment to ensure the continued operation of safety-related equipment under accident conditions.

(3) The HVAC system and components are located in a Seismic Category I structure that is tornado-missle and flood protected.

(4) Tornado missle barriers provided for intake and exhaust structures. 430.241

9.4.1.2.2 Power Generation Design Basis

(1) The HVAC system is designed to provide an environment with controlled temperature during normal operation to ensure the comfort and safety of plant personnel and the integrity of the essential electrical and RCW equipment.

(2) The system is designed to facilitate periodic inspection of the principal system components.

(3) Design outside air temperature for the heat exchanger building HVAC system are 115°F during the summer and -40°F during winter.

9.4.1.2.3 System Description

430.228 The essential electrical HVAC system is divided into 3 independent subsystems with each subsystem serving a designated area. Each Subsystem serve as essential electrical heat exchanger equipment HVAC for Divisions A, B, C, and D.

The control building essential elctrical HVAC system flow rates are given in Table 9.4-3, and system component descriptions are given in Table 9.4-4.

9.4.1.2.3.1 Safety-Related Subsystem 1

Subsystem 1 specifically serves:

(1) Safety-related battery room 1,

(2) Essential chiller room A,

(3) RCW water pump and heat exchanger room A,

(4) HVAC equipment room,

(5) Safety-related electrical equipment room,

(6) Passages,

(7) Non-essential battery room,

(8) Non-essential electrical equipment rooms.

Recirculation unit for subsystem 1 consists of a prefilter section, a high efficient filter section, a cooling coil, and two 100% capacity supply fans.

Two 100% capacity return exhaust fans discharge to the atmosphere.

9.4.1.2.3.2 Safety-Related Subsystem 2

Subsystem 2 specifically serves:

(1) Safety-related battery rooms 2 and 4,

(2) Essential chiller room B,

(3) RCW and heat-exchanger room B,

(4) HVAC equipment room,

(5) Safety-related-electrical equipment room,

(6) Passages,

430.264 (7) Remote Shutdown Panel Room.

Recirculation unit for Subsystem 2 consists of a prefilter section, a high efficient filter section, a cooling coil, and two 100% capacity supply fans.

Two 100% capacity return exhaust fans discharge to the atmosphere.

9.4.1.2.3.3 Safety-Related Subsystem 3

Subsystem 3 specifically serves:

(1) Safety-related battery room 3,

(2) Essential chiller room C,

(3) RCW water pump and heat-exchanger room C,

(4) HVAC equipment room,

(5) Safety-related electrical equipment room,

(6) Passages,

(7) MG sets at EL. 7200 in CB.

Recirculation unit for Subsystem s 3 consists of a prefilter section, a high efficient filter section, a cooling coil, and two 100% capacity supply fans.

Two 100% capacity return exhaust fans discharge to the atmosphere.

9.4.1.2.4 Safety Evaluation

The essential electrical HVAC system is designed to ensure the operability of the essential electrical equipment, and to limit the hydrogen concentration to less than 2% by volume in the battery rooms. 435.43 All safety-related HVAC equipment and surrounding structures are of Seismic Category I design and operable during loss of the offsite power supply,

The ductwork which services these safety functions is termed ESF ductwork, and is of Seismic Category I design. ESF ducting is high pressure safety grade ductwork designed to withstand the maximum positive and/or negative pressure to which it can be subjected under normal or abnormal conditions. Galvanized steel ASTM A526 or ASTM A527 is used for outdoor air intake and exhaust ducts. All other ducts are welded black steel ASTM A570, Grade A or Grade D. Ductwork and hangers are Seismic Category I. Bolted Flange and welded joints are qualified per ERDA 76-21.

Redundant components are provided where necessary to ensure that a single failure will not preclude adequate heat-exchanger building ventilation.

9.4.1.2.5 Inspection and Testing Requirements

Provisions are made for periodic tests of the outdoor air cleanup fans and tilters. These tests include determinations of differential pressure across the filter and of filter efficiency. Connections for testing, such as injection, sampling and monitoring are properly located so that test results are indicative of performance.

The balance of the system is proven operable by its use during normal plant operation. Portions of the system normally closed to flow can be tested to ensure operability and integrity of the system.

9.4.1.2.6 Instrumentation Application

The area exhaust fans are started manually and the fans discharge the air to atmosphere.

On an alarm of exhaust fan or supply fan failure, the standby fan is automatically started, and an alarm is sounded inside the control room indicating fan failure.

A temperature indicating controller senses the temperature of the air leaving the air cleanup system. The controller then modulates an electric heating coil to maintain the leaving air temperature at a preset limit. A limit switch will cause an alarm to be actuated on high air temperature.

The essential electrical return exhaust fans start automatically when the air-conditioning unit is started. Each fan inlet damper is open automatically. The exhaust dampers are closed automatically and the return air dampers to the conditioning unit are opened automatically.

On a smoke alarm in a division of the control building essential electrical HVAC system, that division of HVAC shall be put into smoke removal mode. No other division is effected by this action. For smoke removal, the recirculation duct valve is closed, the fan bypass valve is opened, and the exhaust fan is stopped.

The chiller room cooling unit starts automatically on a signal from the temperature-indicating controller installed in the chiller room. The controller modulates a three-way chilled water valve to maintain the space conditions.

9.4 5 Reactor Building Ventilation System

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9.4.9 Drywell Cooling System

9.4.9.1 Design Bases

The drywell cooling system shall have the capability to maintain the drywell temperature, during normal operation, at temperatures specified in Section 3.11.

The drywell cooling system shall be capable of controlling the temperature rise of the drywell during normal operational transients so that the average drywell temperature does not exceed 135 F. The local temperature shall not exceed 165 F in the CRD area or 149 F elsewhere in the drywell.

The drywell cooling system is designed to provide sufficient air/nitrogen distribution so that proper temperature distribution can be achieved to prevent hot spots from occurring in any area of the drywell.

9.4.9.2 System Description

See Figures 9.4-8 and 9.4-9 for the flow diagram illustrating the drywell cooling system, and Table 9.4-1 for a listing of its components. It is a recirculating system consisting of three fan coil units. Normally, two of the three fan coil units are in operation. Each fan coil unit consists of one cooling coils, a drain pan, and a centrifugal fan. Cooling water comes from the RCW system. The two sets of cooling coils are arranged in series. The return air passes over the first coil, which is cooled by RCW. Part of the cooled air is then cooled by the second coil, which is cooled by HNCW. This twice-cooled air is mixed with the air which bypassed the second cooling coil. Condensate that drips from the coils is routed to the DRW drain system via the leak detection system. Instrumentation is installed in the drain line, in front of the leak detection system connection that monitors cooler condensate flow.

The drywell cooling system supplies conditioned air to a common distribution header. The air/nitrogen is then ducted to areas within the drywell for equipment cooling. These areas consist of the drywell head area, upper drywell, lower drywell, shield wall annulus, and the wetwell air space. The drywell cooling system head loads are provided in Table 3.4-2.

Gravity dampers and adjustable volume dampers control distribution of the air/nitrogen to the drywell space.

High drywell temperatures are alarmed in the main control room, alerting the operator to take appropriate corrective action. During normal plant operation, two fan coil units are operated. During LOPA (when no LOCA signal exists), fan coil units shall restart automatically when power is available from the diesel generators. During LOPA, chilled water from the HNCW system will not be available. Chilling will only be available from the RCW coils. The fan coil units are not operated during LOCA.

9.4.9.3 Safety Evaluation

Operation of the drywell cooling system is not a prerequisite to assurance of either one of the following:

(1) integrity of the reactor coolant pressure boundary, or

(2) capability to safely shut down the reactor and to maintain a safe shutdown condition.

However, the system does incorporate features that provide reliability over the full range of normal plant operation. These features include the installation of redundant principal system components such as:

(1) electric power;

(2) fan coil units;

(3) sources of chilled water;

(4) ductwork;

(5) controls; and

(6) cross connection of all fan coil units.

9.4.9.4 Inspection and Testing Requirements

Equipment design includes provisions for periodic testing of functional performance and inspection for system reliability. Standby components are fitted with test connections so that system effectiveness, except for airflow or static pressure, can be verified without the units being online. Test connections are provided in the discharge air ducts for verifying calibration of the operating controls.

9.4.9.5 Instrumentation Applications

Drywell cooling unit function is manually controlled from the main control room. The instrumentation which monitors system performance is part of the atmospheric control system and the leak detection and isolation system.

TABLE 9.4-1

DRYWELL COOLING SYSTEM COMPONENTS

RCW Cooling Coils

Number	3
Type	Plate Fin
Air Flow Rate	588 ft^3/s
Cooling Capacity	970,000 btu/hr
Air Temperature (Inlet/Outlet)	$135^\circ F/107^\circ F$
Water Temperature (Inlet/Outlet)	$95^\circ F/104^\circ F$
Water Flow Rate	215 gpm

HNCW Cooling Coils

Number	2
Type	Plate Fin
Air Flow Rate	163 ft^3/s
Cooling Capacity	750,000 btu/hr
Air Temperature (Inlet/Outlet)	$111^\circ F/54^\circ F$
Water Temperature (Inlet/Outlet)	$45^\circ F/54^\circ F$
Water Flow Rate	167 gpm

Fans

Number	3
Type	Centrifugal
Capacity	588 ft^3/s
Head	5.9 in. H_2O

TABLE 9.4-2

DRYWELL COOLING SYSTEM HEAT LOADS

Heat Loads		Normal Plant Operation Sensible Heat Load x 10^6 BTU/HR
Sensible Heat Loads	Drywell Head Area	0.139
	Upper Drywell	0.790
	Lower Drywell	0.171
	Shield Wall Annulus	0.742
	Wetwell Air Space	1.012
Equipment	Fan Motors	0.032
	Heatup Load of Fans	0.278
Sensible Heat Load (Total)		3.164
Latent Heat Load		0.282
Design Heat Load		3.446

NOTE:
The sensible heat load during plant maintenance mode is about 0.436×10^6 btu/hr.

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9.5 OTHER AUXILIARY SYSTEMS

9.5.1 Fire Protection System

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9.5 OTHER AUXILIARY SYSTEMS

9.5.3 Lighting and Servicing Power Supply System

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9.5 OTHER AUXILIARY SYSTEMS

9.5.4 Diesel Generator Fuel Oil Storage and Transfer System

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9.5 OTHER AUXILIARY SYSTEMS

9.5.5 Diesel-Generator Jacket Cooling Water System

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9.5 OTHER AUXILIARY SYSTEMS

9.5.8 Diesel-Generator Combustion Air Intake and Exhaust System

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The portions of the flooder pipe that extend from the steel liner in the lower drywell meet the requirements of ASME Class 2 piping components.

An ANSI B16.5 stainless steel weld-neck flange (or equivalent) is used at the interface between the flooder pipe and the fusible plug valve. The flooder pipe is made of the same material as the blowdown vent pipe or of a stainless steel material that is compatible for welding to the blowdown vent pipe.

The fusible plug is required to open fully when the outer metal temperature of the valve reaches 260°C during a severe accident and to pass a minimum of 10.5 l/sec with 375 mm of water above the valve inlet.

A plastic cover on the valve outlet seals the valve from the intrusion of moisture that could cause corrosion of the fusible metal material. The plastic cover has a melting point below 130°C and greater than 70°C and is required to melt completely or offer minimal resistance to valve opening when the opening temperature is reached.

9.5.12.4 Testing and Inspection Requirements

The ability of the LDF to mitigate severe accidents by passing sufficient water to cover and quench the postulated corium in the drywell is confirmed by PRA analysis (Appendix 19D).

No testing of the LDF system will be required during normal operation. During refueling outages, the following surveillance would be required:

(1) During each refueling outage, verify that there is no leakage from the fusible plug valve flange or outlet when the suppression pool is at its maximum level.

(2) Once every four refueling outages, lower suppression pool water level or plug the flooder pipe inlet and replace two fusible plug valves. Test the valves that were removed to confirm their function. This practice follows the precedent set for in-service testing of standby liquid control system (SLCS) explosive valves in earlier boiling water reactors.

9.5.12.5 Instrumentation Requirements

The LDF operates automatically in a passive manner during a severe accident scenario that involves a core melt and vessel failure. No operator action is required; therefore, no instrumentation is placed upon the system. An inadvertent opening or leak would be detected by the lower drywell leak detection system and the suppression pool water level instrumentation which would result in plant shutdown.

During severe accidents, operation of the LDF is confirmed by other instrument readings in the containment. These instruments include those which would record the drywell temperature reduction and the lowering of suppression pool water level.

9.5.13 Interfaces

9.5.13.1 Contamination of the DG Combustion Air Intake

Measures shall be taken to restrict contaminating substances from the plant site which may be available to the diesel generator air intakes. See Subsection 9.5.8.1.

9.5.13.2 Use of Communication System in Emergencies

Procedure for use of the communication system shall be provided. See Subsection 9.5.[illegible].

9.5.13.3 Maintenance and Testing Procedure for Communication Equipment

Maintenance and testing procedures for the plant communication shall be provided. See Subsection 9.5.2.5.

9.5.13.4 Use of Portable Hand Light in Emergency

The portable sealed beam battery powered hand light (used by the fire brigade and other personnel during an emergency to achieve a plant shutdown) is out of ABWR standard design scope. It is an interface requirement that the applicant design will comply with the BTP CMEB 9.5-1, position C.5.g(1) and (2). Applicant will supplement this subsection accordingly as applicable. 430315

9.5.13.5 Vendor Specific Design of Diesel Generator Auxiliaries

The vendor-specific diesel generator support systems (i.e., the D/G fuel oil system, the D/G 430.266 cooling water system, the D/G starting air system, the D/G lubrication system, the D/G combustion air intake and exhaust system) shall be reviewed for differences in design with those discussed in Subsections 9.5.4 through 9.5.8, respectively. A discussion of such differences shall be provided.

Specific NRC requested information lists as follows:

430.274 (1) Deleted

(2) Provision for stick gauges on fuel storage tanks,

430.287 (3) Description of engine cranking devices,

(4) Duration of cranking cycle and number of engine revolutions per start attempt,

430.292 430.294 (5) Lubrication system design criteria (pump flows, operating pressure, temperature differentials, cooling system heat removal capabilities, electric heater characteristics),

(6) Selection of a combustion air flow capacity sufficient to assure complete combustion,

(7) Volume and design pressure of the air revievers (sufficient for 5 start cycles per reciever), and

(8) Compressor size (sufficient discharge flow to recharge the system in 30 minutes or less).

9.5.13.6 Diesel Generator Cooling Water System Design Flow and Heat Removal Requirements

430.279 A table shall be provided which identifies the design flow and heat removal requirements for the diesel generator cooling water system. It shall include the design heat removal capacities of all the coolers or heat exchangers in the system.

Specific NRC requested information lists as follows:

(1) Type of jacket water circulating pumps (i.e., motor-driven or others), 430.280

(2) Type of temperature sensors (use "Amot" brand or equal per NUREG.CR-0660, Page V-17, Recommendation under Item 4),

(3) Expansion tank capacity,

(4) NPSH of jacket water circulating pump, and 430.283

(5) Cooling water loss estimates.

9.5.13.7 Fire Rating for Penetration Seals

The applicant referencing the ABWR design shall provide 3-hour fire rated penetration seals for all high energy piping or, as a minimum, state those conditions when such seals cannot be provided and what will be installed as a substitute. The detail design shall provide completely equivalent construction to tested wall assemblies or testing will be required. 430.341

9.5.13.8 Diesel Generator Requirements

(1) the diesel generator operating procedures for a particular diesel-engine make and model shall require loading of the engine up to a minimum of 40% of full load (or lower load per manufacturer's recommendation) for 1 hour after up to 8 hours of continuous no-load or light load operation. 430.284

(2) selection of diesel generator shall include prudent component design with dust tight enclosures. Construction guidelines shall include provisions for minimizing accumulation of dust and dirt into equipment. 430.289

(3) the diesel generator operating procedure shall include provisions to avoid as much as possible or otherwise restrict the no-load or low-load operation of the engine/generator for prolonged periods of time; or operate the engine at nearly full-load following every no-load or low-load (20% or less) operation lasting for a period of 30 minutes or more. 430.299

9.5.13.9 Applicant Fire Protection Program

The following areas are out of the ABWR Standard Plant design scope, and shall be included in the applicant fire protection program.

(1) Main transformer

430.315 (2) Equipment entry lock

(3) Fire protection pumphouse

(4) Ultimate heat sink

The applicant's fire protection program shall comply with the SRP Section 9.5.1, with ability to bring the plant to safe shutdown condition following a complete fire burnout without a need for recovery.

9.5.13.10 HVAC Pressure Calculations

910.10 The applicant referencing the ABWR design shall provide pressure calculations and confirm capability during pre-operational testing of the smoke control mode of the HVAC systems as described in Subsection 9.5.1.0.6.

9.5.13.11 Plant Security Systems Criteria

The design of the security system shall include an evaluation of its impact on plant operation, testing, and maintenance. This evaluation shall assure that the security restrictions for access to equipment and plant regions is compatible with required operator actions during all operating and emergency modes
430.20 of operation (i.e., loss of offsite power, access for fire protection, health physics, maintenance, testing and local operator). In addition, this evaluation shall assure that:

(a) There are no areas within the Nuclear Island where communication with central and secondary alarm stations is not possible;

(b) Portable security radios will not interfere with plant monitoring equipment;

(c) Minimum isolation zone and protected area illumination capabilities cannot be defeated by sabotage actions outside of the protected area; and,

(d) Electromagnetic interference from plant equipment startups or power transfers will not create nuisance alarms or trip security access control systems.

9.5.13.12 Fire Hazard Analysis

A compliance review of the as built design against the assumptions and requirements stated in the fire hazard analysis (Appendix 9A) shall be conducted. Any non compliance shall be documented as being required and acceptable on the basis of the Fire Hazard Analysis, Appendix 9A, and the Fire Hazard Probabilistic Risk Assessment, Appendix 19M.

9.5.13.13 Diesel Fuel Refueling Procedures

Procedures shall be established to verify that the day tank is full prior to refilling the storage tank. This minimizes the likelihood of sediment obstruction of fuel lines and any deleterious impacts on diesel generator operation.

9.5.14 References

1. Stello, Victor, Jr., *Design Requirements Related To The Evolutionary Advanced Light Water Reactors (ALWRS)*, Policy Issue, SECY-89-013, The Commissioners, United States Nuclear Regulatory Commission, January 19, 1989.

2. Cote, Authur E., *NFPA Fire Protection Handbook*, National Fire Protection Association, Sixteenth Edition.

3. *Design of Smoke Control Systems for Buildings*, American Society of Heating, Refrigerating, and Air Conditioning Engineers, Inc., September 1983.

4. *Recommended Practice for Smoke Control Systems*, NFPA 92A, National Fire Protection Association, 1988.

5. Life Safety Code, NFPA 101, National Fire Protection Association.

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*These drawings are now located in Section 9A.4

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10.4.5 Circulating Water System

The circulating water system (CWS) provides cooling water for removal of the power cycle waste heat from the main condensers and transfers this heat to the ultimate heat sink.

10.4.5.1 Design Bases

10.4.5.1.1 Safety Design Bases

The CWS does not serve or support any safety function and has no safety design basis.

10.4.5.1.2 Power Generation Design Bases

Power Generation Design Basis One - The CWS supplies cooling water at a sufficient flow rate to condense the steam in the condenser, as required for optimum heat cycle efficiency.

Power Generation Design Basis Two - The CWS is automatically isolated in the event of gross leakage into the condenser pit to prevent flooding of the turbine building.

10.4.5.2 Description

10.4.5.2.1 General Description

The circulating water system is illustrated in Figure 10.4-3. The circulating water system consists of the following components: screen house and intake screens; pumps; condenser water boxes and piping and valves; tube side of the main condenser; water box fill and drain subsystem; and related support facilities such as for system water treatment and general maintenance.

The ultimate heat sink is designed to maintain the temperature of the water entering the circulation water system within the range of 32^{O}F to 100^{O}F. The circulating water system is designed to deliver water to the main condenser within a temperature range of 40^{O}F to 100^{O}F. The 40^{O}F minimum temperature is maintained, when needed, by warm water recirculation.

The cooling water is circulated by three fixed speed motor driven pumps.

The pumps are arranged in parallel and discharge into a common header. The discharge of each pump is fitted with a butterfly valve. This arrangement permits isolation and maintenance of any one pump while the others remain in operation.

The circulating water system and condenser is designed to permit isolation of each set of the three series connected tube bundles to permit repair of leaks and cleaning of water boxes while operating at reduced power.

The circulating water system includes water box vents to help fill the condenser water boxes during startup and removes accumulated air and other gases from the water boxes during normal operation.

A chemical additive subsystem is also provided to prevent the accumulation of biological growth and chemical deposits within the wetted surfaces of the system.

10.4.5.2.2 Component Description

Codes and standards applicable to the CWS are listed in Section 3.2. The system is designed and constructed in accordance with quality group D specifications Table 10.4-3 provides design parameters for the major components of the circulating water system.

10.4.5.2.3 System Operation

The CWS operates continuously during power generation including startup and shutdown. Pumps and condenser isolation valve actuation is controlled by locally mounted hand switches or by remote manual switches located in the main control room.

The circulating water pumps are tripped and the pump and condenser valves are closed in the event of a system isolation signal from the condenser pit high-high level switches. A condenser pit high level alarm is provided in the control room. The pit water level trip is set high enough to prevent inadvertent plant trips from unrelated failures, such as a sump overflow.

Draining of any set of series connected condenser water boxes is initiated by closing the associated condenser isolation valves and opening the drain connection and water box vent valve. When the suction standpipe of the condenser drain pump is filled, the pump is manually started. A low level switch is provided in the standpipe, on the suction side of the drain pump. This switch will automatically stop the pump in the event of low water level in the standpipe to protect the pump from excessive cavitation.

10.4.5.3 Evaluation

The CWS is not a safey-related system; however, a flooding analysis of the turbine building is performed on the CWS postulating a complete rupture of a single expansion joint. The analysis assumes that the flow into the condenser pit comes from both the upstream and downstream side of the break and, for conservatism, it assumes that one system isolation valve does not fully close.

Based on the above conservative assumptions, the CWS and related facilities are designed such that the selected combination of plant physical arrangement and system protective features ensures that all credible potential circulating water spills inside the turbine building remain confined inside the condenser pit. Further, plant safety is ensured in case of multiple CWS failures or other negligible probability CWS related events by the plant safety related general flooding protection provisions that are discussed in Section 3.4.

10.4.5.4 Tests and Inspections

The CWS and related systems and facilities are tested and checked for leakage integrity prior to initial plant startup and, as may be appropriate, following major maintenance and inspection.

All active and selected passive components of the circulating water system are accessible for inspection and maintenance/testing during normal power station operation.

10.4.5.5 Instrumentation Applications

Temperature monitors are provided upstream and downstream of each condenser shell section.

Indication is provided in the control room to identify open and closed positions of motor-operated butterfly valves in the CWS piping.

All major circulating water system valves which control the flow path can be operated by local controls or by remote manual switches located on the main control board. The pump discharge isolation valves are interlocked with the circulating water pumps so that when a pump is started, its discharge valve will be opening while the pump is coming up to speed, thus assuring there is water flow through the pump. When the pump is stopped, the discharge valve closes automatically to prevent or minimize backward rotation of the pump and motor.

Level switches monitor water level in the condenser discharge water boxes and provide a permissive for starting the circulating water pumps. These level switches ensure that the supply piping and the condenser are full of water prior to circulating water pump startup thus preventing water pressure surges from damaging the supply piping or the condenser.

To satisfy the bearing lubricating water and shaft sealing water interlocks during startup, the circulating water pump bearing lubricating and shaft seal flow switches, located in the lubricating seal water supply lines, must sense a minimum flow to provide pump start permissive.

Monitoring the performance of the circulating water system is accomplished by differential pressure transducers across each half of the condenser with remote differential pressure indicators located in the main control room. Thermal element signals from the supply and discharge sides of the condenser are transmitted to the plant computer for recording, display and condenser performance calculations.

To prevent icing and freeze up when the ambient temperature of the ultimate heat sink falls below 32°F, warm water from the discharge side of the condenser is recirculated back to the screen house intake. Thermal elements, located in each condenser supply line and monitored in the main control room, are utilized in throttling the warm water recirculation valve, which maintains the minimum inlet temperature of approximately 40°F.

10.4.5.6 Flood Protection

See response to Question 430.73(b), protection against a CWS pipe, water box or expansion joint failure.

10.4.6 Condensate Cleanup System

The condensate cleanup system (CCS) purifies and treats the condensate as required to maintain reactor feedwater purity, using filtration to remove

10.4.6.1 Design Bases

10.4.6.1.1 Safety Design Bases

The CCS does not serve or support any safety function and has no safety design bases.

10.4.6.1.2 Power Generation Design Bases

Power Generation Design Basis One - The CCS continuously removes dissolved and suspended solids from the condensate to maintain reactor feedwater quality.

Power Generation Design Basis Two - The CCS removes corrosion products from the condensate and from drains returned to the condenser hotwell so as to limit any accumulation of corrosion products in the cycle.

Power Generation Design Basis Three - The CCS removes impurities entering the power cycle due to condenser circulating water leaks as required to permit continued power operation within specified water quality limits as long as such condenser leaks are too small to be readily located and repaired.

Power Generation Design Basis Four - The CCS limits the entry of dissolved solids into the feedwater system in the event of large condenser leaks, such as a tube break, to permit a reasonable amount of time for orderly plant shutdown.

Power Generation Design Basis Five - The CCS injects in the condensate such water treatment additives as oxygen and hydrogen as required to minimize corrosion/erosion product releases in the power cycle.

Power Generation Design Basis Six - The CCS maintains the condensate storage tank water quality as required for condensate makeup and miscellaneous condensate supply services.

10.4.6.2 System Description

10.4.6.2.1 General Description

The condensate cleanup system is illustrated in Figure 10.4-4. The CCS consists of six bead resin, mixed bed ion exchange polisher vessels arranged in parallel with, normally five in operation and 1 in standby. A strainer is installed downstream of each polisher vessel to preclude gross resin leakage into the power cycle in case of vessel underdrain failure, and to catch resin fine leakage as much as possible. The design bases influent concentrations are provided in Table 10.4-5. Based on the influent concentrations the condensate polisher effluent water quality is as reported in Table 10.4-6. The CCS components are located in the turbine building.

Provisions are included to permit mechanical ultrasonic washing and replacement of the ion exchange resin. Each of the polisher vessels has fail open inlet and outlet isolation valves which are remotely controlled from the local polisher control panel.

A system flow bypass valve is also provided which is manually controlled from the main control room. Pressure downstream of the polisher system is indicated and low pressure is alarmed in the main control room to alert the operator. The bypass is used only in emergency and for short periods of time until the polisher system flow is returned to normal or the plant is brought to an orderly shutdown. To prevent unpolished condensate from leaking through the bypass, double isolation valves are provided with an orificed leak-off back to the condenser.

10.4.6.2.2 Component Description

Codes and standards applicable to the CCS are listed in Section 3.2. The system is designed and constructed in accordance with quality group D requirements. Design data for major components of the CCS are listed in Table 10.4-4.

Condensate Polishers Vessels - There are six 20-percent-capacity polisher vessels (one on standby) each constructed of carbon steel and lined with natural rubber. Normal operation full load steady state design flowrate is 40 gpm per square foot of bed. Maximum flowrates are 50 and 60 gpm per square foot for steady state and transient operation respectively. The nominal bed depth is 40 inches.

10.4.6.2.3 System Operation

The CCS is continuously operated, as necessary to maintain feedwater purity levels.

Full condensate flow is passed through five of the six polisher vessels, which are piped in parallel. The sixth polisher is on standby or is in the process of being cleaned, emptied or refilled. The service run for each polisher vessel is terminated by either high differential pressure across the vessel or high conductivity or sodium content in the polisher effluent water. Alarms for each of these parameters are provided on the local control panel.

The local control panel is equipped with the appropriate instruments and controls to allow the operators to perform the following operations:

(1) Remove an exhausted polisher from service and replace it with a standby unit

(2) Transfer the resin inventory of any polisher vessel into the resin receiver tank for mechanical cleaning or disposal.

(3) Process the as received resin through the ultrasonic resin cleaner as it is transferred from the receiver tank to the storage tank.

(4) Transfer the resin storage tank resins to any polisher vessel.

(5) Transfer exhausted resin from the receiver tank to the radwaste system.

On termination of a service run, the exhausted polisher vessel is taken out of service, and the standby unit is placed in service by remote manual operation from the local control panel. The resin from the exhausted vessel is transferred to the resin receiver tank and replaced by a clean resin bed that is transferred from the resin storage tank. A final rinse of the new bed is performed in the polisher by condensate full flow recycle to the condenser before it is placed in service. The rinse is monitored by conductivity analyzers, and the process is terminated when the required minimum rinse has been completed and normal clean bed conductivity is obtained.

Through periodic condensate makeup and reject, the condensate storage tank water inventory is processed through the CCS and tank water quality is maintained as required for condensate makeup to the cycle and miscellaneous condensate supply services. The diagram of the condensate storage and transfer system is illustrated in Figure 10.4-5.

The condensate cleanup and related support systems wastes are processed by the radwaste system as described in Chapter 11.

10.4.6.3 Evaluation

The CCS does not serve or support any safety function and has no safety design basis.

The condensate cleanup system removes condensate system corrision products, and impurities from condenser leakage in addition to some radioactive material, activated corrosion products and fission products that are carried-over from the reactor. While these radioactive sources do not affect the capacity of the resin, the concentration of such radioactive material requires shielding (see Chapter 12). Vent gases and other wastes from the condensate cleanup system are collected in controlled areas and sent to the radwaste system for treatment and/or disposal. Chapter 11 describes the activity level and removal of radioactive material from the condensate system.

The condensate cleanup system complies with Regulatory Guide 1.56, *Maintenance of Water Purity in Boiling Water Reactors* and EPRI NP-4947-SR, *BWR Hydrogen Water Chemistry Guidelines*: 1987 Revision, October 1988.

The condensate cleanup system and related support facilities are located in non-safety related buildings. As a result, potential equipment or piping failures can not affect plant safety.

10.4.6.4 Tests and Inspections

Preoperational tests are performed on the condensate cleanup system to ensure operability, reliability, and integrity of the system. Each polisher vessel and system support equipment can be isolated during normal plant operation to permit testing and maintenance.

10.4.6.5 Instrumentation Applications

Conductivity elements are provided for the system influent and for each polisher vessel effluent. System influent conductivity detects condenser leakage; whereas, polisher effluent conductivities provide indication of resin exhaustion. The polisher effluent conductivity elements also monitor the quality of the condensate that is recycled to the condenser after processing through a standby vessel before it is returned to service. Differential pressure is monitored across each polisher vessel and each vessel discharge resin strainer to detect blockage of flow. The flow through each polisher is monitored and used as control input to assure even distribution of condensate flow through all operating vessels and by correlation with the vessel pressure drop, to permit evaluation of the vessel throughput capacity. Individual vessel effluent conductivity, differential pressure, and flow measurements are recorded at the system local control panel. A multipoint annunciator is included in the local panel to alarm abnormal conditions within the system. The local panel is connected to the main control room where local alarms annunicated by a global system alarm but can also be displayed individually if requested by the operators.

Other system instrumentation includes turbidity and other water quality measurements as necessary for proper operation of the polisher and miscellaneous support services, and timers for automatic supervision of the resin transfer and cleaning cycles. The control system prevents the initiation of any operation or sequence of operations which would conflict with any operation or sequence already in progress whether such operation is under automatic or manual control.

10.4.7 Condensate and Feedwater System

The function of the condensate and feedwater system (CFS) is to receive condensate from the condenser hotwells, supply condensate to the cleanup system, and deliver high purity feedwater to the reactor, at the required flow rate, pressure and temperature.

10.4.7.1 Design Bases

10.4.7.1.1 Safety Design Bases

The condensate-feedwater system does not serve or support any safety function and has no safety design bases.

10.4.7.1.2 Power Generation Design Bases

Power Generation Design Basis One - The CFS is designed to provide a continuous and dependable feedwater supply to the reactor at the required flow rate, pressure, and temperature under all anticipated steady-state and transient conditions.

Power Generation Design Basis Two - The CFS is designed to supply up to 115% of the rated feedwater flow demand during steady state power operation and for at least 10 seconds after generator step load reduction or turbine trip, and up to 75% of the rated flow demand thereafter.

Power Generation Design Basis Three - The CFS is designed to permit continuous long term full power plant operation with the following equipment out of service: one feedwater pump, one condensate pump or one heater drain pump or, one high pressure heater string with a slightly reduced final feedwater temperature.

Power Generation Design Basis Four - The CFS is designed to permit continuous long term operation with one LP heater string out of service at the maximum load permitted by the turbine manufacturer, approximately 85%, value which is set by steam flow limitation on the affected LP turbine. 430.90

Power Generation Design Basis Five - The CFS is designed to heat up the reactor feedwater to a nominal temperature of 420F during full load operation and to lower temperatures during part load operation.

Power Generation Design Basis Six - The CFS is designed to minimize the ingress or release of impurities to the reactor feedwater.

10.4.7.2 Description

10.4.7.2.1 General Description

The condensate and feedwater system is illustrated in Figure 10.4-6 and 10.4-7. The condensate and feedwater system consists of the piping, valves, pumps, heat exchangers, controls and instrumentation, and the associated equipment and subsystems which supply the reactor with heated feedwater in a closed steam cycle utilizing regenerative feedwater heating. The system described in this subsection extends from the main condenser outlet to the second isolation valve outside of containment. The remainder of the system, extending from the second isolation valve to the reactor, is described in Chapter 5. Turbine extraction steam is utilized for a total of six stages of closed feedwater heating. The drains from each stage of the low pressure feedwater heaters are cascaded through successively lower pressure feedwater heaters to the main condenser. The high pressure heater drains are pumped backward to the reactor feedwater pumps suction. The cycle extraction steam, drains and vents systems are illustrated in Figures 10.4-8 and 10.4-9.

The CFS consists of four 33% capacity condensate pumps (three normally operating and one on standby), three manually operated 33-50% capacity reactor feedwater pumps , four stages of low-pressure feedwater heaters, and two stages 430.90

of high-pressure feedwater heaters, piping, valves, and instrumentation. The condensate pumps take suction from the condenser hotwell and discharge the deaerated condensate into one common header which feeds the condensate filters and demineralizers. Downstream of the condensate demineralizers, the condensate is taken by a single header and flows in parallel through five auxiliary 430.90 condenser/coolers, (one gland steam exhauster condenser and two sets of steam jet air ejector condensers and offgas recombiner condenser (coolers). The condensate then branches into three parallel strings of low pressure feedwater heaters. Each string contains four stages of low-pressure feedwater heaters. The strings join together at a common header which is routed to the suction of the reactor feedwater pumps.

Another input to the feedwater flow consists of the drains which are pumped backward and injected into the feedwater stream at a point between the fourth stage low-pressure feedwater heaters and the suction side of the reactor feed pumps. These drains, which originate from the crossaround steam moisture separators and reheaters and from the two sets of high-pressure feedwater heaters, are directed to the heater drain tank. The reheater and top heater drains are deaerated in the crossaround 430.90 heaters so that, after mixing with condensate, the drains are compatible with the reactor feedwater quality requirements for oxygen content during normal power operation. The heater drain pumps take suction from their heater drain tank and inject the deaerated drains into the feedwater stream on the suction side of the reactor feed pumps.

The reactor feedwater pumps discharge the feedwater into two parallel high pressure feedwater heater strings, each with two stages of high-pressure feedwater heaters. Downstream of the high-pressure feedwater heaters, the two strings are then joined into a common header, which divides into two feedwater lines which connect to the reactor.

A bypass is provided around the reactor feedwater pumps to permit supplying feedwater to the reactor during early startup without operating the feedwater pumps, using only the condensate pump head.

Another bypass, equiped with a feedwater flow control valve, is provided around the high pressure 430.90 heaters to perform two independent functions. During startup, the bypass and its flow control valve are used to regulate the flow of feedwater supplied by either the condensate pumps or the reactor feed pumps operating at their minimum fixed speed. 430.90 During power operation, the heater bypass function is to maintain full feedwater flow capability when a high pressure heater string must be isolated for maintenance.

During power operation, the condensate is well deaerated in the condenser and continuous oxygen injection is used to maintain the level of oxygen content in the final feedwater as shown in Subsection 10.4.6.

To minimize corrosion product input to the reactor during startup, recirculation lines to the condenser are provided from the reactor feedwater pump suction header and from the high-pressure feedwater heater outlet header.

Prior to plant startup, cleanup is accomplished by allowing the system to recirculate through the condensate polishers for treatment prior to feeding any water to the reactor during startup.

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10.4.7.2.2 Component Description

All components of the condensate and feedwater system that contain the system pressure are designed and constructed in accordance with applicable codes as referenced in Section 3.2.

Condensate Pumps - The four condensate pumps are identical, fixed speed motor driven pumps, three are normally operated, and the fourth 430.90 is on standby. Valving is provided to allow individual pumps to be removed from service.

A minimum flow recirculation line is provided downstream of the auxiliary condensers for condensate pump protection and for auxiliary condenser minimum flow requirements.

Low-pressure Feedwater Heaters - Three parallel and independent strings of four closed feedwater heaters are provided, and one string is installed in each condenser neck. The heaters have integral drain coolers, and their drains are cascaded to the next lower stage heaters of the same string except for the lowest pressure heaters which drain to the main condensers. The heater shells are either carbon steel or low alloy ferritic steel, and the tubes are stainless steel. Each low pressure feedwater heater string has an upstream and downstream isolation valve which closes on detection of high level in any one of the low pressure heaters in the string.

High-pressure Feedwater Heaters - Two parallel and independent strings of two high-pressure feedwater heaters are located in the high pressure end of the turbine building. The No. 6 heaters, which have integral drain coolers, are drained to the No. 5 heaters. The No. 5 heaters, which are con-
430.90 densing only, drain to their respective heater drain tanks. The heater shells are carbon steel, and the tubes are stainless steel.

430.90 Heater string isolation and by pass valves are provided to allow each string of high-pressure heaters to be removed from service, thus, slightly reducing final feedwater temperature but requireing no reduction in plant output. The heater string isolation and bypass valves are actuated on detection of high level in either of the two high pressure heaters in the string.

The startup and operating vents from the steam side of the feedwater heaters are piped to the main condenser except for the highest pressure heater operating vents which discharge to the cold reheat lines. Discharges from shell relief valves on the steam side of the feedwater heaters are piped to the main condenser.

430.90 Heater Drain Tank - Two heater drain tanks are provided. Drain tank level is maintained by the heater drain pump and control valves in drain pump disharge and recirculation line.

The heater drain tank is provided with an alternate drain line to the main condenser for automatic dumping upon detection of high level. The alternate drain line is also used during startup and shutdown when it is desirable to dump the drains for feedwater quality purposes.

The drain tanks and tank drain lines are designed to maintain the drain pumps available suction head in excess of the pump required minimum under all anticiated operating conditions including, particularly, load reduction transients. This is achieved mainly by providing a large elevation difference between tanks and pumps (approximately 50 feet) and optimizing the drain lines which would affect the drain system transient response, particularly, the drain pump suction line.

Heater Drain Pumps - Two motor-driven heater drain pumps operate in parallel, each taking suction from a heater drain tank and discharging into the suction side of the reactor feedwater pumps. The drain system design allows each heater drain pump to be individually removed from service for maintenance while the the balance of the system remains in operation while the affected string drains dump to the condenser.

Controlled drain recirculation is provided from the discharge side of each heater drain pump to the associated heater drain tank. This ensures that the minimum safe flow through each heater drain pump is maintained during operation.

Reactor Feedwater Pumps - Three identical and independent, 33-65% capacity reactor feed pumps (RFPs) are provided. The three pumps manually operate in parallel and discharge to the high-pressure feedwater heaters. The pumps take suction downstream of the last stage low-pressure feedwater heaters and discharge through the high-pressure feedwater heaters. Each pump is driven by an adjustable speed synchronous motor.

Isolation valves are provided which allow each reactor feed pump to be individually removed from service for maintenance, while the plant continues operation at full power on the two remaining pumps.

Controlled feedwater recirculation is provided from the discharge side of each reactor feed pump to the main condenser. This provision ensures that the minimum safe flow through each reactor feed pump is maintained during operation.

10.4.7.2.3 System Operation

NORMAL OPERATION - Under normal operating conditions, system operation is automatic. Automatic level control systems control the levels in all feedwater heaters, the heater drain tanks, and the condenser hotwells. Feedwater heater levels are controlled by modulating drain valves. Control valves in the discharge and recirculation lines of the heater drain pumps control the level in the heater drain tanks. Valves in the makeup line to the condenser from the condensate storage tank and in the return line to the condensate storage tank control the level in the condenser hotwells.

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During power operation feedwater flow is automatically controlled by the reactor feedwater pump speed that is set by the feedpump speed control system. The control system utilizes measurements of steam flow, feedwater flow, and reactor level to regulate the feedwater pump speed. During startup, feedwater flow is automatically regulated by the high pressure heater bypass flow control valve.

Ten-percent step load and 5-percent per minute ramp changes can be accommodated without major effect in the CFS. The system is capable of accepting a full generator load rejection without reducing feedwater flow rate.

10.4.7.3 Evaluation

The condensate and feedwater system does not serve or support any safety function. Systems analysis show that failure of this system cannot compromise any safety-related systems or prevent safe shutdown.

During operation, radioactive steam and condensate are present in the feedwater heating portion of the system, which includes the extraction steam piping, feedwater heater shells, heater drain piping, and heater vent piping. Shielding and access control are provided as necessary (see Chapter 12). The condensate and feedwater system is designed to minimize leakage with welded construction utilized where practicable. Relief discharges and operating vents are channeled through closed systems.

If it is necessary to remove a process nent from service such as a feedwater heater, pump, or control valve, continued operation of the system is possible by use of the multistring arrangement and the provisions for isolating and bypassing equipment and sections of the system.

The majority of the condensate and feedwater piping considered in this section is located within the non-safety related turbine building. The portion which connects to the second valve outside the containment is located in the steam tunnel between the turbine and reactor buildings. This portion of the piping is analyzed for dynamic effect from postulated seismic events and safety-relief valve discharges. The entire condensate and feedwater system piping is analyzed for water hammer loads that could potentially result from anticipated flow transients. 430.90

10.4.7.4 Tests and Inspections

10.4.7.4.1 Preservice Testing

Each feedwater heater and condensate pump receives a shop hydrostatic test which is performed in accordance with applicable codes. All tube joints of feedwater heaters are shop leak tested. Prior to initial operation, the completed condensate and feedwater system receives a field hydrostatic and performance test and inspection in accordance with the applicable code. Periodic tests and inspections of the system are performed in conjunction with scheduled maintenance outages.

10.4.7.4.2 Inservice Inspections

The performance status, leaktightness, and structural leaktight integrity of all system components are demonstrated by continuous operation.

10.4.7.5 Instrumentation Applications

Feedwater flow-control instrumentation measures the feedwater discharge flow rate from each reactor feed pump and the heater bypass startup flow control valve. These feedwater system flow measurements are used by the feedwater control system to regulate the feedwater flow to the reactor to meet system demands. The feedwater control system is described in Subection 7.7.1.4 430.90

Pump flow is measured on the pump inlet line and flow controls provide automatic pump recirculation flow for each reactor feedwater pump. Automatic controls also regulate the condensate flow

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uncertainties in the volume regions near the edge of the core. The level of uncertainties for these regions is estimated at 20%.

12.2.1.2.1.1.3 Core Boundary Neutron Fluxes

Table 12.2-2 presents peak axial neutron multigroup fluxes at the core equivalent radius. The core-equivalent radius is a hypothetical boundary enclosing an area equal to the area of the fuel bundles and the coolant space between them. The peak axial flux occurs adjacent to the portion of the core with the greatest power. While the flux within any given energy group is not known within a factor of 2, the total calculated core boundary flux is estimated to be within ±50%.

12.2.1.2.1.1.4 Gamma Ray Source Energy Spectra

Table 12.2-3 presents average gamma ray energy spectra thermal per watt of reactor power in both core and noncore regions. In Table 12.2-3, part A, the energy spectra in the core are presented. The energy spectra in the core represent the average gamma ray energy released by energy group in Mev/cm^3/second/Megawatt thermal. The energy spectra in MeV per sec per Megawatt thermal per cm^3 can be used with the total core power and power distributions to obtain the source in any part of the core.

The gamma ray energy spectra include the fission gamma rays, the fission product gamma ray and the gamma rays resulting from inelastic neutron scattering and thermal neutron capture. The total gamma ray energy released in the core is estimated to be accurate to within ±10%. The energy release rate above 6 MeV may be in error by as much as a factor of ±2.

Table 12.2-3, part B, gives a gamma ray energy spectrum in MeV/sec/W in spent fuel as a function of time after operation. The data were prepared from tables of fission product decay gamma fitted to integral measurements for operation times of 10^8 sec, or approximately 3.2 years. To obtain shutdown sources in the core the gamma ray energy spectra are combined with the core thermal power and power distributions. Shutdown sources in a single fuel element can be obtained by using the gamma ray energy spectra and the thermal power the element contained during operation.

Table 12.2-3, part C, gives the gamma ray energy spectra in the cylindrical regions of the reactor from the core through the vessel. The energy spectra are given in terms of MeV/cm^3/sec/W at the inside surface and outside surfaces of the region. This energy spectrum, multiplied by the core thermal power, is the gamma ray source. The point on the inside surface of the region is the maximum point within the region. In the radial direction, the variation in source intensity may be approximated by an exponential fit to the data on the inside and outside surfaces of the region. The axial variation in a region can be estimated by using the core axial variation. The uncertainty in the gamma ray energy spectra is due primarily to the uncertainty in the neutron flux in these regions. The uncertainty in the neutron flux is estimated to vary from approximately ±50% at the core boundary to a factor of ±3 at the outside of the vessel. The calculations were carried out with voids beyond the vessel.

12.2.1.2.1.1.5 Gamma Ray and Neutron Fluxes Outside the Vessel

Table 12.2-4 presents the maximum axial neutron and gamma ray fluxes outside the vessel. The maximum axial flux occurs on the vessel opposite the elevation of the core with the maximum outer bundle power level. This elevation can be located using the data from Table 12.2-1. The fluxes at this elevation are based on a mean radius core and do not show azimuths angle variations. The calculational model for these fluxes assumed no shield materials beyond the vessel wall. The presence of shield materials will significantly alter the neutron fluxes in the lower end of the neutron energy spectrum. The gamma ray calculations include gamma ray sources from all of the cylindrical regions between the center of the core and the edge of the vessel. While the uncertainties in a given energy group flux may be a factor of ±3, the uncertainties in the total integral flux are estimated to be within a factor of two.

12.2.1.2.1.1.6 Deleted

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which are sources of radiation whenever possible. For systems that have components that are major sources of radiation, piping and pumps are located in separate cubicles to reduce exposure from these components during maintenance. These major radiation sources are also separately shielded from each other.

(6) Contamination Control

Contaminated piping systems are welded to the most practical extent to minimize leaks through screwed or flanged fittings. For systems containing highly radioactive fluids, drains are hard piped directly to equipment drain sumps, rather than to allow contaminated fluid to flow across the floor to a floor drain. Certain valves in the main steam line are also provided with leakage drains piped to equipment drain sumps to reduce contamination of the steam tunnel. Pump casing drains are employed on radioactive systems whenever possible to remove fluids from the pump prior to disassembly. In addition, provisions for flushing with condensate, and in especially contaminated systems, for chemically cleaning the equipment prior to maintenance, are provided.

The HVAC system is designed to limit the extent of airborne contamination by providing air flow patterns from areas of low contamination to more contaminated areas. Penetrations through outer walls of the building containing radiation sources are sealed to prevent miscellaneous leaks into the environment. The equipment drain sump vents are fitted with charcoal canisters or piped directly to the radwaste HVAC system to remove airborne contaminants evolved from discharges to the sump. Wet transfer of both the steam dryer and separator also reduces the likelihood of contaminants on this equipment being released into the plant atmosphere. In areas where the reduction of airborne contaminants cannot be eliminated efficiently by HVAC systems, breathing air provisions are provided, for example, for CRD removal under the reactor pressure vessel and in the CRD maintenance room.

Appropriately sloped floor drains are provided in shielded cubicles and other areas where the potential for a spill exists to limit the extent of contamination. Curbs are also provided to limit contamination and simplify washdown operations. A cask decontamination vault is located in the reactor building where the spent fuel cask and other equipment may be cleaned. The CRD maintenance room is used for disassembling control rod drives to reduce the contamination potential.

Consideration is given in the design of the plant for reducing the effort required for decontamination. Epoxy-type wall and floor coverings have been selected which provide smooth surfaces to ease decontamination surfaces. Expanded metal-type floor gratings are minimized in favor of smooth surfaces in areas where radioactive spills could occur. Equipment and floor drain sumps are stainless steel lined to reduce crud buildup and to provide surfaces easily decontaminated.

12.3.1.3 Radiation Zoning

Radiation zones are established in all areas of the plant as a function of both the access requirements of that area and the radiation sources in that area. Operating activities, inspection requirements of equipment, maintenance activities, and abnormal operating conditions are considered in determining the appropriate zoning for a given area. The relationship between radiation zone designations and accessibility requirements is presented in the following tabulation:

Zone Designation	Dose Rate (mRem/hr)	Access Description
A	≤ 0.5	Uncontrolled, unlimited access
B	< 1	Controlled, unlimited access

Zone Designation	Dose Rate (mRem/hr)	Description
C	< 5	Controlled, limited access, 20 hr/wk
D	< 25	Controlled, limited access, 4 hr/wk
E	< 100	Controlled, limited access, 1 hr/wk
F	> 100	Controlled access. Authorization required.

The dose rate applicable for a particular zone is based on operating experience and represents design dose rates in a particular zone, and should not be interpreted as the expected dose rates which would apply in all portions of that zone, or for all types of work within that zone, or at all periods of entry into the zone. Large BWR plants have been in operation for two decades, and operating experience with similar design basis numbers shows that only a small fraction of the 10CFR20 maximum permissible dose is received in such zones from radiation sources controlled by equipment layout or the structural shielding provided. Therefore, on a practical basis, a radiation zoning approach as described above accomplishes the as low as reasonably achievable objectives for doses as required by 10 CFR 20.1(c). The radiation zone maps for this plant with zone designations as described in the preceding tabulations are contained in Figures 12.3-1 through 12.3-22 and 12.3-37 through 12.3-55.

Access to areas in the plant is controlled and regulated by the zoning of a given area. Areas with dose rates such that an individual would receive a dose in excess of 100 mRem in a period of one hour are locked and posted with "High Radiation Area" signs. Entry to these areas is on a controlled basis. Areas in which an individual would receive a dose in excess of 5 mRem up to 100 mRem within a period of one hour are posted with signs indicating that this is a radiation area and include, in certain cases, barriers such as ropes or doors.

12.3.1.4 Implementation of ALARA

In this subsection, the implementation of design considerations to radioactive systems for maintaining personnel radiation exposures as low as reasonably achievable is described for the following five systems:

(1) Reactor water cleanup system;

(2) Residual heat removal system (shutdown cooling mode);

(3) Fuel pool cooling and cleanup system;

(4) Main steam; and

(5) Standby gas treatment system

12.3.1.4.1 Reactor Water Cleanup System

This system is designed to operate continuously to reduce reactor water radioactive contamination. Components for this system are located outside the containment and include filter demineralizers, a backwash receiving tank, regenerative and nonregenerative heat exchangers, pumps, and associated valves.

The highest radiation level components include the filter demineralizers, heat exchangers, and backwash receiving tank. The filter demineralizers are located in separate concrete-shielded cubicles which are accessible through shielded hatches. Valves and piping within the cubicles are reduced to the extent that entry into the cubicles is not required during any operational phase. Most of the valves and piping are located in a shielded valve gallery adjacent to the filter demineralizer cubicles. The valves are remotely operable to the greatest practical extent to minimize entry requirements into this area. The RWCS heat exchangers are also located in a shielded cubicle with valves operated remotely by use of extension valve stems, or from instrument panels located outside the cubicle. The backwash tank is shielded separately from the resin transfer pump, permitting maintenance of the pump without being exposed to the spent data, such as cross sections, buildup factors, and radioisotope decay information, are listed in References 2 through 10.

The shielding design is based on the plant operating at maximum design power with the release of fission products resulting in a source of 100,000 mCi/sec of noble gas after a 30 minute decay period, and the corresponding activation and corrosion product concentrations in the reactor water listed in Section 11.1. Radiation sources in various pieces of plant equipment are cited in Section 12.2. Shutdown conditions, such as fuel transfer operation, as well as accident conditions, such as a LOCA or an FHA, have also been considered in designing shielding for the plant.

The mathematical models used to represent a radiation source and associate equipment and shielding are established to ensure conservative calculational results. Depending on the versatility of the applicable computer program, various degrees of complexity of the actual physical situation are incorporated. In general, cylindrically shaped equipment such as tanks, heat exchangers, and demineralizers are mathematically modelled as truncated cylinders. Equipment internals are sectionally homogenized to incorporate density variations where applicable. For example, the tube bundle section of a heat exchanger exhibits a higher density than the tube bundle clearance circle, due to the tube density, and this variation is accounted for in the model. Complex piping runs are conservatively modelled as a series of point sources spaced along the piping run. Equipment containing sources in a parallelpiped configuration, such as fuel assemblies, fuel racks, and the SGTS charcoal filters, are modelled as parallelpiped with a suitable homogenization of materials contained in the equipment. The shielding for these sources is also modelled on a conservative basis, with discontinuities in the shielding, such as penetrations, doors, and partial walls accounted for. The dimension of the floor decking is not considered in the shielding calculation as it is part of the effective shield thickness provided by the floor slab.

Pure gamma dose rate calculations, both scattered and direct, are conducted using point kernel codes (QADF/GGG). The source terms are divided into groups as a function of photon energy, and each group is treated independently of the others. Credit is taken for attenuation through all phases of material, and buildup is accounted for using a third-order polynomial buildup factor equation. The more conservative material buildup coefficients are selected for laminated shield configuration to ensure conservative results.

For combined gamma and neutron shielding situations, discrete ordinates (ANISN) techniques are applied.

The shielding thicknesses are selected to reduce the aggregate dose rate from significant radiation sources in surrounding areas to values below the upper limit of the radiation zone specified in the zone maps in Subsection 12.3.1.3. By maintaining dose rates in these areas at less than the upper limit values specified in the zone maps, sufficient access to the plant areas is allowed for maintenance and operational requirements.

Where shielded entries to high-radiation areas such as labyrinths are required, a gamma ray scattering code (GGG) is used to confirm the adequacy of the labyrinth design. The labyrinths are designed to reduce the scattered as well as the direct contribution to the aggregate dose rate outside the entry, such that the radiation zone designated for the area is not violated.

12.3.2.3 Plant Shielding Description

Figures 12.3-1 through 12.3-11 show the layout of equipment containing radioactive process materials. The general description of the shielding is described below:

(1) Drywell

The major shielding structures located in the drywell area consist of the reactor shield wall and the drywell wall. The reactor shield wall in general consists of 0.6m of concrete sandwiched between two 3.7 cm thick steel plates. The primary function served by the reactor shield wall is the reduction of radiation levels in the drywell due to the reactor, to valves that do not unduly limit the service life of the equipment located in the drywell. In addition, the reactor shield wall reduces gamma heating effects on the drywell wall, as well as providing for low radiation levels in the drywell during reactor shutdown. Penetrations through the reactor shield wall are shielded to the extent that radiation streaming through the penetrations does not exceed the total neutron and gamma 471.33 dose rates at the core midplane just outside the reactor shield wall. The drywell is an F radiation zone during full power reactor operation and is not accessible during this period.

The drywell wall is a 2m thick reinforced concrete cylinder, which is topped by a 2.4m thick reinforced concrete cap. The drywell wall attenuates radiation from the reactor and other radiation sources in the drywell, such as the recirculation system and main steam piping, to allow occupancy of the reactor building during full power reactor operation.

(2) Reactor Building

In general, the shielding for the reactor building is designed to maintain open areas at dose rates less than 0.6 mR/hr.

Penetrations of the drywell wall are shielded to reduce radiation streaming through the penetrations. Localized dose rates outside these penetrations are limited to less than 5 mR/hr. The penetrations through interior shield walls of the reactor building are shielded using a lead-loaded silicone sleeve to reduce the radiation streaming are made available by the penetrations. Penetrations are also located so as to minimize the impact of radiation streaming into surrounding areas.

The components of the reactor water cleanup (RWC) system are located in the reactor building. Both the RWC regenerative and nonregenerative heat exchangers are located in shielded cubicles separated from the other components of the system. Neither cubicle needs to be entered for system operation.

Process piping between the heat exchangers and the filter demineralizers is routed through shielded areas or embedded in concrete to reduce the dose rate in surrounding areas. The two RWC system filter demineralizers are located in separate shielded cubicles, which allows maintenance of one unit while operating the other. The dose rate in the adjoining filter demineralizer cubicle from the operating unit is less than 6 mR/hr. Entry into the filter demineralizer cubicle, which is infrequently required, is via a stepped shield plug at the top of the cubicle. The bulk of the piping and valves for the filter demineralizers is located in an adjacent shielded valve gallery. Backflushing and resin application of the filter demineralizers are controlled from an area where dose rates are less than 1 mR/hr. The RWC system backwash receiving tank is also separately shielded from the other components of the RWC system, including the tank discharge pump, which allows maintenance of the pump without direct exposure to the spent resins contained in the backwash tank. The backwash tank cubicle is shielded to reduce the dose rate outside the entry to less than 1 mR/hr.

The transverse incore probe (TIP) consists of 3 sets of detectors, cables, and mechanical components which are periodically driven into the core via three guide tubes penetrating the primary containment at the TMSL-1700 level above the personnel air lock. A TIP indexer located in the access tunnel then permits the TIPs to be driven into any of 52 separate housing lines into the core for instrumentation calibration. Because the TIP system is subject to neutron activation during core operation, the TIP detector and approximately twelve feet of cable are activated as is discussed in Subsection 12.2.1.2.9.3. Therefore, the TIP has become a special point of protection both during use and when withdrawn from the core as is discussed below.

The TIP is utilized for a period of approximately three hours once a month during power operations when the reactor is above 50% power. For the forty-eight hour period (see Table 12.2-24) following withdrawal of the TIP from the core, special precautions are necessary to protect workers from inadvertent exposure to the TIP. Shielding of the TIP when completely withdrawn from the core and stored is provided by locating the higher radiation components in a separate shielded room with a locked entry at the TMSL 1500 level. The TIP itself is withdrawn into a lead shielded cask with activated cable covered by a lead shield to permit entry into the TIP room during the first 48 hours after withdrawal from the core. The TIP location is maintained by a set of position sensors which are alarmed to the control room. Area radiation monitors in both the TIP room and its associated spooler room maintain a secondary surveillance of both rooms causing alarms in both the control room and locally in the TIP facility mandating immediate egress from the TIP area. In the unlikely event of a spooler failing to stop on TIP withdrawal, the TIP system incorporates an electro- mechanical switch which cuts power to the spoolers thereby preventing damage to the system or pulling the TIP onto the spoolers. After a 48 hour cool down period, radiation levels are sufficiently reduced (to less than 20mrem/hour) to permit maintenance activities.

While in use, the TIPs must transverse a limited but essentially open area from the TIP room to the drywell penetration. To protect workers in the access way to the personnel air lock from inadvertent exposure three measures are taken. The first measure is primarily administrative requiring any work in the area to be done under a controlled radiation work permit (RWP). Such a permit is required prior to entry to this area since the area is always key-locked into the access pathway. No TIP activity should be scheduled when RWPs indicate work in the area. The second measure is a series of two flashing alarms, one located in the access way and the second external to the access way by the locked door. Both alarms are activated upon power being supplied to the TIP spoolers. The alarm in the personnel air lock area requires evacuation of the area while the alarm on the locked door warns against entry to the area when flashing. The third measure is designed to reduce potential exposure in the event prior measures fail. During use, the TIP system moves along the separate lines performing specific measurements in the core. Upon withdrawal from the core, the TIPs automatically switch to high mode motion, pulling the TIPs from the indexer to the TIP room at 90 feet per minute. This provides an estimated exposure time of four seconds for people in the access entrance and an exposure assuming one TIP in motion of less than 100 mrem.

(3) ECCS Components

The ECCS systems are located in separately shielded cubicles. Shield labyrinths are provided to gain entry into the cubicles, and equipment removal doors are shielded with removable horizontally and vertically lapped concrete block. Piping to and from the ECCS system is routed through shielded pipe chases. Access into the cubicles is not required to operate the systems. In general, the radiation levels in the open corridors of the reactor building are less than 1 mR/hr, except during RHR shutdown cooling mode operation, when radiation levels may temporarily range between 1 and 5 mR/hr in areas near the RHR cubicles.

The RWC system pumps are located in a shielded cubicle designed to reduce the radiation levels in the adjoining open corridor to less than 1 mR/hr. The pumps are separated by shield walls to allow operation of one of the pumps while performing maintenance on the other. Dose of concrete or its equivalent (other material or distance) is required on any ray pathway from the main steam lines to any point which may be inhabited during normal operations. The design of the steam tunnel is shown on Figures 1.2-14, 1.2-15, 1.2-20, 1.2-21, and 1.2-28. The tunnel is classified as Seismic Category I in the reactor building and in the control building and is designed to UBC Seismic Standards in the turbine building. The interface between the buildings provides for bayonet connection to permit differential building motion during seismic events and shielding in the areas between buildings. The exact details on the bayonet design are not shown on the referenced arrangement drawings but requires complete shielding in the building interface area. The tunnel also serves a secondary purpose as a relief and release pathway for high energy events in the reactor building. Any high energy event (line break) in the reactor building will, through a series of blow out panels, vent into the steam tunnel and from the steam tunnel through the tunnel vent shaft to the turbine building (see Figure 1.2-28) for processing to the plant stack. See Subsection 6.2.3.3.1 for more complete description of this function.

12.3.3 Ventilation

The HVAC systems for the various buildings in the plant are discussed in Section 9.4, including the design bases, system descriptions, and evaluations with regard to the heating, cooling, and ventilating capabilities of the systems. This section discusses the radiation control aspects of the HVAC systems.

12.3.3.1 Design Objectives

The following design objectives apply to all building ventilation systems:

(1) The systems shall be designed to make airborne radiation exposures to plant personnel and releases to the environment ALARA. To achieve this objective, the guidance provided in Regulatory Guide 8.8 shall be followed.

(2) The concentration of radionuclides in the air in areas accessible to personnel for normal plant surveillance and maintenance shall be kept below the limits of 10CFR20 during normal power operation. This is accomplished by establishing in each area a reasonable compromise between specifications on potential airborne leakages in the area and HVAC flow through the area. Appendix 12A to this chapter outlines the methodology by which such calculations are made.

The applicable guidance provided in Regulatory Guide 1.52 has been implemented for the ESF filter systems for the control building outdoor air cleanup system and the standby gas treatment system (STGS) as described in Subsections 6.5.1 and 9.4.1.

12.3.3.2 Design Description

In the following sections, the design features of the various ventilation systems that achieve the radiation control design objectives are discussed. For all areas potentially having airborne radioactivity, the ventilation systems are designed such that during normal and maintenance operations, airflow between areas is always from an area of low potential contamination to an area of higher potential contamination.

12.3.3.2.1 Control Room Ventilation

The control building atmosphere is maintained at a slightly positive pressure (up to 0.5 in. wg) at all times, except if exhausting or isolation are required, in order to prevent infiltration of contaminants. Fresh air is taken in via a dual inlet system, which has both intake structures on the roof of the building. The inlets are arranged with respect to the SGTS exhaust stack such that at least one of the intakes is free of contamination after a LOCA. Both inlets, however, can be submerged in contaminated air from a LOCA, but the calculated dose in the control room from such an eventuality is still below the limit of Criterion 19 of 10CFR50, Appendix A.

Outside air coming into the intakes is normally filtered by a particulate filter. If a high radiation level in the air is detected by the airborne radiation monitoring system, flow is automatically diverted to another filter train (an outdoor air cleanup unit) that has:

(1) a particular filter;

(2) a HEPA filter;

(3) a charcoal filter; and

(4) another HEPA filter.

Two redundant, divisionally separated radiation monitors and filter trains are provided. (See Subsection 9.4.1 for detailed description of the design.) Conservative calculations show that the filters keep the dose in the control room from a LOCA below the limits of Criterion 19 of 10CFR50, Appendix A.

The outdoor cleanup units are located in individual, closed rooms that help prevent the spread of any radiation during maintenance. Adequate space is provided for maintenance activities. The particulate and HEPA filters can be bagged when being removed from the unit. Before removing the charcoal, any radioactivity is allowed to decay to minimal levels and then removed through a connection in the bottom of the filter by a pneumatic transfer system. Air used in the transfer system goes through a HEPA filter before being exhausted. Face masks can worn during maintenance activities, if desired.

12.3.3.2.2 Drywell

Access into the drywell is not permitted during normal operation. The ventilation system inside merely circulates, without filtering, the air. The only airflow out of the drywell into accessible areas is minor leakage through the wall.

During maintenance, the drywell air is purged before access is allowed.

12.3.3.2.3 Reactor Building

The reactor building HVAC system is divided into three zones, which are separated by leaktight, physical barriers. The zones include:

(1) secondary containment (this area contains equipment that is a potential source of radioactivity and if a leak occurs, the other accessible areas of the building are not contaminated);

(2) electrical equipment area, cable tunnels, cable spreading rooms, remote control panel area, diesel generator rooms, reactor internal pump panel rooms, and the heating and ventilating equipment rooms; and

(3) steam tunnel (this room also contains a potential source of radioactive material leakage).

Air pressure in the rooms in Zone 1 is maintained slightly below outside atmospheric pressure by a fresh air supply and exhaust system. The supply air is filtered by a particulate filter. The exhaust stream is monitored for radioactivity, and if a high activity level is detected, the exhaust stream is diverted to the SGTS.

Normally, exhaust air is drawn from the corridor and various rooms. The exhaust duct has two isolation valves in series and a radiation monitor. The valves isolate the system if high airborne radioactivity is detected by the radiation monitor.

Zone 2 of the reactor building is maintained at a positive pressure during normal operation.

For a description of the reactor building HVAC system, see Subsection 9.4.5.

12.3.3.2.4 Radwaste Building

The radwaste building is divided into two zones for ventilation purposes. The control room is one zone, and the remainder of the building is the other zone. The air pressure in the first zone is maintained slightly above atmospheric, while the air pressure in the second zone is maintained slightly below atmospheric. Air in the second zone is drawn from outside the building and distributed to various work areas within the building. Air flows from the work areas and is then discharged via the reactor building stack. An alarm sounds in the control room if the exhaust fan fails. The exhaust flow is monitored for radioactivity, and if a high activity level is detected, the potentially radioactive cells are automatically isolated, but airflow through the work areas continues.

If the exhaust flow high-radiation alarm continues to annunciate after the tank and pump rooms are isolated, the work area branch exhaust ducts are selectively manually isolated to locate the involved building area. Should this technique fail, because the airborne radiation has spread throughout the building, the control room air conditioning continues, but the air conditioning for the balance of the building is shut down

The work area's exhaust air is drawn through a filter unit consisting of a particulate filter, a HEPA filter, a charcoal filter, and then another HEPA filter, before being discharged to the reactor building stack. The air is monitored for radioactivity, and if a high level is detected, supply and exhaust is terminated, and the SGTS is started.

Maintenance provisions for the filters are similar to those for the control building HVAC system.

See Subsection 9.4.6 for a detailed discussion of the radwaste building HVAC system.

12.3.4 Area Radiation and Airborne Radioactivity Monitoring Instrumentation

The following systems are provided to monitor area radiation and airborne radioactivity within the plant:

(a) The area radiation monitoring system (D21/ARM) continuously measure, indicate and record the gamma radiation levels at strategic locations throughout the plant except within the primary containment, and activate alarms locally as well as in the control room on high levels to warn operating personnel to avoid unnecessary or inadvertent exposure. This system is classified as non-essential.

(b) The containment atmospheric monitoring system (D23/CAM) continuously measure, indicate, and record the gamma radiation levels within the primary containment (drywell and suppression chamber), and activate alarms in the main control room on high radiation levels. As described in Section 7.6.2, four gamma sensitive ion chamber channels are provided to monitor gamma radioactivity in the primary containment during normal, abnormal and accident conditions. Each of the four monitoring channels cover the range from 1R/hr to 10^7 R/hr. The CAM system is classified as safety-related.

(c) The airborne radioactivity in effluent releases and ventilation exhausts is continuously sampled and monitored by the process radiation monitoring system (D11/PRM) for noble gases, air particulates and halogens. As described in Section 11.5, the presence of airborne contamination is sampled and monitored at the stack common discharge, in offgas releases, and in the ventilation exhaust from buildings. Samples are periodically collected and analyzed for radioactivity. In addition to this instrumentation, portable air samplers are used for compliance with 10CFR20 restrictions. This portable system is designed to meet the criteria of DAC 3.7b and monitors airborne radioactivity in work areas prior to entry where potential levels exist that may exceed the allowable concentration limits. The instrumentation provided to monitor airborne radioactivity is classified as non-essential.

12.3.4.1 ARM System Description

The area radiation monitoring system consists of gamma sensitive detectors, digital area radiation monitors, local auxiliary units with indicators and local audible warning alarms, and recording devices. The detector signals are digitized and optically multiplexed for transmission to the radiation monitors in the main control room. Each ARM radiation channel has two independently adjustable trip alarm circuits, one is set to trip on high radiation and the other is set to trip on downscale indication (loss of sensor input). Also, each ARM monitor is equipped with self test feature that monitors for gross failures and will activate an alarm on loss of power or when a failure is detected. Auxiliary units with local alarms are provided in selected local areas for radiation indication and for activating the local audible alarms on abnormal levels. Each area radiation channel is powered from the non-1E vital 120 Vac source which is continuously available during loss of off-site power. The recording devices are powered from the 120 Vac instrument bus.

12.3.4.2 ARM Detector Location and Sensitivity

The location of each area detector is shown on the plant layout drawings for each building, Figures 12.3-56 through 12.3-73. The specific area radiation channels for each building are listed in Tables 12.3-3 through 12.3-7, along with reference to map location of the detector, the channel sensitivity range, and the areas for the local alarms. The range and sensitivity of each area radiation channel is classified as follows:

a. Range 10^{-2} mR/hr to 10^2 mR/hr - H (High Sensitivity)

b. Range 10^{-1} mR/hr to 10^3 mR/hr - M (Medium Sensitivity)

c. Range 1 mR/hr to 10^4 mR/hr - L (Low Sensitivity)

d. Range 10^2 mR/hr to 10^6 mR/hr - LL (Low Low Sensitivity)

e. Range 10^{-1} R/hr to 10^4 R/hr - VL (Very Low Sensitivity

12.3.4.3 Pertinent Design Parameters and Requirements

Two high-range radiation channels are provided to monitor radiation from accidental fuel handling. One detector is positioned near the fuel pool and the other located in the fuel handling area. Criticality detection monitors are not needed to satisfy the criticality accident requirements of 10CFR70.24, because the ABWR design utilizes specialized high density fuel storage racks that preclude the possibility of criticality accident under normal and abnormal conditions. The new fuel bundles are stored in racks that are located in the fuel vault while the spent fuel bundles are stored in racks that are placed at the bottom of the fuel storage pool. A full array of loaded fuel storage racks are designed to be subcritical as defined in Sections 9.1 and 9.2.

The detectors and radiation monitors are responsive to gamma radiation over an energy range of 80 keV to 7 MeV. The energy dependence will not exceed 20% of point from 100 keV to 3 MeV. The overall system design accuracy is within 9.5% of equivalent linear full scale recorder output for any decade.

The alarm setpoints will be established in the field following equipment installation at the site. The exact settings will be based on sensor location, back ground radiation levels, expected radiation levels, and low occupational radiation exposures. The high radiation alarm setpoint for each channel is set slightly above the background radiation level that is normal to the area.

The area radiation monitoring instrumentation is designed to provide early detection and warning for personnel protection to insure that occupational radiation exposures will be as low as is reasonably achieved (ALARA) in accordance with guidelines stipulated in R.G. 8.2 and R.G. 8.8.

The area radiation monitoring system includes instrumentation provided to assess the radiation conditions in crucial areas in the reactor building (the RHR equipment areas) where access may be required to service the safety related equipment during post LOCA per R.G. 1.97.

12.3.5 Post-Accident Access Requirements

The locations requiring access to mitigate the consequences of an accident during the 100-day post-accident period are the control room, the technical support center, the remote shutdown panel, the primary containment sample station (post accident sample system), the health physics facility (counting room), and the nitrogen gas supply bottles. Each area has low post LOCA radiation levels. The dose evaluations in Subsection 15.6.5 are within regulatory guidelines.

Access to vital areas through out the reactor building/control building/turbine building complex is controlled via the service building. Entrance to the service building and access to the other areas are controlled via double locked secured entry ways. Access to the reactor building is via two specific routes, one for clean access and the second for controlled access. During a event such as a design basis accident, the service building/control building are maintained under filtered HVAC at a positive pressure with respect to the environment. Air infiltration is minimized by positive flow via double entry ways. Therefore, radiation exposure is limited to gamma shine from the reactor building, turbine building, main steam line access corridor, and skyline. This shine is minimized by locating highly populated areas below ground.

During a design basis accident event, access to remote shutdown panel, nitrogen bottles, and the PASS and monitor systems is controlled from the service building via the controlled access way. These corridors are not maintained under filtered positive pressure so that personal protection equipment (radiation protection suits, breathing gear, etc.) will be required in the access corridor. Primary contamination would occur from leakage through the PASS system and air infiltration from the environment. Both pathways are considered minimal and minor contamination under even the most adverse conditions is expected.

The reactor building vital areas are all located off one of of the two primary access ways except the nitrogen bottle areas which are located on the refueling floor and are accessible from the clean access corridor at the 4800 level (B1F) and up three floors to the 23500 level (3F). There are two access corri- dors, clean and dirty, with contamination in those areas limited to air infiltration from the environment and penetration leakage from the PASS system. In addition, the lines penetrating the PASS room are doubly valved permitting line isolation in the event of any potential rupture. Sources of radiation therefore are limited to minor leakage and gamma shine including the stack monitor room which contains only instrumentation and associated penetrations for monitoring stack effluent.

12.3.6 Post-Accident Radiation Zone Maps

The post-accident radiation zone maps for the areas in the reactor building are presented in Figures 12.3-12 through 12.3-22. The zone maps represent the maximum gamma dose rates that exist in these areas during the post-accident period. These dose rates do not include the airborne contribution in the reactor building.

Post-accident zone maps of the control building and turbine building are presented in Figures 12.3-54 and 55 respectively. The zone maps are designed to reflect the criteria established in Subsection 3.1.2.2.10.

12.3.7 Deleted

12.3.8 References

1. N. M. Schaeffer, *Reactor Shielding for Nuclear Engineers*, TID-25951, U.S. Atomic Energy Commission (1973).

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5. Lederer, Hollander, and Perlman, *Table of Isotopes*, Sixth Edition, (1968).

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8. ENDF/B-III and ENDF/B-IV Cross Section Libraries, Brookhaven National Laboratory.

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GE PROPRIETARY - provided under separate cover

Figure	Page(s)	Amendment
12.3-36	12.3-49 - 50	21
12.3-37	12.3-51	21
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APPENDIX 12A

CALCULATION OF AIRBORNE RADIONUCLIDES

12A.1 CALCULATION OF AIRBORNE RADIONUCLIDES

This appendix presents a simplified methodology to calculate the airborne concentrations of radionuclides in a compartment. This methodology is conservative in nature and assumes that diffusion and mixing in a compartment is basically instantaneous with respect to those mitigating mechanisms such as radioactive decay and other removal mechanisms. The following calculations need to be performed on an isotope by isotope basis to verify airborne concentrations are within the limits of 10CFR20.

(1) For the compartment, all sources of airborne radionuclides need to be identified such as:

  (a) Flow of contaminated air from other areas

  (b) Gaseous releases from equipment in the compartment

  (c) Evolution of airborne sources from sumps or water leaking from equipment

(2) Second, the primary sinks of airborne radionuclides need to be identified. This will primarily be outflow from the compartment but may also take the form of condensation onto room coolers.

(3) Given the above information the following equation will calculate a conservative concentration.

$$C_i = \frac{1}{V} \sum_j \frac{S_{ij}}{(\lambda_i + \sum_k R_{ijk})}$$

Where:

C_i = Concentration of the ith radionuclides in the room

V = Volume of room

S_{ij} = The jth source (rate) of the ith radionuclide to the room. These sources are discussed below.

R_{ijk} = the kth removal constant for the jth source and the ith radionuclide as discussed below.

λ_i = radionuclide decay constant

Evaluation Parameters

The following parameters require evaluation on a case by case basis dictated by the physical parameters and processes germaine to the modeling process.

(1) S_{ij} - is defined as the source rate for radionuclide i into the compartment. Typically these sources take the form of:

  (a) Inflow of contaminated air from an upstream compartment. Given the concentration of radionuclide i, c_i, in this air and a flow rate of "r", the source rate then becomes $S_{ij} = rc_i$.

  (b) Production of airborne radionuclides from equipment. This typically takes two forms, gaseous leakage, and liquid leakage.

    (i) For gaseous leakage sources, the source rate is equal to the concentration of radionuclide i, c_i, and the leakage rate, "r", or $S_{ij} = rc_i$.

    (ii) For liquid sources, the source rate is similar but more complex. Given a liquid concentration c_i and a leakage rate, "r", the total release from the leak is rc_i. The fraction of this release which then becomes airborne is typically evaluated by a partition factor, P_f which may be conservately estimated from:

Noble Gases $P_f = 1$

All others $P_f = \dfrac{h_t - h_f}{h_s - h_f}$

where: h_t = saturated liquid enthalpy

h_f = saturated liquid enthalpy at one atmosphere = 100.10 Kcal/Kg

h_s = saturated vapor enthalpy at one atmosphere = 639.18 Kcal/Kg

Therefore the liquid release rate becomes, $rc_i P_f$.

(2) R_{ijk} is defined as the removal rate constant and typically consists of:

(a) Exhaust rate from the compartment. This term considers not only the exhaust of any initially contaminated air but also any clean air which may be used to dilute the compartment air.

(b) Compartment filter systems are treated by the equation:

$R_{ijk} = (1-F_i) * r_i$

where r_i = filter system flow rate

F_i = filter efficiency for radionuclide i

(c) Other removal factors on a case by case basis which may be deemed reasonable and conservative.

Example Calculation

(Values used below are examples only and should not be used in any actual evaluation.)

This example will look at I-131 in a compartment 6.1x6.1x7.6 = 282.80 m^2 = V

First all primary source of radionuclides needs to be identified and categorized.

(1) Flow into the compartment equals 424.8m^3 per hour with the input I-131 concen- tration equal to 2 x 10^{-10} μCi/ml (from upstream compartments) or 2.4 x 10^{-11} Ci/sec. No other sources of air either contaminated or clean air are assumed.

(2) The compartment contains a pump carrying reactor coolant with a maximum specified leakage rate of 0.000034 m^3 per hour at 273.6^{O}C.

(a) Conservatively it can be estimated based upon properties from steam tables (see note 1) that under these conditions 44% of the liquid will flash to steam and become airborne. Along with the flashing liquid it is assumed that a proportional amount of I-131 will become airborne therefore P_f = 0.44.

(b) Using the design basis iodine concentrations for reactor water from Table 11.1-2 of 0.016 μCi/gm of I-131, it is calculated that the pump is providing a source of I-131 of 5.0 x 10^{-11} Ci/sec to the air. (see Note 2)

Second, the sinks for airborne material need to be identified. This example include only exhaust which is categorized as flow out of the compartment at 150% per hour or 4.2 x 10^{-4} per second.

Therefore, for an equilibrium situation, the I-131 airborne concentration from this liquid source would be calculated from the following equation.

$A = S_1/(\lambda + R_1) + S_2/(\lambda + R_2)$, where

S_1 = source rate in Curies per second = 5.0 x 10^{-11} Ci/sec from liquid

S_2 = source rate from inflow = 2.4 x 10^{-11} Ci/sec

= isotope decay constant in units of per second = 9.977 x 10^{-7}/sec

R_1 = R_2 = removal rate constant per second (exfiltration) = 4.2 x 10^{-4} per second

A = 6.2 x 10^{-10} μCi/ml of I-131.

Notes:

1. The assumption of 44% flashing at 273.6^{O}C is extremely conservative, see Reference 1 for a discussion of fission product transport.

2. Water density assumed at 0.743 gm/cm^3 based upon standard tables for water at 273.6^{O}C.

12A.2 References

1. Paquette, et al, *Volatility of Fission Products During Reactor Accidents*, Journal of Nuclear Materials, Vol 130 Pg 129-138, 1985.

Pages 12.3-38 thru 12.3-48 have been deleted

SECTION 14.2

CONTENTS

SECTION 14.2

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TABLES

ILLUSTRATIONS

designs. During the construction and testing phases of the plant cycle GE personnel are onsite to offer consultation and technical direction with regard to GE supplied systems and equipment. The GE resident site manager is responsible for all GE supplied equipment disposition and as the senior NSSS vendor representative onsite is the official site spokesman for GE. He coordinates with the plant owner's normal and augmented plant staff for the performance of his duties which are as follows:

(1) reviewing and approving all test procedures, changes to test procedures, and test results for equipment and systems within the GE scope of supply:

(2) providing technical direction to the station staff;

(3) managing the activities of the GE site personnel in providing technical direction to shift personnel in the testing and operation of GE supplied systems;

(4) liaison between the site and the GE San Jose home office to provide rapid and effective solutions for problems which cannot be solved onsite; and

(5) participating as a member of the Startup Coordinating Group (SCG). [Note: The official designation of this group may differ for the plant owner/operator referencing the ABWR Standard Plant design and SCG is used throughout this dicussion for illustrative purposes only.]

14.2.2.4 Others

Other concerned parties, outside the plant staff organization, such as the architect-engineer, the constructor, the turbine-generator supplier, and vendors of other system and equipment, will be involved in the testing program to various degrees. Such involvement may be in a direct role in the startup group as discussed above or in an indirect capacity offering consultation or technical direction concerning the testing, operation, or resolution of problems or concerns with equipment and systems for which they are responsible or are uniquely familiar with.

14.2.2.5 Interrelationships and Interfaces

Effective coordination between the various site organizations involved in the test program is achieved through the SCG which is composed of representatives of the plant owner/operator, GE, and others. The duties of the SCG are to review and approve project testing schedules and to effect timely changes to construction or testing in order to facilitate execution of the preoperational and initial startup test programs.

14.2.3 Test Procedures

In general, testing during all phases of the initial test program is conducted using detailed, step by step written procedures to control the conduct of each test. Such test procedures specify testing prerequisites, describe desired initial conditions, include appropriate methods to direct and control test performance (including the sequencing of testing), specify acceptance criteria by which the test is to be evaluated, and provide for or specify the format by which data or observations are to be recorded. The procedures will be developed and reviewed by personnel with appropriate technical backgrounds and experience. This includes the participation of principal design organizations in the establishment of test performance requirements and acceptance criteria. Specifically, GE will provide the plant/operator referencing the ABWR Standard Plant design with scoping documents (i.e., preoperational and startup test specifications) containing testing objectives and acceptance criteria applicable to its scope of design responsibility. Such documents shall also include, as appropriate, delineation of specific plant operational conditions at which tests are to be conducted, testing methodologies to be utilized, specific data to be collected, and acceptable data reduction techniques. Available information on operating and testing experiences of operating power reactors will be factored into test procedures as appropriate. Test procedures will be reviewed by the SCG and will receive final approval by designated plant management personnel. Approved test procedures for satisfying the commitments of this chapter will be made available to the NRC staff approximately 60 days prior to their intended use for preoperational tests and 60 days prior to scheduled fuel loading for power ascension tests.

14.2.4 Conduct of Test Program

The initial test program is conducted by the startup group in accordance with the startup administrative manual. This manual contains the administrative procedures and requirements that govern the activities of the startup group and their interfaces with other organizations. The startup administrative manual receives the same level of review and approval as do other plant administrative procedures. It defines the specific format and content of preoperational and startup test procedures as well as the review and approval process for both initial procedures and subsequent revisions or changes. The start- up manual also specifies the process for review and approval of test results and for resolution of failures to meet acceptance criteria and of other operational problems or design deficiencies noted. It describes the various phases of the initial test program and establishes the requirements for progressing from one phase to the next as well as those for moving beyond selected hold points or milestones within a given phase. It also describes the controls in place that will assure the as-tested status of each system is known and that will track modifications, including retest requirements, deemed necessary for systems undergoing or already having completed specified testing. Additionally, the startup manual delineates the qualifications and responsibilities of the different positions within the startup group. The startup administrative procedures are intended to supplement normal plant administrative procedures by addressing those concerns that are unique to the startup program or that are best approached in a different manner. To avoid confusion, the startup program will attempt to be consistent with normal plant procedure where practical. The plant staff will typically carry out their duties according to normal plant procedures. However, in areas of potential conflict with the goals of the startup program, the startup manual or the individual test procedures will address the required interface.

14.2.5 Review, Evaluation, and Approval of Test Results

Individual test results are evaluated and reviewed by cognizant members of the startup group. Test exceptions or acceptance criteria violations are communicated to the affected and responsible organizations who will help resolve the issues by suggesting corrective actions, design modifications, and retests. GE and others outside the plant staff organization, as appropriate, will have the opportunity to review the results for conformance to predictions and expectations. Test results, including final resolutions, are then reviewed and approved by designated startup group supervisory personnel. Final approval is obtained from the SCG and the appropriate level of plant management as defined in the startup administrative manual. The SCG and the designated level of plant management will also have responsibility for final review and approval of overall test phase results and of that for selected milestones or hold points within the test phases.

14.2.6 Test Records

Initial test program results are compiled and maintained according to the startup manual, plant administrative procedures, and applicable regulatory requirements. Test records that demonstrate the adequacy of safety-related components, systems and structures shall be retained for the life of the plant. Retention periods for other test records will be based on consideration of their usefulness in documenting initial plant performance characteristics.

14.2.7 Conformance of Test Program with Regulatory Guides

The NRC Regulatory Guides listed below were used in the development of the initial test program and the applicable tests comply with these guides except as noted. The applicable revisions of the regulatory guides listed below can be found in Table 1.8-20.

(1) Regulatory Guide 1.68--*Initial Test Programs for Water-Cooled Nuclear Power Plants.*

(2) Regulatory Guide 1.68.1--*Preoperational and Initial Startup Testing of Feedwater and Condensate Systems for Boiling Water Reactor Power Plants.*

(3) Regulatory Guide 1.68.2--*Initial Startup Test Program to Demonstrate Remote Shutdown Capability for Water-Cooled Nuclear Power Plants.*

(4) Regulatory Guide 1.68.3--*Preoperational Testing of Instrument and Control Air Systems.*

(5) Regulatory Guide 1.20--*Comprehensive Vibration Assessment Program for Reactor Internals During Preoperation and Initial Startup Testing.*

(6) Regulatory Guide 1.41--*Preoperational Testing of Redundant Onsite Electric Power Systems to Verify Proper Load Group Assignments.*

(7) Regulatory Guide 1.52--*Design, Testing, and Maintenance Criteria for Engineered-Safety-Feature Atmosphere Cleanup System Air Filtration and Adsorption Units of Light-Water-Cooled Nuclear Power Plants.*

(8) Regulatory Guide 1.56--*Maintenance of Water Purity in Boiling Water Reactors.*

(9) Regulatory Guide 1.95--*Protection of Nuclear Power Plant Control Room Operators Against an Accidental Chlorine Release.*

(10) Regulatory Guide 1.108--*Periodic Testing of Diesel Generators Used as Onsite Electric Power Systems at Nuclear Power Plants.*

(11) Regulatory Guide 1.139--*Guidance for Residual Heat Removal.*

(12) Regulatory Guide 1.140--*Design, Testing and Maintenance Criteria for Normal Ventilation Exhaust System Air Filtration and Absorbtion Units of Light Water Cooled Nuclear Power Plants.*

14.2.8 Utilization of Reactor Operating and Testing Experience in the Development of Test Program

Since every reactor/plant in a GE BWR product line is an evolutionary development of the previous plant in the product line (and each product line is an evolutionary development from the previous product line), it is evident that the ABWR plants have the benefits of experience acquired with the successful and safe startup of more than 30 previous BWR/1/2/3/4/5/6 plants. The operational experience and knowledge gained from these plants and other reactor types has been factored into the design and test specifications of GE supplied systems and equipment that will be demonstrated during the preoperational and startup test programs. Additionally, reactor operating and testing experience of similar nuclear power plants obtained from NRC Licensee Event Reports and through other industry sources will be utilized to the extent practicable in developing and carrying out the initial test program.

14.2.9 Trial Use of Plant Operating and Emergency Procedures

To the extent practicable throughout the preoperational and initial startup test program, test procedures will utilize operating, emergency, and abnormal procedures where applicable in the performance of tests. The use of these procedures is intended to do the following:

(1) prove the specific procedure or illustrate changes which may be required;

(2) provide training of plant personnel in the use of these procedures; and

(3) increase the level of knowledge of plant personnel on the systems being tested.

A testing procedure utilizing an operating, emergency, or abnormal procedure will reference the procedure directly, extract a series of steps from the procedure, or both in a way that is optimum to accomplishing the above goals while efficiently performing the specified testing.

14.2.10 Initial Fuel Loading and Initial Criticality

Fuel loading and initial criticality are conducted in a very controlled manner in accordance with specific written procedures as part of the startup test phase (see Subsection 14.2.12.2). Approval for commencement of fuel loading is granted by the NRC after it has been verified that all prerequisite testing has been satisfactorily completed. However, there may be unforeseen circumstances that arise that would prevent the completion of all preoperational testing (including the review and approval of the test results) that would not necessarily justify the delay of fuel loading. Under such circustances, the applicant referencing the ABWR design may decide to request permission from the NRC to proceed with fuel loading. If portions of any preoperational tests are intended to be conducted, or their results approved, after commencement of fuel loading, then the following shall be documented in such a request: (1) list each test; (2) state which portions of each test will be delayed until after fuel loading; (3) provide technical justification for delaying these portions; and (4) state when each test will be completed and the results approved.

14.2.10.1 Pre-Fuel Load Checks

Once the plant has been declared ready to load fuel, there are a number of specific checks that shall be made prior to proceeding. These include a final review of the preoperational test results and the status of any design changes, work packages, and/or retests that were initiated as a result of exceptions noted during this phase. Also, the technical specifications surveillance program requirements, as described in Chapter 16, shall be instituted at this time to assure the operability of systems required for fuel loading. Just prior to the initiation of fuel loading the proper vessel water level and chemistry shall be verified and the calibration and response of nuclear instruments should be checked.

14.2.10.2 Initial Fuel Loading

Fuel loading requires the movement of the full core complement of assemblies from the fuel pool to the core, with each assembly being identified by number before being placed in the correct coordinate position. The procedure controlling this movement will specify that shutdown margin and subcritical checks be made at predetermined intervals throughout the loading, thus ensuring safe loading increments. In-vessel neutron monitors provide continuous indication of the core flux level as each assembly is added. A complete check is made of the fully loaded core to ascertain that all assemblies are properly installed, correctly oriented, and occupying their designated positions.

14.2.10.3 Pre-Criticality Testing

Prior to initial criticality the shutdown margin shall be verified for the fully loaded core. The control rods shall be functional and scram tested with the fuel in place. The post fuel load flow test of the reactor internals vibration assessment program, if applicable, shall be conducted at this time as well. Additionally, a final verification that the required technical specification surveillances have been performed shall be made.

14.2.10.4 Initial Criticality

Initial criticality shall be achieved in an orderly, controlled fashion following specific detailed procedures in an approved rod withdrawal sequence. Core neutron flux shall be continuously monitored during the approach to criticality and periodically compared to predictions to allow early detection and evaluation of potential anomalies.

14.2.11 Test Program Schedule

The schedule, relative to the initial fuel load date, for conducting each major phase of the initial test program will be provided by the applicant referencing the ABWR Standard Plant design. This includes the timetable for generation, review, and approval of procedures as well as the actual testing and analysis of results. As a minimum, at least 9 months should be allowed for conducting the preoperational phase prior to the fuel loading date and at least 3 months should be allowed for conducting the startup and power ascension testing that commences with fuel loading. To allow for NRC review, test procedure preparation will be scheduled such that approved procedures are available approximately 60 days prior to their intended use or 60 days prior to fuel load for power ascension test procedures. Although there is considerable flexibility available in the sequencing of testing within a given phase there is also a basic order that will result in the most efficient schedule. During the preoperational phase, testing should be performed as system turnover from construction allows. However, the interdependence of systems should also be considered so that common support systems, such as electrical power distribution, service and instrument air, and the various makeup water and cooling water systems, are tested as early as possible. Sequencing of testing during the startup phase will depend primarily on specified power and flow conditions and intersystem prerequisites. To the extent practicable, the schedule should establish that, prior to exceeding 25% power, the test requirements will be met for those plant structures, systems, and components that are relied on to prevent, limit, or mitigate the consequences of postulated accidents. Additionally, testing shall be sequenced so that the safety of the plant is never totally dependent on untested systems, components, or features. Power ascension testing will be conducted in essentially three phases: (1) initial fuel loading and open vessel testing: (2) Testing during nuclear heatup to rated temperature and pressure: and (3) power operation testing from 5% to 100% rated power. Further, power operation testing will be divided into three sequential testing plateaus as shown on Figure 114.2-1. The testing plateaus consist of low power testing at less than 25% power, mid power testing up to about 75% power between approximately the 50% and 75% rad lines, and high power testing along the 100% rad line up to rated power. Thus, there will be a total of five different testing plateaus designated as described on Figure 14.2-1. Table 14.2-1 indicates in which testing plateaus the various power ascension tests will be performed. Although the order of testing within a given plateau is somewhat flexible, the normal recommended sequence of tests would be: (1) core performance analysis: (2) steady state tests: (3) control system tuning: (4) system transient tests: and (5) major plant transients (including trips). Also, for a given testing plateau, testing at lower power levels should generally be performed prior to that at higher power levels. The detailed testing schedule will be generated by the applicant referencing the ABWR Standard Plant design and will be made available to the NRC prior to actual implementation. The schedule will then be maintained at the job site so that it may be updated and continually optimized to reflect actual progress and subsequent revised projections.

14.2.12 Individual Test Descriptions

14.2.12.1 Preoperational Test Procedures

The following general descriptions relate the objectives of each preoperational test. During the final construction phase, it may be necessary to modify the preoperational test methods as operating and preoperational test procedures are developed. Consequently, methods in the following descriptions are general, not specific.

Specific testing to be performed and the applicable acceptance criteria for each preoperational test will be documented in detailed test procedures to be made available to the NRC approximately 60 days prior to their intended use. Preoperational testing will be in accordance with the detailed system specifications and associated equipment specifications for equipment in those systems (provided as part of scoping documents to be supplied by GE and others as described in Subsection 14.2.3). The tests demonstrate that he installed equipment and systems perform within the limits of these specifications. To insure that the tests are conducted in accordance with established methods and appropriate acceptance criteria, the plant and system preoperational test specifications will also be made available to the NRC.

The preoperational tests anticipated for the ABWR Standard Plant are listed and described in the following paragraphs. Testing of systems outside the scope of the ABWR Standard Plant, but that may have related design and therefore testing requirements, are discussed in Subsection 14.2.13, along with other interface requirements related to the initial test program.

14.2.12.1.1 Nuclear Boiler System Preoperational Test

(1) Purpose

To verify that all pumps, valves, actuators, instrumentation, trip logic, alarms, annunciators, and indications associated with the nuclear boiler system function as specified.

(2) Prerequisites

The construction tests have been successfully completed and the SCG has reviewed the test procedure and has approved the initiation of testing. All required interfacing systems shall be available, as needed, to support the specified testing and the appropriate system configurations.

(3) General Test Methods and Acceptance Criteria

Performance shall be observed and recorded during a series of individual component and integrated system tests to demonstrate the following:

(a) verification that all sensing devices respond to actual process variables and provide alarms and trips at specified values;

(b) proper operation of system instrumentation and any associated logic, including that of the automatic depressurization system (ADS);

(c) proper operation of MSIVs and main steamline drain valves, including verification of closure time in the isolation mode, and test mode, if applicable;

(d) verification of SRV and MSIV accumulator capacity;

(e) proper operation of SRV air piston actuators and discharge line vacuum breakers;

(f) verification of the acceptable leak tightness and overall integrity of the reactor coolant pressure boundary via the leakage rate and/or hydrstatic testing as described in Section 5.2.4.6.1 and 5.2.4.6.2 respectively; and

(g) proper system instrumentation and equipment operation while powered from primary and alternate sources, including transfers, and in degraded modes for which the system and/or components are expected to remain operational.

Other checks shall be performed, as appropriate, to demonstrate that design requirements, such as those for sizing or installation, are met via as built calculations, visual inspections, review of qualification documentation or other methods. For instance, SRV setpoints and capacities shall be verified from certification or bench tests to be consistent with applicable requirements. Additionally, proper installation and setting of supports and restraints for SRV discharge piping will be verified as part of the testing described in 14.2.12.1.51.

14.2.12.1.2 Reactor Recirculation System Preoperational Test

(1) Purpose

To verify the proper operation of the reactor recirculation system at conditions approaching rated volumetric flow, including the reactor internal pumps (RIPs) and motors, and the equipment associated with the motor cooling, seal purge, and inflatable shaft seal subsystems.

(2) Prerequisites

The construction tests have been successfully completed and the SCG has reviewed the test procedure and has approved the initiation of testing. Cooling water from the reactor building cooling water system and seal purge flow from the CRD hydraulic system shall be available. The recirculation flow control system shall be sufficiently tested to support RIP operation. Other interfacing systems shall be available, as needed, to support the specified testing and the corresponding system configurations. Reactor vessel internals shall be capable of being subjected to rated volumetric core flow.

(3) General Test Methods and Acceptance Criteria

Testing of the recirculation system shall be coordinated closely with that of the recirculation flow control system (Subsection 14.2.12.1.3) in order to adequately demonstrate proper integrated system response and operation. Also, the preoperational phase of the reactor internals vibration assessment program (Subsection 14.2.12.1.52) involves extended operation of the recirculation system and should be scheduled accordingly so as to optimize overall plant integrated testing.

The scope and intensity of the preoperational testing of the recirculation system and associated support subsystems will be limited by the unavailability of nuclear heating. Comprehensive testing of the system at rated temperature and pressure will be performed during the startup phase.

Performance shall be observed and recorded during a series of individual component and integrated system tests to demonstrate the following:

(a) proper operation of instrumentation and equipment in all combinations of logic and instrument channel trip;

(b) proper functioning of instrumentation and alarms used to monitor system operation and availability;

(c) proper operation of system valves under expected operating conditions;

(d) proper operation of pumps and motors in all normal design operating modes as well as any specified special testing configurations;

(e) acceptable pump NPSH under the most limiting design flow conditions;

(f) proper system flow rates including individual pump capacity and discharge head;

(g) proper manual and automatic system operation and margin to actuation of protective devices;

(h) proper operation of interlocks and equipment protective devices in pump and motor controls;

(i) proper operation of permissive, prohibit and bypass functions;

(j) proper system operation while powered from primary and alternate sources, including transfers, and in degraded modes for which the system is expected to remain operational;

(k) proper operation of the recirculation motor seal purge subsystem over the full range of RPV pressures including the proper functioning of the main header pressure control valve and proper distribution of seal purge flow to individual pumps and motors;

(l) proper functioning of the recirculation motor cooling subsystem and its ability to remove design heat loads from each RIP motor via the dedicated heat exchangers;

(m) proper functioning of the recirculation motor inflatable shaft seal subsystem and its ability to provide a temporary backup sealing mechanism for each pump motor shaft during recirc motor maintenance or removal;

(n) acceptable pump/motor vibration levels and system piping movements during both transient and steady state operation; and

(o) acceptable reactor vessel internals flow induced vibration levels per the requirements of Subsection 14.2.12.1.52.

System operation is considered acceptable when the observed/measured performance characteristics, from the testing described above, meet the applicable design specifications.

14.2.12.1.3 Recirculation Flow Control System Preoperational Test

(1) Purpose

To verify that the operation of the recirculation flow control system, including that of the adjustable speed drives, RIP trip and runback logic, and the core flow measurement subsystem, is as specified.

(2) Prerequisites

The construction tests have been successfully completed and the SCG has reviewed the test procedure and has approved the initiation of testing. All required interfacing systems shall be available, as needed, to support the specified testing and the corresponding system configurations.

(3) General Test Methods and Acceptance Criteria

Some portions of the recirculation flow control system testing will likely be performed in conjunction with that of the recirculation system, as described in Subsection 14.2.12.1.2. Close coordination of the testing specified for the two systems is required in order to demonstrate the proper integrated system response and operation.

Performance shall be observed and recorded during a series of individual component and integrated system tests to demonstrate the following:

(a) proper operation of instrumentation and equipment in all combinations of logic and instrument channel trip including recirculation pump trip (RPT) and runback circuitry, (RPT testing will specifically include its related ATWS function);

(b) proper functioning of instrumentation and alarms used to monitor system operation and availability;

(c) proper functioning of the core flow measurement subsystem;

(d) proper operation of control systems in all design operating modes and all levels of controls;

(e) proper operation of the adjustable speed drives;

(f) ability of the control system to communicate properly with equipment and controllers in other systems;

(g) proper control of pump motor start sequence;

(h) proper operation of interlocks and equipment protective devices;

(i) proper operation of permissive, prohibit and bypass functions; and

(j) proper system operation while powered from primary and alternate sources, including transfers, and in degraded modes for which the system is expected to remain operational.

System operation is considered acceptable when the observed/measured performance characteristics, from the testing described above, meet the applicable design specifications.

14.2.12.1.4 Feedwater Control System Preoperational Test

(1) Purpose

To verify proper operation of the feedwater control system, including individual components such as controllers, indicators, and controller software settings such as gains and function generator curves.

(2) Prerequisites

The construction tests have been successfully completed and the SCG has reviewed the test procedures and has approved the initiation of testing. Preoperational tests must be completed on lower level controllers that do not strictly belong to the feedwater control system but that may affect system response. All feedwater control system components shall have an initial calibration in accordance with vendor instructions. All required interfacing systems shall be available, as needed, to support the specified testing and the appropriate system configurations.

(3) General Test Methods and Acceptance Criteria

Testing of the feedwater control system during the preoperational phase may be limited by the absence of an acceptable feedwater recirculation flow path. Comprehensive flow testing will be conducted during startup phase.

Performance shall be observed and recorded during a series of individual component and overall system response tests to demonstrate the following:

(a) proper operation of instrumentation and controls in all combinations of logic and instrument channel trips including verification of setpoints;

(b) proper functioning of instrumentation and alarms used to monitor system operation and status;

(c) proper operation of system valves, including timing and stroke, in response to control demands (including the reactor water cleanup system dump valve response to the low flow controller);

(d) proper operation of interlocks and equipment protective devices in pump and valve controls;

(e) proper operation of permissive, prohibit, and bypass functions;

(f) proper system operation while powered from primary and alternate sources, including transfers, and in degraded modes for which the system is expected to remain operational; and

(g) proper communication and interface with other control systems and related equipment.

System operation is considered acceptable when the observed/measured performance characteristics, from the testing described above, meet the applicable design specifications.

14.2.12.1.5 Standby Liquid Control System Preoperational Test

(1) Purpose

To verify that the operation of the standby liquid control (SLC) system, including pumps, tanks, control, logic, and instrumentation, is as specified.

(2) Prerequisites

The construction tests have been successfully completed and the SCG has reviewed the test procedure and has approved the initiation of testing. Valves should be previously bench tested and other precautions relative to positive displacement pumps taken. The reactor vessel shall be available for injecting demineralized water. All required interfacing systems shall be available, as needed, to support the specified testing and the appropriate system configurations.

(3) General Test Methods and Acceptance Criteria

Performance shall be observed and recorded during a series of individual component and integrated system tests to demonstrate the following:

(a) proper operation of instrumentation and equipment in all combinations of logic and instrument channel trip;

(b) proper functioning of instrumentation and alarms used to monitor system operation and availability;

(c) proper operation of system valves, including timing, under expected operating conditions;

(d) proper operation of pumps and motors in all design operating modes;

(e) proper operation of the tank heaters and proper mixing of the neutron absorber solution;

(f) proper system flow paths and flow rates including pump capacity and discharge head (with demineralized water substituted for the neutron absorber mixture);

(g) proper pump motor start sequence and margin to actuation of protective devices;

(h) proper operation of interlocks and equipment protective devices in pump and valve controls;

(i) proper operation of permissive, prohibit, and bypass functions;

(j) proper system operation while powered from primary and alternate sources, including transfers, and in degraded modes for which the system is expected to remain operationai: and

(k) acceptability of pump/motor vibration levels and system piping movements during both transient and steady state operation.

System operation is considered acceptable when the observed/measured performance characteristics, from the testing described above, meet the applicable design specifications.

14.2.12.1.6 Control Rod Drive System Preoperational Test

(1) Purpose

To verify that the control rod (CRD) system, including the CRD hydraulic and fine motion control subsystems, functions as designed.

(2) Prerequisites

The construction tests have been successfully completed and the SCG has reviewed the test procedure and has approved the initiation of testing. The control blades shall be installed and ready to be stroked and scrammed. Reactor building cooling water, instrument air, and other required interfacing systems shall be available, as needed, to support the specified testing and the corresponding system configurations.

Additionally, the rod control and information system shall be functional when needed, with the applicable portion of its specified preoperational testing complete.

(3) General Test Methods and Acceptance Criteria

Performance shall be observed and recorded during a series of individual component and integrated system tests to demonstrate the following:

(a) proper functioning of instrumentation and alarms used to monitor system operation and status;

(b) proper communication with, and response to demands from, the rod control and information system and the reactor protection system, including that associated with alternate rod insertion (ATWS), alternate rod-in (post-scram), and select control rod run-in unctions;

(c) proper functioning of system valves, including purge water pressure control valves, under expected operating conditions;

(d) proper operation of CRD hydraulic subsystem pumps and motors in all design operating modes;

(e) acceptable pump NPSH under the most limiting design flow conditions;

(f) proper pump motor start sequence and margin to actuation of protective devices;

(g) proper system flow paths and flow rates including sufficient pump capacity and discharge head;

(h) proper operation of interlocks and equipment protective devices in pump, motor, and valve controls;

(i) proper operation of permissive, prohibit, and bypass functions;

(j) proper system operation while powered from primary and alternate sources, including transfers, and in degraded modes for which the system is expected to remain operational;

(k) acceptability of pump/motor vibration levels and system piping movements during both transient and steady state operation;

(l) proper operation of fine motion motors and drives and associated control units, including verification of acceptable normal insert and withdraw timing;

(m) proper operation of hydraulic control units and associated valves including CRD scram timing demonstrations against atmospheric pressure.

System operation is considered acceptable when the observed/measured performance characteristics, from the testing described above, meet the applicable design specifications.

14.2.12.1.7 Rod Control and Information System Preoperational Test

(1) Purpose

To verify that the rod control and information system (RC&IS) functions as designed.

(2) Prerequisites

The construction tests, including initial check-out of RC&IS software, have been successfully completed and the SCG has reviewed the test procedure and has approved the initiation of testing.

(3) General Test Methods and Acceptance Criteria

Performance shall be observed and recorded during a series of tests to demonstrate the following:

(a) proper operation of rod blocks and associated alarms and annunciators in all combinations of logic and instrument channel trip including all positions of the reactor mode switch;

(b) proper operation of control rod run-in logic including that associated with ARI (ATWS), SCRRI and normal post-SCRAM follow-in;

(c) proper functioning of instrumentation used to monitor CRD system status such as rod position indication instrumentation and that used to monitor continuous full-in and rod/drive separation status;

(d) proper operation of RC&IS software including verification of gang and group assignments and predictor-comparator, rod worth limiter, and banked position withdrawal sequence functions; and

(e) proper communication with interfacing systems such as the power generation control system, the automatic power regulator, and the automatic rod block monitor.

System operation is considered acceptable when the observed/measured performance characteristics, from the testing described above, meet the applicable design specifications.

14.2.12.1.8 Residual Heat Removal System Preoperational Test

(1) Purpose

To verify the proper operation of the residual heat removal (RHR) system under its various modes of operation: core cooling, shutdown cooling, wetwell and drywell spray, suppression pool cooling, and supplemental fuel pool cooling.

(2) Prerequisites

The construction tests have been successfully completed and the SCG has reviewed the test procedure and has approved the initiation of testing. The reactor vessel shall be intact and capable of receiving injection flow from the various modes of RHR. The

(3) General Test Methods and Acceptance Criteria

Performance shall be observed and recorded during a series of individual component and integrated system tests that includes all modes of RHR system operation in order to demonstrate the following:

(a) proper operation of instrumentation and equipment in all combinations of logic and instrument channel trip;

(b) proper functioning of system instrumentation and alarms used to monitor system operation and availability including that intended to alert when high pressure- low pressure interface valves are not full closed with the reactor coolant system at high pressure (per Reg. Guide 1.139);

(c) proper operation of system valves, including timing, under expected operating conditions verification of proper setpoint of system releif valves per ASME Code requirements, including those intended to meet the requirements of Reg Guide 1.139, may use the results of vendor tests and the appropriate documemtation of such);

(d) proper operation of pumps and motors in all design operating modes;

(e) acceptable pump NPSH under the most limiting design flow conditions;

(f) proper system flow paths and flow rates including pump capacity and discharge head and time to rated flow;

(g) proper operation of containment spray modes including verfication that spray nozzles, headers and piping are free of debris;

(h) proper pump motor start sequence and margin to actuation of protective devices;

(i) proper operation of interlocks and equipment protective devices in pump and valve controls including valve interlocks and controls including valve interlocks and controls designed to protect low pressure portions of the system from the reactor coolant system at high pressure (per Reg Guide 1.139);

(j) proper operation of permissive, prohibit, and bypass functions;

(k) proper system operation while powered from primary and alternate sources, including transfers, and in degraded modes for which the system is expected to remain operational;

(l) acceptability of pump/motor vibration levels and system piping movements during both transient and steady state operation; and

(m) proper operation of pump discharge line keep fill system(s) and its ability to prevent damaging water hammer during system transients.

System operation is considered acceptable when the observed/measured performance characteristics, from the testing described above, meet the applicable design specifications.

14.2.12.1.9 Reactor Core Isolation Cooling System Preoperational Test

(1) Purpose

Verify that the operation of the reactor core isolation cooling (RCIC) system, including the turbine, pump, valves, instrumentation, and control, is as specified.

(2) Prerequisites

The construction tests have been successfully completed and the SCG has reviewed the test procedure and has approved the initiation of testing. A temporary steam supply shall be available for driving the RCIC turbine. The turbine instruction manual shall be reviewed in detail in order that precautions relative to turbine operation are followed. All required interfacing systems shall be available, as needed, to support the specified testing and the corresponding system configurations.

(3) General Test Methods and Acceptance Criteria

The RCIC turbine shall be tested in accordance with the manufacturere's recommendations. Usually this invilves the turbine first being tested while disconnected from and then while coupled to the pump. The intent of this preoperational test is to test the RCIC system to the extent possible. However, since preoperational testing is performed utilizing a temporary steam supply, the attainable RCIC pump flow may be limited. Should this prevent any specified testing from being completed sucessfully, such cases will be documented and scheduled for completion during the power ascension test phase.

Performance shall be observed and recorded during a series of individual component and integrated system tests to demonstrate the following:

(a) proper operation of instrumentation and equipment in all combinations of logic and instrument channel trip;

(b) proper functioning of instrumentation and alarms used to monitor system operation and availability;

(c) proper operation of system valves, including timing, under expected operating conditions;

(d) proper operation of turbine and pump in all design operating modes;

(e) acceptable pump NPSH under the most limiting design flow conditions;

(f) proper system flow paths and flow rates including pump capacity, discharge head and time to rated flow;

(g) proper manual and automatic system operation and margin to actuation of protective devices;

(h) proper operation of interlocks and equipment protective devices in turbine, pump, and valve controls;

(i) proper operation of permissive, prohibit, and bypass functions;

(j) proper system operation while powered from primary and alternate sources, including transfers, and in degraded modes for which the system is expected to remain operational. Included shall be a demonstration of RCIC system ability to start without the aid of AC power, except for RCIC DC/AC inverters; an evaluation of RCIC operation beyond its design basis during an extended loss of AC power to it and its support systems and verification of RCIC DC component operability when the non-RCIC station batteries are disconnected;

(k) acceptability of pump/turbine vibration levels and system piping movements during both transient and steady state operation;

(l) proper operation of the barometric condenser condensate pump and vacuum pump;

(m) the ability of the system to swap pump suction source from the condensate storage pool to the suppression pool without interrupting system operation; and

(n) proper operation of the pump discharge line keep fill system and its ability to prevent damaging water hammer during system transients.

System operation is considered acceptable when the observed/measured performance characteristics, from the testing described above, meet the applicable design specifications (while accounting for the limitations imposed by the temporary steam supply).

14.2.12.1.10 High Pressure Core Flooder System Preoperational Test

(1) Purpose

To verify the operation of the high pressure core flooder (HPCF) system, including related auxiliary equipment, pumps, valves, instrumentation and control, is as specified.

(2) Prerequisites

The construction tests have been successfully completed and the SCG has reviewed the test procedure and has approved the initiation of testing. The suppression pool and condensate storage pool shall be available as HPCF pump suction sources and the reactor vessel shall be sufficiently intact to receive HPCF injection flow. The required interfacing systems shall be available, as needed, to support the specified testing and the appropriate system configurations.

(3) General Test Methods and Acceptance Criteria

Performance shall be observed and recorded during a series of individual component and integrated system tests to demonstrate the following:

(a) proper operation of instrumentation and equipment in all combinations of logic and instrument channel trip;

(b) proper functioning of instrumentation and alarms used to monitor system operation and availability;

(c) proper operation of system valves, including timing, under expected operating conditions;

(d) proper operation of pumps and motors in all design operating modes;

(e) acceptable pump NPSH under the most limiting design flow conditions;

(f) proper system flow paths and flow rates including pump capacity and discharge head and time to rated flow;

(g) proper pump motor start sequence and margin to actuation of protective devices;

(h) proper operation of interlocks and equipment protective devices in pump, motor, and valve controls;

(i) proper operation of permissive, prohibit, and bypass functions;

(j) proper system operation while powered from primary and alternate sources, including transfers, and in degraded modes for which the system is expected to remain operational;

(k) acceptability of pump/motor vibration le- vels and system piping movements during both transient and steady state operation;

(l) the ability of the system to swap pump suction source from the condensate storage pool to the suppression pool without interrupting system operation;

(m) acceptability of the HPCF sparger flooding pattern; and

(n) proper operation of the pump discharge line keep fill system and its ability to prevent damaging water hammer during system transients.

System operation is considered acceptable when the observed/measured performance characteristics, from the testing described above, meet the applicable design specifications.

14.2.12.1.11 Safety System Logic and Control Preoperational Test

(1) Purpose

To verify proper operation of the plant safety system logic and control (SSLC).

(2) Prerequisites

The applicable construction tests have been successfully completed.

(3) General Test Methods and Acceptance Criteria

The SSLC integrates the automatic decision making and trip logic functions associated with the safety action of several of the plants' safety-related systems. Such systems include the RPS, HPCF, RHR, RCIC, LDIS, and ADS. The SSLC is not so much a system itself, but is instead an assembly of the above mentioned safety-related systems signal processors designed and grouped for optimum reliability, availability and oper- ability. The SSLC, therefore, should be adequately tested during the preoperational phase testing of the associated systems in- cluding the integrated LOP/LOCA test. Pro- vided the construction testing and the asso- ciated system preoperational testing has been successfully completed, as it relates to proper operation of the SSLC, no specific additional testing should be necessary.

SSLC performance would then be considered acceptable provided all design and testing specifications are met.

14.2.12.1.12 Multiplexing System Preoperational Test

(1) Purpose

To verify proper functioning of the plant multiplexing system including both essential and nonessential subsystems.

(2) Prerequisites

System construction testing has been successfully completed.

(3) General Test Method and Acceptance Criteria

Since this system is the primary communication interface between the various plant systems it should be adequately tested during the preoperational phase testing performed on those interconnected systems. Provided the construction testing and the associated system testing has been successfully completed as it relates to proper operation of the multiplexing system, no specific additional testing should be necessary.

System performance would then be considered acceptable provided all design specifications are met.

14.2.12.1.13 Leak Detection and Isolation System Preoperational Test

(1) Purpose

To verify proper response and operation of the leak detection and isolation system (LDS) logic.

(2) Prerequisites

The construction tests have been successfully completed and the SCG has reviewed the test procedures and has approved the initiation of testing. The required AC and DC electrical power sources shall be operational and the appropriate interfacing systems shall be available as required to support the specified testing.

(3) General Test Methods and Acceptance Criteria

Since the leak detection and isolation system is comprised mostly of logic, the checks of valve response and timing and the testing of sensors will be performed as part of, or in conjunction with, the various systems with which they are associated. These systems include RHR, RCIC, RWCU, main steam, feedwater, recirculation, radiation monitoring, nuclear boiler, drywell cooling and the drywell sumps.

Performance shall be observed and recorded during a series of individual component and integrated system tests to demonstrate the following:

(a) proper operation of instrumentation and controls in all combinations of logic and instrument channel trip;

(b) proper functioning of indicators, annunciators, and alarms used to monitor system operation and status;

(c) proper operation of leakoff and drainage measurement functions such as those associated with the reactor vessel head flange, drywell cooler condensate, and various primary system valves;

(d) proper response of related system valves, including timing, under expected operating conditions;

(e) proper interface with related systems in regards to the input and output of leak detection indications and isolation initiation commands;

(f) proper operation of bypass switches and related logic; and

(g) proper system operation while powered from primary and alternate sources, including transfers, and in degraded modes for which the system is expected to remain operational.

System operation is considered acceptable when the observed/measured performance characteristics, from the testing described above, meet the applicable design specifications.

14.2.12.1.14 Reactor Protection System Preoperational Test

(1) Purpose

To verify proper operation of the reactor protection system (RPS) including complete channel logic and response time.

(2) Prerequisites

The construction tests have been successfully completed and the SCG has reviewed the test procedures and has approved the initiation of testing. The rod control system, instrument air system, and the required AC and DC electrical power sources are operational. All other required interfacing systems shall be available, as needed, to support the specified testing.

(3) General Test Methods and Acceptance Criteria

Performance shall be observed and recorded during a series of individual component and integrated system tests to demonstrate the following:

(a) proper operation of instrumentation and controls in all combinations of logic and instrument channel trip including those associated with all positions of the reactor mode switch;

(b) proper functioning of instrumentation and alarms used to monitor sensor and channel operation and availability;

(c) proper calibration of primary sensors;

(d) proper trip and alarm settings;

(e) operability of bypass switches including related logic;

(f) proper operation of permissive and prohibit interlocks;

(g) proper system operation while powered from primary and alternate sources, including transfers, and in degraded modes for which the system is expected to remain operational; and

(h) acceptability of instrument channel response times, as measured from each applicable process variable (except for neutron sensors) to the de-energization of the scram pilot valve solenoids.

System operation is considered acceptable when the observed/measured performance characteristics, from the testing described above, meet the applicable design specifications.

The ability of the system to scram the reactor within a specified time must be demonstrated in conjunction with the CRD system preoperational test (Subsection 14.2.12.1.6).

14.2.12.1.15 Neutron Monitoring System Preoperational Test

(1) Purpose

To verify the proper operation of the neutron monitoring system (NMS) including fixed incore startup and power range detectors, traversing incore probes (TIPs) and related hardware and software.

(2) Prerequisites

The construction tests have been successfully completed and the SCG has reviewed the test procedure and has approved the initiation of testing. All startup range neutron monitor subsystem components and power range neutron monitor subsystem components have been calibrated per vendor instructions. Additionally, all required interfacing systems shall be available, as needed, to support the specified testing.

(3) General Test Methods and Acceptance Criteria

Performance shall be observed and recorded during a series of individual component and integrated system tests to demonstrate the following:

(a) proper operation of instrumentation and equipment in all combinations of logic and instrument channel trip including rod block and scram signals feeding the rod control system and the reactor trip system, respectively;

(b) proper functioning of instrumentation, displays, alarms, and annunciators used to monitor system operation and status;

(c) proper operation of detectors and associated cabling, preamplifiers, and power supplies;

(d) proper operation of TIP drive mechanisms and indexers;

(e) proper operation of interlocks and equipment protective devices including those associated with the TIP indexers and drive control units;

(f) proper operation of permissive, prohibit, and bypass functions;

(g) proper system operation while powered from primary and alternate sources, including transfers, and in degraded modes for which the system is expected to remain operational;

(h) proper operation of system and subsystem self-test diagnostic and calibration functions;

(i) the ability to communicate and interface with appropriate plant systems and between NMS subsystems; and

(j) the ability to generate core flow biased trip setpoints from core plate differential pressure measurements.

System operation is considered acceptable when the observed/measured performance characteristics, from the testing described above, meet the applicable design specifications.

14.2.12.1.16 Process Computer System Preoperational Test

(1) Purpose

To verify the proper operation of the process computer system (PCS) including the performance monitoring and control system (PMCS) and the power generation control system (PGCS) and their related functions.

(2) Prerequisites

The construction tests have been successfully completed and the SCG has reviewed the test procedure and has approved the initiation of testing. All programming shall be complete and initial software diagnostic checks determined acceptable. The required input and output devices and various system interfaces shall be connected and available, as needed, for supporting the specified testing configurations.

(3) General Test Methods and Acceptance Criteria

Proper performance of system hardware and software will be verified by a series of individual and integral tests that include the following demonstrations:

(a) proper connection and calibration of all analog and digital signals;

(b) proper operation of data logging and plotting features;

(c) verification of computer printouts and CRT displays;

(d) proper communication and interface with other plant equipment, computers and control systems;

(e) verification of proper data flow and processing and of calculational accuracy;

(f) proper operation of calibration and surveillance support functions; and

(g) proper operation of operator guidance and prompting functions, including alarms and status messages, in all operating modes for plant startup, shutdown and power maneuvering iterations.

Much of the testing performed during the preoperational phase is done utilizing simulated conditions and inputs via system hardware and software. Final system performance during live conditions will be evaluated during the startup phase.

System operation is considered acceptable when the observed/measured performance characteristics, from the testing described above, meet the applicable design specifications.

14.2.12.1.17 Automatic Power Regulator Preoperational Test

(1) Purpose

To verify proper operation of the automatic power regulator (APR) over the range of required operating modes.

(2) Prerequisites

The software programming and initial diagnostic testing has been completed and the SCG has reviewed the test procedure and has approved the initiation of testing. The process computer system, rod control and information system, recirc flow control system, turbine control system, and other required system interfaces shall be available to support the specified system testing.

(3) General Test Methods and Acceptance Criteria

The APR is a top level controller that interfaces with various lower level controllers and systems. APR testing, therefore, shall be closely coordinated with testing of related interfacing and affected systems. Such testing shall include the following demonstrations:

(a) proper operation of instrumentation and controls in all combinations of logic for all modes of operation including transfers;

(b) proper functioning of annunciators, alarms, and displays used to monitor system operation or status;

(c) verification of proper data flow and processing including the accuracy of calculations and control algorithms; and

(d) proper communication and interface with other control systems and related supporting and monitoring functions.

System operation is considered acceptable when the observed performance meets the applicable design specifications.

14.2.12.1.18 Remote Shutdown System Preoperational Test

(1) Purpose

Verify the feasibility and operability of intended remote shutdown functions from the remote shutdown panel and other local and remote locations outside the main control room which will be utilized during the remote shutdown scenario.

(2) Prerequisites

The construction tests have been successfully completed and the SCG has reviewed the test procedure and has approved the initiation of testing. Additionally, control power shall be supplied to the remote shutdown panel and the required system and component interfaces shall be available, as needed, to support the specified testing.

(3) General Test Methods and Acceptance Criteria

The remote shutdown system (RSS) consists of the control and instrumentation available at the dedicated remote shutdown panel(s) and other local and remote locations intended to be used during the remote shutdown scenario.

Much of the specified testing can be accomplished in conjunction with, or as part of, the individual system and component preoperational testing. However, the successful results of such testing shall be documented as part of this test, as applicable. Performance shall be observed and recorded during a series of individual component and integrated system tests to demonstrate the following:

(a) proper functioning of the control and instrumentation associated with the RSS;

(b) proper operation of pumps and valves including establishment of system flow paths using RSS control;

(c) proper functioning of RSS transfer switches including verification of proper override of main control room functions;

(d) proper operation of prohibit and permissive interlocks and bypass functions after transfer of control;

(e) proper system operation while powered from primary and alternate electrical sources; and

(f) the ability to establish and maintain communication among personnel stationed throughout the plant who would be performing the remote shutdown operation.

RSS operation is considered acceptable when the observed and measured performance meets the applicable design specifications.

14.2.12.1.19 Reactor Water Cleanup System Preoperational Test

(1) Purpose

To verify that the operation of the reactor water cleanup system (CUW), including pumps, valves, and filter/demineralizer equipment, is as specified.

(2) Prerequisites

The construction tests have been successfully completed and the SCG has reviewed the test procedure and has approved the initiation of testing. Filter aid and resin material shall be available. Reactor building cooling water, instrument air, CRD purge supply, and other required interfacing systems shall be available, as needed, to support the specified testing and the appropriate system configurations. Special provisions may be required for testing the CUW system in the vessel head spray mode.

(3) General Test Methods and Acceptance Criteria

Performance shall be observed and recorded during a series of individual component and integrated system tests to demonstrate the following:

(a) proper operation of instrumentation and controls in all combinations of logic and instrument channel trip including those associated with the leak detection and isolation system;

(b) proper functioning of instrumentation and alarms used to monitor system operation and availability;

(c) proper operation of system valves, including timing, under expected operating conditions;

(d) proper operation of pumps and motors in all design operating modes;

(e) acceptable pump NPSH under the most limiting design flow conditions;

(f) proper system flow paths and flow rates including pump capacity and discharge head;

(g) proper pump motor start sequence and margin to actuation of protective devices;

(h) proper operation of interlocks and equipment protective devices in pump and valve controls;

(i) proper operation of permissive, prohibit, and bypass functions;

(j) proper system operation while powered from primary and alternate sources, including transfers, and in degraded modes for which the system is expected to remain operational;

(k) acceptability of pump/motor vibration levels and system piping movements during both transient and steady state operation; and

(l) proper operation of the reactor water cleanup filter/demineralizers and associated support facilities.

System operation is considered acceptable when the observed/measured performance characteristics, from the testing described above, meet the applicable design specifications. Proper operation of sampling stations and displays will be demonstrated per Subsection 14.2.12.1.22.

14.2.12.1.20 Suppression Pool Cleanup System Preoperational Test

(1) Purpose

To verify that the operation of the suppression pool cleanup system (SPCU) is as specified in all required operating modes.

(2) Prerequisites

The construction tests have been successfully completed and the SCG has reviewed the test procedure and has approved the initiation of testing. The fuel pool and suppression pool shall be adequately filled and the appropriate filter/demineralizer support facilities and other system interfaces available, as needed, to support the specified testing.

(3) General Test Method and Acceptance Criteria

The suppression pool and fuel pool share common water treatment facilities. The suppression pool cleanup system has a dedicated pump for circulating water to and from the suppression pool and through the common filter/demineralizer. However, the shared filter/demineralizer facilities are considered part of the fuel pool cooling and cleanup system. Therefore, this preoperational test shall be closely coordinated with that of Subsection 14.2.12.1.21.

Performance shall be observed and recorded during a series of individual component and integrated system tests to demonstrate the following:

(a) proper operation of instrumentation and equipment in all combinations of logic and instrument channel trip;

(b) proper functioning of instrumentation and alarms used to monitor system operation and availability;

(c) proper operation of system valves, including timing, under expected operating conditions;

(d) proper operation of pump and motor in all design operation modes;

(e) acceptable pump NPSH under the most limiting design flow conditions;

(f) proper system flow paths and flow rates including pump capacity and discharge head;

(g) proper pump motor start sequence and margin to actuation of protective devices;

(h) proper operation of interlocks and equipment protective devices in pump and valve controls;

(i) proper operation of permissive, prohibit, and bypass functions;

(j) proper system operation while providing the specified intersystem refill capabilities; and

(k) acceptability of pump/motor vibration levels and system piping movements during both transient and steady state operation.

System operation is considered acceptable when the observed/measured performance characteristics, from the testing described above, meet the applicable design specifications.

14.2.12.1.21 Fuel Pool Cooling and Cleanup System Preoperational Test

(1) Purpose

To verify that the operation of the fuel pool cooling and cleanup (FPC) system, including the pumps, heat exchangers, controls, valves, and instrumentation, is as specified.

(2) Prerequisites

The construction tests have been successfully completed and the SCG has reviewed the test procedure and has approved the initiation of testing. The required interfacing systems shall be available, as needed, to support the specified testing and the appropriate system configurations.

(3) General Test Methods and Acceptance Criteria

Performance shall be observed and recorded during a series of individual component and integrated system tests to demonstrate the following:

(a) proper operation of instrumentation and equipment in all combinations of logic and instrument channel trip, including isolation and bypass of the nonsafety related fuel pool cleanup filter/demineralizers;

(b) proper functioning of instrumentation and alarms used to monitor system operation and availability, including those associated with pool water level;

(c) proper operation of system valves, including timing, under expected operating conditions;

(d) proper operation of pumps and motors in all design operating modes;

(e) acceptable pump NPSH under the most limiting design flow conditions;

(f) proper system flow paths and flow rates including pump capacity and discharge head;

(g) proper pump motor start sequence and margin to actuation of protective devices,

(h) proper operation of interlocks and equipment protective devices in pump, motor, and valve controls;

(i) proper operation of permissive, prohibit, and bypass functions;

(j) proper system operation while powered from primary and alternate sources, including transfers, and in degraded modes for which the system is expected to remain operational;

(k) acceptability of pump/motor vibration levels and system piping movements during both transient and steady state operation;

(l) proper functioning of pool antisiphon devices and acceptable nonleakage from pool drains, sectionalizing devices, and gaskets or bellows;

(m) proper functioning of the system in conjunction with the RHR system in the supplemental fuel pool cooling mode; and

(n) proper operation of filter/demineralizer units and their associated support facilities.

Integrated system testing with flow to and from the fuel pool cleanup subsystem will be performed in conjunction with the appropriate portions of the suppression pool cleanup system preop described in Subsection 14.2.12.1.20.

System operation is considered acceptable when the observed/measured performance characteristics, from the testing described above, meet the applicable design specifications.

14.2.12.1.22 Plant Process Sampling System Preoperational Test

(1) Purpose

To verify the proper operation and the accuracy of equipment and techniques to be used for on-line and periodic sampling and analysis of overall reactor water chemistry as well as that of individual plant process streams, including the post accident sampling system (PASS).

(2) Prerequisites

Construction tests have been successfully completed and the SCG has reviewed the test procedure and has approved the initiation of testing. Adequate laboratory facilities and appropriate analytical procedures shall be in place.

(3) General Test Methods and Acceptance Criteria

Performance shall be observed and recorded during as series of tests to demonstrate the following:

(a) proper operation of on-line sampling and monitoring equipment including calibration, indication, and alarm/ functions, including reactor water conductivity instrumentation;

calibration, indication, and alarms;

(b) the capability of obtaining grab samples of designated process streams at the desired locations;

(c) proper functioning of personnel protective devices at local sampling stations; and

(d) the adequacy and accuracy of sample analysis methods.

The above tests should be performed using actual process streams where practicable. System operation is considered acceptable when the observed/measured performance characteristics meet the applicable design specifications.

14.2.12.1.23 Process Radiation Monitoring System Preoperational Test

(1) Purpose

To verify the ability of the process radiation monitoring system (PRMS) to indicate and alarm normal and abnormal radiation levels, and to initiate, if appropriate, isolation and/or cleanup systems upon detection of high radiation levels in any of the process streams that are monitored.

(2) Prerequisites

The construction tests have been successfully completed and the SCG has reviewed the test procedure and has approved the initiation of testing. The various process radiation monitoring subsystems, including preamplifiers, power supplies, indicator and trip units, and sensors and converters, have been calibrated according to vendor instructions. The required interfacing systems shall be available, as needed, to support the specified testing.

(3) General Test Methods and Acceptance Criteria

The PRMS consists of a number of subsystems that monitor various liquid and gaseous process streams, building and area ventilation exhausts, and plant and process effluents. The offgas system and the main steam lines are also monitored.

Performance shall be observed and recorded during a series of individual component and integrated subsystem tests to demonstrate the following:

(a) proper calibration of detector assemblies and associated equipment using a standard radiation source or portable calibration unit;

(b) proper functioning of indicators, recorders, annunciators, and alarms;

(c) proper system trips in response to high radiation and downscale/inoperative conditions;

(d) proper operation of permissive, prohibit, interlock, and bypass functions; and

(e) proper operation of primary and backup sampling functions.

System operation is considered acceptable when the observed/measured performance characteristics, from the testing described above, meet the applicable design specifications.

14.2.12.1.24 Area Radiation Monitoring System Preoperational Test

(1) Purpose

To verify the ability of the area radiation monitoring (ARM) system to indicate and alarm normal and abnormal general area radiation levels throughout the plant.

(2) Prerequisites

The construction tests have been successfully completed and the SCG has reviewed the test procedure and has approved the initiation of testing. Indicator and trip units, power supplies, and sensor/converters have been calibrated according to vendor instructions.

(3) General Test Methods and Acceptance Criteria

Performance shall be observed and recorded during a series of individual component and integrated subsystem tests to demonstrate the following:

(a) proper calibration of detector assemblies and associated equipment using a standard radiation source or portable calibration unit;

(b) proper functioning of indicators, recorders, annunciators, and alarms;

(c) proper system trips in response to high radiation and downscale/inoperative conditions; and

(d) proper operation of permissive, prohibit, interlock, and bypass functions.

System operation is considered acceptable when the observed/measured performance characteristics, from the testing described above, meet the applicable design specifications.

14.2.12.1.25 Dust Radiation Monitoring System Preoperational Test

(1) Purpose

To verify the ability of the dust radiation monitoring system to indicate and alarm normal and abnormal airborne radiation levels throughout the plant.

(2) Prerequisites

The construction tests have been successfully completed and the SCG has reviewed the test procedure and has approved the initiation of testing. Additionally, indicator and trip units, power supplies, and sensor/converters have been calibrated according to vendor instructions.

(3) General Test Methods and Acceptance Criteria

Performance shall be observed and recorded during a series of individual component and integrated subsystem tests to demonstrate the following:

(a) proper calibration of detector assemblies and associated equipment using a standard radiation source or portable calibration unit;

(b) proper functioning of indicators, recorders, annunciators, and alarms;

(c) proper system trips in response to high radiation and downscale/inoperative conditions;

(d) proper operation of permissive, prohibit, interlock, and bypass functions; and

(e) proper operation of filtering and sampling equipment.

System operation is considered acceptable when the observed/measured performance characteristics, from the testing described above, meet the applicable design specifications.

14.2.12.1.26 Containment Atmospheric Monitoring System Preoperational Test

(1) Purpose

To verify the ability of the containment atmospheric monitoring system (CAMS) to monitor oxygen, hydrogen, and gross gamma radiation levels in the wetwell and drywell airspace regions of the primary containment.

(2) Prerequisites

The construction tests have been successfully completed and the SCG has reviewed the test procedure and has approved the initiation of testing. Initial system and component setup has been accomplished per vendor instructions.

(3) General Test Methods and Acceptance Criteria

The containment atmosphere monitoring system consists of radiation, oxygen, and hydrogen monitoring subsystems. Performance of each of these subsystems shall be observed and recorded during a series of individual component and integrated subsystem tests to demonstrate the following:

(a) proper calibration of detector assemblies and associated equipment using a standard source or portable calibration unit;

(b) proper functioning of indicators, recorders, annunciators, and alarms including those monitoring system availability;

(c) proper system trips in response to high setpoint and downscale/inoperative conditions;

(d) proper operation of permissive, prohibit, interlock, and bypass functions;

(e) proper initiation and operation of detection and sampling functions including pump start and valve sequencing, if appropriate, in response to a LOCA signal; and

(f) proper operation of calibration gas supply systems and self calibration functions.

System operation is considered acceptable when the observed/measured performance characteristics, from the testing described above, meet the applicable design specifications.

14.2.12.1.27 Instrument Air and Station Service Air Systems Preoperational Tests

(1) Purpose

To verify the ability of the instrument air and service air systems (IA and SA) to provide the design quantities of clean dry compressed air to user systems and components.

(2) Prerequisites

The construction tests have been successfully completed and the SCG has reviewed the test procedure and has approved the initiation of testing. Primary and backup electrical power, the supplied system and components loads, and other required system interfaces are available, as needed, to support the specified testing.

(3) General Test Methods and Acceptance Criteria

The instrument air system and the service air system are specified as separate systems. However, since they are so closely related the preop test requirements are essentially the same.

Performance shall be observed and recorded during a series of individual component and integrated system tests to demonstrate the following:

(a) proper operation of instrumentation and equipment in all combinations of logic and instrument channel trip;

(b) proper functioning of instrumentation and alarms used to monitor system operation and availability;

(c) proper operation of system valves, including timing, under expected operating conditions;

(d) proper operation of compressors and motors in all design operating modes;

(e) ability of compressor(s) to maintain receiver at specified pressure(s) and to recharge within specified time under design loading conditions;

(f) proper system flow paths and acceptable flow rates to individual loads at specified temperatures and pressures under design loading conditions, including leakage for the system, is in accordance with design;

(g) proper compressor start sequence (including load and unload) and margin to actuation of protective devices;

(h) proper operation of interlocks and equipment protective devices in compressor and valve controls;

(i) proper operation of permissive, prohibit, and bypass functions;

(j) proper system operation while powered from primary and alternate sources, including transfers, and in degraded modes for which the system is expected to remain operational;

(k) acceptability of compressor/motor vibration levels and system piping movements during both transient and steady state operation;

(l) the ability of the air to meet end use cleanliness requirements with respect to oil, water, and particulate matter content;

(m) continued operability of supplied loads in response to credible failures that result in an increase in the supply system pressure;

(n) proper "failure" (open, close, or as is) of supplied components to both instantaneous (pipe break) and slow (plugging or freezing) simulated air losses (per Regulatory Guide 1.68.3); and

(o) the ability of the service air system to act as backup to the instrument air system.

System operation is considered acceptable when the observed/measured performance characteristics, from the testing described above, meet the applicable design specifications.

14.2.12.1.28 High Pressure Nitrogen Gas Supply System Preoperational Test

(1) Purpose

To verify the ability of the high pressure nitrogen gas supply system (HPIN) to furnish compressed nitrogen gas to user systems at design quantity and quality.

(2) Prerequisites

The construction tests have been successfully completed and the SCG has reviewed the test procedure and has approved the initiation of testing. User system loads and other required system interfaces shall be available, as needed, to support the specified system testing.

(3) Test Methods and Acceptance Criteria

Performance shall be observed and recorded during a series of individual component and integrated system tests to demonstrate the following:

(a) proper operation of instrumentation and equipment in all combinations of logic and instrument channel trip;

(b) proper functioning of instrumentation and alarms used to monitor system operation and availability;

(c) proper operation of system valves, including timing, under expected operating conditions;

(d) ability to maintain receiver(s) at specified pressure(s) under design loading conditions;

(e) proper system flow paths and acceptable flow rates to individual loads at specified temperatures and pressures under design loading conditions;

(f) proper operation of interlocks and equipment protective devices;

(g) proper operation of permissive, prohibit, and bypass functions;

(h) proper system operation while powered from primary and alternate sources, including transfers, and in degraded modes for which the system is expected to remain operational;

(i) acceptability of vibration levels and system piping movements during both transient and steady state operation;

(j) the ability of the nitrogen gas to meet end use cleanliness requirements with respect to oil, water, and particulate matter content; and

(k) proper "failure" (open, close, or as is) of supplied components to both instantaneous (pipe break) and slow (plugging or freezing) simulated nitrogen gas supply losses (per Regulatory Guide 1.68.3).

System operation is considered acceptable when the observed/measured performance characteristics, from the testing described above, meet the applicable design specifications.

14.2.12.1.29 Reactor Building Cooling Water System Preoperational Test

(1) Purpose

To verify proper operation of the reactor building cooling water system (RCW) including its ability to supply design quantities of cooling water, at the specified temperatures, to essential and nonessential loads, as appropriate, during normal, abnormal, and accident conditions.

(2) Prerequisites

The construction tests have been successfully completed and the SCG has reviewed the test procedure and has approved the initiation of testing. Primary and backup power, reactor building service water, instrument air, and other required supporting systems shall be available, as needed, for the specified testing configurations. The coole ' components shall be operational and operating to the extent practicable during heat exchanger performance evaluation.

(3) General Test Methods and Acceptance Criteria

Performance shall be observed and recorded during a series of individual component and integrated system tests to demonstrate the following:

(a) proper operation of instrumentation and equipment in all combinations of logic and instrument channel trip;

(b) proper functioning of instrumentation and alarms used to monitor system operation and availability;

(c) proper operation of system valves, including timing, under expected operating conditions;

(d) proper operation of pumps and motors in all design operating modes;

(e) acceptable pump NPSH under the most limiting design flow conditions;

(f) proper system and component flow paths, flow rates, and pressure drops, including pump capacity and discharge head;

(g) proper pump motor start sequence and margin to actuation of protective devices;

(h) proper operation of interlocks and equipment protective devices in pump and valve controls;

(i) proper operation of permissive, prohibit, and bypass functions;

(j) proper system operation while powered from primary and alternate sources, including transfers, and in degraded modes for which the system is expected to remain operational. This includes isolation/shedding of nonessential loads and divisional interties when a LOCA signal is present;

(k) acceptability of pump/motor vibration levels and system piping movements during both transient and steady state operation;

(l) proper operation of system surge tanks and chemical addition tanks and their associated functions; and

(m) acceptable performance of heat exchangers, to the extent practical.

System operation is considered acceptable when the observed/measured performance characteristics, from the testing described above, meet the applicable design specifications. Due to the possibility of insufficient heat loads during the preop phase, the final system flow balancing and heat exchanger performance evaluation may need to be performed during the startup phase.

14.2.12.1.30 Plant Makeup Water System(s) Preoperational Test

(1) Purpose

To verify the ability of the plant make-up water system(s) to resupply the designated plant systems with water of the design quantity and quality for each such system.

(2) Prerequisites

The construction tests have been successfully completed and the SCG has reviewed the test procedure and has approved the initiation of testing. Final interconnection with the supplied systems is complete and those systems are ready to accept transfer of design quantities of makeup water.

(3) General Test Methods and Acceptance Criteria

System performance shall be observed and recorded during a series of individual component and integrated system tests to demonstrate the following:

(a) proper operation of instrumentation and equipment in all combinations of logic;

(b) proper functioning of instrumentation and alarms used to monitor system opera- tion and status;

(c) proper operation of pumps, motors, and valves under expected operating conditions;

(d) proper functioning of interlocks and equipment protective devices in pump, motor, and valve controls;

(e) the adequacy of system flow paths and flow rates including pump and tank capacities;

(f) proper functioning of chemical addition and water treatment facilities and equipment;

(g) proper functioning of freeze protection devices, if applicable; and

(h) acceptability of pump and motor vibration levels and system piping movements during both transient and steady state operations.

System operation is considered acceptable if the observed/measured performance characteristics meet the applicable design specifications.

14.2.12.1.31 Hot Water Heating System Preoperational Test

(1) Purpose

Verify the ability of the hot water heating system to provide hot water to the appropriate HVAC systems in order to maintain the specified design temperatures within the various building rooms and areas.

(2) Prerequisites

The construction tests have been completed and the SCG has reviewed the test procedure and has approved the initiation of testing. Electrical power, the appropriate heating source(s), the various HVAC systems heating coils, and other required interfacing systems shall be available, as needed, to support the specified testing.

(3) General Test Methods and Acceptance Criteria

Performance shall be observed and recorded during a series of individual component and integrated system tests to demonstrate the following:

(a) proper operation of instrumentation and equipment in all combinations of logic and instrument channel trip;

(b) proper functioning of instrumentation and alarms used to monitor system operation;

(c) proper operation of system valves under expected operating conditions;

(d) proper operation of pumps and motors in all design operating modes;

(e) acceptable pump NPSH under the most limiting design flow conditions;

(f) proper system flow paths and flow rates including pump capacity and discharge head;

(g) proper pump motor start sequence and margin to actuation of protective devices;

(h) proper operation of interlocks and equipment protective devices in pump, motor and valve controls;

(i) proper operation of permissive, prohibit, and bypass functions; and

(j) acceptability of pump/motor vibration levels and system piping movements during both transient and steady state operation.

System operation is considered acceptable when the observed/measured performance characteristics, from the testing described above, meet the applicable design specifications. It may not be possible to fully evaluate heat exchanger and heating coil performance during the preoperational test phase because of process temperature limitations.

14.2.12.1.32 HVAC Emergency Chilled Water System Preoperational Test

(1) Purpose

To verify the ability of the HVAC emergency chilled water system (HECW) to supply the design quantities of chilled water at the specified temperatures to the various cooling coils of the HVAC systems serving rooms and areas containing essential systems and equipment.

(2) Prerequisites

The construction tests have been successfully completed and the SCG has reviewed the test procedure and has approved the initiation of testing. Normal and auxiliary electrical power, reactor building cooling water, applicable HVAC system cooling coils, and other required system interfaces shall be available, as needed, to support the specified system testing.

(3) General Test Methods and Acceptance Criteria

Performance shall be observed and recorded during a series of individual component and integrated system tests to demonstrate the following:

(a) proper operation of instrumentation and equipment in all combinations of logic and instrument channel trip;

(b) proper functioning of instrumentation and alarms used to monitor system operation and availability;

(c) proper operation of system valves, including isolation functions, under expected operating conditions;

(d) proper operation of pumps and motors in all design operating modes;

(e) acceptable pump NPSH under the most limiting design flow conditions;

(f) proper system flow paths and flow rates to all supplied loads including pump capacity and discharge head;

(g) proper pump motor start sequence and margin to actuation of protective devices;

(h) proper operation of interlocks and equipment protective devices in pump and valve controls;

(i) proper operation of permissive, prohibit, and bypass functions;

(j) proper system operation while powered from primary and alternate sources, including transfers, and in degraded modes for which the system is expected to remain operational;

(k) acceptability of pump/motor vibration levels and system piping movements during both transient and steady state operation; and

(l) proper functioning of system surge tank and chemical addition features.

System operation is considered acceptable when the observed/measured performance characteristics, from the testing described above, meet the applicable design specifications.

14.2.12.1.33 HVAC Normal Chilled Water System Preoperational Test

(1) Purpose

To verify the ability of the HVAC normal chilled water system (HNCW) to supply the design quantities of chilled water at the specified temperatures to the various cooling coils of the HVAC systems serving rooms and areas containing nonessential equipment and systems.

(2) Prerequisites

The construction tests have been successfully completed and the SCG has reviewed the test procedure and has approved the initiation of testing. Primary and auxiliary electrical power, the associated cooling water system(s), the applicable HVAC system cooling coils, and other required system interfaces shall be available, as needed, to support the specified system testing.

(3) General Test Methods and Acceptance Criteria

Performance shall be observed and recorded during a series of individual component and integrated system tests to demonstrate the following:

(a) proper operation of instrumentation and equipment in all combinations of logic and instrument channel trip;

(b) proper functioning of instrumentation and alarms used to monitor system operation and availability;

(c) proper operation of system valves, including isolation functions, under expected operating conditions;

(d) proper operation of pumps and motors in all design operating modes;

(e) acceptable pump NPSH under the most limiting design flow conditions;

(f) proper system flow paths and flow rates to all supplied loads including pump capacity and discharge head;

(g) proper pump motor start sequence and margin to actuation of protective devices;

(h) proper operation of interlocks and equipment protective devices in pump and valve controls;

(i) proper operation of permissive, prohibit, and bypass functions;

(j) proper system operation while powered from primary and alternate sources, including transfers, and in degraded modes for which the system is expected to remain operational;

(k) acceptability of pump/motor vibration levels and system piping movements during both transient and steady state operation; and

(l) proper functioning of system surge tank and chemical addition features.

System operation is considered acceptable when the observed/measured performance characteristics, from the testing described above, meet the applicable design specifications.

14.2.12.1.34 Heating, Ventilation, and Air Conditioning Systems Preoperational Test

(1) Purpose

To verify the ability of the various HVAC systems to establish and maintain the specified environment, with regards to temperature, pressure, and airborne particulate level, in the applicable rooms, areas, and buildings throughout the plant, supporting essential and nonessential equip- ment and systems.

(2) Prerequisites

The construction tests, including initial flow balancing, have been successfully completed and the SCG has reviewed the test procedure(s) and has approved the initiation of testing. Additionally, the normal and backup electrical power sources, the applicable heating, cooling, and chilled water systems, and any other required system interfaces shall be available, as needed, to support the specified testing.

(3) General Test Methods and Acceptance Criteria

There are numerous HVAC systems in the plant, located throughout the various buildings. Each system typically consists of some combination of supply and exhaust air handling units and local cooling units, and the associated fans, dampers, valves, filters, heating and cooling coils, and control and instrumentation. The HVAC systems to be tested shall include the following: those supporting the reactor building rooms containing the emergency diesel generators and the ECCS pumps and heat exchangers; those serving the electrical equipment rooms of the control building; those supporting the divisional cooling water rooms; those supporting the turbine/generator auxiliaries, those serving the secondary containment and the general areas of the control building, reactor building and turbine building; and the dedicated systems of the drywell and the main control room (including the control room habitability function).

Since the various HVAC systems are similar in design of equipment and function, they are subject to the same basic testing requirements.

Performance shall be observed and recorded during a series of individual component and integrated system tests to demonstrate the following:

(a) proper operation of instrumentation and equipment in all combinations of logic and instrument channel trip;

(b) proper functioning of instrumentation and alarms used to monitor system operation and availability;

(c) proper operation of system valves and dampers, including isolation functions, under expected operating conditions;

(d) proper operation of fans and motors in all design operating modes;

(e) proper system flow paths and flow rates including individual component and total system capacities and overall system flow balancing;

(f) proper operation of interlocks and equipment protective devices;

(g) proper operation of permissive, prohibit, and bypass functions;

(h) proper system operation while powered from primary and alternate sources, including transfers, and in degraded modes for which the system is expected to remain operational;

(i) the ability to maintain the specified positive or negative pressure(s) in the designated rooms and areas and to direct local and total air flow, including any potential leakage, relative to the anticipated contamination levels;

(j) the ability of exhaust, supply, and recirculation filter units to maintain the specified dust and contamination free environment(s);

(k) the ability of the control room habitability function to detect the presence of smoke and\or toxic gas and to remove or prevent in-leakage of such;

(l) proper operation of HEPA filters and charcoal adsorber sections, if applicable, including relative to the in-place testing requirements of Regulatory Guide 1.140 regarding visual inspections and airflow distribution, DOP penetration and bypass leakage testing;

(m) the ability of the heating and cooling coils to maintain the specified thermal environment(s) while considering the heat loads present during the preop test phase; and

(n) the ability of primary and secondary containment HVAC systems to provide sufficient purge, exhaust, and recirculation flows in support of drywell inerting and deinerting operations.

System operation is considered acceptable when the observed/measured performance characteristics, from the testing described above, meet the applicable design specifications.

14.2.12.1.35 Atmospheric Control System Preoperational Test

(1) Purpose

To verify the ability of the atmospheric control system (ACS) to establish and maintain the specified inert atmosphere in the primary containment during all expected plant conditions.

(2) Prerequisites

The construction tests have been successfully completed and the SCG has reviewed the test procedure and has approved the initiation of testing. The primary and secondary containments are intact, their HVAC systems operational, and all other required interfaces available, as needed, to support the specified testing.

(3) General Test Methods and Acceptance Criteria

Performance shall be observed and recorded during a series of individual component and integrated system tests to demonstrate the following:

(a) proper operation of instrumentation and equipment in all combinations of logic;

(b) proper functioning of instrumentation and alarms used to monitor system operation and availability;

(c) proper operation of system valves, including timing, under expected operating conditions;

(d) proper nitrogen/air flow paths and flow rates both into and out of the primary containment;

(e) proper operation of interlocks and equipment protective devices;

(f) proper operation of permissive, prohibit, and bypass functions; and

(g) proper system operation while powered from primary and alternate sources, including transfers, and in degraded modes for which the system is expected to remain operational.

System operation is considered acceptable when the observed/measured performance characteristics, from the testing described above, meet the applicable design specifications.

14.2.12.1.36 Standby Gas Treatment System Preoperational Test

(1) Purpose

To verify the ability of the standby gas treatment system (SGTS) to establish and maintain a negative pressure within the secondary containment and to adequately filter the resultant exhaust air flow.

(2) Prerequisites

The construction tests have been successfully completed and the SCG has reviewed the test procedure and has approved the initiation of testing. The primary and secondary containments are intact and the appropriate interfacing systems are available as required to support the specified testing.

(3) General Test Methods and Acceptance Criteria

Performance shall be observed and recorded during a series of individual component and integrated system tests to demonstrate the following:

(a) proper operation of instrumentation and equipment in all combinations of logic and instrument channel trip;

(b) proper functioning of instrumentation and alarms used to monitor system operation and availability;

(c) proper operation of system valves and dampers, including timing, under expected operating conditions;

(d) proper operation of exhaust fans in all design operating modes;

(e) efficiency of HEPA filters and leak

tightness of charcoal adsorber section per Regulatory Guide 1.5;

(f) proper system and component flow paths and flow rates including overall system flow balance;

(g) ability to maintain the specified negative pressure in the secondary containment;

(h) proper operation of interlocks and equipment protective devices;

(i) proper operation of permissive, prohibit, and bypass functions;

(j) proper operation of heaters, demister, and moisture seperator equipment; and

(k) proper system operation while powered from primary and alternate sources, including transfers, and in degraded modes for which the system is expected to remain operational.

Refer also to Subsection 6.5.1.4.1.

System operation is considered acceptable when the observed/measured performance characteristics, from the testing described above, meet the applicable design specifications.

14.2.12.1.37 Containment Isolation Valve Leakage Rate Tests

Description of and criteria for preoperational leakage rate tests of containment isolation valves are given in Subsection 6.2.6.3.

14.2.12.1.38 Containment Penetration Leakage Rate Tests

Description of and criteria for preoperational leakage rate tests of containment penetrations are given in Subsection 6.2.6.2.

14.2.12.1.39 Containment Airlock Leakage Rate Tests

Description of and criteria for preoperational leakage rate tests of containment airlocks are given in Subsection 6.2.6.2.

14.2.12.1.40.1 Containment Integrated Leakage Rate Test

Description of and criteria for containment integrated leakage rate tests are given in Subsection 6.2.6.1.

14.2.12.1.40.2 Containment Structural Integrity Test

Description of and criteria for the required containment structural inetgrity test is given in Suibsection 3.8.1.7.1.

14.2.12.1.41 Pressure Suppression Containment Bypass Leakage Tests

Test procedures are indentical to those used for other penetrations under isolation conditions as discussed in Subsection 6.2.6.2.

14.2.12.1.42 Containment Isolation Valve Functional and Closure Timing Tests

Preoperational functional and closure timing tests of containment isolation valves is discussed in Subsection 6.2.4.

14.2.12.1.43 Wetwell-to-Drywell Vacuum Breaker System Preoperational Test

(1) Purpose

To verify proper functioning of the wetwell-to-drywell vacuum breakers.

(2) Prerequisites

The construction tests have been successfully completed and the SCG has reviewed the test procedure and has approved the initiation of testing.

(3) General Test Methods and Acceptance Criteria

Performance shall be observed and recorded during a series of individual component and integrated system tests to demonstrate the following:

(a) proper operation of vacuum breaker valves and system logic including verification of opening and closing setpoints and timing;

(b) proper operation of instrumentation and alarms used to monitor system operation and status, such as valve position indication, including verification of operability during loss of preferred power conditions

(c) proper functioning of valve positive closure devices including verification of adequate valve leak tightness; and

(d) proper functioning of vacuum breaker test features.

System operation is considered acceptable when the observed/measured performance characteristics meet the applicable design specifications.

14.2.12.1.44 Primary Containment Monitoring Instrumentation Preoperational Test

(1) Purpose

To verify the proper operation of instrumentation used for long term monitoring of the drywell and wetwell atmospheres and suppression pool temperature and level during both normal operations and accident conditions in the primary containment.

(2) Prerequisites

The construction tests have been successfully completed and the SCG has reviewed the test procedure and has approved the initiation of testing. The suppression pool shall be filled and expected to undergo measurable level and temperature changes at some point during the scheduled testing. The required interfacing systems and components are available, as needed, to support the specified testing. Additionally, any parallel testing to be performed in conjunction with the testing of this subsection is appropriately scheduled.

(3) General Test Methods and Acceptance Criteria

A description of the instrumentation required for containment monitoring is presented in Subsection 6.2.1.7. Preoperational testing of these instruments will be performed in conjunction with the testing of the applicable systems. Only that instrumentation requiring special considerations is discussed below.

Performance shall be observed and recorded during a series of individual component and integrated system tests to demonstrate the following:

(a) proper tracking of drywell pressure by all instrument channels during containment integrated leak rate testing;

(b) proper response of all suppression pool level instrumentation during actual changes in pool level;

(c) proper tracking by all suppression pool temperature instrument channels of an actual change in pool temperature;

(d) proper functioning of associated indicators, recorders, annunciators, and alarms including those monitoring instrumentation status; and

(e) proper system trips in response to the appropriate high and/or low setpoints and inoperative conditions.

System operation is considered acceptable when the observed/measured performance characteristics, from the testing described above, meet the applicable design specifications.

14.2.12.1.45 Electrical Systems Preoperational Test

The total plant electrical distribution network is described in Chapter 8 and is comprised of the following systems:

(1) unit auxillary AC power system;
(2) unit Class 1E AC power system;
(3) safety system logic and control system power system;
(4) instrument power system;
(5) uninterruptible power system;
(6) unit auxillary DC power system; and
(7) unit class 1E DC power system.

Because of the similarities in their design and function, the testing requirements for these systems, and their respective components, can be divided into the four general categories as described below. The specific testing required for each system is described in the applicable design and testing specifications.

14.2.12.1.45.1 DC Power Supply System Preoperational Test

(1) Purpose

To verify the ability of DC power supply systems to supply highly reliable, uninterruptable power for instrumentation, logic, control, lighting and other normal and emergency loads that must remain operational during and after a loss of AC power.

(2) Prerequisites

The construction tests have been successfully completed and the SCG has reviewed the test procedures and has approved the initiation of testing. All interfacing systems and equipment required to support system operation shall be available, as needed, for the specified testing configurations.

(3) General Test Methods and Acceptance Criteria

The DC power supply systems consist of essential and nonessential equipment, including batteries, battery chargers, inverters, static transfer switches, and associated instrumentation and alarms, that is used to supply both normal and emergency loads. Performance shall be observed and recorded during a series of individual component and integrated systems tests to demonstrate the following:

(a) capability of each battery bank to supply its design load for the specified time without the voltage dropping below minimum battery or cell limits;

(b) capability of each battery charger to fully recharge its associated battery (or bank), from the discharged state, within the specified time while simultaneously supplying the specified loads;

(c) verification that actual loading of each DC bus is consistent with battery sizing assumptions;

(d) verification that each DC bus meets the specified level of redundancy and electrical independence for its particular application;

(e) proper functioning of transfer devices, breakers, cables and inverters (including load capability);

(f) proper calibration and trip settings of protective devices, including relaying, and proper operation of permissive and prohibit interlocks;

(g) proper operation of instrumentation and alarms associated with under voltage, over voltage, and ground conditions; and

(h) proper operation of emergency DC lighting, including capacity of self contained batteries.

14.2.12.1.45.2 Emergency AC Power Distribution System Preoperational Test

(1) Purpose

To verify the ability of the Class 1E AC power distribution system to provide both manual and fully automatic means for supplying and regulating AC power to safety equipment, from both offsite and onsite sources, via independent distribution subsystems for each redundant Class 1E load group.

(2) Prerequisites

The construction tests have been successfully completed and the SCG has reviewed the test procedure and has approved the initiation of testing. All interfacing systems and equipment required to support system operation shall be available, as needed, for the specified testing configurations.

(3) General Test Methods and Acceptance Criteria

The Class 1E AC power distribution system is comprised of the equipment required for transformation, conversion, and regulation of voltage to the essential busses, the switchgear and motor control required for the individual loads served, and the coordinated system protective relaying. Performance shall be observed and recorded during a series of individual component and integrated system tests to demonstrate the following:

(a) proper operation of initiating, transfer, and trip devices;

(b) proper operation of relaying and logic, including load shedding features;

(c) proper operation of equipment protective devices, including permissive and prohibit interlocks;

(d) proper operation of instrumentation and alarms used to monitor system and equipment status (including availability);

(e) proper operation and load carrying capability of breakers, motor controllers, switchgear, transformers, and cables;

(f) that a sufficient level of redundancy and electrical independence exists as specified for each application;

(g) the capability to transfer between onsite and offsite power sources as per design;

(h) the ability of emergency and vital loads to start in the proper sequence and to operate properly under simulated accident conditions, while powered from either preferred or standby sources, and over the specified range of available bus voltage; and

(i) the adequacy of the plant emergency and essential lighting systems.

14.2.12.1.45.3 Emergency Diesel Generator Preoperational Test

(1) Purpose

To demonstrate the capability of the emergency diesel generators to provide highly reliable emergency electrical power during normal and simulated accident conditions when normal offsite power sources are unavailable, and to demonstrate the operability of the diesel generator auxiliary systems, e.g., diesel fuel oil transfer, diesel-generator starting air supply, jacket water, and lube oil.

(2) Prerequisites

The construction tests have been successfully completed and the SCG has reviewed the test procedure and has approved the initiation of testing. All interfacing systems and equipment required to support system operation shall be available, as needed, for the specified testing configuration. Additionaly, sufficient diesel fuel shall be available, on site or readily accessible, site to perform the scheduled tests.

(3) General Test Methods and Acceptance Criteria

Performance shall be observed and recorded during a series of individual component and integrated system tests to demonstrate the following:

(a) proper automatic startup and operation of the diesel generators upon simulated loss of a-c voltage and attainment of the required frequency and voltage within the specified time limits;

(b) proper response and operation for design-basis accident loading sequence to design-basis load requirements, and verification that voltage and frequency are maintained within specified limits;

(c) proper operation of the diesel generators during load shedding, load sequencing, and load rejection, including a test of the loss of the largest single load and of the complete loss of load, verifying that voltage and frequency are maintained within design limits and that overspeed limits are not exceeded;

(d) that a LOCA signal will block generator breaker or field tripping by all protective relays except for the generator phase differential current and engine overspeed relays;

(e) that a LOCA signal will initiate termination of parallel operations (test or manual transfer) and that the diesel generator will continue to run unloaded and available;

(f) that the engine speed governor and the generator voltage regulator automatically return to an isochronous (constant speed) mode of operation upon initiation of a LOCA signal;

(g) full-load carrying capability of the diesel generators for a period of not less than 24 hours, of which 22 hours are at a load equivalent to the continuous rating of the diesel generator and 2 hours are at the 2-hour load rating as described in Reg Guide 1.108 including verification that the diesel cooling systems function within design limits, and the diesel generator HVAC system maintains the diesel generator room within design limits;

(h) functional capability at operating temperature conditions by reperforming the tests in (a) and (b) above immediately after completion of the 24-hour load test per (g) above;

(i) the ability to synchronize the diesel generators with offsite power while connected to the emergency load, transfer the load from the diesel generators to the offsite power, isolate the diesel generators, and restore them to standby status;

(j) that the rate of fuel consumption and the operation of any fuel oil supply pumping or transfer devices, while operating at the design-basis accident load, are such that the requirements for 7-day storage inventory are met for each diesel generator;

(k) that all permissive and prohibit interlocks, controls, and alarms (both local and remote) operate in accordance with design specifications;

(l) acceptable diesel generator reliability during starting and loading sequences as described in Reg. Guide 1.108;

(m) proper operation and correct setpoints for initiating and trip devices and verification of system logic not tested otherwise; and

(n) proper operation of auxiliary systems such as those used for starting, cooling, heating, ventilating, lubricating, and fueling the diesel generators.

14.2.12.1.45.4 Normal AC Power Distribution System Preoperational Test

(1) Purpose

To verify the ability of the normal AC power distribution system to provide a means for supplying AC power to nonessential equipment, from both onsite and offsite sources, via the appropriate distribution network(s).

(2) Prerequisites

The construction tests have been successfully completed and the SCG has reviewed the test procedure and has approved the initiation of testing. All interfacing systems and equipment required to support system operation shall be available, as needed, for the specified testing configurations.

(3) General Test Methods and Acceptance Criteria

The normal AC power distribution system is comprised of the equipment used for transformation, conversion, regulation, and distribution of voltage to plant nonessential equipment during normal operation. Performance shall be observed and recorded during a series of individual component and integrated system tests to demonstrate the following:

(a) proper operation of initiating, transfer, and trip devices;

(b) proper operation of relaying and logic, including load shedding features;

(c) proper operation of equipment protective devices, including permissive and prohibit interlocks;

(d) proper operation of instrumentation and alarms used to monitor system and equipment status;

(e) proper operation and load carrying capability of breakers, motor controllers, switchgear, transformers, and cables;

(f) sufficient level of redundancy and electrical independence as specified for each application; and

(g) the capability to transfer between onsite and offsite power sources as per design.

Performance of each of the various plant electrical systems is considered acceptable when the testing described above demonstrates that the requirements of the applicable design and testing specifications have been met.

14.2.12.1.46 Integrated ECCS Loss of Offsite Power (LOP)/LOCA Preoperational Test

(1) Purpose

To verify the proper integrated ECCS and plant electrical system response to a simulated LOP/LOCA condition and to verify the independence of the redundant onsite divisional power sources and their associated load groups.

(2) Prerequisites

The preoperational tests of the plant electrical system, including diesel generators, and the ECCS and related auxiliary systems, have been successfully completed. The reactor vessel shall be ready to accept design ECCS injection flow, all ECCS pumps shall have an adequate suction source, the diesel generators shall have sufficient fuel available, and essential DC power shall be available. All other required systems shall also be available, as needed, to support the specified integrated testing.

(3) General Test Methods and Acceptance Criteria

For each combination of divisional load groups, two at a time (A and B, B and C, A and C), with the other divisional load group completely isolated from both onsite and offsite power sources (including DC sources), simulate a divisional bus under-voltage condition (LOP) followed immediately by a LOCA signal and verify the following:

(a) that the appropriate divisional diesel generators automatically start, reach rated speed and voltage, and connect to their respective divisional buses according to design and within the specified time;

(b) that all relaying and interlocks related to the LOP/LOCA condition operate properly including the specified shedding and sequencing of sources and loads;

(c) that all divisional loads operate as designed in response to the LOP/LOCA condition, including establishment of the appropriate divisional ECCS flow to the vessel within the specified time; and

(d) that all loads and electrical busses associated with the isolated divisional load group remain deenergized.

The test of each combination shall be of sufficient duration to allow establishment of stable operating conditions such that any adverse conditions which might result from improper load group assignment (e.g., lack of forced cooling of a vital component or system) would be detected.

After the proper response of each divisional combination has been separately demonstrated the integrated response of all ECCS and electrical divisions shall be demonstrated by simulating a complete loss of offsite power and LOCA condition and then verifying items (a) through (d) above for all three diesel generators and load groups as they respond and operate simultaneously.

Performance is acceptable when the above testing demonstrates that the applicable design specifications have been met.

14.2.12.1.47 Plant Communications System Preoperational Test

(1) Purpose

To verify the proper operation and adequacy of all plant communications systems and methods that will be used during normal and abnormal operations including those needed to carry out the plant emergency plan.

(2) Prerequisites

The construction tests have been successfully completed and the SCG has reviewed the test procedure and has approved the initiation of testing. Initial system and component settings (gains, volumes, etc.) shall be consistent with expectations of the acoustic environment and background noise levels for each location and for all modes of operation.

(3) General Test Methods and Acceptance Criteria

The communications systems to be tested include the plant PA system, all hardwired systems within the plant, portable radio systems to be used within the plant boundary, normal and dedicated communications links to outside agencies, and the plant emergency alarms. Performance shall be observed and recorded during a series of individual component and integrated system tests to demonstrate the following:

(a) proper functioning of all transmitters and receivers without excessive interference levels;

(b) proper operation of all controls, switches, and interfaces including silencing and muting features;

(c) proper isolation and independence of various channels and systems;

(d) proper operation of systems under multiple user and fully loaded conditions as per design;

(e) proper operation of plant emergency alarms;

(f) audibility of speakers and receivers under anticipated background noise levels;

(g) the ability to establish the required communications with outside agencies; and

(h) proper functioning of dedicated use systems and of those systems expected to function under abnormal conditions such as loss of electrical power or shutdown from outside the control room scenarios.

System operation is considered acceptable when the observed/measured performance characteristics meet the applicable design specifications.

14.2.12.1.48 Fire Protection System Preoperational Test

(1) Purpose

To verify the ability of the fire protection system to detect and alarm the presence of combustion, smoke or fire within the plant and to initiate the appropriate suppression systems or devices.

(2) Prerequisites

The construction tests have been successfully completed and the SCG has reviewed the test procedure and has approved the initiation of testing. The required electrical power and make-up water sources, and other appropriate interfaces and support systems, are available as needed for the specified testing.

(3) General Test Methods and Acceptance Criteria

The fire protection system is but one part of the overall fire protection program. This program is the integrated effort involving components, procedures, and personnel utilized in carrying out all activities of fire protection, in accordance with Criterion 3 of 10CFR50, Appendix A. It includes systems and components, facility design, fire prevention, detection, annunciation, confinement, suppression, administrative controls, fire brigade organization, training, quality assurance, inspection, testing, and maintenance. The fire protection program begins with the initial design of all plant systems and equipment and of the buildings and structures in which they are located. A detailed analysis is then performed on this design to identify, qualify, and quantify all potential fire hazards, and their consequences, within the plant. Specific fire protection equipment is then added, where needed, when individual component design and features such as physical separation, walls, doors, and other barriers and passive devices, do not completely fulfill the requirements of the fire protection program.

The majority of the effort involved in demonstrating that the requirements of the overall fire protection program are met will be through analysis and documentation. Preoperational testing of the fire protection system will mainly be limited to the equipment and facilities designed for the detection, annunciation, and suppression of fires. This testing shall include the following demonstrations:

(a) proper operation of instrumentation and equipment in all combinations of logic and control;

(b) proper functioning of prohibit and permissive interlocks and equipment protective devices;

(c) proper operation of system valves, pumps, and motors under expected operating conditions;

(d) proper system and component flow paths, flow rates and capacities;

(e) proper operation of water based suppression systems such as spray, sprinkler, deluge, and hose devices and of other suppression systems such as those utilizing halon, carbon dioxide, foams and dry chemicals, including both manually and automatically actuated systems;

(f) proper operation of freeze protection devices, if applicable;

(g) proper functioning of smoke, heat and flame detection devices;

(h) proper operation of both local and remote alarms including those interfacing with outside agencies; and

(i) proper operation of primary and secondary electrical power sources including fire protection system diesel generators.

System operation is considered acceptable when the observed and measured performance characteristics, from the testing described above, meet the applicable design specifications.

14.2.12.1.49 Radioactive Liquid Drainage and Transfer Systems Preoperational Tests

(1) Purpose

To verify the proper operation of the various equipment and pathways which make up the radioactive liquid drainage and transfer system within the Nuclear Island.

(2) Prerequisites

The construction tests have been successfully completed and the SCG has reviewed the test procedure(s) and has approved the initiation of testing. An adequate supply of demineralized water, the necessary electrical power, and other required interfacing systems shall be available, as needed, to support the specified testing.

(3) General Test Methods and Acceptance Criteria

The testing described below consists of that of the equipment and pathways for the drainage and transfer of radioactive and potentially radioactive liquids within the plant. Also included are dedicated systems for the handling of liquids that require special collection and disposal considerations such as detergents.

Performance shall be observed and recorded during a series of individual component and integrated system tests to demonstrate the following:

(a) proper operation of equipment controls and logic including prohibit and permissive interlocks;

(b) proper operation of equipment protective features and automatic isolation functions;

(c) proper functioning of instrumentation and alarms used to monitor system operation and status;

(d) acceptable system and component flow paths and flow rates including pump capacities and sump or tank volumes;

(e) proper operation of system pumps, valves, and motors under expected operating conditions;

(f) proper functioning of drains and sumps including those dedicated for handling of specific agents such as detergents; and

(g) proper calibration and operation of radiation detectors and monitors.

System operation is considered acceptable when the observed and measured performance characteristics, from the testing described above, meet the applicable design specifications.

14.2.12.1.50 Fuel-Handling and Reactor Component Servicing Equipment Preoperational Test

(1) Purpose

To verify proper operation of the fuel handling and reactor component servicing equipment. This includes cranes, hoists, grapples, trolleys, platforms, hand tools, viewing aids, and other equipment used to lift, transport, or otherwise manipulate fuel, control rods, neutron instrumentation, and other in-vessel, under-vessel, and drywell components. Also included is equipment needed to lift and relocate structures and components necessary to provide access to fuel, vessel internals, and reactor components during the refueling and servicing operations.

(2) Prerequisites

The construction tests have been successfully completed and the SCG has reviewed the test procedure and has approved the initiation of testing. The required electrical power sources and sufficient lighting shall be available under-vessel, in the drywell, and on the refueling floor. The refueling floor (including the upper pools and reactor cavity) and drywell and under-vessel areas shall be capable of supporting load and travel testing of the various cranes, bridges, and hoists. Other interfacing systems shall be available as required to support the specified testing.

(3) General Test Methods and Acceptance Criteria

Fuel handling and reactor component servicing equipment testing described herein includes that of the reactor building crane, refueling bridge, auxiliary platform, and the associated hoists and grapples, as well as other lifting and rigging devices. Also included are specialized hand tools and viewing aids. Fuel pool cooling and cleanup functions are tested as described in Subsection 14.2.12.1.21. The HVAC systems serving the refueling floor and drywell are tested as described in Subsection 14.2.12.1.34.

Performance shall be observed and recorded during a series of individual component and integrated system tests to demonstrate the following:

(a) proper operation for each crane, bridge, trolley, or platform through its full travel and at up to its maximum speed including verification of braking action and overspeed or overtravel protection devices;

(b) proper operation of the various cables, grapples, and hoists including brakes, limit switches, load cells, and other equipment protective devices;

(c) proper functioning of all control, instrumentation, logic, interlocks and alarms;

(d) proper functioning of other fuel handling and reactor component servicing equipment such as that used for cell disassembly, channel replacement, instrument handling, CRD handling, RIP servicing, SRV and MSIV maintenance, pool and vessel vacuum cleaning, and for underwater lighting and viewing.

(e) proficiency in fuel movement operations using dummy fuel (prior to actual fuel loading); and

(f) dynamic and static load testing of all cranes, hoists, and associated lifting and rigging equipment including static load testing at 125% of rated load and full operational testing at 100% of rated load.

System and component operation is considered acceptable when observed and measured performance characteristics from the testing described above meet the applicable design specifications.

14.2.12.1.51 Expansion, Vibration and Dynamic Effects Preoperational Test

(1) Purpose

To verify that critical components and piping runs are properly designed and supported such that expected steady state and transient vibration and movement due to thermal expansion does not result in excessive stress or fatigue to safety related plant systems and equipment.

(2) Prerequisites

All piping and components and their associated supports and restraints have been inspected and determined to be installed per design. Additionally, support devices such as snubbers and spring cans have been verified to be in their expected cold, static positions and temporary restraining devices such as hanger locking pins have been observed to be removed.

(3) General Test Method and Acceptance Criteria

Vibration and thermal expansion testing will be conducted on plant systems and components of the following classifications:

(a) ASME Code Class 1,2 and 3 systems;

(b) high energy piping systems inside Seismic Category 1 structures;

(c) high energy portions of systems whose failure could reduce the functioning of any Seismic Category 1 plant features to an unacceptable level; and

(d) Seismic Category 1 portions of moderate energy piping systems located outside containment.

Thermal expansion testing during the preoperational phase will be limited to those systems that are expected to be heated up significantly above their normal ambient temperatures. The testing will be in conformance with ANSI/ASME-OM7 as discussed in Subsection 3.9.2.1.2, and will consist of a combination of visual inspections and local and remote displacement measurements. This testing, as well as that performed during the power ascension phase per Subsection 14.2.12.2.10, includes the inspection and testing of RCPB component supports as described in Subsection 5.4.14.4. Visual inspections are performed to identify actual or potential constraints to free thermal growth. Displacement measurements will be made utilizing specially installed instrumentations and also using the position of supports such as snubbers. Results of the thermal expansion testing are acceptable when all systems move as predicted and there are no observed restraints to free thermal growth or when additional analysis shows that any unexpected results will not produce unacceptable stress values.

Vibration testing will be performed on system components and piping during preoperational function and flow testing. This testing will be in accordance with ANSI/ASME-OM3 as discussed in Subsection 3.9.2.1.1 and will include visual observation and local and remote monitioring in critical steady state operating modes and during transients such as pump starts and stops, valve stroking, and significant process flow changes.

Results are acceptable when visual observations show no signs of excessive vibration and when measured vibration amplitudes are within acceptable levels to assure no failures from fatigue over the life of the plant as calculated based on expected steady state and transient operation.

14.2.12.1.52 Reactor Vessel Flow-Induced Vibration Preoperational Test

(1) Purpose

To collect information needed to verify the adequacy of the reactor internals design, manufacture, and assembly with respect to the potential effects of flow induced vibration. Instrumentation of major components and the flow tests and inspections will provide assurance that excessive vibration amplitudes, if they exist, will be detected at the earliest possible time. The data collected will also help establish the margin to safety associated with steady state and anticipated transient conditions and will help confirm the pretest analytical vibration calculations. This testing will fulfill the preoperational requirements of Regulatory Guide 1.20 for a vibration measurement and inspection program for prototype reactor internals,and applies only to the ABWR designated for testing of "prototype" reactor internals. Subsequent ABWRs, whose internals qualify as non-prototype, are subject to a reduced set of testing requirements in accordance with Regulatory Guide 1.20 as discussed in Subsections 3.9.2.4 and 3.9.7.1.

(2) Prerequisites

The initial vibration analysis computations and specification of acceptance criteria shall be complete. These results shall be utilized to define final inspection and measurement programs. Preoperational testing of the recirculation system shall be sufficiently complete to ensure safe operation of the reactor internal pumps at rated volumetric flow for the duration of the scheduled flow testing. This includes all required auxiliary systems. All reactor vessel components and structures shall be installed and secured as designed in expectation of being subjected to rated volumetric core flow. This includes the steam separator assembly and reactor vessel head but excludes the steam dryer. Also, during the flow testing, the control blades shall either be removed or be fully withdrawn and motion inhibited. The assembly and disassembly of vessel internals shall be choreographed such that structures and components requiring inspection are accessible at the proper times. The required sensors shall be installed and calibrated prior to the flow testing. All other systems, components, and structures shall be available, as required, to support the reactor vessel internals vibration assessment program.

(3) General Test Methods and Acceptance Criteria

The reactor internals vibration assessment program consists of three parts: a vibration analysis program, a vibration measurement program, and an inspection program. The vibration analysis portion is performed on the final design, prior to the preoperational test, and the results are used to develop the measurement and inspection portions of the program. The preoperational test therefore consists of an instrumented flow test and pre-and post-test inspections as described in the following paragraphs:

(a) Pre-flow Vessel Inspection

The preflow inspection is performed primarily to establish and document the status of vessel internal structures and components. Some of the inspection requirements may be met by normal visual fabrication inspections. The majority of the inspection requirements will be met by visual and remote observations of the installed reactor internals in a flushed and drained vessel. The following types of structures and components shall be included in the vessel internals inspection program:

(1) major load bearing elements including lateral, vertical and torsional supports;

(2) locking and bolting components whose failure could adversely affect structural integrity;

(3) known or potential contact surfaces;

(4) critical locations as identified by the vibration analysis program; and

(5) interior surfaces for evidence of loose parts or foreign material.

(b) Flow testing

The preoperational flow test will be performed at rated volumetric core flow with the vessel internals completely intact with the exception of the fuel bundles, the control blades (unless fully withdrawn), and the steam dryer assembly. A post fuel load, subcritical flow test will be performed later on the complete reactor assembly unless it is shown analytically or experimentally that the preoperational results are already conservatively bounding. Additionally internals vibration will be measured during individual component or system preoperational testing where operation my result in significant vibrational excitation of reactor internals, such as HPCF testing.

The duration of preoperational testing at the various flow configurations shall ensure that each critical component is subjected to at least 10^6 cycles of vibration, as calculated using the lowest frequency for which the component is expected to experience a significant structural response.

(c) Post Flow Vessel Inspection

The post flow inspection shall be performed after the resultant vibrational excitation from the preoperational flow testing described above. The structures and components inspected shall be the same as specified for the preflow inspection. Visual and remote observations are performed after the vessel has been depressurized and drained. Inspection of critical surfaces and components shall be performed prior to any disassembly required for access to other internal structures.

(d) Acceptance Criteria

The acceptance criteria are generated as part of the analytical portion of the program in terms of maximum vibrational response levels of overall structures and components and translated to specific sensor locations.

Reactor vessel internals vibration is considered acceptable when results of the measurement program correlate and compare favorably with those of the analysis program, and, when the results of the inspections show no signs of defects, loose parts, extraneous material, or excessive wear due to flow testing, and are consistent with the results obtained from the analysis and measurement programs.

14.2.12.1.53 Condensate and Feedwater Systems Preoperational Test

(1) Purpose

To verify proper operation of the various components that comprise the condensate and feedwater systems and their capability to deliver the required flow from the condenser hotwell to the nuclear boiler system.

(2) Prerequisites

The construction tests have been successfully completed and the SCG has reviewed the test procedure(s) and has approved the initiation of testing. The required interfacing systems shall be available as needed, to support the specified testing. For all flow testing their shall be an adequate suction source available and an appropriate flow path established.

(3) General Test Methods and Acceptance Criteria

Preoperational testing of the condensate and feedwater systems will include the piping, components, and instrumentation between the condenser and the nuclear boiler but not the condensate filters or demineralizers nor the feedwater heaters, which will be tested separately per the specific discussions provided for those features.

Performance shall be observed and recorded during a series of individual component and integrated system tests to demonstrate the following:

(a) proper operation of instrumentation and equipment in all combinations of logic and instrument channel trip;

(b) proper functioning of instrumentation and alarms used to monitor system operation and availability;

(c) proper operation of system valves, including timing, under expected operating conditions;

(d) proper operation of pumps and motors in all design operating modes;

(e) acceptable pump NPSH under the most limiting design flow conditions;

(f) proper system flow paths and flow rates including pump capacity and discharge head;

(g) proper pump motor start sequence and margin to actuation of protective devices;

(h) proper operation of interlocks and equipment protective devices in pump, motor, and valve controls;

(i) proper operation of permissive, prohibit, and bypass functions;

(j) proper system operation while powered from primary and alternate sources, including transfers, and in degraded modes for which system components are expected to remain operational;

(k) acceptability of pump/motor vibration levels and system piping movements during both transient and steady state operation; and

(l) proper operation of controllers for pump drivers and flow control valves including those in minimum flow recirculation lines.

System operation is considered acceptable when the observed/measured performance characteristics, from the testing described above, meet the applicable design specifications.

14.2.12.1.54 Condensate Cleanup System Preoperational Test

(1) Purpose

To verify proper operation of the condensate filters and demineralizers and the associated support facilities.

(2) Prerequisites

The construction tests have been successfully completed and the SCG has reviewed the test procedure and has approved the initiation of testing. The condensate system shall be operational with an established flow path capable of supporting full condensate filter and demineralizer flow. Adequate supplies of ion exchange resin should be available and the radwaste system shall be capable of processing the expected quantities of water and spent resins. Other required interfacing systems shall also be available, as needed, to support the specified testing.

(3) General Test Methods and Acceptance Criteria

Performance shall be observed and recorded during a series of individual component and integrated system tests to demonstrate the following:

(a) proper operation of instrumentation and equipment in all combinations of logic and instrument channel trip;

(b) proper functioning of instrumentation and alarms used to monitor system operation and status;

(c) proper operation of system valves, including timing, under expected operating conditions;

(d) proper individual vessel and overall system flow rates and pressure drops including bypass capabilities (for both filter and demineralizer units);

(e) proper operation of interlocks and equipment protective devices;

(f) proper operation of permissive, prohibit, and bypass functions;

(g) the ability to perform on-line exchange of standby and spent filter units and demineralizer vessels; and

(h) proper operation of filter and demineralizer support facilities such as those used for regeneration of resins or for handling of wastes.

System operation is considered acceptable when the observed/measured performance characteristics meet the applicable design specifications.

14.2.12.1.55 Reactor Water Chemistry Control Systems Preoperational Test

(1) Purpose

To verify proper operation of the various chemical addition systems designed for actively controlling the reactor water chemistry, including the oxygen injection system, the zinc injection passivation system, the iron ion injection system, and the hydrogen water chemistry system.

(2) Prerequisites

The construction tests have been successfully completed and the SCG has reviewed the test procedure(s) and has approved the initiation of testing. The required interfacing systems shall be available, as needed, to support the specified testing. The appropriate vendor precautions shall be followed with regards to the operation of the affected sytems and componenets and for the actual reactor water chemistry given the existing reactor operating state.

(3) General Test Methods and Acceptance Criteria

Preoperational testing of these systems will concentrate on verifying proper operation of the equipment skids and the various individual components. Actual chemical injection demonstrations and/or simulations shall be limited to only those cases where it is deemed practicable or appropriate with regards to the aforementioned precautions.

Performance shall be observed [illegible] during a series of individual [illegible] integrated system tests (to th[illegible]) to demonstrate the following:

(a) proper operation of instrumentation and equipment in all combinations of logic and instrument channel trip;

(b) proper functioning of instrumentation and alarms used to monitor system operation and availability;

(c) proper operation of system valves, including timing and sequencing, under expected operating conditions;

(d) proper system flow paths, flow rates and pressures;

(e) proper operation of system interlocks and equipment protective devices; and,

(f) proper operation of permissive, prohibit, and bypass functions;

System operation is considered acceptable when the observed/measured performance characteristics, from the testing described above, meet the applicable design specifications.

14.2.12.1.56 Condenser Air Removal System Preoperational Test

(1) Purpose

To verify the ability for the mechanical vacuum pumps and the steam jet air ejectors to establish and maintain a vacuum in the main condenser as per design.

(2) Prerequisites

Construction tests have been successfully completed and the SCG has reviewed the test procedure and has approved the initiation of testing. The main condenser shall be intact and steam shall be available from the auxiliary boiler or some other temporary source. Other required interfacing systems shall be available, as needed, to support the specified testing.

(3) General Test Methods and Acceptance Criteria

Performance shall be observed and recorded during a series of individual component and integrated system tests to demonstrate the following:

(a) proper operation of instrumentation and equipment in all combinations of logic and instrument channel trip;

(b) proper functioning of instrumentation and alarms used to monitor system operation and status;

(c) proper operation of system valves, including timing, under expected operating conditions;

(d) proper operation of the mechanical vacuum pumps including the ability to establish the required vacuum within the design time frame;

(e) proper operation of the steamjet air ejectors including their ability to maintain the specified vacuum in the main condenser (while accounting for the source of the driving steam used);

(f) proper pump motor start sequence and margin to actuation of protective devices;

(g) proper operation of interlocks and equipment protective devices in pump, motor, and valve controls; and

(h) proper operation of permissive, prohibit, and bypass functions;

Operation is acceptable when the observed/measured performance characteristics meet the applicable design specifications.

14.2.12.1.57 Offgas System Preoperational Test

(1) Purpose

To verify proper operation of the offgas system including valves, recombiner, condensers, coolers, filters, and hydrogen analyzers.

(2) Prerequisites

The construction tests have been successfully completed and the SCG has reviewed the test procedure and has approved the initiation of testing. Additionally, instrument air, electrical power, cooling water, and other required system interfaces shall be available, as needed, to support the specified testing.

(3) General Test Methods and Acceptance Criteria

Performance shall be observed and recorded during a series of individual component and integrated system tests to demonstrate the following:

(a) proper operation of instrumentation and equipment in all combinations of logic and instrument channel trip;

(b) proper functioning of instrumentation and alarms used to monitor system operation and availability;

(c) proper operation of system valves, including isolation features, under expected operating conditions;

(d) proper operation of components in all design operating modes;

(e) proper system and component flow paths and flow rates;

(f) proper operation of interlocks and equipment protective devices;

(g) proper operation of permissive, prohibit, and bypass functions; and

(h) proper system operation while powered from primary and alternate sources, including transfers, and in degraded modes for which the system is expected to remain operational.

System operation is considered acceptable when the observed/measured performance characteristics, from the testing described above, meet the applicable design specifications.

14.2.12.1.58 Hotwell Level Control System Preoperational Test

(1) Purpose

To verify design level control capability in the main condenser hotwell.

(2) Prerequisites

The construction tests have been successfully completed and the SCG has reviewed the test procedure and has approved the initiation of testing. The condenser, condensate storage tank, condensate pumps, and associated valves and piping shall be operational and the other required interfacing systems shall be available, as needed, to support the specified testing.

(3) General Test Methods and Acceptance Criteria

Performance shall be observed and recorded during a series of individual component and integrated system tests to demonstrate the following:

(a) proper operation of system components in all combinations of logic and in response to all expected controller demands;

(b) proper functioning of instrumentation and alarms used to monitor system operation and status;

(c) proper operation of system valves including stroke and timing; and

(d) the ability to maintain the desired hotwell condensate inventory in conjunction with the condensate storage and transfer system.

System operation is considered acceptable when the observed/measured performance characteristics, from the testing described above, meet the applicable design specifications.

14.2.12.1.59 Condensate Storage and Transfer System Preoperational Test

(1) Purpose

To verify the ability of the condensate storage and transfer system to provide an adequate reserve of condensate quality water for make-up to the condensate system, as a preferred suction source for the RCIC and HPCS systems, and for other uses as designed.

(2) Prerequisites

The construction tests have been successfully completed and the SCG has reviewed the test procedure and has approved the initiation of testing. All required interfacing systems shall be available, as needed, to support the specified testing.

(3) General Test Methods and Acceptance Criteria

Performance shall be observed and recorded during a series of individual component and integrated system tests to demonstrate the following:

(a) proper operation of instrumentation and equipment in all combinations of logic;

(b) proper functioning of permissive and prohibit interlocks;

(c) proper functioning of instrumentation and alarms used to monitor system operation and status including CST volume and/or level;

(d) proper operation of freeze protection devices, if applicable; and

(e) the ability of the system to provide desired flow rates and volumes to the applicable systems and/or components.

Operation is considered acceptable when the observed/measured performance characteristics meet the applicable design specifications.

14.2.12.1.60 Circulating Water System Preoperational Test

(1) Purpose

To verify the proper operation of the circulating water system and its ability to circulate cooling water from the ultimate heat sink through the tubes of the main condenser in sufficient quantities to condense the steam exhausted from the main turbine under all expected operating conditions.

(2) Prerequisites

The construction tests have been successfully completed and the SCG has reviewed the test procedure and has approved the initiation of testing. The main condenser, ultimate heat sink, appropriate electrical power source(s) and other required interfacing systems shall be available, as needed, to support the specified testing.

(3) General Test Methods and Acceptance Criteria

Performance shall be observed and recorded during a series of individual component and integrated system tests to demonstrate the following:

(a) proper operation of instrumentation and equipment in all combinations of logic and instrument channel trip;

(b) proper functioning of instrumentation and alarms used to monitor system operation and availability;

(c) proper operation of system valves, including timing, under expected operating conditions;

(d) proper operation of pumps and motors in all design operating modes;

(e) acceptable pump NPSH under the most limiting design flow conditions;

(f) proper system flow paths and flow rates including pump capacity and discharge head;

(g) proper pump motor start sequence and margin to actuation of protective devices;

(h) proper operation of interlocks and equipment protective devices in pump and valve controls;

(i) proper operation of permissive, prohibit, and bypass functions;

(j) proper operation of freeze protection devices, if applicable;

(k) proper system operation while powered from primary and alternate sources, including transfers, and in degraded modes for which the system is expected to remain operational; and

(l) acceptability of pump/motor vibration levels and system piping movements during both transient and steady state operation.

System operation is considered acceptable when the observed/ easured performance characteristics, from the testing described above, meet the applicable design specifications. However, due to the lack of significant heat loads during the preoperational test phase, condenser and ultimate heat sink performance evaluation will be performed during the startup phase with the turbine-generator on line.

14.2.12.1.61 Reactor Service Water System Preoperational Test

(1) Purpose

To verify proper operation of the reactor service water (RSW) system and its ability to supply design quantities of cooling water to the RCW system heat exchangers.

(2) Prerequisites

The construction tests have been successfully completed and the SCG has reviewed the test procedure and has approved the initiation of testing. Primary and backup electrical power, the RCW system (including heat exchangers), instrument air, and other required interfacing systems shall be available, as needed, to support the specified testing.

(3) General Test Methods and Acceptance Criteria

Performance shall be observed and recorded during a series of individual component and integrated system tests to demonstrate the following:

(a) proper operation of instrumentation and equipment in all combinations of logic and instrument channel trip;

(b) proper functioning of instrumentation and alarms used to monitor system operation and availability;

(c) proper operation of system valves, including timing, under expected operating conditions;

(d) proper operation of pumps and motors in all design operating modes;

(e) acceptable pump NPSH under the most limiting design flow conditions;

(f) proper system flow paths and flow rates including pump capacity and discharge head;

(g) proper pump motor start sequence and margin to actuation of protective devices;

(h) proper operation of interlocks and equipment protective devices in pump, motor and valve controls;

(i) proper operation of permissive, prohibit, and bypass functions;

(j) proper operation of freeze protection devices, if applicable;

(k) proper system operation while powered from primary and alternate sources, including transfers, and in degraded modes for which the system is expected to remain operational; and

(l) acceptability of pump/motor vibration levels and system piping movements during both transient and steady state operation.

System operation is considered acceptable when the observed/measured performance characteristics, from the testing described above, meet the applicable design specifications. The heat exchangers which serve as the interface with the RCW system are considered part of that system and will be tested as such. However, due to the probability of insufficient heat loads during the preoperational test phase, it is likely that heat exchanger performance verification will be delayed until the startup phase.

14.2.12.1.62 Turbine Building Cooling Water System Preoperational Test

(1) Purpose

To verify proper operation of the turbine building cooling water (TCW) system and its ability to supply design quantities of cooling water, at the specified temperatures, to designated plant loads.

(2) Prerequisites

The construction tests have been successfully completed and the SCG has reviewed the test procedure and has approved the initiation of testing. Primary and backup power, turbine service water (TSW), instrument air, and other required supporting systems shall be available, as needed, for the specified testing configurations. The cooled components should be operational and operating to the extent possible during heat exchanger performance evaluation.

(3) General Test Methods and Acceptance Criteria

Performance shall be observed and recorded during a series of individual component and integrated system tests to demonstrate the following:

(a) proper operation of instrumentation and equipment in all combinations of logic and instrument channel trip;

(b) proper functioning of instrumentation and alarms used to monitor system operation and availability;

(c) proper operation of system valves, including timing, under expected operating conditions;

(d) proper operation of pumps and motors in all design operating modes;

(e) acceptable pump NPSH under the most limiting design flow conditions;

(f) proper system and component flow paths, flow rates, and pressure drops, including pump capacity and discharge head;

(g) proper pump motor start sequence and margin to actuation of protective devices;

(h) proper operation of interlocks and equipment protective devices in pump and valve controls;

(i) proper operation of permissive, prohibit, and bypass functions;

(j) proper system operation while powered from primary and alternate sources, including transfers, and in degraded modes for which the system is expected to remain operational;

(k) acceptability of pump/motor vibration levels and system piping movements during both transient and steady state operation;

(l) proper operation of system surge tanks and chemical addition tanks and their associated functions; and

(m) acceptable performance of TCW system heat exchangers, to the extent practical.

System operation is considered acceptable when the observed/measured performance characteristics, from the testing described above, meet the applicable design specifications. Due to the possibility of insufficient heat loads during the preop phase, the final system flow balancing and heat exchanger performance evaluation may have to be performed during the startup phase.

14.2.12.1.63 Turbine Service Water System Preoperational Test

(1) Purpose

To verify the ability of the turbine service water (TSW) system to supply design quantities of cooling water to the TCW heat exchangers.

(2) Prerequisites

The construction tests have been successfully completed and the SCG has reviewed the test procedure and has approved the initiation of testing. Primary and backup electrical power, TCW system heat exchangers, instrument air, and other required interfacing systems shall be available, as needed, to support the specified testing.

(3) General Test Methods and Acceptance Criteria

Performance shall be observed and recorded during a series of individual component and integrated system tests to demonstrate the following:

(a) proper operation of instrumentation and equipment in all combinations of logic and instrument channel trip;

(b) proper functioning of instrumentation and alarms used to monitor system operation and availability;

(c) proper operation of system valves, including timing, under expected operating conditions;

(d) proper operation of pumps and motors in all design operating modes;

(e) acceptable pump NPSH under the most limiting design flow conditions;

(f) proper system flow paths and flow rates including pump capacity and discharge head;

(g) proper pump motor start sequence and margin to actuation of protective devices;

(h) proper operation of interlocks and equipment protective devices in pump and valve controls;

(i) proper operation of permissive, prohibit, and bypass functions;

(j) proper operation of freeze protection devices, if applicable;

(k) proper system operation while powered from primary and alternate sources, including transfers, and in degraded modes for which the system is expected to remain operational; and

(l) acceptability of pump/motor vibration levels and system piping movements during both transient and steady state operation.

System operation is considered acceptable when the observed/measured performance characteristics, from the testing described above, meet the applicable design specifications. The heat exchangers which serve as the interface with the TBCWS are considered part of that system and will be tested as such. However, due to the probability of insufficient heat loads during the preoperational test phase, it is likely that heat exchanger performance verification will be delayed until the startup phase.

14.2.12.1.64 Main Turbine Control System Preoperational Test

(1) Purpose

To verify proper operation of the turbine control system which includes the turbine stop valves, control valves, intermediate stop and intercept valves, and their associated actuators and hydraulic control.

(2) Prerequisites

The construction tests have been successfully completed and the SCG has reviewed the test procedure and has approved the initiation of testing. The steam bypass and pressure control system shall be operational and other required interfacing systems shall be available, as needed, to support the specified testing.

(3) General Test Methods and Acceptance Criteria

Performance shall be observed and recorded during a series of component and system tests to demonstrate the following:

(a) proper functioning of instrumentation and equipment in all combinations of logic and instrument channel trip;

(b) proper operation of instrumentation and alarms used to monitor system operation and status;

(c) proper operation of main stop and control valves and intermediate stop and intercept valves in normal control, trip and test modes (including timing);

(d) proper operation of valve auxiliaries such as hydraulic fluid systems, including pumps and accumulators, and power supplies; and

(e) proper interface with (i.e. response and feedback to) the steam bypass and pressure control system.

Operation is considered acceptable when the observed/measured performance characteristics meet the applicable design specifications.

14.2.12.1.65 Main Turbine Bypass System Preoperational Test

(1) Purpose

To verify proper operation of the turbine bypass system which includes the main turbine bypass valves and their associated actuators and hydraulic control.

(2) Prerequisites

The construction tests have been successfully completed and the SCG has reviewed the test procedure and has approved the initiation of testing. The steam bypass and pressure control system shall be operational and other required interfacing system shall be available, as needed, to support the specified testing.

(3) General Test Methods and Acceptance Criteria

Performance shall be observed and recorded during a series of component and system tests to demonstrate the following:

(a) proper functioning of instrumentation and equipment in all combinations of logic and instrument channel trip;

(b) proper operation of instrumentation and alarms used to monitor system operation and status;

(c) proper operation of main turbine bypass valves in normal control, trip and test modes (including timing);

(d) proper operation of valve auxiliaries such as hydraulic fluid systems, including pumps and accumulators, and power supplies; and

(e) proper interface with (i.e. response and feedback to) the steam bypass and pressure control system.

Operation is considered acceptable when the observed/measured performance characteristics meet the applicable design specifications.

14.2.12.1.66 Steam Bypass and Pressure Control System Preoperational Test

(1) Purpose

To verify proper operation of the steam bypass and pressure control system (SBPCS) including, as appropriate, higher level control of the turbine bypass system, the turbine control system, and the recirc flow control system.

(2) Prerequisites

The construction tests have been successfully completed and the SCG has reviewed the test procedure and has approved the initiation of testing. The preoperational tests have been completed on the turbine bypass and control systems (including the EHC system) to extent necessary to support integrated system testing and all SBPCS components have been initially calibrated in accordance with vendor instructions. The required supporting systems and equipment shall be available, as needed, for the specified testing configurations.

(3) General Test Methods and Acceptance Criteria

The SBPCS is primarily an electronic control system. It does not include any large mechanical equipment (i.e. turbine stop, control and bypass valves) nor any associated hydraulic actuators, but does provide for their integrated control. System preoperational testing will be limited to demonstrations without (or with significantly reduced, from a temporary source) turbine steam flow. Comprehensive steam flow testing will be conducted during the startup phase.

Performance shall be observed and recorded during a series of individual component and integrated system test to demonstrate the following:

(a) proper operation of instrumentation and controls in all combinations of logic and instrument channel trip, including verification of setpoints;

(b) proper functioning of instrumentation and alarms used to monitor system operation and availability;

(c) proper operation of associated valves, including timing and stroke, in response to control system demands;

(d) proper operation of interlocks and equipment protective devices;

(e) proper operation of permissive, prohibit, and bypass functions;

(f) proper system operation while powered from primary and alternate sources, including transfers, and in degraded modes for which the system is expected to remain operational; and

(g) proper communication and interface with other equipment and control systems.

System operation is considered acceptable when the observed/ measured performance characteristics, from the testing described above, meet the applicable design specifications

14.2.12.1.67 Feedwater Heater and Drain System Preoperational Test

(1) Purpose

To verify proper operation of the feedwater heaters and their associated drains including heater level control capabilities.

(2) Prerequisites

The construction tests have been successfully completed and the SCG has reviewed the test procedure and has approved the initiation of testing. All required interfacing systems shall be available, as needed, to support the specified testing.

(3) General Test Method and Acceptance Criteria

The feedwater heater and drain system includes the feedwater heaters, internal and external drain coolers, normal and emergency dump valves, shell and tube side isolation valves, shell side vents and safety relief valves, and associated instrumentation, control and logic.

Performance shall be observed and recorded during a series of individual component and integrated system tests to demonstrate the following:

(a) proper operation of instrumentation and equipment in all combinations of logic and instrument channel trip;

(b) proper functioning of instrumentation and alarms used to monitor system operation and status;

(c) proper operation of system valves and actuators under expected operating conditions;

(d) proper operation of interlocks and equipment protective devices;

(e) proper operation of permissive, prohibit, and bypass functions; and

(f) proper operation of heater level controls including response of the associated drain/dump valves.

Operation is acceptable when the observed/measured performance characteristics meet the applicable design specifications.

14.2.12.1.68 Extraction Steam System Preoperational Test

(1) Purpose

To verify proper operation of the components which comprise the extraction steam system.

(2) Prerequisites

The construction tests have been successfully completed and the SCG has reviewed the test procedure and has approved the initiation of testing. All required interfacing systems shall be available, as needed, to support the specified testing.

(3) General Test Methods and Acceptance Criteria

Comprehensive testing of the extraction steam system will require the turbine generator to be on line with a substantial amount of steam flow available. Since significant steam flow conditions are dependent on nuclear heating,the preoperational phase testing that is possible will be limited. Performance shall be observed and recorded during a series of component and system tests to demonstrate the following:

(a) proper operation of instrumentation and equipment in all combinations of logic and instrument channel trip;

(b) proper functioning of instrumentation and alarms used to monitor system operation and status;

(c) proper operation of system valves under expected operating conditions including response of air assisted nonreturn check valves to a turbine trip signal;

(d) proper operation of interlocks and equipment protective devices; and

(e) proper operation of permissive, prohibit, and bypass functions.

Operation is acceptable when the observed/measured performance characteristics meet the applicable design specifications.

14.2.12.1.69 Moisture Seperator/Reheater System Preoperational Test

(1) Purpose

To verify proper operation of the turbine moisture sperator/ reheaters (MSRs) and their associated drain pathways, steam extraction lines, and isolation and non-return check valves.

(2) Prerequisites

The construction tests have been successfully completed and the SCG has reviewed the test procedure and has approved the initiation of testing. All required interfacing systems shall be available, as needed, to support the specified testing.

(3) General Test Methods and Acceptance Criteria

The MSRs include both a moisture seperator and reheater compartment each with their owndrains, shell and tube side isolation valves, shell side vents and safety relief valves, and associated instrumentation, control and logic.

[illegible]prehensive testing of the extraction steam [illegible] will require the turbine generator to be [illegible] with a substantial amount of steam flow [illegible]ble. Since significant steam flow [illegible]ons are dependent on nuclear heating, [illegible]operational phase testing that is possible [illegible] limited.

Performance shall be observed and recorded during a series of individual component and integrated system tests to demonstrate the following:

(a) proper operation of instrumentation and equipment in all combinations of logic and instrument channel trip;

(b) proper functioning of instrumentation and alarms used to monitor system operation and status;

(c) proper operation of system valves and actuators (including isolation and non-return check valves) under expected operating conditions;

(d) proper operation of interlocks and equipment protective devices;

(e) proper operation of permissive, prohibit, and bypass functions; and

(f) proper operation of moisture seperator and reheater compartment drain pathways.

Operation is acceptable when the observed/measured performance characteristics meet the applicable design specifications.

14.2.12.1.70 Main Turbine and Auxiliaries Preoperational Test

(1) Purpose

To verify that the operation of the main turbine and its auxiliariy systems, including the gland sealing system, lube oil system, turning gear, supervisory instrumentation, and turbine protection system (including overspeedprotection), is as specified. Testing of the turbine valves and associated control systems is specified separately (elsewhere).

(2) Prerequisites

The construction tests have been successfully completed and the SCG has reviewed the test procedure and has approved the initiation of testing. To the extent practicable, a temporary steam supply shall be available for driving the turbine. The turbine instruction manual shall be reviewed in detail in order that precautions relative to turbine operation are followed. All required interfacing systems shall be available, as needed, to support the specified testing and the corresponding system configurations.

(3) General Test Methods and Acceptance Criteria

Since preoperational testing is performed utilizing a temporary steam supply, the extent to which the turbine itself can be tested may be limited. Therefore, the testing effort at this stage will concentrate on assuring that the necessary turbine auxiliaries are functioning properly.

Performance shall be observed and recorded during a series of individual component, subsystem and integrated system tests (to the extent possible) to demonstrate the following, with regrads to both the turbine and its auxiliaries:

(a) proper operation of instrumentation and equipment in all combinations of logic and instrument channel trip;

(b) proper functioning of instrumentation and alarms used to monitor system operation and availability, including the turbine supervisory instrumentation;

(c) proper operation of system pumps and valves in all design operating modes;

(d) proper system flow paths, flow rates and pressures (particularly with regards to the lube oil and gland sealing steam systems);

(e) proper operation of interlocks and equipment protective devices in variousturbine, pump, and valve controls (including the various primary and backup turbine overspeed protection devices);

(f) proper operation of permissive, prohibit, and bypass functions;

(g) proper operation while powered from both primary and alternate sources, including transfers, and in degraded modes for which the system, subsystem or component is expected to remain operational;

(h) proper turbine alignment, including acceptability of displacement and vibration levels,if possible, during both transient and steady state operation;

System operation is considered acceptable when the observed/ measured performance characteristics, from the testing described above, meet the applicable design specifications (while accounting for the testing limitations imposed).

14.2.12.1.71 Main Generator and Auxiliary Systems Preoperational Test

(1) Purpose

Verify that the operation of the main generator and its auxiliariy systems, including the generator hydrogen system and its associated seal oil and cooling systems, those subsystems and/or components that provide cooling to the generator exciter, stator, circuit breakers and isophase bus duct, and the generator protection system, is as specified.

(2) Prerequisites

The construction tests have been successfully completed and the SCG has reviewed the test procedure(s) and has approved the initiation of testing. To the extent practicable, and in conjunction with the turbine preoperational testing, a temporary steam supply shall be available for driving the turbine/generator. The generator instruction manual shall be reviewed in detail in order that precautions relative to generator operation are followed. All required interfacing systems shall be available, as needed, to support the specifiedtesting and the corresponding system configurations.

(3) General Test Methods and Acceptance Criteria

Since preoperational testing in part is performed utilizing a temporary steam supply, the extent to which the turbine, and therefore the generator, can be tested may be limited. Therefore, the testing effort at this stage will concentrate on assuring that the necessary individual generator components and auxiliaries are functioning properly.

Performance shall be observed and recorded during a series of individual component, subsystem and integrated system tests (to the extent possible) to demonstrate the following, with regrads to both the generator and its auxiliaries:

(a) proper operation of instrumentation and equipment in all combinations of logic and instrument channel trip;

(b) proper functioning of instrumentation and alarms used to monitor system operation and availability;

(c) proper operation of system pumps, valves, fans, and piping or ducting in all design operating modes;

(d) proper system flow paths, flow rates and pressures (particularly with regards to the generator hydrogen system and its associated seal oil and cooling systems);

(e) proper operation of interlocks and equipment protective devices in the various generator and auxiliary system controls;

(f) proper operation of permissive, prohibit, and bypass functions;

(g) proper operation while powered from primary and any alternate sources, including transfers, and in degraded modes for which the system, subsystem or component is expected to remain operational;

(h) proper generator alignment, including acceptability of clearance and vibration levels, if possible, during both transient and steady state operation;

System operation is considered acceptable when the observed/measured performance characteristics, from the testing described above, meet the applicable design specifications (while accounting for the testing limitations imposed).

14.2.12.1.72 Flammability Control System Preoperational Test

(1) Purpose

To verify the ability of the flammability control system (FCS) to recombine hydrogen and oxygen and therefore maintain the specified inert atmosphere in the primary containment during long term post accident conditions.

(2) Prerequisites

The construction tests have been successfully completed and the SCG has reviewed the test procedure and has approved the initiation of testing. The wetwell and drywell airspace regions of the primary containment shall be intact, and all other required interfaces available, as needed, to support the specified testing.

(3) General Test Methods and Acceptance Criteria

Performance shall be observed and recorded during a series of individual component and integrated system tests to demonstrate the following:

(a) proper operation of instrumentation and equipment in all combinations of logic;

(b) proper functioning of instrumentation and alarms used to monitor system operation and availability;

(c) proper operation of system valves, including timing, under expected operating conditions;

(d) proper system flow paths and flow rates both into and out of the primary containment;

(e) proper operation of interlocks and equipment protective devices in valve and recombiner skid controls;

(f) proper operation of permissive, prohibit, and bypass functions; and

(g) proper system operation while powered from primary and alternate sources, including transfers, and in degraded modes for which the system is expected to remain operational.

System operation is considered acceptable when the observed/ measured performance characteristics, from the testing described above, meet the applicable design specifications.

14.2.12.1.73 Loose Parts Monitoring System Preoperational Test

(1) Purpose

To verify proper functioning of loose parts monitoring equipment.

(2) Prerequisites

The construction tests have been successfully completed and the SCG has reviewed the test procedure and has approved the initiation of testing. Reactor internals shall be in place with all system sensors connected.

(3) General Test Methods and Acceptance Criteria

Performance shall be observed and recorded during a series of system and component test to demonstrate the following:

(a) proper operation of instrumentation and alarms; and

(b) the adequacy of alert level setpoints based on preliminary data.

System operation is considered acceptable when the observed/measured performance characteristics meet the applicable design specifications.

14.2.12.1.74 Seismic Monitoring System Preoperational Test

(1) Purpose

To verify that the seismic monitoring system will operate as designed in response to a seismic event.

(2) Prerequisites

The construction tests have been successfully completed and the SCG has reviewed the test procedure and has approved the initiation of testing. The required electrical power shall be available and all system recording devices shall have sufficient storage medium available, based on the expected duration of the testing scheduled.

(3) General Test Methods and Acceptance Criteria

Performance shall be observed and recorded during a series of tests, as recommended by the manufacturer, to demonstrate the following:

(a) proper calibration and response of seismic instrumentation including verification of alarm and initiation setpoints;

(b) proper operation of internal calibration or test features;

(c) proper operation of recording and playback devices; and

(d) proper integrated system response to a simulated seismic event.

System operation is considered acceptable when the observed/measured performance characteristics meet the applicable design specifications.

14.2.12.1.75 Liquid and Solid Radwaste Systems Preoperational Tests

(1) Purpose

To verify the proper operation of the various equipment and processes which make up the liquid and solid radwaste systems.

(2) Prerequisites

The construction tests have been successfully completed and the SCG has reviewed the test procedure(s) and has approved the initiation of testing. There shall be access to appropriate laboratory facilities and an acceptable effluent discharge path shall be established. Additionally, an adequate supply of demineralized water, the necessary electrical power, and other required interfacing systems shall be available, as needed, to support the specified testing.

(3) General Test Methods and Acceptance Criteria

The testing described below consists of that of the equipment and processes for the handling, treating, storing, and preparation for the disposal or discharge of liquid and solid radwaste. Gaseous effluents are treated and released by the offgas system or the standby gas treatment system, the testing of which is specifically described elsewhere.

For the liquid and solid radwaste systems performance shall be observed and recorded during a series of individual component and integrated system tests to demonstrate the following:

(a) proper operation of equipment controls and logic including prohibit and permissive interlocks;

(b) proper operation of equipment protective features and automatic isolation functions including those for ventilation systems and liquid effluent pathways;

(c) proper functioning of instrumentation and alarms used to monitor system operation and status;

(d) acceptable system and component flow paths and flow rates including pump capacities and tank volumes;

(e) proper operation of system pumps, valves, and motors under expected operating conditions;

(f) proper operation of phase separators and waste evaporators;

(g) proper operation of concentrating, solidifying, and packaging functions including verification of the absence of free liquids in packaged waste;

(h) proper operation of filter and demineralizer units and their associated support facilities;

(i) proper functioning of drains and sumps including those dedicated for handling of specific agents such as detergents; and

(j) proper calibration and operation of radiation detectors and monitors.

System operation is considered acceptable when the observed and measured performance characteristics, from the testing described above, meet the applicable design specifications

14.2.12.1.76 (Moved to 14.2.12.2.35)

14.2.12.1.77 Ultimate Heat Sink Preoperational Test

(1) Purpose

To verify that the ultimate heat sink is capable of supplying design quantities of make-up and/or return water to the circulating water system and the reactor turbine service water systems.

(2) Prerequisites

The construction tests have been successfully completed and the SCG has reviewed the test procedure and has approved the initiation of testing. The circulating water system and the reactor and turbine service water systems shall be operational and other required interfacing systems shall be available, as needed, to support the specified testing.

(3) General Test Methods and Acceptance Criteria

Performance shall be observed and recorded during a series of component and system tests to demonstrate the following:

(a) proper operation of instrumentation and alarms used to monitor system operation and status;

(b) proper operation of active cooling devices, if applicable, such as forced or natural draft towers, spray ponds, etc.; and

(c) the adequacy of intake and discharge structures, including screens or strainers, or other interfaces with the circulating water system, such as freeze protection devices, as applicable.

Operation is acceptable when the observed/measured performance characteristics meet the applicable design specifications.

14.2.12.2 General Discussion of Startup Tests

Those tests proposed and expected to comprise the startup test phase are discussed in this subsection. For each test a general description is provided for test purpose, test prerequisites, test description and test acceptance criteria, where applicable.

Since additions, deletions, and changes to these discussions are expected to occur as the test program is developed and implemented, the descriptions remain general in scope. In describing a test however, an attempt is made to identify those operating and safety-oriented characteristics of the plant which are being explored and evaluated.

Where applicable, the relevant acceptance criteria for the test are discussed. Some of the criteria relate to the value of process variables assigned in the design or analysis of the plant, component systems, and associated equipment. If a criterion of this nature is not satisfied, the plant will be placed in a suitable hold condition until resolution is obtained. Tests compatible with this hold condition may be continued. Following resolution, applicable tests may be repeated to verify that the requirements of the criterion are ultimately satisfied. Other criteria may be associated with expectations relating to the performance of systems. If this type of criterion is not satisfied, operating and testing plans would not necessarily be altered. However, investigations of the measurements and of the analytical techniques used for the predictions would be started. Specific actions for dealing with criteria failures and other testing exceptions or anamolies will be described in the startup administrative manual.

vity, with the analytically determined highest worth rod pair fully withdrawn (a rod pair is defined as having a shared accumulator).

14.2.12.2.4 Full Core Shutdown Margin Demonstration

(1) Purpose

To demonstrate that the reactor will be subcritical throughout the first fuel cycle with the highest worth control rod pair (two CRDs with a shared accumulator) fully withdrawn.

(2) Prerequisites

The following prerequisites will be met prior to performing the full core shutdown margin tests:

(a) the predicted critical rod position will be available;

(b) the Standby Liquid Control System will be available;

(c) nuclear instrumentation will be available with the minimum neutron count rate and signal-to-noise ratio as specified by technical specifications; and

(d) high-flux scram trips are set conservatively low.

(3) Description

This test will be performed in the fully loaded core in the xenon-free condition. The shutdown margin test will be performed by withdrawing the control rods from the all-rods-in configuration until criticality is reached. If the highest worth rod pair will not be withdrawn in sequence, other rods may be withdrawn providing that the reactivity worth is equivalent. The difference between the measured K_{eff} and the calculated K_{eff} for the insequence critical will be applied to the calculated value to obtain the true shutdown margin.

(4) Criteria

The shutdown margin of the fully loaded, cold (68°F), xenon-free core occurring at the most reactive time during the cycle must be at least that amount required by technical specifications with the analytically strongest rod pair (or the reactivity equivalent) fully withdrawn. If the shutdown margin is determined at some time during the cycle other than the most reactive time, compliance with the above criterion is shown by demonstrating that the shutdown margin is the specified amount plus an exposure dependent correction factor which adjusts for the difference in core reactivity between the most reactive time and the time at which the shutdown margin is demonstrated. Additionally, criticality should occur within the specified tolerance of the predicted critical.

14.2.12.2.5 Control Rod Drive System Performance

(1) Purpose

To demonstrate that the control rods operate properly over the full range of primary coolant temperatures and pressures from ambient to operating, in both the scram and fine motion control modes, in conjunction with the rod control and information system (RC&IS).

(2) Prerequisites

The preoperational tests have been completed and plant management has reviewed the test procedures and has approved the initiation of testing. For each scheduled testing iteration the plant shall be in the appropriate operational configuration with the specified prerequisite testing complete. The applicable instrumentation shall be checked or calibrated as appropriate.

(3) Description

The control rod drive (CRD) testing performed during the heatup and power ascension phases of the startup test program is designed as an extension of the testing performed during the preoperational phase.

Thus, after it is verified that all CRDs operate properly when installed, tests are performed periodically during heatup to assure that there is no significant binding caused by thermal expansion of the core components and no significant effect on performance due to increased pressure, power or flow. Additionally, software functions such as those associated with the RC&IS are tested to the extent that they could not be checked during preoperational testing. Testing will also be conducted to verify proper operation of the SCRRI logic and function. The particular testing of the SCRRI function might be conducted, at least in part, with the RIP trip test described in 14.2.12.2.30 where the planned trip will automatically result in SCRRI actuation.

(4) Criteria

Each CRD shall have a measured scram time that is less than the technical specifications requirements and consistent with safety analysis assumptions during both individual rod pair and full core scrams, as applicable. Each CRD shall have a measured insert/withdrawal speed consistent with specified design requirements including those associated with group or gang movement. Additionally, the CRDs shall meet friction test requirements and those for demonstrating proper operation of rod deceleration devices. Also, all software functions or features shall perform as specified.

14.2.12.2.6 Neutron Monitoring System Performance

(1) Purpose

To verify response, calibration and operation of startup range neutron monitors (SRNMs), local power range monitors (LPRMs), average power range monitors (APRMs), traversing in-core probes (TIPs), and other hardware and software of the neutron monitoring system during fuel loading, control rod withdrawal, heatup and power ascension.

(2) Prerequisites

The applicable preoperational phase testing is complete and the plant management has reviewed the test procedure(s) and has approved the initiation of testing. For each scheduled test iteration the plant shall be in the appropriate operational configuration with all specified prerequisite testing complete. The applicable instrumentation shall be checked or calibrated as is appropriate.

(3) Description

Testing of the neutron monitoring system will commence prior to fuel load and will continue at intervals up to and including rated power. The SRNMs and operational sources will be tested during fuel loading and during rod withdrawal on the approach to criticality and heatup to rated temperature and pressure. The LPRMs, APRMs and TIPs will be tested as soon as sufficient flux levels exist and at specified intervals during the ascension to rated power. Testing will include response checks, calibrations and verification of system software calculations using actual core flux levels and other live plant inputs.

(4) Criteria

The SRNMs, in conjunction with the installed neutron sources, shall have count rates and signal-to-noise ratios that meet technical specifications and/or design requirements, as applicable. The respective range functions of the SRNMs and APRMs shall provide for overlapping neutron flux indication as required by plant technical specifications and the applicable design specifications. The APRMs shall be calibrated against core thermal power by means of a heat balance. The accuracy of this calibration shall be consistent with technical specifications. When technical specifications are not applicable the APRMs shall conservatively indicate reactor power. The LPRMs shall be calibrated consistent with design calibration and accuracy requirements. Additionally, all system hardware and software shall function properly in response to actual core flux levels.

various plant control systems during actual plant operating conditions.

(2) Prerequisites

The applicable preoperational tests have been completed and plant management has reviewed the testing procedure(s) and has approved the initiation of testing. For each scheduled testing iteration the plant shall be in the appropriate operational configuration with all specified prerequisite testing complete.

(3) Description

During plant heatup and the ascension to rated power the various NSSS and BOP process variables that are monitored by the PCS begin to enter their respective ranges for normal plant operation. During this time it will be verified that the PCS correctly receives, validates, processes, and displays the applicable plant information. Recording and playback features will also be tested. Data manipulation and plant performance calculations using actual plant inputs will be verified for accuracy, using independent calculations for comparison. Also, the ability of the PCS to interface correctly with other plant control systems during operation will be demonstrated.

(4) Criteria

The performance of the PCS shall be as specified by the applicable design requirements. Additionally, plant performance calculations, especially those used to demonstrate compliance with core thermal limits, shall meet the accuracy requirements of the applicable plant safety analysis design assumptions.

14.2.12.2.8 Core Performance

(1) Purpose

To demonstrate that the various core and reactor performance characteristics such as power versus flow, core power distributions, and those parameters used to demonstrate compliance with core thermal limits and plant license conditions are in accordance with design limits and expectations.

(2) Prerequisites

The applicable preoperational tests have been completed and plant management has reviewed the test procedure(s) and has approved the initiation of testing. For each scheduled testing iteration the plant shall be in the appropriate operational configuration with all specified prerequisite testing complete, especially on plant systems to be used for collection or evaluation of pertinent data.

(3) Description

This test will collect data sufficient to demonstrate that reactor and core performance characteristics remain within design limits and expectations for all operational conditions which the plant is normally expected to encounter. Beginning with rod withdrawal and continuing through initial criticality, plant heatup, and the ascension to rated power, pertinent data will be collected at various rod patterns and power and flow conditions sufficient to determine the axial and radial core power distributions, compliance with core thermal limits, and the level of consistency with predicted core reactivity and power versus flow characteristics. Unusual plant conditions such as during control rod sequence exchange or natural circulation will also be investigated, if applicable.

(4) Criteria

Technical specification and license condition requirements involving core thermal limits, maximum power level, total core flow, and any observed reactivity anamolies or core instabilities shall be met when applicable. Other observations shall meet predictions and expectations or else should be evaluated and explained accordingly.

14.2.12.2.9 Nuclear Boiler Process Monitoring

(1) Purpose

To verify proper operation of various nuclear boiler process instrumention and to collect pertinent data from such instrumentation at various plant operating conditions in order to validate design assumptions and identify any operational limitations that may exist.

(2) Prerequisites

The applicable preoperational testing has been completed and plant management has reviewed the test procedure(s) and has approved the initiation of testing. For each scheduled testing iteration the plant shall be in the appropriate operational configuration with all specified prerequisite testing complete.

(3) Description

During plant heatup and power ascension pertinent parameters such as reactor coolant temperature, vessel dome pressure, vessel water level, and core flow will be monitored at selected intervals and plant conditions. This data will be used to verify proper instrument response to changing plant conditions and to document the relationships amongst these parameters and with other important parameters such as reactor power, feedwater flow and steam flow. The data will also be used to validate design assumptions such as those used in the calibration of vessel level or core flow indication. Additionally, the data will be used to help identify potential operational condition limitations such as excessive coolant temperature stratification in the vessel bottom head region.

(4) Criteria

The various nuclear boiler process instrumentation shall operate as designed in response to changes in plant conditions. The observed process characteristics shall be conservative relative to applicable safety analysis assumptions and should be consistent with design expectations.

14.2.12.2.10 System Expansion

(1) Purpose

The purpose of the thermal expansion test is to confirm that the pipe suspension system is working as designed and the pipeing is free of obstructions that could constrain free pipe movement caused by thermal expansion.

(2) Prerequisites

The preoperational tests have been completed and plant management has reviewed the test procedures and has approved the initiation of testing. For each scheduled testing iteration the plant shall be in the appropriate operational configuration with the specified prerequisite testing complete. The applicable instrumentation shall be checked or calibrated as is appropriate.

(3) Description

The thermal expansion tests consist of measuring displacements and temperatures of piping during various operating modes. The first power level used to verify expansion shall be as low as practicable. Thermal movement and temperature measurements shall be recorded at at least the following test points (following a suitable hold period to assure steady state temperatures):

(a) during reactor pressure vessel heatup at at least one intermediate temperature prior to reaching normal operating temperature, including an inspection of the piping and its suspension for obstructions or inoperable supports;

(b) following reactor pressure vessel heat up to normal operating temperature;

(c) following heatup of other piping systems to normal operating temperature (those systems whose heatup cycles differ from (2) above); and

(d) on subsequent heatup/cooldown cycles, as specified, at the applicable operating and shutdown temperatures, to measure possible shakedown effects.

Thermal expansion shall be conducted on plant systems of the following classifications:

(a) ASME Code Class 1, 2, and 3 systems;

(b) high energy piping systems inside Seismic Category I structures;

(c) high energy portions of systems whose failure could reduce the functioning of any Seismic Category I plant features to an unacceptable level; and

(d) Seismic Category I portions of moderate energy piping systems located outside containment.

(4) Criteria

The thermal expansion acceptance criteria are based upon the actual movements being within a prescribed tolerance of the movements predicted by analysis. Measured movements are not expected to precisely correspond with those mathematically predicted. Therefore, a tolerance is specified for differences between measured and predicted movement. The tolerances are based on consideration of measurement accuracy, suspension free play, and piping temperature distributions. If the measured movement does not vary from the predictions by more than the specified tolerance, the piping is expanding in a manner consistent with predictions and is therefore acceptable. Tolerances should be the same for all operating test conditions. The locations to be monitored and the predicted displacements for the monitored locations in each plant will be provided by the applicable design or testing specification.

14.2.12.2.11 System Vibration

(1) Purpose

To verify that the vibration of critical plant system components and piping is within acceptable limits during normal steady state power operation and during expected operational transients.

(2) Prerequisites

The applicable preoperational phase testing is complete and plant management has reviewed the test procedure(s) and has approved the initiation of testing. For each scheduled test iteration the plant shall be in the appropriate operational configuration with all specified prerequisite testing complete. The required remote monitoring instrumentation shall be calibrated and operational.

(3) Description

Vibration testing during the power ascension phase will be limited to those systems that could not be adequately tested during the preoperational phase. Systems within the scope of this testing are therefore the same as mentioned in Subsection 14.2.12.1.51. However, the systems that remain to be tested will primarily be those exposed to and affected by steam flow and high rates of core flow. Due to the potentially high levels of radiation present during power operation, the testing will be performed using remote monitoring instrumentation. Displacement, acceleration, and strain data will be collected at various critical steady state operating conditions and during significant transients such as turbine or generator trip, main steamline isolation, SRV actuation and RIP trip (if not already performed). Steady state and transient vibration affecting the RCIC steamline will also be monitored.

(4) Criteria

Criteria will be calculated for those points monitored for vibration for both steady state and transient cases. Two levels of criteria will be generated, one level for predicted vibration and one level based on acceptable values of displacement and acceleration and the associated stress to assure that there will be no failures from fatigue over the life of the plant. Failures to remain within the predicted levels of vibration should be investigated but do not necessarily preclude the continuation of further testing. However, failure to meet the criteria based on stress limits will require immediate investigation and resolution while the plant or affected system is placed in a safe condition.

14.2.12.2.12 Reactor Internals Vibration

(1) Purpose

To collect information needed to verify the adequacy of the design, manufacture, and assembly of reactor vessel internals with respect to the potential affects of flow induced vibration.

(2) Prerequisite

The applicable preoperational phase testing is complete, including the required inspections, and plant management has reviewed the test procedure and has approved the initiation of testing. For each scheduled testing iteration the plant shall be in the appropriate operational configuration with all specified prerequisite testing complete. The necessary special instrumentation shall be calibrated and operational.

(3) Description

Reactor internal vibration testing subsequent to fuel loading is merely an extension of the program described during the preoperational phase in Subsection 14.2.12.1.52. The vibration measurement portion of that program is expanded during the power ascension phase to include intermediate and critical power and flow conditions during steady state operation and anticipated operational transients that are expected to result in limiting or significant levels of reactor internals vibration over and above what was observed during the preoperational phase. The extent to which reactor internals vibration testing is conducted during the power ascension phase is dependent on the classification of the reactor internals as prototype or not in accordance with Regulatory Guide 1.20 as discussed in Subsections 3.9.2.4 and 3.9.7.1.

(4) Criteria

Criteria for limits on reactor internals vibration levels are developed during the vibration analysis portion of the assessment program as described in Subsection 14.2.12.1.52.

14.2.12.2.13 Recirculation Flow Control

(1) Purpose

To demonstrate that the stability and response characteristics of the recirculation flow control system are in accordance with design requirements for all applicable modes of control across the span of expected operational conditions.

(2) Prerequisites

The preoperational tests have been completed and plant management has reviewed the test procedure and has approved the initiation of testing. For each scheduled testing iteration the plant shall be in the appropriate operational configuration with all specified prerequisite testing complete. This includes preliminary adjustment and optimization of control system components, as appropriate.

(3) Description

Startup phase testing of the recirculation flow control system is intended to demonstrate that the overall response and stability of the system meets design requirements subsequent to controller optimization. Performance shall be demonstrated at a sufficient number of power and flow points to bound the expected system operational conditions including applicable modes of control (speed, flow and automatic load following) for each such demonstration. Testing will be accomplished by manual manipulation of controllers and/or by direct input of demand changes at various levels of control. Special control features such as those used to maintain a specified margin to the high flux scram setpoint or to avoid regions of potential core instability should also be demonstrated as appropriate.

(4) Criteria

Above all else, system performance shall be stable such that any type of divergent response is avoided. The response should also be sufficiently fast but with any oscillatory modes of response well damped, usually with decay ratios less than .25.

The overall response of the system, at all levels of control, should be within design requirements with respect to such standard control system criteria as response time, rise time, overshoot, and settling time. Also, the overall system performance should be in accordance with expectations for anticipated transients.

14.2.12.2.14 Feedwater Control

(1) Purpose

To demonstrate that the stability and response characteristics of the feedwater control system are in accordance with design requirements for applicable system configurations and operational conditions.

(2) Prerequisites

The preoperational tests are complete and plant management has reviewed the test procedure and has approved the initiation of testing. For each scheduled testing iteration the plant shall be in the appropriate operational configuration with all specified prerequisite testing complete. This includes preliminary adjustments and optimization of control system components, as appropriate.

(3) Description

Startup phase testing of the feedwater control system is intended to demonstrate that the overall response and stability of the system meets design requirements subsequent to controller optimization. Testing will begin during plant heatup for any special configurations designed for very low feedwater or condensate flow rates and will continue up through the normal full power line up. Testing shall include all modes of control and shall encompass the spectrum of plant power levels and operational conditions. Testing will be accomplished by manual manipulation of controllers and/or by direct input of demand changes at various levels of control. System response shall also be evaluated under transient operational conditions such as an unexpected loss of a feedwater pump or a rapid reduction in core flow and/or power level and after plant trips such as turbine trip or main steam line isolation. Proper setup of control system components or features designed to handle the nonlinearities or dissimilarities in system response at various conditions shall also be demonstrated. The above testing will also serve to demonstrate overall core stability to subcooling changes.

(4) Criteria

Above all else the feedwater control system performance shall be stable such that any type of divergent response is avoided. The response should be sufficiently fast but with any oscillatory modes of response well damped, usually with decay ratios less than 0.25. Additionally, the open loop response of the system should meet design requirements with respect to such standard control system criteria as response time, rise time, overshoot, and settling time. Also, the overall system response should be as expected following major plant transients and trips.

14.2.12.2.15 Pressure Control

(1) Purpose

To demonstrate that the stability and response characteristics of the pressure regulation system are in accordance with the design requirements for all modes of control under expected operating conditions.

(2) Prerequisites

The preoperational tests have been completed and plant management has reviewed the test procedure and has approved the initiation of testing. For each scheduled testing iteration the plant shall be in the appropriate operational configuration with all specified prerequisite testing complete. This includes preliminary adjustment and optimization of control system components, as appropriate.

(3) Description

Startup phase testing of the pressure control system is intended to demonstrate that the overall response and stability of the system meets design requirements, subsequent to control system optimization. Performance shall be evaluated across the spectrum of anticipated steam flows for both the pressure regulation and load following modes of control, as applicable. Testing shall demonstrate acceptable response with either the turbine control valves or bypass valves in control and for the transition between the two. Testing will be accomplished by manual manipulation of controllers and/or direct input of demand changes at various levels of control. It shall also be demonstrated that other affected parameters remain within acceptable limits during such pressure regulator induced transient maneuvers. Overall system response will be evaluated during other plant transients as well. Additionally, proper setup of components or features designed to deal with the nonlinearities or dissimilarities in system response that may exist under various conditions shall be demonstrated.

(4) Criteria

Above all else, system performance shall be stable such that any type of divergent reonse is avoided. The response should be sufficiently fast but with any oscillatory modes of response well damped, usually with decay ratios less than .25. The overall response of the system, for each mode and level of control, should be within design requirements for such standard control system criteria as response time, rise time, overshoot and setting time. Also, the overall system performance should be in accordance with expectations for anticipated transients.

14.2.12.2.16 Plant Automation and Control

(1) Purpose

To verify proper plant performance in automatic modes of control such as during automatic plant startup or automatic load following (ALF) under the direction of the power generation control system (PGCS) and the automatic power regulator (APR).

(2) Prerequisites

The applicable preoperational tests have been completed and plant management has reviewed the testing procedure and has approved the initiation of testing. Affected systems and equipment, including lower level control systems such as RC&IS, recirc flow control, feedwater control and turbine control, as well as monitoring and predicting functions of the plant process computer and/or automation computer, shall have been adequately tested under actual operating conditions.

(3) Description

A comprehensive series of tests will be performed in order to demonstrate proper functioning of the various plant automation and control features. This testing shall include or bound all expected plant operating conditions under all permissable modes of control and shall also verify, to the extent possible, avoidance of prohibited or undesirable conditions or control modes. ALF capabilities will be demonstrated under control of the APR for both control rod movements and core flow changes including anticipated transition regions. Such testing will include demonstration(s) that the dynamic response of the plant to design load swings for the facility, including limiting step and ramp changes as appropriate, is in accordance with design. The ability of the PGCS to properly orchestrate automated plant startup, shutdown and power maneuvering will be shown. Also to be tested are system components or interfaces that perform monitoring, prediction, processing, validation, alarm, protection or control functions.

(4) Criteria

The PGCS, APR and other features and functions of plant automation and control shall perform in accordance with the applicable design and testing specifications. Automatic maneuvering characteristics of plant and systems shall meet the appropriate response and stability requirements. Safety and protection features shall perform consistant with safety analysis assumptions and predictions.

14.2.12.2.17 Reactor Recirculation System Performance

(1) Purpose

To verify that reactor recirculation system performance characteristics are in accordance with design requirements.

(2) Prerequisites

The preoperational testing is complete and plant management has reviewed the test procedure and has approved the initiation of testing. For each scheduled testing iteration the plant shall be in the appropriate operational configuration with all specified prerequisite testing complete. Instrumentation has been checked or calibrated, as is appropriate.

(3) Description

Pertinent recirculation system and related parameters will be monitored at a variety of power and flow conditions in order to demonstrate that system operation is in accordance with design. Parameters to be monitored and evaluated should include RIP speeds, pump deck and core plate differential pressures, pump efficiencies, maximum core flow capability, and any number of other variables that may indicate the status of the RIPs and their shafts, motors, or heat exchangers. Data shall also be taken and evaluated during transient conditions such as pump trips and restarts, and during off normal conditions such as one pump out of service operation. Of particular interest will be the onset of reverse flow through idle pumps and the calibration of total core flow indictions during both normal and off normal operating conditions.

(4) Criteria

When applicable, measured parameters shall compare conservatively with safety analysis design assumptions. Additionally, test data should demonstrate that system steady state and transient performance meets design requirements.

14.2.12.2.18 Feedwater System Performance

(1) Purpose

To verify that the overall feedwater system operates in accordance with design requirements.

(2) Prerequisites

The preoperational testing is complete and plant management has reviewed the test procedure and has approved the initiation of testing. For each scheduled testing iteration the plant shall be in the appropriate operational configuration with all specified prerequisite testing complete. Applicable instrumentation has been checked or calibrated as is appropriate.

(3) Description

Pertinent parameters will be monitored throughout the feedwater system, and condensate system if appropriate, across the spectrum of system flow and plant operating conditions in order to demonstrate that system operation is in accordance with design. Parameters to be monitored may include temperatures, pressures, flow rates, pressure drops, pump speeds and developed heads, and general equipment status. Of special interest will be data that serves to verify design assumptions used in plant transient performance and safety analysis calculations like maximum feedwater runout capabilities and feedwater temperature versus power level relationships. Steady state and transient testing will be conducted as necessary, to assure that adequate margins exist between system variables and setpoints of instruments monitoring these variables to prevent spurious actuations or loss of system pumps and motor-operated valves.

(4) Criteria

When applicable, measured parameters shall compare conservatively with safety analysis design assumptions. Additionally, test data should demonstrate that system steady state and transient performance meets design requirements.

14.2.12.2.19 Main Steam System Performance

(1) Purpose

To verify that main steam system related performance characteristics are in accordance with design requirements.

(2) Prerequisites

The preoperational tests are complete and plant management has reviewed the test procedure and has proved the initiation of testing. For each scheduled testing iteration the plant shall be in the appropriate operational configuration with all prerequisite testing complete. Applicable instrumentation shall be checked or calibrated as is appropriate.

(3) Description

Pertinent system parameters, such as temperatures, pressures, and flows, will be monitored at various steam flow rates in order to demonstrate that system operation is in accordance with design. The steam flow measuring devices that provide input to feedwater control and/or leak detection logic shall be crosschecked to verify the accuracy of design calibration assumptions. If appropriate, the pressure drop developed across critical components shall be compared with design values. The quality of the steam leaving the reactor shall also be determined to be within design requirements (if not previously tested).

(4) Criteria

When applicable, measured parameters shall compare conservatively with safety analysis design assumptions. Additionally, test data should demonstrate that system steady state and transient performance meets design requirements.

14.2.12.2.20 Residual Heat Removal System Performance

(1) Purpose

To verify that residual heat removal system performance is in accordance with design for actual plant operating conditions.

(2) Prerequisites

The preoperational testing is complete and plant management has reviewed the test procedure and has approved the initiation of testing. For each scheduled testing iteration the plant shall be in the appropriate operational configuration with all specified prerequisite testing complete. Instrumentation has been checked or calibrated as appropriate.

(3) Description

Startup phase testing of the RHR system is intended to demonstrate the capabilities of the system beyond what was possible during the preoperational phase due to insufficient temperature and pressure conditions. Pertinent system parameters will be monitored in the suppression pool cooling and shutdown cooling modes to verify that overall system operation and heat removal capabilities are in accordance with design requirements. An attempt shall be made to obtain results with flow rates and temperatures near process diagram values. However, due to the relatively low core exposures and decay heat loads expected during the startup program, care shall be taken such that the limit on vessel cooldown rate is not exceeded.

(4) Criteria

System performance, especially heat removal capability, shall meet safety analysis requirements. Additionally, measured parameters should indicate that overall system performance is consistent with design expectations.

14.2.12.2.21 Reactor Water Cleanup System Performance

(1) Purpose

To verify that reactor water cleanup system performance, in all modes of operation, is in accordance with design requirements at rated reactor temperature and pressure conditions.

(2) Prerequisites

The preoperational testing is complete and plant management has reviewed the test procedure and has approved the initiation of testing. For each scheduled testing iteration the plant shall be in the appropriate operational configuration with the specified prerequisite testing complete. Instrumentation has been checked or calibrated as appropriate.

(3) Description

Startup phase testing of the RWCU system is an extension of the preoperational tests for rated temperature and pressure conditions. System parameters will be monitored in the various modes of operation at critical temperature, pressure and flow conditions.

The performance of system heat exchangers and filter/demineralizer units will be evaluated at hot operating conditions. The ability of the system to reject excess vessel inventory during plant heatup will be verified. Other system features shall be demonstrated as appropriate.

(4) Criteria

System performance should meet the specified design requirements in all operating modes.

14.2.12.2.22 RCIC System Performance

(1) Purpose

To verify proper operation of the RCIC system over its expected operating pressure and flow ranges, and to demonstrate reliability in automatic starting from cold standby with the reactor at power.

(2) Prerequisites

The preoperational tests are complete and plant management has reviewed the test procedure and has approved the initiation of testing. For each scheduled testing iteration the plant shall be in the appropriate operational configuration with all specified prerequisite testing complete. All applicable instrumentation shall be checked or calibrated as is appropriate.

(3) Description

The RCIC system will be tested in two ways, through a full flow test line leading to the suppression pool and by flow injection directly into the reactor vessel. The first set of tests will consist of manual and automatic mode starts and steady state operation, at 150 psig and near rated reactor pressure conditions, in the full flow test mode. During these tests an attempt will be made to throttle pump discharge pressure in order to simulate reactor pressure and the expected pipeline pressure drop. This testing is done to demonstrate general system operability and to make most controller adjustments. Reactor vessel injection tests will follow to complete the controller adjustments. Proper controller adjustment is verified by introducing small step disturbances in speed and flow demand and then demonstrating satisfactory system response and stability. This will be done at both low RCIC pump flow (but above minimum turbine speed) and near rated RCIC pump flow conditions, and at reactor pressures of 150 psig and rated, in order to span the RCIC operating range.

After all controller and system adjustments have been made a defined set of demonstrations will be performed with the final settings. This will include two consecutive successful reactor vessel injections, by automatic initiation from the cold standby condition, to demonstrate system reliability. Cold is defined as a minimum of 72 hours without any kind of RCIC operation. Following these tests, system data will be collected while operating in the full flow test mode to provide a benchmark for comparison with future surveillance tests. Additionally, a demonstration of extended operation of up to two hours (or until the pump and turbine and their auxiliaries have stabilized) of continuous operation at rated flow conditions will be performed. For all testing proper operation of the system and related auxiliaries will be evaluated.

Additionally, proper functioning of the RCIC steamline isolation valves will be verified at rated temperature and pressure and at higher power levels if appropriate. This verification will include proper valve operation and acceptable closure timing in response to an isolation signal. Also, sufficient operating data will be taken in order to verify proper setting of, or to adjust as necessary, the high RCIC steamline flow trip setting of the leak detection and isolation system trip logic.

Also, any RCIC system testing that was not performed during the preoperational test phase, due to the insufficiency of the temporay steam supply source utilized, will be completed as early in the program as is practicable.

(4) Criteria

The RCIC turbine shall not trip or isolate during the manual or automatic start tests and should avoid the applicable trip or isolation setpoints by the specified margins. For automatic initiations the time to rated flow shall meet technical specification and safety analysis requirements. Overall system operation, and that of the applicable auxiliary equipment, shall meet safety design requirements and should be consistent with performance expectations. The RCIC control system shall not evidence divergent tendencies and should provide quick but stable response.

14.2.12.2.23 Plant Cooling/Service Water System(s) Performance

(1) Purpose

To verify performance of the various plant cooling/service water systems, including the reactor building cooling water system, the reactor service water system, the turbine building cooling water system and the turbine service water system under expected reactor power operation load conditions.

(2) Prerequisites

The preoperational tests are complete and plant management has reviewed the test procedure and has approved the initiation of testing. For each scheduled testing iteration, the plant shall be in the appropriate operational configuration with the specified prerequisite testing complete. All applicable instrumentation shall be checked or calibrated as is appropriate.

(3) Description

Power ascension phase testing of plant cooling water systems is necessary only to the extent that fully loaded conditions could not be approached during the preoperational phase. Pertinent parameters shall be monitored in order to provide a final verification of proper system flow balancing and heat exchanger performance under near design or special conditions, as is appropriate. This will include extrapolation of results obtained under normal or test conditions as needed to demonstrate required performance at limiting or accident conditions.

(4) Criteria

System performance should be consistent with design requirements. For systems that are taken credit for in the plant safety analysis, performance shall meet the minimum requirements assumed in such analysis.

14.2.12.2.24 HVAC System Performance

(1) Purpose

To verify various HVAC systems performance for the loads present during reactor power operation.

(2) Prerequisites

The preoperational tests are complete and plant management has reviewed the test procedure(s) and has approved the initiation of testing. For each scheduled testing iteration, the plant shall be in the appropriate operational configuration with the specified prerequisite testing complete. All applicable instrumentation shall be checked or calibrated as is appropriate.

(3) Description

Power ascension phase testing of plant HVAC systems is necessary only to the extent that fully loaded conditions could not be approached during the preoperational phase. Pertinent parameters shall be monitored in order to provide a final verification of proper system flow balancing and cooler performance under near design or special situation conditions, as is appropriate. This will include extrapolation of results obtained under normal or test conditions as needed to demonstrate required performance at limiting or accident conditions.

(4) Criteria

System performance should be consistent with design requirements. For systems that are taken credit for in the plant safety analysis, performance shall meet the minimum requirements assumed in such analysis.

14.2.12.2.25 Turbine Valve Performance

(1) Purpose

To demonstrate proper functioning of the main turbine control, stop, and bypass valves during reactor power operation.

(2) Prerequisites

The preoperational tests are complete and plant management has reviewed the test procedure(s) and has approved the initiation of testing. For each scheduled testing iteration, the plant shall be in the appropriate operational configuration with the specified prerequisite testing complete. All applicable instrumentation shall be checked or calibrated as is appropriate.

(3) Description

Early in the startup test phase with the reactor at a moderate power level and with the turbine generator on line, the operability of the control, stop, and bypass valves will be demonstrated. This testing will be similar to the individual valve testing required by the technical specification surveillance program. In addition to valve operability the overall plant response will be observed. Since turbine valve testing is required routinely during power operation, it is also desirable to determine the maximum power level at which such tests can safely be performed by observing plant response during such tests at successively higher power levels.

(4) Criteria

All turbine valves shall operate properly and in accordance with applicable technical specification requirements. Valve performance and plant response should be consistent with design requirements. During high power testing, minimum trip avoidance margins should be maintained.

14.2.12.2.26 MSIV Performance

(1) Purpose

To demonstrate proper operation of and to verify closure times for main steamline isolation valves, including branch steamline isolation valves, during power operation.

(2) Prerequisites

The preoperational tests are complete and plant management has reviewed the test procedure(s) and has approved the initiation of testing. For each scheduled testing iteration, the plant shall be in the appropriate operational configuration with the specified prerequisite testing complete. All applicable instrumentation shall be checked or calibrated as is appropriate.

(3) Description

At rated temperature and pressure, and then again at an intermediate power level, each MSIV will be individually stroked in the fast closure mode. Valve operability and closure time will be verified and overall plant response observed. Closure times will be evaluated consistent with technical specification and safety analysis requirements. If appropriate, it is also desirable to determine the maximum power level at which such tests can safely be performed by observing plant response during such tests at successively higher power levels. In addition, at rated temperature and pressure, proper functioning and stroke timing of branch steamline isolation valves (e.g. on common drain line) will be demonstrated.

(4) Criteria

MSIV closure times shall be within the limits required by plant technical specifications and those assumed in the plant safety analysis. Overall valve performance should be in accordance with design requirements. During higher power level tests minimum plant trip avoidance margins should be maintained.

14.2.12.2.27 SRV Performance

(1) Purpose

To demonstrate that each safety/relief valve can be opened and closed properly in the relief mode during reactor power operation.

(2) Prerequisites

The preoperational tests are complete and plant management has reviewed the test procedure(s) and has approved the initiation of testing. For each scheduled testing iteration, the plant shall be in the appropriate operational configuration with the specified prerequisite testing complete. All applicable instrumentation shall be checked or calibrated as is appropriate.

(3) Description

A functional test of each SRV shall be made as early in the power ascension as is practicable based on the valve manufacturer's recommendations. This is normally the first time the plant reaches rated temperature and pressure. Opening and closing of each valve, as well as evidence of steam flow, will be verified by response of SRV discharge tailpipe sensors and by observed changes in steamflow in the main steamlines downstream of the SRVs. Tailpipe sensors may include temperature indications, pressure switches or acoustic monitors. Downstream indications of SRV operation could be changes in such parameters as turbine valve positions or generator output. Such changes will also be evaluated for anomalies which may indicate a restriction or blockage in a particular SRV tailpipe by making valve to valve comparisons. Tailpipe backpressures shall also be evaluated against any bounding design assumptions. Additionally, during applicable plant transient testing, where SRVs are expected to open, operability, opening setpoints, and reset pressures will be verified.

(4) Criteria

There shall be a positive indication of steam discharge during each manual valve opening. For automatic openings the relief setpoints and reset pressures shall be within technical specification limits. SRV open and close indications, including tailpipe sensors, should function as designed. For manual openings the apparent steam flow through each SRV should not vary significantly from the average for all valves. Tailpipe back pressures should be consistent with design assumptions.

14.2.12.2.28 Loss of Feedwater Heating

(1) Purpose

To demonstrate proper integrated plant response to a loss of feedwater heating event and to verify the adequacy of the modeling and associated assumptions used for this transient in the plant licensing analysis.

(2) Prerequisites

The preoperational tests are complete and plant management has reviewed the test procedure and has approved the initiation of testing. The plant shall be in the appropriate operational configuration with the specified prerequisite testing complete. All applicable instrumentation shall be checked or calibrated as is appropriate.

(3) Description

The credible single failure or operator error that has been indentified as resulting in the largest feedwater temperature reduction will be initiated at a significantly high power level, while considering the event analyzed and the predicted results. Core performance and overall plant response will be observed in order to demonstrate proper integrated response and to compare actual results with those predicted. This comparison will take into account the differences between actual initial conditions and observed results and the assumptions used for the analytical predictions.

(4) Criteria

Resultant MCPR shall remain greater than the fuel thermal safety limit and measured results shall compare conservatively with design assumptions and predictions. The overall plant response should be according to design and testing specifications.

14.2.12.2.29 Feedwater Pump Trip

(1) Purpose

To demonstrate the ability of the plant to respond to and survive the loss of an operating feedwater pump from near rated power conditions.

(2) Prerequisites

The preoperational tests are complete and plant management has reviewed the test procedure and has approved the initiation of testing. The plant shall be in the appropriate operational configuration with the specified prerequisite testing complete. Applicable instrumentation shall be checked or calibrated as is appropriate.

(3) Description

From an initial reactor power level near rated, one of the operating feedwater pumps will be tripped and it will be demonstrated that the overall plant response is such that a reactor trip is avoided. Specifically, it shall be verified that the feedwater control system is sufficiently responsive, in conjunction with specified mitigating features, to prevent a reactor trip due to the water level transient. Separate tests may be required to demonstrate features such as automatic core flow runback or auto start of a standby feedpump, if appropriate.

(4) Criteria

From normal operating conditions, the reactor should remain operating with adequate margin to a water level setpoint trip.

14.2.12.2.30 Recirculation Pump Trip

(1) Purpose

To demonstrate acceptable plant response and to obtain recirculation system performance data during and subsequent to potential reactor internal pump (RIP) trip transients.

(2) Prerequisites

The preoperational tests are complete and plant management has reviewed the test procedure and has approved the initiation of testing. The plant shall be in the appropriate operational configuration with the specified prerequisite testing complete. The applicable instrumentation shall be checked or calibrated as is appropriate.

(3) Description

A potential threat to plant availability is the reactor trip due to high water level that may result from an unexpected trip of one or more of the RIPs. From near rated power and flow the most limiting, credible RIP trip scenario, for which the plant is designed to remain operating, will be initiated in order to verify proper plant response. Of major concern is the feedwater control systems ability to control reactor water level in time to avoid a high water level trip. Also to be demonstrated are the coastdown characteristics of the tripped pump(s), the onset of reverse flow through the idle pump(s), and the ability to restart the pump(s). The coastdown characteristics are of importance especially during a high power turbine or generator trip where the RPT logic actuates to provide increased margin to core thermal limits. Therefore, an evaluation will be made during the testing of Subsection 14.2.12.2.33 to demonstrate that coastdown characteristics are conservative relative to safety analysis assumptions. The testing described will also help to verify proper operation of the SCRRI logic and function in response to actual RIP trip, and will help demonstrate proper overall plant response to events that result in SCRRI actuation.

(4) Criteria

The reactor should not trip following any RIP trip scenario for which it is designed to remain operating. Recirculation system performance and overall plant response should be in accordance with design expectations. RIP and core flow coastdown characteristics shall be conservative relative to safety analysis design assumptions. During all RIP trip and restart scenarios tested, the applicable parameters should maintain the specified minimum margins to their associated trip setpoints.

14.2.12.2.31 Shutdown From Outside the Main Control Room

(1) Purpose

To demonstrate that the reactor can be shut down from normal power operation to the point where a controlled cooldown has been established, via decay heat rejection to the ultimate heat sink, with vessel pressure and water level under control, all using means entirely outside the main control room.

(2) Prerequisites

The preoperational tests are complete and plant management has reviewed the test procedure and has approved the initiation of testing. The plant shall be in the appropriate operational configuration with the specified prerequisite testing complete. The applicable instrumentation shall be checked or calibrated as is appropriate. An adequate number of qualified personnel shall be on site to perform the specified testing as well as their normal plant operational duties.

(3) Description

This test shall be performed from a low

initial power level but from one that is sufficiently high such that a majority of plant systems are in their normal configurations for power operation. This test is as much a test of normal and emergency plant procedures and the ability of plant personnel to carry them out as it is a test of plant systems and equipment. Therefore, the test shall be performed using the minimum shift crew that would be available during an actual event. Additional qualified personnel will be available in the control room to monitor the progress of the test and to re-establish control of the plant should an unsafe condition develop. These personnel will also perform predefined non-safety related activities to protect plant equipment where such activities would not be required during an actual emergency situation. The test will be initiated by simulating a control room evacuation and then tripping the reactor by means outside of the control room. Achievement and maintenance of the hot standby condition is then demonstrated through control of vessel pressure and water level. The ability to reach cold shutdown is demonstrated by cooling the reactor down to where some form of residual heat removal can be and is initiated by establishing a heat rejection path to the ultimate heat sink, again by means entirely outside of the main control room. The cold shutdown capability does not necessarily have to be demonstrated immediately following the shutdown and hot standby demonstration as long as the total integrated capability is adequately demonstrated. Also, additional personnel, over and above the minimum shift crew, may be utilized for the cold shutdown portion of the test consistent with plant procedure and management's ability to assemble extra help at the plant site in emergency situations.

(4) Criteria

The remote shutdown test shall, as a minimum, demonstrate the capability of plant personnel, equipment, and procedures to initiate a reactor trip, to achieve and maintain hot standby conditions for at least 30 minutes, and to initiate decay heat removal such that coolant temperature is reduced by at least $50^{\circ}F$, all from outside the main control room. Additionally, system and plant performance should be consistent with design and testing specification requirements.

14.2.12.2.32 Loss of Turbine Generator and Offsite Power

(1) Purpose

To verify proper electrical equipment response and reactor system transient performance during and subsequent to a turbine generator trip with coincident loss of all offsite power sources.

(2) Prerequisites

The preoperational tests are complete and plant management has reviewed the test procedure and has approved the initiation of testing. The plant shall be in the appropriate operational configuration with all specified prerequisite testing complete. Applicable instrumentation shall be checked or calibrated as is appropriate. A sufficient number of qualified personnel shall be available to handle the needs of this test as well as those associated with normal plant operation.

(3) Description

This test shall be performed at a relatively low power level early in the power ascension phase, but with the generator on line at greater than 10% load. The test will be initiated in a way such that the turbine generator is tripped and the plant is completely disconnected from all offsite power sources. The plant shall then be maintained isolated from offsite power for a minimum of 30 minutes. During this time, appropriate parameters will be monitored in order to verify the proper response of plant systems and equipment, including the proper switching of electrical equipment and the proper starting and sequencing of onsite power sources and their respective loads.

(4) Criteria

All safety-related equipment and systems, and others judged to be important to safety for this event, shall function as designed in accordance with technical specification and safety analysis requirements. All other systems and equipment should perform consistent with applicable design and testing specifications.

14.2.12.2.33 Turbine Trip and Generator Load Rejection

(1) Purpose

To verify that the dynamic response of the reactor and applicable systems and equipment is in accordance with design for protective trips of the turbine and generator during power operation.

(2) Prerequisites

The preoperational tests are complete and plant management has reviewed the test procedure and has approved the initiation of testing. The plant shall be in the appropriate operational configuration with all specified prerequisite testing complete. All applicable instrumentation shall be checked or calibrated as is appropriate.

(3) Description

From an initial power level near rated, the main generator will be tripped in order to verify the proper reactor and integrated plant response. The method for initiating the trip shall be chosen so that the turbine is subjected to maximum overspeed potential, provided there are expected to be relevant differences amongst the options available. Reactor parameters such as vessel dome pressure and simulated fuel surface heat flux will be monitored and compared with predictions so that the adequacy and conservatism of the analytical models and assumptions used to license the plant can be verified. Proper response of systems and equipment such as the turbine stop, control, and bypass valves, main steam relief valves, the reactor protection system, and the feedwater and recirculation systems will also be demonstrated. The core flow coastdown characteristics should be evaluated upon actuation of the recirculation pump trip logic. The ability of the feedwater system to control vessel level after a reactor trip shall also be verified. Overspeed of the main turbine shall also be evaluated since the generator is unloaded prior to complete shutoff of steam to the turbine.

For a turbine trip, the generator remains loaded and there is no overspeed. However, the dynamic response of the reactor may be different if the steam shutoff rate is different. If there is expected to be a significant difference, then it may be necessary to perform a separate demonstration and evaluation, similar to that discussed above, but initiated by a direct trip of the main turbine.

A turbine or generator trip should also be performed at an initial power level that is below that where a direct reactor trip is actuated and within the capacity of the bypass valves. Reactor dynamic response is not as important for this transient except for the ability to remain operating as designed. More important is the demonstration of proper integrated plant and system performance.

(4) Criteria

The reactor shall not scram during turbine or generator trips initiated from power levels within the capacity of the bypass valves and below the point at which the direct scram trip on turbine stop valve closure or control valve fast closure is enabled. For high power turbine or generator trips, reactor dynamic response should be consistent with predictions based on expected system characteristics and shall be conservative relative to safety analysis results based on design assumptions. Of particular importance are vessel dome pressure and simulated fuel surface heat flux. Safety-related and essential equipment and systems shall respond, as applicable, consistent with technical specification and safety analysis requirements. Other plant systems and equipment shall perform in accordance with the appropriate design and testing specifications.

14.2.12.2.34 Reactor Full Isolation

(1) Purpose

To verify that the dynamic response of the reactor and applicable systems and equipment is in accordance with design for a simultaneous full closure of all MSIVs from near rated reactor power.

(2) Prerequisites

The preoperational tests are complete and plant management has reviewed the test procedure and has approved the initiation of testing. The plant shall be in the appropriate operational configuration with all specified prerequisite testing complete. All applicable instrumentation shall be checked or calibrated as is appropriate.

(3) Description

A simultaneous full closure of all MSIVs will be initiated from near rated power in order to verify proper reactor and integrated plant response. Reactor dynamic response, as determined by such parameters as vessel dome pressure and simulated fuel surface heat flux, will be compared with analytical predictions in order to verify the adequacy and conservatism of the models and assumptions used in the plant safety and licensing analysis. Proper response of systems and equipment such as the MSIVs, SRVs, the reactor protection system, and the feedwater and recirculation systems will also be demonstrated.

(4) Criteria

The reactor dynamic response should be consistent with predictions based on expected system characteristics and shall be conservative relative to safety analysis results based on design assumptions. Safety-related and essential equipment and systems shall respond, as applicable, consistent with technical specification and safety analysis requirements. Other plant systems and equipment should perform in accordance with the appropriate design and testing specifications.

14.2.12.2.35 Offgas System

(1) Purpose

To verify proper operation of the various components of the offgas system over the expected operating range of the system.

(2) Prerequisites

The preoperational tests have been completed and plant management has reviewed the test procedure and has approved the initiation of testing. For each scheduled testing interation, the plant shall be in the appropriate operational configuration with the specified prerequisites testing complete. All applicable instrumentation shall be checked or calibrated as is appropriate.

(3) Description

Proper operation of the offgas system will be demonstrated by monitoring pertinent parameters such as temperature, pressure, flow rate, humidity, hydrogen content, and effluent radioactivity. Data shall be collected at selected operating points such that each critical component of the system is evaluated over its particular expected operating range. Performance shall be demonstrated for specific components such as catalytic recombiners, and activated carbon absorbers as well as the various heaters, coolers, dryers and filters. Also to be evaluated are the piping, valving, instrumentation and control that comprise the overall system. Testing of the offgas system is also discussed in Section 11.3.9.

(4) Criteria

Hydrogen concentration and radioactivity effluents shall not exceed technical specification limits. All applicable system and component parameters should be consistent with design and testing specification requirements.

14.2.12.2.36 Loose Parts Monitoring Baseline Data

(1) Purpose

To collect baseline data for the loose parts monitoring system under normal plant operational conditions.

(2) Prerequisites

The preoperational tests are complete and plant management has reviewed the test procedure and has approved the iniation of testing. The plant shall be in the appropriate operational configuration for the scheduled testing. Applicable instrumentation shall be checked or calibrated as is appropriate.

(3) Description

Loose parts monitoring system data will be collected at appropriate power and flow conditions to provide a baseline set of data indicative of normal plant operations. The data obtained will be used to help verify the adequacy of, or to facilitate needed changes to, initial alert level settings above normal levels.

(4) Criteria

Sufficient baseline data shall be obtained so as to verify the adequacy of system alert level settings in accordance with design requirements.

14.2.12.2.37 Concrete Penetration Temperature Surveys

(1) To demonstrate the acceptability of concrete wall temperatures in the vicinity of selected high temperature penetrations under normal plant operational conditions.

(2) The preoperational tests are complete and plant management has reviewed the test procedure and has approved the initiation of testing. The plant shall be in the appropriate operational configuration for the scheduled testing. Applicable instrumentation shall be installed and checked or calibrated as is appropriate.

(3) Description

Concrete temperature data will be collected, around selected high temperature penetrations, at various power levels and system configurations in order to verify acceptable performance under expected plant operational conditions. Penetrations and measurement locations selected for monitoring, as well as the test conditions at which data is collected, shall be sufficiently comprehensive so as to include the expected limiting thermal loading conditions on critical concrete walls and structures within the plant.

(4) Criteria

The temperature(s) of the concrete at the monitored locations should be consistent with design predictions and shall not exceed design basis requirements or assumptions critical to associated design basis analysis.

14.2.12.2.38 Radioactive Waste Systems Performance

(1) Purpose

To demonstrate acceptable performance of gaseous and liquid radioactive waste processing, storage and release systems under normal plant operational conditions.

(2) The preoperational tests are complete and plant management has reviewed the test procedure and has approved the initiation of testing. The plant shall be in the appropriate operational configuration for the scheduled testing. The necessary instrumentation shall be checked or calibrated. Appropriate precautions shall be taken relative to activities conducted in the vicinity of radioactive material or potential radiation areas.

(3) Radioactive waste systems operation will be monitored, and appropriate data collected, during the power ascension test phase to demonstrate system operation is in accordance with design requirements. Operation and testing of liquid and gaseous radioactive waste systems is discussed in

detail in Sections 11.2 and 11.3, respectively. Testing specific to the main condenser offgas system is also discussed separately in Subsection 14.2.12.2.35.

(4) Criteria

Performance characteristics of the liquis and gaseous radioactive waste systems should be in accordance with the appropriate design and testing specifications, and as discussed in Sections 11.2 and 11.3, respectively. Handling and release of radioactive wastes shall be in conformance with all applicable regulations.

14.2.12.2.39 Steam and Power Conversion Systems Performance

(1) Purpose

To demonstrate acceptable performance of the various plant steam driven auxiliaries and power conversion systems under expected operational conditions, particularly that equipment that could not be fully tested during the preoperational phase due to inadequate steam flow conditions.

(2) Prerequisites

The preoperational tests are complete and plant management has reviewed the test procedure and has approved the initiation of testing. The plant shall be in the appropriate operational configuration for the scheduled testing. The necessary instrumentation shall be checked or calibrated/.

(3) Description

Operation of steam driven plant auxiliaries and power conversion systems will ne monitored, and appropriate data collected, during the power ascesion test phase to demonstrate system operation is in accordance with design requirements. Systems to be monitored include the main turbine and generator and their auxiliaries, the feedwater heaters and moisture separator/reheaters, the main condenser and condenser evacuation system, and the main circulating water system. Operation and testing of power conversion systems is discussed in detail in Chapter 10. The main turbine generator and related auxiliaries are discussed in Section 10.2 and other power conversion equipment and systems are discussed in Section 10.4. Testing specific to turbine valves is described in Subsection 14.2.12.2.25 and plant transient testing involving the main turbine generator is described in Subsection 14.2.12.2.33.

(4) Criteria

Performance characteristics of the various systems monitored should be in accordance with the appropriate design and testing specifications, and as discussed in Sections 10.2 and 10.4.

14.2.13 COL License Information

The preceding discussion of preoperational and startup tests were limited to those systems and components within, or directly related to, the ABWR Standard Plant. Other testing, with respect to site specific aspects of the plant will be necessary to satisfy certain ABWR interface requirements. Testing of such systems and components shall be adequate to demonstrate conformance to such requirements as defined throughout the specific chapters of the SSAR. Below are systems that may require such testing:

(1) electrical switchyard and equipment;

(2) the site security plan;

(3) personnel monitors and radiation survey instruments; and

(4) the automatic dispatcher control system (if applicable).

Also to be supplied by the applicant referencing the ABWR design is the startup administration manual described in Section 14.2.4, which will describe, among other things, what specific permissions are required for the approval of test results and the permission to proceed to the next testing plateau.

The applicant referencing the ABWR Standard Plant shall also provide a list of those tests to be performed as part of the power ascension test phase that are proposed to be exempt from operating license conditions requiring NRC prior approval for major test changes. Such tests are those which are not essential to the demonstration of conformance with design requirements for structures, systems, components, and design features which meet any of the following criteria:

(a) Those that will be used for safe shutdown and cooldown of the reactor under normal plant conditions and for maintaining the reactor in a safe condition for an extended shutdown period;

(b) Those that will be used for safe shutdown and cooldown of the reactor under transient (infrequent or moderately frequent events) conditions and postulated accident conditions and for maintaining the reactor in safe condition for an extended shutdown period following such conditions;

(c) Those that will be used for establishing conformance with safety limits or limiting conditions for operation that will be included in the facility technical specifications;

(d) Those that are classified as engineered safety features or will be used to support or ensure the operation of engineered safety features within the design limits;

(e) Those that are assumed to function or for which credit is taken in the accident analysis for the facility, as described in the FSAR; or

(f) Those that will be used to process, store, control, or limit the release of radioactive materials.

Of the tests described in Subsection 14.2.12.2 for the ABWR Standard Plant the following tests, or designated portions thereof, meet the above criteria:

(1) 14.2.12.2.13 Recirculation Flow Control - <u>except</u> for those features intended to limit maximum core flow;

(2) 14.2.12.2.21 Reactor Water Cleanup System Performance

(3) 14.2.12.2.23 Plant Cooling/Service Water System Performance - those portions pertaining to the turbine building and service water systems;

(4) 14.2.12.2.24 HVAC System Performance - Those portions pertaining to the normal HVAC system and its associated nonessential chilled water system;

(5) 14.2.12.2.29 Feedwater Pump Trip; and

(6) 14.2.12.2.39 Steam and Power Conversion System Performance.

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Table 14.2-1

POWER ASCENSION TEST MATRIX

POWER ASCENSION TEST	TESTING PLATEAU: OV	HU	LP	MP	HP	NOTES
Reactor Water Cleanup System Performance						
Steady State Performance		✓			✓	
Inventory Rejection Mode		✓				
F/D Performance					✓	May be accomplished during earlier testing plateaus
RCIC System Performance						
Low Reactor Pressure		✓				
High Reactor Pressure		✓				
Hot/Cold Quick Starts		✓	✓			As needed to complete required quick starts subsequent to TC-HU
Plant Cooling/Service Water System Performance						
Steady State Power Operations		✓	✓	✓	✓	
Off-Normal Operations		✓	✓		✓	During RHR Hx operation, as practicable
HVAC System Performance						
Steady State Power Operations		✓	✓	✓	✓	
Off-Normal Operations		✓	✓	✓	✓	In individual spaces as conditions allow (i.e. as pertinent equipment is operated)
Turbine Valve Performance		✓	✓	✓	✓	Only bypass valves need be tested at HU
MSIV Performance						
Individual MSIV Closure/ Timing		✓	✓		✓	Fast closure not req'd at High Power
Branch Line Closure/ Timing		✓	✓			
SRV Performance						
Individual Valve Functioning		✓	✓			
Automatic Opening Verification			✓	✓	✓	During planned trips, as applicable

OV = Open Vessel HU = Nuclear Heatup LP = Low Power MP = Mid Power HP = High Power

Table 14.2-1

POWER ASCENSION TEST MATRIX (Continued)

POWER ASCENSION TEST	TESTING PLATEAU					NOTES
	OV	HU	LP	MP	HP	
Chemical and Radiochemical Measurements						
Sampling System Functioning		✔	✔	✔	✔	
Process Rad Monitoring Functioning	✔	✔	✔	✔	✔	
Steady State Performance Measurements	✔	✔	✔	✔	✔	Includes verification of water quality
Steam Separator/Dryer Performance				✔		At low power, high flow corner of power flow map
Radiation Measurements						
Steady State Measurements	✔	✔	✔	✔	✔	
Shielding Adequacy Assessment				✔	✔	
Fuel Loading						
Core Loading	✔					
Partial Core S/D Margin	✔					
Full Core Verification	✔					
Full Core Shutdown Margin Demonstration	✔					
Rod Control System Performance						
CRD Functional Testing	✔	✔				
Friction Testing	✔	✔				
Rod Pair Scram Testing	✔	✔				
Full Core Scram			✔	✔	✔	With planned scrams
SCRRI Functioning					✔	At low power end of rated rod line prior to planned RIP trips and when actuated following RIP trips
Alternate Rod Run-in Functioning			✔	✔	✔	Post scram verification folowing planned trips

OV = Open Vessel HU = Nuclear Heatup LP = Low Power MP = Mid Power HP = High Power

Table 14.2-1

POWER ASCENSION TEST	TESTING PLATEAU					NOTES
	OV	HU	LP	MP	HP	
Neutron Monitoring System Performance						
SRNM Calibration/Response	✔	✔				
LPRM Calibration/Response		✔	✔	✔	✔	
APRM Calibration/Response		✔	✔	✔	✔	
TIP System Alignment/Response	✔	✔	✔			Only as needed to complete tests subsequent to HU
Process Computer System Operation						
NSS/BOP Monitoring Programs		✔	✔	✔	✔	
Automation Programs		✔	✔	✔	✔	
RWM/RC&IS Functioning		✔	✔		✔	
Core Performance		✔	✔	✔	✔	
Nuclear Boiler Process Monitoring						
Reactor Coolant Temperature Measurement		✔		✔	✔	At MP & HP during steady state and RIP trip testing
Reactor Water Level Measurement	✔	✔	✔	✔	✔	
Core Flow Calibration/Measurement		✔	✔	✔	✔	
System Expansion						
Support Inspection/Interference Check		✔	✔	✔	✔	Only as needed upon return to cold setting conditions after planned shutdowns subsequent to HU
Displacement Measurements		✔	✔	✔	✔	
System Vibration						
Steady State Measurements		✔	✔	✔	✔	
Transient Response			✔	✔	✔	
Reactor Internals Vibration (If Required)		✔	✔	✔	✔	Specified testing may not be required. See Subsection 14.2.12.2.12 for discussion of applicability of testing based on classification of reactor internals (i.e., prototype or not) in accordance with R.G. 1.20. Cold, zero power, test, if required, will be done with RPV head on during HU

Table 14.2-1

POWER ASCENSION TEST MATRIX (Continued)

POWER ASCENSION TEST	TESTING PLATEAU					NOTES
	OV	HU	LP	MP	HP	
Recirculation Flow Control						
Control System Adjustment/Confirmation			✔	✔	✔	
Feedwater Control						
Control System Adjustment/Confirmation		✔	✔	✔	✔	
Pressure Control						
Control System Adjustment/Confirmation		✔	✔	✔	✔	
Plant Automation and Control						
Plant Startup/ Shutdown		✔	✔	✔	✔	
Load Following					✔	
Reactor Recirculation System Performance						
Steady State Performance		✔	✔	✔	✔	
RIPs Cut of Service				✔	✔	
Pump Restarts				✔	✔	
Feedwater System Performance						
Steady State Performance		✔	✔	✔	✔	
Maximum Runout Flow Determination					✔	
Main Steam System Performance						
Steady State Performance		✔	✔	✔	✔	
Residual Heat Removal System Performance						
Suppression Pool Cooling		✔			✔	After testing which adds heat to the suppression pool; May not be sufficient heat at lower power levels to fully demonstrate Hx heat removal capability
Shutdown Cooling		✔			✔	System operability must be demonstarted prior to exceeding 25% RTP. However, there may not be sufficient reactor decay heat at lower power levels to demonstrate Hx heat removal capability

OV = Open Vessel HU = Nuclear Heatup LP = Low Power MP = Mid Power HP = High Power

Table 14.2-1

POWER ASCENSION TEST MATRIX (Continued)

POWER ASCENSION TEST	OV	HU	LP	MP	HP	NOTES
	TESTING PLATEAU					
Loss of Feedwater Heating					✔	At 80-90% CTP, 100% Flow during HP
Feedwater Pump Trip					✔	
Recirculation Pump Trip						
One RIP Trip				✔	✔	At near rated flow
Two RIP Trip				✔	✔	At near rated flow
Three RIP Trip				✔	✔	At near rated flow
Shutdown from Outside the Control Room			✔			At >10% Generator Load
Loss of Turbine Generator and Offsite Power			✔			At 10-20% rated power
Turbine Trip and Generator Load Rejection						
Load Rejection within Bypass Capacity			✔			
Turbine Trip				✔		
Full Power Load Rejection					✔	
Reactor Full Isolation					✔	
Offgas System Performance		✔	✔	✔	✔	
Power Conversion Equipment Performance		✔	✔	✔	✔	
Loose Parts Monitoring System Baseline Data		✔	✔	✔	✔	
RadWaste Systems Performance			✔		✔	
Concrete Temperature Surveys		✔			✔	

OV = Open Vessel   HU = Nuclear Heatup   LP = Low Power   MP = Mid Power   HP = High Power

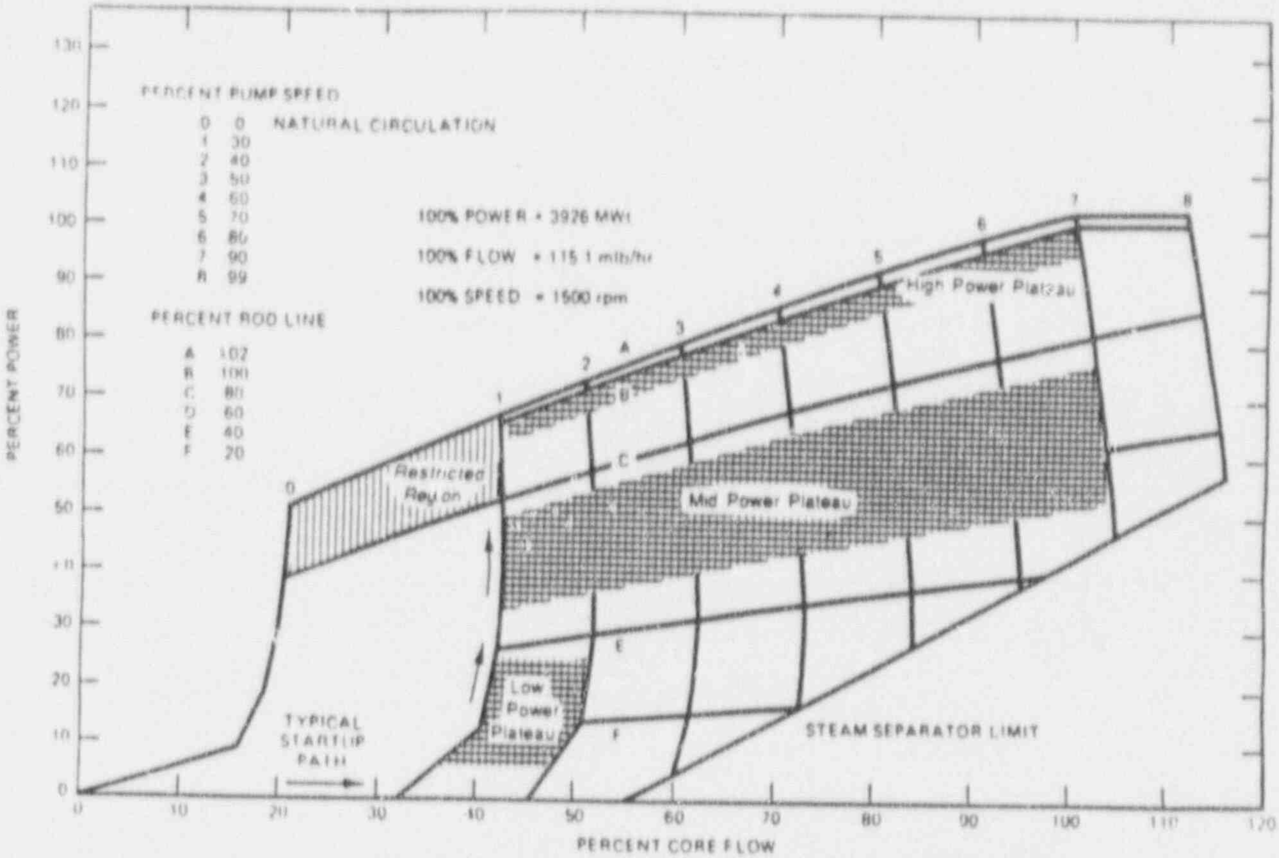
Table 14.2-1

POWER ASCENSION TEST MATRIX (Continued)

POWER ASCENSION TEST	TESTING PLATEAU					NOTES
	OV	HU	LP	MP	HP	
Loss of Feedwater Heating					✔	At 80-90% CTP, 100% Flow during HP
Feedwater Pump Trip					✔	
Recirculation Pump Trip						
One RIP Trip				✔	✔	At near rated flow
Two RIP Trip				✔	✔	At near rated flow
Three RIP Trip				✔	✔	At near rated flow
Shutdown from Outside the Control Room			✔			At >10% Generator Load
Loss of Turbine Generator and Offsite Power			✔			At 10-20% rated power
Turbine Trip and Generator Load Rejection						
Load Rejection within Bypass Capacity			✔			
Turbine Trip				✔		
Full Power Load Rejection					✔	
Reactor Full Isolation					✔	
Offgas System Performance		✔	✔	✔	✔	
Power Conversion Equipment Performance		✔	✔	✔	✔	
Loose Parts Monitoring System Baseline Data		✔	✔	✔	✔	
RadWaste Systems Performance			✔		✔	
Concrete Temperature Surveys		✔			✔	

OV = Open Vessel   HU = Nuclear Heatup   LP = Low Power   MP = Mid Power   HP = High Power

Figure 14.2-1
Power-Flow Operating Map and Testing Plateau Definitions



Testing Plateau	Description (1)
Open Vessel (**OV**)	With the RPV head removed, from initiation of fuel loading to cold conditions with a fully loaded core
Nuclear Heat-Up (**HU**)	During nuclear heat-up, from ambient conditions and 0 psig to rated temperature and pressure within the RPV, with reactor power typically less than 5% of rated
Low Power (**LP**)	Between 5% and 25% rated thermal power, with the reactor internal pumps (RIPs) within 10% of minimum speed
Mid Power (**MP**)	Between approximately the 50% and 75% power rod lines, with the RIPs operating between minimum and rated speeds, with the lower power corner within the capacity of the bypass valves.
High Power (**HP**)	Along and just below (+0,-5%) the 100% power rod line, from minimum RIP speed to rated core flow

(1) Descriptions of testing plateaus are offered for illustrative purposes and general guidance only, as some tests are intended to be conducted outside the general testing plateaus described. Neither the above descriptions, nor the corresponding boundary lines on the power-flow map, are meant to be absolute limits. Any operating limits will be specified in the plant license. Any other testing restrictions will be specified either within the plant administrative procedures covering the power ascension test program or within the individual test procedure for a given test.

documentation. The limiting events which establish CPR operating limit:

(1) **Limiting Pressurization Events:** Inadvertent closure of one turbine control valve, and generator load rejection with all bypass valve failure.

(2) **Limiting Decrease in Core Coolant Temperature Events:** Feedwater Controller Failure - Maximum Demand

For the core loading in Figure 4.3-1, the resulting initial core MCPR operating limit is 1.17. The operating limit based on the plant loading pattern will be provided by the utility applicant referencing the ABWR design to the USNRC for information, see Subsection 15.0.5.2 for interface requirement.

Results of the transient analyses for individual plant reference core loading patterns will differ from the results shown in this chapter. However, the relative results between core associated events do not change. Therefore, only the results of the identified limiting events given in Tables 15.0-4 will be provided by the utility applicant referencing the ABWR design to the USNRC for information. See Subsection 15.0.5.1.

15.0.4.5.1 Effect of Single Failures and Operator Errors

The effect of a single equipment failure or malfunction or operator error is provided in Appendix 15A.

15.0.4.5.2 Analysis Uncertainties

The analysis uncetainties meet the criteria in Appendix 4B.

In Table 15.0-3, a summary of applicable accidents is provided. This table compares GE calculated amount of failed fuel to that used in worst-case radiological calculatiuons for the core shown in Figure 4.3-1. Radiological calculations for a plant initial core will be provided by the utility to the USNRC for information. (See Subsection 15.0.5 for interface requirements).

15.0.4.5.3 Barrier Performance

The significant areas of interest for internal pressure damage are the high pressure portions of the reactor coolant pressure boundary (the reactor vessel and the high pressure pipelines attached to the reactor vessel). The plant shall meet the criteria in Appendix 4B.

15.0.4.5.4 Radiological Consequences

In this chapter, the consequences of radioactivity release for the core loading in Figure 4.3-1 during the three types of events: (a) incidents of moderate frequency (anticipated operational occurences); (b) infrequent incidents (abnormal operational occurences); and (c) limiting faults (design basis accidents), are given. For all events whose consequences are limiting, a detailed quantitative evaluation is presented. For nonlimiting events, a qualitive evaluation is presented or results are referenced from a more limiting or enveloping case or event.

15.0.5 Interface Requirements

15.0.5.1 Anticipated Operational Occurences (AOO)

The results of the events identified in Subsection 15.0.4.5 for plant core loading will be provided by the ultiity appiicant referencing the ABWR design to the USNRC for information.

15.0.5.2 Operating Limits

The operating limit resulting from the analyses normally provided in this subsection will be provided by the ultiity applicant referencing the ABWR design to the USNRC for information.

15.0.5.3 Design Basis Accidents

Results of the design basis accidents including radiological consequences will be provided by the ultiity applicant referencing the ABWR design to the USNRC for information.

Table 15.0-1

INPUT PARAMETERS AND INITIAL CONDITIONS FOR SYSTEM RESPONSE ANALYSIS TRANSIENTS (Continued)

29.	S/R Valve Reclosure Setpoint - Both Modes (% of setpoint)	
	- Maximum Safety Limit (used in analysis)	98
	- Minimum Operational Limit	93
30.	High Flux Trip (% NBR)	
	Analysis Setpoint (125 x 1.02)	127.5
31.	High Pressure Scram Setpoint (Kg/cm^2g)	77.7
32.	Vessel level Trips (m above bottom of separator skirt bottom)	
	Level 8 - (L8) (m)	1.73
	Level 4 - (L4) (m)	1.08
	Level 3 - (L3) (m)	0.57
	Level 2 - (L2) (m)	-0.75
33.	APRM Simulated Thermal Power Trip Scram % NBR	
	Analysis Setpoint (115 x 1.02)	117.3
	Time Constant (sec)	7
34.	Reactor Internal Pump Trip Delay (sec)	0.16
35.	Recirculation Pump Trip Inertia Time Constant for Analysis (sec) ***	0.62
36.	Total Steamline Volume (m^3)	113.2
37.	Set pressure of Recirculation pump trip (Kg/cm^2g)	79.1

* For transients simulated on the ODYN model, this input is calculated by ODYN.

** EOEC = End of Equilibrium Cycle.

*** The inertia time constant is defined by the expression:

$$t = \frac{2 \pi J_o n}{g T_o}$$, where

t = inertia time constant (sec);
J_o = pump motor inertia (kg-m);
n = pump speed (rps);
g = gravitational constant (m/sec^2); and
T_o = pump shaft torque (kg-m)

Table 15.0-2

RESULTS SUMMARY OF SYSTEM RESPONSE ANALYSIS TRANSIENT EVENTS

Sub Section I.D.	Figure I.D.	Description	Max. Neutron Flux % NBR	Max. Dome Pressure (Kg/Cm^2g)	Max. Vessel Bottom Pressure (Kg/Cm^2g)	Max. Steam Line Pressure (Kg/Cm^2g)	Max Core Average Surface Heat Flux (% of Initial)	Δ in CPR	Freq. Category*	No. of Valves First Blowdown	Duration of Blowdown (seconds)
15.1		Decrease in core coolant temperature									
15.1.1		Loss of Feedwater heating	112.8	73.1	75.9	71.6	112.8	0.07	a	0	0
15.1.2	15.1-2	Runout of one feedwater pump	104.5	73.2	75.8	71.7	101.8	0.0[illegible]	c	0	0
15.1.2	15.1-3	Feedwater Controller failure - Maximum Demand	139.0	83.3	84.9	82.8	105.9	0.10	a+	10	6
15.1.3	15.1-4	Opening of one Bypass Valve	102.1	73.1	75.6	71.6	100.0	**	a	0	0
15.1.3	15.1-5	Opening of all Control and Bypass Valves	102.0	80.4	81.8	80.1	100.0	**	a+	0	0
15.1.4		Inadvertent opening of One SRV				SEE	TEXT				
15.1.6		Inadvertent RHR Shutdown Cooling				SEE	TEXT				
15.2		Increase in Reactor Pressure									
15.2.1	15.2-1a	Fast Closure of One Turbine Control Valve	129.4	75.1	77.6	73.7	103.5	0.10	a	0	0
15.2.1	15.2-1b	Slow Closure of One Turbine Control Valve	110.3	74.8	77.3	73.3	103.3	0.09			
15.2.1	15.2-2	Pres. Regulator Downscale Fail.	154.8	85.8	87.4	85.1	103.0	xxx	c	18	6
15.2.2	15.2-3	Generator Load Rejection, Bypass on	148.1	83.2	[illegible]	82.7	100.2	0.06	a	10	5

- * *Frequency definition is discussed in Subsection 15.0.4.1*
- ** *Not limiting (See Subsection 15.0.4.5.)*
- *xx* *CPR Criterion does not apply*
- *a* *Moderate Frequency*
- *b* *Infrequent*
- *c* *Limiting Fault*
- *N/A* *Not applicable*
- \+ *This event should be classified as a limiting fault. However, criteria for moderate frequent incidents are conservatively applied.*

Table 15.0-2

RESULTS SUMMARY OF SYSTEM RESPONSE ANALYSIS TRANSIENT EVENTS (Cont.)

Sub Section I.D.	Figure I.D.	Description	Max. Neutron Flux % NBR	Max. Dome Pressure (Kg/Cm^2g)	Max. Vessel Bottom Pressure (Kg/Cm^2g)	Max. Steam Line Pressure (Kg/Cm^2g)	Max Core Average Surface Heat Flux (% of Initial)	Δ in CPR	Freq Category*	No. of Valves First Blowdown	Duration of Blowdown (seconds)
15.2.2	15.2-4	Generator Load Rejection, Failure of One Bypass Valve	155.3	84.2	85.8	83.6	100.5	0.07	a+	14	5
15.2.2	15.2-5	Generator Load Rejection with failure of all Bypass Valves	184.6	86.1	87.7	85.6	102.3	0.10	a+	18	6
15.2.3	15.2-6	Turbine Trip Bypass--On	122.1	83.0	84.6	82.6	100.0	0.05	a	10	5
15.2.3	15.2-7	Turbine Trip w/Failure of One Bypass Valve	131.9	84.1	85.6	83.4	100.0	0.05	a+	14	5
15.2.3	15.2-8	Turbine Trip with failure of all Bypass Valves	158.6	86.1	87.7	85.4	100.6	0.08	a+	18	6
15.2.4	15.2-9	Inadvertent MSIV Closure	102.1	84.6	86.4	84.1	100.1	**	a	18	5
15.2.5	15.2-10	Loss of Condenser Vacuum	122.3	83.0	84.6	82.6	100.0	**	a	10	5
15.2.6	15.2-11	Loss of AC Power	113.2	82.9	84.4	82.7	100.0	0.05	a	10	5
15.2.7	15.2-12	Loss of All Feedwater Flow	102.0	73.1	75.7	71.6	100.1	**	a	0	0
15.2.8		Feedwater Piping Break			SEE	TEXT					

* *Frequency definition is discussed in Subsection 15.0.4.1*
** *Not limiting (See Subsection 15.0.4.5.)*
a *Moderate Frequency*
b *Infrequent*
c *Limiting Fault*
N/A *Not applicable*
\+ *This event should be classified as an infrequent event or a limiting fault. However, criteria for moderate frequent incidents are conservatively applied.*

Table 15.0-2

RESULTS SUMMARY OF SYSTEM RESPONSE ANALYSIS TRANSIENT EVENTS (Cont.)

Sub Section I.D.	Figure I.D.	Description	Max. Neutron Flux % NBR	Max. Dome Pressure (Kg/Cm^2g)	Max. Vessel Bottom Pressure (Kg/Cm^2g)	Max. Steam Line Pressure (Kg/Cm^2g)	Max Core Average Surface Heat Flux (% of Initial)	Δ in CPR	Freq Category*	No. of Valves First Blowdown	Duration of Blowdown (seconds)
15.2.9		Failure of RHR Shutdown Cooling			SEE	TEXT					
15.3		Decrease in Reactor Coolant System Flow Rate									
15.3.1	15.3-1	Trip of Three Reactor Internal Pumps	102.0	73.3	76.0	71.7	100.1	0.04	a	0	0
15.3.1	15.3-2	Trip of All Reactor Internal Pumps	102.0	83.2	84.1	82.7	100.2	***	c		
15.3.2	15.3-3	Fast Runback of One Reactor Internal Pump	102.0	73.0	75.9	71.6	100.0	**	a	0	0
15.3.2	15.3-4	Fast Runback of All Reactor Internal Pumps	102.0	73.1	76.0	71.6	100.0	**	a+	0	0
15.3.3	15.3-5	Seizure of One Reactor Internal Pump	102.0	73.1	75.9	71.6	100.0	**	c	0	0
15.3.4		One Pump Shaft Break			SEE	TEXT					
15.4		Reactivity and Power Distribution Anomalies									
15.4.1.1		RWE-Refueling			SEE	TEXT					

* *Frequency definition is discussed in Subsection 15.0.4.1*
** *Not limiting (See Subsection 15.0.4.5.)*
*** *CPR criterion does not apply. PCT < 593.3°C*
a *Moderate Frequency*
b *Infrequent*
c *Limiting Fault*
\+ *This event should be classified as a limiting fault. However, criteria for moderate frequent incidents are conservatively applied.*

Table 15.0-2

RESULTS SUMMARY OF SYSTEM RESPONSE ANALYSIS TRANSIENT EVENTS (Cont.)

Sub Section I.D.	Figure I.D.	Description	Max. Neutron Flux % NBR	Max. Dome Pressure (Kg/Cm^2g)	Max. Vessel Bottom Pressure (Kg/Cm^2g)	Max. Steam Line Pressure (Kg/Cm^2g)	Max Core Average Surface Heat Flux (% of Initial)	Δ in CPR	Freq. Category*	No. of Valves First Blowdown	Duration of Blowdown (seconds)
15.4.1.2		RWE-Startup			SEE	TEXT					
15.4.2		RWE at Power			SEE	TEXT					
15.4.3		Control Rod Misoperation			SEE	TEXT					
15.4.4		Abnormal Startup of One Reactor Internal Pump			SEE	TEXT					
15.4.5	15.4-2	Fast Runout of One Reactor Internal Pump	89.8	71.1	72.3	70.6	116.1	****	a	0	0
15.4.5	15.4-3	Fast Runout of All Reactor Internal Pumps	135.0	72.5	74.7	71.5	168.5	****	a+	0	0
15.4.7		Misplaced Bundle Accident				SEE	TEXT				
15.4.8		Rod Ejection Accident				SEE	TEXT				
15.4.9		Control Rod Drop Accident				SEE	TEXT				
15.5		Increase in Reactor Coolant Inventory									
15.5.1	15.5-1	Inadvertent HPCF Startup	102.0	73.1	75.6	71.6	100.0	**	a+	0	0

* *Frequency definition is discussed in Subsection 15.0.4.1*
** *Not limiting (See Subsection 15.0.4.5.)*
**** *Transients initiated from low power.*
a *Moderate Frequency*
b *Infrequent*
c *Limiting Fault*
\+ *This event should be classified as a limiting fault. However, criteria for moderate frequent incidents are conservatively applied.*

Table 15.0-3

SUMMARY OF ACCIDENTS

SUBSECTION I.D.	TITLE	FAILED FUEL RODS: GE CALCULATED VALUE	FAILED FUEL RODS: NRC WORST-CASE ASSUMPTION
15.2.1	Pressure Regulator Downscale Failure	None	<0.2%
15.3.1	Trip of All Reactor Internal Pumps	None	<0.2%
15.3.3	Seizure of one Reactor Internal Pump	None	None
15.3.4	Reactor Internal Pump Shaft Break	None	None
15.6.2	Instrument Line Break	None	None
15.6.4	Steam System Pipe Break Outside Containment	None	None
15.6.5	LOCA Within RCPB	None	100%
15.6.6	Feedwater Line Break	None	None
15.7.1.1	Main Condenser Gas Treatment System Failure	N/A	N/A
15.7.3	Liquid Radwaste Tank Failure	N/A	N/A
15.7.4	Fuel-Handling Accident	<125	125
15.7.5	Cask Drop Accident	None	All Rods in Cask

Table 15.0-4

CORE-WIDE TRANSIENT ANALYSIS RESULTS TO BE PROVIDED FOR DIFFERENT CORE DESIGN

TRANSIENT	MAX. NEUTRON FLUX (%NBR)	MAX. CORE AVERAGE SURFACE HEAT FLUX (%NBR)	DELTA CPR	FIGURE
Closure of One Turbine Control Valve	X	X	X	X
Load Rejection with all Bypass Valves Failure	X	X	X	X
Feedwater Controller Failure - Maximum Demand	X	X	X	X

SECTION 15.1

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TABLES

SECTION 15.1

ILLUSTRATIONS

15.1 DECREASE IN REACTOR COOLANT TEMPERATURE

15.1.1 Loss of Feedwater Heating

15.1.1.1 Identification of Causes and Frequency Classification

15.1.1.1.1 Identification of Causes

A feedwater heater can be lost in at least two ways:

(1) steam extraction line to heater is closed; or

(2) steam is bypassed around heater.

The first case produces a gradual cooling of the feedwater. In the second case, the steam bypasses the heater and no heating of that feedwater occurs. In either case, the reactor vessel receives cooler feedwater. The maximum number of feedwater heaters which can be tripped or bypassed by a single event represents the most severe transient for analysis considerations.

The ABWR is designed such that no single operator error or equipment failure shall cause a loss of more than 55.6°C (100°F) feedwater leakage. The reference steam and power conversion system shown in figures 10.1-1 to 10.1-3 meets this requirement. In fact, the feedwater temperature drop based on the reference heat balance, shown in Figure 10.1-1, is less than 30°C (100°F). Therefore, the use of 55.6°C (100°F) temperature drop in the transient analysis is conservative.

This event has been conservatively estimated to incur a loss of up to 55.6°C of the feedwater heating capability of the plant and causes an increase in core inlet subcooling. This increases core power due to the negative void reactivity coefficient. However, the power increase is slow.

The feedwater control system (FWCS) includes a logic intended to mitigate the consequences of a loss of feedwater heating capability. The system will be constantly monitoring the actual feedwater temperature and comparing it with a reference temperature. When a loss of feedwater heating is detected (i.e., when the difference between the actual and reference temperatures exceeds a ΔT setpoint, which is currently set at 16.7°C), the FWCS sends an alarm to the operator. The operator can then take actions to mitigate the event. This will avoid a scram and reduce the Δ CPR during the event. The same signal is also sent to the RC&IS to initiate the SCRRI (selected control rods run-in) to automatically reduce the reactor power and avoid a scram. This will prevent the reactor from violating any thermal limits.

Because this event is very slow, the operator action or automatic SCRRI will terminate this event. Therefore, the worst event is the loss of feedwater heating resulting in a temperature difference just below the ΔT setpoint. However, a loss of 55.6°C feedwater temperature is analyzed to bound his event.

15.1.1.1.2 Frequency Classification

The probability of this event is considered low enough to warrant it being categorized as an infrequent incident. However, because of the lack of a sufficient frequency data base, this transient disturbance is analyzed as an incident of moderate frequency.

15.1.1.2 Sequence of Events and Systems Operation

15.1.1.2.1 Sequence of Events

Table 15.1-1 lists the sequence of events for this transient.

15.1.1.2.1.1 Identification of Operator Actions

Because no scram occurs during this event, no immediate operator action is required. As soon as possible, the operator should verify that no operating limits are being exceeded. Also, the operator should determine the cause of failure prior to returning the system to normal.

15.1.1.2.2 Systems Operation

In establishing the expected sequence of events and simulating the plant performance, it was assumed that normal functioning occurred in the plant instrumentation and controls, plant protection and reactor protection systems.

expected for this transient.

15.1.1.3 Core and System Performance

15.1.1.3.1 Input Parameters and Initial Conditions

The transient is simulated by programming a change in feedwater enthalpy corresponding to a 55.6°C loss is feedwater heating. Another case with the ΔT setpiont in FWCS of 16.7°C is also analysed.

15.1.1.3.2 Results

Because the power increase during this event is relatively slow, it can be treated as a quasi steady-state transient. The 3-D core simulator, Panacea, has been used to evaluate this event for the equilibrium cycle. The results are summarized in Tables 15.1-2 and 15.1-2a.

The MCPR response of this event is small due to the mild thermal power increase with shifting axial shape. The worst Δ CPR response is 0.07.

No scram is initiated in this event. The increased core inlet subcooling aids thermal margins. Nuclear system pressure does not change significantly (less than 0.4 Kg/Cm^2) and consequently, the reactor coolant pressure boundary is not threatened.

15.1.1.4 Barrier Performance

As noted previously the consequences of this event do not result in any temperature or pressure transient in excess of the criteria for which the fuel, pressure vessel containment are designed; therefore, these barriers maintain their integrity and function as designed.

15.1.1.5 Radiological Consequences

Because this event does not result in any fuel failures or any release of primary coolant to either the secondary containment or to the environment, there are no radiological consequences associated with this event.

15.1.2 Feedwater Controller Failure--Maximum Demand

15.1.2.1 Identification of Causes and Frequency Classification

15.1.2.1.1 Identification of Causes

This event is postulated on the basis of a single failure of a control device, specifically one which can directly cause an increase in coolant inventory by increasing the feedwater flow.

The ABWR feedwater control system uses a triplicated digital control system, instead of a single-channel analog system as used in current BWR designs (BWR 2-6). The digital systems consist of a triplicated fault-tolerant digital controller, the operator control stations and displays. The digital controller contains three parallel processing channels, each containing the microprocessor-based hardware and associated software necessary to perform all the control calculations. The operator interface provides information regarding system status and the required control functions.

Redundant transmitters are provided for key process inputs, and input voting and validation are provided such that faults can be identified and isolated. Each system input is triplicated internally and sent to the three processing channels. (See Figure 15.1-1) The channels will produce the same output during normal operation. Interprocessor communication provides self-diagnostic capability. A two-out-of-three voter compares the processor outputs to generate a validated output to the control actuator. A separate voter is provided for each actuator. A "ringback" feature feeds back the final voter output to the processors. A voter failure will thereby be detected and alarmed. In some cases a protection circuit will lock the actuator into its existing position promptly after the failure is detected.

Table 15.1-3 lists the failure modes of a triplicated digital control system and outlines the effects of each failure. Because of the triplicated architecture, it is possible to take one channel out of service for maintenance or repair while the system is on-line. Modes 2 and 5 of Table 15.1-3 address a failure of a component while an associated redundant component is out of service. This type of failure could potentially cause a system failure. However, the probability of a component failure during servicing of a counterpart component is considered to be so low that these failure modes will not be considered incidents of moderate frequency, but will be considered limiting faults.

Adverse effects minimization is mentioned in the effects of Mode 2. This feature stems from the additional intelligence of the system provided by the microprocessor. When possible, the system will be programmed to take action in the event of some failure which will reduce the severity of the transient. For example, if the total steam flow or total feedwater flow signals failed, the feedwater control system will detect this by the input reasonability checks and automatically switch to one-element mode (i.e., control by level feedback only). The level control would essentially be unaffected by this failure.

The only credible single failures which would lead to some adverse affect on the plant are Modes 6 and 7, a failure of the output voter and a control actuator failure. Both of these failures would lead to a loss of control of only one actuator (i.e., only one feedwater pump with increasing flow). A voter failure is detected by the ringback feature. The FWCS will initiate a lock-up of the actuator upon detection of the failure. The probabilities of failure of the variety of control actuators are very low based on operating experience (less than 0.0088 failures per reactor year). In the event of one pump run-out, the FWCS would then reduce the demand to the remaining pump, thereby automatically compensating for the excessive flow from the failed pump. Therefore, the worst single failure in the feedwater control system causes a run-out of one feedwater pump to its maximum capacity. However, the demand to the remaining feedwater pump will decrease to offset the increased flow of the failed pump. The effect on total flow to the vessel will not be significant. The worst additional single failure would cause all feedwater pumps to run out to their maximum capacity. However the probability of this to occur is extremely low (less than 7 x 10^{-5} failure per reactor year).

15.1.2.1.2 Frequency Classification

15.1.2.1.2.1 Runout of One Feedwater Pump

Although the frequency of occurrence for this event is less than once per 100 reactor years, this event is conservatively evaluated as an incident of moderate frequency.

15.1.2.1.2.2 Feedwater Controller Failure - Maximum Demand

The frequency of occurrence for this event is estimated to be less than once per 10000 years. It should be classified as a limiting fault as specified in Chapter 15 of Regulatory Guide 1.70. Nonetheless, the criteria of moderate frequent incidents are conservatively applied to this event.

15.1.2.2 Sequence of Events and Systems Operation

15.1.2.2.1 Sequence of Events

15.1.2.2.1.1 Runout of One Feedwater Pump

With momentary increase in feedwater flow, the water level rises and then settles back to its normal level. Table 15.1-4 lists the sequencing of events for Figure 15.1-2.

15.1.2.2.1.2 Feedwater Controller Failure - Maximum Demand

With excess feedwater flow, the water level rises to the high-level reference point, at which time the feedwater pumps and the main turbine are tripped and a scram is initiated. Table 15.1-5 lists the sequence of events for Figure 15.1-3. The figure shows the changes in important variables during this transient.

15.1.2.2.1.3 Identification of Operator Actions

15.1.2.2.1.3.1 Runout of One Feedwater Pump

Because no scram occurs for runout of one feedwater pump, no immediate operator action is required. As soon as possible, the operator should verify that no operating limits are being exceeded. Also, the operator should determine the cause of failure prior to returning the system to normal.

15.1.2.2.1.3.2 Feedwater Controller Failure - Maximum Demand

The operator should:

(1) observe that high feedwater pump trip has terminated the failure event;

(2) switch the feedwater controller from auto to manual control to try to regain a correct output signal; and

(3) identify causes of the failure and report all key plant parameters during the event.

15.1.2.2.2 Systems Operation

15.1.2.2.2.1 Runout of One Feedwater Pump

Runout of a single feedwater pump requires no protection system or safeguard system operation. This analysis assumes normal functioning of plant instrumentation and controls.

15.1.2.2.2.2 Feedwater Controller Failure - Maximum Demand

To properly simulate the expected sequence of events, the analysis of this event assumes normal functioning of plant instrumentation and controls, plant protection and reactor protection systems. Important system operational actions for this event are high level tripping of the main turbine and feedwater pumps, scram and recirculation pump trip (RPT) due to turbine trip, and low water level initiation of the reactor core isolation cooling (RCIC) system to maintain long-term water level control following tripping of feedwater pumps.

15.1.2.3 Core and System Performance

15.1.2.3.1 Input Parameters and Initial Conditions

The runout capacity of one feedwater pump is assumed to be 75% of rated flow at the design pressure of 74.9 Kg/Cm^2g. The total feedwater flow for all pumps runout is assumed to be 130% of rated at the design pressure of 74.9 Kg/Cm^2g.

15.1.2.3.2 Results

15.1.2.3.2.1 Runout of One Feedwater Pump

The simulated runout of one feedwater pump event is presented in Figure 15.1-2. When the increase of feedwater flow is sensed, the feedwater controller starts to command the remaining feedwater pump to reduce its flow immediately. The vessel water level increases slightly (about 6 inches) and then settles back to its normal level. The vessel pressures only increase about 0.1 Kg/Cm^2. MCPR remains above the safety limit.

15.1.2.3.2.2 Feedwater Controller Failure - Maximum Demand

The simulated runout of all feedwater pumps is shown in Figure 15.1-3. The high water level turbine trip and feedwater pump trip are initiated at approximately 18 seconds. Scram occurs and limits the neutron flux peak and fuel thermal transient so that no fuel damage occurs. It is calculated that the MCPR is right at the safety limit. Therefore, the design limit for the moderate frequent incident is met. The turbine bypass system opens to limit peak pressure in the steamline near the SRVs to 82.8Kg/Cm^2g and the pressure at the bottom of the vessel to about 84.9 Kg/Cm^2g.

The level will gradually drop to the Low Level reference point (Level 2), activating the RCIC system for long-term level control.

The applicant will provide reanalysis of this event for the specific core configuration.

15.1.2.4 Barrier Performance

As previously noted the consequence of this event does not result in any temperature or pressure transient in excess of the criteria for which the fuel, pressure vessel or containment are designed; therefore, these barriers maintain that water level swells to the sensed level trip setpoint (L8), initiating main turbine and feedwater pump trips. Position switches on the turbine stop valves initiate reactor scram and a trip of 4 RIPs.

After a presssurization resulting from the turbine stop valve closure, pressure again drops and continues to drop until turbine inlet pressure is below the low turbine pressure isolation setpoint when main steamline isolation finally terminates the depressurization. The turbine trip and isolation limit the duration and severity of the depressurization so that no significant thermal stresses are imposed on the reactor coolant pressure boundary. No significant reduction in fuel thermal margins occur; therefore, this event does not have to be analyzed for specific core configurations.

15.1.3.4 Barrier Performance

Barrier performance analyses were not required because the consequences of this event do not result in any temperature or pressure transient in excess of the criteria for which fuel, pressure vessel or containment are designed. During the event of inadvertent opening of all turbine control and bypass valves, peak pressure in the bottom of the vessel reaches 81.8 kg/cm^2g, which is below the ASME code limit of 96.7 kg/cm^2g for the reactor coolant pressure boundary. Vessel dome pressure reaches 80.4 kg/cm^2g, below the setpoint of the second pressure relief group. Minimum vessel dome pressure of 50.6 kg/cm^2g occurs at about 40 seconds.

15.1.3.5 Radiological Consequences

While the consequences of this event do not result in any fuel failures, radioactivity is nevertheless discharged to the suppression pool as a result of SRV actuation. However, the mass input, and hence activity input, for this event is much less than those consequences identified in Subsection 15.2.4.5 for Type 2 events. Therefore, the radiological exposures noted in Subsection 15.2.4.5 cover the consequences of this event.

15.1.4 Inadvertent Safety/Relief Valve Opening

15.1.4.1 Identification of Causes and Frequency Classification

15.1.4.1.1 Identification of Causes

Cause of inadvertent opening is attributed to malfunction of the valve or an operator initiated opening. It is therefore simply postulated that a failure occurs and the event is analyzed accordingly. Detailed discussion of the valve design is provided in Chapter 5.

15.1.4.1.2 Frequency Classification

This transient disturbance is categorized as an infrequent incident.

15.1.4.2 Sequence of Events and Systems Operation

15.1.4.2.1 Sequence of Events

Table 15.1-8 lists the sequence of events for this event.

15.1.4.2.1.1 Identification of Operator Actions

The plant operator must reclose the valve as soon as possible and check that reactor and T-G output return to normal. If the valve cannot be closed, plant shutdown should be initiated.

15.1.4.2.2 Systems Operation

This event assumes normal functioning of normal plant instrumentation and controls, specifically the operation of the pressure regulator and level control systems.

15.1.4.3 Core and System Performance

The opening of one SRV allows steam to be discharged into the suppression pool. The sudden increase in the rate of steam flow leaving the reactor vessel causes a mild depressurization transient.

The SB&PCS senses the nuclear system pressure decrease and within a few seconds closes the turbine control valves far enough to stabilize the reactor vessel pressure at a slightly lower value and the reactor settles at nearly the initial power level. Thermal margins decrease only slightly through the transient, and no fuel damage results from the transient. MCPR is essentially unchanged and , therefore, the safety limit margin is unaffected and this event does not have to be reanalyzed for specific core configurations.

The discharge of steam to the suppression pool causes the temperature of the suppression pool to increase. When the pool temperature reaches the setpoint of 43.3°C (110°F), the suppression pool cooling function of the RHR system is automatically initiated. The pool temperature continues to increase due to the mismatch of cooling capacity and steam discharged into the pool. When the pool temperature reaches the next setpoint of 48.9°C (120°F), a reactor Scram is automatically initiated.

15.1.4.4 Barrier Performance

As presented previously, the transient resulting from a stuck open relief valve is a mild depressurization which is within the range of normal load following and therefore has no significant effect on RCPB and containment design pressure limits.

15.1.4.5 Radiological Consequences

While the consequence of this event does not result in fuel failure, it does result in the discharge of normal coolant activity to the suppression pool via SRV operation. Because this activity is contained in the primary containment, there will be no exposures to operating personnel. Because this event does not result in an uncontrolled release to the environment, the plant operator can choose to leave the activity bottled up in the containment or discharge it to the environment under controlled release conditions. If purging of the containment is chosen, the release will be in accordance with the established technical specifications; therefore, this event, at the worst, would only result in a small increase in the yearly integrated exposure level.

15.1.5 Spectrum of Steam System Piping Failures Inside and Outside Containment in a PWR

This event is not applicable to BWR plants.

15.1.6 Inadvertent RHR Shutdown Cooling Operation

15.1.6.1 Identification of Causes and Frequency Classification

15.1.6.1.1 Identification of Causes

At design power conditions, no conceivable malfunction in the shutdown cooling system could cause a temperature reduction.

In startup or cooldown operation, if the reactor were critical or near critical, a very slow increase in reactor power could result. A shutdown cooling malfunction leading to a moderate temperature decrease could result from misoperation of the cooling water controls for the RHR heat exchangers. The resulting temperature decrease would cause a slow insertion of positive reactivity into the core. If the operator did not act to control the power level, a high neutron flux reactor scram would terminate the transient without violating fuel thermal limits and without any measurable increase in nuclear system pressure.

15.1.6.1.2 Frequency Classification

Because no single failure could cause this event, it should be categorized as a limiting fault. However, criteria for moderate frequent incidents are conservatively applied.

15.1.6.2 Sequence of Events and Systems Operation

15.1.6.2.1 Sequence of Events

A shutdown cooling malfunction leading to a moderator temperature decrease could result from misoperation of the cooling water controls for RHR heat exchangers. The resulting temperature decrease causes a slow insertion of positive reactivity into the core. Scram occurs before any thermal limits are reached if the operator does not take action. The sequence of events for this event is shown in Table 15.1-9.

15.1.6.2.2 System Operation

A shutdown cooling malfunction causing a moderator temperature decrease must be considered in all operating states. However, this event is not considered while at power operation because the nuclear system pressure is too high to permit operation of the shutdown cooling mode of the RHRs.

No unique safety actions are required to avoid unacceptable safety results for transients as a result of a reactor coolant temperature decrease induced by misoperation of the shutdown cooling heat exchangers. In startup or cooldown operation, where the reactor is at or near critical, the slow power increase resulting from the cooler moderator temperature is controlled by the operator in the same manner normally used to control power in the startup range.

15.1.6.3 Core and System Performance

The increased subcooling caused by misoperation of the RHR shutdown cooling mode could result in a slow power increase due to the reactivity insertion. This power rise is terminated by a flux scram before fuel thermal limits are approached. Therefore, only qualitative description is provided here and this event does not have to be analyzed for specific core configuration.

15.1.6.4 Barrier Performance

As previously presented, the consequences of this event do not result in any temperature or pressure transient in excess of the criteria for which the fuel, pressure vessel or containment are designed; therefore, these barriers maintain their integrity and function as designed.

15.1.6.5 Radiological Consequences

Because this event does not result in any fuel failures, no analysis of radiological consequences is required for this event.

Table 15.1-1

SEQUENCE OF EVENTS FOR LOSS OF FEEDWATER HEATING

TIME (sec)	EVENT
0	Initiate a 55.6°C (or 16.7°C) temperature reduction in the feedwater system
5	Initial effect of unheated feedwater starts to raise core power level
100(est.)	Reactor variables settle into new steady state

Table 15.1-2

LOSS OF 55.6°C FEEDWATER HEATING

	BOC* to EOC*
Change in Core Power (%)	12.8
Change in MCPR	0.07

Table 15.1-2a

LOSS OF 16.7°C FEEDWATER HEATING

	BOC* to EOC*
Change in Core Power (%)	3.9
Change in MCPR	0.02

* *BOC = Beginning of Cycle*
EOC = End of Cycle

Table 15.1-3

SINGLE FAILURE MODES FOR DIGITAL CONTROLS

MODES	DESCRIPTION	EFFECTS
1.	Critical input failure	None- Redundant transmitter takes over- Operator informed of failure
2.	Input failure while one sensor out of service	Possible system failure. Adverse effects minimized when possible
3.	Operator switch single contact failure	None- Triplicated contacts
4.	Processor channel failure	None- Redundant processors maintain control; Operator informed of failure
5.	Processor failure while one channel out of service	System failure
6.	Voter failure	Loss of control of one actuator (i.e., one feedwater pump only) FWCS will lock up actuators
7.	Actuator failure	Loss of one actuator (i.e., One feedwater pump only)

Table 15.1-4

SEQUENCE OF EVENTS FOR FIGURE 15.1-2

TIME (sec)	EVENTS
0	Initiate simulated runout of one feedwater pump (at system design pressure of 74.9 Kg/Cm^2g the pump runout flow is 75% of rated feedwater flow)
~0.1	Feedwater controller starts to reduce the feedwater flow from the other feedwater pump
16.6	Vessel water level reaches its peak value and starts to return to its normal value
~60 (est.)	Vessel water level returns to its normal value.

Table 15.1-5

SEQUENCE OF EVENTS FOR FIGURE 15.1-3

TIME (sec)	EVENT
0	Initiate simulated runout of all feedwater pumps (130% at system design pressure of 74.9 Kg/Cm^2g on feedwater flow)
18.35	L8 vessel level setpoint initiates trip of main turbine and feedwater pumps.
18.36	Reactor scram and trip of 4 RIPs are actuated by stop valve position switches
18.5	Main turbine bypass valves opened due to turbine trip
20.1	SRVs open due to high pressure
>25	SRVs close
>40 (est.)	Water level dropped to low water level setpoint (Level 2)
>70 (est.)	RCIC flow into vessel (not simulated)

Table 15.1-6

SEQUENCE OF EVENTS FOR FIGURE 15.1-4

TIME (sec)	EVENTS
0	Simulate one bypass valve to open
~0.5	Pressure control system senses the decrease of reactor pressure and commands control valves to close
5.0	Reactor settles at another steady state

Table 15.1-7

SEQUENCE OF EVENTS FOR FIGURE 15.1-5

TIME (sec)	EVENTS
0	Simulate all turbine control valves and bypass valves to open.
2.8	Turbine control valves wide open.
2.87	Vessel water level (L8) trip initiates main turbine and feedwater pump trips.
2.9	Main turbine stop valves reach 85% open position and initiates reactor scram and trip of 4 RIPs.
2.97	Turbine stop valves closed.
17.2	Vessel water level reaches L2 setpoint. The remaining 6 RIPs are tripped. RCIC is initiated.
36.2	Low turbine inlet pressure trip initiates main steamline isolation
41.2	Main steam isolation valves closed. Bypass valves remain open, exhausting steam in steamlines downstream of isolation valves.
47.2 (est.)	RCIC flow enters vessel (not simulated).

TABLE 15.1-8

SEQUENCE OF EVENTS FOR INADVERTENT SAFETY\RELIEF VALVE OPENING

TIME (sec)	EVENT
0	Initiated opening of one SRV.
0.5 (est.)	Relief flow reaches full flow.
15 (est.)	System establishes new steady-state operation.
750 (est.)	Suppression pool temperature reaches setpoint; suppression pool cooling function is initiated.
1200 (est.)	Suppression pool temperature reaches setpoint; reactor scram is automatically initiated.

TABLE 15.1-9

SEQUENCE OF EVENTS FOR INADVERTENT RHR SHUTDOWN COOLING OPERATION

APPROXIMATE ELAPSED TIME	EVENT
0	Reactor at states B or D (of Appendix 15A) when RHR shutdown cooling inadvertently activated.
0-10 min.	Slow rise in reactor power.
+10 min.	Operator may take action to limit power rise. Flux scram will occur if no action is taken.

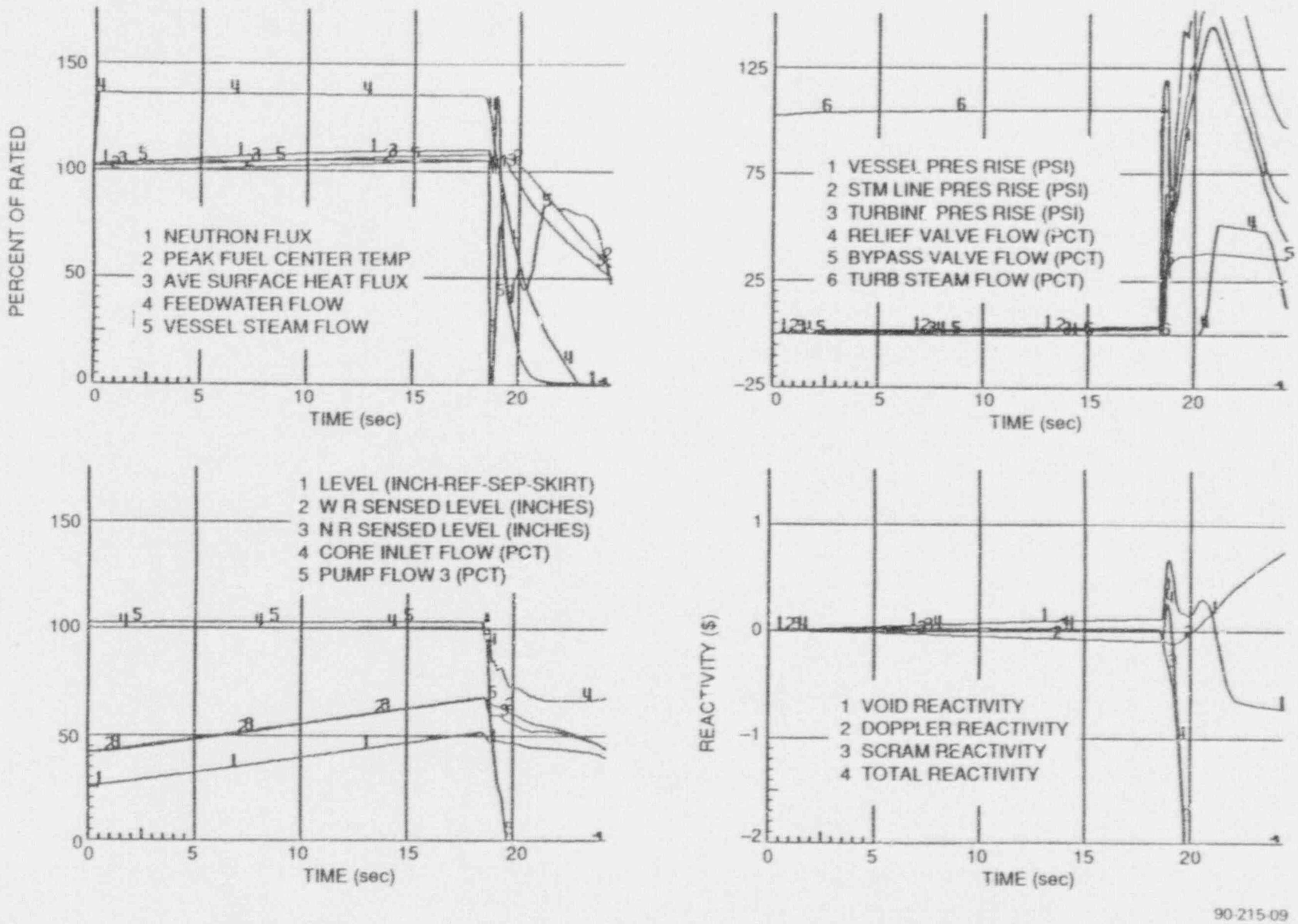

Figure 15.1-3 FEEDWATER CONTROLLER FAILURE - MAXIMUM DEMAND

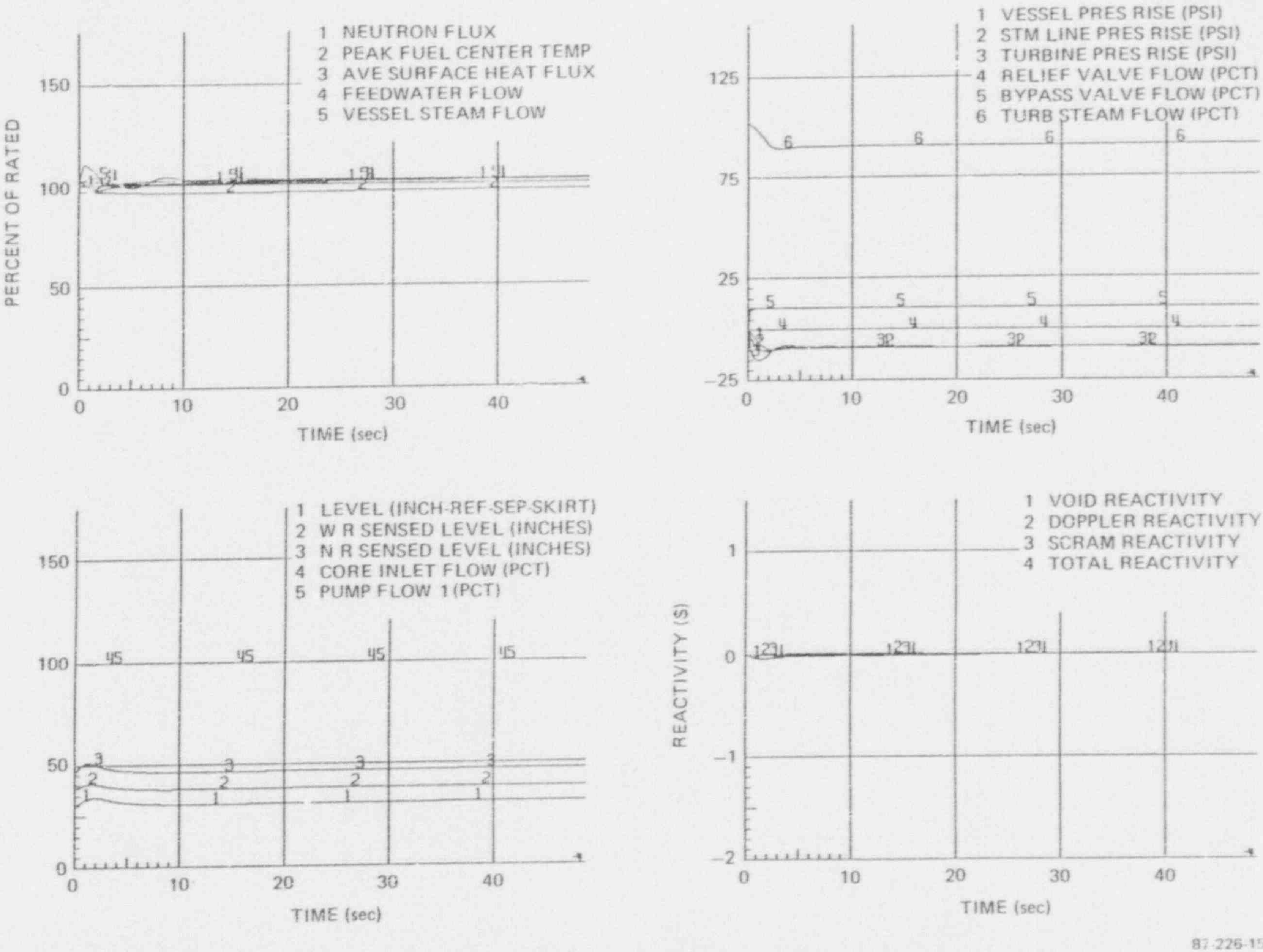

Figure 15.1–4 INADVERTENT OPENING OF ONE BYPASS VALVE

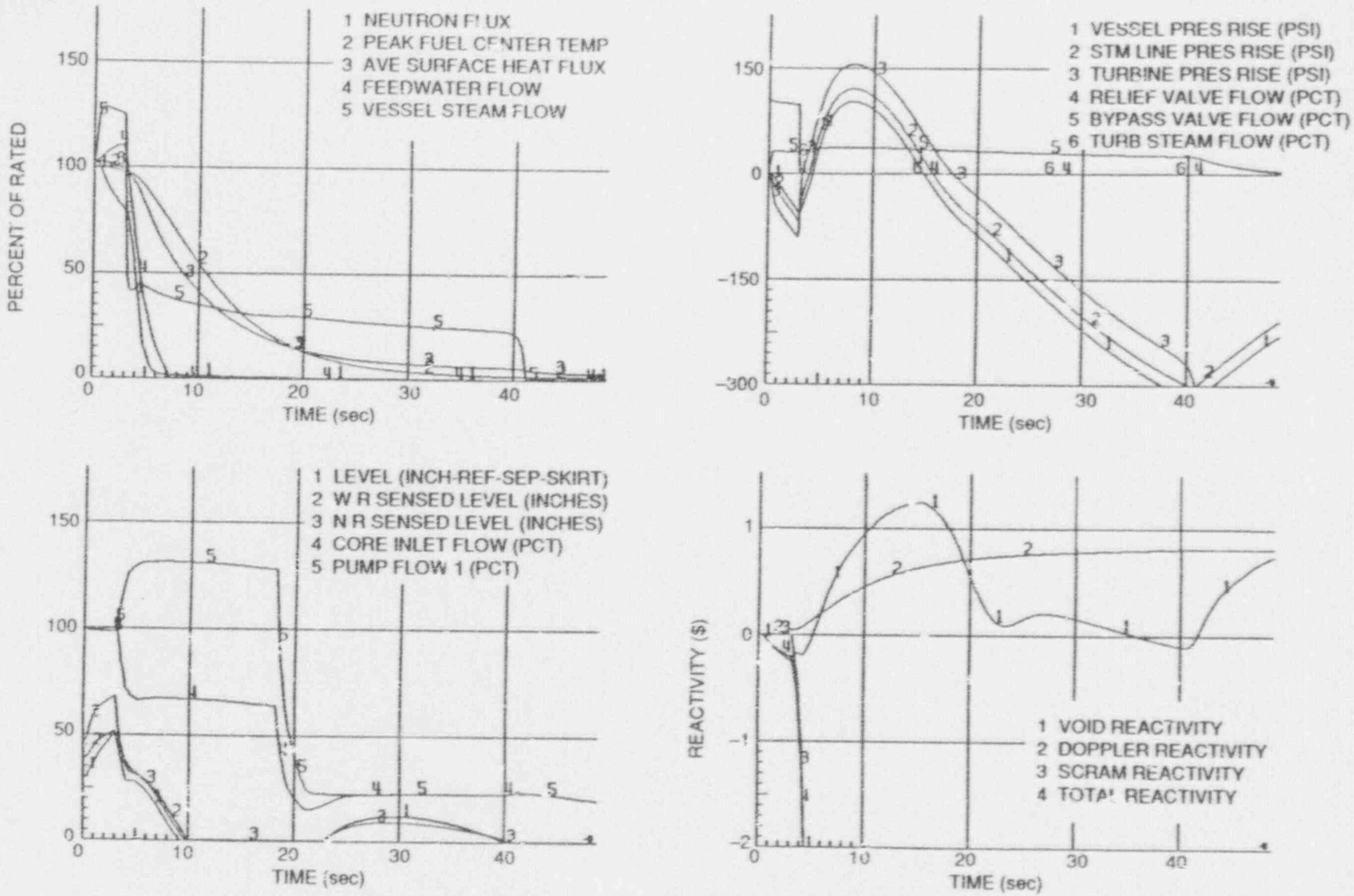

Figure 15.1-5 OPENING OF ALL CONTROL AND BYPASS VALVES

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TABLES

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TABLES (Continued)

ILLUSTRATIONS

15.2 INCREASE IN REACTOR PRESSURE

15.2.1 Pressure Regulator Failure--Closed

15.2.1.1 Identification of Causes and Frequency Classification

15.2.1.1.1 Identification of Causes

The ABWR steam bypass and pressure control system (SB&PCS) uses a triplicated digital control system, instead of an analog system as used in BWR/2 through BWR/6. The SB&PCS controls turbine control valves and turbine bypass valves to maintain reactor pressure. As presented in Subsection 15.1.2.1.1, no credible single failure in the control system will result in a minimum demand to all turbine control valves and bypass valves. A voter or actuator failure may result in an inadvertent closure of one turbine control valve or one turbine bypass valve if it is open at the time of failure. In this case, the SB&PCS will sense the pressure change and command the remaining control valves or bypass valves, if needed, to open, and thereby automatically mitigate the transient and try to maintain reactor power and pressure.

Because turbine bypass valves are normally closed during normal full power operation, it is assumed for purposes of this transient analysis that a single failure causes a single turbine control valve to fail closed. Should this event occur at full power, the opening of remaining control valves may not be sufficient to maintain the reactor pressure, depending on the turbine design. Neutron flux will increase due to void collapse resulting from the pressure increase. A reactor scram will be initiated when the high flux scram setpoint is exceeded.

No single failure will cause the SB&PCS to issue erroneously a minimum demand to all turbine control valves and bypass valves. However, as discussed in Subsection 15.1.2.1.1, multiple failures might cause the SB&PCS to fail and erroneously issue a minimum demand. Should this occur, it would cause full closure of turbine controls valves as well as an inhibit of steam bypass flow and thereby increase reactor power and pressure. When this occurs, reactor scram will be initiated when the high reactor flux scram setpoint is reached. This event is analyzed here as the simultaneous failure of two control processors, called "pressure regulator downscale failure." However, the probability of this event to occur is extremely low (less than $7x10^{-6}$ failure per reactor year), and hence the event is considered as a limiting fault.

15.2.1.1.2 Frequency Classification

15.2.1.1.2.1 Inadvertent Closure of One Turbine Control Valve

This event is conservatively treated as a moderate frequency event, although the voter/actuator failure rate is very low (0.0088 failure per reactor year).

15.2.1.1.2.2 Pressure Regulator Downscale Failure

The probability of occurence of this event is calculated to be less than $7x10^{-5}$ per year as shown in Appendix 15D. This event is treated as a limiting fault.

15.2.1.2 Sequence of Events and System Operation

15.2.1.2.1 Inadvertent Closure of One Turbine Control Valve

Postulating a actuator failure of the SB&PCS as presented in Subsection 15.2.1.1.1 will cause one turbine control valve to close. The pressure will increase because the reactor is still generating the initial steam flow. The SB&PCS will open the remaining control valves and some bypass valves. This sequence of events is listed in Table 15.2-1a for Figure 15.2-1a, for a fast closure, and in Table 15.2-1b for Figure 15.2-1b, for a slow closure.

15.2.1.2.1.2 Pressure Regulator Downscale Failure

Table 15.2-2 lists the sequence of events for Figure 15.2-2.

15.2.1.2.1.3 Identification of Operator Actions

The operator should:

(1) monitor that all rods are in;

(2) monitor reactor water level and pressure;

(3) observe turbine coastdown and break vacuum before the loss of steam seals (check

turbine auxiliaries);

(4) observe that the reactor pressure relief valves open at their setpoint;

(5) monitor reactor water level and continue cooldown per the normal procedure; and

(6) complete the scram report and initiate a maintenance survey of pressure regulator before reactor restart.

15.2.1.2.2 Systems Operation

15.2.1.2.2.1 Inadvertent Closure of One Turbine Control Valve

Normal plant instrumentation and control are assumed to function. This event takes credit for high neutron flux scram to shut down the reactor.

After a closure of one turbine control valve, the steam flow rate that can be transmitted through the remaining three turbine control valves depends upon the turbine configuration. For plants with full-arc turbine admission, the steam flow through the remaining three turbine control valves is at least 95% of rated steam flow. On the other hand, this capacity drops to about 85% of rated steam flow for plants with partial-arc turbine admission. Therefore, this transient is less severe for plants with full-arc turbine admission. In this analysis, cases with full-arc and partial-arc turbine admission are analyzed to cover all potential operating conditions.

This event is sensitive to the closure time of the turbine control valve, and the bypass capacity available during this event. A wide range of closure time, including very slow closure, has been assumed in the analysis. A fast closure causes the reactor to be scrammed on high neutron flux trip, while a slow closure allows the reactor to settle in another steady state.

The turbine bypass capacity during this event is controlled by the setpoint of the maximum combined steam flow limits in the pressure control system. A nominal 115% setpoint will allow for about 12% bypass capacity, while a nominal 125% setpoint for about 22%, assuming a 3% bypass bias. It is concluded from analysis that the nominal setpoint for the maximum combined flow limits should be set at 115% for plants with full-arc turbine admission, and at 125% for plants with partial-arc turbine admission.

15.2.1.2.2.2 Pressure Regulator Downscale Failure

Analysis of this event assumes normal functioning of plant instrumentation and controls, and plant protection and reactor protection systems. Specifically, this event takes credit for high neutron flux scram to shut down the reactor. High system pressure is limited by the pressure relief valve system operation.

15.2.1.3 Core and System Performance

15.2.1.3.1 Inadvertent Closure of One Turbine Control Valve

A simulated fast closure of one turbine control valve (2.5 seconds) is presented in Figure 15.2-1a. The analysis assumes that about 85% of rated steam flow can pass through the remaining three turbine control valves.

Neutron flux increases rapidly because of the void reduction caused by the pressure increase. When the sensed neutron flux reaches the high neutron flux scram setpoint, a reactor scram is initiated. The neutron flux increase is limited to 124 % NBR by the reactor scram. Peak fuel surface heat flux does not exceed 103.6% of its initial value. MCPR for this transient is still above the safety MCPR limit (ΔCPR =0.10). Therefore, the design basis is satisfied.

A slow closure of one turbine control valve is also analyzed as shown in Figure 15.2-1b. In this case, the neutron flux increase does not reach the high neutron flux scram setpoint. Since the available turbine bypass capacity is enough to bypass all steam flow not passing through the remaining three turbine control valves, the reactor power settles back to its steady state. During the transient, the peak fuel surface heat flux does not exceed 103.6% of its initial value. MCPR is still above the safety limit (ΔCPR =0.09). Therefore, the design basis is satisfied.

The applicant will provide reanalysis of this event for the specific core configuration.

15.2.1.3.2 Pressure Regulator Downscale Failure

A pressure regulator downscale failure is simulated at 102% NBR power as shown in Figure 15.2-2.

Neutron flux increases rapidly because of the void reduction caused by the pressure increase. When the sensed neutron flux reaches the high neutron flux scram setpoint, a reactor scram is initiated. The neutron flux increase is limited to 155% NBR by the reactor scram. Peak fuel surface heat flux does not exceed 103% of its initial value. It is estimated less than 0.2% of rods will get into transition boiling. Therefore, the design limit for the limiting fault event is met.

15.2.1.4 Barrier Performance

15.2.1.4.1 Inadvertent Closure of One Turbine Control Valve

Peak pressure at the SR valves reaches 74.5 Kg/Cm^{2}g. The peak vessel bottom pressure reaches 78.2 Kg/Cm^{2}g, below the transient pressure limit of 96.7 Kg/Cm^{2}g.

15.2.1.4.2 Pressure Regulator Downscale Failure

Peak pressure at the SRVs reaches 85.1 Kg/Cm^{2}g. The peak nuclear system pressure reaches 87.4 Kg/Cm^{2}g at the bottom of the vessel, below the nuclear barrier pressure limit.

15.2.1.5 Radiological Consequences

15.2.1.5.1 Inadvertent Closure of One Turbine Control Valve

The consequences of this event do not result in any fuel failures, nor any discharge to the suppression pool. Therefore, the radiological exposures noted in Subsection 15.2.4.5 cover the consequences of this event.

15.2.1.5.2 Pressure Regulator Downscale Failure

During this event, less than 0.2% of fuel rods get into transition boiling. No fuel failures are expected. However it is con- servatively assumed that 0.2% of fuel rods fail in the radiological dose calculation. The results show that both, the whole body dose and thyroid dose, are well within 10% of 10CFR100 requirements. Therefore, the acceptance criteria are met.

15.2.2 Generator Load Rejection

15.2.2.1 Identification of Causes and Frequency Classification

15.2.2.1.1 Identification of Causes

Fast closure of the turbine control valves (TCV) is initiated whenever electrical grid disturbances occur which result in significant loss of electrical load on the generator. The turbine control valves are required to close as rapidly as possible to prevent excessive overspeed of the turbine-generator (T-G) rotor. Closure of the main turbine control valves will cause a sudden reduction in steam flow, which results in an increase in system pressure and reactor shutdown.

After sensing a significant loss of electrical load on the generator, the turbine control valves are commanded to close rapidly. At the same time, the turbine bypass valves are signaled to open in the "fast" opening mode by the Steam Bypass and Pressure Control System (SB&PCS), which uses a triplicated digital controller. As presented in Subsection 15.1.2.1.1, no single failure can cause all turbine bypass valves fail to open on demand. The worst single failure can only cause one turbine bypass valve fail to open on demand. Therefore, the probability of this to occur is very low (less than one failure every 11 year). Therefore, generator load rejection with failure of one turbine bypass valve is considered an infrequent event; while generator load rejection with failure of all turbine bypass valves is a limiting fault.

15.2.2.1.2 Frequency Classification

15.2.2.1.2.1 Generator Load Rejection

This event is categorized as an incident of moderate frequency.

15.2.2.1.2.2 Generator Load Rejection with Failure of One Bypass Valve

This event should be categorized as an infrequent event. However, criteria for moderate frequent incidents are conservetively applied.

15.2.2.1.2.3 Generator Load Rejection with Failure of All Bypass Valves

Frequency: $<3.6\times10^{-5}$ /plant year

Frequency Basis: Thorough search of domestic plant operating records have revealed three instances of bypass failure during 628 bypass system operations. This gives a probability of bypass failure of 0.0048. Combining the actual frequency of a generator load rejection with the failure rate of bypass yields a frequency of a generator load rejection with bypass failure of 0.0036 event/plant year. With the triplicated fault-tolerant design used in ABWR, this failure frequency is lowered by at least a factor of 100. Therefore, this event should be classified as a limiting fault, However, criteria for moderate frequent incidents are conservetively applied.

15.2.2.2 Sequence of Events and System Operation

15.2.2.2.1 Sequence of Events

15.2.2.2.1.1 Generator Load Rejection--Turbine Control Valve Fast Closure

A loss of generator electrical load from high power conditions produces the sequence of events listed in Table 15.2-3.

15.2.2.2.1.2 Generator Load Rejection with Failure of One Bypass Valve

A loss of generator electrical load from high power conditions with failure of one bypass valve produces the sequence of events listed in Table 15.2-4.

15.2.2.2.1.3 Generator Load Rejection with Failure of All Bypass Valves

A loss of generator electrical load at high power with failure of all bypass valves produces the sequence of events listed in Table 15.2-5.

15.2.2.2.1.4 Identification of Operator Actions

The operator should:

(1) verify proper bypass valve performance;

(2) observe that the feedwater/level controls have maintained the reactor water level at a satisfactory value;

(3) observe that the pressure regulator is controlling reactor pressure at the desired value;

(4) observe reactor peak power and pressure ; and

(5) verify relief valve operation.

Table 15.2-1a

SEQUENCE OF EVENTS FOR FIGURE 15.2-1a

TIME (sec)	EVENT
0	Simulate one main turbine control valve to fast close.
0	Failed turbine control valves start to close.
3.0	Neutron flux reaches high flux scram setpoint and initiates a reactor scram.
2.8	Turbine bypass valves start to open.
8.1	Water level reaches level 3 setpoint. Four RIPs are tripped.

Table 15.2-1b

SEQUENCE OF EVENTS FOR FIGURE 15.2-1b

TIME (sec)	EVENT
0	Simulate one main turbine valve to slow close.
0	Failed turbine control valve starts to close.
16.0	Neutron flux reaches its peak. No scram in initiated.
15.6	Turbine bypass valves start to open.
~30	Reactor power settles back to steady state.

Table 15.2-2

SEQUENCE OF EVENTS FOR FIGURE 15.2-2

TIME (sec)	EVENT
0	Simulate zero steam flow demand to main turbine and bypass valves.
0	Turbine control valves start to close.
1.0	Neutron flux reaches high flux scram setpoint and initiates a reactor scram.
2.4	Four RIPs are tripped due to high dome pressure.
2.6	Safety/relief valves open due to high pressure.
8.9	Safety/relief valves close.
9.4	Group 1 safety/relief valves open again to relieve decay heat
9.8	Group 2 safety/relief valves open again to relieve decay heat.
15 (est.)	Safety/relief valves close.

Table 15.2-3

SEQUENCE OF EVENTS FOR FIGURE 15.2-3

TIME (sec)	EVENT
(-)0.015	Turbine-generator detection of loss of electrical load.
0.0	Turbine-generator load rejection sensing devices trip to initiate turbine control valves fast closure and main turbine bypass system operation.
0.0	Fast control valve closure (FCV) initiates reactor scram and a trip of 4 RIPs.
0.07	Turbine control valves closed.
0.1	Turbine bypass valves start to open.
1.9	Safety/relief valves open due to high pressure.
7.0	Safety/relief valves close.

Table 15.2-4

SEQUENCE OF EVENTS FOR FIGURE 15.2-4

TIME (sec)	EVENT
(-)0.015	Turbine-generator detection of loss of electrical load.
0.0	Turbine-generator load rejection sensing devices trip to initiate turbine control valves fast closure and main turbine bypass system operation.
0.0	One turbine bypass valve fails to operate on demand.
0.0	Fast control valve closure (FCV) initiates reactor scram and a trip of 4 RIPs.
0.07	Turbine control valves closed.
0.1	Remaining bypass valves start to open.
1.6	Safety/relief valves open due to high pressure.
6.9	Safety/relief valves close.

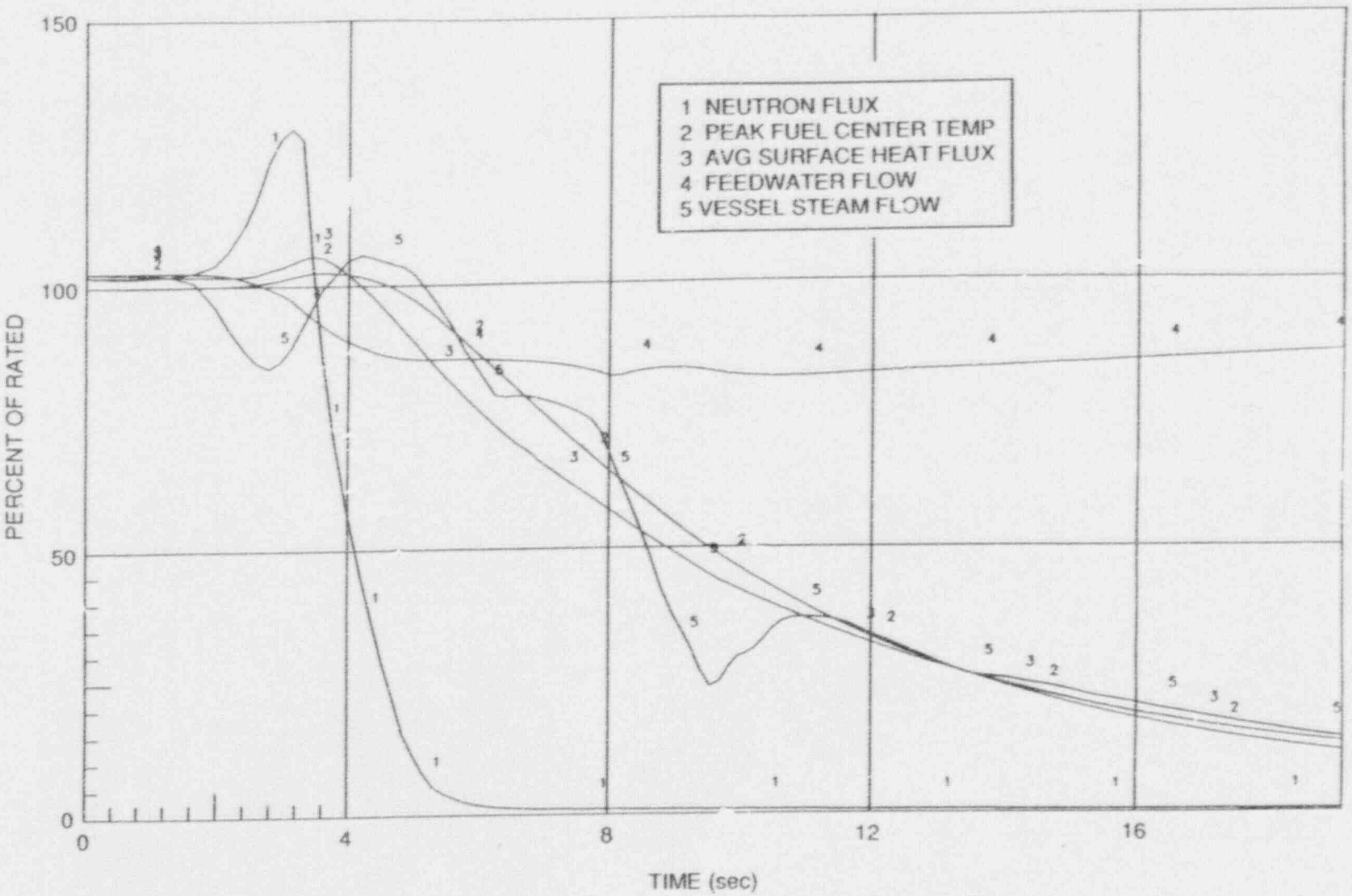

Figure 15.2-1a FAST CLOSURE OF ONE TURBINE VALVE

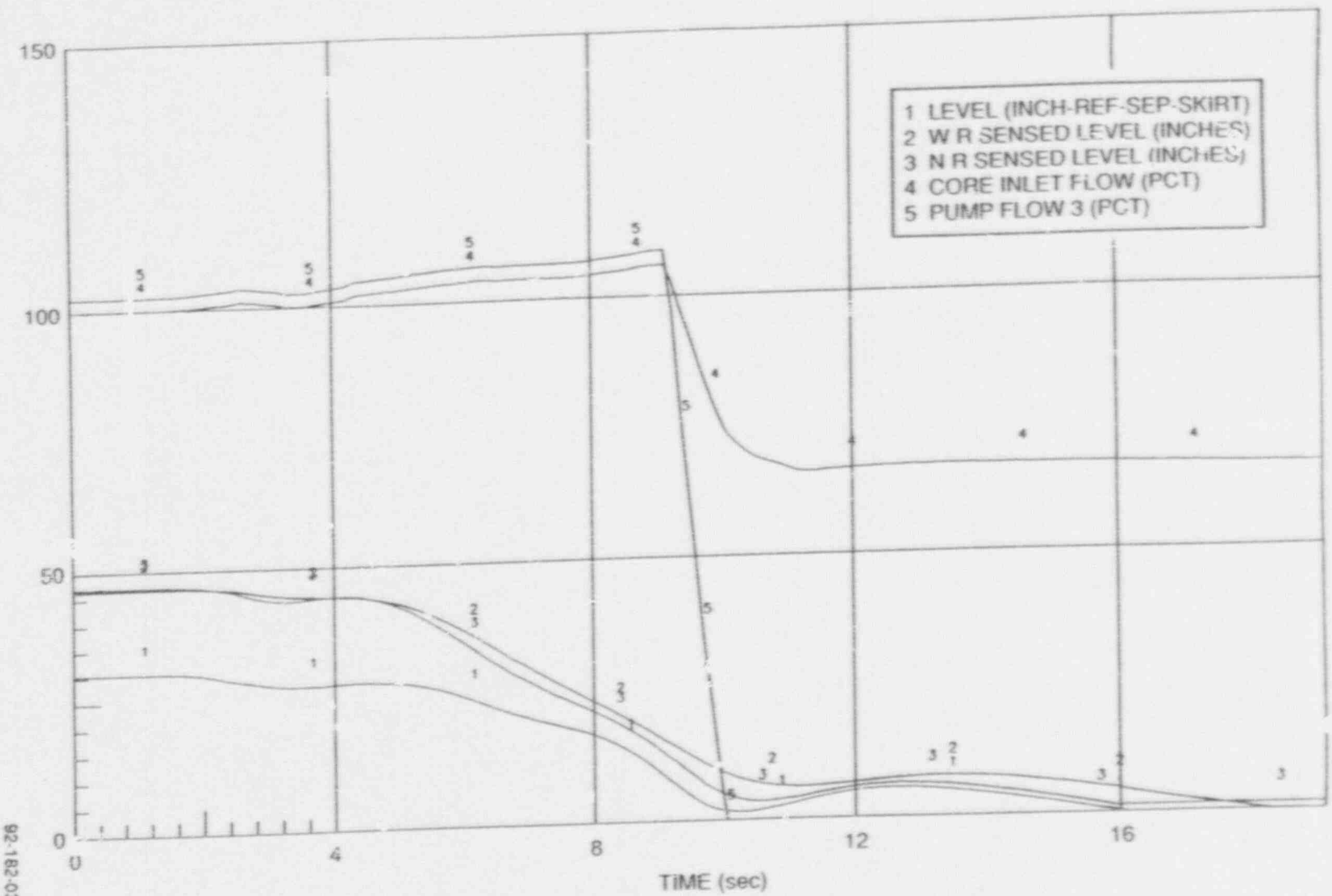

Figure 15.2-1a FAST CLOSURE OF ONE TURBINE VALVE (Continued)

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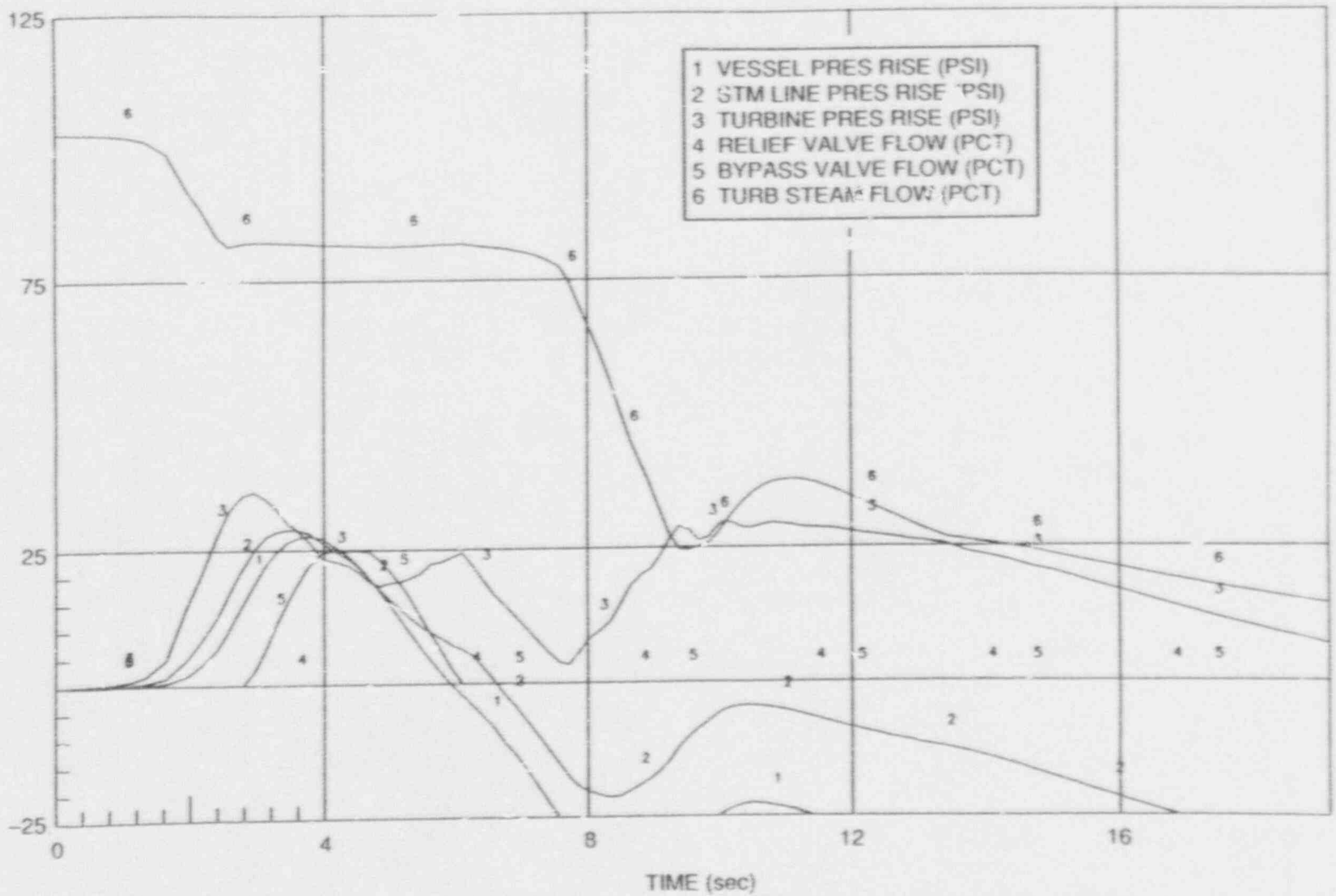

Figure 15.2-1a FAST CLOSURE OF ONE TURBINE VALVE (Continued)

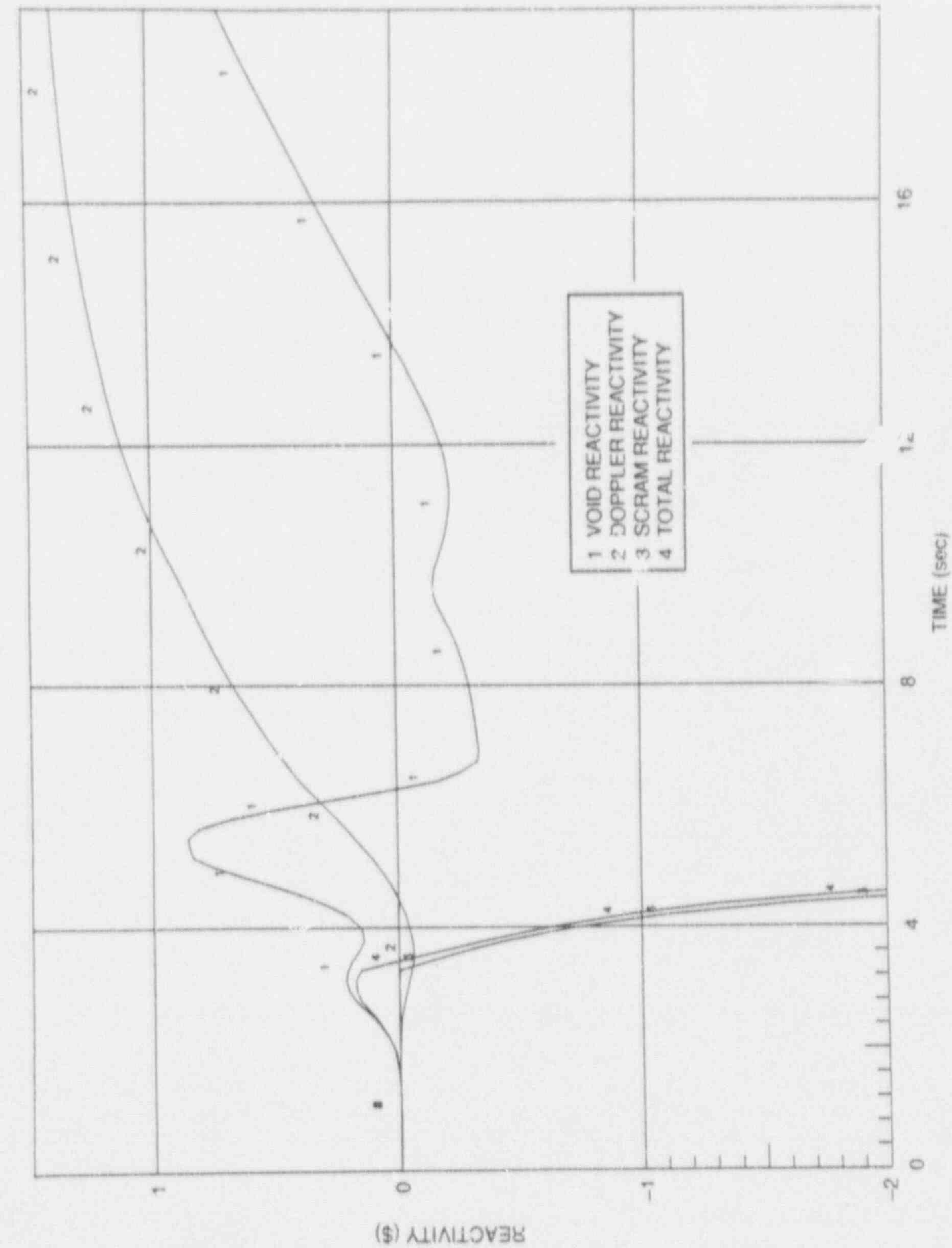

Figure 15.2-1a FAST CLOSURE OF ONE TURBINE VALVE (Continued)

92-182-01

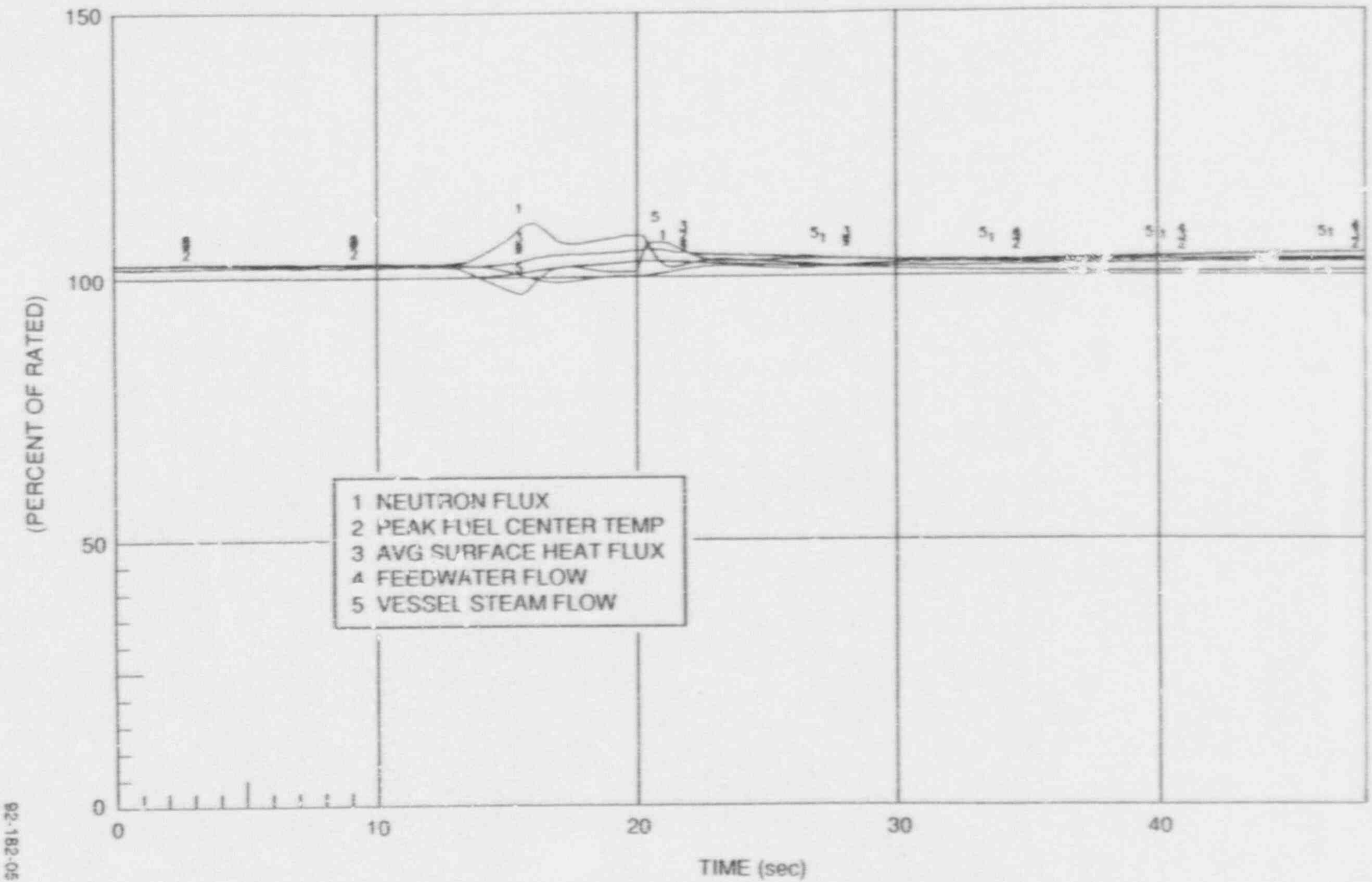

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Figure 15.2-1b SLOW CLOSURE OF ONE CONTROL VALVE

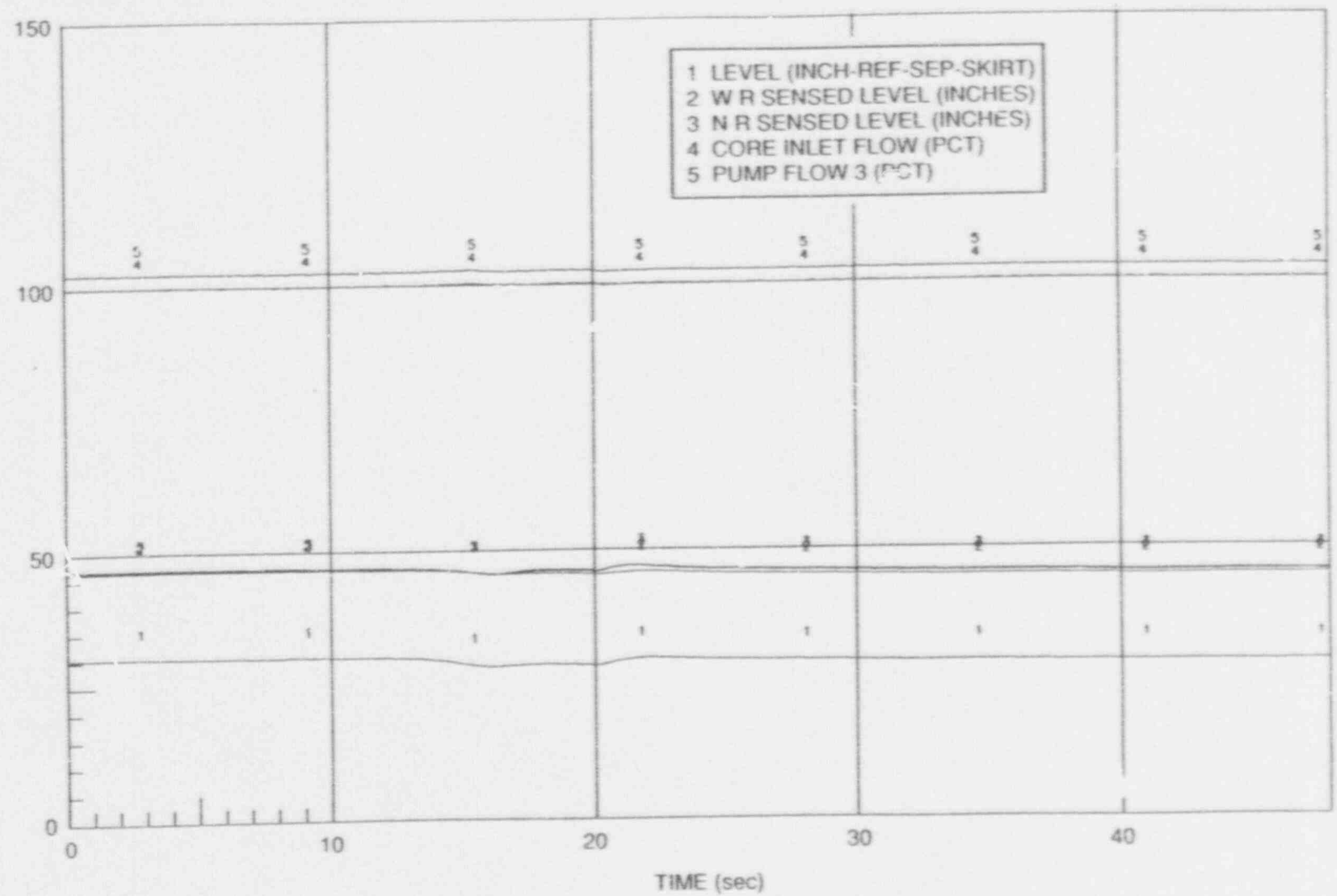

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Figure 15.2-1b SLOW CLOSURE OF ONE CONTROL VALVE (Continued)

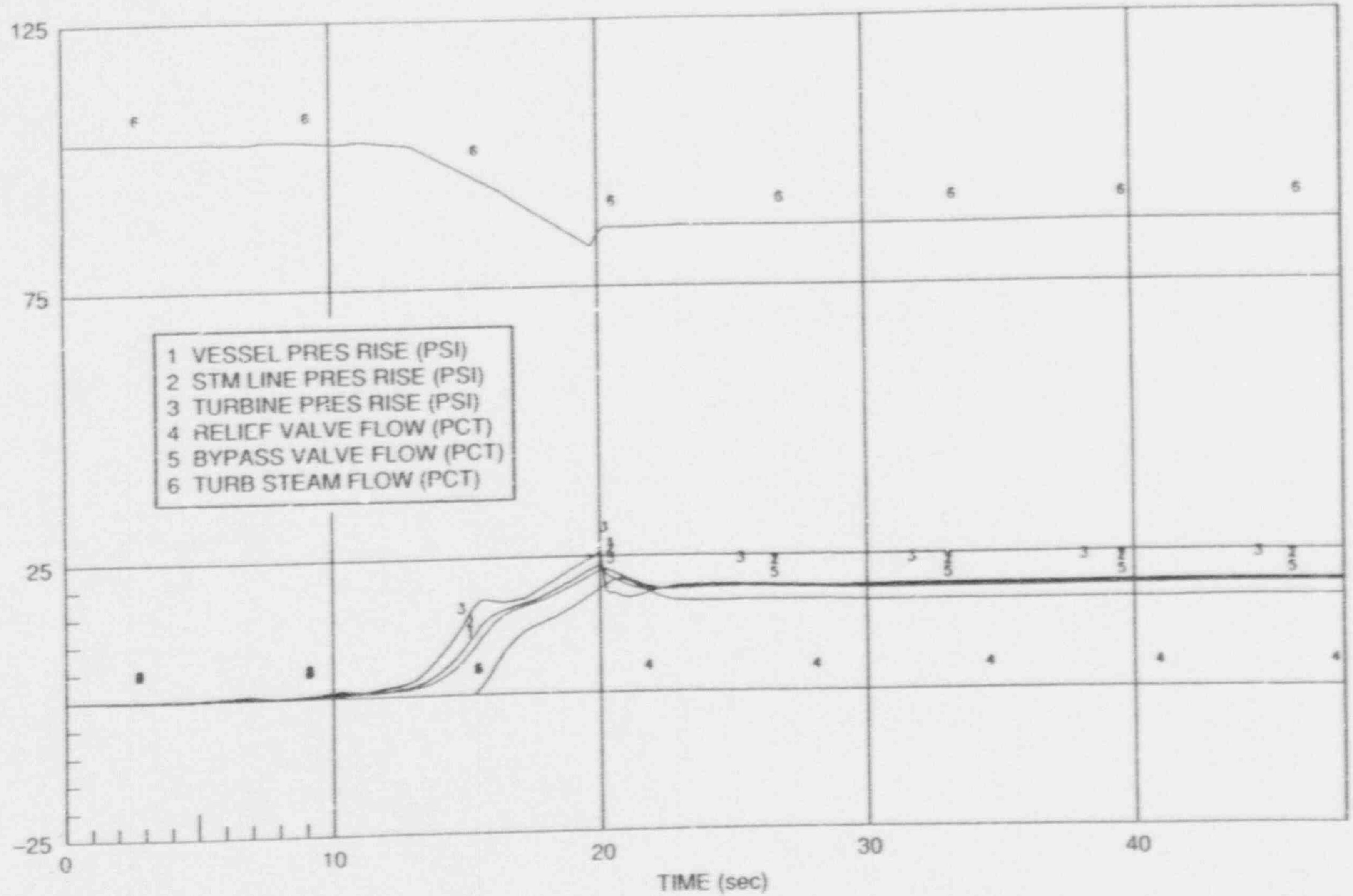

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Figure 15.2-1b SLOW CLOSURE OF ONE CONTROL VALVE (Continued)

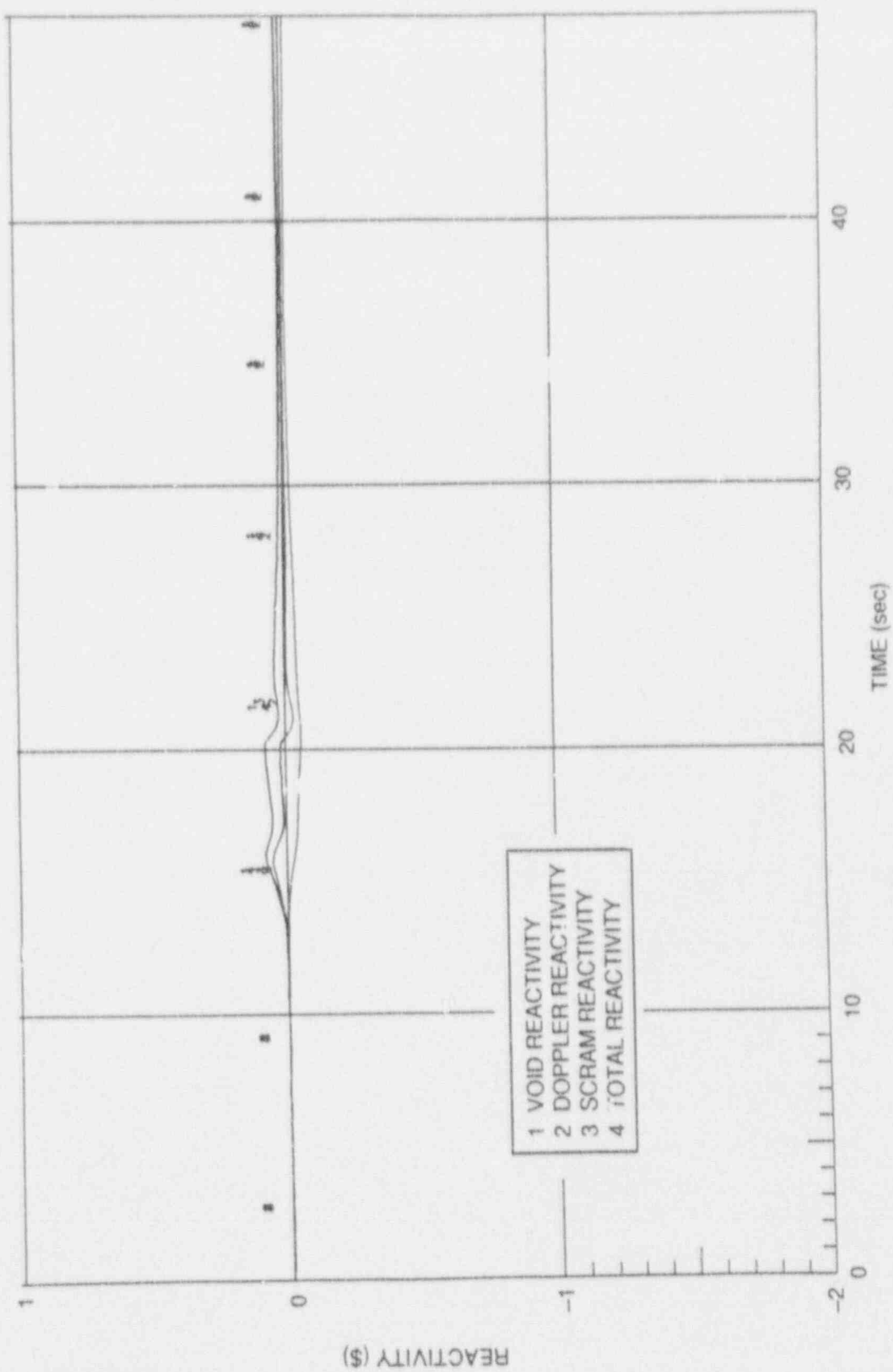

Figure 15.2-1b SLOW CLOSURE OF ONE CONTROL VALVE (Continued)

92-182-08

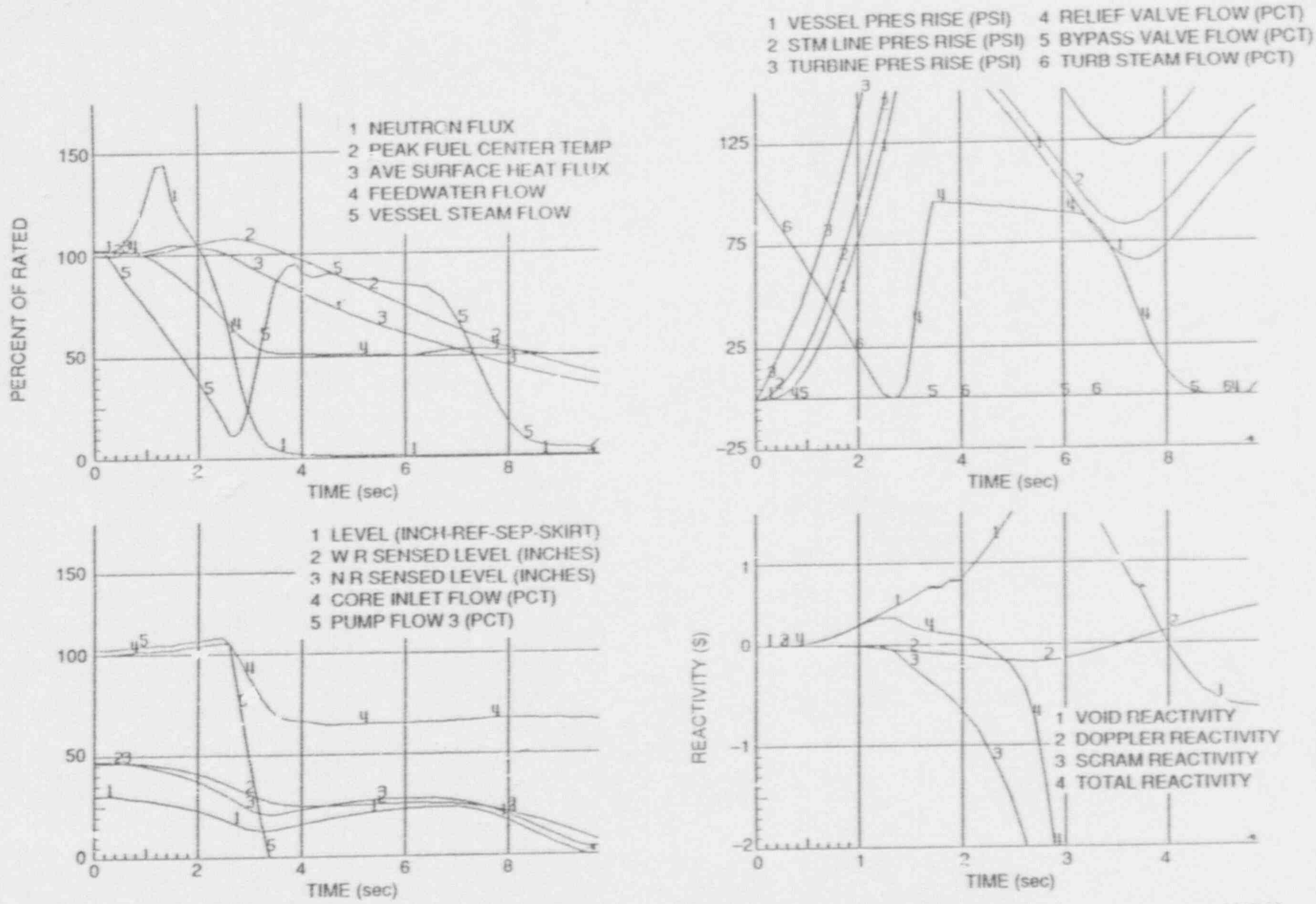

Figure 15.2–2 PRESSURE REGULATOR DOWNSCALE FAILURE

SECTION 15.3

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SECTION 15.3

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SECTION 15.3

TABLES

ILLUSTRATIONS

15.3 DECREASE IN REACTOR COOLANT SYSTEM FLOW RATE

15.3.1 Reactor Internal Pump Trip

15.3.1.1 Identification of Causes and Frequency Classification

15.3.1.1.1 Identification of Causes

Reactor internal pump (RIP) motor operation can be tripped off by design for intended reduction of other transient core and RCPB effects, as well as randomly by unpredictable operational failures. Intentional tripping will occur in response to :

(1) reactor vessel water level L3 setpoint trip (4 RIPs);

(2) reactor vessel water level L2 setpoint trip (the other 6 RIPs);

(3) TCV fast closure or stop valve closure (the same 4 RIPs as L3 trip);

(4) high pressure setpoint trip (the same 4 RIPs as L3 trip);

(5) motor overcurrent protection (single pump); and

(6) motor overload and short circuit protection (single pump).

Random tripping will occur in response to:

(1) operator error;

(2) loss of electrical power source to the pumps; and

(3) equipment or sensor failures and malfunctions which initiate the above intended trip response. However, all trip logics use redundant digital designs. No credible single failure will initiate any of the above intended trips.

Thus, the worst single-failure event is a loss of electrical power bus, which supplies power to RIPs. Since four buses are used to supply power to the RIPs, the worst single failure can only cause three RIPs to trip.

A loss of AC power to station auxiliaries may cause some RIPs to trip. However, not all RIPs could be tripped at the same time due to the M/G sets. Transients caused by a loss of AC power are discussed in Subsection 15.2.6.

The effect of additional single failure on this event (i.e., trip of three RIPs) is the tripping of additional RIPs. For example, if an additional power bus fails at the same time, the number of RIPs tripped are five or six, instead of three. However, the probability of this occurring is low (less than 10^{-6} per year as shown in Appendix 15C). Therefore, this event is classified as a limiting fault. The probability that exactly 1, or 2, or....10 out of 10 RIPs will trip simultaneously is evaluated in Appendix 15C. From this evaluation, it is concluded that any trip of more than 3 RIPs simultaneously should be classified as a limiting fault. In this analysis, an analysis of trip of all RIPs is provided to bound the events in their limiting fault category.

When a rapid core flow reduction caused by a trip of all RIPs is sensed, a reactor scram is initiated to terminate the power generation. The core flow reduces rapidly due to the relatively small inertia of the RIPs. However, natural circulation is still available to keep the reactor core covered and cooled.

15.3.1.1.2 Frequency Classification

15.3.1.1.2.1 Trip of Three Reactor Internal Pumps

This transient event is categorized as one of moderate frequency.

15.3.1.1.2.2 Trip of All Reactor Internal Pumps

This event is categorized as a limiting fault. For detailed evaluation of frequency of occurrence, see Appendix 15C.

15.3.1.2 Sequence of Events and Systems Operation

15.3.1.2.1 Sequence of Events

15.3.1.2.1.1 Trip of Three Reactor Internal Pumps

Table 15.3-1 lists the sequence of events for Figure 15.3-1.

15.3.1.2.1.2 Trip of All Reactor Internal Pumps

Table 15.3-2 lists the sequence of events for Figure 15.3-2.

15.3.1.2.1.3 Identification of Operator Actions

15.3.1.2.1.3.1 Trip of Three Reactor Internal Pumps

Because no scram occurs for trip of three RIPs, no immediate operator action is required. As soon as possible, the operator should verify that no operating limits are being exceeded. The operator should also determine the cause of failure prior to returning the system to normal operation.

15.3.1.2.1.3.2 Trip of All Reactor Internal Pumps

The operator should ascertain that the reactor scram is initiated. If the main turbine and feedwater pumps are tripped resulting from reactor water level swell, the operator should regain control of reactor water level through RCIC operation, monitoring reactor water level and pressure after shutdown. When both reactor pressure and level are under control, the operator should secure RCIC as necessary. The operator should also determine the cause of the trip prior to returning the system to normal operation.

15.3.1.2.2 Systems Operation

15.3.1.2.2.1 Trip of Three Reactor Internal Pumps

Tripping of three RIPs requires no protection system or safeguard system operation. This analysis assumes normal functioning of plant instrumentation and controls.

15.3.1.2.2.2 Trip of All Reactor Internal Pumps

Analysis of this event assumes normal functioning of plant instrumentation and controls, and plant protection and reactor protection systems.

If a trip of all RIPs is caused by multiple failures in an electrical power supply to the RIPs, a reactor scram will be initiated at time 0 due to load rejection or turbine trip at time 0. For other causes a reactor scram will be initiated upon the condition of high simulated thermal power scram, turbine trip due to high water level, or rapid core flow coastdown. High system pressure is limited by the pressure relief valve system operation.

Since the event becomes more severe when the reactor scram is delayed, the analysis conservatively assumes that the reactor scram is initiated by the last signal (i.e., core flow rapid coastdown scram). It is also conservatively assumed that the event is caused by a common mode failure in all ASD's, which results in a trip of all RIPs.

15.3.1.3 Core and System Performance

15.3.1.3.1 Input Parameters and Initial Conditions

Pump motors and pump rotors are simulated with minimum specified rotating inertias. The nuclear conditions for the beginning of life (BOC) are used to provide conservative bounding analysis.

15.3.1.3.2 Results

15.3.1.3.2.1 Trip of Three Reactor Internal Pumps

Figure 15.3-1 shows the results of losing three RIPs. MCPR remains above the safety limit; thus, the fuel thermal limits are not violated. During this transient, level swell is not sufficient to cause turbine trip and scram.

Figure 15.3-2 graphically shows this event with the minimum specified rotating inertia for the RIPs. The vessel water level swell due to rapid flow coastdown is expected to reach the high level trip, thereby tripping the main turbine and feed pumps. Subsequent events, such as initiation of the RCIC system occurring late in this event, have no significant effect on the results. The peak clad temperature during this event is calculated to be less than 600°C, which is below the applicable limit of 1200°C. The cladding temperature during this event is shown in Figure 15.3-2a. The time that the cladding temperature is above the coolant saturated temperature is less than 60 seconds, and the peak cladding temperature is less than 600°C, no fuel failure is expected.

This event is very sensitive to the core condition. It is expected that about 60% of the rods will be in transition boiling at the beginning of the core life, and about 6% at the end of the first fuel cycle. This value drops to about 4% at the end of the equilibrium cycle. However, not fuel failures are expected.

15.3.1.4 Barrier Performance

15.3.1.4.1 Trip of Three Reactor Internal Pumps

The results shown in Figure 15.3-1 indicate that peak pressures stay well below the 96.7 Kg/cm^2g limit allowed by the applicable code. Therefore, the barrier pressure boundary is not threatened.

15.3.1.4.2 Trip of All Reactor Internal Pumps

The results shown in Figure 15.3.2 indicate that peak pressures stay well below the limit allowed by the applicable code. Therefore, the barrier pressure boundary is not threatened.

15.3.1.5 Radiological Consequences

15.3.1.5.1 Trips of Three Reactor Internal Pumps

The consequences if this event will not result in any fuel failures, nor any discharge to the suppression pool. Therefore, the radiological exposures noted in Subsection 15.2.4.5 cover the consequences of this event.

15.3.1.5.2 Trip of All Reactor Internal Pumps

The approved procedures for radiological dose calculation for this event are as follows:

(a) For fuel rods with less than or equal to 20 GWD/T exposure, fuel failures are assumed if the peak cladding temperature (PCT) stays above 600°C for more than 60 seconds.

(b) For fuel rods with greater than 20 GWD/T exposure, rods that are in transition boiling shall be assumed to fail radiological dose calculations.

(c) The radiological doses shall be lees than 10% of 10CFR100 requirements.

As discussed in Subsection 15.3.1.3.2.2, the PCT during this event is less tahn 600°C and the time at high temperature is less than 60 seconds. Therefore, no fuel failures need to be assumed for fuel rods with less than or equal to 29 GWD/T exposure.

In general, fuel rods with more than 20 GWD/T exposure are those remaining in the core for more than two fuel cycles. In the equilibrium cycle, these fuel bundles only account for about 45% of the total bundles. The power generated by these bundles are usually 20% less than the hottest bundles. Less than 0.2% of these rods get into transition boiling. Therefore, the 10%% requirement of 10CFR100 are met.

15.3.2 Recirculation Flow Control Failure--Decreasing Flow

15.3.2.1 Identification of Causes and Frequency Classification

15.3.2.1.1 Identification of Causes

The recirculation flow control system (RFCS) uses a triplicated, fault-tolerant digital control system, instead of an analog system as used in BWR 2 through BWR 6. The RFCS controls all ten reactor internal pumps (RIPs) at the same speed. As presented in Subsection 15.1.2.1.1, no credible single failure in the control system will result in a minimum demand to all RIPs. A voter or actuator failure may result in an inadvertent runback of one RIP at its maximum drive speed (~40%/sec.). In this case, the RFCS will sense the core flow change and command the remaining RIPs to increase speeds and thereby automatically mitigate the transient and maintain the core flow.

As presented in Subsection 15.1.2.1.1, multiple failures in the control system might cause the RFCS to erroneously issue a minimum demand to all RIPs. Should this occur, all RIPs could reduce speed simultaneously. Each RIP drive has a speed limiter which limits the maximum speed change rate to 5%/sec. However, the probability of this event occurring is low (less than 7 x 10^{-5} failures per reactor year); and hence, the event should be considered as a limiting fault.

15.3.2.1.2 Frequency Classification

15.3.2.1.2.1 Fast Runback of One Reactor Internal Pump

The failure rate of a voter or an actuator is about 0.0088 failures per reactor year. However, it is analyzed as an incident of moderate frequency.

15.3.2.1.2.2 Fast Runback of All Reactor Internal Pumps

This event should be classified as a limiting fault event. However, criteria for moderate frequent incidents are conservatively applied.

15.3.2.2 Sequence of Events and Systems Operation

15.3.2.2.1 Sequence of Events

15.3.2.2.1.1 Fast Runback of One Reactor Internal Pump

Table 15.3-3 lists the sequence of events for Figure 15.3-3.

15.3.2.2.1.2 Fast Runback of All Reactor Internal Pumps

Table 15.3-4 lists the sequence of events for Figure 15.3-4.

15.3.2.2.1.3 Identification of Operator Actions

15.3.2.2.1.3.1 Fast Runback of One Reactor Internal Pump

As soon as possible, the operator verifies that no operating limits are being exceeded. The operator determines the cause of failure prior to returning the system to normal.

15.3.2.2.1.3.2 Fast Runback of All Reactor Internal Pumps

As soon as possible, the operator verifies that no operating limits are being exceeded. If they are, corrective actions must be initiated. Also the operator determines the cause of the failures prior to returning the system to normal.

15.3.2.2.2 Systems Operation

15.3.2.2.2.1 Fast Runback of One Reactor Internal Pump

Normal plant instrumentation and control is assumed to function.

15.3.2.2.2.2 Fast Runback of All Reactor Internal Pumps

Normal plant instrumentation and control is assumed to function.

15.3.2.3 Core and System Performance

15.3.2.3.1 Input Parameters and Initial Conditions

15.3.2.3.1.1 Fast Runback of One Reactor Internal Pump

Failure can result in the maximum speed of the RIP decreasing at a rate of 40%/sec as limited by the pump drive.

15.3.2.3.1.2 Fast Runback of All Reactor Internal Pumps

A downscale failure of the master controller will generate a zero flow demand signal to all RIPs. Each individual RIP drive has a speed limiter which limits the maximum speed decrease to a rate of 5%/sec. Core flow decreases to approximately 40% of rated. This is the flow expected when the RIPs are maintained at their minimum speeds.

15.3.2.3.2 Results

15.3.2.3.2.1 Fast Runback on One Reactor Internal Pump

Figure 15.3-3 illustrates the fast runback of one RIP event with the maximum rate which is limited by hydraulic means. The MCPR remains above the safety limit. Therefore, this event does not have to be reanalyzed for specific core configurations.

15.3.2.3.2.2 Fast Runback of All Reactor Internal Pumps

Figure 15.3-4 illustrates the expected event. Design of limiter operation is intended to render this event to be less severe than the trip of all RIPs. No fuel damage is expected to occur. Therefore, this event does not have to be reanalyzed for specific core configurations.

15.3.2.4 Barrier Performance

15.3.2.4.1 Fast Runback of One Reactor Internal Pump

Peak pressures are less than those for the *Fast Runback of All RIPs* presented in Subsection 15.3.2.4.2.

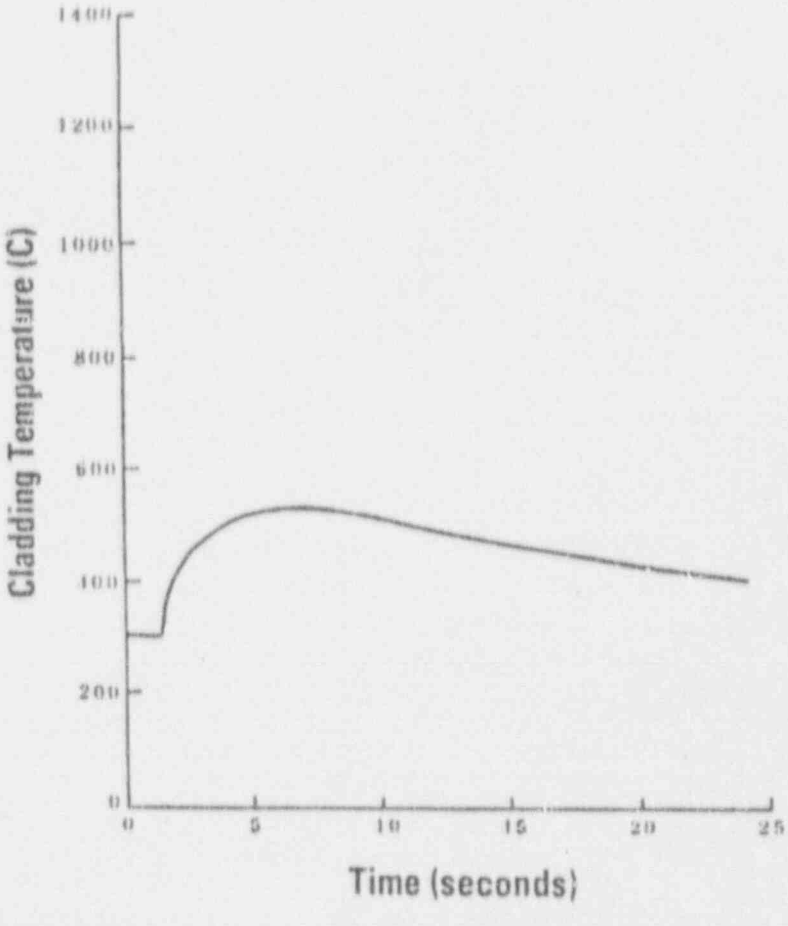

Figure 15.3-2a CLADDING TEMPERATURE DURING ALL PUMP TRIP

15.8 ANTICIPATED TRANSIENTS WITHOUT SCRAM

15.8.1 Requirements

SRP 15.8 requires a automatic recirculation pump trip (RPT) and emergency procedures for ATWS. This SRP has been somewhat superseded by the issuance of 10CFR50.62, which requires the BWR to have automatic RPT, an alternate rod insertion (ARI) system and an automatic standby liquid control system (SLCS) with a minimum flow capacity and boron content equivalent to 86 gpm of 13 weight percent sodium pentaborate solution.

15.8.2 Plant Capabilities

For ATWS prevention/mitigation for ABWR, the following are provided:

a. An ARI system that utilizes sensors and logic which are diverse and independent of the reactor protection system,

b. Electrical insertion of FMCRDs that also utilize sensors and logic which are diverse and independent of the reactor protection system,

c. Automatic recirculation pump trip under conditions indicative of an ATWS, and

d. Automatic initiation of SLCS with 100 gpm capacity under conditions indicative of an ATWS.

The ABWR has the ATWS-RPT feature which prevents reactor vessel overpressure and possible short-term fuel damage for the most limiting postulated ATWS events. The design details of this system are given in Section 7.7. Emergency procedures for ATWS are described in Chapter 18. Thus, the SRP 15.8 is satisfied.

The ATWS rule of 10CFR50.62 was written as hardware-specific, rather than functionally, because it clearly reflected the BWR use of locking-piston control rod drives. The ABWR however, uses a fine motion control rod drive (FMCRD) design with both hydraulic and electric means to achieve shutdown. This drive design is described in detail in Section 4.6. The use of this design eliminates the common mode failure potentials of the existing locking-piston CRD by eliminating the scram discharge volume (mechanical common mode potential failure) and by having an electric motor run-in diverse from the hydraulic scram feature.

This latter feature allows rod run-in if scram air header pressure is not exhausted because of a postulated common mode electrical failure and simutaneous failure of the ARI system, and therefore satisfies the intent required by 10CFR50.62. Thus, the design does not need an SLCS to respond to an ATWS threatening event.

The SLCS is required by 10CFR50 Appendix A Criterion and is described in Section 9. Because the new drive design eliminates the previous common-mode failure potential and because of the very low probability of simultaneous modem failure of a large number of drives, a failure to achieve shutdown is deemed incredible. However, automatic initiation of SLCS under conditions indicative of an ATWS os also oncorporated in order to meet the rule specified in 10CFR50.62.

Supporting analysis is documented in Appendix 15E.

TABLE 17.0-1

ABWR COMPLIANCE WITH QUALITY RELATED REGULATORY GUIDES

	Regulatory Guide	Rev.	Comments
201.1	1.8	1	No exceptions.
	1.26	4	No exceptions.
	1.28	3	Except for NRC accepted alternate positions documented in Table 2-1 of Reference 1.
201.1	1.29	3	No exceptions.
	1.30	0	No exceptions.
	1.37	0	Except for NRC accepted alternate positions documented in Table 2-1 of Reference 1.
	1.38	2	Except for NRC accepted alternate positions documented in Table 2-1 of Reference 1.
	1.39	2	No exceptions.
	1.58		Superseded by Reg. Guide 1.28, Rev.3 except for NRC accepted alternate positions documented in Table 2-1 of Reference 1.
	1.64		Superseded by Reg. Guide 1.28, Rev. 3 except for NRC accepted alternate positions documented in Table 2-1 of Reference 1.
	1.74		Superseded by Reg. Guide 1.28, Rev. 3
	1.88		Superseded by Reg. Guide 1.28, Rev. 3 except for NRC accepted alternate positions documented in Table 2-1 of Reference 1.
240.2	1.94	1	No exceptions. Will be applied during construction.
	1.116	0-R	Except for NRC accepted alternate positions documented in Table 2-1 of Reference 1.
	1.123		Superseded by Reg. Guide 1.28, Rev. 3 except for NRC accepted alternate positions documented in Table 2-1 of Reference 1.
	1.144		Superseded by Reg. Guide 1.28, Rev.3.
	1.146		Superseded by Reg. Guide 1.28, Rev. 3 except for NRC accepted alternate positions as documented in Table 2-1 of Reference 1.

17.1 QUALITY ASSURANCE DURING DESIGN AND CONSTRUCTION

17.1.1. Organization

See Section 1 of Reference 1.

This section complies with Basic Requirement 1 and Supplement 1S-1 of ANSI/ASME NQA-1-1983.

The following additional information describes the relationship between GE and its technical associates.

GE, with the support of major technical associates, is designing the ABWR. This is a common engineering effort to design and specify systems and equipment from the standard plant through major purchasing specifications. The designs, specifications, and drawings are based upon various joint development and engineering studies performed by GE and its associates.

The lead responsibility to produce each specification and drawing is formally assigned to one design organization. However, the content of each document is reviewed and approved by GE. While all common engineering documents reflect the formal consensus of all parties, GE is responsible for the design and the supporting calculations and records for the ABWR project.

17.1.2 Quality Assurance Program

See Section 2 of Reference 1.

This section complies with Basic Requirement 2 and Supplements 2S-1, 2S-2, and 2S-3 of ANSI/ASME NQA-1-1983 and NQA-1a-1983 as modified by the NRC-accepted alternate positions identified in Table 2-1 of Reference 1 relating to NRC Regulatory Guides: 1.28, Revision 0; 1.58, Revision 1; and 1.146, Revision 0.

The following additional information describes the relationship between GE and its technical associates.

GE and each of its associates have their own quality assurance program based on Reference 2. GE has performed a review of the QA programs of each of the associates to assure that the engineering designs and documentation produced by the associates meet the requirements of the GE quality program. These reviews found the QA programs of the technical associates to meet GE requirements and the applicable requirements of Appendix B to 10CFR50.

Agreements between GE and its associates require an annual review to assure that the quality systems are being implemented. All associates are committed to correct discrepancies noted during these reviews.

The identification of safety-related structures, systems, and components (Q list) to be controlled by the quality assurance program is shown on Table 3.2-1. Additional items will be added to Table 3.2-1, as necessary.

17.1.3 Design Control

See Section 3 of Reference 1.

This section complies with Basic Requirement 3 and Supplement 3S 1 of ANSI/ASME NQA-1-1983 as modified by the NRC-accepted alternate position identified in Table 2-1 of Reference 1 relating to NRC Regulatory Guide 1.64, Revision 2.

The following additional information describes the relationship between GE and its technical associates.

GE and its associates control the review and approval of ABWR design documents with a procedure using the Engineering Review Memorandum (ERM). The lead design organization prepares the document and circulates it internally for engineering review, approval, and design verification. Evidence of verification is entered into design records of the responsible design organization. Each document is distributed by ERM to the design organizations of the other parties for their review and approval of technical content and design interfaces. All comments resulting from this process are resolved to the satisfaction of all parties. After resolution of all the comments, the design verification is reviewed and, when necessary, updated to assure that changes did not invalidate the original verification. After final agreement is reached, the document is finalized by the lead design organization, circulated to the other parties for their approval signatures, and then issued.

Changes to ABWR documents are also approved by GE and its associates. The changed document's revision status is advanced or a new document initiated. The new or changed document is circulated for review, verification, and approval to all parties that performed the original review, verification, and approval.

Differences between international and domestic designs are identified in a controlled list for future design action and application.

17.1.4 Procurement Document Control

See Section 4 of Reference 1.

This section complies with Basic Requirement 4 and Supplement 4S-1 of ANSI/ASME NQA-1-1983 as modified by the NRC-accepted alternate position identified in Table 2-1 of Reference 1 relating to NRC Regulatory Guide 1.123, Revision 1.

17.1.5 Instruction, Procedures, and Drawings

See Section 5 of Reference 1.

This section complies with Basic Requirement 5 of ANSI/ASME NQA-1-1983.

17.1.6 Document Control

See Section 6 of Reference 1

This section complies with Basic Requirement 6 and Supplement 6S-1 of ANSI/ASME NQA-1-1983.

The following additional information describes the relationship between GE and its technical associates.

All ABWR documents produced by GE and its associates are entered on the GE Master Parts List (MPL) for the ABWR. These documents are under GE configuration control. Changes to these documents require verification and GE review and approval before they are entered into the GE document control system and applied to the MPL.

17.1.7 Control of Purchased Material, Equipment, and Services

See Section 7 of Reference 1.

This section complies with Basic Requirement 7 and Supplement 7S-1 of ANSI/ASME NQA-1-1983 as modified by the NRC-accepted alternate position identified in Table 2-1 of Reference 1 relating to NRC Regulatory Guide 1.123, Revision 1.

17.1.8 Identification and Control of Materials, Parts, and Components

See Section 8 of Reference 1.

This section complies with Basic Requirement 8 and Supplement 8S-1 of ANSI/ASME NQA-1-1983.

17.1.9 Control of Special Processes

See Section 9 of Reference 1.

This section complies with Basic Requirement 9 and Supplement 9S-1 of ANSI/ASME NQA-1-1983.

17.1.10 Inspection

See Section 10 of Reference 1.

This section complies with Basic Requirement 10 and Supplement 10S-1 of ANSI/ASME NQA-1-1983 and NQA-1a-1983 as modified by the NRC-accepted alternate position identified in Table 2-1 of Reference 1 relating to NRC Regulatory Guide 1.116, Revision 0-R.

17.1.11 Test Control

See Section 11 of Reference 1.

This section complies with Basic Requirement 11 and Supplement 11S-1 of ANSI/ASME NQA-1-1983 as modified by the NRC-accepted alternate position identified in Table 2-1 of Reference 1 relating to NRC Regulatory Guide 1.116, Revision O-R.

17.1.12 Control of Measuring and Test Equipment

See Section 12 of Reference 1.

This section complies with Basic Requirement 12 and Supplement 12S-1 of ANSI/ASME NQA-1-1983.

17.1.13 Handling, Storage, and Shipping

See Section 13 of Reference 1.

This section complies with Basic Requirement 13 and Supplement 13S-1 of ANSI/ASME NQA-1-1983 as modified by the NRC-accepted alternate position identified in Table 2-1 of Reference 1 relating to NRC Regulatory Guide 1.38, Revision 2.

17.1.14 Inspection, Test, and Operating Status

See Section 14 of Reference 1.

This section complies with Basic Requirement 14 of ANSI/ASME NQA-1-1983.

17.1.15 Nonconforming Materials, Parts, or Components

See Section 15 of Reference 1.

This section complies with Basic Requirement 15 and Supplement 15S-1 of ANSI/ASME NQA-1-1983.

17.1.16 Corrective Action

See Section 16 of Reference 1.

This section complies with Basic Requirement 16 of ANSI/ASME NQA-1-1983.

17.1.17 Quality Assurance Records

See Section 17 of Reference 1.

This section complies with Basic Requirement 17, Supplement 17S-1, ASME NQA-1-1983 as modified by the NRC-accepted alternate position identified in Table 2-1 of Reference 1 relating to NRC Regula- tory Guide 1.88, Revision 2.

17.1.18 Audits

See Section 18 of Reference 1.

This section complies with Basic Requirement 18 and Supplement 18S-1, of ANSI/ASME NQA-1-1983 and NQA-1a-1983 as modified by the NRC-accepted alternate position identified in Table 2-1 of Reference 1 relating to ANSI Standard N45.2.12-1977.

17.1.19 References

1. *Nuclear Energy Business Operations Quality Assurance Program Description,* May 1987, NEDO-11209-04A, the latest NRC accepted revision.

2. *ABWR Project Application Engineering Organization and Procedures Manual,* General Electric Company, February 5, 1987.

SECTION 17.3

CONTENTS

SECTION 17.3

TABLES

ILLUSTRATIONS

17.3 RELIABILITY ASSURANCE PROGRAM DURING DESIGN PHASE

This section presents the ABWR Design Reliability Assurance Program (D–RAP).

17.3.1 Introduction

The ABWR Design Reliability Assurance Program (D-RAP) is a program that will be performed by GE Nuclear Energy (GE-NE) during detailed design and specific equipment selection phases to assure that the important ABWR reliability assumptions of the probabilistic risk assessment (PRA) will be considered throughout the plant life. The plant owner/operator will also have an operational RAP (O-RAP) that tracks equipment reliability to demonstrate that the plant is being operated and maintained consistent with PRA assumptions so that overall risk is not unknowingly degraded. The PRA evaluates the plant response to initiating events to assure that plant damage has a very low probability and risk to the public is very low. Input to the PRA includes details of the plant design and assumptions about the reliability of the plant risk-significant structures, systems and components (SSCs) throughout plant life.

The D-RAP will include the design evaluation of the ABWR. It will identify relevant aspects of plant operation, maintenance, and performance monitoring of important plant SSCs for owner/operator consideration in assuring safety of the equipment and limited risk to the public. The policy and implementation procedures will be specified by the owner/operator.

Also included in this explanation of the D-RAP is a descriptive example of how the D-RAP will apply to one potentially important plant system, the standby liquid control system (SLCS). The SLCS example shows how the principles of D-RAP will be applied to other systems identified by the PRA as being significant with respect to risk.

17.3.2 Scope

The ABWR D-RAP will include the future design evaluation of the ABWR, and it will identify relevant aspects of plant operation, maintenance, and performance monitoring of plant risk-significant SSCs. The PRA for the ABWR and other industry sources will be used to identify and prioritize those SSCs that are important to prevent or mitigate plant transients or other events that could present a risk to the public.

17.3.3 Purpose

The purpose of the D-RAP is to assure that the plant safety as estimated by the probabilistic risk analysis (PRA) is maintained as the detailed design evolves through the implementation and procurement phases and that pertinent information is provided in the design documentation to the future owner/operator so that equipment reliability, as it affects plant safety, can be maintained through operation and maintenance during the entire plant life.

17.3.4 Objective

The objective of the D-RAP is to identify those plant SSCs that are significant contributors to risk, as shown by the PRA or other sources, and to assure that, during the implementation phase, the plant design continues to utilize risk- significant SSCs whose reliability is commensurate with the PRA assumptions. The D-RAP will also identify key assumptions regarding any operation, maintenance and monitoring activities that the owner/operator should consider in developing its O-RAP to assure that such SSCs can be expected to operate throughout plant life with reliability consistent with that assumed in the PRA.

A major factor in plant reliability assurance is risk-focused maintenance, by which maintenance resources are focused on those SSCs that enable the ABWR systems to fulfill their essential safety functions and on SSCs whose failure may directly initiate challenges to safety systems. All plant modes are considered, including equipment directly relied upon in Emergency Operating Procedures (EOPs). Such a focus of maintenance will help to maintain an acceptably low level of risk, consistent with the PRA.

17.3.5 GE-NE Organization for D-RAP

The relevant portion of the GE-NE organization chart for a future ABWR D-RAP is shown in Figure 17.3-1. The

Managers of the Nuclear Services and Projects Department and of the Nuclear Operations Department report to the Vice President and General Manager of GE Nuclear Energy. Two sections involved with an ABWR D-RAP are the Advanced Reactor Programs Section and the Engineering Services Section.

Authority for the management of an ABWR program is centered with the Advanced Reactor Programs Manager. Day-to-day details of an ABWR program are directed by the Project Manager, who reports to the Advanced Reactor Programs Manager. The Project Manager and his staff coordinate both the GE-NE support for the Project and the work of external organizations, such as the Architect Engineer.

Responsibility for the design of key equipment, components and subsystems is shared by the several units in the Advanced Reactor Programs Section together with external organizations, including the Architect Engineer. Reporting directly to each engineering functional manager will be performing engineers, including system designers and component designers. Design support will also be provided by other design sections within GE-NE and the Nuclear Services and Projects Department. Responsibility for ABWR safety analysis and PRA studies is under the Systems Integration and Performance Engineering Unit.

The Manager, System Integration and Performance Engineering, will be assigned the responsibility of managing and integrating the D-RAP Program. He will have direct access to the ABWR Project Manager and will keep him abreast of D-RAP critical items, program needs and status. He has organizational freedom to:

(1) Identify D-RAP problems.
(2) Initiate, recommend or provide solution to problems through designated organizations.
(3) Verify implementation of solution.
(4) Function as an integral part of the final design process.

Reliability analyses, including the PRA, are performed by the Reliability Engineering Services U[illegible] the Reliability and Analysis Services Subsection of the Engineering Services Section (Figure 17.3-1). Thus, the PRA input to the D-RAP and many of the ABWR reliability analyses will be performed in this organization, within the Nuclear Operations Department. Responsibility for reliability review of designed ABWR systems and components also falls on the Reliability Engineering Services Unit, under direction from the Systems Integration and Performance Engineering Unit.

17.3.6 SSC Identification /Prioritization

The PRA prepared for the ABWR will be the primary source for identifying risk-significant SSCs that should be given special consideration during the detailed design and procurement phases and/or considered for inclusion in the O-RAP. The method by which the PRA is used to identify risk-significant SSCs is described in Chapter 19. It is also possible that some risk-significant SSCs will be identified from sources other than the PRA, such as nuclear plant operating experience, other industrial experience, and relevant component failure data bases.

17.3.7 Design Considerations

The reliability of risk-significant SSCs, which are identified by the PRA, will be evaluated at the detailed design stage by appropriate design reviews and reliability analyses. Current data bases will be used to identify appropriate values for failure rates of equipment as designed, and these failure rates will be compared with those used in the PRA. Normally the failure rates will be similar, but in some cases they may differ because of recent design or data base changes. Whenever failure rates of designed equipment are significantly greater than those assumed in the PRA, an evaluation will be performed to determine if the equipment is acceptable or if it must be redesigned to achieve a lower failure rate.

For those risk-significant SSCs, as indicated by PRA or other sources, component redesign (including selection of a different component) will be considered as a way to reduce the CDF contribution. (If the system unavailability or the CDF is acceptably low, less effort will be expended toward redesign.) If there are practical ways to redesign a risk-significant SSC, it will be redesigned and the change in system fault tree results will be calculated. Following the redesign phase, dominant SSC failure modes will be identified so that protection against such failure modes can be accomplished by appropriate activities during plant life. The design considerations that will go into determining an acceptable, reliable design and the

SSCs that must be considered for O-RAP activities are shown in Figure 17.3-2.

GE-NE will identify in the PRA or other design documents to the plant owner/operator the risk-significant SSCs and the associated reliability assumptions, including any pertinent bases and uncertainties considered in the PRA. GE-NE will also provide information for the plant owner/operator to incorporate into the O-RAP to help assure that PRA results will be achieved over the life of the plant. This information can be used by the owner/operator for establishing appropriate reliability targets and the associated maintenance practices for achieving them.

17.3.8 Defining Failure Modes

The determination of dominant failure modes of risk-significant SSCs will include historical information, analytical models and existing requirements. Many BWR systems and components have compiled a significant historical record, so an evaluation of that record comprises Assessment Path A in Figure 17.3-3. Details of Path A are shown in Figure 17.3-4.

For those SSCs for which there is not an adequate historical basis to identify critical failure modes, an analytical approach is necessary, shown as Assessment Path B in Figure 17.3-3. The details of Path B are given in Figure 17.3-5. The failure modes identified in Paths A and B are then reviewed with respect to the existing maintenance activities in the industry and the maintenance requirements, Assessment Path C in Figure 17.3-3. Detailed steps in Path C are outlined in Figure 17.3-6.

17.3.9 Operational Reliability Assurance Activities

Once the dominant failure modes are determined for risk-significant SSCs, an assessment is required to determine suggested O-RAP activities that will assure acceptable performance during plant life. Such activities may consist of periodic surveillance inspections or tests, monitoring of SSC performance, and/or periodic preventive maintenance (Ref. 1). An example of a decision tree that would be applicable to these activities is shown in Figure 17.3-7. As indicated, some SSCs may require a combination of activities to assure that their performance is consistent with that assumed in the PRA.

Periodic testing of SSCs may include startup of standby systems, surveillance testing of instrument circuits to assure that they will respond to appropriate signals, and inspection of passive SSCs (such as tanks and pipes) to show that they are available to perform as designed. Performance monitoring, including condition monitoring, can consist of measurement of output (such as pump flow rate or heat exchanger temperatures), measurement of magnitude of an important variable (such as vibration or temperature), and testing for abnormal conditions (such as oil degradation or local hot spots).

Periodic preventive maintenance is an activity performed at regular intervals to preclude problems that could occur before the next PM interval. This could be regular oil changes, replacement of seals and gaskets, or refurbishment of equipment subject to wear or age related degradation.

Planned maintenance activities will be integrated with the regular operating plans so that they do not disrupt normal operation. Maintenance that will be performed more frequently than refueling outages must be planned so as to not disrupt operation or be likely to cause reactor scram, ESF actuation, or abnormal transients. Maintenance planned for performance during refueling outages must be conducted in such a way that it will have little or no impact on plant safety, on outage length or on other maintenance work.

17.3.10 Owner/Operator's Reliability Assurance Program

The O-RAP that will be prepared and implemented by the ABWR owner/operator will make use of the information provided by GE-NE. This information will help the owner/operator determine activities that should be included in the O-RAP. Examples of elements that might be included in an O-RAP are:

1. Reliability Performance Monitoring: Measurement of the performance of equipment to determine that it is accomplishing its goals and/or that it will continue to operate with low probability of failure.

2. Reliability Methodology: Methods by which the plant owner/operator can compare plant data to the SSC data in the PRA.

3. Problem Prioritization: Identification, for each of the risk- significant SSCs, of the importance of that item as a contributor to its system unavailability and assignment of priorities to problems that are detected with such equipment.

4. Root Cause Analysis: Determination, for problems that occur regarding reliability of risk-significant SSCs, of the root causes, those causes which, after correction, will not recur to again degrade the reliability of equipment.

5. Corrective Action Determination: Identification of corrective actions needed to restore equipment to its required functional capability and reliability, based on the results of problem identification and root cause analysis.

6. Corrective Action Implementation: Carrying out identified corrective action on risk-significant equipment to restore equipment to its intended function in such a way that plant safety is not compromised during work.

7. Corrective Action Verification: Post-corrective action tasks to be followed after maintenance on risk significant equipment to assure that such equipment will perform its safety functions.

8. Plant Aging: Some of the risk-significant equipment is expected to undergo age related degradation that will require equipment replacement or refurbishment.

9. Feedback to Designer: The plant owner/operator will periodically compare performance of risk-significant equipment to that specified in the PRA and D-RAP, as mentioned in item 1, above, and, at its discretion, may feedback SSC performance data to plant or equipment designers in those cases that consistently show performance below that specified.

10. Programmatic Interfaces: Reliability assurance interfaces related to the work of the several organizations and personnel groups working on risk-significant SSCs.

The plant owner/operator's O-RAP will address the interfaces with construction, startup testing, operations, maintenance, engineering, safety, licensing, quality assurance and procurement of replacement equipment.

17.3.11 D-RAP Implementation

An example of implementation of the D-RAP is given for the standby liquid control system (SLCS). The purpose of the SLCS is to inject neutron absorbing poison into the reactor, upon demand, providing a backup reactor shutdown capability independent of the control rods. The system is capable of operating over a wide range of reactor pressure conditions. The SLCS may or may not be identified by the final PRA as a significant contributor to CDF or to offsite risk. For the purpose of this example it is assumed that the SLCS is identified as a significant contributor to CDF or to offsite risk.

17.3.11.1 SLCS Description

During normal operation the SLCS is on standby, only to function in event the operators are unable to control reactivity with the normal control rods. The SLCS consists of a boron solution storage tank, two positive displacement pumps, two motor operated injection valves (provided in parallel for redundancy), and associated piping and valves used to transfer borated water from the storage tank to the reactor pressure vessel (RPV).

The borated solution is discharged through the 'B' high pressure core flooder (HPCF) subsystem sparger. A schematic diagram of the SLCS, showing major system components, is presented in Figure 17.3-8. Some locked open maintenance valves and some check valves are not shown. Key equipment performance requirements are:

a. Pump flow	50 gpm per pump
b. Maximum reactor pressure (for injection)	1250 psig
c. Pumpable volume in storage tank (minimum)	6100 U.S. gal

Design provisions to permit system testing include a test tank and associated piping and valves. The tank can be supplied with demineralized water which can be pumped in a closed loop through either pump or injected into the reactor.

The SLCS uses a dissolved solution of sodium pentaborate as the neutron-absorbing poison. This solution is held in a heated storage tank to maintain the solution above its saturation temperature. The SLCS solution tank, a test water tank, the two positive displacement pumps, and associated valving are located in the secondary containment on the floor elevation below the operating floor. This is a Seismic Category I structure, and the SLCS equipment is protected from phenomena such as earthquakes, tornados, hurricanes and floods as well as [illegible] internal postulated accident phenomena. In this area, [illegible] SLCS is not subject to conditions such as missiles, pipe [illegible] discharging fluids.

[illegible] pumps are capable of producing discharge pressure to [illegible] the solution into the reactor when the reactor is at [illegible] pressure conditions corresponding to the system [illegible] valve actuation. Signals indicating storage tank [illegible] level, tank outlet valve position, pump discharge [illegible] and injection valve position are available in the cont[illegible] room.

The pumps, heater, valves and controls are powered from the standby power supply or normal offsite power. The pumps and valves are powered and controlled from separate buses and circuits so that single active failures will not prevent system operation. The power supplied to one motor operated injection valve, storage tank discharge valve, and injection pump is from Division I, 480 VAC. The power supply to the other motor-operated injection valve, storage tank outlet [illegible], and injection pump is from Division II, 4[illegible] The power supply to the tank heater and heater controls is connectable to a standby power source. The standby power source is Class 1E from an on-site source and is independent of the off-site power.

All components of the system which are required for injection of the neutron absorber into the reactor are classified Seismic Category I. All major mechanical components are designed to meet ASME Code requirements as shown below.

Component	ASME Code Class	Design Conditions Pressure	Temperature
Storage Tank	2	Static Head	150°F
Pump	2	1560 psig	150°F
Injection Valves	1	1560 psig	150°F
Piping Inboard of Injection Valves	1	1250 psig	575 °F

17.3.11.2 SLCS Operation

The SLCS is initiated by one of three means: (a) manually initiated from the main control room, (b) automatically initiated if conditions of high reactor pressure and power level not below the ATWS permissive power level exist for 3 minutes, or (c) automatically initiated if conditions of RPV water level below the level 2 setpoint and power level not below the ATWS permissive power level exist for 3 minutes. The SLCS provides borated water to the reactor core to introduce negative reactivity effects during the required conditions.

To meet its negative reactivity objective, it is necessary for the SLCS to inject a quantity of boron which produces a minimum concentration of 850 ppm of natural boron in the reactor core at 68 F. To allow for potential leakage and imperfect mixing in the reactor system, an additional 25% (220 ppm) margin is added to the above requirement. The required concentration is achieved accounting for dilution in the RPV with normal water level and including the volume in the residual heat removal shutdown cooling piping. This quantity of boron solution is the amount which is above the pump suction shutoff level in the storage tank thus allowing for the portion of the tank volume which cannot be injected.

17.3.11.3 Major Differences From Operating BWRs

The SLCS design is very similar to that of operating BWRs. Automatic actuation of the ABWR SLCS is similar to that incorporated in some operating BWRs. Because of the larger ABWR RPV volume, the pumping capacity has been increased from 43 to 50 gpm per pump. Injection of SLCS solution through the HPCF sparger has been shown by boron mixing tests to give better mixing than the operating plant injection through a standpipe.

Injection valves of operating plants are leak proof explosive valves to keep boron out of the reactor during SLCS testing. In the ABWR the injection valves are motor operated and a suction pipe fill system keeps the lines filled with distilled water at slightly higher pressure than that of the boron storage tank to preclude entry of boron into the reactor. The motor operated injection valves provide the following advantages over explosive valves:

a. Radiation exposure to personnel is potentially reduced during testing and maintenance because less work will be required at the valves.

b. Post-injection containment isolation capability is enhanced because the motor operated valves can be closed following boron injection. Explosive valves cannot be reclosed to provide containment isolation.

17.3.11.4 SLCS Fault Tree

The top level fault tree for the SLCS is shown in Figure 17.3.9, with the top gate defined as failure to deliver 50 gpm of borated water from the storage tank to the RPV. Details providing input to most of the events in Figure 17.3.9 are contained in the several additional branches to the fault tree.

It is assumed that the SLCS has been identified by the PRA as a system making significant contribution to CDF. A listing of the SLCS components or events by Fussell-Vesely Importance was made, and those SSCs with greatest importance are given in Table 17.3-1. No SSCs appear to be risk-significant because of aging or common cause considerations. The seven most significant components are listed in Table 17.3-2, so these SSCs should be considered as risk-significant candidates for O-RAP activities.

17.3.11.5 System Design Response

The seven SLCS risk significant components identified in Table 17.3.2 as having high importance in the SLCS fault tree are now considered for redesign or for O-RAP activities, as noted above. The flow chart of Figure 17.3-2 guides the designer.

Two of the events in Table 17.3-2 result from flow of SLCS fluid being diverted through relief valves back to pump suction rather than into the RPV. Since gate and check valve failures (which could result in relief valve operation) are accounted for by separate events, the relief valve failures of concern can be considered to be valve body failures or inadvertent opening of the relief valves. Plugging of the suction lines from the storage tank could result from some contamination of the tank fluid or collection of foreign matter in the tank. The pump failures to start upon demand could result from electrical or mechanical problems at the pumps or their control circuits.

Two AC electrical system failures that contribute to SLCS system failure are identified in Table 17.3-2. No further details of electrical system failures or maintenance are included here. That leaves the five components noted above for special attention with regard to reducing the risk of system failure.

a. Redesign

The design evaluation of Figure 17.3-2 is used by the designer. The design assessment shows that the component failure rates are the same as those used in the PRA, so there is no need to recalculate the PRA. Also, no one SSC has a major impact on SLCS system unavailability, so redesign or reselection of components is not required and the seven components are identified for consideration by the O-RAP.

Redesign considerations, if they had been required, would have included trying to identify more reliable relief valves and pumps and suction lines less likely to plug. The latter might be achieved by using larger diameter pipes or multiple suction lines. Pump and valve reliability might be enhanced by specific design changes or by selection of a different component. Any such redesign would have to be evaluated by balancing the increase in reliability against the added complication to plant equipment and layout.

b. Failure Mode Identification

If redesign is not necessary, or after redesign has been completed, the appropriate O-RAP activities would be identified for the three SLCS component types identified by the fault tree and discussed above. This begins with determining the likely failure modes that will lead to loss of function, following the steps in Figure 17.3-3. The components of SLCS have adequate failure history to identify critical failure modes, so Assessment Paths A and C (Figures 17.3-4 and 17.3-6, respectively) would be followed to define the failure modes for consideration.

For the SLCS relief valves past experience with similar valves shows that the major failure modes are fluid leakage from the valve body and a spurious opening as result of failure of the spring, the spring fastener, the valve stem or the disk. Past pump failures fall into two general categories, electrical problems resulting in failure to start on demand and mechanical problems that cause a running pump to stop or fail to provide rated flow. The plugging of fluid lines generally results from presence of sediment or precipitation of compounds from saturated fluid.

Following the flow chart of Figure 17.3-4, the designer would determine more details about each failure mode, including pieceparts most likely to fail and the frequency of each failure mode category or piecepart failure. This would result in a list of the dominant failure modes to be considered for the O-RAP. ASME Section XI requirement for inservice inspection and other mandated inspections and test would be identified, as indicated in Figure 17.3-6.

Examples of the types of failure modes that could impact reliability of these identified components are shown in Table 17.3.3. The table is not a complete listing of important failure modes, but is intended to indicate the types of failures that would be considered.

c. **Identification of Maintenance Requirements**

For each identified failure mode the appropriate maintenance tasks will be identified to assure that the failure mode will be (a) avoided, (b) rendered insignificant, or (c) kept to an acceptably low probability. The type of maintenance and the maintenance frequencies are both important aspects of assuring that the equipment failure rate will be consistent with that assumed for the PRA. As indicated in Figure 17.3-7, the designer would consider periodic testing, performance testing or periodic preventive maintenance as possible O-RAP activities to keep failure rates acceptable.

For the SLCS relief valves, which normally have no cycles during operation, A visual inspection for leakage and periodic inspections of internals are judged to be appropriate. The pumps can be functionally tested periodically for ability to start and run and vibration can be measured during functional tests to detect potential mechanical problems. Detailed disassembly, inspection and refurbishment would be done less frequently. To prevent line plugging the storage tank can be sampled for sediment and/or liquid saturation, with appropriate cleaning or temperature increase as necessary. Examples of maintenance activities and frequencies are shown in Table 17.3.3 for each identified failure mode. The O-RAP will include documentation of the basis for each suggested O-RAP activity.

17.3.12. Glossary of Terms

ATWS — Anticipated Transient Without Scram.

CDF — The core damage frequency as calculated by the PRA.

D-RAP — Design Reliability Assurance Program performed by the plant designer to assure that the plant is designed so that it can be operated and maintained in such a way that the reliability assumptions of the PRA apply throughout plant life.

Fussell-Vesely Importance — A measure of the component contribution to system unavailability. Numerically, the percentage contribution of component to system unavailability.

GE-NE — GE Nuclear Energy, ABWR plant designer.

Owner/Operator — The utility or other organization that owns and operates the ABWR following construction.

O-RAP — Operational Reliability Assurance Program performed by the plant owner/operator to assure that the plant is operated and maintained safely and in such a way that the reliability assumptions of the PRA apply throughout plant life.

Piecepart — A portion of a (risk-significant) component whose failure would cause the failure of the component as a whole. The precise definition of a "piecepart" will vary between component types, depending upon their complexity.

PRA — Probabilistic risk assessment performed to identify and quantify the risk associated with the ABWR.

Risk-Significant	Those SSCs which are identified as contributing significantly to the system unavailability.
SSCs	Structures, systems and components identified as being important to the plant operation and safety.

17.3.12 Reference

(1) E. V. Lofgren, et. al., *A Process for Risk-Focused Maintenance*, SAIC, NUREG/CR-5695, March 1991.

Table 17.3–1.

SLCS Components with Largest Contribution to System Unavailability

COMPONENT		FUSSELL–VESELY IMPORTANCE
OVF001HW	Flow Diverted Through Relief Valve F003A	0.50
OVF002HW	Flow Diverted Through Relief Valve F003B	0.50
OFL000HW	Plugged Suction Lines From Tank	0.24
OPM001HW	SLCS Pump A (C001A) Fails to Operate	0.05
OPM002HW	SLCS Pump B (C001B) Fails to Operate	0.05
ECA003H	AC Power Cable 03 Failure	0.05
ECA013H	AC Power Cable 13 Failure	0.05

Table 17.3–2.

Risk–Significant SSCs for SLCS

Relief Valves F003A and F003B
Suction Lines from Tank
Pumps C001A and C001B
AC Power Cable 03
AC Power Cable 13

TABLE 17.3–3.

EXAMPLES OF SLCS FAILURE MODES & O–RAP ACTIVITES

COMPONENT	FAILURE MODE/CAUSE	RECOMMENDED MAINTENANCE	MAINTENANCE INTERVAL	BASIS*
Relief Valve	Body leakage	Visual inspection	24 months	Experience
	Spurious opening, spring failure	Inspect closure for breaks; measure spring constant; replace spring.	10 years	Low failure rate; ASME Code ISI.
	Spurious opening, spring fastener failure	Visual inspection of spring fastener; replace if necessary.	10 years	Low failure rate; ASME Code ISI.
	Spurious opening, failure of valve stem or disk	Visual and penetrant inspection of stem, ultrasonic inspection of stem; replace if necessary.	10 years	Infrequent use, low failure rate, ASME Code ISI.
Pump	Fails to start, electrical problems	Functional test of pump with suction from test tank, no flow from storage tank	6 months	Experience with other electrical pumps.
	Fails to run, mechanical problems	Measure pump vibration during pump operation in functional test.	6 months	Infrequent use, little wear.
		Disassemble/inspect pump for corrosion, wear. Refurbish as necessary.	5 years	Infrequent use, low failure rate, ASME Code ISI.
Suction Lines	Lines plugged by sediment	Sample storage tank water for sediment; clean tank as necessary.	6 months	Clean system, little chance of sediment.
	Lines plugged by precipitated boron compounds	Sample storage tank for degree of saturatin of boron compounds. Increase tank temperature as necessary.	1 month	Saturated solution most likely source of line plugging.

* All SLCS components have been used in operating BWRs, so there is much experience to guide owners/operators in care of the equipment.

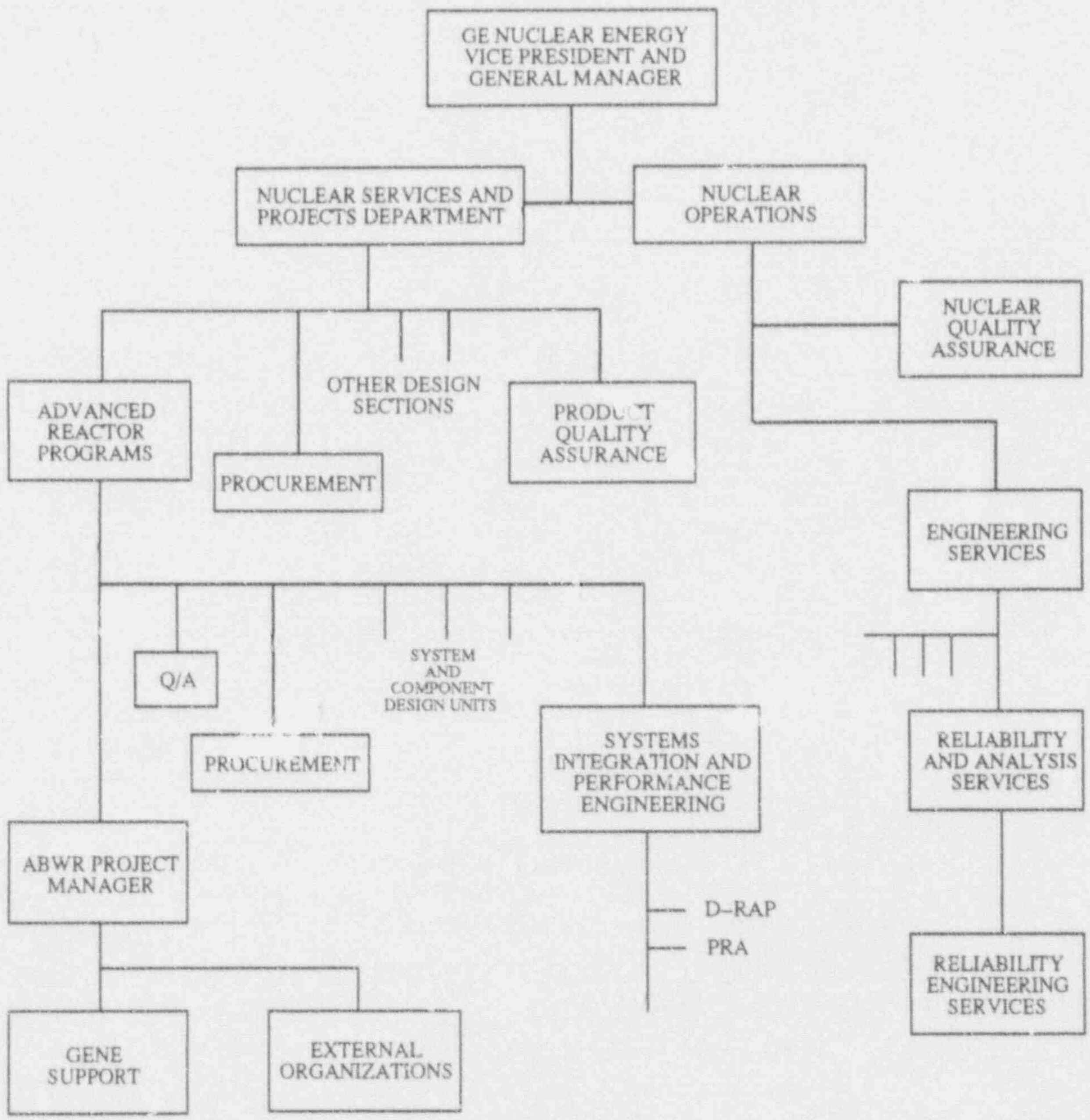

Figure 17.3–1. Typical GE–NE Organization for an ABWR Project

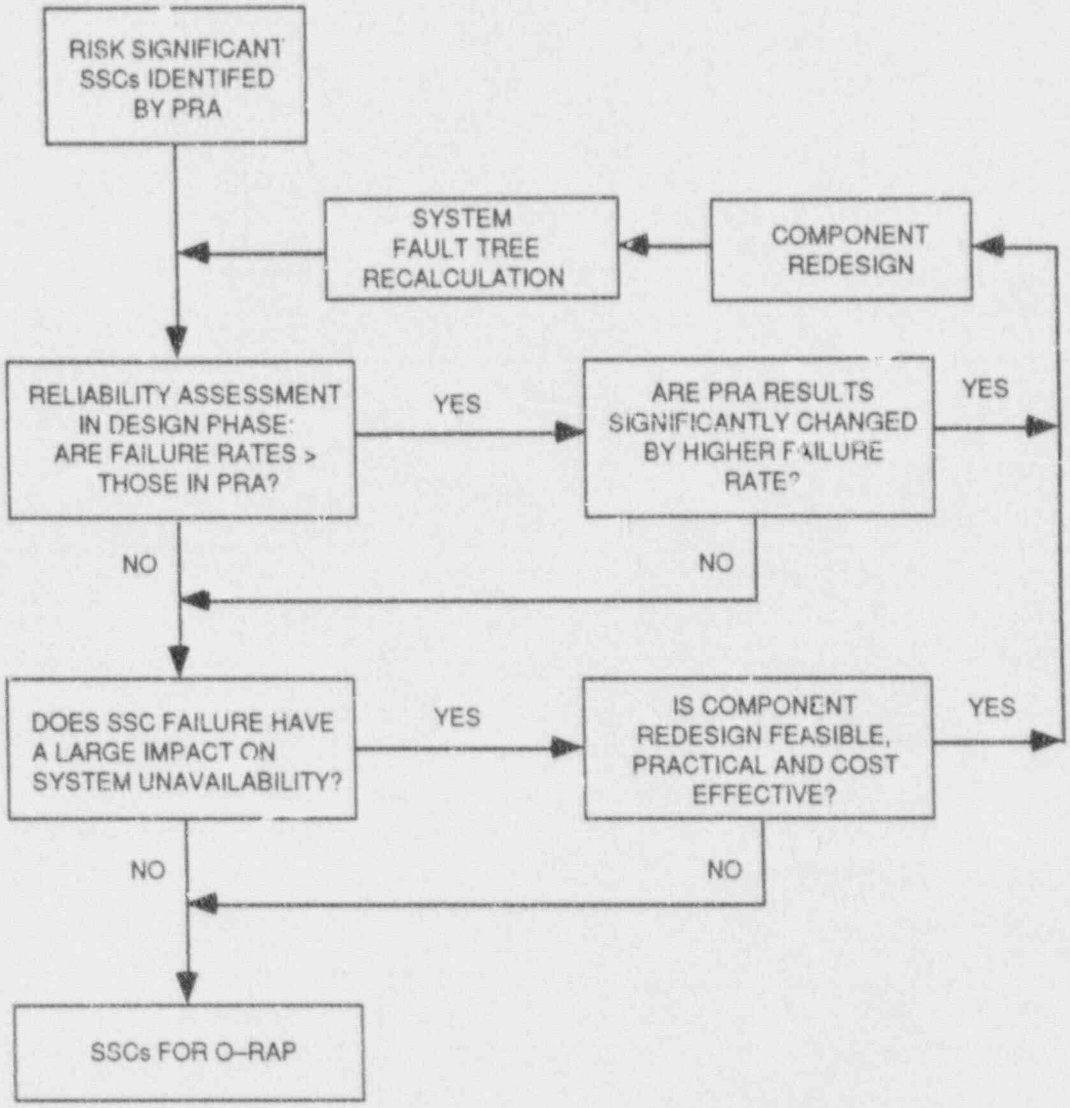

Figure 17.3-2. Design Evaluations for SSCs

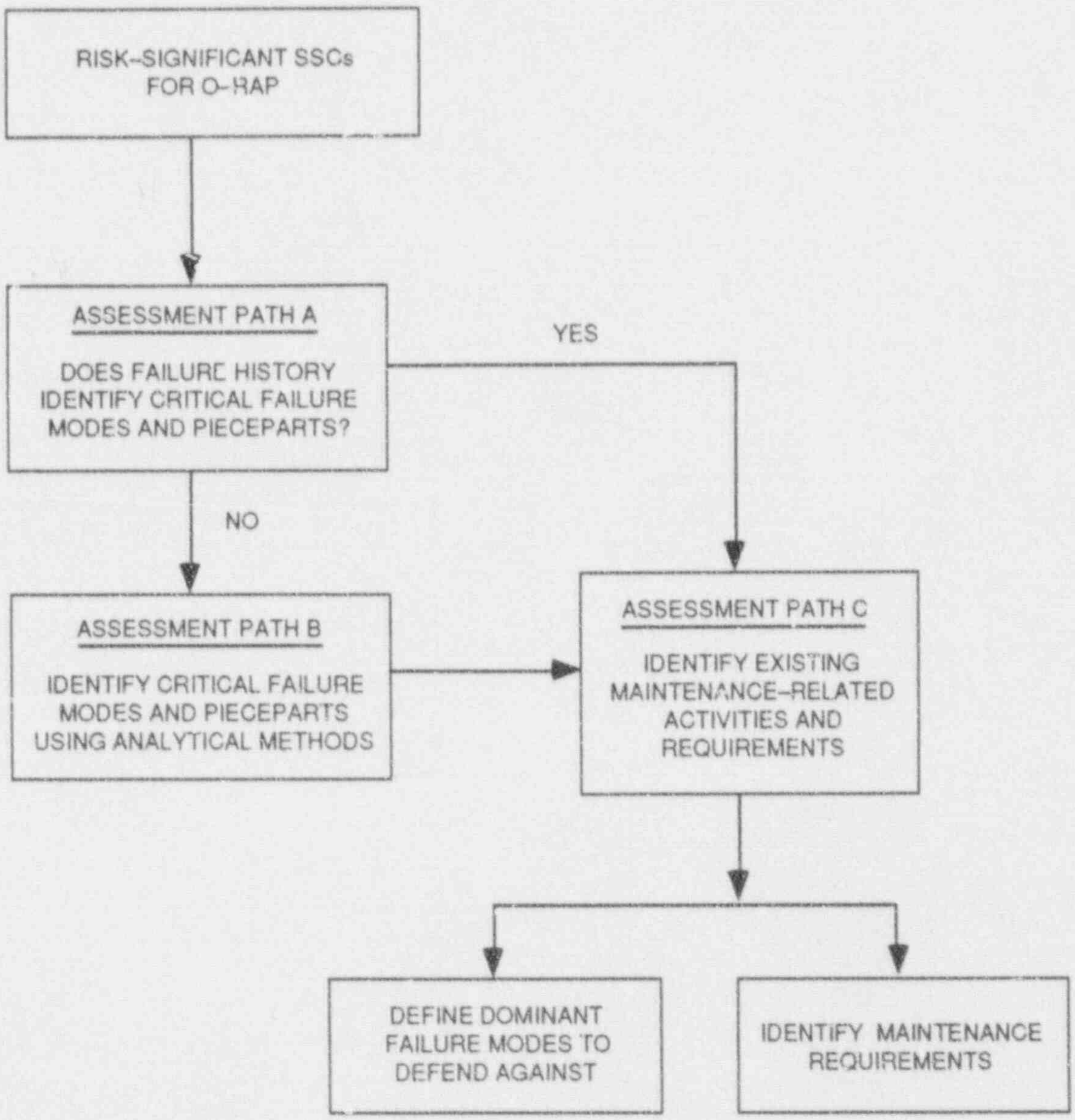

Figure 17.3-3. Process for Determining Dominant Failure Modes of Risk-Significant SSCs

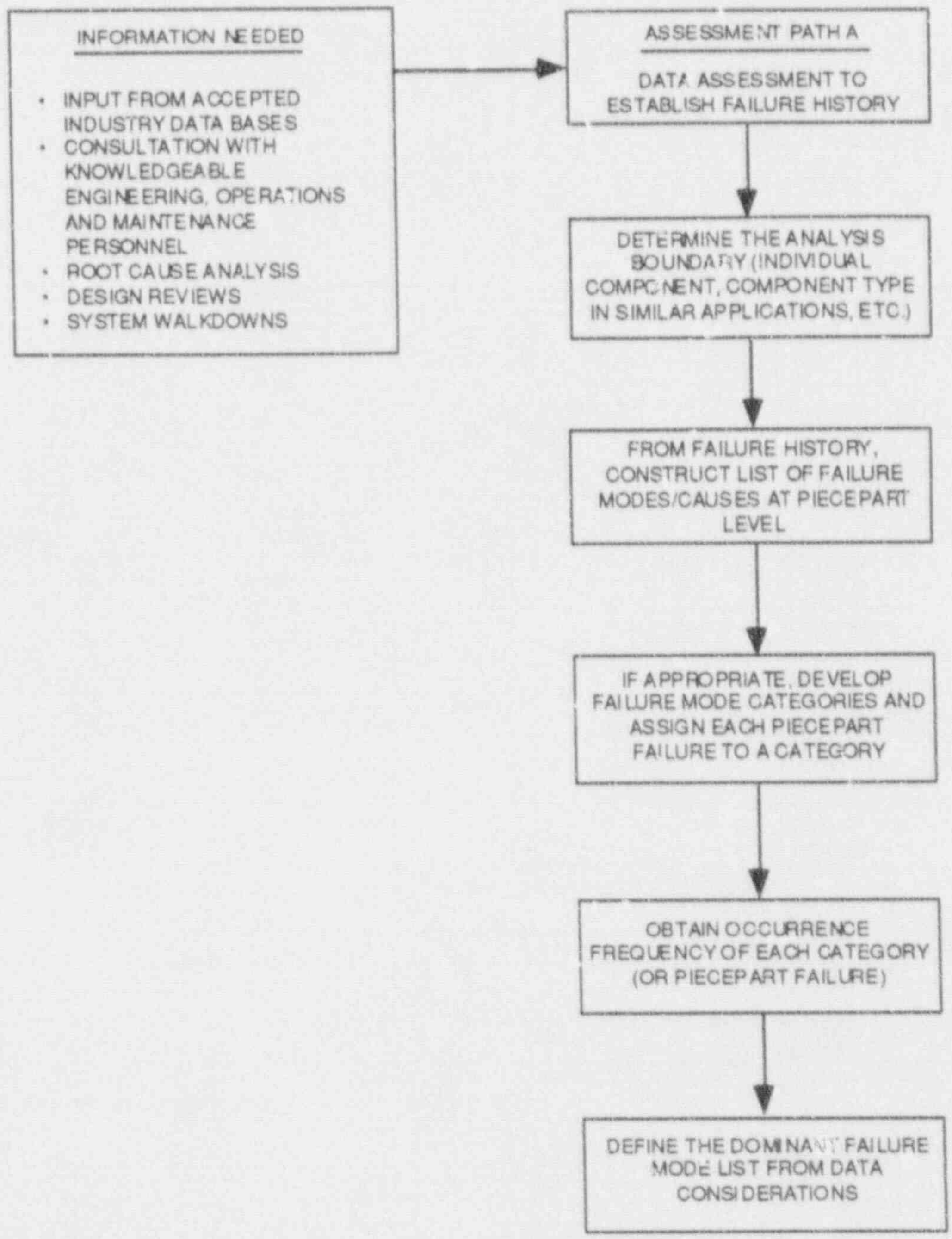

Figure 17.3–4. Use of Failure History to Define Failure Modes

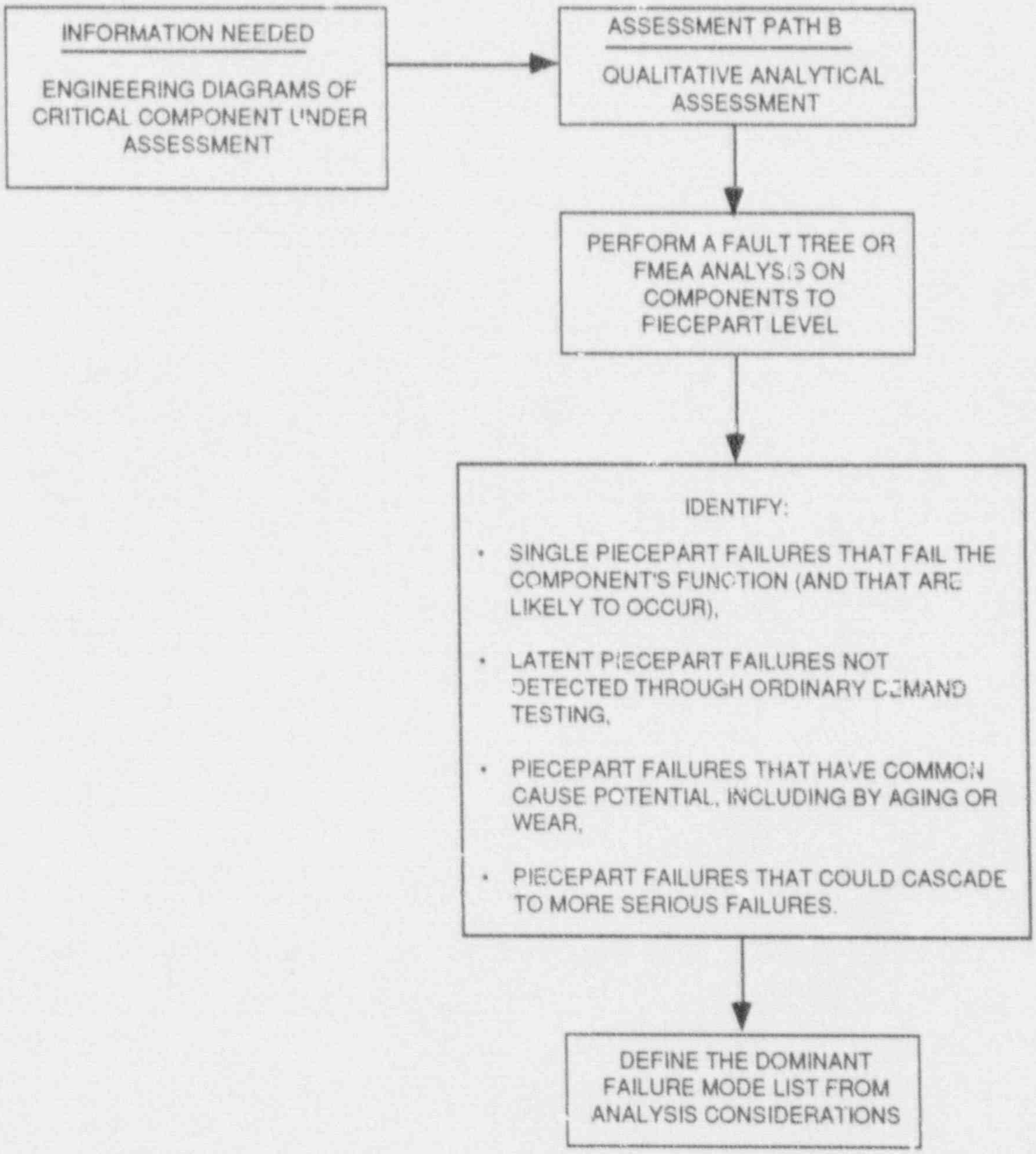

Figure 17.3–5. Analytical Assessment to Define Failure Modes

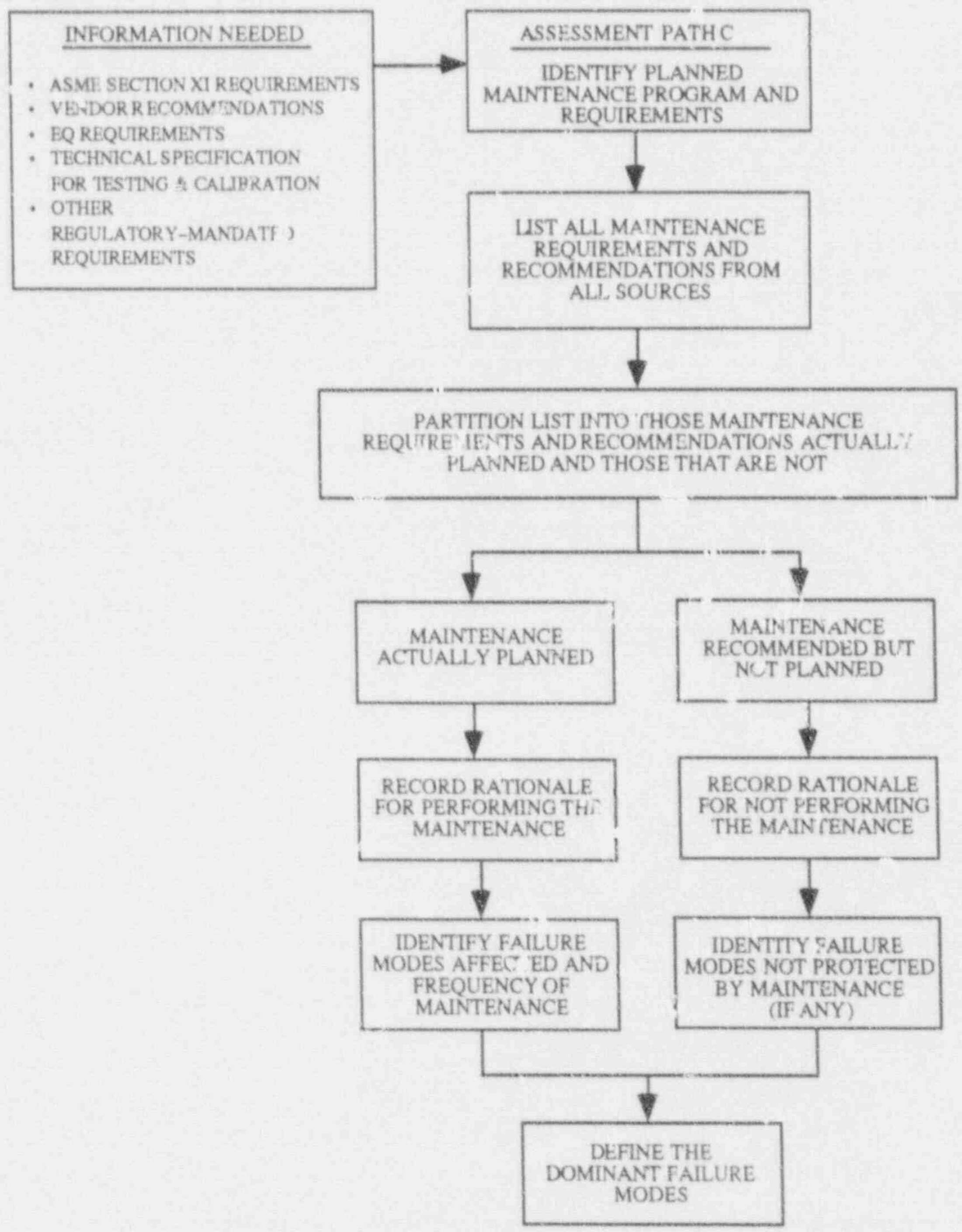

Figure 17.3–6. Inclusion of Maintenance Requirements in the Definition of Failure Modes

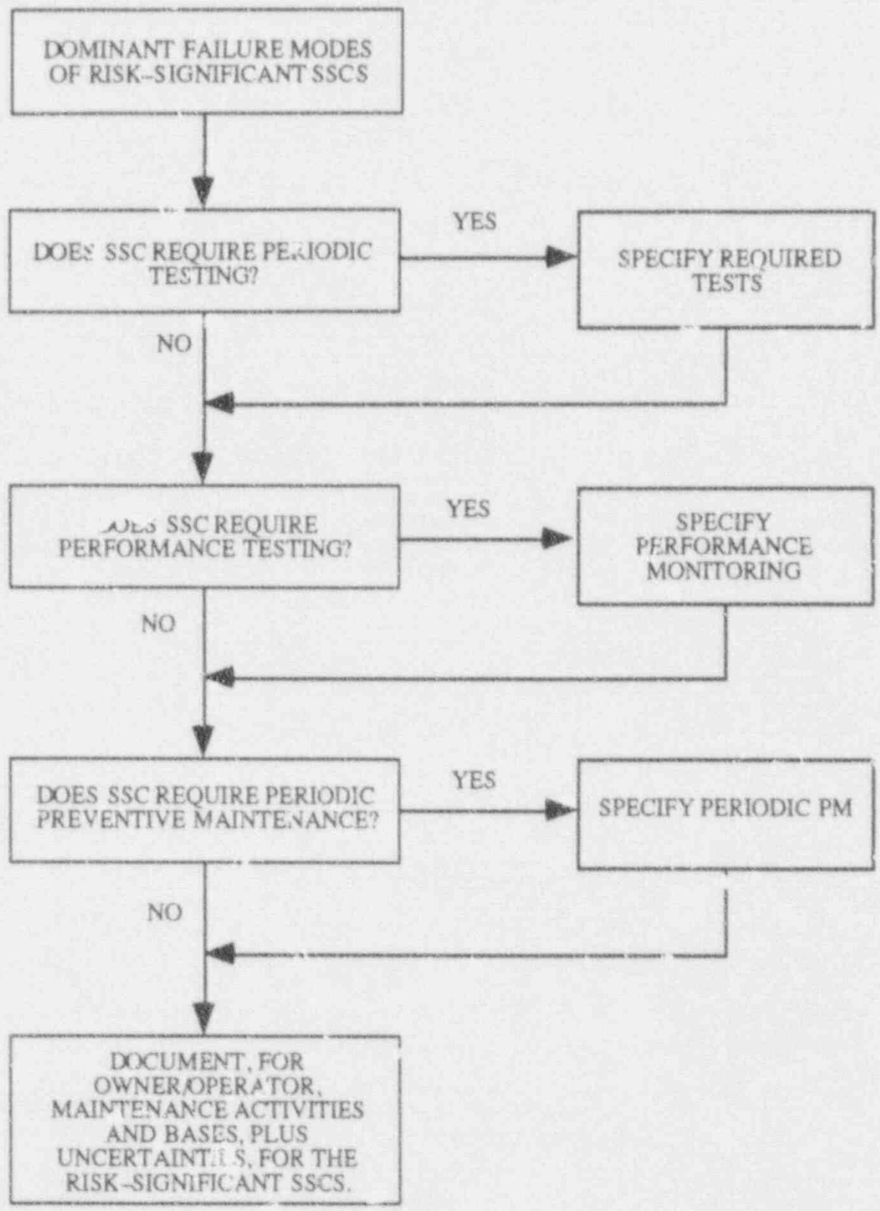

Figure 17.3-7. Identification of Risk-Significant SSC O-RAP Activities

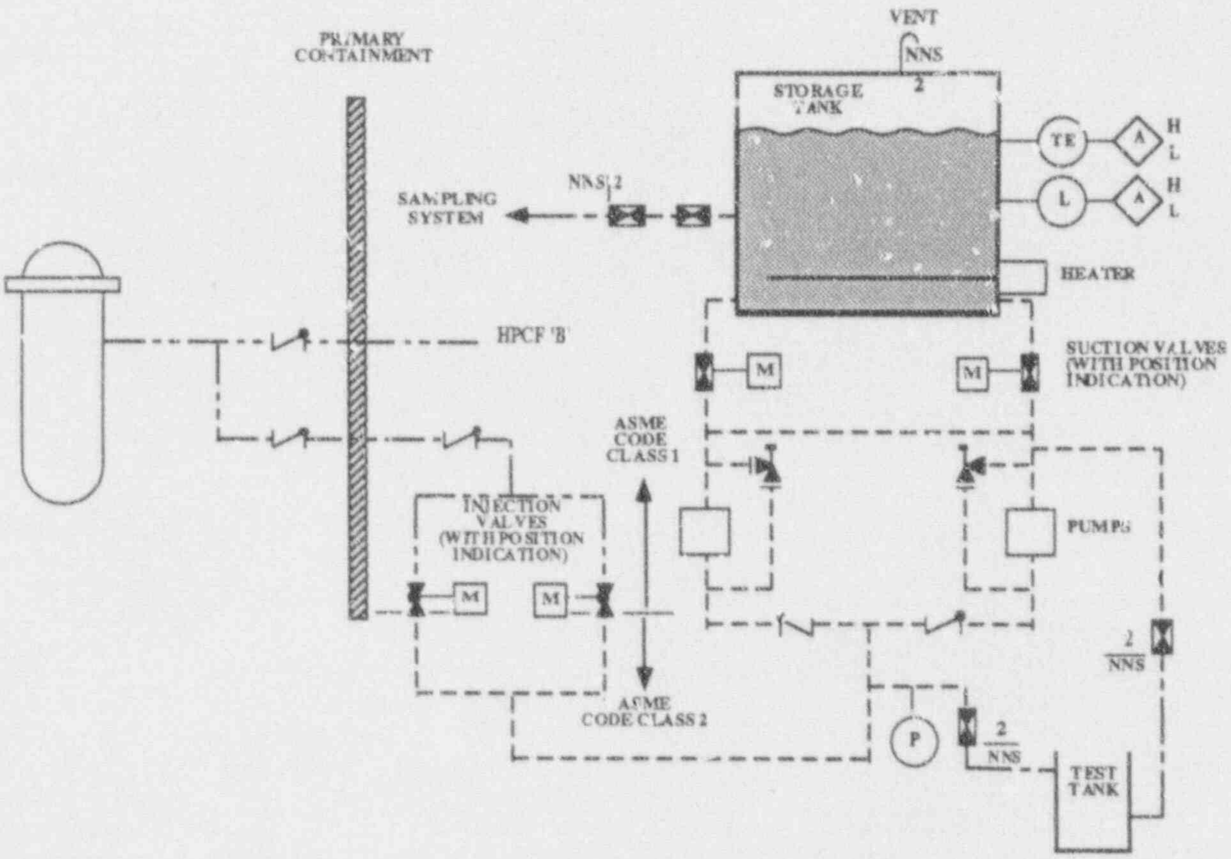

Figure 17.3–8. Standby Liquid Control System (Standby Mode)

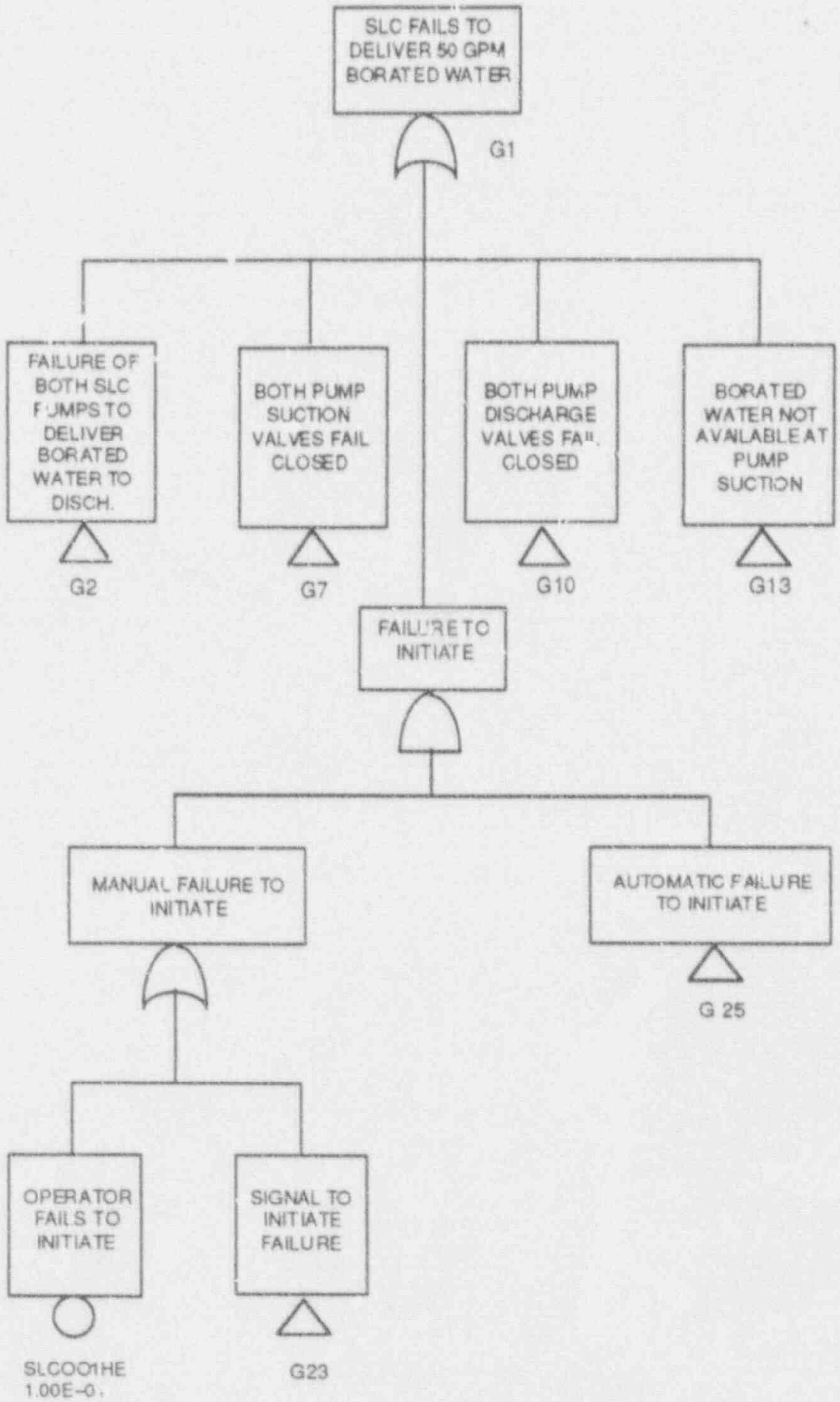

Figure 17.3–9. Standby Liquid Control System Top Level Fault Tree

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20.2.15 Chapter 15 Questions

420.28

Section 15.A.2.2 defines "Safety" and "Power Genration." The staff did not locate definitions for "important to safety" and "safety related" which are used in Chapter 7. (15A)

420.96

The safety system auxiliaries (Figure 15A.6-1) should be modified to include any HVAC required to assure continued operation of the electronics. (15A.6)

420.118

Describe when appropriate operator action in seconds is required to prevent significant radiological impact. (15.2.4.5.1)

420.122

Is the instrumentation required for the operator to verify bypass valve performance and relief valve operation 1E or N-1E? (15.2.2.2.1.4)

430.58

The accident analyzed under this section considers only the airborne radioactivity that may be released due to potential failure of a concentrated waste tank in the radwaste enclosure. The SRP acceptance criteria, however, requires demonstration that the liquid radwaste concentration at the nearest potable water supply in an unrestricted area resulting from transport of the liquid radwaste to the unrestricted area does not exceed the radionuclide concentration limits specified in 10 CFR Part 20, Appendix B Table II, Column 2. Such a demonstration will require information on possible dilution and/or decay during transit which, in turn, will depend upon site specific data such as surface and ground water hydrology and the parameters governing liquid waste movement through the soil. Additionally, special design features (e.g., steel liners or walls in the radwaste enclosure) may be provided as part of the liquid radwaste treatment systems at certain sites. The staff will, therefore, review the site specific characteristics mentioned above individually for each plant referencing the ABWR and confine its review of ABWR, only to the choice of the liquid radwaste tank. Therefore, provide information on the following: (15.7.3)

(a) Basis for determining the concentrated waste tank as the worst tank (this may very well be the case, but in the absence of information on the capacities of major tanks, particularly the waste holdup tanks, it is hard to conclude that the above tank both in terms of radionuclide concentrations and inventories will turn out to be the worst tank).

(b) Radionuclide source terms, particularly for the long-lived radionuclides such as Cs-137 and Sr-90 (these may be the critical isotopes for sites that can claim only decay credit during transit) in the major liquid radwaste tanks.

440.108

Provide further justification for the fact that the input parameters and initial conditions for analyzed events are conservative. Provide a list of what paramenters will be checked at startup and which will be in the Technical Specifications. You should define the range of operating conditions and fuel types for which your input parameters will remain valid. For example, would these parameters valid for 9x9 or 7x7 fuel or similar large change in the fuel lattice. (15)

470.1

Subsection 15.6.2 of the ABWR FSAR provides your analysis for the radiological consequences of a failure of small lines carrying primary coolant outside of containment. This analysis only considers the failure of an instrument line with a 1/4-inch flow restricting orifice. Show that this failure scenario provides the most severe radioactive releases of any postulated failure of a small line. Your evaluation should include lines that meet GDC 55 as well as small lines exempt from GDC 55.

470.2

Provide a justification for your assumption that the plant continues to operate (and therefore no iodine peaking is experienced) during a small line break outside containment (Subsection 15.6.2) accident scenario. Also provide the basis for the assumption that the release duration is only two hours.

470.3

Subsection 15.6.4.5.1.1 of the FSAR gives the iodine source term (concentration and isotopic mix) used to analyze the steam line break outside of containment accident. The noble gas source term, however, is not addressed. Provide the noble gas source term used. Also, the table in Subsection 15.6.4.5.1.1 seems heavily weighted to the shorter lived activities (i.e., (I-134). Provide the bases for the isotopic mix used in your analysis (iodine and noble gas).

470.4

Subsection 15.6.5.5 states that the analysis is based on assumptions provided in Regulatory Guide 1.3 except where noted. For all assumptions (e.g., release assumed to occur one hour after accident initiation, the chemical species fractions for iodine, the temporal decrease in primary containment leakage rates, credit for condenser leakage rates, and dose conversion factors) which deviate from NRC guidance such as regulatory guides and ICRP2, provide a detailed description of the justification for the deviation or a reference to another section of the SSAR where the deviations are discussed in detail. Provide a comparison of the dose estimates using these assumptions versus those which would result from using the NRC guidance.

470.5

Provide a discussion of, or reference to, the analysis of the radiological consequences of leakage from engineered safety feature components after a design basis LOCA.

470.6

For the spent fuel cask drop accident, what is the assumed period for decay from the stated power condition? What is the justification for that assumption?

470.7

The tables in Chapter 15 should be checked and revised as appropriate. In several cases the footnotes contain typographical errors related to defining the scientific notation. Table 15.7-12 also appears to contain inappropriate references to Table 15.7-16, rather that Table 15.7-13.

RESPONSE 430.31

The plant protection signals that automatically isolate the secondary containment and activate the SGTS are:

(1) Secondary containment high radiation signal.

(2) Refueling floor high radiation signal.

(3) Drywell pressure high signal.

(4) Reactor water level low signal.

(5) Secondary containment HVAC supply/exhaust fans stop.

Isolation of the secondary containment is accomplished by closure of the secondary containment HVAC supply/exhaust line ducts which pass through the secondary containment boundary. The HVAC isolation valves consist of two valves in series in each of the supply/exhaust lines. These valves are air-operated, normally-open, fail closed butterfly vales.

Further details are provided in Subsection 6.2.3, 9.4.5.1 and Section 6.5

QUESTION 430.32

Identify and tabulate by size, piping which is not provided with isolation features. Provide an analysis to demonstrate the capability of the Standby Gas Treatment System to maintain the design negative pressure following a design basis accident with all non isolated lines open and the event of the worst single failure of a secondary containment isolation valve to close. (6.2)

RESPONSE 430.32

Response to this question will be provided in revised Subsection 6.5.1.3.1 and new Subsection 6.5.5.1.

QUESTION 430.33

Discuss the design provisions that prevent primary containment leakage from bypassing the secondary containment standby gas treatment system and escaping directly to the environment. Include a tabulation of potential bypass leakage paths, including the types of information indicated in Table 6-18 of Regulatory Guide 1.70, Revision 3. Provide an evaluation of potential bypass leakage paths considering equipment design limitations and test sensitivities. Specify and justify the maximum allowable fraction of primary containment leakage that may bypass the secondary containment structure. The guidelines of BTP 6-3 should be addressed in considering potential bypass leakage paths. (6.2)

RESPONSE 430.33

The secondary containment completely surrounds the primary containment except at the basemat. In addition the lower third of the secondary containment is surrounded by soil, thereby reducing leakage paths. No measurable leakage is expected through its walls except at penetrations. The secondary containment will be maintained at subatmospheric conditions to prevent leakage from bypassing the secondary containment. Only valve leakage through process piping can bypass the secondary containment. This leakage will be monitored via the containment leakage test type C on the outboard containment isolation valves. The secondary containment leak rate calculation is provided in the response to Question 430.52c.

QUESTION 430.34

Provide a list of the secondary containment openings and the instrumentation means by which each is assured to be closed during a postulated design basis accident. (6.2)

RESPONSE 430.34

Response to this question is provided in revised Subsection 6.2.3.2 and new Table 6.2-9.

QUESTION 430.35

Provide a table of design information regarding the containment isolation provisions for fluid system lines and fluid instrument lines penetrating the containment which are within the GE scope of the ABWR design. Include as a minimum the following information:

(1) General design criteria or regulatory guide recommendations that have been met or other defined bases for acceptability;

(2) System name;

(3) Fluid contained;

(4) Line size;

QUESTION 410.23

Give details for the worst case flooding arising from a postulated pipe failure and include the mitigation features provided. Note that for flooding analysis purposes, the complete failure of non-seismic Category I moderate-energy piping systems should be considered in lieu of cracks in determining the worst case flooding condition. (3.6.1)

RESPONSE 410.23

Subsection 3.4.1.1.2 contains descriptions and evaluations of compartment flooding from postulated pipe failures, and provides a description of measures for protecting safety-related systems and components. Consistent with ANSI/ANS 58.11-1988 (American National Standard Design Criteria for Protection Against Compartment Flooding in Light Water Reactor Plants) and ANSI/ANS 58.2-1988 (American National Standard Design Basis for Protection of Light Water Reactor Nuclear Power Plants Against the Effects of Pipe Rupture), these flooding evaluations assume leakage cracks with a flow area equal to the product of one-half the pipe inside diameter and one-half the pipe wall thickness.

QUESTION 410.24

Identify all the high-energy piping lines outside the containment (but within the ABWR scope), the adverse effects that may result from failures of applicable lines among them, and the protection provided against such effects for each of such lines (e.g., barriers and restraints). (3.6.1)

RESPONSE 410.24

The high-energy lines outside the containment are provided in Table 3.6-4. The adverse effects that may result from failures of applicable lines among them, and the protection provided against such lines is addressed in response to Question 410.22.

QUESTION 410.25

Clarify whether the reactor building steam tunnel is part of the break exclusion boundary. Also, provide a subcompartment analysis for the steam tunnel. Discuss how the structural integrity of the tunnel and the equipment in the tunnel are protected against failures in the tunnel. (3.6.1)

RESPONSE 410.25

A subcompartment analysis for the reactor building steam tunnel is provided in Subsection 6.2.3.3.1. The steam tunnel has been designed for the worst case line break plus other appropriate loads per ACI349. The valves and pipes in the steam tunnel will be qualified for the environment, plus shielded from jet loads. All safety-related pipes and valves will be protected from whipping pipes.

QUESTION 410.26

State how the MSIV functional capability is protected. (3.6.1)

RESPONSE 410.26

As noted in the response to Question 410.22, to properly apply the protection methods, the actual pipe dimensions, pipe routings, material properties, equipment and the detailed piping stress analyses must be available to define the specific measure for protection against the associated consequences of the postulated piping failure. Since this information will not be available until an applicant references the ABWR design in a specific licensing application, the applicant referencing the ABWR design will submit the details of now the MSIV functional capability is protected. This has been added as an interface requirement and added to Subsection 3.6.4.1.

QUESTION 410.27

Provide a summary table of the findings of an analysis of a postulated worst-case DBA rupture of a high or moderate-energy line for each of the following areas: 1) RCIC compartment, 2) RWCU equipment and valve room, 3) other applicable areas outside the containment (e.g., housing RHR piping). (3.6.1)

RESPONSE 410.27

The compartment pressurization effects of postulated worst-case DBA ruptures in the areas above are described in Subsection 6.2.3.3.1. Findings of analyses of other postulated pipe rupture effects on these areas will be provided by applicant referencing the ABWR design as specified in Subsection 3.6.4.1.

QUESTION 410.28

Clarify whether protection for safety-related systems and components against the dynamic effects of pipe failures include their enclosures in suitable design structures or components, drainage systems and equipment environmental qualification as required. If so, give typical examples for the above type of protection.

QUESTION 410.43

Discuss compliance with GDC 4, "Environment and Missile Design Bases" and GDC 61, "Fuel Storage and Handling and Radioactivity Control" as it relates to handling the spent fuel cask. (9.1.5)

RESPONSE 410.43

The fuel storage pool is inside a tornado and missile protected building (reactor building). No additional protection from externally generated missiles needs to be provided. Internally generated missiles, such as crane load drop, are protected by electrical interlocks and single-failure-proof cranes and hoists.

The following safeguards have been incorporated into the reactor building crane for working with heavy loads.

(1) While carrying heavy loads, such as spent fuel cask, the reactor building crane is prohibited from moving the heavy load over the spent fuel portion of the spent fuel pool.

(2) The spent fuel cask pool is separate from the spent fuel storage pool by a water tight gate.

(3) Only the spent fuel cask is carried over the spent fuel pool. The cask is carried over the cask pit portion of the spent fuel pool.

QUESTION 410.44

Provide P&IDs for the Condensate Storage Facilities and Distribution System (i.e., Makeup Water Condensate (MUWC) System). Also, provide a list of tanks (with capacity) and other requirements in the system. (9.2.9)

RESPONSE 410.44

The MUWC P&ID is provided as Figure 9.2-4. The only tank in this system is the condensate storage tank which has a capacity of approximately 560,000 gallons. This tank is located outdoors adjacent to the turbine building. The other requirements of this system are provided in Subsection 9.2.9.

QUESTION 410.45

Clarify which portion of the MUWC system is within the ABWR scope. Also, identify the system interfaces which include flow rates, supply pressure and temperature. (9.2.9)

RESPONSE 410.45

All of the MUWC system is within the ABWR scope.

QUESTION 410.46

Clarify whether the distribution system includes any surge volume and, if so, how much and for suction of which pumps. Also, if applicable, describe how protection against the effects of flooding resulting from possible failure of the surge volume is ensured. Define what "HPCF pumps" means. (9.2.9)

GE PROPRIETARY - provided under separate cover

Question/Response	Page(s)	Amendment
430.218	20.3-354.12	21

GE PROPRIETARY - provided under separate cover

Question/Response	Page(s)	Amendment
430.223	20.3-354.13.1	21

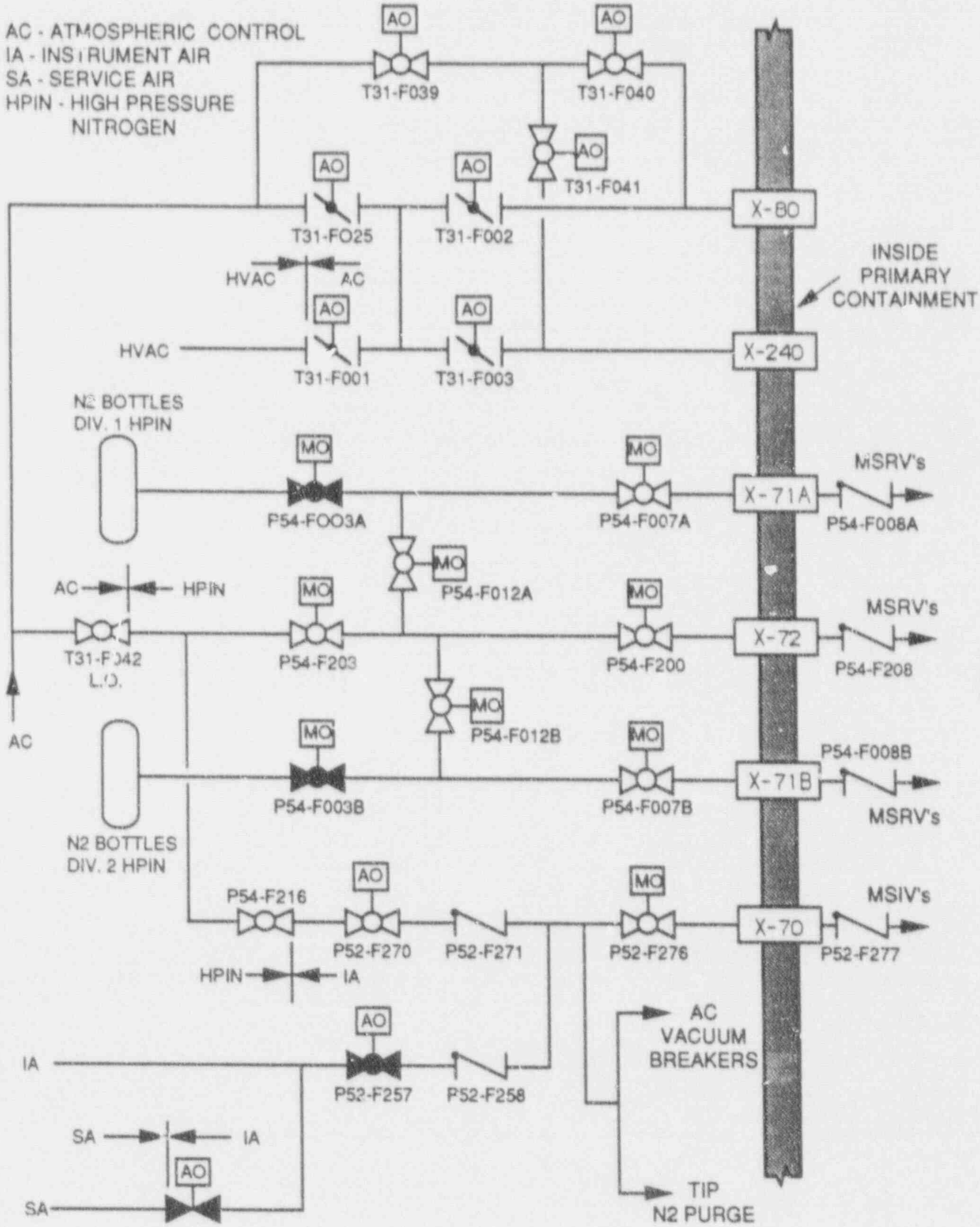

Figure 20.3 - 55 COMPRESSED GAS SYSTEMS INTERCONNECTIONS
(Response to Question 430.217)