Docket No.: 50-387

APR 12 1985

Mr. Norman W. Curtis
Vice President
Engineering and Construction - Nuclear
Pennsylvania Power & Light Company
2 North Ninth Street
Allentown, Pennsylvania 18101

Dear Mr. Curtis:

Subject: Amendment No. 36 to Facility Operating License No. NPF-14 - Susquehanna Steam Electric Station, Unit 1

The Nuclear Regulatory Commission has issued the enclosed Amendment No. 36 to Facility Operating License No. NPF-14 for the Susquehanna Steam Electric Station, Unit 1. The amendment is in response to your letter dated May 18, 1984, as supplemented, on September 20, 1984, March 11 and 13, 1985, and April 4, 1985, and your letter dated September 7, 1984. This amendment updates the Unit 1 Technical Specifications to provide consistency between Unit 1 and Unit 2. Additionally, this amendment changes the required isolation times on the containment purge valves and removes the 50% blocking requirement.

A copy of the related safety evaluation supporting Amendment No. 36 to Facility Operating License No. NPF-14 is enclosed.

Sincerely,

/S/

A. Schwencer, Chief
Licensing Branch No. 2
Division of Licensing

Enclosures:
1. Amendment No. 36 to NPF-14
2. Safety Evaluation

cc w/enclosures: See Reports
See next page

*Previous concurrence concurred on by:

*LB#2:DL	*LB#2:DL	*LB#2:DL	*OELD	~~AD:L:DL~~
MCampagnone:kab	EHylton	ASchwencer		TNovak
04/03/85	04/04/85	04/04/85	04/05/85	04/12/85

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DISTRIBUTION: Dated: April 12, 1985

Docket File (DCS-016) (Docket No. 50-387)
NRC PDR
L PDR
PRC System
NSIC
LB#2 R/F
EHylton
MCampagnone
JSaltzman, SAB
OELD
CMiles
HDenton
JRutberg
AToalston
WMiller, LFMB
JPartlow
BGrimes
EJordan
LHarmon
EButcher, SSPB
TBarnhart (4)
IBailey

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

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Licensing Branch No. 2
Division of Licensing

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1. Amendment No. 36 to NPF-14
2. Safety Evaluation

cc w/enclosures:
See next page

Susquehanna

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

PENNSYLVANIA POWER & LIGHT COMPANY

ALLEGHENY ELECTRIC COOPERATIVE, INC.

DOCKET NO. 50-387

SUSQUEHANNA STEAM ELECTRIC STATION, UNIT 1

AMENDMENT TO FACILITY OPERATING LICENSE

Amendment No. 36
License No. NPF-14

1. The Nuclear Regulatory Commission (the Commission or the NRC) having found that:

   A. The application for an amendment filed by the Pennsylvania Power & Light Company, dated May 18, 1984 as supplemented on September 20, 1984 and a letter dated September 7, 1984, complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act), and the Commission's 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 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 the Facility Operating License No. NPF-14 is hereby amended to read as follows:

   (2) Technical Specifications and Environmental Protection Plan

   The Technical Specifications contained in Appendix A, as revised through Amendment No. 36 , and the Environmental Protection Plan contained in Appendix B, are hereby incorporated in the license. PP&L shall operate the facility in accordance with the Technical Specifications and the Environmental Protection Plan.

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3. This amendment is effective as of the date of issuance except for the amendment to the Technical Specifications listed below. The amendment to the Technical Specifications indicated below is effective as of 90 days from the date of issuance.

Specification

Table 3.3.2-3, function 1d
Table 3.3.2-3, function 1e
Table 3.3.2-3, function 5j
Table 3.3.2-3, function 6j
Table 4.3.2.1-1, function 1d
Table 4.3.2.1-1, function 1e
Table 4.3.2.1-1, function 3i
Table 4.3.2.1-1, function 5j
Table 4.3.2.1-1, function 6j
Table 4.3.2.1-1, function 7g
Table 4.3.3.1-1, function 2c(2)
Table 3.6.3-1, HV-151F008, signal A
Table 3.6.3-1, HV-151F009, signal A
Table 3.6.3-1, HV-151F022, signal A
Table 3.6.3-1, HV-151F023, signal A
Table 3.6.3-1, SV-12661, signal B
Table 3.6.3-1, SV-12671, signal B
Table 3.6.3-1, HV-15703, signal B
Table 3.6.3-1, HV-15704, signal B
Table 3.6.3-1, HV-15705, signal B
Table 3.6.3-1, HV-15711, signal B
Table 3.6.3-1, HV-15713, signal B
Table 3.6.3-1, HV-15714, signal B
Table 3.6.3-1, HV-15721, signal B
Table 3.6.3-1, HV-15722, signal B
Table 3.6.3-1, HV-15723, signal B
Table 3.6.3-1, HV-15724, signal B
Table 3.6.3-1, HV-15725, signal B
Table 3.6.3-1, HV-18791, A1, A2, B1, B2, signal B
Table 3.6.3-1, HV-18792, A1, A2, B1, B2, signal B
Table 3.6.3-1, HV-12603, signal Z
Table 3.6.3-1, SV-12605, signal Z
Table 3.6.3-1, SV-12651, signal Z
Table 3.6.3-1, HV-11313, signal Z
Table 3.6.3-1, HV-11314, signal Z
Table 3.6.3-1, HV-11345, signal Z
Table 3.6.3-1, HV-11346, signal Z
Table 3.6.3-1, HV-18781, A1, A2, B1, B2, signal Z
Table 3.6.3-1, HV-18782, A1, A2, B1, B2, signal Z
Table 3.6.3-1, SV-15734, A, B, signal B
Table 3.6.3-1, SV-15736, A, B, signal B
Table 3.6.3-1, SV-15737, signal B

Table 3.6.3-1, SV-15740, A, B, signal B
Table 3.6.3-1, SV-15742, A, B, signal B
Table 3.6.3-1, SV-15750, A, B, signal B
Table 3.6.3-1, SV-15752, A, B, signal B
Table 3.6.3-1, SV-15767, signal B
Table 3.6.3-1, SV-15774, A, B, signal B
Table 3.6.3-1, SV-15776, A, B, signal B
Table 3.6.3-1, SV-15780, A, B, signal B
Table 3.6.3-1, SV-15782, A, B, signal B
Table 3.6.3-1, HV-16108, A1, A2, signal B
Table 3.6.3-1, HV-16116, A1, A2, signal B
Table 3.6.3-1, SV-15736B, signal R
Table 3.6.3-1, SV-15776B, signal R
Table 3.6.3-1, HV-151F011, A, B, signals X, Z
Table 3.6.3-1, HV-15766, signal A
Table 3.6.3-1, HV-15768, signal A
Table 3.6.3-1, TIP Ball Valves, signal A
Table 3.6.5.2-1, Additional dampers

FOR THE NUCLEAR REGULATORY COMMISSION

A. Schwencer

A. Schwencer, Chief
Licensing Branch No. 2
Division of Licensing

Attachment:
Changes to the Technical
Specifications

Date of Issuance: APR 12 1985

ATTACHMENT TO LICENSE AMENDMENT NO. 36

FACILITY OPERATING LICENSE NO. NPF-14

DOCKET NO. 50-387

Replace the following pages of the Appendix "A" Technical Specifications with enclosed pages. The revised pages are identified by Amendment number and contain vertical lines indicating the area of change.

REMOVE	INSERT
vii	vii
viii	viii
1-1	1-1
1-2	1-2
2-3	2-3
2-4	2-4
3/4 1-1	3/4 1-1
3/4 1-2	3/4 1-2
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3/4 3-77	3/4 3-77
3/4 3-78	3/4 3-78
3/4 3-78A	3/4 3-78A
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3/4 6-31b	3/4 6-31b
3/4 6-32	3/4 6-32
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3/4 7-1	3/4 7-1
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3/4 8-3	3/4 8-3
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3/4 8-8	3/4 8-8
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B 3/4 7-2	B 3/4 7-2
B 3/4 7-3	B 3/4 7-3
B 3/4 7-4	B 3/4 7-4

LIMITING CONDITIONS FOR OPERATION AND SURVEILLANCE REQUIREMENTS

SECTION		PAGE
3/4.6 CONTAINMENT SYSTEMS		
3/4.6.1	PRIMARY CONTAINMENT	
	Primary Containment Integrity	3/4 6-1
	Primary Containment Leakage	3/4 6-2
	Primary Containment Air Locks	3/4 6-5
	MSIV Leakage Control System	3/4 6-7
	Primary Containment Structural Integrity	3/4 6-8
	Drywell and Suppression Chamber Internal Pressure	3/4 6-9
	Drywell Average Air Temperature	3/4 6-10
	Drywell and Suppression Chamber Purge System	3/4 6-11
3/4.6.2	DEPRESSURIZATION SYSTEMS	
	Suppression Chamber	3/4 6-12
	Suppression Pool Spray	3/4 6-15
	Suppression Pool Cooling	3/4 6-16
3/4.6.3	PRIMARY CONTAINMENT ISOLATION VALVES	3/4 6-17
3/4.6.4	VACUUM RELIEF	3/4 6-29
3/4.6.5	SECONDARY CONTAINMENT	
	Secondary Containment Integrity	3/4 6-31
	Secondary Containment Automatic Isolation Dampers	3/4 6-32
	Standby Gas Treatment System	3/4 6-34
3/4.6.6	PRIMARY CONTAINMENT ATMOSPHERE CONTROL	
	Drywell and Suppression Chamber Hydrogen Recombiner Systems	3/4 6-37
	Drywell Air Flow System	3/4 6-38
	Drywell and Suppression Chamber Oxygen Concentration	3/4 6-39

SECTION		PAGE
3/4.7 PLANT SYSTEMS		
3/4.7.1	SERVICE WATER SYSTEMS	
	Residual Heat Removal Service Water System.....	3/4 7-1
	Emergency Service Water System.....	3/4 7-2 29
	Ultimate Heat Sink.....	3/4 7-4
3/4.7.2	CONTROL ROOM EMERGENCY OUTSIDE AIR SUPPLY SYSTEM.....	3/4 7-5
3/4.7.3	REACTOR CORE ISOLATION COOLING SYSTEM.....	3/4 7-8
3/4.7.4	SNUBBERS.....	3/4 7-10
3/4.7.5	SEALED SOURCE CONTAMINATION.....	3/4 7-14
3/4.7.6	FIRE SUPPRESSION SYSTEMS	
	Fire Suppression Water System.....	3/4 7-16
	Spray and Sprinkler Systems.....	3/4 7-19
	CO_2 Systems.....	3/4 7-21
	Halon Systems.....	3/4 7-22
	Fire Hose Stations.....	3/4 7-23
	Yard Fire Hydrants and Hydrant Hose Houses.....	3/4 7-25
3/4.7.7	FIRE RATED ASSEMBLIES.....	3/4 7-26
3/4.7.8	MAIN TURBINE BYPASS SYSTEM.....	3/4 7-28

1.0 DEFINITIONS

The following terms are defined so that uniform interpretation of these specifications may be achieved. The defined terms appear in capitalized type and shall be applicable throughout these Technical Specifications.

ACTION

1.1 ACTION shall be that part of a Specification which prescribes remedial measures required under designated conditions.

AVERAGE PLANAR EXPOSURE

1.2 The AVERAGE PLANAR EXPOSURE shall be applicable to a specific planar height and is equal to the sum of the exposure of all the fuel rods in the specified bundle at the specified height divided by the number of fuel rods in the fuel bundle.

AVERAGE PLANAR LINEAR HEAT GENERATION RATE

1.3 The AVERAGE PLANAR LINEAR HEAT GENERATION RATE (APLHGR) shall be applicable to a specific planar height and is equal to the sum of the LINEAR HEAT GENERATION RATES for all the fuel rods in the specified bundle at the specified height divided by the number of fuel rods in the fuel bundle.

CHANNEL CALIBRATION

1.4 A CHANNEL CALIBRATION shall be the adjustment, as necessary, of the channel output such that it responds with the necessary range and accuracy to known values of the parameter which the channel monitors. The CHANNEL CALIBRATION shall encompass the entire channel including the sensor and alarm and/or trip functions, and shall include the CHANNEL FUNCTIONAL TEST. The CHANNEL CALIBRATION may be performed by any series of sequential, overlapping or total channel steps such that the entire channel is calibrated.

CHANNEL CHECK

1.5 A CHANNEL CHECK shall be the qualitative assessment of channel behavior during operation by observation. This determination shall include, where possible, comparison of the channel indication and/or status with other indications and/or status derived from independent instrument channels measuring the same parameter.

CHANNEL FUNCTIONAL TEST

1.6 A CHANNEL FUNCTIONAL TEST shall be:

a. Analog channels - the injection of a simulated signal into the channel as close to the sensor as practicable to verify OPERABILITY including alarm and/or trip functions and channel failure trips.

b. Bistable channels - the injection of a simulated signal into the sensor to verify OPERABILITY including alarm and/or trip functions.

The CHANNEL FUNCTIONAL TEST may be performed by any series of sequential, overlapping or total channel steps such that the entire channel is tested.

CORE ALTERATION

1.7 CORE ALTERATION shall be the addition, removal, relocation or movement of fuel, sources, or reactivity controls within the reactor pressure vessel with the vessel head removed and fuel in the vessel. Normal-movement of the SRMs, IRMs, TIPs or special moveable detectors is not considered a CORE ALTERATION. Suspension of CORE ALTERATIONS shall not preclude completion of the movement of a component to a safe conservative position.

CRITICAL POWER RATIO

1.8 The CRITICAL POWER RATIO (CPR) shall be the ratio of that power in the assembly which is calculated by application of the appropriate correlation(s) to cause some point in the assembly to experience boiling transition, divided by the actual assembly operating power.

DOSE EQUIVALENT I-131

1.9 DOSE EQUIVALENT I-131 shall be that concentration of I-131, microcuries per gram, which alone would produce the same thyroid dose as the quantity and isotopic mixture of I-131, I-132, I-133, I-134, and I-135 actually present. The thyroid dose conversion factors used for this calculation shall be those listed in Table III of TID-14844, "Calculation of Distance Factors for Power and Test Reactor Sites."

$\bar{E}$-AVERAGE DISINTEGRATION ENERGY

1.10 $\bar{E}$ shall be the average, weighted in proportion to the concentration of each radionuclide in the reactor coolant at the time of sampling, of the sum of the average beta and gamma energies per disintegration, in MeV, for isotopes, with half lives greater than 15 minutes, making up at least 95% of the total non-iodine activity in the coolant.

EMERGENCY CORE COOLING SYSTEM (ECCS) RESPONSE TIME

1.11 The EMERGENCY CORE COOLING SYSTEM (ECCS) RESPONSE TIME shall be that time interval from when the monitored parameter exceeds its ECCS actuation setpoint at the channel sensor until the ECCS equipment is capable of performing its safety function, i.e., the valves travel to their required positions, pump discharge pressures reach their required values, etc. Times shall include diesel generator starting and sequence loading delays where applicable. The response time may be measured by any series of sequential, overlapping or total steps such that the entire response time is measured.

END-OF-CYCLE RECIRCULATION PUMP TRIP SYSTEM RESPONSE TIME

1.12 The END-OF-CYCLE RECIRCULATION PUMP TRIP SYSTEM RESPONSE TIME shall be that time interval to complete supression of the electric arc between the fully open contacts of the recirculation pump circuit breaker from initial movement of the associated:

a. Turbine stop valves, and

b. Turbine control valves.

This total system response time consists of two components, the instrumentation response time and the breaker arc suppression time. These times may be measured by any series of sequential, overlapping or total steps such that the entire response time is measured.

2.2 LIMITING SAFETY SYSTEM SETTINGS

REACTOR PROTECTION SYSTEM INSTRUMENTATION SETPOINTS

2.2.1 The reactor protection system instrumentation setpoints shall be set consistent with the Trip Setpoint values shown in Table 2.2.1-1.

APPLICABILITY: As shown in Table 3.3.1-1.

ACTION:

With a reactor protection system instrumentation setpoint less conservative than the value shown in the Allowable Values column of Table 2.2.1-1, declare the channel inoperable and apply the applicable ACTION statement requirement of Specification 3.3.1 until the channel is restored to OPERABLE status with its setpoint adjusted consistent with the Trip Setpoint value.

TABLE 2.2.1-1

REACTOR PROTECTION SYSTEM INSTRUMENTATION SETPOINTS

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUES
1. Intermediate Range Monitor, Neutron Flux-High	≤ 120/125 divisions of full scale	≤ 122/125 divisions of full scale
2. Average Power Range Monitor:		
a. Neutron Flux-Upscale, Setdown	≤ 15% of RATED THERMAL POWER	≤ 20% of RATED THERMAL POWER
b. Flow Biased Simulated Thermal Power-Upscale		
1) Flow Biased	≤ 0.58 W+59%, with a maximum of ≤ 113.5% of RATED THERMAL POWER	≤ 0.58 W+62%, with a maximum of ≤ 115.5% of RATED THERMAL POWER 17
2) High Flow Clamped		
c. Neutron Flux-Upscale	≤ 118% of RATED THERMAL POWER	≤ 120% of RATED THERMAL POWER
d. Inoperative	NA	NA
3. Reactor Vessel Steam Dome Pressure - High	≤ 1037 psig	≤ 1057 psig
4. Reactor Vessel Water Level - Low, Level 3	≥ 13.0 inches above instrument zero*	≥ 11.5 inches above instrument zero
5. Main Steam Line Isolation Valve - Closure	≤ 10% closed	≤ 11% closed
6. Main Steam Line Radiation - High	≤ 3.0 x full power background	≤ 3.6 x full power background
7. Drywell Pressure - High	≤ 1.72 psig	≤ 1.88 psig
8. Scram Discharge Volume Water Level - High	≤ 88 gallons	≤ 88 gallons
9. Turbine Stop Valve - Closure	≤ 5.5% closed	≤ 7% closed
10. Turbine Control Valve Fast Closure, Trip Oil Pressure - Low	≥ 500 psig	≥ 460 psig
11. Reactor Mode Switch Shutdown Position	NA	NA
12. Manual Scram	NA	NA

*Se ses Figure B 3/4 3-1.

3/4.1 REACTIVITY CONTROL SYSTEMS

3/4.1.1 SHUTDOWN MARGIN

LIMITING CONDITION FOR OPERATION

3.1.1 The SHUTDOWN MARGIN shall be equal to or greater than:

a. 0.38% delta k/k with the highest worth rod analytically determined, or

b. 0.28% delta k/k with the highest worth rod determined by test.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, 3, 4 and 5.

ACTION:

With the SHUTDOWN MARGIN less than specified:

a. In OPERATIONAL CONDITION 1 or 2, reestablish the required SHUTDOWN MARGIN within 6 hours or be in at least HOT SHUTDOWN within the next 12 hours.

b. In OPERATIONAL CONDITION 3 or 4, immediately verify all insertable control rods to be inserted and suspend all activities that could reduce the SHUTDOWN MARGIN. In OPERATIONAL CONDITION 4, establish SECONDARY CONTAINMENT INTEGRITY within 8 hours.

c. In OPERATIONAL CONDITION 5, suspend CORE ALTERATIONS and other activities that could reduce the SHUTDOWN MARGIN and insert all insertable control rods within 1 hour. Establish SECONDARY CONTAINMENT INTEGRITY within 8 hours.

SURVEILLANCE REQUIREMENTS

4.1.1 The SHUTDOWN MARGIN shall be determined to be equal to or greater than specified at any time during the fuel cycle:

a. By measurement, prior to or during the first startup after each refueling.

b. By measurement, within 500 MWD/T prior to the core average exposure at which the predicted SHUTDOWN MARGIN, including uncertainties and calculation biases, is equal to the specified limit.

c. Within 12 hours after detection of a withdrawn control rod that is immovable, as a result of excessive friction or mechanical interference, or is untrippable, except that the above required SHUTDOWN MARGIN shall be verified acceptable with an increased allowance for the withdrawn worth of the immovable or untrippable control rod.

3/4.1.2 REACTIVITY ANOMALIES

LIMITING CONDITION FOR OPERATION

3.1.2 The reactivity equivalence of the difference between the actual ROD DENSITY and the predicted ROD DENSITY shall not exceed 1% delta k/k.

APPLICABILITY: OPERATIONAL CONDITIONS 1 and 2.

ACTION:

With the reactivity different by more than 1% delta k/k:

a. Within 12 hours perform an analysis to determine and explain the cause of the reactivity difference; operation may continue if the difference is explained and corrected.

b. Otherwise, be in at least HOT SHUTDOWN within the next 12 hours.

SURVEILLANCE REQUIREMENTS

4.1.2 The reactivity equivalence of the difference between the actual ROD DENSITY and the predicted ROD DENSITY shall be verified to be less than or equal to 1% delta k/k:

a. During the first startup following CORE ALTERATIONS, and

b. At least once per 31 effective full power days during POWER OPERATION.

3/4.1.3 CONTROL RODS

CONTROL ROD OPERABILITY

LIMITING CONDITION FOR OPERATION

3.1.3.1 All control rods shall be OPERABLE.

APPLICABILITY: OPERATIONAL CONDITIONS 1 and 2.

ACTION:

a. With one control rod inoperable due to being immovable, as a result of excessive friction or mechanical interference, or known to be untrippable:

   1. Within one hour:

      a) Verify that the inoperable control rod, if withdrawn, is separated from all other inoperable control rods by at least two control rods in all directions.

      b) Disarm the associated directional control valves** either:

         1) Electrically, or

         2) Hydraulically by closing the drive water and exhaust isolation valves.

      Otherwise, be in at least HOT SHUTDOWN within the next 12 hours.

   2. Restore the inoperable control rod to OPERABLE status within 48 hours or be in at least HOT SHUTDOWN within the next 12 hours.

b. With one or more control rods inoperable for causes other than addressed in ACTION a, above:

   1. If the inoperable control rod(s) is withdrawn, within one hour verify:

      a) That the inoperable withdrawn control rod(s) is separated from all other inoperable control rods by at least two control rods in all directions, and

      b) The insertion capability of the inoperable withdrawn control rod(s) by inserting the control rod(s) at least one notch by drive water pressure within the normal operating range*.

      Otherwise, insert the inoperable withdrawn control rod(s) and disarm the associated directional control valves** either:

      a) Electrically, or

      b) Hydraulically by closing the drive water and exhaust water isolation valves.

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*The inoperable control rod may then be withdrawn to a position no further withdrawn than its position when found to be inoperable.

**May be rearmed intermittently under administrative control to permit testing associated with restoring the control rod to OPERABLE status.

LIMITING CONDITION FOR OPERATION (Continued)

ACTION (Continued)

2. If the inoperable control rod(s) is inserted within 1 hour, disarm the associated directional control valves** either:

   a) Electrically, or

   b) Hydraulically by closing the drive water and exhaust water isolation valves.

   Otherwise, be in at least HOT SHUTDOWN within the next 12 hours.

3. The provisions of Specification 3.0.4 are not applicable.

c. With more than 8 control rods inoperable, be in at least HOT SHUTDOWN within 12 hours.

d. With one scram discharge volume vent valve and/or one scram discharge volume drain valve inoperable and open, restore the inoperable valve(s) to OPERABLE status within 24 hours or be in at least HOT SHUTDOWN within the next 12 hours.

e. With any scram discharge volume vent valve(s) and/or any scram discharge volume drain valve(s) otherwise inoperable, restore at least one vent valve and one drain valve to OPERABLE status within 8 hours or be in at least HOT SHUTDOWN within the next 12 hours.

SURVEILLANCE REQUIREMENTS

4.1.3.1.1 The scram discharge volume drain and vent valves shall be demonstrated OPERABLE by:

a. At least once per 31 days verifying each valve to be open,* and

b. At least once per 92 days cycling each valve through at least one complete cycle of full travel.

4.1.3.1.2 When above the low power setpoint of the RWM and RSCS, all withdrawn control rods not required to have their directional control valves disarmed electrically or hydraulically shall be demonstrated OPERABLE by moving each control rod at least one notch:

a. At least once per 7 days, and

*These valves may be closed intermittently for testing under administrative controls.

**May be rearmed intermittently, under administrative controls, to permit testing associated with restoring the control rod to OPERABLE status.

SURVEILLANCE REQUIREMENTS (Continued)

b. At least once per 24 hours when any control rod is immovable as a result of excessive friction or mechanical interference.

4.1.3.1.3 All control rods shall be demonstrated OPERABLE by performance of Surveillance Requirements 4.1.3.2, 4.1.3.4, 4.1.3.5, 4.1.3.6 and 4.1.3.7.

4.1.3.1.4 The scram discharge volume shall be determined OPERABLE by demonstrating:

a. The scram discharge volume drain and vent valves OPERABLE, when control rods are scram tested from a normal control rod configuration of less than or equal to 50% ROD DENSITY at least once per 18 months*, by verifying that the drain and vent valves: 125

   1. Close within 30 seconds after receipt of a signal for control rods to scram, and

   2. Open when the scram signal is reset.

b. Proper float response by verification of proper float switch actuation after each scram from a pressurized condition greater than or equal to 900 psig.

*The provisions of Specification 4.0.4 are not applicable for entry into OPERATIONAL CONDITION 2 provided the surveillance is performed within 12 hours after achieving less than or equal to 50% ROD DENSITY.

CONTROL ROD MAXIMUM SCRAM INSERTION TIMES

LIMITING CONDITION FOR OPERATION

3.1.3.2 The maximum scram insertion time of each control rod from the fully withdrawn position to notch position 5, based on de-energization of the scram pilot valve solenoids as time zero, shall not exceed 7.0 seconds.

APPLICABILITY: OPERATIONAL CONDITIONS 1 and 2.

ACTION:

a. With the maximum scram insertion time of one or more control rods exceeding 7.0 seconds:

   1. Declare the control rod(s) with the slow insertion time inoperable, and

   2. Perform the Surveillance Requirements of Specification 4.1.3.2.c at least once per 60 days when operation is continued with three or more control rods with maximum scram insertion times in excess of 7.0 seconds.

Otherwise, be in at least HOT SHUTDOWN within 12 hours.

b. The provisions of Specification 3.0.4 are not applicable.

SURVEILLANCE REQUIREMENTS

4.1.3.2 The maximum scram insertion time of the control rods shall be demonstrated through measurement with reactor coolant pressure greater than or equal to 950 psig and, during single control rod scram time tests, the control rod drive pumps isolated from the accumulators:

a. For all control rods prior to THERMAL POWER exceeding 40% of RATED THERMAL POWER following CORE ALTERATIONS* or after a reactor shutdown that is greater than 120 days,

b. For specifically affected individual control rods following maintenance on or modification to the control rod or control rod drive system which could affect the scram insertion time of those specific control rods, and

c. For at least 10% of the control rods, on a rotating basis, at least once per 120 days of POWER OPERATION.

*Except normal control rod movement.

CONTROL ROD AVERAGE SCRAM INSERTION TIMES

LIMITING CONDITION FOR OPERATION

3.1.3.3 The average scram insertion time of all OPERABLE control rods from the fully withdrawn position, based on de-energization of the scram pilot valve solenoids as time zero, shall not exceed any of the following:

Position Inserted From Fully Withdrawn	Average Scram Insertion Time (Seconds)
45	0.43
39	0.86
25	1.93
05	3.49

APPLICABILITY: OPERATIONAL CONDITIONS 1 and 2.

ACTION:

With the average scram insertion time exceeding any of the above limits, be in at least HOT SHUTDOWN within 12 hours.

SURVEILLANCE REQUIREMENTS

4.1.3.3 All control rods shall be demonstrated OPERABLE by scram time testing from the fully withdrawn position as required by Surveillance Requirement 4.1.3.2.

FOUR CONTROL ROD GROUP SCRAM INSERTION TIMES

LIMITING CONDITION FOR OPERATION

3.1.3.4 The average scram insertion time, from the fully withdrawn position, for the three fastest control rods in each group of four control rods arranged in a two-by-two array, based on deenergization of the scram pilot valve solenoids as time zero, shall not exceed any of the following:

Position Inserted From Fully Withdrawn	Average Scram Insertion Time (Seconds)
45	0.45
39	0.92
25	2.05
05	3.70

APPLICABILITY: OPERATIONAL CONDITIONS 1 and 2.

ACTION:

a. With the average scram insertion times of control rods exceeding the above limits:

1. Declare the control rods with the slower than average scram insertion times inoperable until an analysis is performed to determine that required scram reactivity remains for the slow four control rod group, and

2. Perform the Surveillance Requirements of Specification 4.1.3.2.c at least once per 60 days when operation is continued with an average scram insertion time(s) in excess of the average scram insertion time limit.

Otherwise, be in at least HOT SHUTDOWN within the next 12 hours.

b. The provisions of Specification 3.0.4 are not applicable.

SURVEILLANCE REQUIREMENTS

4.1.3.4 All control rods shall be demonstrated OPERABLE by scram time testing from the fully withdrawn position as required by Surveillance Requirement 4.1.3.2.

CONTROL ROD SCRAM ACCUMULATORS

LIMITING CONDITION FOR OPERATION

3.1.3.5 All control rod scram accumulators shall be OPERABLE.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2 and 5*.

ACTION:

a. In OPERATIONAL CONDITIONS 1 or 2:

1. With one control rod scram accumulator inoperable within 8 hours:

a) Restore the inoperable accumulator to OPERABLE status, or

b) Declare the control rod associated with the inoperable accumulator inoperable.

Otherwise, be in at least HOT SHUTDOWN within the next 12 hours.

2. With more than one control rod scram accumulator inoperable, declare the associated control rods inoperable and: 129

a) If any control rod associated with any inoperable scram accumulator is withdrawn, immediately verify that at least one control rod drive pump is operating by inserting at least one withdrawn control rod at least one notch or place the reactor mode switch in the Shutdown position.

b) Insert the inoperable control rods and disarm the associated directional control valves either:

1) Electrically, or
2) Hydraulically by closing the drive water and exhaust water isolation valves.

Otherwise, be in at least HOT SHUTDOWN within 12 hours.

b. In OPERATIONAL CONDITION 5*: 16

1. With one withdrawn control rod with its associated scram accumulator inoperable, insert the affected control rod and

*At least the accumulator associated with each withdrawn control rod. Not applicable to control rods removed per Specification 3.9.10.1 or 3.9.10.2.

LIMITING CONDITION FOR OPERATION (continued)

disarm the associated directional control valves within 1 hour, either: |29

a) Electrically, or

b) Hydraulically by closing the drive water and exhaust water isolation valves.

2. With more than one withdrawn control rod with the associated scram accumulators inoperable or with no control rod drive pump operating, immediately place the reactor mode switch in the Shutdown position. |29

c. The provisions of Specification 3.0.4 are not applicable. |

SURVEILLANCE REQUIREMENTS

4.1.3.5 Each control rod scram accumulator shall be determined OPERABLE:

a. At least once per 7 days by verifying that the indicated pressure is greater than or equal to 940 psig unless the control rod is inserted and disarmed or scrammed.

b. At least once per 18 months by:

1. Performance of a:

a) CHANNEL FUNCTIONAL TEST of the leak detectors, and

b) CHANNEL CALIBRATION of the pressure detectors, and verifying an alarm setpoint of $\geq$ 940 psig on decreasing pressure. |

2. Verifying that each individual accumulator check valve maintains the associated accumulator pressure above the alarm set point for greater than or equal to 10 minutes with no control rod drive pump operating.

CONTROL ROD DRIVE COUPLING

LIMITING CONDITION FOR OPERATION

3.1.3.6 All control rods shall be coupled to their drive mechanisms.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2 and 5*.

ACTION:

a. In OPERATIONAL CONDITION 1 and 2 with one control rod not coupled to its associated drive mechanism, within 2 hours:

   1. If permitted by the RWM and RSCS, insert the control rod drive mechanism to accomplish recoupling and verify recoupling by withdrawing the control rod, and:

      a) Observing any indicated response of the nuclear instrumentation, and

      b) Demonstrating that the control rod will not go to the overtravel position.

   2. If recoupling is not accomplished on the first attempt or, if not permitted by the RWM or RSCS, then until permitted by the RWM and RSCS, declare the control rod inoperable, insert the control rod and disarm the associated directional control valves** either:

      a) Electrically, or

      b) Hydraulically by closing the drive water and exhaust water isolation valves.

   Otherwise, be in at least HOT SHUTDOWN within the next 12 hours.

b. In OPERATIONAL CONDITION 5* with a withdrawn control rod not coupled to its associated drive mechanism, within 2 hours, either:

   1. Insert the control rod to accomplish recoupling and verify recoupling by withdrawing the control rod and demonstrating that the control rod will not go to the overtravel position, or

   2. If recoupling is not accomplished, insert the control rod and disarm the associated directional control valves** either:

      a) Electrically, or

      b) Hydraulically by closing the drive water and exhaust water isolation valves.

c. The provisions of Specification 3.0.4 are not applicable.

*At least each withdrawn control rod. Not applicable to control rods removed per Specification 3.9.10.1 or 3.9.10.2.

**May be rearmed intermittently, under administrative control, to permit testing associated with restoring the control rod to OPERABLE status.

SURVEILLANCE REQUIREMENTS

4.1.3.6 Each affected control rod shall be demonstrated to be coupled to its drive mechanism by observing any indicated response of the nuclear instrumentation while withdrawing the control rod to the fully withdrawn position and then verifying that the control rod drive does not go to the overtravel position:

a. Prior to reactor criticality after completing CORE ALTERATIONS that could have affected the control rod drive coupling integrity,

b. Anytime the control rod is withdrawn to the "Full out" position in subsequent operation, and

c. Following maintenance on or modification to the control rod or control rod drive system which could have affected the control rod drive coupling integrity.

CONTROL ROD POSITION INDICATION

LIMITING CONDITION FOR OPERATION

3.1.3.7 The control rod position indication system shall be OPERABLE.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2 and 5*.

ACTION:

a. In OPERATIONAL CONDITION 1 or 2 with one or more control rod position indicators inoperable, within 1 hour: 29

1. Determine the position of the control rod by:

a) Moving the control rod, by single notch movement, to a position with an OPERABLE position indicator,

b) Returning the control rod, by single notch movement, to its original position, and

c) Verifying no control rod drift alarm at least once per 12 hours, or

2. Move the control rod to a position with an OPERABLE position indicator, or

3. When THERMAL POWER is:

a) Within the low power setpoint of the RSCS:

1) Declare the control rod inoperable, and

2) Verify the position and bypassing of control rods with inoperable "Full-in" and/or "Full-out" position indicators by a second licensed operator or other technically qualified member of the unit technical staff.

b) Greater than the low power setpoint of the RSCS, declare the control rod inoperable, insert the control rod and disarm the associated directional control valves either:

1) Electrically, or

2) Hydraulically by closing the drive water and exhaust water isolation valves.

Otherwise, be in at least HOT SHUTDOWN within the next 12 hours.

b. In OPERATIONAL CONDITION 5* with a withdrawn control rod position indicator inoperable, move the control rod to a position with an OPERABLE position indicator or insert the control rod.

c. The provisions of Specification 3.0.4 are not applicable.

*At least each withdrawn control rod. Not applicable to control rods removed per Specification 3.9.10.1 or 3.9.10.2.

SURVEILLANCE REQUIREMENTS

4.1.3.7 The control rod position indication system shall be determined OPERABLE by verifying:

a. At least once per 24 hours that the position of each control rod is indicated,

b. That the indicated control rod position changes during the movement of the control rod drive when performing Surveillance Requirement 4.1.3.1.2, and

c. That the control rod position indicator corresponds to the control rod position indicated by a "Full out" position indicator when performing Surveillance Requirement 4.1.3.6.b.

TABLE 3.3.1-1 (Continued)

REACTOR PROTECTION SYSTEM INSTRUMENTATION

FUNCTIONAL UNIT	APPLICABLE OPERATIONAL CONDITIONS	MINIMUM OPERABLE CHANNELS PER TRIP SYSTEM (a)	ACTION
7. Drywell Pressure - High	1, 2(h)	2	1
8. Scram Discharge Volume Water Level - High	1, 2	2	1
	5(i)	2	3
9. Turbine Stop Valve - Closure	1(j)	4(k)	6
10. Turbine Control Valve Fast Closure, Valve Trip System Oil Pressure - Low	1(j)	2(k)	6
11. Reactor Mode Switch Shutdown Position	1, 2	1	1
	3, 4	1	7
	5	1	3
12. Manual Scram	1, 2	2	1
	3, 4	2	8
	5	2	9

TABLE 3.3.1-1 (Continued)

REACTOR PROTECTION SYSTEM INSTRUMENTATION

ACTION STATEMENTS

ACTION 1 - Be in at least HOT SHUTDOWN within 12 hours.

ACTION 2 - Verify all insertable control rods to be inserted in the core and lock the reactor mode switch in the Shutdown position within 1 hour.

ACTION 3 - Suspend all operations involving CORE ALTERATIONS and insert all insertable control rods within 1 hour.

ACTION 4 - Be in at least STARTUP within 6 hours.

ACTION 5 - Be in STARTUP with the main steam line isolation valves closed within 6 hours or in at least HOT SHUTDOWN within 12 hours.

ACTION 6 - Initiate a reduction in THERMAL POWER within 15 minutes and reduce turbine first stage pressure until the function is automatically bypassed within 2 hours.

ACTION 7 - Verify all insertable control rods to be inserted within 1 hour.

ACTION 8 - Lock the reactor mode switch in the Shutdown position within 1 hour.

ACTION 9 - Suspend all operations involving CORE ALTERATIONS, and insert all insertable control rods and lock the reactor mode switch in the SHUTDOWN position within 1 hour.

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	SA	2
	S	W	SA	3, 4, 5
b. Inoperative	NA	S/U[c],W	NA	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	SA	3, 5
b. Flow Biased Simulated Thermal Power - Upscale	S, D[g]	S/U[c], W	W[d][e], SA, R[h]	1
c. Fixed Neutron Flux - Upscale	S	S/U[c], W	W[d], SA	1
d. Inoperative	NA	S/U[c]W	NA	1, 2, 3, 5
3. Reactor Vessel Steam Dome Pressure - High	NA	M	Q	1, 2
4. Reactor Vessel Water Level - Low, Level 3	S	M	R	1, 2
5. Main Steam Line Isolation Valve - Closure	NA	M	R	1
6. Main Steam Line Radiation - High	S	M	R	1, 2[i]
7. Drywell Pressure - High	NA	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	NA	M	R	1, 2, 5[j]
9. Turbine Stop Valve - Closure	NA	M	R	1
10. Turbine Control Valve Fast Closure Valve Trip System Oil Pressure - Low	NA	M	R	1
11. Reactor Mode Switch Shutdown Position	NA	R	NA	1, 2, 3, 4, 5
12. Manual Scram	NA	M	NA	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 0.5 decades during each startup after entering OPERATIONAL CONDITION 2 and the IRM and APRM channels shall be determined to overlap for at least 0.5 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 to be greater than or equal to established core flow at the existing loop flow.
(h) This calibration shall consist of verifying the 6 ± 1 second simulated thermal power time constant.
(i) This function is not required to be OPERABLE when the reactor pressure vessel head is unbolted or removed per Specification 3.10.1.
(j) With any control rod withdrawn. Not applicable to control rods removed per Specification 3.9.10.1 or 3.9.10.2.

TABLE 3.3.2-1

ISOLATION ACTUATION INSTRUMENTATION

TRIP FUNCTION	ISOLATION SIGNAL(s)[a]	MINIMUM OPERABLE CHANNELS PER TRIP SYSTEM (b)	APPLICABLE OPERATIONAL CONDITION	ACTION
1. PRIMARY CONTAINMENT ISOLATION				
a. Reactor Vessel Water Level				
1) Low, Level 3	A	2	1, 2, 3	20
2) Low Low, Level 2	B	2	1, 2, 3	20
3) Low Low Low, Level 1	X	2	1, 2, 3	20
b. Drywell Pressure - High	Y,Z,X	2	1, 2, 3	20
c. Manual Initiation	NA	1	1, 2, 3	24
d. SGTS Exhaust Radiation-High	R	1	1, 2, 3,4***,5***	20
e. Main Steam Line Radiation-High	C	2	1, 2, 3	20
2. SECONDARY CONTAINMENT ISOLATION				
a. Reactor Vessel Water Level - Low Low, Level 2	**	2	1, 2, 3 and *	25
b. Drywell Pressure - High	**	2	1, 2, 3	25
c. Refuel Floor High Exhaust Duct Radiation - High	**	2	1, 2, 3 and *	25
d. Railroad Access Shaft Exhaust Duct Radiation - High	**	2	1, 2, 3 and *	25
e. Refuel Floor Wall Exhaust Duct Radiation - High	**	2	1, 2, 3 and *	25
f. Manual Initiation	NA	1	1, 2, 3 and *	24

TABLE 3.3.2-1 (Continued)

ISOLATION ACTUATION INSTRUMENTATION

TRIP FUNCTION	ISOLATION SIGNAL(s)[a]	MINIMUM OPERABLE CHANNELS PER TRIP SYSTEM (b)	APPLICABLE OPERATIONAL CONDITION	ACTION
3. MAIN STEAM LINE ISOLATION				
a. Reactor Vessel Water Level - Low, Low, Level 2	B	2	1, 2, 3	21
b. Main Steam Line Radiation - High	C	2	1, 2, 3	21
c. Main Steam Line Pressure - Low	P	2	1	22
d. Main Steam Line Flow - High	D	2/line	1, 2, 3	20
e. Condenser Vacuum - Low	UA	2	1, 2, 3	21
f. Reactor Building Main Steam Line Tunnel Temperature - High	E	2	1, 2, 3	21
g. Reactor Building Main Steam Line Tunnel Δ Temperature - High	E	2	1, 2, 3	21
h. Manual Initiation	NA	1	1, 2, 3	24
i. Turbine Building Main Steam Line Tunnel Temperature-High	E	2	1, 2, 3	21
4. REACTOR WATER CLEANUP SYSTEM ISOLATION				
a. RWCU Δ Flow - High	J	1	1, 2, 3	23
b. RWCU Area Temperature - High	W	3	1, 2, 3	23
c. RWCU Area Ventilation Δ Temp. - High	W	3	1, 2, 3	23
d. SLCS Initiation	I	2	1, 2, 3	23
e. Reactor Vessel Water Level - Low Low, Level 2	B	2	1, 2, 3	23
f. RWCU Flow - High	J	1	1, 2, 3	23
g. Manual Initiation	NA	1	1, 2, 3	24

TABLE 3.3.2-1 (Continued)

ISOLATION ACTUATION INSTRUMENTATION

TRIP FUNCTION	ISOLATION SIGNAL(s)[a]	MINIMUM OPERABLE CHANNELS PER TRIP SYSTEM (b)	APPLICABLE OPERATIONAL CONDITION	ACTION
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	KB	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 Emergency Area Cooler Temperature - High	K	1	1, 2, 3	23
g. RCIC Pipe Routing Area Δ Temperature - High	K	1	1, 2, 3	23
h. RCIC Pipe Routine Area Temperature - High	K	1	1, 2, 3	23
i. Manual Initiation	NA	1	1, 2, 3	24
j. Drywell Pressure - High	Z	2	1, 2, 3	23

TABLE 3.3.2-1 (Continued)

ISOLATION ACTUATION INSTRUMENTATION

TRIP FUNCTION	ISOLATION SIGNAL(s)[a]	MINIMUM OPERABLE CHANNELS PER TRIP SYSTEM (b)	APPLICABLE OPERATIONAL CONDITION	ACTION
6. HIGH PRESSURE COOLANT INJECTION SYSTEM ISOLATION				
a. HPCI Steam Line Δ Pressure - High	L	1	1, 2, 3	23
b. HPCI Steam Supply Pressure-Low	LB	2	1, 2, 3	23
c. HPCI Turbine Exhaust Diaphragm Pressure - High	L	2	1, 2, 3	23
d. HPCI Equipment Room Temperature - High	L	1	1, 2, 3	23
e. HPCI Equipment Room Δ Temperature - High	L	1	1, 2, 3	23
f. HPCI Emergency Area Cooler Temperature - High	L	1	1, 2, 3	23
g. HPCI Pipe Routing Area Temperature - High	L	1	1, 2, 3	23
h. HPCI Pipe Routine Area Δ Temperature - High	L	1	1, 2, 3	23
i. Manual Initiation	NA	1	1, 2, 3	24
j. Drywell Pressure - High	Z	2	1, 2, 3	23

TABLE 3.3.2-1 (Continued)

ISOLATION ACTUATION INSTRUMENTATION

TRIP FUNCTION	ISOLATION SIGNAL(s)[a]	MINIMUM OPERABLE CHANNELS PER TRIP SYSTEM (b)	APPLICABLE OPERATIONAL CONDITION	ACTION
7. RHR SYSTEM SHUTDOWN COOLING/HEAD SPRAY MODE ISOLATION				
a. Reactor Vessel Water Level - Low, Level 3	A	2	1, 2, 3	26
b. Reactor Vessel (RHR Cut-in Permissive) Pressure - High	UB	1	1, 2, 3	26
c. RHR Equipment Area Δ Temperature - High	M	1	1, 2, 3	26
d. RHR Equipment Area Temperature - High	M	1	1, 2, 3	26
e. RHR Flow - High	M	1	1, 2, 3	26
f. Manual Initiation	NA	1	1, 2, 3	24
g. Drywell Pressure - High	Z	2	1, 2, 3	26

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 - Close the affected system isolation valves within 1 hour and declare the affected system inoperable.

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 - Lock the affected system isolation valves closed within 1 hour and declare the affected system inoperable.

NOTES

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

** Actuates dampers shown in Table 3.6.5.2-1.

*** When VENTING or PURGING the drywell per Specification 3.11.2.8.

(a) See Specification 3.6.3, Table 3.6.3-1 for 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.

TABLE 3.3.2-2

ISOLATION ACTUATION INSTRUMENTATION SETPOINTS

TRIP FUNCTION	TRIP SETPOINT	ALLOWABLE VALUE
1. PRIMARY CONTAINMENT ISOLATION		
a. Reactor Vessel Water Level		
1) Low, Level 3	≥ 13.0 inches*	≥ 11.5 inches
2) Low Low, Level 2	≥ -38.0 inches*	≥ -45.0 inches
3) Low Low Low, Level 1	≥ -129 inches*	≥ -136 inches
b. Drywell Pressure - High	≤ 1.72 psig	≤ 1.88 psig
c. Manual Initiation	NA	NA
d. SGTS Exhaust Radiation - High	≤23.0 mR/hr	≤31.0 mR/Hr
e. Main Steam Line Radiation - High	≤ 3 x full power background	≤3.6 x full power background
2. SECONDARY CONTAINMENT ISOLATION		
a. Reactor Vessel Water Level - Low Low, Level 2	≥ -38.0 inches*	≥ -45.0 inches
b. Drywell Pressure - High	≤ 1.72 psig	≤ 1.88 psig
c. Refuel Floor High Exhaust Duct Radiation - High	≤ 2.5 mR/hr.**	≤ 4.0 mR/hr.**
d. Railroad Access Shaft Exhaust Duct Radiation - High	≤ 2.5 mR/hr.**	≤ 4.0 mR/hr.**
e. Refuel Floor Wall Exhaust Duct Radiation - High	≤ 2.5 mR/hr.**	≤ 4.0 mR/hr.**
f. Manual Initiation	NA	NA
3. MAIN STEAM LINE ISOLATION		
a. Reactor Vessel Water Level - Low Low, Level 2	≥ -38 inches*	≥ -45.0 inches
b. Main Steam Line Radiation - High	≤ 3 X full power background	≤ 3.6 X full power background
c. Main Steam Line Pressure - Low	≥ 861 psig	≥ 841 psig
d. Main Steam Line Flow - High	≤ 107 psid	≤ 110 psid

4

TABLE 3.3.2-2 (Continued)

ISOLATION ACTUATION INSTRUMENTATION SETPOINTS

TRIP FUNCTION	TRIP SETPOINT	ALLOWABLE VALUE
MAIN STEAM LINE ISOLATION (Continued)		
e. Condenser Vacuum - Low	≥ 9.0 inches Hg vacuum	≥ 8.8 inches Hg vacuum
f. Reactor Building Main Steam Line Tunnel Temperature - High	≤ 177°F	≤ 184°F
g. Reactor Building Main Steam Line Tunnel Δ Temperature - High	≤ 99°F	≤ 108°F
h. Manual Initiation	NA	NA
i. Turbine Building Main Steam Line Tunnel Temperature-High	≤177°F	≤184°F
4. REACTOR WATER CLEANUP SYSTEM ISOLATION		
a. RWCU Δ Flow - High	≤ 60 gpm	≤ 80 gpm
b. RWCU Area Temperature - High	≤ 147°F or 118.3°F#	≤ 154°F or 125.3°F#
c. RWCU/Area Ventilation Δ Temperature - High	≤ 69°F or 35.3°F#	≤ 78°F or 44.3°F#
d. SLCS Initiation	NA	NA
e. Reactor Vessel Water Level - Low Low, Level 2	≥ -38 inches*	≥ -45 inches
f. RWCU Flow - High	≤ 426 gpm	≤ 436 gpm
g. Manual Initiation	NA	NA
5. REACTOR CORE ISOLATION COOLING SYSTEM ISOLATION		
a. RCIC Steam Line Δ Pressure - High	≤ 177" H_2O**	≤ 189" H_2O**
b. RCIC Steam Supply Pressure - Low	≥ 60 psig	≥ 53 psig
c. RCIC Turbine Exhaust Diaphragm Pressure - High	≤ 10.0 psig	≤ 20.0 psig

29

29

TABLE 3.3.2-2 (Continued)

ISOLATION ACTUATION INSTRUMENTATION SETPOINTS

TRIP FUNCTION	TRIP SETPOINT	ALLOWABLE VALUE
REACTOR CORE ISOLATION COOLING SYSTEM ISOLATION Continued)		
d. RCIC Equipment Room Temperature - High	≤ 167°F**	≤ 174°F**
e. RCIC Equipment Room Δ Temperature - High	≤ 89°F	≤98°F
f. RCIC Pipe Routing Area Temperature - High	≤ 167°F##	≤ 174°F##
g. RCIC Pipe Routing Area Δ Temperature - High	≤ 89°F##	≤ 98°F##
h. RCIC Emergency Area Cooler Temperature - High	≤ 147°F	≤ 154°F
i. Manual Initiation	NA	NA
j. Drywell Pressure - High	≤1.72 psig	≤1.88 psig 1
6. HIGH PRESSURE COOLANT INJECTION SYSTEM ISOLATION		
a. HPCI Steam Line Flow - High	≤ 350 inches H_2O**	≤ 367 inches H_2O** 15
b. HPCI Steam Supply Pressure - Low	≥ 104 psig	≥ 90 psig
c. HPCI Turbine Exhaust Diaphragm Pressure - High	≤ 10 psig	≤ 20 psig
d. HPCI Equipment Room Temperature - High	≤ 167°F	≤ 174°F
e. HPCI Equipment Room Δ Temperature - High	≤ 89°F	≤ 98°F
f. HPCI Emergency Area Cooler Temperature - High	≤ 147°F	≤154°F
g. HPCI Pipe Routing Area Temperature - High	≤ 167°F##	≤ 174°F##

TABLE 3.3.2-2 (Continued)

ISOLATION ACTUATION INSTRUMENTATION SETPOINTS

TRIP FUNCTION	TRIP SETPOINT	ALLOWABLE VALUE
h. HPCI Pipe Routing Area Δ Temperature - High	≤ 89°F##	≤ 98°F##
i. Manual Initiation	NA	NA
j. Drywell Pressure - High	≤1.72 psig	≤1.88 psig
7. RHR SYSTEM SHUTDOWN COOLING/HEAD SPRAY MODE ISOLATION		
a. Reactor Vessel Water Level - Low, Level 3	≥ 13.0 inches*	≥ 11.5 inches
b. Reactor Vessel (RHR Cut-in Permissive) Pressure - High	≤ 98 psig	≤ 108 psig
c. RHR Equipment Area Δ Temperature - High	≤ 89°F**	≤ 90.5°F**
d. RHR Equipment Area Temperature - High	≤ 167°F**	≤ 170.5°F**
e. RHR Flow - High	≤ 25,000 gpm	≤ 26,000 gpm
f. Manual Initiation	NA	NA
g. Drywell Pressure - High	≤1.72 psig	≤1.88 psig

*See Bases Figure B 3/4 3-1.
**Initial setpoint. Final setpoint to be determined during startup test program. Any required change to this setpoint shall be submitted to the Commission within 90 days of test completion.
#Lower setpoints for TSH-G33-N600 E, F and TSH-G33-N602 E, F.
##15 minute time delay.

TABLE 3.3.2-3

ISOLATION SYSTEM INSTRUMENTATION RESPONSE TIME

TRIP FUNCTION	RESPONSE TIME (Seconds)#
1. PRIMARY CONTAINMENT ISOLATION	
a. Reactor Vessel Water Level	
1) Low, Level 3	$\leq 10^{(a)}$
2) Low Low, Level 2	$\leq 1.0^{*}/\leq 10^{(a)**}$
3) Low Low Low, Level 1	$\leq 10^{(a)}$
b. Drywell Pressure - High	$\leq 10^{(a)}$
c. Manual Initiation	NA
d. SGTS Exhaust Radiation - High[(b)]	$\leq 10^{(a)}$
e. Main Steam Line Radiation - High[(b)]	$\leq 10^{(a)}$
2. SECONDARY CONTAINMENT ISOLATION	
a. Reactor Vessel Water Level-Low Low, Level 2	$\leq 10^{(a)}$
b. Drywell Pressure - High	$\leq 10^{(a)}$
c. Refuel Floor High Exhaust Duct Radiation - High[(b)]	$\leq 10^{(a)}$
d. Railroad Access Shaft Exhaust Duct Radiation - High[(b)]	$\leq 10^{(a)}$
e. Refuel Floor Wall Exhaust Duct Radiation -High[(b)]	$\leq 10^{(a)}$
f. Manual Initiation	NA
3. MAIN STEAM LINE ISOLATION	
a. Reactor Vessel Water Level- Low Low, Level 2	$\leq 10^{(a)}$
b. Main Steam Line Radiation - High[(b)]	$\leq 1.0^{*}/\leq 10^{(a)**}$
c. Main Steam Line Pressure - Low	$\leq 1.0^{*}/\leq 10^{(a)**}$
d. Main Steam Line Flow-High	$\leq 0.5^{*}/\leq 10^{(a)**}$
e. Condenser Vacuum - Low	NA
f. Reactor Building Main Steam Line Tunnel Temperature - High	NA
g. Reactor Building Main Steam Line Tunnel Δ Temperature - High	NA
h. Manual Initiation	NA
i. Turbine Building Main Steam Line Tunnel Temperature - High	NA
4. REACTOR WATER CLEANUP SYSTEM ISOLATION	
a. RWCU Δ Flow - High	$\leq 10^{(a)\#\#}$
b. RWCU Area Temperature - High	NA
c. RWCU Area Ventilation Temperature ΔT - High	NA
d. SLCS Initiation	NA
e. Reactor Vessel Water Level - Low Low, Level 2	$\leq 10^{(a)}$
f. RWCU Flow - High	NA
g. Manual Initiation	NA
5. REACTOR CORE ISOLATION COOLING SYSTEM ISOLATION	
a. RCIC Steam Line Δ Pressure - High	$\leq 10^{(a)\#\#\#}$
b. RCIC Steam Supply Pressure - Low	$\leq 10^{(a)}$
c. RCIC Turbine Exhaust Diaphragm Pressure - High	NA
d. RCIC Equipment Room Temperature - High	NA

TABLE 3.3.2-3 (Continued)

ISOLATION SYSTEM INSTRUMENTATION RESPONSE TIME

TRIP FUNCTION	RESPONSE TIME (Seconds)#
e. RCIC Equipment Room Δ Temperature - High	NA
f. RCIC Pipe Routing Area Temperature - High	NA
g. RCIC Pipe Routing Area Δ Temperature - High	NA
h. RCIC Emergency Area Cooler Temperature - High	NA
i. Manual Initiation	NA
j. Drywell Pressure - High	≤10(a)
6. HIGH PRESSURE COOLANT INJECTION SYSTEM ISOLATION	
a. HPCI Steam Flow - High	≤10(a)####
b. HPCI Steam Supply Pressure - Low	≤10(a)
c. HPCI Turbine Exhaust Diaphragm Pressure - High	NA
d. HPCI Equipment Room Temperature - High	NA
e. HPCI Equipment Room Δ Temperature - High	NA
f. HPCI Emergency Area Cooler Temperature - High	NA
g. HPCI Pipe Routing Area Temperature - High	NA
h. HPCI Pipe Routing Area Δ Temperature - High	NA
i. Manual Initiation	NA
j. Drywell Pressure - High	≤10(a)
7. RHR SYSTEM SHUTDOWN COOLING/HEAD SPRAY MODE ISOLATION	
a. Reactor Vessel Water Level - Low, Level 3	≤10(a)
b. Reactor Vessel (RHR Cut-in Permissive) Pressure - High	NA
c. RHR Equipment Area Δ Temperature - High	NA
d. RHR Equipment Area Temperature - High	NA
e. RHR Flow - High	NA
f. Manual Initiation	NA
g. Drywell Pressure - High	≤10(a)

(a) The isolation system instrumentation response time shall be measured and recorded as a part of the ISOLATION SYSTEM RESPONSE TIME. Isolation system instrumentation response time specified includes the delay for diesel generator starting assumed in the accident analysis.

(b) Radiation detectors are exempt from response time testing. Response time shall be measured from detector output or the input of the first electronic component in the channel.

*Isolation system instrumentation response time for MSIVs only. No diesel generator delays assumed for MSIV Valves.

**Isolation system instrumentation response time for associated valves except MSIVs.

#Isolation system instrumentation response time specified for the Trip Function actuating each valve group shall be added to isolation time shown in Table 3.6.3-1 and 3.6.5.2-1 for valves in each valve group to obtain ISOLATION SYSTEM RESPONSE TIME for each valve.

##With time delay of 45 seconds.

###With time delay of 3 seconds.

####With time delay of 3 seconds.

TABLE 4.3.2.1-1

ISOLATION ACTUATION INSTRUMENTATION SURVEILLANCE REQUIREMENTS

TRIP FUNCTION	CHANNEL CHECK	CHANNEL FUNCTIONAL TEST	CHANNEL CALIBRATION	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED
1. PRIMARY CONTAINMENT ISOLATION				
a. Reactor Vessel Water Level -				
1) Low, Level 3	S	M	R	1, 2, 3
2) Low Low, Level 2	S	M	R	1, 2, 3
3) Low Low Low, Level 1	S	M	R	1, 2, 3
b. Drywell Pressure - High	NA	M	R	1, 2, 3
c. Manual Initiation	NA	R	NA	1, 2, 3
d. SGTS Exhaust Radiation - High	S	M	R	1, 2, 3, 4, 5,
e. Main Steam Line Radiation - High	S	M	R	1, 2, 3
2. SECONDARY CONTAINMENT ISOLATION				
a. Reactor Vessel Water Level - Low Low, Level 2	S	M	R	1, 2, 3 and *
b. Drywell Pressure - High	NA	M	Q	1, 2, 3
c. Refuel Floor High Exhaust Duct Radiation - High	S	M	R	1, 2, 3 and *
d. Railroad Access Shaft Exhaust Duct Radiation - High	S	M	R	1, 2, 3 and *
e. Refuel Floor Wall Exhaust Duct Radiation - High	S	M	R	1, 2, 3 and *
f. Manual Initiation	NA	R	NA	1, 2, 3 and *

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
3. MAIN STEAM LINE ISOLATION				
a. Reactor Vessel Water Level - Low Low, Level 2	S	M	R	1, 2, 3
b. Main Steam Line Radiation - High	S	M	R	1, 2, 3
c. Main Steam Line Pressure - Low	NA	M	Q	1
d. Main Steam Line Flow - High	S	M	R	1, 2, 3
e. Condenser Vacuum - Low	NA	M	Q	1, 2**, 3**
f. Reactor Building Main Steam Line Tunnel Temperature - High	NA	M	Q	1, 2, 3
g. Reactor Building Main Steam Line Tunnel Δ Temperature - High	NA	M	Q	1, 2, 3
h. Manual Initiation	NA	R	NA	1, 2, 3
i. Turbine Building Main Steam Line Tunnel Temperature - High	NA	M	Q	1, 2, 3
4. REACTOR WATER CLEANUP SYSTEM ISOLATION				
a. RWCU Δ Flow - High	S	M	R	1, 2, 3
b. RWCU Area Temperature - High	NA	M	Q	1, 2, 3
c. RWCU Area Ventilation Δ Temperature - High	NA	M	Q	1, 2, 3
d. SLCS Initiation	NA	R	NA	1, 2, 3
e. Reactor Vessel Water Level - Low Low, Level 2	S	M	R	1, 2, 3
f. RWCU Flow - High	S	M	R	1, 2, 3
g. Manual Initiation	NA	R	NA	1, 2, 3

29

29

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	NA	M	Q	1, 2, 3
b. RCIC Steam Supply Pressure - Low	NA	M	Q	1, 2, 3
c. RCIC Turbine Exhaust Diaphragm Pressure - High	NA	M	Q	1, 2, 3
d. RCIC Equipment Room Temperature - High	NA	M	Q	1, 2, 3
e. RCIC Equipment Room Δ Temperature - High	NA	M	Q	1, 2, 3
f. RCIC Pipe Routing Area Temperature - High	NA	M	Q	1, 2, 3
g. RCIC Pipe Routing Area Δ Temperature - High	NA	M	Q	1, 2, 3
h. RCIC Emergency Area Cooler Temperature - High	NA	M	Q	1, 2, 3
i. Manual Initiation	NA	R	NA	1, 2, 3
j. Drywell Pressure - High	NA	M	R	1, 2, 3
6. HIGH PRESSURE COOLANT INJECTION SYSTEM ISOLATION				
a. HPCI Steam Line Δ Pressure - High	NA	M	Q	1, 2, 3
b. HPCI Steam Supply Pressure - Low	NA	M	Q	1, 2, 3
c. HPCI Turbine Exhaust Diaphragm Pressure - High	NA	M	Q	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
HIGH PRESSURE COOLANT INJECTION SYSTEM ISOLATION (Continued)				
d. HPCI Equipment Room Temperature - High	NA	M	Q	1, 2, 3
e. HPCI Equipment Room Δ Temperature - High	NA	M	Q	1, 2, 3
f. HPCI Emergency Area Cooler Temperature - High	NA	M	Q	1, 2, 3
g. HPCI Pipe Routing Area Temperature - High	NA	M	Q	1, 2, 3
h. HPCI Pipe Routing Area Δ Temperature - High	NA	M	Q	1, 2, 3
i. Manual Initiation	NA	R	NA	1, 2, 3
j. Drywell Pressure - High	NA	M	R	1, 2, 3
7. RHR SYSTEM SHUTDOWN COOLING/HEAD SPRAY MODE ISOLATION				
a. Reactor Vessel Water Level - Low, Level 3	S	M	R	1, 2, 3
b. Reactor Vessel (RHR Cut-in Permissive) Pressure - High	NA	M	Q	1, 2, 3
c. RHR Equipment Area Δ Temperature - High	NA	M	Q	1, 2, 3
d. RHR Equipment Area Temperature - High	NA	M	Q	1, 2, 3
e. RHR Flow - High	S	M	R	1, 2, 3
f. Manual Initiation	NA	R	NA	1, 2, 3
g. Drywell Pressure - High	NA	M	R	1, 2, 3

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

** en reactor steam dome pressure ≥ 1043 psig and/o y turbine stop valve is open.

3/4.3.3 EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.3 The emergency core cooling system (ECCS) actuation instrumentation channels shown in Table 3.3.3-1 shall be OPERABLE with their trip setpoints set consistent with the values shown in the Trip Setpoint column of Table 3.3.3-2 and with EMERGENCY CORE COOLING SYSTEM RESPONSE TIME as shown in Table 3.3.3-3.

APPLICABILITY: As shown in Table 3.3.3-1.

ACTION:

a. With an ECCS actuation instrumentation channel trip setpoint less conservative than the value shown in the Allowable Values column of Table 3.3.3-2, declare the channel inoperable until the channel is restored to OPERABLE status with its trip setpoint adjusted consistent with the Trip Setpoint value.

b. With one or more ECCS actuation instrumentation channels inoperable, take the ACTION required by Table 3.3.3-1.

SURVEILLANCE REQUIREMENTS

4.3.3.1 Each ECCS 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 4.3.3.1-1.

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

4.3.3.3 The ECCS RESPONSE TIME of each ECCS trip function shown in Table 3.3.3-3 shall be demonstrated to be within the limit at least once per 18 months. Each test shall include at least one channel per trip system such that all channels are tested at least once every N times 18 months where N is the total number of redundant channels in a specific ECCS trip system.

TABLE 3.3.3-1

EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION

TRIP FUNCTION	MINIMUM OPERABLE CHANNELS PER TRIP SYSTEM[a]	APPLICABLE OPERATIONAL CONDITIONS	ACTION
1. CORE SPRAY 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 Steam Dome Pressure - Low (Permissive)	2	1, 2, 3 4*, 5*	31 32
d. Manual Initiation	1/subsystem	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 Steam Dome Pressure - Low (Permissive)			
1) System Initiation	2	1, 2, 3 4*, 5*	31 32
2) Recirculation Discharge Valve Closure	2	1, 2, 3, 4*, 5*	31 32
d. Manual Initiation	1/subsystem	1, 2, 3, 4*, 5*	33
3. HIGH PRESSURE COOLANT INJECTION SYSTEM#			
a. Reactor Vessel Water Level - Low Low, Level 2	2	1, 2, 3	30
b. Drywell Pressure - High	2	1, 2, 3	30
c. Condensate Storage Tank Level - Low	2[b]	1, 2, 3	34
d. Suppression Pool Water Level - High	2	1, 2, 3	34
e. Reactor Vessel Water Level - High, Level 8	2[c]	1, 2, 3	31
f. Manual Initiation	1/system	1, 2, 3	33

TABLE [illegible].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	≥-129 inches*	≥-136 inches
b. Drywell Pressure - High	≤ 1.72 psig	≤ 1.88 psig
c. Reactor Vessel Steam Dome Pressure - Low	≥ 436 psig, decreasing	≥ 416 psig, decreasing
d. Manual Initiation	NA	NA
2. LOW PRESSURE COOLANT INJECTION MODE OF RHR SYSTEM		
a. Reactor Vessel Water Level - Low Low Low, Level 1	≥-129 inches*	≥-136 inches
b. Drywell Pressure - High	≤ 1.72 psig	≤ 1.88 psig
c. Reactor Vessel Steam Dome Pressure - Low		
1) System Initiation	≥436 psig, decreasing	≥416 psig, decreasing
2) Recirculation Discharge Valve Closure	≥236 psig, decreasing	≥216 psig, decreasing
d. Manual Initiation	NA	NA
3. HIGH PRESSURE COOLANT INJECTION SYSTEM		
a. Reactor Vessel Water Level - Low Low, Level 2	≥-38 inches*	≥ -45 inches
b. Drywell Pressure - High	≤ 1.72 psig	≤ 1.88 psig
c. Condensate Storage Tank Level - Low	≥ 36.0 inches above tank bottom	≥ 36.0 inches above tank bottom
d. Reactor Vessel Water Level - High, Level 8	≤ 54 inches	≤ 55.5 inches
e. Suppression Pool Water Level - High	≤ 23 feet 9 inches	≤ 24 feet
f. Manual Initiation	NA	NA

TABLE 3.3.3-2 (Continued)

EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION SETPOINTS

TRIP FUNCTION	TRIP SETPOINT	ALLOWABLE VALUE
4. AUTOMATIC DEPRESSURIZATION SYSTEM		
a. Reactor Water Level - Low Low Low, Level 1	≥ -129 inches*	≥-136 inches
b. Drywell Pressure - High	≤ 1.72 psig	≤ 1.88 psig
c. ADS Timer	≤ 102 seconds	≤ 114 seconds
d. Core Spray Pump Discharge Pressure - High	145 ± 10 psig	145 ± 20 psig
e. RHR LPCI Mode Pump Discharge Pressure - High	125 ± 4 psig	125 ± 10 psig
f. Reactor Vessel Water Level-Low, Level 3	≥ 13 inches	≥ 11.5 inches
g. Manual Initiation	NA	NA
5. LOSS OF POWER		
a. 4.16 kv ESS Bus Undervoltage (Loss of Voltage, <20%)	a. 4.16 kv Basis - 840 ± 16.8 volts b. 120 v Basis - 24 ± 0.48 volts c. 0.5 ± 0.1 second time delay	840 ± 59.6 volts 24 ± 1.7 volts 0.5 ± 0.1 second time delay
b. 4.16 kv ESS Bus Undervoltage (Degraded Voltage, <65%)	a. 4.16 kv Basis - 2695 ± 53.9 volts b. 120 v Basis - 77 ± 1.54 volts c. 3.0 ± 0.3 second time delay	2695 ± 191.3 volts 77 ± 5.5 volts 3 ± 0.3 second time delay
c. 4.16 kv ESS Bus Undervoltage (Degraded Voltage, <84%)	a. 4.16 kv Basis - 3483 ± 69.7 volts b. 120 v Basis - 99.5 ± 1.99 volts c. 5 minute ± 30 second time delay without LOCA 10 ± 1.0 second time delay with LOCA	3483 + 247.3, - 69.7 volts 99.5 + 7.1 volts, -1.99 volts 5 minutes ± 30 second time delay without LOCA 10 ± 1.0 second time delay with LOCA

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

TABLE 3.3.3-3

EMERGENCY CORE COOLING SYSTEM RESPONSE TIMES

TRIP FUNCTION	RESPONSE TIME (Seconds)
1. CORE SPRAY SYSTEM	
a. Reactor Vessel Water Level-Low Low Low, Level 1	≤27
b. Drywell Pressure-High	≤27
c. Reactor Vessel Steam Dome Pressure-Low	≤27
d. Manual Initation	NA
2. LOW PRESSURE COOLANT INJECTION MODE OF RHR SYSTEM	
a. Reactor Vessel Water Level-Low Low Low, Level 1	≤40
b. Drywell Pressure-High	≤40
c. Reactor Vessel Steam Dome Pressure-Low	
1) System Initiation	≤40
2) Recirculation Discharge Valve Closure	≤40
d. Manual Initiation	NA
3. HIGH PRESSURE COOLANT INJECTION SYSTEM	
a. Reactor Vessel Water Level - Low Low, Level 2	≤30
b. Drywell Pressure - High	≤30
c. Condensate Storage Tank Level-Low	NA
d. Reactor Vessel Water Level-High, Level 8	NA
e. Suppression Pool Water Level-High	NA
f. Manual Initiation	NA
4. AUTOMATIC DEPRESSURIZATION SYSTEM	
a. Reactor Vessel Water Level-Low Low Low, Level 1	NA
b. Drywell Pressure-High	NA
c. ADS Timer	NA
d. Core Spray Pump Discharge Pressure-High	NA
e. RHR LPCI Mode Pump Discharge Pressure-High	NA
f. Reactor Vessel Water Level-Low, Level 3	NA
g. Manual Initiation	NA
5. LOSS OF POWER	
a. 4.16 kV ESS Bus Undervoltage (Loss of Voltage <20%)	NA
b. 4.16 kV ESS Bus Undervoltage (Degraded Voltage <65%)	NA
c. 4.16 kV ESS Bus Undervoltage (Degraded Voltage <84%)	NA

TABLE 4.3.3.1-1

EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION SURVEILLANCE REQUIREMENTS

TRIP FUNCTION	CHANNEL CHECK	CHANNEL FUNCTIONAL TEST	CHANNEL CALIBRATION	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED
1. CORE SPRAY SYSTEM				
a. Reactor Vessel Water Level - Low Low Low, Level 1	S	M	R	1, 2, 3, 4*, 5*
b. Drywell Pressure - High	NA	M	Q	1, 2, 3
c. Reactor Vessel Steam Dome Pressure - Low	NA	M	Q	1, 2, 3, 4*, 5*
d. Manual Initiation	NA	R	NA	1, 2, 3, 4*, 5*
2. LOW PRESSURE COOLANT INJECTION MODE OF RHR SYSTEM				
a. Reactor Vessel Water Level - Low Low Low, Level 1	S	M	R	1, 2, 3, 4*, 5*
b. Drywell Pressure - High	NA	M	Q	1, 2, 3
c. Reactor Vessel Steam Dome Pressure - Low				
1) System Initiation	NA	M	Q	1, 2, 3, 4*, 5*
2) Recirculation Discharge Valve Closure	NA	M	Q	1, 2, 3, 4*, 5*
d. Manual Initiation	NA	R	NA	1, 2, 3, 4*, 5*
3. HIGH PRESSURE COOLANT INJECTION SYSTEM#				
a. Reactor Vessel Water Level - Low Low, Level 2	S	M	R	1, 2, 3
b. Drywell Pressure - High	NA	M	Q	1, 2, 3
c. Condensate Storage Tank Level - Low	NA	M	Q	1, 2, 3
d. Suppression Pool Water Level - High	NA	M	Q	1, 2, 3
e. Reactor Vessel Water Level - High, Level 8	NA	M	Q	1, 2, 3
Manual Initiation	NA		NA	1, 2, 3

TABLE 3.3.6-1 (Continued)

CONTROL ROD BLOCK INSTRUMENTATION

ACTION

ACTION 60 - Declare the RBM inoperable and take the ACTION required by Specification 3.1.4.3.

ACTION 61 - With the number of OPERABLE Channels:

a. One less than required by the Minimum OPERABLE Channels per Trip Function requirement, restore the inoperable channel to OPERABLE status within 7 days or place the inoperable channel in the tripped condition within the next hour.

b. Two or more less than required by the Minimum OPERABLE Channels per Trip Function requirement, place at least one inoperable channel in the tripped condition within 1 hour.

ACTION 62 - With the number of OPERABLE channels less than required by the Minimum OPERABLE Channels per Trip Function requirement, place the inoperable channel in the tripped condition within 1 hour.

NOTES

* With THERMAL POWER ≥ 30% of RATED THERMAL POWER.

** With more than one control rod withdrawn. Not applicable to control rods removed per Specification 3.9.10.1 or 3.9.10.2.

a. The RBM shall be automatically bypassed when a peripheral control rod is selected or the reference APRM channel indicates less than 30% of RATED THERMAL POWER.

b. This function shall be automatically bypassed if detector count rate is ≥ 100 cps or the IRM channels are on range 3 or higher.

c. This function is automatically bypassed when the associated IRM channels are on range 8 or higher.

d. This function is automatically bypassed when the IRM channels are on range 3 or higher.

e. This function is automatically bypassed when the IRM channels are on range 1.

TABLE 3.3.6-2

CONTROL ROD BLOCK INSTRUMENTATION SETPOINTS

TRIP FUNCTION	TRIP SETPOINT	ALLOWABLE VALUE
1. ROD BLOCK MONITOR		
a. Upscale	$\leq$ 0.66 W + 40%	$\leq$ 0.66 W + 43%
b. Inoperative	NA	NA
c. Downscale	$\geq$ 5/125 divisions of full scale	$\geq$ 3/125 of divisions full scale
2. APRM		
a. Flow Biased Neutron Flux - Upscale	$\leq$ 0.58 W + 50%*	$\leq$ 0.58 W + 53%*
b. Inoperative	NA	NA
c. Downscale	$\geq$ 5% of RATED THERMAL POWER	$\geq$ 3% of RATED THERMAL POWER
d. Neutron Flux - Upscale Startup	$\leq$ 12% of RATED THERMAL POWER	$\leq$ 14% of RATED THERMAL POWER
3. SOURCE RANGE MONITORS		
a. Detector not full in	NA	NA
b. Upscale	$\leq 2 \times 10^5$ cps	$\leq 4 \times 10^5$ cps
c. Inoperative	NA	NA
d. Downscale	$\geq$ 0.7 cps**	$\geq$ 0.5 cps**
4. INTERMEDIATE RANGE MONITORS		
a. Detector not full in	NA	NA
b. Upscale	$\leq$ 108/125 divisions of full scale	$\leq$ 110/125 divisions of full scale
c. Inoperative	NA	NA
d. Downscale	$\geq$ 5/125 divisions of full scale	$\geq$ 3/125 divisions of full scale
5. SCRAM DISCHARGE VOLUME		
a. Water Level - High	$\leq$ 44 gallons	$\leq$ 44 gallons
6. REACTOR COOLANT SYSTEM RECIRCULATION FLOW		
a. Upscale	$\leq$ 108/125 divisions of full scale	$\leq$ 111/125 divisions of full scale
b. Inoperative	NA	NA
c. Comparator	$\leq$ 10% flow deviation	$\leq$ 11% flow deviation

*The Average Power Range Monitor rod block function is varied as a function of recirculation loop flow (' The trip setting of this function must be main ed in accordance with Specification 3.2.2.
** (ded signal-to-noise ratio is $\geq$2. Otherwise, 3c s trip setpoint and 2.8cps for allowable val.

TABLE 4.3.6-1

CONTROL ROD BLOCK INSTRUMENTATION SURVEILLANCE REQUIREMENTS

TRIP FUNCTION	CHANNEL CHECK	CHANNEL FUNCTIONAL TEST	CHANNEL CALIBRATION[a]	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED
1. ROD BLOCK MONITOR				
a. Upscale	NA	S/U[b],M	Q	1*
b. Inoperative	NA	S/U[b],M	NA	1*
c. Downscale	NA	S/U[b],M	Q	1*
2. APRM				
a. Flow Biased Neutron Flux - Upscale	S	S/U[b],W	SA	1
b. Inoperative	NA	S/U[b],W	NA	1, 2, 5
c. Downscale	S	S/U[b],W	SA	1
d. Neutron Flux - Upscale, Startup	S	S/U[b],W	SA	2, 5
3. SOURCE RANGE MONITORS				
a. Detector not full in	NA	S/U[b],W	NA	2, 5
b. Upscale	NA	S/U[b],W	Q	2, 5
c. Inoperative	NA	S/U[b],W	NA	2, 5
d. Downscale	NA	S/U[b],W	Q	2, 5
4. INTERMEDIATE RANGE MONITORS				
a. Detector not full in	NA	S/U[b],W	NA	2, 5
b. Upscale	S	S/U[b],W	Q	2, 5
c. Inoperative	NA	S/U[b],W	NA	2, 5
d. Downscale	S	S/U[b],W	Q	2, 5
5. SCRAM DISCHARGE VOLUME				
a. Water Level-High	NA	M	R	1, 2, 5**
6. REACTOR COOLANT SYSTEM RECIRCULATION FLOW				
a. Upscale	NA	S/U[b],M	Q	1
b. Inoperative	NA	S/U[b],M	NA	1
c. Comparator	NA	S/U[b],M	Q	1

29

TABLE 4.3.6-1 (Continued)

CONTROL ROD BLOCK INSTRUMENTATION SURVEILLANCE REQUIREMENTS

TABLE NOTATIONS

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

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

* With THERMAL POWER $\geq$ 30% of RATED THERMAL POWER.

** With more than one control rod withdrawn. Not applicable to control rods removed per Specification 3.9.10.1 or 3.9.10.2.

TABLE 3.3.7.1-1 (Continued)

RADIATION MONITORING INSTRUMENTATION

ACTION STATEMENTS 29

ACTION 70 -

a. With one of the required monitors inoperable, place the inoperable channel in the downscale tripped condition within 1 hour; restore the inoperable channel to OPERABLE status within 7 days, or, within the next 6 hours, initiate and maintain operation of the control room emergency filtration system in the isolation mode of operation. 29

b. With both of the required monitors inoperable, initiate and maintain operation of the control room emergency filtration system in the isolation mode of operation within 1 hour. 29

ACTION 71 - With the required monitor inoperable, assure a portable continuous monitor with the same alarm setpoint is OPERABLE in the vicinity of the installed monitor during any fuel movement. If no fuel movement is being made, perform area surveys of the monitored area with portable monitoring instrumentation at least once per 24 hours.

TABLE 4.3.7.1-1

RADIATION MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS

INSTRUMENTATION	CHANNEL CHECK	CHANNEL FUNCTIONAL TEST	CHANNEL CALIBRATION	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED
1. Main Control Room Outside Air Intake Radiation Monitor	S	M	R	1, 2, 3, 5 and *
2. Area Monitors				
a. Criticality Monitors				
1) New Fuel Storage Vault	S	M	R	(a)
2) Spent Fuel Storage Pool	S	M	R	(b)

(a) With fuel in the new fuel storage vault.
(b) With fuel in the spent fuel storage pool.
* When irradiated fuel is being handled in the secondary containment.

TABLE 4.3.7.2-1

SEISMIC MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS

INSTRUMENTS AND SENSOR LOCATIONS	CHANNEL FUNCTIONAL TEST	CHANNEL CALIBRATION
1. Triaxial Accelerometers and Triggers		
a. Reactor Equipment, Unit 1	SA	R
b. Reactor Bldg. Floor (RHR), Unit 1	SA	R
c. ESSW Pumphouse Floor[a]	SA	R
d. Containment Foundation, Unit 1[a]	SA	R
e. Containment Structure, Unit 1	SA	R
2. Peak Accelerographs		
a. Reactor Equipment, Unit 2	NA	R
b. Reactor Piping, Unit 2	NA	R
c. RHR Pump Room, Unit 2	NA	R
3. Response-Spectrum Analyzer/Recorders	SA	NA

29

[a] The Unit 1 Containment Foundation and the ESW Pumphouse Floor are the triaxial accelerometer channels with triggers. The triggers are functionally tested and calibrated with their associated channels. 29

METEOROLOGICAL MONITORING INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.7.3 The meteorological monitoring instrumentation channels shown in Table 3.3.7.3-1 shall be OPERABLE.

APPLICABILITY: At all times.

ACTION:

a. With one or more meteorological monitoring instrumentation channels inoperable for more than 7 days, prepare and submit a Special Report to the Commission pursuant to Specification 6.9.2 within the next 10 days outlining the cause of the malfunction and the plans for restoring the instrumentation to OPERABLE status. 26

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

SURVEILLANCE REQUIREMENTS

4.3.7.3 Each of the above required meteorological monitoring instrumentation channels shall be demonstrated OPERABLE by the performance of the CHANNEL CHECK and CHANNEL CALIBRATION operations at the frequencies shown in Table 4.3.7.3-1.

TABLE 4.3.7.4-1

REMOTE SHUTDOWN MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS

INSTRUMENT	CHANNEL CHECK	CHANNEL CALIBRATION
1. Reactor Vessel Steam Dome Pressure	M	R
2. Reactor Vessel Water Level	M	R
3. Suppression Pool Water Level	M	R
4. Suppression Pool Water Temperature	M	R
5. RHR System Flow	M	R
6. RHR Service Water System Flow	M	R
7. RCIC Turbine Speed or RCIC Pump Flow	M	R

ACCIDENT MONITORING INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.7.5 The accident monitoring instrumentation channels shown in Table 3.3.7.5-1 shall be OPERABLE.

APPLICABILITY: As shown in Table 3.3.7.5-1.

ACTION:

With one or more accident monitoring channels inoperable, take the ACTION required by Table 3.3.7.5-1.

SURVEILLANCE REQUIREMENTS

4.3.7.5 Each of the above required accident monitoring instrumentation channels shall be demonstrated OPERABLE by performance of the CHANNEL CHECK and CHANNEL CALIBRATION operations at the frequencies shown in Table 4.3.7.5-1.

TABLE 3.3.7.5-1

ACCIDENT MONITORING INSTRUMENTATION

INSTRUMENT	REQUIRED NUMBER OF CHANNELS	MINIMUM CHANNELS OPERABLE	ACTION	APPLICABLE OPERATIONAL CONDITION
1. Reactor Vessel Steam Dome Pressure	2	1	80	1, 2
2. Reactor Vessel Water Level	2	1	80	1, 2
3. Suppression Chamber Water Level	2	1	80	1, 2
4. Suppression Chamber Water Temperature	8, 6 locations	6, 1/location	80	1, 2
5. Suppression Chamber Air Temperature	2	1	80	1, 2
6. Primary Containment Pressure	2/range	1/range	80	1, 2
7. Drywell Temperature	2	1	80	1, 2
8. Drywell Gaseous Analyzer				
a. Oxygen	2	1	80	1#, 2#
b. Hydrogen	2	1	82	1#, 2#
9. Safety/Relief Valve Position Indicators	1/valve*	1/valve*	80	1, 2
10. Containment High Radiation	2	1	81	1, 2
11. Noble gas monitors**				
a. Reactor Bldg. Vent	1	1	81	1, 2 and ***
b. SGTS Vent	1	1	81	1, 2 and *** 6
c. Turbine Bldg. Vent	1	1	81	1, 2

*Acoustic monitor.
**Mid-range and high-range channels
***When moving irradiated fuel in the secondary containment.
#See Special Test Exception 3.10.1

TABLE 3.3.7.5-1 (Continued)

ACCIDENT MONITORING INSTRUMENTATION

ACTION STATEMENT

ACTION 80 -

a. With the number of OPERABLE accident monitoring instrumentation channels less than the Required Number of Channels shown in Table 3.3.7.5-1, restore the inoperable channel(s) to OPERABLE status within 7 days or be in at least HOT SHUTDOWN within the next 12 hours.

b. With the number of OPERABLE accident monitoring instrumentation channels less than the Minimum Channels OPERABLE requirements of Table 3.3.7.5-1, restore the inoperable channel(s) to OPERABLE status within 48 hours or be in at least HOT SHUTDOWN within the next 12 hours.

ACTION 81 - With the number of OPERABLE Channels less than required by the Minimum Channels OPERABLE requirement, initiate the preplanned alternate method of monitoring the appropriate parameter(s) within 72 hours, and:

1. either restore the inoperable channel(s) to OPERABLE status within 7 days of the event, or

2. prepare and submit a Special Report to the Commission pursuant to Specification 6.9.2 within 14 days following the event outlining the action taken, the cause of the inoperability, and the plans and schedule for restoring the system to OPERABLE status.

ACTION 82 -

a. With the number of OPERABLE channels one less than the required Number of Channels shown in Table 3.3.7.5-1, restore the inoperable channel to OPERABLE status within 30 days or be in at least HOT SHUTDOWN within the next 12 hours.

b. With the number of OPERABLE channels less than the Minimum Channels OPERABLE requirements of Table 3.3.7.5-1, restore at least one channel to OPERABLE status within 7 days or be in at least HOT SHUTDOWN within the next 12 hours.

TABLE 4.3.7.5-1

ACCIDENT MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS

INSTRUMENT	CHANNEL CHECK	CHANNEL CALIBRATION
1. Reactor Vessel Steam Dome Pressure	M	R
2. Reactor Vessel Water Level	M	R
3. Suppression Chamber Water Level	M	R
4. Suppression Chamber Water Temperature	M	R
5. Suppression Chamber Air Temperature	M	R
6. Primary Containment Pressure	M	R
7. Drywell Temperature	M	R
8. Drywell Oxygen/Hydrogen Analyzer	M	Q*
9. Safety/Relief Valve Position Indicators	M	R
10. Containment High Radiation	M	R**
11. Noble gas monitors		
a. Reactor Bldg. Vent	M	R
b. SGTS Vent	M	R
c. Turbine Bldg. Vent	M	R

*For hydrogen analyzer, use sample gas containing:
a. Nominal zero volume percent hydrogen, balance nitrogen.
b. Nominal thirty volume percent hydrogen, balance nitrogen.

**CHANNEL CALIBRATION shall consist of an electronic calibration of the channel, not including the detector, for range decades above 10 R/hr and a one point calibration check of the detector below 10 R/hr with an installed or portable gamma source.

INSTRUMENTATION

SOURCE RANGE MONITORS

LIMITING CONDITION FOR OPERATION

3.3.7.6 At least three source range monitor channels shall be OPERABLE.

APPLICABILITY: OPERATIONAL CONDITIONS 2*, 3 and 4.

ACTION:

a. In OPERATIONAL CONDITION 2* with one of the above required source range monitor channels inoperable, restore at least 3 source range monitor channels to OPERABLE status within 4 hours or be in at least HOT SHUTDOWN within the next 12 hours.

b. In OPERATIONAL CONDITION 3 or 4 with two or more of the above required source range monitor channels inoperable, verify all insertable control rods to be inserted in the core and lock the reactor mode switch in the Shutdown position within 1 hour. |29

SURVEILLANCE REQUIREMENTS

4.3.7.6 Each of the above required source range monitor channels shall be demonstrated OPERABLE by:

a. Performance of a:

1. CHANNEL CHECK at least once per:

a) 12 hours in CONDITION 2*, and

b) 24 hours in CONDITION 3 or 4.

2. CHANNEL CALIBRATION** at least once per 18 months.

b. Performance of a CHANNEL FUNCTIONAL TEST:

1. Within 24 hours prior to moving the reactor mode switch from the Shutdown position, if not performed within the previous 7 days, and

2. At least once per 31 days.

c. Verifying, prior to withdrawal of control rods, that the SRM count rate is at least 0.7 cps*** with the detector fully inserted.

*With IRM's on range 2 or below.
**Neutron detectors may be excluded from CHANNEL CALIBRATION.
***Provided signal-to-noise ratio is $\geq$ 2, otherwise 3 cps.

INSTRUMENTATION

TRAVERSING IN-CORE PROBE SYSTEM

LIMITING CONDITION FOR OPERATION

3.3.7.7. The traversing in-core probe system shall be OPERABLE with:

a. Five movable detectors, drives and readout equipment to map the core, and

b. Indexing equipment to allow all five detectors to be calibrated in a common location.

APPLICABILITY: When the traversing in-core probe is used for:

a. Recalibration of the LPRM detectors, and

b.* Monitoring the APLHGR, LHGR, MCPR, or MFLPD.

ACTION:

With the traversing in-core probe system inoperable, suspend use of the system for the above applicable monitoring or calibration functions. The provisions of Specifications 3.0.3 and 3.0.4 are not applicable.

SURVEILLANCE REQUIREMENTS

4.3.7.7 The traversing in-core probe system shall be demonstrated OPERABLE by normalizing each of the above required detector outputs within 72 hours prior to use for the above applicable monitoring or calibration functions.

*Only the detector(s) in the required measurement location(s) are required to be OPERABLE.

INSTRUMENTATION

CHLORINE DETECTION SYSTEM

LIMITING CONDITION FOR OPERATION

3.3.7.8 The chlorine detection system shall be OPERABLE with two independent chlorine detectors with their alarm/trip saturation point adjusted to actuate within 5 seconds at a chlorine concentration of $\leq$ 5 ppm.

APPLICABILITY: All OPERATIONAL CONDITIONS.

ACTION:

a. With one chlorine detector inoperable, restore the inoperable detector to OPERABLE status within 7 days or, within the next 6 hours, initiate and maintain operation of at least one control room emergency outside air supply subsystem in the recirculation mode of operation.

b. With the chlorine detection system otherwise inoperable, within 1 hour initiate and maintain operation of at least one control room emergency outside air supply subsystem in the recirculation mode of operation.

c. The provisions of Specification 3.0.4 are not applicable.

SURVEILLANCE REQUIREMENTS

4.3.7.8 The above required chlorine detection system shall be demonstrated OPERABLE by performance of a:

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

b. Detector functional test at least once per 18 months by introducing a measured amount of chlorine into each detector, equivalent to a chlorine concentration of $\leq$ 5 ppm, and verifying the elapsed time to actuate each detector is less than or equal to 5 seconds.

FIRE DETECTION INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.7.9 As a minimum, the fire detection instrumentation for each fire detection zone shown in Table 3.3.7.9-1 shall be OPERABLE.

APPLICABILITY: Whenever equipment protected by the fire detection instrument is required to be OPERABLE.

ACTION:

With the number of OPERABLE fire detection instruments less than the Minimum Instruments OPERABLE requirement of Table 3.3.7.9-1:

a. Within 1 hour, establish a fire watch patrol to inspect the zone(s) with the inoperable instrument(s) at least once per hour, unless the instrument(s) is located inside an inaccessible zone, then inspect the area surrounding the inaccessible zone at least once per hour.

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

SURVEILLANCE REQUIREMENTS

4.3.7.9.1 Each of the above required fire detection instruments which are accessible during unit operation shall be demonstrated OPERABLE at least once per 6 months by performance of a CHANNEL FUNCTIONAL TEST. Fire detectors which are not accessible during unit operation shall be demonstrated OPERABLE by the performance of a CHANNEL FUNCTIONAL TEST during each COLD SHUTDOWN exceeding 24 hours unless performed in the previous 6 months.

4.3.7.9.2 The supervised circuits supervision associated with the detector alarms of each of the above required fire detection instruments shall be demonstrated OPERABLE at least once per 6 months.

TABLE 3.3.7.9-1

FIRE DETECTION INSTRUMENTATION

INSTRUMENT LOCATION			INSTRUMENTS OPERABLE					
FIRE ZONE	ROOM OR AREA	ELEV.	HEAT TOTAL	HEAT MIN.	IONIZATION TOTAL	IONIZATION MIN.	PHOTO-ELECTRIC TOTAL	PHOTO-ELECTRIC MIN.
a. Control Building								
0-24D	Lower Relay Room	698'-1"	4	2	4	2	NA	NA
0-24D	PGCC	698'-1"	54	27	30	15	NA	NA
0-25E	Lower Cable Spreading Rm.	714'-0"	26	13	6	3	NA	NA
0-25A	Lower Cable Spreading Rm.	714'-0"	20	10	6	3	NA	NA
0-26H	Control Rm. (Under Flr. Unit 1)*	729'-1"	NA	NA	18	9	NA	NA
0-26H	Control Room (Under Flr. Unit 2)*	729'-1"	NA	NA	15	8	NA	NA
0-26H	Control Room	729'-1"	NA	NA	10	5	NA	NA
0-26H	Control Rm. (Above Clg)*	729'-1"	NA	NA	9	5	NA	NA
0-27C	Upper Cable Spreading Rm.	753'-0"	29	15	8	4	NA	NA
0-27B	Upper Cable Spreading Rm.	753'-0"	28	14	5	3	NA	NA
0-27E	Upper Relay Room	754'-1"	4	2	2	1	NA	NA
0-27E	PGCC	754'-1"	55	28	30	15	NA	NA
0-28K	Battery Room	771'-0"	NA	NA	1	1	NA	NA
0-28L	Battery Room	771'-0"	NA	NA	1	1	NA	NA
0-28M	Battery Room	771'-0"	NA	NA	1	1	NA	NA
0-28N	Battery Room	771'-0"	NA	NA	1	1	NA	NA
0-28I	Battery Room	771'-0"	NA	NA	1	1	NA	NA
0-28J	Battery Room	771'-0"	NA	NA	1	1	NA	NA
0-28G	Battery Room	771'-0"	NA	NA	1	1	NA	NA
0-28F	Battery Room	771'-0"	NA	NA	1	1	NA	NA
0-28E	Battery Room	771'-0"	NA	NA	1	1	NA	NA
0-28C	Battery Room	771'-0"	NA	NA	1	1	NA	NA
0-28D	Battery Room	771'-0"	NA	NA	1	1	NA	NA
0-28T	Battery Room	771'-0"	NA	NA	1	1	NA	NA

TABLE 3.3.7.9-1 (Continued)

FIRE DETECTION INSTRUMENTATION

INSTRUMENT LOCATION			INSTRUMENTS OPERABLE					
FIRE ZONE	ROOM OR AREA	ELEV.	HEAT TOTAL	HEAT MIN.	IONIZATION TOTAL	IONIZATION MIN.	PHOTO-ELECTRIC TOTAL	PHOTO-ELECTRIC MIN.
0-22A	Filter Area	687'-8"	NA	NA	11	6	NA	NA
0-26B	South Cable Chase	729'-1"	NA	NA	1	1	NA	NA
0-26C	Center Cable Chase	729'-1"	NA	NA	1	1	NA	NA
0-26D	North Cable Chase	729'-1"	NA	NA	1	1	NA	NA
0-26F	Vestibule	729'-1"	NA	NA	1	1	NA	NA
0-26G	Shift Office	729'-1"	NA	NA	1	1	NA	NA
0-26J	Vestibule	729'-1"	NA	NA	1	1	NA	NA
0-26M	Soffit	729'-1"	NA	NA	4	2	NA	NA
0-26N	Control Room Soffit	729'-1"	NA	NA	2	1	NA	NA
0-26P	Control Room Soffit	729'-1"	NA	NA	2	1	NA	NA
0-26R	Soffit	729'-1"	NA	NA	4	2	NA	NA
0-26S	South Cable Chase	729'-1"	1	1	NA	NA	NA	NA
0-26T	Center Cable Chase	729'-1"	1	1	NA	NA	NA	NA
0-26V	North Cable Chase	729'-1"	1	1	NA	NA	NA	NA
0-27F	South Cable Chase	754'-1"	1	1	NA	NA	NA	NA
0-27G	Center Cable Chase	754'-1"	1	1	NA	NA	NA	NA
0-27H	North Cable Chase	754'-1"	1	1	NA	NA	NA	NA
0-28A	Equipment Room	771'-0"	NA	NA	4	2	NA	NA
0-28B	Equipment Room	771'-0"	NA	NA	4	2	NA	NA
0-28H	Repair Shop	771'-0"	NA	NA	2	1	NA	NA
0-28P	South Cable Chase	771'-0"	1	1	NA	NA	NA	NA
0-28R	North Cable Chase	771'-0"	1	1	NA	NA	NA	NA
0-29B	H&V Equipment Room	783'-0"	NA	NA	10	5	NA	NA
0-30A	HVAC Equipment Room	806'-0"	NA	NA	20	10	NA	NA
0-25B	South Cable Chase	714'-0"	1	1	NA	NA	NA	NA
0-25C	Center Cable Chase	714'-0"	1	1	NA	NA	NA	NA
0-25D	North Cable Chase	714'-0"	1	1	NA	NA	NA	NA
0-28Q	Center Cable Chase	771'-0"	1	1	NA	NA	NA	NA
0-26I	Operational Support Center	729'-1"	NA	NA	1	1	NA	NA

TABLE 3.3.7.9-1 (Continued)

FIRE DETECTION INSTRUMENTATION

INSTRUMENT LOCATION			INSTRUMENTS OPERABLE						
FIRE ZONE	ROOM OR AREA	ELEV.	HEAT TOTAL	HEAT MIN.	IONIZATION TOTAL	IONIZATION MIN.	PHOTO-ELECTRIC TOTAL	PHOTO-ELECTRIC MIN.	
b.	Reactor Building								
1-1B	Core Spray Pump Room	645'-0"	NA	NA	5	3	NA	NA	
1-1A	Core Spray Pump Room	645'-0"	NA	NA	7	4	NA	NA	
1-1E	RHR Pump Room	645'-0"	NA	NA	NA	NA	13	7	
1-1F	RHR Pump Room	645'-0"	NA	NA	NA	NA	15	8	
1-1D	RCIC Pump Room	645'-0"	2	1	NA	NA	5	3	
1-1C	HPCI Pump Room	645'-0"	2	1	NA	NA	7	4	
1-1G	Sump Room	645'-0"	NA	NA	2	1	NA	NA	
1-2B	Access Area	670'-0"	NA	NA	7	4	NA	NA	
1-5A	Fuel Pool Pumps and Heat Exchangers	749'-1"	NA	NA	22	11	7	4	
1-2D	Remote Shutdown Panel Rm.	670'-0"	NA	NA	2	1	NA	NA	17
1-4C	Switchgear Room	719'-0"	NA	NA	2	1	NA	NA	
1-4D	Switchgear Room	719'-0"	NA	NA	2	1	NA	NA	
1-4A	Containment Access Area	719'-0"	NA	NA	27	14	4	2	
1-5F	Load Center Room	749'-1"	NA	NA	2	1	NA	NA	
1-5G	Load Center Room	749'-1"	NA	NA	2	1	NA	NA	
1-2A	Access Area	670'-0"	NA	NA	7	4	NA	NA	
1-3A	Access Area	683'-0"	NA	NA	7	4	NA	NA	
1-3B	Access Area	683'-0"	NA	NA	12	6	NA	NA	
1-3C	Access Area	683'-0"	NA	NA	NA	NA	13	7	16
1-4B	Pipe Penetration Room	719'-1"	NA	NA	1	1	NA	NA	
1-4G	Main Steam Piping	719'-1"	NA	NA	NA	NA	6	3	
1-5B	Valve Access Area	761'-10"	NA	NA	NA	NA	2	1	
1-5D	RWCU Pumps & Heat Exchangers	749'-1"	NA	NA	NA	NA	12	6	
1-5E	Penetration Room	749'-1"	NA	NA	NA	NA	2	1	
1-6A	Access Area	779'-1"	NA	NA	9	5	NA	NA	
1-6I	Fuel Pooling Holding Pump Room	779'-1	NA	NA	NA	NA	2	1	

TABLE 3.3.7.9-1 (Continued)

FIRE DETECTION INSTRUMENTATION

INSTRUMENT LOCATION			INSTRUMENTS OPERABLE						
FIRE ZONE	ROOM OR AREA	ELEV.	HEAT TOTAL	HEAT MIN.	IONIZATION TOTAL	IONIZATION MIN.	PHOTO-ELECTRIC TOTAL	PHOTO-ELECTRIC MIN.	17
Reactor Building (Continued)									
1-6D	H&V Equipment Room	779'-1"	NA	NA	12	6	NA	NA	
1-6E	Recirculation Fans Area	779'-1"	NA	NA	2	1	NA	NA	
0-6G	Surge Tank Vault	779'-4"	NA	NA	2	1	NA	NA	
1-7A	H&V Fan and Filter Rooms	799'-1"	24	12	15	8	NA	NA	
0-8A	Refueling Floor	818'-1"	NA	NA	NA	NA	59	30	
c. ESSW Pumphouse									
0-51	Pump Room	685'-6"	NA	NA	6	3	NA	NA	
0-52	Pump Room	685'-6"	NA	NA	6	3	NA	NA	
					INFRA-RED (FLAME) TOTAL	INFRA-RED (FLAME) MIN.			
d. Diesel Generator Building									
0-41A	Diesel Generator Rooms and	660'-0" 677'-0"	22	11	2	1	15	8	
0-41C	Diesel Generator Rooms and	660'-0" 677'-0"	22	11	2	1	15	8	
0-41B	Diesel Generator Rooms and	660'-0" 677'-0"	23	12	2	1	15	8	
0-41D	Diesel Generator Rooms and	660'-0" 677'-0"	22	11	2	1	15	8	

*Not accessible.

RADIOACTIVE LIQUID EFFLUENT MONITORING INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.7.10 The radioactive liquid effluent monitoring instrumentation channels shown in Table 3.3.7.10-1 shall be OPERABLE with their alarm/trip setpoints set to ensure that the limits of Specification 3.11.1.1 are not exceeded. The alarm/trip setpoints of these channels shall be determined in accordance with the methodology and parameters described in the Offsite Dose Calculation Manual (ODCM).

APPLICABILITY: At all times.

ACTION:

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

b. With less than the minimum number of radioactive liquid effluent monitoring instrumentation channels OPERABLE, take the ACTION shown in Table 3.3.7.10-1. 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

4.3.7.10 Each radioactive liquid 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 4.3.7.10-1.

TABLE 3.3.7.10-1

RADIOACTIVE LIQUID EFFLUENT MONITORING INSTRUMENTATION

INSTRUMENT	MINIMUM CHANNELS OPERABLE	ACTION
1. GROSS RADIOACTIVITY MONITORS PROVIDING AUTOMATIC TERMINATION OF RELEASE		
a. Liquid Radwaste Effluent Line	1*	100
2. GROSS RADIOACTIVITY MONITORS NOT PROVIDING AUTOMATIC TERMINATION OF RELEASE		
a. Service Water System Effluent Line	1	101
b. RHR Service Water Systme Effluent Line	1/loop	101
3. FLOW RATE MEASUREMENT DEVICES		
a. Liquid Radwaste Effluent Line	1	102
b. Discharge Canal	1	102

*The monitor is required to be OPERABLE when liquid radwaste is being discharged or the channel shall be declared inoperable. The monitor, including the sample pump, is required to be in operation at all times if any discharge valve interlock is in an off-normal condition or is not functioning, i.e., sample pump flow low, high radiation alarm; radiation monitor failure; Unit 1 cooling tower blowdown low flow or Unit 2 cooling tower blowdown low flow.

TABLE 3.3.7.11-1

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/operating train	**	110
2. REACTOR BUILDING VENTILATION MONITORING SYSTEM			
a. Noble Gas Activity Monitor	1##	*	111
b. Iodine Monitor	1	*	112
c. Particulate Monitor	1	*	112
d. Effluent System Flow Rate Monitor	1	*	113
e. Sampler Flow Rate Monitor	1	*	113

TABLE 3.3.7.11-1

RADIOACTIVE GASEOUS EFFLUENT MONITORING INSTRUMENTATION

INSTRUMENT	MINIMUM CHANNELS OPERABLE	APPLICABILITY	ACTION
3. TURBINE BUILDING VENTILATION MONITORING SYSTEM			
a. Noble Gas Activity Monitor	1##	*	114
b. Iodine Monitor	1	*	112
c. Particulate Monitor	1	*	112
d. Effluent System Flow Rate Monitor	1	*	113
e. Sampler Flow Rate Monitor	1	*	113
4. MAIN CONDENSER OFFGAS PRE-TREATMENT RADIOACTIVITY MONITOR (Prior to Input to Holdup System)			
a. Noble Gas Activity Monitor	1	**	115
5. STANDBY GAS TREATMENT SYSTEM MONITOR			
a. Noble Gas Activity Monitor	1##	#	116
b. Iodine Monitor	1	#	112
c. Particulate Monitor	1	#	112
d. Effluent System Flow Rate Monitor	1	#	113
e. Sampler Flow Rate Monitor	1	#	113

TABLE 3.3.7.11-1 (Continued)

TABLE NOTATION

#During operation of the standby gas treatment system.

##Low-range channel of monitor only

* At all times.

** During operation of the main condenser air ejector and offgas treatment system.

ACTION 110 - With the number of channels OPERABLE less than required by the Minimum Channels OPERABLE requirement, operation of main condenser offgas treatment system may continue for up to 30 days provided grab samples are collected at least once per 4 hours and analyzed within the following 4 hours.

ACTION 111 - With the number of channels OPERABLE less than required by the Minimum Channels OPERABLE requirement, effluent releases via this pathway may continue for up to 30 days provided grab samples are taken at least once per 8 hours and these samples are analyzed for gross activity within 24 hours.

ACTION 112 - With the number of channels OPERABLE less than required by the Minimum Channels OPERABLE requirement, effluent releases via this pathway may continue for up to 30 days provided samples are continuously collected with auxiliary sampling equipment as required in Table 4.11.2.1.2-1.

ACTION 113 - With the number of channels OPERABLE less than required by the Minimum Channels OPERABLE requirement, effluent releases via this pathway may continue for up to 30 days provided the flow rate is estimated at least once per 4 hours.

ACTION 114 - With the number of channels OPERABLE less than required by the Minimum Channels OPERABLE requirement, effluent releases via this pathway may continue for up to 30 days provided grab samples are taken at least once per 8 hours and these samples are analyzed for gross activity within 24 hours and provided the mechanical vacuum pumps are not operated.

ACTION 115 - With the number of channels OPERABLE less than required by the Minimum Channels OPERABLE requirement, releases to the environment may continue for up to 72 hours provided:

a. The offgas system is not bypassed, and

b. The Turbine Building vent noble gas activity monitor is OPERABLE;

Otherwise, be in at least HOT SHUTDOWN within 12 hours.

ACTION 116 - With the number of channels OPERABLE less than required by the Minimum Channels OPERABLE requirement, effluent releases via this pathway may continue for up to 30 days provided grab samples are taken at least once per 4 hours and these samples are analyzed for gross activity within 24 hours.

TABLE 4.3.7.11-1

RADIOACTIVE GASEOUS EFFLUENT MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS

INSTRUMENT	CHANNEL CHECK	SOURCE CHECK	CHANNEL CALIBRATION	CHANNEL FUNCTIONAL TEST	MODES IN WHICH SURVEILLANCE REQUIRED
1. MAIN CONDENSER OFFGAS TREATMENT SYSTEM EXPLOSIVE GAS MONITORING SYSTEM					
a. Hydrogen Monitor	D	N/A	Q(3)	M	**
2. REACTOR BUILDING VENTILATION MONITORING SYSTEM					
a. Noble Gas Activity Monitor	D	M	R(2)	Q(1)	*
b. Iodine Monitor	W	M	R(2)	Q(1)	*
c. Particulate Monitor	W	M	R(2)	Q(1)	*
d. Effluent System Flow Rate Monitor	D	N.A.	R	Q	*
e. Sampler Flow Rate Monitor	D	N.A.	R	Q	*

INSTRUMENTATION

LOOSE-PART DETECTION SYSTEM

LIMITING CONDITION FOR OPERATION

3.3.7.12 The loose-part detection system shall be OPERABLE.

APPLICABILITY: OPERATIONAL CONDITIONS 1 and 2.

ACTION:

a. With one or more loose part detection system channels inoperable for more than 30 days, prepare and submit a Special Report to the Commission pursuant to Specification 6.9.2 within the next 10 days outlining the cause of the malfunction and the plans for restoring the channel(s) to OPERABLE status.

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

SURVEILLANCE REQUIREMENTS

4.3.7.12 Each channel of the loose-part detection system shall be demonstrated OPERABLE by performance of a:

a. CHANNEL CHECK at least once per 24 hours,

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

c. CHANNEL CALIBRATION at least once per 18 months.

3/4.3.8 TURBINE OVERSPEED PROTECTION SYSTEM

LIMITING CONDITION FOR OPERATION

3.3.8 One turbine overspeed protection system shall be OPERABLE.

APPLICABILITY: OPERATIONAL CONDITIONS 1 and 2.

ACTION:

With the above required turbine overspeed protection system inoperable, within 6 hours isolate the turbine from the steam supply.

SURVEILLANCE REQUIREMENTS

4.3.8.1 The provisions of Specification 4.0.4 are not applicable.

4.3.8.2 The above required turbine overspeed protection system shall be demonstrated OPERABLE:

a. At least once per 7 days by:

   1. Cycling each of the following valves from the running position and observing valve closure:

      a) Four high pressure turbine control valves,

      b) Six low pressure turbine combined intermediate valves, and

      c) Four high pressure turbine stop valves.

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

c. 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 corrosion.

3/4.4.2 SAFETY/RELIEF VALVES

LIMITING CONDITION FOR OPERATION

3.4.2 The safety valve function of at least 10 of the following reactor coolant system safety/relief valves shall be OPERABLE with the specified code safety valve function lift settings:* ** |29

2 safety-relief valves @ 1146 psig ±1%
4 safety-relief valves @ 1175 psig ±1%
4 safety-relief valves @ 1185 psig ±1%
3 safety-relief valves @ 1195 psig ±1%
3 safety-relief valves @ 1205 psig ±1%

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2 and 3.

ACTION:

a. With the safety valve function of one or more of the above required safety/relief valves inoperable, be in at least HOT SHUTDOWN within 12 hours and in COLD SHUTDOWN within the next 24 hours.

b. With one or more safety/relief valves stuck open, provided that suppression pool average water temperature is less than 105°F, close the stuck open relief valve(s); if unable to close the open valve(s) within 2 minutes or if suppression pool water temperature is 105°F or greater, place the reactor mode switch in the Shutdown position.

c. With one or more safety/relief valve acoustic monitors inoperable, restore the inoperable monitor(s) 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.

SURVEILLANCE REQUIREMENTS

4.4.2 The acoustic monitor for each safety/relief valve shall be demonstrated OPERABLE with the setpoint verified to be 0.25 of the full open noise level by performance of a:

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

b. Calibration in accordance with procedures prepared in conjunction with its manufacturer's recommendations at least once per 18 months.## |29

*The lift setting pressure shall correspond to ambient conditions of the valves at nominal operating temperatures and pressures.
**Up to 2 inoperable valves may be replaced with spare OPERABLE valves with lower setpoints until the next refueling.
##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. |29

3/4.4.3 REACTOR COOLANT SYSTEM LEAKAGE

LEAKAGE DETECTION SYSTEMS

LIMITING CONDITION FOR OPERATION

3.4.3.1 At least the following reactor coolant system leakage detection systems shall be OPERABLE:

a. One primary containment atmosphere particulate radioactivity monitoring system channel aligned to the drywell. 15

b. Two drywell floor drain sump level channels or the flow rate monitoring system, and

c. One primary containment atmosphere gaseous radioactivity monitoring system channel aligned to the drywell. 15

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2 and 3.

ACTION:

With only two of the above required leakage detection systems OPERABLE, operation may continue for up to 30 days provided grab samples of the containment atmosphere are obtained and analyzed at least once per 24 hours when the required gaseous or particulate radioactive monitoring system is inoperable; otherwise, be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours. 29

SURVEILLANCE REQUIREMENTS

4.4.3.1 The reactor coolant system leakage detection systems shall be demonstrated OPERABLE by:

a. Primary containment atmosphere particulate and gaseous monitoring systems-performance of a CHANNEL CHECK at least once per 12 hours, a CHANNEL FUNCTIONAL TEST at least once per 31 days and a CHANNEL CALIBRATION at least once per 18 months.

b. Drywell floor drain sump level or flow rate monitoring system-performance of a CHANNEL FUNCTIONAL TEST at least once per 31 days and a CHANNEL CALIBRATION 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. 25 gpm total leakage averaged over any 24-hour period.

d. 1 gpm leakage at a reactor coolant system pressure of 1000 ± 10 psig from any reactor coolant system pressure isolation valve specified in Table 3.4.3.2-1.

e. 2 gpm increase in UNIDENTIFIED LEAKAGE within any 4-hour period. 7

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 and/or c, 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 closed manual or deactivated automatic 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 pressure 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.

e. With any reactor coolant system UNIDENTIFIED LEAKAGE increase greater than 2 gpm within any 4-hour period, identify the source of leakage increase as not service sensitive Type 304 or 316 austenitic stainless steel within 4 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours. 7

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 particulate and gaseous radioactivity at least once per 4 hours, and

b. Monitoring the drywell floor drain sump level or flow rate at least once per 4 hours.

c. Determining the total IDENTIFIED LEAKAGE at least once per 24 hours.

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 the alarm setpoints per 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.

LIMITING CONDITION FOR OPERATION (Continued) 29

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 $\leq$ 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 $\leq$ 100 psig within the next 24 hours.

e. With a CSS header ΔP instrumentation channel inoperable, restore the inoperable channel to OPERABLE status with 72 hours or determine the ECCS header ΔP locally at least once per 12 hours; otherwise, declare the CSS inoperable. 29 29

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 injection nozzle shall be provided in this Special Report whenever its value exceeds 0.70.

g. With the condensate transfer pump discharge low pressure alarm instrumentation inoperable, monitor the CSS, LPCI and HPCI pressure locally at least once per 24 hours.

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 that the system piping from the pump discharge valve to the system isolation valve is filled with water by:

1. Venting at the high point vents

2. Performing a CHANNEL FUNCTIONAL TEST of the condensate transfer pump discharge low pressure alarm instrumentation.

b) Verifing 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 CSS, performance of a CHANNEL FUNCTIONAL TEST of the core spray header ΔP instrumentation.

3. For the LPCI system, verifying that at least one LPCI system subsystem cross-tie valve is closed with power removed from the valve operator.

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

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

1. The two CSS pumps in each subsystem together develop a total flow of at least 6350 gpm against a test line pressure of greater than or equal to 269 psig, corresponding to a reactor vessel steam dome pressure of ≥ 105 psig.

2. Each LPCI pump in each subsystem develops a flow of at least 12,200 gpm against a test line pressure of ≥ 204 psig, corresponding to a reactor vessel to primary containment differential pressure ≥ 20 psid. 6

3. The HPCI pump develops a flow of at least 5000 gpm against a test line pressure of ≥ 1266 psig when steam is being supplied to the turbine at 920, +140, - 20 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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*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.

**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.

SURVEILLANCE REQUIREMENTS (Continued)

2. For the HPCI system, verifying that the system develops a flow of at least 5000 gpm against a test line pressure of 210 ± 15 psig when steam is being supplied to the turbine at 150 ± 15 psig.*

3. Performing a CHANNEL CALIBRATION of the CSS header ΔP instrumentation and verifying the setpoint to be ≤ 1 psid. 29

4. Verifying that the suction for the HPCI system 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.

5. Performing a CHANNEL CALIBRATION of the condensate transfer pump discharge low pressure alarm instrumentation and verifying the low pressure alarm setpoint to be ≥ 113 psig.

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 systems and verifying air alarm setpoint of 2070 ± 35 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.

**ADS solenoid energization shall be used alternating between ADS Division 1 and ADS Division 2.

3/4 5.2 ECCS - SHUTDOWN

LIMITING CONDITION FOR OPERATION

3.5.2 At least two of the following subsystems 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 49%.

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

1. At least one OPERABLE LPCI pump, and
2. An OPERABLE flow path capable of taking suction from the suppression chamber upon being manually realigned and transferring the water to the reactor vessel.

APPLICABILITY: OPERATIONAL CONDITION 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.

*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 Specification 3.9.8 and 3.9.9.

LIMITING CONDITION FOR OPERATION (Continued)

ACTION (Continued)

restore:

a. The overall integrated leakage rate to less than or equal to 0.75 L_a, and

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*, main steam line drain valves* and valves which are hydrostatically leak 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 46 scf per hour for all four main steam lines through the isolation valves, and

d. The leakage rate to less than or equal to 1.2 scf per hour for any one main steam line drain valve, and

e. The combined leakage rate for all containment isolation valves in hydrostatically tested lines which penetrate the primary containment to less than or equal to 3.3 gpm,

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 50 using the methods and provisions of ANSI N45.4 - 1972:

a. Three Type A Overall Integrated Containment Leakage Rate tests shall be conducted at 40 ± 10 month intervals during shutdown at P_a, 45.0 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 .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 .75 L_a, a Type A test shall be performed at least every 18 months until two consecutive Type A tests meet .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.

   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 equivalent to at least 25 percent of the total measured leakage at P_a, 45.0 psig.

SURVEILLANCE REQUIREMENTS (Continued)

d. Type B and C tests shall be conducted with gas at P_a, 45.0 psig,* at intervals no greater than 24 months except for tests involving:

   1. Air locks,

   2. Main steam line isolation valves and main steam line drain valves,

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

   4. Purge supply and exhaust isolation valves with resilient material seals.

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

f. Main steam line isolation valves and main steam line drain 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. Purge supply and exhaust isolation valves with resilient material seals shall be tested and demonstrated OPERABLE per Surveillance Requirement 4.6.1.8.2.

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

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

DRYWELL AND SUPPRESSION CHAMBER INTERNAL PRESSURE

LIMITING CONDITION FOR OPERATION

3.6.1.6 Drywell and suppression chamber internal pressure shall be maintained between -1.0 and +2.0 psig.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2 and 3.

ACTION:

With the drywell and/or suppression chamber internal pressure outside of the specified limits, restore the internal pressure to within the limit within 1 hour or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

SURVEILLANCE REQUIREMENTS

4.6.1.6 The drywell and suppression chamber internal pressure shall be determined to be within the limits at least once per 12 hours.

DRYWELL AVERAGE AIR TEMPERATURE

LIMITING CONDITION FOR OPERATION

3.6.1.7 Drywell average air temperature shall not exceed 135°F.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2 and 3.

ACTION:

With the drywell average air temperature greater than 135°F, reduce the average air temperature to within the limit within 8 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

SURVEILLANCE REQUIREMENTS

4.6.1.7 The drywell average air temperature shall be the arithmetical average of the higher temperature at a minimum of 3 of the following elevations and shall be determined to be within the limit at least once per 24 hours:

	Elevation	Azimuth
a.	797'8"	110°, 295°
b.	752'2"	90°, 270°
*c.	737'	150°, 300°
*d.	711' or 720'	270°, 85°

14

34

*Measurements taken at these elevations will only contribute one value towards the minimum three valves required to compute the average.

DRYWELL AND SUPPRESSION CHAMBER PURGE SYSTEM

LIMITING CONDITION FOR OPERATION

3.6.1.8 The drywell and suppression chamber purge system may be in operation for up to 90 hours each 365 days with the supply and exhaust isolation valves in one supply line and one exhaust line open for inerting, deinerting or pressure control.*

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2 and 3.

ACTION:

a. With a drywell and/or suppression chamber purge supply and/or exhaust isolation valve open, except as permitted above, close the valve(s) within four hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

b. With a containment purge supply and/or exhaust isolation valve(s) with resilient material seals having a measured leakage rate exceeding the limit of Surveillance Requirement 4.6.1.8.2, restore the inoperable valve(s) 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.

SURVEILLANCE REQUIREMENTS

4.6.1.8.1 Before being opened, the drywell and suppression chamber purge supply and exhaust butterfly isolation valves shall be verified not to have been open for more than 90 hours in the previous 365 days.*

4.6.1.8.2 Each 18 inch and 24 inch drywell and suppression chamber purge supply and exhaust with resilient material seals shall be demonstrated OPERABLE by verifying that the measured leakage rate is less than or equal to 0.05 L_a when pressurized to P_a at least once per 6 months.

*Valves open for pressure control are not subject to the 90 hour per 365 day limit provided the 2-inch bypass line is being utilized.

3/4.6.2 DEPRESSURIZATION SYSTEMS

SUPPRESSION CHAMBER#

LIMITING CONDITION FOR OPERATION

3.6.2.1 The suppression chamber shall be OPERABLE with:

a. The pool water:

1. Volume between 133,540 ft^3 and 122,410 ft^3, equivalent to a level between 24'0" and 22'0", and a
2. Maximum average temperature of 90°F during OPERATIONAL CONDITION 1 or 2, except that the maximum average temperature may be permitted to increase to:

a) 105°F during testing which adds heat to the suppression chamber.
b) 110°F with THERMAL POWER less than or equal to 1% of RATED THERMAL POWER.
c) 120°F with the main steam line isolation valves closed following a scram.

b. Drywell-to-suppression chamber bypass leakage less than or equal to 10% of the acceptable $A/\sqrt{k}$ design value of 0.0535 ft^2.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2 and 3.

ACTION:

a. With the suppression chamber water level outside the above limits, restore the water level to within the limits within 1 hour or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

b. In OPERATIONAL CONDITION 1 or 2 with the suppression chamber average water temperature greater than 90°F, restore the average temperature to less than or equal to 90°F within 24 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours, except, as permitted above:

1. With the suppression chamber average water temperature greater than 105°F during testing which adds heat to the suppression chamber, stop all testing which adds heat to the suppression chamber and restore the average temperature to less than 90°F within 24 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.
2. With the suppression chamber average water temperature greater than:

a) 90°F for more than 24 hours and THERMAL POWER greater than 1% of RATED THERMAL POWER, be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

#See Specification 3.5.3 for ECCS requirements.

LIMITING CONDITION FOR OPERATION (Continued)

ACTION: (Continued)

b) 110°F, place the reactor mode switch in the Shutdown position and operate at least one residual heat removal loop in the suppression pool cooling mode.

3. With the suppression chamber average water temperature greater than 120°F, depressurize the reactor pressure vessel to less than 200 psig within 12 hours.

c. With only one suppression chamber water level indicator OPERABLE and/or with less than eight suppression pool water temperature indicators covering at least six locations OPERABLE, restore the inoperable indicator(s) to OPERABLE status within 7 days or verify suppression chamber water level and/or temperature to be within the limits at least once per 12 hours.

d. With no suppression chamber water level indicators OPERABLE and/or with less than one suppression pool water temperature indicator at at least six different locations OPERABLE, restore at least one water level indicator and at least one water temperature indicator at at least six different locations to OPERABLE status within 48 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

e. With the drywell-to-suppression chamber bypass leakage in excess of the limit, restore the bypass leakage to within the limit prior to increasing reactor coolant temperature above 200°F.

SURVEILLANCE REQUIREMENTS

4.6.2.1 The suppression chamber shall be demonstrated OPERABLE:

a. By verifying the suppression chamber water volume to be within the limits at least once per 24 hours.

b. At least once per 24 hours in OPERATIONAL CONDITION 1 or 2 by verifying the suppression chamber average water temperature to be less than or equal to 90°F, except:

1. At least once per 5 minutes during testing which adds heat to the suppression chamber, by verifying the suppression chamber average water temperature less than or equal to 105°F.

2. At least once per hour when suppression chamber average water temperature is greater than or equal to 90°F, by verifying:

a) Suppression chamber average water temperature to be less than or equal to 110°F, and

b) THERMAL POWER to be less than or equal to 1% of RATED THERMAL POWER after suppression chamber average water temperature has exceeded 90°F for more than 24 hours.

SURVEILLANCE REQUIREMENTS (Continued)

c. By verifying at least two suppression chamber water level indicators and at least sixteen surface water temperature indicators, at least one pair in each suppression pool sector, OPERABLE by performance of a:

1. CHANNEL CHECK at least once per 24 hours,

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

3. CHANNEL CALIBRATION at least once per 18 months,

with the water level and temperature alarm setpoint for:

1. High water level $\leq$ 23'9",

2. Low water level $\geq$ 22'3", and

3. High water temperature:

   a) First setpoint, $\leq$ 90°F,
   b) Second setpoint, $\leq$ 105°F,
   c) Third setpoint, $\leq$ 110°F, and
   d) Fourth setpoint, $\leq$ 120°F.

d. At least once per 18 months by conducting a drywell-to-suppression chamber bypass leak test at an initial differential pressure of at least 4.3 psi and verifying that the $A/\sqrt{k}$ calculated from the measured leakage is within the specified limit. If any drywell-to-suppression chamber bypass leak test fails to meet the specified limit, the test schedule for subsequent tests shall be reviewed and approved by the Commission. If two consecutive tests fail to meet the specified limit, a test shall be performed at least every 9 months until two consecutive tests meet the specified limit, at which time the 18 month test schedule may be resumed.

SUPPRESSION POOL SPRAY

LIMITING CONDITION FOR OPERATION

3.6.2.2 The suppression pool spray mode of the residual heat removal (RHR) system shall be OPERABLE with two independent loops, each loop consisting of:

a. One OPERABLE RHR pump, and

b. An OPERABLE flow path capable of recirculating water from the suppression chamber through an RHR heat exchanger.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2 and 3.

ACTION:

a. With one suppression pool spray loop inoperable, restore the inoperable loop 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.

b. With both suppression pool spray loops inoperable, be in at least HOT SHUTDOWN within 12 hours and in COLD SHUTDOWN* within the next 24 hours.

SURVEILLANCE REQUIREMENTS

4.6.2.2 The suppression pool spray mode of the RHR system 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 that is not locked, sealed or otherwise secured in position, is in its correct position.

b. By verifying that each of the required RHR pumps develops a flow of 10,000 +0, -250 gpm per Specification 4.6.2.3.b.

c. At least once per 5 years by performing an air or water flow test through the spray header and each nozzle to verify that the flow path is unobstructed. 29

*Whenever both RHR 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.

SUPPRESSION POOL COOLING

LIMITING CONDITION FOR OPERATION

3.6.2.3 The suppression pool cooling mode of the residual heat removal (RHR) system shall be OPERABLE with two independent loops, each loop consisting of:

a. One OPERABLE RHR pump; and

b. An OPERABLE flow path capable of recirculating water from the suppression chamber through an RHR heat exchanger.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2 and 3.

ACTION:

a. With one suppression pool cooling loop inoperable, restore the inoperable loop 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.

b. With both suppression pool cooling loops inoperable, be in at least HOT SHUTDOWN within 12 hours and in COLD SHUTDOWN* within the next 24 hours.

SURVEILLANCE REQUIREMENTS

4.6.2.3 The suppression pool cooling mode of the RHR system 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 that is not locked, sealed or otherwise secured in position, is in its correct position.

b. By verifying that each of the required RHR pumps develops a flow of 10,000 +0, -250 gpm on recirculation flow through the RHR heat exchanger and the suppression pool when tested pursuant to Specification 4.0.5.

*Whenever both RHR 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.

3/4.6.3 PRIMARY CONTAINMENT ISOLATION VALVES

LIMITING CONDITION FOR OPERATION

3.6.3 The primary containment isolation valves and the reactor 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 CONDITION 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 and 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 reactor 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 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 at least once per 31 days by verifying the continuity of the explosive charge.

TABLE 3.6.3-1

PRIMARY CONTAINMENT ISOLATION VALVES

VALVE FUNCTION AND NUMBER	MAXIMUM ISOLATION TIME (Seconds)	ISOLATION SIGNAL(s)[a]
a. Automatic Isolation Valves		
MSIV		
HV-141F022 A,B,C,D	5	B,C,D,E,P,UA
HV-141F028 A,B,C,D	5	B,C,D,E,P,UA
MSL Drain		
HV-141F016	10	B,C,D,E,P,UA
HV-141F019	10	B,C,D,E,P,UA
RCIC Steam Supply		
HV-149F007	20	K,KB
HV-149F008	20	K,KB
HV-149F088	3	K,KB
HPCI Steam Supply		
HV-155F002	50	L,LB
HV-155F003	50	L,LB
HV-155F100	3	L,LB
RHR - Shutdown Cooling Suction		
HV-151F008	52	A,M,UB 18
HV-151F009	52	A,M,UB 23
RWCU Suction[b]		
HV-144F001	30	B,J,W 18
HV-144F004	30	I,B,J,W
RHR - Reactor Vessel Head Spray		
HV-151F022	30	A,M,UB,Z
HV-151F023	20	A,M,UB,Z

TABLE 3.6.3-1 (Continued)

PRIMARY CONTAINMENT ISOLATION VALVES

VALVE FUNCTION AND NUMBER	MAXIMUM ISOLATION TIME (Seconds)	ISOLATION SIGNAL(s)[a]
Automatic Isolation Valves (Continued)		
Containment Instrument Gas		
HV-12603	20	X,Z
SV-12605	N/A	X,Z
SV-12651	N/A	X,Z
SV-12661	N/A	Y,B
SV-12671	N/A	Y,B
RBCCW		
HV-11313	30	X,Z
HV-11314	30	X,Z
HV-11345	30	X,Z
HV-11346	30	X,Z
Containment Purge		
HV-15703	15	B,Y,R
HV-15704	15	B,Y,R
HV-15705	15	B,Y,R
HV-15711	15	B,Y,R
HV-15713	15	B,Y,R
HV-15714	15	B,Y,R
HV-15721	15	B,Y,R
HV-15722	15	B,Y,R
HV-15723	15	B,Y,R
HV-15724	15	B,Y,R
HV-15725	15	B,Y,R
RHR - Drywell Spray[c]		
HV-151F016 A,B	90	X,Z
RB Chilled Water		
HV-18781 A1,A2,B1,B2	40	X,Z
HV-18782 A1,A2,B1,B2	6	X,Z
HV-18791 A1,A2,B1,B2	15	Y,B
HV-18792 A1,A2,B1,B2	4	Y,B

TABLE 3.6.3-1 (Continued)

PRIMARY CONTAINMENT ISOLATION VALVES

VALVE FUNCTION AND NUMBER	MAXIMUM ISOLATION TIME (Seconds)	ISOLATION SIGNAL(s)[a]
Automatic Isolation Valves (Continued)		
Containment Atmosphere Sample		
SV-15734 A,B	N/A	B,Y
SV-15736 A	N/A	B,Y
SV-15736 B	N/A	B,Y,R
SV-15737	N/A	B,Y,R
SV-15740 A,B	N/A	B,Y
SV-15742 A,B	N/A	B,Y
SV-15750 A,B	N/A	B,Y
SV-15752 A,B	N/A	B,Y
SV-15767	N/A	B,Y,R
SV-15774 A,B	N/A	B,Y
SV-15776 A	N/A	B,Y
SV-15776 B	N/A	B,Y,R
SV-15780 A,B	N/A	B,Y
SV-15782 A,B	N/A	B,Y
Reactor Coolant Sample		
HV-143F019	2	B,C
HV-143F020	2	B,C
Liquid Radwaste		
HV-16108 A1,A2	15	B,Z
HV-16116 A1,A2	15	B,Z
RHR - Suppression Pool Cooling/Spray[c]		23
HV-151F011 A,B	23	X,Z 23
HV-151F028 A,B	90	X,Z
CS Test[b][c]		
HV-152F015 A,B	60	X,Z
HPCI Suction [b][c]		
HV-155F042	90	L,LB

TABLE 3.6.3-1 (Continued)

PRIMARY CONTAINMENT ISOLATION VALVES

VALVE FUNCTION AND NUMBER	MAXIMUM ISOLATION TIME (Seconds)	ISOLATION SIGNAL(s)[a]
Automatic Isolation Valves (Continued)		
Suppression Pool Cleanup[b]		
HV-15766	30	A,Z
HV-15768	30	A,Z
HPCI Vacuum Breaker		
HV-155F075	15	LB,Z
HV-155F079	15	LB,Z
RCIC Vacuum Breaker		
HV-149F062	10	KB,Z
HV-149F084	10	KB,Z
TIP Ball Valves [d]		
C51-J004 A,B,C,D,E	5	A,Z
b. Manual Isolation Valves		
MSIV-LCS Bleed Valve		
HV-139F001 B,F,K,P		
Feedwater[e]		
HV-141F032 A,B		
RWCU Return		
HV-144F042		
HV-144F104		
RCIC Injection		
HV-149F013		
1-49-020		

TABLE 3.6.3-1 (Continued)

PRIMARY CONTAINMENT ISOLATION VALVES

VALVE FUNCTION AND NUMBER

Manual Isolation Valves (Continued)

RCIC Suction[b][c]

HV-149F031

RCIC Turbine Exhaust[b]

HV-149F059

RCIC Vacuum Pump Discharge[b]

HV-149F060

HPCI Injection

HV-155F006
1-55-038

RHR - Shutdown Cooling Return/
LPCI Injection

HV-151F015 A,B

RHR - Suppression Pool Suction[b][c]

HV-151F004 A,B,C,D

RHR Heat Exchanger Vent[c]

HV-151F103 A,B

CS Injection

HV-152F005 A,B
HV-152F037 A,B

CS Suction[b][c]

HV-152F001 A,B

Containment Instrument Gas

SV-12654 A,B

TABLE 3.6.3-1 (Continued)

PRIMARY CONTAINMENT ISOLATION VALVES

VALVE FUNCTION AND NUMBER

Manual Isolation Valves (Continued)

SLCS[b]

HV-148F006

Demineralized Water

1-41-017
1-41-018

ILRT

1-57-193
1-57-195

HPCI Turbine Exhaust[b]

HV-155F066

RHR - Shutdown Cooling Return/
LPCI Injection - Pressure Equalizing Valve

HV-151F122 A,B

c. Other Valves

Feedwater

141F010 A,B

RHR - Shutdown Cooling Suction

PSV-151F126

RHR - Shutdown Cooling Return/
LPCI Injection

HV-151F050 A,B

TABLE 3.6.3-1 (Continued)

PRIMARY CONTAINMENT ISOLATION VALVES

VALVE FUNCTION AND NUMBER

Other Valves (Continued)

RHR-Minimum Recirculation Flow[b][c]

HV-151F007 A,B

RHR - Relief Valve Discharge[c]

PSV-151F055 A,B
PSV-15106 A,B
PSV-151F097

CS Injection

HV-152F006 A,B

CS Minimum Recirculation Flow[b][c]

HV-152F031 A,B

Containment Instrument Gas

1-26-070
1-26-072
1-26-074
1-26-152
1-26-154

Recirculation Pump Seal Water

143F013 A,B
XV-143F017 A,B

TIP Shear Valves[d]

C51-J004 A,B,C,D,E

SLCS[b]

148F007

HPCI Turbine Exhaust[b]

155F049

TABLE 3.6.3-1 (Continued)

PRIMARY CONTAINMENT ISOLATION VALVES

VALVE FUNCTION AND NUMBER

Other Valves (Continued)

HPCI Minimum Recirculation Flow[b][c]

HV-155F012

RCIC Turbine Exhaust[b]

149F040

RCIC Minimum Recirculation Flow[b][c]

FV-149F019

RCIC Vacuum Pump Discharge[b]

149F028

d. Excess Flow Check Valves

HPCI

XV-155F024 A,B,C,D

Core Spray

XV-152F018 A,B

RHR

XV-15109 A,B,C,D

RCIC

XV-149F044 A,B,C,D

RWCU

XV-14411 A,B,C,D
XV-144F046

TABLE 3.6.3-1 (Continued)

PRIMARY CONTAINMENT ISOLATION VALVES

VALVE FUNCTION AND NUMBER

Excess Flow Check Valves (Continued)

Reactor Recirculation

XV-143F003	A,B
XV-143F004	A,B
XV-143F009	A,B,C,D
XV-143F010	A,B,C,D
XV-143F011	A,B,C,D
XV-143F012	A,B,C,D
XV-143F040	A,B,C,D
XV-143F057	A,B

Nuclear Boiler Vessel Instrument

XV-142F041	
XV-142F043	A,B
XV-142F045	A,B
XV-142F047	A,B
XV-142F051	A,B,C,D
XV-142F053	A,B,C,D
XV-142F055	
XV-142F057	
XV-142F059	A,B,C,D,E,F,G,H,L,M,N,P,R,S,T,U
XV-142F061	
XV-14201	

Nuclear Boiler

XV-141F070	A,B,C,D
XV-141F071	A,B,C,D
XV-141F072	A,B,C,D
XV-141F073	A,B,C,D
XV-141F009	

MSIVLCS

XV-13910	B,F,K,P

TABLE 3.6.3-1 (Continued)

PRIMARY CONTAINMENT ISOLATION VALVES
NOTATION

(a) See Specification 3.3.2, Table 3.3.2-1, for isolation signal(s) that operates each automatic isolation valve. All power operated isolation valves may be opened or closed remote-manually.

(b) Isolation barrier remains water filled or a water seal remains in the line post-LOCA. Isolation valve is tested with water. Isolation valve leakage is not included in 0.60 La total Type B and C tests.

(c) Redundant isolation boundary for this valve is provided by the closed system whose integrity is verified by Type A test.

(d) Automatic isolation signal causes TIP to retract; ball valve closes when probe is fully retracted.

(e) Power assisted check valve.

b. Operating one standby gas treatment subsystem for 1 hour and maintaining greater than or equal to 0.25 inch of vacuum water gauge in the secondary containment at a flow rate of less than or equal to 4000 cfm from Zone I, Zone II, and Zone III, or

3. For two zone operation with Unit 2 shutdown and Zone II isolated from Zone I and Zone III:

a. Verifying that one standby gas treatment subsystem will draw down the secondary containment (Zone I and Zone III) to greater than or equal to 0.25 inch of vacuum water gauge in less than or equal to 83 seconds, and

b. Operating one standby gas treatment subsystem for 1 hour and maintaining greater than or equal to 0.25 inch of vacuum water gauge in the secondary containment at a flow rate of less than or equal to 2885 cfm from Zone I and Zone III. 21

d. At least once per 60 months:

1. Verifying that one standby gas treatment subsystem will draw down the secondary containment (Zone I, Zone II and Zone III) to greater than or equal to 0.25 inch of vacuum water gauge in less than or equal to 92 seconds, and

2. Operating one standby gas treatment subsystem for 1 hour and maintaining greater than or equal to 0.25 inch of vacuum water gauge in the secondary containment at a flow rate of less than or equal to 4000 cfm from Zone I, Zone II, and Zone III.

SECONDARY CONTAINMENT AUTOMATIC ISOLATION DAMPERS

LIMITING CONDITION FOR OPERATION

3.6.5.2 The secondary containment ventilation system automatic isolation dampers shown in Table 3.6.5.2-1 shall be OPERABLE with isolation times less than or equal to the times shown in Table 3.6.5.2-1.

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

ACTION:

With one or more of the secondary containment ventilation system automatic isolation dampers shown in Table 3.6.5.2-1 inoperable, maintain at least one isolation damper OPERABLE in each affected penetration that is open and within 8 hours either:

a. Restore the inoperable damper to OPERABLE status, or

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

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

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.

Otherwise, in Operational Condition *, 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

4.6.5.2 Each secondary containment ventilation system automatic isolation damper shown in Table 3.6.5.2-1 shall be demonstrated OPERABLE:

a. Prior to returning the damper to service after maintenance, repair or replacement work is performed on the damper or its associated actuator, control or power circuit by cycling the damper 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 damper actuates to its isolation position.

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

*For Zone III dampers when irradiated fuel is being handled in the secondary containment and during CORE ALTERATIONS and operations with a potential for draining the reactor vessel.

TABLE 3.6.5.2-1

SECONDARY CONTAINMENT VENTILATION SYSTEM AUTOMATIC ISOLATION DAMPERS

DAMPER FUNCTION	MAXIMUM ISOLATION TIME (Seconds)
1. Reactor Building Zone I Supply System Dampers (HD-17586 A&B)	7.5
2. Reactor Building Zone I Filtered Exhaust System Dampers (HD-17524 A&B)	5.0
3. Reactor Building Zone I Unfiltered Exhaust System Dampers (HD-17576 A&B)	3.0
4. Reactor Building Zone II Supply System Dampers (HD-27586 A&B)	7.5
5. Reactor Building Zone II Filtered Exhaust System Dampers (HD-27524 A&B)	5.0
6. Reactor Building Zone II Unfiltered Exhaust System Dampers (HD-27576 A&B)	3.0
7. Reactor Building Zone III Supply System Dampers (HD-17564 A&B)	14.0
8. Reactor Builidng Zone III Filtered Exhaust System Dampers (HD-17514 A&B)	6.5
9. Reactor Building Zone III Unfiltered Exhaust System Dampers (HD-17502 A&B)	6.0
10. Reactor Building Zone III Supply System Dampers (HD-27564 A&B)	14.0
11. Reactor Building Zone III Filtered Exhaust System Dampers (HD-27514 A&B)	6.5
12. Reactor Building Zone III Unfiltered Exhaust System Dampers (HD-27502 A&B)	6.0

STANDBY GAS TREATMENT SYSTEM

LIMITING CONDITION FOR OPERATION

3.6.5.3 Two independent standby gas treatment subsystems shall be OPERABLE.

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

ACTION:

a. With one standby gas treatment subsystem inoperable, restore the inoperable subsystem to OPERABLE status within 7 days, or:

   1. 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.

   2. In Operational Condition *, 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.

b. With both standby gas treatment subsystems inoperable in Operational Condition *, suspend handling of irradiated fuel in the secondary containment, CORE ALTERATIONS or operations with a potential for draining the reactor vessel. The provisions of Specification 3.0.3. are not applicable.

SURVEILLANCE REQUIREMENTS

4.6.5.3 Each standby gas treatment subsystem shall be demonstrated OPERABLE:

a. At least once per 31 days by initiating, from the control room, flow through the HEPA filters and charcoal adsorbers and verifying that the subsystem operates for at least 10 hours with the heaters OPERABLE.

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

3/4.7 PLANT SYSTEMS

3/4.7.1 SERVICE WATER SYSTEMS

RESIDUAL HEAT REMOVAL SERVICE WATER SYSTEM

LIMITING CONDITION FOR OPERATION

3.7.1.1 Two independent residual heat removal service water (RHRSW) system subsystems shall be OPERABLE with each subsystem comprised of:

a. One OPERABLE RHRSW pump*, and

b. An OPERABLE flow path capable of taking suction from the spray pond and transferring the water through one RHR heat exchanger.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, 3, 4, and 5.**

ACTION:

a. In OPERATIONAL CONDITION 1, 2 or 3:

1. With one RHRSW subsystem inoperable, restore the inoperable subsystem to OPERABLE status with at least one OPERABLE pump* within 72 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

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

b. In OPERATIONAL CONDITION 3 or 4 with the RHRSW subsystem, which is associated with an RHR loop required OPERABLE by Specification 3.4.9.1 or 3.4.9.2, inoperable, declare the associated RHR loop inoperable and take the ACTION required by Specification 3.4.9.1 or 3.4.9.2, as applicable.

c. In OPERATIONAL CONDITION 5 with one RHRSW subsystem, which is associated with an RHR system required OPERABLE by Specification 3.9.11.1 or 3.9.11.2, inoperable, declare the associated RHR system inoperable and take the ACTION required by Specification 3.9.11.1 or 3.9.11.2, as applicable.

SURVEILLANCE REQUIREMENTS

4.7.1.1 Each residual heat removal service water system subsystem shall be demonstrated OPERABLE at least once per 31 days by verifying that each valve in the flow path that is not locked, sealed or otherwise secured in position, is in its correct position.

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*May not be a pump required for Unit 2.
**See Specification 3.9.11.1 and 3.9.11.2 for applicability.
***Whenever both RHRSW 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.

EMERGENCY SERVICE WATER SYSTEM

LIMITING CONDITION FOR OPERATION

3.7.1.2 Two independent emergency service water system loops shall be OPERABLE with each loop comprised of:

a. Two OPERABLE emergency service water pumps, and
b. An OPERABLE flow path capable of taking suction from the spray pond and transferring the water to the associated safety related equipment.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, 3, 4, 5 and *.

ACTION:

a. In OPERATIONAL CONDITION 1, 2, or 3:
   1. With one emergency service water pump inoperable, restore the inoperable pump to OPERABLE status within 7 days or be in a least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.
   2. With two emergency service water pumps inoperable, restore at least one inoperable pump 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.
   3. With one emergency service water system loop otherwise inoperable, restore the inoperable loop to OPERABLE status with at least one OPERABLE pump within 72 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

b. In OPERATIONAL CONDITION 4, 5 or *:
   1. With one pump in an emergency service water system loop inoperable, verify adequate cooling capability remains available for the diesel generators required to be operable by Specification 3.8.1.2 or declare the affected diesel generator(s) inoperable and take the ACTION required by Specification 3.8.1.2.
   2. With two pumps in an emergency service water system loop inoperable or with the loop otherwise inoperable declare the associated safety related equipment inoperable (except diesel generators), and follow the applicable ACTION statements. Verify adequate cooling remains available for the diesel generators required to be operable by Specification 3.8.1.2 or declare the affected diesel generator(s) inoperable and take the ACTION required by Specification 3.8.1.2.

*When handling irradiated fuel in the secondary containment.

SURVEILLANCE REQUIREMENTS

4.7.1.2 The emergency service water system shall be demonstrated OPERABLE:

a. At least once per 31 days by verifying that each valve (manual, power operated or automatic) servicing safety-related equipment that is not locked, sealed or otherwise secured in position, is in its correct position. 29

b. At least once per 18 months by verifying that each pump starts automatically when its associated diesel generator starts.

c. At least once per 18 months by verifying that each automatic valve properly cycles to its proper position in its required time following receipt of an automatic pump start signal.

ULTIMATE HEAT SINK

LIMITING CONDITION FOR OPERATION

3.7.1.3 The spray pond shall be OPERABLE.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, 3, 4, 5 and *.

ACTION:

a. With the groundwater level at any spray pond area observation well greater than or equal to 663' Mean Sea Level (MSL), prepare and submit a Special Report to the Commission pursuant to Specification 6.9.2 within the next 10 days outlining the cause of the high groundwater level and the plans for restoring the level to within the limit. 26

b. With the spray pond otherwise inoperable:

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

2. In OPERATIONAL CONDITION 4 or 5, declare the RHRSW system and the emergency service water system inoperable and take the ACTION required by Specifications 3.7.1.1 and 3.7.1.2.

3. In Operational Condition *, declare the emergency service water system inoperable and take the ACTION required by Specification 3.7.1.2. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.7.1.3 The spray pond shall be determined OPERABLE by verifying:

a. The average water temperature, which shall be the arithmetical average of the spray pond water temperature at the surface, mid and bottom levels, to be less than or equal to 88°F at least once per 24 hours. 26

b. The water level at the overflow weir is greater than or equal to 678'1" MSL USGS, at least once per 12 hours. 23

c. The groundwater level at observation wells 1, 3, 4, 5, 6, and 1113 to be less than 663' MSL at least once per 31 days.** 1

*When handling irradiated fuel in the secondary containment. 1

3/4.7.2 CONTROL ROOM EMERGENCY OUTSIDE AIR SUPPLY SYSTEM

LIMITING CONDITION FOR OPERATION

3.7.2 Two independent control room emergency outside air supply system subsystems shall be OPERABLE with each subsystem consisting of:

a. One makeup fan, and

b. One filter train.

APPLICABILITY: All OPERATIONAL CONDITIONS and *.

ACTION:

a. In OPERATIONAL CONDITION 1, 2 or 3 with one control room emergency outside air supply subsystem inoperable, restore the inoperable 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.

b. In OPERATIONAL CONDITION 4, 5 or *:

1. With one control room emergency outside air supply subsystem inoperable, restore the inoperable subsystem to OPERABLE status within 7 days or initiate and maintain operation of the OPERABLE subsystem in the pressurization mode of operation.

2. With both control room emergency outside air supply subsystems inoperable, suspend CORE ALTERATIONS, handling of irradiated fuel in the secondary containment and operations with a potential for draining the reactor vessel.

c. The provisions of Specification 3.0.3 are not applicable in Operational Condition *.

SURVEILLANCE REQUIREMENTS

4.7.2 Each control room emergency outside air supply subsystem shall be demonstrated OPERABLE:

a. At least once per 31 days on a STAGGERED TEST BASIS by initiating, from the control room, flow through the HEPA filters and charcoal adsorbers and verifying that the subsystem operates for at least 10 hours with the heaters OPERABLE.

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: 16

*When irradiated fuel is being handled in the secondary containment.

SURVEILLANCE REQUIREMENTS (Continued)

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 procedures of 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 5810 cfm ± 10%. 16 35

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 16 35

3. Verifying a subsystem flow rate of 5810 cfm ± 10% during subsystem operation when tested in accordance with ANSI N510-1975. 16

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 Positon 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 prefilter, upstream and downstream HEPA filters and charcoal adsorber banks is less than 9.1 inches Water Gauge while operating the subsystem at a flow rate of 5810 cfm ± 10%.

2. Verifying that on each of the below isolation mode actuation test signals, the subsystem automatically switches to the isolation mode of operation and the isolation dampers close within 8 seconds:

   a) Outside air intake chlorine - high,
   b) Outside air intake radiation - high, and
   c) Reactor Building isolation.

3. Verifying that on each of the below pressurization mode actuation test signals, the subsystem automatically switches to the pressurization mode of operation and the control structure is maintained at a positive pressure of 1/8 inch W.G. relative to the outside atmosphere during subsystem operation at a flow rate less than or equal to 5810 cfm:

   a) Reactor Building isolation, and
   b) Outside air intake radiation - high.

4. Verifying that the heaters dissipate 30 ± 3.0 Kw when tested in accordance with ANSI N510-1975.

SURVEILLANCE REQUIREMENTS (Continued)

e. After each complete or partial replacement of a HEPA filter bank by verifying that the HEPA filter bank satisfies the in-place penetration and bypass leakage testing acceptance criteria of less than 0.05% in accordance with ANSI N510-1975 for a DOP test aerosol while operating the system at a flow rate of 5810 cfm ± 10%. 35

f. After each complete or partial replacement of a charcoal adsorber bank by verifying that the charcoal adsorber bank satisfies the in-place penetration and bypass leakage testing acceptance criteria of less than 0.05% in accordance with ANSI N510-1975 for a halogenated hydrocarbon refrigerant test gas while operating the system at a flow rate of 5810 cfm ± 10%. 35

3/4.7.3 REACTOR CORE ISOLATION COOLING SYSTEM

LIMITING CONDITION FOR OPERATION

3.7.3 The reactor core isolation cooling (RCIC) system shall be OPERABLE with an OPERABLE flow path capable of taking suction from the suppression pool and transferring the water to the reactor pressure vessel.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, and 3 with reactor steam dome pressure greater than 150 psig.

ACTION:

a. With the condensate transfer pump discharge low pressure alarm instrumentation inoperable, monitor the CSS, LPCI, HPCI and RCIC pressure locally at least once per 24 hours.

b. With the RCIC system otherwise inoperable, operation may continue provided the HPCI system is OPERABLE; restore the RCIC 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 less than or equal to 150 psig within the following 24 hours.

SURVEILLANCE REQUIREMENTS

4.7.3 The RCIC system shall be demonstrated OPERABLE:

a. At least once per 31 days by:

1. Verifying that the system piping from the pump discharge valve to the system isolation valve is filled with water by:

   a. Venting at the high point vents.

   b. Performance a CHANNEL FUNCTIONAL TEST of the condensate transfer pump discharge low pressure alarm instrumentation.

2. 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.

3. Verifying that the pump flow controller is in the correct position.

b. At least once per 92 days by verifying that the RCIC pump develops a flow of greater than or equal to 600 gpm in the test flow path with a system head corresponding to reactor vessel operating pressure when steam is being supplied to the turbine at 920 + 140, - 0 psig.*

*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.

SURVEILLANCE REQUIREMENTS (Continued)

c. At least once per 18 months by:

1. Performing a system functional test which includes simulated automatic actuation and restart and verifying that each automatic valve in the flow path actuates to its correct position, but may exclude actual injection of coolant into the reactor vessel.

2. Verifying that the system will develop a flow of greater than or equal to 600 gpm in the test flow path when steam is supplied to the turbine at a pressure of 150, + 15, -0 psig.*

3. Verifying that the suction for the RCIC system is automatically transferred from the condensate storage tank to the suppression pool on a condensate storage tank water level-low signal.

4. Performing a CHANNEL CALIBRATION of the condensate transfer pump discharge low pressure alarm instrumentation and verifying the low pressure alarm setpoint to be greater than or equal to 113 psig.

d. In the event the RCIC 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 injection nozzle shall be provided in this Special Report whenever its value exceeds 0.70.

*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 tests.

3/4.7.4 SNUBBERS

LIMITING CONDITION FOR OPERATION

3.7.4 All snubbers shall be OPERABLE.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2 and 3 and OPERATIONAL CONDITIONS 4 and 5 for snubbers located on systems required OPERABLE in those OPERATIONAL CONDITIONS.

ACTION:

With one or more snubbers inoperable, within 72 hours replace or restore the inoperable snubber(s) to OPERABLE status and perform an engineering evaluation per Specification 4.7.4.c on the supported component or declare the supported system inoperable and follow the appropriate ACTION statement for that system.

SURVEILLANCE REQUIREMENTS

4.7.4 Each snubber shall be demonstrated OPERABLE by performance of the following augmented inservice inspection program and the requirements of Specification 4.0.5.

a. Visual Inspections

The first inservice visual inspection of snubbers shall be performed after 4 months but within 10 months of commencing POWER OPERATION and shall include all snubbers listed in Table 3.7.4-1. If all snubbers of each type are found OPERABLE during the first inservice visual inspection, the second inservice visual inspection shall be performed at the first refueling outage. Otherwise, subsequent visual inspections shall be performed in accordance with the following schedule:

No. Inoperable Snubbers per Inspection Period	Subsequent Visual Inspection Period*#
0	18 months ± 25%
1	12 months ± 25%
2	6 months ± 25%
3,4	124 days ± 25%
5,6,7	62 days ± 25%
8 or more	31 days ± 25%

The snubbers may be categorized into two groups: Those accessible and those inaccessible during reactor operation. Each group may be inspected independently in accordance with the above schedule.

*The inspection interval shall not be lengthened more than one step at a time.
#The provisions of Specification 4.0.2 are not applicable.

b. Visual Inspection Acceptance Criteria

Visual inspections shall verify (1) that there are no visible indications of damage or impaired OPERABILITY, (2) that attachments to the foundation or supporting structure are secure, and (3) in those locations where snubber movement can be manually induced without disconnecting the snubber, that the snubber has freedom of movement and is not frozen up. Snubbers which appear inoperable as a result of these visual inspections may be determined OPERABLE for the purpose of establishing the next visual inspection interval, providing that (1) the cause of the rejection is clearly established and remedied for that particular snubber and for other snubbers that may be generically susceptible, and (2) the affected snubber is functionally tested in the as found condition and determined OPERABLE per Surveillance Requirements 4.7.4.d.

c. Functional Tests

During the first refueling shutdown and at least once per 18 months thereafter during shutdown, a representative sample of at least that number of snubbers which follows the expression $35\ (1 + 2)^c$, where c = 4, is the allowable number of snubbers not meeting the acceptance criteria selected by the operator, shall be functionally tested either in-place or in a bench test. For each number of snubbers above c which does not meet the functional test acceptance criteria of Specifications 4.7.4.d., an additional sample selected according to the expression $35\ (1 + \frac{c}{2})\ (\frac{2}{c + 1})^2\ (a - c)$ shall be functionally tested, where a is the total number of snubbers found inoperable during the functional testing of the representative sample.

Functional testing shall continue according to the expression $b\ [35\ (1 + \frac{c}{2})\ (\frac{2}{c + 1})^2]$ where b is the number of snubbers found inoperable in the previous re-sample, until no additional inoperable snubbers are found within a sample or until all snubbers in Table 3.7.4-1 have been functionally tested.

The representative sample selected for functional testing shall include the various configurations, operating environments and the range of size and capacity of snubbers. At least 25% of the snubbers in the representative sample shall include snubbers from the following three categories:

1. The first snubber away from each reactor vessel nozzle.
2. Each snubber within 5 feet of heavy equipment, valve, pump, turbine, motor, etc.
3. Each snubber within 10 feet of the discharge from a safety relief valve.

Functional Test (Continued)

In addition to the regular sample, snubbers which failed the previous functional test shall be retested during the next test period. If a spare snubber has been installed in place of a failed snubber, then both the failed snubber, if it is repaired and installed in another position, and the spare snubber shall be retested. Test results of these snubbers may not be included for the re-sampling.

If any snubber selected for functional testing either fails to lockup or fails to move, i.e., frozen in place, the cause will be evaluated and if caused by manufacturer or design deficiency all snubbers of the same design subject to the same defect shall be functionally tested. This testing requirement shall be independent of the requirements stated above for snubbers not meeting the functional test acceptance criteria.

For any snubber(s) found inoperable, an engineering evaluation shall be performed on the components which are supported by the snubber(s). The purpose of this engineering evaluation shall be to determine if the components supported by the snubber(s) were adversely affected by the inoperability of snubber(s) in order to ensure that the supported component remains capable of meeting the designed service.

d. Mechanical Snubbers Functional Test Acceptance Criteria

The mechanical snubber functional test shall verify that:

1. The force that initiates free movement of the snubber rod in either tension or compression is less than the specified maximum drag force. Drag force shall not have increased more than 50% since the last surveillance test.

2. Activation (restraining action) is achieved within the specified range of velocity or acceleration in both tension and compression.

3. Snubber release rate, where required, is within the specified range in compression or tension. For snubbers specifically required not to displace under continuous load, the ability of the snubber to withstand load without displacement shall be verified.

SURVEILLANCE REQUIREMENTS (Continued)

e. Snubber Service Life Monitoring

A record of the service life of each snubber, the date at which the designated service life commences and the installation and maintenance records on which the designated service life is based shall be maintained as required by Specification 6.10.2.

Concurrent with the first inservice visual inspection and at least once per 18 months thereafter, the installation and maintenance records for each snubber listed in Tables 3.7.4-1 shall be reviewed to verify that the indicated service life has not been exceeded or will not be exceeded prior to the next scheduled snubber service life review. If the indicated service life will be exceeded prior to the next scheduled snubber service life review, the snubber service life shall be reevaluated or the snubber shall be replaced or reconditioned so as to extend its service life beyond the date of the next scheduled service life review. This reevaluation, replacement or reconditioning shall be indicated in the records.

3/4.7.5 SEALED SOURCE CONTAMINATION

LIMITING CONDITION FOR OPERATION

3.7.5 Each sealed source containing radioactive material either in excess of 100 microcuries of beta and/or gamma emitting material or 5 microcuries of alpha emitting material shall be free of greater than or equal to 0.005 microcurie of removable contamination. |29

APPLICABILITY: At all times.

ACTION:

a. With a sealed source having removable contamination in excess of the above limit, withdraw the sealed source from use and either:

   1. Decontaminate and repair the sealed source, or

   2. Dispose of the sealed source in accordance with Commission Regulations.

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

SURVEILLANCE REQUIREMENTS

4.7.5.1 Test Requirements - Each sealed source shall be tested for leakage and/or contamination by:

a. The licensee, or

b. Other persons specifically authorized by the Commission or an Agreement State.

The test method shall have a detection sensitivity of at least 0.005 microcurie per test sample. |29

4.7.5.2 Test Frequencies - Each category of sealed sources, excluding startup sources and fission detectors previously subjected to core flux, shall be tested at the frequency described below.

a. Sources in use - At least once per six months for all sealed sources containing radioactive material:

   1. With a half-life greater than 30 days, excluding Hydrogen 3 (tritium), and |29

   2. In any form other than gas.

b. Stored sources not in use - Each sealed source and fission detector shall be tested prior to use or transfer to another licensee unless tested within the previous six months. Sealed sources and fission detectors transferred without a certificate indicating the last test date shall be tested prior to being placed into use.

c. Startup sources and fission detectors - Each sealed startup source and fission detector shall be tested within 31 days prior to being subjected to core flux or installed in the core and following repair or maintenance to the source.

4.7.5.3 Reports - A report shall be prepared and submitted to the Commission on an annual basis if sealed source or fission detector leakage tests reveal the presence of greater than or equal to 0.005 microcurie of removable contamination. 29

3/4.7.6 FIRE SUPPRESSION SYSTEMS

FIRE SUPPRESSION WATER SYSTEM

LIMITING CONDITION FOR OPERATION

3.7.6.1 The fire suppression water system shall be OPERABLE with:

a. Two OPERABLE fire suppression pumps, one electric motor driven and one diesel driven, each with a capacity of 2500 gpm, with their discharge aligned to the fire suppression header,

b. At least two separate water supplies, each with a minimum contained volume of 300,000 gallons, and

c. Two OPERABLE flow paths capable of taking suction from any two of the following: (1) Unit 1 cooling tower basin, (2) Unit 2 cooling tower basin, (3) clarified water storage tank, and transferring the water through distribution piping with OPERABLE sectionalizing control or isolation valves to the yard hydrant curb valves, the last valve ahead of the water flow alarm device on each sprinkler or hose standpipe and the last valve ahead of the deluge valve on each deluge or spray system required to be OPERABLE per Specifications 3.7.6.2, 3.7.6.5, and 3.7.6.6.

APPLICABILITY: At all times.

ACTION:

a. With one fire pump and/or one of the above required water supplies inoperable, restore the inoperable equipment to OPERABLE status within 7 days or provide an alternate backup pump or supply. The provisions of Specifications 3.0.3 and 3.0.4 are not applicable. 26

b. With the fire suppression water system otherwise inoperable establish a backup fire suppression water system within 24 hours. 26

4.7.6.1.1 The fire suppression water system shall be demonstrated OPERABLE:

a. At least once per 7 days by verifying the minimum contained water supply volume.

b. At least once per 31 days by starting the electric motor driven fire suppression pump and operating it for at least 15 minutes on recirculation flow.

c. 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.

d. At least once per 12 months by performance of a system flush.

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

f. At least once per 18 months by performing a system functional test which includes simulated automatic actuation of the system throughout its operating sequence, and:

1. Verifying that each automatic valve in the flow path actuates to its correct position,

2. Verifying that each fire suppression pump develops at least 2500 gpm at a system head of 125 psig,

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

4. Verifying that each fire suppression pump starts sequentially to maintain the fire suppression water system pressure greater than or equal to 85 psig.

g. At least once per 3 years by performing a flow test of the system in accordance with Chapter 5, Section 11 of the Fire Protection Handbook, 14th Edition, published by the National Fire Protection Association.

4.7.6.1.2 The diesel driven fire suppression pump shall be demonstrated OPERABLE:

a. At least once per 31 days by:

1. Verifying the fuel storage tank contains at least 250 gallons of fuel.

2. Starting the diesel driven pump from ambient conditions and operating for greater than or equal to 30 minutes on recirculation flow.

SURVEILLANCE REQUIREMENTS (Continued)

b. At least once per 92 days by verifying that a sample of diesel fuel from the fuel storage tank, obtained in accordance with ASTM-D270-75, is within the acceptable limits specified in Table 1 of ASTM-D975-77 when checked for viscosity, water and sediment.

c. At least once per 18 months by subjecting the diesel to an inspection in accordance with procedures prepared in conjunction with its manufacturer's recommendations for the class of service.

4.7.6.1.3 The diesel driven fire pump diesel 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 pilot cell is above the plates,

2. The pilot cell specific gravity, corrected to 77°F, is greater than or equal to 1.200,

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 oncer per 18 months by verifying that:

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

2. Terminal connections are clean, tight, free of corrosion and coated with anti-corrosion material.

LIMITING CONDITION FOR OPERATION

3.7.6.2 The following spray and sprinkler systems shall be OPERABLE:

a. RCIC Pump Room, Unit 1
b. HPCI Pump Room, Unit 1
c. Upper Cable Spreading Room, Unit 1
d. Lower Cable Spreading Room, Unit 1
e. Diesel Generator A Room
f. Diesel Generator B Room
g. Diesel Generator C Room
h. Diesel Generator D Room
i. Fire Zones 1-3A and 1-3B
j. Fire Zone 1-4A
k. Fire Zone 1-5A
l. Fire Zone 1-2B 110
m. Fire Zone 0-29B
n. Fire Zone 0-30A

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. 129 126

b. The provisions of Specification 3.0.3 and 3.0.4 are not applicable.

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 deluge 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 and verifying each open head spray and sprinkler nozzle is unobstructed.

CO_2 SYSTEMS

LIMITING CONDITIONS

3.7.6.3 The following low pressure CO_2 systems shall be OPERABLE:

a. Control Room Under Floor, Unit 1
b. Control Room Under Floor, Unit 2
c. Lower Relay Room, Unit 1#
d. Upper Relay Room, Unit 1#
e. South Cable Chase
f. Center Cable Chase
g. North Cable Chase
h. Room C-411 Soffit
i. Control Room Soffit, Unit 1
j. Control Room Soffit, Unit 2
k. Room C-412 Soffit

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

ACTION:

a. With one or more of the above required CO_2 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. 26

b. The provisions of Specification 3.0.3 and 3.0.4 are not applicable.

SURVEILLANCE REQUIREMENTS

4.7.6.3.1 Each of the above required low pressure CO_2 systems 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.

4.7.6.3.2. Each of the above required low pressure CO_2 systems shall be demonstrated OPERABLE:

a. 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 270 psig, and 29

b. At least once per 18 months by:

1. Verifying the system valves and associated ventilation dampers and fire door release mechanisms actuate manually and automatically, upon receipt of a simulated actuation signal, and

2. Flow from each accessible nozzle by performance of a "Puff Test."

#Accessible nozzles.

HALON SYSTEMS

LIMITING CONDITION FOR OPERATION

3.7.6.4 The Halon systems in the following panel modules shall be OPERABLE with the storage tanks having at least 95% of full charge weight and 90% of full charge pressure:

10700	10701	10702	10703	10704	10705
10706	10730	10731	10732		

APPLICABILITY: Whenever equipment protected by the Halon systems is required to be OPERABLE.

ACTION:

a. With one or more of the above required Halon 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. 29 26

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

SURVEILLANCE REQUIREMENTS

4.7.6.4 Each of the above required Halon 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 6 months by verifying Halon storage tank weight and pressure.

c. At least once per 18 months by:

1. Performance of a flow test through accessible headers and nozzles to assure no blockage.

2. Performance of a functional test of the general alarm circuit and associated alarm and interlock devices.

FIRE HOSE STATIONS

LIMITING CONDITION FOR OPERATION

3.7.6.5 The fire hose stations shown in Table 3.7.6.5-1 shall be OPERABLE.

APPLICABILITY: Whenever equipment in the areas protected by the fire hose stations is required to be OPERABLE.

ACTION:

a. With one or more of the fire hose stations shown in Table 3.7.6.5-1 inoperable, route an additional fire hose of equal or greater diameter to the unprotected area(s) from an OPERABLE hose station within 1 hour if the inoperable fire hose is the primary means of fire suppression; otherwise, route the additional hose within 24 hours. |26

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

SURVEILLANCE REQUIREMENTS

4.7.6.5 Each of the fire hose stations shown in Table 3.7.6.5-1 shall be demonstrated OPERABLE:

a. At least once per 31 days by a visual inspection of the fire hose stations accessible during plant operation to assure all required equipment is at the station.

b. At least once per 18 months by:

1. Visual inspection of the fire hose stations not accessible during plant operation to assure all required equipment is at the station.

2. Removing the hose for inspection and re-racking for all fire hose stations, and |29

3. Inspecting all gaskets and replacing any degraded gaskets in the couplings for all fire hose stations. |29

c. At least once per 3 years by:

1. Partially opening each hose station valve to verify valve OPERABILITY and no flow blockage.

2. Conducting a hose hydrostatic test at a pressure of 150 psig or at least 50 psig above the maximum fire main operating pressure, whichever is greater.

TABLE 3.7.6.5-1

FIRE HOSE STATIONS

LOCATIONS	COLUMN	HOSE RACK NUMBER
a. Control Structure		
El. 697'-0"	L-26	1HR-171
El. 697'-0"	L-32	2HR-171
El. 714'-0"	L-26	1HR-162
El. 714'-0"	L-31	2HR-162
El. 729'-0"	L-25.9	1HR-158
El. 729'-0"	L-32.1	2HR-158
El. 754'-0"	L-26	1HR-136
El. 754'-0"	L-32	2HR-136
El. 771'-0"	L-26	1HR-125
El. 771'-0"	L-31	2HR-125
b. Reactor Building		
El. 645'-0"	R-29	1HR-271
El. 645'-0"	P-20.6	1HR-272
El. 645'-0"	U-22	1HR-273
El. 645'-0"	R-37.4	2HR-271
El. 645'-0"	U-30.5	2HR-272
El. 645'-0"	R-30	2HR-273
El. 670'-0"	O-27.5	1HR-261
El. 670'-0"	Q-29	1HR-262
El. 670'-0"	T-22	1HR-263
El. 683'-0"	Q-27.5	1HR-251
El. 683'-0"	Q-20.6	1HR-252
El. 683'-0"	T-22	1HR-253
El. 719'-1"	Q-27.5	1HR-241
El. 719'-1"	S-27.5	1HR-242
El. 719'-1"	Q-20.6	1HR-243
El. 719'-1"	T-20.6	1HR-244
El. 719'-1"	T-23.5	1HR-245
El. 749'-1"	S-27.5	1HR-231
El. 749'-1"	S-27.5	1HR-231
El. 749'-1"	Q-20.6	1HR-232
El. 749'-1"	T-20.6	1HR-233
El. 779'-1"	P-26.5	1HR-221
El. 779'-1"	S-26.5	1HR-222
El. 779'-1"	Q-22	1HR-223
El. 779'-1"	U-20.6	1HR-224
El. 779'-1"	T-23.3	1HR-211
El. 818'-1"	P-26.5	1HR-201
El. 818'-1"	U-26.5	1HR-202
El. 818'-1"	Q-20.6	1HR-203

20

YARD FIRE HYDRANTS AND HYDRANT HOSE HOUSES

LIMITING CONDITION FOR OPERATION

3.7.6.6 Yard fire hydrants 1FH122 and 1FH104 and associated hydrant hose houses shall be OPERABLE.

APPLICABILITY: Whenever equipment in the areas protected by the yard fire hydrants is required to be OPERABLE.

ACTION:

a. With yard fire hydrants 1FH122 and/or 1FH104 and/or associated hydrant hose houses inoperable, route sufficient additional lengths of fire hose of equal or greater diameter located in adjacent OPERABLE hydrant hose house(s) to provide service to the unprotected area(s) within 1 hour. |26 |29

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

SURVEILLANCE REQUIREMENTS

4.7.6.6 Yard fire hydrants 1FH122 and 1FH104 and associated hydrant hose houses shall be demonstrated OPERABLE:

a. At least once per 31 days by visual inspection of the hydrant hose houses to assure all required equipment is at the hose houses.

b. At least once per 6 months, during March, April or May and during September, October or November, by visually inspecting the yard fire hydrants and verifying that the hydrant barrels are dry and that the hydrants are not damaged.

c. At least once per 12 months by:

1. Conducting hose hydrostatic tests at a pressure of 150 psig or at least 50 psig above the maximum fire main operating pressure, whichever is greater.

2. Replacement of all degraded gaskets in couplings.

3. Performing a flow check of each hydrant.

3/4.7.7 FIRE RATED ASSEMBLIES

LIMITING CONDITION FOR OPERATION

3.7.7 All fire rated assemblies, including walls, floor/ceilings, cable tray enclosures and other fire barriers separating safety related fire areas or separating portions of redundant systems important to safe shutdown within a fire area, and all sealing devices in fire rated assembly penetrations, including fire doors, fire windows, fire dampers, cable and piping penetration seals and ventilation seals shall be OPERABLE.

APPLICABILITY: At all times.

ACTION:

a. With one or more of the above required fire rated assemblies and/or sealing devices inoperable, within 1 hour establish a continuous fire watch on at least one side of the affected assembly and/or sealing device or verify the OPERABILITY of fire detectors on at least one side of the inoperable fire assembly and/or sealing device and establish an hourly fire watch patrol. 29 26

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

SURVEILLANCE REQUIREMENTS

4.7.7.1 Each of the above required fire rated assemblies and sealing devices shall be verified OPERABLE at least once per 18 months by performing a visual inspection of:

a. The exposed surfaces of each fire rated assembly.

b. Each fire window, fire damper, and associated hardware.

c. At least 10 percent of each type of sealed penetration. If apparent changes in appearance or abnormal degradations are found, a visual inspection of an additional 10 percent of each type of sealed penetration shall be made. This inspection process shall continue until a 10 percent sample with no apparent changes in appearance or abnormal degradation is found. Samples shall be selected such that each penetration will be inspected every 15 years.

SURVEILLANCE REQUIREMENTS (Continued)

4.7.7.2 Each of the above required fire doors shall be verified OPERABLE by:

a. Verifying the position of each closed fire door at least once per 24 hours.

b. Verifying that doors with automatic hold-open and release mechanisms are free of obstructions at least once per 24 hours.

c. Verifying the position of each locked closed fire door at least once per 7 days.

d. Verifying the OPERABILITY of the fire door supervision system by performing a CHANNEL FUNCTIONAL TEST at least once per 31 days.

e. Inspecting the automatic hold-open, release and closing mechanism and latches at least once per 6 months.

3/4.7.8 MAIN TURBINE BYPASS SYSTEM

LIMITING CONDITION FOR OPERATION

3.7.8 The main turbine bypass system shall be OPERABLE.

APPLICABILITY: OPERATIONAL CONDITION 1.

ACTION: With the main turbine bypass system inoperable, restore the system to OPERABLE status within 2 hours or determine MCPR to be equal to or greater than the applicable MCPR limit without bypass within 1 hour or take the ACTION required by Specification 3.2.3. 29

SURVEILLANCE REQUIREMENTS

4.7.8 The main turbine bypass system shall be demonstrated OPERABLE at least once per:

a. 7 days by cycling each turbine bypass valve through at least one complete cycle of full travel, and

b. 18 months by:

   1. Performing a system functional test which includes simulated automatic actuation and verifying that each automatic valve actuates to its correct position.

   2. Demonstrating TURBINE BYPASS SYSTEM RESPONSE TIME to be less than or equal to 0.30 seconds.

4.8.1.1.1 Each of the above required independent circuits between the offsite transmission network and the onsite Class 1E distribution system shall be:

a. Determined OPERABLE at least once per 7 days by verifying correct breaker alignments and indicated power availability, and

b. Demonstrated OPERABLE at least once per 18 months during shutdown by transferring, manually and automatically, unit power supply from the normal circuit to the alternate circuit.

4.8.1.1.2 Each of the above required diesel generators shall be demonstrated OPERABLE:

a. In accordance with the frequency specified in Table 4.8.1.1.2-1 on a STAGGERED TEST BASIS by:

1. Verifying the fuel level in the engine-mounted day fuel tank.

2. Verifying the fuel level in the fuel storage tank.

3. Verifying the fuel transfer pump starts and transfers fuel from the storage system to the engine-mounted day fuel tank.

4. Verifying the diesel starts from ambient condition and accelerates to at least 600 rpm in less than or equal to 10 seconds. The generator voltage and frequency shall be 4160 ± 400 volts and 60 ± 3.0 Hz within 10 seconds after the start signal. The diesel generator shall be started for this test by using one of the following signals:

a) Manual.
b) Simulated loss of offsite power by itself.
c) Simulated loss of offsite power in conjunction with an ESF actuation test signal.
d) An ESF actuation test signal by itself.

5. Verifying the diesel generator is synchronized, loaded to greater than or equal to 4000 kw in less than or equal to 90 seconds, and operates with this load for at least 60 minutes.

6. Verifying the diesel generator is aligned to provide standby power to the associated emergency busses.

7. Verifying the pressure in all diesel generator air start receivers to be greater than or equal to 240 psig.

b. At least once per 31 days and after each operation of the diesel where the period of operation was greater than or equal to 1 hour by checking for and removing accumulated water from the engine-mounted day fuel tanks.

c. At least once per 92 days and from new fuel oil prior to addition to the storage tanks by verifying that a sample obtained in accordance with ASTM-D270-1975 has a water and sediment content of less than or equal to .05 volume percent and a kinematic viscosity @ 40°C of greater than or equal to 1.3 but less than or equal to 2.4 for 1D oil or ≥1.9 but ≤4.1 for 2D oil when tested in accordance with ASTM-D975-77, and an impurity level of less than 2 mg. of insolubles per 100 ml. when tested in accordance with ASTM-D2274-70.

d. At least once per 18 months by:

1. Subjecting the diesel to an inspection in accordance with procedures prepared in conjunction with its manufacturer's recommendations for this class of standby service.

2. Verifying the diesel generator capability to reject a load of greater than or equal to 1425 kw while maintaining voltage at 4160 ± 400 volts and frequency at 60 ± 3.0 Hz.

3. Verifying the diesel generator capability to reject a load of 4000 kw without tripping. The generator voltage shall not exceed 4360 volts during and following the load rejection.

4. Simulating a loss of offsite power by itself, and:

   a) Verifying deenergization of the emergency busses and load shedding from the emergency busses.

   b) Verifying the diesel generator starts on the auto-start signal, energizes the emergency busses with permanently connected loads within 10 seconds and operates for greater than or equal to 5 minutes while its generator is loaded with the shutdown loads. After energization, the steady state voltage and frequency of the emergency busses shall be maintained at 4160 ± 200 volts and 60 ± 0.5 Hz during this test.

5. Verifying that on an ECCS actuation test signal, without loss of offsite power, the diesel generator starts on the auto-start signal and operates on standby for greater than or equal to 5 minutes. The generator voltage and frequency shall be 4160 ± 200 volts and 60 ± 0.5 Hz within 10 seconds after the auto-start signal; the steady state generator voltage and frequency shall be maintained within these limits during this test.

SURVEILLANCE REQUIREMENTS (Continued)

6. Simulating a loss-of-offsite power in conjunction with an ECCS actuation test signal, and: |29

   a) Verifying deenergization of the emergency busses and load shedding from the emergency busses.

   b) Verifying the diesel generator starts on the auto-start signal, energizes the emergency busses with permanently connected loads within 10 seconds, energizes the auto-connected loads through the load timers and operates for greater than or equal to 5 minutes while its generator is loaded with the emergency loads. After energization, the steady state voltage and frequency of the emergency busses shall be maintained at 4160 ± 400 volts and 60 ± 3.0 Hz during this test.

   c) Verifying that all automatic diesel generator trips, except engine overspeed, generator differential and engine low lube oil pressure, are automatically bypassed upon loss of voltage on the emergency bus concurrent with an ECCS actuation signal.

7. Verifying the diesel generator operates for at least 24 hours. During the first 2 hours of this test, the diesel generator shall be loaded to greater than or equal to 4700 kW and during the remaining 22 hours of this test, the diesel generator shall be loaded to 4000 kW. The generator voltage and frequency shall be 4160 ± 400 volts and 60 ± 3.0 Hz within 10 seconds after the start signal; the steady state generator voltage and frequency shall be maintained within these limits during this test. Within 5 minutes after completing this 24-hour test, perform Surveillance Requirement 4.8.1.1.2.d.4.b).* |29 |29

8. Verifying that the auto-connected loads to each diesel generator do not exceed the 2000-hour rating of 4700 kW. |29

9. Verifying the diesel generator's capability to:

   a) Synchronize with the offsite power source while the generator is loaded with its emergency loads upon a simulated restoration of offsite power,

   b) Transfer its loads to the offsite power source, and

   c) Be restored to its standby status.

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*If Surveillance Requirement 4.8.1.1.2.d.4.b) is not satisfactorily completed, it is not necessary to repeat the preceding 24 hour test. Rather, the diesel generator may be operated at 4000 kW for 1 hour or until operating temperature has stabilized. |29

10. Verifying that with the diesel generator operating in a test mode and connected to its bus, a simulated ECCS actuation signal overrides the test mode by (1) returning the diesel generator to standby operation, and (2) automatically energizes the emergency loads with offsite power.

11. Verifying that the fuel transfer pump transfers fuel from each fuel storage tank to the engine-mounted day tank of each diesel via the installed cross connection lines.

12. Verifying that each diesel generator loading sequence timer shown in Table 4.8.1.1.2-2 is OPERABLE with its setpoint within ± 10% of its design setpoint.

13. Verifying that the following diesel generator lockout features prevent diesel generator starting and/or operation only when required:

    a) Engine overspeed.
    b) Generator differential.
    c) Engine low lube oil pressure.

e. At least once per 10 years or after any modifications which could affect diesel generator interdependence by starting all diesel generators simultaneously, during shutdown, and verifying that all diesel generators accelerate to at least 600 rpm in less than or equal to 10 seconds.

f. At least once per 10 years by:

    1. Draining each fuel oil storage tank, removing the accumulated sediment and cleaning the tank using a sodium hypochlorite or equivalent solution, and

    2. Performing a pressure test of those portions of the diesel fuel oil system designed to Section III, subsection ND of the ASME Code in accordance with ASME Code Section XI Article IWD-5000. 29

4.8.1.1.3 Reports - All diesel generator failures, valid or non-valid, shall be reported to the Commission in a Special Report pursuant to Specification 6.9.2 26 within 30 days. Reports of diesel generator failures shall include the information recommended in Regulatory Position C.3.b of Regulatory Guide 1.108, Revision 1, August 1977. If the number of failures in the last 100 valid tests, on a per nuclear unit basis, is greater than or equal to 7, the report shall be supplemented to include the additional information recommended in Regulatory Position C.3.b of Regulatory Guide 1.108, Revision 1, August 1977.

TABLE 4.8.1.1.2-1

DIESEL GENERATOR TEST SCHEDULE

Number of Failures in Last 100 Valid Tests*	Test Frequency
≤ 1	At least once per 31 days
2	At least once per 14 days
3	At least once per 7 days
≥ 4	At least once per 3 days

*Criteria for determining number of failures and number of valid tests shall be in accordance with Regulatory Position C.2.e of Regulatory Guide 1.108, Revision 1, August 1977, where the last 100 tests are determined on a per nuclear unit basis. For the purposes of this test schedule, only valid tests conducted after the OL issuance date shall be included in the computation of the "last 100 valid tests." Entry into this test schedule shall be made at the 31 day test frequency.

TABLE 4.8.1.1.2-2
UNIT 1 UNIT 2
DIESEL GENERATOR LOADING TIMERS

DEVICE TAG NO.	SYSTEM	LOCATION	TIME SETTING
62A-20102	RHR Pump 1A	1A201	3 sec
62A-20202	RHR Pump 1B	1A202	3 sec
62A-20302	RHR Pump 1C	1A203	3 sec
62A-20402	RHR Pump 1D	1A204	3 sec
62A-20102	RHR Pump 2A	2A201	3 sec
62A-20202	RHR Pump 2B	2A202	3 sec
62A-20302	RHR Pump 2C	2A203	3 sec
62A-20402	RHR Pump 2D	2A204	3 sec
K116A	CS pp 1A	1C626	10.5 sec
K116B	CS pp 1B	1C627	10.5 sec
K125A	CS pp 1C	1C626	10.5 sec
K125B	CS pp 1D	1C627	10.5 sec
K116A	CS pp 2A	2C626	10.5 sec
K116B	CS pp 2B	2C627	10.5 sec
K125A	CS pp 2C	2C626	10.5 sec
K125B	CS pp 2D	2C627	10.5 sec
62AX2-20108	Emergency Service Water (ESW)	1A201	40 sec
62AX2-20208	Emergency Service Water (ESW)	1A202	40 sec
62AX2-20303	Emergency Service Water (ESW)	1A203	44 sec
62AX2-20403	Emergency Service Water (ESW)	1A204	48 sec
62X3-20304	Control Structure Chilled Water System	0C877A	60 sec
62X3-20404	Control Structure Chilled Water System	0C877B	60 sec
62X-20104	Emergency Switchgear Rm. Cooler A & RHR SW pp H&V Fan A	0C877A	60 sec

TABLE 4.8.1.1.2-2 (Continued)

UNIT 1 AND UNIT 2

DIESEL GENERATOR LOADING TIMERS

DEVICE TAG NO.	SYSTEM	LOCATION	TIME SETTING
62X-20204	Emergency Switchgear Rm Cooler B & RHR SW pp H&V Fan B	0C877B	60 sec
262X-20104	Emergency Switchgear Rm Cooler A	0C877A	120 sec
262X-20204	Emergency Switchgear Rm Cooler B	0C877B	120 sec
62X-516	DG Rm Exh Fan A	0B516	2 min
62X-526	DG Rm Exh Fan B	0B526	2 min
62X-536	DG Rm Exh Fan C	0B536	2 min
62X-546	DG Rm Exh Fan D	0B546	2 min
62X1-20304	Control Structure Chilled Water System	0C877A	3 min
62X1-20404	Control Structure Chilled Water System	0C877B	3 min
62X1-20310	Control Structure Chilled Water System	0C876A	3 min
62X2-20410	Control Structure Chilled Water System	0C876B	3 min
62X2-20304	Control Structure Chilled Water System	0C877A	3.5 min
62X2-20404	Control Structure Chilled Water System	0C877B	3.5 min
62X-K11AB	Emergency Switchgear Rm Cooling Compressor A	2CB250A	260 sec
62X-K11BB	Emergency Switchgear Rm Cooling Compressor B	2CB250B	260 sec

LIMITING CONDITION FOR OPERATION (Continued)

ACTION: (Continued)

2. Transfer the Unit 1 and common loads aligned to the inoperable Unit 2 battery bank(s) to the corresponding Unit 1 battery bank(s). 31

Otherwise, declare the Unit 1 and common loads aligned to the inoperable Unit 2 battery bank(s) inoperable and take the ACTION required by the applicable Specification(s).

c. With the Unit 1 loads associated with one or more of the above required Unit 1 125-volt DC load group battery bank(s) aligned to the corresponding Unit 2 load group battery bank(s), realign the Unit 1 loads to the Unit 1 battery bank(s) within 72 hours after restoring the Unit 1 battery bank(s) to OPERABLE status; otherwise, declare the Unit 1 loads aligned to the Unit 2 battery bank(s) inoperable and take the ACTION required by the applicable Specification(s).

d. With one of the above required ± 24 volt DC load group battery banks inoperable, declare the associated equipment inoperable and take the ACTION required by the applicable Specification(s). 31

e. With one of the above required chargers inoperable, demonstrate the OPERABILITY of its associated battery bank by performing Surveillance Requirement 4.8.2.1.a.1 within 1 hour and at least once per 8 hours thereafter. If any Category A limit in Table 4.8.2.1-1 is not met, declare the battery inoperable. 31 29

SURVEILLANCE REQUIREMENTS

4.8.2.1 Each of the above required ± 24-volt, 125-volt and 250-volt batteries and chargers shall be demonstrated OPERABLE:

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

1. The parameters in Table 4.8.2.1-1 meet the Category A limits, and

2. There is correct breaker alignment to the battery chargers, and total battery terminal voltage is greater than or equal to 26, 129, 258-volts on float charge.

b. At least once per 92 days and within 7 days after a battery discharge with battery terminal voltage below 22, 110 or 220 volts, as applicable, or battery overcharge with battery terminal voltage above 30, 150 or 300 volts, as applicable, by verifying that:

1. The parameters in Table 4.8.2.1-1 meet the Category B limits,

2. There is no visible corrosion at either terminals or connectors, or the connection resistance of these items is less than 150×10^{-6} ohm, and 29

3. The average electrolyte temperature of 4, 10 or 20, as applicable, of connected cells for the 24, 125 and 250 volt batteries is above 60°F.

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

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

2. The cell-to-cell and terminal connections are clean, tight, free of corrosion and coated with anti-corrosion material,

3. The resistance of each cell-to-cell and terminal connection of each 125-volt and 250-volt battery is less than or equal to 150×10^{-6} ohm, and 29

4. The battery charger, for at least 4 hours, will supply at least:

a) For the ± 24-volt batteries, 25 amperes at a minimum of 25.7 volts.

b) For the 125-volt batteries, 100 amperes at a minimum of 127.8 volts.

c) For the 250-volt batteries, 300 amperes at a minimum of 255.6 volts.

d. At least once per 18 months by verifying that either:

1. The battery capacity is adequate to supply and maintain in OPERABLE status all of the actual emergency loads for the design duty cycle when the battery is subjected to a battery service test, or

2. The battery capacity is adequate to supply a dummy load of the following profile, which is verified to be greater than the actual emergency loads, while maintaining the battery terminal voltage greater than or equal to ± 21, 105 or 210 volts, as applicable.

a) For ± 24-volt battery banks 1D670, 1D670-1, 1D680 and 1D680-1, 9.37 amperes for the entire 4 hour test.

b) For 125-volt batteries:

1) Channel A battery 1D612:
325 amperes for 60 seconds
107 amperes for the remainder of the 4 hour test

2) Channel "B" battery 1D622:
323 amperes for 60 seconds
105 amperes for the remainder of the 4 hour test 31

3) Channel "C" battery 1D632:
340 amperes for 60 seconds
121 amperes for the remainder of the 4 hour test

4) Channel "D" battery 1D642:
323 amperes for 60 seconds
104 amperes for the remainder of the 4 hour test.

5) Channel "A" battery 2D612:
   328 amperes for 60 seconds
   112 amperes for the remainder of the 4 hour test.
6) Channel "B" battery 2D622:
   326 amperes for 60 seconds
   110 amperes for the remainder of the 4 hour test.
7) Channel "C" battery 2D632:
   343 amperes for 60 seconds
   128 amperes for the remainder of the 4 hour test.
8) Channel "D" battery 2D642:
   326 amperes for 60 seconds
   111 amperes for the remainder of the 4 hour test.

31

c) For 250-volt batteries:

1) Battery bank 1D650:

1091	amperes for	60	seconds
567	amperes for	29.0	minutes
113	amperes for	60.0	minutes
24	amperes for	150.0	minutes

2) Battery bank 1D660:

1314	amperes for	60	seconds
465	amperes for	60	seconds
365	amperes for	28.0	minutes
323	amperes for	15.0	minutes
185	amperes for	195.0	minutes

e. At least once per 60 months by verifying that the battery capacity is at least 80% of the manufacturer's rating when subjected to a performance discharge test. Once per 60 month interval, this performance discharge test may be performed in lieu of the battery service test.

f. Annual performance discharge tests of battery capacity shall be given to any battery that shows signs of degradation or has reached 85% of the service life expected for the application. Degradation is indicated when the battery capacity drops more than 10% of rated capacity from its average on previous performance tests, or is below 90% of the manufacturer's rating.

TABLE 4.8.2.1-1

BATTERY SURVEILLANCE REQUIREMENTS

Parameter	CATEGORY A(1)	CATEGORY B(2)	
	Limits for each designated pilot cell	Limits for each connected cell	Allowable(3) value for each connected cell
Electrolyte Level	>Minimum level indication mark, and ≤ ¼" above maximum level indication mark	>Minimum level indication mark, and ≤ ¼" above maximum level indication mark	Above top of plates, and not overflowing
Float Voltage	> 2.13 volts	≥ 2.13 volts(c)	> 2.07 volts
Specific Gravity(a)	≥ 1.200(b)	≥ 1.195(b) Average of all connected cells > 1.205(b)	Not more than .020 below the average of all connected cells Average of all connected cells ≥ 1.195(b)

(a) Corrected for electrolyte temperature and level.
(b) Or battery charging current is less than 0.01, 0.1 and 0.25 amperes for the ±24, 125 and 250 volt batteries, respectively, when on float charge.
(c) May be corrected for average electrolyte temperature.
(1) For any Category A parameter(s) outside the limit(s) shown, the battery may be considered OPERABLE provided that within 24 hours all the Category B measurements are taken and found to be within their allowable values, and provided all Category A and B parameter(s) are restored to within limits within the next 6 days.
(2) For any Category B parameter(s) outside the limit(s) shown, the battery may be considered OPERABLE provided that the Category B parameters are within their allowable values and provided the Category B parameter(s) are restored to within limits within 7 days.
(3) Any Category B parameter not within its allowable value indicates an inoperable battery.

3/4.8.3 ONSITE POWER DISTRIBUTION SYSTEMS

DISTRIBUTION - OPERATING

LIMITING CONDITION FOR OPERATION

3.8.3.1 The following power distribution system divisions shall be energized with tie breakers open both between redundant buses within the unit and between units at the same station:

a. A.C. power distribution:	
1. Division I, consisting of:	
a) Load group Channel "A", consisting of:	
1) 4160 volt A.C. switchgear bus	1A201
2) 480 volt A.C. load center	1B210
3) 480 volt A.C. motor control center	0B516
b) Load group Channel "C", consisting of:	
1) 4160 volt A.C. switchgear bus	1A203
2) 480 volt A.C. load center	1B230
3) 480 volt A.C. motor control center	0B536
c) Load group 480 volt A.C. motor control centers	0B517, 0B136 1B216, 1B236 1B217, 1B237 1B219#
d) Load group 208/120 volt A.C. instrument panels	1Y216, 1Y236
2. Division II, consisting of:	
a) Load group Channel"B", consisting of:	
1) 4160 volt A.C. switchgear bus	1A202
2) 480 volt A.C. load center	1B220
3) 480 volt A.C. motor control center	0B526
b) Load group Channel "D", consisting of:	
1) 4160 volt A.C. switchgear bus	1A204
2) 480 volt A.C. load center	1B240
3) 480 volt A.C. motor control center	0B546
c) Load group 480 volt A.C. motor control centers	0B527, 0B146 1B226, 1B246 1B227, 1B247 1B229#
d) Load group 208/120 volt A.C. instrument panels	1Y226, 1Y246
b. D.C. power distribution:	
1. Division I, consisting of:	
a) Load group Channel "A", consisting of:	
1) 125 volt DC buses	1D612, 2D612,* 1D614, 2D614*
2) Fuse box	1D611, 2D611*
b) Load group Channel "C", consisting of:	
1) 125 volt DC buses	1D632, 2D632* 1D634, 2D634*
2) Fuse box	1D631, 2D631*
c) Load group "I", consisting of:	
1) 250 volt DC buses	1D652, 1D254
2) Fuse box	1D651

*Not required to be OPERABLE when the requirements of ACTION c have been satisfied. 31
#The associated swing bus automatic transfer switch shall be OPERABLE.

LIMITING CONDITION FOR OPERATION (Continued)

D.C. power distribution: (Continued)

d) Load group "I", consisting of:		
1) ± 24 volt DC buses	1D672	
2) Fuse box	1D671	
2. Division II, consisting of:		
a) Load group Channel "B" consisting of:		31
1) 125 volt DC buses	1D622, 2D622* 1D624, 2D624*	
2) Fuse box	1D621, 2D621*	
b) Load group Channel "D" consisting of:		
1) 125 volt DC buses	1D642, 2D642* 1D644, 2D644*	
2) Fuse box	1D641, 2D641*	
c) Load group "II" consisting of:		
1) 250 volt DC buses	1D662, 1D264, 1D274	8
2) Fuse box	1D661	
d) Load group "II" consisting of:		
1) ± 24 volt DC buses	1D682	
2) Fuse box	1D681	

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2 and 3.

ACTION:

a. With one of the above required A.C. distribution system load groups not energized, re-energize the load group within 8 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

b. With one of the above required Unit 1 D.C. distribution system load groups not energized, re-energize the load group within 2 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours. 31 8

c. With one or more of the above required Unit 2 D.C. distribution system load groups not energized, within 2 hours either:

1. Reenergize the load group(s), or

2. Transfer the Unit 1 and common loads aligned to the deenergized Unit 2 load group(s) to the corresponding Unit 1 load group(s). 31

Otherwise, declare the Unit 1 and common loads aligned to the deenergized Unit 2 load group(s) inoperable and take the ACTION required by the applicable Specification(s).

*Not required to be OPERABLE when the requirements of ACTION c have been satisfied

LIMITING CONDITION FOR OPERATION (Continued)

d. With the Unit 1 loads associated with one or more of the above required Unit 1 125-volt D.C. load group(s) aligned to the corresponding Unit 2 load group(s), realign the Unit 1 loads to the Unit 1 load group(s) within 72 hours after restoring the Unit 1 load group(s) to OPERABLE status; otherwise, declare the Unit 1 loads aligned to the Unit 2 load group(s) inoperable and take the ACTION required by the applicable Specification(s). 31

e. With an A.C. power distribution system swing bus transfer switch inoperable, restore the inoperable bus transfer switch 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.

SURVEILLANCE REQUIREMENTS

4.8.3.1.1 Each of the above required power distribution system load groups shall be determined energized at least once per 7 days by verifying correct breaker alignment and voltage on the busses/MCCs/panels. 31

4.8.3.1.2 The A.C. power distribution system swing bus automatic transfer switches shall be demonstrated OPERABLE at least once per 31 days by actuating the load test switch or by disconnecting the normal power source to the transfer switch and verifying that swing bus automatic transfer is accomplished.

LIMITING CONDITION FOR OPERATION

3.8.3.2 As a minimum, the following power distribution system divisions shall be energized:

a. For A.C. power distribution, Division I or Division II with:

1. Division I consisting of:

a)	Load group Channel "A", consisting of:	
	1) 4160 volt A.C. switchgear bus	1A201
	2) 480 volt A.C. load center	1B210
	3) 480 volt A.C. motor control center	0B516
b)	Load group Channel "C", consisting of:	
	1) 4160 volt A.C. switchgear bus	1A203
	2) 480 volt A.C. load center	1B230
	3) 480 volt A.C. motor control center	0B536
c)	Load group 480 volt A.C. motor control centers	0B517, 0B136 1B216, 1B236 1B217, 1B237 1B219*
d)	Load group 208/120 volt A.C. instrument panels	1Y216, 1Y236

2. Division II consisting of:

a)	Load group Channel"B", consisting of:	
	1) 4160 volt A.C. switchgear bus	1A202
	2) 480 volt A.C. load center	1B220
	3) 480 volt A.C. motor control center	0B526
b)	Load group Channel "D", consisting of:	
	1) 4160 volt A.C. switchgear bus	1A204
	2) 480 volt A.C. load center	1B240
	3) 480 volt A.C. motor control center	0B546
c)	Load group 480 volt A.C. motor control centers	0B527, 0B146 1B226, 1B246 1B227, 1B247 1B229**
d)	Load group 208/120 volt A.C. instrument panels	1Y226, 1Y246

*The associated swing bus automatic transfer switch shall be OPERABLE if LPCI pumps A and C alone are fulfilling the requirements of Specification 3.5.2.
**The associated swing bus automatic transfer switch shall be OPERABLE if LPCI pumps B and D alone are fulfilling the requirements of Specification 3.5.2.

LIMITING CONDITION FOR OPERATION (Continued)

b. For D.C. power distribution, Division I or Division 2, with:

1. Division I consisting of:

a)	Load group Channel "A", consisting of:	
	1) 125 volt DC buses	1D612, 2D612** 1D614, 2D614**
	2) Fuse box	1D611, 2D611**
b)	Load group Channel "C", consisting of:	
	1) 125 volt DC buses	1D632, 2D632** 1D634, 2D634**
	2) Fuse box	1D631, 2D631**
c)	Load group "I", consisting of:	
	1) 250 volt DC buses	1D652, 1D254
	2) Fuse box	1D651
d)	Load group "I", consisting of:	
	1) ± 24 volt DC buses	1D672
	2) Fuse box	1D671

2. Division II consisting of:

a)	Load group Channel "B", consisting of:	
	1) 125 volt DC buses	1D622, 2D622** 1D624, 2D624**
	2) Fuse box	1D621, 2D621**
b)	Load group Channel "D", consisting of:	
	1) 125 volt DC buses	1D642, 2D642** 1D644, 2D644**
	2) Fuse box	1D641, 2D641**
c)	Load group "II", consisting of:	
	1) 250 volt DC buses	1D662, 1D264, 1D274
	2) Fuse box	1D661
d)	Load group "II", consisting of:	
	1) ± 24 volt DC buses	1D682
	2) Fuse box	1D681

APPLICABILITY: OPERATIONAL CONDITIONS 4, 5 and *.

*When handling irradiated fuel in the secondary containment.
**Not required to be OPERABLE when the requirements of ACTION c have been satisfied.

The measured response time will be compared to the manufacturer's data to insure that it is less than or equal to a value specified by the manufacturer. Circuit breakers found inoperable during functional testing shall be restored to OPERABLE status prior to resuming operation. For each circuit breaker found inoperable during these functional tests, an additional representative sample of at least 10% of all the circuit breakers of the inoperable type shall also be functionally tested until no more failures are found or all circuit breakers of that type have been functionally tested.

2. a. By selecting and functionally testing a representative sample of each type of fuse on a rotating basis. Each representative sample of fuses shall include at least 10% of all fuses of that type. The functional test shall consist of a non-destructive resistance measurement test which demonstrates that the fuse meets its manufacturer's design criteria. Fuses found inoperable during these functional testing shall be replaced with OPERABLE fuses prior to resuming operation. For each fuse found inoperable during these functional tests; an additional representative sample of at least 10% of all fuses of that type shall be functionally tested until no more failures are found or all fuses of that type have been functionally tested, or

   b. By replacing 100% of all required fuses.

3. Functionally testing each overcurrent relay listed in Table 3.8.4.1-1. Testing of these relays shall consist of injecting a current in excess of 120% of the nominal relay initiation current and measuring the response time. The measured response time shall be within ± 10% of the specified value. 32

b. At least once per 60 months by subjecting each circuit breaker to an inspection and preventive maintenance in accordance with procedures prepared in conjunction with its manufacturer's recommendations.

TABLE 3.8.4.1-1

PRIMARY CONTAINMENT PENETRATION CONDUCTOR OVERCURRENT PROTECTIVE DEVICES

CIRCUIT BREAKER LOCATION		TYPE*	FRAME RATING/UL	TRIP SET POINT (Amperes)	RESPONSE TIME (Milli-seconds/ Cycles)	SYSTEMS OR EQUIPMENT POWERED
a. Type 2 Molded Case Circuit Breakers#						
1.	1B219022	HFB-M	150/30	270	NA	HVB311F031A RRP "A" DSCH VLV
2.	1B237043	HFB-M	150/30	270	NA	HVB311F023A Recirc. PP "A" Suction
3.	1B236052	HFB-M	150/30	215	NA	HVE111F009 RHR Pump Suction Shutoff
4.	1B236023	HFB-M	150/3	18	NA	HV12603 Containment Inst. Compressor Suct. Iso. Valve
5.	1B236011	HFB-M	150/30	250	NA	1V413A - Drywell Area Unit Cooler
6.	1B236033	HFB-M	150/30	220	NA	1V414A - Drywell Area Unit Cooler
7.	1B236021	HFB-M	150/30	175	NA	1V417A - Drywell Area Unit Cooler
8.	1B236032	HFB-M	150/30	180	NA	1V412A - Drywell Area Unit Cooler
9.	1B236042	HFB-M	150/30	150	NA	1V411A - Drywell Area Unit Cooler
10.	1B236043	HFB-M	150/30	160	NA	1V416A - Drywell Area Unit Cooler
11.	1B236082	HFB-M	150/30	150	NA	1V415A - Drywell Area Unit Cooler
12.	1B236102	HFB-M	150/3	8	NA	HVB211F001 - Reactor Head Vent Valve
13.	1B236053	HFB-M	150/5	45	NA	HVG331F001 - Reac. Wtr. Clean up inboard isolation
14.	1B237072	HFB-M	150/5	25	NA	HVB211F016 - Main Stm. Line Drain Inboard Isolation
15.	1B219023	HFB-M	150/10	80	NA	HVB311F032A - RRP "A" Dsch Byps Vlv

TABLE 3.8.4.1-1 (Continued)

PRIMARY CONTAINMENT PENETRATION CONDUCTOR OVERCURRENT PROTECTIVE DEVICES

CIRCUIT BREAKER LOCATION	TYPE**	FRAME RATING/UL	RESPONSE TIME (Milli-seconds/ Cycles)	SYSTEMS OR EQUIPMENT POWERED
b. Type 3 Molded Case Circuit Breakers				
1. 1B236103	KB-TM	250/150	NA	1E440C - Containment Recomb Elect. Htr. Ass'y.
2. 1B246033	KB-TM	250/150	NA	1E440D - Containment Recomb Elect. Htr. Ass'y.
3. 1B226103	KB-TM	250/150	NA	1E440B - Containment Recomb Elect. Htr. Ass'y.
4. 1B216092	KB-TM	250/150	NA	1E440A - Containment Recomb. Elect. Htr. Ass'y.
5. 1B253041	KB-TM	150/15	NA	TBB15 Pri. Cont. MSIV Iso. Hoist
6. 1B263021	KB-TM	150/15	NA	TBB16 Pri. Cont. MSIV Iso. Hoist

c. Circuit Breakers Tripped By Overcurrent Relays	Relay Type	Relay Initiation Current (Amperes)	Response Time (Seconds)	Systems or Equipment Powered
1. 1A20501	50D	5	80	1 P401A Reactor Recirc Pump
2. 1A20502	50D	5	80	1 P401A Reactor Recirc Pump
3. 1A20601	50D	5	80	1 P401B Reactor Recirc Pump
4. 1A20602	50D	5	80	1 P401B Reactor Recirc Pump

-TM - Westinghouse Type KB, Thermal-magnetic

MOTOR OPERATED VALVES THERMAL OVERLOAD PROTECTION

LIMITING CONDITION FOR OPERATION

3.8.4.2 The thermal overload protection of each valve shown in Table 3.8.4.2-1 shall be bypassed continuously by an OPERABLE bypass device integral with the motor starter.

APPLICABILITY: Whenever the motor operated valve is required to be OPERABLE.

ACTION:

a. With thermal overload protection for one or more of the above required valves not bypassed continuously by an OPERABLE integral bypass device, take administrative action to continuously bypass the thermal overload within 8 hours or declare the affected valve(s) inoperable and apply the appropriate ACTION statement(s) for the affected system(s).

b. The provisions of Specification 3.0.4 are not applicable.

SURVEILLANCE REQUIREMENTS

4.8.4.2.1 The thermal overload protection for the above required valves shall be verified to be bypassed continuously by an OPERABLE integral bypass device by verifying that the thermal overload protection is bypassed: 29

a. At least once per 18 months, and

b. Following maintenance on the motor starter.

4.8.4.2.2 The thermal overload protection shall be verified to be bypassed following activities during which the thermal overload protection was temporarily placed in force. 29

REACTOR PROTECTION SYSTEM ELECTRIC POWER MONITORING

LIMITING CONDITION FOR OPERATION

3.8.4.3 Two RPS electric power monitoring assemblies for each inservice RPS MG set or alternate power supply shall be OPERABLE.

APPLICABILITY: At all times.

ACTION:

a. With one RPS electric power monitoring assembly for an inservice RPS MG set or alternate power supply inoperable, restore the inoperable power monitoring assembly to OPERABLE status within 72 hours or remove the associated RPS MG set or alternate power supply from service.

b. With both RPS electric power monitoring assemblies for an inservice RPS MG set or alternate power supply inoperable, restore at least one electric power monitoring assembly to OPERABLE status within 30 minutes or remove the associated RPS MG set or alternate power supply from service.

SURVEILLANCE REQUIREMENTS

4.8.4.3 The above specified RPS electric power monitoring assemblies shall be determined OPERABLE:

a. By performance of a CHANNEL FUNCTIONAL TEST each time the plant is in COLD SHUTDOWN for a period of more than 24 hours, unless performed within the previous 6 months.

b. At least once per 18 months by demonstrating the OPERABILITY of overvoltage, undervoltage and underfrequency protective instrumentation by performance of a CHANNEL CALIBRATION including simulated automatic actuation of the protective relays, tripping logic and output circuit breakers and verifying the following setpoints: 29

		RPS Division A	RPS Division B
1.	Overvoltage	≤ 128.3 VAC	≤ 129.5 VAC
2.	Undervoltage	≥ 110.7 VAC	≥ 111.9 VAC
3.	Underfrequency	≥ 57 Hz	≥ 57 Hz

6 29

3/4.9.2 INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.9.2 At least 2 source range monitor* (SRM) channels shall be OPERABLE and inserted to the normal operating level with:

a. Continuous visual indication in the control room,

b. At least one with audible alarm in the control room,

c. One of the required SRM detectors located in the quadrant where CORE ALTERATIONS are being performed and the other required SRM detector located in an adjacent quadrant, and

d. The "shorting links" removed from the RPS circuitry prior to and during the time any control rod is withdrawn** and shutdown margin demonstrations are in progress.

APPLICABILITY: OPERATIONAL CONDITION 5.

ACTION:

With the requirements of the above specification not satisfied, immediately suspend all operations involving CORE ALTERATIONS and insert all insertable control rods.

SURVEILLANCE REQUIREMENTS

4.9.2 Each of the above required SRM channels shall be demonstrated OPERABLE by:

a. At least once per 12 hours:

1. Performance of a CHANNEL CHECK,
2. Verifying the detectors are inserted to the normal operating level, and
3. During CORE ALTERATIONS, verifying that the detector of an OPERABLE SRM channel is located in the core quadrant where CORE ALTERATIONS are being performed and another is located in an adjacent quadrant.

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*The use of special movable detectors during CORE ALTERATIONS in place of the normal SRM nuclear detectors is permissible as long as these special detectors are connected to the normal SRM circuits.

**Not required for control rods removed per Specification 3.9.10.1 and 3.9.10.2.

SURVEILLANCE REQUIREMENTS (Continued)

b. Performance of a CHANNEL FUNCTIONAL TEST:

1. Within 24 hours prior to the start of CORE ALTERATIONS, and

2. At least once per 7 days.

c. Verifying that the channel count rate is at least 0.7 cps:***

1. Prior to control rod withdrawal,

2. Prior to and at least once per 12 hours during CORE ALTERATIONS, and

3. At least once per 24 hours.

d. Verifying that the RPS circuitry "shorting links" have been removed within 8 hours prior to and at least once per 12 hours during:

1. The time any control rod is withdrawn,## or

2. Shutdown margin demonstrations.

***Provided the signal-to-noise ratio is $\geq$ 2; otherwise, 3 cps.

##Not required for control rods removed per Specification 3.9.10.1 or 3.9.10.2.

3/4.9.5 COMMUNICATIONS

LIMITING CONDITION FOR OPERATION

3.9.5 Direct communication shall be maintained between the control room and refueling floor personnel.

APPLICABILITY: OPERATIONAL CONDITION 5, during CORE ALTERATIONS.*

ACTION:

When direct communication between the control room and refueling floor personnel cannot be maintained, immediately suspend CORE ALTERATIONS.*

SURVEILLANCE REQUIREMENTS

4.9.5 Direct communication between the control room and refueling floor personnel shall be demonstrated within one hour prior to the start of and at least once per 12 hours during CORE ALTERATIONS.*

*Except movement of control rods with their normal drive system.

3/4.9.6 REFUELING PLATFORM

LIMITING CONDITION FOR OPERATION

3.9.6 The refueling platform shall be OPERABLE and used for handling fuel assemblies or control rods within the reactor pressure vessel.

APPLICABILITY: During handling of fuel assemblies or control rods within the reactor pressure vessel.

ACTION:

With the requirements for refueling platform OPERABILITY not satisfied, suspend use of any inoperable refueling platform equipment from operations involving the handling of control rods and fuel assemblies within the reactor pressure vessel after placing the load in a safe condition.

SURVEILLANCE REQUIREMENTS

4.9.6.1 The refueling platform main hoist used for handling of control rods or fuel assemblies within the reactor pressure vessel shall be demonstrated OPERABLE within 7 days prior to the start of such operations by:

a. Demonstrating operation of the overload cutoff when the cable load is 1200 ± 50 pounds.

b. Demonstrating operation of the normal uptravel stop when uptravel brings the tip of the grapple hook to greater than or equal to 8 feet below the refueling floor level.

c. Demonstrating operation of the downtravel stop when downtravel of the grapple tip is 4 + 0, - 1 inches below the top of the fuel bundle handle.

d. Demonstrating operation of the slack cable cutoff when the load is 50 ± 10 pounds.

e. Demonstrating operation of the hoist loaded interlock when the load is 550 + 0, - 50 pounds.

f. Performing a load test of 1200 + 50, -0 pounds applied to the hoist cable.

3/4.10 SPECIAL TEST EXCEPTIONS

3/4.10.1 PRIMARY CONTAINMENT INTEGRITY

LIMITING CONDITION FOR OPERATION

3.10.1 The provisions of Specifications 3.4.2, 3.6.1.1, 3.6.1.3, 3.9.1, Function 8 of Specification 3.3.7.5 and Table 1.2 may be suspended to permit the safety valve function of the safety/relief valve to be inoperable, the reactor pressure vessel closure head and the drywell head to be removed and the primary containment air lock doors to be open when the reactor mode switch is in the Startup position during low power PHYSICS TESTS with THERMAL POWER less than 1% of RATED THERMAL POWER and reactor coolant temperature less than 200°F.

APPLICABILITY: OPERATIONAL CONDITION 2, during low power PHYSICS TESTS.

ACTION:

With THERMAL POWER greater than or equal to 1% of RATED THERMAL POWER or with the reactor coolant temperature greater than or equal to 200°F, immediately place the reactor mode switch in the Shutdown position.

SURVEILLANCE REQUIREMENTS

4.10.1 The THERMAL POWER and reactor coolant temperature shall be verified to be within the limits at least once per hour during low power PHYSICS TESTS.

3/4.10.2 ROD SEQUENCE CONTROL SYSTEM

LIMITING CONDITION FOR OPERATION

3.10.2 The sequence constraints imposed on control rod groups by the rod sequence control system (RSCS) per Specification 3.1.4.2 may be suspended by means of bypass switches for the following tests provided that the rod worth minimizer is OPERABLE per Specification 3.1.4.1:

a. Shutdown margin demonstrations, Specification 4.1.1.

b. Control rod scram, Specification 4.1.3.2.

c. Control rod friction measurements.

d. Startup Test Program with the THERMAL POWER less than 20% of RATED THERMAL POWER.

APPLICABILITY: OPERATIONAL CONDITIONS 1 and 2.

ACTION:

With the requirements of the above specification not satisfied, verify that the RSCS is OPERABLE per Specification 3.1.4.2.

SURVEILLANCE REQUIREMENTS

4.10.2 When the sequence constraints imposed by the RSCS are bypassed, verify;

a. That the RWM is OPERABLE per Specification 3.1.4.1.

b. That movement of control rods from 75% ROD DENSITY to the RSCS low power setpoint is blocked or limited to the approved control rod withdrawal sequence during scram and friction tests.

c. That movement of control rods during shutdown margin demonstrations is limited to the prescribed sequence per Specification 3.10.3.

d. Conformance with this specification and test procedures by a second licensed operator or other technically qualified member of the unit technical staff.

VENTING OR PURGING

LIMITING CONDITION FOR OPERATION

3.11.2.8 VENTING or PURGING of the Mark II containment drywell shall be through the Standby Gas Treatment System.

APPLICABILITY: Whenever the drywell is vented or purged.

ACTION:

a. With the requirements of the above specification not satisfied, suspend all VENTING and PURGING of the drywell.

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

SURVEILLANCE REQUIRMENTS

4.11.2.8.1 The containment drywell shall be determined to be aligned for VENTING or PURGING through the Standby Gas Treatment System within 4 hours prior to start of and at least once per 12 hours during VENTING or PURGING of the drywell.

4.11.2.8.2 Prior to use of the purge system through the standby gas treatment system assure that:

a. Both standby gas treatment system trains are OPERABLE whenever the purge system is in use, and

b. Whenever the purge system is in use during OPERATIONAL CONDITION 1 or 2 or 3, only of the standby gas treatment system trains may be used.

3/4.11.3 SOLID RADWASTE SYSTEM

LIMITING CONDITION FOR OPERATION

3.11.3 The solid radwaste system shall be used in accordance with a PROCESS CONTROL PROGRAM, for the processing and packaging of radioactive wastes to ensure compliance with 10 CFR Part 20, 10 CFR Part 71, and Federal regulations governing the disposal of the waste.

APPLICABILITY: At all times.

ACTION:

a. With the requirements of 10 CFR Part 20, and/or 10 CFR Part 71, not satisfied, suspend shipments of defectively processed or defectively packaged solid radioactive wastes from the site.

b. With the solid radwaste system inoperable for more than 31 days, prepare and submit to the Commission within 30 days pursuant to Specification 6.9.2 a Special Report which includes the following information:

   1. Identification of the inoperable equipment or subsystems and the reason for inoperability,

   2. Action(s) taken to restore the inoperable equipment to OPERABLE status,

   3. A description of the alternative used for SOLIDIFICATION and packaging of radioactive wastes, and

   4. Summary description of action(s) taken to prevent a recurrence.

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

SURVEILLANCE REQUIREMENTS

4.11.3.1 The solid radwaste system shall be demonstrated OPERABLE at least once per 92 days by:

a. Operating the solid radwaste system at least once in the previous 92 days in accordance with the PROCESS CONTROL PROGRAM, or

b. Verification of the existence of a valid contract for SOLIDIFICATION to be performed by a contractor in accordance with a PROCESS CONTROL PROGRAM.

TABLE 3.12.1-1

RADIOLOGICAL ENVIRONMENTAL MONITORING PROGRAM

EXPOSURE PATHWAY AND/OR SAMPLE	NUMBER OF REPRESENTATIVE SAMPLES AND SAMPLE LOCATIONS[a]	SAMPLING AND COLLECTION FREQUENCY	TYPE AND FREQUENCY OF ANALYSIS
1. DIRECT RADIATION[b]	40 routine monitoring stations with two or more dosimeters or with one instrument for measuring and recording dose rate continuously placed as follows: 1) An inner ring of stations, one in each meteorological sector, in the general area of the SITE BOUNDARY; 2) An outer ring of stations, one in each meteorological sector, in the 3 to 9 mile range from the site; 3) The balance of the stations placed in special interest areas such as population centers, nearby residences, schools, and in 1 or 2 areas to serve as control stations.	Quarterly.	Gamma dose quarterly.
2. AIRBORNE			
Radioiodine and Particulates	Samples from 5 locations: a. 3 samples from close to the 3 SITE BOUNDARY locations (in different sectors) in one of the highest calculated annual average groundlevel χ/Q. b. 1 sample from the vicinity community having one of the highest calculated annual highest groundlevel χ/Q.	Continual sampler operation with sample collection weekly, or more frequently if required[c] by dust loading.	Radioiodine Cannister: I-131 Analysis weekly. Particulate Sampler: Gross Beta radio activity analysis following filter change;[d] Gamma isotopic analysis[e] of composite (by location) quarterly.

TABLE 3.12.1-1 (Continued)

RADIOLOGICAL ENVIRONMENTAL MONITORING PROGRAM

EXPOSURE PATHWAY AND/OR SAMPLE	NUMBER OF REPRESENTATIVE SAMPLES AND SAMPLE LOCATIONS[a]	SAMPLING AND COLLECTION FREQUENCY	TYPE AND FREQUENCY OF ANALYSIS
2. AIRBORNE (Continued)			
	1 sample from a control location, as for example 15-30 km distant and in the least prevalent wind direction		
3. WATERBORNE			
a. Surface[f]	1 sample upstream 1 sample downstream	Composite sample over one-month period.[g]	Gamma isotopic analysis[e] monthly. Composite for tritium analysis quarterly.
b. Ground	Samples from 1 or 2 sources only if likely to be affected.[h]	Quarterly.	Gamma isotopic[e] and tritium analysis quarterly.
c. Drinking	1 samples of each of 1 to 3 of the nearest water supplies that could be affected by its discharge	Composite sample over 2-week period[(g)] when I-131 analysis is performed, monthly composite otherwise.	I-131 analysis on each composite when the dose calculated for the consumption of the water is greater than 1 mrem per year.[i] Composite for gross beta and gamma isotopic analyses monthly. Composite for tritium analysis quarterly.
	1 sample from a control location.		
d. Sediment from shoreline	1 sample from downstream area with existing or potential recreational value.	Semiannually.	Gamma isotopic analysis[e] semiannually.

TABLE 3.12.1-1 (Continued)

RADIOLOGICAL ENVIRONMENTAL MONITORING PROGRAM

EXPOSURE PATHWAY AND/OR SAMPLE	NUMBER OF REPRESENTATIVE SAMPLES AND SAMPLE LOCATIONS[a]	SAMPLING AND COLLECTION FREQUENCY	TYPE AND FREQUENCY OF ANALYSIS
4. INGESTION			
a. Milk	a. Samples from milking animals in 3 locations within 5 km distant having the highest dose potential. If there are none, then, 1 sample from milking animals in each of 3 areas between 5 to 8 km distant where doses are calculated to be greater than 1 mrem per yr[i].	Semimonthly when animals are on pasture, monthly at other times.	Gamma isotopic and I-131 analysis semimonthly when animals are on pasture; monthly at other times.
	1 sample from milking animals at a control location (15-30 km distant and in the least prevalent wind direction).		
b. Fish and Invertebrates	a. 1 sample of two recreationally important species in vicinity of plant discharge area.	Sample in season, or semiannually if they are not seasonal.	Gamma isotopic analysis on edible portions.
	1 sample of same species in areas not influenced by plant discharge.		
c. Food Products	a. 1 sample of each principal class of food products from any area which is irrigated by water in which liquid plant wastes have been discharged.	At time of harvest[j].	Gamma isotopic analysis on edible portions.

TABLE 3.12.1-1 (Continued)

RADIOLOGICAL ENVIRONMENTAL MONITORING PROGRAM

EXPOSURE PATHWAY AND/OR SAMPLE	NUMBER OF REPRESENTATIVE SAMPLES AND SAMPLE LOCATIONS[a]	SAMPLING AND COLLECTION FREQUENCY	TYPE AND FREQUENCY OF ANALYSIS
c. Food Products (cont'd)	Samples of 3 different kinds of broad leaf vegetation grown nearest each of two different offsite locations of highest predicted annual average ground level D/Q if milk sampling is not performed.	Monthly when available.	Gamma isotopic[e] and I-131 analysis.
	1 sample of each of the similar broad leaf vegetation grown 15-30 km distant in the least prevalent wind direction if milk sampling is not performed.	Monthly when available.	Gamma isotopic[e] and I-131 analysis.

TABLE 3.12.1-2

REPORTING LEVELS FOR RADIOACTIVITY CONCENTRATIONS IN ENVIRONMENTAL SAMPLES

Reporting Levels

Analysis	Water (pCi/l)	Airborne Particulate or Gases (pCi/m^3)	Fish (pCi/Kg, wet)	Milk (pCi/l)	Food Products (pCi/Kg, wet)
H-3	20,000*				
Mn-54	1,000		30,000		
Fe-59	400		10,000		
Co-58	1,000		30,000		
Co-60	300		10,000		
Zn-65	300		20,000		
Zr-Nb-95	400[a]				
I-131	2	0.9		3	100
Cs-134	30	10	1,000	60	1,000
Cs-137	50	20	2,000	70	2,000
Ba-La-140	200[a]			300	

*For drinking water samples. This is 40 CFR Part 141 value. If no drinking water pathway exists, a value of 30,000 pCi/l may be used.

[a]Total for parent and daughter.

TABLE 4.12.1-1

DETECTION CAPABILITIES FOR ENVIRONMENTAL SAMPLE ANALYSIS[a]

LOWER LIMIT OF DETECTION (LLD)[b][c]

Analysis	Water (pCi/l)	Airborne Particulate or Gas (pCi/m³)	Fish (pCi/kg, wet)	Milk (pCi/l)	Food Products (pCi/kg, wet)		Sediments (pCi/kg, dry)
Gross Beta	4	0.01					
H-3	2000						
Mn-54	15		130				
Fe-59	30		260				
Co-58, 60	15		130				
Zn-65	30		260				
Zr-95	30						
Nb-95	15						
I-131	1[d]	0.07		1	60		
Cs-134	15	0.05	130	15	60	150	
Cs-137	18	0.06	150	18	80	180	
Ba-140	60			60			
La-140	15			15			

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.

MAP DEFINING UNRESTRICTED AREAS 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 MEMBERS OF THE PUBLIC, shall be as shown in Figures 5.1.3-1a and 5.1.3-1b.

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 attached to the suppression chamber through a series of downcomer vents. The drywell has a minimum free air volume of 239,600 cubic feet. The suppression chamber has an air region of 148,590 cubic feet and a water region of 142,160 cubic feet.

DESIGN TEMPERATURE AND PRESSURE

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

a. Maximum internal pressure 53 psig.

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

c. Maximum external pressure 5 psig.

d. Maximum floor differential pressure: 28 psid, downward.
5.5 psid, upward.

SECONDARY CONTAINMENT

5.2.3 The secondary containment consists of the Unit 1 and Unit 2 Reactor Building, the Reactor Building recirculation fan room, the equipment access structure and a portion of the main steam tunnel and has a minimum free volume of 5,755,600 cubic feet.

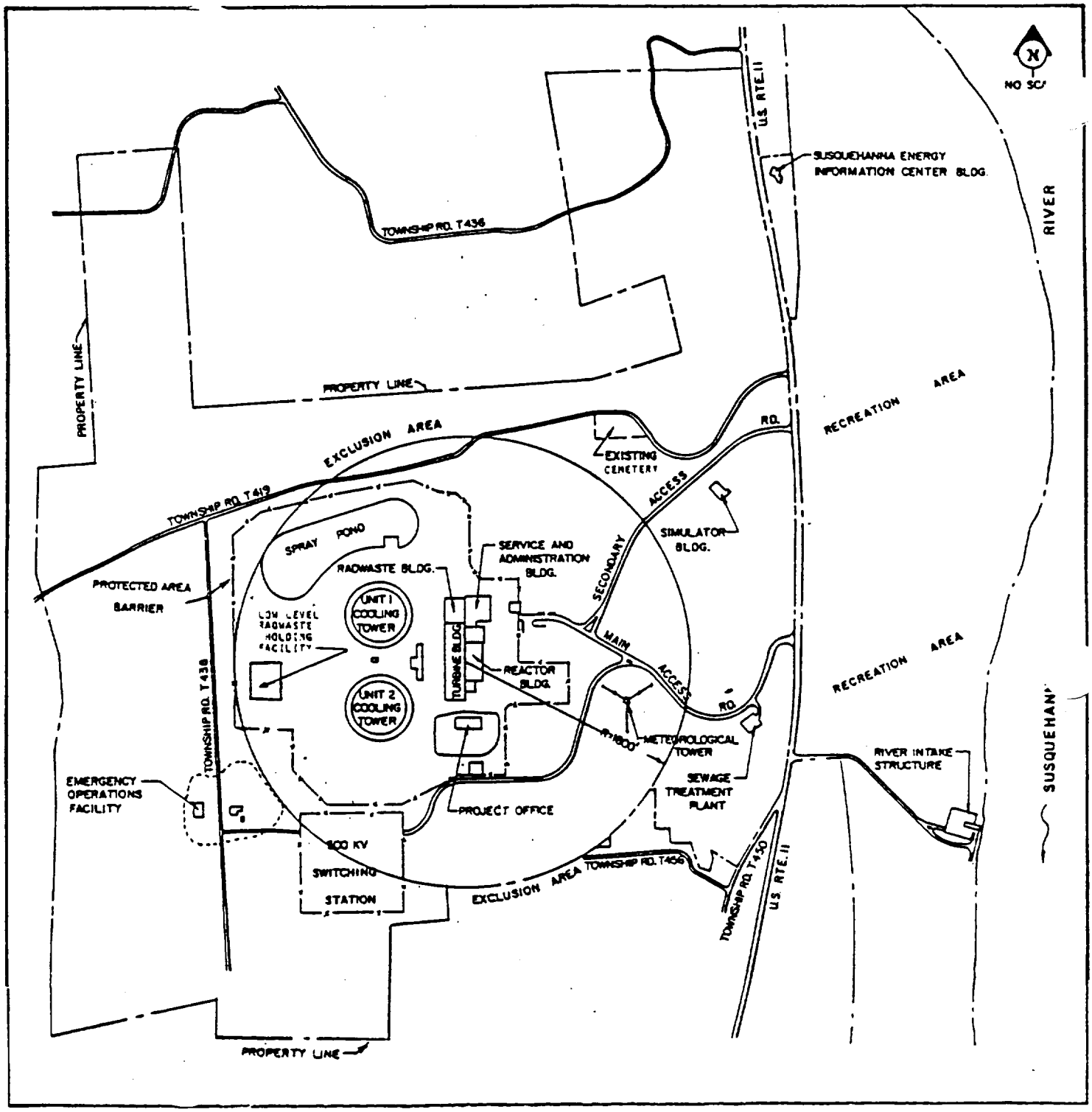

FIGURE 5.1.1-1

EXCLUSION AREA

3/4.7.1 SERVICE WATER SYSTEMS

The OPERABILITY of the service water systems ensures that sufficient cooling capacity is available for continued operation of safety-related equipment during normal and accident conditions. The redundant cooling capacity of these systems, assuming a single failure, is consistent with the assumptions used in the accident conditions within acceptable limits.

3/4.7.2 CONTROL ROOM EMERGENCY OUTSIDE AIR SUPPLY SYSTEM

The OPERABILITY of the control room emergency outside air supply system ensures that the control room will remain habitable for operations personnel during and following all design basis accident conditions. The OPERABILITY of this system in conjunction with control room design provisions is based on limiting the radiation exposure to personnel occupying the control room to 5 rem or less whole body, or its equivalent. This limitation is consistent with the requirements of General Design Criteria 19 of Appendix "A", 10 CFR Part 50. Cumulative operation of the system with the heaters OPERABLE for 10 hours over a 31 day period is sufficient to reduce the buildup of moisture on the adsorbers and HEPA filters.

3/4.7.3 REACTOR CORE ISOLATION COOLING SYSTEM

The reactor core isolation cooling (RCIC) system is provided to assure adequate core cooling in the event of reactor isolation from its primary heat sink and the loss of feedwater flow to the reactor vessel without requiring actuation of any of the Emergency Core Cooling System equipment. The RCIC system is conservatively required to be OPERABLE whenever reactor pressure exceeds 150 psig. This pressure is substantially below that for which the RCIC system can provide adequate core cooling for events requiring the RCIC system.

The RCIC system specifications are applicable during OPERATIONAL CONDITIONS 1, 2 and 3 when reactor vessel pressure exceeds 150 psig because RCIC is the primary non-ECCS source of emergency core cooling when the reactor is pressurized.

With the RCIC system inoperable, adequate core cooling is assured by the OPERABILITY of the HPCI system and justifies the specified 14 day out-of-service period.

The surveillance requirements provide adequate assurance that RCIC will be OPERABLE when required. Although all active components are testable and full flow can be demonstrated by recirculation during reactor operation, a complete functional test requires reactor shutdown. The pump discharge piping is maintained full to prevent water hammer damage and to start cooling at the earliest possible moment.

3/4.7.4 SNUBBERS

All snubbers are required OPERABLE to ensure that the structural integrity of the reactor coolant system and all other safety-related systems is maintained during and following a seismic or other event initiating dynamic loads. Snubbers excluded from this inspection program are those installed on nonsafety-related systems and then only if their failure or failure of the system on which they are installed would have no adverse effect on any safety-related system.

The visual inspection frequency is based upon maintaining a constant level of snubber protection to systems. Therefore, the required inspection internal varies inversely with the observed snubber failure and is determined by the number of inoperable snubbers found during an inspection. Inspections performed before that interval has elapsed may be used as a new reference point to determine the next inspection. However, the results of such early inspections performed before the original required time interval has elapsed, nominal time less 25%, may not be used to lengthen the required inspection interval. Any inspection whose results require a shorter inspection interval will override the previous schedule.

When the cause of the rejection of a snubber is clearly established and remedied for that snubber and for any other snubbers that may be generically susceptible, and verified by inservice functional testing, that snubber may be exempted from being counted as inoperable. Generically susceptible snubbers are those snubbers which are of a specific make or model and have the same design features directly related to rejection of the snubber by visual inspection or are similarly located or exposed to the same environmental conditions, such as temperature, radiation, and vibration.

When a snubber is found inoperable, an engineering evaluation is performed, in addition to the determination of the snubber mode of failure, in order to determine if any safety-related component or system has been adversely affected by the inoperability of the snubber. The engineering evaluation shall determine whether or not the snubber mode of failure has imparted a significant effect or degradation on the supported component or system.

To provide further assurance of snubber reliability, a representative sample of the installed snubbers will be functionally tested during plant shutdowns at 18 month intervals. Selection of a representative sample according to the expression 35 $(1 + \frac{c}{2})$ provides a confidence level of approximately 95% that 90% to 100% of the snubbers in the plant will be OPERABLE within acceptance limits. Observed failures of these sample snubbers will require functional testing of additional units.

Hydraulic snubbers and mechanical snubbers may each be treated as a different entity for the above surveillance programs.

3/4 7.4 SNUBBERS (continued)

The service life of a snubber is evaluated via manufacturer input and information through consideration of the snubber service conditions and associated installation and maintenance records (newly installed snubber, seal replaced, spring replaced, in high radiation area, in high temperature area, etc...). The requirement to monitor the snubber service life is included to ensure that the snubbers periodically undergo a performance evaluation in view of their age and operating conditions. These records will provide statistical bases for future consideration of snubber service life. The requirements for the maintenance of records and the snubber service life review are not intended to affect plant operation.

3/4 7.5 SEALED SOURCE CONTAMINATION

The limitations on removable contamination for sources required leak testing, including alpha emitters, is based on 10 CFR 70.39(c) limits for plutonium. this limitation will ensure that leakage from byproduct, source, and special nuclear material sources will not exceed allowable intake values. Sealed sources are classified into three groups according to their use, with surveillance requirements commensurate with the probability of damage to a source in that group. Those sources which are frequently handled are required to be tested more often than those which are not. Sealed sources which are continuously enclosed within a shielded mechanism, i.e., sealed sources within radiation monitoring or boron measuring devices, are considered to be stored and need not be tested unless they are removed from the shielded mechanism.

3/4 7.6 FIRE SUPPRESSION SYSTEMS

The OPERABILITY of the fire suppression systems ensures that adequate fire suppression capability is available to confine and extinguish fires occurring in any portion of the facility where safety related equipment is located. The fire suppression system consists of the water system, spray and/or sprinklers, CO_2 systems, Halon systems and fire hose stations. The collective capability of the fire suppression systems is adequate to minimize potential damage to safety related equipment and is a major element in the facility fire protection program.

In the event that portions of the fire suppression systems are inoperable, alternate backup fire fighting equipment is required to be made available in the affected areas until the inoperable equipment is restored to service. When the inoperable fire fighting equipment is intended for use as a backup means of fire suppression, a longer period of time is allowed to provide an alternate means of fire fighting than if the inoperable equipment is the primary means of fire suppression.

3/4 7.6 FIRE SUPPRESSION SYSTEMS (continued)

The surveillance requirements provide assurances that the minimum OPERABILITY requirements of the fire suppression systems are met. An allowance is made for ensuring a sufficient volume of Halon in the Halon storage tanks by verifying the weight and pressure of the tanks.

In the event the fire suppression water system becomes inoperable, immediate corrective measures must be taken since this system provides the major fire suppression capability of the plant. The requirement for a twenty-four hour report to the Commission provides for prompt evaluation of the acceptability of the corrective measures to provide adequate fire suppression capability for the continued protection of the nuclear plant.

3/4 7.7 FIRE RATED ASSEMBLIES

The OPERABILITY of the fire barriers and barrier penetrations ensure that fire damage will be limited. These design features minimize the possibility of a single fire involving more than one fire area prior to detection and extinguishment. The fire barriers, fire barrier penetrations for conduits, cable trays and piping, fire windows, fire dampers, and fire doors are periodically inspected to verify their OPERABILITY.

3/4 7.8 MAIN TURBINE BYPASS SYSTEM

The required OPERABILITY of the main turbine bypass system is consistent with the assumptions of the feedwater controller failure analysis in Chapter 15 of the FSAR.

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

APR 12 1985

SAFETY EVALUATION

AMENDMENT NO. 36 TO NPF-14

SUSQUEHANNA STEAM ELECTRIC STATION, UNIT 1

DOCKET NO. 50-387

Introduction

The licensee in their letters dated May 18, 1984 September 7, 1984, September 20, 1984, March 11, 1985, March 13, 1984, and April 4, 1985 proposed changes to the Technical Specifications (TS) of the operating license for Susquehanna Steam Electric Station, Unit 1. These changes will update the Unit 1 TS to reflect the Unit 2 TS as appropriate; additionally this amendment changes the required isolation times on the containment purge valves and removes the 50% blocking requirement.

Evaluation

Page/Item

1-2/Definition 1.7 and 3/4 3-4/Footnote*: The licensee's proposed change to the definition of CORE ALTERATION has been used in older plant TS. It allows for the deletion of several footnotes and tends to simplify the TS without changing the substance. This change is acceptable.

2-4/Function Unit: This change corrects a typographical error in the Drywell Pressure - High setpoint and is therefore acceptable.

3/4 1-1/4.1.1.c, 3/4 1-3/3.1.3.1.a.1.c: The amount of time allowed to determine the shutdown margin has been increased from 1 hour to 12 hours for the case of a stuck rod. It is not practical to determine the shutdown margin in 1 hour since core calculations must be performed by General Electric. In the event that a scram occurs in the presence of the stuck rod and another rod fails to insert, hot shutdown is assured. Cold shutdown could be achieved for the next 18 or more hours due to the presence of xenon in the core. 12 hours is adequate time to insert the failed rod or to operate the standby liquid control system. This change is, therefore, acceptable.

3/4 1-4/3.1.3.1.b.3, 3/4 1-4/Insert A, 3/4 1-5/4.1.3.1.4.b: A statement, 3.1.3.1.b.3, has been added to assert that the provisions of Specifications 3.0.4 are not applicable. Specification 3.0.4 would prohibit entry into Operational Condition 1 or 2 unless Specification 3.1.3.1 were satisfied without reliance on the action statements. However, analysis of the limiting reactivity insertion event, the rod drop accident, has been performed under the assumption of up to eight inoperable rods. Further, other specifications regarding shutdown margin and rod pattern controls must be met. We thus conclude that this change is acceptable.

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Additional requirements, Specification 3.1.3.1.d and e have been inserted to provide requirements to be met by the scram discharge valves. This change is being made to correct an oversight in the Specification and is acceptable.

3/4 1-6/New action b, and Footnote*, 3/4 1-8/New action b, 3/4 1-9, 1-11, 1-13/New action c: In each of these TS the statement that "The requirements of Specification 3.0.4 are not applicable" has been added. For the same reason stated above for page 1-2 this change is acceptable.

3/4 1-10/4.1.3.5.b.1.b: The value of the control rod scram accumulator alarm setpoint on the accumulator pressure detector has been altered to permit any value greater than 940 psig. This change is more conservative since the higher values give an earlier warning of trouble and is, therefore, acceptable.

3/4 3-7/all changes: The changes to this page were reviewed and found to be acceptable. The changes reviewed were editorial in nature as they provide consistency within the TS to clarify original information that was awkward and subject to misinterpretation. Additionally, these changes corrected some typographical errors.

3/4 3-8/Footnote g: The specification currently reads "Verify measured core flow to be greater than or equal to established core flow at the existing pump speed." The licensee has proposed to change "pump speed" to "loop flow."

This footnote applies to a surveillance requirement for the flow-biased Simulated Thermal Power Trip (STPT). The logic for this system compares indicated core flow and neutron flux with prescribed setpoint values and generates a scram signal when required. The indicated core flow input to the STPT is based on measurements of recirculation loop flow which are adjusted by appropriate factors to indicate core flow. The adjustment factors are based upon core flow/loop relationships determined during the startup test program and verified by this surveillance.

The current surveillance requires that core flow be compared with recirculation pump speed. Since pump speed is related to loop flow, and loop flow to core flow, the APRM core flow/loop flow adjustment factors can be verified in this way. The licensee has proposed, however, the more direct verification of the APRM adjustment factors by comparison of loop flow with core flow. We conclude that the use of a more direct measurement is a safety enhancement and is, therefore, acceptable.

3/4 3-11 thru 3/4 3-26/all changes: The changes on these pages have been reviewed along with the pertinent descriptions and justifications provided in the licensee's submittal and the applicable information in the FSAR. These TS changes can be placed in one of the following categories: to correct or clarify original information; to reflect the as built design of the plant or to provide supporting setpoint, response time and surveillance requirement information. The NRC staff finds these changes acceptable.

3/4 3-28, 3/4 3-31, 3/4 3-34/Function 2C1 and 2C2: This change adds a safety-related function to the table enhancing safe operation. Additionally, the recirculation discharge valve closure which is essential to supporting LPCI injection as assumed in the FSAR analysis has been added. This change is an improvement in the TS and, therefore, acceptable.

3/4 3-32/Function 5cb: This change corrects an error in the TS, and is consistent with the Unit 2 TS. The staff finds this change acceptable as it is a more restrictive requirement.

3/4 3-54/Function 3d, Footnote** and 3/4 3-74/Footnote***: These changes are in response to recommendations provided by the staff and represent more conservative values. The NRC staff therefore finds these changes acceptable.

3/4 3-55/Table 4.3.6-1: The NRC staff finds the changes to the CHANNEL CHECK and CHANNEL FUNCTIONAL TEST to be acceptable but finds the proposed changes to the CHANNEL CALIBRATION surveillance intervals to be unacceptable for those that are less conservative than the present requirement. Therefore, the staff denies the requested changes to the channel calibration serveillance intervals which are less conservative and finds all others acceptable.

3/4 3-59/ACTION 71: This additional control allows a portable monitor to replace an inoperable criticality monitor rather than performing daily surveys during fuel movements. This more continuous protection not only enhances safe operation but is consistent with the basis which calls for continuous monitoring and alarming at a defined setpoint. This changes is acceptable to the NRC staff.

3/4 3-63/Function 4a: The CHANNEL CALIBRATION requirement was deleted as it is an inappropriate requirement for this instrumentation. The licensee has stated that a CHANNEL FUNCTIONAL TEST is performed to verify the instrument performance against a known test tape. After having reviewed additional information on these particular Response-Spectrum Analyzer Recorders the staff agrees that the calibration of this instrument is inappropriate and finds this change acceptable.

3/4 3-70 thru 3/4 3-73/all changes: These changes were made in response to NRC Generic Letter No. 83-36, "NUREG-0737 Technical Specifications." The staff has reviewed these changes along with the information provided in the licensee's submittal and they were found to be acceptable.

3/4 3-75/3.3.7.7a and b: The change in this TS is made to reflect the as-built system and is conservative with respect to the current TS and is, therefore, acceptable.

3/4 3-78 and 3/4 3-79/Table 3.3.7.9-1: The changes to this table were proposed in an effort to provide consistency between the Unit 1 and Unit 2 TS. These changes more accurately reflect the as-built plant and are consistent with the Fire Protection Review Report. This change also provides information additional to that in the present TS and is, therefore, acceptable.

3/4 3-82/Footnote*: This change adds information necessary to complete the listing of required interlocks and reflects the as built plant. Since this additional information is appropriate the NRC staff finds this change acceptable.

3/4 3-87 and 3/4 3-89/all changes: These changes were reviewed along with the justification given in the licensee's submittal and found to be acceptable as they are consistent with the more recently issued Unit 2 TS.

3/4 3-94/3.3.8: Since only one turbine overspeed protection mechanism is required, the staff has replaced the wording "at least one" with "one", this change is an administrative clarification and acceptable to the staff.

3/4 4-5/4.4.2: This change is a clarification providing design setpoint information that ensures proper operation of the safety/relief valve acoustic monitors per manufacturer's recommendations and is acceptable to the NRC staff.

3/4 4-6/all changes and 3/4 4-8/4.4.3.2.1.b: The design of this system is being improved to allow flow rate monitoring of the drywell floor drain sump and these TS changes support the system modification. The NRC staff finds this change acceptable.

3/4 4-7/Action c: This change reflects the as-built design capability and is acceptable to the staff.

3/4 4-8/4.4.3.2.1.c: This additional requirement ensures the verification of compliance with the associated LCO 3.4.3.2.c; presently the surveillance requirements only require verification of the unidentified portion of total leakage. This is an additional requirement to the TS which the NRC staff finds acceptable.

3/4 5-3 Action g; and 3/4 7-7 Actions a, b: The licensee has proposed the addition of a new action statement for the condition when the ECCS or RCIC keep fill instrumentation is INOPERABLE. The current specification would require expedited plant shutdown in this circumstance. The proposed action requires local monitoring of the pressure in the keep fill lines rather than plant shutdown.

The keep fill instrumentation provides no signals for safety system actuation or safety system interlocks. Its purpose is to alarm the operator in the event that low pressure exists in the keep fill lines. Low pressure can be an indication of voids in the discharge lines, which in turn can result in water hammer on system initiation. Since the keep fill instrumentation provides only an alarm function, the same function can be accomplished by local, periodic monitoring. The licensee's proposal is, therefore, acceptable.

3/4 6-13/ACTIONS c and d: This change allows more flexibility as the revised statement requires that a minimum of six suppression pool locations must be monitored with one temperature detector at each location. Upon review the NRC staff has determined that this change is acceptable as it poses no additional safety implications.

3/4 6-15/3.6.2.2.a and 3.4 6-16/3.6.2.3.a: These changes reflect the as-built design that only one RHR pump is required to support a loop of suppression pool spray. These changes are consistent with the approved FSAR analysis and are acceptable to the NRC staff.

3/4 6-17/new ACTION a.4: The licensee's proposed action statement would allow changes in OPERATIONAL CONDITIONS with inoperable containment isolation valves, if the valves continue to perform their intended safety function (i.e., isolating primary containment). The staff finds this acceptable based on the assumption that containment isolation is accomplished within 4 hours from the time of discovery of an inoperable primary containment isolation valve. The staff is concerned that the new action statement might be misinterpreted to allow 8 hours prior to isolating the affected penetration because of the redundant reference to "within 4 hours" in ACTION a. as well as Action a.4. With this clarification the staff finds this TS change acceptable.

3/4 6-19 and 3/4 6-28/Table 3.6.3-1: The changes requested in the May 18, 1984 submittal are a result of PP&L efforts to correct this table based on operational experience. These changes are administrative in nature and are acceptable to the NRC staff as they correct the TS. Additionally, in the licensee's submittal of September 7, 1984, a change to Page 3/4 6-20 was requested. This change involves the maximum closure time for the containment isolation valves in the purge and vent system to require all of them to close within 15 seconds. In reviewing the vent/purge system for operating plants (TMI Task Action Plan Item II.E.4.2, Multi-plant Action Item B-24) the staff developed the requirement of fifteen seconds. Since the licensee's request is within the allowable time for qualified containment purge valves, this change is acceptable.

3.4 6-32/4.6.5.2b: The TS as written would force a two-unit shutdown in order to perform surveillances on the common isolation dampers. The licensee has requested that the words "during shutdown or refueling" be deleted. The NRC staff finds this change acceptable as the requirement can be complied with by entering an LCO to perform the surveillance. This does not impose a safety problem as the action statement requirements were designed to allow systems to be out of service for allowable time intervals. In addition, performance of this surveillance at power poses no real safety problems.

3/4 6-33/Insert A: This change reflects two unit operation and the revised three zone basis for the Reactor Building HVAC. As a result each damper is applicable to both units and has been added to Table 3.6.5.2-1. Based on the licensee's justification the NRC staff finds this change acceptable.

3/4 7-1/APPLICABILITY: Footnote** has been added to clarify requirements. The new footnote allows the licensee to comply with the intended meaning as interpreted by the staff without relying upon similar interpretation by the licensee's staff. This change for clarification is appropriate as well as acceptable.

3/4 7-2/ACTION a3: This action statement has been revised to insert the word "otherwise." Without the insertion of this word, the loss of one ESW pump would put the operator into action a3, since a loop is defined as consisting of two pumps and a flow path. This was not the intent. The revised a3 allows action statement a1 to be followed. This change is acceptable to the NRC staff.

3/4 7-2/4.7.1.2.b: This statement has been revised in order to avoid a forced two unit shutdown since the ESW system is common to both units. The NRC staff finds this change acceptable.

3/4 7-2/4.7.1.2.c: The licensee has requested the addition of a new surveillance requirement to ensure the reliability of the subject safety-related valves and associated logic. This change enhances safe operation and is, therefore, acceptable to the NRC staff.

3/4 7-9 through 7-30/Snubbers: The licensee has requested changes to TS Section 3/4.7.4, "snubbers." First the licensee has requested the elimination of Table 3.7.4-1, "Safety Related Mechanical Snubbers" which is a tabular listing of all safety-related mechanical snubbers in SSES Unit 1. The staff finds this change acceptable as the elimination of this tabular listing agrees with the present staff policy. In addition to the above change, the licensee proposed a revision to the Unit 1 TS which would place the inspection schedules of snubbers on a system basis rather than a plant or unit basis. This change is unacceptable as it conflicts with present staff policy and it therefore is denied. The intent of the visual inspection is to survey all snubbers in a plant and to locate those which may suffer from an identified failure mode which is not system specific. If the failure mode can be narrowed to a specific design, model or type of snubber, then only those snubbers must be inspected. This selection must be made from the entire unit or plant population of snubbers, not just from the system in which the valid failure mode was identified. The staff recognizes that this denial causes Units 1 and 2 to be different. The staff believes that since not only SSES Unit 2 has this system oriented TS for snubbers, but several other licenses issued in the Unit 2 time frame have an identical TS, the staff believes that this problem should be handled on a generic basis when the new policy and industry standard is complete. At this time, the staff has concluded that in the interim period the Unit 2 TS pose no safety implications which would necessitate early action.

3/4 7-36/3.7.6.2 and 3/4 7-38/3.7.6.3: These changes reflect the as-built plant and two unit operation. The NRC staff finds this change acceptable.

3/4 7-43/3.7.7: The licensee requested the addition of a requirement to ensure that in sampling 10 percent of the population that the same 10 percent sample is not inspected every 18 months. The NRC staff recommends this requirement and finds it prudent.

3/4 8-4/d: The words "during shutdown" have been removed in order to avoid unnecessarily shutting down Unit 1 and the possibility of unnecessarily shutting down both Units 1 and 2. For the tests for which it is necessary to be shutdown in order to perform the surveillances the licensee is governed by the requirements of the TS to have certain equipment operable in order to remain at power. The staff does not normally, nor in this case does the staff feel it necessary to, prescribe the operational condition necessary to perform a surveillance. When a test renders certain equipment, inoperable the licensee's operational condition is governed by the operability of the equipment already prescribed as necessary in the TS. Therefore, the NRC staff feels that these additional words "during shutdown" do not add to the safety of operation but restricts unnecessarily the licensee by forcing a shutdown for the listed surveillances. The staff finds this change acceptable.

3/4 8-4/d.6: This surveillance requirement has been deleted in response to NRC Generic Letter 83-30 and, therefore, acceptable.

3/4 8-6/12: This surveillance requirement has been deleted as a result of staff reevaluation of the intent of this requirement. After investigating the basis of this requirement, the staff believes that the same level of safety can be achieved without unnecessary wear on the diesels. The original intent of this 5 start requirement on the diesels was developed as a method of verifying the diesel generator air accumulator capacity was large enough to support diesel starting with sufficient air capacity remaining after a diesel start. The staff intended that this provided an additional conservatism.

At this time the staff finds that if the same level of safety can be achieved without over burdensome starting of the diesels, that this is a more prudent approach so as not to increase premature diesel wear. The licensee in response to the staff has provided adequate justification for the removal of this requirement along with the assurance that it is PP&L's good maintenance practice that the diesel generator air start compressors and receivers are inspected and maintained as part of our Preventative Maintenance Program. This Program schedules periodic preventative maintenance based on manufacturer's recommendations. Preventative Maintenance work activities are performed in accordance with plant procedures. In addition, should any significant degradation in the diesel generator air starting system be discovered, PP&L, per good practice, will initiate steps to investigate the problem and provide proper corrective action. Such action may include recording air receiver pressure before and after certain required starts and trending the information in order to more closely monitor the system. Based on this justification, the NRC staff finds this change acceptable.

3/4 8-6/e: This change from 13 seconds to 10 seconds corrects a typographical error. The staff agrees that this correction is appropriate and, therefore, acceptable.

3/4 8-8/Table 4.8.1.1.2-2: The Emergency Diesel Generators are shared standby emergency power sources for Units 1 and 2. The load sequencer (loading timer) is a part of the standby supplying systems and impacts both units. As a result, the Unit 2 loading timers have been added to the current table of Unit 1 timers in order to ensure that the activities for the shutdown will not impact the other operating unit. The change to have separate unit associated loading timers enhances safety during two unit operation. Other changes have corrected typographical errors and put the equipment timers in sequential order by time settings. The staff has evaluated the licensee's request and justification and finds them acceptable.

3/4 8-11/4.8.2.1.a.2: A requirement to check circuit breaker alignment to the battery chargers is proposed to verify OPERABILITY at least once per 7 days. This change to the surveillance requirements enhances safe operation of the plant and is, therefore, acceptable.

3/4 8-12/d and 3/4 8-13e: The subject dc supply systems are not shared between the two units; therefore, removal of the words "during shutdown" does not address a problem that would force a two unit shutdown, but instead addresses the problem of a single unit shutdown. As stated in the justification for 3/4 8-4/d, the staff does not find it necessary to prescribe the operational condition for which a surveillance must be performed as the operability of the equipment prescribed as necessary by the TS governs whether or not the unit can remain at power, which in turn governs the condition for which the surveillance must be performed.

3/4 8-17/3.8.3.1.a and 3/4 8-19/3.8.3.2.a: This change provides a reference to the swing bus automatic transfer switch in the LCO providing additional controls over safety-related equipment and is, therefore, acceptable to the NRC staff.

3/4 8-18/ACTION c and 3/4 8-18/4.8.3.1.2: These changes provide the appropriate action statement and surveillance requirement necessary to support the change on 3.4 8-17/3.8.3.1.a.

3/4 8-23/2b: This change provides an option to functionally testing a representative sample of each type of fuse by instead replacing 100% of all required fuses. The NRC staff previously reviewed this option and found it to be acceptable; this determination still holds true.

3/4 8-28/ACTION b: ACTION b proposes an addition to the Limiting Condition for Operation for MOV thermal overload protection to clarify the current TS. The current TS has given credit to administrative action to continuously bypass the thermal overload within 8 hours. The action statement forces administrative action to put the bypass in effect, and if this action cannot be done, the

appropriate system action statements must be followed. The licensee has proposed a change to add ACTION b which allows changes of OPERATIONAL CONDITIONS while the administrative action is in effect. This may include an exemption to Specification 3.0.4. The staff finds this change acceptable.

3/4 8-33/4.8.4.3.a: The information provided in the licensee's May 18, 1984 submittal was inadequate in addressing this change; as a result, several conference calls took place resulting in an additional submittal dated March 11, 1985 as supplemented by a March 13, 1985 submittal. Having reviewed this additional information the staff has determined that SURVEILLANCE REQUIREMENT 4.8.4.3 for the specific SSES plant design should be performed while the plant is shutdown. At SSES the risk of the plant suffering a full scram as a result of performing this surveillance at power does not justify performing this test while not in cold shutdown. In addition, forcing the unit to shutdown for the performance of this test every six months is also not justified. As a result, the NRC staff finds the licensee's proposed wording "By performance of a CHANNEL FUNCTIONAL TEST each time the plant is in COLD SHUTDOWN for a period of more than 24 hours, unless performed within the previous 6 months" to be acceptable. This wording was originally proposed by the NRC staff for the SSES Unit 2 TS when this plant specific problem was first discovered for Unit 2 during the Unit 2 licensing process.

3/4 9-3, 3/4 9-4 and 3/4 9-7/all changes: The footnote addressing movement of incore instruments is removed along with the reference to it in the specification. This change is acceptable as previously addressed in this evaluation.

The operability requirement on count rate for the Source Range Monitor (SRM) Channel has been reduced to 0.7 counts per second. This change has been previously approved for other plants and is acceptable. The minimum count rate for the SRM channels is established in order to provide assurance that these channels are monitoring the neutron flux level of the core. The accompanying requirement (in the footnote) that the signal-to-noise ratio be $\geq$ 2.0 provides that assurance for the lower count rate.

3/4 9-8/4.9.6.1.b: The licensee has proposed to insert the words "greater than or equal to" in front of the words "8 feet." The staff finds this to be a clarification which provides consistency within the TS, and is, therefore, acceptable.

3/4 10-1/3.10.1: The change requests that the hydrogen-oxygen analyzer discussed in Specification 3.3.7.5 not be required OPERABLE during the low power physics tests which are discussed in Specification 3.10.1.

The hydrogen-oxygen analyzer is part of the accident monitoring equipment system and is intended to sample the drywell atmosphere following an accident. The low power physics tests discussed in Specification 3.10.1 are performed at less than 1% rated thermal power and with a reactor coolant temperature

of less than 200°F. The likelihood of a severe accident is greatly reduced under these conditions. We conclude, therefore, that the hydrogen-oxygen analyzer makes no significant contribution to safety during these tests. The licensee's request is acceptable.

3/4 11 and 3/4 12/all changes: The staff has reviewed these changes and found them to be consistent with the Unit 2 TS as issued, as well as being presently acceptable to the NRC staff.

5-1/5.2.3: This change updates the TS to reflect two unit operation making the TS correct. This change is appropriate and acceptable to the staff.

Environmental Consideration

This amendment involves a change in the installation or use of a facility component located within the restricted area as defined in 10 CFR Part 20. The staff has determined that the amendment involves no significant increase in the amounts, and no significant change in the types, of any effluents that may be released offsite, and that there is no significant increase in individual or cumulative occupational radiation exposure. The Commission has previously issued a proposed finding that this amendment involve no significant hazards consideration and there has been no public comment on such findings. Accordingly, this amendment meets the eligibility criteria for categorical exclusion set forth in 10 CFR 51.22(c)(9). Pursuant to 10 CFR 51.22(b) no environmental impact statement or environmental assessment need be prepared in connection with the issuance of this amendment.

Conclusion

We have concluded, based on the considerations discussed above, that: (1) there is reasonable assurance that the health and safety of the public will not be endangered by operation in the proposed manner, and (2) such activities will be conducted in compliance with the Commission's regulations and the issuance of this amendment will not be inimical to the common defense and security or to the health and safety of the public.

Dated: APR 12 1985