UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D. C. 20555

PHILADELPHIA ELECTRIC COMPANY

DOCKET NO. 50-352

LIMERICK GENERATING STATION, UNIT 1

AMENDMENT TO FACILITY OPERATING LICENSE

Amendment No. 33
License No. NPF-39

1. The Nuclear Regulatory Commission (the Commission) has found that

   A. The application for amendment by Philadelphia Electric Company (the licensee) dated May 26, 1989, as supplemented by letter dated August 7, 1989, complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act), and the Commission's rules and regulations set forth in 10 CFR Chapter I;

   B. The facility will operate in conformity with the application, the provisions of the Act, and the rules and regulations of the Commission;

   C. There is reasonable assurance (i) that the activities authorized by this amendment can be conducted without endangering the health and safety of the public, and (ii) that such activities will be conducted in compliance with the Commission's regulations;

   D. The issuance of this amendment will not be inimical to the common defense and security or to the health and safety of the public; and

   E. The issuance of this amendment is in accordance with 10 CFR Part 51 of the Commission's regulations and all applicable requirements have been satisfied.

2. Accordingly, the license is amended by changes to the Technical Specifications as indicated in the attachment to this license amendment, and paragraph 2.C.(2) of Facility Operating License No. NPF-39 is hereby amended to read as follows:

   Technical Specifications

   The Technical Specifications contained in Appendix A and the Environmental Protection Plan contained in Appendix B, as revised through Amendment No. 33 , are hereby incorporated into this license. Philadelphia Electric Company shall operate the facility in accordance with the Technical Specifications and the Environmental Protection Plan.

3. This license amendment is effective as of its date of issuance.

FOR THE NUCLEAR REGULATORY COMMISSION

/s/

Walter R. Butler, Director
Project Directorate I-2
Division of Reactor Projects I/II

Attachment:
Changes to the Technical
Specifications

Date of Issuance: **October 30, 1989**

Previously concurred*

PDI-2/LA	PDI-2/PM	PDI-2/PM *	OGC*	PDI-2/D
MO'Brien	RClark	ETrottier:mj	JMoore	WButler
10/26/89	10/06/89	09/06/89	09/25/89 subject to changes in Fed. Reg. Notice	10/30/89

WB

3. This license amendment is effective as of its date of issuance.

FOR THE NUCLEAR REGULATORY COMMISSION

Walter R. Butler

Walter R. Butler, Director
Project Directorate I-2
Division of Reactor Projects I/II

Attachment:
Changes to the Technical
Specifications

Date of Issuance: October 30, 1989

ATTACHMENT TO LICENSE AMENDMENT NO. 33

FACILITY OPERATING LICENSE NO. NPF-39

DOCKET NO. 50-352

Replace the following pages of the Appendix A Technical Specifications with the attached page. The revised pages are identified by Amendment number and contain vertical lines indicating the area of change. Overleaf pages provided to maintain document completeness.*

Remove	Insert
i	i
ii	ii
iii	iii*
iv	iv
v	v*
vi	vi
via	via
-	-
vii	vii
viii	viii*
xi	xi*
xii	xii
xiii	xiii*
xiv	xiv
xv	xv*
xvi	xvi
xvii	xvii*
xviii	xviii
xix	xix*
xx	xx
xxv	xxv*
xxvi	xxvi
1-5	1-5*
1-6	1-6
B 2-5	B 2-5
B 2-6	B 2-6*

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3/4 3-7	3/4 3-7
3/4 3-8	3/4 3-8*
3/4 3-13	3/4 3-13
3/4 3-14	3/4 3-14*
3/4 3-15	3/4 3-15
3/4 3-16	3/4 3-16*
3/4 3-19	3/4 3-19
3/4 3-20	3/4 3-20
3/4 3-21	3/4 3-21
3/4 3-22	3/4 3-22*
3/4 3-23	3/4 3-23*
3/4 3-24	3/4 3-24
3/4 3-29	3/4 3-29
3/4 3-30	3/4 3-30*
3/4 3-33	3/4 3-33*
3/4 3-34	3/4 3-34
3/4 3-37	3/4 3-37
3/4 3-38	3/4 3-38*
3/4 3-55	3/4 3-55
3/4 3-56	3/4 3-56*
3/4 3-77	3/4 3-77*
3/4 3-78	3/4 3-78
3/4 3-81	3/4 3-81
3/4 3-82	3/4 3-82*
3/4 3-93	3/4 3-93
3/4 3-94	3/4 3-94*

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3/4 3-95	3/4 3-95
3/4 3-96	3/4 3-96
3/4 3-103	3/4 3-103*
3/4 3-104	3/4 3-104
3/4 3-111	3/4 3-111
3/4 3-112	3/4 3-112*
3/4 4-9	3/4 4-9*
3/4 4-10	3/4 4-10
3/4 4-17	3/4 4-17
3/4 4-18	3/4 4-18*
3/4 5-1	3/4 5-1
3/4 5-2	3/4 5-2*
3/4 5-3	3/4 5-3
3/4 5-4	3/4 5-4*
3/4 5-5	3/4 5-5
3/4 5-6	3/4 5-6*
3/4 6-3	3/4 6-3*
3/4 6-4	3/4 6-4
3/4 6-5	3/4 6-5
3/4 6-6	3/4 6-6*
3/4 6-17	3/4 6-17*
3/4 6-18	3/4 6-18
3/4 6-19	3/4 6-19
3/4 6-20	3/4 6-20
3/4 6-21	3/4 6-21
3/4 6-22	3/4 6-22*
3/4 6-23	3/4 6-23*
3/4 6-24	3/4 6-24
3/4 6-25	3/4 6-25
3/4 6-26	3/4 6-26

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3/4 6-27	3/4 6-27
3/4 6-28	3/4 6-28*
3/4 6-29	3/4 6-29
3/4 6-30	3/4 6-30*
3/4 6-31	3/4 6-31
3/4 6-32	3/4 6-32*
3/4 6-33	3/4 6-33
3/4 6-34	3/4 6-34*
3/4 6-41	3/4 6-41*
3/4 6-42	3/4 6-42
3/4 6-45	3/4 6-45
3/4 6-46	3/4 6-46*
3/4 6-47	3/4 6-47*
3/4 6-48	3/4 6-48
3/4 6-53	3/4 6-53
3/4 6-54	3/4 6-54*
3/4 7-21	3/4 7-21*
3/4 7-22	3/4 7-22
3/4 7-23	3/4 7-23*
3/4 7-24	3/4 7-24
3/4 7-27	3/4 7-27
3/4 7-28	3/4 7-28
3/4 8-25	3/4 8-25
3/4 8-26	3/4 8-26*
3/4 11-1	3/4 11-1
3/4 11-2	3/4 11-2*
3/4 11-3	3/4 11-3
3/4 11-4	3/4 11-4*

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3/4 11-11	3/4 11-11
3/4 11-12	3/4 11-12*
3/4 12-7	3/4 12-7
3/4 12-8	3/4 12-8
B 3/4 3-1	B 3/4 3-1*
B 3/4 3-2	B 3/4 3-2
B 3/4 3-7	B 3/4 3-7
B 3/4 3-8	B 3/4 3-8*
B 3/4 4-7	B 3/4 4-7*
B 3/4 4-8	B 3/4 4-8
B 3/4 6-1	B 3/4 6-1
B 3/4 6-2	B 3/4 6-2*
B 3/4 6-3	B 3/4 6-3
B 3/4 6-4	B 3/4 6-4*
B 3/4 8-3	B 3/4 8-3
-	-
B 3/4 10-1	B 3/4 10-1
-	-
5-1	5-1
5-2	5-2*
6-5	6-5
6-6	6-6*
6-7	6-7
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DESIGN FEATURES

ADMINISTRATIVE CONTROLS

PRESSURE BOUNDARY LEAKAGE

1.28 PRESSURE BOUNDARY LEAKAGE shall be leakage through a nonisolable fault in a reactor coolant system component body, pipe wall or vessel wall.

PRIMARY CONTAINMENT INTEGRITY

1.29 PRIMARY CONTAINMENT INTEGRITY shall exist when:

a. All primary containment penetrations required to be closed during accident conditions are either:

1. Capable of being closed by an OPERABLE primary containment automatic isolation system, or
2. Closed by at least one manual valve, blind flange, or deactivated automatic valve secured in its closed position, except as provided in Table 3.6.3-1 of Specification 3.6.3.

b. All primary containment equipment hatches are closed and sealed.

c. The primary containment air lock is in compliance with the requirements of Specification 3.6.1.3.

d. The primary containment leakage rates are within the limits of Specification 3.6.1.2.

e. The suppression chamber is in compliance with the requirements of Specification 3.6.2.1.

f. The sealing mechanism associated with each primary containment penetration; e.g., welds, bellows, or O-rings, is OPERABLE.

PROCESS CONTROL PROGRAM

1.30 The PROCESS CONTROL PROGRAM (PCP) shall contain the provisions to assure that the SOLIDIFICATION or dewatering and packaging of radioactive wastes results in a waste package with properties that meet the minimum and stability requirements of 10 CFR Part 61 and other requirements for transportation to the disposal site and receipt at the disposal site. With SOLIDIFICATION, the PCP shall identify the process parameters influencing SOLIDIFICATION such as pH, oil content, H_2O content, solids content ratio of solidification agent to waste and/or necessary additives for each type of anticipated waste, and the acceptable boundary conditions for the process parameters shall be identified for each waste type, based on laboratory scale and full scale testing or experience. With dewatering, the PCP shall include an identification of conditions that must be satisfied, based on full scale testing, to assure that dewatering of bead resins, powdered resins, and filter sludges will result in volumes of free water, at the time of disposal, within the limits of 10 CFR Part 61 and of the low-level radioactive waste disposal site.

PURGE - PURGING

1.31 PURGE or PURGING shall be the controlled process of discharging air or gas from a confinement to maintain temperature, pressure, humidity, concentration or other operating condition, in such a manner that replacement air or gas is required to purify the confinement.

RATED THERMAL POWER

1.32 RATED THERMAL POWER shall be a total reactor core heat transfer rate to the reactor coolant of 3293 MWt.

REACTOR ENCLOSURE SECONDARY CONTAINMENT INTEGRITY

1.33 REACTOR ENCLOSURE SECONDARY CONTAINMENT INTEGRITY shall exist when:

a. All reactor enclosure secondary containment penetrations required to be closed during accident conditions are either:

   1. Capable of being closed by an OPERABLE secondary containment automatic isolation system, or

   2. Closed by at least one manual valve, blind flange, slide gate damper, or deactivated automatic valve secured in its closed position, except as provided in Table 3.6.5.2.1-1 of Specification 3.6.5.2.1.

b. All reactor enclosure secondary containment hatches and blowout panels are closed and sealed.

c. The standby gas treatment system is in compliance with the requirements of Specification 3.6.5.3.

d. The reactor enclosure recirculation system is in compliance with the requirements of Specification 3.6.5.4.

e. At least one door in each access to the reactor enclosure secondary containment is closed.

f. The sealing mechanism associated with each reactor enclosure secondary containment penetration, e.g., welds, bellows, or O-rings, is OPERABLE.

g. The pressure within the reactor enclosure secondary containment is less than or equal to the value required by Specification 4.6.5.1.1a.

REACTOR PROTECTION SYSTEM RESPONSE TIME

1.34 REACTOR PROTECTION SYSTEM RESPONSE TIME shall be the time interval from when the monitored parameter exceeds its trip setpoint at the channel sensor until de-energization of the scram pilot valve solenoids. The response time may be measured by any series of sequential, overlapping or total steps such that the entire response time is measured.

REFUELING FLOOR SECONDARY CONTAINMENT INTEGRITY

1.35 REFUELING FLOOR SECONDARY CONTAINMENT INTEGRITY shall exist when:

a. All refueling floor secondary containment penetrations required to be closed during accident conditions are either:

   1. Capable of being closed by an OPERABLE secondary containment automatic isolation system, or

   2. Closed by at least one manual valve, blind flange, slide gate damper, or deactivated automatic valve secured in its closed position, except as provided in Table 3.6.5.2.2-1 of Specification 3.6.5.2.2.

2.1.3 REACTOR COOLANT SYSTEM PRESSURE

The Safety Limit for the reactor coolant system pressure has been selected such that it is at a pressure below which it can be shown that the integrity of the system is not endangered. The reactor pressure vessel is designed to Section III of the ASME Boiler and Pressure Vessel Code 1968 Edition, including Addenda through Summer 1969, which permits a maximum pressure transient of 110%, 1375 psig, of design pressure 1250 psig. The Safety Limit of 1325 psig, as measured by the reactor vessel steam dome pressure indicator, is equivalent to 1375 psig at the lowest elevation of the reactor coolant system. The reactor coolant system is designed to the ASME Boiler and Pressure Vessel Code, 1977 Edition, including Addenda through Summer 1977 for the reactor recirculation piping, which permits a maximum pressure transient of 110%, 1375 psig of design pressure, 1250 psig for suction piping and 1500 psig for discharge piping. The pressure Safety Limit is selected to be the lowest transient overpressure allowed by the ASME Boiler and Pressure Vessel Code Section III, Class I.

2.1.4 REACTOR VESSEL WATER LEVEL

With fuel in the reactor vessel during periods when the reactor is shutdown, consideration must be given to water level requirements due to the effect of decay heat. If the water level should drop below the top of the active irradiated fuel during this period, the ability to remove decay heat is reduced. This reduction in cooling capability could lead to elevated cladding temperatures and clad perforation in the event that the water level became less than two-thirds of the core height. The Safety Limit has been established at the top of the active irradiated fuel to provide a point which can be monitored and also provide adequate margin for effective action.

2.2 LIMITING SAFETY SYSTEM SETTINGS

BASES

2.2.1 REACTOR PROTECTION SYSTEM INSTRUMENTATION SETPOINTS

The Reactor Protection System instrumentation setpoints specified in Table 2.2.1-1 are the values at which the reactor trips are set for each parameter. The Trip Setpoints have been selected to ensure that the reactor core and reactor coolant system are prevented from exceeding their Safety Limits during normal operation and design basis anticipated operational occurrences and to assist in mitigating the consequences of accidents. Operation with a trip set less conservative than its Trip Setpoint but within its specified Allowable Value is acceptable on the basis that the difference between each Trip Setpoint and the Allowable Value is equal to or less than the drift allowance assumed for each trip in the safety analyses.

1. Intermediate Range Monitor, Neutron Flux - High

The IRM system consists of 8 chambers, 4 in each of the reactor trip systems. The IRM is a 5 decade 10 range instrument. The trip setpoint of 120 divisions of scale is active in each of the 10 ranges. Thus as the IRM is ranged up to accommodate the increase in power level, the trip setpoint is also ranged up. The IRM instruments provide for overlap with both the APRM and SRM systems.

The most significant source of reactivity changes during the power increase is due to control rod withdrawal. In order to ensure that the IRM provides the required protection, a range of rod withdrawal accidents have been analyzed. The results of these analyses are in Section 15.4 of the FSAR. The most severe case involves an initial condition in which THERMAL POWER is at approximately 1% of RATED THERMAL POWER. Additional conservatism was taken in this analysis by assuming the IRM channel closest to the control rod being withdrawn is bypassed. The results of this analysis show that the reactor is shutdown and peak power is limited to 21% of RATED THERMAL POWER with the peak fuel enthalpy well below the fuel failure threshold of 170 cal/gm. Based on this analysis, the IRM provides protection against local control rod errors and continuous withdrawal of control rods in sequence and provides backup protection for the APRM.

2. Average Power Range Monitor

For operation at low pressure and low flow during STARTUP, the APRM scram setting of 15% of RATED THERMAL POWER provides adequate thermal margin between the setpoint and the Safety Limits. The margin accommodates the anticipated maneuvers associated with power plant startup. Effects of increasing pressure at zero or low void content are minor and cold water from sources available during startup is not much colder than that already in the system. Temperature coefficients are small and control rod patterns are constrained by the RWM. Of all the possible sources of reactivity input, uniform control rod withdrawal is the most probable cause of significant power increase.

TABLE 4.3.1.1-1

REACTOR PROTECTION SYSTEM INSTRUMENTATION SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL FUNCTIONAL TEST	CHANNEL CALIBRATION[a]	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED
1. Intermediate Range Monitors:				
a. Neutron Flux - High	S/U,S(b)	S/U(c), W	R	2
	S	W(j)	R	3, 4, 5
b. Inoperative	N.A.	W(j)	N.A.	2, 3, 4, 5
2. Average Power Range Monitor[f]:				
a. Neutron Flux - Upscale, Setdown	S/U,S(b)	S/U(c), W	SA	2
	S	W(j)	SA	3, 5
b. Neutron Flux - Upscale				
1) Flow Biased	S,D(g)	S/U(c), W	W(d)(e),SA	1
2) High Flow Clamped	S	S/U(c), W	W(d)(e), SA	1
c. Inoperative	N.A.	W(j)	N.A.	1, 2, 3, 5
d. Downscale	S	W	SA	1
3. Reactor Vessel Steam Dome Pressure - High	S	M	R	1, 2(h)
4. Reactor Vessel Water Level - Low, Level 3	S	M	R	1, 2
5. Main Steam Line Isolation Valve - Closure	N.A.	M	R	1
6. Main Steam Line Radiation - High	S	M	R	1, 2(h)
7. Drywell Pressure - High	S	M	R	1, 2

TABLE 4.3.1.1-1 (Continued)

REACTOR PROTECTION SYSTEM INSTRUMENTATION SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL FUNCTIONAL TEST	CHANNEL CALIBRATION	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED
8. Scram Discharge Volume Water Level - High				
a. Level Transmitter	S	M	R	1, 2, 5[i]
b. Float Switch	N.A.	M	R	1, 2, 5[i]
9. Turbine Stop Valve - Closure	N.A.	M	R	1
10. Turbine Control Valve Fast Closure, Trip Oil Pressure - Low	N.A.	M	R	1
11. Reactor Mode Switch Shutdown Position	N.A.	R	N.A.	1, 2, 3, 4, 5
12. Manual Scram	N.A.	M	N.A.	1, 2, 3, 4, 5

(a) Neutron detectors may be excluded from CHANNEL CALIBRATION.

(b) The IRM and SRM channels shall be determined to overlap for at least ½ decades during each startup after entering OPERATIONAL CONDITION 2 and the IRM and APRM channels shall be determined to overlap for at least ½ decades during each controlled shutdown, if not performed within the previous 7 days.

(c) Within 24 hours prior to startup, if not performed within the previous 7 days.

(d) This calibration shall consist of the adjustment of the APRM channel to conform to the power values calculated by a heat balance during OPERATIONAL CONDITION 1 when THERMAL POWER > 25% of RATED THERMAL POWER. Adjust the APRM channel if the absolute difference is greater than 2% of RATED THERMAL POWER. Any APRM channel gain adjustment made in compliance with Specification 3.2.2 shall not be included in determining the absolute difference.

(e) This calibration shall consist of the adjustment of the APRM flow biased channel to conform to a calibrated flow signal.

(f) The LPRMs shall be calibrated at least once per 1000 effective full power hours (EFPH) using the TIP system.

(g) Verify measured core flow (total core flow) to be greater than or equal to established core flow at the existing loop flow (APRM % flow). During the startup test program, data shall be recorded for the parameters listed to provide a basis for establishing the specified relationships. Comparisons of the actual data in accordance with the criteria listed shall commence upon the conclusion of the startup test program.

(h) This function is not required to be OPERABLE when the reactor pressure vessel head is removed per Specification 3.10.1.

(i) With any control rod withdrawn. Not applicable to control rods removed per Specification 3.9.10.1 or 3.9.10.2.

(j) If the RPS shorting links are required to be removed per Specification 3.9.2, they may be reinstalled for up to 2 hours for required surveillance. During this time, CORE ALTERATIONS shall be suspended and no control rod shall be moved from its existing position.

TABLE 3.3.2-1 (Continued)
ISOLATION ACTUATION INSTRUMENTATION

TRIP FUNCTION	ISOLATION SIGNAL (a)	MINIMUM OPERABLE CHANNELS PER TRIP SYSTEM (b)	APPLICABLE OPERATIONAL CONDITION	ACTION
4. HIGH PRESSURE COOLANT INJECTION SYSTEM ISOLATION (Continued)				
f. HPCI Pipe Routing Area Temperature - High	L	4	1, 2, 3	23
g. Manual Initiation	NA(e)	1/system	1, 2, 3	24
h. HPCI Steam Line Δ Press Timer	NA	1	1, 2, 3	23
5. REACTOR CORE ISOLATION COOLING SYSTEM ISOLATION				
a. RCIC Steam Line Δ Pressure - High	K	1	1, 2, 3	23
b. RCIC Steam Supply Pressure - Low	KA	2	1, 2, 3	23
c. RCIC Turbine Exhaust Diaphragm Pressure - High	K	2	1, 2, 3	23
d. RCIC Equipment Room Temperature - High	K	1	1, 2, 3	23
e. RCIC Equipment Room Δ Temperature - High	K	1	1, 2, 3	23
f. RCIC Pipe Routing Area Temperature - High	K	5	1, 2, 3	23
g. Manual Initiation	NA(e)	1/system	1, 2, 3	24
h. RCIC Steam Line Δ Pressure Timer	NA	1	1, 2, 3	23

TABLE 3.3.2-1 (Continued)
ISOLATION ACTUATION INSTRUMENTATION

TRIP FUNCTION	ISOLATION SIGNAL [a]	MINIMUM OPERABLE CHANNELS PER TRIP SYSTEM [b]	APPLICABLE OPERATIONAL CONDITION	ACTION
6. PRIMARY CONTAINMENT ISOLATION				
a. Reactor Vessel Water Level				
1) Low, Low - Level 2	B	2	1, 2, 3	20
2) Low, Low, Low - Level 1	C	2	1, 2, 3	20
b. Drywell Pressure - High	H	2	1, 2, 3	20
c. North Stack Effluent Radiation - High [g]	W	1	1, 2, 3	23
d. Deleted				
e. Reactor Enclosure Ventilation Exhaust Duct-Radiation - High	S	2	1, 2, 3	23
f. Outside Atmosphere to Reactor Enclosure Δ Pressure - Low	U	1	1, 2, 3	23
g. Deleted				
h. Drywell Pressure - High/ Reactor Pressure - Low	G	2/2	1, 2, 3	26
i. Primary Containment Instrument Gas Line to Drywell Δ Pressure-Low	M	1	1, 2, 3	26
j. Manual Initiation	NA	1	1, 2, 3	24

TABLE 3.3.2-1 (Continued)
ISOLATION ACTUATION INSTRUMENTATION

TRIP FUNCTION	ISOLATION SIGNAL (a),(c)	MINIMUM OPERABLE CHANNELS PER TRIP SYSTEM (b)	APPLICABLE OPERATIONAL CONDITION	ACTION
7. SECONDARY CONTAINMENT ISOLATION				
a. Reactor Vessel Water Level Low, Low - Level 2	B	2	1, 2, 3	25
b. Drywell Pressure - High	H	2	1, 2, 3	25
c.1. Refueling Area Unit 1 Ventilation Exhaust Duct Radiation - High	R	2	*#	25
2. Refueling Area Unit 2 Ventilation Exhaust Duct Radiation - High	R	2	*#	25
d. Reactor Enclosure Ventilation Exhaust Duct Radiation - High	S	2	1, 2, 3	25
e. Outside Atmosphere To Reactor Enclosure Δ Pressure - Low	U	1	1, 2, 3	25
f. Outside Atmosphere To Refueling Area Δ Pressure - Low	T	1	*	25
g. Reactor Enclosure Manual Initiation	NA	1	1, 2, 3	24
h. Refueling Area Manual Initiation	NA	1	*	25

TABLE 3.3.2-1 (Continued)
ISOLATION ACTUATION INSTRUMENTATION
ACTION STATEMENTS

ACTION 20 - Be in at least HOT SHUTDOWN within 12 hours and in COLD SHUTDOWN within the next 24 hours.

ACTION 21- Be in at least STARTUP with the associated isolation valves closed within 6 hours or be in at least HOT SHUTDOWN within 12 hours and in COLD SHUTDOWN within the next 24 hours.

ACTION 22 - Be in at least STARTUP within 6 hours.

ACTION 23 - In OPERATIONAL CONDITION 1 or 2, verify the affected system isolation valves are closed within 1 hour and declare the affected system inoperable. In OPERATIONAL CONDITION 3, be in at least COLD SHUTDOWN within 12 hours.

ACTION 24 - Restore the manual initiation function to OPERABLE status within 8 hours or close the affected system isolation valves within the next hour and declare the affected system inoperable or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

ACTION 25 - Establish SECONDARY CONTAINMENT INTEGRITY with the standby gas treatment system operating within 1 hour.

ACTION 26 - Close the affected system isolation valves within 1 hour.

TABLE NOTATIONS

* When handling irradiated fuel in the secondary containment and during CORE ALTERATIONS and operations with a potential for draining the reactor vessel

** May be bypassed under administrative control, with all turbine stop valves closed.

\# During operation of the associated Unit 1 or Unit 2 ventilation exhaust system.

(a) See Specification 3.6.3, Table 3.6.3-1 for primary containment isolation valves which are actuated by these isolation signals.

(b) A channel may be placed in an inoperable status for up to 2 hours for required surveillance without placing the channel or trip system in the tripped condition provided at least one other OPERABLE channel in the same trip system is monitoring that parameter. In addition, for the HPCI system and RCIC system isolation, provided that the redundant isolation valve, inboard or outboard, as applicable, in each line is OPERABLE and all required actuation instrumentation for that valve is OPERABLE, one channel may be placed in an inoperable status for up to 8 hours for required surveillance without placing the channel or trip system in the tripped condition.

(c) Actuates secondary containment isolation valves shown in Table 3.6.5.2.1-1 and/or 3.6.5.2.2-1 and signals B, H, S, U, R and T also start the standby gas treatment system.

(d) RWCU system inlet outboard isolation valve closes on SLCS "B" initiation. RWCU system inlet inboard isolation valve closes on SLCS "A" or SLCS "C" initiation.

Effective when OL is issued to Unit 2

TABLE 3.3.2-2 (Continued)

ISOLATION ACTUATION INSTRUMENTATION SETPOINTS

TRIP FUNCTION	TRIP SETPOINT	ALLOWABLE VALUE
3. REACTOR WATER CLEANUP SYSTEM ISOLATION		
a. RWCS Δ Flow - High	≤ 54.9 gpm	≤ 65.2 gpm
b. RWCS Area Temperature - High	≤ 135°F or 122°F**	≤ 145°F or 130°F**
c. RWCS Area Ventilation Δ Temperature - High	≤ 32°F	≤ 40°F
d. SLCS Initiation	N.A.	N.A.
e. Reactor Vessel Water Level - Low, Low, - Level 2	≥ -38 inches*	≥ -45 inches
f. Manual Initiation	N.A.	N.A.
4. HIGH PRESSURE COOLANT INJECTION SYSTEM ISOLATION		
a. HPCI Steam Line Δ Pressure - High	≤ 343" H_2O	≤ 358" H_2O
b. HPCI Steam Supply Pressure - Low	≥ 100 psig	≥ 90 psig
c. HPCI Turbine Exhaust Diaphragm Pressure - High	≤ 10 psig	≤ 20 psig
d. HPCI Equipment Room Temperature - High	175°F	≥ 165°F, ≤ 200°F
e. HPCI Equipment Room Δ Temperature - High	≤ 80°F	≤ 88°F
f. HPCI Pipe Routing Area Temperature - High	175°F	≥ 165°F, ≤ 200°F
g. Manual Initiation	N.A.	N.A.
h. HPCI Steam Line Δ Pressure - Timer	$3 \leq \tau \leq 12.5$ seconds	$2.5 \leq \tau \leq 13$ seconds

TABLE 3.3.2-2 (Continued)

ISOLATION ACTUATION INSTRUMENTATION SETPOINTS

TRIP FUNCTION	TRIP SETPOINT	ALLOWABLE VALUE
5. REACTOR CORE ISOLATION COOLING SYSTEM ISOLATION		
a. RCIC Steam Line Δ Pressure - High	≤ 213" H_2O	≤ 223" H_2O
b. RCIC Steam Supply Pressure - Low	≥ 64.5 psig	≥ 56.5 psig
c. RCIC Turbine Exhaust Diaphragm Pressure - High	≤ 10.0 psig	≤ 20.0 psig
d. RCIC Equipment Room Temperature - High	175°F	≥ 165°F, ≤ 200°F
e. RCIC Equipment Room Δ Temperature - High	≤ 80°F	≤ 88°F
f. RCIC Pipe Routing Area Temperature - High	175°F	≥ 165°F, ≤ 200°F
g. Manual Initiation	N.A.	N.A.
h. RCIC Steam Line Δ Pressure Timer	$3 \leq \tau \leq 12.5$ seconds	$2.5 \leq \tau \leq 13$ seconds

TABLE 3.3.2-2 (Continued)

ISOLATION ACTUATION INSTRUMENTATION SETPOINTS

TRIP FUNCTION	TRIP SETPOINT	ALLOWABLE VALUE
6. PRIMARY CONTAINMENT ISOLATION		
a. Reactor Vessel Water Level		
1. Low, Low - Level 2	$\geq$ -38 inches*	$\geq$ -45 inches
2. Low, Low, Low, Level 1	$\geq$ -129 inches*	$\geq$ -136 inches
b. Drywell Pressure - High	$\leq$ 1.68 psig	$\leq$ 1.88 psig
c. North Stack Effluent Radiation - High	$\leq$ 2.1 μCi/cc	$\leq$ 4.0 μCi/cc
d. Deleted		
e. Reactor Enclosure Ventilation Exhaust Duct - Radiation - High	$\leq$ 1.35 mR/h	$\leq$ 1.5 mR/h
f. Outside Atmosphere To Reactor Enclosure Δ Pressure - Low	$\geq$ 0.1" of H_2O	$\geq$ 0.0" of H_2O
g. Deleted		
h. Drywell Pressure - High/ Reactor Pressure - Low	$\leq$ 1.68 psig/ $\geq$ 455 psig (decreasing)	$\leq$ 1.88 psig/ $\geq$ 435 psig (decreasing)
i. Primary Containment Instrument Gas to Drywell Δ Pressure-Low	$\geq$ 2.0 psi	$\geq$ 1.9 psi
j. Manual Initiation	N.A.	N.A.

TABLE 3.3.2-2 (Continued)

ISOLATION ACTUATION INSTRUMENTATION SETPOINTS

TRIP FUNCTION	TRIP SETPOINT	ALLOWABLE VALUE
7. SECONDARY CONTAINMENT ISOLATION		
a. Reactor Vessel Water Level - Low, Low - Level 2	$\geq$ -38 inches*	$\geq$ -45 inches
b. Drywell Pressure - High	$\leq$ 1.68 psig	$\leq$ 1.88 psig
c.1. Refueling Area Unit 1 Ventilation Exhaust Duct Radiation - High	$\leq$ 2.0 mR/h	$\leq$ 2.2 mR/h
2. Refueling Area Unit 2 Ventilation Exhaust Duct Radiation - High	$\leq$ 2.0 mR/h	$\leq$ 2.2 mR/h
d. Reactor Enclosure Ventilation Exhaust Duct Radiation - High	$\leq$ 1.35 mR/h	$\leq$ 1.5 mR/h
e. Outside Atmosphere To Reactor Enclosure Δ Pressure - Low	$\geq$ 0.1" of H_2O	$\geq$ 0.0" of H_2O
f. Outside Atmosphere To Refueling Area Δ Pressure - Low	$\geq$ 0.1" of H_2O	$\geq$ 0.0" of H_2O
g. Reactor Enclosure Manual Initiation	N.A.	N.A.
h. Refueling Area Manual Initiation	N.A.	N.A.

*See Bases Figure B 3/4 3-1.

**The low setpoints are for the RWCU Heat Exchanger Rooms; the high setpoints are for the pump rooms.

Correction ...
... 6-28-94

TABLE 3.3.2-3

ISOLATION SYSTEM INSTRUMENTATION RESPONSE TIME

TRIP FUNCTION	RESPONSE TIME (Seconds)#
1. MAIN STEAM LINE ISOLATION	
a. Reactor Vessel Water Level	
1) Low, Low - Level 2	$\leq 13^{(a)}$**
2) Low, Low, Low - Level 1	≤ 1.0*/$\leq 13^{(a)}$**
b. Main Steam Line Radiation - High(b)	≤ 1.0*/$\leq 13^{(a)}$**
c. Main Steam Line Pressure - Low	≤ 1.0*/$\leq 13^{(a)}$**
d. Main Steam Line Flow - High	≤ 0.5*/$\leq 13^{(a)}$**
e. Condenser Vacuum - Low	N.A.
f. Outboard MSIV Room Temperature - High	N.A.
g. Turbine Enclosure - Main Steam Line Tunnel Temperature - High	N.A.
h. Manual Initiation	N.A.
2. RHR SYSTEM SHUTDOWN COOLING MODE ISOLATION	
a. Reactor Vessel Water Level Low - Level 3	$\leq 13^{(a)}$
b. Reactor Vessel (RHR Cut-In Permissive) Pressure - High	N.A.
c. Manual Initiation	N.A.
3. REACTOR WATER CLEANUP SYSTEM ISOLATION	
a. RWCS Δ Flow - High	≤ 13##
b. RWCS Area Temperature - High	N.A.
c. RWCS Area Ventilation Δ Temperature - High	N.A.
d. SLCS Initiation	N.A.
e. Reactor Vessel Water Level - Low, Low - Level 2	$\leq 13^{(a)}$
f. Manual Initiation	N.A.

TABLE 3.3.2-3 (Continued)

ISOLATION SYSTEM INSTRUMENTATION RESPONSE TIME

TRIP FUNCTION	RESPONSE TIME (Seconds)#
4. HIGH PRESSURE COOLANT INJECTION SYSTEM ISOLATION	
a. HPCI Steam Line Δ Pressure - High	≤ 13[(a)]
b. HPCI Steam Supply Pressure - Low	≤ 13[(a)]
c. HPCI Turbine Exhaust Diaphragm Pressure - High	N.A.
d. HPCI Equipment Room Temperature - High	N.A.
e. HPCI Equipment Room Δ Temperature - High	N.A.
f. HPCI Pipe Routing Area Temperature - High	N.A.
g. Manual Initiation	N.A.
5. REACTOR CORE ISOLATION COOLING SYSTEM ISOLATION	
a. RCIC Steam Line Δ Pressure - High	≤ 13[(a)]
b. RCIC Steam Supply Pressure - Low	≤ 13[(a)]
c. RCIC Turbine Exhaust Diaphragm Pressure - High	N.A.
d. RCIC Equipment Room Temperature - High	N.A.
e. RCIC Equipment Room Δ Temperature - High	N.A.
f. RCIC Pipe Routing Area Temperature - High	N.A.
g. Manual Initiation	N.A.

TABLE 4.3.2.1-1 (Continued)

ISOLATION ACTUATION INSTRUMENTATION SURVEILLANCE REQUIREMENTS

TRIP FUNCTION	CHANNEL CHECK	CHANNEL FUNCTIONAL TEST	CHANNEL CALIBRATION	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED
5. REACTOR CORE ISOLATION COOLING SYSTEM ISOLATION				
a. RCIC Steam Line Δ Pressure - High	S	M	R	1, 2, 3
b. RCIC Steam Supply Pressure - Low	S	M	R	1, 2, 3
c. RCIC Turbine Exhaust Diaphragm Pressure - High	S	M	R	1, 2, 3
d. RCIC Equipment Room Temperature - High	S	M	R	1, 2, 3
e. RCIC Equipment Room Δ Temperature - High	S	M	R	1, 2, 3
f. RCIC Pipe Routing Area Temperature - High	S	M	R	1, 2, 3
g. Manual Initiation	N.A.	R	N.A.	1, 2, 3
h. RCIC Steam Line Δ Pressure Timer	N.A.	M	R	1, 2, 3

TABLE 4.3.2.1-1 (Continued)

ISOLATION ACTUATION INSTRUMENTATION SURVEILLANCE REQUIREMENTS

TRIP FUNCTION	CHANNEL CHECK	CHANNEL FUNCTIONAL TEST	CHANNEL CALIBRATION	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED
6. PRIMARY CONTAINMENT ISOLATION				
a. Reactor Vessel Water Level				
1) Low, Low - Level 2	S	M	R	1, 2, 3
2) Low, Low, Low - Level 1	S	M	R	1, 2, 3
b. Drywell Pressure - High	S	M	R	1, 2, 3
c. North Stack Effluent Radiation - High	S	Q	R	1, 2, 3
d. Deleted				
e. Reactor Enclosure Ventilation Exhaust Duct - Radiation - High	S	M	R	1, 2, 3
f. Outside Atmosphere To Reactor Enclosure Δ Pressure - Low	N.A.	M	Q	1, 2, 3
g. Deleted				
h. Drywell Pressure - High/ Reactor Pressure - Low	S	M	R	1, 2, 3
i. Primary Containment Instrument Gas to Drywell Δ Pressure - Low	N.A.	M	Q	1, 2, 3
j. Manual Initiation	N.A.	R	N.A.	1, 2, 3

TABLE 3.3.3-1

EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION

TRIP FUNCTION	MINIMUM OPERABLE CHANNELS PER TRIP FUNCTION(a)	APPLICABLE OPERATIONAL CONDITIONS	ACTION
1. CORE SPRAY SYSTEM***			
a. Reactor Vessel Water Level - Low Low Low, Level 1	2/pump(b)	1, 2, 3, 4*, 5*	30
b. Drywell Pressure - High	2/pump(b)	1, 2, 3	30
c. Reactor Vessel Pressure - Low (Permissive)	6(b)	1, 2, 3 4*, 5*	31 32
d. Manual Initiation	2(e)	1, 2, 3, 4*, 5*	33
2. LOW PRESSURE COOLANT INJECTION MODE OF RHR SYSTEM***			
a. Reactor Vessel Water Level - Low Low Low, Level 1	2	1, 2, 3, 4*, 5*	30
b. Drywell Pressure - High	2	1, 2, 3	30
c. Reactor Vessel Pressure - Low (Permissive)	2	1, 2, 3	31
d. Injection Valve Differential Pressure-Low (Permissive)	1/valve	1, 2, 3, 4*, 5*	31
e. Manual Initiation	1	1, 2, 3, 4*, 5*	33
3. HIGH PRESSURE COOLANT INJECTION SYSTEM##			
a. Reactor Vessel Water Level - Low Low Level 2	4	1, 2, 3	34
b. Drywell Pressure - High	4	1, 2, 3	34
c. Condensate Storage Tank Level - Low	2(c)	1, 2, 3	35
d. Suppression Pool Water Level - High	2	1, 2, 3	35
e. Reactor Vessel Water Level - High, Level 8	4(d)	1, 2, 3	31
f. Manual Initiation	1/system	1, 2, 3	33

TABLE 3.3.3-1 (Continued)

EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION

TRIP FUNCTION	MINIMUM OPERABLE CHANNELS PER TRIP FUNCTION(a)	APPLICABLE OPERATIONAL CONDITIONS	ACTION
4. AUTOMATIC DEPRESSURIZATION SYSTEM#***			
a. Reactor Vessel Water Level - Low Low Low, Level 1	2	1, 2, 3	30
b. Drywell Pressure - High	2	1, 2, 3	30
c. ADS Timer	1	1, 2, 3	31
d. Core Spray Pump Discharge Pressure - High (Permissive)	2	1, 2, 3	31
e. RHR LPCI Mode Pump Discharge Pressure High (Permissive)	4	1, 2, 3	31
f. Reactor Vessel Water Level - Low, Level 3 (Permissive)	1	1, 2, 3	31
g. Manual Initiation	2	1, 2, 3	33
h. ADS Drywell Pressure Bypass Timer	2	1, 2, 3	31

TRIP FUNCTION	TOTAL NO. OF CHANNELS(f)	CHANNELS TO TRIP	MINIMUM CHANNELS OPERABLE	APPLICABLE OPERATIONAL CONDITIONS	ACTION
5. LOSS OF POWER					
1. 4.16 kV Emergency Bus Under-voltage (Loss of Voltage)	1/bus	1/bus	1/bus	1,2,3,4**,5**	36
2. 4.16 kV Emergency Bus Under-voltage (Degraded Voltage)	1/source/bus	1/source/bus	1/source/bus	1,2,3,4**,5**	37

***The Minimum OPERABLE Channels Per Trip Function is per subsystem.

TABLE 3.3.3-2

EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION SETPOINTS

TRIP FUNCTION	TRIP SETPOINT	ALLOWABLE VALUE
1. CORE SPRAY SYSTEM		
a. Reactor Vessel Water Level - Low Low Low, Level 1	$\geq$ -129 inches*	$\geq$ -136 inches
b. Drywell Pressure - High	$\leq$ 1.68 psig	$\leq$ 1.88 psig
c. Reactor Vessel Pressure - Low	$\geq$ 455 psig,(decreasing)	$\geq$ 435 psig, (decreasing)
d. Manual Initiation	N.A.	N.A.
2. LOW PRESSURE COOLANT INJECTION MODE OF RHR SYSTEM		
a. Reactor Vessel Water Level - Low Low Low, Level 1	$\geq$ -129 inches*	$\geq$ -136 inches
b. Drywell Pressure - High	$\leq$ 1.68 psig	$\leq$ 1.88 psig
c. Reactor Vessel Pressure - Low	$\geq$ 455 psig,(decreasing)	$\geq$ 435 psig, (decreasing)
d. Injection Valve Differential Pressure - Low	$\geq$ 74 psid, (decreasing)	$\geq$ 64 psid and $\leq$ 84 psid
e. Manual Initiation	N.A.	N.A.
3. HIGH PRESSURE COOLANT INJECTION SYSTEM		
a. Reactor Vessel Water Level - Low Low, Level 2	$\geq$ -38 inches*	$\geq$ -45 inches
b. Drywell Pressure - High	$\leq$ 1.68 psig	$\leq$ 1.88 psig
c. Condensate Storage Tank Level - Low	$\geq$ 167.8 inches**	$\geq$ 164.3 inches
d. Suppression Pool Water Level - High	$\leq$ 24 feet 1.5 inches	$\leq$ 24 feet 3 inches
e. Reactor Vessel Water Level - High, Level 8	$\leq$ 54 inches	$\leq$ 60 inches
f. Manual Initiation	N.A.	N.A.
4. AUTOMATIC DEPRESSURIZATION SYSTEM		
a. Reactor Vessel Water Level - Low Low Low, Level 1	$\geq$ -129 inches*	$\geq$ -136 inches
b. Drywell Pressure - High	$\leq$ 1.68 psig	$\leq$ 1.88 psig
c. ADS Timer	$\leq$ 105 seconds	$\leq$ 117 seconds
d. Core Spray Pump Discharge Pressure - High	$\geq$ 145 psig,(increasing)	$\geq$ 125 psig, (increasing),
e. RHR LPCI Mode Pump Discharge Pressure-High	$\geq$ 125 psig,(increasing)	$\geq$ 115 psig, (increasing)
f. Reactor Vessel Water Level-Low, Level 3	$\geq$ 12.5 inches	$\geq$ 11.0 inches
g. Manual Initiation	N.A.	N.A.
h. ADS Drywell Pressure Bypass Timer	$\leq$ 420 seconds	$\leq$ 450 seconds

*See Bases Figure B 3/4.3-1.

**Corresponds to 2.3 feet indicated.

TABLE 3.3.3-2 (Continued)
EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION SETPOINTS

TRIP FUNCTION	RELAY		TRIP SETPOINT	ALLOWABLE VALUE
5. LOSS OF POWER				
a. 4.16 kV Emergency Bus Undervoltage (Loss of Voltage)	127-11X		NA	NA
b. 4.16 kV Emergency Bus Undervoltage (Degraded Voltage)				
	127-11X0X and 102-11X0X	a.	4.16 kV Basis 2905 ± 115 volts	2905 ± 145 volts
		b.	120 V Basis 83 ± 3 volts	83 ± 4 volts
		c.	≤ 1 second time delay	≤ 1.5 second time delay
	127Y-11X0X** and 127Y-1-11X0X	a.	4.16 kV Basis 3640 ± 91 volts	3640 ± 182 volts
		b.	120 V Basis 104 ± 3 volts	104 ± 5.2 volts
		c.	≤ 52 second time delay	≤ 60 second time delay
	127Z-11X0X and 162Y-11X0X	a.	4.16 kV Basis 3910 ± 11 volts	3910 ± 19 volts
		b.	120 V Basis 111.7 ± 0.3 volts	111.7 ± 0.5 volts
		c.	≤ 10 second time delay	≤ 11 second time delay
	127Z-11X0X and 162Z-11X0X	a.	4.16 kV Basis 3910 ± 11 volts	3910 ± 19 volts
		b.	120 V Basis 111.7 ± 0.3 volts	111.7 ± 0.5 volts
		c.	≤ 61 second time delay	≤ 64 second time delay

**This is an inverse time delay voltage relay. The voltages shown are the maximum that will not result in a trip. Some voltage conditions will result in decreased trip times.

TABLE 3.3.5-2

REACTOR CORE ISOLATION COOLING SYSTEM ACTUATION INSTRUMENTATION SETPOINTS

FUNCTIONAL UNITS	TRIP SETPOINT	ALLOWABLE VALUE
a. Reactor Vessel Water Level - Low Low, Level 2	$\geq$-38 inches*	$\geq$-45 inches
b. Reactor Vessel Water Level - High, Level 8	$\leq$ 54 inches	$\leq$ 60 inches
c. Condensate Storage Tank Level - Low	$\geq$ 135.8** inches	$\geq$ 132.3 inches
d. Manual Initiation	N.A.	N.A.

*See Bases Figure B 3/4.3-1.

**Corresponds to 2.3 feet indicated.

TABLE 4.3.5.1-1

REACTOR CORE ISOLATION SYSTEM ACTUATION INSTRUMENTATION SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNITS	CHANNEL CHECK	CHANNEL FUNCTIONAL TEST	CHANNEL CALIBRATION
a. Reactor Vessel Water Level - Low Low, Level 2	S	M	R
b. Reactor Vessel Water Level - High, Level 8	S	M	R
c. Condensate Storage Tank Level - Low	S	M	R
d. Manual Initiation	N.A.	R	N.A.

TABLE 3.3.7.4-1

REMOTE SHUTDOWN SYSTEM INSTRUMENTATION AND CONTROLS

INSTRUMENT	MINIMUM INSTRUMENTS OPERABLE
1. Reactor Vessel Pressure	1
2. Reactor Vessel Water Level	1
3. Safety/Relief Valve Position, 3 valves	1/valve
4. Suppression Chamber Water Level	1
5. Suppression Chamber Water Temperature (Actually RHR Pump "A" Suction Temperature)	1
6. Drywell Pressure	1
7. Drywell Temperature	1
8. RHR System Flow	1
9. RHR Service Water Pump Discharge Pressure	1
10. RHR Heat Exchanger Service Water Outlet Pressure	1
11. RCIC System Flow	1
12. RCIC Turbine Speed	1
13. Emergency Service Water Pump Discharge Pressure	1
14. Condensate Storage Tank Level	1
15. RHR Heat Exchanger Bypass Valve (HV51-1F048A) Position Indication (0 - 100%)	1
16. RCIC Turbine Tripped Indication	1
17. RCIC Turbine Bearing Oil Pressure Low Indication	1
18. RCIC LP Bearing Oil Temperature High Indication	1
19. RHR Heat Exchanger Discharge Line High Radiation Indication	1

TABLE 3.3.7.4-1 (Continued)

REMOTE SHUTDOWN SYSTEM CONTROLS

RCIC SYSTEM

HSS-49-191	Control-Transfer Switch
HSS-49-192	Control-Transfer Switch
HSS-49-193	Control-Transfer Switch
HSS-49-195	Control-Transfer Switch
HSS-49-196	Control-Transfer Switch
HV-49-1F076	Control-Steam Line warmup bypass valve
HV-49-1F060	Control-RCIC turb exhaust to suppression pool isolation
HV-50-112	Control-Turb trip throttle valve
HV-50-1F045	Control-Turbine steam supply valve
HV-49-1F008	Control-Turbine steam line outboard isolation valve
HV-49-1F007	Control-Turbine steam line inboard isolation valve
HV-49-1F031	Control-RCIC pump suction from suppression pool
HV-49-1F029	Control-RCIC pump suction from suppression pool
HV-49-1F010	Control-RCIC pump suction from condensate storage tank
HV-49-1F019	Control-Minimum flow bypass to suppression pool
HV-49-1F022	Control-Test return to condensate storage tank
HV-50-1F046	Control-RCIC turbine cooling water valve
HV-49-1F012	Control-RCIC pump disch valve
HV-49-1F013	Control-RCIC pump disch valve
10P220	Control-Vacuum tank condensate pump
10P219	Control-Barometric condenser vacuum pump
HV-49-1F002	Control-Barometric condenser vacuum pump disch

Table 3.3.7.4-1 (Continued)

RHR SERVICE WATER SYSTEM (Continued)

HSS-12-094	Control-Transfer switch
HSS-12-093	Control-Transfer switch
HV-51-1F014A	Control-1A RHR heat exchanger tube side inlet
OAP506	Control-RHR Service Water pump
HV-51-1F068A	Control-1A RHR Heat exchanger tube side outlet

EMERGENCY SERVICE WATER SYSTEM

OAP548	Control-A emergency service water pump
HV-11-011A	Control-A emergency service water disch to RHR service water
HSS-11-091	Control-Transfer switch
HSS-11-092	Control-Transfer switch
HSS-11-093	Control-Transfer switch

The following valves of the ESW and RHRSW systems are actuated by signals from the transfer switches:

HV-12-005	ESW and RHRSW pumps wetwell intertie gate
HV-11-015A	ESW loop A discharge to RHRSW loop B
HV-12-017A	ESW and RHRSW cooling tower return cross-tie

STANDBY AC POWER SUPPLY

152-11509/CSR	101-D11 Safeguard SWGR feeder bkr.
152-11609/CSR	101-D12 Safeguard SWGR feeder bkr.
152-11709/CSR	101-D13 Safeguard SWGR feeder bkr.
152-11502/CSR	201-D11 Safeguard SWGR feeder bkr.
152-11602/CSR	201-D12 Safeguard SWGR feeder bkr.
152-11702/CSR	201-D13 Safeguard SWGR feeder bkr.
152-11505/CSR	D114 Safeguard LC XFMR breaker

Table 3.3.7.4-1 (Continued)

STANDBY AC POWER SUPPLY (Continued)

152-11605/CSR	D124 Safeguard LC XFMR breaker
152-11705/CSR	D134 Safeguard LC XFMR breaker
143-115/CS	Transfer switch
143-116/CS	Transfer switch
143-117/CS	Transfer switch

TABLE 3.3.7.9-1

FIRE DETECTION INSTRUMENTATION

INSTRUMENT LOCATION				TOTAL NUMBER OF INSTRUMENTS*		
FIRE ZONE	STRUCTURE	ELEV.	AREA	HEAT (x/y)	SMOKE (x/y)	FLAME (x/y)
1L	Control	200'	Control Structure Chillers and Chilled Water Pump Area 258	NA	3/0	NA
1M	Control	200'	Control Structure Chillers and Chilled Water Pump Area 263	NA	3/0	NA
2	Control	217'	13-kV Switchgear Area 336	NA	34/0	NA
3	Control	217'	Battery Room 323 (1D)	1/0	1/0	NA
4	Control	217'	Battery Room 324 (1C)	1/0	1/0	NA
7	Control	239'	Corridor 437	NA	5/0	NA
8	Control	239'	Battery Room 425 (1B1/1B2)	1/0	2/0	NA
9	Control	239'	Battery Room 436 (1A1/1A2)	1/0	2/0	NA
12	Control	239'	4-kV Switchgear Compartment 434 (D13)	2/0	2/0	NA
13	Control	239'	4-kV Switchgear Compartment 435 (D11)	2/0	2/0	NA
14	Control	239'	4-kV Switchgear Compartment 432 (D14)	2/0	2/0	NA
15	Control	239'	4-kV Switchgear Compartment 433 (D12)	2/0	2/0	NA
20	Control	254'	Static Inverter Room Unit 1, Area 452	NA	4/0	NA
22	Control	254'	Cable Spreading Room Unit 1, Area 449	NA	14/0	NA
24A	Control	269'	Control Room 533	NA	23(a)/0 11(b)/0	NA
24B	Control	269'	Control Room Utility Room 529	NA	1/0	NA
24C	Control	269'	Control Room Office 531	NA	1/0	NA
24D	Control	269'	Control Room Shift Supt. 536	NA	1/0	NA
24E	Control	269'	Control Room Shop 534	NA	1/0 (Photo-Elect)	NA
24F	Control	269'	Control Room Instrument Lab 535	NA	1/0 (Photo-Elect)	NA
24G	Control	269'	Control Room Shift Supt. 532	NA	1/0	NA

TABLE 3.3.7.9-1 (Continued)

FIRE DETECTION INSTRUMENTATION

INSTRUMENT LOCATION				TOTAL NUMBER OF INSTR		
FIRE ZONE	STRUCTURE	ELEV.	AREA	HEAT (x/y)	SMOKE (x/y)	FLAME (x/y)
25	Control	289'	Auxiliary Equipment Room 542	0/112 (PGCC Floor) 0/13 (Non-PGCC Floor)	57/0 (Ceiling) 56/0 (PGCC Floor) 14/0 (Non-PGCC Floor) 32/0 (Terminal Cabinets)	NA
26	Control	289'	Remote Shutdown Panel Area 540	0/4 (Non-PGCC Floor)	3/0 (Ceiling Level) 2/0 (Non-PGCC Floor)	NA
27	Control	304'	Control Structure Fan Room 619	0/23 4/0 (inside plenum)	10/0	NA
28A	Control	332'	SGTS Access Area 625 (SGTS Room Ventilation Exhaust)	4/0 (inside plenum)	NA	NA
28B	Control	332'	SGTS Filter Compartment 624	4/0 (inside plenum)	NA	NA
28C	Control	332'	Control Room Fresh Air Intake Plenum	NA	3/0	NA
31	Unit 1 Reactor	177'	RHR Heat Exchanger & Pump Room 103 (B&D)	NA	6/0	NA
32	Unit 1 Reactor	177'	RHR Heat Exchanger & Pump Room 102 (A&C)	NA	5/0	NA
33	Unit 1 Reactor	177'	RCIC Pump Room 108	0/3	2/0	NA
34	Unit 1 Reactor	177'	HPCI Pump Room 109	0/4	3/0	NA
35	Unit 1 Reactor	177'	'A' Core Spray Pump Room 110	NA	2/0	NA

TABLE 3.3.7.9-1 (Continued)

FIRE DETECTION INSTRUMENTATION

INSTRUMENT LOCATION				TOTAL NUMBER OF INSTRUMENTS*		
FIRE ZONE	STRUCTURE	ELEV.	AREA	HEAT (x/y)	SMOKE (x/y)	FLAME (x/y)
36	Unit 1 Reactor	177'	'C' Core Spray Pump Room 113	NA	2/0	NA
37	Unit 1 Reactor	177'	'D' Core Spray Pump Room 114	NA	2/0	NA
38	Unit 1 Reactor	177'	'B' Core Spray Pump Room 117	NA	2/0	NA
39	Unit 1 Reactor	177'	Sump Room 115; Passageway 118	NA	4/0	NA
40	Unit 1 Reactor	177'	Corridor 111	NA	2/0	NA
41	Unit 1 Reactor	201'	RECW Equipment Area 207	0/10	3/0	NA
42A	Unit 1 Reactor	201'	Safeguard System Access Area 200	0/12	3/0	NA
43	Unit 1 Reactor	217'	Safeguard System Isolation Valve Area 309	NA	8/0	NA
44	Unit 1 Reactor	217'	Safeguard System Access Area 304	0/8 (Southwest) 0/14 (Northeast)	27/0	NA
45A	Unit 1 Reactor	253'	CRD Hydraulic Equipment Area 402	0/16	20/0	NA
45B	Unit 1 Reactor	253'	Neutron Monitoring System Area 406	0/2	2/0	NA
45C	Unit 1 Reactor	253'	CRD Repair Room 403	NA	1/0	NA
47A	Unit 1 Reactor	283'	Corridor 506; General Equipment Area 500	0/18	21/0	NA
47B	Unit 1 Reactor	295'	Isolation Valve Compartment 523	NA	2/0	NA
47C	Unit 1 Reactor	283'	Fuel Pool Cooling Water Pump and Heat Exchanger Area 511	NA	2/0	NA
47D	Unit 1 Reactor	283'	Isolation Valve Compartment 510/522	NA	1/0	NA

TABLE 3.3.7.9-1 (Continued)

FIRE DETECTION INSTRUMENTATION

INSTRUMENT LOCATION				TOTAL NUMBER OF INSTRUMENTS*		
FIRE ZONE	STRUCTURE	ELEV.	AREA	HEAT (x/y)	SMOKE (x/y)	FLAME (x/y)
48A	Unit 1 Reactor	313'	Laydown Areas 601 and 602; Corridor and RERS Fan Area 605	NA	8/0	NA
51A	Unit 1 Reactor	331'	RERS Filter Compartment 618	2/0 (inside plenum)	NA	NA
51B	Unit 1 Reactor	331'	RERS Filter Compartment 612	2/0 (inside plenum)	NA	NA
79	Diesel-Generator	217'	Diesel-Generator Cell Unit 1	1/5	4/0	1/0
80	Diesel-Generator	217'	Diesel-Generator Cell Unit 1	1/5	4/0	1/0
81	Diesel-Generator	217'	Diesel-Generator Cell Unit 1	1/5	4/0	1/0
82	Diesel-Generator	217'	Diesel-Generator Cell Unit 1	1/5	4/0	1/0
122A	Spray Pond Pump Structure	268'	ESW and RHRSW Pump Area	NA	4/0	NA
122E	Spray Pond Pump Structure	251'	RHRSW Valve Compartment	NA	2/0	NA
123A	Spray Pond Pump Structure	268'	ESW and RHRSW Pump Area	NA	4/0	NA
123E	Spray Pond Pump Structure	251'	RHRSW Valve Compartment	NA	2/0	NA
124A	Diesel-Generator	217'	Diesel-Generator Access Corridor 313	NA	4/0	NA
126A	Common Reactor	412'	North Stack Instrument Room 713	NA	2/0	NA

* (x/y): X is the number of Function A (Early Warning Fire Detection and Notification Only) Instruments.

Y is the number of Function B (Activation of Fire Suppression System and Early Warning Notification) Instruments.

(a) These smoke detectors are located below the suspended ceiling in the Control Room.

(b) These smoke detectors are located above the suspended ceiling in the Control Room.

INSTRUMENTATION

RADIOACTIVE GASEOUS EFFLUENT MONITORING INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.7.12 The radioactive gaseous effluent monitoring instrumentation channels shown in Table 3.3.7.12-1 shall be OPERABLE with their alarm/trip setpoints set to ensure that the limits of Specification 3.11.2.1 are not exceeded. The alarm/trip setpoints* of the applicable channels shall be determined in accordance with the methodology and parameters in the ODCM.

APPLICABILITY: As shown in Table 3.3.7.12-1

ACTION:

a. With a radioactive gaseous effluent monitoring instrumentation channel alarm/trip setpoint less conservative than required by the above Specification, immediately suspend the release of radioactive gaseous effluents monitored by the affected channel or declare the channel inoperable.

b. With less than the minimum number of radioactive gaseous effluent monitoring instrumentation channels OPERABLE, take the ACTION shown in Table 3.3.7.12-1. Restore the inoperable instrumentation to OPERABLE status within the time specified in the ACTION or explain why this inoperability was not corrected in a timely manner in the next Semiannual Radioactive Effluent Release Report.

c. The provisions of Specifications 3.0.3 and 3.0.4 are not applicable.

SURVEILLANCE REQUIREMENTS

4.3.7.12 Each radioactive gaseous effluent monitoring instrumentation channel shall be demonstrated OPERABLE by performance of the CHANNEL CHECK, SOURCE CHECK, CHANNEL CALIBRATION, and CHANNEL FUNCTIONAL TEST operations at the frequencies shown in Table 4.3.7.12-1.

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*The alarm/trip setpoints for the Main Condenser Offgas Treatment System Explosive Gas Monitoring System and the Main Condenser Offgas Pretreatment Radiation Monitor are set in accordance with Specification 3.11.2.5 and 3.11.2.6, respectively.

TABLE 3.3.7.12-1

RADIOACTIVE GASEOUS EFFLUENT MONITORING INSTRUMENTATION

INSTRUMENT	MINIMUM CHANNELS OPERABLE	APPLICABILITY	ACTION
1. MAIN CONDENSER OFFGAS TREATMENT SYSTEM EXPLOSIVE GAS MONITORING SYSTEM			
a. Hydrogen Monitor	1	**	110
2. SOUTH STACK EFFLUENT MONITORING SYSTEM			
a. Noble Gas Activity Monitor	1	*	111
b. Iodine Sampler	1	*	112
c. Particulate Sampler	1	*	112
d. Effluent System Flow Rate Monitor	1	*	113
e. Sampler Flow Rate Monitor	1	*	113
3. NORTH STACK EFFLUENT MONITORING SYSTEM			
a. Noble Gas Activity Monitor	1	*	114
b. Iodine Sampler	1	*	112
c. Particulate Sampler	1	*	112
d. Effluent System Flow Rate Monitor	1	*	113
e. Sampler Flow Rate Monitor	1	*	113

b. At least once per 31 days by:

1. Cycling each of the following valves through at least one complete cycle from the running position:

a) For the overspeed protection control system;

1) Four high pressure turbine control valves

b) For the electrical overspeed trip system and the mechanical overspeed trip system;

1) Four high pressure turbine control valves

c. At least once per 18 months by performance of a CHANNEL CALIBRATION of the turbine overspeed protection instrumentation.

d. At least once per 40 months by disassembling at least one of each of the above valves and performing a visual and surface inspection of all valve seats, disks and stems and verifying no unacceptable flaws or excessive corrosion. If unacceptable flaws or excessive corrosion are found, all other valves of that type shall be inspected.

3/4.3.9 FEEDWATER/MAIN TURBINE TRIP SYSTEM ACTUATION INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.9 The feedwater/main turbine trip system actuation instrumentation channels shown in Table 3.3.9-1 shall be OPERABLE with their trip setpoints set consistent with the values shown in the Trip Setpoint column of Table 3.3.9-2.

APPLICABILITY: As shown in Table 3.3.9-1.

ACTION:

a. With a feedwater/main turbine trip system actuation instrumentation channel trip setpoint less conservative than the value shown in the Allowable Values column of Table 3.3.9-2, declare the channel inoperable and either place the inoperable channel in the tripped condition until the channel is restored to OPERABLE status with its trip setpoint adjusted consistent with the Trip Setpoint value, or declare the associated system inoperable.

b. With the number of OPERABLE channels one less than required by the Minimum OPERABLE Channels requirement, restore the inoperable channel to OPERABLE status within 7 days or be in at least STARTUP within the next 6 hours.

c. With the number of OPERABLE channels two less than required by the Minimum OPERABLE Channels requirement, restore at least one of the inoperable channels to OPERABLE status within 72 hours or be in at least STARTUP within the next 6 hours.

SURVEILLANCE REQUIREMENTS

4.3.9.1 Each feedwater/main turbine trip system actuation instrumentation channel shall be demonstrated OPERABLE by the performance of the CHANNEL CHECK, CHANNEL FUNCTIONAL TEST, and CHANNEL CALIBRATION operations for the OPERATIONAL CONDITIONS and at the frequencies shown in Table 4.3.9.1-1.

4.3.9.2 LOGIC SYSTEM FUNCTIONAL TESTS and simulated automatic operation of all channels shall be performed at least once per 18 months.

OPERATIONAL LEAKAGE

LIMITING CONDITION FOR OPERATION

3.4.3.2 Reactor coolant system leakage shall be limited to:

a. No PRESSURE BOUNDARY LEAKAGE.

b. 5 gpm UNIDENTIFIED LEAKAGE.

c. 30 gpm total leakage.

d. 25 gpm total leakage averaged over any 24-hour period.

e. 1 gpm leakage at a reactor coolant system pressure of 950 ±10 psig from any reactor coolant system pressure isolation valve specified in Table 3.4.3.2-1.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, and 3.

ACTION:

a. With any PRESSURE BOUNDARY LEAKAGE, be in at least HOT SHUTDOWN within 12 hours and in COLD SHUTDOWN within the next 24 hours.

b. With any reactor coolant system leakage greater than the limits in b, c, and/or d., above, reduce the leakage rate to within the limits within 4 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

c. With any reactor coolant system pressure isolation valve leakage greater than the above limit, isolate the high pressure portion of the affected system from the low pressure portion within 4 hours by use of at least one other closed manual, deactivated automatic, or check* valves, or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

d. With one or more of the high/low pressure interface valve leakage pressure monitors shown in Table 3.4.3.2-1 inoperable, restore the inoperable monitor(s) to OPERABLE status within 7 days or verify the pressure to be less than the alarm setpoint at least once per 12 hours; restore the inoperable monitor(s) to OPERABLE status within 30 days or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

*Which have been verified not to exceed the allowable leakage limit at the last refueling outage or after the last time the valve was disturbed, whichever is more recent.

SURVEILLANCE REQUIREMENTS

4.4.3.2.1 The reactor coolant system leakage shall be demonstrated to be within each of the above limits by:

a. Monitoring the primary containment atmospheric gaseous radioactivity at least once per 12 hours (not a means of quantifying leakage),

b. Monitoring the drywell floor drain sump and drywell equipment drain tank flow rate at least once per 12 hours,

c. Monitoring the drywell unit coolers condensate flow rate at least once per 12 hours,

d. Monitoring the primary containment pressure at least once per 12 hours (not a means of quantifying leakage),

e. Monitoring the reactor vessel head flange leak detection system at least once per 24 hours, and

f. Monitoring the primary containment temperature at least once per 24 hours (not a means of quantifying leakage).

4.4.3.2.2 Each reactor coolant system pressure isolation valve specified in Table 3.4.3.2-1 shall be demonstrated OPERABLE by leak testing pursuant to Specification 4.0.5 and verifying the leakage of each valve to be within the specified limit:

a. At least once per 18 months, and

b. Prior to returning the valve to service following maintenance, repair or replacement work on the valve which could affect its leakage rate.

The provisions of Specification 4.0.4 are not applicable for entry into OPERATIONAL CONDITION 3.

4.4.3.2.3 The high/low pressure interface valve leakage pressure monitors shall be demonstrated OPERABLE with alarm setpoints set less than the allowable values in Table 3.4.3.2-1 by performance of a:

a. CHANNEL FUNCTIONAL TEST at least once per 31 days, and

b. CHANNEL CALIBRATION at least once per 18 months.

TABLE 4.4.5-1

PRIMARY COOLANT SPECIFIC ACTIVITY SAMPLE AND ANALYSIS PROGRAM

TYPE OF MEASUREMENT AND ANALYSIS	SAMPLE AND ANALYSIS FREQUENCY	OPERATIONAL CONDITIONS IN WHICH SAMPLE AND ANALYSIS IS REQUIRED
1. Gross Beta and Gamma Activity Determination	At least once per 72 hours	1, 2, 3
2. Isotopic Analysis for DOSE EQUIVALENT I-131 Concentration	At least once per 31 days	1
3. Radiochemical for $\bar{E}$ Determination	At least once per 6 months*	1
4. Isotopic Analysis for Iodine	a) At least once per 4 hours, whenever the specific activity exceeds a limit, as required by ACTION b.	1**, 2**, 3**, 4**
	b) At least one sample, between 2 and 6 hours following the change in THERMAL POWER or off-gas level, as required by ACTION c.	1, 2
5. Isotopic Analysis of an Off-gas Sample Including Quantitative Measurements for at least Xe-133, Xe-135, and Kr-88	At least once per 31 days	1

*Sample to be taken after a minimum of 2 EFPD and 20 days of POWER OPERATION have elapsed since reactor was last subcritical for 48 hours or longer.

**Until the specific activity of the primary coolant system is restored to within its limits.

3/4.4.6 PRESSURE/TEMPERATURE LIMITS

REACTOR COOLANT SYSTEM

LIMITING CONDITION FOR OPERATION

3.4.6.1 The reactor coolant system temperature and pressure shall be limited in accordance with the limit lines shown on Figure 3.4.6.1-1 (1) curves A and A' for hydrostatic or leak testing; (2) curves B and B' for heatup by non-nuclear means, cooldown following a nuclear shutdown and low power PHYSICS TESTS; and (3) curves C and C' for operations with a critical core other than low power PHYSICS TESTS, with:

a. A maximum heatup of 100°F in any 1-hour period,

b. A maximum cooldown of 100°F in any 1-hour period,

c. A maximum temperature change of less than or equal to 20°F in any 1-hour period during inservice hydrostatic and leak testing operations above the heatup and cooldown limit curves, and

d. The reactor vessel flange and head flange temperature greater than or equal to 80°F when reactor vessel head bolting studs are under tension.

APPLICABILITY: At all times.

ACTION:

With any of the above limits exceeded, restore the temperature and/or pressure to within the limits within 30 minutes; perform an engineering evaluation to determine the effects of the out-of-limit condition on the structural integrity of the reactor coolant system; determine that the reactor coolant system remains acceptable for continued operations or be in at least HOT SHUTDOWN within 12 hours and in COLD SHUTDOWN within the following 24 hours.

SURVEILLANCE REQUIREMENTS

4.4.6.1.1 During system heatup, cooldown and inservice leak and hydrostatic testing operations, the reactor coolant system temperature and pressure shall be determined to be within the above required heatup and cooldown limits and to the right of the limit lines of Figure 3.4.6.1-1 curves A and A', B and B', or C and C' as applicable, at least once per 30 minutes.

3/4.5.1 ECCS - OPERATING

LIMITING CONDITION FOR OPERATION

3.5.1 The emergency core cooling systems shall be OPERABLE with:

a. The core spray system (CSS) consisting of two subsystems with each subsystem comprised of:

1. Two OPERABLE CSS pumps, and

2. An OPERABLE flow path capable of taking suction from the suppression chamber and transferring the water through the spray sparger to the reactor vessel.

b. The low pressure coolant injection (LPCI) system of the residual heat removal system consisting of four subsystems with each subsystem comprised of:

1. One OPERABLE LPCI pump, and

2. An OPERABLE flow path capable of taking suction from the suppression chamber and transferring the water to the reactor vessel.

c. The high pressure coolant injection (HPCI) system consisting of:

1. One OPERABLE HPCI pump, and

2. An OPERABLE flow path capable of taking suction from the suppression chamber and transferring the water to the reactor vessel.

d. The automatic depressurization system (ADS) with at least five OPERABLE ADS valves.

APPLICABILITY: OPERATIONAL CONDITION 1, 2* ** #, and 3* ** ##.

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*The HPCI system is not required to be OPERABLE when reactor steam dome pressure is less than or equal to 200 psig.

**The ADS is not required to be OPERABLE when reactor steam dome pressure is less than or equal to 100 psig.

#See Special Test Exception 3.10.6.

##Two LPCI subsystems of the RHR system may be inoperable in that they are aligned in the shutdown cooling mode when reactor vessel pressure is less than the RHR Shutdown cooling permissive setpoint.

LIMITING CONDITION FOR OPERATION (Continued)

ACTION:

a. For the core spray system:

1. With one CSS subsystem inoperable, provided that at least two LPCI subsystems are OPERABLE, restore the inoperable CSS subsystem to OPERABLE status within 7 days or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

2. With both CSS subsystems inoperable, be in at least HOT SHUTDOWN within 12 hours and in COLD SHUTDOWN within the next 24 hours.

b. For the LPCI system:

1. With one LPCI subsystem inoperable, provided that at least one CSS subsystem is OPERABLE, restore the inoperable LPCI pump to OPERABLE status within 30 days or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

2. With one RHR cross-tie valve (HV-51-182 A or B) open, or power not removed from one closed RHR cross-tie valve operator, close the open valve and/or remove power from the closed valves operator within 72 hours, or be in at least HOT SHUTDOWN within 12 hours and in COLD SHUTDOWN within the next 24 hours.

3. With no RHR cross-tie valves (HV-51-182 A, B) closed, or power not removed from both closed RHR cross-tie valve operators, or with one RHR cross-tie valve open and power not removed from the other RHR cross-tie valve operator, be in at least HOT SHUTDOWN within 12 hours and in COLD SHUTDOWN within the next 24 hours.

4. With two LPCI subsystems inoperable, provided that at least one CSS subsystem is OPERABLE, restore at least three LPCI subsystems to OPERABLE status within 7 days or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

5. With three LPCI subsystems inoperable, provided that both CSS subsystems are OPERABLE, restore at least two LPCI subsystems to OPERABLE status within 72 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

6. With all four LPCI subsystems inoperable, be in at least HOT SHUTDOWN within 12 hours and in COLD SHUTDOWN within the next 24 hours.*

c. For the HPCI system, provided the CSS, the LPCI system, the ADS and the RCIC system are OPERABLE:

1. With the HPCI system inoperable, restore the HPCI system to OPERABLE status within 14 days or be in at least HOT SHUTDOWN within the next 12 hours and reduce reactor steam dome pressure to $\leq$ 200 psig within the following 24 hours.

*Whenever both shutdown cooling subsystems are inoperable, if unable to attain COLD SHUTDOWN as required by this ACTION, maintain reactor coolant temperature as low as practical by use of alternate heat removal methods.

LIMITING CONDITION FOR OPERATION (Continued)

ACTION: (Continued)

d. For the ADS:

1. With one of the above required ADS valves inoperable, provided the HPCI system, the CSS and the LPCI system are OPERABLE, restore the inoperable ADS valve to OPERABLE status within 14 days or be in at least HOT SHUTDOWN within the next 12 hours and reduce reactor steam dome pressure to ≤ 100 psig within the next 24 hours.

2. With two or more of the above required ADS valves inoperable, be in at least HOT SHUTDOWN within 12 hours and reduce reactor steam dome pressure to ≤ 100 psig within the next 24 hours.

e. With a CSS and/or LPCI header ΔP instrumentation channel inoperable, restore the inoperable channel to OPERABLE status within 72 hours or determine the ECCS header ΔP locally at least once per 12 hours; otherwise, declare the associated CSS and/or LPCI, as applicable, inoperable.

f. In the event an ECCS system is actuated and injects water into the reactor coolant system, a Special Report shall be prepared and submitted to the Commission pursuant to Specification 6.9.2 within 90 days describing the circumstances of the actuation and the total accumulated actuation cycles to date. The current value of the usage factor for each affected safety injection nozzle shall be provided in this Special Report whenever its value exceeds 0.70.

SURVEILLANCE REQUIREMENTS

4.5.1 The emergency core cooling systems shall be demonstrated OPERABLE by:

a. At least once per 31 days:

1. For the CSS, the LPCI system, and the HPCI system:

   a) Verifying by venting at the high point vents that the system piping from the pump discharge valve to the system isolation valve is filled with water.

   b) Verifying that each valve (manual, power-operated, or automatic) in the flow path that is not locked, sealed, or otherwise secured in position, is in its correct* position.

2. For the LPCI system, verifying that both LPCI system subsystem cross-tie valves (HV-51-182 A, B) are closed with power removed from the valve operators.

3. For the HPCI system, verifying that the HPCI pump flow controller is in the correct position.

4. For the CSS and LPCI system, performance of a CHANNEL FUNCTIONAL TEST of the injection header ΔP instrumentation.

b. Verifying that, when tested pursuant to Specification 4.0.5:

1. Each CSS pump in each subsystem develops a flow of at least 3175 gpm against a test line pressure corresponding to a reactor vessel to primary containment differential pressure of $\geq$ 105 psid plus head and line losses.

2. Each LPCI pump in each subsystem develops a flow of at least 10,000 gpm against a test line pressure corresponding to a reactor vessel to primary containment differential pressure of $\geq$ 20 psid plus head and line losses.

3. The HPCI pump develops a flow of at least 5600 gpm against a test line pressure which corresponds to a reactor vessel pressure of 1000 psig plus head and line losses when steam is being supplied to the turbine at 1000, +20, -80 psig.**

c. At least once per 18 months:

1. For the CSS, the LPCI system, and the HPCI system, performing a system functional test which includes simulated automatic actuation of the system throughout its emergency operating sequence and verifying that each automatic valve in the flow path actuates to its correct position. Actual injection of coolant into the reactor vessel may be excluded from this test.

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*Except that an automatic valve capable of automatic return to its ECCS position when an ECCS signal is present may be in position for another mode of operation.

**The provisions of Specification 4.0.4 are not applicable, provided the surveillance is performed within 12 hours after reactor steam pressure is adequate to perform the test. If OPERABILITY is not successfully demonstrated within the 12-hour period, reduce reactor steam dome pressure to less than 200 psig within the following 72 hours.

2. For the HPCI system, verifying that:

   a) The system develops a flow of at least 5600 gpm against a test line pressure corresponding to a reactor vessel pressure of $\geq$ 200 psig plus head and line losses, when steam is being supplied to the turbine at 200 + 15, - 0 psig.**

   b) The suction is automatically transferred from the condensate storage tank to the suppression chamber on a condensate storage tank water level - low signal and on a suppression chamber water level - high signal.

3. Performing a CHANNEL CALIBRATION of the CSS, LPCI, and HPCI system discharge line "keep filled" alarm instrumentation.

4. Performing a CHANNEL CALIBRATION of the CSS header ΔP instrumentation and verifying the setpoint to be $\leq$ the allowable value of 4.4 psid.

5. Performing a CHANNEL CALIBRATION of the LPCI header ΔP instrumentation and verifying the setpoint to be $\leq$ the allowable value of 3.0 psid.

d. For the ADS:

1. At least once per 31 days, performing a CHANNEL FUNCTIONAL TEST of the accumulator backup compressed gas system low pressure alarm system.

2. At least once per 18 months:

   a) Performing a system functional test which includes simulated automatic actuation of the system throughout its emergency operating sequence, but excluding actual valve actuation.

   b) Manually opening each ADS valve when the reactor steam dome pressure is greater than or equal to 100 psig** and observing that either:

      1) The control valve or bypass valve position responds accordingly, or

      2) There is a corresponding change in the measured steam flow.

   c) Performing a CHANNEL CALIBRATION of the accumulator backup compressed gas system low pressure alarm system and verifying an alarm setpoint of 90 ± 2 psig on decreasing pressure.

**The provisions of Specification 4.0.4 are not applicable, provided the surveillance is performed within 12 hours after reactor steam pressure is adequate to perform the test. If HPCI or ADS OPERABILITY is not successfully demonstrated within the 12-hour period, reduce reactor steam dome pressure to less than 200 psig or 100 psig, respectively within the following 72 hours.

3/4 5.2 ECCS - SHUTDOWN

LIMITING CONDITION FOR OPERATION

3.5.2 At least two of the following shall be OPERABLE:

a. Core spray system (CSS) subsystems with a subsystem comprised of:

1. Two OPERABLE CSS pumps, and

2. An OPERABLE flow path capable of taking suction from at least one of the following water sources and transferring the water through the spray sparger to the reactor vessel:

a) From the suppression chamber, or

b) When the suppression chamber water level is less than the limit or is drained, from the condensate storage tank containing at least 135,000 available gallons of water, equivalent to a level of 29 feet.

b. Low pressure coolant injection (LPCI) system subsystems with a subsystem comprised of:

1. One OPERABLE LPCI pump, and

2. An OPERABLE flow path capable of taking suction from the suppression chamber and transferring the water to the reactor vessel.

APPLICABILITY: OPERATIONAL CONDITIONS 4 and 5*.

ACTION:

a. With one of the above required subsystems inoperable, restore at least two subsystems to OPERABLE status within 4 hours or suspend all operations with a potential for draining the reactor vessel.

b. With both of the above required subsystems inoperable, suspend CORE ALTERATIONS and all operations with a potential for draining the reactor vessel. Restore at least one subsystem to OPERABLE status within 4 hours or establish SECONDARY CONTAINMENT INTEGRITY within the next 8 hours.

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*The ECCS is not required to be OPERABLE provided that the reactor vessel head is removed, the cavity is flooded, the spent fuel pool gates are removed, and water level is maintained within the limits of Specifications 3.9.8 and 3.9.9.

CONTAINMENT SYSTEMS

LIMITING CONDITION FOR OPERATION (Continued)

ACTION: (Continued)

b. The combined leakage rate for all penetrations and all valves listed in Table 3.6.3-1, except for main steam line isolation valves* and valves which are hydrostatically tested per Table 3.6.3-1, subject to Type B and C tests to less than or equal to 0.60 L_a, and

c. The leakage rate to less than or equal to 11.5 scf per hour for any one main steam line through the isolation valves, and

d. The combined leakage rate for all containment isolation valves in hydrostatically tested lines which pentrate the primary containment to less than or equal to 1 gpm times the total number of such valves,

prior to increasing reactor coolant system temperature above 200°F.

SURVEILLANCE REQUIREMENTS

4.6.1.2 The primary containment leakage rates shall be demonstrated at the following test schedule and shall be determined in conformance with the criteria specified in Appendix J of 10 CFR Part 50 using the methods and provisions of ANSI 45.4-1972 and BN-TOP-1 and verifying the result by the Mass Point Methodology described in ANSI N56.8-1981:

a. Three Type A Overall Integrated Containment Leakage Rate tests shall be conducted at 40 ± 10 month intervals during shutdown at P_a, 44.0 psig, during each 10-year service period. The third test of each set shall be conducted during the shutdown for the 10-year plant inservice inspection.

b. If any periodic Type A test fails to meet 0.75 L_a, the test schedule for subsequent Type A tests shall be reviewed and approved by the Commission. If two consecutive Type A tests fail to meet 0.75 L_a, a Type A test shall be performed at least every 18 months until two consecutive Type A tests meet 0.75 L_a, at which time the above test schedule may be resumed.

c. The accuracy of each Type A test shall be verified by a supplemental test which:

   1. Confirms the accuracy of the test by verifying that the difference between the supplemental data and the Type A test data is within 0.25 L_a. The formula to be used is: $[L_o + L_{am} - 0.25\ L_a] \le L_c \le [L_o + L_{am} + 0.25\ L_a]$ where L_c = supplemental test result; L_o = superimposed leakage; L_{am} = measured Type A leakage.

   2. Has duration sufficient to establish accurately the change in leakage rate between the Type A test and the supplemental test.

   3. Requires the quantity of gas injected into the containment or bled from the containment during the supplemental test to be between 0.75 L_a and 1.25 L_a.

*Exemption to Appendix "J" to 10 CFR Part 50.

SURVEILLANCE REQUIREMENTS (Continued)

d. Type B and C tests shall be conducted with gas at P_a, 44.0 psig*, at intervals no greater than 24 months except for tests involving:

   1. Air locks,

   2. Main steam line isolation valves,

   3. Containment isolation valves in hydrostatically tested lines which penetrate the primary containment, and

e. Air locks shall be tested and demonstrated OPERABLE per Surveillance Requirement 4.6.1.3.

f. Main steam line isolation valves shall be leak tested at least once per 18 months.

g. Containment isolation valves in hydrostatically tested lines which penetrate the primary containment shall be leak tested at least once per 18 months.

h. The provisions of Specification 4.0.2 are not applicable to Specifications 4.6.1.2a., 4.6.1.2b., 4.6.1.2c., 4.6.1.2d., and 4.6.1.2e.

*Unless a hydrostatic test is required per Table 3.6.3-1.

PRIMARY CONTAINMENT AIR LOCK

LIMITING CONDITION FOR OPERATION

3.6.1.3 The primary containment air lock shall be OPERABLE with:

a. Both doors closed except when the air lock is being used for normal transit entry and exit through the containment, then at least one air lock door shall be closed, and

b. An overall air lock leakage rate of less than or equal to 0.05 L_a at P_a, 44.0 psig.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2*, and 3.

ACTION:

a. With one primary containment air lock door inoperable:

1. Maintain at least the OPERABLE air lock door closed and either restore the inoperable air lock door to OPERABLE status within 24 hours or lock the OPERABLE air lock door closed.

2. Operation may then continue until performance of the next required overall air lock leakage test provided that the OPERABLE air lock door is verified to be locked closed at least once per 31 days.

3. Otherwise, be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

4. The provisions of Specification 3.0.4 are not applicable.

b. With the primary containment air lock inoperable, except as a result of an inoperable air lock door, maintain at least one air lock door closed; restore the inoperable air lock to OPERABLE status within 24 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

*See Special Test Exception 3.10.1.

SURVEILLANCE REQUIREMENTS

4.6.1.3 The primary containment air lock shall be demonstrated OPERABLE:

a. By verifying the seal leakage rate to be less than or equal to 5 scf per hour when the gap between the door seals is pressurized to 10 psig:

1. within 72 hours after each closing, except when the air lock is being used for multiple entries, then at least once per 72 hours; and

2. prior to establishing PRIMARY CONTAINMENT INTEGRITY when the air lock has been used and no maintenance has been performed on the air lock.**

b. By conducting an overall air lock leakage test at P_a, 44.0 psig, and by verifying that the overall air lock leakage rate is within its limit:

1. At least once per 6 months,* and

2. Prior to establishing PRIMARY CONTAINMENT INTEGRITY when maintenance has been performed on the air lock that could affect the air lock sealing capability.**

c. At least once per 6 months by verifying that only one door in the air lock can be opened at a time.***

*The provisions of Specification 4.0.2 are not applicable.

**Exemption to Appendix J, Paragraph III.D.2.(b)(ii) of 10 CFR Part 50.

***Except that the airlock doors need not be opened to verify interlock OPERABILITY when the primary containment is inerted, provided that the airlock doors' interlock is tested within 8 hours after the primary containment has been deinerted and provided the shield door to the airlock is maintained locked closed.

3/4.6.3 PRIMARY CONTAINMENT ISOLATION VALVES

LIMITING CONDITION FOR OPERATION

3.6.3 The primary containment isolation valves and the instrumentation line excess flow check valves shown in Table 3.6.3-1 shall be OPERABLE with isolation times less than or equal to those shown in Table 3.6.3-1.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, and 3.

ACTION:

a. With one or more of the primary containment isolation valves shown in Table 3.6.3-1 inoperable, maintain at least one isolation valve OPERABLE in each affected penetration that is open and within 4 hours either:

   1. Restore the inoperable valve(s) to OPERABLE status, or
   2. Isolate each affected penetration by use of at least one deactivated automatic valve secured in the isolated position,* or
   3. Isolate each affected penetration by use of at least one closed manual valve or blind flange.*
   4. The provisions of Specification 3.0.4 are not applicable provided that within 4 hours the affected penetration is isolated in accordance with ACTION a.2. or a.3. above, and provided that the associated system, if applicable, is declared inoperable and the appropriate ACTION statements for that system are performed.

   Otherwise, be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

b. With one or more of the instrumentation line excess flow check valves shown in Table 3.6.3-1 inoperable, operation may continue and the provisions of Specifications 3.0.3 and 3.0.4 are not applicable provided that within 4 hours either:

   1. The inoperable valve is returned to OPERABLE status, or
   2. The instrument line is isolated and the associated instrument is declared inoperable.

   Otherwise, be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

---

*Isolation valves closed to satisfy these requirements may be reopened on an intermittent basis under administrative control.

SURVEILLANCE REQUIREMENTS

4.6.3.1 Each primary containment isolation valve shown in Table 3.6.3-1 shall be demonstrated OPERABLE prior to returning the valve to service after maintenance, repair or replacement work is performed on the valve or its associated actuator, control or power circuit by cycling the valve through at least one complete cycle of full travel and verifying the specified isolation time.

4.6.3.2 Each primary containment automatic isolation valve shown in Table 3.6.3-1 shall be demonstrated OPERABLE during COLD SHUTDOWN or REFUELING at least once per 18 months by verifying that on a containment isolation test signal each automatic isolation valve actuates to its isolation position.

4.6.3.3 The isolation time of each primary containment power operated or automatic valve shown in Table 3.6.3-1 shall be determined to be within its limit when tested pursuant to Specification 4.0.5.

4.6.3.4 Each reactor instrumentation line excess flow check valve shown in Table 3.6.3-1 shall be demonstrated OPERABLE at least once per 18 months by verifying that the valve checks flow.

4.6.3.5 Each traversing in-core probe system explosive isolation valve shall be demonstrated OPERABLE:

a. At least once per 31 days by verifying the continuity of the explosive charge.

b. At least once per 18 months by removing the explosive squib from the explosive valve, such that each explosive squib in each explosive valve will be tested at least once per 90 months, and initiating the explosive squib. The replacement charge for the exploded squib shall be from the same manufactured batch as the one fired or from another batch which has been certified by having at least one of that batch successfully fired. No squib shall remain in use beyond the expiration of its shelf-life and/or operating life, as applicable.

TABLE 3.6.3-1

PART A - PRIMARY CONTAINMENT ISOLATION VALVES

PENETRATION NUMBER	FUNCTION	INBOARD ISOLATION BARRIER	OUTBOARD ISOLATION BARRIER	MAX. ISOL. TIME. IF APP. (SEC)(26)	ISOL. SIGNAL(S), IF APP. (20)	NOTES	P&ID
003B	CONTAINMENT INSTRUMENT GAS SUPPLY - HEADER 'B'	59-1005B (CK)		NA			59
			HV59-129B	7	C,H,S		
003D-2	CONTAINMENT INSTRUMENT GAS SUPPLY TO ADS VALVES E & K	59-1112(CK)		NA			
			HV59-151B	45	M		59
007A(B,C,D)	MAIN STEAM LINE 'A'(B,C,D)	HV41-1F022A (B,C,D)		5*	C,D,E,F,P,Q	6	41
			HV41-1F028A (B,C,D)	5*	C,D,E,F,P,Q	6	
			HV40-1F001B (F,K,P)	45	EA	6	
			(XV40-101B (F,K,P) SEE PART B, THIS TABLE)	NA		6,1	
008	MAIN STEAM LINE DRAIN	HV41-1F016		30	C,D,E,F,P,Q	4	41
			HV41-1F019	30	C,D,E,F,P,Q		
009A	FEEDWATER	41-1F010A(CK)		NA			41
			HV41-1F074A(CK)	NA			
			41-1036A(CK)	NA			
			HV41-130B	45			
			HV41-133A	45			
			HV41-109A	NA		32	
			HV41-1F032A(CK)	NA			
			HV55-1F105	30		7	
			HV44-1F039(CK) (X-9B)	NA			
			41-1016(X-9B, X-44)	NA		31	

TABLE 3.6.3-1 (Continued)

PART A - PRIMARY CONTAINMENT ISOLATION VALVES

PENETRATION NUMBER	FUNCTION	INBOARD ISOLATION BARRIER	OUTBOARD ISOLATION BARRIER	MAX. ISOL. TIME, IF APP. (SEC)(26)	ISOL. SIGNAL(S), IF APP. (20)	NOTES	P&ID
009B	FEEDWATER	41-1F010B(CK)		NA			
			HV41-1F074B(CK)	NA			41
			41-1036B(CK)	NA			
			HV41-130A	45			
			HV41-133B	45			
			HV41-109B	NA		32	
			HV41-1F032B(CK)	NA			
			HV49-1F013	23	LFCC		
			HV44-1F039(CK) (X-9A)	NA			
			41-1016(X-9A, X-44)	NA		31	
010	RCIC STEAM SUPPLY	HV49-1F007		7.2*	K, KA	5	49
			HV49-1F008	7.2*	K, KA		
			HV49-1F076	45	K, KA		
011	HPCI STEAM SUPPLY	HV55-1F002		12*	L, LA	5	55
			HV55-1F003	12*	L, LA		
			HV55-1F100	45	L, LA		
012	RHR SHUTDOWN COOLING SUPPLY	HV51-1F009		100	A,V	9,22	51
		PSV51-155		NA			
			HV51-1F008	100	A,V		
013A(B)	RHR SHUTDOWN COOLING RETURN	HV51-1F050A(B) (CK)		NA	A,V	9,22	51
		HV51-151A(B)		20	A,V		
			HV51-1F015A(B)	45	A,V		
014	RWCU - SUCTION	HV44-1F001		10*	B,J,Y		44
			HV44-1F004	10*	B,J,Y		

TABLE 3.6.3-1 (Continued)

PART A - PRIMARY CONTAINMENT ISOLATION VALVES

PENETRATION NUMBER	FUNCTION	INBOARD ISOLATION BARRIER	OUTBOARD ISOLATION BARRIER	MAX. ISOL. TIME. IF APP. (SEC)(26)	ISOL. SIGNAL(S), IF APP. (20)	NOTES	P&ID
016A	CORE SPRAY INJECTION	HV52-1F006A(CK)		NA		9,22	52
		HV52-1F039A		7		9,22	
			HV52-1F005	18			
016B	CORE SPRAY INJECTION	HV52-1F006B(CK)		NA		9,22	52
		HV52-1F039B		7		9,22	
			HV52-108(CK)	NA			
021	SERVICE AIR TO DRYWELL	15-1140		NA			15
			15-1139	NA			
022	DRYWELL PRESSURE INSTRUMENTATION		HV42-147C	45		10	42
023	RECW SUPPLY TO RECIRC PUMPS	HV13-106		40	C,H	11	13
			HV13-108	30	C,H	11	
			HV13-109	NA		11,13	
024	RECW RETURN FROM RECIRC PUMPS	HV13-107		40	C,H	11	13
			HV13-111	30	C,H	11	
			HV13-110	NA		11,13	

TABLE 3.6.3-1 (Continued)

PART A - PRIMARY CONTAINMENT ISOLATION VALVES

PENETRATION NUMBER	FUNCTION	INBOARD ISOLATION BARRIER	OUTBOARD ISOLATION BARRIER	MAX. ISOL. TIME, IF APP. (SEC)(26)	ISOL. SIGNAL(S), IF APP. (20)	NOTES	P&ID
025	DRYWELL PURGE SUPPLY	HV57-121(X-201A)		5**	B,H,S,U,W,R,T	3,11,14	57
		HV57-123		5**	B,H,S,U,W,R,T	3,11,14	
			HV57-109 (X-201A)	6**	B,H,S,U,W,R,T	11	
			HV57-131 (X-201A)	5**	B,H,S,U,W,R,T	11	
			HV57-135	6**	B,H,S,U,W,R,T	11	
	HYDROGEN RECOMBINER "B" INLET	HV57-163		9	B,H,R,S	3,11,14	
			FV-C-DO-101B	90	B,H,R,S	11	
026	DRYWELL PURGE EXHAUST	HV57-114		5**	B,H,S,U,W,R,T	3,11,14,33	57
		HV57-111		15**	B,H,S,U,R,T	11	
		SV57-139		5		10	
			HV57-115	6**	B,H,S,U,W,R,T	11,33	
			HV57-117	5**	B,H,S,U,R,T	11	
			SV57-145	5	B,H,R,S	11	
	HYDROGEN RECOMBINER "A" INLET	HV57-161		9	B,H,R,S	3,11,14	
			FV-C-DO-101A	90	B,H,R,S	11	
027A	CONTAINMENT INSTRUMENT GAS SUPPLY TO ADS VALVES H,M,&S	59-1128(CK)		NA			59
			HV59-151A	45	M		
028A-1	RECIRC LOOP SAMPLE	HV43-1F019		10	B,D		43
			HV43-1F020	10	B,D		
028A-2	DRYWELL H2/02 SAMPLE	SV57-132		5	B,H,R,S	11	57
			SV57-142	5	B,H,R,S	11	
028A-3	DRYWELL H2/02 SAMPLE	SV57-134		5	B,H,R,S	11	57
			SV57-144	5	B,H,R,S	11	

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TABLE 3.6.3-1 (Continued)

PART A - PRIMARY CONTAINMENT ISOLATION VALVES

PENETRATION NUMBER	FUNCTION	INBOARD ISOLATION BARRIER	OUTBOARD ISOLATION BARRIER	MAX. ISOL. TIME, IF APP. (SEC)(26)	ISOL. SIGNAL(S), IF APP (20)	NOTES	P&ID
028B	DRYWELL H2/O2 SAMPLE	SV57-133		5	B,H,R,S	11	57
			SV57-143	5	B,H,R,S	11	
			SV57-195	5	B,H,R,S	11	
030B-1	DRYWELL PRESSURE INSTRUMENTATION		HV42-147A	45		10	42
035B	TIP PURGE	59-1056(CK) (DOUBLE "O" RING)		NA			59
			HV59-131	7	B,H,S	16	
035C-G	TIP DRIVES	XV59-141A-E (DOUBLE "O" RING)		NA	B,H	11,16,21	59
			XV59-140A-E	NA		11,16	
037A-D	CRD INSERT LINES	BALL CHECK		NA		12	47
			HCU	NA		12	
038A-D	CRD WITHDRAW LINES SDV VENTS & DRAINS		HCU	NA		12	47
			XV47-1F010	25		30	
			XV47-1F180	30		30	
			XV47-1F011	25		30	
			XV47-1F181	30		30	
039A(B)	DRYWELL SPRAY	HV51-1F021A(B)		160		4,11	51
			HV51-1F016A(B)	160		11	
040E	DRYWELL PRESSURE INSTRUMENTATION		HV42-147D	45		10	42
040F-2	CONTAINMENT INSTRUMENT GAS -SUCTION	HV59-101		45	C,H,S	5	59
			HV59-102	7	C,H,S		

TABLE 3.6.3-1 (Continued)

PART A - PRIMARY CONTAINMENT ISOLATION VALVES

PENETRATION NUMBER	FUNCTION	INBOARD ISOLATION BARRIER	OUTBOARD ISOLATION BARRIER	MAX. ISOL. TIME. IF APP. (SEC)(26)	ISOL. SIGNAL(S), IF APP. (20)	NOTES	P&ID
040G-1	ILRT DATA ACQUISITION	60-1057		NA		11	60
			60-1058	NA		11	
040G-2	ILRT DATA ACQUISITION	60-1071		NA		11	60
			60-1070	NA		11	
040H-1	CONTAINMENT INSTRUMENT GAS SUPPLY - HEADER 'A'	59-1005A(CK)		NA			59
			HV59-129A	7	C,H,S		
042	STANDBY LIQUID CONTROL	48-1F007(CK) (X-116)		NA			48
			HV48-1F006A	60		29	
043B	MAIN STEAM SAMPLE	HV41-1F084		10	B,D		41
			HV41-1F085	10	B,D		
044	RWCU ALTERNATE RETURN	41-1017		NA		5,31	41
			41-1016(X-9A, X-9B)	NA			
			PSV41-112	NA			
045A(B,C,D)	LPCI INJECTION 'A'(B,C,D)	HV51-1F041A(B,C, D)(CK)	NA		9,22	51	
		HV51-142A(B,C, D)		7		9,22	
			HV51-1F017A (B,C,D)	38			
050A-1	DRYWELL PRESSURE INSTRUMENTATION		HV42-147B	45		10	42
053	DRYWELL CHILLED WATER SUPPLY - LOOP 'A'	HV87-128		60	C,H	11	87
			HV87-120A	60	C,H	11	
			HV87-125A	60	C,H	11	

TABLE 3.6.3-1 (Continued)

PART A - PRIMARY CONTAINMENT ISOLATION VALVES

PENETRATION NUMBER	FUNCTION	INBOARD ISOLATION BARRIER	OUTBOARD ISOLATION BARRIER	MAX. ISOL. TIME. IF APP. (SEC)(26)	ISOL. SIGNAL(S), IF APP. (20)	NOTES	P&ID
054	DRYWELL CHILLED WATER RETURN - LOOP 'A'	HV87-129		60	C,H	11	87
			HV87-121A	60	C,H	11	
			HV87-124A	60	C,H	11	
055	DRYWELL CHILLED WATER SUPPLY - LOOP 'B'	HV87-122		60	C,H	11	87
			HV87-120B	60	C,H	11	
			HV87-125B	60	C,H	11	
056	DRYWELL CHILLED WATER RETURN - LOOP 'B'	HV87-123		60	C,H	11	87
			HV87-121B	60	C,H	11	
			HV87-124B	60	C,H	11	
061-1	RECIRC PUMP 'A' SEAL PURGE	43-1004A(CK)		NA		15	43
			(XV43-103A - SEE PART B, THIS TABLE)	NA		1	
061-2	RECIRC PUMP 'B' SEAL PURGE	43-1004B(CK)		NA		15	43
			(XV43-103B - SEE PART B, THIS TABLE)	NA		1	
062	DRYWELL H2/02 SAMPLE RETURN, N2 MAKE-UP	SV57-150(X-220A)		5	B,H,R,S	11	57
			SV57-159 (X-220A)	5	B,H,R,S	11	
			HV57-116 (X-220A)	30**	B,H,R,S	11	
			SV57-190 (X-220A)	5	B,H,R,S	11	

TABLE 3.6.3-1 (Continued)
PART A - PRIMARY CONTAINMENT ISOLATION VALVES

PENETRATION NUMBER	FUNCTION	INBOARD ISOLATION BARRIER	OUTBOARD ISOLATION BARRIER	MAX. ISOL. TIME. IF APP. (SEC)(26)	ISOL. SIGNAL(S), IF APP. (20)	NOTES	P&ID
			SV57-191 (X-220A)	5	B,H,R,S	11	
116	STANDBY LIQUID CONTROL	48-1F007(CK) (X-42)		NA			48
			HV48-1F006B	60		29	
117B-1	DRYWELL RADIATION MONITORING SUPPLY	SV26-190A		5	B,H,R,S	11	26
			SV26-190B	5	B,H,R,S	11	
117B-2	DRYWELL RADIATION MONITORING RETURN	SV26-19[illegible]		5	B,H,R,S	11	26
			SV26-190D	5	B,H,R,S	11	
201A	SUPPRESSION POOL PURGE SUPPLY	HV57-124		5**	B,H,S,U,W,R,T	3,11,14	57
		HV57-131(X-25)		5**	B,H,S,U,W,R,T	3,11,14	
			HV57-109(X-25)	6**	B,H,S,U,W,R,T	11	
			HV57-147	6**	B,H,S,U,W,R,T	11	
			HV57-121(X-25)	5**	B,H,S,U,W,R,T	11	
	HYDROGEN RECOMBINER "B" EXHAUST	HV57-164		9	B,H,R,S	3,11,14	
			HV57-169	9	B,H,R,S	11	
202	SUPPRESSION POOL PURGE EXHAUST	HV57-104		5**	B,H,S,U,W,R,T	3,11,14,33	57
		HV57-105		15**	B,H,S,U,R,T	11	
			HV57-112	6**	B,H,S,U,W,R,T	11, 33	
			HV57-118	5**	B,H,S,U,R,T	11	
			SV57-185	5	B,H,R,S	11	
	HYDROGEN RECOMBINER "A" EXHAUST	HV57-162		9	B,H,R,S	3,11,14	
			HV57-166	9	B,H,R,S	11	
203A(B,C,D)	RHR PUMP SUCTION		HV51-1F004A(B, C,D)	240		4,22, 29	51
			PSV51-1F030A (B,C,D)	NA		19,22	

TABLE 3.6.3-1 (Continued)

PART A - PRIMARY CONTAINMENT ISOLATION VALVES

PENETRATION NUMBER	FUNCTION	INBOARD ISOLATION BARRIER	OUTBOARD ISOLATION BARRIER	MAX. ISOL. TIME. IF APP. (SEC)(26)	ISOL. SIGNAL(S), IF APP. (20)	NOTES	P&ID
204A(B)	RHR PUMP TEST LINE AND CONTAINMENT COOLING		HV51-125A(B)	180		4,22,29	51
205A(B)	SUPPRESSION POOL SPRAY		HV51-1F027A(B)	45	C,G	11	51
206A(B,C,D)	CS PUMP SUCTION		HV52-1F001A (B,C,D)	160		4,22,29	52
207A(B)	CS PUMP TEST AND FLUSH		HV52-1F015A(B)	23	C,G	5,22	52
208B	CS PUMP MINIMUM RECIRC		HV52-1F031B	45	LFCH	5,22,29	52
209	HPCI PUMP SUCTION		HV55-1F042	160	L,LA	4,22	55
210	HPCI TURBINE EXHAUST		HV55-1F072	120		4,22,29	55
212	HPCI PUMP TEST AND FLUSH		HV55-1F071	40	B,H	4,22	55
214	RCIC PUMP SUCTION		HV49-1F031	60		4,22,29	49
215	RCIC TURBINE EXHAUST		HV49-1F060	80		4,22,29	49
216	RCIC MINIMUM FLOW		HV49-1F019	8	LFRC	5,22	49

TABLE 3.6.3-1 (Continued)

PART A - PRIMARY CONTAINMENT ISOLATION VALVES

PENETRATION NUMBER	FUNCTION	INBOARD ISOLATION BARRIER	OUTBOARD ISOLATION BARRIER	MAX. ISOL. TIME. IF APP. (SEC)(26)	ISOL. SIGNAL(S), IF APP. (20)	NOTES	P&ID
217	RCIC VACUUM PUMP DISCH	HV49-1F002		60		5,29	49
			49-1F028(CK)	NA			
218	INSTRUMENT GAS TO VACUUM RELIEF VALVES	59-1001(CK)		NA			59
			HV59-135	7	C,H,S		
219A	INSTRUMENTATION - SUPPRESSION POOL LEVEL	--	HV55-121	45		10	55
219B	INSTRUMENTATION - SUPPRESSION POOL LEVEL	--	HV55-120	45		10	55
220A	H2/02 SAMPLE RETURN	SV57-191(X-62)		5	B,H,R,S	11	57
			SV57-190(X-62)	5	B,H,R,S	11	
			HV57-116(X-62)	30**	B,H,R,S	11	
			SV57-150(X-62)	5	B,H,R,S	11	
			SV57-159(X-62)	5	B,H,R,S	11	
220B	INSTRUMENTATION - SUPPRESSION POOL PRESSURE SUPPRESSION POOL LEVEL	--	SV57-101	5		10	57
221A	WETWELL H2/02 SAMPLE	SV57-181		5	B,H,R,S	11	57
			SV57-141	5	B,H,R,S	11	
			SV57-184	5	B,H,R,S	11	
221B	WETWELL H2/02 SAMPLE	SV57-183		5	B,H,R,S	11	57
			SV57-186	5	B,H,R,S	11	

TABLE 3.6.3-1 (Continued)

PART A - PRIMARY CONTAINMENT ISOLATION VALVES

PENETRATION NUMBER	FUNCTION	INBOARD ISOLATION BARRIER	OUTBOARD ISOLATION BARRIER	MAX. ISOL. TIME. IF APP. (SEC)(36)	ISOL. SIGNAL(S), IF APP. (20)	NOTES	P&ID
225	RHR VACUUM RELIEF SUCTION	HV51-130		60	B,H	4,11	51
			HV51-131	60	B,H	11	
226A	RHR MINIMUM RECIRC		HV51-105A	40		4,22,29	51
226B	RHR MINIMUM RECIRC		HV51-105B	40		4,22,29	51
227	ILRT DATA ACQUISITION	60-1073		NA			60
	SYSTEM		60-107[illegible]	NA			
228D	HPCI VACUUM RELIEF	HV55-1F095		40	H,LA	4,11,24	55
			HV55-1F093	40	H,LA	11,24	
230B	INSTRUMENTATION - DRYWELL	--	HV61-102	45		1,23,29	61
	SUMP LEVEL		HV61-112	45		23,29	
			HV61-132	45		23,29	
231A	DRYWELL FLOOR DRAIN	HV61-110		30	B,H	11,22	61
	SUMP DISCHARGE		HV61-111	30	B,H	11,22	
231B	DRYWELL EQUIPMENT DRAIN	HV61-130		30	B,H	11,22	61
	TANK DISCHARGE		HV61-131	30	B,H	11,22	
235	CS PUMP MINIMUM RECIRC		HV52-1F031A	45	LFCH	5,22,29	52
236	HPCI PUMP MINIMUM RECIRC		HV55-1F012	15	LFHP	5,22	55

TABLE 3.6.3-1 (Continued)

PART A - PRIMARY CONTAINMENT ISOLATION VALVES

PENETRATION NUMBER	FUNCTION	INBOARD ISOLATION BARRIER	OUTBOARD ISOLATION BARRIER	MAX. ISOL. TIME. IF APP. (SEC)(26)	ISOL. SIGNAL(S), IF APP. (20)	NOTES	P&ID
237-1	SUPPRESSION POOL CLEANUP PUMP SUCTION	HV52-127		60	B,H	4,11,22	52
			PSV52-127	NA		11,22	
			HV52-128	60	B,H	11,22	
237-2	SUPPRESSION POOL LEVEL INSTRUMENTATION		HV52-139	45		10	52
			SV52-139	6		10	
238	RHR RELIEF VALVE DISCHARGE		HV-C-51-1F104B	18	C,G		51
			PSV51-106B	NA		19	
			PSV51-1F055B	NA		19	
			PSV51-101B	NA		19	
239	RHR RELIEF VALVE DISCHARGE		HV-C-51-1F103A	18	C,G		51
			PSV51-106A	NA		19	
			PSV51-1F055A	NA		19	
			PSV51-101A	NA		19	
240	RHR RELIEF VALVE DISCHARGE		PSV51-1F097	NA		19	51
241	RCIC VACUUM RELIEF	HV49-1F084		40	H,KA	4,11,24	49
			HV49-1F080	40	H,KA	11,24	

TABLE 3.6.3-1 (Continued)

PART B - PRIMARY CONTAINMENT ISOLATION EXCESS FLOW CHECK VALVES

PENETRATION NUMBER	FUNCTION	INBOARD ISOLATION BARRIER	OUTBOARD ISOLATION BARRIER	MAX. ISOL. TIME. IF APP. (SEC)(26)	ISOL. SIGNAL(S), IF APP. (20)	NOTES	P&ID
003A-1	INSTRUMENTATION - 'D' MAIN STEAM LINE FLOW	--	XV41-1F070D XV41-1F073D			1	41
003A-2	INSTRUMENTATION - 'A' RECIRC PUMP SEAL PRESSURE	--	XV43-1F003A			1	43
003C-1	INSTR. - HPCI STEAM FLOW	--	XV55-1F024A			1	55
003C-2	INSTR. - HPCI STEAM FLOW	--	XV55-1F024C			1	55
003D-1	INSTR. - 'A' MAIN STEAM LINE FLOW	--	XV41-1F070A XV41-1F073A			1	41
007A(B,C,D)	INSTR - 'A'(B,C,D) MAIN STEAM LINE PRESSURE	(HV41-1F022A(B, C,D) SEE PART A THIS TABLE)		5*	C,D,E,F,P,Q	6	41
			(HV41-1F028A (B,C, D) SEE PART A THIS TABLE)	5*	C,D,E,F,P,Q	6	
			(HV40-1F001B (F,K,P) SEE PART A THIS TABLE)	45	EA	6	
			XV40-101B(F, K,P)			1,6	
020A-1	INSTR - RPV LEVEL	--	XV42-1F045B			1	42
020A-2	INSTR - 'B' LPCI DELTA P	--	XV51-102B			1	51
020A-3	INSTR - 'D' LPCI DELTA P	--	XV51-103B			1	51
020B-1	INSTR - RPV LEVEL	--	XV42-1F045C			1	42
020B-2	INSTR - 'C' LPCI DELTA P	--	XV51-102C			1	51

TABLE 3.6.3-1 (Continued)

PART B - PRIMARY CONTAINMENT ISOLATION EXCESS FLOW CHECK VALVES

PENETRATION NUMBER	FUNCTION	INBOARD ISOLATION BARRIER	OUTBOARD ISOLATION BARRIER	MAX. ISOL. TIME. IF APP. (SEC)(26)	ISOL. SIGNAL(S), IF APP. (20)	NOTES	P&ID
027B-1	INSTR - HPCI FLOW	--	XV55-1F024B			1	55
027B-2	INSTR - HPCI FLOW	--	XV55-1F024D			1	55
029A	INSTR - RPV FLANGE LEAKAGE	--	XV41-1F009			1,27	41
029B	INSTR - CS DELTA P	--	XV52-1F018A			1	52
030A	INSTR - 'D' MAIN STEAM FLOW	--	XV41-1F071D XV41-1F072D			1	41
030B-2	INSTR - 'C' MAIN STEAM LINE FLOW	--	XV41-1F071C XV41-1F072C			1	41
031A	INSTR - JET PUMP FLOW	--	XV42-1F059B (JP1) XV42-1F059D (JP2) XV42-1F059F (JP3)			1	42
031B	INSTR - JET PUMP FLOW	--	XV42-1F059H (JP4) XV42-1F051B (JP5) XV42-1F053B (JP6)			1	42

TABLE 3.6.3-1 (Continued)

PART B - PRIMARY CONTAINMENT ISOLATION EXCESS FLOW CHECK VALVES

PENETRATION NUMBER	FUNCTION	INBOARD ISOLATION BARRIER	OUTBOARD ISOLATION BARRIER	MAX. ISOL. TIME. IF APP. (SEC)(26)	ISOL. SIGNAL(S), IF APP. (20)	NOTES	P&ID
032A	INSTR - JET PUMP FLOW	--	XV42-1F059M (JP6) XV42-1F059P (JP7) XV42-1F059S (JP8)		1	42	
032B	INSTR - JET PUMP FLOW	--	XV42-1F059U (JP9) XV42-1F051D (JP10) XV42-1F053D (JP10)		1	42	
033A-1	INSTR-PRESSURE ABOVE CORE PLATE	--	XV42-1F055 XV42-1F076		1	42	
033A-2	INSTR-PRESSURE BELOW CORE PLATE	--	XV42-1F061		1	42	
033B	INSTR-RCIC STEAM FLOW	--	XV49-1F044A,C		1	49	
034A	INSTR - 'C' MAIN STEAM LINE FLOW	--	XV41-1F070C XV41-1F073C		1	41	
034B-1	INSTR - RECIRC FLOW	--	XV43-1F009C XV43-1F010D		1	43	
034B-2	INSTR - RECIRC FLOW	--	XV43-1F009D XV43-1F010C		1	43	

TABLE 3.6.3-1 (Continued)

PART B - PRIMARY CONTAINMENT ISOLATION EXCESS FLOW CHECK VALVES

PENETRATION NUMBER	FUNCTION	INBOARD ISOLATION BARRIER	OUTBOARD ISOLATION BARRIER	MAX. ISOL. TIME, IF APP. (SEC)(26)	ISOL. SIGNAL(S), IF APP. (20)	NOTES	P&ID
040A	INSTR - JET PUMP FLOW	--	XV42-1F059L (JP15) XV42-1F059N (JP17) XV42-1F059R (JP18)			1	42
040B	INSTR - JET PUMP FLOW	--	XV42-1F059G (JP14) XV42-1F051A (JP16) XV42-1F053A (JP16)			1	42
040C	INSTR - JET PUMP FLOW	--	XV42-1F059A (JP11) XV42-1F059C (JP12) XV42-1F059E (JP13)			1	42
040D-1	INSTR - PRESSURE BELOW CORE PLATE	--	XV42-1F057			1	42
040D-2	INSTR - RWCU BOTTOM DRAIN FLOW	--	XV44-170 XV44-171			1	44

TABLE 3.6.3-1
PRIMARY CONTAINMENT ISOLATION VALVES
NOTATION

NOTES

1. Instrumentation line isolation provisions consist of an orifice and excess flow-check valve or remote manual isolation valve. The excess flow-check valve is subjected to operability testing, but no Type C test is performed or required. The line does not isolate during a LOCA and can leak only if the line or instrument should rupture. Leaktightness of the line is verified during the integrated leak rate test (Type A test).

2. Penetration is sealed by a blind flange or door with double O-ring seals. These seals are leakage rate tested by pressurizing between the O-rings.

3. Inboard butterfly valve tested in the reverse direction.

4. Inboard gate valve tested in the reverse direction.

5. Inboard globe valve tested in the reverse direction.

6. The MSIVs and this penetration are tested by pressurizing between the valve Testing of the inboard valve in the reverse direction tends to unseat the valve and is therefore conservative. The valves are Type C tested at a tes pressure of 22 psig.

7. Gate valve tested in the reverse direction.

8. Electrical penetrations are tested by pressurizing between the seals.

9. The isolation provisions for this penetration consist of two isolation valves and a closed system outside containment. Because a water seal is maintained in these lines by the safeguard piping fill system, the inboard valve may be tested with water. The outboard valve will be pneumatically tested.

10. The valve does not receive an isolation signal but remains open to measure containment conditions post-LOCA. Leaktightness of the penetration is verified during the Type A test. Type C test is not required.

11. All isolation barriers are located outside containment.

12. Leakage monitoring of the control rod drive insert and withdraw line is provided by Type A leakage rate test. Type C test is not required.

13. The motor operators on HV-13-109 and HV-13-110 are not connected to any power supply.

14. Valve is provided with a separate testable seal assembly, with double concentric O-ring seals installed between the pipe flange and valve flange facing primary containment. Leakage through these seals is included within the Type C leakage rate for this penetration.

NOTES (Continued)

15. Check valve used instead of flow orifice.

16. Penetration is sealed by a flange with double O-ring seals. These seals are leakage rate tested by pressurizing between the O-rings. Both the TIP Purge Supply (Penetration 35B) and the TIP Drive Tubes (Penetrations 35 C thru G)are welded to their respective flanges. Leakage through these seals is included in the Type C leakage rate total for this penetration. The ball valves (XV-141A thru E) are Type C tested. It is not practicable to leak test the shear valves (XV-140A thru E) because squib firing is required for closure. Shear valves (XV-140A thru E) are normally open.

17. Instrument line isolation provisions consist of an excess flow check valve. Because the instrument line is connected to a closed cooling water system inside containment, no flow orifice is provided. The excess flow check valves are subject to operability testing, but no Type C test is performed nor required. The line does not isolate during a LOCA and can leak only if the line or instrument should rupture. Leaktightness of the line is verified during the integrated leak rate test (Type A test).

18. In addition to double "O" ring seals, this penetration is tested by pressurizing volume between doors per Specification 4.6.1.3.

19. The RHR system safety pressure relief valves which are flanged to facilitate removal will be equipped with double O-ring seal assemblies on the flange closest to primary containment. These seals will be leak rate tested by pressurizing between the O-rings, and the results added into the Type C total for this penetration.

20. See Specification 3.3.2, Table 3.3.2-1, for a description of the PCRVICS isolation signal(s) that initiate closure of each automatic isolation valve. In addition, the following non-PCRVICS isolation signals also initiate closure of selected valves:

    EA Main steam line high pressure, high steam line leakage flow, low MSIV-LCS dilution air flow

    LFHP With HPCI pumps running, opens on low flow in associated pipe, closes when flow is above setpoint

    LFRC With RCIC pump running, opens on low flow in associated pipe, closes when flow is above setpoint

    LFCH With CSS pump running, opens on low flow in associated pipe, closes when flow is above setpoint

    LFCC Steam supply valve fully closed or RCIC turbine stop valve fully closed

All power operated isolation valves may be opened or closed remote manually.

SURVEILLANCE REQUIREMENTS

4.6.4.1 Each suppression chamber - drywell vacuum breaker shall be:

a. Verified closed at least once per 7 days.

b. Demonstrated OPERABLE:

1. At least once per 31 days and within 2 hours after any discharge of steam to the suppression chamber from the safety/relief valves, by cycling each vacuum breaker through at least one complete cycle of full travel.

2. At least once per 31 days by verifying both position indicators OPERABLE by observing expected valve movement during the cycling test.

3. At least once per 18 months by;

a) Verifying each valve's opening setpoint, from the closed position, to be 0.5 psid ± 5%, and

b) Verifying both position indicators OPERABLE by performance of a CHANNEL CALIBRATION.

c) Verifying that each outboard valve's position indicator is capable of detecting disk displacement $\geq$0.050", and each inboard valve's position indicator is capable of detecting disk displacement $\geq$0.120".

CONTAINMENT SYSTEMS

3/4.6.5 SECONDARY CONTAINMENT

REACTOR ENCLOSURE SECONDARY CONTAINMENT INTEGRITY

LIMITING CONDITION FOR OPERATION

3.6.5.1.1 REACTOR ENCLOSURE SECONDARY CONTAINMENT INTEGRITY shall be maintained.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, and 3.

ACTION:

Without REACTOR ENCLOSURE SECONDARY CONTAINMENT INTEGRITY, restore REACTOR ENCLOSURE SECONDARY CONTAINMENT INTEGRITY within 4 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

SURVEILLANCE REQUIREMENTS

4.6.5.1.1 REACTOR ENCLOSURE SECONDARY CONTAINMENT INTEGRITY shall be demonstrated by:

a. Verifying at least once per 24 hours that the pressure within the reactor enclosure secondary containment is greater than or equal to 0.25 inch of vacuum water gauge.

b. Verifying at least once per 31 days that:

   1. All reactor enclosure secondary containment equipment hatches and blowout panels are closed and sealed.

   2. At least one door in each access to the reactor enclosure secondary containment is closed.

   3. All reactor enclosure secondary containment penetrations not capable of being closed by OPERABLE secondary containment automatic isolation dampers/valves and required to be closed during accident conditions are closed by valves, blind flanges, slide gate dampers or deactivated automatic dampers/valves secured in position.

c. At least once per 18 months:

   1. Verifying that one standby gas treatment subsystem will draw down the reactor enclosure secondary containment to greater than or equal to 0.25 inch of vacuum water gauge in less than or equal to 121 seconds with the reactor enclosure recirc system in operation, and

   2. Operating one standby gas treatment subsystem for one hour and maintaining greater than or equal to 0.25 inch of vacuum water gauge in the reactor enclosure secondary containment at a flow rate not exceeding 1250 cfm with wind speeds of $\leq$ 7.0 mph as measured on the wind instrument on Tower 1 elevation 30' or, if that instrument is unavailable, Tower 2, elevation 159'.

CONTAINMENT SYSTEMS

3/4.6.5 SECONDARY CONTAINMENT

REFUELING AREA SECONDARY CONTAINMENT INTEGRITY

LIMITING CONDITION FOR OPERATION

3.6.5.1.2 REFUELING AREA SECONDARY CONTAINMENT INTEGRITY shall be maintained.

APPLICABILITY: OPERATIONAL CONDITION *.

ACTION:

Without REFUELING AREA SECONDARY CONTAINMENT INTEGRITY, suspend handling of irradiated fuel in the secondary containment, CORE ALTERATIONS and operations with a potential for draining the reactor vessel. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.6.5.1.2 REFUELING AREA SECONDARY CONTAINMENT INTEGRITY shall be demonstrated by:

a. Verifying at least once per 24 hours that the pressure within the refueling area secondary containment is greater than or equal to 0.25 inch of vacuum water gauge.

b. Verifying at least once per 31 days that:

   1. All refueling area secondary containment equipment hatches and blowout panels are closed and sealed.

   2. At least one door in each access to the refueling area secondary containment is closed.

   3. All refueling area secondary containment penetrations not capable of being closed by OPERABLE secondary containment automatic isolation dampers/valves and required to be closed during accident conditions are closed by valves, blind flanges, slide gate dampers or deactivated automatic dampers/valves secured in position.

c. At least once per 18 months:

   Operating one standby gas treatment subsystem for one hour and maintaining greater than or equal to 0.25 inch of vacuum water gauge in the refueling area secondary containment at a flow rate not exceeding 764 cfm.

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*Required when (1) irradiated fuel is being handled in the refueling area secondary containment, or (2) during CORE ALTERATIONS, or (3) during operations with a potential for draining the reactor vessel, with the vessel head removed and fuel in the vessel.

REACTOR ENCLOSURE SECONDARY CONTAINMENT AUTOMATIC ISOLATION VALVES

LIMITING CONDITION FOR OPERATION

3.6.5.2.1 The reactor enclosure secondary containment ventilation system automatic isolation valves shown in Table 3.6.5.2.1-1 shall be OPERABLE with isolation times less than or equal to the times shown in Table 3.6.5.2.1-1.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, and 3.

ACTION:

With one or more of the reactor secondary containment ventilation system automatic isolation valves shown in Table 3.6.5.2.1-1 inoperable, maintain at least one isolation valve OPERABLE in each affected penetration that is open and within 8 hours either:

a. Restore the inoperable valves to OPERABLE status, or

b. Isolate each affected penetration by use of at least one deactivated valve secured in the isolation position, or

c. Isolate each affected penetration by use of at least one closed manual valve, blind flange or slide gate damper.

Otherwise, in OPERATIONAL CONDITION 1, 2 or 3, be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

SURVEILLANCE REQUIREMENTS

4.6.5.2.1 Each reactor enclosure secondary containment ventilation system automatic isolation valve shown in Table 3.6.5.2.1-1 shall be demonstrated OPERABLE:

a. Prior to returning the valve to service after maintenance, repair or replacement work is performed on the valve or its associated actuator, control or power circuit by cycling the valve through at least one complete cycle of full travel and verifying the specified isolation time.

b. At least once per 18 months by verifying that on a containment isolation test signal each isolation valve actuates to its isolation position.

c. By verifying the isolation time to be within its limit at least once per 92 days.

b. At least once per 18 months or (1) after any structural maintenance on the HEPA filter or charcoal adsorber housings, or (2) following painting, fire, or chemical release in any ventilation zone communicating with the subsystem by:

   1. Verifying that the subsystem satisfies the in-place penetration and bypass leakage testing acceptance criteria of less than 0.05% and uses the test procedure guidance in Regulatory Positions C.5.a, C.5.c and C.5.d of Regulatory Guide 1.52, Revision 2, March 1978, and the system flow rate is 3000 cfm ± 10%.

   2. Verifying within 31 days after removal that a laboratory analysis of a representative carbon sample obtained in accordance with Regulatory Position C.6.b of Regulatory Guide 1.52, Revision 2, March 1978, meets the laboratory testing criteria of Regulatory Position C.6.a of Regulatory Guide 1.52, Revision 2, March 1978, for a methyl iodide penetration of less than 0.175%; and

   3. Verify that when the fan is running the subsystem flowrate is 2800 cfm minimum from each reactor enclosure (Zones I and II) and 2200 cfm minimum from the refueling area (Zone III) when tested in accordance with ANSI N510-1980.

   4. Verify that the pressure drop across the refueling area to SGTS prefilter is less than 0.25 inches water gage while operating at a flow rate of 2400 cfm ± 10%.

c. After every 720 hours of charcoal adsorber operation by verifying within 31 days after removal that a laboratory analysis of a representative carbon sample obtained in accordance with Regulatory Position C.6.b of Regulatory Guide 1.52, Revision 2, March 1978, meets the laboratory testing criteria of Regulatory Position C.6.a of Regulatory Guide 1.52, Revision 2, March 1978, for a methyl iodide penetration of less than 0.175%.

d. At least once per 18 months by:

   1. Verifying that the pressure drop across the combined HEPA filters and charcoal adsorber banks is less than 9.1 inches water gauge while operating the filter train at a flow rate of 8400 cfm ± 10%.

SURVEILLANCE REQUIREMENTS (Continued)

2. Verifying that the fan starts and isolation valves necessary to draw a suction from the refueling area or the reactor enclosure recirculation discharge open on each of the following test signals:

    a) Manual initiation from the control room, and

    b) Simulated automatic initiation signal.

3. Verifying that the temperature differential across each heater is $\geq$ 15°F when tested in accordance with ANSI N510-1980.

e. After each complete or partial replacement of a HEPA filter bank by verifying that the HEPA filter bank satisfies the inplace penetration and leakage testing acceptance criteria of less than 0.05% in accordance with ANSI N510-1980 while operating the system at a flow rate of 3000 cfm ± 10%.

f. After each complete or partial replacement of a charcoal adsorber bank by verifying that the charcoal adsorber bank satisfies the inplace penetration and leakage testing acceptance criteria of less than 0.05% in accordance with ANSI N510-1980 for a halogenated hydrocarbon refrigerant test gas while operating the system at a flow rate of 3000 cfm ± 10%.

g. Prior to initial criticality of Unit 2 or after any major system alteration:

1. Verify that when the SGTS fan is running the subsystem flowrate is 2800 cfm minimum from each reactor enclosure (Zones I and II) and 2200 cfm minimum from the refueling area (Zone III).

2. Verify that one standby gas treatment subsystem will drawdown reactor enclosure Zone I secondary containment to greater than or equal to 0.25 inch of vacuum water gauge in less than or equal to 121 seconds with the reactor enclosure recirculation system in operation and the adjacent reactor enclosure and refueling area zones are in their isolation modes.

SURVEILLANCE REQUIREMENTS (Continued)

4.7.6.1.3 The diesel-driven fire pump starting 24-volt battery bank and charger shall be demonstrated OPERABLE:

a. At least once per 7 days by verifying that:

1. The electrolyte level of each cell is above the plates,

2. The pilot cell specific gravity, corrected to 77°F and full electrolyte level, is greater than or equal to 1.260, and

3. The overall battery voltage is greater than or equal to 24 volts.

b. At least once per 92 days by verifying that the specific gravity is appropriate for continued service of the battery.

c. At least once per 18 months by verifying that:

1. The batteries, cell plates, and battery racks show no visual indication of physical damage or abnormal deterioration, and

2. Battery-to-battery and terminal connections are clean, tight, free of corrosion, and coated with anticorrosion material.

PLANT SYSTEMS

SPRAY AND/OR SPRINKLER SYSTEMS

LIMITING CONDITION FOR OPERATION

3.7.6.2 The following spray and sprinkler systems shall be OPERABLE:

Fire Zone	Description
	Reactor Enclosure Hatchway Water Curtains:
	1. EL 253'
	2. EL 283'
	3. EL 313'
	Fire Area Separation Water Curtains:
48A	1. Area 602, EL 313'
45A	2. Area 402, EL 253'
44	3. Area 304, EL 217' (2 curtains)
22	Cable Spreading Room, Room 449, EL 254'
27	Control Structure Fan Room, EL 304'
27	CREFAS System Filters, EL 304'
28A	SGTS Access Area 625, EL 332'
28B	SGTS Filters, Compartment 624, EL 332'
33	RCIC Pump Room, Room 108, EL 177'
34	HPCI Pump Room, Room 109, EL 177'
41	RECW Area 207, EL 201'
42A	Safeguard System Access Area 200, EL 201'
44	Safeguard System Access Area 304, EL 217' (Partial) (2 systems)
45A	CRD Hydraulic Equipment Area 402, Reactor Enclosure, EL 253' (Partial)
45B	Neutron Monitoring System Area 406, El 253' (Partial)
47A	General Equipment Area 500 and Corridor 506, Reactor Enclosure, EL 283' (Partial)
51A & B	Reactor Enclosure Recirculation System Filters, EL 331'
79,80,81,82	Diesel Generator cells (4 Cells)

APPLICABILITY: Whenever equipment protected by the spray and/or sprinkler systems is required to be OPERABLE.

ACTION:

a. With one or more of the above required spray and/or sprinkler systems inoperable, within 1 hour establish a continuous fire watch with backup fire suppression equipment for those areas in which redundant systems or components could be damaged; for other areas, establish an hourly fire watch patrol.

b. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.7.6.2 Each of the above required spray and sprinkler systems shall be demonstrated OPERABLE:

a. At least once per 31 days by verifying that each valve (manual, power-operated, or automatic) in the flow path is in its correct position.

b. At least once per 12 months by cycling each testable valve in the flow path through at least one complete cycle of full travel.

c. At least once per 18 months:

1. By performing a system functional test which includes simulated automatic actuation of the system, and:

a) Verifying that the automatic valves in the flow path actuate to their correct positions on a test signal, and

b) Cycling each valve in the flow path that is not testable during plant operation through at least one complete cycle of full travel.

2. By a visual inspection of the dry pipe spray and sprinkler headers to verify their integrity, and

3. By a visual inspection of each sprinkler nozzle's spray area to verify that the spray pattern is not obstructed.

d. At least once per 3 years by performing an air or water flow test through each open head spray and sprinkler header system and verifying each open head spray nozzle and sprinkler header system is unobstructed, except the charcoal filter system spray nozzles which only need to be visually inspected and verified to be unobstructed each time the charcoal is changed.

PLANT SYSTEMS

CO_2 SYSTEMS

LIMITING CONDITION FOR OPERATION

3.7.6.3 The following low pressure CO_2 system shall be OPERABLE:

a. Control Room Entrance, Hose Rack OHR601 and OHR602.

APPLICABILITY: Whenever equipment protected by the CO_2 system is required to be OPERABLE.

ACTION:

a. With the above required CO_2 system inoperable, within 1 hour establish a continuous fire watch with backup fire suppression equipment for those areas in which redundant systems or components could be damaged; for other areas, establish an hourly fire watch patrol.

b. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.7.6.3.1 The above required low pressure CO_2 system shall be demonstrated OPERABLE at least once per 7 days by verifying the CO_2 storage tank level to be greater than 25% and pressure to be greater than 265 psig.

4.7.6.3.2 The above required CO_2 system shall be demonstrated OPERABLE at least once per 31 days by verifying that each valve (manual, power-operated, or automatic) in the flow path is in its correct position.

TABLE 3.7.6.5-1

FIRE HOSE STATIONS

LOCATION	ELEVATION	HOSE RACK IDENTIFICATION
1. Control Enclosure:		
Stairwell	350'	1HR-141
Stairwell, Outside SGTS Room	332'	1HR-140
Stairwell, Outside Fan Room	304'	1HR-103
Outside 13kV Switchgear Room	217'	1HR-116
Stairwell, Outside Aux Equip Rm	289'	1HR-130
Stairwell, Outside Cable Spreading Rm	254'	1HR-250
Wall, Outside 4kV Switchgear & Battery Rooms	239'	1HR-251
Corridor 448, South Side of 4kV Switchgear & Battery Rooms	239'	1HR-124
Wall, Corridor 265	200'	1HR-120
Wall, Corridor 164	180'	1HR-121
2. Refueling Area:		
SW Corner Refuel Floor	352'	1HR-201
NW Corner Refuel Floor	352'	1HR-202
North Wall-Center	352'	1HR-203
South Wall-Center	352'	1HR-204
3. Reactor Enclosure:		
SW Corner Reactor Enclosure	331'	1HR-205
SW Corner Reactor Enclosure (RERS Fan Area)	313'	1HR-207
NW Corner Reactor Enclosure (Laydown Area 601)	313'	1HR-208
SE Corner Reactor Enclosure (Near Refuel Floor Exh. Fans)	313'	1HR-209
NE Corner Reactor Enclosure (Near D124 Load Center)	313'	1HR-210
SW Corner Reactor Enclosure (Corridor 506)	283'	1HR-215
NW Corner Reactor Enclosure (Corridor 506)	283'	1HR-216

TABLE 3.7.6.5-1 (Continued)

FIRE HOSE STATIONS

LOCATION	ELEVATION	HOSE RACK IDENTIFICATION
3. Reactor Enclosure: (Continued)		
SE Corner Reactor Enclosure (SLC Pumps Area 500)	283'	1HR-217
NE Corner Reactor Enclosure	283'	1HR-218
SW Corner Reactor Enclosure (Area 402A, Near CRD Repair)	253'	1HR-223
NW Corner Reactor Enclosure (Near Drywell Equip Hatch)	253'	1HR-224
SE Corner Reactor Enclosure (Near Drywell Personnel Lock)	253'	1HR-225
East Wall Reactor Enclosure (Near TIP Machines)	253'	1HR-226
SW Corner Reactor Enclosure (Near RCIC Equip Hatch)	217'	1HR-232
NW Corner Reactor Enclosure (Near Supp Pool Access Hatch)	217'	1HR-233
East Wall Reactor Enclosure (Near Equipment Airlock 300)	217'	1HR-234
NE Corner Reactor Enclosure (Near MCC D124-R-G)	217'	1HR-235
SW Corner Reactor Enclosure (Near MCC D134-R-H)	201'	1HR-240
NW Corner Reactor Enclosure (Near MCC D134-R-H1)	201'	1HR-241
East Wall Reactor Enclosure (Near RECW Heat Exchangers)	201'	1HR-242
NE Corner Reactor Enclosure (Near RECW Pumps)	201'	1HR-243
SW Corner Reactor Enclosure	177'	1HR-252
NW Corner Reactor Enclosure	177'	1HR-253
NE Corner Reactor Enclosure	177'	1HR-142

TABLE 3.8.4.1-1 (Continued)

PRIMARY CONTAINMENT PENETRATION CONDUCTOR

OVERCURRENT PROTECTIVE DEVICES

2. 480-VOLT MOLDED CASE BREAKERS (Continued)

CIRCUIT BREAKER NO.	LOCATION	TYPES	SYSTEMS OR EQUIPMENT POWERED
52-22410	D144-R-E	IM HFB100 TM HFB100	1B2 Drywell Area Unit Cooler 1B2V212
52-22411	D144-R-E	IM HFB100 TM HFB100	1H2 Drywell Area Unit Cooler 1H2V212
52-22418	D144-R-E	IM HFB50 TM HFB150	HPCI Mn Stm Supply Inbrd Isol Vlv HV-55-1F002
52-22516	114B-R-C	IM HFB25 TM HFB100	1A Reac Recirc Pump Suction VLV HV-43-1F023A
52-22518	114B-R-C	IM HFB25 TM HFB100	1A Reac Recirc Pump Discharge VLV HV-43-1F031A
52-22520	114B-R-C	IM HFB25 TM HFB40	Reactor Bottom Head Drain VLV HV-44-1F100
52-22536	114B-R-C	IM HFB25 TM HFB40	RWCU Inlet from Rx Recirc loop B HV-44-1F105
52-22534	114B-R-C	IM HFB25 TM HFB40	Reactor Vessel Head Vent HV-41-1F001
52-22535	114B-R-C	IM HFB25 TM HFB40	Reactor Vessel Head Vent HV-41-1F005
52-22537	114B-R-C	TM HFB15 TM HFB20	Disposal Cask Removal Cart Hoist 10H236
52-22538	114B-R-C	TM HFB15 TM HFB20	Control Rod Drive Platform Hoist 10H229
52-22608	124B-R-C	TM HFB15 TM HFB20	CRD Equipment Handling Platform 10N22608
52-22618	124B-R-C	IM HFB25 TM HFB100	1B Reac. Recirc. Pump Discharge VLV HV-43-1F031B
*52-22622	124B-R-C	TM HFB125	Permanent Plant In-Containment Welding System 10NW201

TABLE 3.8.4.1-1 (Continued)

PRIMARY CONTAINMENT PENETRATION CONDUCTOR

OVERCURRENT PROTECTIVE DEVICES

2. 480-VOLT MOLDED CASE BREAKERS (Continued)

CIRCUIT BREAKER NO.	LOCATION	TYPES	SYSTEMS OR EQUIPMENT POWERED
*52-22626 1L36 (Main Breaker)	124B-R-C 1L36	TM HFB50 EB3090**	Unit 1 Reactor Enclosure Lighting XFMR 1X28
*52-22630	124B-R-C	TM HFB20 TM HFB20	1A Reac. Recirc. Pump Motor Hoist 1AH203
*52-22631	124B-R-C	TM HFB20 TM HFB20	1B Reac. Recirc. Pump Motor Hoist 1BH203
52-22634	124B-R-C	IM HFB25 TM HFB40	Reactor Vessel Head Vent HV-41-1F002
*52-22707	114C-R-A	TM HFB15 TM HFB15	Mn Stm Relief Vlv Removal Hoist 10H232
*52-22708	114C-R-A	TM HFB15 TM HFB15	Mn Stm Relief Vlv Removal Hoist 10H230

*These breakers shall be administratively maintained open in OPERATIONAL CONDITIONS 1, 2 and 3 and are not required to be tested.

**208 VAC circuit breaker

ABBREVIATIONS:

TM Thermal Magnetic
IM Instantaneous Magnetic

3/4.11 RADIOACTIVE EFFLUENTS
3/4.11.1 LIQUID EFFLUENTS

CONCENTRATION

LIMITING CONDITION FOR OPERATION

3.11.1.1 The concentration of radioactive material released in liquid effluents to UNRESTRICTED AREAS (see Figure 5.1.3-1) shall be limited to the concentrations specified in 10 CFR Part 20, Appendix B, Table II, Column 2 for radionuclides other than dissolved or entrained noble gases. For dissolved or entrained noble gases, the concentration shall be limited to 2×10^{-4} microcuries/ml total activity.

APPLICABILITY: At all times.

ACTION:

With the concentration of radioactive material released in liquid effluents to UNRESTRICTED AREAS exceeding the above limits, immediately restore the concentration to within the above limits.

SURVEILLANCE REQUIREMENTS

4.11.1.1.1 Radioactive liquid wastes shall be sampled and analyzed according to the sampling and analysis program of Table 4.11.1.1.1-1.

4.11.1.1.2 The results of the radioactivity analyses shall be used in accordance with the methodology and parameters in the ODCM to assure that the concentrations at the point of release are maintained within the limits of Specification 3.11.1.1.

TABLE 4.11.1.1.1-1

RADIOACTIVE LIQUID WASTE SAMPLING AND ANALYSIS PROGRAM

LIQUID RELEASE TYPE	SAMPLING FREQUENCY	MINIMUM ANALYSIS FREQUENCY	TYPE OF ACTIVITY ANALYSIS	LOWER LIMIT OF DETECTION (LLD)[a] (μCi/mL)
A. Batch Waste Release Tanks[b]	P Each Batch	P Each Batch	Principal Gamma Emitters[c]	$5x10^{-7}$
			I-131	$1x10^{-6}$
1. Floor Drain Sample Tank No. 2	P One Batch/M	M	Dissolved and Entrained Gases (Gamma Emitters)	$1x10^{-5}$
2. Laundry Drain Sample Tank	P Each Batch	M Composite[d]	H-3	$1x10^{-5}$
			Gross Alpha	$1x10^{-7}$
	P Each Batch	Q Composite[d]	Sr-89, Sr-90	$5x10^{-8}$
			Fe-55	$1x10^{-6}$
B. Continuous Release[e]	W Grab Sample	W	Principal Gamma Emitters[c]	$5x10^{-7}$
			I-131	$1x10^{-6}$
1. RHR Service Water System Effluent Line[f]	W Grab Sample	W	Dissolved and Entrained Gases (Gamma Emitters)	$1x10^{-5}$
2. Service Water System Effluent Line[f]	W Grab Sample	M Composite[d]	H-3	$1x10^{-5}$
			Gross Alpha	$1x10^{-7}$
	W Grab Sample	Q Composite[d]	Sr-89, Sr-90	$5x10^{-8}$
			Fe-55	$1x10^{-6}$

TABLE 4.11.1.1.1-1 (Continued)

TABLE NOTATIONS

[a]The LLD is defined, for purposes of these specifications, as the smallest concentration of radioactive material in a sample that will yield a net count, above system background, that will be detected with 95% probability with only 5% probability of falsely concluding that a blank observation represents a "real" signal.

For a particular measurement system, which may include radiochemical separation:

$$LLD = \frac{4.66 s_b}{E \cdot V \cdot 2.22 \times 10^6 \cdot Y \cdot \exp(-\lambda \Delta t)}$$

Where:

LLD is the *a priori* lower limit of detection as defined above (as microcuries per unit mass or volume),

s_b is the standard deviation of the background counting rate or of the counting rate of a blank sample as appropriate (as counts per minute),

E is the counting efficiency, as counts per disintegration,

V is the sample size, in units of mass or volume,

2.22×10^6 is the number of disintegrations per minute per microcurie,

Y is the fractional radiochemical yield, when applicable,

λ is the radioactive decay constant for the particular radionuclide, and

Δt for the plant effluents is the elapsed time between the midpoint of sample collection and time of counting.

Typical values of E, V, Y, and Δt should be used in the calculation.

It should be recognized that the LLD is defined as an *a priori* (before the fact) limit representing the capability of a measurement system and not as an *a posteriori* (after the fact) limit for a particular measurement.

TABLE 4.11.1.1.1-1 (Continued)

TABLE NOTATIONS

[b]A batch release is the discharge of liquid wastes of a discrete volume. Prior to sampling for analyses, each batch shall be isolated, and then thoroughly mixed to assure representative sampling.

[c]The principal gamma emitters for which the LLD specification applies include the following radionuclides: Mn-54, Fe-59, Co-58, Co-60, Zn-65, Mo-99, Cs-134, Cs-137, Ce-141, and Ce-144. This list does not mean that only these nuclides are to be considered. Other gamma peaks that are identifiable, together with those of the above nuclides, shall also be analyzed and reported in the Semiannual Radioactive Effluent Release Report pursuant to Specification 6.9.1.8.

[d]A composite sample is one in which the quantity of liquid sampled is proportional to the quantity of liquid waste discharged and in which the method of sampling employed results in a specimen that is representative of the liquids released.

[e]A continuous release is the discharge of liquid wastes of a nondiscrete volume, e.g., from a volume of a system that has an input flow during the continuous release.

[f]Whenever effluent releases are in excess of the monitor's setpoint.

TABLE 4.11.2.1.2-1 (Continued)

TABLE NOTATIONS

[b]Sampling and analyses shall also be performed following shutdown, startup, or a THERMAL POWER change exceeding 15% of the RATED THERMAL POWER within a 1-hour period. This requirement does not apply if (1) analysis shows that the DOSE EQUIVALENT I-131 concentration in the primary coolant has not increased more than a factor of 3; and (2) the main condenser offgas pretreatment radioactivity monitor shows that effluent activity has not increased more than a factor of 3.

[c]Samples shall be changed at least once per 7 days and analyses shall be completed within 48 hours after changing, or after removal from sampler. Sampling shall also be performed at least once per 24 hours for at least 7 days following each shutdown, startup, or THERMAL POWER change exceeding 15% of RATED THERMAL POWER in 1 hour and analyses completed within 48 hours of changing. When samples collected for 24 hours are analyzed, the corresponding LLDs may be increased by a factor of 10. This requirement does not apply if (1) analysis shows that the DOSE EQUIVALENT I-131 concentration in the primary coolant has not increased more than a factor of 3; and (2) the noble gas monitor shows that effluent activity has not increased more than a factor of 3.

[d]The ratio of the sample flow rate to the sampled stream flow rate shall be known for the time period covered by each dose or dose rate calculation made in accordance with Specifications 3.11.2.1, 3.11.2.2, and 3.11.2.3.

[e]The principal gamma emitters for which the LLD specification applies include the following radionuclides: Kr-87, Kr-88, Xe-133, Xe-133m, Xe-135, Xe-135m and Xe-138 for gaseous emissions and Mn-54, Fe-59, Co-58, Co-60, Zn-65, Mo-99, I-131, Cs-134, Cs-137, Ce-141 and Ce-144 for particulate emissions. This list does not mean that only these nuclides are to be considered. Other gamma peaks which are identifiable, together with those of the above nuclides, shall also be analyzed and reported in the Semiannual Radioactive Effluent Release Report, pursuant to Specification 6.9.1.8.

[f]Under the provisions of footnote e. above, only noble gases need to be considered.

[g]Deleted.

[h]Required for the hot maintenance shop ventilation exhaust only during operation of the hot maintenance shop ventilation exhaust system.

DOSE - NOBLE GASES

LIMITING CONDITION FOR OPERATION

3.11.2.2 The air dose due to noble gases released in gaseous effluents, from the site to areas at and beyond the SITE BOUNDARY (see Figure 5.1.3-1) shall be limited to the following:

a. During any calendar quarter: Less than or equal to 10 mrads for gamma radiation and less than or equal to 20 mrads for beta radiation, and

b. During any calendar year: Less than or equal to 20 mrads for gamma radiation and less than or equal to 40 mrads for beta radiation.

APPLICABILITY: At all times.

ACTION:

a. With the calculated air dose from radioactive noble gases in gaseous effluents exceeding any of the above limits, prepare and submit to the Commission within 30 days, pursuant to Specification 6.9.2, a Special Report which identifies the cause(s) for exceeding the limit(s) and defines the corrective actions that have been taken to reduce the releases and the proposed corrective actions to be taken to assure that subsequent releases will be in compliance with the above limits.

b. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.11.2.2 Cumulative dose contributions for the current calendar quarter and current calendar year for noble gases shall be determined in accordance with the methodology and parameters in the ODCM at least once per 31 days.

Effective When OL is issued to Unit 2

TABLE 3.12.1-1 (Continued)

RADIOLOGICAL ENVIRONMENTAL MONITORING PROGRAM

TABLE NOTATIONS

[a]Specific parameters of distance and direction sector from the centerline of the two reactors and additional description where pertinent, shall be provided for each and every sample location in Table 3.12.1-1 in a table and figure(s) in the ODCM. Deviations are permitted from the required sampling schedule if specimens are unobtainable due to hazardous conditions, seasonal unavailability, malfunction of automatic sampling equipment and other legitimate reasons. If specimens are unobtainable due to sampling equipment malfunction, every effort shall be made to complete corrective action prior to the end of the next sampling period. All deviations from the sampling schedule shall be documented in the Annual Radiological Environmental Operating Report pursuant to Specification 6.9.1.7. It is recognized that, at times, it may not be possible or practicable to continue to obtain samples of the media of choice at the most desired location or time. In these instances suitable alternative media and locations may be chosen for the particular pathway in question and appropriate substitutions made within 30 days in the radiological environmental monitoring program. Pursuant to Specification 6.9.1.8, identify the cause of the unavailability of samples for that pathway and identify the new location(s) for obtaining replacement samples in the next Semiannual Radioactive Effluent Release Report and also include in the report a revised figure(s) and table for the ODCM reflecting the new location(s).

[b]One or more instruments, such as a pressurized ion chamber, for measuring and recording dose rate continuously may be used in place of, or in addition to, integrating dosimeters. For the purposes of this table, a thermoluminescent dosimeter (TLD) is considered to be one phosphor; two or more phosphors in a packet are considered as two or more dosimeters. Film badges shall not be used as dosimeters for measuring direct radiation.

[c]Methodology for recovery of radioiodine shall be described in the ODCM.

[d]Airborne particulate sample filters shall be analyzed for gross beta radio activity 24 hours or more after sampling to allow for radon and thoron daughter decay. If gross beta activity in air particulate samples is greater than 10 times the yearly mean of control samples, gamma isotopic analysis shall be performed on the individual samples.

[e]Gamma isotopic analysis means the identification and quantification of gamma-emitting radionuclides that may be attributable to the effluents from the facility.

[f]The "upstream sample" shall be taken at a distance beyond significant influence of the discharge. The "downstream" sample shall be taken in an area beyond but near the mixing zone.

TABLE 3.12.1-1 (Continued)

RADIOLOGICAL ENVIRONMENTAL MONITORING PROGRAM

TABLE NOTATIONS

[g]A composite sample is one in which the quantity (aliquot) of liquid sampled is proportional to the quantity of flowing liquid and in which the method of sampling employed results in a specimen that is representative of the liquid flow. In this program composite sample aliquots shall be collected at time intervals that are very short (e.g., hourly) relative to the compositing period (e.g., monthly) in order to assure obtaining a representative sample.

[h]Groundwater samples shall be taken when this source is tapped for drinking or irrigation purposes in areas where the hydraulic gradient or recharge properties are suitable for contamination.

[i]The dose shall be calculated for the maximum organ and age group, using the methodology and parameters in the ODCM.

3/4.3.1 REACTOR PROTECTION SYSTEM INSTRUMENTATION

The reactor protection system automatically initiates a reactor scram to:

a. Preserve the integrity of the fuel cladding.

b. Preserve the integrity of the reactor coolant system.

c. Minimize the energy which must be absorbed following a loss-of-coolant accident, and

d. Prevent inadvertent criticality.

This specification provides the limiting conditions for operation necessary to preserve the ability of the system to perform its intended function even during periods when instrument channels may be out of service because of maintenance. When necessary, one channel may be made inoperable for brief intervals to conduct required surveillance.

The reactor protection system is made up of two independent trip systems. There are usually four channels to monitor each parameter with two channels in each trip system. The outputs of the channels in a trip system are combined in a logic so that either channel will trip that trip system. The tripping of both trip systems will produce a reactor scram. The system meets the intent of IEEE-279 for nuclear power plant protection systems. The bases for the trip settings of the RPS are discussed in the bases for Specification 2.2.1.

The measurement of response time at the specified frequencies provides assurance that the protective functions associated with each channel are completed within the time limit assumed in the safety analyses. No credit was taken for those channels with response times indicated as not applicable. Response time may be demonstrated by any series of sequential, overlapping or total channel test measurement, provided such tests demonstrate the total channel response time as defined. Sensor response time verification may be demonstrated by either (1) inplace, onsite or offsite test measurements, or (2) utilizing replacement sensors with certified response times.

3/4.3.2 ISOLATION ACTUATION INSTRUMENTATION

This specification ensures the effectiveness of the instrumentation used to mitigate the consequences of accidents by prescribing the OPERABILITY trip setpoints and response times for isolation of the reactor systems. When necessary, one channel may be inoperable for brief intervals to conduct required surveillance. Some of the trip settings may have tolerances explicitly stated where both the high and low values are critical and may have a substantial effect on safety. The setpoints of other instrumentation, where only the high or low end of the setting have a direct bearing on safety, are established at a level away from the normal operating range to prevent inadvertent actuation of the systems involved.

Except for the MSIVs, the safety analysis does not address individual sensor response times or the response times of the logic systems to which the sensors are connected. For D.C. operated valves, a 3 second delay is assumed before the valve starts to move. For A.C. operated valves, it is assumed that the A.C. power supply is lost and is restored by startup of the emergency diesel generators. In this event, a time of 13 seconds is assumed before the valve starts to move. In addition to the pipe break, the failure of the D.C. operated valve is assumed; thus the signal delay (sensor response) is concurrent with the 10-second diesel startup and the 3 second load center loading delay. The safety analysis considers an allowable inventory loss in each case which in turn determines the valve speed in conjunction with the 13-second delay. It follows that checking the valve speeds and the 13-second time for emergency power establishment will establish the response time for the isolation functions.

Operation with a trip set less conservative than its Trip Setpoint but within its specified Allowable Value is acceptable on the basis that the difference between each Trip Setpoint and the Allowable Value is an allowance for instrument drift specifically allocated for each trip in the safety analyses.

3/4.3.3 EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION

The emergency core cooling system actuation instrumentation is provided to initiate actions to mitigate the consequences of accidents that are beyond the ability of the operator to control. This specification provides the OPERABILITY requirements, trip setpoints and response times that will ensure effectiveness of the systems to provide the design protection. Although the instruments are listed by system, in some cases the same instrument may be used to send the actuation signal to more than one system at the same time.

Operation with a trip set less conservative than its Trip Setpoint but within its specified Allowable Value is acceptable on the basis that the difference between each Trip Setpoint and the Allowable Value is an allowance for instrument drift specifically allocated for each trip in the safety analyses.

3/4.3.7.12 RADIOACTIVE GASEOUS EFFLUENT MONITORING INSTRUMENTATION

The radioactive gaseous effluent instrumentation is provided to monitor and control, as applicable, the releases of radioactive materials in gaseous effluents during actual or potential releases of gaseous effluents. The alarm/trip setpoints for these instruments shall be calculated in accordance with the procedures in the ODCM to ensure that the alarm/trip will occur prior to exceeding the limits of 10 CFR Part 20. This instrumentation also includes provisions for monitoring the concentrations of potentially explosive gas mixtures in the off-gas system. The OPERABILITY and use of this instrumentation is consistent with the requirements of General Design Criteria 60, 63, and 64 of Appendix A to 10 CFR Part 50.

3/4.3.8 TURBINE OVERSPEED PROTECTION SYSTEM

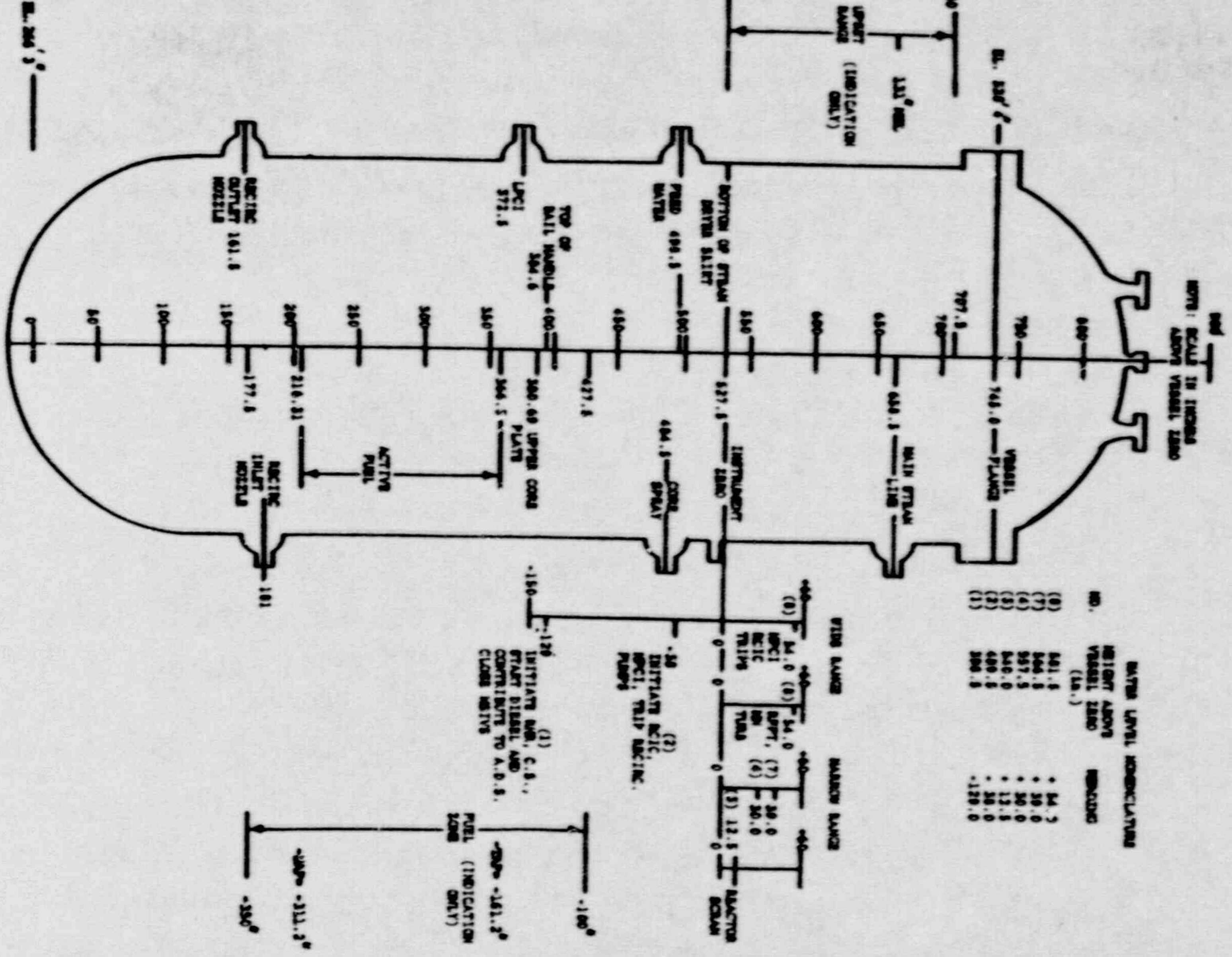
This specification is provided to ensure that the turbine overspeed protection system instrumentation and the turbine speed control valves are OPERABLE and will protect the turbine from excessive overspeed. Protection from turbine excessive overspeed is required since excessive overspeed of the turbine could generate potentially damaging missiles which could impact and damage safety related components, equipment or structures.

3/4.3.9 FEEDWATER/MAIN TURBINE TRIP SYSTEM ACTUATION INSTRUMENTATION

The feedwater/main turbine trip system actuation instrumentation is provided to initiate action of the feedwater system/main turbine trip system in the event of failure of feedwater controller under maximum demand.

Wide Range Level

This indication is reactor coolant temperature sensitive. The calibration is thus made at rated conditions. The level error at low pressures (temperatures) is bounded by the safety analysis which reflects the weight-of-coolant above the lower tap, and not indicated level.



BASES FIGURE B 3/4.3-1

REACTOR VESSEL WATER LEVEL

BASES TABLE B 3/4.4.6-1

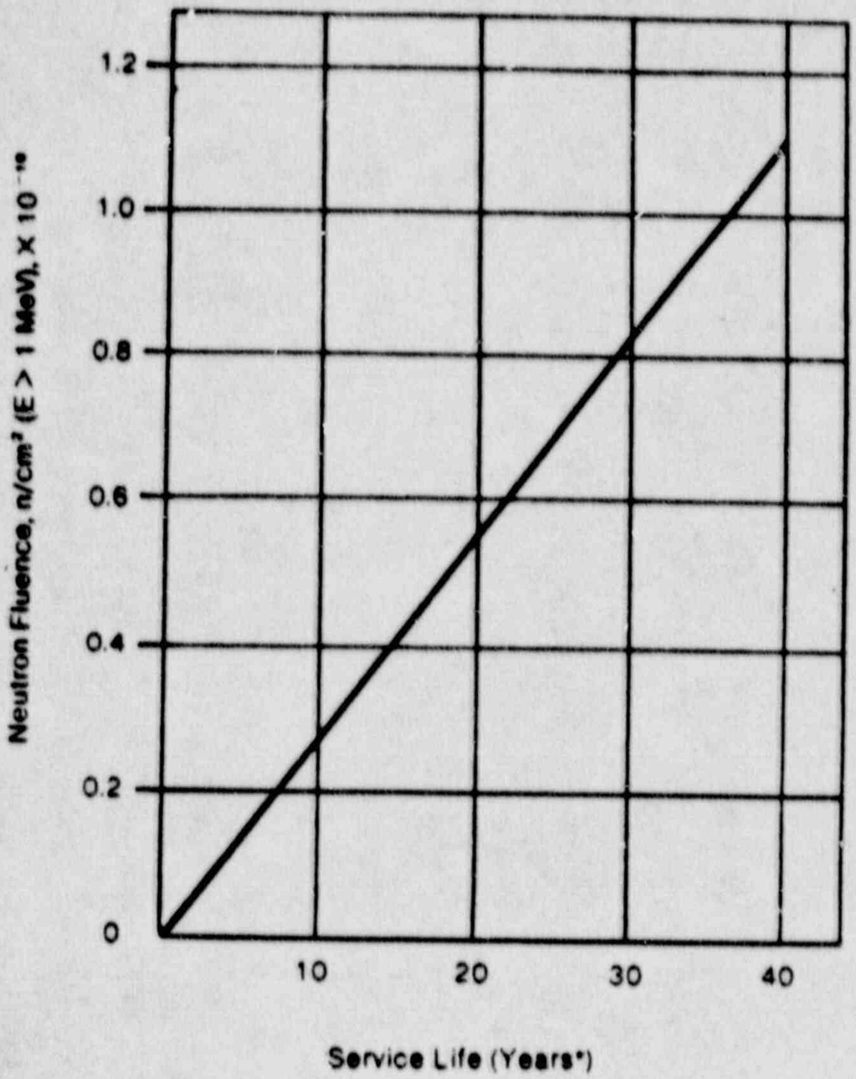
REACTOR VESSEL TOUGHNESS

BELTLINE COMPONENT	WELD SEAM I.D. OR MAT'L TYPE	HEAT/SLAB OR HEAT/LOT	CU (%)	P (%)	HIGHEST STARTING RT_{NDT} (°F)	MAX. * LRT_{NDT} (°F)	MIN. UPPER SHELF (LFT-LBS)	MAX. RT_{NDT} (°F)
Plate	SA-533 Gr B CL.1	C 7677-1	.11	.016	+20	+36	NA	+56
Weld	SFA 5.5, (E 80T8-G)	662A746/ H013A27A	.03	.021	-20	+35	NA	+15

NOTE:* These values are given only for the benefit of calculating the end-of-life (EOL) RT_{NDT}

NON-BELTLINE COMPONENT	MT'L TYPE OR WELD STEAM I.D.	HEAT/SLAB OR HEAT/LOT	HIGHEST STARTING RT_{NDT} (°F)
Shell Ring	SA 533, Gr. B, CL. 1	C7711-1	+20
Bottom Head Dome	"	C7973-1	+12
Bottom Head Torus	"	C7973-1	+12
Top Head Dome	"	A6834-1	+10
Top Head Torus	"	B1993-1	+10
Top Head Flange	SA-508, CL. 2	123B195-289	0
Vessel Flange	"	2V1924-302	-30
Feedwater Nozzle	"	Q2Q22W-412	-10
Weld	Non-Beltline	All	0
LPCI Nozzle *	SA-508, CL. 2	Q2Q25W	-6
Closure Studs	SA-540, Gr. B-24	All	Meet requirements of 45 ft-lbs and 25 mils Lat. Exp. at +10°F

* The design of the LPCI nozzles results in their experiencing an EOL fluence in excess of 10^{17} N/Cm^2 which predicts an EOL RT_{NDT} of +14°F.



FAST NEUTRON FLUENCE (E>1 MeV) AT ¼ T AS A FUNCTION OF SERVICE LIFE*

BASES FIGURE B 3/4.4.6-1

* At 90% of RATED THERMAL POWER and 90% availability.

3/4.6.1 PRIMARY CONTAINMENT

3/4.6.1.1 PRIMARY CONTAINMENT INTEGRITY

PRIMARY CONTAINMENT INTEGRITY ensures that the release of radioactive materials from the containment atmosphere will be restricted to those leakage paths and associated leak rates assumed in the safety analyses. This restriction, in conjunction with the leakage rate limitation, will limit the SITE BOUNDARY radiation doses to within the limits of 10 CFR Part 100 during accident conditions.

3/4.6.1.2 PRIMARY CONTAINMENT LEAKAGE

The limitations on primary containment leakage rates ensure that the total containment leakage volume will not exceed the value assumed in the safety analyses at the peak accident pressure of 44.02 psig, P_a. As an added conservatism, the measured overall integrated leakage rate is further limited to less than or equal to 0.75 L_a during performance of the periodic tests to account for possible degradation of the containment leakage barriers between leakage tests.

Operating experience with the main steam line isolation valves has indicated that degradation has occasionally occurred in the leak tightness of the valves; therefore the special requirement for testing these valves.

The surveillance testing for measuring leakage rates is consistent with the requirements of Appendix J of 10 CFR Part 50 with the exception of exemptions granted for leak testing of the main steam isolation valves, the airlock and TIP shear valves.

3/4.6.1.3 PRIMARY CONTAINMENT AIR LOCK

The limitations on closure and leak rate for the primary containment air lock are required to meet the restrictions on PRIMARY CONTAINMENT INTEGRITY and the primary containment leakage rate given in Specifications 3.6.1.1 and 3.6.1.2. The specification makes allowances for the fact that there may be long periods of time when the air lock will be in a closed and secured position during reactor operation. Only one closed door in the air lock is required to maintain the integrity of the containment.

3/4.6.1.4 MSIV LEAKAGE CONTROL SYSTEM

Calculated doses resulting from the maximum leakage allowance for the main steamline isolation valves in the postulated LOCA situations would be a small fraction of the 10 CFR Part 100 guidelines, provided the main steam line system from the isolation valves up to and including the turbine condenser remains intact. Operating experience has indicated that degradation has occasionally occurred in the leak tightness of the MSIVs such that the specified leakage requirements have not always been maintained continuously. The requirement for the leakage control system will reduce the untreated leakage from the MSIVs when isolation of the primary system and containment is required.

3/4.6.1.5 PRIMARY CONTAINMENT STRUCTURAL INTEGRITY

This limitation ensures that the structural integrity of the containment will be maintained comparable to the original design standards for the life of the unit. Structural integrity is required to ensure that the containment will withstand the maximum pressure of 44.02 psig in the event of a LOCA. A visual inspection in conjunction with Type A leakage tests is sufficient to demonstrate this capability.

3/4.6.1.6 DRYWELL AND SUPPRESSION CHAMBER INTERNAL PRESSURE

The limitations on drywell and suppression chamber internal pressure ensure that the containment peak pressure of 44.02 psig does not exceed the design pressure of 55 psig during LOCA conditions or that the external pressure differential does not exceed the design maximum external pressure differential of 5.0 psid. The limit of - 1.0 to + 2.0 psig for initial containment pressure will limit the total pressure to 44.02 psig which is less than the design pressure and is consistent with the safety analysis.

3/4.6.1.7 DRYWELL AVERAGE AIR TEMPERATURE

The limitation on drywell average air temperature ensures that the containment peak air temperature does not exceed the design temperature of 340°F during steam line break conditions and is consistent with the safety analysis.

3/4.6.1.8 DRYWELL AND SUPPRESSION CHAMBER PURGE SYSTEM

The drywell and suppression chamber purge supply and exhaust isolation valves are required to be closed during plant operation except as required for inerting, deinerting and pressure control. The 90 hours per 365 day limit on purge valve operation is imposed to protect the integrity of the SGTS filters. Analysis indicates that should a LOCA occur while this pathway is being utilized, the associated pressure surge through the (18 or 24") purge lines will adversely affect the integrity of SGTS. This limit is not imposed, however, on the subject valves when pressure control is being performed through the 2-inch bypass line, since a pressure surge through this line does not threaten the OPERABILITY of SGTS.

3/4.6.2. DEPRESSURIZATION SYSTEMS

The specifications of this section ensure that the primary containment pressure will not exceed the design pressure of 55 psig during primary system blowdown from full operating pressure.

The suppression chamber water provides the heat sink for the reactor coolant system energy release following a postulated rupture of the system. The suppression chamber water volume must absorb the associated decay and structural sensible heat released during reactor coolant system blowdown from 1040 psig. Since all of the gases in the drywell are purged into the suppression chamber air space during a loss-of-coolant accident, the pressure of the suppression chamber air space must not exceed 55 psig. The design volume of the suppression chamber, water and air, was obtained by considering that the total volume of reactor coolant is discharged to the suppression chamber and that the drywell volume is purged to the suppression chamber.

Using the minimum or maximum water volumes given in this specification, suppression pool pressure during the design basis accident is approximately 30 psig which is below the design pressure of 55 psig. Maximum water volume of 134,600 ft^3 results in a downcomer submergence of 12'3" and the minimum volume of 122,120 ft^3 results in a submergence approximately 2'3" less. The majority of the Bodega tests were run with a submerged length of 4 feet and with complete condensation. Thus, with respect to the downcomer submergence, this specification is adequate. The maximum temperature at the end of the blowdown tested during the Humboldt Bay and Bodega Bay tests was 170°F and this is conservatively taken to be the limit for complete condensation of the reactor coolant, although condensation would occur for temperatures above 170°F.

Should it be necessary to make the suppression chamber inoperable, this shall only be done as specified in Specification 3.5.3.

Under full power operating conditions, blowdown through safety/relief valves assuming an initial suppression chamber water temperature of 95°F results in a bulk water temperature of approximately 136°F immediately following blowdown which is below the 190°F bulk temperature limit used for complete condensation via T-quencher devices. At this temperature and atmospheric pressure, the available NPSH exceeds that required by both the RHR and core spray pumps, thus there is no dependency on containment overpressure during the accident injection phase. If both RHR loops are used for containment cooling, there is no dependency on containment overpressure for post-LOCA operations.

Experimental data indicate that excessive steam condensing loads can be avoided if the peak local temperature of the suppression pool is maintained below 200°F during any period of relief valve operation for T-quencher devices. Specifications have been placed on the envelope of reactor operating conditions so that the reactor can be depressurized in a timely manner to avoid the regime of potentially high suppression chamber loadings.

DEPRESSURIZATION SYSTEMS (Continued)

Because of the large volume and thermal capacity of the suppression pool, the volume and temperature normally changes very slowly and monitoring these parameters daily is sufficient to establish any temperature trends. By requiring the suppression pool temperature to be frequently recorded during periods of significant heat addition, the temperature trends will be closely followed so that appropriate action can be taken.

In addition to the limits on temperature of the suppression chamber pool water, operating procedures define the action to be taken in the event a safety-relief valve inadvertently opens or sticks open. As a minimum this action shall include: (1) use of all available means to close the valve, (2) initiate suppression pool water cooling, (3) initiate reactor shutdown, and (4) if other safety-relief valves are used to depressurize the reactor, their discharge shall be separated from that of the stuck-open safety/relief valve to assure mixing and uniformity of energy insertion to the pool.

3/4.6.3 PRIMARY CONTAINMENT ISOLATION VALVES

The OPERABILITY of the primary containment isolation valves ensures that the containment atmosphere will be isolated from the outside environment in the event of a release of radioactive material to the containment atmosphere or pressurization of the containment and is consistent with the requirements of GDC 54 through 57 of Appendix A of 10 CFR Part 50. Containment isolation within the time limits specified for those isolation valves designed to close automatically ensures that the release of radioactive material to the environment will be consistent with the assumptions used in the analyses for a LOCA.

3/4.6.4 VACUUM RELIEF

Vacuum relief valves are provided to equalize the pressure between the suppression chamber and drywell. This system will maintain the structural integrity of the primary containment under conditions of large differential pressures.

The vacuum breakers between the suppression chamber and the drywell must not be inoperable in the open position since this would allow bypassing of the suppression pool in case of an accident. There are four pairs of valves to provide redundancy so that operation may continue for up to 72 hours with no more than one pair of vacuum breakers inoperable in the closed position.

Each vacuum breaker valve's position indication system is of great enough sensitivity to ensure that the maximum steam bypass leakage coefficient of

$$\frac{A}{\sqrt{k}} = 0.05 \text{ ft}^2$$

for the vacuum relief system (assuming one valve fully open) will not be exceeded.

3/4.8.4 ELECTRICAL EQUIPMENT PROTECTIVE DEVICES

Primary containment electrical penetrations and penetration conductors are protected by either de-energizing circuits not required during reactor operation or demonstrating the OPERABILITY of primary and backup overcurrent protection circuit breakers by periodic surveillance.

The surveillance requirements applicable to lower voltage circuit breakers provides assurance of breaker reliability by testing at least one representative sample of each manufacturers brand of circuit breaker. Each manufacturer's molded case circuit breakers are grouped into representative samples, which are then tested on a rotating basis to ensure that all breakers are tested.

The bypassing of the motor operated valves thermal overload protection continuously by integral bypass devices ensures that the thermal overload protection will not prevent safety related valves from performing their function. The Surveillance Requirements for demonstrating the bypassing of the thermal overload protection continuously are met by functionally testing the automatic operation of the motor operated valve and ensuring that the motor thermal overload protection design does not change and is in accordance with Regulatory Guide 1.106 "Thermal Overload Protection for Electric Motors on Motor Operated Valves", Revision 1, March 1977.

3/4.10.1 PRIMARY CONTAINMENT INTEGRITY

The requirement for PRIMARY CONTAINMENT INTEGRITY is not applicable during the period when open vessel tests are being performed during the low power PHYSICS TESTS.

3/4.10.2 ROD WORTH MINIMIZER

In order to perform the tests required in the technical specifications it is necessary to bypass the sequence restraints on control rod movement. The additional surveillance requirements ensure that the specifications on heat generation rates and shutdown margin requirements are not exceeded during the period when these tests are being performed and that individual rod worths do not exceed the values assumed in the safety analysis.

3/4.10.3 SHUTDOWN MARGIN DEMONSTRATIONS

Performance of shutdown margin demonstrations with the vessel head removed requires additional restrictions in order to ensure that criticality does not occur. These additional restrictions are specified in this LCO.

3/4.10.4 RECIRCULATION LOOPS

This special test exception permits reactor criticality under no flow conditions and is required to perform certain startup and PHYSICS TESTS while at low THERMAL POWER levels.

3/4.10.5 OXYGEN CONCENTRATION

Relief from the oxygen concentration specifications is necessary in order to provide access to the primary containment during the initial startup and testing phase of operation. Without this access the startup and test program could be restricted and delayed.

3/4.10.6 TRAINING STARTUPS

This special test exception permits training startups to be performed with the reactor vessel depressurized at low THERMAL POWER and temperature while controlling RCS temperature with one RHR subsystem aligned in the shutdown cooling mode in order to minimize contaminated water discharge to the radioactive waste disposal system.

5.0 DESIGN FEATURES

5.1 SITE

EXCLUSION AREA

5.1.1 The exclusion area shall be as shown in Figure 5.1.1-1.

LOW POPULATION ZONE

5.1.2 The low population zone shall be as shown in Figure 5.1.2-1.

MAPS DEFINING UNRESTRICTED AREAS AND SITE BOUNDARY FOR RADIOACTIVE GASEOUS AND LIQUID EFFLUENTS

5.1.3 Information regarding radioactive gaseous and liquid effluents, which will allow identification of structures and release points as well as definition of UNRESTRICTED AREAS within the SITE BOUNDARY that are accessible to MEMBER OF THE PUBLIC, shall be as shown in Figures 5.1.3-1a and 5.1.3-1b.

METEOROLOGICAL TOWER LOCATION

5.1.4 The meteorological towers shall be located as shown on Figure 5.1.4-1.

5.2 CONTAINMENT

CONFIGURATION

5.2.1 The primary containment is a steel lined reinforced concrete structure consisting of a drywell and suppression chamber. The drywell is a steel-lined reinforced concrete vessel in the shape of a truncated cone on top of a water filled suppression chamber and is separated by a diaphragm slab and connected to the suppression chamber through a series of downcomer vents. The drywell has a maximum free air volume of 243,580 cubic feet at a minimum suppression pool level of 22 feet. The suppression chamber has a maximum air region of 159,540 cubic feet and a minimum water region of 122,120 cubic feet.

DESIGN TEMPERATURE AND PRESSURE

5.2.2 The primary containment is designed and shall be maintained for:

a. Maximum internal pressure 55 psig.

b. Maximum internal temperature: drywell 340°F.
suppression pool 220°F.

c. Maximum external to internal differential pressure 5 psid.

d. Maximum floor differential pressure: 30 psid, downward.
20 psid, upward.

FIGURE 5.1.1-1

EXCLUSION AREA

TABLE 6.2.2-1

MINIMUM SHIFT CREW COMPOSITION

TWO UNITS WITH A COMMON CONTROL ROOM

WITH UNIT 2 IN CONDITION 4 OR 5 OR DEFUELED

POSITION	NUMBER OF INDIVIDUALS REQUIRED TO FILL POSITION	
	CONDITION 1, 2, or 3	CONDITION 4 or 5
SS	1*	1*
SRO	1*	1*
RO	2	1
NLO	2	2**
STA	1	None

WITH UNIT 2 IN CONDITION 1, 2, OR 3

POSITION	NUMBER OF INDIVIDUALS REQUIRED TO FILL POSITION	
	CONDITION 1, 2, or 3	CONDITION 4 or 5
SS	1*	1*
SRO	1*	1*
RO	2**	1
NLO	2**	1
STA	1*	None

TABLE NOTATIONS

*Individual may fill the same position on Unit 2.
**One of the two required individuals may fill the same position on Unit 2.

SS - Shift Superintendent or Shift Supervisor with a Senior Operator license on Unit 1.
SRO - Individual with a Senior Operator license on Unit 1.
RO - Individual with an Operator license on Unit 1.
NLO - Non-licensed operator properly qualified to support the unit to which assigned.
STA - Shift Technical Advisor

Except for Shift Supervision (SS), the shift crew composition may be one less than the minimum requirements of Table 6.2.2-1 for a period of time not to exceed 2 hours in order to accommodate unexpected absence of on-duty shift crew members provided immediate action is taken to restore the shift crew composition to within the minimum requirements of Table 6.2.2-1. This provision does not permit any shift crew position to be unmanned upon shift change due to an oncoming shift crewman being late or absent.

During any absence of Shift Supervision (SS) from the control room while the unit is in OPERATIONAL CONDITION 1, 2, or 3, an individual (other than the Shift Technical Advisor) with a valid Senior Operator license shall be designated to assume the control room command function. During any absence of Shift Supervision from the control room while the unit is in OPERATIONAL CONDITION 4 or 5, an individual with a valid Senior Operator license or Operator license shall be designated to assume the control room command function.

6.2.3 INDEPENDENT SAFETY ENGINEERING GROUP (ISEG)

FUNCTION

6.2.3.1 The ISEG shall function to examine unit operating characteristics, NRC issuances, industry advisories, Licensee Event Reports, and other sources of unit design and operating experience information, including units of similar design, which may indicate areas for improving unit safety. The ISEG shall make detailed recommendations for revised procedures, equipment modifications, maintenance activities, operations activities, or other means of improving unit safety. Such recommendations shall be submitted through the General Manager-Nuclear Quality Assurance to the Senior Vice President-Nuclear.

COMPOSITION

6.2.3.2 The Limerick ISEG shall be composed of at least three, dedicated, full-time engineers, including the ISEG Supervisor, located onsite. Each shall have a bachelor's degree in engineering or related science and at least two years professional level experience in his or her field. The Limerick ISEG Supervisor shall have at least six years of experience in the nuclear field. The corporate ISEG shall be composed of two dedicated full time engineers each with a Bachelors degree in engineering or related science and at least 2 years professional level experience in his or her field, at least 1 year of which experience shall be in the nuclear field. The LGS ISEG reports to the Independent Safety Engineering Manager.

RESPONSIBILITIES

6.2.3.3 The ISEG shall be responsible for maintaining surveillance of unit activities to provide independent verification[*] that these activities are performed correctly and that human errors are reduced as much as practical.

RECORDS

6.2.3.4 Records of activities performed by the ISEG shall be prepared, maintained, and forwarded each calendar month to the Independent Safety Engineering Manager.

6.2.4 SHIFT TECHNICAL ADVISOR

6.2.4.1 The Shift Technical Adviser shall provide advisory technical support to Shift Supervision in the areas of thermal hydraulics, reactor engineering, and plant analysis with regard to safe operation of the unit. The Shift Technical Advisor shall have a bachelor's degree or equivalent in a scientific or engineering discipline and shall have received specific training in the response and analysis of the unit for transients and accidents, and in unit design and layout, including the capabilities of instrumentation and controls in the control room.

6.3 UNIT STAFF QUALIFICATIONS

6.3.1 Each member of the unit staff shall meet or exceed the minimum qualifications of ANSI/ANS 3.1-1978 for comparable positions, except for the Senior Health Physicist who shall meet or exceed the qualifications of Regulatory Guide 1.8, September 1975. The licensed Operators and Senior Operators shall also meet or exceed the minimum qualifications of the supplemental requirements specified in Sections A and C of Enclosure 1 of the March 28, 1980 NRC letter to all licensees.

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*Not responsible for sign-off function.

6.4 TRAINING

6.4.1 A retraining and replacement training program for the unit staff shall be maintained under the direction of site training organization and shall meet or exceed the requirements of ANSI/ANS 3.1-1978 and 10 CFR Part 55 and the supplemental requirements specified in Sections A and C of Enclosure 1 of the March 28, 1980 NRC letter to all licensees, and shall include familiarization with relevant industry operational experience.

6.5 REVIEW AND AUDIT

6.5.1 PLANT OPERATIONS REVIEW COMMITTEE (PORC)

FUNCTION

6.5.1.1 The PORC shall function to advise the Plant Manager on all matters related to nuclear safety.

COMPOSITION

6.5.1.2 The PORC shall be composed of the:

Chairman:	Superintendent - Operations
Member:	Superintendent - Technical
Member:	Superintendent - Maintenance/Instrumentation and Controls
Member:	Superintendent - Plant Services
Member:	Assistant Superintendent - Operations
Member:	Regulatory Engineer
Member:	Technical Engineer
Member:	Shift Superintendent
Member:	Maintenance Engineer

ALTERNATES

6.5.1.3 All alternate members shall be appointed in writing by the PORC Chairman to serve on a temporary basis; however, no more than two alternates shall participate as voting members in PORC activities at any one time.

MEETING FREQUENCY

6.5.1.4 The PORC shall meet at least once per calendar month and as convened by the PORC Chairman or his designated alternate.

QUORUM

6.5.1.5 The quorum of the PORC necessary for the performance of the PORC responsibility and authority provisions of these Technical Specifications shall consist of the Chairman or his designated alternate and four members including alternates.

RESPONSIBILITIES

6.5.1.6 The PORC shall be responsible for:

a. Review of (1) all procedures required by Specification 6.8 and changes thereto, (2) all programs required by Specification 6.8 and changes thereto, and (3) any other procedures or changes thereto as determined by the Plant Manager to affect nuclear safety;

b. Review of all proposed tests and experiments that affect nuclear safety;

c. Review of all proposed changes to Appendix A Technical Specifications;

d. Review of all proposed changes or modifications to unit systems or equipment that affect nuclear safety;

e. Review of the safety evaluations for procedures and changes thereto completed under the provisions of 10 CFR 50.59.

f. Investigation of all violations of the Technical Specifications, including the preparation and forwarding of reports covering evaluation and recommendations to prevent recurrence, to the Vice President, Limerick Generating Station, Plant Manager, and to the Nuclear Review Board;

g. Review of all REPORTABLE EVENTS;

h. Review of unit operations to detect potential hazards to nuclear safety;

i. Performance of special reviews, investigations, or analyses and reports thereon as requested by the Vice President, Limerick Generating Station, Plant Manager or the Chairman of the Nuclear Review Board;

j. Review of the Security Plan and implementing procedures and submittal of recommended changes to the Nuclear Review Board; and

k. Review of the Emergency Plan and implementing procedures and submittal of the recommended changes to the Nuclear Review Board.

l. Review of every unplanned onsite release of radioactive material to the environs including the preparation and forwarding of reports covering evaluation, recommendations and disposition of the corrective action to prevent recurrence to the Vice President, Limerick Generating Station, Plant Manager, and to the Nuclear Review Board.

m. Review of changes to the PROCESS CONTROL PROGRAM, OFFSITE DOSE CALCULATION MANUAL, and radwaste treatment systems.

6.5.1.7 The PORC shall:

a. Recommend in writing to the Plant Manager approval or disapproval of items considered under Specification 6.5.1.6a. through d. prior to their implementation.

b. Render determinations in writing with regard to whether or not each item considered under Specification 6.5.1.6a. through f. constitutes an unreviewed safety question.

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