NIAGARA MOHAWK

NIAGARA MOHAWK POWER CORPORATION/300 ERIE BOULEVARD WEST, SYRACUSE, N.Y. 13202/TELEPHONE (315) 474-1511

December 30, 1985
(NMP2L 0569)

Ms. Elinor G. Adensam, Director
BWR Project Directorate No. 3
U.S. Nuclear Regulatory Commission
7920 Norfolk Avenue
Washington, DC 20555

Dear Ms. Adensam:

Re: Nine Mile Point Unit 2
Docket No. 50-410

Enclosed is our marked-up copy of the "proof and review" version of the Technical Specifications, which we received from you on November 22, 1985 (Attachment A). This marked-up copy reflects our comments based on our review against the current plant design. Justification for proposed Technical Specification changes is provided in Attachment B, which also contains additional comments and clarifications, and several additional pages which should be incorporated into the Technical Specifications. Attachment C identifies the changes in Amendment 23 of the Final Safety analysis Report which affect the Technical Specifications.

We are also including at this time proposed Technical Specifications for "Single Loop Operation" (Attachment D), and "End of Cycle Recirculation Pump Trip Inoperable and Turbine Bypass Inoperable" (Attachment E). These Specifications represent enhancements to the operational flexibility of Unit 2 and have already been approved for several other Boiling Water Reactors. Attachments F and G contain the analyses necessary to support these requested changes.

We are continuing our program of Safety Analysis Report and Technical Specification verification and will incorporate any identified changes as we resolve comments developed during the Branch Technical Review process.

Very truly yours,

for C. V. Mangan
Senior Vice President

KWK:ja
Attachments
xc: R. A. Gramm, NRC Resident Inspector
Project File (2)

~~8601060036~~

ATTACHMENT D

SINGLE LOOP OPERATION
PROPOSED TECHNICAL SPECIFICATION CHANGES

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2.0 SAFETY LIMITS AND LIMITING SAFETY SYSTEM SETTINGS

2.1 SAFETY LIMITS

THERMAL POWER, Low Pressure or Low Flow

2.1.1 THERMAL POWER shall not exceed 25% of RATED THERMAL POWER with the reactor vessel steam dome pressure less than 785 psig or core flow less than 10% of rated flow.

APPLICABILITY: OPERATIONAL CONDITIONS 1 and 2.

ACTION:

With THERMAL POWER exceeding 25% of RATED THERMAL POWER and the reactor vessel steam dome pressure less than 785 psig or core flow less than 10% of rated flow, be in at least HOT SHUTDOWN within 2 hours and comply with the requirements of Specification 6.7.1.

two recirculation loop operation and shall not be less than 1.07 with single recirculation loop operation with

THERMAL POWER, High Pressure and High Flow

2.1.2 The MINIMUM CRITICAL POWER RATIO (MCPR) shall not be less than 1.06 with the reactor vessel steam dome pressure greater than 785 psig and core flow greater than 10% of rated flow.

APPLICABILITY: OPERATIONAL CONDITIONS 1 and 2.

ACTION:

with two recirculation loop operation or less than 1.07 with single loop operation

With MCPR less than 1.06 and the reactor vessel steam dome pressure greater than 785 psig and core flow greater than 10% of rated flow, be in at least HOT SHUTDOWN within 2 hours and comply with the requirements of Specification 6.7.1.

REACTOR COOLANT SYSTEM PRESSURE

2.1.3 The reactor coolant system pressure, as measured in the reactor vessel steam dome, shall not exceed 1325 psig.

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

ACTION:

With the reactor coolant system pressure, as measured in the reactor vessel steam dome, above 1325 psig, be in at least HOT SHUTDOWN with reactor coolant system pressure less than or equal to 1325 psig within 2 hours and comply with the requirements of Specification 6.7.1.

NINE MILE POINT - UNIT 2

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	0.66(W-ΔW)+51%# ≤ ~~0.66 W+51%~~, with a maximum of	0.66(W-ΔW)+54%# ≤ ~~0.66 W+54%~~, with a maximum of
2) High Flow Clamped	≤ 113.5% of RATED THERMAL POWER	≤ 115.5% of RATED THERMAL POWER
c. Fixed 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	≥ 159.3 inches above instrument zero*	≥ 157.8 inches above instrument zero
5. Main Steam Line Isolation Valve - Closure	≤ 6% closed	≤ 7% closed
6. Main Steam Line Radiation - High	≤ 3.0 x full power background	≤ 3.6 x full power background
7. Drywell Pressure - High	≤ 1.68 psig	≤ 1.88 psig
8. Scram Discharge Volume Water Level - High		
a. Level Transmitter/Trip Units	≤ 46.5 inches	≤ 79.5 inches
b. Float Switch	≤ 46.5 inches	≤ 79.5 inches
9. Turbine Stop Valve - Closure	≤ 5% closed	≤ 7% closed
10. Turbine Control Valve Fast Closure, Trip Oil Pressure - Low	≥ 530 psig	≥ 465 psig
11. Reactor Mode Switch Shutdown Position	NA	NA
12. Manual Scram	NA	NA

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

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Notes

(a) The Average Power Range Monitor Scram Function varies as a function of recirculation loop drive flow (W). ΔW is defined as the difference in indicated drive flow (in percent of drive flow which produces rated core flow) between two loop and single loop operation at the same core flow.

$\Delta W = 0$ for two loop operation

$\Delta W = 5\%$ for single loop operation

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BASES

2.0 INTRODUCTION

for two recirculation loop operation and 1.07 for single recirculation loop operation

The fuel cladding, reactor pressure vessel and primary system piping are the principal barriers to the release of radioactive materials to the environs. Safety Limits are established to protect the integrity of these barriers during normal plant operations and anticipated transients. The fuel cladding integrity Safety Limit is set such that no fuel damage is calculated to occur if the limit is not violated. Because fuel damage is not directly observable, a step-back approach is used to establish a Safety Limit such that the MCPR is not less than 1.06. MCPR greater than 1.06 represents a conservative margin relative to the conditions required to maintain fuel cladding integrity. The fuel cladding is one of the physical barriers which separate the radioactive materials from the environs. The integrity of this cladding barrier is related to its relative freedom from perforations or cracking. Although some corrosion or use-related cracking may occur during the life of the cladding, fission product migration from this source is incrementally cumulative and continuously measurable. Fuel cladding perforations, however, can result from thermal stresses which occur from reactor operation significantly above design conditions and the Limiting Safety System Settings. While fission product migration from cladding perforation is just as measurable as that from use-related cracking, the thermally caused cladding perforations signal a threshold beyond which still greater thermal stresses may cause gross rather than incremental cladding deterioration. Therefore, the fuel cladding Safety Limit is defined with a margin to the conditions which would produce onset of transition boiling, MCPR of 1.0. These conditions represent a significant departure from the condition intended by design for planned operation.

2.1.1 THERMAL POWER, Low Pressure or Low Flow

The use of the GEXL correlation is not valid for all critical power calculations at pressures below 785 psig or core flows less than 10% of rated flow. Therefore, the fuel cladding integrity Safety Limit is established by other means. This is done by establishing a limiting condition on core THERMAL POWER with the following basis. Since the pressure drop in the bypass region is essentially all elevation head, the core pressure drop at low power and flows will always be greater than 4.5 psi. Analyses show that with a bundle flow of 28×10^3 lbs/hr, bundle pressure drop is nearly independent of bundle power and has a value of 3.5 psi. Thus, the bundle flow with a 4.5 psi driving head will be greater than 28×10^3 lbs/hr. Full scale ATLAS test data taken at pressures from 14.7 psia to 800 psia indicate that the fuel assembly critical power at this flow is approximately 3.35 MWt. With the design peaking factors, this corresponds to a THERMAL POWER of more than 50% of RATED THERMAL POWER. Thus, a THERMAL POWER limit of 25% of RATED THERMAL POWER for reactor pressure below 785 psig is conservative.

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Bases Table B2.1.2-1

UNCERTAINTIES USED IN THE DETERMINATION OF THE FUEL CLADDING SAFETY LIMIT*

Quantity	Standard Deviation (% of Point)
Feedwater Flow	1.76
Feedwater Temperature	0.76
Reactor Pressure	0.5
Core Inlet Temperature	0.2
Core Total Flow	~~2.5~~
Two Recirculation Loop Operation	2.5
Single Recirculation Loop Operation	6.0
Channel Flow Area	3.0
Friction Factor Multiplier	10.0
Channel Friction Factor Multiplier	5.0
TIP Readings	~~6.3~~
Two Recirculation Loop Operation	6.3
Single Recirculation Loop Operation	6.8
R Factor	1.5
Critical Power	3.6

* The uncertainty analysis used to establish the core wide Safety Limit MCPR is based on the assumption of quadrant power symmetry for the reactor core. The values herein apply to both two recirculation loop operation and single recirculation loop operation, except as noted.

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3/4.2 POWER DISTRIBUTION LIMITS

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3/4.2.1 AVERAGE PLANAR LINEAR HEAT GENERATION RATE

LIMITING CONDITION FOR OPERATION

3.2.1 All AVERAGE PLANAR LINEAR HEAT GENERATION RATES (APLHGRs) for each type of fuel as a function of AVERAGE PLANAR EXPOSURE shall not exceed the limits shown in Figures 3.2.1-1, 3.2.1-2, and 3.2.1-3.

APPLICABILITY: OPERATIONAL CONDITION 1, when THERMAL POWER is greater than or equal to 25% of RATED THERMAL POWER.

ACTION:

With an APLHGR exceeding the limits of Figure 3.2.1-1, 3.2.1-2, or 3.2.1-3, initiate corrective action within 15 minutes and restore APLHGR to within the required limits within 2 hours or reduce THERMAL POWER to less than 25% of RATED THERMAL POWER within the next 4 hours.

The Limits of Figures 3.2.1-1, 3.2.1-2 and 3.2.1-3 shall be reduced to a value of 0.81 times the two recirculation loop operation limit when in single recirculation loop operation.

SURVEILLANCE REQUIREMENTS

4.2.1 All APLHGRs shall be verified to be equal to or less than the limits determined from Figures 3.2.1-1, 3.2.1-2, and 3.2.1-3:

a. At least once per 24 hours,

b. Within 12 hours after completion of a THERMAL POWER increase of at least 15% of RATED THERMAL POWER, and

c. Initially and at least once per 12 hours when the reactor is operating with a LIMITING CONTROL ROD PATTERN for APLHGR.

d. The provisions of Specification 4.0.4 are not applicable.

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POWER DISTRIBUTION LIMITS

3/4.2.2 APRM SETPOINTS

LIMITING CONDITION FOR OPERATION

3.2.2 The APRM flow biased simulated thermal power-upscale scram trip setpoint (S) and flow biased neutron flux-upscale control rod block trip setpoint (S_{RB}) shall be established according to the following relationships:

TRIP SETPOINT	ALLOWABLE VALUE
$S \le (0.66\cancel{W} + 51\%)T$	$S \le (0.66\cancel{W} + 54\%)T$
$S_{RB} \le (0.66\cancel{W} + 42\%)T$	$S_{RB} \le (0.66\cancel{W} + 45\%)T$

$(W-\Delta W)$** $(W-\Delta W)$**

where: S and S_{RB} are in percent of RATED THERMAL POWER,

W = Loop recirculation flow as a percentage of the loop recirculation flow which produces a rated core flow of 108.5 million lbs/hr.

T = The ratio FRACTION OF RATED THERMAL POWER divided by the CORE MAXIMUM FRACTION OF LIMITING POWER DENSITY. T is applied only if less than or equal to 1.0.

APPLICABILITY: OPERATIONAL CONDITION 1, when THERMAL POWER is greater than or equal to 25% of RATED THERMAL POWER.

ACTION:

With the APRM flow biased simulated thermal power-upscale scram trip setpoint and/or the flow biased neutron flux-upscale control rod block trip setpoint less conservative than the value shown in the Allowable Value column for S or S_{RB}, as above determined, initiate corrective action within 15 minutes and adjust S and/or S_{RB} to be consistent with the Trip Setpoint value* within 6 hours or reduce THERMAL POWER to less than 25% of RATED THERMAL POWER within the next 4 hours.

SURVEILLANCE REQUIREMENTS

4.2.2 The FRTP and the CMFLPD shall be determined, the value of T calculated, and the most recent actual APRM flow biased simulated thermal power-upscale scram and flow biased neutron flux-upscale control rod block trip setpoints verified to be within the above limits or adjusted, as required:

a. At least once per 24 hours,

b. Within 12 hours after completion of a THERMAL POWER increase of at least 15% of RATED THERMAL POWER, and

c. Initially and at least once per 12 hours when the reactor is operating with CMFLPD greater than or equal to FRTP.

d. The provisions of Specification 4.0.4 are not applicable.

*With CMFLPD greater than the FRTP ~~during power ascension up to 90% of RATED THERMAL POWER~~, rather than adjusting the APRM setpoints, the APRM gain may be adjusted such that APRM readings are greater than or equal to 100% times CMFLPD provided that the adjusted APRM reading does not exceed 100% of RATED THERMAL POWER and a notice of adjustment is posted on the reactor control panel.

** See note (a) to Table 2.2.1-1

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TABLE 3.3.6-2

CONTROL ROD BLOCK INSTRUMENTATION SETPOINTS

TRIP FUNCTION	TRIP SETPOINT	ALLOWABLE VALUE
1. ROD BLOCK MONITOR		
a. Upscale	≤ 0.66 W + 40%	≤ 0.66 W + 43%
b. Inoperative	NA	NA
c. Downscale	≥ 5% of RATED THERMAL POWER	≥ 3% of RATED THERMAL POWER
2. APRM		
a. Flow Biased Neutron Flux Upscale	≤ 0.66 ~~W~~ (W−ΔW) + 42%*	≤ 0.66 ~~W~~ (W−ΔW) + 45%*
b. Inoperative	NA	NA
c. Downscale	≥ 4% of RATED THERMAL POWER	≥ 3% of RATED THERMAL POWER
d. Neutron Flux - Upscale, Startup	≤ 12% of RATED THERMAL POWER	≤ 14% of RATED THERMAL POWER
3. SOURCE RANGE MONITORS		
a. Detector not full in	NA	NA
b. Upscale	< 1 x 10⁵ cps	< 1.6 x 10⁵ cps
c. Inoperative	NA	NA
d. Downscale	≥ 3 cps**	≥ 1.8 cps**
4. INTERMEDIATE RANGE MONITORS		
a. Detector not full in	NA	NA
b. Upscale	≤ 108/125 divisions of full scale	≤ 110/125 divisions of full scale
c. Inoperative	NA	NA
d. Downscale	≥ 5/125 divisions of full scale	≥ 3/125 divisions of full scale
5. SCRAM DISCHARGE VOLUME		
a. Water Level-High	< 16.5 in.	< 39.75 in.
~~b. Scram Trip Bypass~~	~~NA~~	~~NA~~
6. REACTOR COOLANT SYSTEM RECIRCULATION FLOW		
a. Upscale	< 108% rated flow	< 111% rated flow
b. Inoperative	NA	NA
c. Comparator	≤ 10% flow deviation	≤ 11% flow deviation

*The Average Power Range Monitor rod block function is varied as a function of recirculation loop flow (W). The trip setting of this function must be maintained in accordance with Specification 3.2.2.

**For initial loading and startup the count rate may be less than 3 cps if the following conditions are met; (1) the signal to noise ratio is greater than 2.0, and (2) the signal is greater than 0.7 cps~~; and (3) and counting interval sufficient to accumulate at least 500 counts is employed~~.

and note (a) of Table 3.3.1-1

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3/4.4 REACTOR COOLANT SYSTEM

3/4.4.1 RECIRCULATION SYSTEM

RECIRCULATION LOOPS

LIMITING CONDITION FOR OPERATION

3.4.1.1 Two reactor coolant system recirculation loops shall be in operation with:

a. Total core flow greater than or equal to 45% of rated core flow, or

b. THERMAL POWER within the unrestricted zone of Figure 3.4.1.1-1.

APPLICABILITY: OPERATIONAL CONDITIONS 1* and 2*.

ACTION:

a. With one reactor coolant system recirculation loop not in operation:

1. Within four hours:

a) Place the recirculation flow control system in the Local Manual (Position Control) mode, and

b) Reduce THERMAL POWER to ≤70% of RATED THERMAL POWER, and,

c) Increase the MINIMUM CRITICAL POWER RATIO (MCPR) Safety Limit by 0.01 to 1.07 per Specification 2.1.2, and,

d) Reduce the Maximum Average Planar Linear Heat Generation Rate (MAPLHGR) limit to a value of 0.81 times the two recirculation loop operation limit per Specification 3.2.1, and,

e) Reduce the Average Power Range Monitor (APRM) Scram and Rod Block and Rod Block Monitor Trip Setpoints and Allowable Values to those applicable for single recirculation loop operation per Specifications 2.2.1, 3.2.2 and 3.3.6.

f) Reduce the volumetric flow rate of the operating recirculation loop to ≤ 41,000** gpm.

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* See Special Test Exception 3.10.4.

** This value represents the design volumetric recirculation loop flow which produces 100% core flow at 100% THERMAL POWER. The actual value will be established during the Startup Test Program.

LIMITING CONDITION FOR OPERATION (Continued)

g) Perform Surveillance Requirement 4.4.1.1.2 if THERMAL POWER is $\leq$ 30%*** of RATED THERMAL POWER or the recirculation loop flow in the operating loop is $\leq$ 50%*** of rated loop flow.

h) Determine that the reactor THERMAL POWER level is not within the restricted zone of Figure 3.4.1.1-1; otherwise, reduce the THERMAL POWER level or increase core flow.

2. The provisions of Specification 3.0.4 are not applicable.

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

b. With no reactor coolant system recirculation loops in operation, immediately initiate action to reduce THERMAL POWER such that it is not within the restricted zone of Figure 3.4.1.1-1 within two hours, and initiate measures to place the unit in at least STARTUP within six hours and in HOT SHUTDOWN within the next six hours.

c. With two reactor coolant system recirculation loops in operation and total core flow less than 45% of rated core flow and THERMAL POWER greater than the limit specified in Figure 3.4.1.1-1:

1. Determine the APRM and LPRM** noise levels (Surveillance 4.4.1.1.4):

a) At least once per eight hours, and

b) Within 30 minutes after the completion of a THERMAL POWER increase of at least 5% of RATED THERMAL POWER.

2. With the APRM or LPRM** neutron flux noise levels greater than three times their established baseline noise levels, immediately initiate corrective action to restore the noise levels within the required limits within two hours by increasing core flow to greater than 45% of rated core flow or by reducing THERMAL POWER so that it is not within the restricted zone of Figure 3.4.1.1-1.

** Detector levels A and C of one LPRM string per core octant plus detectors A and C of one LPRM strong in the center of the core should be monitored.

*** Initial values. Final values to be determined during Startup Testing based upon the threshold THERMAL POWER and recirculation loop flow which will sweep the cold water from the vessel bottom heat preventing stratification.

SURVEILLANCE REQUIREMENTS

4.4.1.1.1 With one reactor coolant system recirculation loop not in operation, at least once per 12 hours verify that:

a. Reactor THERMAL POWER is ≤ 70% of RATED THERMAL POWER,

b. The recirculation flow control system is in the Local Manual (Position Control) mode, and

c. The volumetric flow rate of the operating loop is ≤ 41,000 gpm.*

4.4.1.1.2 With one reactor coolant system recirculation loop not in operation, within no more than 15 minutes prior to either THERMAL POWER increase or recirculation loop flow increase, verify that the following differential temperature requirements are met if THERMAL POWER is ≤ 30%** of RATED THERMAL POWER or the recirculation loop flow in the operating recirculation loop is ≤ 50%*** of rated loop flow:

a. ≤ 145°F between reactor vessel steam space coolant and bottom head drain line coolant,

b. ≤ 50°F between the reactor coolant within the loop not in operation and the coolant in the reactor pressure vessel, and

c. ≤ 50°F between the reactor coolant within the loop not in operation and the operating loop.

The differential temperature requirements of Specification 4.4.1.1.2b. and c. do not apply when the loop not in operation is isolated from the reactor pressure vessel.

4.4.1.1.3 Each reactor coolant system recirculation loop flow control valve shall be demonstrated OPERABLE at least once per 18 months by:

a. Verifying that the control valve fails "as is" on loss of hydraulic pressure at the hydraulic control unit, and

b. Verifying that the average rate of control valve movement is:

1. Less than or equal to 11% of stroke per second opening, and

2. Less than or equal to 11% of stroke per second closing.

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* This value represents the design volumetric recirculation loop flow which produces 100% core flow at 100% THERMAL POWER. The actual value will be established during the Startup Test Program.

** Initial values. Final values to be determined during Startup Testing based upon the threshold THERMAL POWER and recirculation loop flow which will sweep the cold water from the vessel bottom head preventing stratification.

SURVEILLANCE REQUIREMENTS (Continued)

4.4.1.1.4 Establish a baseline APRM and LPRM* neutron flux noise value within the regions for which monitoring is required (Specification 3.4.1.1, ACTION c) within two hours of entering the region for which monitoring is required unless baselining has previously been performed in the region since the last refueling outage.

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* Detector levels A and C of one LPRM string per core octant plus detectors A and C of one LPRM string in the center of the core should be monitored.

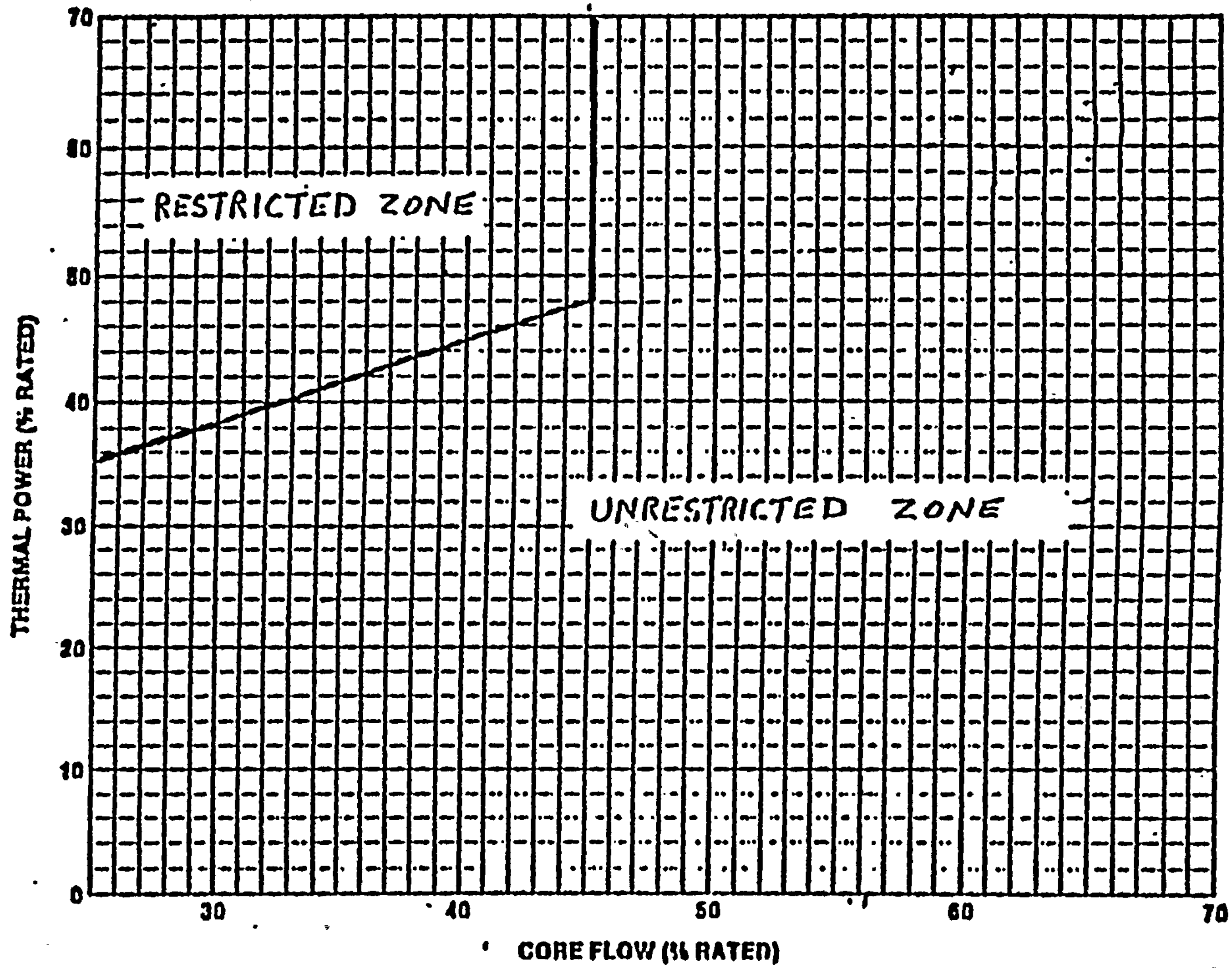

FIGURE 3.4.1.1-1
THERMAL POWER VERSUS CORE FLOW

JET PUMPS

LIMITING CONDITION FOR OPERATION

3.4.1.2 All jet pumps shall be OPERABLE.

APPLICABILITY: OPERATIONAL CONDITIONS 1 and 2.

ACTION:

With one or more jet pumps inoperable, be in at least HOT SHUTDOWN within 12 hours.

SURVEILLANCE REQUIREMENTS

4.4.1.2 All jet pumps shall be demonstrated OPERABLE as follows:

a. Each of the above required jet pumps shall be demonstrated OPERABLE prior to THERMAL POWER exceeding 25% of RATED THERMAL POWER, and at least once per 24 hours while greater than 25% of RATED THERMAL POWER, by determining recirculation loop flow, total core flow and diffuser-to-lower plenum differential pressure for each jet pump and verifying that no two of the following conditions occur when both recirculation loop indicated flows are in compliance with Specification 3.4.1.3.

   1. The indicated recirculation loop flow differs by more than 10% from the established* flow control valve position-loop flow characteristics.

   2. The indicated total core flow differs by more than 10% from the established* total core flow value derived from recirculation loop flow measurements.

   3. The indicated diffuser-to-lower plenum differential pressure of any individual jet pump differs from established* patterns by more than 10%.

b. During single recirculation loop operation, each of the above required jet pumps shall be demonstrated OPERABLE at least once per 24 hours by verifying that no two of the following conditions occur:

   1. The indicated recirculation loop flow in the operating loop differs by more than 10% from the established single recirculation flow control valve position-loop flow characteristics.

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*To be determined during the startup test program.

SURVEILLANCE REQUIREMENTS (Continued)

2. The indicated total core flow differs by more than 10% from the established total core flow value derived from single recirculation loop flow measurements.

3. The indicated difference-to-lower plenum differential pressure of any individual jet pump differs from established single recirculation loop patterns by more than 10%.

c. The provisions of Specification 4.0.4 are not applicable provided that this surveillance is performed within 24 hours after exceeding 25% of RATED THERMAL POWER.

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RECIRCULATION LOOP FLOW

LIMITING CONDITION FOR OPERATION

3.4.1.3 Recirculation loop flow mismatch shall be maintained within:

a. 5% of rated ~~recirculation~~ core flow with effective core flow* greater than or equal to 70% of rated core flow.

b. 10% of rated ~~recirculation~~ core flow with effective core flow less than 70% of rated core flow.

APPLICABILITY: OPERATIONAL CONDITIONS 1** and 2** during two recirculation loop operation.

ACTION:

With the recirculation loop flows different by more than the specified limits, either:

a. Restore the recirculation loop flows to within the specified limit within 2 hours, or

b. ~~Declare the recirculation loop with the lower flow not in operation and take the ACTION required by Specification 3.4.1.1.~~ Shutdown one of the recirculation loops and take the ACTION required by Specification 3.4.1.1

c. The provisions of Specification 3.0.4 are not applicable.

SURVEILLANCE REQUIREMENTS

4.4.1.3 Recirculation loop flow mismatch shall be verified to be within the limits at least once per 24 hours.

**See Special Test Exception 3.10.4.

* Effective core flow shall be the core flow that would result if both recirculation loop flows were assumed to be at the smaller value of the two loop flows.

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3/4.1.3 CONTROL RODS

The specification of this section ensure that (1) the minimum SHUTDOWN MARGIN is maintained, (2) the control rod insertion times are consistent with those used in the safety analyses, and (3) limit the potential effects of the rod drop accident. The ACTION statements permit variations from the basic requirements but at the same time impose more restrictive criteria for continued operation. A limitation on inoperable rods is set such that the resultant effect on total rod worth and scram shape will be kept to a minimum. The requirements for the various scram time measurements ensure that any indication of systematic problems with rod drives will be investigated on a timely basis.

Damage within the control rod drive mechanism could be a generic problem, therefore with a control rod immovable because of excessive friction or mechanical interference, operation of the reactor is limited to a time period which is reasonable to determine the cause of the inoperability and at the same time prevent operation with a large number of inoperable control rods.

Control rods that are inoperable for other reasons are permitted to be taken out of service provided that those in the nonfully-inserted position are consistent with the SHUTDOWN MARGIN requirements.

The number of control rods permitted to be inoperable could be more than the eight allowed by the specification, but the occurrence of eight inoperable rods could be indicative of a generic problem and the reactor must be shutdown for investigation and resolution of the problem. the fuel cladding safety li

The control rod system is designed to bring the reactor subcritical at a rate fast enough to prevent the MCPR from becoming less than ~~1.06~~ during the limiting power transient analyzed in Section 15.4 of the FSAR. This analysis shows that the negative reactivity rates resulting from the scram with the average response of all the drives as given in the specifications, provide the required protection and MCPR remains greater than ~~1.06~~. The occurrence of scram times longer then those specified should be viewed as an indication of a systemic problem with the rod drives and therefore the surveillance interval is reduced in order to prevent operation of the reactor for long periods of time with a potentially serious problem.

The scram discharge volume is required to be OPERABLE so that it will be available when needed to accept discharge water from the control rods during a reactor scram and will isolate the reactor coolant system from the containment when required.

Control rods with inoperable accumulators are declared inoperable and Specification 3.1.3.1 then applies. This prevents a pattern of inoperable accumulators that would result in less reactivity insertion on a scram than has been analyzed even though control rods with inoperable accumulators may still be inserted with normal drive water pressure. Operability of the accumulator ensures that there is a means available to insert the control rods even under the most unfavorable depressurization of the reactor.

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AVERAGE PLANAR LINEAR HEAT GENERATION RATE (Continued)

b. Model Change

1. Core CCFL pressure differential - 1 psi - Incorporate the assumption that flow from the bypass to lower plenum must overcome a 1 psi pressure drop in core.

2. Incoporate NRC pressure transfer assumption - The assumption used in the SAFE-REFLOOD pressure transfer when the pressure is increasing was changed.

A few of the changes affect the accident calculation irrespective of CCFL. These changes are listed below.

a. Input Change

1. Break Areas - The DBA break area was calculated more accurately.

b. Model Change

1. Improved Radiation and Conduction Calculation - Incorporation of CHASTE 05 for heatup calculation.

A list of the significant plant input parameters to the loss-of-coolant accident analysis is presented in Bases Table B 3.2.1-1.

3/4.2.2 APRM SETPOINTS

The fuel cladding integrity Safety Limits of Specification 2.1 were based on a power distribution which would yield the design LHGR at RATED THERMAL POWER. The flow biased simulated thermal power-upscale scram setting and flow biased neutron flux upscale control rod block functions of the APRM instruments must be adjusted to ensure that the MCPR does not become less than 1.06 or that $\geq$ 1% plastic strain does not occur in the degraded situation. The scram set point and rod block settings are adjusted in accordance with the formula in this specification when the combination of THERMAL POWER and CMFLPD indicates a higher peaked power distribution to ensure that an LHGR transient would not be increased in the degraded condition.

For plant operation with single recirculation loop, the MAPLHGR limits of Figures 3.2.1-1, 3.2.1-2 and 3.2.1-3 are multiplied by 0.81. The constant factor 0.81, is derived from LOCA analysis initiated from single loop operation to account for earlier boiling transition of the limiting fuel node compared to the standard LOCA evaluation

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Bases Table B 3.2.1-1

SIGNIFICANT INPUT PARAMETERS TO THE

LOSS-OF-COOLANT ACCIDENT ANALYSIS

Plant Parameters;

Core THERMAL POWER .... 3461 MWt* which corresponds to 105% of rated steam flow

Vessel Steam Output .... 15.0×10^6 lbm/hr which corresponds to 105% of rated steam flow

Vessel Steam Dome Pressure.............. 1055 psia

Design Basis Recirculation Line Break Area for:

a. Large Breaks 3.1 ft^2

b. Small Breaks 0.09 ft^2

Fuel Parameters:

FUEL TYPE	FUEL BUNDLE GEOMETRY	PEAK TECHNICAL SPECIFICATION LINEAR HEAT GENERATION RATE (kw/ft)	DESIGN AXIAL PEAKING FACTOR	INITIAL MINIMUM CRITICAL POWER RATIO
Initial Core	8 x 8	13.4	1.4	1.20 **

A more detailed listing of input of each model and its source is presented in Section II of Reference 1 and subsection 6.3.3 of the FSAR.

*This power level meets the Appendix K requirement of 102%. The core heatup calculation assumes a bundle power consistent with operation of the highest powered rod at 102% of its Technical Specification LINEAR HEAT GENERATION RATE limit.

** For single recirculation loop operation, loss of nucleate boiling is assumed at 0.1 second after LOCA regardless of initial MCPR.

3/4.2.3 MINIMUM CRITICAL POWER RATIO

The required operating limit MCPRs at steady state operating conditions as specified in Specification 3.2.3 are derived from the established fuel cladding integrity Safety Limit MCPR ~~of 1.06~~, and an analysis of abnormal operational transients. For any abnormal operating transient analysis evaluation with the initial condition of the reactor being at the steady state operating limit, it is required that the resulting MCPR does not decrease below the Safety Limit MCPR at any time during the transient assuming instrument trip setting given in Specification 2.2.

To assure that the fuel cladding integrity Safety Limit is not exceeded during any anticipated abnormal operational transient, the most limiting transients have been analyzed to determine which result in the largest reduction in CRITICAL POWER RATIO (CPR). The type of transients evaluated were loss of flow, increase in pressure and power, positive reactivity insertion, and coolant temperature decrease. ~~The limiting transient yields the largest delta MCPR. When added to the Safety Limit MCPR of 1.06, the required minimum operating limit MCPR of Specification 3.2.3 is obtained and presented in Figure 3.2.3-1.~~

The evaluation of a given transient begins with the system initial parameters shown in FSAR Table 15.0.3 that are input to a GE-core dynamic behavior transient computer program. The code used to evaluate pressurization events is described in NEDO-24154[3] and the program used in non-pressurization events is described in NEDO-10802[2]. The outputs of this program along with the initial MCPR form the input for further analyses of the thermally limiting bundle with the single channel transient thermal hydraulic TASC code described in NEDE-25149[4]. The principal result of this evaluation is the reduction in MCPR caused by the transient.

The purpose of the K_f factor of Figure 3.2.3-1 is to define operating limits at other than rated core flow conditions. At less than 100% of rated flow the required MCPR is the product of the MCPR and the K_f factor. The K_f factors assure that the Safety Limit MCPR will not be violated. The K_f factors were derived using THERMAL POWER and core flow corresponding to 105% of rated steam flow.

The K_f factors were calculated such that for the maximum core flow rate and the corresponding THERMAL POWER along the 105% of rated steam flow control line, the limiting bundle's relative power was adjusted until the MCPR was slightly above the Safety Limit. Using this relative bundle power, the MCPRs were calculated at different points along the 105% of rated steam flow control line corresponding to different core flows. The ratio of the MCPR calculated at a given point of core flow, divided by the operating limit MCPR, determines the K_f.

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BASES

3/4.4.1 RECIRCULATION SYSTEM

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~~Operation with one reactor core coolant recirculation loop inoperable is prohibited until an evaluation of the performance of the ECCS during one loop operation has been performed, evaluated and determined to be acceptable.~~

The objective of GE BWR plant and fuel design is to provide stable operation with margin over the normal operating domain. However, at the high power/low flow corner of the operating domain, a small probability of limit cycle neutron flux oscillations exists depending on combinations of operating conditions (e.g., rod pattern, power shape). To provide assurance that neutron flux limit cycle oscillations are detected and suppressed, APRM and LPRM neutron flux noise levels should be monitored while operating in this region.

Stability tests at operating BWRs were reviewed to determine a generic region of the power/flow map in which surveillance of neutron flux noise levels should be performed. A conservative decay ratio of 0.6 was chosen as the bases for determining the generic region for surveillance to account for the plant to plant variability of decay ratio with core and fuel designs. This generic region has been determined to correspond to a core flow of less than or equal to 45% of rated core flow and a THERMAL POWER greater than that specified in Figure 3.4.1.1-1.

Plant specific calculations can be performed to determine an applicable region for monitoring neutron flux noise levels. In this case the degree of conservatism can be reduce since plant to plant variability would be eliminated. In this case, adequate margin will be assured by monitoring the region which has a decay ratio greater than or equal to 0.8.

Neutron flux noise limits are also established to ensure early detection of limit cycle neutron flux oscillations. BWR cores typically operate with neutron flux noise caused by random boiling and flow noise. Typical neutron flux noise levels of 1-12% of rated power (peak-to-peak) have been reported for the range of low to high recirculation loop flow during both single and dual recirculation loop operation. Neutron flux noise levels which significantly bound these values are considered in the thermal/mechanical design of GE BWR fuel and are found to be of negligible consequence. In addition, stability tests at operating BWRs have demonstrated that when stability related neutron flux limit cycle oscillations occur they result in peak-to-peak neutron flux limit cycles of 5-10 times the typical values. Therefore, actions taken to reduce neutron flux noise levels exceeding three (3) times the typical value are sufficient to ensure early detection of limit cycle neutron flux oscillations.

Typically, neutron flux noise levels show a gradual increase in absolute magnitude as core flow is increased (constant control rod pattern) with two reactor recirculation loops in operation. Therefore, the baseline neutron

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3/4.4.1 RECIRCULATION SYSTEM (Continued)

flux noise level obtained at a specified core flow can be applied over a range of core flows. To maintain a reasonable variation between the low flow and high flow end of the flow range, the range over which a specific baseline is applied should not exceed 20% of rated core flow with two recirculation loops in operation. Data from tests and operating plants indicate that a range of 20% of rated core flow will result in approximately a 50% increase in neutron flux noise level during operation with two recirculation loops. Baseline data should be taken near the maximum rod line at which the majority of operation will occur. However, baseline data taken at lower rod lines (i.e., lower power will result in a conservative value since the neutron flux noise level is proportional to the power level at a given core flow.

An inoperable jet pump is not, in itself, a sufficient reason to declare a recirculation loop inoperable, but it does, in case of a design-basis-accident, increase the blowdown area and reduce the capability of reflooding the core; thus, the requirement for shutdown of the facility with a jet pump inoperable. Jet pump failure can be detected by monitoring jet pump performance on a prescribed schedule for significant degradation.

for two recirculation loop operation

Recirculation loop flow mismatch limits are in compliance with the ECCS LOCA analysis design criteria. The limits will ensure an adequate core flow coastdown from either recirculation loop following a LOCA.

Replace with Insert "F"

In order to prevent undue stress on the vessel nozzles and bottom head region, the recirculation loop temperatures shall be within 50°F of each other prior to startup of an idle loop. The loop temperature must also be within 50°F of the reactor pressure vessel coolant temperature to prevent thermal shock to the recirculation pump and recirculation nozzles. ~~Since the coolant in the bottom of the vessel is at a lower temperature than the coolant in the upper regions of the core, undue stress on the vessel would result if the temperature difference was greater than 145° F.~~

3/4.4.2 SAFETY/RELIEF VALVES

Replace with Insert "G"

The safety/relief valves operate during a postulated ATWS event to prevent the reactor coolant system being pressurized above a design allowable value of 1375 psig in accordance with the ASME Code. A total of 17 OPERABLE safety/relief valves is required to limit local pressure at active components to within ASME III allowable design values (Service Level A). All other appropriate ASME III limits are also bounded by this requirement.

Demonstration of the safety-relief valve lift settings will occur only during shutdown and will be performed in accordance with the provisions of Specification 4.0.5.

INSERT "E"

The impact of single recirculation loop operation upon plant safety is assessed and shows that single-loop operation is permitted if the MCPR fuel cladding safety limit is increased as noted by Specification 2.1.2, APRM scram and control rod block setpoints are adjusted as noted in Tables 2.2.1-1 and 3.3.6.2, respectively, MAPLHGR limits are decreased by the factor given in Specification 3.2.1, and MCPR operating limits are adjusted per Section 3/4.2.3.

Additionally, surveillance on the volumetric flow rate of the operating recirculation loop is imposed to exclude the possibility of excessive core internals vibration. The surveillance on differential temperatures below 30%* THERMAL POWER or 50%* rated recirculation loop flow is to mitigate the undue thermal stress on vessel nozzles, recirculation pump and vessel bottom head during the extended operation of the single recirculation loop mode.

INSERT "F"

In the case where the mismatch limits cannot be maintained during two loop operation, continued operation is permitted in a single recirculation loop mode.

INSERT "G"

Sudden equalization of a temperature difference 145°F between the reactor vessel bottom head coolant and the coolant in the upper region of the reactor vessel by increasing core flow rate would cause undue stress in the reactor vessel bottom head.

---

* Initial values. The final values are determined during startup testing based upon the threshold THERMAL POWER and recirculation loop flow which will sweep the cold water from the vessel bottom head, preventing saturation.

ATTACHMENT E

END OF CYCLE – RECIRCULATION PUMP TRIP
INOPERABLE AND TURBINE BYPASS INOPERABLE
PROPOSED TECHNICAL SPECIFICATION CHANGES

3/4.2.3 MINIMUM CRITICAL POWER RATIO

LIMITING CONDITION FOR OPERATION

3.2.3 The MINIMUM CRITICAL POWER RATIO (MCPR) shall be equal to or greater than the MCPR limit shown in Figure 3.2.3-1 times the K_f shown in Figure 3.2.3-2 with:

$$\tau = \frac{(\tau_{ave} - \tau_B)}{\tau_A - \tau_B}$$

where:

τ_A = 0.86 seconds, control rod average scram insertion time limit to notch 39 per Specification 3.1.3.3,

$$\tau_B = 0.688 + 1.65\left[\frac{N_1}{\sum_{i=1}^{n} N_i}\right]^{1/2}\left[0.052\right],$$

$$ave = \frac{\sum_{i=1}^{n} N_i \tau_i}{\sum_{i=1}^{n} N_i},$$

n = number of surveillance tests performed to date in cycle,

N_i = number of active control rods measured in the i^{th} surveillance test,

τ_i = average scram time to notch 39 of all rods measured in the i^{th} surveillance test, and

N_1 = total number of active rods measured in Specification 4.1.3.2.a.

APPLICABILITY:

OPERATION CONDITION 1, when THERMAL POWER is greater than or equal to 25% of RATED THERMAL POWER.

LIMITING CONDITION FOR OPERATION (Continued)

ACTION

a. With the end-of-cycle recirculation pump trip system inoperable per Specification 3.3.4.2, operation may continue and the provisions of Specification 3.0.4 are not applicable provided that, within one hour, MCPR is determined to be equal to or greater than the MCPR limit shown in Figure 3.2.3-1 EOC-RPT inoperable curve, times the K_f shown in Figure 3.2.3-2.

b. With the main turbine bypass system inoperable per Specification 3.7.8, operation may continue and the provisions of Specification 3.0.4 are not applicable provided that, within one hour, MCPR is determined to be equal to or greater than the MCPR limit shown in Figure 3.2.3-1, main turbine bypass inoperable curve times the K_f shown in Figure 3.2.3-2.

c. With MCPR less than the applicable MCPR limit determined from Figures 3.2.3-1 and 3.2.3-2, as applicable, initiate corrective action within 15 minutes to restore MCPR within the required limit. Restore MCPR to within the required limit within 4 hours, if necessary, by reducing THERMAL POWER to the level required.

SURVEILLANCE REQUIREMENTS

4.2.3 MCPR, with:

a. τ = 1.0 prior to performance of the initial scram time measurements for the cycle in accordance with Specification 4.1.3.2, or

b. τ as defined in Specification 3.2.3 used to determine the limit within 72 hours of the conclusion of each scram time surveillance test required by Specification 4.1.3.2,

c. The provisions of Specification 4.0.4 are not applicable

shall be determined to be equal to or greater than the applicable MCPR limit determined from Figures 3.2.3-1 and 3.2.3-2:

a. At least once per 24 hours,

b. Within 12 hours after completion of a THERMAL POWER increase of at least 15% of RATED THERMAL POWER, and

c. Initially and at least once per 12 hours when the reactor is operating with a LIMITING CONTROL ROD PATTERN for MCPR.

d. The provisions of Specification 4.0.4 are not applicable.

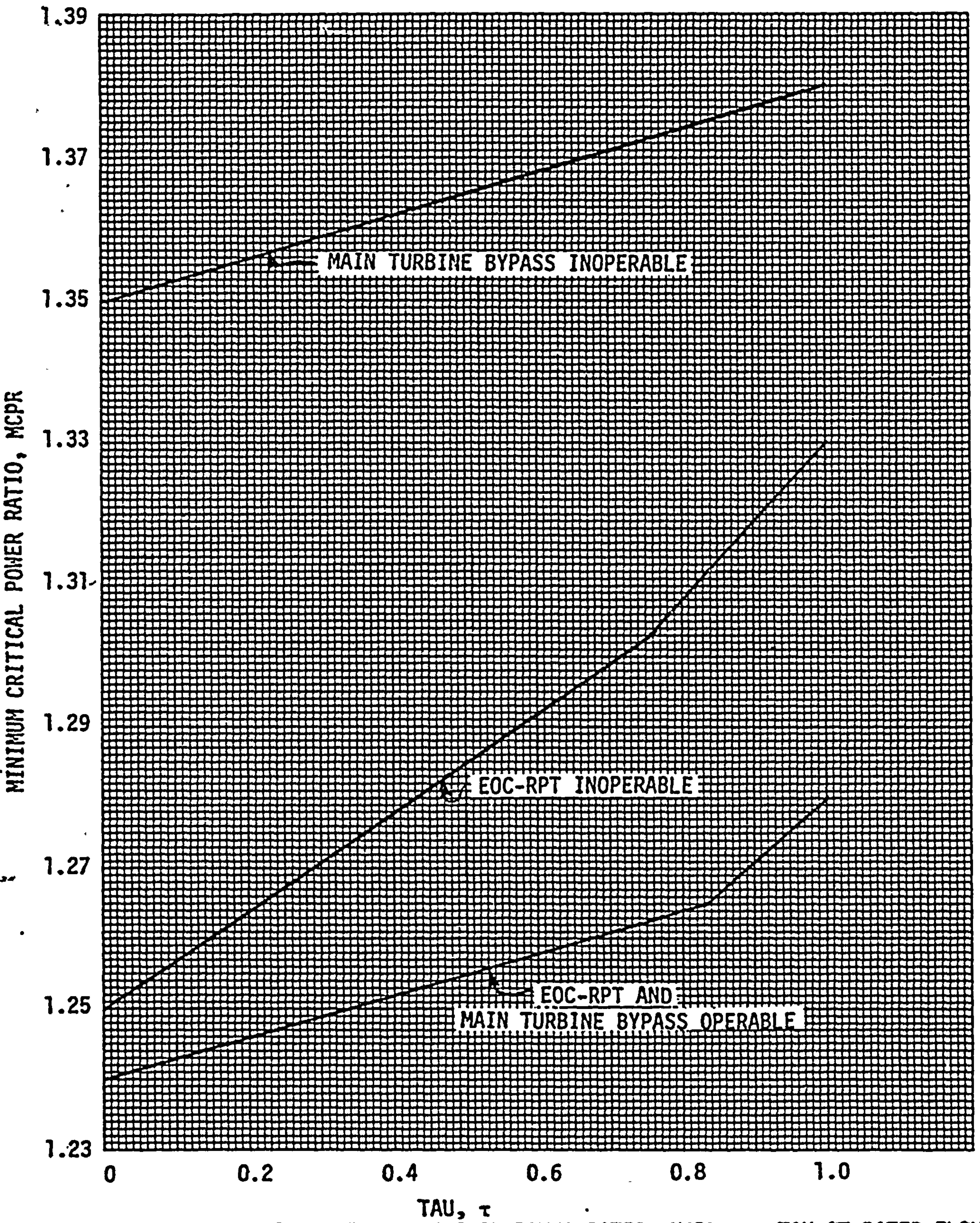

FIGURE 3.2.3-1 MINIMUM CRITICAL POWER RATIO, MCPR, vs TAU AT RATED FLOW

NINE MILE POINT-UNIT 2

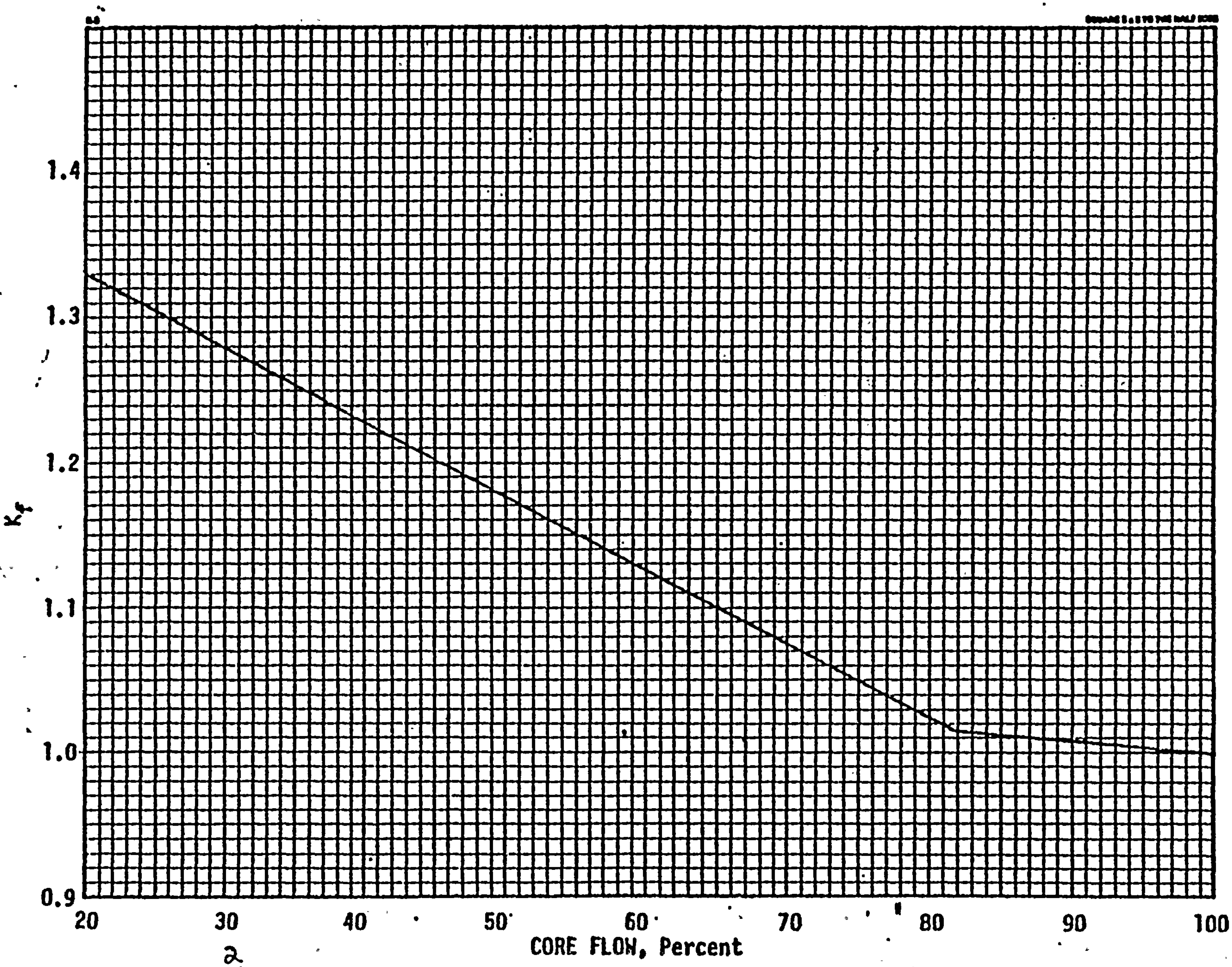

FIGURE 3.2.3 K_f AS A FUNCTION OF PERCENT CORE FLOW

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END-OF-CYCLE RECIRCULATION PUMP TRIP SYSTEM INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.4.2 The end-of-cycle recirculation pump trip (EOC-RPT) system instrumentation channels shown in Table 3.3.4.2-1 shall be OPERABLE with their trip setpoints set consistent with the values shown in the Trip Setpoint column of Table 3.3.4.2-2 and with the END-OF-CYCLE RECIRCULATION PUMP TRIP SYSTEM RESPONSE TIME as shown in Table 3.3.4.2-3.

APPLICABILITY: OPERATIONAL CONDITION 1, when THERMAL POWER is greater than or equal to 30% of RATED THERMAL POWER.

ACTION:

a. With an end-of-cycle recirculation pump trip system instrumentation channel trip setpoint less conservative than the value shown in the Allowable Values column of Table 3.3.4.2-2, declare the channel inoperable until the channel is restored to OPERABLE status with the channel setpoint adjusted consistent with the Trip Setpoint value.

b. With the number of OPERABLE channels one less than required by the Minimum OPERABLE Channels per Trip System requirement for one or both trip systems, place the inoperable channel(s) in the tripped condition within one hour.

c. With the number of OPERABLE channels two or more less than required by the Minimum OPERABLE Channels per Trip System requirement for one trip system and:

   1. If the inoperable channels consist of one turbine control valve channel and one turbine stop valve channel, place both inoperable channels in the tripped condition within one hour.

   2. If the inoperable channels include two turbine control valve channels or two turbine stop valve channels, declare the trip system inoperable.

d. With one trip system inoperable, restore the inoperable trip system to OPERABLE status within 72 hours or ~~reduce THERMAL POWER to less than 30% of RATED THERMAL POWER within the next 6 hours.~~ take the ACTION required by Specification 3.2.3.

e. With both trip systems inoperable, restore at least one trip system to OPERABLE status within one hour or ~~reduce THERMAL POWER to less than 30% of RATED THERMAL POWER within the next 6 hours.~~ take the ACTION required by Specification 3.2.3.

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PLANT SYSTEMS

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3/4.7.9 MAIN TURBINE BYPASS SYSTEM

LIMITING CONDITION FOR OPERATION

3.7.9 The main turbine bypass system shall be OPERABLE.

APPLICABILITY: OPERATIONAL CONDITION 1 when THERMAL POWER is greater than or equal to 25% of RATED THERMAL POWER.

ACTION: With the main turbine bypass system inoperable, restore the system to OPERABLE status within 1 hour or ~~reduce THERMAL POWER to less than 25% of RATED THERMAL POWER within the next 4 hours.~~ take the ACTION required by Specification 3.2.3.

SURVEILLANCE REQUIREMENTS

4.7.9 The main turbine bypass system shall be demonstrated OPERABLE:

a. At least once per 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 meets the following requirements when measured from initial movement of the main turbine stop or control valve:

   a. 80% of the turbine bypass system capacity shall be established within 0.3 seconds, and

   b. Bypass valve opening shall start in less than or equal to 0.1 seconds.

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3/4.2.3 MINIMUM CRITICAL POWER RATIO

The required operating limit MCPRs at steady state operating conditions as specified in Specification 3.2.3 are derived from the established fuel cladding integrity Safety Limit MCPR of 1.06, and an analysis of abnormal operational transients. For any abnormal operating transient analysis evaluation with the initial condition of the reactor being at the steady state operating limit, it is required that the resulting MCPR does not decrease below the Safety Limit MCPR at any time during the transient assuming instrument trip setting given in Specification 2.2.

To assure that the fuel cladding integrity Safety Limit is not exceeded during any anticipated abnormal operational transient, the most limiting transients have been analyzed to determine which result in the largest reduction in CRITICAL POWER RATIO (CPR). The type of transients evaluated were loss of flow, increase in pressure and power, positive reactivity insertion, and coolant temperature decrease. The limiting transient yields the largest delta MCPR. When added to the Safety Limit MCPR of 1.06, the required minimum operating limit MCPR of Specification 3.2.3 is obtained and presented in Figure 3.2.3-1.

The evaluation of a given transient begins with the system initial parameters shown in FSAR Table 15.0.3 that are input to a GE-core dynamic behavior transient computer program. The code used to evaluate pressurization events is described in NEDO-24154[3] and the program used in non-pressurization events is described in NEDO-10802[2]. The outputs of this program along with the initial MCPR form the input for further analyses of the thermally limiting bundle with the single channel transient thermal hydraulic TASC code described in NEDE-25149[4]. The principal result of this evaluation is the reduction in MCPR caused by the transient.

The purpose of the K_f factor of Figure 3.2.3-~~1~~2 is to define operating limits at other than rated core flow conditions. At less than 100% of rated flow the required MCPR is the product of the MCPR and the K_f factor. The K_f factors assure that the Safety Limit MCPR will not be violated. The K_f factors were derived using THERMAL POWER and core flow corresponding to 105% of rated steam flow.

The K_f factors were calculated such that for the maximum core flow rate and the corresponding THERMAL POWER along the 105% of rated steam flow control line, the limiting bundle's relative power was adjusted until the MCPR was slightly above the Safety Limit. Using this relative bundle power, the MCPRs were calculated at different points along the 105% of rated steam flow control line corresponding to different core flows. The ratio of the MCPR calculated at a given point of core flow, divided by the operating limit MCPR, determines the K_f.

ATTACHMENT F

SINGLE LOOP OPERATION ANALYSIS

APPENDIX 15.B

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15.B RECIRCULATION SYSTEMS SINGLE-LOOP OPERATION

15.B.1 INTRODUCTION AND SUMMARY

Single-loop operation (SLO) at reduced power is highly desirable in the event recirculation pump or other component maintenance renders one loop inoperative. To justify single-loop operation, accidents and abnormal operational transients associated with power operations, as presented in Sections 6.2 and 6.3 and the main text of Chapter 15.0, were reviewed for the single-loop case with only one pump in operation. This appendix presents the results of this safety evaluation for the operation of the Nine Mile Point Unit 2 (NMP2) with single recirculation loop inoperable. This evaluation is performed for GE-6 fueled NMP2 on an initial cycle basis and is applicable to GE-6 fueled normal initial cycle operation. The conditions are those of continued operation in the operating domain currently defined in Figure 4.4.5 of Chapter 4 up to maximum power of approximately 70% of rated.

Increased uncertainties in the core total flow and Traversing In-Core Probe (TIP) readings resulted in a 0.01 incremental increase in the Minimum Critical Power Ratio (MCPR) fuel cladding integrity safety limit during single-loop operation. No increase in rated MCPR operating limit and no change in the flow dependent MCPR limit ($MCPR_f$) is required because all abnormal operational transients analyzed for single-loop operation indicated that there is more than enough MCPR margin to compensate for this increase in MCPR safety limit. The recirculation flow rate dependent rod block and scram setpoint equation given in Chapter 16 (Technical Specifications) are adjusted for one-pump operation.

Thermal-hydraulic stability was evaluated for its adequacy with respect to General Design Criteria 12 (10CFR50, Appendix A). It is shown that SLO satisfies this stability criterion. It is further shown that the increase in neutron noise observed during SLO is independent of system stability margin.

To prevent potential control oscillations from occurring in the recirculation flow control system, the flow controller should be in master manual for single-loop operation.

The limiting Maximum Average Planar Linear Heat Generation Rate (MAPLHGR) reduction factor for single-loop operation is calculated to be 0.81.

The containment response for a Design Basis Accident (DBA) recirculation line break with single-loop operation is bounded by the rated power two-loop operation analysis presented in Section 6.2. This conclusion covers all single-loop operation power/flow conditions.

The impact of single loop operation on the Anticipated Transient Without Scram (ATWS) analysis was evaluated. It is found that all ATWS acceptance criteria are met during SLO.

The fuel thermal and mechanical duty for transient events occurring during SLO is found to be bounded by the fuel design bases. The Average Power Range Monitor (APRM) fluctuation should not exceed a flux amplitude of ±15% of rated and the core plate differential pressure fluctuation should not exceed 3.2 psi peak to peak to be consistent with the fuel rod and assembly design bases.

A recirculation pump drive flow limit is imposed for SLO. The highest drive flow that meets acceptable vessel internal vibration criteria is the drive flow limit for SLO. The expected allowable drive flow in SLO is approximately 41,000 gpm. Actual drive flow flimit in SLO will be determined during the startup test program at NMP2.

15.B.2 MCPR FUEL CLADDING INTEGRITY SAFETY LIMIT

Except for core total flow and TIP reading, the uncertainties used in the statistical analysis to determine the MCPR fuel cladding integrity safety limit are not dependent on whether coolant flow is provided by one or two recirculation pumps. Uncertainties used in the two-loop operation analysis are documented in the FSAR. A 6% core flow measurement uncertainty has been established for single-loop operation (compared to 2.5% for two-loop operation). As shown below, this value conservatively reflects the one standard deviation (one sigma) accuracy of the core flow measurement system documented in Reference 15.B.8-1. The random noise component of the TIP reading uncertainty was revised for single recirculation loop operation to reflect the operating plant test results given in Subsection 15.B.2.2. This revision resulted in a single-loop operation process computer effective TIP uncertainty of 6.8% of initial cores and 9.1% for reload cores. Comparable two-loop process computer uncertainty values are 6.3% for initial cores and 8.7% for reload cores. The net effect of these two revised uncertainties is a 0.01 increase in the required MCPR fuel cladding integrity safety limit.

15.B.2.1 Core Flow Uncertainty

15.B.2.1.1 Core Flow Measurement During Single-Loop Operation

The jet pump core flow measurement system is calibrated to measure core flow when both sets of jet pumps are in forward flow; total core flow is the sum of the indicated loop flows. For single-loop operation, however, some inactive jet pumps will be backflowing (at active pump flow above approximately 38%). Therefore, the measured flow in the backflowing jet pumps must be subtracted from the measured flow in the active loop to obtain the total core flow. In addition, the jet pump coefficient is different for reverse flow than for forward flow, and the measurement of reverse flow must be modified to account for this difference.

In single-loop operation, the total core flow is derived by the following formula:

$$\text{Total Core Flow} = \left(\begin{array}{c}\text{Active Loop}\\\text{Indicated Flow}\end{array}\right) - C \left(\begin{array}{c}\text{Inactive Loop}\\\text{Indicated Flow}\end{array}\right)$$

Where C (= 0.95) is defined as the ratio of "Inactive Loop True Flow" to "Inactive Loop Indicated Flow". "Loop Indicated Flow" is the flow measured by the jet pump "single-tap" loop flow summers and indicators, which are set to read forward flow correctly.

The 0.95 factor was the result of a conservative analysis to appropriately modify the single-tap flow coefficient for reverse flow.* If a more exact, less conservative core flow is required, special in-reactor calibration tests would have to be made. Such calibration tests would involve: calibrating core support plate ΔP versus core flow during one-pump and two-pump operation along with 100% flow control line and calculating the correct value of C based on the core support plate ΔP and the loop flow indicator readings.

15.B.2.1.2 Core Flow Uncertainty Analysis

The uncertainty analysis procedure used to establish the core flow uncertainty for one-pump operation is essentially the same as for two-pump operation, with some exceptions. The core flow uncertainty analysis is described in Reference 15.B.8-1. The analysis of one-pump core flow uncertainty is summarized below.

For single-loop operation, the total core flow can be expressed as follows (refer to Figure 15.B.2-1):

*The analytical expected value of the "C" coefficient for NMP2 is 0.88.

$$W_C = W_A - W_I$$

where:

W_C = total core flow,

W_A = active loop flow, and

W_I = inactive loop (true) flow.

By applying the "propagation of errors" method to the above equation, the variance of the total flow uncertainty can be approximated by:

$$\sigma^2_{W_C} = \sigma^2_{W_{sys}} + \left(\frac{1}{1-a}\right)^2 \sigma^2_{W_{A_{rand}}} + \left(\frac{a}{1-a}\right)^2 \left(\sigma^2_{W_{I_{rand}}} + \sigma^2_C\right)$$

where:

σ_{W_C} = uncertainty of total core flow;

$\sigma_{W_{sys}}$ = uncertainty systematic to both loops;

$\sigma_{W_{A_{rand}}}$ = random uncertainty of active loop only;

$\sigma_{W_{I_{rand}}}$ = random uncertainty of inactive loop only;

σ_C = uncertainty of "C" coefficient; and

a = ratio of inactive loop flow (W_I) to active loop flow (W_A).

From an uncertainty analysis, the conservative, bounding values of $\sigma_{W_{sys}}$, $\sigma_{W_{A_{rand}}}$, $\sigma_{W_{I_{rand}}}$ and σ_C are 1.6%, 2.6%, 3.5%, and 2.8%, respectively. Based on the above uncertainties and a bounding value of 0.36* for "a", the variance of the total flow uncertainty is approximately:

$$\sigma^2_{W_C} = (1.6)^2 + \left(\frac{1}{1-0.36}\right)^2 (2.6)^2 + \left(\frac{0.36}{1-0.36}\right)^2 \left((3.5)^2 + (2.8)^2\right)$$
$$= (5.0\%)^2$$

When the effect of 4.1% core bypass flow split uncertainty at 12% (bounding case) bypass flow fraction is added to the total core flow uncertainty, the active coolant flow uncertainty is:

$$\sigma^2_{\substack{\text{active}\\\text{coolant}}} = (5.0\%)^2 + \left(\frac{0.12}{1-0.12}\right)^2 (4.1\%)^2 = (5.1\%)^2$$

which is less than the 6% flow uncertainty assumed in the statistical analysis.

In summary, core flow during one-pump operation is measured in a conservative way and its uncertainty has been conservatively evaluated.

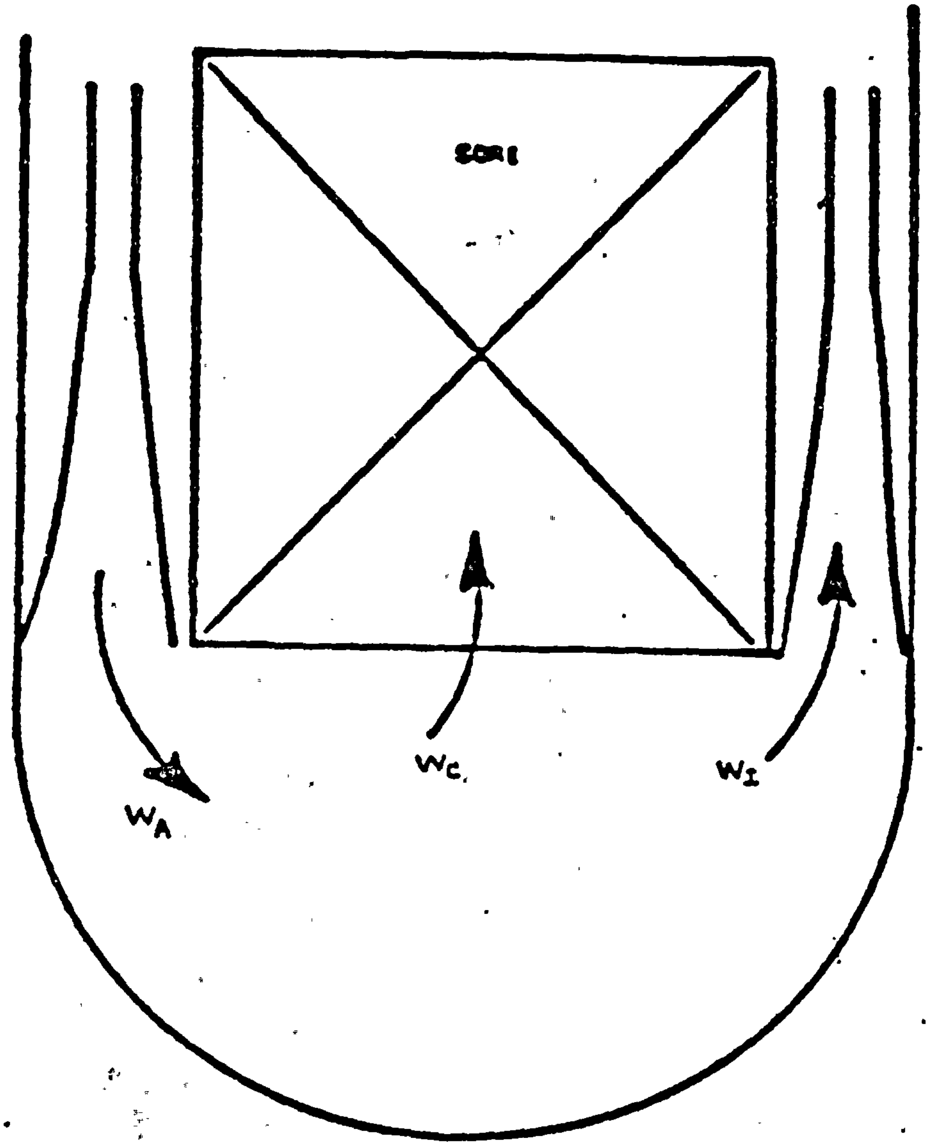
15.B.2.2 TIP READING UNCERTAINTY

To ascertain the TIP noise uncertainty for single recirculation loop operation, a test was performed at an operating BWR. The test was performed at a power level 59.3% of rated with a single recirculation pump in operation (core flow 46.3% of rated). A rotationally symmetric control rod pattern existed during the test.

---

*This flow split ratio varies from about 0.13 to 0.36. The 0.36 value is a conservative bounding value. The analytical expected value of the flow split ratio for NMP2 is ~ 0.23.

Five consecutive traverses were made with each of five TIP machines, giving a total of 25 traverses. Analysis of this data resulted in a nodal TIP noise of 2.85%. Use of this TIP noise value as a component of the process computer total uncertainty results in a one-sigma process computer total effective TIP uncertainty value for single-loop operation of 6.8% for initial cores and 9.1% for reload cores.



W_C = Total Core Flow
W_A = Active Loop Flow
W_I = Inactive Loop Flow

Niagara Mohawk Power Corp.	Illustration of Single Recirculation Loop Operation Flows	Figure 15.B.2-1

15.B.3 MCPR OPERATING LIMIT

15.B.3.1 ABNORMAL OPERATING TRANSIENTS

Operating with one recirculation loop results in a maximum power output which is about 30% below that which is attainable for two-pump operation. Therefore, the consequences of abnormal operation transients from one-loop operation will be considerably less severe than those analyzed from a two-loop operational mode. For pressurization, flow increase, flow decrease, and cold water injection transients, the results presented in Chapter 15 bound both the thermal and overpressure consequences of one-loop operation.

Figure 15.B.3-1 shows the consequences of a typical pressurization transient (generator load rejection) as a function of power level. As can be seen, the consequences of one-loop operation are considerably less because of the associated reduction in operating power level.

The consequences of flow decrease transients are also bounded by the full power analysis. A single pump trip from one-loop operation is less severe than a two-pump trip from full power because of the reduced initial power level.

The worst flow increase transient results from recirculation flow controller failure, and the worst cold water injection transient results from the loss of feedwater heater. For the former, the $MCPR_f$ (K_f) curve is derived assuming both recirculation loop controllers fail. This condition produces the maximum possible power increase and hence maximum ΔCPR for transients initiated from less than rated power and flow. When operating with only one recirculation loop, the flow and power increase associated with this failure with only one loop will be less than that associated with both loops; therefore, the K_f curve derived with the two-pump assumption is conservative for single-loop operation. The latter event, loss of feedwater heating, is generally the most severe cold water increase event with respect to increase in core power. This event is caused by positive reactivity insertion from core inlet

subcooling and it is relatively insensitive to initial power level. A generic statistical loss of feedwater heater analysis using different initial power levels and other core design parameters concluded one-pump operation with lower initial power level is conservatively bounded by the full power two-pump analysis. Inadvertent restart of the idle recirculation pump has been analyzed in the FSAR (Chapter 15.4.4) and is still applicable for single-loop operation.

From the above discussions, it is concluded that the transient consequence from one-loop operation is bounded by previously submitted full power analyses. The maximum power level that can be attained with one-loop operation is only restricted by the MCPR and overpressure limits established from a full-power analysis.

In the following sections, the results of two of the most limiting transients analyzed for single-loop operation are presented. They are, respectively:

a. feedwater flow controller failure (maximum demand), (FWCF)

b. generator load rejection with bypass failure, (LRBPF).

The plant initial conditions are given in Table 15.B.3-1.

15.B.3.1.1 <u>Feedwater Controller Failure - Maximum Demand</u>

This event is postulated on the basis of a single failure of a control device, specifically one which can directly cause an increase in coolant inventory by increasing the feedwater flow. The most severe applicable event is a feedwater controller failure to maximum flow demand. The feedwater controller is forced to its upper limit at the beginning of the event.

With excess feedwater flow, the water level rises to the high-level reference point at which time the feedwater pumps and the main turbine are tripped and a scram is initiated. Table 15.B.3-2 lists the sequence

of events. Figure 15.B.3-2 shows the changes in important variables during this transient.

The computer model described in Reference 15.B.8-2 was used to simulate this event.

The analysis has been performed with the plant conditions tabulated in Table 15.B.3-1, except the initial vessel water level at level setpoint L4 for conservatism. By lowering the initial water level, more cold feedwater will be injected before Level 8 is reached resulting in higher heat fluxes.

The same void reactivity coefficient used for the pressurization transient is applied since a more negative value conservatively increases the severity of the power increase. End of cycle (all rods out) scram characteristics are assumed. The safety/relief valve action is conservatively assumed to occur with higher than nominal setpoints. The transient is simulated by programming an upper limit failure in the feedwater system such that 145% of rated feedwater flow occurs at the design pressure of 1060 psig. Since the reactor is initially operating at a lower power level, the feedwater sparger experiences a pressure which is much lower than the design pressure, hence the feedwater runout capacity reaches 167% of initial flow.

<u>Results</u>

The simulated feedwater controller transient is shown in Figure 15.B.3-2 for the case of 75% power and 60% core flow. The high-water level turbine trip and feedwater pump trip are initiated at approximately 6.4 seconds. Scram occurs simultaneously from stop valve closure, and limits the neutron flux peak and fuel thermal transient so that no fuel damage occurs. Table 15.B.3-4 gives a summary of the transient analysis results. The calculated MCPR is 1.20, which is well above the safety limit MCPR of 1.07 so no fuel failure due to boiling transition is predicted. The peak vessel pressure predicted is 1134 psig and is well below the ASME limit of 1375 psig.

15.B.3.1.2 Generator Load Rejection With Bypass Failure

Fast closure of the turbine control valves (TCV) is initiated whenever electrical grid disturbances occur which result in significant loss of electrical load on the generator. The turbine control valves are required to close as rapidly as possible to prevent overspeed of the turbine-generator rotor. Closure of the main turbine control valves will increase system pressure. Mitigation of pressure increase during this transient is accomplished by the scram and RPT.

A loss of generator electrical load at 75% power and 60% flow under single recirculation loop operation produces the sequence of events listed in Table 15.B.3-3. Figure 15.B.3-3 shows the changes in important variables during this transient.

The computer model described in Reference 15.B.8-2 was used to simulate this event.

The analysis has been performed with the plant conditions tabulated in Table 15.B.3-1, except that the turbine bypass function is assumed to fail.

The simulated generator load rejection with bypass failure is shown in Figure 15.B.3-3.

Table 15.B.3-4 summarizes the transient analysis results. The peak neutron flux reaches about 166% of rated and average surface heat flux peaks at 106.5% of its initial value. The peak vessel pressure predicted is 1175 psig and is well below the ASME limit of 1375 psig. The calculated MCPR is 1.27 which is considerably above the safety limit MCPR of 1.07.

15.B.3.1.3 Summary and Conclusions

The transient peak value results and the Critical Power Ratio results are summarized in Table 15.B.3-4. This table indicates that for the transient events analyzed here, the MCPRs for all transients are above the single-loop operation safety limit value of 1.07. It is concluded the operating limit MCPRs established for two-pump operation are also applicable to single-loop operation conditions.

For pressurization, Table 15.B.3-4 indicates the peak pressures are below the ASME code value of 1375 psig. Hence, it is concluded the pressure barrier integrity is maintained under single-loop operation conditions.

15.B.3.2 ROD WITHDRAWAL ERROR

The rod withdrawal error at rated power is given in the FSAR. These analyses are performed to demonstrate, even if the operator ignores all instrument indications and the alarm which could occur during the course of the transient, the rod block system will stop rod withdrawal at a minimum critical power ratio (MCPR) which is higher than the fuel cladding integrity safety limit. Modification of the rod block equation (below) assures the MCPR safety limit is not violated.

The Average Power Range Monitor (APRM) rod block system provides additional alarms and rod blocks when power levels are grossly exceeded. Modification of the APRM rod block equation (below) is required to maintain the two loop rod block versus power relationship when in one loop operation.

One-pump operation results in backflow through 10 of the 20 jet pumps while the flow is being supplied into the lower plenum from the 10 active jet pumps. Because of the backflow through the inactive jet pumps, the present rod block equation was conservatively modified for use during one-pump operation because the direct active-loop flow measurement may not indicate actual flow above about 38% core flow without correction.

A procedure has been established for correcting the APRM rod block equation to account for the discrepancy between actual flow and indicated flow in the active loop. This preserves the original relationship between APRM rod block and actual effective drive flow when operating with a single loop.

The two-pump rod block equation is:

$$RB = mW + RB_{100} - m(100)$$

The one-pump equation becomes:

$$RB = mW + RB_{100} - m(100) - m\Delta W$$

where

ΔW = difference between two-loop and single-loop effective drive flow at the same core flow. This value is expected to be 5% of rated (to be determined by the Niagara Mohawk Power Corporation)

RB = power at rod block in %

m = flow reference slope

W = drive flow in % of rated.

RB_{100} = top level rod block at 100% flow.

If the rod block setpoint (RB_{100}) is changed, the equation must be recalculated using the new value.

The APRM scram trip settings are flow biased in the same manner as the APRM rod block setting. Therefore, the APRM scram trip settings are subject to the same procedural changes as the rod block settings discussed above.

15.B.3.3 OPERATING MCPR LIMIT

For single-loop operation, the operating MCPR limit remains unchanged from the normal two-loop operation limit. Although the increased uncertainties in core total flow and TIP readings resulted in a 0.01 increase in MCPR fuel cladding integrity safety limit during single-loop operation (Section 15.B.2), the limiting transients have been analyzed to indicate that there is more than enough MCPR margin during single-loop operation to compensate for this increase in safety limit. For single loop operation at off-rated conditions, the steady-state operating MCPR limit is established by the K_f curve. This ensures the 99.9% statistical limit requirement is always satisfied for any postulated abnormal operational occurrence. Since the maximum core flow runout during single loop operation is only about 60% of rated, the current flow dependent K_f curve which is generated based on the flow runout up to rated core flow are also adequate to protect the flow runout events during single loop operation.

TABLE 15.B.3-1

INPUT PARAMETERS AND INITIAL CONDITIONS

1.	Thermal Power Level, MWt Analysis Value	2492
2.	Steam Flow, lb per hr Analysis Value	10.28×10^6
3.	Core Flow, lb per hr	65.10×10^6
4.	Feedwater Flow Rate, lb per hr Analysis Value	10.28×10^6
5.	Feedwater Temperature, °F	394
6.	Vessel Dome Pressure, psig	981
7.	Core Pressure, psig	987
8.	Turbine Bypass Capacity, % NBR	25.
9.	Core Coolant Inlet Enthalpy, Btu per lb	515.1
10.	Turbine Inlet Pressure, psig	952
11.	Fuel Lattice	P8x8R
12.	Core Average Gap Conductance, Btu/sec-ft²-°F	0.1744
13.	Core Bypass Flow, %	11.84
14.	Required MCPR Operating Limit Option A Option B	 1.44 1.40
15.	MCPR Safety Limit	1.07
16.	Doppler Coefficient ¢/°F	*
17.	Void Coefficient ¢/% Rated Voids	*
18.	Core Average Rated Void Fraction, %	43.5
19.	Scram Reactivity, $ΔK	*

*This value is calculated within the Computer code (Reference 15.B.8-2) for end of Cycle 1 condition based on the input from CRUNCH tape.

TABLE 15.B.3-1 (Continued)

INPUT PARAMETERS AND INITIAL CONDITIONS

20.	Control Rod Drive Speed Position Versus Time	Figure 15.0-3
21.	Jet Pump Ratio, M	3.16
22.	Safety/Relief Valve Capacity, % NBR @ 103% of 1177 psig Manufacturer Quantity Installed	 > 113.8 DIKKERS 18
23.	Relief Function Delay, seconds	0.4
24.	Relief Function Response Time Constant, sec.	0.1
25.	Set Points for Safety/Relief Valves Safety Function, psig Relief Function, psig	 1177, 1187, 1197, 1207, 1217 1106, 1116, 1126, 1136, 1146
26.	Number of Valve Groupings Simulated Safety Function, No. Relief Function, No.	 5 5
27.	High Flux Trip, % NBR Analysis Set Point (121 x 1.043)	 126.2
28.	High Pressure Scram Set Point, psig	1071
29.	Vessel Level Trips, Feet Above Separator Skirt Bottom Level 8 - (L8), Feet Level 4 - (L4), Feet Level 3 - (L3), Feet Level 2 - (L2), Feet	 6.175 3.75 1.75 -4.708

TABLE 15.B.3-1 (Continued)

INPUT PARAMETERS AND INITIAL CONDITIONS

30.	APRM Thermal Trip Set Point, % NBR @ 100% Core Flow (117 x 1.043)	122
31.	RPT Delay, seconds	0.19
32.	Time Constant of Recirculation Pump - Motor, seconds** Analysis Value	6.0
33.	Set Pressure of ATWS Recirculation Pump Trip, psig	1080
34.	Total Steam Line Volume, ft^3	4012

**The inertia time constant is defined by the expression:

$$t = \frac{2\pi J_o n}{g T_o}$$

where:

t = inertia time constant (sec)
J_o = pump motor inertia (lb-ft)
n = rated pump speed (rps)
g = gravitational constant (ft/sec^2)
T_o = pump shaft torque (ft-lb)

TABLE 15.B.3-2

SEQUENCE OF EVENTS FOR FEEDWATER CONTROLLER FAILURE, MAXIMUM DEMAND (Figure 15.B.3-2)

Time-sec	Event
0	Initiate simulated failure to the upper limit on feedwater flow.
6.4	L8 vessel level set point trips main turbine and feedwater pumps.
6.4	Reactor scram trip actuated from main turbine stop valve position switches.
6.4	Recirculation pump trip (RPT) actuated by stop valve position switches.
6.5	Main turbine stop valves closed and turbine bypass valves start to open.
6.6	Recirculation pump motor circuit breakers open causing decrease in core flow to natural circulation.
9.5	Group 1 relief valves actuated.
10.0	Group 2 relief valves actuated.
15.2	All relief valves are closed.

TABLE 15.B.3-3

SEQUENCE OF EVENTS FOR GENERATOR LOAD REJECTION WITH BYPASS FAILURE (Figure 15.B.3-3)

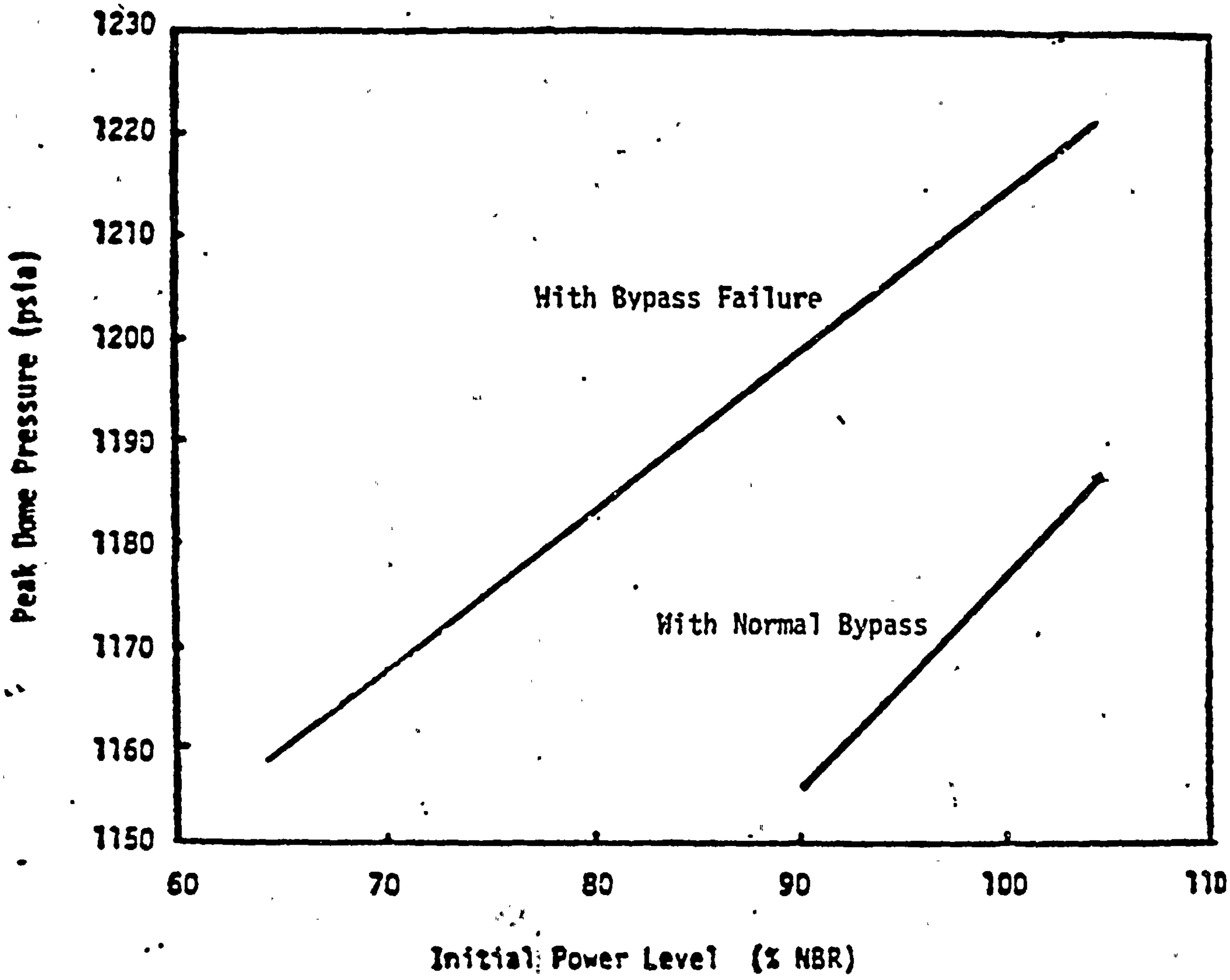
Time-sec	Event
(-)0.015 (approx.)	Turbine-generator detects loss of electrical load.
0	Turbine-generator load rejection sensing devices trip to initiate turbine control valve fast closure.
0	Turbine bypass valves fail to operate.
0	Fast control valve closure (FCV) initiates scram trip and recirculation pump trip (RPT).
0.07	Turbine control valves closed.
0.10	Turbine bypass valves should start to open - assumed to fail.
0.19	Recirculation pump motor circuit breakers open causing decrease in core flow to natural circulation.
2.1	Group 1 relief valves actuated.
2.2	Group 2 relief valves actuated.
2.4	Group 3 relief valves actuated.
2.5	Group 4 relief valves actuated.
2.8	Group 5 relief valves actuated.
5.4	Feedwater pump motors tripped on L8 high water level.
5.5	Group 5 relief valves start to close.
8.2	All relief valves are closed.

TABLE 15.B.3-4

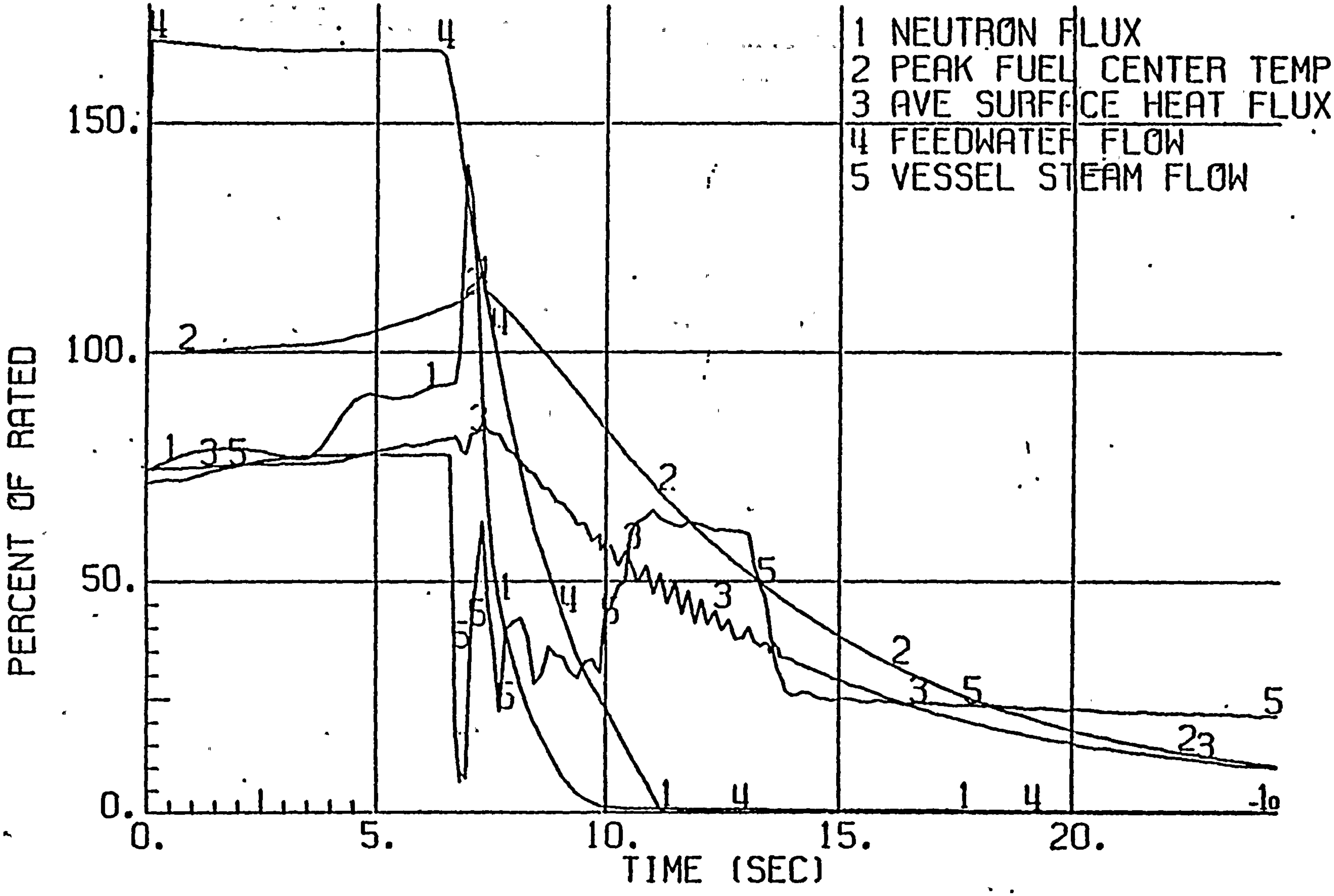
SUMMARY OF TRANSIENT PEAK VALUE AND CPR RESULTS

	LRBPF	FWCF
Initial Power/Flow (% Rated)	75/60	75/60
Peak Neutron Flux (% NBR)	165.7	157.3
Peak Heat Flux (% Initial)	106.5	113.8
Peak Dome Pressure (psig)	1160	1120
Peak Vessel Bottom Pressure (psig)	1175	1134
Required Initial MCPR Operating Limit at SLO Condition	1.44	1.44
ΔCPR	0.17*	0.24*
Transient MCPR	1.27	1.20
SLMCPR at SLO	1.07	1.07
Margin to SLMCPR	0.20	0.13

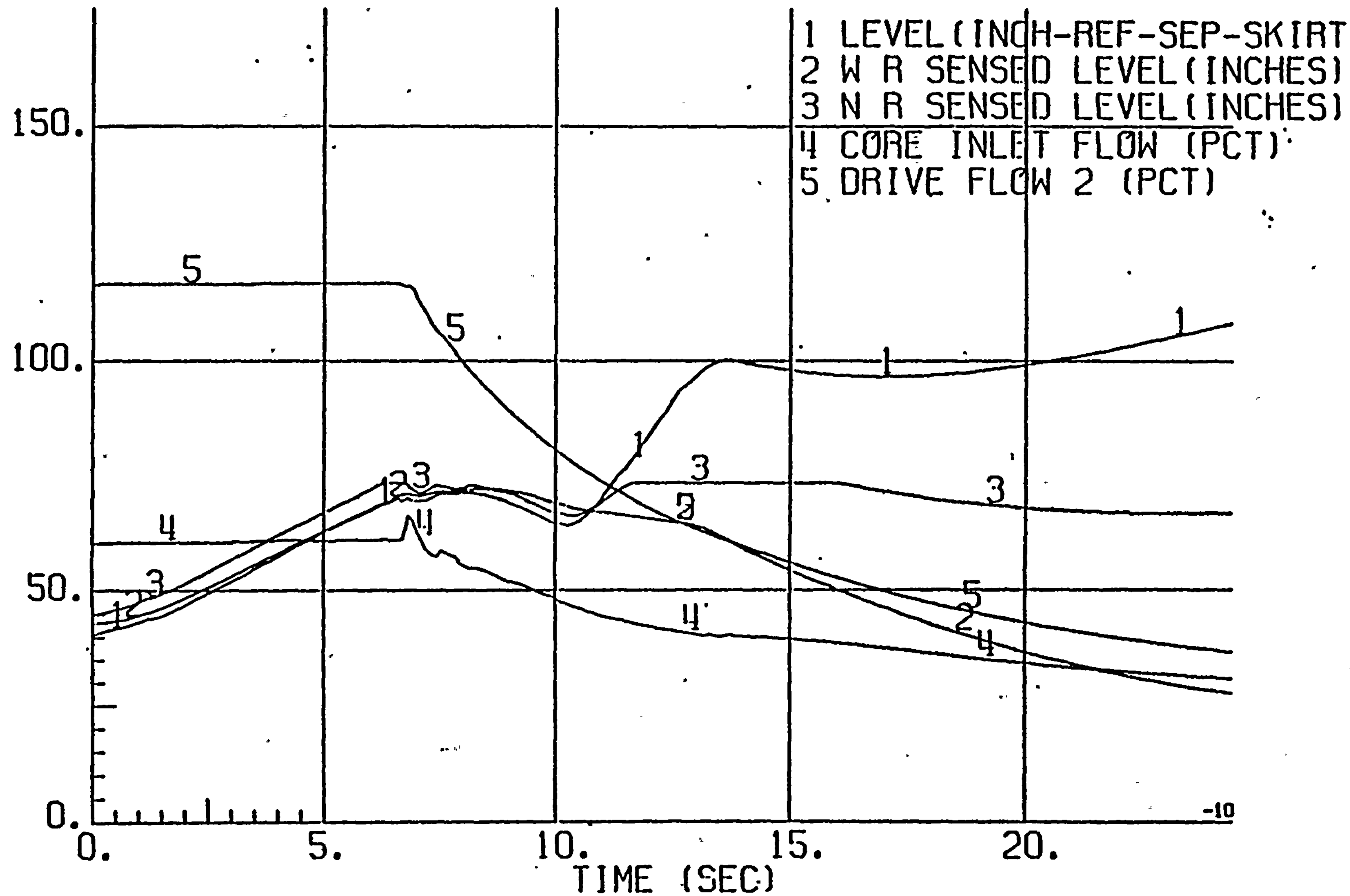
*Value includes option A adder



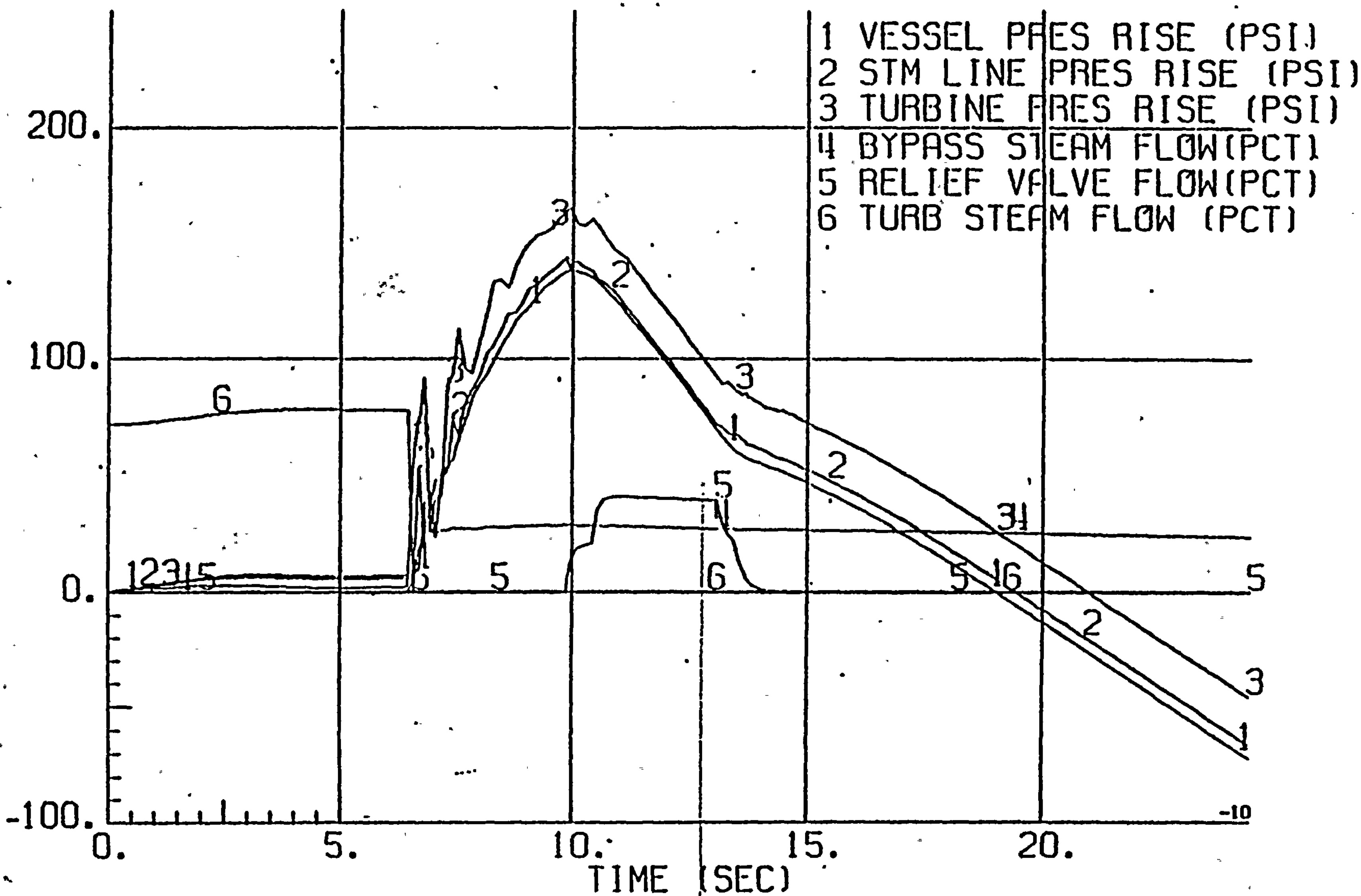
Niagara Mohawk Power Corporation	Peak Dome Pressure vs. Initial Power Level, LRBPF at EOC	Figure 15.B.3-1



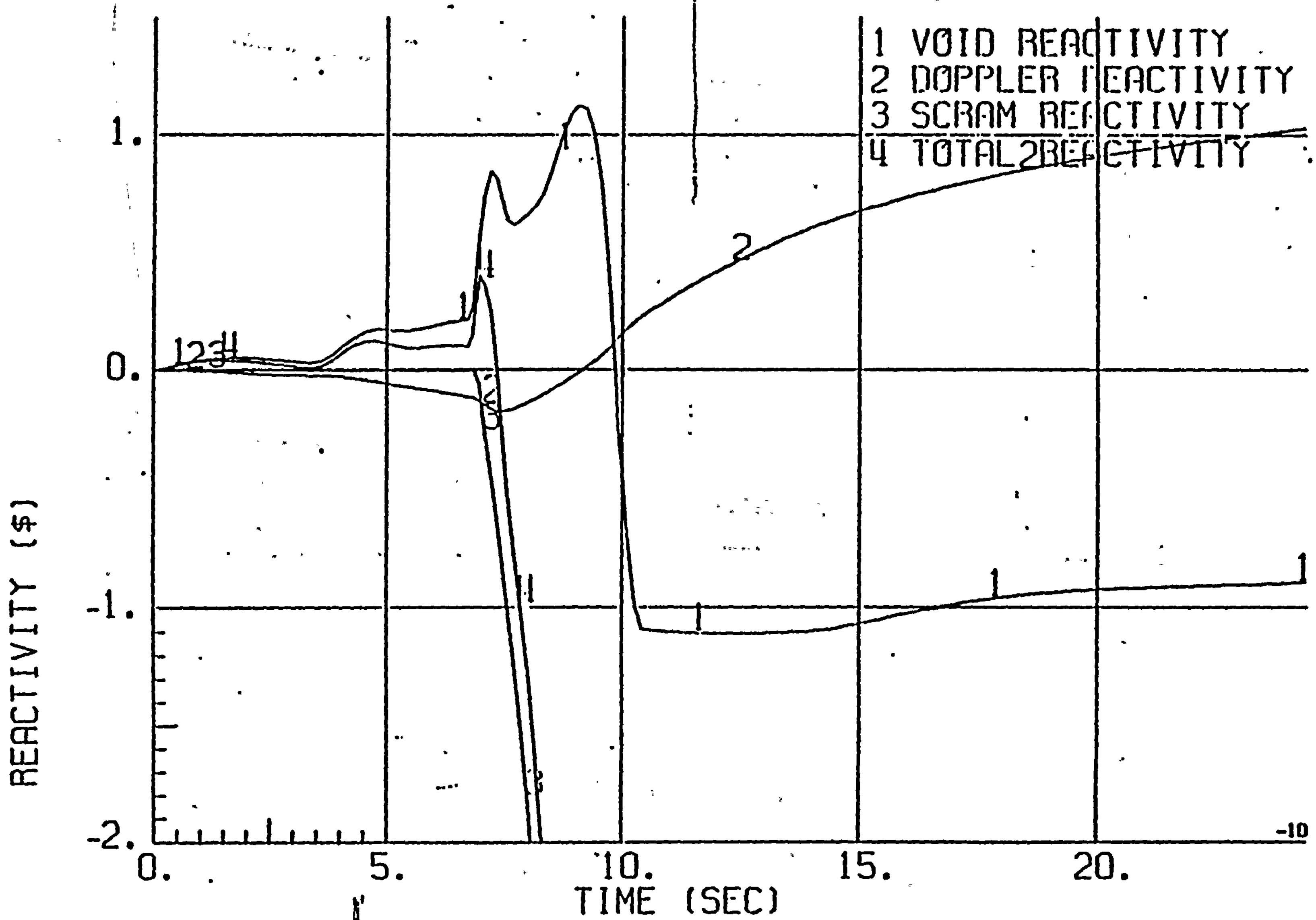
NIAGARA MOHAWK POWER CORPORATION	Feedwater Controller Failure - Maximum Demand 75% Power, 60% Flow	Figure 15.B.3-2



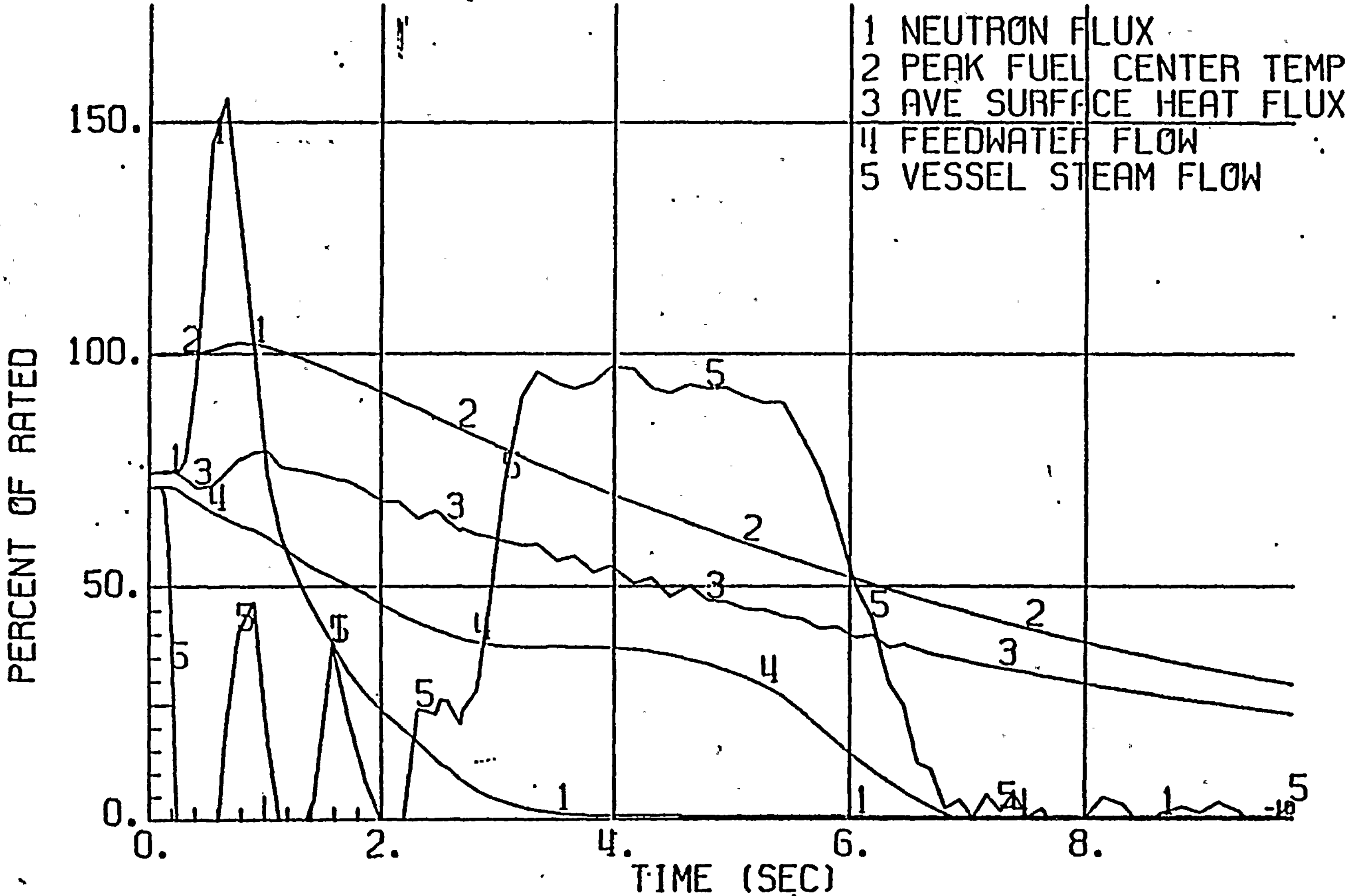
NIAGARA MOHAWK POWER CORPORATION	Feedwater Controller Failure - Maximum Demand 75% Power, 60% Flow	Figure 15.B.3-2 Cont'd.



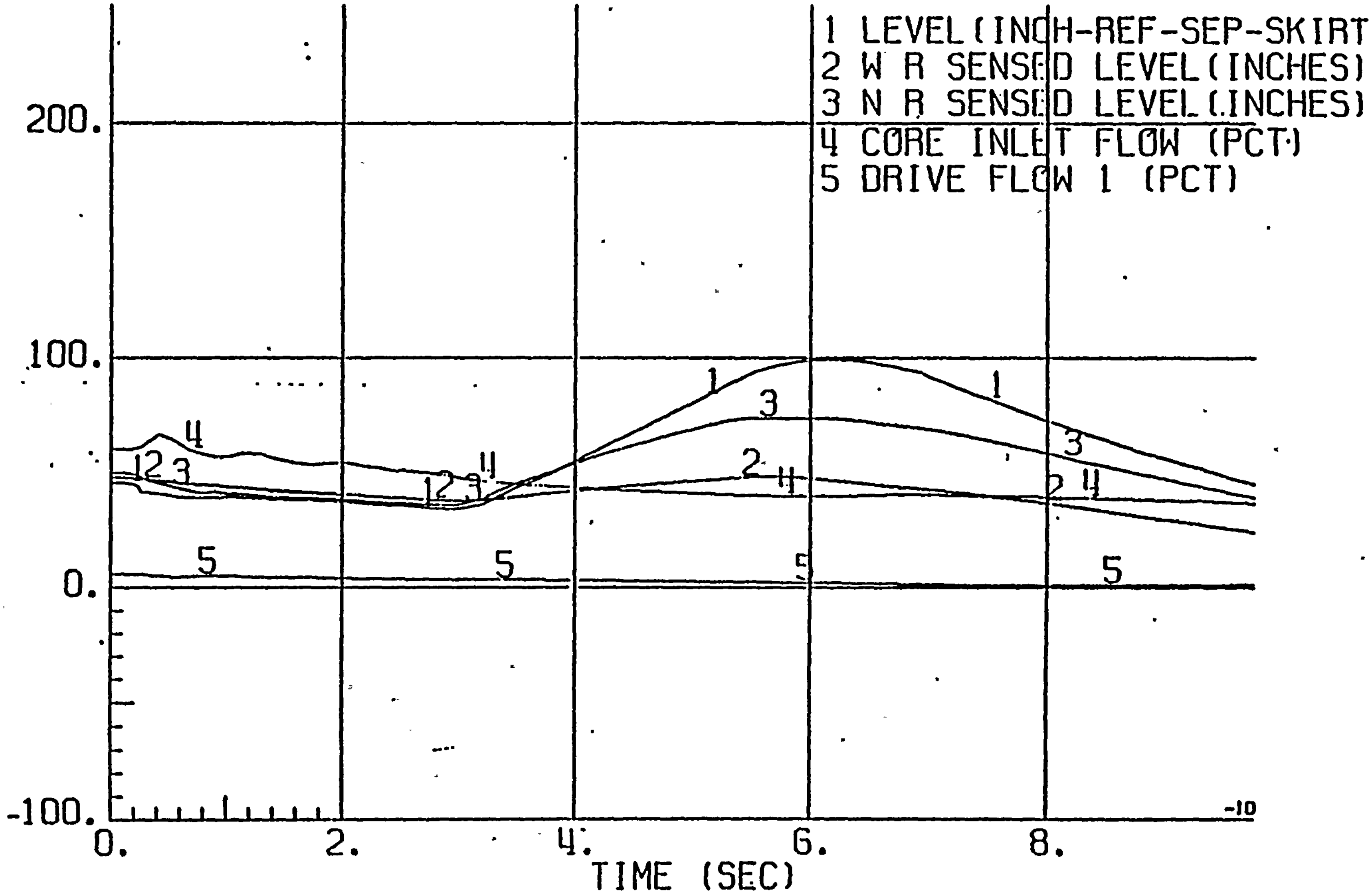
NIAGARA MOHAWK POWER CORPORATION	Feedwater Controller Failure - Maximum Demand 75% Power, 60% Flow	Figure 15.B.3-2 Cont'd.



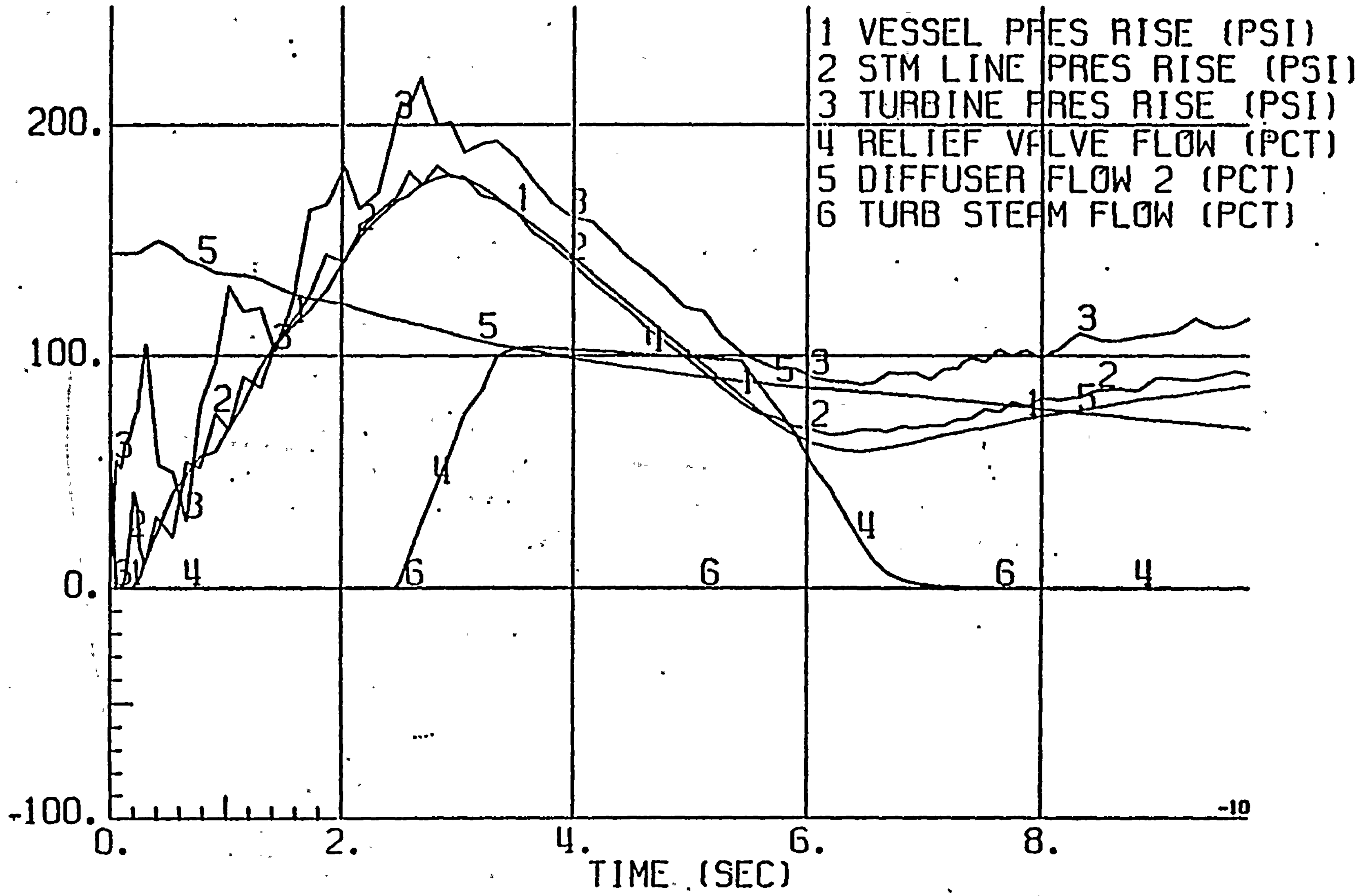
NIAGARA MOHAWK POWER CORPORATION	Feedwater Controller Failure - Maximum Demand 75% Power, 60% Flow	Figure 15.B.3-2 Cont'd.



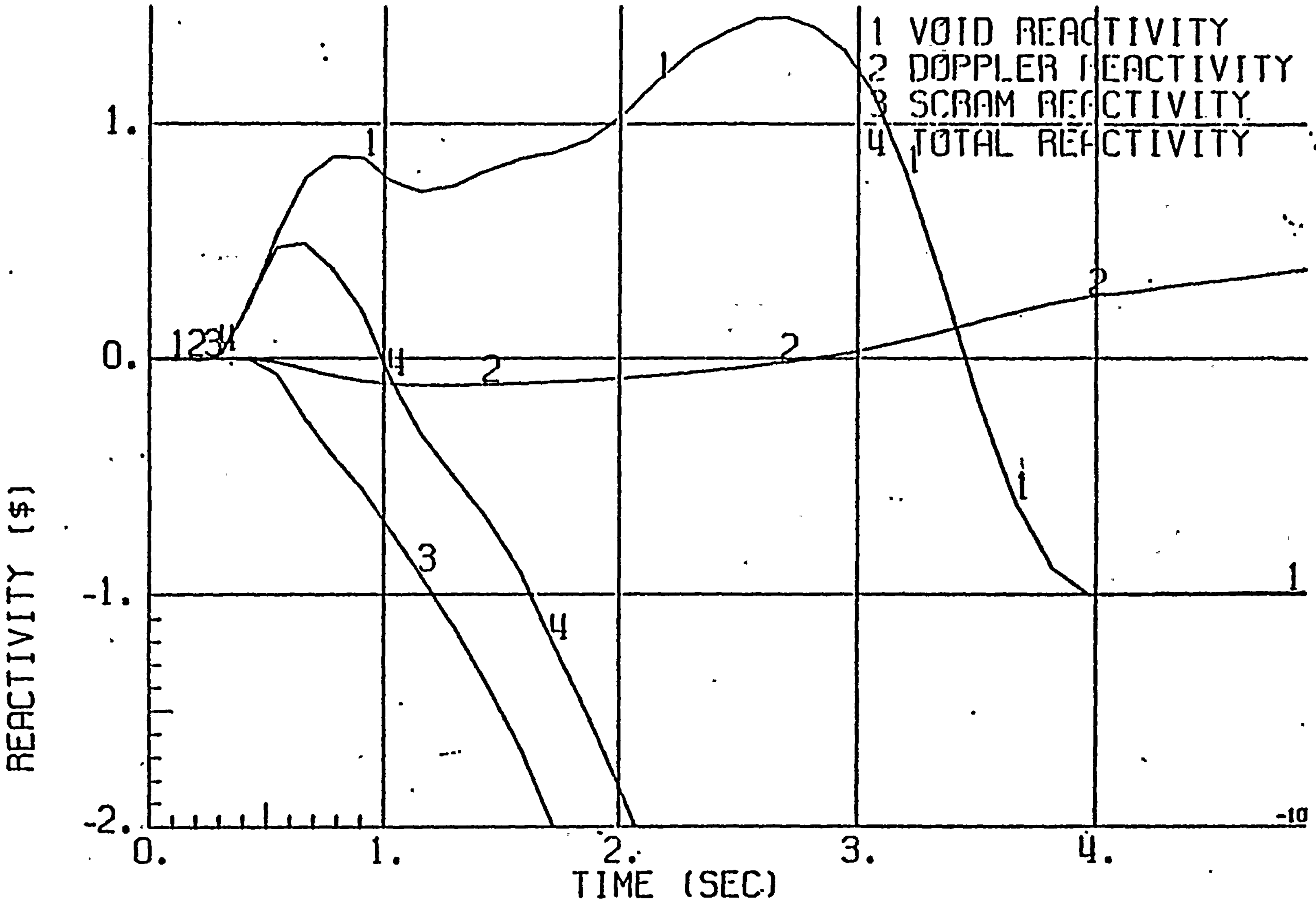
NIAGARA MOHAWK POWER CORPORATION	Load Rejection With Bypass Failure 75% Power, 60% Flow	Figure 15.B.3-3



NIAGARA MOHAWK POWER CORPORATION	Load Rejection With Bypass Failure 75% Power, 60% Flow	Figure 15.B.3-3 Cont'd.



NIAGARA MOHAWK POWER CORPORATION	Load Rejection with Bypass Failure 75% Power, 60% Flow	Figure 15.B.3-3 Cont'd.



NIAGARA MOHAWK POWER CORPORATION	Load Rejection with Bypass Failure 75% Power, 60% Flow	Figure 15.B.3-3 Cont'd.

15.B.4 STABILITY ANALYSIS

15.B.4.1 Phenomena

The primary contributing factors to the stability performance with one recirculation loop not in service are the power/flow ratio and the recirculation loop characteristics. At forced circulation with only one recirculation loop in operation, the reactor core stability is influenced by the inactive recirculation loop. As core flow increases in SLO, the inactive jet pump forward flow decreases because the driving head across the inactive jet pumps decreases with increasing core flow. The reduced flow in the inactive loop reduces the resistance that the recirculation loops impose on reactor core flow perturbations thereby adding a destabilizing effect. At the same time the increased core flow results in a lower power/flow ratio which is a stabilizing effect. These two countering effects result in slightly decreased stability margin (higher decay ratio) initially as core flow is increased (from minimum) in SLO and then an increase in stability margin (lower decay ratio) as core flow is increased further and reverse flow in the inactive loop is established.

As core flow is increased further during SLO and substantial reverse flow is established in the inactive loop an increase in jet pump flow, core flow and neutron noise is observed. A cross flow is established in the annular downcomer region near the jet pump suction entrance caused by the reverse flow of the inactive recirculation loop. This cross flow interacts with the jet pump suction flow of the active recirculation loop and increases the jet pump flow noise. This effect increases the total core flow noise which tends to drive the neutron flux noise.

To determine if the increased noise is being caused by reduced stability margin as SLO core flow was increased, an evaluation was performed which phenomenologically accounts for single loop operation effects on stability, as summarized in Reference 15.B.8-4. The model predictions were initially compared with test data and showed very good agreement for both two loop and single loop test conditions. An evaluation was performed to determine the effect of reverse flow on stability during SLO. With increasing reverse flow, SLO exhibited slightly lower decay ratios than two loop operation. However, at core flow conditions with no reverse flow, SLO was slightly less stable. This is consistent with observed behavior in stability tests at operating BWRs (Reference 15.B.8-5).

In addition to the above analyses, the cross flow established during reverse flow conditions was simulated analytically and shown to cause an increase in the individual and total jet pump flow noise, which is consistent with test data (Reference 15.B.8-4). The results of these analyses and tests indicate that the stability characteristics are not significantly different from two loop operation. At low core flow, SLO may be slightly less stable than two loop operation but as core flow is increased and reverse flow is established the stability performance is similar. At even higher core flow with substantial reverse flow in the inactive recirculation loop, the effect of cross flow on the flow noise results in an increase in system noise (jet pump, core flow and neutron flux noise).

15.B.4.2 <u>Compliance to Stability Criteria</u>

Consistent with the philosophy applied to two loop operation, the stability compliance during single loop operation is demonstrated on a generic basis. Stability acceptance criteria have been established to demonstrate compliance with the requirements set forth in 10CFR50, Appendix A, General Design Criterion (GDC) 12 (Reference 15.B.8-6). Generic analyses which cover those fuels contained in the General Electric Standard Application for Reload Fuel (Reference 15.B.8-7 through Amendment 10) have been performed. The analyses demonstrate that in the event limit

cycle neutron flux oscillations occur within the bounds of safety system intervention, specified acceptable fuel design limits are not exceeded. Since the reactor core is assumed to be in an oscillatory mode, the question of stability margin during SLO is not relevant from a safety standpoint (i.e., the analysis already assumes no stability margin).

The fuel performance during limit cycle oscillations is characteristically dependent on fuel design and certain fixed system features (high neutron flux scram setpoint, channel inlet orifice diameter, etc.). Therefore the acceptability of GE fuel designs independent of plant and cycle parameters has been established. Only those parameters unique to SLO which affect fuel performance need to be evaluated. The major consideration of SLO is the increased Minimum Critical Power Ratio (MCPR) safety limit caused by increased uncertainties in system parameters during SLO. However, the increase in MCPR safety limit (0.01) is well within the margin of the limit cycle analyses (Reference 15.B.8-6) and therefore it is demonstrated that stability compliance criteria are satisfied during single loop operation. Operationally, the effects of higher flow noise and neutron flux noise observed at high SLO core flow are evaluated to determine if acceptable vessel internal vibration levels are met and to determine the effects on fuel and channel fatigue, and are not considered in the compliance to stability criteria.

Service Information Letter-380, Revision 1 (Reference 15.B.8-8) has been developed to inform plant operators how to recognize and suppress unanticipated oscillations when encountered during plant operation.

As a result of the above analysis and operator recommendations, the NRC staff has approved the generic stability analysis for application to single loop operation (Reference 15.B.8-9) provided that the recommendations of SIL-380 have been incorporated into the Plant Technical Specifications.

15.B.5 LOSS-OF-COOLANT ACCIDENT ANALYSIS

If two recirculation loops are operating and a pipe break occurs in one of the two recirlation loops, the pump in the unbroken loop is assumed to immediately trip and begin to coast down. The decaying core flow due to the pump coastdown results in very effective heat transfer (nucleate boiling) during the initial phase of the blowdown. Typically, nucleate boiling will be sustained during the first 5 to 9 seconds after the accident, for the design basis accident (DBA).

If only one recirculation loop is operating, and the break occurs in the operating loop, continued core flow is provided only by natural circulation because the vessel is blowing down to the reactor containment through both sections of the broken loop. The core flow decreases more rapidly than in the two-loop operating case, and the departure from nucleate boiling for the high power node might occur 1 or 2 seconds after the postulated accident, resulting in more severe cladding heatup for the one-loop operating case.

In addition to changing the blowndown heat transfer characteristics, losing recirculation pump coastdown flow can also affect the system inventory and reflooding phenomena. Of particular interest are the changes in the high-power node uncovery and reflooding times, the system pressure and the time of rated core spray for different break sizes. One-loop operation results in small changes in the high-power node uncovery times and times of rated spray. The effect of the reflooding times for various break sizes is also generally small.

An analysis of single recirculation loop operation using the models and assumptions documented in Reference 15.B.8-10 was performed for NMP2. Using this method, SAFE/REFLOOD computer code runs were made for a full spectrum of large break sizes for only the recirculation suction line breaks (most limiting for NMP2). Because the reflood minus uncovery time for the single-loop analysis is similar to the two-loop analysis, the maximum planar linear heat generation rate (MAPLHGR) curves were modified

by derived reduction factors for use during one recirculation pump operation.

15.B.5.1 BREAK SPECTRUM ANALYSIS

SAFE/REFLOOD calculations were performed using assumptions given in Section II.A.7.3.1 of Reference 15.B.8-10. Hot node uncovered time (time between uncovery and reflood) for single-loop operation is compared to that for two-loop operation in Figure 15.B.5-1.

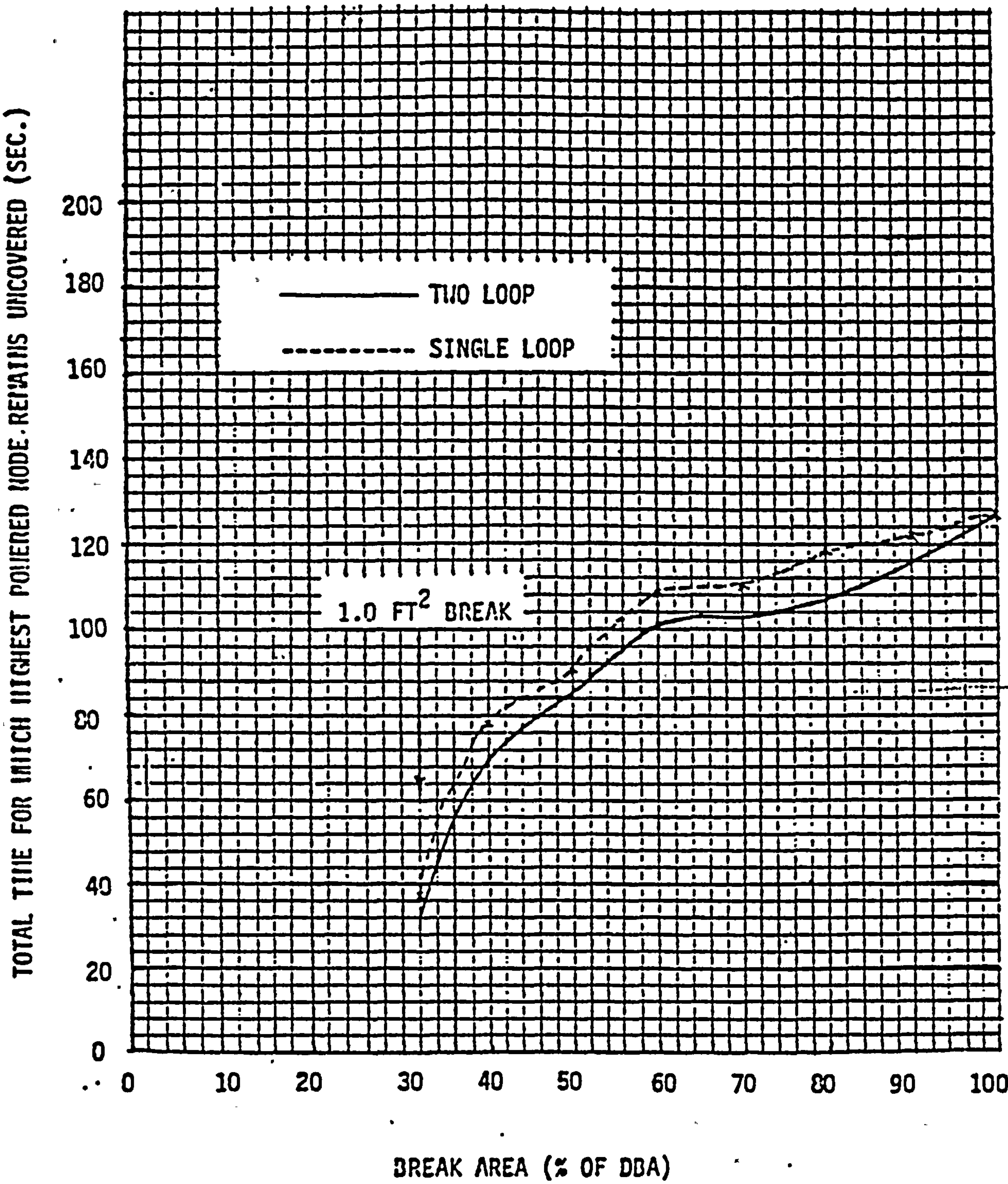
The total uncovered time for two-loop operation is 127 seconds for the 100% DBA suction break. This is the most limiting break for two-loop operation. For single-loop operation, the total uncovered time is 127 seconds and for the 100% DBA suction break. This is the most limiting break for single-loop operation.

15.B.5.2 SINGLE-LOOP MAPLHGR DETERMINATION

The small differences in uncovered time and reflood time for the limiting break size would result in a small change in the calculated peak cladding temperature. Therefore, as noted as Reference 15.B.8-10, the one and two-loop SAFE/REFLOOD results can be considered similar and the generic alternate procedure described in Section II.A.7.4. of this reference was used to calculate the MAPLHGR reduction factors for single-loop operation. The most limiting single-loop operation MAPLHGR reduction factor (i.e., yielding the lowest MAPLHGR) for GE6 8x8 retrofit-fuel is 0.81. One-loop operation MAPLHGR values are derived by multiplying the current two-loop MAPLHGR values by the reduction factor (0.81). As discussed in Reference 15.B.8-10, single recirculation loop MAPLHGR values are conservative when calculated in this manner.

15.B.5.3 SMALL BREAK PEAK CLADDING TEMPERATURE

Section II.A.7.4.4.2 of Reference 15.B.8-10 discusses the low sensitivity of the calculated peak cladding temperature (PCT) to the assumptions used in the one-pump operation analysis and the duration of nucleate boiling. As this slight increase (∿ 50°F) in PCT is overwhelmingly offset by the decreased MAPLHGR (equivalent to 300°F to 500°F PCT) for one-pump operation, the calculated PCT values for small breaks will be well below the 1522°F small break PCT value previously reported for NMP2, and significantly below the 2200°F 10CFR50.46 cladding temperature limit.



Niagara Mohawk Power Corp.	Uncovered Time vs. Break Area-Suction Break, LPCS Diesel Generator Failure	Figure 15.B.5-1

15.B.6 CONTAINMENT ANALYSIS

A single-loop operation containment analysis was performed for NMP2. The peak wetwell pressure, peak drywell pressure, chugging loads, condensation oscillation and pool swell containment response were evaluated over the entire single-loop operation power/flow region.

The analysis shows that the peak drywell and wetwell pressure during single loop operation is 33.1 psig and 27.2 psig respectively and occur under recirculation line break at the maximum vessel subcooling condition in the power/flow map. The corresponding differential peak drywell-to-wetwell pressure is 17.2 psid. A base case, corresponding to the FSAR condition of 102% power/100% core flow, was also analyzed for comparison. The results are presented in Table 15.B.6-1. As noted from the table, the peak drywell and wetwell pressure and the peak drywell-to-wetwell pressure for the SLO are all bounded by those of the base case and are substantially below the design limits. The pressure and temperature responses for the SLO are shown in Figure 15.B.6-1 and 15.B.6-2.

The containment dynamic loads evaluation was performed at the worst condition for the SLO and compared with those for the base case. Pool swell, condensation oscillation, and chugging loads were assessed for the initial phase of a postulated recirculation line break. Additionally, Safety Relief Valve actuation loads were considered. It is concluded from the evaluation results that the current FSAR containment loadings bound the worst SLO loadings.

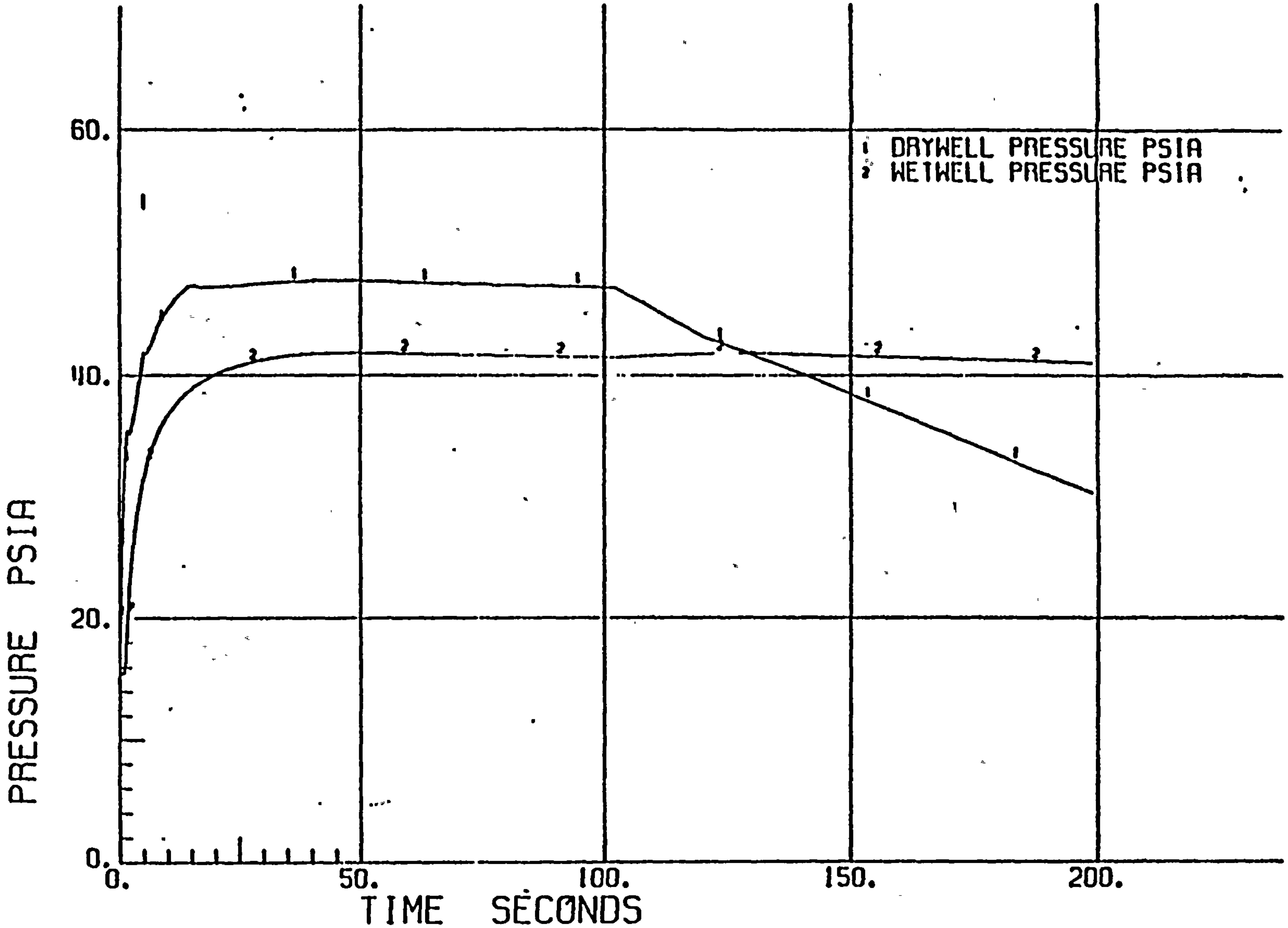
The bounding event for the drywell temperature response is a main steamline break. Under SLO, the increased vessel subcooling has no impact on the steam break flow. However, the lower vessel pressure resulting from SLO reduces the steam break flow. It is concluded that the peak drywell temperature for SLO is bounded by that of the FSAR.

Finally, the peak suppression pool and wetwell airspace temperatures are governed by the long-term release of decay heat and energy removal by the RHR service water. Since the power levels for the SLO are bounded by that of the FSAR, it is therefore concluded that the peak suppression pool temperature is bounded by the peak suppression pool temperature given in the FSAR.

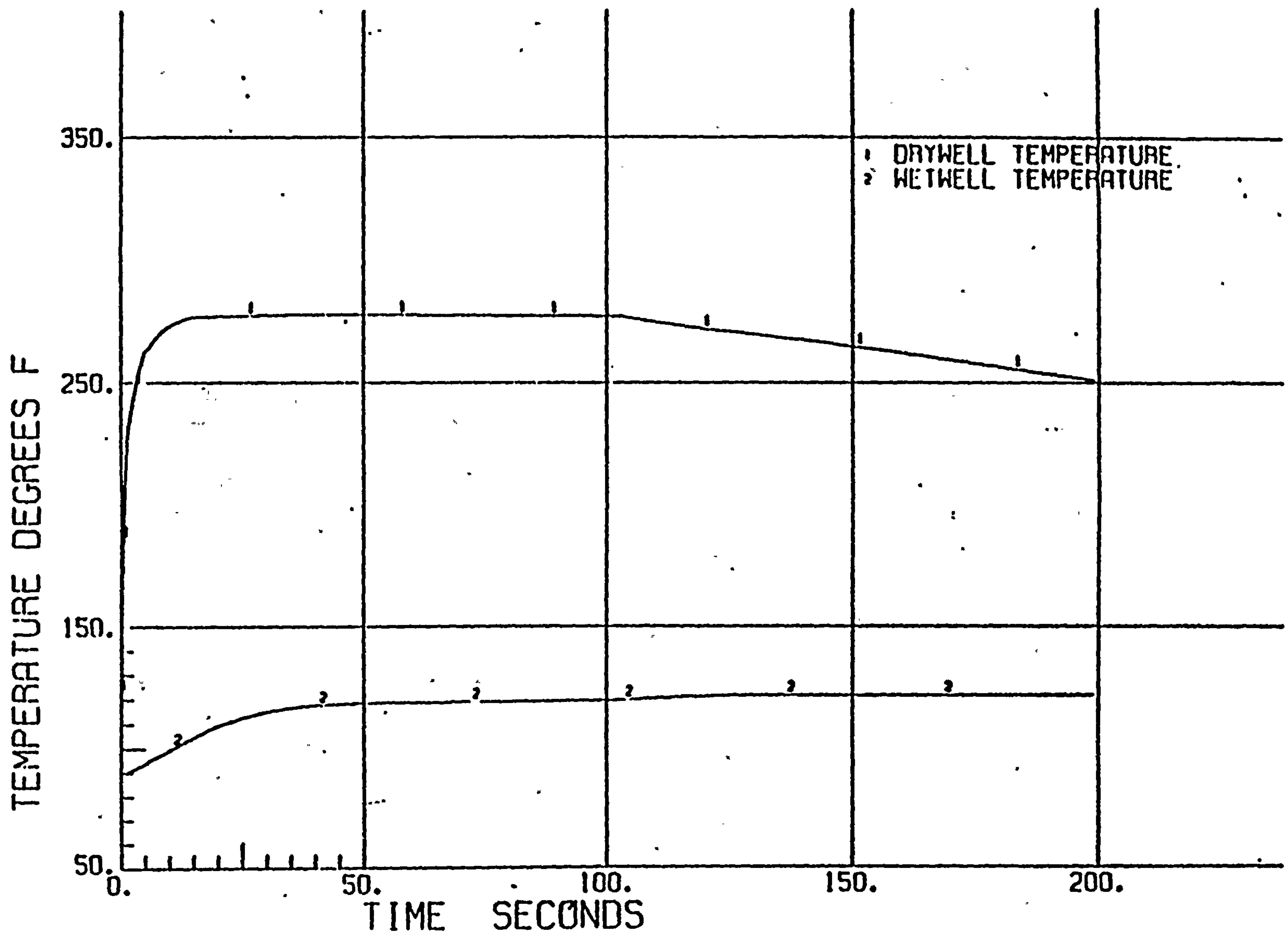
Table 15.B.6-1

Comparison of Containment Peak Pressures

	Base Case (102% Power/ 100% Core Flow)	SLO (54% Power/ 35% Core Flow)	Design Limits
Peak Drywell Pressure, PSIG	34.62	33.07	45
Peak Drywell-To-Wetwell Delta P PSID	17.81	17.17	25
Peak Wetwell Pressure, PSIG	28.63	27.18	45



NIAGARA MOHAWK POWER CORPORATION	DRYWELL AND WETWELL PRESSURE RESPONSES - RECIRCULATION LINE BREAK, 55% POWER, 35% CORE FLOW	FIGURE 15.B.6-1



NIAGARA MOHAWK POWER CORPORATION	DRYWELL AND WETWELL TEMPERATURE RESPONSES - RECIRCULATION LINE BREAK, 55% POWER, 35% CORE FLOW	FIGURE 15.B.6-2

15.B.7 MISCELLANEOUS IMPACT EVALUATION

15.B.7.1 Anticipated Transient Without Scram (ATWS) Impact Evaluation

The principal difference between single loop operation (SLO) and normal two loop operation (TLO) affecting Anticipated Transient Without Scram (ATWS) performance is that of initial reactor conditions. Since the SLO initial power flow condition is less than the rated condition used for TLO ATWS analysis, the transient response is less severe and therefore bounded by the TLO analyses.

It is concluded that if an ATWS event were initiated at NMP2 from the SLO conditions, the results would be less severe than if it were initiated from rated conditions.

15.B.7.2 Fuel Mechanical Performance

The thermal and mechanical duty for the transients analyzed have been evaluated and found to be bounded by the fuel design bases.

It is observed that due to the substantial reverse flow established during SLO both the Average Power Range Monitor (APRM) noise and core plate differential pressure noise are slightly increased. An analysis has been carried out to determine that the APRM fluctuation should not exceed a flux amplitude of ±15% of rated and the core plate differential pressure fluctuation should not exceed 3.2 psi peak to peak to be consistent with the fuel rod and assembly design bases.

15.B.7.3 Vessel Internal Vibration

A recirculation pump drive flow limit is imposed for SLO. The highest drive flow that meets acceptable vessel internal vibration criteria is the drive flow limit for SLO.

An assessment has been made for the expected reactor vibration level during SLO for NMP2.

Before providing the results of the assessment, it is prudent to define the term "maximum flow" during balanced 2-loop operation and single loop operation. Maximum flow for two-pump balanced operation is equal to rated volumetric core flow at normal reactor operating conditions. Maximum flow for single-pump operation is that flow obtained with the recirculation pump drive flow equal to that required for maximum flow during two-pump balanced operation. For rated reactor water temperature and pressure, the maximum allowable recirculation pump drive flow for NMP2 is about 41,000 gpm.

Startup tests at the Tokai 2 plant showed all components, including the in-core guide tube during single-loop operation, to have vibration levels within acceptance limits. The Tokai 2 is the BWR 5/251 prototype plant. Since NMP2 is not a prototype plant, there is no reactor internal vibration monitoring program. Instead, the data from the Tokai 2 plant is used for NMP2 SLO assessment. Based on the Tokai 2 plant data, it can be inferred that the vibration levels of the reactor internal components for NMP2 would be expected to be within acceptance limits during single-loop operation with maximum flow as defined above.

For the jet pumps, the NMP2 startup testing will yield the required confirmation as NMP2 jet pumps are instrumented.

15.B.8 REFERENCES

15.B.8-1 "General Electric BWR Thermal Analysis Basis (GETAB); Data, Correlation, and Design Application", NEDO-10958-A, January 1977.

15.B.8-2 "Qualification of the One-Dimensional Core Transient Model for Boiling Water Reactors", NEDO-24154, October 1978.

15.B.8-3 R. B. Linford, "Analytical Methods of Plant Transients Evaluation for the General Electric Boiling Water Reactor", NEDO-10802, April 1973.

15.B.8-4 Letter, H. C. Pfefferlen (GE) to C. O. Thomas (NRC), "Submittal of Response to Stability Action Item from NRC Concerning Single-Loop Operation," September 1983.

15.B.8-5 S. F. Chen and R. O. Niemi, "Vermont Yankee Cycle 8 Stability and Recirculation Pump Trip Test Report", General Electric Company, August 1982 (NEDE-25445, Proprietary Information).

15.B.8-6 G. A. Watford, "Compliance of the General Electric Boiling Water Reactor Fuel Designs to Stability Licensing Criteria", General Electric Company, October 1984 (NEDE-22277-P-1, Proprietary Information).

15.B.8-7 "General Electric Standard Application for Reload Fuel", General Electric Company, April 1983 (NEDE-24011-P-A-6).

15.B.8-8 "BWR Core Thermal Hydraulic Stability", General Electric Company, February 10, 1984 (Service Information Letter-380, Revision 1).

15.B.8 REFERENCES (Cont'd)

15.B.8-9 Letter, C. O. Thomas (NRC) to H. C. Pfefferlen (GE), "Acceptance for Referencing of Licensing Topical Report NEDE-24011, Rev. 6, Amendment 8, Thermal Hydraulic Stability Amendment to GESTAR II," April 24, 1985.

15.B.8-10 "General Electric Company Analytical Model for Loss-of-Coolant Analysis in Accordance with 10CFR50 Appendix K Amendment No. 2 - One Recirculation Loop Out-of-Service", NEDO-20566-2 Revision 1, July 1978.

ATTACHMENT G

END OF CYCLE - RECIRCULATION PUMP TRIP INOPERABLE AND TURBINE BYPASS INOPERABLE ANALYSIS

Subject: Justification for EOC-RPT Inoperable and Turbine Bypass Inoperable Technical Specification Changes

In order to improve operating flexibility and plant availability, two transient scenarios have been analyzed to support Tech. Spec. changes for minimizing power level reduction.

1. <u>EOC-RPT Inoperable</u>

   The current Limiting Condition for Operation requires that the thermal power be reduced to less than 30% in case the end-of-cycle recirculation pump trip becomes inoperable. In the supporting analysis to jusitfy less power reduction, two limiting cases were examined with the transient code ODYN to define the bounding operating limit critical power ratio (OLCPR).

   a. Feedwater controller failure with EOC-RPT inoperable

   b. Generator load rejection without bypass when EOC-RPT is inoperable

2. <u>Turbine Bypass Inoperable</u>

   The current Limiting Condition for Operation requires that the thermal power be reduced to less than 25% in case the turbine bypass becomes inoperable. In the supporting analysis to justify less power reduction, two limiting cases were examined with ODYN to define the bounding OLCPR.

   a. Feedwater controller failure with turbine bypass inoperable

   b. Loss of feedwater heater with turbine bypass inoperable

Using input determined from EOC-1 nuclear characteristics (see FSAR Table 15.0-3), the bounding OLCPR vs. scram speed is generated for each transient scenario. This OLCPR plot and related Tech. Spec. text revision are included in the attachment.

Please note that these postulated scenarios are transient events beyond the design basis documented in the FSAR. Therefore, FSAR revision is not required.

The attached LCO 3.2.3 and two associated figures replace, in its entirety, the proof and review revision of LCO 3.2.3 and its associated figure on pages 3/4 2-6 and 2-7.

Changes are also provided for LCO's 3.3.4.2 and 3.7.9 for proof and review version of Technical Specifications.

A change is provided for Bases pages B3/4 2-4.

ATTACHMENT A

MARKED UP PROOF AND REVIEW VERSION OF TECHNICAL SPECIFICATIONS

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NINE MILE POINT UNIT 2

TECHNICAL SPECIFICATIONS

APPENDIX "A"

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TECHNICAL SPECIFICATIONS

APPENDIX "A"

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SECTION 1.0

DEFINITIONS

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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.

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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 movable 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.

CORE MAXIMUM FRACTION OF LIMITING POWER DENSITY

1.8 The CORE MAXIMUM FRACTION OF LIMITING POWER DENSITY (CMFLPD) shall be highest value of the FLPD which exists in the core.

CRITICAL POWER RATIO

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

DOSE EQUIVALENT I-131

1.10 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." or Table E-7 of Regulatory Guide 1.109, "Calculation of Annual Doses to Man from Routine Release of Reactor Effluents for the Purpose of Evaluating Compliance with 10 CFR Part 50, Appendix I," Revision 1, October 1977.

$\bar{E}$-AVERAGE DISINTEGRATION ENERGY

1.11 $\bar{E}$ 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

1.12 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,

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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

1.13 The END-OF-CYCLE RECIRCULATION PUMP TRIP SYSTEM RESPONSE TIME shall be that time interval to complete suppression 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.

The response time may be measured by any series of sequential, overlapping or total steps such that the entire response time is measured.

FRACTION OF LIMITING POWER DENSITY

1.14 The FRACTION OF LIMITING POWER DENSITY (FLPD) shall be the LHGR existing at a given location divided by the specified LHGR limit for that bundle type.

FRACTION OF RATED THERMAL POWER

1.15 The FRACTION OF RATED THERMAL POWER (FRTP) shall be the measured THERMAL POWER divided by the RATED THERMAL POWER.

FREQUENCY NOTATION

1.16 The FREQUENCY NOTATION specified for the performance of Surveillance Requirements shall correspond to the intervals defined in Table 1.1.

GASEOUS RADWASTE TREATMENT SYSTEM

1.17 A GASEOUS RADWASTE TREATMENT SYSTEM shall be any system designed and installed to reduce radioactive gaseous effluents by collecting offgases from the main condenser evacuation system and providing for delay or holdup for the purpose of reducing the total radioactivity prior to release to the environment.

IDENTIFIED LEAKAGE

1.18 IDENTIFIED LEAKAGE shall be:

a. Leakage into collection systems, such as pump seal or valve packing leaks, that is captured and conducted to a sump or collecting tank, or

b. Leakage into the containment atmosphere from sources that are both specifically located and known either not to interfere with the operation of the leakage detection systems or not to be PRESSURE BOUNDARY LEAKAGE.

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ISOLATION SYSTEM RESPONSE TIME

1.19 The ISOLATION SYSTEM RESPONSE TIME shall be that time interval from when the monitored parameter exceeds its isolation actuation setpoint at the channel sensor until the isolation valves travel to their required positions. 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.

LIMITING CONTROL ROD PATTERN

1.20 A LIMITING CONTROL ROD PATTERN shall be a pattern which results in the core being on a thermal hydraulic limit, i.e., operating on a limiting value for APLHGR, LHGR, or MCPR.

LINEAR HEAT GENERATION RATE

1.21 LINEAR HEAT GENERATION RATE (LHGR) shall be the heat generation per unit length of fuel rod. It is the integral of the heat flux over the heat transfer area associated with the unit length.

LOGIC SYSTEM FUNCTIONAL TEST

1.22 A LOGIC SYSTEM FUNCTIONAL TEST shall be a test of all logic components, i.e., all relays and contacts, all trip units, solid state logic elements, etc., of a logic circuit, from sensor through and including the actuated device, to verify OPERABILITY. The LOGIC SYSTEM FUNCTIONAL TEST may be performed by any series of sequential, overlapping or total system steps such that the entire logic system is tested.

MEMBER(S) OF THE PUBLIC

1.23 MEMBER(S) OF THE PUBLIC shall include all persons who are not occupationally associated with the Nine Mile Point Nuclear Station and James A. FitzPatrick Nuclear Power Plant. This category does not include employees of Niagara Mohawk Power Corporation, the New York State Power Authority, their contractors or vendors. Also excluded from this category are persons who enter the site to service equipment or to make deliveries. This category does include persons who use portions of the site for recreational, occupational or other purposes not associated with Nine Mile Point Nuclear Station and James A. FitzPatrick Nuclear Power Plant.

MINIMUM CRITICAL POWER RATIO

1.24 The MINIMUM CRITICAL POWER RATIO (MCPR) shall be the smallest CPR which exists in the core.

MILK SAMPLING LOCATION

1.25 A MILK SAMPLING LOCATION is a location where 10 or more head of milk animals are available for the collection of milk samples.

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OFFSITE DOSE CALCULATION MANUAL

1.26 The OFFSITE DOSE CALCULATION MANUAL (ODCM) shall contain the current methodology and parameters used in the calculation of offsite doses due to radioactive gaseous and liquid effluents and in the calculation of gaseous and liquid effluent monitoring alarm/trip setpoints.

OPERABLE - OPERABILITY

1.27 A system, subsystem, train, component or device shall be OPERABLE or have OPERABILITY when it is capable of performing its specified function(s) and when all necessary attendant instrumentation, controls, electrical power, cooling or seal water, lubrication or other auxiliary equipment that are required for the system, subsystem, train, component or device to perform its function(s) are also capable of performing their related support function(s).

OPERATIONAL CONDITION - CONDITION

1.28 An OPERATIONAL CONDITION, i.e., CONDITION, shall be any one inclusive combination of mode switch position and average reactor coolant temperature as specified in Table 1.2.

PHYSICS TESTS

1.29 PHYSICS TESTS shall be those tests performed to measure the fundamental nuclear characteristics of the reactor core and related instrumentation and 1) described in Chapter 14 of the FSAR, 2) authorized under the provisions of 10 CFR 50.59, or 3) otherwise approved by the Commission.

PRESSURE BOUNDARY LEAKAGE

1.30 PRESSURE BOUNDARY LEAKAGE shall be leakage through a non-isolable fault in a reactor coolant system component body, pipe wall or vessel wall.

PRIMARY CONTAINMENT INTEGRITY

1.31 PRIMARY CONTAINMENT INTEGRITY shall exist when:

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

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

   2. Closed by at least one manual valve, blind flange, or deactivated automatic valve secured in its closed position, except as provided in Table 3.6.3-1 of Specification 3.6.3.

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

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

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

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

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

PROCESS CONTROL PROGRAM

1.32 The PROCESS CONTROL PROGRAM (PCP) shall contain the sampling, analysis, and formulation determination by which SOLIDIFICATION of radioactive wastes from liquid systems is assured.

PURGE - PURGING

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

RATED THERMAL POWER

1.34 RATED THERMAL POWER shall be a total reactor core heat transfer rate to the reactor coolant of 3323 MWt.

REACTOR PROTECTION SYSTEM RESPONSE TIME

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

REPORTABLE EVENT

1.36 A REPORTABLE EVENT shall be any of those conditions specified in Section 50.73 to 10 CFR Part 50.

ROD DENSITY

1.37 ROD DENSITY shall be the number of control rod notches inserted as a fraction of the total number of control rod notches. All rods fully inserted is equivalent to 100% ROD DENSITY.

SECONDARY CONTAINMENT INTEGRITY

1.38 SECONDARY CONTAINMENT INTEGRITY shall exist when:

a. All Reactor Building and Auxiliary Bays penetrations required to be closed during accident conditions are either:

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1. Capable of being closed by an OPERABLE Reactor Building automatic isolation system, or

2. Closed by at least one manual valve, blind flange, or deactivated automatic damper secured in its closed position, except as provided in Table 3.6.5.2-1 of Specification 3.6.5.2.

b. All Auxiliary Bays hatches are closed and sealed.

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

d. At least one door in each access to the Reactor Building and Auxiliary Bays are closed.

e. The sealing mechanism associated with each Reactor Building and Auxiliary Bays penetration, e.g., welds, bellows or O-rings, is OPERABLE.

f. The pressure within the Reactor Building, and Auxiliary Bays is less than or equal to the value required by Specification 4.6.5.1.a.

SHUTDOWN MARGIN

1.39 SHUTDOWN MARGIN shall be the amount of reactivity by which the reactor is subcritical or would be subcritical assuming all control rods are fully inserted except for the single control rod of highest reactivity worth which is assumed to be fully withdrawn and the reactor is in the shutdown condition; cold, i.e., 68°F; and xenon free.

SITE BOUNDARY

1.40 The SITE BOUNDARY shall be that line around the Nine Mile Point Nuclear Station beyond which the land is not owned, leased, or otherwise controlled by the Niagara Mohawk Power Corporation or the New York State Power Authority.

SOLIDIFICATION

1.41 SOLIDIFICATION shall be the conversion of wet wastes into a form that meets shipping and burial ground requirements.

SOURCE CHECK

1.42 A SOURCE CHECK shall be the qualitative assessment of channel response when the channel sensor is exposed to a source of increased activity.

STAGGERED TEST BASIS

1.43 A STAGGERED TEST BASIS shall consist of:

a. A test schedule for n systems, subsystems, trains or other designated components obtained by dividing the specified test interval into n equal subintervals.

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b. The testing of one system, subsystem, train or other designated component at the beginning of each subinterval.

THERMAL POWER

1.44 THERMAL POWER shall be the total reactor core heat transfer rate to the reactor coolant.

TURBINE BYPASS SYSTEM RESPONSE TIME

1.45 The TURBINE BYPASS SYSTEM RESPONSE TIME consists of two time intervals:

a. Time from initial movement of the main turbine stop valve or control valve until 80% of turbine bypass capacity is established, and

b. the time from initial movement of the main turbine stop valve or control valve until initial movement of the turbine bypass valve. Either response times may be measured by any series of sequential, overlapping or total steps such that both entire response time components are measured.

UNIDENTIFIED LEAKAGE

1.46 UNIDENTIFIED LEAKAGE shall be all leakage which is not IDENTIFIED LEAKAGE.

UNRESTRICTED AREA

1.47 An UNRESTRICTED AREA shall be any area at or beyond the SITE BOUNDARY access to which is not controlled by the Niagara Mohawk Power Corporation or the New York State Power Authority for purposes of protection of individuals from exposure to radiation and radioactive materials, or any area within the site boundary used for residential quarters or for industrial, commercial, institutional, and/or recreational purposes.

VENTILATION EXHAUST TREATMENT SYSTEM

1.48 A VENTILATION EXHAUST TREATMENT SYSTEM shall be any system designed and installed to reduce gaseous radioiodine or radioactive material in particulate form in effluents by passing ventilation or vent exhaust gases through charcoal adsorbers and/or HEPA filters for the purpose of removing iodines or particulates from the gaseous exhaust stream prior to the release to the environment (such a system is not considered to have any effect on noble gas effluents). Engineered Safety Features (ESF) atmospheric cleanup systems are not considered to be VENTILATION EXHAUST TREATMENT SYSTEM components.

VENTING

1.49 VENTING shall be the controlled process of discharging air or gas from a confinement to maintain temperature, pressure, concentration, or other operating condition, in such a manner that replacement air or gas is not provided or required during VENTING. Vent, used in system names, does not imply a VENTING process.

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TABLE 1.1

SURVEILLANCE FREQUENCY NOTATION

NOTATION	FREQUENCY
S	At least once per 12 hours.
D	At least once per 24 hours.
W	At least once per 7 days.
M	At least once per 31 days.
Q	At least once per 92 days.
SA	At least once per 184 days.
A	At least once per 366 days.
R	At least once per 18 months (550 days).
S/U	Prior to each reactor startup.
P	Prior to each radioactive release
NA	Not applicable.

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TABLE 1.2

OPERATIONAL CONDITIONS

CONDITION	MODE SWITCH POSITION	AVERAGE REACTOR COOLANT TEMPERATURE
1. POWER OPERATION	Run	Any temperature
2. STARTUP	Startup/Hot Standby	Any temperature
3. HOT SHUTDOWN	Shutdown#,***	> 200°F
4. COLD SHUTDOWN	Shutdown#,##,***	≤ 200°F
5. REFUELING*	Shutdown or Refuel**,#	≤ 140°F

#The reactor mode switch may be placed in the Run or Startup/Hot Standby position to test the switch interlock functions provided that the control rods are verified to remain fully inserted by a second licensed operator or other technically qualified member of the unit technical staff.

##The reactor mode switch may be placed in the Refuel position while a single control rod drive is being removed from the reactor pressure vessel per Specification 3.9.10.1.

*Fuel in the reactor vessel with the vessel head closure bolts less than fully tensioned or with the head removed.

**See Special Test Exceptions 3.10.1 and 3.10.3.

***The reactor mode switch may be placed in the Refuel position while a single control rod is being recoupled provided that the one-rod-out interlock is OPERABLE.

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SECTION 2.0

SAFETY LIMITS

AND

LIMITING SAFETY SYSTEM SETTINGS

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2.0 SAFETY LIMITS AND LIMITING SAFETY SYSTEM SETTINGS

2.1 SAFETY LIMITS

THERMAL POWER, Low Pressure or Low Flow

2.1.1 THERMAL POWER shall not exceed 25% of RATED THERMAL POWER with the reactor vessel steam dome pressure less than 785 psig or core flow less than 10% of rated flow.

APPLICABILITY: OPERATIONAL CONDITIONS 1 and 2.

ACTION:

With THERMAL POWER exceeding 25% of RATED THERMAL POWER and the reactor vessel steam dome pressure less than 785 psig or core flow less than 10% of rated flow, be in at least HOT SHUTDOWN within 2 hours and comply with the requirements of Specification 6.7.1.

THERMAL POWER, High Pressure and High Flow

2.1.2 The MINIMUM CRITICAL POWER RATIO (MCPR) shall not be less than 1.06 with the reactor vessel steam dome pressure greater than 785 psig and core flow greater than 10% of rated flow.

APPLICABILITY: OPERATIONAL CONDITIONS 1 and 2.

ACTION:

With MCPR less than 1.06 and the reactor vessel steam dome pressure greater than 785 psig and core flow greater than 10% of rated flow, be in at least HOT SHUTDOWN within 2 hours and comply with the requirements of Specification 6.7.1.

REACTOR COOLANT SYSTEM PRESSURE

2.1.3 The reactor coolant system pressure, as measured in the reactor vessel steam dome, shall not exceed 1325 psig.

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

ACTION:

With the reactor coolant system pressure, as measured in the reactor vessel steam dome, above 1325 psig, be in at least HOT SHUTDOWN with reactor coolant system pressure less than or equal to 1325 psig within 2 hours and comply with the requirements of Specification 6.7.1.

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SAFETY LIMITS (Continued)

REACTOR VESSEL WATER LEVEL

2.1.4 The reactor vessel water level shall be above the top of the active irradiated fuel.

APPLICABILITY: OPERATIONAL CONDITIONS 3, 4 and 5

ACTION:

With the reactor vessel water level at or below the top of the active irradiated fuel, manually initiate the ECCS to restore the water level, after depressurizing the reactor vessel, if required. Comply with the requirements of Specification 6.7.1.

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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	≤ 0.66 W+51%, with a maximum of	≤ 0.66 W+54%, with a maximum of
2) High Flow Clamped	≤ 113.5% of RATED THERMAL POWER	≤ 115.5% of RATED THERMAL POWER
c. Fixed 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	≥ 159.3 inches above instrument zero*	≥ 157.8 inches above instrument zero
5. Main Steam Line Isolation Valve - Closure	≤ 6% closed	≤ 7% closed
6. Main Steam Line Radiation - High	≤ 3.0 x full power background	≤ 3.6 x full power background
7. Drywell Pressure - High	≤ 1.68 psig	≤ 1.88 psig
8. Scram Discharge Volume Water Level - High		
a. Level Transmitter/Trip Units	≤ 46.5 inches	≤ 79.5 inches
b. Float Switch	≤ 46.5 inches	≤ 79.5 inches
9. Turbine Stop Valve - Closure	≤ 5% closed	≤ 7% closed
10. Turbine Control Valve Fast Closure, Trip Oil Pressure - Low	≥ 530 psig	≥ 465 psig
11. Reactor Mode Switch Shutdown Position	NA	NA
12. Manual Scram	NA	NA

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

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BASES

FOR

SECTION 2.0

SAFETY LIMITS

AND

LIMITING SAFETY SYSTEM SETTINGS

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NOTE

The BASES contained in succeeding pages summarize the reasons for the Specifications in Section 2.0, but in accordance with 10 CFR 50.36 are not part of these Technical Specifications.

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BASES

2.0 INTRODUCTION

The fuel cladding, reactor pressure vessel and primary system piping are the principal barriers to the release of radioactive materials to the environs. Safety Limits are established to protect the integrity of these barriers during normal plant operations and anticipated transients. The fuel cladding integrity Safety Limit is set such that no fuel damage is calculated to occur if the limit is not violated. Because fuel damage is not directly observable, a step-back approach is used to establish a Safety Limit such that the MCPR is not less than 1.06. MCPR greater than 1.06 represents a conservative margin relative to the conditions required to maintain fuel cladding integrity. The fuel cladding is one of the physical barriers which separate the radioactive materials from the environs. The integrity of this cladding barrier is related to its relative freedom from perforations or cracking. Although some corrosion or use-related cracking may occur during the life of the cladding, fission product migration from this source is incrementally cumulative and continuously measurable. Fuel cladding perforations, however, can result from thermal stresses which occur from reactor operation significantly above design conditions and the Limiting Safety System Settings. While fission product migration from cladding perforation is just as measurable as that from use-related cracking, the thermally caused cladding perforations signal a threshold beyond which still greater thermal stresses may cause gross rather than incremental cladding deterioration. Therefore, the fuel cladding Safety Limit is defined with a margin to the conditions which would produce onset of transition boiling, MCPR of 1.0. These conditions represent a significant departure from the condition intended by design for planned operation.

2.1.1 THERMAL POWER, Low Pressure or Low Flow

The use of the GEXL correlation is not valid for all critical power calculations at pressures below 785 psig or core flows less than 10% of rated flow. Therefore, the fuel cladding integrity Safety Limit is established by other means. This is done by establishing a limiting condition on core THERMAL POWER with the following basis. Since the pressure drop in the bypass region is essentially all elevation head, the core pressure drop at low power and flows will always be greater than 4.5 psi. Analyses show that with a bundle flow of 28 x 10^3 lbs/hr, bundle pressure drop is nearly independent of bundle power and has a value of 3.5 psi. Thus, the bundle flow with a 4.5 psi driving head will be greater than 28 x 10^3 lbs/hr. Full scale ATLAS test data taken at pressures from 14.7 psia to 800 psia indicate that the fuel assembly critical power at this flow is approximately 3.35 MWt. With the design peaking factors, this corresponds to a THERMAL POWER of more than 50% of RATED THERMAL POWER. Thus, a THERMAL POWER limit of 25% of RATED THERMAL POWER for reactor pressure below 785 psig is conservative.

2.1.2 THERMAL POWER, High Pressure and High Flow

The fuel cladding integrity Safety Limit is set such that no fuel damage is calculated to occur if the limit is not violated. Since the parameters which result in fuel damage are not directly observable during reactor operation, the thermal and hydraulic conditions resulting in a departure from nucleate boiling have been used to mark the beginning of the region where fuel damage could occur. Although it is recognized that a departure from nucleate boiling would not necessarily result in damage to BWR fuel rods, the critical power at which boiling transition is calculated to occur has been adopted as a convenient limit. However, the uncertainties in monitoring the core operating state and in the procedures used to calculate the critical power result in an uncertainty in the value of the critical power. Therefore, the fuel cladding integrity Safety Limit is defined as the CPR in the limiting fuel assembly for which more than 99.9% of the fuel rods in the core are expected to avoid boiling transition considering the power distribution within the core and all uncertainties.

The Safety Limit MCPR is determined using the General Electric Thermal Analysis Basis, GETAB[a], which is a statistical model that combines all of the uncertainties in operating parameters and the procedures used to calculate critical power. The probability of the occurrence of boiling transition is determined using the General Electric Critical Quality (X) Boiling Length (L), (GEXL), correlation. The GEXL correlation is valid over the range of conditions used in the tests of the data used to develop the correlation.

The required input to the statistical model are the uncertainties listed in Bases Table B2.1.2-1 and the nominal values of the core parameters listed in Bases Table B2.1.2-2.

The bases for the uncertainties in the core parameters are given in NEDO-20340[b] and the basis for the uncertainty in the GEXL correlation is given in NEDO-10958-A[a]. The power distribution is based on a typical 764 assembly core in which the rod pattern was arbitrarily chosen to produce a skewed power distribution having the greatest number of assemblies at the highest power levels. The worst distribution during any fuel cycle would not be as severe as the distribution used in the analysis.

---

a. "General Electric BWR Thermal Analysis Bases (GETAB) Data, Correlation and Design Application," NEDO-10958-A.

b. General Electric "Process Computer Performance Evaluation Accuracy" NEDO-20340 and Amendment 1, NEDO-20340-1 dated June 1974 and December 1974, respectively.

Bases Table B2.1.2-1

UNCERTAINTIES USED IN THE DETERMINATION

OF THE FUEL CLADDING SAFETY LIMIT*

Quantity	Standard Deviation (% of Point)
Feedwater Flow	1.76
Feedwater Temperature	0.76
Reactor Pressure	0.5
Core Inlet Temperature	0.2
Core Total Flow	2.5
Channel Flow Area	3.0
Friction Factor Multiplier	10.0
Channel Friction Factor Multiplier	5.0
TIP Readings	6.3
R Factor	1.5
Critical Power	3.6

* The uncertainty analysis used to establish the core wide Safety Limit MCPR is based on the assumption of quadrant power symmetry for the reactor core.

Bases Table B2.1.2-2

NOMINAL VALUES OF PARAMETERS USED IN

THE STATISTICAL ANALYSIS OF FUEL CLADDING INTEGRITY SAFETY LIMIT

THERMAL POWER	3323 MW
Core Flow	108.5 Mlb/hr
Dome Pressure	1010.4 psig
Channel Flow Area	0.1089 ft^2
R-Factor	High enrichment - 1.043 Medium enrichment - 1.039 Low enrichment - 1.030

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2.1.3 REACTOR COOLANT SYSTEM PRESSURE

The Safety Limit for the reactor coolant system pressure has been selected such that it is at a pressure below which it can be shown that the integrity of the system is not endangered. The reactor pressure vessel is designed to Section III of the ASME Boiler and Pressure Vessel Code 1971 Edition, including Addenda through Winter 1972, which permits a maximum pressure transient of 110%, 1375 psig, of design pressure, 1250 psig. The Safety Limit of 1325 psig, as measured by the reactor vessel steam dome pressure indicator, is equivalent to 1375 psig at the lowest elevation of the reactor coolant system. The reactor coolant system is designed to Section III of the ASME Boiler and Pressure Vessel Code, 1977 Edition, including Addenda through Summer 1977 for the reactor recirculation piping, which permits a maximum pressure transient of 120% of design pressure. The design pressures are 1250 psig for suction piping and 1650 psig for discharge piping to the exit of the discharge block valve and 1550 psig for the remainder of the discharge piping to the vessel nozzles. The pressure Safety Limit is selected to be the lowest transient overpressure allowed by Section III of the ASME Boiler and Pressure Vessel Code, 1971 Edition, including Addenda through, Winter 1972.

2.1.4 REACTOR VESSEL WATER LEVEL

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

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2.2.1 REACTOR PROTECTION SYSTEM INSTRUMENTATION SETPOINTS

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

1. Intermediate Range Monitor, Neutron Flux - High

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

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

2. Average Power Range Monitor

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

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REACTOR PROTECTION SYSTEM INSTRUMENTATION SETPOINTS (Continued)

Average Power Range Monitor (Continued)

rod withdrawal is the most probable cause of significant power increase. Because the flux distribution associated with uniform rod withdrawals does not involve high local peaks and because several rods must be moved to change power by a significant amount, the rate of power rise is very slow. Generally the heat flux is in near equilibrium with the fission rate. In an assumed uniform rod withdrawal approach to the trip level, the rate of power rise is not more than 5% of RATED THERMAL POWER per minute and the APRM system would be more than adequate to assure shutdown before the power could exceed the Safety Limit. The 15% neutron flux trip remains active until the mode switch is placed in the Run position.

The APRM trip system is calibrated using heat balance data taken during steady state conditions. Fission chambers provide the basic input to the system and therefore the monitors respond directly and quickly to changes due to transient operation for the case of the Fixed Neutron Flux-Upscale setpoint; i.e., for a power increase, the THERMAL POWER of the fuel will be less than that indicated by the neutron flux due to the time constants of the heat transfer associated with the fuel. For the Flow Biased Simulated Thermal Power-Upscale setpoint, a time constant of 6 ± 0.6 seconds is introduced into the flow biased APRM in order to simulate the fuel thermal transient characteristics. A more conservative maximum value is used for the flow biased setpoint as shown in Table 2.2.1-1.

The APRM setpoints were selected to provide adequate margin for the Safety Limits and yet allow operating margin that reduces the possibility of unnecessary shutdown. The flow referenced trip setpoint must be adjusted by the specified formula in Specification 3.2.2 in order to maintain these margins when CMFLPD is greater than or equal to FRTP.

3. Reactor Vessel Steam Dome Pressure-High

High pressure in the nuclear system could cause a rupture to the nuclear system process barrier resulting in the release of fission products. A pressure increase while operating will also tend to increase the power of the reactor by compressing voids thus adding reactivity. The trip will quickly reduce the neutron flux, counteracting the pressure increase. The trip setting is slightly higher than the operating pressure to permit normal operation without spurious trips. The setting provides for a wide margin to the maximum allowable design pressure and takes into account the location of the pressure measurement compared to the highest pressure that occurs in the system during a transient. This trip setpoint is effective at low power/flow conditions when the turbine control valve fast closure, and turbine stop valve closure trips are bypassed. For load rejection or a turbine trip under these conditions, the transient analysis indicated an adequate margin to the thermal hydraulic limit.

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REACTOR PROTECTION SYSTEM INSTRUMENTATION SETPOINTS (Continued)

4. Reactor Vessel Water Level-Low

The reactor vessel water level trip setpoint was chosen far enough below the normal operating level to avoid spurious trips but high enough above the fuel to assure that there is adequate protection for the fuel and pressure limits.

5. Main Steam Line Isolation Valve-Closure

The main steam line isolation valve closure trip was provided to limit the amount of fission product release for certain postulated events. The MSIV's are closed automatically from measured parameters such as high steam flow, high steam line radiation, low reactor water level, high steam tunnel temperature, and low steam line pressure. The MSIV's closure scram anticipates the pressure and flux transients which could follow MSIV closure and thereby protects reactor vessel pressure and fuel thermal/hydraulic Safety Limits.

6. Main Steam Line Radiation-High

The main steam line radiation detectors are provided to detect a gross failure of the fuel cladding. When the high radiation is detected, a trip is initiated to reduce the continued failure of fuel cladding. At the same time the main steam line isolation valves are closed to limit the release of fission products. The trip setting is high enough above background radiation levels to prevent spurious trips yet low enough to promptly detect gross failures in the fuel cladding.

7. Drywell Pressure-High

High pressure in the drywell could indicate a break in the primary pressure boundary systems. The reactor is tripped in order to minimize the possibility of fuel damage and reduce the amount of energy being added to the coolant. The trip setting was selected as low as possible without causing spurious trips.

8. Scram Discharge Volume Water Level-High

The scram discharge volume receives the water displaced by the motion of the control rod drive pistons during a reactor scram. Should this volume fill up to a point where there is insufficient volume to accept the displaced water at pressures below 65 psig, control rod insertion would be hindered. The reactor is therefore tripped when the water level has reached a point high enough to indicate that it is indeed filling up, but the volume is still great enough to accommodate the water from the movement of the rods at pressures below 65 psig when they are tripped. The trip setpoint for each scram discharge volume is equivalent to a contained volume of approximately 25 gallons of water.

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REACTOR PROTECTION SYSTEM INSTRUMENTATION SETPOINTS (Continued)

9. Turbine Stop Valve-Closure

5%

The turbine stop valve closure trip anticipates the pressure, neutron flux, and heat flux increases that would result from closure of the stop valves. With a trip setting of ~~6%~~ of valve closure from full open, the resultant increase in heat flux is such that adequate thermal margins are maintained during the worst case transient.

10. Turbine Control Valve Fast Closure, Trip Oil Pressure-Low

The turbine control valve fast closure trip anticipates the pressure, neutron flux, and heat flux increase that could result from fast closure of the turbine control valves due to load rejection with or without coincident failure of the turbine bypass valves. The Reactor Protection System initiates a trip when fast closure of the control valves is initiated by the fast acting solenoid valves and in less than 30 milliseconds after the start of control valve fast closure. This is achieved by the action of the fast acting solenoid valves in rapidly reducing hydraulic trip oil pressure at the main turbine control valve actuator disc dump valves. This loss of pressure is sensed by pressure switches whose contacts form the one-out-of-two-twice logic input to the Reactor Protection System. This trip setting, a slower closure time, and a different valve characteristic from that of the turbine stop valve, combine to produce transients which are very similar to that for the stop valve. Relevant transient analyses are discussed in Section 15.2.2 of the Final Safety Analysis Report.

11. Reactor Mode Switch Shutdown Position

The reactor mode switch Shutdown position is a redundant channel to the automatic protective instrumentation channels and provides additional manual reactor trip capability.

12. Manual Scram

The Manual Scram is a redundant channel to the automatic protective instrumentation channels and provides manual reactor trip capability.

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SECTIONS 3.0 and 4.0

LIMITING CONDITIONS FOR OPERATION

AND

SURVEILLANCE REQUIREMENTS

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LIMITING CONDITION FOR OPERATION

3.0.1 Compliance with the Limiting Conditions for Operation contained in the succeeding Specifications is required during the OPERATIONAL CONDITIONS or other conditions specified therein; except that upon failure to meet the Limiting Conditions for Operation, the associated ACTION requirements shall be met.

3.0.2 Noncompliance with a Specification shall exist when the requirements of the Limiting Condition for Operation and associated ACTION requirements are not met within the specified time intervals. If the Limiting Condition for Operation is restored prior to expiration of the specified time intervals, completion of the Action requirements is not required.

3.0.3 When a Limiting Condition for Operation is not met, except as provided in the associated ACTION requirements, within one hour action shall be initiated to place the unit in an OPERATIONAL CONDITION in which the Specification does not apply by placing it, as applicable, in:

1. At least STARTUP within the next 6 hours,
2. At least HOT SHUTDOWN within the following 6 hours, and
3. At least COLD SHUTDOWN within the subsequent 24 hours.

Where corrective measures are completed that permit operation under the ACTION requirements, the ACTION may be taken in accordance with the specified time limits as measured from the time of failure to meet the Limiting Condition for Operation. Exceptions to these requirements are stated in the individual Specifications.

This Specification is not applicable in OPERATIONAL CONDITIONS 4 or 5.

3.0.4 Entry into an OPERATIONAL CONDITION or other specified condition shall not be made unless the conditions for the Limiting Condition for Operation are met without reliance on provisions contained in the ACTION requirements. This provision shall not prevent passage through or to OPERATIONAL CONDITIONS as required to comply with ACTION requirements. Exceptions to these requirements are stated in the individual Specifications.

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APPLICABILITY

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SURVEILLANCE REQUIREMENTS

4.0.1 Surveillance Requirements shall be met during the OPERATIONAL CONDITIONS or other conditions specified for individual Limiting Conditions for Operation unless otherwise stated in an individual Surveillance Requirement.

4.0.2 Each Surveillance Requirement shall be performed within the specified time interval with:

a. A maximum allowable extension not to exceed 25% of the surveillance interval, but

b. The combined time interval for any three consecutive surveillance intervals shall not exceed 3.25 times the specified surveillance interval.

4.0.3 Failure to perform a Surveillance Requirement within the specified time interval shall constitute a failure to meet the OPERABILITY requirements for a Limiting Condition for Operation. Exceptions to these requirements are stated in the individual Specifications. Surveillance requirements do not have to be performed on inoperable equipment.

4.0.4 Entry into an OPERATIONAL CONDITION or other specified applicable condition shall not be made unless the Surveillance Requirement(s) associated with the Limiting Condition for Operation have been performed within the applicable surveillance interval or as otherwise specified.

4.0.5 Surveillance Requirements for inservice inspection and testing of ASME Code Class 1, 2, and 3 components shall be applicable as follows:

a. Inservice inspection of ASME Code Class 1, 2, and 3 components and inservice testing of ASME Code Class 1, 2, and 3 pumps and valves shall be performed in accordance with Section XI of the ASME Boiler and Pressure Vessel Code and applicable Addenda as required by 10 CFR 50, Section 50.55a(g), except where specific written relief has been granted by the Commission pursuant to 10 CFR 50, Section 50.55a(g)(6)(i).

b. Surveillance intervals specified in Section XI of the ASME Boiler and Pressure Vessel Code and applicable Addenda for the inservice inspection and testing activities required by the ASME Boiler and Pressure Vessel Code and applicable Addenda shall be applicable as follows in these Technical Specifications:

ASME Boiler and Pressure Vessel Code and applicable Addenda terminology for inservice inspection and testing activities	Required frequencies for performing inservice inspection and testing activities
Weekly	At least once per 7 days
Monthly	At least once per 31 days
Quarterly or every 3 months	At least once per 92 days
Semiannually or every 6 months	At least once per 184 days
Every 9 months	At least once per 276 days
Yearly or annually	At least once per 366 days

APPLICABILITY

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SURVEILLANCE REQUIREMENTS (Continued)

c. The provisions of Specification 4.0.2 are applicable to the above required frequencies for performing inservice inspection and testing activities.

d. Performance of the above inservice inspection and testing activities shall be in addition to other specified Surveillance Requirements.

e. Nothing in the ASME Boiler and Pressure Vessel Code shall be construed to supersede the requirements of any Technical Specification.

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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.

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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 equivalence difference exceeding 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.

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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 cells in all directions.

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

      ~~1) Electrically, or~~

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

   c) Comply with Surveillance Requirement 4.1.1.c.

   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 trippable but inoperable for causes other than addressed in ACTION a, above:

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

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

   b) Demonstrate 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.

*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.

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LIMITING CONDITION FOR OPERATION (Continued)

ACTION (Continued)

2. If the inoperable control rod(s) is inserted, within one 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.

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

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.

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

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

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SURVEILLANCE REQUIREMENTS (Continued)

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 at least once per 18 months, by verifying that the drain and vent valves:

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 within 72 hours after each scram from a pressurized condition greater than or equal to 900 psig.

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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 deenergization 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.

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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 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	0.43
39	0.86
25	1.93
5	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.

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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
5	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.

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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:

   a) If the 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 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*:

1. With one withdrawn control rod with its associated scram accumulator inoperable, insert the affected control rod and disarm the associated directional control valves within one hour, either:

   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 accumulator inoperable or no control rod drive pump operating, immediately place the reactor mode switch in the Shutdown position.

c. The provisions of Specification 3.0.4 are not applicable.

*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.

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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 ≥ ~~940~~ psig on decreasing pressure.
1625 +30 −0

2. Measuring and recording for up to 10 minutes that each individual accumulator check valve maintains the associated accumulator pressure above the alarm set point with no control rod drive pump charging water supplying the scram accumulators by closing charging water manual isolation valve V28 and depressurizing charging water header by opening valves V67 and V68.

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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.

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

   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.

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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.

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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 one hour:

   1. Determine the position of the control rod

      a) By full out indication if rod is fully withdrawn, or

      b) By full in indication if rod is fully inserted, or

      c) For the affected inoperable control rod position, verify one notch "out" and one notch "in" control rod indicators OPERABLE, and

      d) 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

* 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.

ACTION: (Continued)

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.

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 the full out position indicator when performing Surveillance Requirement 4.1.3.6.b.

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

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CONTROL ROD DRIVE HOUSING SUPPORT

LIMITING CONDITION FOR OPERATION

3.1.3.8 The control rod drive housing support shall be in place.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2 and 3.

ACTION:

With the control rod drive housing support not in place, be in at least HOT SHUTDOWN within 12 hours and in COLD SHUTDOWN within the following 24 hours.

SURVEILLANCE REQUIREMENTS

4.1.3.8 The control rod drive housing support shall be verified to be in place by a visual inspection prior to startup any time it has been disassembled or when maintenance has been performed in the control rod drive housing support area.

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3/4.1.4 CONTROL ROD PROGRAM CONTROLS

ROD WORTH MINIMIZER

LIMITING CONDITION FOR OPERATION

3.1.4.1 The rod worth minimizer (RWM) shall be OPERABLE.

APPLICABILITY: OPERATIONAL CONDITIONS 1 and 2*, when THERMAL POWER is less than or equal to 20% of RATED THERMAL POWER, the minimum allowable low power setpoint.

ACTION:

a. With the RWM inoperable, verify control rod movement and compliance with the prescribed control rod pattern by a second licensed operator or other technically qualified member of the unit technical staff who is present at the reactor control console. Otherwise, control rod movement is permitted only by actuating the manual scram or by placing the reactor mode switch in the Shutdown position.

b. The provisions of Specification 3.0.4 are not applicable.

SURVEILLANCE REQUIREMENTS

4.1.4.1 The RWM shall be demonstrated OPERABLE:

a. In OPERATIONAL CONDITION 2 within 8 hours prior to withdrawal of control rods for the purpose of making the reactor critical, and in OPERATIONAL CONDITION 1 within 8 hours prior to RWM automatic initiation when reducing THERMAL POWER, by verifying proper indication of the selection error of at least one out-of-sequence control rod.

b. In OPERATIONAL CONDITION 2 within 8 hours prior to withdrawal of control rods for the purpose of making the reactor critical, by verifying the rod block function by demonstrating inability to withdraw an out-of-sequence control rod.

c. In OPERATIONAL CONDITION 1 within one hour after RWM automatic initiation when reducing THERMAL POWER, by verifying the rod block function by demonstrating inability to withdraw an out-of-sequence control rod.

d. By demonstrating that the control rod patterns and sequence input to the RWM computer are correctly loaded following any loading of the program into the computer.

*Entry into OPERATIONAL CONDITION 2 and withdrawal of selected control rods is permitted for the purpose of determining the OPERABILITY of the RWM prior to withdrawal of control rods for the purpose of bringing the reactor to criticality.

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ROD SEQUENCE CONTROL SYSTEM

LIMITING CONDITION FOR OPERATION

3.1.4.2 The rod sequence control system (RSCS) shall be OPERABLE.

APPLICABILITY: OPERATIONAL CONDITIONS 1 and 2*#, when THERMAL POWER is less than or equal to 20% RATED THERMAL POWER, the minimum allowable low power setpoint.

ACTION:

a. With the RSCS inoperable, control rod movement shall not be permitted, except by a scram.

b. With an inoperable control rod(s), OPERABLE control rod movement may continue by bypassing the inoperable control rod(s) in the RSCS provided that:

 1. The position and bypassing of inoperable control rods is verified by a second licensed operator or other technically qualified member of the unit technical staff, and
 2. There are not more than 3 inoperable control rods in any RSCS group.

SURVEILLANCE REQUIREMENTS

4.1.4.2 The RSCS shall be demonstrated OPERABLE by:

a. Performance of a self-test:

 1. Within 8 hours prior to each reactor startup, and
 2. Prior to movement of a control rod after rod inhibit mode automatic initiation when reducing THERMAL POWER.

b. Attempting to select and move an inhibited control rod:

 1. After withdrawal of the first insequence control rod for each reactor startup, and
 2. Within one hour after rod inhibit mode automatic initiation when reducing THERMAL POWER.

*See Special Test Exception 3.10.2
#Entry into OPERATIONAL CONDITION 2 and withdrawal of selected control rods is permitted for the purpose of determining the OPERABILITY of the RSCS prior to withdrawal of control rods for the purpose of bringing the reactor to criticality.

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ROD BLOCK MONITOR

LIMITING CONDITION FOR OPERATION

3.1.4.3 Both rod block monitor (RBM) channels shall be OPERABLE.

APPLICABILITY: OPERATIONAL CONDITION 1, when THERMAL POWER is greater than or equal to 30% of RATED THERMAL POWER.

ACTION:

a. With one RBM channel inoperable:

   1. Verify that the reactor is not operating on a LIMITING CONTROL ROD PATTERN, and

   2. Restore the inoperable RBM channel to OPERABLE status within 24 hours.

   Otherwise, place the inoperable rod block monitor channel in the tripped condition within the next hour.

b. With both RBM channels inoperable, place at least one inoperable rod block monitor channel in the tripped condition within one hour.

SURVEILLANCE REQUIREMENTS

4.1.4.3 Each of the above required RBM channels shall be demonstrated OPERABLE by performance of a:

a. CHANNEL FUNCTIONAL TEST and CHANNEL CALIBRATION at the frequencies and for the OPERATIONAL CONDITIONS specified in Table 4.3.6-1.

b. CHANNEL FUNCTIONAL TEST prior to control rod withdrawal when the reactor is operating on a LIMITING CONTROL ROD PATTERN.

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3/4.1.5 STANDBY LIQUID CONTROL SYSTEM

LIMITING CONDITION FOR OPERATION

3.1.5 The standby liquid control system shall be OPERABLE.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, and 5*

ACTION:

a. In OPERATIONAL CONDITION 1 or 2:

1. With one pump and/or one explosive valve inoperable, restore the inoperable pump and/or explosive valve to OPERABLE status within 7 days or be in at least HOT SHUTDOWN within the next 12 hours.

2. With the standby liquid control system otherwise inoperable, restore the system to OPERABLE status within 8 hours or be in at least HOT SHUTDOWN within the next 12 hours.

b. In OPERATIONAL CONDITION 5*:

1. With one pump and/or one explosive valve inoperable, restore the inoperable pump and/or explosive valve to OPERABLE status within 30 days or insert all insertable control rods within the next hour.

2. With the standby liquid control system otherwise inoperable, insert all insertable control rods within one hour.

SURVEILLANCE REQUIREMENTS

4.1.5 The standby liquid control system shall be demonstrated OPERABLE:

a. At least once per 24 hours by verifying that;

1. The temperature of the sodium pentaborate solution in the storage tank is $\geq$ 70°F.

2. The available volume of sodium pentaborate solution is within the limits of Figure 3.1.5-1.

3. The temperature of the pump suction piping is $\geq$ 70°F.

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

b. At least once per 31 days by:

1. Verifying the continuity of the explosive charge.

2. Determining that the available weight of sodium pentaborate is greater than or equal to 5493 lbs and the concentration of boron in solution is within the limits of Figure 3.1.5-1 by chemical analysis.*

3. 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.

c. Demonstrating that, when tested pursuant to Specification 4.0.5 the minimum flow requirement of 41.2 gpm per pump at a pressure of greater than or equal to 1220 psig is met.

d. At least once per 18 months during shutdown by:

1. Initiating one of the standby liquid control system loops, including an explosive valve, and verifying that a flow path from the pumps to the reactor pressure vessel is available by pumping demineralized water into the reactor vessel. The replacement charge for the explosive valve shall be from the same manufactured batch as the one fired or from another batch which has been certified by having one of that batch successfully fired. Both injection loops shall be tested in 36 months.

2. Demonstrating that the pump relief valve setpoint is less than or equal to 1387*** psig and verifying that the relief valve does not actuate during recirculation to the test tank.

3. **Demonstrating that all heat traced piping between the storage tank and the reactor vessel is unblocked by pumping from the storage tank to the test tank and then draining and flushing the piping with demineralized water.

4. Demonstrating that the storage tank heaters are OPERABLE by verifying the expected temperature rise of the sodium pentaborate solution in the storage tank after the heaters are energized.

*This test shall also be performed anytime water or boron is added to the solution or when the solution temperature drops below 70°F.

**This test shall also be performed whenever both heat tracing circuits have been found to be inoperable and may be performed by any series of sequential, overlapping or total flow path steps such that the entire flow path is included.

***Bench tested setpoint value.

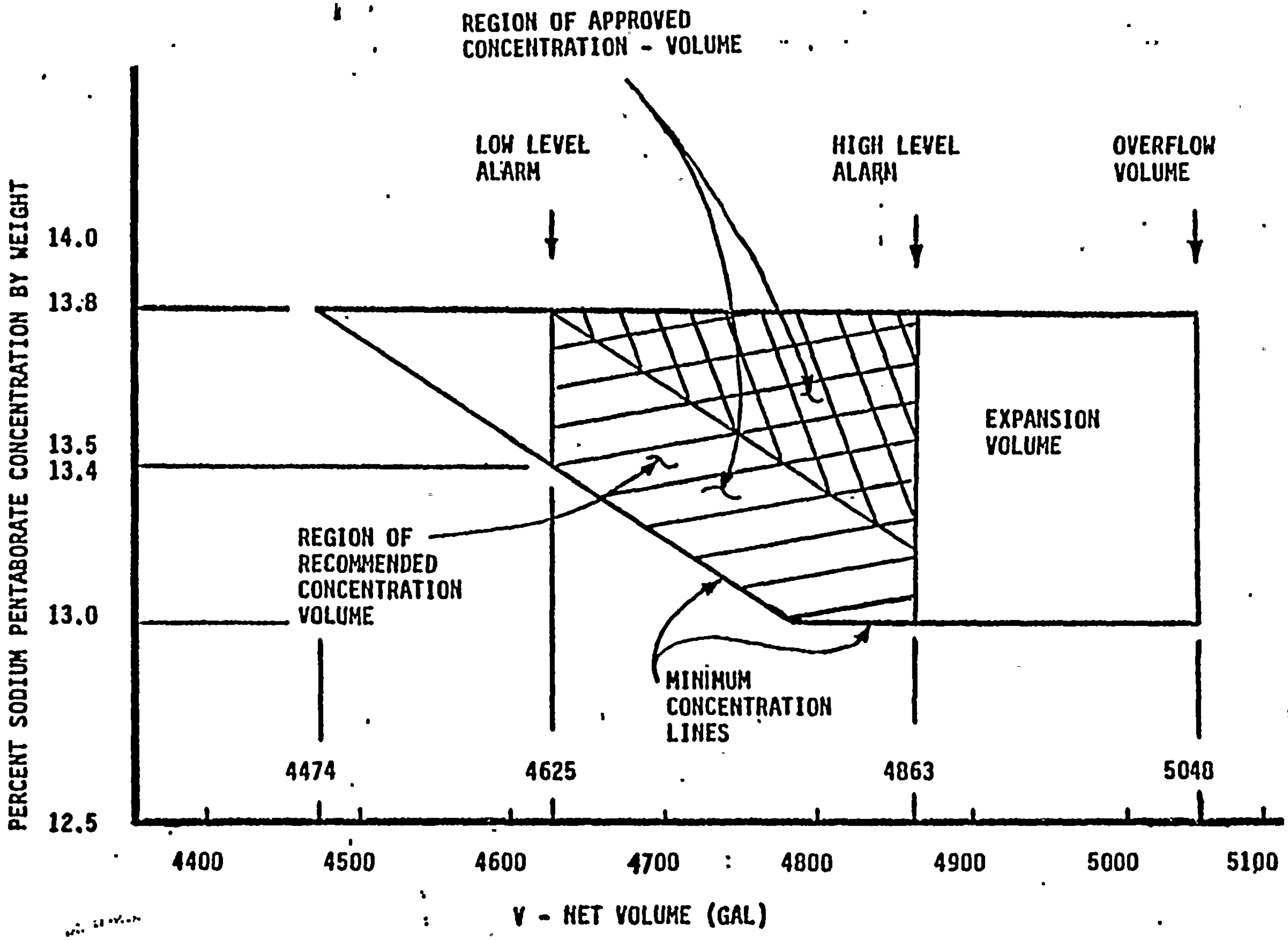

Figure 3.1.5-1 Sodium-Pentaborate Tank Volume vs Concentration Requirements

3/4.2.1 AVERAGE PLANAR LINEAR HEAT GENERATION RATE

LIMITING CONDITION FOR OPERATION

3.2.1 All AVERAGE PLANAR LINEAR HEAT GENERATION RATES (APLHGRs) for each type of fuel as a function of AVERAGE PLANAR EXPOSURE shall not exceed the limits shown in Figures 3.2.1-1, 3.2.1-2, and 3.2.1-3.

APPLICABILITY: OPERATIONAL CONDITION 1, when THERMAL POWER is greater than or equal to 25% of RATED THERMAL POWER.

ACTION:

With an APLHGR exceeding the limits of Figure 3.2.1-1, 3.2.1-2, or 3.2.1-3, initiate corrective action within 15 minutes and restore APLHGR to within the required limits within 2 hours or reduce THERMAL POWER to less than 25% of RATED THERMAL POWER within the next 4 hours.

SURVEILLANCE REQUIREMENTS

4.2.1 All APLHGRs shall be verified to be equal to or less than the limits determined from Figures 3.2.1-1, 3.2.1-2, and 3.2.1-3:

a. At least once per 24 hours,

b. Within 12 hours after completion of a THERMAL POWER increase of at least 15% of RATED THERMAL POWER, and

c. Initially and at least once per 12 hours when the reactor is operating with a LIMITING CONTROL ROD PATTERN for APLHGR.

d. The provisions of Specification 4.0.4 are not applicable.

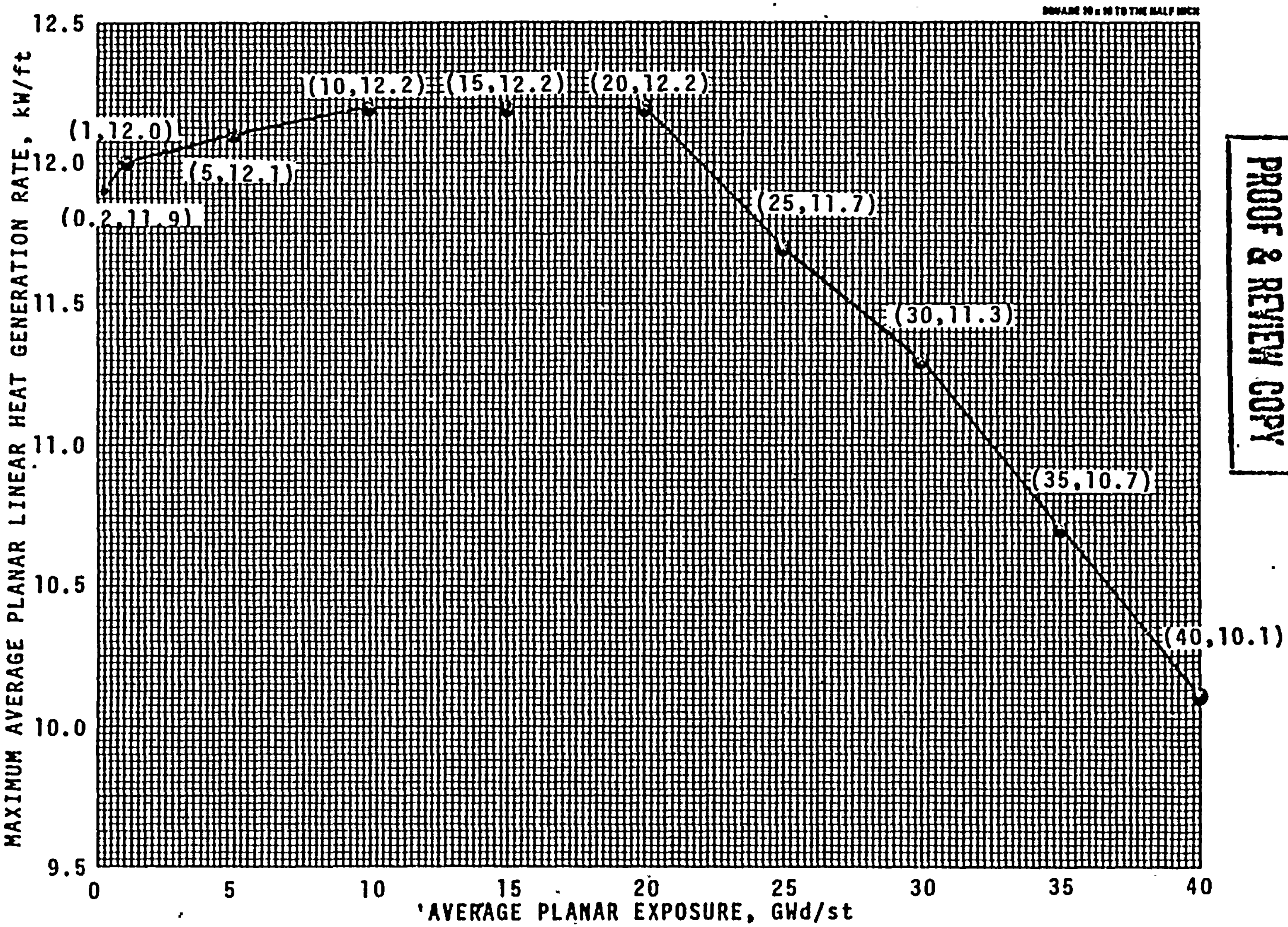

FIGURE 3.2.1-1 MAXIMUM AVERAGE PLANAR LINEAR HEAT GENERATION RATE (MAPLHGR) VS AVERAGE PLANAR EXPOSURE. FUEL TYPE P8CIB219

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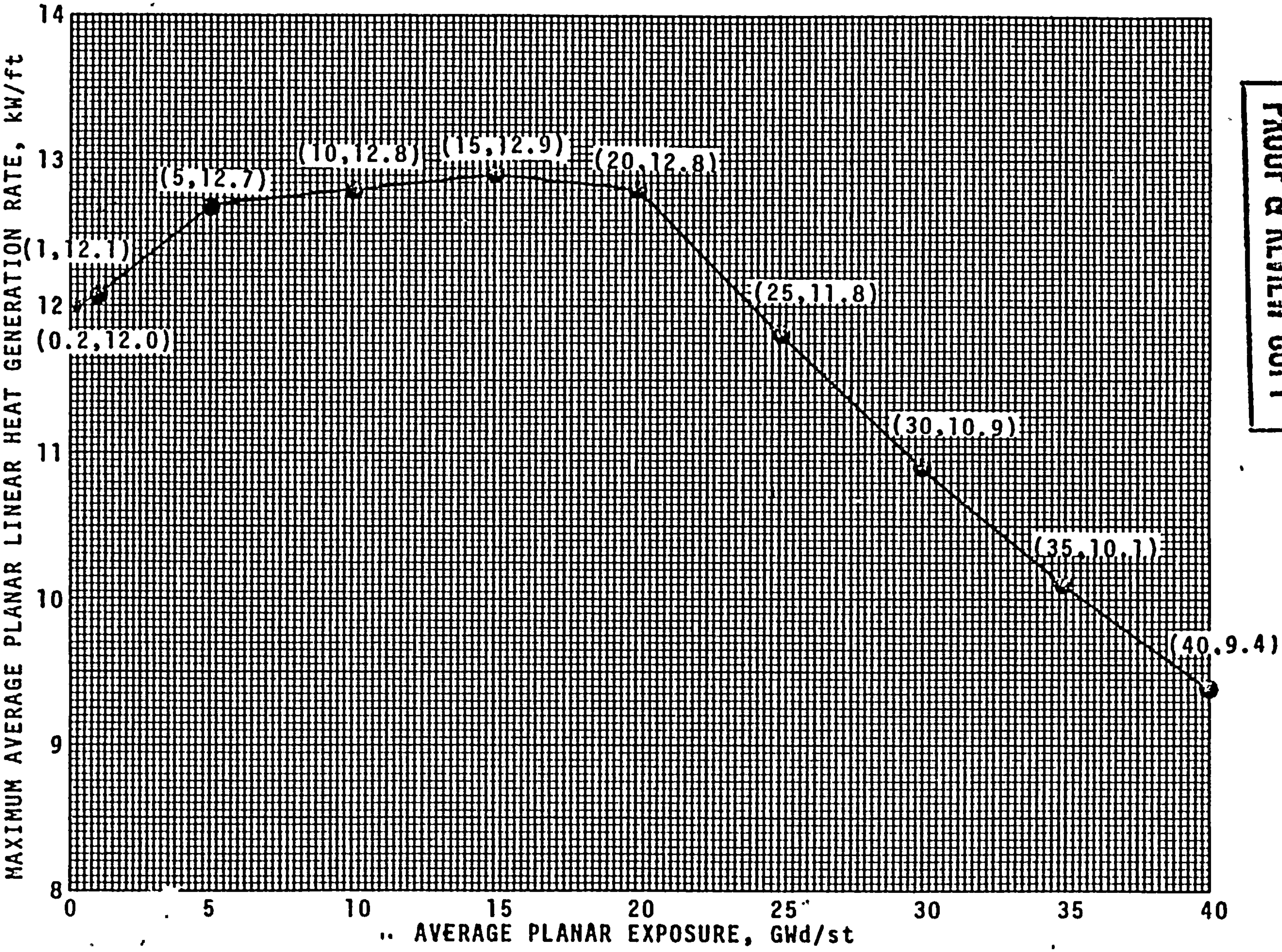

FIGURE 3.2.1-2 MAXIMUM AVERAGE PLANAR LINEAR HEAT GENERATION RATE (MAPLHGR) VS AVERAGE PLANAR EXPOSURE. FUEL TYPE P8CIB176

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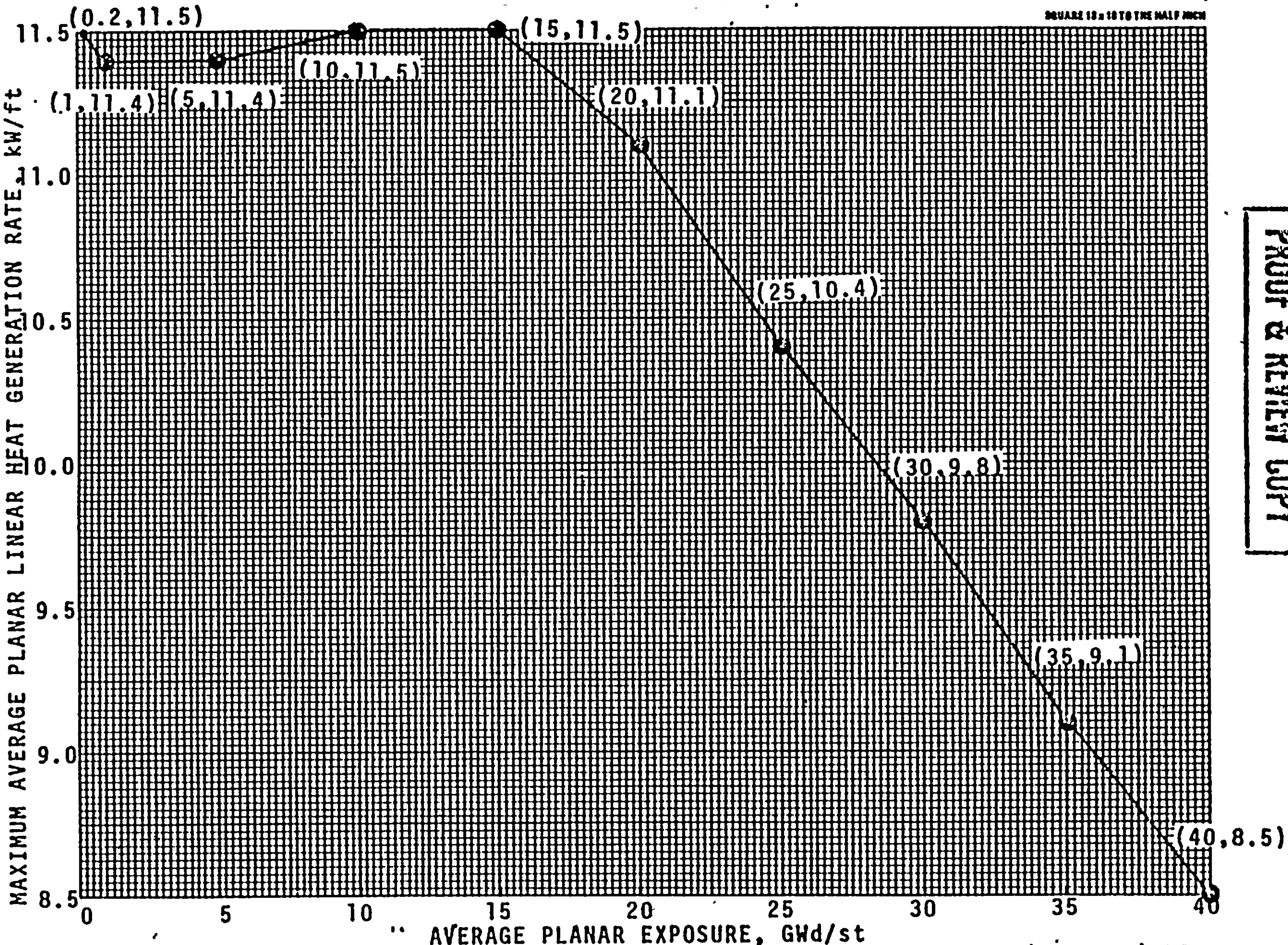

FIGURE 3.2.1-3 MAXIMUM AVERAGE PLANAR LINEAR HEAT GENERATION RATE (MAPLHGR) VS AVERAGE PLANAR EXPOSURE. FUEL TYPE P8CIB071

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3/4.2.2 APRM SETPOINTS

LIMITING CONDITION FOR OPERATION

3.2.2 The APRM flow biased simulated thermal power-upscale scram trip setpoint (S) and flow biased neutron flux-upscale control rod block trip setpoint (S_{RB}) shall be established according to the following relationships:

TRIP SETPOINT	ALLOWABLE VALUE
$S \leq (0.66W + 51\%)T$	$S \leq (0.66W + 54\%)T$
$S_{RB} \leq (0.66W + 42\%)T$	$S_{RB} \leq (0.66W + 45\%)T$

where: S and S_{RB} are in percent of RATED THERMAL POWER,

W = Loop recirculation flow as a percentage of the loop recirculation flow which produces a rated core flow of 108.5 million lbs/hr.

T = The ratio FRACTION OF RATED THERMAL POWER divided by the CORE MAXIMUM FRACTION OF LIMITING POWER DENSITY. T is applied only if less than or equal to 1.0.

APPLICABILITY: OPERATIONAL CONDITION 1, when THERMAL POWER is greater than or equal to 25% of RATED THERMAL POWER.

ACTION:

With the APRM flow biased simulated thermal power-upscale scram trip setpoint and/or the flow biased neutron flux-upscale control rod block trip setpoint less conservative than the value shown in the Allowable Value column for S or S_{RB}, as above determined, initiate corrective action within 15 minutes and adjust S and/or S_{RB} to be consistent with the Trip Setpoint value* within 6 hours or reduce THERMAL POWER to less than 25% of RATED THERMAL POWER within the next 4 hours.

SURVEILLANCE REQUIREMENTS

4.2.2 The FRTP and the CMFLPD shall be determined, the value of T calculated, and the most recent actual APRM flow biased simulated thermal power-upscale scram and flow biased neutron flux-upscale control rod block trip setpoints verified to be within the above limits or adjusted, as required:

a. At least once per 24 hours,

b. Within 12 hours after completion of a THERMAL POWER increase of at least 15% of RATED THERMAL POWER, and

c. Initially and at least once per 12 hours when the reactor is operating with CMFLPD greater than or equal to FRTP.

d. The provisions of Specification 4.0.4 are not applicable.

*With CMFLPD greater than the FRTP ~~during power ascension up to 90% of RATED THERMAL POWER,~~ rather than adjusting the APRM setpoints, the APRM gain may be adjusted such that APRM readings are greater than or equal to 100% times CMFLPD provided that the adjusted APRM reading does not exceed 100% of RATED THERMAL POWER and a notice of adjustment is posted on the reactor control panel.

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3/4.2.3 MINIMUM CRITICAL POWER RATIO

LIMITING CONDITION FOR OPERATION

3.2.3 The MINIMUM CRITICAL POWER RATIO (MCPR), as a function of core flow, shall be equal to or greater than 1.24 times the K_f limits shown in Figure 3.2.3-1.

APPLICABILITY: OPERATIONAL CONDITION 1, when THERMAL POWER is greater than or equal to 25% of RATED THERMAL POWER.

ACTION:

With MCPR less than the MCPR limit times K_f determined from Figure 3.2.3-1, initiate corrective action within 15 minutes and restore MCPR to within the required limit within 2 hours or reduce THERMAL POWER to less than 25% of RATED THERMAL POWER within the next 4 hours.

SURVEILLANCE REQUIREMENTS

4.2.3 MCPR shall be determined to be equal to or greater than the MCPR limit determined from Figure 3.2.3-1:

a. At least once per 24 hours,

b. Within 12 hours after completion of a THERMAL POWER increase of at least 15% of RATED THERMAL POWER, and

c. Initially and at least once per 12 hours when the reactor is operating with a LIMITING CONTROL ROD PATTERN for MCPR.

d. The provisions of Specification 4.0.4 are not applicable.

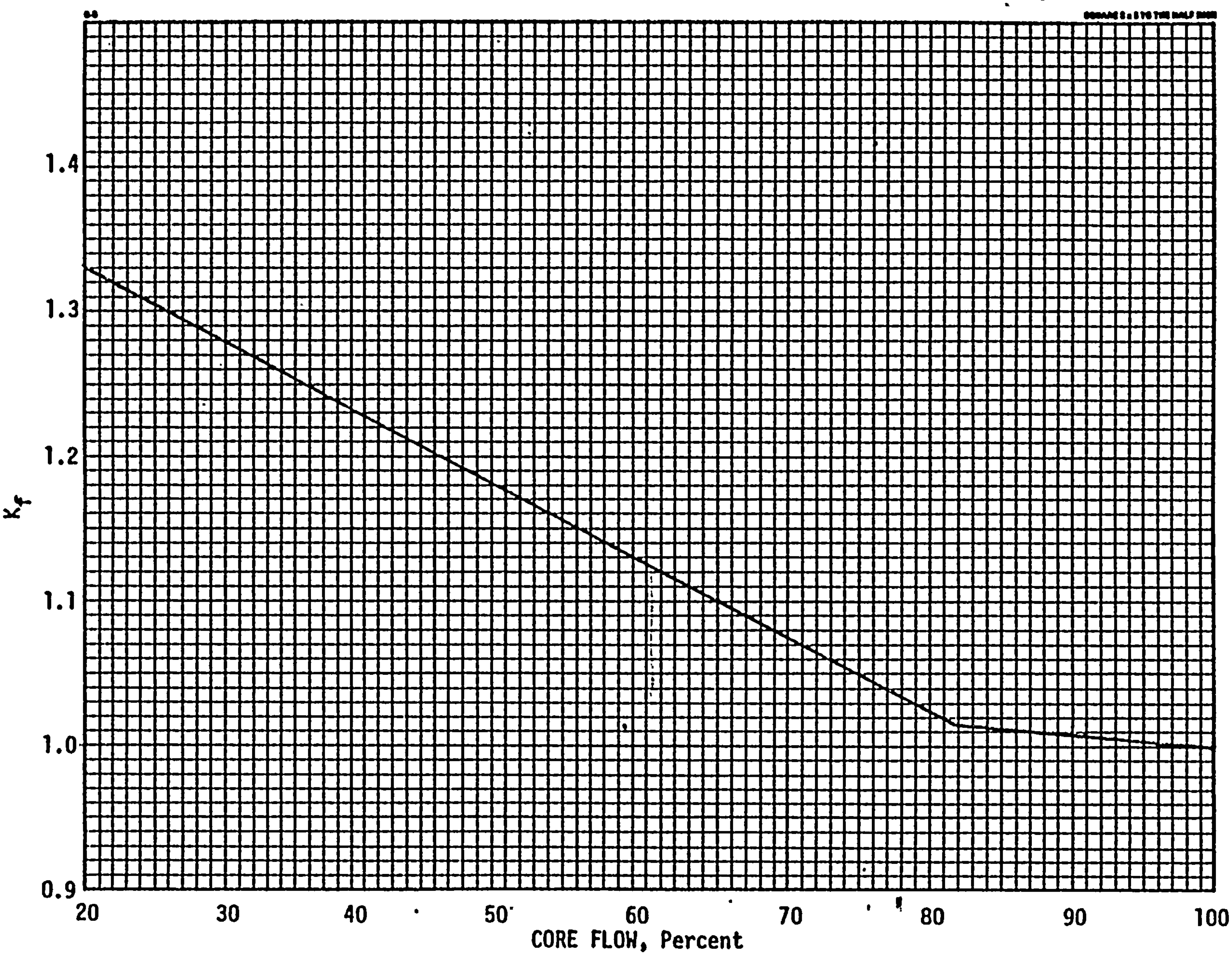

FIGURE 3.2.3-1 K_f AS A FUNCTION OF PERCENT CORE FLOW

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3/4.2.4 LINEAR HEAT GENERATION RATE

LIMITING CONDITION FOR OPERATION

3.2.4 The LINEAR HEAT GENERATION RATE (LHGR) shall not exceed 13.4 kw/ft.

APPLICABILITY: OPERATIONAL CONDITION 1, when THERMAL POWER is greater than or equal to 25% of RATED THERMAL POWER.

ACTION:

With the LHGR of any fuel rod exceeding the limit, initiate corrective action within 15 minutes and restore the LHGR to within the limit within 2 hours or reduce THERMAL POWER to less than 25% of RATED THERMAL POWER within the next 4 hours.

SURVEILLANCE REQUIREMENTS

4.2.4 LHGR's shall be determined to be equal to or less than the limit:

a. At least once per 24 hours,

b. Within 12 hours after completion of a THERMAL POWER increase of at least 15% of RATED THERMAL POWER, and

c. Initially and at least once per 12 hours when the reactor is operating on a LIMITING CONTROL ROD PATTERN for LHGR.

d. The provisions of Specification 4.0.4 are not applicable.

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3/4.3.1 REACTOR PROTECTION SYSTEM INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.1 As a minimum, the reactor protection system instrumentation channels shown in Table 3.3.1-1 shall be OPERABLE with the REACTOR PROTECTION SYSTEM RESPONSE TIME as shown in Table 3.3.1-2.

APPLICABILITY: As shown in Table 3.3.1-1.

ACTION:

a. With the number of OPERABLE channels less than required by the Minimum OPERABLE Channels per Trip System requirement for one trip system, place the inoperable channel(s) and/or that trip system in the tripped condition* within one hour. The provisions of Specification 3.0.4 are not applicable.

b. With the number of OPERABLE channels less than required by the Minimum OPERABLE Channels per Trip System requirement for both trip systems, place at least one trip system** in the tripped condition within one hour and take the ACTION required by Table 3.3.1-1.

SURVEILLANCE REQUIREMENTS

4.3.1.1 Each reactor protection system 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 4.3.1.1-1.

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

4.3.1.3 The REACTOR PROTECTION SYSTEM RESPONSE TIME of each reactor trip functional unit shown in Table 3.3.1-2 shall be demonstrated to be within its 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 reactor trip system.

*An inoperable channel need not be placed in the tripped condition where this would cause the Trip Function to occur. In these cases, the inoperable channel shall be restored to OPERABLE status within 2 hours or the ACTION required by Table 3.3.1-1 for that Trip Function shall be taken.

**The trip system need not be placed in the tripped condition if this would cause the Trip Function to occur. When a trip system can be placed in the tripped condition without causing the Trip Function to occur, place the trip system with the most inoperable channels in the tripped condition, if both systems have the same number of inoperable channels, place either trip system in the tripped condition.

TABLE 3.3.1-1

REACTOR PROTECTION SYSTEM INSTRUMENTATION

FUNCTIONAL UNIT	APPLICABLE OPERATIONAL CONDITIONS	MINIMUM OPERABLE CHANNELS PER TRIP SYSTEM (a)	ACTION
1. Intermediate Range Monitors:			
a. Neutron Flux - High	2	3	1
	3, 4	3	2
	5(b)	3	3
b. Inoperative	2	3	1
	3, 4	3	2
	5	3	3
2. Average Power Range Monitor(c):			
a. Neutron Flux - Upscale, Setdown	2	2	1
	3, 4	2	2
	5(b)	2	3
b. Flow Biased Simulated Thermal Power - Upscale	1	2	4
c. Fixed Neutron Flux - Upscale	1	2	4
d. Inoperative	1, 2	2	1
	3, 4	2	2
	5	2	3
3. Reactor Vessel Steam Dome Pressure - High	1, 2(e)	2	1
4. Reactor Vessel Water Level - Low, Level 3	1, 2	2	1
5. Main Steam Line Isolation Valve - Closure	1(d)	4	4

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TABLE 3.3.1-1 (Continued)

REACTOR PROTECTION SYSTEM INSTRUMENTATION

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

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TABLE 3.3.1-1 (Continued)

REACTOR PROTECTION SYSTEM INSTRUMENTATION

ACTION

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 one hour.

ACTION 3 - Suspend all operations involving CORE ALTERATIONS and insert all insertable control rods within one 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 to ≤ ~~205~~ 129.6* psig, equivalent to THERMAL POWER less than 30% of RATED THERMAL POWER, within 2 hours.

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

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

To allow for instrument accuracy, calibration and drift, a setpoint of less than or equal to 119 psig turbine first stage pressure shall be used.

---

*~~This number to be provided prior to issuance of the unit low power operating license and verified in writing to the Project Manager within 90 days of reaching 30% of RATED THERMAL POWER~~

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TABLE 3.3.1-1 (Continued)

REACTOR PROTECTION SYSTEM INSTRUMENTATION

TABLE NOTATIONS

(a) A channel may be placed in an inoperable status for up to 2 hours for required surveillance without placing the trip system in the tripped condition provided at least one OPERABLE channel in the same trip system is monitoring that parameter.

(b) ~~The "shorting links" shall be removed from the RPS circuitry prior to and during the time any control rod is withdrawn* and shutdown margin demonstrations are being performed per Specification 3.10.3.~~

(c) An APRM channel is inoperable if there are less than 2 LPRM inputs per level or less than 14 LPRM inputs to an APRM channel.

(d) This function shall be automatically bypassed when the reactor mode switch is not in the Run position.

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

(f) This function is not required to be OPERABLE when PRIMARY CONTAINMENT INTEGRITY is not required.

(g) Also actuates the standby gas treatment system.

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

(i) This function shall be automatically bypassed when turbine first stage pressure is ≤ ~~205~~** psig, equivalent to THERMAL POWER less than 30% of RATED THERMAL POWER.
129.6

(j) Also actuates the EOC-RPT system.

Unless adequate shutdown margin has been demonstrated per Specification 3.1.1, and the "one rod out" interlock is OPERABLE per Specification 3.9.1, the shorting links shall be removed from the RPS circuitry prior to, and any time any control rod is withdrawn.

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

**~~This number to be provided prior to issuance of the unit lower power operating license and verified in writing to the Project Manager within 90 days of reaching 30% of RATED THERMAL POWER.~~

** To allow for instrument accuracy, calibration and drift, a setpoint of less than or equal to 119 psig turbine first stage pressure shall be used.

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TABLE 3.3.1-2

REACTOR PROTECTION SYSTEM RESPONSE TIMES

FUNCTIONAL UNIT	RESPONSE TIME (Seconds)
1. Intermediate Range Monitors:	
a. Neutron Flux - High	NA
b. Inoperative	NA
2. Average Power Range Monitor*:	
a. Neutron Flux - Upscale, Setdown	NA
b. Flow Biased Simulated Thermal Power - Upscale	≤ 0.09**
c. Fixed Neutron Flux - Upscale	≤ 0.09
d. Inoperative	NA
3. Reactor Vessel Steam Dome Pressure - High	≤ 0.55
4. Reactor Vessel Water Level - Low, Level 3	≤ 1.05
5. Main Steam Line Isolation Valve - Closure	≤ 0.06
6. Main Steam Line Radiation - High	NA
7. Drywell Pressure - High	NA
8. Scram Discharge Volume Water Level - High	NA
9. Turbine Stop Valve - Closure	≤ 0.06
10. Turbine Control Valve Fast Closure, Valve Trip System Oil Pressure - Low	≤ 0.08#
11. Reactor Mode Switch Shutdown Position	NA
12. Manual Scram	NA

*Neutron detectors are exempt from response time testing. Response time shall be measured from the detector output or from the input of the first electronic component in the channel.

**Not including simulated thermal power time constant, 6 ± 0.6 seconds.

#Measured from start of turbine control valve fast closure.

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TABLE 4.3.1.1-1

REACTOR PROTECTION SYSTEM INSTRUMENTATION SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL FUNCTIONAL TEST	CHANNEL CALIBRATION[a]	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED
1. Intermediate Range Monitors:				
a. Neutron Flux - High	S/U,S,(b)	S/U[c], W,R[l]	R	2
	S	W	R	3, 4, 5
b. Inoperative	NA	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, 4, 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	W	NA	1, 2, 3, 4, 5
3. Reactor Vessel Steam Dome Pressure - High	S	M	R[k]	1, 2
4. Reactor Vessel Water Level - Low, Level 3	S	M	R[k]	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	S	M	R[k]	1, 2[m]

TABLE 4.3.1.1-1 (Continued)

REACTOR PROTECTION SYSTEM INSTRUMENTATION SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL FUNCTIONAL TEST	CHANNEL CALIBRATION[(a)]	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED
8. Scram Discharge Volume Water Level - High				
a. Transmitter	S	M	R[(k)]	1, 2, 5[(j)]
b. Float Switches	NA	Q	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 1/2 decade during each startup after entering OPERATIONAL CONDITION 2 and the IRM and APRM channels shall be determined to overlap for at least 1/2 decade 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 $\geq$ 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 drive flow to be less than or equal to established drive flow at the existing control valve position.

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TABLE 4.3.1.1-1 (Continued)

REACTOR PROTECTION SYSTEM INSTRUMENTATION SURVEILLANCE REQUIREMENTS

(h) This calibration shall consist of verifying the 6 ± 0.6 second simulated thermal power time constant.
(i) This function is not required to be OPERABLE when the reactor pressure vessel head is 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.
(k) Calibrate trip unit at least once per 31 days.
(l) Perform a CHANNEL FUNCTIONAL TEST with the mode switch in STARTUP.
(m) This function is not required to be OPERABLE when PRIMARY CONTAINMENT INTEGRITY is not required to be OPERABLE per Special Test Exception 3.10.1.

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3/4.3.2 ISOLATION ACTUATION INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.2 The isolation actuation instrumentation channels shown in Table 3.3.2-1 shall be OPERABLE with their trip setpoints set consistent with the values shown in the Trip Setpoint column of Table 3.3.2-2 and with ISOLATION SYSTEM RESPONSE TIME as shown in Table 3.3.2-3.

APPLICABILITY: As shown in Table 3.3.2-1.

ACTION:

a. With an isolation actuation instrumentation channel trip setpoint less conservative than the value shown in the Allowable Values column of Table 3.3.2-2, 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 the number of OPERABLE channels less than required by the Minimum OPERABLE Channels per Trip System requirement for one trip system, place the inoperable channel(s) and/or that trip system in the tripped condition* within one hour. The provisions of Specification 3.0.4 are not applicable.

c. With the number of OPERABLE channels less than required by the Minimum OPERABLE Channels per Trip System requirement for both trip systems, place at least one trip system** in the tripped condition within one hour and take the ACTION required by Table 3.3.2-1.

*An inoperable channel need not be placed in the tripped condition where this would cause the Trip Function to occur. In these cases, the inoperable channel shall be restored to OPERABLE status within 2 hours or the ACTION required by Table 3.3.2-1 for that Trip Function shall be taken.

**The trip system need not be placed in the tripped condition if this would cause the Trip Function to occur. When a trip system can be placed in the tripped condition without causing the Trip Function to occur, place the trip system with the most inoperable channels in the tripped condition, if both e systems have the same number of inoperable channels, place wither trip system in the tripped condition.

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SURVEILLANCE REQUIREMENTS

SOURCE CHECK.

4.3.2.1 Each isolation 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 4.3.2.1-1.

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

4.3.2.3 The ISOLATION SYSTEM RESPONSE TIME of each isolation trip function shown in Table 3.3.2-3 shall be demonstrated to be within its 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 isolation trip system.

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TABLE 3.3.2-1

ISOLATION ACTUATION INSTRUMENTATION

TRIP FUNCTION	VALVE GROUPS OPERATED BY SIGNAL (i)	MINIMUM OPERABLE CHANNELS PER TRIP SYSTEM (a)	APPLICABLE OPERATIONAL CONDITION	ACTION
1. PRIMARY CONTAINMENT ISOLATION				
a. Reactor Vessel Water Level				
1. Low, Low, Low, Level 1	1	2	1, 2, # 3	20
2. Low, Low, Level 2 (b)(e)	2,3,6,7,8,9	2	1,2,3# and #	20
3. Low, Level 3	4,5	2	1,2,3# and #	20
b. Drywell Pressure - High (b)(e)	4,3,8,9	2	1,2,3	20
c. Main Steam Line				
1. Radiation - High (c)	1,2	2	1,2,3	21
2. Pressure - Low	1	2	1	23
3. Flow - High	1	2/Line	1,2,3	21
d. Main Steam Line Tunnel				
1. Temperature - High	1	2	1,2,3	21
2. ΔTemperature - High	1	2	1,2,3	21
3. ~~Turbine Bldg. MSL (High Space Temperature) Enclosure~~ Temperature - High MSL Lead Enclosure	1	6	1,2,3	21
e. Condenser Vacuum Low	1	2	1,2*,3*	21
f. RHR Equipment Area				
1. Temperature High (HX's/A&B Pump Rooms)	4,5,10	2	1,2,3	28
~~2. ΔTemperature - High~~	~~4,5,10~~	~~2~~	~~1,2,3~~	~~28~~
g. Reactor Vessel Pressure High (RHR cut-in permissive)	5	2	1,2,3	28
~~h. Reactor Level - Low, Low, Low, Level 1***~~	~~12~~	~~2~~	~~1,2,3~~	~~28~~

TABLE 3.3.2-1 (Cont.)

ISOLATION ACTUATION INSTRUMENTATION

TRIP FUNCTION	VALVE GROUPS OPERATED BY SIGNAL (i)	MINIMUM OPERABLE CHANNELS PER TRIP SYSTEM (a)	APPLICABLE OPERATIONAL CONDITION	ACTION
1. PRIMARY CONTAINMENT ISOLATION SIGNALS (Cont.)				
i. SGTS Exhaust - High Radiation	9	1	1,2,3	29
j. RWCU Equipment				
1. ΔFlow - High	6,7	1	1,2,3	22
2. ΔFlow High, Timer	6,7	1	1,2,3	22
3. Standby Liquid Control, SLCS, Initiation	6,7(f)	1	1,2,~~3~~ 5	22
k. RWCU Equipment Area				
1. Temperature - High (HX's/A&B Pump Rooms)	6,7	3	1,2,3	22
~~2. ΔTemperature - High~~	~~6,7~~	~~3~~	~~1,2,3~~	~~22~~
l. Manual Isolation Pushbutton [NSSS]	1	2	1,2,3	24
	2,4,5	2	1,2,3	26
	3,6,7	1	1,2,3	26
	8	2	1,2,3	25,27
	9	2	1,2,3	29
m. - Reactor Bldg. pipe chase temp. High	4,5,6,7,10	2/Location	1,2,3	22
n. Reactor Bldg. temp. high	4,5 & 10	1/Location	1,2,3	22
2. RCIC ISOLATION SIGNALS				
a. RCIC Steam Line Flow - High, Timer	10	1	1,2,3	22
b. RCIC Steam Supply Pressure - Low (g)	10, 11	2	1,2,3	22
c. RCIC Steam Line Flow, High	10	1	1,2,3	22
d. RCIC Turbine Exhaust Diaphragm Pressure - High (g)	10	2	1,2,3	22

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TABLE 3.3.2-1 (Cont.)

ISOLATION ACTUATION INSTRUMENTATION

TRIP FUNCTION	VALVE GROUPS OPERATED BY SIGNAL (i)	MINIMUM OPERABLE CHANNELS PER TRIP SYSTEM (a)	APPLICABLE OPERATIONAL CONDITION	ACTION
2. RCIC ISOLATION SIGNALS (Cont.)				
e. RCIC Equipment Area				
1. Temperature - High ~~(g)~~ l	10	1	1,2,3	22
~~2. ΔTemperature (g)~~	~~10~~	~~1~~	~~1,2,3~~	~~22~~
f. RCIC Steam Line Tunnel				
1. Temperature - High ~~(g)~~ l	10	1	1,2,3	22
~~2. ΔTemperature - High (g)~~	~~10~~	~~1~~	~~1,2,3~~	~~22~~
g. Manual Isolation Push Button [RCIC] (h)	10	1/Division 1 only	1,2,3	26
h. Drywell Pressure - High***	11(d)	2	1,2,3	22
i. RHR/RCIC Steam Flow - High ~~(g)~~ l	10	1	1,2,3	22
3. SECONDARY CONTAINMENT ISOLATION SIGNALS				
a. Reactor Building Above the Refuel Floor Exhaust Radiation High	(b)(e)	1	1,2,3,5 and **	27
b. Reactor Building Below the Refuel Floor Exhaust Radiation High	(b)(e)	1	1,2,3,5 and **	27
~~4. HIGH PRESSURE CORE SPRAY~~				
~~a. Drywell Pressure - High~~	~~14~~	~~##~~	~~##~~	~~##~~
~~b. Reactor Water Level - Low, Low, Level 2~~	~~14~~	~~##~~	~~##~~	~~##~~

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TABLE 3.3.2-1 (Continued)

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ISOLATION ACTUATION INSTRUMENTATION

ACTION

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

ACTION 23 - Be in at least STARTUP within 6 hours.

ACTION 24 - Restore the manual isolation function to OPERABLE status within 8 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

ACTION 25 - Restore the manual isolation function 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.

ACTION 26 - Restore the manual isolation function to OPERABLE status within 8 hours or close the affected system isolation valves within the next hour and declare the affected system inoperable.

ACTION 27 - Establish REACTOR BUILDING INTEGRITY with the standby gas treatment system operating within one hour.

ACTION 28 - Lock the affected system isolation valves closed within one hour and declare the affected system inoperable.

ACTION 29 - With the number of OPERABLE channels less than required by the Minimum OPERABLE Channel requirement, close the Primary Containment purge valves within one hour or initiate the pre-planned alternate method of monitoring. With the channel at high setpoint, clear personnel from vicinity of all purge lines and valves, purging may continue, and observe main stack effluent monitor alarm status to ensure that offsite dose criteria are not exceeded.

NOTES

* When any turbine stop valve is greater than 90% open and/or when the key locked Condenser Low Vacuum Bypass switch is open.

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

*** Signal from LPCS/RHR initiation circuitry. ~~For applicable operating conditions, setpoints and surveillance requirements see Tables 3.3.3-2 and 4.3.2.1-1, respectively.~~

(a) A channel may be placed in an inoperable status for up to 2 hours for required surveillance without placing the trip system in the tripped condition provided at least one other OPERABLE channel in the same trip system is monitoring that parameter.

(b) Also actuates the standby gas treatment system.

(c) Also trips and isolates the air removal pumps.

(d) Only used in conjunction with low RCIC steam supply pressure and high drywell pressure to isolate 2ICS*MOV148 and 2ICS*MOV164. One trip system per valve.

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TABLE 3.3.2-1 (Continued)

ISOLATION ACTUATION INSTRUMENTATION

(e) Also actuates Reactor Building ventilation isolation dampers per Table 3.6.5.2-1.

(f) Initiation of SLCS Pump 2SLS*P1B closes 2WCS*MOV102 and manual initiation of SLCS pump 2SLS*P1A closes 2WCS*MOV112.

(g) For this signal one trip system has 2 channels which close valves 2ICS*MOV 128 and 2ICS*MOV 170, while the other trip system has 2 channels which close 2ICS*MOV 121.

(h) Manual initiation only isolates 2ICS*MOV121 and only following manual or automatic initiation of the RCIC system.

(i) Refer to Table 3.6.3-1 for applicable valves in each valve group. Refer to Table 3.3.2-4 for valve groups and associated isolated signals and to Table 3.3.2-5 for key to isolation signals.

\# During CORE ALTERATIONS and operations with a potential for draining the reactor vessel.

~~## Signal from HPCS initiation circuitry. See Table 3.3.3-1 for applicable minimum channels and applicable operational conditions.~~

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TABLE 3.3.2-2

ISOLATION ACTUATION INSTRUMENTATION SETPOINTS

TRIP FUNCTION	TRIP SETPOINT	ALLOWABLE VALUE
1. PRIMARY CONTAINMENT ISOLATION SIGNALS		
a. Reactor Vessel Water Level*		
1. Low, Low, Low, Level 1	$\geq$ 17.8 inches	$\geq$10.8 inches
2. Low, Low, Level 2	$\geq$108.8 inches	$\geq$ 101.8 inches
3. Low, Level 3	$\geq$ 159.3 inches	$\geq$ 157.8 inches
b. Drywell Pressure - High	$\leq$ 1.68 psig	$\leq$ 1.88 psig
c. Main Steam Line		
1. Radiation - High	$\leq$ 3 X Full Power Background	$\leq$ 3.6 X Full Power Background
2. Pressure - Low	$\geq$ ~~756~~ psig 766	$\geq$ ~~736~~ psig 746
3. Flow - High	$\leq$ 103 psid	$\leq$ 109.5 psid
d. Main Steam Line Tunnel		
1. Temperature - High	$\leq$ 175°F†	$\leq$ 178°F†
2. ΔTemperature - High	$\leq$ 50°F†	$\leq$ 53°F†
3. ~~Turbine Bldg. MSL (High Space Temperature) Enclosure~~ Temperature–High MSL LEAD Enclosure	$\leq$ 140°F†	$\leq$ 143°F†
e. Condenser Vacuum Low	$\geq$ 8.5 in Hg vacuum	$\geq$ 7.6 in Hg vacuum
f. RHR Equipment Area		
1. Temperature High (HX's/A&B Pump Rooms)	$\leq$ 135°F†	$\leq$ 138°F†
~~2. ΔTemperature - High~~	~~$\leq$ 100°F†~~	~~( )†~~
g. Reactor Vessel Pressure High (RHR cut-in permissive).	$\leq$ 128 psig	$\leq$ 148 psig
~~h. Reactor Level - Low, Low, Low, Level 1*~~	~~$\geq$ 17.8 inches~~	~~$\geq$ 10.8 inches~~
i. SGTS Exhaust - High Radiation	$\leq$ 1.6 X 10^{-2} µCi/cc	$\leq$2.0 X 10^{-2}µCi/cc

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TABLE 3.3.2-2

ISOLATION ACTUATION INSTRUMENTATION SETPOINTS

TRIP FUNCTION	TRIP SETPOINT	ALLOWABLE VALUE
1. PRIMARY CONTAINMENT ISOLATION SIGNALS		
j. RWCU Equipment		
1. Δ Flow - High	≤ 150.5 gpm	≤ 165.5 gpm
2. Δ Flow High Timer	≤ 45 sec	≤ 47 sec
3. Standby Liquid Control, SLCS, Initiation	N/A	N/A
k. RWCU Equipment Area		
1. Temperature - High (HX's/A&B Pump Rooms)	≤ 135°F†	138°F†
~~2. ΔTemperature - High~~	~~≤ 50°F†~~	~~† ( )~~
l. Manual Isolation Pushbutton [NSSS]	N/A	N/A
2. RCIC ISOLATION SIGNALS		
a. RCIC Steam Line Flow High Timer	≥ 3 sec, < 13 sec	13 sec
b. RCIC Steam Supply Pressure - Low	≥ ~~60~~ 75 psi~~g~~a	≥ ~~55~~ 70 psi~~g~~a
c. RCIC Steam Line Flow High	≤ 184.5 in. H_2O†	≤ 193.0 in. H_2O†
d. RCIC Turbine Exhaust Diaphragm Pressure - High	≤ 10 psig	≤ 20 psig
e. RCIC Equipment Area		
1. Temperature - High	~~> 135°F~~ ≤ 135°F†	~~138°F†~~ ≤ 138°F†
~~2. ΔTemperature - High~~	~~≤ 100°F†~~	~~† ( )~~
m. Reactor Bldg. Pipe chase temp. High.	≤ 135°F†	≤ 138°F†
n. Reactor Bldg. temp. high.	≤ 135°F†	≤ 138°F†

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TABLE 3.3.2-2 (Continued)

ISOLATION ACTUATION INSTRUMENTATION SETPOINTS

TRIP FUNCTION	TRIP SETPOINT	ALLOWABLE VALUE
2. RCIC ISOLATION SIGNALS		
f. RCIC Steam Line Tunnel		
1. Temperature - High	135°F† ≤ ~~200°F†~~	≤138°F† ~~† ( )~~
~~2. ΔTemperature - High~~	~~≤ 100°F†~~	~~† ( )~~
g. Manual Isolation Push Buttom [RCIC]	N/A	N/A
h. Drywell Pressure - High	≤ 1.68 psig	≤ 1.88 psig
i. RHR/RCIC Steam Flow - High	≤ 96 in H_2O	≤ 104.5 in H_2O
3. SECONDARY CONTAINMENT ISOLATION SIGNALS		
a. Reactor Building Above the Refuel Floor Exhaust Radiation High	≤ 1.7 x 10^{-3} μCi/cc	≤ 2.1 x 10^{-3} μCi/cc
b. Reactor Building Below the Refuel Floor Exhaust Radiation High	≤ 1.7 x 10^{-3} μCi/cc	≤ 2.1 x 10^{-3} μCi/cc
~~4. HIGH PRESSURE CORE SPRAY~~		
~~a. Drywell Pressure - High~~	~~≤ 1.68 psig~~	~~≤ 1.88 psig~~
~~b. Reactor Water Level - Low, Low, Level 2*~~	~~≥ 108.8 in.~~	≥ 101.8 in.

*See Bases Figure B 3/4 3-1
† Preliminary setpoint - actual setpoint to be determined during startup test program.

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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, Low, Low, Level 1	$\leq$ 1.0*/$\leq$ 13(a)**
2) Low, Low, Level 2	$\leq$ 13(a)
3) Low, Level 3	$\leq$ 13(a)
b. Drywell Pressure - High	$\leq$ 13(a)
c. Main Steam Line	
1) Radiation - High(b)	$\leq$ 1.0*/$\leq$ 13(a)**
2) Pressure - Low	$\leq$ 1.0*/$\leq$ 13(a)**
3) Flow - High	$\leq$ 0.5*/$\leq$ 13(a)**
d. Main Steam Line Tunnel	
1) Temperature - High	NA
2) Δ Temperature - High	NA
3) ~~Turbine Bldg. MSL (High Space Temperature) Enclosure~~ Temperature - High MSL Lead Enclosure	NA
e. Condenser Vacuum - Low	NA
f. RHR Equipment Area	
1) Temperature - High (Heat Exchangers/A & B Pump Rms)	NA
~~2) Δ Temperature - High~~	~~NA~~
g. Reactor Vessel Pressure - High (RHR cut-in permissive)	NA
~~h. Reactor Level - Low, Low, Low, Level 1~~	~~(c)~~
i. SGTS Exhaust - High Radiation(b)	NA
j. RWCU Equipment	
1) Δ Flow - High	$\leq$ 13(a)~~(d)~~
2) Δ Flow - High, Timer(d)	NA
3) SLCS Initiation	NA
k. RWCU Equipment Area	
1) Temperature - High (Heat Exchanger/Pump Rms)	NA
~~2) Δ Temperature - High~~	~~NA~~
l. Manual Isolation Pushbutton [NSSS]	NA
m. Reactor Bldg. Pipe Chase temp. High	NA
n. Reactor Bldg temp. High	NA

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TABLE 3.3.2-3 (Continued)

ISOLATION SYSTEM INSTRUMENTATION RESPONSE TIME

TRIP FUNCTION	RESPONSE TIME (Seconds)#
2. REACTOR CORE ISOLATION COOLING SYSTEM ISOLATION	
a. RCIC Steam Line Flow - High, Timer (d)	~~(d)~~ NA
b. RCIC Steam Supply Pressure - Low	≤ 13(a)
c. RCIC Steam Line Flow - High	≤ 13(a) ~~(d)~~
d. RCIC Turbine Exhaust Diaphragm Pressure - High	NA
e. RCIC Equipment Area	
1) Temperature - High	NA
~~2) Δ Temperature - High~~	~~NA~~
f. RCIC Steam Line Tunnel	
1) Temperature - High	NA
~~2) Δ Temperature - High~~	~~NA~~
g. Manual Isolation Push Button [RCIC]	NA
h. Drywell Pressure-High	NA
i. RHR/RCIC Steam Flow - High	≤ 13(a)
3. SECONDARY CONTAINMENT ISOLATION	
a. Reactor Building Above the Refuel Floor Exhaust Radiation High(b)	NA
b. Reactor Building Below the Refuel Floor Exhaust Radiation High(b)	NA
~~4. HIGH PRESSURE CORE SPRAY~~	
~~a. Drywell Pressure - High~~	~~(c)~~
~~b. Reactor Vessel Water Level - Low, Low, Level 2~~	~~(c)~~

(a) Isolation system instrumentation response time specified includes the diesel generator starting and sequence loading delays.

(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.

~~(c) Response time located on Table 3.3.3-3.~~ (c) Not used

(d) See Table 3.3.2-2 for timer delay.

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

**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.

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TABLE 3.3.2-4

VALVE GROUPS AND ASSOCIATED ISOLATION SIGNALS

VALVE GROUPS	ASSOCIATED CONTAINMENT ISOL. VLVS BY FUNCTION	ISOLATION SIGNALS
1	MSIV's and MSL Drains	Z,X,C,D,E,P,T,R,RM,AA
2	Recirc system sample valves	B,C,Z,RM
3	TIP Isolation	B,F,Z,RM
4	RHR Sample & Rad. Waste Valves	A,M,Z,F,RM,CC,DD
5	RHR Shutdown Cooling Valves	A,L,M,Z,RM,CC,DD
6	RWCU Outboard Isol. Valve	B,U,J,S,Z,RM,DD
7	RWCU Inboard Isol. Valve	B,J,U,S,Z,RM,DD
8	All Containment Isolation Valves not assigned to another group	B,F,Z,RM
9	Containment Purge Valves	B,F,Y,Z,RM
10	RCIC Steam Supply Valves	K,M,H,Z,RM,BB,CC,DD
11	RCIC Vacuum Breaker Isolation Valves	H* & F*,RM,~~BB~~
~~12~~	~~Suppression Pool Spray Valves~~	~~G, RM~~
12 ~~13~~	Remote Manually Operated Containment Valves	RM
~~14~~	~~HPCS Full Flow Test Valve~~	~~N,RM~~

*Both signsls must be coincident to cause isolation

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TABLE 3.3.2-5

KEY TO ISOLATION SIGNALS

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A = Low reactor vessel water, level 3
B = Low reactor vessel water, level 2
C = High main steam line radiation
D = High main steam line flow
E = High main steam line tunnel ambient temperature
F = High drywell pressure
G = ~~Low pressure ECCS initiation signal (X,F)~~ not used
H = Low RCIC steam supply pressure
J = High reactor water cleanup system equipment area ~~differential and~~ ambient temperature
K = Reactor core isolation cooling high pipe routing area temperature and equipment area temperature, high steam line flow, high turbine exhaust diaphragm pressure
L = High reactor vessel pressure
M = High residual heat removal system equipment area ~~differential and~~ ambient temperatures
N = ~~HPCS initiation signal (B,F)~~ not used
P = Low main steam line turbine inlet pressure
R = Low main condenser vacuum
S = Standby liquid control system actuated
T = High main steam line tunnel differential temperatures
U = High reactor water cleanup system differential flow
W = This letter not used
X = Low reactor water level, level 1
Y = Standby gas treatment exhaust high radiation
LC = Locked closed
RM = Remote manual switch from control room
LMC = Locked closed - position indicator
Z = Manual isolation
AA = ~~Turbine building high space temperature~~ Main steam Line Lead Enclosure high Ambient temp.
BB = RCIC/RHR Steamline Flow-High
CC = Reactor Building High Ambient Temperature
DD = Reactor Building Pipe Chase High Ambient Temperature

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TABLE 4.3.2.1-1

ISOLATION ACTUATION INSTRUMENTATION SURVEILLANCE REQUIREMENTS

TRIP FUNCTION	CHANNEL CHECK	CHANNEL FUNCTION TEST	CHANNEL CALIBRATION	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED
1. PRIMARY CONTAINMENT ISOLATION SIGNALS				
a. Reactor Vessel Water Level				
1. Low, Low, Low, Level 1	S	M	R	1,2,3
2. Low, Low, Level 2	S	M	R	1,2,3 and #
3. Low, Level 3	S	M	R	1,2,3 ~~and #~~
b. Drywell Pressure High	S	M	R	1,2,3
c. Main Steam Line				
1. Radiation - High	S	M	R	1,2,3
2. Pressure - Low	S	M	R	1
3. Flow - High	S	M	R	1,2,3
d. Main Steam Line Tunnel				
1. Temperature - High	S	M	R(d)	1,2,3
2. ΔTemperature - High	S	M	R(d)	1,2,3
3. ~~Turbine Bldg. MSL (High Space Temp.) Enclosure~~ Temperature - High MSL LEAD ENCLOSURE	S	M	R(d)	1,2,3
e. Condenser Vacuum Low	S	M	R	1,2*,3*
f. RHR Equipment Area				
1. Temperature - High (HX's/A&B Pump Rooms)	NA	M	R(d)	1,2,3
~~2. ΔTemperature - High~~	~~NA~~	~~M~~	~~R(d)~~	~~1,2,3~~
g. Reactor Vessel Pressure High (RHR cut-in permissive)	S	M	R(d)	1,2,3
~~h. Reactor Level Low, Low, Low, Level 1~~	~~***~~	~~***~~	~~***~~	~~***~~

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TABLE 4.3.2.1-1 (Continued)

ISOLATION ACTUATION INSTRUMENTATION SURVEILLANCE REQUIREMENTS

TRIP FUNCTION	CHANNEL CHECK	CHANNEL FUNCTION TEST	CHANNEL CALIBRATION	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED
1. PRIMARY CONTAINMENT ISOLATION SIGNALS (Continued)				
i. SGTS Exhaust - High Radiation	S	SA(e)	R	1,2,3
j. RWCU Equipment				
1. ΔFlow - High	S	M	R	1,2,3
2. ΔFlow High Timer	NA	M	R	1,2,3
3. Standby Liquid Control, SLCS, Initiation	NA	~~M(b)~~ R	NA	1,2,3
k. RWCU Equipment Area				
1. Temperature - High (HX's/A&B Pump Rooms)	S	M	R(d)	1,2,3
~~2. ΔTemperature - High~~	~~S~~	~~M~~	~~R(d)~~	~~1,2,3~~
l. Manual Isolation Pushbutton [NSSS]	NA	M(a)	NA	1,2,3
m. Rx Bldg. Pipe Chase temp High	S	M	R (d)	1,2,3
n. Rx Bldg. temp.	S	M	R(d)	1,2,3
2. RCIC ISOLATION SIGNALS				
a. RCIC Steam Line Flow High, Timer	NA	M	R	1,2,3
b. RCIC Steam Supply Pressure - Low	S	M	R	1,2,3
c. RCIC Steam Line Flow, High	S	M	R	1,2,3
d. RCIC Turbine Exhaust Diaphragm Pressure - High	S	M	R	1,2,3
e. RCIC Equipment Area				
1. Temperature - High	S	M	R(d)	1,2,3
~~2. ΔTemperature - High~~	~~S~~	~~M~~	~~R(d)~~	~~1,2,3~~

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TABLE 4.3.2.1-1 (Continued)

ISOLATION ACTUATION INSTRUMENTATION SURVEILLANCE REQUIREMENTS

TRIP FUNCTION	CHANNEL CHECK	CHANNEL FUNCTION TEST	CHANNEL CALIBRATION	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED
2. RCIC ISOLATION SIGNALS				
f. RCIC Steam Line Tunnel				
1. Temperature - High	S	M	R(d)	1,2,3
~~2. ΔTemperature - High~~	~~S~~	~~M~~	~~R(d)~~	~~1,2,3~~
g. Manual Isolation Push Button [RCIC]	NA	M	NA	1,2,3
h. Drywell Pressure - High*	~~***~~ S	~~***~~ M	~~***~~ R	1,2,3
i. RHR/RCIC Steam Flow - High	S	M	R	1,2,3
3. SECONDARY CONTAINMENT ISOLATION SIGNALS				
a. Reactor Building Above the Refuel Floor Exhaust Radiation - High	S	SA(e)	R	1,2,3 and **
b. Reactor Building Below the Refuel Floor Exhaust Radiation - High	S	SA(e)	R	1,2,3 and **
~~4. HIGH PRESSURE CORE SPRAY~~				
~~a. Drywell Pressure - High~~	~~##~~	~~##~~	~~##~~	~~##~~
~~b. Reactor Water Level - Low, Low, Level 2~~	~~##~~	~~##~~	~~##~~	~~##~~

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TABLE 4.3.2.1-1 (Continued)

ISOLATION ACTUATION INSTRUMENTATION SURVEILLANCE REQUIREMENTS

~~## See Table 4.3.3.1-1 for applicable Surveillance Requirements.~~ when

* When any turbine stop valve is greater than 90% open and/or the key locked Condenser Low Vacuum Bypass Switch is ~~in the Bypass position.~~ OPEN

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

*** Signals from LPCS and RHR initiation signals; see Table 4.3.3.1-1

\# During CORE ALTERATIONS and operation with a potential for draining the reactor vessel.

(a) Manual Isolation pushbuttons are tested at least once per operating cycle during shutdown. All other circuitry associated with Manual Isolation shall receive a Channel Functional Test at least once per 31 days as part of the circuitry required to be tested for the Automatic System Isolation.

(b) ~~Each train of logic shall be tested at least every other 31 days.~~ This note not used.

(c) Footnote not used.

(d) Calibration excludes sensors; sensor response and comparison shall be done in lieu of.

(e) ~~Source check~~ required once per 31 days.
SOURCE CHECK

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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.

c. With either ADS trip system "A" or "B" inoperable, restore the inoperable trip system to OPERABLE status within:

   1. 7 days, provided that the HPCS and RCIC systems are OPERABLE, or

   2. 72 hours, provided either the HPCS or RCIC systems are inoperable.

   Otherwise, be in at least HOT SHUTDOWN within the next 12 hours and reduce reactor steam dome pressure to less than or equal to 100 psig within the following 24 hours.

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.

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TABLE 3.3.3-1

EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION

TRIP FUNCTION	MINIMUM OPERABLE CHANNELS PER TRIP FUNCTION[a]	APPLICABLE OPERATIONAL CONDITIONS	ACTION
A. DIVISION I TRIP SYSTEM			
1. RHR-A (LPCI MODE) & LPCS SYSTEM			
a. Reactor Vessel Water Level - Low, Low, Low, Level 1	2[b]	1, 2, 3, 4*, 5*	30
b. Drywell Pressure - High	2[b]	1, 2, 3	30
c. LPCS Pump Discharge Flow-Low (Bypass)~~##~~	1/pump	1, 2, 3, 4*, 5*	31
d. LPCS Injection Valve Permissive	1/valve	1, 2, 3, 4*, 5*	32 33
e. LPCI Injection Valve Permissive	1/valve	1, 2, 3, 4*, 5*	32 33
f. LPCI Pump A Start Time Delay Relay Normal Power	1	1, 2, 3, 4*, 5*	32
g. LPCI Pump A Start Time Delay Relay Emer. Power	1	1, 2, 3, 4*, 5*	32
h. LPCS Pump Start Time Delay Normal Power	1	1, 2, 3, 4*, 5*	32
i. LPCS Pump Start Time Delay Emer. Power	1	1, 2, 3, 4*, 5*	32
j. LPCI Pump A Discharge Flow-Low (Bypass)~~##~~	1/pump	1, 2, 3, 4*, 5*	31
k. Manual Initiation	1/system	1, 2, 3, 4*, 5*	35
2. AUTOMATIC DEPRESSURIZATION SYSTEM TRIP SYSTEM "A"#			
a. Reactor Vessel Water Level - Low, Low, Low, Level 1	2[b]	1, 2, 3	30
b. ADS Timer	1	1, 2, 3	32
c. Reactor Vessel Water Level - Low, Level 3 (Permissive)	1	1, 2, 3	32
d. LPCS Pump Discharge Pressure-High (Permissive)	2	1, 2, 3	32
e. LPCI Pump A Discharge Pressure-High (Permissive)	2	1, 2, 3	32
f. Manual Inhibit	1	1, 2, 3	32
g. Manual Initiation	2/system	1, 2, 3	35

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TABLE 3.3.3-1 (Cont'd)

EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION

TRIP FUNCTION	MINIMUM OPERABLE CHANNELS PER TRIP FUNCTION[(a)]	APPLICABLE OPERATIONAL CONDITIONS	ACTION
B. DIVISION II TRIP SYSTEM			
1. RHR B (LPCI MODE)			
a. Reactor Vessel Water Level - Low, Low, Low, Level 1	2[(b)]	1, 2, 3, 4*, 5*	30
b. Drywell Pressure - High	2[(b)]	1, 2, 3	30
c. LPCI Injection Valve Permissive	1/valve	1, 2, 3, 4*, 5*	32 33
d. LPCI Pump B Start Time Delay Relay Normal Power	1	1, 2, 3, 4*, 5*	32
e. LPCI Pump C Start Time Delay Relay Normal Power	1	1, 2, 3, 4*, 5*	32
f. LPCI Pump B Start Time Delay Relay Emer. Power	1	1, 2, 3, 4*, 5*	32
g. LPCI Pump C Start Time Delay Relay Emer. Power	1	1, 2, 3, 4*, 5*	32
h. LPCI Pump Discharge Flow-Low (Bypass)##	1/pump	1, 2, 3, 4*, 5*	31
i. Manual Initiation	1/system	1, 2, 3, 4*, 5*	35
2. AUTOMATIC DEPRESSURIZATION SYSTEM TRIP SYSTEM "B"#			
a. Reactor Vessel Water Level - Low, Low, Low, Level 1	2[(b)]	1, 2, 3	30
b. ADS Timer	1	1, 2, 3	32
c. Reactor Vessel Water Level - Low, Level 3 (Permissive)	1	1, 2, 3	32
d. LPCI Pump (B and C) Discharge Pressure - High (Permissive)	2 ~~1~~/pump	1, 2, 3	32
e. Manual Inhibit	1	1, 2, 3	32
f. Manual Initiation	2/(system)	1, 2, 3	35

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TABLE 3.3.3-1 (Cont'd)
EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION

TRIP FUNCTION	MINIMUM OPERABLE CHANNELS PER TRIP FUNCTION[(a)]	APPLICABLE OPERATIONAL CONDITIONS	ACTION
C. DIVISION III TRIP SYSTEM			
1. HPCS SYSTEM			
a. Reactor Vessel Water Level - Low, Low, Level 2	4[(b)]	1, 2, 3, 4*, 5*	36
b. Drywell Pressure - High (###)	4[(b)]	1, 2, 3	36
c. Reactor Vessel Water Level-High, Level 8	4[(c)]	1, 2, 3, 4*, 5*	32
d. Condensate Storage Tank Level-Low	2[(d)]	1, 2, 3, 4*, 5*	37
e. Suppression Pool Water Level-High	2[(d)]	1, 2, 3, 4*, 5*	37
f. HPCS System Flow Rate-Low (Bypass) ##	1	1, 2, 3, 4*, 5*	~~31~~ 34
g. Manual Initiation (###)	1/system	1, 2, 3, 4*, 5*	35
h. Pump Discharge Pressure - High (Bypass) ##	1	1, 2, 3, 4*, 5*	~~31~~ 34

	TOTAL NO. OF CHANNELS	CHANNELS TO TRIP	MINIMUM CHANNELS OPERABLE	APPLICABLE OPERATIONAL CONDITIONS	ACTION
D. LOSS OF POWER (Divisions I, II, and III)					
1. 4.16 kV Emergency Bus Under-voltage-Loss of Voltage	3/bus	2/bus	2/bus	1, 2, 3, 4**, 5**	38
2. 4.16 kV Emergency Bus Under-voltage-Degraded Voltage	3/bus	2/bus	2/bus	1, 2, 3, 4**, 5**	39

(a) A channel may be placed in an inoperable status for up to 2 hours during periods of required surveillance without placing the trip system in the tripped condition provided at least one other OPERABLE channel in the same trip system is monitoring that parameter.
(b) Also actuates the associated division diesel generator.
(c) Provides signal to close HPCS pump injection valve only.
(d) Provides signal to HPCS pump suction valves only.
* When the system is required to be OPERABLE per Specification 3.5.2 or 3.5.3.
** Required when ESF equipment is required to be OPERABLE.
\# Not required to be OPERABLE when reactor steam dome pressure is less than or equal to 100 psig.
\#\# ~~Footnote not used~~. These trip functions are not required for ECCS actuation.
\#\#\# The injection function of Drywell Pressure High and Manual Initiation is not required to be OPERABLE with indicated reactor vessel water level on the wide range instrument greater than level 8 setpoint coincident with the vessel pressure less than 600 psig.

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TABLE 3.3.3-1 (Continued)

EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION

ACTION

ACTION 30 - With the number of OPERABLE channels less than required by the Minimum OPERABLE Channels per Trip Function requirement:

a. With one channel inoperable, place the inoperable channel in the tripped condition within one hour* or declare the associated system inoperable.
b. With more than one channel inoperable, declare the associated system inoperable.

ACTION 31 - ~~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 one hour; restore the inoperable channel to OPERABLE status within 7 days or declare the associated system inoperable.~~

ACTION 32 - With the number of OPERABLE channels less than required by the Minimum OPERABLE Channels per Trip Function requirement, declare the associated ADS trip system or ECCS inoperable.

ACTION 33 - 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 one hour.

ACTION 34 - ~~With the number of OPERABLE channels less than required by the minimum OPERABLE channels per Trip Function requirement, verify bus power availability at least once per 12 hours or declare the associated ECCS inoperable.~~

ACTION 35 - With the number of OPERABLE channels less than required by the Minimum OPERABLE Channels per Trip Function requirement, restore the inoperable channel to OPERABLE status within 8 hours or declare the associated ADS valve or ECCS inoperable.

ACTION 36 - With the number of OPERABLE channels less than required by the Minimum OPERABLE Channels per Trip Function requirement:

a. For one trip system, place that trip system in the tripped condition within one hour* or declare the HPCS system inoperable.
b. For both trip systems, declare the HPCS system inoperable.

ACTION 37 - With the number of OPERABLE channels less than required by the Minimum OPERABLE Channels per Trip Function requirement, place at least one inoperable channel in the tripped condition within one hour* or declare the HPCS system inoperable.

ACTION 38 - With the number of OPERABLE channels less than the Total Number of Channels, declare the associated emergency diesel generator inoperable and take the ACTION required by Specification 3.8.1.1 or 3.8.1.2, as appropriate.

ACTION 39 - With the number of OPERABLE channels one less than the Total Number of Channels, place the inoperable channel in the tripped condition within 1 hour*; operation may then continue until performance of the next required CHANNEL FUNCTIONAL TEST.

*The provisions of Specification 3.0.4 are not applicable.

Insert following for action 31 on page 3/4 3-32

Disable the applicable LPCS or LPCI. "Pump Discharge Flow - Low" channel logic and ensure low flow bypass valve is in open position. Restore channel logic to OPERABLE status within 7 days or declare the associated ECCS inoperable.

Add the following new action statement for HPCS under action 34

[redacted] Valve HPCS suction to suppression pool. Disable "Pump Discharge Pressure - High" and/or "HPCS System Flow Rate - Low" channel logic, and ensure low flow bypass valve is in open position. Restore channel logic to OPERABLE status in 7 days or declare the associated ECCS inoperable.

TABLE 3.3.3-2

EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION SETPOINTS

TRIP FUNCTION	TRIP SETPOINT	ALLOWABLE VALUE
A. DIVISION I TRIP SYSTEM		
1. RHR-A (LPCI MODE) AND LPCS SYSTEM		
a. Reactor Vessel Water Level - Low, Low, Low, Level 1	≥ 17.8 in.*	≥ 10.8 in.
b. Drywell Pressure - High	≤ 1.68 psig	≤ 1.88 psig
c. LPCS Pump Discharge Flow-Low (Bypass)#	≥ 1200 gpm	≥ 1000 gpm
d. LPCS Injection Valve Permissive	≤ 88 psid, decreasing	≤ 98 psid, decreasing
e. LPCI Injection Valve Permissive	≤ 130 psid, decreasing	≤ 150 psid, decreasing
f. LPCI Pump A Start Time Delay Relay Normal Power	≤ 5 sec	≤ 7 sec
g. LPCI Pump A Start Time Delay Relay Emer. Power	≤ 1 sec	≤ 2 sec
h. LPCS Pump Start Time Delay Normal Power	≤ 10 sec	≤ 12 sec
i. LPCS Pump Start Time Delay Emer. Power	≤ 6 sec	≤ 7 sec
j. LPCI Pump A Discharge Flow-Low (Bypass)#	≥ 1400 gpm	≥ 1200 gpm
k. Manual Initiation	NA	NA
2. AUTOMATIC DEPRESSURIZATION SYSTEM TRIP SYSTEM "A"		
a. Reactor Vessel Water Level - Low, Low, Low, Level 1	≥ 17.8 in.*	≥ 10.8 in.
b. ADS Timer	≤ 105 sec	≤ 117 sec
c. Reactor Vessel Water Level-Low, Level 3 (Permissive)	≥ 159.3 in.*	≥ 157.8 in.
d. LPCS Pump Discharge Pressure-High (Permissive)	≥ 145 psig, increasing	≥ 125 psig, increasing
e. LPCI Pump A Discharge Pressure-High (Permissive)	≥ 125 psig, increasing	≥ 115 psig, increasing
f. Manual Inhibit	NA	NA
g. Manual Initiation	NA	NA

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TABLE 3.3.3-2 (Continued)

EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION SETPOINTS

TRIP FUNCTION	TRIP SETPOINT	ALLOWABLE VALUE
B. DIVISION II TRIP SYSTEM		
1. RHR B AND C (LPCI MODE)		
a. Reactor Vessel Water Level - Low, Low, Low, Level 1	$\geq$ 17.8 in.*	$\geq$ 10.8 in.
b. Drywell Pressure - High	$\leq$ 1.68 psid	$\leq$ 1.88 psid
c. LPCI Injection Valve Permissive	$\leq$ 130 psid, decreasing	$\leq$ 150 psid, decreasing
d. LPCI Pump B Start Time Delay Relay Normal Power	$\leq$ 5 sec	$\leq$ 7 sec
e. LPCI Pump C Start Time Delay Relay Normal Power	$\leq$ 10 sec	$\leq$ 12 sec
f. LPCI Pump B Start Time Delay Relay Emergency Power	$\leq$ 1 sec	$\leq$ 2 sec
g. LPCI Pump C Start Time Delay Emergency Power	$\leq$ 6 sec	$\leq$ 7 sec
h. LPCI Pump Discharge Flow-Low (Bypass)#	$\geq$ 1400 gpm	$\geq$ 1200 gpm
i. Manual Initiation	NA	NA
2. AUTOMATIC DEPRESSURIZATION SYSTEM TRIP SYSTEM "B"		
a. Reactor Vessel Water Level - Low, Low, Low, Level 1	$\geq$ 17.8 in.*	$\geq$ 10.8 in.
b. ADS Timer	$\leq$ 105 sec	$\leq$ 117 sec
c. Reactor Vessel Water Level-Low, Level 3 (Permissive)	$\geq$ 159.3 in.*	$\geq$ 157.8 in.
d. LPCI Pump (B and C) Discharge Pressure-High (Permissive)	$\geq$ 125 psig, increasing	$\geq$ 115 psig, increasing
e. Manual Inhibit	NA	NA
f. Manual Initiation	NA	NA

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TABLE 3.3.3-2 (Continued)

EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION SETPOINTS

TRIP FUNCTION		TRIP SETPOINT	ALLOWABLE VALUE
C. DIVISION III TRIP SYSTEM			
1. HPCS SYSTEM			
a. Reactor Vessel Water Level - Low, Low, Level 2		≥ 108.8 in.*	≥ 101.8 in.
b. Drywell Pressure - High		≤ 1.68 psig	≤ 1.88 psig
c. Reactor Vessel Water Level - High, Level 8		≤ 202.3 in.*	≤ 209.3 in.
d. Condensate Storage Tank Level - Low		≥ ~~7.8~~ ft 9.3	≥ ~~7.6~~ ft 9.0 #
e. Suppression Pool Water Level - High (Bypass)		≤ 201.0' el.	≤ 201.1' el.
f. HPCS System Flow Rate - Low		≥ 750 gpm	≥ 700 gpm
h ~~g~~. Manual Intiation		NA	NA
g ~~h~~. Pump Discharge Pressure - High (Bypass)#		≥ ~~145~~ psig 240	≥ ~~120~~ psig 220
D. LOSS OF POWER (DIVISIONS I, II, III)			
1. 4.16 kV Emergency Bus Under-voltage## - Loss of Voltage	a.	4.16 kV Basis - 3268 ±161 volts	3268 ±315 volts
	b.	≤ 3 sec. time delay	≤ 3 sec. time delay
2. 4.16 kv Emergency Bus Under-voltage - Degraded Voltage	a.	4.16 kV Basis - 3843 ±9 volts	3843 ±7 volts
	b.	8 ± 0.16 sec. time delay##	8 ± 0.32 sec. time delay##
	c.	30 ±0.6 sec. time delay	30 ± 1.2 sec. time delay

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

##Alarm only without LOCA signal present; Alarm and trip with LOCA signal present.

These trip functions are not required for ECCS actuation.

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TABLE 3.3.3-3

EMERGENCY CORE COOLING SYSTEM RESPONSE TIMES

ECCS	RESPONSE TIME (Seconds)
1. LOW PRESSURE CORE SPRAY SYSTEM	
a. Diesel Generator Start Time*	$\leq$ 10
b. Injection Valve Opening Time	$\leq$ 20
2. LOW PRESSURE COOLANT INJECTION MODE OF RHR SYSTEM (Division I and Division II)	
a. Diesel Generator Start Time	$\leq$ 10
b. Injection Valve Opening Time	$\leq$ 20
3. AUTOMATIC DEPRESSURIZATION SYSTEM	NA
4. HIGH PRESSURE CORE SPRAY SYSTEM	$\leq$ 27
5. LOSS OF POWER	NA

*Time to rated speed and voltage upon receipt of start signal.

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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
A. DIVISION I TRIP SYSTEM				
1. RHR-A (LPCI MODE) AND LPCS SYSTEM				
a. Reactor Vessel Water Level - Low, Low, Low, Level 1	S	M	R	1, 2, 3, 4*, 5*
b. Drywell Pressure - High	S	M	R	1, 2, 3
c. LPCS Pump Discharge Flow-Low (Bypass)	S	M	R	1, 2, 3, 4*, 5*
d. LPCS Injection Valve Permissive	S	M	R	1, 2, 3, 4*, 5*
e. LPCI Injection Valve Permissive	S	M	R	1, 2, 3, 4*, 5*
f. LPCI Pump A Start Time Delay Relay Normal Power	NA	M	R	1, 2, 3, 4*, 5*
g. LPCI Pump A Start Time Delay Relay Emer. Power	NA	M	R	1, 2, 3, 4*, 5*
h. LPCS Pump Start Time Delay Normal Power	NA	M	R	1, 2, 3, 4*, 5*
i. LPCS Pump Start Time Delay Emer. Power	NA	M	R	1, 2, 3, 4*, 5*
j. LPCI Pump A Discharge Flow-Low (Bypass)	S	M	R	1, 2, 3, 4*, 5*
k. Manual Initiation	NA	M(a)	NA	1, 2, 3, 4*, 5*
2. AUTOMATIC DEPRESSURIZATION SYSTEM TRIP SYSTEM "A"#				
a. Reactor Vessel Water Level - Low, Low, Low, Level 1	S	M	R	1, 2, 3
b. ADS Timer	NA	M	Q	1, 2, 3
c. Reactor Vessel Water Level - Low, Level 3 (Permissive)	S	M	R	1, 2, 3
d. LPCS Pump Discharge Pressure-High (Permissive)	S	M	R	1, 2, 3
e. LPCI Pump A Discharge Pressure-High (Permissive)	S	M	R	1, 2, 3
f. Manual Inhibit	NA	M	NA	1, 2, 3
g. Manual Initiation	NA	M(a)	NA	1, 2, 3

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TABLE 4.3.3.1-1 (Continued)

EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION SURVEILLANCE REQUIREMENTS

TRIP FUNCTION	CHANNEL CHECK	CHANNEL FUNCTIONAL TEST	CHANNEL CALIBRATION	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED
B. DIVISION II TRIP SYSTEM				
1. RHR B AND C (LPCI MODE)				
a. Reactor Vessel Water Level - Low, Low, Low, Level 1	S	M	R	1, 2, 3, 4*, 5*
b. Drywell Pressure - High	S	M	R	1, 2, 3
c. LPCI Injection Valve Permissive	S	M	R	1, 2, 3, 4*, 5*
d. LPCI Pump B Start Time Delay Relay Normal Power	NA	M	R	1, 2, 3, 4*, 5*
e. LPCI Pump C Start Time Delay Relay Normal Power	NA	M	R	1, 2, 3, 4*, 5*
f. LPCI Pump B Start Time Delay Emergency Power	NA	M	R	1, 2, 3, 4*, 5*
g. LPCI Pump C Start Time Delay Relay Emergency Power	NA	M	R	1, 2, 3, 4*, 5*
h. LPCI Pump Discharge Flow-Low (Bypass)	S	M	R	1, 2, 3, 4*, 5*
i. Manual Initiation	NA	M(a)	NA	1, 2, 3, 4*, 5*
2. AUTOMATIC DEPRESSURIZATION SYSTEM TRIP SYSTEM "B"#				
a. Reactor Vessel Water Level - Low, Low, Low, Level 1	S	M	R	1, 2, 3
b. ADS Timer	NA	M	Q	1, 2, 3
c. Reactor Vessel Water Level - Low, Level 3 (Permissive)	S	M	R	1, 2, 3
d. LPCI Pump (B and C) Discharge Pressure-High (Permissive)	S	M	R	1, 2, 3
e. Manual Inhibit	NA	M	NA	1, 2, 3
f. Manual Initiation	NA	M(a)	NA	1, 2, 3

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TABLE 4.3.3.1-1 (Continued)

EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION SURVEILLANCE REQUIREMENTS

TRIP FUNCTION	CHANNEL CHECK	CHANNEL FUNCTIONAL TEST	CHANNEL CALIBRATION	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED
C. DIVISION III TRIP SYSTEM				
1. HPCS SYSTEM				
a. Reactor Vessel Water Level - Low, Low, Level 2	S	M	R	1, 2, 3, 4*, 5*
b. Drywell Pressure-High (b)	S	M	R	1, 2, 3
c. Reactor Vessel Water Level-High, Level 8	S	M	R	1, 2, 3, 4*, 5*
d. Condensate Storage Tank Level - Low	S	M	R	1, 2, 3, 4*, 5*
e. Suppression Pool Water Level - High	S	M	R	1, 2, 3, 4*, 5*
f. HPCS System Flow Rate-Low (Bypass)	S	M	R	1, 2, 3, 4*, 5*
g. Pump Discharge Pressure - High (Bypass)	S	M	R	1, 2, 3, 4*, 5*
h. Manual Initiation (b)	NA	M(a)	NA	1, 2, 3, 4*, 5*
D. LOSS OF POWER				
1. 4.16 kV Emergency Bus Undervoltage Loss of Voltage	S	M	R	1, 2, 3, 4**, 5**
2. 4.16 kV Emergency Bus Undervoltage Degraded Voltage	S	M	R	1, 2, 3, 4**, 5**

\# Not required to be OPERABLE when reactor steam dome pressure is less than or equal to 100 psig.
* When the system is required to be OPERABLE per Specification 3.5.2.
** Required when ESF equipment is required to be OPERABLE.
(a) Manual initiation switches shall be tested at least once per 18 months during shutdown. All other circuitry associated with manual initiation shall receive a CHANNEL FUNCTIONAL TEST at least once per 31 days as part of circuitry required to be tested for automatic system actuation.
(b) The injection function of Drywell Pressure-High and Manual Initiation is not required to be OPERABLE with indicated reactor vessel water level on the wide range instrument greater than Level 8 setpoint coincident with the vessel pressure less than 600 psig.

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3/4.3.4 RECIRCULATION PUMP TRIP ACTUATION INSTRUMENTATION

ATWS RECIRCULATION PUMP TRIP SYSTEM INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.4.1 The anticipated transient without scram recirculation pump trip (ATWS-RPT) system instrumentation channels shown in Table 3.3.4.1-1 shall be OPERABLE with their trip setpoints set consistent with values shown in the Trip Setpoint column of Table 3.3.4.1-2.

APPLICABILITY: OPERATIONAL CONDITION 1.

ACTION:

a. With an ATWS-RPT system instrumentation channel trip setpoint less conservative then the value shown in the Allowable Value column of Table 3.3.4.1-2, declare the channel inoperable until the channel is restored to OPERABLE status with the channel trip setpoint adjusted consistent with the Trip Setpoint value.

b. With the number of OPERABLE channels one less than required by the Minimum OPERABLE Channels per Trip System requirement for one or both trip systems, place the inoperable channel(s) in the tripped condition within one hour.

c. With the number of OPERABLE channels two or more less than required by the Minimum Operable Channels per Trip System requirement for one trip system and:

   1. If the inoperable channels consist of one reactor vessel water level channel and one reactor vessel pressure channel, place both inoperable channels in the tripped condition* within one hour.

   2. If the inoperable channels include two reactor vessel water level channels or two reactor vessel pressure channels, declare the trip system inoperable.

d. With one trip system inoperable, restore the inoperable trip system to OPERABLE status within 72 hours or be in at least STARTUP within the next 6 hours.

e. With both trip systems inoperable, restore at least one trip system to OPERABLE status within one hour or be in at least STARTUP within the next 6 hours.

SURVEILLANCE REQUIREMENTS

4.3.4.1.1. Each ATWS-RPT system instrumentation channel shall be demonstrated OPERABLE by the performance of the CHANNEL CHECK, CHANNEL FUNCTIONAL TEST and CHANNEL CALIBRATION operations at the frequencies shown in Table 4.3.4.1-1.

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

*The inoperable channels need not be placed in the tripped condition where this would cause the Trip Function to occur. In this case, the inoperable channels shall be restored to OPERABLE status within 2 hours, or the trip system shall be declared inoperable.

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TABLE 3.3.4.1-1

ATWS RECIRCULATION PUMP TRIP SYSTEM INSTRUMENTATION

TRIP FUNCTION	MINIMUM OPERABLE CHANNELS PER TRIP SYSTEM[a]
1. Reactor Vessel Water Level - Low Low, Level 2	2
2. Reactor Vessel Pressure - High	2

(a) One channel and its associated trip system may be placed in an inoperable status for up to 2 hours for required surveillance provided the other channel and its trip system is OPERABLE.

TABLE 3.3.4.1-2

ATWS RECIRCULATION PUMP TRIP SYSTEM INSTRUMENTATION SETPOINTS

TRIP FUNCTION	TRIP SETPOINT	ALLOWABLE VALUE
1. Reactor Vessel, Water Level - Low Low, Level 2	$\geq$ 108.8 in*	$\geq$ 101.8 in
2. Reactor Vessel Pressure - High	$\leq$ 1050 psig	$\leq$ 1065 psig

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

TABLE 4.3.4.1-1

ATWS RECIRCULATION PUMP TRIP ACTUATION INSTRUMENTATION SURVEILLANCE REQUIREMENTS

TRIP FUNCTION	CHANNEL CHECK	CHANNEL FUNCTIONAL TEST	CHANNEL CALIBRATION
1. Reactor Vessel Water Level - Low Low, Level 2	S	M	R
2. Reactor Vessel Pressure - High	S	M	R

END-OF-CYCLE RECIRCULATION PUMP TRIP SYSTEM INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.4.2 The end-of-cycle recirculation pump trip (EOC-RPT) system instrumentation channels shown in Table 3.3.4.2-1 shall be OPERABLE with their trip setpoints set consistent with the values shown in the Trip Setpoint column of Table 3.3.4.2-2 and with the END-OF-CYCLE RECIRCULATION PUMP TRIP SYSTEM RESPONSE TIME as shown in Table 3.3.4.2-3.

APPLICABILITY: OPERATIONAL CONDITION 1, when THERMAL POWER is greater than or equal to 30% of RATED THERMAL POWER.

ACTION:

a. With an end-of-cycle recirculation pump trip system instrumentation channel trip setpoint less conservative than the value shown in the Allowable Values column of Table 3.3.4.2-2, declare the channel inoperable until the channel is restored to OPERABLE status with the channel setpoint adjusted consistent with the Trip Setpoint value.

b. With the number of OPERABLE channels one less than required by the Minimum OPERABLE Channels per Trip System requirement for one or both trip systems, place the inoperable channel(s) in the tripped condition within one hour.

c. With the number of OPERABLE channels two or more less than required by the Minimum OPERABLE Channels per Trip System requirement for one trip system and:

   1. If the inoperable channels consist of one turbine control valve channel and one turbine stop valve channel, place both inoperable channels in the tripped condition within one hour.

   2. If the inoperable channels include two turbine control valve channels or two turbine stop valve channels, declare the trip system inoperable.

d. With one trip system inoperable, restore the inoperable trip system to OPERABLE status within 72 hours or reduce THERMAL POWER to less than 30% of RATED THERMAL POWER within the next 6 hours.

e. With both trip systems inoperable, restore at least one trip system to OPERABLE status within one hour or reduce THERMAL POWER to less than 30% of RATED THERMAL POWER within the next 6 hours.

SURVEILLANCE REQUIREMENTS

4.3.4.2.1 Each end-of-cycle recirculation pump trip system instrumentation channel shall be demonstrated OPERABLE by the performance of the CHANNEL FUNCTIONAL TEST and CHANNEL CALIBRATION operations at the frequencies shown in Table 4.3.4.2.1-1.

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

4.3.4.2.3 The END-OF-CYCLE RECIRCULATION PUMP TRIP SYSTEM RESPONSE TIME of each trip function shown in Table 3.3.4.2-3 shall be demonstrated to be within its limit at least once per 18 months. Each test shall include at least the logic of one type of channel input, turbine control valve fast closure or turbine stop valve closure, such that both types of channel inputs are tested at least once per 36 months.

TABLE 3.3.4.2-1

END-OF-CYCLE RECIRCULATION PUMP TRIP SYSTEM INSTRUMENTATION

TRIP FUNCTION	MINIMUM OPERABLE CHANNELS PER TRIP SYSTEM[(a)]
1. Turbine Stop Valve - Closure	2[(b)]
2. Turbine Control Valve-Fast Closure	2[(b)]

(a) A trip system may be placed in an inoperable status for up to 2 hours for required surveillance provided that the other trip system is OPERABLE.

(b) ~~This function shall be automatically bypassed when turbine first stage pressure is less than or equal to 205 psig, equivalent to THERMAL POWER less than 30% of RATED THERMAL POWER. The turbine first stage pressure to be provided prior to issuance of the unit low power operating license and verified in writing to the Project Manager within 90 days of reaching 30% of RATED THERMAL POWER.~~
This function shall be automatically bypassed when turbine first stage pressure is less than or equal to 129.6 psig, equivalent to THERMAL POWER less than 30% of RATED THERMAL POWER. To allow for instrument accuracy, calibration and drift, a setpoint of less than or equal to 119 psig shall be used.

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TABLE 3.3.4.2-2

END-OF-CYCLE RECIRCULATION PUMP TRIP SETPOINTS

TRIP FUNCTION	TRIP SETPOINT	ALLOWABLE VALUE
1. Turbine Stop Valve-Closure	$\leq$ 5% closed	$\leq$ 7% closed
2. Turbine Control Valve-Fast Closure	$\geq$ 530 psig	$\geq$ 465 psig

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TABLE 3.3.4.2-3

END-OF-CYCLE RECIRCULATION PUMP TRIP SYSTEM RESPONSE TIME

TRIP FUNCTION	RESPONSE TIME (Milliseconds)
1. Turbine Stop Valve-Closure	$\leq$ 190
2. Turbine Control Valve-Fast Closure	$\leq$ 190

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TABLE 4.3.4.2.1-1

END-OF-CYCLE RECIRCULATION PUMP TRIP SYSTEM SURVEILLANCE REQUIREMENTS

TRIP FUNCTION	CHANNEL FUNCTIONAL TEST	CHANNEL CALIBRATION
1. Turbine Stop Valve-Closure	M	R
2. Turbine Control Valve-Fast Closure	M	R

3/4.3.5 REACTOR CORE ISOLATION COOLING SYSTEM ACTUATION INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.5 The reactor core isolation cooling (RCIC) system actuation instrumentation channels shown in Table 3.3.5-1 shall be OPERABLE with their trip setpoints set consistent with the values shown in the Trip Setpoint column of Table 3.3.5-2.

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

ACTION:

a. With a RCIC system actuation instrumentation channel trip setpoint less conservative than the value shown in the Allowable Values column of Table 3.3.5-2, 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 RCIC system actuation instrumentation channels inoperable, take the ACTION required by Table 3.3.5-1.

SURVEILLANCE REQUIREMENTS

4.3.5.1 Each RCIC system actuation instrumentation channel shall be demonstrated OPERABLE by the performance of the CHANNEL CHECK, CHANNEL FUNCTIONAL TEST and CHANNEL CALIBRATION operations at the frequencies shown in Table 4.3.5.1-1.

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

TABLE 3.3.5-1

REACTOR CORE ISOLATION COOLING SYSTEM ACTUATION INSTRUMENTATION

FUNCTIONAL UNITS	MINIMUM OPERABLE CHANNELS PER TRIP SYSTEM[(a)]	ACTION
a. Reactor Vessel Water Level - Low, Low, Level 2	2	50
b. Reactor Vessel Water Level - High, Level 8[(e)]	2	50
c. Condensate Storage Tank "A" Water Level - Low	2(b)	51
d. Manual Initiation[(d)]	1/system(c)	52

(a) A channel may be placed in an inoperable status for up to 2 hours for required surveillance without placing the trip system in the tripped condition provided at least one other OPERABLE channel in the same trip system is monitoring that parameter.
(b) One trip system with one-out-of-two logic.
(c) One trip system with one channel.
(d) Manual initiation is not required to be OPERABLE with indicated reactor vessel water level on the wide range instrument greater than Level 8 setpoint coincident with the vessel pressure less than 600 psig.
(e) ~~High~~ Level 8 trips may be bypassed to perform RCIC 150 psig operational surveillance test in accordance with Specification 4.7.4.c.2.

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TABLE 3.3.5-1 (Continued)

REACTOR CORE ISOLATION COOLING SYSTEM

ACTUATION INSTRUMENTATION

ACTION 50 - With the number of OPERABLE channels less than required by the Minimum OPERABLE Channels per Trip System requirement:

a. For one trip system, place the inoperable channel(s) and/or that trip system in the tripped condition within one hour or declare the RCIC system inoperable.

b. For both trip systems with more than one channel inoperable, declare the RCIC system inoperable.

ACTION 51 - With the number of OPERABLE channels less than required by the Minimum OPERABLE Channels per Trip System requirement, place at least one inoperable channel in the tripped condition within one hour or declare the RCIC system inoperable.

ACTION 52 - With the number of OPERABLE channels one less than required by the Minimum OPERABLE Channels per Trip System requirement, restore the inoperable channel to OPERABLE status within 8 hours or declare the RCIC system inoperable.

TABLE 3.3.5-2

REACTOR CORE ISOLATION COOLING SYSTEM ACTUATION INSTRUMENTATION SETPOINTS

FUNCTIONAL UNITS	TRIP SETPOINT	ALLOWABLE VALUE
a. Reactor Vessel Water Level - Low, Low, Level 2	≥ 108.8 inches*	≥ 101.8 inches
b. Reactor Vessel Water Level - High, Level 8	≤ 202.3 inches*	≤ 209.3 inches
c. Condensate Storage Tank Level "A" - Low	≥ ~~7.8~~ 6.15 ft	≥ ~~7.6~~ 5.9 ft
d. Manual Initiation	NA	NA

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

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TABLE 4.3.5.1-1

REACTOR CORE ISOLATION COOLING SYSTEM ACTUATION INSTRUMENTATION SURVEILLANCE REQUIREMENTS

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

(a) Manual initiation switches shall be tested at least once per 18 months during shutdown. All other circuitry associated with manual initiation shall receive a CHANNEL FUNCTIONAL TEST at least once per 31 days as part of circuitry required to be tested for automatic system actuation.

(b) Manual initiation is not required to be OPERABLE with indicated reactor vessel water level on the wide range instrument greater than Level 8 setpoint coincident with the vessel pressure less than 600 psig.

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3/4.3.6 CONTROL ROD BLOCK INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.6. The control rod block instrumentation channels shown in Table 3.3.6-1 shall be OPERABLE with their trip setpoints set consistent with the values shown in the Trip Setpoint column of Table 3.3.6-2.

APPLICABILITY: As shown in Table 3.3.6-1.

ACTION:

a. With a control rod block instrumentation channel trip setpoint less conservative than the value shown in the Allowable Values column of Table 3.3.6-2, 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 the number of OPERABLE channels less than required by the Minimum OPERABLE Channels per Trip Function requirement, take the ACTION required by Table 3.3.6-1.

SURVEILLANCE REQUIREMENTS

4.3.6 Each of the above required control rod block trip systems and instrumentation channels 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 4.3.6-1.

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TABLE 3.3.6-1

CONTROL ROD BLOCK INSTRUMENTATION

TRIP FUNCTION	MINIMUM OPERABLE CHANNELS PER TRIP FUNCTION	APPLICABLE OPERATIONAL CONDITIONS	ACTION
1. ROD BLOCK MONITOR(a)			
a. Upscale	2	1*	60
b. Inoperative	2	1*	60
c. Downscale	2	1*	60
2. APRM			
a. Flow Biased Neutron Flux Upscale	4	1	61
b. Inoperative	4	1, 2, 5	61
c. Downscale	4	1	61
d. Neutron Flux - Upscale, Startup	4	2, 5	61
3. SOURCE RANGE MONITORS			
a. Detector not full in(b)	3	2	61
	2	5	61
b. Upscale(c)	3	2	61
	2	5	61
c. Inoperative(c)	3	2	61
	2	5	61
d. Downscale(d)	3	2	61
	2	5	61
4. INTERMEDIATE RANGE MONITORS			
a. Detector not full in	6	2, 5	61
b. Upscale	6	2, 5	61
c. Inoperative	6	2, 5	61
d. Downscale(e)	6	2, 5	61
5. SCRAM DISCHARGE VOLUME			
a. Water Level-High	2	1, 2, 5**	62
~~b. Scram Trip Bypass~~	~~2~~	~~3, 4, 5**~~	~~62~~
6. REACTOR COOLANT SYSTEM RECIRCULATION FLOW			
a. Upscale	~~2~~ 3	1	62
b. Inoperative	~~2~~ 3	1	62
c. Comparator	~~2~~ 3	1	62
7. REACTOR MODE SWITCH			
a. Shutdown Mode	2	3, 4	62
b. Refuel Mode	2	5	62

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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 one 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 one hour.

NOTES

* 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.

a. The RBM shall be automatically bypassed when a peripheral control rod is selected.

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 shall be automatically bypassed when the associated IRM channels are on range 8 or higher.

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

e. This function shall be 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% of RATED THERMAL POWER	$\geq$ 3% of RATED THERMAL POWER.
2. APRM		
a. Flow Biased Neutron Flux Upscale	$\leq$ 0.66 W + 42%*	$\leq$ 0.66 W + 45%*
b. Inoperative	NA	NA
c. Downscale	$\geq$ 4% 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	$\leq 1 \times 10^5$ cps	$\leq 1.6 \times 10^5$ cps
c. Inoperative	NA	NA
d. Downscale	$\geq$ 3 cps**	$\geq$ 1.8 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	$\leq$ 16.5 in.	$\leq$ 39.75 in.
~~b. Scram Trip Bypass~~	~~NA~~	~~NA~~
6. REACTOR COOLANT SYSTEM RECIRCULATION FLOW		
a. Upscale	$\leq$ 108% rated flow	$\leq$ 111% rated flow
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 (W). The trip setting of this function must be maintained in accordance with Specification 3.2.2.

**For initial loading and startup the count rate may be less than 3 cps if the following conditions are met; (1) the signal to noise ratio is greater than 2.0 and (2) the signal is greater than 0.7 cps~~; and (3) and counting interval sufficient to accumulate at least 500 counts is employed~~.

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TABLE 3.3.6-2 (Continued)

CONTROL ROD BLOCK INSTRUMENTATION SETPOINTS

TRIP FUNCTION	TRIP SETPOINT	ALLOWABLE VALUE
7. REACTOR MODE SWITCH		
a. Shutdown Mode	NA	NA
b. Refuel Mode	NA	NA

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)(c),M(c)	Q	1*
b. Inoperative	NA	S/U(b)(c),M(c)	NA	1*
c. Downscale	NA	S/U(b)(c),M(c)	Q	1*
2. APRM				
a. Flow Biased Neutron Flux Upscale	NA	S/U(b),W	Q	1
b. Inoperative	NA	S/U(b),W	NA	1, 2, 5
c. Downscale	NA	S/U(b),W	Q	1
d. Neutron Flux - Upscale, Startup	NA	S/U(b),W	Q	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	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
5. SCRAM DISCHARGE VOLUME				
a. Water Level-High	NA	Q	R	1, 2, 5**
~~b. Scram Trip Bypass~~	~~NA~~	~~M~~	~~NA~~	~~3, 4, 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

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TABLE 4.3.6-1 (Continued)

CONTROL ROD BLOCK INSTRUMENTATION SURVEILLANCE REQUIREMENTS

TRIP FUNCTION	CHANNEL CHECK	CHANNEL FUNCTIONAL TEST	CHANNEL CALIBRATION[a]	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED
7. REACTOR MODE SWITCH				
a. Shutdown Mode	NA	R	NA	3, 4
b. Refuel Mode	NA	R	NA	5

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TABLE 4.3.6-1 (Continued)

CONTROL ROD BLOCK INSTRUMENTATION SURVEILLANCE REQUIREMENTS

NOTES:

a. Neutron detectors may be excluded from CHANNEL CALIBRATION.

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

c. Includes reactor manual control multiplexing system input.

* 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.

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INSTRUMENTATION

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3/4.3.7 MONITORING INSTRUMENTATION

RADIATION MONITORING INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.7.1 The radiation monitoring instrumentation channels shown in Table 3.3.7.1-1 shall be OPERABLE with their alarm/trip setpoints within the specified limits.

APPLICABILITY: As shown in Table 3.3.7.1-1.

ACTION:

a. With a radiation monitoring instrumentation channel alarm/trip setpoint exceeding the value shown in Table 3.3.7.1-1, adjust the setpoint to within the limit within 4 hours or declare the channel inoperable.

b. With one or more radiation monitoring channels inoperable, take the ACTION required by Table 3.3.7.1-1.

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

SURVEILLANCE REQUIREMENTS

4.3.7.1 Each of the above required radiation monitoring instrumentation channels shall be demonstrated OPERABLE by the performance of the CHANNEL CHECK, CHANNEL FUNCTIONAL TEST and CHANNEL CALIBRATION operations for the conditions and at the frequencies shown in Table 4.3.7.1-1.

SOURCE CHECK

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TABLE 3.3.7.1-1

RADIATION MONITORING INSTRUMENTATION

INSTRUMENTATION	MINIMUM CHANNELS OPERABLE	APPLICABLE CONDITIONS	ALARM/TRIP SETPOINT	ACTION
1. Main Control Room Ventilation Radiation Monitors	1/system*	1,2,3,5 and**	$\leq 1.3\times10^{-5}$ µCi/cc[(a)]	74
2. Area Monitors				
a. Criticality Monitor				
1) New Fuel Storage Vault	1	#	$\leq 1.0\times10^{2}$ mR/hr[(b)]	76
b. Control Room Direct Radiation Monitor	1	At all times	$\leq 2.5\times10^{-1}$ mR/hr[(b)]	76

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TABLE 3.3.7.1-1 (Continued)

RADIATION MONITORING INSTRUMENTATION

TABLE NOTATION

*Two trip systems are provided with two channels per trip system. An inoperable or downscale channel produces a high setpoint signal.

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

#With fuel in the new fuel storage vault.

(a)Initiates control room emergency filtration with both channels of one trip system at high setpoint.

(b)Alarm only.

(c)Above measured background.

TABLE 3.3.7.1-1 (Continued)

RADIATION MONITORING INSTRUMENTATION

ACTION

ACTION 72 - Deleted

ACTION 73 - Deleted

ACTION 74 -

a. With two channels of one trip system inoperable restore at least one of the inoperable channels to OPERABLE status within 7 days, or within the next 6 hours, ensure operation of the control room emergency filtration system in the filtration mode of operation.

b. With two channels of both trip systems inoperable, within one hour, ensure operation of the control room emergency filtration system in the filtration mode of operation.

ACTION 75 - Deleted

ACTION 76 - With the required monitor inoperable, perform area surveys of the monitored area with portable monitoring instrumentation at least once per 24 hours.

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TABLE 4.3.7.1-1

RADIATION MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS

INSTRUMENTATION	CHANNEL CHECK	SOURCE CHECK	CHANNEL FUNCTIONAL TEST	CHANNEL CALIBRATION	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED
1. Main Control Room Ventilation Radiation Monitors	S	M	~~M~~ SA	R	1,2,3,5 and *
2. Area Monitors					
a. Criticality Monitors					
1) New Fuel Storage Vault	S	M	~~M~~ SA	R	#
b. Control Room Direct Radiation Monitor	S	M	~~M~~ SA	R	1,2,3,4,5

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TABLE 4.3.7.1-1 (Continued)

RADIATION MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS

TABLE NOTATION

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

#With fuel in the new fuel storage vault.

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INSTRUMENTATION

SEISMIC MONITORING INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.7.2 The seismic monitoring instrumentation shown in Table 3.3.7.2-1 shall be OPERABLE.

APPLICABILITY: At all times.

ACTION:

a. With one or more of the above required seismic monitoring instruments 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 instrument(s) to OPERABLE status.

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

SURVEILLANCE REQUIREMENTS

4.3.7.2.1 Each of the above required seismic monitoring instruments shall be demonstrated OPERABLE by the performance of the CHANNEL CHECK, CHANNEL FUNCTIONAL TEST and CHANNEL CALIBRATION operations at the frequencies shown in Table 4.3.7.2-1.

4.3.7.2.2 Each of the above required seismic monitoring instruments actuated during a seismic event greater than or equal to 0.01 g shall be restored to OPERABLE status within 24 hours and a CHANNEL CALIBRATION performed within 5 days following the seismic event. Data shall be retrieved from actuated instruments and analyzed to determine the magnitude of the vibratory ground motion. A Special Report shall be prepared and submitted to the Commission pursuant to Specification 6.9.2 within 10 days describing the magnitude, frequency spectrum and resultant effect upon unit features important to safety.

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TABLE 3.3.7.2-1

SEISMIC MONITORING INSTRUMENTATION

INSTRUMENTS AND SENSOR LOCATIONS	MEASUREMENT RANGE	MINIMUM INSTRUMENTS OPERABLE
1. Triaxial Time-History Accelerographs		
a. Reactor Bldg. Mat. El. 175'-0"	0 ± 1.0g	1
b. Reactor Bldg. Refueling Floor El. 353'-10"	0 ± 1.0g	1
c. Control Bldg. Mat. El. 214'-0"	0 ± 1.0g	1
2. Triaxial Peak Accelerographs		
a. Diesel Generator Bldg. Service Water Piping	0-5g (b)	1
b. Prim. Cont. High Pr. Core Spray Piping	0-10g (b)	1
c. Prim. Cont. Recirc. Pump Motor	0-10g (b)	1
3. Triaxial Seismic Switches		
a. Reactor Bldg. Mat. El. 175'-0"	0.025-0.25g (adjustable)	1(a)
4. Triaxial Response-Spectrum Recorders		
a. Reactor Bldg. Mat. El. 175'-0"	0 ± 2g (b)	1(a)
b. Prim. Cont. RHR Piping Pene. El. 294'-6"	0 ± 2g (b)	1
c. Reactor Bldg. Refueling Fl. El. 353'-10"	0 ± 2g (b)	1
d. Control Bldg. Mat. El. 214'-0"	0 ± 2g (b)	1
5. Triaxial Seismic Trigger		
a. Reactor Bldg. Mat. EL. 175'-0"	0.005-0.05g	1

(a) With ~~reactor~~ control room ~~indication and~~ annunciation.

(b) stated operable range, calibration to be ± 1g span

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TABLE 4.3.7.2-1

SEISMIC MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS

INSTRUMENTS AND SENSOR LOCATIONS	CHANNEL CHECK	CHANNEL FUNCTIONAL TEST	CHANNEL CALIBRATION
1. Triaxial Time-History Accelerographs			
a. Reactor Bldg. Mat. El. 175'-0"	~~M~~ NA	SA	R
b. Reactor Bldg. Refueling Fl. El. 353'-10"	~~M~~ NA	SA	R
c. Control Bldg. Mat. El. 214'-0"	~~M~~ NA	SA	R
2. Triaxial Peak Accelerographs			
a. Diesel Gen. Bldg. Service Water Piping	NA	NA	R (b)
b. Prim. Cont. High Pr. Core Spray Piping	NA	NA	R (b)
c. Prim. Cont. Recirc. Pump Motor	NA	NA	R (b)
3. Triaxial Seismic Switches			
a. Reactor Bldg. Mat. El. 175'-0"	~~M(a)~~ NA	SA	R
4. Triaxial Response-Spectrum Recorders			
a. Reactor Bldg. Mat. El. 175'-0"	~~M~~ NA	SA	R (b)
b. Prim. Cont. RHR Piping Pene. El. 294'-6"	NA	NA	R (b)
c. Reactor Bldg. Refueling Fl. El. 353'-10"	NA	~~SA~~ NA	R (b)
d. Control Bldg. Mat. El. 214'-0"	NA	~~SA~~ NA	R (b)
5. Triaxial Seismic Trigger			
a. Reactor Bldg. Mat. 175'-0"	NA	SA	R

(a) Except seismic trigger.

(b) stated operable range, calibration to be ± 1g span

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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:

consecutive

a. With one or more meteorological monitoring instrumentation channels inoperable for more than 7 days, in lieu of any other report required by Specification 6.9.1, 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.

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.

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TABLE 3.3.7.3-1

METEOROLOGICAL MONITORING INSTRUMENTATION

INSTRUMENT	MINIMUM INSTRUMENTS OPERABLE
a. Wind Speed	
1. Elev. 30 ft.	1
2. Elev. 200 ft.	1
b. Wind Direction	
1. Elev. 30 ft.	1
2. Elev. 200 ft.	1
c. Air Temperature Difference	
1. Elev. 30/200 ft.	1

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TABLE 4.3.7.3-1

METEOROLOGICAL MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS

INSTRUMENT	CHANNEL CHECK	CHANNEL CALIBRATION
a. Wind Speed		
1. Elev. 30 ft.	D	SA
2. Elev. 200 ft.	D	SA
b. Wind Direction		
1. Elev. 30 ft.	D	SA
2. Elev. 200 ft.	D	SA
c. Air Temperature Difference		
1. Elev. 30/200 ft.	D	SA

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REMOTE SHUTDOWN SYSTEM INSTRUMENTATION AND CONTROLS

LIMITING CONDITION FOR OPERATION

3.3.7.4 The remote shutdown system instrumentation and controls* shown in Table 3.3.7.4-1 shall be OPERABLE.

APPLICABILITY: OPERATIONAL CONDITIONS 1 and 2.

ACTION:

a. With the number of OPERABLE remote shutdown system instrumentation channels less than required by Table 3.3.7.4-1, 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 remote shutdown system control channels less than required by Table 3.3.7.4-1, restore the inoperable channel(s) to OPERABLE status within 7 days or be in at least HOT SHUTDOWN within the next 12 hours.

c. The provisions of Specification 3.0.4 are not applicable.

SURVEILLANCE REQUIREMENTS

4.3.7.4.1 Each of the above required remote shutdown monitoring instrumentation channels shall be demonstrated OPERABLE by performance of the CHANNEL CHECK and CHANNEL CALIBRATION operations at the frequencies shown in Table 4.3.7.4-1.

4.3.7.4.2 Each of the above remote shutdown control switch(es) and control circuits shall be demonstrated OPERABLE by verifying its capability to perform its intended function(s) at least once per 18 months.

*Includes transfer switches associated with remote shutdown system controls.

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TABLE 3.3.7.4-1

REMOTE SHUTDOWN MONITORING INSTRUMENTATION

INSTRUMENT	READOUT LOCATION	MINIMUM INSTRUMENTS OPERABLE
1. Service Water Pump Disch Flow (6)	2CES*PNL405	2/Division
2. Reactor Vessel Pressure (2)	2CES*PNL405	1
3. RX Vessel Water Level Wide Range (2)	2CES*PNL405	1
4. RX Vessel Water Level Narrow Range (2)	2CES*PNL405	1
5. RX Vessel Shell Flg. Temp. (1)	2CES*PNL405	1
6. RX Vessel Bottom Head Temp. (1)	2CES*PNL405	1
7. RCIC Turbine Speed (1)	2CES*PNL405	1
8. Suppression Pool Water Level (2)	2CES*PNL405	1
9. CST "A" Level (1)	2CES*PNL405	1
10. CST "B" Level (1)	2CES*PNL405	1
11. RHR Loop "A" Flow (1) SERVICE WATER	2CES*PNL405	1
12. RHR HT. EX. "A" ~~Outlet~~ Flow (1)	2CES*PNL405	1
13. RHR HT. EX. "A" Service Water Outlet Temp. (1)	2CES*PNL405	1
14. RHR HT. EX. "A" In/Out Temp. (1)	2CES*PNL405	1
15. Suppression Pool Temp. (2)	2CES*PNL405	1
16. RHR HT. EX. "B" Service Water Outlet Temp. (1)	2CES*PNL405	1
17. RHR HT. EX. "B" In/Out Temp. (1)	2CES*PNL405	1
18. RHR Loop "B" Flow (1) SERVICE WATER	2CES*PNL405	1
19. RHR HT. EX. "B" ~~Outlet~~ Flow	2CES*PNL405	1
20. RHR Discharge Temp. to Radwaste (1)	2CES*PNL405	1
21. ADS Acc. Tank No. 32 Pressure (1)	2CES*PNL405	1
22. ADS Acc. Tank No. 33 Pressure (1)	2CES*PNL405	1
23. ADS Acc. Tank No. 38 Pressure (1)	2CES*PNL405	1
24. ADS Acc. Tank No. 35 Pressure (1)	2CES*PNL405	1
25. Safety/Relief Valve Position (4 Valves)	2CES*PNL405	1/valve

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Table 3.3.7.4-1 (Continued)

REMOTE SHUTDOWN SYSTEM CONTROLS

System/Subsystems*			Systems/Subsystems	Minimum Operable Systems/Sub Sys.
1.	RCIC System		1	1
2.	RHR System			
	A.	Shutdown Cooling Mode	2	1
	B.	Suppression Pool Cooling Mode	2	1
3.	Service Water System			
	A.	Pumps	6	2
	B..	Supply Valves to Div I & Div II Diesels	1/Div	1/Div
4.	ADS System (Pressure Relief)		4 Valves/Div	4 Valves
5.	Nuclear Steam Supply Shutoff System (Isolation Groups 4 & 5 Reset)		1/Div	1/Div
6.	Nitrogen Supply to ADS Accumulator Tanks		1/Div	1/Div

* Includes Applicable Transfer Switches

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TABLE 4.3.7.4-1

REMOTE SHUTDOWN MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS

INSTRUMENT	CHANNEL CHECK	CALIBRATION	READOUT LOCATION
1. Service Water Pump Disch Flow (6)	M	R	2CES*PNL405
2. Reactor Vessel Pressure (2)	M	R	2CES*PNL405
3. RX Vessel Water Level Wide Range (2)	M	R	2CES*PNL405
4. RX Vessel Water Level Narrow Range (2)	M	R	2CES*PNL405
5. RX Vessel Shell Flg. Temp. (1)	M	R	2CES*PNL405
6. RX Vessel Bottom Head Temp. (1)	M	R	2CES*PNL405
7. RCIC Turbine Speed (1)	M	R	2CES*PNL405
8. Suppression Pool Water Level (2)	M	R	2CES*PNL405
9. CST "A" Level (1)	M	R	2CES*PNL405
10. CST "B" Level (1)	M	R	2CES*PNL405
11. RHR Loop "A" Flow (1) SERVICE WATER	M	R	2CES*PNL405
12. RHR HT. EX. "A" ~~Outlet~~ Flow (1)	M	R	2CES*PNL405
13. RHR HT. EX. "A" Service Water Outlet Temp. (1)	M	R	2CES*PNL405
14. RHR HT. EX. "A" In/Out Temp. (1)	M	R	2CES*PNL405
15. Suppression Pool Temp. (2)	M	R**	2CES*PNL405
16. RHR HT. EX. "B" Service Water Outlet Temp. (1)	M	R	2CES*PNL405
17. RHR HT. EX. "B" In/Out Temp. (1)	M	R	2CES*PNL405
18. RHR Loop "B" Flow (1) SERVICE WATER	M	R	2CES*PNL405
19. RHR HT. EX. "B" ~~Outlet~~ Flow	M	R	2CES*PNL405
20. RHR Discharge Temp. to Radwaste (1)	M	R	2CES*PNL405
21. ADS Acc. Tank No. 32 Pressure (1)	M	R	2CES*PNL405
22. ADS Acc. Tank No. 33 Pressure (1)	M	R	2CES*PNL405
23. ADS Acc. Tank No. 38 Pressure (1)	M	R	2CES*PNL405
24. ADS Acc. Tank No. 35 Pressure (1)	M	R	2CES*PNL405
25. Safety/Relief Valve Position (4 Valves)	M	R*	2CES*PNL405

*CHANNEL calibration is done per Spec. 4.4.2

**CHANNEL calibration excludes sensors; sensor comparison shall be done in lieu of sensor calibration.

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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 instrumentation 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	APPLICABLE OPERATIONAL CONDITIONS	ACTION
1. Reactor Vessel Pressure	2	1	1, 2, 3	80
2. Reactor Vessel Water Level	2	1	1, 2, 3	80
3. Suppression Pool Water Level	2	1	1, 2, 3	80
4. Suppression Pool Water Temperature	8,2/quadrant	4,1/quadrant	1, 2, 3	80
5. Suppression Chamber Air Temperature	2	1	1, 2, 3	80
6. Drywell Pressure	2	1	1, 2, 3	80
7. Drywell Air Temperature	2	1	1, 2, 3	80
8. Drywell Oxygen Concentration	2	1	1, 2, 3	80
9. Drywell Hydrogen Concentration Analyzer and Monitor	2	1	1, 2, 3	80
10. Safety/Relief Valve Position Indicators	2/valve	1/valve	1, 2, 3	80
11. Drywell High Range Radiation Monitors	2	1	1, 2, 3	81
12. RHR Heat Exchanger Service Water Radiation Monitor	1/Heat Exchanger	1/Heat Exchanger	1, 2, 3	81
13. Refuel Platform Area Radiation Monitor	1	1	*	82

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Table 3.3.7.5-1 (Continued)

ACCIDENT MONITORING INSTRUMENTATION

ACTION STATEMENTS

and unirradiated

*When handling new fuel, irradiated fuel, or irradiated components in the fuel pool or reactor cavity.

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 accident monitoring instrumentation channels less than required by the Minimum Channels OPERABLE requirement, either restore the inoperable channel(s) to OPERABLE status within 72 hours, or:

a. Initiate the preplanned alternate method of monitoring the appropriate parameter(s), and

b. In lieu of another report required by Specification 6.9.2, 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 - With the number of OPERABLE accident monitoring instrumentaiton channels less than the Minimum Channels OPERABLE requirements of Table 3.3.7.5-1, suspend movement of irradiated components in the fuel pool or reactor cavity, or, initiate the preplanned alternate method of monitoring the appropriate parameter(s).

and unirradiated

new fuel, irradiated fuel

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TABLE 4.3.7.5-1

ACCIDENT MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS

INSTRUMENT	CHANNEL CHECK	CHANNEL CALIBRATION	APPLICABLE OPERATIONAL CONDITIONS
1. Reactor Vessel Pressure	M	R	1, 2
2. Reactor Vessel Water Level	M	R	1, 2
3. Suppression Pool Water Level	M	R	1, 2
4. Suppression Pool Water Temperature	M	R#	1, 2
5. Suppression Chamber Air Temperature	M	R#	1, 2
6. Drywell Pressure	M	R	1, 2
7. Drywell Air Temperature	M	R#	1, 2
8. Drywell Oxygen Concentration	M	R	1, 2
9. Drywell Hydrogen Concentration Analyzer and Monitor	M	Q**	1, 2
10. Safety/Relief Valve Position Indicators	M	R	1, 2
11. Drywell High Range Radiation Monitors	M	R***	1, 2, 3
12. RHR Heat Exchanger Service Water Radiation Monitor	M	R	1, 2, 3
13. Refuel Platform Area Radiation Monitor	M	R	*

*When handling new fuel, irradiated fuel or irradiated and unirradiated components in the fuel pool or reactor cavity.

**Using sample gas containing:
a. One volume percent hydrogen, balance nitrogen.
b. Four volume percent hydrogen, balance nitrogen.

***The 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.

#Excludes sensors; sensor comparison shall be done in lieu of sensor calibration.

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INSTRUMENTATION

SOURCE RANGE MONITORS

LIMITING CONDITION FOR OPERATION

3.3.7.6 At least the following source range monitor channels shall be OPERABLE:

a. In OPERATIONAL CONDITION 2*, three

b. In OPERATIONAL CONDITION 3 and 4, two.

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 one 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 one hour.

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 3 cps# with the detector fully inserted.

---

*With IRM's on range 2 or below.

**Neutron detectors may be excluded from CHANNEL CALIBRATION.

#For initial loading and startup the count rate may be less than 3cps if the following conditions are ~~not~~ met; (1) the signal to noise ratio is greater than 2.0, and (2) the signal is greater than 0.7 cps. ~~and (3) a counting interval sufficient to accumulate at least 500 counts is employed.~~

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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 LPRM calibration functions.

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

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INSTRUMENTATION

FIRE DETECTION INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.7.8 As a minimum, the fire detection instrumentation for each fire detection zone shown in Table 3.3.7.8-1 shall be OPERABLE.

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

ACTION:

a. With any,* but not more than one-half the total in any fire zone, Function ~~A~~ fire detection instruments shown in Table 3.3.7.8-1 inoperable, restore the inoperable Function ~~A~~ N* instrument(s) to OPERABLE status within 14 days or within 1 hour establish a fire watch patrol to inspect the zone(s) with the inoperable instrument(s) at least once per hour.

b. With more than one-half the Function ~~A~~ N* fire detection instruments in any *fire zone shown in Table 3.3.7.8-1 inoperable or with any Function ~~B~~ instruments shown in Table 3.3.7.8-1 inoperable, or with any two or more adjacent instruments shown in Table 3.3.7.8-1 inoperable, within 1 hour establish a fire watch patrol to inspect the zone(s) with the inoperable instrument(s) at least once per hour.

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

SURVEILLANCE REQUIREMENTS

4.3.7.8.1 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.

4.3.7.8.2 The NFPA Standard 72D 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.

4.3.7.8.3 The non-supervised circuits associated with detector alarms between the instruments and the control room shall be demonstrated OPERABLE at least once per 31 days.

* These Letters are found in the ~~np~~ alpha-numeric fire zone designation and are explained in the footnote to Table 3.3.7.8-1.

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TABLE 3.3.7.8-1

FIRE DETECTION INSTRUMENTATION

INSTRUMENT LOCATION			TOTAL NUMBER OF INSTRUMENTS**		
Fire Zone*	Room or Area	Elev	Heat	Ionization	Photo-Electric
Reactor Building/Auxiliary Bays					
201SW	CCP HTXCH & LPCS Pump Room	175'-0"	NA	16	NA
202SW	RHR Pump A Room	175'-0"	NA	7	NA
203SW	RHR HTXCH A Room	175'-0"	NA	6	NA
204SW	RCIC Pump Room	175'-0"	6	NA	NA
205NZ	HPCS Pump Room	175'-0"	NA	7	NA
206SW	RHR HTXCH B Room	175'-0"	NA	8	NA
207SW	RHR Pump B Room	175'-0"	NA	7	NA
208SW	RHR Pump C Room	175'-0"	NA	11	NA
212SW	Gen Area North	175'-0" 196'-0"	13	34	NA
213SW	Gen Area South	175'-0" 196'-0"	20	35	NA
211SW	N Aux Bay Above Pump Rooms	198'-0"	NA	22	NA
214SW	S Aux Bay Above Pump Rooms	198'-0"	NA	22	NA
221SW	N Aux Bay Above Pump Rooms	215'-0"	NA	28	NA
222SW	Gen Area 0°-180°	215'-0"	NA	39	NA
223SW	Gen Area 180°-360°	215'-0"	NA	39	NA
224SW	S Aux Bay Above Pump Rooms	215'-0"	NA	25	NA
231SW	N Aux Bay Elect MCC Area	240'-0"	NA	31	NA
232SW	Gen Area 0°-180°	240'-0"	5	32	NA
238SW	Gen Area 180°-360°	240'-0"	1	32	NA

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TABLE 3.3.7.8-1 (Continued)

FIRE DETECTION INSTRUMENTATION

INSTRUMENT LOCATION			TOTAL NUMBER OF INSTRUMENTS**		
Fire Zone*	Room or Area	Elev	Heat	Ionization	Photo-Electric
Reactor Building/Auxiliary Bays (cont)					
239SW	S. Aux Bay Elect MCC Area	240'-0"	NA	29	NA
243SW	Gen Area 0°-180°	261'-0"	5	38	NA
245SW	Gen Area 180°-360°	261'-0"	2	37	NA
252SW	Gen Area 0°-180°	289'-0"	4	39	NA
253XL	Elect Load Center Room	289'-0"	NA	6	NA
255SW	Gen Area 180°-360°	289'-0"	4	~~32~~ 33	NA
261NZ	Pipe Chase	306'-0"	14	NA	NA
262NZ	Gen Area 180°-360°	306'-0"	NA	26	NA
271SW	Gen Area 0°-90°	328'-10"	NA	19	NA
272SW	Gen Area 27°-360°	328'-10"	NA	19	NA
273SW	Gen Area 90°-180°	328'-10"	NA	15	NA
274SW	Gen Area 180°-270°	328'-10"	NA	19	NA
281NZ	Gen Area 0°-360°	353'-10"	NA	~~85~~ 84	NA
Control Building					
305NW	Div I Rizer Area	214'-0"	NA	4	NA
306NW	Div I Cable Area	214'-0"	NA	9	NA
307NZ	24 V Battery Room	214'-0"	NA	1	NA
308NZ	24 V Battery Room	214'-0"	NA	1	NA
309NW	Div II Cable Chase	214'-0"	NA	5	NA
310NZ	Records Room	214'-0"	NA	4	NA
311NZ	Computer Battery Room	214'-0"	NA	3	NA
312NW	Div II Cable Area	214'-0"	NA	9	NA

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TABLE 3.3.7.8-1 (Continued)

FIRE DETECTION INSTRUMENTATION

INSTRUMENT LOCATION			TOTAL NUMBER OF INSTRUMENTS**		
Fire Zone*	Room or Area	Elev	Heat	Ionization	Photo-Electric
Control Building (cont)					
321NW	Div I Ri~~z~~ser Area	237'-0"	NA	4	NA
322NW	Div I Cable Area	237'-0"	NA	14	NA
323NW	Div II Cable Area	237'-0"	NA	15	NA
324NW	Div II Ri~~z~~ser Area	237'-0"	NA	4	NA
325NW	Div I Cable Area	237'-0"	NA	5	NA
326NW	Div II Cable Area	237'-0"	NA	5	NA
327NW	Div III Cable Area	237'-0"	NA	6	NA
331NW	Corridor	261'-0"	NA	20	NA
332NW	Div I Cable Chase	261'-0"	NA	5	NA
333XL	Div I Switchgear Room	261'-0"	NA	7	NA
334NZ	Div I Battery Room	261'-0"	NA	4	NA
335NZ	Div II Battery Room	261'-0"	NA	4	NA
336XL	Div II Switchgear Room	261'-0"	NA	7	NA
337NW	Div II and III Cable Chase	261'-0"	NA	5	NA
338NZ	Remote Shutdown Room B	261'-0"	NA	2	NA
339NZ	HPCS Battery Room	261'-0"	NA	1	NA
340NZ	Div I Chiller Room	261'-0"	NA	2	NA
341NZ	Div II Chiller Room	261'-0"	NA	2	NA
342XL	Div III Switchgear Room	261'-0"	NA	4	NA
343NZ	Remote Shutdown Room A	261'-0"	NA	2	NA
351NZ	Instrument Room and Corridor	288'-6"	NA	17	NA

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TABLE 3.3.7.8-1 (Continued)

FIRE DETECTION INSTRUMENTATION

INSTRUMENT LOCATION			TOTAL NUMBER OF INSTRUMENTS**		
Fire Zone*	Room or Area	Elev	Heat	Ionization	Photo-Electric
Control Building (cont)					
352NW	Div I Cable Chase	288'-6"	NA	4	NA
353SG	Relay Room	288'-6"	50	106	NA
354SG	Relay Room	288'-6"	50	120	NA
356NZ	Relay Room	288'-6"	NA	~~20~~ 14	NA
357XG	Computer Room	288'-6"	NA	8	NA
358XG	Computer Room	288'-6"	NA	4	NA
359NW	Div II and III Cable Chase	288'-6"	NA	5	NA
360NZ	HVAC Equipment Room	288'-6"	NA	11	NA
362SG	Relay Room	288'-6"	40	72	NA
371NW	Div I Cable Chase	306'-0"	NA	4	NA
373NZ	Control Room	306'-0"	NA	~~26~~ 25	NA
374SG	Control Room	306'-0"	43	68	NA
375SG	Control Room	306'-0"	44	75	NA
376SG	Control Room	306'-0"	NA	11	NA
377NW	Div II and III Cable Chase	306'-0"	NA	3	NA
378NZ	HVAC Equipment Room	306'-0"	NA	9	NA
380NZ	Instrument Room and Corridor	306'-0"	NA	13	NA
381SG	Control Room	306'-0"	62	88	NA
Diesel Generator Building					
400NZ	Div I, II, and III Day Tank Room	272'-0"	NA	NA	3
401NZ	Div I, II, and III Control Room	261'-0"	NA	NA	9

TABLE 3.3.7.8-1 (Continued)

FIRE DETECTION INSTRUMENTATION

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INSTRUMENT LOCATION			TOTAL NUMBER OF INSTRUMENTS**		
Fire Zone*	Room or Area	Elev	Heat	Ionization	Photo-Electric
Diesel Generator Building (cont)					
402SW	Div I D/G Room	261'-0"	NA	NA	6
403SW	Div II D/G Room	261'-0"	NA	NA	6
404SW	HPCS D/G Room	261'-0"	NA	NA	6
Electrical Tunnels					
301NW	140° Tunnel	215'-0"	NA	23	NA
302NW	35° Tunnel	215'-0"	NA	15	NA
303NW	315° Tunnel	215'-0"	NA	3	NA
304NW	230° Tunnel	215'-0"	NA	~~11~~ 12	NA
236NZ	Div I HVAC Room	237'-0"	NA	8	NA
237NZ	Div II HVAC Room	237'-0"	NA	9	NA
Service Water Pump Bays					
806NZ	Div I Pump Bay	244'-0"	NA	6	NA
807NZ	Div II Pump Bay	244'-0"	NA	6	NA
Fire Pump Rooms					
804NW	Diesel Engine Fire Pump Room	261'-0"	NA	NA	8
805NZ	Elect Motor Fire Pump Room	261'-0"	NA	2	NA
Standby Gas Treatment Rooms					
247NZ	Div I GTS Room	261'-0"	NA	7	NA
248NZ	Div II GTS Room	261'-0"	NA	9	NA
Steam Tunnel					
256NZ	Steam Tunnel	240'-0"	9	NA	NA

*The first letter in the alpha-numeric fire zone designation denotes: S, actuation of fire suppression; N, no actuation of fire suppression; and X, actuation of fire suppression (Halon and CO^2 only) provided one detector is tripped in each of two loops. The second letter denotes: W-water; L-low pressure CO^2; G-Halon, Z-nothing; and F-Foam.

**In the case for a fire zone which contains two fire detection loops (denoted by an X in the fire zone designation) the number listed is the total number of dectectors in both loops.

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LOOSE-PART DETECTION SYSTEM

LIMITING CONDITION FOR OPERATION

3.3.7.9 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

4.3.7.9 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. Once every 7 days, listen to the audio output,

c. CHANNEL FUNCTIONAL TEST at least once per 31 days,

d. Once every 92 days, verify the background noise, and

e. CHANNEL CALIBRATION at least once per 18 months.

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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 and adjusted in accordance with the methodology and parameters 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, without delay suspend the release of radioactive liquid effluents monitored by the affected channel, or declare the channel inoperable, or change the setpoint so it is acceptably conservative.

b. With the number of channels OPERABLE less than the Minimum Channels OPERABLE requirement, take the ACTION shown in Table 3.3.7.10-1. Restore the instruments to OPERABLE status within 30 days and, if unsuccessful, explain in the next Semiannual Radioactive Effluent Release Report why the inoperability was not corrected in a timely manner.

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 at the frequencies shown in Table 4.3.7.10-1.

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TABLE 3.3.7.10-1

RADIOACTIVE LIQUID EFFLUENT MONITORING INSTRUMENTATION

INSTRUMENT	MINIMUM CHANNELS OPERABLE	ACTION
1. Radioactivity Monitors Providing Alarm and Automatic Termination of Release		
a. Liquid radwaste effluent line	1	128
2. Radioactivity Monitors Providing Alarm But Not Providing Automatic Termination of Release		
a. Service water effluent line A	1	130
b. Service water effluent line B	1	130
c. Cooling tower blowdown line	1	130
3. Flow Rate Measurement Devices		
a. Liquid radwaste effluent line	1	131
b. Service water effluent line A	1	131
c. Service water effluent line B	1	131
d. Cooling tower blowdown line	1	131
4. Tank Level Indicating Devices*	1	132

*Tanks included in this specification are those outdoor tanks that are not surrounded by liners, dikes, or walls capable of holding the tank contents and do not have tank overflows and surrounding area drains connected to the liquid radwaste treatment system, such as temporary tanks.

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TABLE 3.3.7.10-1 (Continued)

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TABLE NOTATION

ACTION 128 - With the number of channels OPERABLE less than required by the Minimum Channels OPERABLE requirement, effluent releases may continue provided that prior to initiating a release:

a. At least two independent samples are analyzed in accordance with Specification 4.11.1.1.1, and

b. At least two technically qualified members of the Facility Staff independently verify the release rate calculations and discharge line valving;

Otherwise, suspend release of radioactive effluents via this pathway.

ACTION 129 - Not Used

ACTION 130 - With the number of channels OPERABLE less than required by the Minimum Channels OPERABLE requirement, effluent releases via this pathway may continue provided that, at least once per 12 hours, grab samples are collected and analyzed for radioactivity at a limit of detection of at least 10^{-7} microcuries/ml.

ACTION 131 - With the number of channels OPERABLE less than required by the Minimum Channels OPERABLE requirement, effluent releases via this pathway may continue provided the flow rate is estimated at least once per 4 hours during actual releases. Pump performance curves generated in place may be used to estimate flow.

ACTION 132 - With the number of channels OPERABLE less than required by the Minimum Channels OPERABLE requirement, liquid additions to this tank may continue provided the tank liquid level is estimated during all liquid additions to the tank.

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TABLE 4.3.7.10-1

RADIOACTIVE LIQUID EFFLUENT MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS

INSTRUMENT	CHANNEL CHECK	SOURCE CHECK	CHANNEL CALIBRATION	CHANNEL FUNCTIONAL TEST
1. RADIOACTIVITY MONITORS PROVIDING ALARM AND AUTOMATIC TERMINATION OF RELEASE				
a. Liquid Radwaste Effluent Line	D	P	R(c)	SA(a,b)
2. RADIOACTIVITY MONITORS PROVIDING ALARM BUT NOT PROVIDING AUTOMATIC TERMINATION OF RELEASE				
a. Service Water Effluent Line A	D	M	R(c)	SA(b)
b. Service Water Effluent Line B	D	M	R(c)	SA(b)
c. Cooling Tower Blowdown Line	D	M	R(c)	SA(b)
3. FLOW RATE MEASUREMENT DEVICES (4)				
a. Liquid Radwaste Effluent Line	D(d)	NA	R	Q
b. Service Water Effluent Line A	D(d)	NA	R	Q
c. Service Water Effluent Line B	D(d)	NA	R	Q
d. Cooling Tower Blowdown Line	D(d)	NA	R	Q
4. TANK LEVEL INDICATING DEVICES*	D**	NA	R	Q

*Tanks included in this specification are those outdoor tanks that are not surrounded by liners, dikes or walls capable of holding the tank contents and do not have tank overflows and surrounding area drains connected to the liquid radwaste treatment system, such as temporary tanks.
**During liquid additions to the tank.

TABLE NOTATIONS

(a) The CHANNEL FUNCTIONAL TEST shall also demonstrate that automatic isolation of this pathway and control room alarm annunciation occurs if the instrument indicates measured levels above the Alarm/Trip Setpoint.

(b) The CHANNEL FUNCTIONAL TEST shall also demonstrate that control room alarm annunciation occurs if any of the following conditions exists:

(1) Instrument indicates measured levels above the Alarm Setpoint, or

(2) Circuit failure, or

(3) Instrument indicates a downscale failure, or

(4) Instrument controls not set in operate mode.

(c) The CHANNEL CALIBRATION shall be performed using one or more of the reference standards certified by the National Bureau of Standards, standards that are traceable to the National Bureau of Standards, or using actual samples of liquid effluents that have been analyzed on a system that has been calibrated with National Bureau of Standards traceable sources. These standards shall permit calibrating the system over its intended range of energy and measurement. For subsequent CHANNEL CALIBRATION, sources that have been related to the initial calibration may be used.

(d) CHANNEL CHECK shall consist of verifying indication of flow during periods of release. CHANNEL CHECK shall be made at least once per 24 hours on days on which continuous, periodic, or batch releases are made.

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LIMITING CONDITION FOR OPERATION

3.3.7.11 The radioactive gaseous effluent monitoring instrumentation channels shown in Table 3.3.7.11-1 shall be OPERABLE with their alarm/trip setpoints set to ensure that the limits of Specification 3.11.2.1 are not exceeded. The alarm/trip setpoints of these channels shall be determined and adjusted in accordance with the methodology and parameters in the ODCM.

APPLICABILITY: As shown in Table 3.3.7.11-1.

ACTION:

a. With a radioactive gaseous effluent monitoring instrumentation channel alarm/trip setpoint less conservative than required by the above specification, without delay suspend the release of radioactive gaseous effluents monitored by the affected channel, or declare the channel inoperable, or change the setpoint so it is acceptably conservative.

b. With the number of channels OPERABLE less than the Minimum Channels OPERABLE requirement, take the ACTION shown in Table 3.3.7.11-1. Restore the instruments to OPERABLE status within 30 days and, if unsuccessful, explain in the next Semiannual Radioactive Effluent Release Report why the inoperability was not corrected in a timely manner.

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

SURVEILLANCE REQUIREMENTS

4.3.7.11 Each radioactive gaseous effluent monitoring instrumentation channel shall be demonstrated OPERABLE by performance of the CHANNEL CHECK, SOURCE CHECK, CHANNEL CALIBRATION and CHANNEL FUNCTIONAL TEST operations at the frequencies shown in Table 4.3.7.11-1.

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TABLE 3.3.7.11-1

RADIOACTIVE GASEOUS EFFLUENT MONITORING INSTRUMENTATION

INSTRUMENT	MINIMUM CHANNELS OPERABLE	APPLICABILITY	ACTION
1. OFFGAS SYSTEM			
a. Noble Gas Activity Monitor - Providing Alarm and Automatic Termination of Release	1	**	136
b. System Flow Rate Measuring Device	1	**	135
c. Sampler Flow Rate Measuring Device	1	**	135
2. OFFGAS SYSTEM EXPLOSIVE GAS MONITORING SYSTEM***			
a. Hydrogen Monitor Train A (Instrument 20FG-AT-16A or 20FG-AT-115)	1	**	137
b. Hydrogen Monitor Train B (Instrument 20FG-AT-16B or 20FG-AT-115)	1	**	137
3. RADWASTE/REACTOR BUILDING VENT EFFLUENT			
a. Noble Gas Activity Monitor#	1	*	139
b. Iodine Sampler	1	*	138
c. Particulate Sampler	1	*	138
d. Flow Rate Monitor	1	*	135
e. Sampler Flow Rate Monitor	1	*	135
4. MAIN STACK EFFLUENT			
a. Noble Gas Activity Monitor#	1	*	139
b. Iodine Sampler	1	*	138
c. Particulate Sampler	1	*	138
d. Flow Rate Monitor	1	*	135
e. Sampler Flow Rate Monitor	1	*	135

#High range noble gas monitors.

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TABLE NOTATION

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*At all times.

**During offgas system operation.

***Only one train required to be in operation.

ACTION 135 - With the number of channels OPERABLE less than required by the Minimum Channels OPERABLE requirement, effluent releases via this pathway may continue provided the flow rate is estimated at least once per 4 hours.

ACTION 136 - With the number of channels OPERABLE less than required by the Minimum Channels OPERABLE requirement, effluent releases via this pathway may continue provided grab samples are taken at least once per 12 hours and these samples are analyzed for gross activity within 24 hours.

ACTION 137 - With the number of channels OPERABLE less than required by the Minimum Channels OPERABLE requirement operation of the offgas system may continue provided grab samples are collected at least once per 4 hours and analyzed within the following 4 hours.

ACTION 138 - With the number of channels OPERABLE less than required by the Minimum Channels OPERABLE requirement, effluent releases via this pathway may continue provided samples are continuously collected with auxiliary sampling equipment as required in Table 4.11-2.

ACTION 139 -

a. With the number of channels OPERABLE less than required by the Minimum Channels OPERABLE requirement, effluent releases via this pathway may continue provided grab samples are taken at least once per 12 hours and these samples are analyzed for gross activity within 24 hours.

b. Restore the inoperable channel(s) to OPERABLE status within 72 (hours) or in lieu of another report required by Specification 6.9.1, 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 schedule for restoring the system to OPERABLE status.

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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. OFFGAS SYSTEM					
a. Noble Gas Activity Monitor - Providing Alarm and Automatic Termination of Release	D	M	R(c)	SA(a,b)	**
b. System Flow Measuring Device	D	NA	R	SA	**
c. Sampler Flow Rate Measuring Device	D	NA	R	SA	**
2. OFFGAS SYSTEM EXPLOSIVE GAS MONITORING SYSTEM					
a. Hydrogen Monitor Train A	D	NA	Q(d)	M	**
b. Hydrogen Monitor Train B	D	NA	Q(d)	M	**
3. RADWASTE/REACTOR BUILDING VENT EFFLUENT SYSTEM					
a. Noble Gas Activity Monitor	D	M	R(c)	Q(b)	*
b. Iodine Sampler	W	NA	NA	NA	*
c. Particulate Sampler	W	NA	NA	NA	*
d. Flow Rate Monitor	D	NA	R	Q	*
e. Sampler Flow Rate Monitor	D	NA	R	Q	*

TABLE 4.3.7.11-1 (Continued)

RADIOACTIVE GASEOUS EFFLUENT MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS

INSTRUMENT	CHANNEL CHECK	SOURCE CHECK	CHANNEL CALIBRATION	CHANNEL FUNCTIONAL TEST	MODES IN WHICH SURVEILLANCE REQUIRED
4. MAIN STACK EFFLUENT					
a. Noble Gas Activity Monitor	D	M	R(c)	Q(b)	*
b. Iodine Sampler	W	NA	NA	NA	*
c. Particulate Sampler	W	NA	NA	NA	*
d. Flow Rate Monitor	D	NA	R	Q	*
e. Sampler Flow Rate Monitor	D	NA	R	Q	*

TABLE 4.3.7.11-1 (Continued)

TABLE NOTATION

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*At all times.

**During offgas system operation.

(a) The CHANNEL FUNCTIONAL TEST shall also demonstrate that automatic isolation of this pathway and control room alarm annunciation occurs if the instrument indicates measured levels above the alarm/trip setpoint.

(b) The CHANNEL FUNCTIONAL TEST shall also demonstrate that control room alarm annunciation occurs if any of the following conditions exists:

(1) Instrument indicates measured levels above the alarm setpoint.

(2) Circuit failure.

(3) Instrument indicates a downscale failure.

(4) Instrument controls not set in operate mode.

(c) The initial CHANNEL CALIBRATION shall be performed using one or more of the reference standards certified by the National Bureau of Standards (NBS) or using standards that have been obtained by suppliers that participate in measurement assurance activities with NBS, or using actual samples of gaseous effluents that have been analyzed on a system that has been calibrated with NBS traceable sources. These standards shall permit calibrating the system over its intended range of energy and measurement. For subsequent CHANNEL CALIBRATION, sources that have been related to the initial calibration may be used.

(d) The CHANNEL CALIBRATION shall include the use of standard gas samples containing a nominal:

(1) One volume percent hydrogen, balance nitrogen, and

(2) Four volume percent hydrogen, balance nitrogen.

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3/4.3.8 TURBINE OVERSPEED PROTECTION SYSTEM

LIMITING CONDITION FOR OPERATION

3.3.8 At least one turbine overspeed protection system shall be OPERABLE.

APPLICABILITY: OPERATIONAL CONDITIONS 1 and 2.

ACTION:

a. With one turbine control valve, one turbine throttle stop valve or one turbine reheat stop valve per high pressure turbine steam lead inoperable and/or with one turbine interceptor valve per low pressure turbine steam lead inoperable, restore the inoperable valve(s) to OPERABLE status within 72 hours or close at least one valve in the affected steam lead(s) or isolate the turbine from the steam supply within the next 6 hours.

b. With the above required turbine overspeed protection system otherwise 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 cycling each of the following valves through at least one complete cycle from the running position:

1. Four high pressure turbine stop valves,
2. Four high pressure turbine control valves, and
3. Six low pressure turbine combined stop and intercept valves.

b. At least once per 31 days by movement of each of the above valves through at least one complete cycle from the running position.

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

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

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3/4.3.9 PLANT SYSTEMS ACTUATION INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.9 The plant systems actuation instrumentation channels shown in Table 3.3.9-1 shall be OPERABLE with their trip setpoints set consistent with the values shown in the Trip Setpoint column of Table 3.3.9-2.

APPLICABILITY: As shown in Table 3.3.9-1.

ACTION:

a. With a plant system actuation instrumentation channel trip setpoint less conservative than the value shown in the Allowable Values column of Table 3.3.9-2, declare the channel inoperable and take the action required by Table 3.3.9-1.

b. With one or more Plant System Actuation Instrumentation channels inoperable take the ACTION required by Table 3.3.9-1.

SURVEILLANCE REQUIREMENTS

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

TABLE 3.3.9-1

PLANT SYSTEMS ACTUATION INSTRUMENTATION

TRIP FUNCTION	INSTRUMENT NUMBER	MINIMUM OPERABLE CHANNELS (a)	APPLICABLE OPERATIONAL CONDITIONS	ACTION
1. FEEDWATER SYSTEM/MAIN TURBINE TRIP SYSTEM				
a. Reactor Vessel Water Level-High Level 8		3	1	85
2. SERVICE WATER SYSTEM				
a. Discharge Bay Level	2SWP*LS-30A,B	2	1,2,3,4,5	87
b. Intake Tunnel 1 & 2 Water Temperature	2SWP*TSL-64A,65A 2SWP*TSL-64B,65B	1/Div 1/Div	1,2,3,4,5 1,2,3,4,5	89 89
c. Service Water Bay	2SWP*LS-73A,B	2	1,2,3,4,5	88
d. Service Water Pumps Discharge Strainer Differential Pressure-Train "A"	2SWP*PDT A,C,E	1/strainer	1,2,3,4,5	91,92
e. Service Water Pumps Discharge Strainer Differential Pressure-Train "B"	2SWP*PDT B,F,D	1/strainer	1,2,3,4,5	91,92
f. Service Water Supply Header Discharge Water Temperature	2SWP*TL-31A,B	2	1,2,3,4,5	92
g. Service Water Inlet Pressure for EDG-2 (HPCS, Div III)	2SWP*PSL-95A,B	2	1,2,3,4,5	90
h. Control Building Water Flow	2SWP*-FSL-29A,B	2	1,2,3,4,5	86

(a) A channel may be placed in an inoperable status for up to 2 hours for required surveillance without placing the trip system in the tripped condition, except for discharge bay level and service water bay level which may be placed in an inoperable status for up to 4 hours without placing the trip system in a triped condition.

TABLE 3.3.9-1 (Continued)

PLANT SYSTEMS ACTUATION INSTRUMENTATION

TRIP FUNCTION	INSTRUMENT NUMBER	MINIMUM OPERABLE CHANNELS (a)	APPLICABLE OPERATIONAL CONDITIONS	ACTION
2. SERVICE WATER SYSTEM (Continued)				
i. Control Building Service Water Inlet Temperature	2SWP*-TSL-91A,B	2	1,2,3,4,5	86
j. Control Building Service Water Outlet Temperature	2SWP*TC-35A,B	2	1,2,3,4,5	86

(a) A channel may be placed in an operable status for up to 2 hours for required surveillance without placing the trip system in the tripped condition.

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TABLE 3.3.9-1 (Continued)

PLANT SYSTEMS ACTUATION INSTRUMENTATION

ACTION 85 - a. With the number of OPERABLE channels one less than required by the Minimum OPERABLE Channels requirement, restore the inoperable channel to OPERABLE status within 7 days or be in at least STARTUP within the next 6 hours.

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

ACTION 86 - Start 2HVK*CHL 1A or B as applicable or establish flow manually.

ACTION 87 - Monitor discharge bay level continuously if level reaches trip setpoint, provide an alternate flow discharge path by locking closed 2SWP*MOV-30A or 2SWP*MOV-30B.

ACTION 88 - Monitor service water bay level continuously if level reaches trip setpoint provide an alternate intake to the service bay by locking open 2SWP*MOV-77A or 2SWP*MOV-77B.

ACTION 89 - Place intake heaters in service if lake $\leq$ 39°F.

ACTION 90 - Lock close 2SWP*MOV-95A or 2SWP*MOV-95B and declare EDG-2 (HPCS, Div III) inoperable and take the action required by Specification 3.8.1.

ACTION 91 - Monitor the effected pump discharge pressure and the applicable service water loop header pressure to determine the differential pressure across the strainer; if the differential pressure exceeds the setpoint manually start the strainer.

ACTION 92 - Monitor service water local discharge temperature indicators as applicable per specifications 4.7.1.1.a.2 or 4.7.1.2.a.2.

TABLE 3.3.9-2

PLANT SYSTEMS ACTUATION INSTRUMENTATION SETPOINTS

TRIP FUNCTION	TRIP SETPOINT	ALLOWABLE VALUE
1. FEEDWATER SYSTEM/MAIN TURBINE TRIP SYSTEM		
a. Reactor Vessel Water Level-High Level 8	≤ 202.3 inches*	≤ 203.8 inches
2. SERVICE WATER SYSTEM		
a. Discharge Bay Level	≤ 275' Elev.	≤ 275' 1/4" Elev.
b. Intake Tunnel 1 & 2 Water Temperature	≥ 39°F	≥ 38°F
c. Service Water Bay	≥ 234' Elev.	≥ 233' 11 3/4" Elev.
d. Service Water Pumps Discharge - Strainer Differential Pressure-Train "A"	≤10 psid	≤ 10.5 psid
e. Service Water Pumps Discharge Strainer Differential Pressure-Train "B"	≤10 psid	≤ 10.5 psid
f. Service Water Supply Header Discharge Water Temperature	NA	NA
g. Service Water Inlet Pressure for EDG-2 (HPCS, Div III)	≥25 psig	≥21.5 psig
h. Control Building Water FLow	≥ 225 gpm	≥ 209 gpm
i. Control Building Service Water Inlet Temperature	≥ 60°F	≥ 58°F
j. Control Building Service Water Outlet Temperature**	≤ 72°F	≤ 75.5°F

*See Bases Figure B 3/4 3-1.
**This is an operating control valve, not a trip setpoint.

TABLE 4.3.9.11-1

PLANT SYSTEMS ACTUATION INSTRUMENTATION SURVEILLANCE REQUIREMENTS

TRIP FUNCTION	CHANNEL CHECK	CHANNEL FUNCTIONAL TEST	CHANNEL CALIBRATION	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED
1. FEEDWATER SYSTEM/MAIN TURBINE TRIP SYSTEM				
a. Reactor Vessel Water Level-High [Level 8]	NA	M	R	1
2. SERVICE WATER SYSTEM				
a. Discharge Bay Level	NA	R	R	1,2,3,4,5
b. Intake Tunnel 1 & 2 Water Temperature	W	R	R*	1,2,3,4,5
c. Service Water Bay	NA	R	R	1,2,3,4,5
d. Service Water Pumps Discharge Strainer Differential Pressure-Train "A"	S	R	R	1,2,3,4,5
e. Service Water Pumps Discharge Strainer Differential Pressure-Train "B"	S	R	R	1,2,3,4,5
f. Service Water Supply Header Discharge Water Temperature	S	R	R	1,2,3,4,5
g. Service Water Inlet Pressure for EDG-2 (HPCS, Div III)	NA	R	R	1,2,3,4,5
h. Control Building Water Flow	NA	R	R	1,2,3,4,5

*Calibration excludes sensors; a comparison test of the four RTDs will be done.

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TABLE 4.3.9.11-1 (Continued)

PLANT SYSTEMS ACTUATION INSTRUMENTATION SURVEILLANCE REQUIREMENTS

TRIP FUNCTION	CHANNEL CHECK	CHANNEL FUNCTIONAL TEST	CHANNEL CALIBRATION	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED
2. SERVICE WATER SYSTEM (Continued)				
i. Control Building Service Water Inlet Temperature	NA	R	R	1,2,3,4,5
j. Control Building Service Water Out Temperature	NA	R	R	1,2,3,4,5

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3/4.4 REACTOR COOLANT SYSTEM

3/4.4.1 RECIRCULATION SYSTEM

RECIRCULATION LOOPS

LIMITING CONDITION FOR OPERATION

3.4.1.1 Two reactor coolant system recirculation loops shall be in operation with:

a. Total core flow greater than or equal to 45% of rated core flow, or

b. THERMAL POWER less than or equal to the limit specified in Figure 3.4.1.1-1

APPLICABILITY: OPERATIONAL CONDITIONS 1* and 2*.

ACTION:

a. With one reactor coolant system recirculation loop not in operation, immediately initiate action to reduce THERMAL POWER to less than or equal to the limit specified in Figure 3.4.1.1-1 within 2 hours and initiate measures to place the unit in at least HOT SHUTDOWN within 12 hours.

b. With no reactor coolant system recirculation loops in operation immediately initiate action to reduce THERMAL POWER to less than or equal to the limit specified in Figure 3.4.1.1-1 within 2 hours and initiate measures to place the unit in at least STARTUP within 6 hours and in HOT SHUTDOWN within the next 6 hours.

c. With two reactor coolant system recirculation loops in operation and total core flow less than 45% of rated core flow and THERMAL POWER greater than the limit specified in Figure 3.4.1.1-1:

   1. Determine the APRM and LPRM** noise levels (Surveillance 4.4.1.1.2)

      a) At least once per 8 hours, and

      b) Within 30 minutes after the completion of a THERMAL POWER increase of at least 5% of RATED THERMAL POWER.

   2. With the APRM or LPRM** neutron flux noise levels greater than three times their established baseline noise levels, immediately initiate corrective action to restore the noise levels to within the required limits within 2 hours by increasing core flow to greater than 45% of rated core flow or by reducing THERMAL POWER to less than or equal to the limit specified in Figure 3.4.1.1-1.

*See Special Test Exception 3.10.4.

**Detector levels A and C of one LPRM string per core octant plus detectors A and C of one LPRM string in the center of the core should be monitored.

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SURVEILLANCE REQUIREMENTS

4.4.1.1.1 Each reactor coolant system recirculation loop flow control valve shall be demonstrated OPERABLE at least once per 18 months by:

a. Verifying that the control valve fails "as is" on loss of hydraulic pressure at the hydraulic control unit, and

b. Verifying that the average rate of control valve movement is:

   1. Less than or equal to 11% of stroke per second opening, and

   2. Less than or equal to 11% of stroke per second closing.

4.4.1.1.2 Establish a baseline APRM and LPRM** neutron flux noise value within the region for which monitoring is required (Specification 3.4.1.1, ACTION c) within 2 hours of entering the region for which monitoring is required unless baselining has previously been performed in the region since the last REFUELING OUTAGE.

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*See Special Test Exception 3.10.4.

**Detector levels A and C of one LPRM string per core octant plus detectors A and C of one LPRM string in the center of the core should be monitored.

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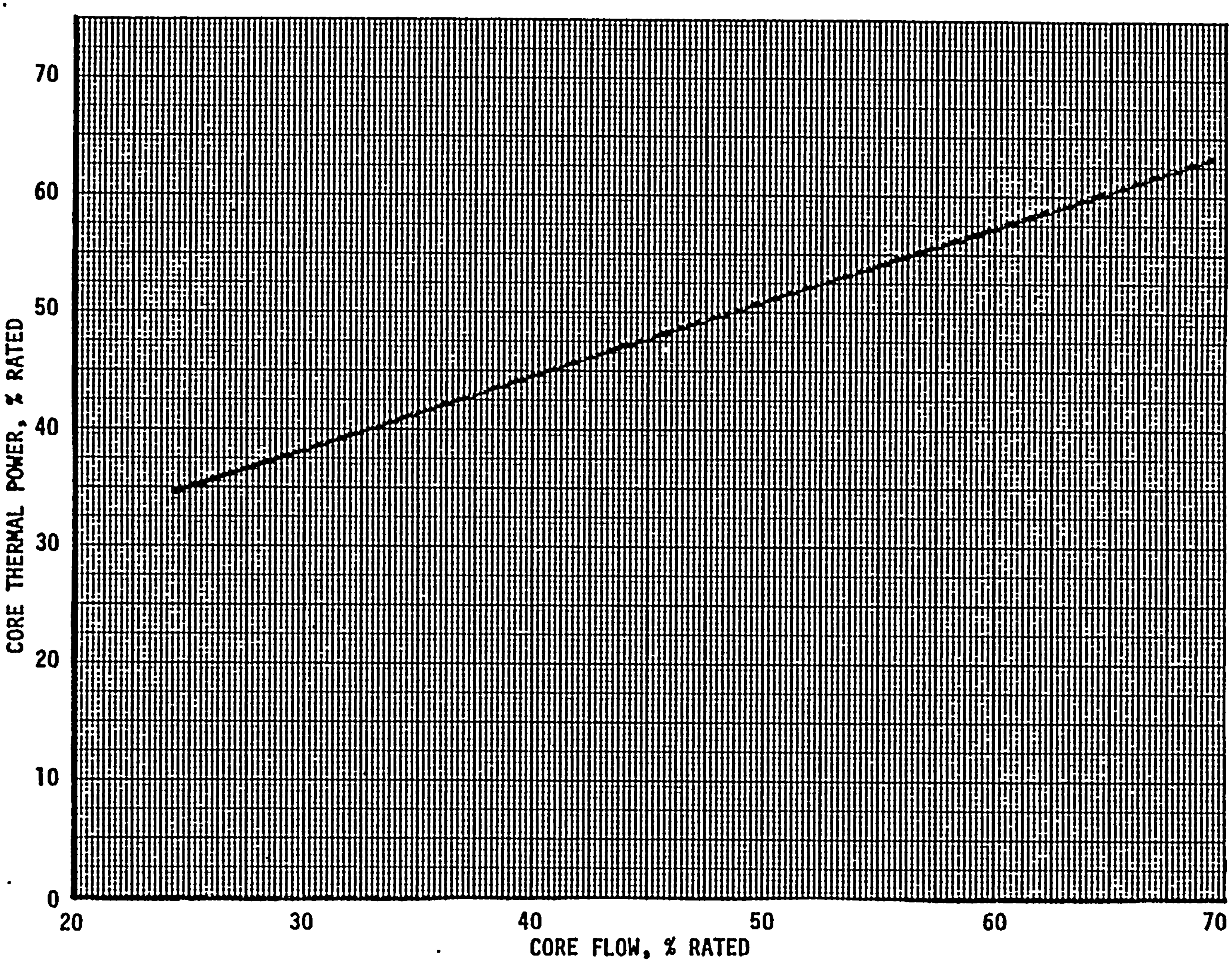

FIGURE 3.4.1.1-1 PERCENT OF RATED CORE THERMAL POWER VS PERCENT OF RATED CORE FLOW

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JET PUMPS

LIMITING CONDITION FOR OPERATION

3.4.1.2 All jet pumps shall be OPERABLE.

APPLICABILITY: OPERATIONAL CONDITIONS 1 and 2.

ACTION:

With one or more jet pumps inoperable, be in at least HOT SHUTDOWN within 12 hours.

SURVEILLANCE REQUIREMENTS

4.4.1.2 Each of the above required jet pumps shall be demonstrated OPERABLE prior to THERMAL POWER exceeding 25% of RATED THERMAL POWER and at least once per 24 hours by determining recirculation loop flow, total core flow and diffuser-to-lower plenum differential pressure for each jet pump and verifying that no two of the following conditions occur when the recirculation loops are operating at the same flow control valve position.

a. The indicated recirculation loop flow differs by more than 10% from the established flow control valve position-loop flow characteristics.

b. The indicated total core flow differs by more than 10% from the established total core flow value derived from recirculation loop flow measurements.

c. The indicated diffuser-to-lower plenum differential pressure of any individual jet pump differs from established patterns by more than 10%.

RECIRCULATION LOOP FLOW

LIMITING CONDITION FOR OPERATION

3.4.1.3 Recirculation loop flow mismatch shall be maintained within:

a. 5% of rated recirculation flow with core flow greater than or equal to 70% of rated core flow.

b. 10% of rated recirculation flow with core flow less than 70% of rated core flow.

APPLICABILITY: OPERATIONAL CONDITIONS 1* and 2*.

ACTION:

With the recirculation loop flows different by more than the specified limits, either:

a. Restore the recirculation loop flows to within the specified limit within 2 hours, or

b. Declare the recirculation loop with the lower flow not in operation and take the ACTION required by Specification 3.4.1.1.

SURVEILLANCE REQUIREMENTS

4.4.1.3 Recirculation loop flow mismatch shall be verified to be within the limits at least once per 24 hours.

*See Special Test Exception 3.10.4.

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IDLE RECIRCULATION LOOP STARTUP

LIMITING CONDITION FOR OPERATION

3.4.1.4 An idle recirculation loop shall not be started unless the temperature differential between the reactor pressure vessel steam space coolant and the bottom head drain line coolant is less than or equal to 145°F, and:

a. When both loops have been idle, unless the temperature differential between the reactor coolant within the idle loop to be started up and the coolant in the reactor pressure vessel is less than or equal to 50°F, or

b. When only one loop has been idle, unless the temperature differential between the reactor coolant within the idle and operating recirculation loops is less than or equal to 50°F and the operating loop flow rate is less than or equal to 50% of rated loop flow.

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

ACTION:

With temperature differences and/or flow rates exceeding the above limits, suspend startup of any idle recirculation loop.

SURVEILLANCE REQUIREMENTS

4.4.1.4 The temperature differentials and flow rate shall be determined to be within the limits within 15 minutes prior to startup of an idle recirculation loop.

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3/4.4.2 SAFETY/RELIEF VALVES

SAFETY/RELIEF VALVES

LIMITING CONDITION FOR OPERATION

3.4.2 The safety valve function of at least 17 of the following reactor coolant system safety/relief valves shall be OPERABLE with the specified code safety valve function lift settings*; the acoustic monitor for each OPERABLE valve shall be OPERABLE.

2 safety-relief valves @ 1148 psig ±1%
4 safety-relief valves @ 1175 psig ±1%
4 safety-relief valves @ 1185 psig ±1%
4 safety-relief valves @ 1195 psig ±1%
4 safety-relief valves @ 1205 psig ±1%

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2 and 3.

ACTION:

a. With the safety~~/relief~~ 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 110°F, close the stuck open safety/relief valve(s); if unable to close the open valve(s) within 5 minutes or if suppression pool average water temperature is 110°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. CHANNEL CALIBRATION at least once per 18 months.**

*The lift setting pressure shall correspond to ambient conditions of the valves at nominal operating temperatures and pressures.

**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.

#Initial setting shall be in accordance with the manufacturers recommendation. Adjustment to the valve full open noise level shall be accomplished during the startup test program.

3/4.4.3 REACTOR COOLANT SYSTEM LEAKAGE

LEAKAGE DETECTION SYSTEMS

LIMITING CONDITION FOR OPERATION

3.4.3.1 The following reactor coolant system leakage detection systems shall be OPERABLE:

a. The primary containment airborne particulate radioactivity monitoring system,

b. The primary containment drywell floor drain tank and equipment drain tank fill rate monitoring systems, and

c. The primary containment airborne gaseous radioactivity monitoring system.

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 and/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.

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~~ 184 days and a CHANNEL CALIBRATION at least once per 18 months.

b. Primary containment sump flow monitoring system-performance of a CHANNEL FUNCTIONAL TEST at least once per 31 days and a CHANNEL CALIBRATION TEST at least once per 18 months.

a SOURCE CHECK at least once per 31 days

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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. 0.5 gpm leakage per nominal inch of valve size up to a maximum 5 gpm at a reactor coolant system pressure of 1020± 20 psig from any reactor coolant system pressure isolation valve specified in Table 3.4.3.2-1.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2 and 3.

ACTION:

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

b. With any reactor coolant system leakage greater than the limits in b 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 two other closed (manual or deactivated automatic or check*) valves, or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

d. With one or more of the high/low pressure interface valve leakage pressure monitors shown in Table 3.4.3.2-2 inoperable, restore the inoperable monitor(s) to OPERABLE status within 7 days or verify the pressure to be less than the alarm setpoint at least once per 12 hours; restore the inoperable monitor(s) to OPERABLE status within 30 days or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

e. With one or more of the required interlocks shown in Table 3.4.3.2-3 inoperable restore the inoperable interlock to OPERABLE status within 7 days or isolate the affected heat exchanger(s) from the RCIC steam supply by closing and deenergizing heat exchanger valves 2 RHS*MOV-22A and 2RHS*MOV-80A or 2RHS*MOV22B and 2RHS*MOV80B, as appropriate.

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

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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 airborne particulate radioactivity at least once per 12 hours,

b. Monitoring the primary containment drywell floor drain tank and equipment drain tank fill rate at least once per 12 hours,

c. Monitoring the primary containment airborne gaseous radioactivity at least once per 12 hours, and

d. Monitoring the reactor vessel head flange leak detection system 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 setpoints per Table 3.4.3.2-2 by performance of a:

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

b. CHANNEL CALIBRATION at least once per 18 months.

4.4.3.2.4 The high/low pressure interface interlock for the steam condensing mode bypass valve shall be demonstrated OPERABLE with trips setpoints per Table 3.4.3.2-3 by performance of:

a. CHANNEL FUNCTIONAL TEST at least once per 92 days, and

b. CHANNEL CALIBRATION at least once per 18 months.

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TABLE 3.4.3.2-1

REACTOR COOLANT SYSTEM PRESSURE ISOLATION VALVES

VALVE NUMBER	SYSTEM
2CSH*MOV107	HPCS
2CSH*MOV108	HPCS
2CSL*MOV104	LPCS
2CSL*AOV101	LPCS
2ICS*AOV156	RCIC
2ICS*AOV157	RCIC
2RHS*MOV112	RHR
2RHS*MOV113	RHR
2RHS*MOV104	RHR
2RHS*MOV40 A&B	RHR
2RHS*MOV67 A&B	RHR
2RHS*MOV24 A,B&C	RHR-(LPCI)
2RHS*AOV16 A,B&C	RHR-(LPCI)
2RHS*AOV39 A&B	RHR
2RHS*MOV22 A&B	RHR
2RHS*MOV23 A&B	RHR
2RHS*MOV80 A&B	RHR

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TABLE 3.4.3.2-2

REACTOR COOLANT SYSTEM INTERFACE VALVES LEAKAGE PRESSURE MONITORS

INSTRUMENT NUMBER	VALVE NUMBER	SETPOINT (PSIG)
2RHS*PIS7A	2RHS*MOV24A	480 ±6
	2RHS*MOV40A	480 ±6
	2RHS*MOV22A	480 ±6
	2RHS*MOV23A	480 ±6
	2RHS*MOV80A	480 ±6
2RHS*PIS7B	2RHS*MOV24B	480 ±6
	2RHS*MOV40B	480 ±6
	2RHS*MOV22B	480 ±6
	2RHS*MOV23B	480 ±6
	2RHS*MOV80B	480 ±6
	2RHS*MOV104	480 ±6
2RHS*PIS7C	2RHS*MOV24C	480 ±6
2CSL*PS108	2CSL*MOV104	525 ~~575~~ ±6
2RHS*PIS111	2RHS*MOV112	200 ±6
	~~2RHS*MOV113~~	200 ±6

TABLE 3.4.3.2-3

HIGH/LOW PRESSURE INTERFACE INTERLOCKS

INSTRUMENT NUMBER	VALVE NUMBER	SETPOINT (PSIG)
2RHS*PIS75A/76A	2RHS*MOV23A	465 ±12
2RHS*PIS75B/76B	2RHS*MOV23B	465 ±12

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3/4.4.4 CHEMISTRY

LIMITING CONDITION FOR OPERATION

3.4.4 The chemistry of the reactor coolant system shall be maintained within the limits specified in Table 3.4.4-1.

APPLICABILITY: At all times.

ACTION:

a. In OPERATIONAL CONDITION 1:

1. With the conductivity, chloride concentration or pH exceeding the limit specified in Table 3.4.4-1 for less than 72 hours during one continuous time interval and, for conductivity and chloride concentration, for less than 336 hours per year, but with the conductivity less than 10 μmho/cm at 25°C and with the chloride concentration less than 0.5 ppm, this need not be reported to the Commission and the provisions of Specification 3.0.4 are not applicable.

2. With the conductivity, chloride concentration or pH exceeding the limit specified in Table 3.4.4-1 for more than 72 hours during one continuous time interval or with the conductivity and chloride concentration exceeding the limit specified in Table 3.4.4-1 for more than 336 hours per year, be in at least STARTUP within the next 6 hours.

3. With the conductivity exceeding 10 μmho/cm at 25°C or chloride concentration exceeding 0.5 ppm, be in at least HOT SHUTDOWN within 12 hours and in COLD SHUTDOWN within the next 24 hours.

b. In OPERATIONAL CONDITION 2 and 3 with the conductivity, chloride concentration or pH exceeding the limit specified in Table 3.4.4-1 for more than 48 hours during one continuous time interval, be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

c. At all other times:

1. With the:

   a) Conductivity or pH exceeding the limit specified in Table 3.4.4-1, restore the conductivity and pH to within the limit within 72 hours, or

   b) Chloride concentration exceeding the limit specified in Table 3.4.4-1, restore the chloride concentration to within the limit within 24 hours, or

   perform an engineering evaluation to determine the effects of the out-of-limit condition on the structural integrity of the reactor coolant system. Determine that the structural integrity of the reactor coolant system remains acceptable for continued operation prior to proceeding to OPERATIONAL CONDITION 3.

2. The provisions of Specification 3.0.3 are not applicable.

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SURVEILLANCE REQUIREMENTS

4.4.4 The reactor coolant shall be determined to be within the specified chemistry limit by:

a. Measurement prior to pressurizing the reactor during each startup, if not performed within the previous 72 hours.

b. Analyzing a sample of the reactor coolant for:

1. Chlorides at least once per:

a) 72 hours, and

b) 8 hours whenever conductivity is greater than the limit in Table 3.4.4-1.

2. Conductivity at least once per 72 hours.

3. pH at least once per:

a) 72 hours, and

b) 8 hours whenever conductivity is greater than the limit in Table 3.4.4-1.

c. Continuously recording the conductivity of the reactor coolant, or, when the continuous recording conductivity monitor is inoperable, for up to 31 days, obtaining an in-line conductivity measurement at least once per:

1. 4 hours in OPERATIONAL CONDITIONS 1, 2 and 3, and

2. 24 hours at all other times.

d. Performance of a CHANNEL CHECK of the continuous conductivity monitor with an in-line flow cell at least once per:

1. 7 days, and

2. 24 hours whenever conductivity is greater than the limit in Table 3.4.4-1.

TABLE 3.4.4-1

REACTOR COOLANT SYSTEM CHEMISTRY LIMITS

OPERATIONAL CONDITION	CHLORIDES	CONDUCTIVITY (μmhos/cm @25°C)	PH
1	$\leq$ 0.2 ppm	$\leq$ 1.0	5.6 $\leq$ pH $\leq$ 8.6
2 and 3	$\leq$ 0.1 ppm	$\leq$ 2.0	5.6 $\leq$ pH $\leq$ 8.6
At all other times	$\leq$ 0.5 ppm	$\leq$ 10.0	5.3 $\leq$ pH $\leq$ 8.6

REACTOR COOLANT SYSTEM

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3/4.4.5 SPECIFIC ACTIVITY

LIMITING CONDITION FOR OPERATION

3.4.5 The specific activity of the reactor coolant shall be limited to:

a. Less than or equal to 0.2 microcuries per gram DOSE EQUIVALENT I-131, and

b. Less than or equal to 100/Ē microcuries per gram.

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

ACTION:

a. In OPERATIONAL CONDITIONS 1, 2 or 3 with the specific activity of the primary coolant;

1. Greater than 0.2 microcuries per gram DOSE EQUIVALENT I-131 but less than or equal to 4.0 microcuries per gram DOSE EQUIVALENT I-131 for more than 48 hours during one continuous time interval or greater than 4.0 microcuries per gram DOSE EQUIVALENT I-131, be in at least HOT SHUTDOWN with the main steam line isolation valves closed within 12 hours.

2. Greater than 100 /Ē microcuries per gram, be in at least HOT SHUTDOWN with the main steamline isolation valves closed within 12 hours.

b. In OPERATIONAL CONDITIONS 1, 2, 3 or 4, with the specific activity of the primary coolant greater than 0.2 microcuries per gram DOSE EQUIVALENT I-131 or greater than 100/Ē microcuries per gram, perform the sampling and analysis requirements of Item 4a of Table 4.4.5-1 until the specific activity of the primary coolant is restored to within its limit.

c. In OPERATIONAL CONDITION 1 or 2, with:

1. THERMAL POWER changed by more than 15% of RATED THERMAL POWER in one hour*, or

2. The off-gas level, downstream of the recombiner, increased by more than 10,000 microcuries per second in one hour during steady state operation at release rates less than 75,000 microcuries per second, or

3. The off-gas level, at the SJAE, increased by more than 15% in one hour during steady state operation at release rates greater than 75,000 microcuries per second,

perform the sampling and analysis requirements of Item 4b of Table 4.4.5-1 until the specific activity of the primary coolant is restored within its limit.

*Not applicable during the startup test program

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SURVEILLANCE REQUIREMENTS

4.4.5 The specific activity of the reactor coolant shall be demonstrated to be within the limits by performance of the sampling and analysis program of Table 4.4.5-1.

TABLE 4.4.5-1

PRIMARY COOLANT SPECIFIC ACTIVITY SAMPLE AND ANALYSIS PROGRAM

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

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

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

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3/4.4.6 PRESSURE/TEMPERATURE LIMITS

REACTOR COOLANT SYSTEM

LIMITING CONDITION FOR OPERATION

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

a. A maximum water heatup of 100°F in any one hour period,

b. A maximum water cooldown of 100°F in any one hour period,

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

d. The reactor vessel flange and head flange temperature greater than or equal to 70°F when reactor vessel head bolting studs are under full tension.

APPLICABILITY: At all times.

ACTION:

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

SURVEILLANCE REQUIREMENTS

4.4.6.1.1 During system heatup, cooldown and inservice leak and hydrostatic testing operations, the reactor vessel pressure and metal temperature of the reactor vessel flange surfaces, bottom outside surface and bottom head inside surface as measured by the bottom head drain temperature shall be determined to be within the above operating limits defined by Figures 3.4.6.1-1, ~~3.4.6.1-2 and 3.4.6.1-3 curve A, B or C~~ as applicable, at least once per 30 minutes.
or Figure 3.4.6.1-2 curve B,
Curve A

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SURVEILLANCE REQUIREMENTS (Continued)

4.4.6.1.2 The reactor coolant system temperature and pressure shall be determined to be to the right of the criticality limit line of Figure 3.4.6.1-3 curve C within 15 minutes prior to the withdrawal of control rods to bring the reactor to criticality and at least once per 30 minutes during system heatup.

4.4.6.1.3 The reactor vessel material surveillance specimens shall be removed and examined, to determine changes in reactor pressure vessel material properties as required by 10 CFR 50, Appendix H in accordance with the schedule in Table 4.4.6.1.3-1. The results of these examinations shall be used to update the curves of Figures 3.4.6.1-1, 3.4.6.1-2 and 3.4.6.1-3.

4.4.6.1.4 The reactor vessel flange and head flange temperature shall be verified to be greater than or equal to 70°F when reactor vessel head bolting studs are under full tension:

a. In OPERATIONAL CONDITION 4 when reactor coolant system temperature is:

   1. $\leq$ 90°F, at least once per 12 hours.

   2. $\leq$ 80°F, at least once per 30 minutes.

b. Within 30 minutes prior to and at least once per 30 minutes during tensioning of the reactor vessel head bolting studs. except 10% of the bolting studs may be fully tensioned below 70'F,

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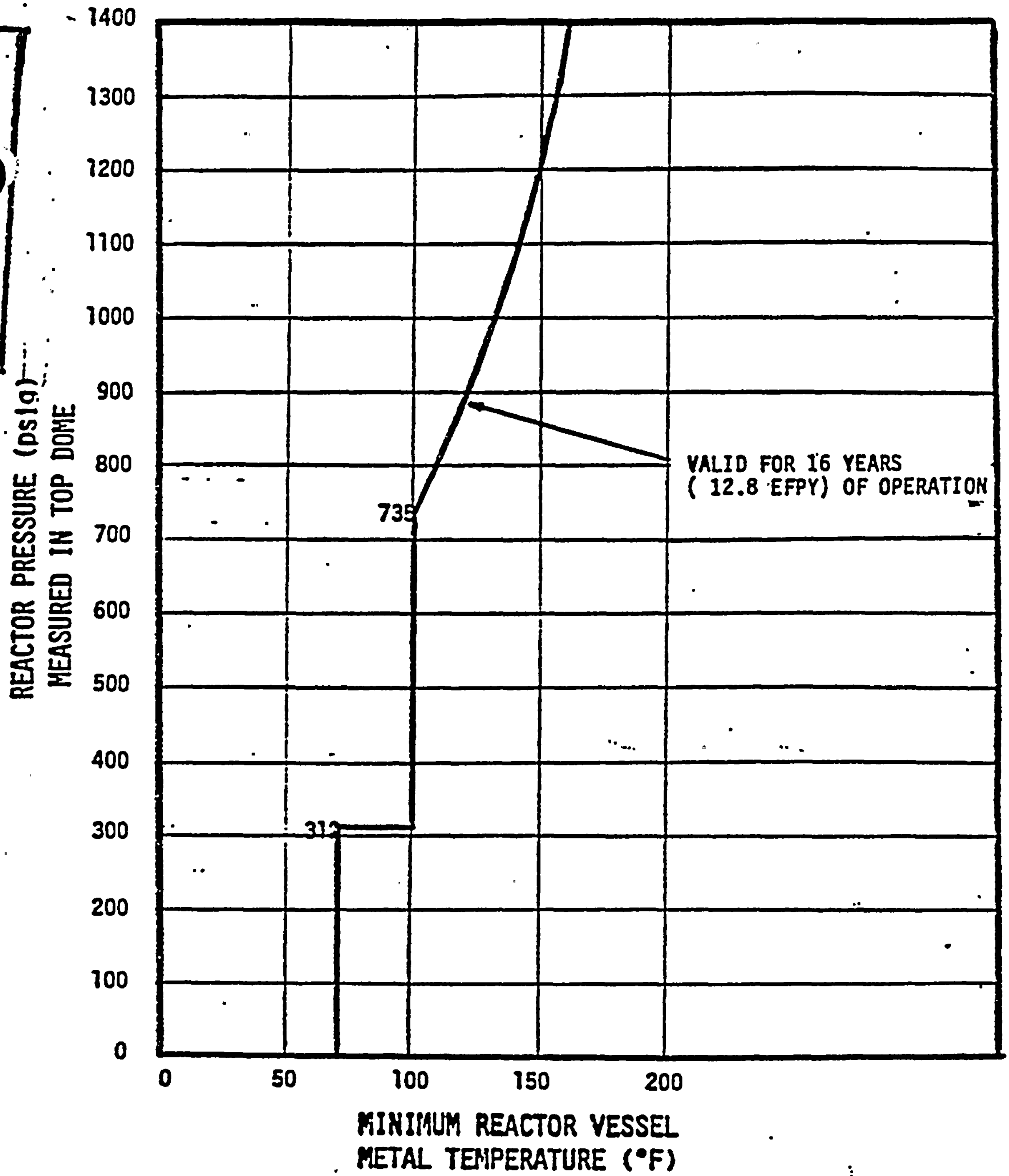

FIGURE 3.4.6.1-1 MINIMUM REACTOR VESSEL TEMPERATURE FOR PRESSURIZATION DURING IN-SERVICE HYDROSTATIC TESTING AND LEAK TESTING (CURVE A)

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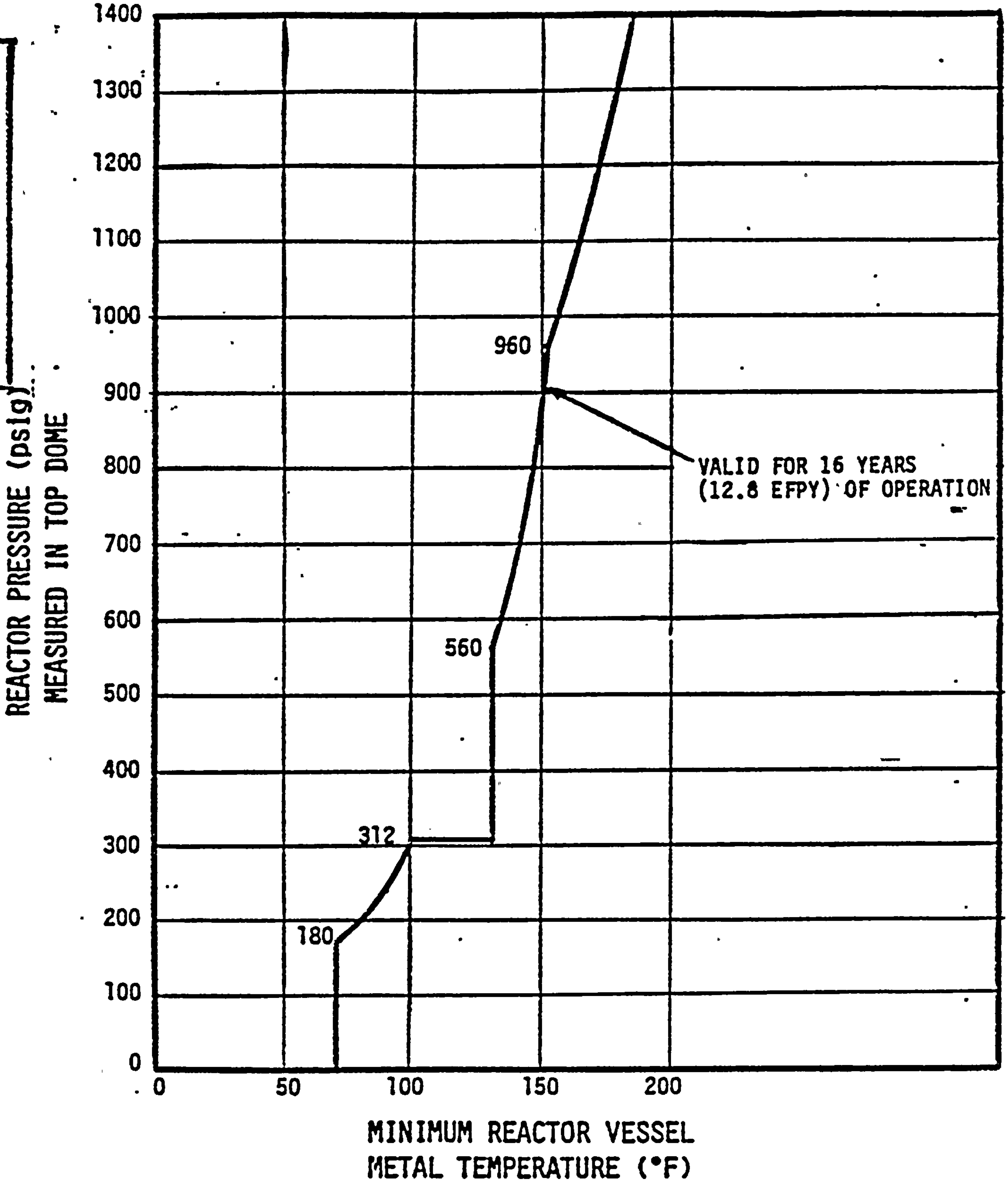

FIGURE 3.4.6.1-2 MINIMUM REACTOR VESSEL TEMPERATURE FOR PRESSURIZATION DURING NON-NUCLEAR HEATUP/ COOLDOWN AND LOW POWER PHYSICS TESTS (CURVE ~~B~~)
B

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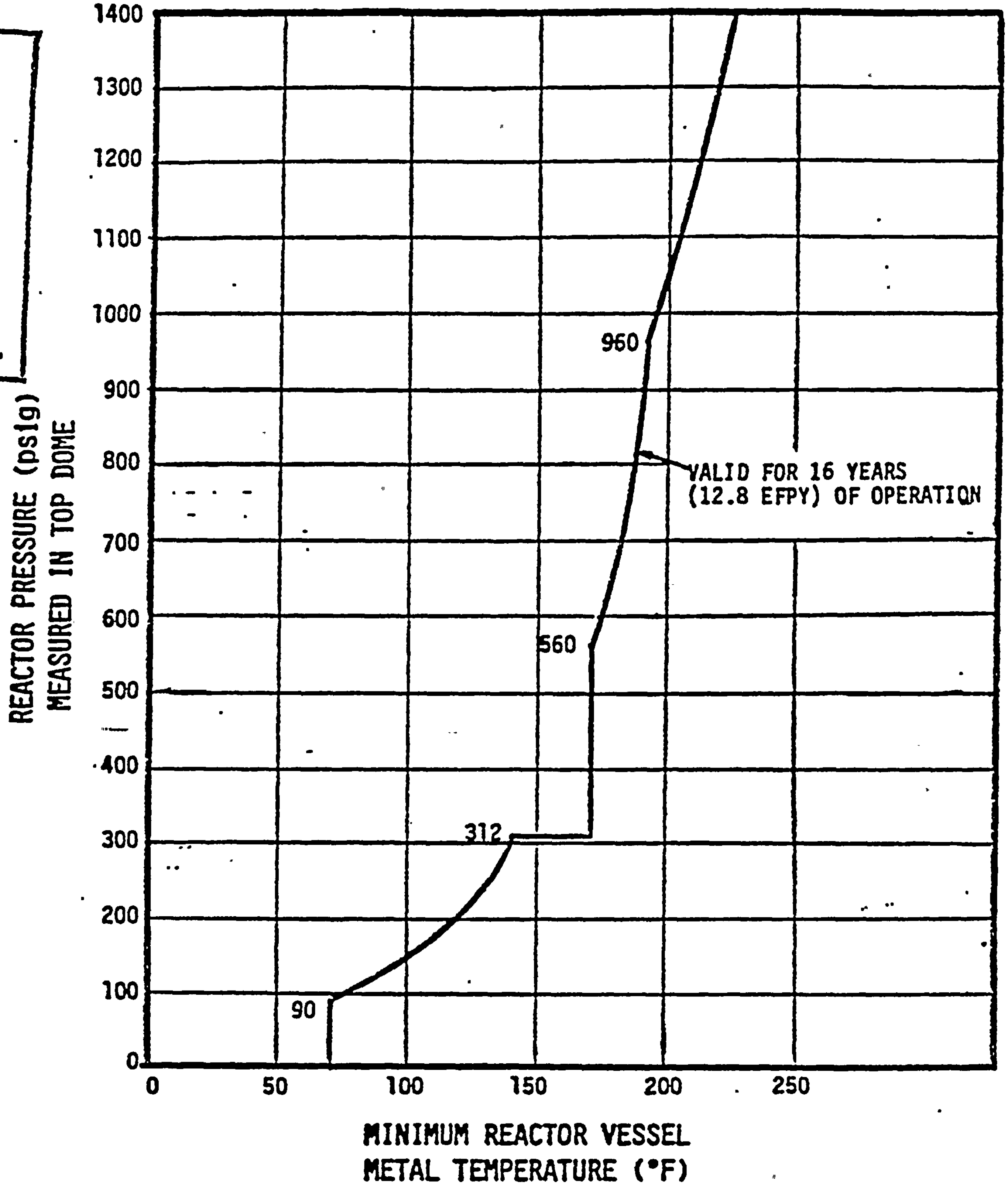

FIGURE 3.4.6.1-3 MINIMUM REACTOR VESSEL TEMPERATURE FOR PRESSURIZATION DURING CORE CRITICAL OPERATION OPERATION (CURVE C)

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TABLE 4.4.6.1.3-1

REACTOR VESSEL MATERIAL SURVEILLANCE PROGRAM-WITHDRAWAL SCHEDULE

CAPSULE NUMBER	VESSEL LOCATION	LEAD FACTOR @ 1/4 T	WITHDRAWAL TIME (EFPY)
1	3°	0.41	10
2	177°	0.41	20
3	183°	0.41	spare

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REACTOR STEAM DOME

LIMITING CONDITION FOR OPERATION

3.4.6.2 The pressure in the reactor steam dome shall be less than 1020 psig.

APPLICABILITY: OPERATIONAL CONDITION 1* and 2*.

ACTION:

With the reactor steam dome pressure exceeding 1020 psig, reduce the pressure to less than 1020 psig within 15 minutes or be in at least HOT SHUTDOWN within 12 hours.

SURVEILLANCE REQUIREMENTS

4.4.6.2 The reactor steam dome pressure shall be verified to be less than 1020 psig at least once per 12 hours.

*Not applicable during anticipated transients.

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3/4.4.7 MAIN STEAM LINE ISOLATION VALVES

LIMITING CONDITION FOR OPERATION

3.4.7 Two main steam line isolation valves (MSIVs) per main steam line shall be OPERABLE with closing times greater than or equal to 3 and less than or equal to 5 seconds.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2 and 3.

ACTION:

a. With one or more MSIVs inoperable:

   1. Maintain at least one MSIV OPERABLE in each affected main steam line that is open and within 4 hours, either:

      a) Restore the inoperable valve(s) to OPERABLE status, or

      b) Isolate the affected main steam line by use of a deactivated MSIV in the closed position.

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

b. The provisions of Specification 3.0.4 are not applicable.

SURVEILLANCE REQUIREMENTS

4.4.7 Each of the above required MSIVs shall be demonstrated OPERABLE by verifying full closure between 3 and 5 seconds when tested pursuant to Specification 4.0.5.

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3/4.4.8 STRUCTURAL INTEGRITY

LIMITING CONDITION FOR OPERATION

3.4.8 The structural integrity of ASME Code Class 1, 2 and 3 components shall be maintained in accordance with Specification 4.4.8.

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

ACTION:

a. With the structural integrity of any ASME Code Class 1 component(s) not conforming to the above requirements, restore the structural integrity of the affected component(s) to within its limit or isolate the affected component(s) prior to increasing the Reactor Coolant System temperature more than 50°F above the minimum temperature required by NDT considerations.

b. With the structural integrity of any ASME Code Class 2 component(s) not conforming to the above requirements, restore the structural integrity of the affected component(s) to within its limit or isolate the affected component(s) prior to increasing the Reactor Coolant System temperature above 200°F.

c. With the structural integrity of any ASME Code Class 3 component(s) not conforming to the above requirements, restore the structural integrity of the affected component(s) to within its limit or isolate the affected component(s) from service.

d. The provisions of Specification 3.0.4 are not applicable.

SURVEILLANCE REQUIREMENTS

4.4.8 No requirements other than Specification 4.0.5.

REACTOR COOLANT SYSTEM

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3/4.4.9 RESIDUAL HEAT REMOVAL

HOT SHUTDOWN

LIMITING CONDITION FOR OPERATION

3.4.9.1 Two# shutdown cooling mode loops of the residual heat removal (RHR) system shall be OPERABLE and, unless at least one recirculation pump is in operation, at least one shutdown cooling mode loop shall be in operation*,## with each loop consisting of at least:

a. One OPERABLE RHR pump, and

b. One OPERABLE RHR heat exchanger.

APPLICABILITY: OPERATIONAL CONDITION 3, with reactor vessel pressure less than the RHR cut-in permissive setpoint.

ACTION:

a. With less than the above required RHR shutdown cooling mode loops OPERABLE, immediately initiate corrective action to return the required loops to OPERABLE status as soon as possible. Within one hour and at least once per 24 hours thereafter, demonstrate the operability of at least one alternate method capable of decay heat removal for each inoperable RHR shutdown cooling mode loop. Be in at least COLD SHUTDOWN within 24 hours.**

b. With no RHR shutdown cooling mode loop in operation, immediately initiate corrective action to return at least one loop to operation as soon as possible. Within one hour establish reactor coolant circulation by an alternate method and monitor reactor coolant temperature and pressure at least once per hour.

SURVEILLANCE REQUIREMENTS

4.4.9.1 At least one shutdown cooling mode loop of the residual heat removal system or alternative method shall be determined to be in operation and circulating reactor coolant at least once per 12 hours.

#One RHR shutdown cooling mode loop may be inoperable for up to 2 hours for surveillance testing provided the other loop is OPERABLE and in operation.

*~~The~~ this shutdown cooling pump may be removed from operation for up to 2 hours per 8 hour period provided the other loop is OPERABLE.

##The RHR shutdown cooling mode loop may be removed from operation during hydrostatic testing.

**Whenever two or more 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.

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COLD SHUTDOWN

LIMITING CONDITION FOR OPERATION

3.4.9.2 Two# shutdown cooling mode loops of the residual heat removal (RHR) system shall be OPERABLE and, unless at least one recirculation pump is in operation, at least one shutdown cooling mode loop shall be in operation*,## with each loop consisting of at least:

a. One OPERABLE RHR pump, and

b. One OPERABLE RHR heat exchanger.

APPLICABILITY: OPERATIONAL CONDITION 4.

ACTION:

a. With less than the above required RHR shutdown cooling mode loops OPERABLE, within one hour and at least once per 24 hours thereafter, demonstrate the operability of at least one alternate method capable of decay heat removal for each inoperable RHR shutdown cooling mode loop.

b. With no RHR shutdown cooling mode loop in operation, within one hour establish reactor coolant circulation by an alternate method and monitor reactor coolant temperature and pressure at least once per hour.

SURVEILLANCE REQUIREMENTS

4.4.9.2 At least one shutdown cooling mode loop of the residual heat removal system or alternative method shall be determined to be in operation and circulating reactor coolant at least once per 12 hours.

#One RHR shutdown cooling mode loop may be inoperable for up to 2 hours for surveillance testing provided the other loop is OPERABLE and in operation.

*The shutdown cooling pump may be removed from operation for up to 2 hours per 8 hour period provided the other loop is OPERABLE.

##The shutdown cooling mode loop may be removed from operation during hydrostatic testing.

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3/4.5.1 ECCS - OPERATING

LIMITING CONDITION FOR OPERATION

3.5.1 ECCS divisions I, II and III shall be OPERABLE with:

a. ECCS division I consisting of:

1. The OPERABLE low pressure core spray (LPCS) system with a flow path capable of taking suction from the suppression pool and transferring the water through the spray sparger to the reactor vessel.

2. The OPERABLE low pressure coolant injection (LPCI) subsystem "A" of the RHR system with a flow path capable of taking suction from the suppression pool and transferring the water to the reactor vessel.

3. Seven OPERABLE ADS valves.

b. ECCS division II consisting of:

1. The OPERABLE low pressure coolant injection (LPCI) subsystems "B" and "C" of the RHR system, each with a flow path capable of taking suction from the suppression pool and transferring the water to the reactor vessel.

2. Seven OPERABLE ADS valves.

c. ECCS division III consisting of the OPERABLE high pressure core spray (HPCS) system with a flow path capable of taking suction from the suppression pool and transferring the water through the spray sparger to the reactor vessel.

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

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

#See Special Test Exception 3.10.6.

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

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LIMITING CONDITION FOR OPERATION (Continued)

ACTION:

a. For ECCS division I, provided that ECCS divisions II and III are OPERABLE:

1. With the LPCS system inoperable, restore the inoperable LPCS system to OPERABLE status within 7 days.

2. With LPCI subsystem "A" inoperable, restore the inoperable LPCI subsystem "A" to OPERABLE status within 7 days.

3. With the LPCS system inoperable and LPCI subsystem "A" inoperable, restore at least the inoperable LPCI subsystem "A" or the inoperable LPCS system to OPERABLE status within 72 hours.

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

b. For ECCS division II, provided that ECCS divisions I and III are OPERABLE:

1. With either LPCI subsystem "B" or "C" inoperable, restore the inoperable LPCI subsystem "B" or "C" to OPERABLE status within 7 days.

2. With both LPCI subsystems "B" and "C" inoperable, restore at least the inoperable LPCI subsystem "B" or "C" to OPERABLE status within 72 hours.

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

c. For ECCS division III, provided that ECCS divisions I and II and the RCIC system are OPERABLE:

1) With ECCS division III inoperable, restore the inoperable division to OPERABLE status within 14 days.

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

d. For ECCS divisions I and II, provided that ECCS division III is OPERABLE:

1) With LPCI subsystem "A" and either LPCI subsystem "B" or "C" inoperable, restore at least the inoperable LPCI subsystem "A" or the inoperable LPCI subsystem "B" or "C" to OPERABLE status within 72 hours.

*Whenever two or more 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.

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LIMTING CONDITION FOR OPERATION (Continued)

ACTION: (Continued)

2) With the LPCS system inoperable and either LPCI subsystems "B" or "C" inoperable, restore at least the inoperable LPCS system or the inoperable LPCI subsystem "B" or "C" to OPERABLE status within 72 hours.

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

e. For ECCS divisions I and II, provided that ECCS division III is OPERABLE and Divisions I and II are otherwise OPERABLE:

1. With one of the above required ADS valves inoperable, 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.

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 useage factor for each affected safety injection nozzle shall be provided in this Special Report whenever its value exceeds 0.70.

*Whenever two or more 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.

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SURVEILLANCE REQUIREMENTS

4.5.1 ECCS division I, II and III shall be demonstrated OPERABLE by:

a. At least once per 31 days for the LPCS, LPCI and HPCS systems:

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

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.

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

1. LPCS pump develops a flow of at least 6350 gpm against a test line pressure greater than or equal to 278† psig.

2. LPCI pump develops a flow of at least 7450 gpm against a test line pressure greater than or equal to 154† psig.

3. HPCS pump develops a flow of at least 6350 gpm against a test line pressure greater than or equal to 385† psig.

c. For the LPCS, LPCI and HPCS ** systems, at least once per 18 months, 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.

d. For the HPCS system, at least once per 18 months, verifying that the suction is automatically transferred from the condensate storage tank to the suppression pool on a condensate storage tank low water level signal and on a suppression pool high water level signal.

*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.

**Verify HPCS pump will auto-restart on low reactor vessel water level, level 2, if the pump has been manually stopped.

†These ECCS test line pressures are preliminary numbers to be verified during preoperational testing . Any changes to these numbers will be submitted in writing to the Commission within 90 days of their determination.

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SURVEILLANCE REQUIREMENTS (Continued)

e. For the ADS by:

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 SRV Discharge Acoustic Monitoring System ~~control valve or bypass valve position~~ responds accordingly, or

2) ~~There is a corresponding change in the measured steam flow~~ or the SRV Discharge Line Temperature Monitoring System responds accordingly, or

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

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

c) Performing a CHANNEL CALIBRATION of the accumulator backup compressed gas system low pressure alarm system and verifying an alarm setpoint of 163.5 + 2.5, -2.5 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.

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3/4 5.2 ECCS - SHUTDOWN

LIMITING CONDITION FOR OPERATION

3.5.2 At least two of the following shall be OPERABLE:

a. The low pressure core spray (LPCS) system with a flow path capable of taking suction from the suppression chamber and transferring the water through the spray sparger to the reactor vessel.

b. Low pressure coolant injection (LPCI) subsystem "A" of the RHR system with a flow path capable of taking suction from the suppression chamber and transferring the water to the reactor vessel.

c. Low pressure coolant injection (LPCI) subsystem "B" of the RHR system with a flow path capable of taking suction from the suppression chamber and transferring the water to the reactor vessel.

d. Low pressure coolant injection (LPCI) subsystem "C" of the RHR system with a flow path capable of taking suction from the suppression chamber and transferring the water to the reactor vessel.

e. The high pressure core spray (HPCS) system with a flow path capable of taking suction from one of the following water sources and transferring the water through the spray sparger to the reactor vessel:

1. From the suppression chamber, or

2. When the suppression pool level is less than the limit or is drained, from the "B" condensate storage tank containing at least 283,000 available gallons of water, equivalent to a level of 30.1'.

APPLICABILITY: OPERATIONAL CONDITION 4 and 5*.

ACTION:

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

b. With both of the above required subsystems/systems inoperable, suspend CORE ALTERATIONS and all operations that have a potential for draining the reactor vessel. Restore at least one subsystem/system 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.

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SURVEILLANCE REQUIREMENTS

4.5.2.1 At least the above required ECCS divisions shall be demonstrated OPERABLE per Surveillance Requirement 4.5.1.

4.5.2.2 The HPCS system shall be determine OPERABLE at least once per 12 hours by verifying the condensate storage tank required volume when the condensate storage tank is required to be OPERABLE per Specification 3.5.2.e.

3/4.5.3 SUPPRESSION POOL

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LIMITING CONDITION FOR OPERATION

3.5.3 The suppression pool shall be OPERABLE:

a. In OPERATIONAL CONDITION 1, 2 and 3 with a contained water volume of at least 145,495 ft^3, equivalent to an elevation of 199'-6"

b. In OPERATIONAL CONDITION 4 and 5* with a contained water volume of at least 145,495 ft^3, equivalent to a level of 199'-6", except that the suppression pool level may be less than the limit or may be drained provided that:

1. No operations are performed that have a potential for draining the reactor vessel,

2. The reactor mode switch is locked in the Shutdown or Refuel position,

3. The "B" condensate storage tank contains at least 283,000 available gallons of water, equivalent to a level of 30.1', and

4. The HPCS system is OPERABLE per Specification 3.5.2 with an OPERABLE flow path capable of taking suction from the "B" condensate storage tank and transferring the water through the spray sparger to the reactor vessel.

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

ACTION:

a. In OPERATIONAL CONDITION 1, 2 or 3 with the suppression pool water level less than the above limit, restore the water level 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.

b. In OPERATIONAL CONDITION 4 or 5* with the suppression pool water level less than the above limit or drained and the above required conditions not satisfied, suspend CORE ALTERATIONS and all operations that have a potential for draining the reactor vessel and lock the reactor mode switch in the Shutdown position. Establish SECONDARY CONTAINMENT INTEGRITY within 8 hours.

*The suppression pool is not required to be OPERABLE in OPERATIONAL CONDITION 5 provided that the reactor vessel head is removed, the cavity is flooded or being flooded, the spent fuel pool gates are removed (when the cavity is flooded), and the water level is maintained within the limits of Specification 3.9.8 and 3.9.9.

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SURVEILLANCE REQUIREMENTS

4.5.3.1 The suppression pool shall be determined OPERABLE by verifying the water level to be greater than or equal to 199'-6" at least once per 24 hours.

4.5.3.2 With the suppression pool level less than the above limit or drained in OPERATIONAL CONDITION 4 or 5*, at least once per 12 hours:

a. Verify the required conditions of Specification 3.5.3.b to be satisfied, or

b. Verify footnote conditions * to be satisfied.

*The suppression pool is not required to be OPERABLE in OPERATIONAL CONDITION 5 provided that the reactor vessel head is removed, the cavity is flooded or being flooded, the spent fuel pool gates are removed (when the cavity is flooded), and the water level is maintained within the limits of Specification 3.9.8 and 3.9.9.

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3/4.6.1 PRIMARY CONTAINMENT

PRIMARY CONTAINMENT INTEGRITY

LIMITING CONDITION FOR OPERATION

3.6.1.1 PRIMARY CONTAINMENT INTEGRITY shall be maintained.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2* and 3.

ACTION:

Without PRIMARY CONTAINMENT INTEGRITY, restore PRIMARY CONTAINMENT INTEGRITY 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

4.6.1.1 PRIMARY CONTAINMENT INTEGRITY shall be demonstrated:

a. After each closing of each penetration subject to Type B testing, except the primary containment air locks, if opened following Type A or B test, by leak rate testing the seals with gas at Pa, 39.75 psig, and verifying that when the measured leakage rate for these seals is added to the leakage rates determined pursuant to Surveillance Requirement 4.6.1.2.d for all other Type B and C penetrations, the combined leakage rate is less than or equal to 0.60 La.

b. At least once per 31 days by verifying that all primary containment penetrations** not capable of being closed by OPERABLE containment automatic isolation valves and required to be closed during accident conditions are closed by valves, blind flanges, or deactivated automatic valves secured in position, except as provided in Table 3.6.3-1 of Specification 3.6.3.

c. By verifying each primary containment air lock is in compliance with the requirements of Specification 3.6.1.3.

d. By verifying the suppression chamber is in compliance with the requirements of Specification 3.6.2.1.

*See Special Test Exception 3.10.1

**Except valves, blind flanges, and deactivated automatic valves which are located inside the containment, and are locked, sealed or otherwise secured in the closed position. These penetrations shall be verified closed during each COLD SHUTDOWN except such verification need not be performed when the primary containment has not been de-inerted since the last verification or more often than once per 92 days.

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PRIMARY CONTAINMENT LEAKAGE

LIMITING CONDITION FOR OPERATION

3.6.1.2 Primary containment leakage rates shall be limited to:

a. An overall integrated leakage rate of less than or equal to:

1. La, 1.1 percent by weight of the containment air per 24 hours at Pa, 39.75 psig, or

2. Lt, 0.55* percent by weight of the containment air per 24 hours at a reduced pressure of Pt, 20.0 psig.

b. A combined leakage rate of less than or equal to 0.60 L_a for all penetrations and all valves listed in Table 3.6.3-1, except for main steam line isolation valves** (and valves which are hydrostatically leak tested per Table 3.6.3-1), subject to Type B and C tests when pressurized to Pa, 39.75 psig.

c. **Less than or equal to 6.0 scf per hour for any one main steam line isolation valve when tested at 40.0 psig.

d. A combined leakage rate of less than or equal to 1 gpm times the total number of containment isolation valves in hydrostatically tested lines which penetrate the primary containment, when tested at 1.10 Pa, 43.73 psig.

e. Less than or equal to that specified in Table 3.6.1.2-1 through valves in lines that are potential bypass leakage pathways when tested at 40.0 psig.

APPLICABILITY: When PRIMARY CONTAINMENT INTEGRITY is required per Specification 3.6.1.1.

ACTION:

With:

a. The measured overall integrated primary containment leakage rate exceeding 0.75 La or 0.75 Lt, as applicable, or

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

c. The measured leakage rate exceeding 6.0 scf per hour for any one main steam line isolation valve, or

d. The measured combined leakage rate for all containment isolation valves in hydrostatically tested lines which penetrate the primary containment exceeding 1 gpm times the total number of such valves

e. The measured leakage rate through any valve that is part of a potential bypass leakage pathway exceeding the limit specified in Table 3.6.1.2-1

*Final number to be determined after initial Type "A" test done in accordance with Appendix "J" of 10 CFR Part 50 and reported to the Commission within 90 days of test completion.

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

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LIMITING CONDITION FOR OPERATION (Continued)

ACTION (Continued)

restore:

a. The overall integrated leakage rate(s) to less than or equal to 0.75 La or 0.75 Lt, as applicable, and

b. The combined leakage rate for all penetrations and all valves listed in Table 3.6.3-1, except for main steamline isolation 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 La, and

c. The leakage rate to less than or equal to 6.0 scf per hour for any one main steam line isolation valve, and

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

e. The leakage rate to less than or equal to that specified in Table 3.6.1.2-1 for any valve that is part of a potential bypass leakage path.

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 Pa, 39.75 psig or at Pt, 20.0 psig, during each 10-year service period. The third test of each set shall be conducted during the shutdown for the 10-year plant inservice inspection.

b. If any periodic Type A test fails to meet 0.75 La or 0.75 Lt, as applicable, the test schedule for subsequent Type A tests shall be reviewed and approved by the Commission. If two consecutive Type A tests fail to meet 0.75 La or 0.75 Lt, as applicable, a Type A test shall be performed at least every 18 months until two consecutive Type A tests meet 0.75 La or 0.75 Lt, as applicable, 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 La or 0.25 Lt, as applicable.

** Exemption to Appendix "J" of 10CFR50

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SURVEILLANCE REQUIREMENTS (Continued)

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 Pa, 39.75 psig, or Pt, 20.0 psig, as applicable.

d. Type B and C tests shall be conducted with gas at Pa, 39.75 psig,* at intervals no greater than 24 months except for tests involving:

1. Air locks,

2. Main steam line isolation valves,

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

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

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

g. Type B tests for penetrations employing a continuous leakage monitoring system shall be conducted at Pa, 39.75 psig, at intervals no greater than once per 3 years.

h. Leakage from isolation valves that are sealed with fluid from a seal system may be excluded, subject to the provisions of Appendix J, Section III.C.3, when determining the combined leakage rate provided the seal system and valves are pressurized to at least 1.10 Pa, 43.73 psig, and the seal system capacity is adequate to maintain system pressure for at least 30 days.

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

j. Purge supply and exhaust isolation valves with resilient material seals shall be tested and demonstrated OPERABLE per Surveillance Requirements 4.6.1.8.2.

k. The provisions of Specification 4.0.2 are not applicable.

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

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TABLE 3.6.1.2-1

ALLOWABLE LEAK RATES THROUGH VALVES IN POTENTIAL BYPASS LEAKAGE PATHS

Line Description	Valve Mark No	Termination Region	Bypass Leakage Barrier	Tech Spec Leak Rate (2) SCFH (1)
4 Main steam lines	2MSS*HYV6A,B,C,D 2MSS*HYV7A,B,C,D	Turbine Bldg.	2-21" valves in each line	6.0
Main steam drain line (inboard)	2MSS*MOV111,112	Turbine Bldg.	1-5" valve	1.875
Main steam drain line (outboard)	2MSS*MOV208	Turbine Bldg.	1-2" valve	0.625
4 Post accident sampline lines	2CMS*SOV77A,B 2CMS*SOV74A,B 2CMS*SOV75A,B 2CMS*SOV76A,B	Radwaste Tunnel	1-3/4" valve in each line	0.2344
Drywell equipment drain line	2DER*MOV119 2DER*MOV120	Radwaste Tunnel	1-4" valve	1.25
Drywell equipment vent line	2DER*MOV130 2DER*MOV131	Radwaste Tunnel	1-2" valve	0.625
Drywell floor drain line	2DFR*MOV120 2DFR*MOV123	Radwaste Tunnel	1-6" valve	1.875
Drywell floor vent line.	2DFR*MOV139 2DFR*MOV140	Radwaste Tunnel	1-3" valve	0.9375
RWCU line	2WCS*MOV102 2WCS*MOV112	Turbine Bldg.	1-8" valve	2.5
Feedwater line	2FWS*AOV23A 2FWS*V12A 2FWS*AOV23B 2FWS*V12B	Turbine Bldg.	2-24" check valves	12.0
CPS supply line to drywell	2CPS*AOV104 2CPS*AOV106	Standby Gas Trtmt Area	2-14" valves	4.38
CPS supply line to drywell	2CPS*SOV120 2CPS*SOV122	Standby Gas Trtmt Area	2-2" valves	0.625
CPS supply line to supp. chamber	2CPS*AOV105 2CPS*AOV107	Standby Gas Trtmt Area	2-12" valves	3.75
CPS supply line to supp. chamber	2CPS*AOV119 2CPS*AOV121	Standby Gas Trtmt Area	2-2" valves.	0.625

(1) Std Conditions: 14.7 psia and 68°F
(2) Test Conditions: Air medium; 40 psig and 80°F; Leak rate per valve

PRIMARY CONTAINMENT AIR LOCKS

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LIMITING CONDITION FOR OPERATION

3.6.1.3 Each primary containment air lock shall be OPERABLE with:

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

b. An overall air lock leakage rate of less than or equal to 0.05 La at Pa, 39.75 psig.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2* and 3.

ACTION:

a. With one primary containment air lock door inoperable:

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

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

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

4. The provisions of Specification 3.0.4 are not applicable.

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

*See Special Test Exception 3.10.1.

4.6.1.3 Each primary containment air lock shall be demonstrated OPERABLE:

a. Within 72 hours following each closing, except when the air lock is being used for multiple entries, then at least once per 72 hours, by verifying seal leakage rate less than or equal to 5 scf per hour when the gap between the door seals is pressurized to greater than or equal to 10 psig.

b. By conducting an overall air lock leakage test at Pa, 39.75 psig and by verifying that the overall air lock leakage rate is within its limit:

   1. At least once per 6 months#, and

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

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

#The provisions of Specification 4.0.2 are not applicable.

*Exception to Appendix J of 10 CFR 50.

**Except that the inner door need not be opened to verify interlock OPERABILITY when the primary containment is inerted, provided that the inner door interlock is tested within 8 hours after the primary containment has been de-inerted.

CONTAINMENT SYSTEMS

PRIMARY CONTAINMENT STRUCTURAL INTEGRITY

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LIMITING CONDITION FOR OPERATION

3.6.1.5 The structural integrity of the primary containment shall be maintained at a level consistent with the acceptance criteria in Specification 4.6.1.5.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2 and 3.

ACTION:

With the structural integrity of the primary containment not conforming to the above requirements, restore the structural integrity to within the limits 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

4.6.1.5.1 The structural integrity of the exposed accessible interior and exterior surfaces of the primary containment, including the liner plate and drywell to wetwell bypass paths, shall be determined during the shutdown for each Type A containment leakage rate test by a visual inspection of those surfaces. This inspection shall be performed prior to the Type A containment leakage rate test to verify no apparent changes in appearance or other abnormal degradation.

4.6.1.5.2 Reports Any abnormal degradation of the containment structure detected during the above required inspections shall be reported to the Commission pursuant to Specification 6.9.2 within 30 days. This report shall include a description of the condition of the vessel and the annulus fill concrete, the inspection procedure, the tolerances on concrete cracking, and the corrective actions taken.

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DRYWELL AND SUPPRESSION CHAMBER INTERNAL PRESSURE

LIMITING CONDITION FOR OPERATION

3.6.1.6 Drywell and suppression chamber internal pressure shall be maintained between 14.2 and 15.45 psia.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2 and 3.

ACTION:

With the drywell and 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.

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DRYWELL AVERAGE AIR TEMPERATURE

LIMITING CONDITION FOR OPERATION

3.6.1.7 Drywell average air temperature shall not exceed 150°F.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2 and 3.

ACTION:

With the drywell average air temperature greater than 150°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 temperatures at the following locations and shall be determined to be within the limit at least once per 24 hours:

	Elevation	Azimuth
a.	306'-9"	354°
b.	294'-5"	117°
c.	283'-0"	58°
d.	268'-0"	203°
e.	255'-6"	326°
f.	244'-0"	295°
g.	306'-9"	189°
h.	296'-4"	323°
i.	282'-6"	243°
j.	262'-3"	28°
k.	253'-11"	169°
l.	244'-0"	110°

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PRIMARY CONTAINMENT PURGE SYSTEM

LIMITING CONDITION FOR OPERATION

3.6.1.8 The drywell and suppression chamber 12 inch and 14 inch purge supply and exhaust isolation valves shall be OPERABLE and:

a. The purge system may be in operation for up to 90 hours per 365 days for inerting, deinerting~~, or pressure control.~~

~~b. Purge system valves 2CPS* AOV-105 (12 inch), 2CPS* AOV-107 (12 inch), 2CPS* AOV-110 (14 inch), and 2CPS* AOV-111 (12 inch) shall be sealed closed.~~

b. ~~c.~~ Purge system valves 2CPS * AOV 105 (12 inch) and 2CPS * AOV 110 (12 inch) ~~valve 2CPS-AOV-104 (14 inch)~~ shall be blocked to limit the opening to 70°. Purge System valve 2CPS* AOV111 shall be blocked to limit the opening to 60°.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2 and 3.

ACTION:

~~a. With any sealed closed drywell and suppression chamber purge supply and/or exhaust isolation valve(s) open or not sealed closed, close and/or seal the valve(s); otherwise isolate the penetration 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 the drywell and suppression chamber purge supply and/or exhaust isolation valve(s) inoperable or open for more than 90 hours per 365 days for other than ~~inerting, deinerting or~~ pressure control, close the open valve(s); otherwise isolate the penetration(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.

c. With a drywell and suppression chamber purge supply and/or exhaust isolation valve(s) with resilient material seals having a measured leakage rate exceeding the limit of Surveillance Requirements 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 At least once per 31 days each drywell and suppression chamber purge supply and exhaust isolation valve of Specification 3.6.1.8.b ~~and 3.6.1.8.c~~ shall be verified ~~to be sealed closed or~~ blocked to limit the opening to 70° or 60° as applicable.

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SURVEILLANCE REQUIREMENTS (Continued)

4.6.1.8.2 At least once per 92 days each 12 and 14 inch drywell and suppression chamber purge supply and exhaust isolation valve with resilient material seals shall be demonstrated OPERABLE by verifying that the measured leakage rate is less than or equal to 4.38 scf per hour per 14 inch valve and 3.75 scf per hour per 12 inch valve when pressurized to 40 psig.

3/4.6.2 DEPRESSURIZATION SYSTEMS

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SUPPRESSION POOL

LIMITING CONDITION FOR OPERATION

3.6.2.1 The suppression pool shall be OPERABLE with:

a. The pool water:

1. Volume between 154,794 ft^3 and 145,495 ft^3, equivalent to an elevation between 201' and 199'-6" 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 pool.

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 pool bypass leakage less than or equal to 10% of the acceptable $A/\sqrt{K}$ design value of 0.054 ft^2.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2 and 3.

ACTION:

a. With the suppression pool 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 pool 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 pool average water temperature greater than 105°F during testing which adds heat to the suppression pool, stop all testing which adds heat to the suppression pool 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 pool 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 12 hours and in COLD SHUTDOWN within the next 24 hours.

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.

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LIMITING CONDITION FOR OPERATION (Continued)

ACTION: (Continued)

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

c. With one suppression pool water temperature instrumentation channel in any pair(s) of temperature instrumentation channels in the same sector inoperable, restore the inoperable channel(s) to OPERABLE status within 7 days or verify suppression pool water temperature to be within the limits at least once per 12 hours.

d. With both suppression pool water temperature instrumentation channels in any pair(s) of temperature instrumentation channels in the same sector inoperable, restore at least one inoperable water temperature instrumentation channel in each pair of temperature instrumentation channels in the same sector to OPERABLE status within 8 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 pool 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 pool shall be demonstrated OPERABLE:

a. By verifying the suppression pool 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 pool 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 pool by verifying the suppression chamber average water temperature less than or equal to 105°F.

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

a) Suppression pool 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 pool average water temperature has exceeded 90°F for more than 24 hours.

3. At least once per 30 minutes following a scram with suppression pool average water temperature greater than or equal to 90°F, by verifying suppression pool average water temperature less than or equal to 120°F.

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SURVEILLANCE REQUIREMENTS (Continued)

c. By verifying at least twenty suppression pool water temperature instrumentation channels, at least one pair in each of 10 suppression pool sectors, 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 high temperature alarm setpoint for $\leq$ 90°F.

d. At least once per 18 months by conducting a drywell-to-suppression pool bypass leak test at an initial differential pressure of 3 psi and verifying that the $A/\sqrt{K}$ calculated from the measured leakage is within the specified limit. If any drywell-to-suppression pool 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.

*Calibration excludes sensors; sensors comparisons shall be made in lieu of calibration.

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SUPPRESSION POOL AND DRYWELL SPRAY

LIMITING CONDITION FOR OPERATION

3.6.2.2 The suppression pool and drywell 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 pool through an RHR heat exchanger and the suppression chamber and drywell spray sparger(s).

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2 and 3.

ACTION:

a. With one suppression chamber and/or drywell spray loop inoperable, restore the inoperable loop 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. With both suppression chamber and/or drywell spray loops inoperable, restore at least one loop to OPERABLE status 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

4.6.2.2 The suppression chamber and drywell 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 at least 450 gpm on recirculation flow through the RHR heat exchanger and suppression pool spray sparger when tested pursuant to Specification 4.0.5.

c. By performance of an air flow test of the drywell spray nozzles at least once per 5 years and verifying that each spray nozzle is unobstructed.

*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.

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SUPPRESSION POOL COOLING

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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 at least 7450 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.

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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 CONDITIONS 1, 2 and 3

ACTION:

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

   1. Restore the inoperable valve(s) to OPERABLE status, or

   2. Isolate each affected penetration by use of at least one deactivated automatic valve secured in the isolated position,* or

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

   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.

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SURVEILLANCE REQUIREMENTS

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

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

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

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

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

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

b. At least once per 18 months by removing at least one explosive squib from at least one explosive valve , such that each explosive squib in each explosive valve will be tested at least once per 36 months, and initiating the explosive squib. The replacement charge for the exploded squib shall be from the same manufactured batch as the one fired or from another batch which has been certified by having at least one of that batch successfully fired. No squib shall remain in use beyond the expiration of its shelf-life and operating life, as applicable.

Table 3.6.3-1

PRIMARY CONTAINMENT ISOLATION VALVES

	VALVE NUMBER AND FUNCTION	VALVE GROUPS	ISOLATION SIGNALS	MAXIMUM CLOSING TIME (SECONDS)
A. AUTOMATIC ISOLATION VALVES				
2MSS*HYV6 A, B, C, D	Inside MSIV	1	Z,X,C,D,E,P,T,R,RM,AA	3 to 5
2MSS*HYV7 A, B, C, D	Outside MSIV	1	Z,X,C,D,E,P,T,R,RM,AA	3 to 5
2MSS*MOV208	DSL Drain Line Outside IV	1	Z,X,C,D,E,P,T,R,RM,AA	15
2MSS*MOV111	Main Steam Drain Line Inside IV	1	Z,X,C,D,E,P,T,R,RM,AA	15
2MSS*MOV112	Main Steam Drain Line Outside IV	1	Z,X,C,D,E,P,T,R,RM,AA	15
2RHS*MOV33 A,B	RHS Cont. Spray Outside IV's	* ~~12~~	~~G~~, RM and *	35
2RHS*MOV104	RHS Reactor Head Spray Outside IV	5	A,L,M,Z,RM, CC, DD	50
2RHS*MOV40 A,B	Shutdown Cooling Return Outside IV's	5	A,L,M,Z,RM, CC, DD	40
2RHS*MOV67 A,B	SDC Inboard IV Bypass Valves	5	A,L,M,Z,RM, CC, DD	15
2RHS*MOV112	SDC Supply Inside IV	5	A,L,M,Z,RM, CC, DD	45
2RHS*MOV113	SDC Supply Outside IV	5	A,L,M,Z,RM, CC, DD	45
2CSH*MOV111	CSH Test Return to Suppression Pool Outside IV	* ~~14~~	~~N~~, RM and *	60
2ICS*MOV164	RCIC Vacuum Breaker Outside IV	11	H & F, RM STET	15
2CCP*MOV94 A,B	CCP Supply to RCS Inside IV's	8	B,F,Z,RM	30
2CCP*MOV17 A,B	CCP Supply to RCS Outside IV's	8	B,F,Z,RM	30
2CCP*MOV16 A,B	CCP Return from RCS Pumps Inside IV's	8	B,F,Z,RM	30
2CCP*MOV15 A,B	CCP Return from RCS Pumps Outside IV's	8	B,F,Z,RM	30
2DFR*MOV120	DFR Drain Tank ~~Vent~~ Line Outside IV	8	B,F,Z,RM	45
2DFR*MOV121	DFR Drain Tank ~~Ven~~ Line Inside IV	8	B,F,Z,RM	45

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Table 3.6.3-1 (Cont.)

PRIMARY CONTAINMENT ISOLATION VALVES

VALVE NUMBER AND FUNCTION		VALVE GROUPS	ISOLATION SIGNALS	MAXIMUM CLOSING TIME (SECONDS)
2DER*MOV119	DER Line from Drywell Inside IV	8	B,F,Z,RM	35
2DER*MOV120	DER Line from Drywell Outside IV	8	B,F,Z,RM	35
2RCS*SOV104	RCS Sample Inside IV	2	B,C,Z,RM	NA
2RCS*SOV105	RCS Sample Outside IV	2	B,C,Z,RM	NA
~~2FPW*SOV218(i)~~	~~RCS A Water Spray Outside IV~~	~~8~~	~~B,F,Z,RM~~	~~NA~~
~~2FPW*SOV219(i)~~	~~RCS A Water Spray Inside IV~~	~~8~~	~~B,F,Z,RM~~	~~NA~~
~~2FPW*SOV220(i)~~	~~RCS B Water Spray Outside IV~~	~~8~~	~~B,F,Z,RM~~	~~NA~~
~~2FPW*SOV221(i)~~	~~RCS B Water Spray Inside IV~~	~~8~~	~~B,F,Z,RM~~	~~NA~~
2DFR*MOV139	DFR Vent Line Outside IV	8	B,F,Z,RM	25
2DFR*MOV140	DFR Vent Line Inside IV	8	B,F,Z,RM	25
2DER*MOV130	DER Vent Line Inside IV	8	B,F,Z,RM	15
2DER*MOV131	DER Vent Line Outside IV	8	B,F,Z,RM	15
2CCP*MOV265	Sply to Drywell Space Cooler Outside IV	8	B,F,Z,RM	60
2CCP*MOV273	Sply to Drywell Space Cooler Inside IV	8	B,F,Z,RM	60
2CCP*MOV122	Return from Drywell Space Cooler Inside IV	8	B,F,Z,RM	60
2CCP*MOV124	Return from Drywell Space Cooler Outside IV	8	B,F,Z,RM	60
2CPS*AOV104	Purge Inlet to Drywell Outside IV	9	B,F,Y,Z,RM	5
2CPS*AOV105	Purge Inlet to Sup. Chamber Outside IV	9	B,F,Y,Z,RM	5
2CPS*AOV106(n)	Purge Inlet to Drywell Inside IV	9	B,F,Y,Z,RM	5
2CPS*AOV107(n)	Purge Inlet to Sup. Chamber Inside IV	9	B,F,Y,Z,RM	5
2CPS*AOV108(n)	Purge Exhaust from Drywell Inside IV	9	B,F,Y,Z,RM	5
2CPS*AOV109(n)	Purge Exhaust from Sup. Chamber Inside IV	9	B,F,Y,Z,RM	5
2CPS*AOV110	Purge Exhaust from Drywell Outside IV	9	B,F,Y,Z,RM	5
2CPS*AOV111	Purge Exhaust from Sup. Chamber Outside IV	9	B,F,Y,Z,RM	5

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Table 3-1 (Cont.)

PRIMARY CONTAINMENT ISOLATION VALVES

VALVE NUMBER	AND FUNCTION	VALVE GROUPS	ISOLATION SIGNALS	MAXIMUM CLOSING TIME (SECONDS)
2IAS*SOV164	ADS Hdr A N_2 supply	8	B,F,Z,RM	NA
2IAS*SOV165	ADS Hdr B N_2 supply	8	B,F,Z,RM	NA
2IAS*SOV166	IAS Drywell Relief Valve	8	B,F,Z,RM	NA
2IAS*SOV184	IAS Drywell Relief Valve	8	B,F,Z,RM	NA
2IAS*SOV168	Inst. Air to Testable Check Outside IV	8	B,F,Z,RM	NA
2IAS*SOV180	Inst. Air to Testable Check Inside IV	8	B,F,Z,RM	NA
2IAS*SOV167	IAS to Test Ck. & Vac. Bkrs. Outside IV	8	B,F,Z,RM	NA
2IAS*SOV185	IAS to Test Ck. & Vac. Bkrs. Inside IV	8	B,F,Z,RM	NA
2HCS*MOV1 A,B	H_2 Recombiners Sply to Supp. Chamber Outside IV's	8	B,F,Z,RM	30
2HCS*MOV2 A,B	H_2 Recomb. Ret. from Supp. Chamber Outside IV's	8	B,F,Z,RM	30
2HCS*MOV3 A,B	H_2 Recomb. Return from Drywell Outside	8	B,F,Z,RM	30
2HCS*MOV4 A,B(n)	H_2 Recomb. Suply. to Supp. Chamber Inside IV's	8	B,F,Z,RM	30
2HCS*MOV5 A,B(n)	H_2 Recomb. Ret. from Supp. Chamber Inside IV's	8	B,F,Z,RM	30
2HCS*MOV6 A,B(n)	H_2 Recomb. Ret. from Drywell Inside IV's	8	B,F,Z,RM	30
2CPS*SOV119	Containment Purge to Supp. Chamber Outside ~~Inside~~ IV	9	B,F,Y,Z,RM	NA
2CPS*SOV120	Containment Purge to Drywell Outside IV	9	B,F,Y,Z,RM	NA
2CPS*SOV121(n)	Containment Purge to Supp. Chamber Inside IV	9	B,F,Y,Z,RM	NA
2CPS*SOV122(n)	Containment Purge to Drywell Inside IV	9	B,F,Y,Z,RM	NA
2CMS*SOV24 A,B,C,D	CMS from Drywell Inside & Outside IV's	8	B,F,Z,RM	NA
2CMS*SOV26 A,B,C,D	CMS from SP Inside & Outside IV's	8	B,F,Z,RM	NA
2CMS*SOV32 A,B	CMS to Drywell Outside IV's	8	B,F,Z,RM	NA
2CMS*SOV33 A,B(n)	CMS to Drywell Inside IV's	8	B,F,Z,RM	NA
2CMS*SOV34 A,B(n)	CMS to SP Inside IV's	8	B,F,Z,RM	NA
2CMS*SOV35 A,B	CMS to SP Outside IV's	8	B,F,Z,RM	NA
2CMS*SOV60 A,B	CMS to Drywell Outside IV's	8	B,F,Z,RM	NA
2CMS*SOV61 A,B(n)	CMS to Drywell Inside IV's	8	B,F,Z,RM	NA
2CMS*SOV62 A,B	CMS to Drywell Outside IV's	8	B,F,Z,RM	NA
2CMS*SOV63 A,B(n)	CMS to Drywell Inside IV's	8	B,F,Z,RM	NA

Table 3.6.3-1 (Cont.)

PRIMARY CONTAINMENT ISOLATION VALVES

VALVE NUMBER AND FUNCTION		VALVE GROUPS	ISOLATION SIGNALS	MAXIMUM CLOSING TIME (SECONDS)
2LMS*SOV152(i)	LMS from Drywell Inside IV	8	B,F,Z,RM	NA
2LMS*SOV153(i)	LMS from Drywell Outside IV	8	B,F,Z,RM	NA
2LMS*SOV156(i)	LMS from SP Inside IV	8	B,F,Z,RM	NA
2LMS*SOV157(i)	LMS from SP Outside IV	8	B,F,Z,RM	NA
2RCS*SOV65 A,B(L)	Hyd. Unit to RCS FCV's Outside IV's	8	B,F,Z,RM	NA
2RCS*SOV66 A,B(L)	Hyd. Unit to RCS FCV's Outside IV's	8	B,F,Z,RM	NA
2RCS*SOV67 A,B(L)	Hyd. Unit to RCS FCV's Outside IV's	8	B,F,Z,RM	NA
2RCS*SOV68 A,B(L)	Hyd. Unit from RCS FCV's Outside IV's	8	B,F,Z,RM	NA
2RCS*SOV79 A,B(L)	Hyd. Unit to RCS FCV's Inside IV's	8	B,F,Z,RM	NA
2RCS*SOV80 A,B(L)	Hyd. Unit to RCS FCV's Inside IV's	8	B,F,Z,RM	NA
2RCS*SOV81 A,B(L)	Hyd. Unit to RCS FCV's Inside IV's	8	B,F,Z,RM	NA
2RCS*SOV82 A,B(L)	Hyd. Unit from RCS FCV's Inside IV's	8	B,F,Z,RM	NA
2ICS*MOV121	RCIC Steam supply Outside IV	10	K,M,H,Z,RM,BB, CC, PD	14
2ICS*MOV128(n)	RCIC Steam supply Inside IV	10	K,M,H,Z,RM,BB, CC, PD	14
2ICS*MOV170	RCIC Warmup Valve Inside IV	10	K,M,H,Z,RM,BB, CC, PD	20
2WCS*MOV102	WCS Supply from RCS & RPV Inside IV	7	B,J,U,S,Z,RM, DD	14
2WCS*MOV112	WCS Supply from RCS & RPV Outside IV	6	B,J,U,S,Z,RM, PD	14
2ICS*MOV148	RCIC Vacuum Breaker Outside IV	11	H & F, RM STET	15
TIP BALL VALVES (SOVs) (A, B, C, D, E)		3	B,F,Z,RM	NA
2GSN*SOV166	Nitrogen Purge to TIP Indexing Mechanism Outside IV	3	B,F,Z,RM	NA

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Table 3.6.3-1 (Cont.)

PRIMARY CONTAINMENT ISOLATION VALVES

	VALVE NUMBER AND FUNCTION	VALVE GROUPS	ISOLATION SIGNALS	MAXIMUM CLOSING TIME (SECONDS)
2RHS*MOV142(j)(m)	RHR Drain to Radwaste Outside IV	4	A,M,Z,F,RM,CC,DD	18
2RHS*MOV149(j)(m)	RHR Drain to Radwaste Inside IV	4	A,M,Z,F,RM,CC,DD	16
2RHS*SOV35 A/B(j)(m)	RHR Sample Inside IVs Hex	4	A,M,Z,F,RM,CC,DD	NA
2RHS*SOV36 A/B(j)(m)	RHR Sample Outside IVs Hex	4	A,M,Z,F,RM,CC,DD	NA
2RDS*AOV124(k)(m)	SCRAM Discharge volume vent	N/A		30
2RDS*AOV132(k)(m)	SCRAM Discharge volume vent	N/A		30
2RDS*AOV123(k)(m)	SCRAM Discharge volume drain	N/A		30
2RDS*AOV130(k)(m)	SCRAM Discharge volume drain	N/A		30
B. REMOTE MANUAL ISOLATION VALVES				
2RHS*MOV15 A,B	Containment Spray to Drywell Outside IV's	1~~8~~2	RM	130
2RHS*MOV 1 A,B,C,	RHS Pump Suction Outside IVs	1~~8~~2	RM	60
2RHS*MOV30 A,B	RHS Test Line to SP Outside Ivs	1~~8~~2	RM	130
2RHS*MOV25 A,B(n)	Containment Spray to Drywell Outside IVs	1~~8~~2	RM	130
2RHS*MOV24 A,B,C	RHS/LPCI to RPV Outside IVs	1~~8~~2	RM	30
2CSH*MOV118(n)	CSH Suction from SP Outside IV	1~~8~~2	RM	30
2CSH*MOV105	HPCS Min Flow Bypass Outside IV	1~~8~~2	RM	10
2CSH*MOV107	CSH to RPV Outside IV	1~~8~~2	RM	45
2CSL*MOV112	CSL Suction from SP Outside IV	1~~8~~2	RM	130
2CSL*MOV104	CSL to RPV Outside IV	1~~8~~2	RM	60
2ICS*MOV136(n)	ICS Suction from SP Outside IV	1~~8~~2	RM	50
2ICS*MOV143(n)	ICS Min flow to SP Outside IV	1~~8~~2	RM	10

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Table 3.6.3-1 (Cont.)

PRIMARY CONTAINMENT ISOLATION VALVES

	VALVE NUMBER AND FUNCTION	VALVE GROUPS	ISOLATION SIGNALS	MAXIMUM CLOSING TIME (SECONDS)
2ICS*MOV122(n)	ICS turbine exhaust to SP	1~~3~~2	RM	90
2ICS*MOV126	ICS to RPV Outside IV	1~~3~~2	RM	20
TIP SHEAR (EXPLOSIVE) VALVES A, B, C, D, E		1~~3~~2	RM	NA
2FWS*MOV21 A,B	Feedwater to RPV Outside IVs	1~~3~~2	RM	80
2WCS*MOV200	WCS to RPV Outside IV	1~~3~~2	RM	65
2RHS*MOV26 A,B(C)	RHS Hx vent Inboard IVs	1~~3~~2	RM	15
2RHS*MOV~~3~~27 A,B(C)	RHS Hx vent Outboard IVs	1~~3~~2	RM	15
2MSS*SOV97 A,B,C,D	Main Steam Line Drains	1~~3~~2	RM	NA
C. MANUAL ISOLATION VALVES				
2SAS*HCV160(b)	SAS to Drywell Outside IV			
2SAS*HCV161(b)	SAS to Drywell Outside IV			
2SAS*HCV162(b)	SAS to Drywell Inside IV			
2SAS*HCV163(b)	SAS to Drywell Inside IV			
2AAS*HCV134(b)	AAS to Drywell Outside IV			
2AAS*HCV135(b)	AAS to Drywell Outside IV			
2AAS*HCV136(b)	AAS to Drywell Inside IV			
2AAS*HCV137(b)	AAS to Drywell Inside IV			
2FWS*AOV23 A, B(h)	Feedwater to RPV Outside IVs			
2FWS*V12 A,B	Feedwater to RPV Inside IVs			

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Table 3.6.3-1 (Cont.)

PRIMARY CONTAINMENT ISOLATION VALVES

VALVE NUMBER	AND FUNCTION	VALVE GROUPS	ISOLATION SIGNALS	MAXIMUM CLOSING TIME (SECONDS)
2RHS*AOV16, A,B,C(h)	RHS/LPCI to RPV Inside IVs			
2RHS*AOV39, A,B,C(h)	SDC to RCS Inside IVs			
2CSH*AOV108(h)	CSH to RPV Inside IV			
2CSL*AOV101(h)	CSL to RPV Inside IV			
2ICS*AOV156(h)	ICS to RPV Outside IV			
2ICS*AOV157(h)	ICS to RPV Inside IV			
2SLS*V10	SLS to RPV Inside IV			
2SLS*MOV5 A,B(g)	SLS to RPV Outside IV			
2FPW-V629(i)	Fire Water to Drywell Standpipes Inside IV			
2GSN*V170	N_2 Purge to Tip Index Mech. Inside IV			
2IAS*V448	IAS to ADS Accumulators Inside IV			
2IAS*V449	IAS to ADS Accumulators Inside IV			
2SFC*V203	Inner Refuel Seal Leakoff Outboard IV			
2SFC*V204	Inner Refuel Seal Leakoff Inboard IV			
2RCS*V59 A,B	RDS to RCS Pump A Seal Outside IVs			
2RCS*V60 A,B	RDS to RCS Pump A Seal Inside IVs			
2RCS*V90 A,B	RDS to RCS Pump A Seal Outside IVs			
2RHS*V19(d)(f)	Discharge Check from RCIC to Supp. Pool			
2RHS*V20(d)(f)	Discharge Check from RCIC to Supp. Pool			
2RHS*V117(d)(f)	Check Valve from RCIC Drain to Supp. Pool			
2RHS*V118(d)(f)	Check Valve from RCIC Drain to Supp. Pool			

Table 3.6.3-1 (Cont.)

PRIMARY CONTAINMENT ISOLATION VALVES

VALVE NUMBER AND FUNCTION		VALVE GROUPS	ISOLATION SIGNALS	MAXIMUM CLOSING TIME (SECONDS)
D. OTHER ISOLATION VALVES				
SAFETY RELIEF VALVES (d)				
2RHS*RV20 A,B,C	RHS Rv disch. to SP Outside IVs			
2RHS*RV61 A,B,C	RHS Rv disch. to SP Outside IVs			
2RHS*RV108	RHS Rv disch. to SP Outside IVs			
2RHS*RV110	SDC to RHR Pump suction Rv			
2RHS*RV139	RHR Hdr. Flush to Radwaste RV			
2RHS*RV152	SDC Supply from RCS RV Inside IV			
2RHS*RV56 A,B	RHS Hx shell side RVs			
2RHS*RV34 A,B	RHS Hx steam supply Safety valves			
2RHS*RV62 A,B	RHS Hx steam supply Safety valves			
2RHS*RVV35 A,B	RHS Vacuum Breakers			
2CSL*RV105	CSL RV Disch. to SP Outside IV			
2CSL*RV123	CSL RV Disch. to SP Outside IV			
2RHS*RVV36 A,B	RHS Vacuum Breakers			
2CSH*RV113	CSH RV Disch. to SP Outside IV			
2CSH*RV114	CSH RV Disch. to SP Outside IV			
EXCESS FLOW CHECK VALVES (e) REACTOR INSTRUMENTATION LINES				
2ISC*EFV1	Inst. Line from MSS			
2ISC*EFV2	Inst. Line from N14,200°			
2ISC*EFV3	Inst. Line from N14,160°			
2ISC*EFV4	Inst. Line from N13,190°			
2ISC*EFV5	Inst. Line from N14,20°			
2ISC*EFV6	Inst. Line from N14,340°			

Table 3.6.3-1 (Cont.)

PRIMARY CONTAINMENT ISOLATION VALVES

VALVE NUMBER AND FUNCTION		VALVE GROUPS	ISOLATION SIGNALS	MAXIMUM CLOSING TIME (SECONDS)
2ISC*EFV7	Inst. Line from N13,10°			
2ISC*EFV8	Inst. Line from N12,160°			
2ISC*EFV10	Inst. Line from N12,200°			
2ISC*EFV11	To 2ISC*FT47K,FT48B			
2ISC*EFV13	To 2ISC*FT47H			
2ISC*EFV14	Vessel Bottom tap, loop A Jet Pump			
2ISC*EFV15	Inst. Line from N12,340°			
2ISC*EFV17	Inst. Line from N12,20°			
2ISC*EFV18	To 2ISC*FT47J,FT48A			
2ISC*EFV20	To 2ISC*FT47E			
2ISC*EFV21	Vessel Bottom tap for CSH, RDS			
2ISC*EFV22	Vessel Bottom Tap for WCS and Loop B J.P.			
2ISC*EFV23	To 2ICS*FT48C and Post Accident Sampling			
2ISC*EFV24	To 2ISC*FT48D and Post Accident Sampling			
2ISC*EFV25	To 2ISC*FT47L			
2ISC*EFV26	To 2ISC*FT47C			
2ISC*EFV27	To 2ISC*FT47A			
2ISC*EFV28	To 2ISC*FT47R			
2ISC*EFV29	To 2ISC*FT47G			
2ISC*EFV30	To 2ISC*FT47N			
2ISC*EFV31	To 2ISC*FT48A			
2ISC*EFV32	To 2ISC*FT47T			
2ISC*EFV33	To 2ISC*FT47V,FT48C			

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Table 3.6.3-1 (Cont.)

PRIMARY CONTAINMENT ISOLATION VALVES

	VALVE NUMBER AND FUNCTION	VALVE GROUPS	ISOLATION SIGNALS	MAXIMUM CLOSING TIME (SECONDS)
2ISC*EFV34	To 2ISC*FT47B			
2ISC*EFV35	To 2ISC*FT47D			
2ISC*EFV36	TO 2ISC*FT47F			
2ISC*EFV37	To 2ISC*FT47S			
2ISC*EFV38	To 2ISC*FT47M			
2ISC*EFV39	To 2ISC*FT47P			
2ISC*EFV40	To 2ISC*FT48B			
2ISC*EFV41	To 2ISC*FT47U			
2ISC*EFV42	To 2ISC*FT47W,FT48D			
2ISC*EFV9	Containment Pressure 2ISC*PT15C, 16B, 16D			
2ISC*EFV12	Containment Pressure 2ISC*PT15B, 17B, 17D			
2ISC*EFV16	Containment Pressure 2ISC*PT15A, 16A, 16C			
2ISC*EFV19	Containment Pressure 2ISC*PT15D, 17A, 17C			
2CMS*EFV1A	To CMS*PT1A			
2CMS*EFV1B	To CMS*PT1B			
2CMS*EFV3A	To CMS*PT2A			
2CMS*EFV3B	To CMS*PT2B			
2CMS*EFV5A	To CMS*PT7A			
2CMS*EFV5B	To CMS*PT7B			
2CMS*EFV6	To CMS*~~TT169~~ PT 168			
2CMS*EFV8A	To CMS*LT9A, 11A, 114			
2CMS*EFV8B	To CMS*LT9B, 11B, 105			
2CMS*EFV9A	To CMS*LT9A, 11A, 114			
2CMS*EFV9B	To CMS*LT9B, 11B, 105			
2CMS*EFV10	To CMS-P1173			
2ICS*EFV1	To 2ICS*PDT167			
2ICS*EFV2	To 2ICS*PDT167			
2DER*EFV31	TO 2DER*PT134			

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Table 3.6.3-1 (Cont.)

PRIMARY CONTAINMENT ISOLATION VALVES

	VALVE NUMBER AND FUNCTION	VALVE GROUPS	ISOLATION SIGNALS	MAXIMUM CLOSING TIME (SECONDS)
2ICS*EFV3	To 2ICS*PDT168			
2ICS*EFV4	To 2ICS*PDT168			
2IAS*EFV200	To 2IAS*PT230 off ADS Accum.			
2IAS*EFV201	To 2IAS*PT231 off ADS Accum.			
2IAS*EFV202	To 2IAS*PT232 off ADS Accum.			
2IAS*EFV203	To 2IAS*PT233 off ADS Accum.			
2IAS*EFV204	To 2IAS*PT234 off ADS Accum.			
2IAS*EFV205	To 2IAS*PT235 off ADS Accum.			
2IAS*EFV206	To 2IAS*PT236 off ADS Accum.			
2RHS*EFV 5, 6	To 2RHS*PDT18B			
~~2RHS*EFV9~~	~~To 2RHS*PDT24C~~			
2RHS*EFV7	To 2RHS*PDT18A			
~~2RHS*EFV8A~~	~~To 2RHS*PDT24A~~			
2MSS*EFV 1A,B,C,D	To Flow elements A, B, C, D steamlines			
2MSS*EFV 2A,B,C,D	To Flow elements A, B, C, D steamlines			
2MSS*EFV 3A,B,C,D	To Flow elements A, B, C, D steamlines			
2MSS*EFV 4A,B,C,D	To Flow elements A, B, C, D steamlines			
2RCS*EFV44 A, B	To 2RCS*PT 84 A/B			
2RCS*EFV45 A, B	To 2RCS*~~FT 7B, FT 9B~~ FT 7A/B, FT 9A/B			
2RCS*EFV46 A, B	To 2RCS*~~FT 7B, FT 9B~~ FT 7A/B, FT 9A/B			
2RCS*EFV47 A, B	To 2RCS*FT 6 A/B, FT 8 A/B			
2RCS*EFV48 A, B	To 2RCS*FT 6 A/B, FT 8 A/B			
2RCS*EFV52 A, B	To 2RCS*PDT ~~15B~~ 15A/B			
2RCS*EFV53 A, B	To 2RCS*PDT ~~15B~~ 15 A/B			
2RCS*EFV62 A, B	To 2RCS*PT~~42 A/B~~ 44 A/B			
2RCS*EFV63 A, B	To 2RCS*PT~~44 A/B~~ 42 A/B			

Table 3.6.3-1 (Cont.)

PRIMARY CONTAINMENT ISOLATION VALVES

VALVE FUNCTION AND NUMBER		VALVE GROUPS	ISOLATION SIGNALS	MAXIMUM CLOSING TIME (SECONDS)
2WCS*EFV221	To 2WCS-FT 134			
2WCS*EFV222	To 2WCS*FT67X, PDS 115			
2WCS*EFV223	To 2WCS*FT67Y			
2WCS*EFV224	To 2WCS*FT67Y			
2WCS*EFV~~800~~ 300	To 2WCS*FT67X, PDS 115			
2CSH*EFV1	To 2CSH*LT123, LT124			
2CSH*EFV2	To 2CSH*LT123, LT124			
2CSH*EFV3	To 2CSH*PDT109			
2CSL*EFV1	To 2CSL*PDT132 and 2RHS*PDT18A			

TABLE NOTATION

(a) See Specification 3.3.2, Table 3.3.2-1, Table 3.3.2-4 and Table 3.3.2-5 for isolation signal(s) that operate each valve group.

(b) May be opened on an intermittent basis under administrative control.

(c) These valves are the RHR heat exchangers vent lines isolation valves. The vent line connects to the RHR safety relief valves (SRVs) Discharge Header before it penetrates the primary containment. The position indicators for these valves are provided in the Control Room for remote manual isolation. Not subject to Type C test.

(d) Not subject to Type C leakage tests.

(e) Subject to Type A test. Type C test not required.

(f) These valves are check valves, located on the vacuum breaker lines for RHR SRVs discharge headers. The SRV discharge header terminates under pool water and therefore has no containment isolation valves other than those on lines feeding into it.

Table 3.6.3-1 (Cont.)

PRIMARY CONTAINMENT ISOLATION VALVES

TABLE NOTATION

(g) 2SLS MOV5 A & B are globe stop check valves. These valves close upon reverse flow. The motor operator is provided to remote manually close the valve from the control room.

(h) These valves are testable check valves. They close upon reverse flow. The air operator on each valve is provided only for periodic testing of the valve. These valves can only be tested against a zero d/p.

(i) Valves closed and the associated system is isolated during normal operation.

(j) Not primary containment penetration isolation valves. These valves close on an isolation signal to provide integrity of "A" and "B" LPCI loops.

(k) Valves close on a SCRAM signal; not part of Primary Containment Isolation System.

(l) Not subject to Type A or Type C leak test due to constant monitoring under constant 1800 psig pressure and the possible detrimental effects of shutdown.

(m) Not subject to Type C test per 10 CFR Part 50, Appendix J. A hydrostatic test is performed in accordance with Specification 4.6.1.2.d.3.

(n) These valves are Type C tested in the reverse direction.

* Isolates on injection signal, not part of primary containment isolation system.

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3/4.6.4 SUPPRESSION CHAMBER - DRYWELL VACUUM BREAKERS

LIMITING CONDITION FOR OPERATION

3.6.4 All suppression chamber - drywell vacuum breakers shall be OPERABLE and closed.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2 and 3.

ACTION:

a. With one or more vacuum breakers in one pair of suppression chamber - drywell vacuum breakers inoperable for opening but known to be closed, restore the inoperable pair of vacuum breakers 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 one suppression chamber - drywell vacuum breaker open, verify the other vacuum breaker in the pair to be closed within 2 hours; restore the open vacuum breaker to the closed position within 72 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

c. With the position indicator of any suppression chamber - drywell vacuum breaker inoperable verify the other vacuum breaker in the pair to be closed within 2 hours and at least once per 15 days thereafter.

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

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SURVEILLANCE REQUIREMENTS

4.6.4 Each suppression chamber - drywell vacuum breaker shall be:

a. Verified closed at least once per 7 days.

b. Demonstrated OPERABLE:

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

2. At least once per 31 days by verifying the position indicator(s) OPERABLE by observing expected valve movement during the cycling test.*

3. At least once per 18 months by;

a) Verifying the opening setpoint, from the closed position, to be less than or equal to 0.25 psid, and

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

*Observation of expected valve movement during cycling test will be accomplished for the purposes of this surveillance by observing valve position indicators in the control room.

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3/4.6.5 SECONDARY CONTAINMENT

SECONDARY CONTAINMENT INTEGRITY

LIMITING CONDITION FOR OPERATION

3.6.5.1 SECONDARY CONTAINMENT INTEGRITY shall be maintained.

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

ACTION:

Without SECONDARY CONTAINMENT INTEGRITY:

a. In OPERATIONAL CONDITION 1, 2 or 3, restore SECONDARY CONTAINMENT INTEGRITY within 4 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

b. 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

4.6.5.1 SECONDARY CONTAINMENT INTEGRITY shall be demonstrated by:

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

b. Verifying at least once per 31 days that:

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

2. At least one door in each access to the secondary containment is closed. ~~except during normal entry and exit~~.

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

c. At least once per 18 months:

1. Verifying that each standby gas treatment subsystem will draw down the secondary containment to greater than or equal to-0.25 inches of vacuum water gauge in less than or equal to 90 seconds when starting at a pressure no less than zero psig, and

2. Operating one standby gas treatment subsystem for one hour and maintaining greater than or equal to-0.25 inches of vacuum water gauge in the secondary containment at a flow rate not exceeding ~~3600~~ 3160 cfm.

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

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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(s) 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~~ damper 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. During COLD SHUTDOWN or REFUELING at least once per 18 months by verifying that on a containment isolation test signal each isolation damper actuates to its isolation position.

c. By verifying the isolation time to be within its limit when tested pursuant to Specification 4.0.5.

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

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TABLE 3.6.5.2-1

SECONDARY CONTAINMENT VENTILATION SYSTEM AUTOMATIC ISOLATION DAMPERS

DAMPER FUNCTION	MAXIMUM ISOLATION TIME (Seconds)
1. Reactor Building Ventilation Supply Damper 2HVR*AOD1A or 2HVR*AOD1B	6
2. Reactor Building Ventilation Exhaust Damper 2HVR*AOD9A or 2HVR*AOD9B	5
3. Reactor Building Ventilation Exhaust Damper 2HVR*AOD10A or 2HVR*AOD10B	5

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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.

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SURVEILLANCE REQUIREMENTS (Continued)

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

   1. Verifying that the subsystem satisfies the in-place penetration and bypass leakage testing acceptance criteria of less than 0.05% and uses the test procedure guidance in Regulatory Positions C.5.a, C.5.c and C.5.d of Regulatory Guide 1.52*, Revision 2, March 1978, and the subsystem flow rate is 3500 cfm ± 10%.

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

   3. Verifying a subsystem flow rate of 3500 cfm ± 10% during system operation when tested in accordance with ANSI N510-1980.

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

d. At least once per 18 months by:

   1. Verifying that the pressure drop across the combined HEPA filters and charcoal adsorber banks is less than 5.5 inches Water Gauge while operating the filter train at a flow rate of ~~(2300)~~ 3500 cfm ± 10%.

   2. Verifying that the filter train starts and isolation valves open on each of the following test signals:

      a. Manual initiation from the control room, and

      b. Simulated automatic initiation signal.

   3. Verifying that the decay heat removal isolation valves are open and the fan can be manually started.

   4. Verifying that the heaters dissipate 20.0 ± 2.0 kw when tested in accordance with ANSI N510-1980.

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*ANSI N510-1980 ~~to~~ is applicable in place of ANSI N510-1975 and ANSI N509-1980 is applicable in place of ANSI N509-1976.

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SURVEILLANCE REQUIREMENTS (Continued)

e. After each complete or partial replacement of a HEPA filter bank by verifying that the HEPA filter bank satisfies the inplace penetration and bypass leakage testing acceptance criteria of less than 0.05% in accordance with ANSI N510-1980 while operating the system at a flow rate of 3500 cfm ± 10%.

f. After each complete or partial replacement of a charcoal adsorber bank by verifying that the charcoal adsorber bank satisfies the inplace penetration and bypass leakage testing acceptance criteria of less than 0.05% in accordance with ANSI N510-1980 for a halogenated hydrocarbon refrigerant test gas while operating the system at a flow rate of 3500 cfm ± 10%.

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3/4.6.6 PRIMARY CONTAINMENT ATMOSPHERE CONTROL

DRYWELL AND SUPPRESSION CHAMBER HYDROGEN RECOMBINER SYSTEMS

LIMITING CONDITION FOR OPERATION

3.6.6.1 Two independent drywell and suppression chamber hydrogen recombiner systems shall be OPERABLE.

APPLICABILITY: OPERATIONAL CONDITIONS 1 and 2.

ACTION:

With one drywell and/or suppression chamber hydrogen recombiner system inoperable, restore the inoperable system to OPERABLE status within 30 days or be in at least HOT SHUTDOWN within the next 12 hours.

SURVEILLANCE REQUIREMENTS

4.6.6.1 Each drywell and suppression chamber hydrogen recombiner system shall be demonstrated OPERABLE:

a. At least once per 6 months by verifying during a recombiner system functional test that the minimum outlet gas temperature increases to greater than or equal to 700°F within 90 minutes. Maintain $\geq$ 1150°F for at least 4 hours.

b. At least once per 18 months by:

   1. Performing a CHANNEL CALIBRATION of all recombiner instrumentation and control circuits.

   2. Verifying the integrity of all heater electrical circuits by performing a resistance to ground test within 30 minutes following the above required functional test. The resistance to ground for any heater phase shall be greater than or equal to 1,000,000 ohms.

   3. Verifying through a visual examination that there is no evidence of abnormal conditions within the recombiner enclosure; i.e, loose wiring or structural connections, deposits of foreign materials, etc.

c. By measuring the system leakage rate:

   1. As a part of the overall integrated leakage rate test required by Specification 3.6.1.2, or

   2. By measuring the leakage rate of the system outside of the containment isolation valves at Pa, 39.75 psig, on the schedule required by Specification 4.6.1.2, and including the measured leakage as a part of the leakage determined in accordance with Specification 4.6.1.2.

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PRIMARY CONTAINMENT ATMOSPHERE CONTROL

DRYWELL AND SUPPRESSION CHAMBER OXYGEN CONCENTRATION

LIMITING CONDITION FOR OPERATION

3.6.6.2 The drywell and suppression chamber atmosphere oxygen concentration shall be less than 4% by volume.

APPLICABILITY: OPERATIONAL CONDITION 1*, during the time period:

a. Within 24 hours after THERMAL POWER is greater than 15% of RATED THERMAL POWER, following startup, to

b. Within 24 hours prior to reducing THERMAL POWER to less than 15% of RATED THERMAL POWER, preliminary to a scheduled reactor shutdown.

ACTION:

With the oxygen concentration in the drywell and/or suppression chamber exceeding the limit, restore the oxygen concentration to within the limit within 24 hours or be in at least STARTUP within the next 8 hours.

SURVEILLANCE REQUIREMENTS

4.6.6.2 The oxygen concentration in the drywell and suppression chamber shall be verified to be within the limit within 24 hours after THERMAL POWER is greater than 15% of RATED THERMAL POWER and at least once per 7 days thereafter.

*See Special Test Exception 3.10.5.

3/4.7 PLANT SYSTEMS

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3/4.7.1 PLANT SERVICE WATER SYSTEM

PLANT SERVICE WATER-OPERATING

LIMITING CONDITION FOR OPERATION

3.7.1.1 Two independent plant service water system loops shall be OPERABLE with one loop in operation. Each loop shall be comprised of:

a. Two plant service water pumps capable of taking suction from Lake Ontario and transferring the water to the associated safety related equipment.

b. Service water supply header discharge water temperature of $\leq$ 76°F.

The ~~An~~ Intake Deicing Heater System shall be in operation when intake tunnel water temperature is $\leq$ 38°F with Division I having 7 heaters in operation in each intake structure and Division II having 7 heaters in operation in each intake structure.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, 3.

ACTION:

a. With 1 inoperable service water pump in one loop, restore the inoperable pump to OPERABLE status within 30 days or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

b. With 1 inoperable plant service water pump in each loop, restore at least one inoperable pump 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.

c. With 1 plant service water system loop 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. Also take the ACTION required by Specification 3.5.2 and 3.8.1.2.

d. With the service water supply header discharge water temperature over any 24 hour period exceeding 76°F, be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

e. With less than the required Division I and Division II heaters operable, be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

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SURVEILLANCE REQUIREMENTS - OPERATING

4.7.1.1 The Plant Service Water System shall be demonstrated OPERABLE:

a. At least once per 12 hours by:

1. Verifying the water level at the service water pump intake is greater than or equal to 233.1 feet Elevation.

2. Verifying the service water supply header discharge water temperature is ≤ 76°F.

b. At least once per 7 days by verifying that the current of the heater feeder cables at the motor control centers is ≥ ~~9~~ 10 amps*(total) at ≥518 volts* per divisional heater in each intake structure.

c. 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.

d. At least once per 18 months during shutdown, by verifying that:

1. After a simulated test signal each automatic valve servicing non-safety related equipment actuates to its isolation position on an isolation test signal.

2. Each associated service water system cross connect and pump discharge valve actuate automatically to their isolation position, and that a single service water pump starts automatically in each division and that the associated pump discharge valve reopens automatically; in order to supply flow to the system safety related components.

3. Each pump runs and maintains service water pump discharge pressure equal to or greater than 90 psig with each pump flow equal to or greater than 2500 gpm.

4. The resistance to ground is ≥ ~~32~~ 28 ohms for each feeder cable that powers the Intake Deicing Heater Systems.

*For 7 heater elements in operation.

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PLANT SERVICE WATER - SHUTDOWN

LIMITING CONDITION FOR OPERATION

3.7.1.2 Two independent plant service water system loops shall be OPERABLE with one loop in operation. Each loop shall be comprised of:

a. One OPERABLE plant service water pump capable of taking suction from Lake Ontario and transferring the water to the associated safety related equipment.

b. Service water supply header discharge water temperature of $\leq$ 76°F.

The ~~An~~ Intake Deicing Heater Systems shall be in operation when intake tunnel water temperature is $\leq$ 38°F with Division I having 7 heaters in operation in each intake structure and Division II having 7 heaters in operation in each intake structure.

APPLICABILITY: OPERATIONAL CONDITIONS 4,5.

ACTION:

a. With less than one OPERABLE service water pump in each loop, declare the associated safety related equipment inoperable and take ACTION required by Specifications 3.5.2 and 3.8.1.2.

b. With the service water supply header discharge temperature over any 24 hour period exceeding 76°F, suspend CORE ALTERATIONS and all operations that have a potential for draining the reactor vessel.

c. With less than the required Division I and Division II heaters operable, suspend CORE ALTERATIONS and all operations that have a potential for draining the reactor vessel.

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SURVEILLANCE REQUIREMENTS

4.7.1.2 The Plant Service Water System shall be demonstrated OPERABLE:

a. At least once per 12 hours by:

1. Verifying the water level at the Service Water Pump intake is greater than or equal to 233.1 feet Elevation.

2. Verifying the service water supply header discharge temperature on an operation loop is $\leq 76°F$.

b. At least once per 7 days by verifying that the current of the heater feeder cables at the motor control centers is $\geq$ ~~9~~ 10 amps*(total) at $\geq$518 volts* per divisional heater in each intake structure.

c. 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.

d. At least once per 18 months during shutdown, by verifying that:

1. After a simulated test signal each automatic valve servicing non-safety related equipment actuates to its isolation position on an isolation test signal.

2. Each associated service water system cross connect and pump discharge valve actuate automatically to their isolation position, and that a single service water pump starts automatically in each division and that the associated pump discharge valve reopens automatically; in order to supply flow to the system safety related components.

3. Each pump runs and maintains service water pump discharge pressure equal to or greater than 90 psig with each pump flow equal to or greater than 2500 gpm.

4. The resistance to ground is $\geq$ ~~32~~ 28 ohms for each feeder cable that powers the Intake Deicing Heater Systems.

*For 7 heater elements in operation.

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3/4.7.2 REVETMENT-DITCH STRUCTURE

LIMITING CONDITION FOR OPERATION

3.7.2 The revetment-ditch structure shall be structurally sound and capable of limiting wave action as intended. The revetment-ditch structure shall be maintained such that the elevation of each survey point listed in Table 3.7.2-1 is not more than 1.0 foot below the listed elevation.

APPLICABILITY: At all times.

ACTION:

With the elevation of one or more survey points more than 1 foot below the elevation given in Table 3.7.2-1, prepare and submit to the Commission within 90 days, pursuant to Specification 6.9.2, a Special Report which includes the following information:

a. Explanation of how the elevation change occurred and if the revetment-ditch structure is continuing to change;

b. A planned course of repair (if required) and a schedule for accomplishing the repair;

c. Evaluation of and justification for continued plant operation; and

d. The current elevation of each survey point shown in Table 3.7.2-1.

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

SURVEILLANCE REQUIREMENTS

4.7.2 The revetment-ditch structure shall be capable of limiting wave action and shall be determined to be structurally sound by performing:

a. A visual and a limited survey* inspection once a year.

b. A full survey* prior to fuel load and once every two years thereafter provided that the maximum elevation change of one or more control points in that period is less than two inches. If the elevation change of one or more control points exceeds two inches in any two year period, a full survey will be performed once a year thereafter, or until two consecutive surveys shows any additional elevation change to be less than two inches in each two year period;

c. A visual inspection and a full survey* within 7 days after a severe storm in which the wave runup goes over the top of the revetment.

d. A visual inspection and a full survey* within 7 days after any earthquake event with an intensity greater than the operating basis earthquake (OBE).

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*Limited and full surveys shall be performed with survey equipment to at least third-order accuracy.

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TABLE 3.7.2-1

SURVEY POINTS FOR REVETMENT-DITCH STRUCTURE

SURVEY POINT*	NORTH-SOUTH	EAST-WEST	OCTOBER 1985 CONTROL ELEVATION
1C	N 1283798.13	E 546895.34	252.165
1B	N 1283821.89	E 546888.75	263.075
1A	N 1283828.48	E 546887.88	264.290
2C	N 1283770.08	E 546799.33	253.765
2B	N 1283793.42	E 546793.66	263.725
2A	N 1283800.75	E 546802.21	264.585
3C	N 1283741.94	E 546703.71	252.920
3B	N 1283766.13	E 546696.05	263.130
3A	N 1283771.53	E 546695.04	263.215
4C	N 1283660.46	E-546608.29	254.450
4B	N 1283681.23	E 546606.66	263.560
4A	N 1283684.30	E 546597.26	263.950
5C	N 1283688.87	E 546510.60	255.665
5B	N 1283705.21	E 546496.47	263.820
5A	N 1283714.96	E 546498.16	263.440
6C	N 1283672.49	E 546405.17	255.870
6B	N 1283689.60	E 546407.84	264.180
6A	N 1283694.74	E 546404.07	264.756
7C	N 1283675.92	E 546305.02	256.575
7B	N 1283696.02	E 546299.75	263.680
7A	N 1283705.09	E 546309.27	265.235
8C	N 1283684.19	E 546205.09	256.300
8B	N 1283705.28	E 546205.14	263.125
8A	N 1283712.00	E 546206.38	263.155
9C	N 1283691.57	E 546110.39	257.715
9B	N 1283710.39	E 546108.25	263.660
9A	N 1283720.79	E 546102.81	263.090
10C	N 1283673.00	E 546016.51	257.135
10B	N 1283693.66	E 546004.95	265.540
10A	N 1283701.25	E 546006.68	264.035

*See Figures B 3/4 7.1-1 and B 3/4 7.1-2 for location sketches.

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TABLE 3.7.2-1

SURVEY POINTS FOR REVETMENT-DITCH STRUCTURE

SURVEY POINT*	NORTH-SOUTH	EAST-WEST	OCTOBER 1985 CONTROL ELEVATION
11C	N 1283646.76	E 545918.23	256.155
11B	N 1283666.83	E 545918.76	263.720
11A	N 1283675.17	E 545912.02	263.385
12C	N 1283626.37	E 545839.53	256.395
12B	N 1283650.74	E 545835.16	264.085
12A	N 1283656.67	E 545831.43	264.105

Survey Points Are Anchored Into Back Armor Using Stainless Steel HILTI Quick Bolts.

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3/4.7.3 CONTROL ROOM OUTDOOR AIR SPECIAL FILTER TRAIN SYSTEM

LIMITING CONDITION FOR OPERATION

3.7.3 Two independent control room emergency outdoor air special filter train shall be OPERABLE.

APPLICABILITY: All OPERATIONAL CONDITIONS and *.

ACTION:

a. In OPERATIONAL CONDITION 1, 2, or 3 with one control room filter train inoperable, restore the inoperable filter train 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 filter train inoperable, restore the inoperable filter train to OPERABLE status within 7 days or initiate and maintain operation or the OPERABLE filter train in the pressurization mode of operation.

   2. With both control room filter trains inoperable, suspend CORE ALTERATIONS, handling of irradiated fuel in the reactor building 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

4.7.3 Each control room outdoor air special filter train shall be demonstrated OPERABLE:

a. At least once per 12 hours by verifying that the control room air temperature is less than or equal to 120°F.

b. 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 filter train operates for at least 10 hours with the heaters OPERABLE.

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

c. 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 filter trains by:

1. Verifying that the filter train satisfies the in-place penetration and bypass testing acceptance criteria of less than 0.05% and uses the test procedure guidance in Regulatory Positions C.5.a, C.5.c and C.5.d of Regulatory Guide 1.52*, Revision 2, March 1978, and the sytem flow rate is 2250 cfm ± 10%.

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

3. Verifying a subsystem flow rate of 2250 cfm ± 10% during subsystem operation when tested in accordance with ANSI N510-1980.

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

e. At least once per 18 months by:

1. Verifying that the pressure drop across the combined HEPA filters and charcoal adsorber banks is less than 5.5 inches Water Gauge while operating the subsystem at a flow rate of 2250 cfm ± 10%.

2. Verifying that on each of the below pressurization mode actuation test signals, the filter train automatically switches to the pressurization mode of operation and the control room is maintained at a positive pressure of 1/8 inch W.G. relative

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*ANSI-N510-1980 is applicable in place of ANSI-N510-1975. and ANSI N509-1980 is applicable in place of ANSI N509-1976.

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to the outside atmosphere during subsystem operation at an outside air intake flow rate less than or equal to (1500) cfm:

a) Air intake radiation monitors, and

3. Verifying that the heaters dissipate ≥ 7.95 kW when tested in accordance with ANSI N510-1980.

f. After each complete or partial replacement of a HEPA filter bank by verifying that the HEPA filter bank satisfies the inplace penetration and bypass leakage testing acceptance criteria of less than 0.05% in accordance with ANSI N510-1980 while operating the system at a flow rate of 2250 cfm ± 10%.

g. After each complete or partial replacement of a charcoal adsorber bank by verifying that the charcoal adsorber bank satisfies the inplace penetration and bypass leakage testing acceptance criteria of less than 0.05% in accordance with ANSI N510-1980 for a halogenated hydrocarbon refrigerant test gas while operating the system at a flow rate of 2250 cfm ± 10%.

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3/4.7.4 REACTOR CORE ISOLATION COOLING SYSTEM

LIMITING CONDITION FOR OPERATION

3.7.4 The reactor core isolation cooling (RCIC) system shall be OPERABLE with an OPERABLE flow path capable of automatically 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:

With the RCIC system inoperable, operation may continue provided the HPCS 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

4.7.4 The RCIC system shall be demonstrated OPERABLE:

a. At least once per 31 days by:

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

   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. When tested pursuant to Specification 4.0.5 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 1000 + 20, - 80 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.

** Manual initiation function is not required to be OPERABLE with indicated reactor vessel level on the wide range instrumentation greater than the level 8 setpoint coincident with steam dome pressure < 600 psig.

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. Actual injection of coolant into the reactor vessel may be excluded.

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.

*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.

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3/4.7.5 SNUBBERS

LIMITING CONDITION FOR OPERATION

3.7.5 All snubbers shall be OPERABLE. The only snubbers excluded from the requirements 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.

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 4.7.5 on the supported component or declare the supported system inoperable and follow the appropriate ACTION statement for that system.

SURVEILLANCE REQUIREMENTS

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

a. Inspection Types

As used in this specification, type of snubber shall mean snubbers of the same design and manufacturer, irrespective of capacity.

b. Visual Inspections

Snubbers are categorized as inaccessible or accessible during reactor operation. Each category may be inspected independently according to the schedule below. The first inservice visual inspection of snubbers shall be performed after 2 months but within 12 months of commencing POWER OPERATION and shall include all snubbers. If all snubbers 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 inspection interval shall not be lengthened more than one step at a time.
#The provisions of Specification 4.0.2 are not applicable.

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c. 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 OPERABLE, and (3) fasteners for attachment of the snubber to the component and to the snubber anchorage are OPERABLE. 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, provided that: (1) the cause of the rejection is clearly established and remedied for that particular snubber and for other snubbers irrespective of the type on that system that may be generically susceptible; or ~~and~~ (2) the affected snubber is functionally tested in the as-found condition and determined OPERABLE per Surveillance Requirement(s) 4.7.5.f.

d. Transient Event Inspection

An inspection shall be performed of all snubbers attached to sections of systems that have experienced unexpected, potentially damaging transients, as determined from a review of operational data or a visual inspection of the systems, within 72 hours for accessible areas and within 6 months for inaccessible areas following this determination. In addition to satisfying the visual inspection acceptance criteria, freedom-of-motion of mechanical snubbers shall be verified using at least one of the following: (1) manually induced snubber movement; or (2) evaluation of in-place snubber piston setting; or (3) stroking the mechanical snubber through its full range of travel.

e. Functional Tests

During the first refueling shutdown and at least once per 18 months thereafter during shutdown, a representative sample of snubbers shall be tested using one of the following sample plans for each type of snubber. The sample plan shall be selected prior to the test period and cannot be changed during the test period. The NRC Regional Administrator shall be notified in writing of the sample plan selected prior to the test period or the sample plan used in the prior test period shall be implemented:

1) At least 10% of the total of each type of snubber shall be functionally tested either in-place or in a bench test. For each snubber of a type that does not meet the functional test acceptance criteria of Specification 4.7.5.f, an additional 10% of that type of snubber shall be functionally tested until no more failures are found or until all snubbers of that type have been functionally tested; or

2) A representative sample of each type of snubber shall be functionally tested in accordance with Figure 4.7.5-1. "C" is the total number of snubbers of a type found not meeting the acceptance requirements of Specification 4.7.5.f. The cumulative number of snubbers of a type tested is denoted by "N". At the end of each day's testing, the new values of "N" and "C" (previous day's total plus current day's increments) shall be plotted on Figure 4.7.5-1. If at any time the point plotted falls in the "Reject" region all snubbers of that type shall be functionally tested. If at any time the point plotted falls in the "Accept" region, testing of snubbers of that type may be terminated. When the point plotted lies in the "Continue Testing" region, additional snubbers of that type shall be tested until the ponit falls in the "Accept" region or the "Reject" region, or all the snubbers of that type have been tested; or

3) An initial representative sample of 55 snubbers of each type shall be functionally tested. For each snubber type which does not meet the functional test acceptance criteria, another sample of at least one-half the size of the initial sample shall be tested until the total number tested is equal to the initial sample size multiplied by the factor, $1 + C/2$, where "C" is the number of snubbers found which do not meet the functional test acceptance criteria. The results from this sample plan shall be plotted using an "Accept" line which follows the equation $N = 55(1 + C/2)$. Each snubber point should be plotted as soon as the snubber is tested. If the point plotted falls on or below the "Accept" line, testing of that type of snubber may be terminated. If the point plotted falls above the "Accept" line, testing must continue until the point falls in the "Accept" region or all the snubbers of that type have been tested.

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Testing equipment failure during functional testing may invalidate that day's testing and allow that day's testing to resume a new at a later time, providing all snubbers tested with the failed equipment during the day of equipment failure are retested. The representative sample selected for the functional test sample plans shall be randomly selected from the snubbers of each type and reviewed before beginning the testing. The review shall ensure as far as practical that they are representative of the various configurations, operating environments, range of size, and capacity of snubbers of each type. Snubbers placed in the same locations as snubbers which failed the previous functional test shall be retested at the time of the next functional test but shall not be included in the sample plan. If during the functional testing, additional sampling is required due to failure of only one type of snubber, the functional testing results shall be reviewed at the time to determine if additional samples should be limited to the type of snubber which has failed the functional testing.

f. Functional Test Acceptance Criteria
The snubber functional test shall verify that:
1) Activation (restraining action) is achieved within the specified range in both tension and compression;

2) For mechanical snubbers, the force required to initiate or maintain motion of the snubber is within the specified range in both directions of travel; and

Testing methods may be used to measure parameters indirectly or parameters other than those specified if those results can be correlated to the specified parameters through established methods.

g. Functional Test Failure Analysis
An engineering evaluation shall be made of each failure to meet the functional test acceptance criteria to determine the cause of the failure. The results of this evaluation shall be used, if applicable, in selecting snubbers to be tested in an effort to determine the OPERABILITY of other snubbers irrespective of type which may be subject to the same failure mode.

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

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SURVEILLANCE REQUIREMENTS (Continued)

If any snubber selected for functional testing either fails to lock up 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 type subject to the same defect shall be functionally tested. This testing requirement shall be independent of the requirements stated in Specification 4.7.5.e for snubbers not meeting the functional test acceptance criteria.

h. Functional Testing of Repaired and Replaced Snubbers

Snubbers that fail the visual inspection or the functional test acceptance criteria shall be repaired or replaced. Replacement snubbers and snubbers that have repairs that might affect the functional test result shall be tested to meet the functional test criteria before installation in the unit. Mechanical snubbers shall have met the acceptance criteria subsequent to their most recent service, and the freedom-of-motion test must have been performed within 12 months before being installed in the unit.

i. Snubber Service Life Program

The service life of all snubbers shall be monitored to ensure that the service life is not exceeded between surveillance inspections. The maximum expected service life for various seals, springs, and other critical parts shall be determined and established based on engineering information and shall be extended or shortened based on monitored test results and failure history. Critical parts shall be replaced so that the maximum service life will not be exceeded during a period when the snubber is required to be OPERABLE. The parts replacements shall be documented and the documentation shall be retained in accordance with Specification 6.10.1.2.

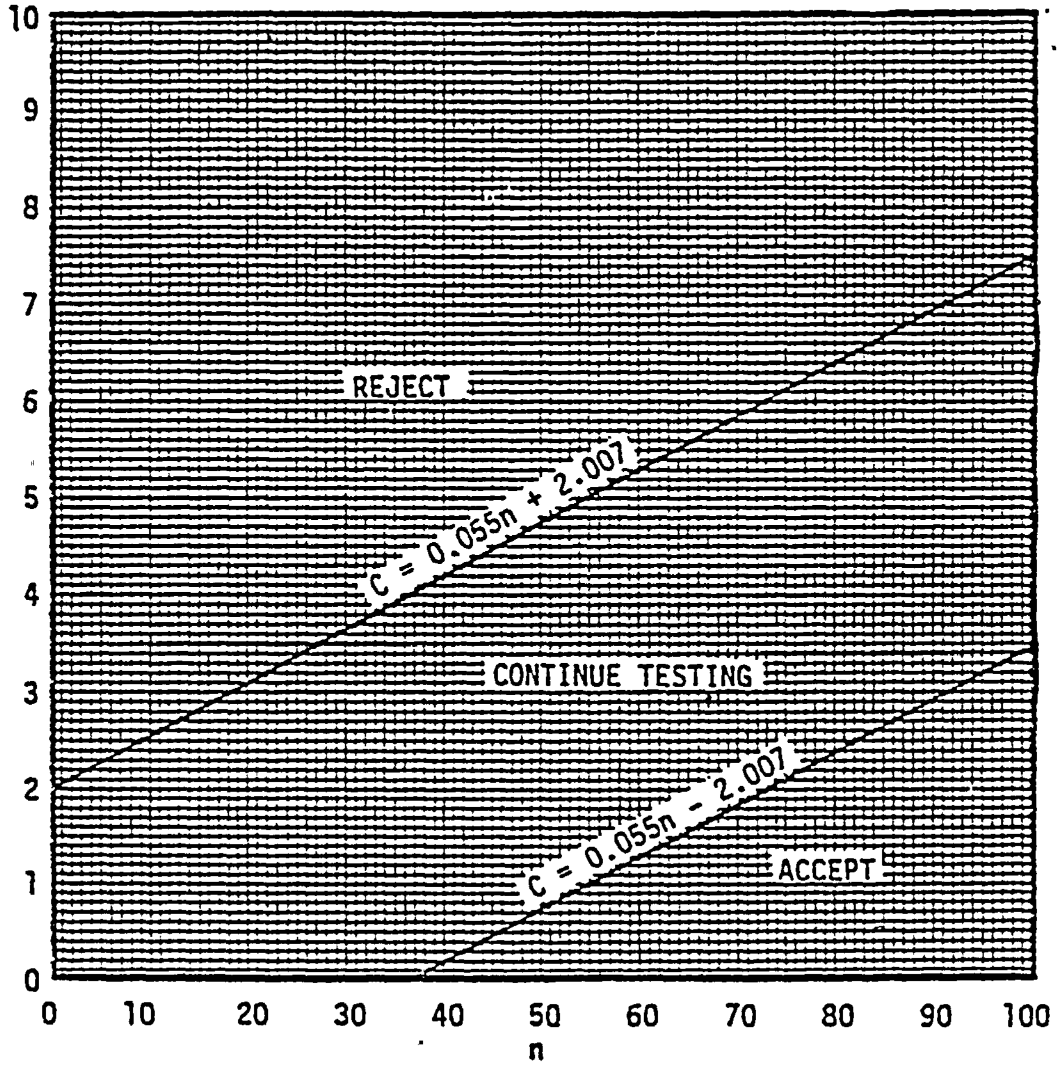

FIGURE 4.7.5-1
SAMPLE PLAN 2 FOR SNUBBER FUNCTIONAL TEST

3/4.7.6 SEALED SOURCE CONTAMINATION

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LIMITING CONDITION FOR OPERATION

3.7.6 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 microcuries of removable contamination.

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

4.7.6.1 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 microcuries per test sample.

4.7.6.2 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, and

   2. In any form other than gas.

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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.

4.7.6.3 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 microcuries of removable contamination.

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3/4.7.7 FIRE SUPPRESSION SYSTEMS

FIRE SUPPRESSION WATER SYSTEM

LIMITING CONDITION FOR OPERATION

3.7.7.1 The fire suppression water system shall be OPERABLE with:

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

b. An OPERABLE flow path capable of taking suction from the Service Water Bay 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 3.7.7.2, 3.7.7.5, and 3.7.7.6.

APPLICABILITY: At all times.

ACTION:

a. With one pump 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.

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

SURVEILLANCE REQUIREMENTS

4.7.7.1.1 The fire suppression water system shall be demonstrated OPERABLE:

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

b. 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.

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SURVEILLANCE REQUIREMENTS (Continued)

c. At least once per 6 months by performance of a system flush.

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

e. 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 net discharge head of 113 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 and maintains the fire suppression water system pressure greater than or equal to 125 psig.

f. At least once per 3 years by performing a flow test of the system in accordance with Chapter 6, Section 16 of the Fire Protection Handbook, 15th Edition, published by the National Fire Protection Association.

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

a. At least once per 31 days by:

   1. Verifying the fuel day tank contains at least 350 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.

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~~ D4057-81, is within the acceptable limits specified in Table 1 of ASTM ~~D975-77~~ D975-81 when checked for viscosity, water and sediment.

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

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

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

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

   2. The pilot cell specific gravity, corrected to 77°F and full electrolyte level, is greater than or equal to 1.235,

   3. The overall battery voltage is greater than or equal to 25.5 volts* with the battery on float charge.

b. At least once per 92 days by verifying that all cell parameters for all battery cells are demonstrated OPERABLE per Specification 4.7.7.1.3.a and the difference between the pilot cell with the highest specific gravity when compared to the pilot cell with the lowest specific gravity is $\leq$ 0.015.

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

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

   2. Battery and terminal connections are clean, tight and free of corrosion.

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*An overall battery voltage of $\geq$ 25.5 volts represents twelve pilot cells each carring at least a 2.13 volt charge.

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SPRAY AND/OR SPRINKLER SYSTEMS

LIMITING CONDITION FOR OPERATION

3.7.7.2 The following spray and sprinkler systems shall be OPERABLE:

a. SPRAY AND SPRINKLER SYSTEMS

	SYSTEM NO.	BUILDING/ELEVATION
1.	W-33	Electrical Tunnel - 35
2.	W-34	Electrical Tunnel - 140
3.	W-35	Electrical Tunnel - 230
4.	W-36	Electrical Tunnel - 315
5.	W-42	Control Bldg. - El. 288'-6"
6.	W-43	Control Bldg. - El. 306'-0"
7.	W-44	Control Bldg. - El. 214'-0" to 306'-0"
8.	W-45	Control Bldg. - El. 214'-0" to 237'-0"
9.	W-46	Control Bldg. - El. 214'-0" to 306'-0"
10.	W-47	Control Bldg. - El. 214'-0" to 237'-0"
11.	W-55	Reactor Bldg. - El. 175'-0"
12.	W-57	Reactor Bldg. - El. 261'-0"
13.	W-60	Diesel Fire Pump Rm. - El. 261'-0"

b. PRE-ACTION SYSTEMS

	SYSTEM NO.	BUILDING/ELEVATION
1.	W-48	Diesel Generator Bldg. - El. 261'-0"
2.	W-49	Diesel Generator Bldg. - El. 261'-0"
3.	W-50	Diesel Generator Bldg. - El. 261'-0"
4.	W-54	Reactor Bldg. - South El. 175'-0" to 328'-10"
5.	W-56	Reactor Bldg. - North El. 175'-0" to 328'-10"

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 one hour convert the applicable dry system(s) to a wet pipe system or establish a continuous fire watch with backup fire suppression equipment for those areas in which redundant systems or components could be damaged; for other areas, establish an hourly fire watch patrol.

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

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SURVEILLANCE REQUIREMENTS

4.7.7.2 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 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.

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CO_2 SYSTEMS

LIMITING CONDITION FOR OPERATION

3.7.7.3 The following low pressure CO_2 systems shall be OPERABLE:

	ZONE NUMBER	BUILDING/ELEVATION
a.	336 XL	Control Building/El. 261'-0"
b.	333 XL	Control Building/El. 261'-0"
c.	342 XL	Control Building/El. 261'-0"
d.	253 XL	Reactor Building/El. 289'-0"

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 one hour establish a continuous fire watch with backup fire suppression equipment for those areas in which redundant systems or components could be damaged; for other areas, establish an hourly fire watch patrol.

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

SURVEILLANCE REQUIREMENTS

4.7.7.3.1 Each of the above required 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.

4.7.7.3.2 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 2FPL-TK1 contains 3 tons of CO_2 at a pressure to be greater than 275 psig, and

b. At least once per 18 months by verifying:

1. The system, including associated ventilation system fire dampers actuate manually and automatically, upon receipt of a simulated actuation signal, and

2. Flow from each nozzle during a "Puff Test."

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PLANT SYSTEMS

HALON SYSTEMS

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LIMITING CONDITION FOR OPERATION

3.7.7.4 The following Halon systems shall be OPERABLE with the storage tanks having at least 95% of full charge weight or level and 90% of full charge pressure:

	ZONE NO.	BUILDING/ELEVATION
a.	353 SG	Control Bldg. - El. 288'-6"
b.	354 SG	Control Bldg. - El. 288'-6"
c.	362 SG	Control Bldg. - El. 288'-6"
d.	357 XG	Control Bldg. - El. 288'-6"
e.	358 XG	Control Bldg. - El. 288'-6"
f.	374 SG	Control Bldg. - El. 306'-0"
g.	375 SG	Control Bldg. - El. 306'-0"
h.	381 SG	Control Bldg. - El. 306'-0"
i.	376 XG	Control Bldg. - El. 306'-0"

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 one hour establish a continuous fire watch with backup fire suppression equipment for those areas in which redundant systems or components could be damaged; for other areas, establish an hourly fire watch patrol.

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

SURVEILLANCE REQUIREMENTS

4.7.7.4 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 or level and pressure.

c. At least once per 18 months by:

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

2. Performance of an air flow test through headers and nozzles to assure no blockage.

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FIRE HOSE STATIONS

LIMITING CONDITION FOR OPERATION

3.7.7.5 The fire hose stations shown in Table 3.7.7.5-1 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, provide gated wye(s) on the nearest OPERABLE hose station(s). One outlet of the wye shall be connected to the standard length of hose provided for the hose station. The second outlet of the wye shall be connected to a length of hose sufficient to provide coverage for the area left unprotected by the inoperable hose station. Where it can be demonstrated that the physical routing of the fire hose would result in a recognizable hazard to operating technicians, plant equipment, or the hose itself, the fire hose shall be stored in a roll at the outlet of the OPERABLE hose station. Signs shall be mounted above the gated wye(s) to identify the proper hose to use. The above ACTION shall be accomplished within 1 hour if the inoperable fire hose is the primary means of fire suppression; otherwise route the additional hose within 24 hours.

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

SURVEILLANCE REQUIREMENTS

4.7.7.5 Each of the fire hose stations shown in Table 3.7.7.5-1 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, and

    3. Inspecting all gaskets and replacing any degraded gaskets in the couplings.

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.

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TABLE 3.7.7.5-1

FIRE HOSE STATIONS

LOCATION	ELEVATION	HOSE RACK INDENTIFICATION
Control Bldg.	214'-0"	FHR 118
Control Bldg.	214'-0"	FHR 119
Control Bldg.	237'-0"	FHR 113
Control Bldg.	237'-0"	FHR 117
Control Bldg.	250'-0"	FHR 30
Control Bldg.	261'-0"	FHR 116
Control Bldg.	261'-0"	FHR 112
Control Bldg.	288'-6"	FHR 111
Control Bldg.	288'-6"	FHR 115
Control Bldg.	306'-0"	FHR 114
Control Bldg.	306'-0"	FHR 110
Diesel Generator Bldg.	261'-0"	FHR 22
Diesel Generator Bldg.	261'-0"	FHR 33
Reactor Bldg.	175'-0"	FHR 74
Reactor Bldg.	175'-0"	FHR 90
Reactor Bldg.	175'-0"	FHR 100
Reactor Bldg.	198'-0"	FHR 102
Reactor Bldg.	198'-0"	FHR 101
Reactor Bldg.	198'-0"	FHR 103
Reactor Bldg.	215'-0"	FHR 73
Reactor Bldg.	215'-0"	FHR 89
Reactor Bldg.	215'-0"	FHR 99
Reactor Bldg.	240'-0"	FHR 72
Reactor Bldg.	240'-0"	FHR 88
Reactor Bldg.	240'-0"	FHR 98
Reactor Bldg.	261'-0"	FHR 71
Reactor Bldg.	261'-0"	FHR 79
Reactor Bldg.	261'-0"	FHR 87
Reactor Bldg.	261'-0"	FHR 94
Reactor Bldg.	289'-0"	FHR 70
Reactor Bldg.	289'-0"	FHR 78
Reactor Bldg.	289'-0"	FHR 86
Reactor Bldg.	289'-0"	FHR 93
Reactor Bldg.	306'-~~0"~~ 6"	FHR 69
Reactor Bldg.	306'-~~0"~~ 6"	FHR 77
Reactor Bldg.	328'-10"	FHR 68
Reactor Bldg.	328'-10"	FHR 76
Reactor Bldg.	328'-10"	FHR 85
Reactor Bldg.	328'-10"	FHR 92
Reactor Bldg.	353'-10"	FHR 67
Reactor Bldg.	353'-10"	FHR 75
Reactor Bldg.	353'-10"	FHR ~~94~~ 84
Reactor Bldg.	353'-10"	FHR 91

TABLE 3.7.7.5-1 (Continued)

FIRE HOSE STATIONS

LOCATION	ELEVATION	HOSE RACK INDENTIFICATION
Aux. Bay North	175'-0"	FHR 97
Aux. Bay North	198'-0"	FHR 104
Aux. Bay North	215'-0"	FHR 96
Aux. Bay North	240'-0"	FHR 95
Aux. Bay South	175'-0"	FHR 83
Aux. Bay South	198'-0"	FHR 82
Aux. Bay South	215'-0"	FHR 81
Aux. Bay South	240'-0"	FHR 80
Screenwell Bldg.	261'-0"	FHR 56
ELectrical Tunnels	216' 0'	FHR 137
	214' 6"	FHR 139
	214' 6"	FHR 135
	214' 6"	FHR 136
	220' 6"	FHR 138

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YARD FIRE HYDRANTS AND HYDRANT HOSE HOUSES

LIMITING CONDITION FOR OPERATION

3.7.7.6 The yard fire hydrants and associated hydrant hose houses shown in Table 3.7.7.6-1 shall be OPERABLE.

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

ACTION:

a. With one or more of the yard fire hydrants or associated hydrant hose houses shown in Table 3.7.7.6-1 inoperable, within 1 hour have sufficient additional lengths of 2 1/2 inch diameter hose located in an adjacent OPERABLE hydrant hose house to provide service to the unprotected area(s) if the inoperable fire hydrant or associated hydrant hose house is the primary means of fire suppression; otherwise provide the additional hose within 24 hours.

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

SURVEILLANCE REQUIREMENTS

4.7.7.6 Each of the 115 kV switch yard fire hydrants and associated hydrant hose houses shown in Table 3.7.7.6-1 shall be demonstrated OPERABLE:

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

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

c. At least once per 12 months by:

   1. 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.

   2. Replacement of all degraded gaskets in couplings.

   3. Performing a flow check of each hydrant.

TABLE 3.7.7.6-1

YARD FIRE HYDRANTS AND ASSOCIATED HYDRANT HOSE HOUSES

LOCATION	HYDRANT NUMBER
115 kV Yard	FH 14
115 kV Yard	FH 10

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3/4.7.8 FIRE RATED ASSEMBLIES

LIMITING CONDITION FOR OPERATION

3.7.8 All fire barrier 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 dampers, cable and piping penetration 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 one hour establish a continuous fire watch on at least one side of the affected assembly(s) and/or sealing device(s) or verify the OPERABILITY of fire detectors on at least one side of the inoperable assembly(s) and/or sealing device(s) and establish an hourly fire watch patrol.

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

SURVEILLANCE REQUIREMENTS

4.7.8.1 Each of the above required fire rated assemblies and penetration 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. At least 10 percent of the above required fire dampers shall be verified OPERABLE ~~at least once per month~~ by removal of the fusable link and observing closure of the associated damper. If a damper fai~~ls to~~ close, an additional 10 percent shall be tested until a 10 percent sample with no failures is found. Samples shall be selected such that each ~~penetration seal~~ fire damper will be inspected at least once per 15 years.

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 seal will be inspected at least once per 15 years.

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4.7.8.2 Each of the above required fire doors shall be verified OPERABLE by inspecting release and closing mechanism and latches at least once per 6 months, and by verifying:

a. That each locked-closed fire door is closed at least once per 7 days.

b. That doors with release mechanisms are free of obstructions at least once per 24 hours and performing a functional test of these mechanisms at least once per 18 months.

c. That each unlocked fire door is closed at least once per 24 hours.

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3/4.7.9 MAIN TURBINE BYPASS SYSTEM

LIMITING CONDITION FOR OPERATION

3.7.9 The main turbine bypass system shall be OPERABLE.

APPLICABILITY: OPERATIONAL CONDITION 1 when THERMAL POWER is greater than or equal to 25% of RATED THERMAL POWER.

ACTION: With the main turbine bypass system inoperable, restore the system to OPERABLE status within 1 hour or reduce THERMAL POWER to less than 25% of RATED THERMAL POWER within the next 4 hours.

SURVEILLANCE REQUIREMENTS

4.7.9 The main turbine bypass system shall be demonstrated OPERABLE:

a. At least once per 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 meets the following requirements when measured from initial movement of the main turbine stop or control valve:

    a. 80% of the turbine bypass system capacity shall be established within 0.3 seconds, and

    b. Bypass valve opening shall start in less than or equal to 0.1 seconds.

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3/4.8 ELECTRICAL POWER SYSTEMS

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3/4.8.1 A.C. SOURCES

A.C. SOURCES - OPERATING

LIMITING CONDITION FOR OPERATION

3.8.1.1 As a minimum, the following A.C. electrical power sources shall be OPERABLE:

a. Two physically independent circuits between the offsite transmission network and the onsite Class 1E distribution system, and

b. Three separate and independent diesel generators, each with:

   1. Separate day fuel tanks containing a minimum of 250 gallons of fuel,

   2. A separate fuel storage system containing a minimum of 52,664 gallons of fuel for EDG-1 (Div. I) and EDG-3 (Div. II), and 36,173 gallons for EDG-2 (HPCS-Div. III)

   3. ~~A separate~~ Two fuel oil transfer pumps~~, and~~

   ~~4. A room temperature greater than or equal to 65°F for EDG-2.~~

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, and 3.

ACTION:

a. With one offsite circuit of the above required A.C. electrical power sources inoperable, demonstrate the OPERABILITY of the remaining A.C. sources by performing Surveillance Requirements 4.8.1.1.1.a within one hour and at least once per 8 hours thereafter. If either diesel generator EDG-1 or EDG-3 has not been successfully tested within the past 24 hours, demonstrate its OPERABILITY by performing Surveillance Requirements 4.8.1.1.2.a.4 and 4.8.1.1.2.a.5 for each such diesel generator, separately, within 24 hours unless the diesel generators are already operating and loaded. Restore the offsite circuit 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 either diesel generator EDG-1 or EDG-3 inoperable, demonstrate the OPERABILITY of the above required A.C. offsite sources by performing Surveillance Requirement 4.8.1.1.1.a within 1 hour and at least once per 8 hours thereafter. If the diesel generator became inoperable due to any cause other than preplanned preventive maintenance or testing, demonstrate the OPERABILITY of the remaining OPERABLE diesel generators, separately, by performing Surveillance Requirements 4.8.1.1.2.a.4 and 4.8.1.1.2.a.5 separately for each diesel generator with 24 hours.* Restore the inoperable diesel

*This test is required to be completed regardless of when the inoperable diesel generator is restored to OPERABLE status.

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LIMITING CONDITION FOR OPERATION (Continued)

ACTION (Continued)

generator 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.

c. With one offsite circuit of the above-required A.C. sources and diesel generator EDG-1 or EDG-3 of the above required A.C. electrical power sources inoperable, demonstrate the OPERABILITY of the remaining A.C. sources by performing Surveillance Requirement 4.8.1.1.a within 1 hour and at least once per 8 hours thereafter. If a diesel generator became inoperable due to any cause other than preplanned preventive maintenance or testing, demonstrate the OPERABILITY of the remaining OPERABLE diesel generators, separately for each diesel generator, by performing Surveillance Requirements 4.8.1.1.2.a.4 and 4.8.1.1.2.a.5 within 8 hours for each diesel generator which has not been successfully tested in the past 24 hours unless the diesel generators are already operating and loaded.* Restore at least one of the inoperable A.C. sources to OPERABLE status within 12 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours. Restore at least two offsite circuits and diesel generators EDG-1 and EDG-3 to OPERABLE status within 72 hours from time of initial loss or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

d. With diesel generator EDG-2 of the above required A.C. electrical power sources inoperable for reasons other than diesel generator room air temperature, demonstrate the OPERABILITY of the offsite A.C. sources by performing Surveillance Requirement 4.8.1.1.1.a within 1 hour and at least once per 8 hours thereafter. If the diesel generator become inoperable as a result of any cause other than diesel generator room air temperature or preplanned preventive maintenance or testing, demonstrate the OPERABILITY of the remaining OPERABLE diesel generators, separately by performing Surveillance Requirements 4.8.1.1.2.a.4 and 4.8.1.1.2.a.5 within 24 hours.* Restore diesel generator EDG-2 to OPERABLE status within 72 hours or declare the HPCS system inoperable and take the ACTION required by Specifications 3.5.1 and 3.7.1.1. ~~With EDG-2 diesel room air temperature less than 65°F, within one hour restore the room temperature to equal to or greater than 65°F or declare the HPCS system inoperable and take the ACTION required by Specification 3.5.1.~~

e. With diesel generator EG-1 or EDG-3 of the above required A.C. electrical power sources inoperable, in addition to taking ACTION b or c, as applicable, verify within 2 hours that all required systems, subsystems, trains, components and devices that depend on the remaining OPERABLE diesel generator as a source of emergency power are also OPERABLE otherwise, be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

*This test is required to be completed regardless of when the inoperable diesel generator is restored to OPERABLE status.

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f. With both of the above required offsite circuits inoperable, demonstrate the OPERABILITY of three diesel generators, separately, by performing Surveillance Requirements 4.8.1.1.2.a.4 and 4.8.1.1.2.a.5 separately for each diesel generator within 8 hours unless the diesel generators are already operating and loaded; restore at least one of the above-required offsite circuits to OPERABLE status within 24 hours or ~~be in at least HOT SHUTDOWN~~ within the next 12 hours. With only one offsite circuit restored to OPERABLE status, restore at least two offsite circuits to OPERABLE status within 72 hours from time of initial loss or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours. A successful test(s) of diesel generator OPERABILITY per Surveillance Requirements 4.8.1.1.2.a.4 and 4.8.1.1.2.a.5, performed under this ACTION statement for the OPERABLE diesel generators, satisfies the diesel generator test requirements of ACTION statement a.

g. With diesel generators EDG-1 and EDG-3 of the above-required A.C. electrical power sources inoperable, demonstrate the OPERABILITY of the remaining A.C. sources by performing Surveillance Requirement 4.8.1.1.1.a within 1 hour and at least once per 8 hours thereafter and Surveillance Requirements 4.8.1.1.2.a.4 and 4.8.1.1.2.a.5 for diesel generator EDG-2 within 8 hours.* Restore at least one of the inoperable diesel generators EDG-1 and EDG-3 to OPERABLE status within 2 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours. Restore both diesel generators EDG-1 and EDG-3 to OPERABLE status within 72 hours from time of initial loss or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

h. With one offsite circuit of the above-required A.C. electrical power sources inoperable and diesel generator EDG-2 inoperable, apply the requirements of ACTION a and d specified above.

i. With either diesel generator EDG-1 or EDG-3 inoperable and diesel generator EDG-2 inoperable, apply the requirements of ACTION b, d and e specified above.

reduce power to ≤ 15%

*This test is required to be completed regardless of when the inoperable diesel generator is restored to OPERABLE status.

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SURVEILLANCE REQUIREMENTS ~~(Continued)~~

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.

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 day fuel tank.
2. Verifying the fuel level in the fuel storage tank.
3. Verifying each ~~the~~ fuel transfer pump starts and transfers fuel from the storage system to the day fuel tank.
4. Verifying diesels EDG-1 and EDG-3 start from ambient conditions and accelerate to at least 600 rpm in less than or equal to 10 seconds and diesel EDG-2 starts from ambient conditions and accelerates to at least 870 rpm in less than or equal to 10 seconds.* The generator voltage and frequency shall be 4160 ± 416 volts and 60 ± 1.2 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 ≥ 4300 kW for diesel generators EDG-1 and EDG-3 and ≥ 2500 kW for diesel generator EDG-2 in accordance with the diesel generator manufacturers recommendations and operates with these loads 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 diesel generator air start receivers for EDG-1 and EDG-3 to be greater than or equal to 225** psig and greater than or equal to 225** psig for EDG-2.

*The diesel generator starts from ambient conditions shall be performed at least once per 184 days for EDG-1 and EDG-3 and at least once per 366 days for EDG-2 in the surveillance tests. All other engine starts for the purpose of this surveillance testing may be preceeded by an engine prelube period and/or other warmup procedures recommended by the manufacturer so that mechanical stress and wear on the diesel engines is minimized.

**To be verified ~~in writing during low power testing~~. prior to fuel Load.

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SURVEILLANCE REQUIREMENTS (Continued)

~~b. At least once per shift verify the Division III diesel generator room air temperature is equal to or greater than 65°F.~~

~~c. At least once per 7 days manually prelube the Division III diesel generator.~~

b ~~d.~~ At least once per 14 days, separately, rotate EDG-1 and EDG-3 on their jacking gear if they have not been started in the past 14 days.

c. ~~e.~~ By removing accumulated water:

1. From the day tank at least once per 31 days and after each occasion when the diesel is operated from greater than 1 hour, and
2. From the storage tank at least once per 31 days.

d ~~f.~~ By sampling new fuel oil in accordance with ASTM D4057-81 prior to addition to the storage tanks and:

1. By verifying in accordance with the tests specified in ASTM D975-81 prior to addition to the storage tanks that the sample has:

   a) An API Gravity of within 0.3 degrees at 60°F or a specific gravity of within 0.0016 at 60/60°F, when compared to the supplier's certificate or an absolute specific gravity at 60/60°F of greater than or equal to 0.83 but less than or equal to 0.89 or an API gravity 60°F of greater than or equal to 27 degrees but less than or equal to 39 degrees.

   b) A kinematic viscosity at 40°C of greater than or equal to 1.9 centistokes, but less than or equal to 4.1 centistokes, if gravity was not determined by comparison with the supplier's certification.

   c) A flash point equal to or greater than 125°F, and

   d) A clear and bright appearance with proper color when tested in accordance with ASTM D4176-82.

2. By verifying within 31 days of obtaining the sample that the other properties specified in Table 1 of ASTM D975-81 are met when tested in accordance with ASTM D975-81 except that the analysis for sulfur may be performed in accordance with ASTM D1552-79 or ASTM D2622-82.

e. ~~g.~~ At least once every 31 days by obtaining a sample of fuel oil from the storage tanks in accordance with ASTM D2276-78, and verifying that total particulate contamination is less than 10 mg/liter when checked in accordance with ASTM D2276-78, Method A.

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e, ~~h~~. At least once per 18 months,# during shutdown, 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 1125 kW for diesel generator EDG-1, greater than or equal to 750 kW for diesel generator EDG-3, and greater than or equal to 2433 kW for diesel generator EDG-2 while maintaining engine speed < 75% of the difference between nominal speed and the overspeed trip setpoint or 15% above nominal, whichever is less.

3. Verifying the diesel generator capability to reject a load of 4300 kW for diesel generators EDG-1 and EDG-3 and 2500 kW for diesel generator EDG-2 without tripping.* The generator voltage shall not exceed 4576 volts for EDG-1 and EDG-3 and 5824 volts for EDG-2 during and following the load rejection.

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

   a) For divisions I and II:

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

      2) Verifying the diesel generator starts** on the auto-start signal, energizes the emergency busses with permanently connected loads within 13 seconds, energizes the auto-connected (shutdown) loads through the load timers 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 ± 416 volts and 60 ± 1.2 Hz during this test.

   b) For division III:

      1) Verifying de-energization of the emergency bus.

      2) Verifying the diesel generator starts** on the auto-start signal, energizes the emergency bus with the permanently connected loads within 13 seconds and operates for

see single asterik footnote should ~~be same as~~ on 3/4 8-4

#For any start of a diesel, the diesel must be operated with a load in accordance with the manufacturer's recommendations.

*Momentary transients due to changing bus loads shall not invalidate the test.

**~~All diesel generator starts for the purpose of this surveillance test may be preceded by an engine prelube period. Further, all surveillance tests, with the exception of once per 184 days, may also be preceded by warmup procedures and may also include gradual loading as recommended by the manufacturer so that the mechanical stress and wear on the diesel engine is minimized.~~

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SURVEILLANCE REQUIREMENTS (Continued)

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 bus shall be maintained at 4160 ± 416 volts and 60 ± 1.2 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 ± 416 volts and 60 ± 1.2 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.

~~6. Verifying that on a simulated loss of the diesel generator, with offsite power not available, the loads are shed from the emergency busses and that subsequent loading of the diesel generator is in accordance with design requirements.~~

7. Simulating a loss of offsite power in conjunction with an ECCS actuation test signal, and:

   a) For divisions I and II:

      1) Verifying deenergization of the emergency busses and loads shedding from the emergency busses.

      2) 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 (shutdown) 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 ± 416 volts and 60 ± 1.2 Hz during this test.

   b) For division III:

      1) Verifying de-energization of the emergency bus.

      2) Verifying the diesel generator starts* on the auto-start signal, energizes the emergency bus with the permanently connected loads and the auto-connected emergency loads within 10 seconds 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 bus shall be maintained at 4160 ± 416 volts and 60 ± 1.2 Hz during this test.

see signal asterisk note on 3/4 8-4

~~*All diesel generator starts for the purpose of this surveillance test may be preceded by an engine starts for the purpose of this surveillance test, with the exception of once per 184 days, may also be preceded by warmup procedures and may also include gradual loading as recommended by the manufacturer so that the mechanical stress and wear on the diesel engine is minimized.~~

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8. Verifying that all automatic diesel generator trips are automatically bypassed upon loss of voltage on the emergency bus concurrent with an ECCS actuation signal except engine overspeed and generator differential, ~~current.~~

9. 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 $\geq$ 4840 kW for diesel generators EDG-1 and EDG-3 and 2850 kW for diesel generator EDG-2.# During the remaining 22 hours of this test, the diesel generator shall be loaded to $\geq$ 4300 kW for diesel generators EDG-1 and EDG-3 and $\geq$ 2500 kW for diesel generator EDG-2.# The generator voltage and frequency shall be 4160 ± 416 volts and 60 ± 1.2 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.e.4.a~~2)~~ and ~~b)2)~~ e.4.b.**

10. Verifying that the auto-connected loads to each diesel generator do not exceed the 2000-hour rating of 4750 kW for diesel generators EDG-1 and EDG-3 and 2850 kW for diesel generator EDG-2.

11. Verifying the diesel generator's capability to:

    a) Manually 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.

see single asterisk footnote on 3/4 8-4

~~*All diesel generator starts for the purpose of this surveillance test may be preceded by an engine starts for the purpose of this surveillance test, with the exception of once per 184 days, may also be preceded by warmup procedures and may also include gradual loading as recommended by the manufacturer so that the mechanical stress and wear on the diesel engine is minimized.~~

**If Surveillance Requirement 4.8.1.1.2.~~e~~f.4.a)2) and/or b)2) are not satisfactorily completed, it is not necessary to repeat the preceding 24 hour test. Instead, the diesel generator may be operated at $\geq$ 4300 kW for EDG-1 and EDG-3 and $\geq$ 2500 kW for EDG-2 for one hour or until operating temperature has stabilized, then reperform 4.8.1.1.2.f.4.a and/or 4.b.

#Momentary transients due to changing bus loads shall not invalidate the test.

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12. 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.

13. Verifying that the automatic load timer relays are OPERABLE with the interval between each load block within ± 10% of its design interval for diesel generators EDG-1 and EDG-3.

14. Verifying that the following diesel generator lockout features prevent diesel generator starting only when required:

    a) For Divisions I and II, turning gear engaged and emergency stop.

    b) For Division III, engine in the maintenance mode and diesel generator lockout.

g. ~~f.~~ At least once per 10 years or after any modifications which could affect diesel generator interdependence by starting all three diesel generators simultaneously, during shutdown, and verifying that all diesel generators EDG-1 and EDG-3 accelerate to at least 600 rpm and EDG-2 accelerates to at least 870 rpm in less than or equal to 10 seconds.

h. ~~g.~~ 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 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 II Article IWD-5000.

4.8.1.1.3 Reports - All diesel generator failures, valid or non-valid, shall be reported to the Commission pursuant to Specification 6.9.1. 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.

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TABLE 4.8.1.1.2-1

DIESEL GENERATOR TEST SCHEDULE

Number of Failures in Last 100 Valid Tests*	Number of Failures in Last 100 Valid Tests*	Test Frequency
≤ 1	≤ 4	At least once per 31 days
≥ 2**	≥ 5	At least once per 14 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, but determined on a per diesel generator basis.

For the purposes of determining the required test frequency, the previous test failure count may be reduced to zero if a complete diesel overhaul to like-new condition is completed, provided that the overhaul, including appropriate post-maintenance operation and testing, is specifically approved by the manufacturer <u>and</u> if acceptable reliability has been demonstrated. The reliability criterion shall be the successful completion of 14 consecutive tests in a single series. Ten of these test shall be in accordance with the routine Surveillance Requirements 4.8.1.1.2.a.4 and 4.8.1.1.2.a.5 and four tests in accordance with the 184-day and the 366-day testing requirement, as applicable, of Surveillance Requirements 4.8.1.1.2.a.4 and 4.8.1.1.2.a.5. If this criterion is not satisfied during the first series of tests, any alternate criterion to be used to transvalue the failure count to zero requires NRC approval.

**The associated test frequency shall be maintained until seven consecutive failure free demands have been performed <u>and</u> the number of failures in the last 20 valid demands has been reduced to one.

A.C. SOURCES - SHUTDOWN

LIMITING CONDITION FOR OPERATION

3.8.1.2 As a minimum, the following A.C. electrical power sources shall be OPERABLE:

a. One circuit between the offsite transmission network and the onsite Class 1E distribution system, and

b. Diesel generator EDG-1 or EDG-3, and diesel generator EDG-2 when the HPCS system is required to be OPERABLE, with each diesel generator having:

1. Day and engine mounted fuel tanks containing a minimum of 250 gallons of fuel.
2. A fuel storage system containing a minimum of 52,664 gallons of fuel for EDG-1 and EDG-3 and 36,173 gallons of fuel for EDG-2.
3. ~~A~~ Two fuel oil transfer pumps.

APPLICABILITY: OPERATIONAL CONDITIONS 4, 5 and *.

ACTION:

a. With less than the the above required A.C. electrical power sources OPERABLE, suspend CORE ALTERATIONS, handling of irradiated fuel in the secondary containment, operations with a potential for draining the reactor vessel and crane operations over the spent fuel storage pool when fuel assemblies are stored therein. In addition, in OPERATIONAL CONDITION 5, with the water level less than 22'-3" above the reactor pressure vessel flange, immediately initiate corrective action to restore the required power sources to OPERABLE status as soon as practical.

b. With diesel generator EDG-2 of the above required A.C. electrical power sources inoperable, restore the inoperable diesel generator to OPERABLE status within 72 hours or declare the HPCS system inoperable and take the ACTION required by Specification 3.5.2 and 3.5.3

c. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.8.1.2 At least the above required A.C. electrical power sources shall be demonstrated OPERABLE per Surveillance Requirements 4.8.1.1.1, 4.8.1.1.2, and 4.8.1.1.3, except for the requirement of 4.8.1.1.2.a.5.

*When handling irradiated fuel in the secondary containment.

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3/4.8.2 D.C. SOURCES

D.C. SOURCES - OPERATING

LIMITING CONDITION FOR OPERATION

3.8.2.1 As a minimum, the following D.C. electrical power sources shall be OPERABLE:

a. Division I, consisting of:
   1. 125 volt battery 2BYS*BAT 2A and
   2. one 125 volt full capacity charger.

b. Division II, consisting of:
   1. 125 volt battery 2BYS*BAT 2B and
   2. one 125 volt full capacity charger.

c. Division III, consisting of:
   1. 125 volt battery 2BYS*BAT 2C and
   2. one 125 volt full capacity charger.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2 and 3.

ACTION:

a. With either Division I or Division II battery and/or charger of the above required D.C. electrical power sources inoperable, restore the inoperable division D.C. electrical power source(s) to OPERABLE status within 2 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

b. With Division III battery and/or charger of the above required D.C. electrical power sources inoperable, declare the HPCS system inoperable and take the ACTION required by Specification 3.5.1.

SURVEILLANCE REQUIREMENTS

4.8.2.1 Each of the above required 125-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. Total battery terminal voltage is greater than or equal to 130-volts on float charge.

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SURVEILLANCE REQUIREMENTS (Continued)

b. At least once per 92 days and within 7 days after a battery discharge with battery terminal voltage below 107-volts, or battery overcharge with battery terminal voltage above 142-volts, 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.

   3. The average electrolyte temperature of one out of five connected cells 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,

   3. The resistance of each cell-to-cell and terminal connection is ≤ 120% of the resistance readings taken during initial installation,* and

   4. The battery charger will supply:

      1. For Divisions I and II, at least 300 amperes at a minimum of 130 volts for at least 4 hours.

      2. For Division III, at least 50 amperes at a minimum of 130 volts for at least 4 hours.

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

   1. The battery capacity is adequate to supply and maintain in OPERABLE status all of the actual emergency loads for 2 hours for Divisions I and II, and 2 hours for Division III 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 while maintaining the battery terminal voltage greater than or equal to 105 volts.

      a) <u>Division I</u>. Greater than or equal to 818 amperes during the initial 60 seconds; greater than or equal to 445 amperes during the next 118 minutes; and greater than or equal to 701 amperes during the remainder of the 2 hour test.

      b) <u>Division II</u>. Greater than or equal to ~~576~~ 570 amperes during the initial 60 seconds; greater than or equal to 449 amperes during the next 118 minutes; and greater than or equal to 505 amperes during the remainder of the 2 hour test.

      c) <u>Division III</u>. Greater than or equal to 54.6 amperes during the initial 60 seconds; greater than or equal to 15.4 amperes during the remainder of the 2 hour test.

*In accordance with IEEE 450-1980.

SURVEILLANCE REQUIREMENTS (Continued)

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

f. At least once per 18 months, during shutdown, perform 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.

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TABLE 4.8.2.1-1

BATTERY SURVEILLANCE REQUIREMENTS

	CATEGORY A[1]	CATEGORY B[2]	
PARAMETER	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	Not more than 0.020 below the average of all connected cells
		Average of all connected cells > 1.205	Average of all connected cells ≥ 1.195[b]

[a] Corrected for electrolyte temperature and level.

[b] Or battery charging current is less than 2 amperes 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.

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D.C. SOURCES - SHUTDOWN

LIMITING CONDITION FOR OPERATION

3.8.2.2 As a minimum, Division I or Division II, and, when the HPCS system is required to be OPERABLE, Division III, of the D.C. electrical power sources shall be OPERABLE with:

a. Division I consisting of:
   1. 125 volt battery 2BYS*BAT 2A and
   2. one 125 volt full capacity charger.

b. Division II consisting of:
   1. 125 volt battery 2BYS*BAT 2B and
   2. one 125 volt full capacity charger.

c. Division III consisting of:
   1. 125 volt battery 2BYS*BAT 2C and
   2. one 125 volt full capacity charger.

APPLICABILITY: OPERATIONAL CONDITIONS 4, 5 and *.

ACTION:

a. With less than the Division I and/or Division II battery and/or charger of the above required D.C. electrical power sources OPERABLE, suspend CORE ALTERATIONS, handling of irradiated fuel in the secondary containment and operations with a potential for draining the reactor vessel.

b. With Division III battery and/or charger of the above required D.C. electrical power sources inoperable, declare the HPCS system inoperable and take the ACTION required by Specification 3.5.2 and 3.5.3.

c. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.8.2.2 At least the above required battery and charger shall be demonstrated OPERABLE per Surveillance Requirement 4.8.2.1.

*When handling irradiated fuel in the secondary containment.

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ELECTRICAL POWER SYSTEMS

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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 between Division I and Division II buses:

a. A.C. Power Distribution

1. Division I, consisting of:

   a) 4160 volt A.C. bus.
   b) 600 volt A.C. Load Center/MCC's/distribution panels.
   c) 240/120 volt A.C. and 120 volt A.C. distribution panels energized from inverter 2VB~~S~~A*UPS 2A.*

2. Division II, consisting of:

   a) 4160 volt A.C. bus.
   b) 600 volt A.C. Load Center/MCC's/distribution panels.
   c) 240/120 volt A.C. and 120 A.C. volt distribution panels energized from inverter 2VB~~S~~A*UPS 2B*

3. Division III, consisting of:

   a) 4160 volt A.C. bus.
   b) 600 volt A.C. Load Center/MCC's/distribution panels.
   c) 240/120 volt A.C. an~~d~~ 208 120 volt A.C. distribution panels
   d) HPC~~I~~S inverter energized from Division III batteries.

b. D.C. Power Distribution

1. Division I, consisting of 125 volt D.C. switchgear, MCC and associated distribution panels: 2BYS*PNL 201A; 2BYS*PNL 202A; 2BYS*PNL 204A.

2. Division II, consisting of 125 volt D.C. switchgear, MCC and associated distribution panels: 2BYS*PNL 201B; 2BYS*PNL 202B; 2BYS*PNL 204B.

3. Division III, consisting of 125 volt D.C. switchgear, MCC and associated distribution panels: 2BYS*PNL 201C; 2BYS*PNL 202C, 2BYS*PNL 204C.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2 and 3.

ACTION:

a. For A.C. power distribution:

1. With either Division I or Division II of the above required A.C. distribution system not energized, re-energize the division within 8 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

2. With Division III of the above required A.C. distribution system not energized, declare the HPCS system inoperable and take the ACTION required by Specification 3.5.1.

*The UPS shall be energized from their normal A.C. supply or their backup D.C. supply.

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LIMITING CONDITION FOR OPERATION (Continued)

ACTION: (Continued)

b. For D.C. power distribution:

1. With either Division I or Division II of the above required D.C. distribution system not energized, re-energize the division within 2 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

2. With Division III of the above required D.C. distribution system not energized, declare the HPCS system inoperable and take the ACTION required by Specification 3.5.1.

SURVEILLANCE REQUIREMENTS

4.8.3.1.1 Each of the above required power distribution system divisions shall be determined energized at least once per 7 days by verifying correct supply breaker alignment and by verifying no bypass inoperability status indicator lights in the control room are lit.*

4.8.3.1.2 Each of the above required power distribution switchgear shall be determined energized at least once per 7 days by verifying the voltage on the panels.

*Which would indicate a loss of power to one or more of the required MCCs, load center or panels.

DISTRIBUTION - SHUTDOWN

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, and when the HPCS system is required to be OPERABLE, Division III, with:

1. Division I consisting of:
    a) 4160 volt A.C. bus.
    b) 600 volt A.C. Load Center/MCC's/distribution panels.
    c) 240/120 volt A.C. and ~~208/~~120 volt A.C. distribution panels; energized from inverter 2VB~~S~~A*UPS~~*~~2A or alternate supply.

2. Division II consisting of:
    a) 4160 volt A.C. bus.
    b) 600 volt A.C. Load Center/MCC's/distribution panels.
    c) 240/120 volt A.C. and ~~208/~~120 volt A.C. distribution panels; energized from inverter 2VB~~S~~A*UPS~~*~~2B or alternate supply.

3. Division III consisting of:
    a) 4160 volt A.C. bus.
    b) 600 volt A.C. Load Center/MCC's/distribution panels.
    c) 240/120 volt A.C. and ~~208/~~120 volt A.C. distribution panels;
    d) HPC~~I~~S inverter energized from Division III batteries. STET

b. For D.C. power distribution, Division I or Division II, and when the HPCS system is required to be OPERABLE, Division III, with:

1. Division I consisting of 125 volt D.C. Switchgear, MCC and distribution panels.

2. Division II consisting of 125 volt D.C. Switchgear, MCC and distribution panels.

3. Division III consisting of 125 volt D.C. Switchgear, MCC and distribution panels.

APPLICABILITY: OPERATIONAL CONDITIONS 4, 5 and *.

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*When handling irradiated fuel in the secondary containment.

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LIMITING CONDITION FOR OPERATION (Continued

ACTION:

a. For A.C. power distribution:

1. With less than Division I and Division II of the above required A.C. distribution system energized, suspend CORE ALTERATIONS, handling of irradiated fuel in the reactor building and operations with a potential for draining the reactor vessel.

2. With Division III of the above required A.C. distribution system not energized, declare the HPCS system inoperable and take the ACTION required by Specification 3.5.2 and 3.5.3.

b. For D.C. power distribution:

1. With less than Division I and Division II of the above required D.C. distribution system energized, suspend CORE ALTERATIONS, handling of irradiated fuel in the Reactor Building, and operations with a potential for draining the reactor vessel.

2. With Division III of the above required D.C. distribution system not energized, declare the HPCS system inoperable and take the ACTION required by Specification 3.5.2 and 3.5.3.

c. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.8.3.2.1 At least the above required power distribution system divisions shall be determined energized at least once per 7 days by verifying correct supply breaker alignment and by verifying no bypass inoperability status indicator lights in the control room are lit.*

4.8.3.2.2 Each of the above required power distribution switchgear shall be determined energized at least once per 7 days by verifying the voltage on the panels.

*Which would indicate loss of power to one or more of the required MCCs, load centers or panels.

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3/4.8.4 ELECTRICAL EQUIPMENT PROTECTIVE DEVICES

A.C. CIRCUITS INSIDE PRIMARY CONTAINMENT

LIMITING CONDITION FOR OPERATION

3.8.4.1 The A.C. circuits inside primary containment shown in Table 3.8.4.1-1 shall be de-energized:*

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2 and 3.

ACTION:

With any of the above required circuits energized, trip the associated circuit breaker(s) in the specified panel(s) within 1 hour.

SURVEILLANCE REQUIREMENTS

4.8.4.1 Each of the above required A.C. circuits shall be determined to be de-energized at least once per 24 hours** by verifying that the associated circuit breakers are in the tripped condition.

*Required prior to power ascension and following final drywell inspection.

**Except at least once per 31 days if locked, ~~sealed~~ and secured in the tripped condition by tagging out the equipment.

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TABLE 3.8.4.1-1

PRIMARY CONTAINMENT AC CIRCUITS DEENERGIZED

CIRCUIT NO	POWER SOURCE	CIRCUIT BKR NO	EQUIPMENT POWERED
N12-11	2LAR-PNLN12	11	Normal Lighting CKTS - Elev. 261'
N12-12	2LAR-PNLN12	12	Normal Lighting CKTS - Elev. 261'
N12-13	2LAR-PNLN12	13	Normal Lighting CKTS - Elev. 261'
N12-14	2LAR-PNLN12	14	Normal Lighting CKTS - Elev. 289'
N12-15	2LAR-PNLN12	15	Normal Lighting CKTS - Elev. 289'
N12-16	2LAR-PNLN12	16	Normal Lighting CKTS - Elev. 289'
N12-17	2LAR-PNLN12	17	Normal Lighting CKTS - Elev. 240'
N12-18	2LAR-PNLN12	18	Normal Lighting CKTS - Elev. 240'
N12-19	2LAR-PNLN12	19	Normal Lighting CKTS - Elev. 240'
N12-1	2LAR-PNLN12	1	Normal Receptacle CKTS - Elev. 240'
N12-2	2LAR-PNLN12	2	Normal Receptacle CKTS - Elev. 261'
N12-3	2LAR-PNLN12	3	Normal Receptacle CKTS - Elev. 289'
N05-14	2LAR-PNLN05	14	SW For Normal LTG Contractor Coil CKT
U02-14	2LAR-PNLU02	14	Essential Lighting CKTS - Elev. 240'
U02-15	2LAR-PNLU02	15	Essential Lighting CKTS - Elev. 261'
U02-16	2LAR-PNLU02	16	Essential Lighting CKTS - Elev. 289'
U02-12	2LAR-PNLU02	12	SW For Essential LTG Contractor Coil CKT
N03-7	2LAR-PNLN03	7	Normal Receptacle CKTS - Supp Pool
NA	2WPS-PNL200	20	2WPS-RCPT51A & B - Welding Recept Elev 261'
NA	2WPS-PNL200	22	2WPS-RCPT51A & B - Welding Recept Elev 261'
NA	2WPS-PNL200	24	2WPS-RCPT51A & B - Welding Recept Elev 261'
NA	2WPS-PNL200	26	2WPS-RCPT52A & B - Welding Recept Elev 261'
NA	2WPS-PNL200	28	2WPS-RCPT52A & B - Welding Recept Elev 261'
NA	2WPS-PNL200	30	2WPS-RCPT52A & B - Welding Recept Elev 261'

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TABLE 3.8.4.1-1 (cont)

PRIMARY CONTAINMENT AC CIRCUITS DEENERGIZED

CIRCUIT NO	POWER SOURCE	SECT	EQUIPMENT POWERED
2DERA03	2NNS-MCC012	7B	2DER*MOV128 - REACTOR DRAIN ISOL. VALVE
2RHSA25	2EHS*MCC103	22A	2RHS*MOV67A - RHR A SHT ON CLG CV BYPASS
2RHSB25	2EHS*MCC303	21C	2RHS*MOV67B - RHR B SHT ON CLG CV BYPASS
NA	2NHS-MCC005	7B	2MHR-CRN3 - RECIRC MTR HNDLG CRANE-AMHR-PNL101
NA	2NHS-MCC005	7C	2MHR-CRN4 - RECIRC MTR HNDLG CRANE-AMHR-PNL102
NA	2NHS-MCC005	7D	2MHR-CRN65 - MONRAIL 2 TON FOR 2MSS*PSV
NA	2NHS-MCC005	7E	ZMHR-CRN66 - MONORAIL 2 TON FOR RDS CART
NA	2NHS-MCC005	7F	ZMHR-CRN67 - MONORAIL 2 TON FOR ZMSS*HVY VALVES

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TABLE 3.8.4.1-1 (cont)

PRIMARY CONTAINMENT AC CIRCUITS DEENERGIZED

CIRCUIT NO	POWER SOURCE	CIRCUIT BKR NO	EQUIPMENT POWERED
U01-15	2LAR-PNLU01	15	Comm-Party Paging Suppression Pool
U03-12	2LAR-PNLU03	12	Comm-Party Paging Above Suppression Pool

CIRCUIT NO	MAINTENANCE/CALIBR. SELECTOR SWITCH PANEL	SWITCH NO	EQUIPMENT POWERED
NA	RSC-88	124	Maintenance/Calibration Jack - JK124
NA	RSC-88	128	Maintenance/Calibration Jack - JK128
NA	RSC-88	134	Maintenance/Calibration Jack - JK134
NA	RSC-88	137	Maintenance/Calibration Jack - JK137

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PRIMARY CONTAINMENT PENETRATION CONDUCTOR OVERCURRENT PROTECTIVE DEVICES

LIMITING CONDITION FOR OPERATION

3.8.4.2 All Primary containment penetration conductor overcurrent protective devices* shall be OPERABLE.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2 and 3.

ACTION:

a. With one or more of the primary containment penetration conductor overcurrent protective devices* inoperable, declare the affected system or component inoperable and apply the appropriate ACTION statement for the affected system and:

   1. For 13.8 ~~or 1.25 kV~~ circuit breakers, de-energize the 13.8 ~~or 1.25 kV~~ kV circuits by tripping the associated redundant circuit breaker(s) within 72 hours and verify the redundant circuit breaker to be tripped at least once per 7 days thereafter.

   2. For 600 volt MCC circuit breakers, remove the inoperable circuit breaker(s) from service by racking out the breaker within 72 hours and verify the inoperable breaker(s) to be in the disconnect position at least once per 7 days thereafter.

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

b. The provisions of Specification 3.0.4 are not applicable to overcurrent devices in 13.8 kV ~~or 1.25 kV~~ circuits which have their redundant circuit breakers tripped or to 600 volt circuits which have the inoperable circuit breaker disconnected.

SURVEILLANCE REQUIREMENTS

4.8.4.2 Each of the primary containment penetration conductor overcurrent protective devices* shall be demonstrated OPERABLE:

a. At least once per 18 months:

   1. By verifying that the medium voltage 13.8 ~~and 1.25~~ kV circuit breakers are OPERABLE by selecting, on a rotating basis, at least 10% of the circuit breakers of each voltage level and performing:

      a) A CHANNEL CALIBRATION of the associated protective relays, and

      b) An integrated system functional test which includes simulated automatic actuation of the system and verifying that each relay and associated circuit breakers and overcurrent control circuits function as designed.

*Excluded from this specification are those penetration assemblies that are capable of withstanding the maximum current available due to an electrical fault inside containment.

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SURVEILLANCE REQUIREMENTS (Continued)

c) 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. By selecting and functionally testing a representative sample of at least 10% of each type of lower voltage circuit breakers. Circuit breakers selected for functional testing shall be selected on a rotating basis. Testing of these circuit breakers shall consist of injecting a current with a value equal to 300% of the pickup of the long time delay trip element and 150% of the pickup of the short time delay trip element, and verifying that the circuit breaker operates within the time delay band width for that current specified by the manufacturer. The instantaneous element shall be tested by injecting a current equal to ± 20% of the pickup value of the element and verifying that the circuit breaker trips instantaneously with no intentional time delay. Molded case circuit breaker testing shall also follow this procedure except that generally no more than two trip elements, time delay and instantaneous, will be involved.) 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.

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.

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EMERGENCY LIGHTING SYSTEM - OVERCURRENT PROTECTIVE DEVICES

LIMITING CONDITION FOR OPERATION

3.8.4.3 The emergency lighting system overcurrent protection devices shown in Table 3.8.4.3-1 shall be OPERABLE.

APPLICABILITY: At all times.

ACTION:

With one or more of the overcurrent protective devices* shown in Table 3.8.4.3-1 inoperable, within 72 hours remove the inoperable circuit breaker(s) from service by opening the breaker. Return the breaker(s) to OPERABLE status within 7 days, otherwise be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

SURVEILLANCE REQUIREMENTS

4.8.4.3 The overcurrent protective devices shall be demonstrated OPERABLE at least once per 18 months by selecting and testing one-half of each type of circuit breaker on a rotating basis. Testing of these circuit breakers shall consist of injecting currents in excess of the breaker's normal setpoint and measuring ~~the response time of the long time and short time delay elements and~~ the setpoint of the instantaneous element, as appropriate. The measured data shall be compared to the manufacturer's data to ensure that it is less than or equal to a value specified by the manufacturer.

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Table 3.8.4.3-1

OVER CURRENT PROTECTIVE DEVICES FOR NON CLASS 1E LIGHTING FIXTURES ON CLASS 1E EMERGENCY SYSTEM

PRIMARY CIRCUIT BREAKER			BACKUP CIRCUIT BREAKER			
MFR/TYPE	CURRENT RATING	EQUIPMENT POWERED LOCATION-120/208V	MFR/TYPE	CURRENT RATING	CIR NO.	POWER SUPPLY LOCATION-600V
GOULD - EH	100A	2LAC * PNLE01 Div I SWGR, ~~&~~ DIESEL GEN. RM. & REMOTE SHUTDOWN RM.	GOULD - HE	45A	1	2LAC*PNL100A
GOULD - EH	100A	2LAC * PNLE04 RELAY ROOM	GOULD - HE	45A	2	2LAC * PNL100A
GOULD - EH	100A	2LAC * PNLE06 CONTROL ROOM	GOULD - HE	45A	8	2LAC*PNL100A
GOULD - EH	100A	2LAC * PNLE02 Div II SWGR, ~~&~~ DIESEL GEN. RM. & REMOTE SHUTDOWN RM.	GOULD - HE	45A	1	2LAC *PNL300B
GOULD - EH	100A	2LAC * PNLE05 RELAY ROOM	GOULD - HE	45A	2	2LAC * PNL300B
GOULD - EH	100A	2LAC * PNLE07 CONTROL ROOM	GOULD - HE	45A	8	2LAC*PNL300B
GOULD - EH	100A	2LAC * PNLE03 Div. III SWGR, ~~&~~ DIESEL GEN RM.	GOULD - HE	45A	Compt 10B	2EHS * MCC201

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REACTOR PROTECTION SYSTEM ELECTRIC POWER MONITORING (RPS LOGIC)

LIMITING CONDITION FOR OPERATION

3.8.4.4.1 Two RPS UPS electric power monitoring channels (EPA's) for each inservice UPS set or alternate source shall be OPERABLE.

APPLICABILITY: At all times.

ACTION:

a. With one RPS electric power monitoring channel for an inservice RPS UPS inoperable, restore the inoperable power monitoring channel to OPERABLE status within 72 hours or remove the associated RPS UPS from service.

b. With both RPS electric power monitoring channels for an inservice RPS UPS inoperable, restore at least one electric power monitoring channel to OPERABLE status within 30 minutes or remove the associated RPS UPS from service.

SURVEILLANCE REQUIREMENTS

4.8.4.4.1 The above specified RPS power monitoring channels instrumentation 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 in the previous six months.

b. At least once per 18 months by demonstrating the OPERABILITY of over-voltage, under-voltage and under-frequency 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.

   1. Over-voltage $\leq$ 132*VAC

   2. Under-voltage $\geq$ 108*VAC

   3. Under-frequency $\geq$ 57 Hz, -0+2%.

*Initial Setpoints, final values to be determined during preoperational testing.

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REACTOR PROTECTION SYSTEM ELECTRIC POWER MONITORING (SCRAM SOLENOIDS)

LIMITING CONDITION FOR OPERATION

3.8.4.4.2 Two RPS UPS electric power monitoring channels (EPA's) for each inservice RPS (MG set or alternate source) shall be OPERABLE.

APPLICABILITY: At all times.

ACTION:

a. With one RPS electric power monitoring channel for an inservice RPS MG set or alternate power supply) inoperable, restore the inoperable power monitoring channel 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 channels for an inservice RPS MG set or alternate power supply) inoperable, restore at least one electric power monitoring channel to OPERABLE status within 30 minutes or remove the associated RPS MG set or alternate power supply from service.

SURVEILLANCE REQUIREMENTS

4.8.4.4.2 The above specified RPS power monitoring channels instrumentation 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 in the previous six months.

b. At least once per 18 months by demonstrating the OPERABILITY of over-voltage, under-voltage and under-frequency 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.

   1. Over-voltage $\leq$ 125*VAC

   2. Under-voltage $\geq$ 105*VAC

   3. Under-frequency $\geq$ 57 Hz, -0 +2%.

*Initial Setpoints, final values to be determined during preoperational testing.

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3/4.9 REFUELING OPERATIONS

3/4.9.1 REACTOR MODE SWITCH

LIMITING CONDITION FOR OPERATION

3.9.1 The reactor mode switch shall be OPERABLE and locked in the Shutdown or Refuel position. When the reactor mode switch is locked in the Refuel position:

a. A control rod shall not be withdrawn unless the Refuel position one-rod-out interlock is OPERABLE.

b. CORE ALTERATIONS shall not be performed using equipment associated with a Refuel position interlock unless at least the following associated Refuel position interlocks are OPERABLE for such equipment.

1. All rods in.
2. Refuel platform position.
3. Refuel platform hoists fuel-loaded.
4. Fuel grapple position.
5. Service platform hoist fuel-loaded.

APPLICABILITY: OPERATIONAL CONDITION 5* #

ACTION:

a. With the reactor mode switch not locked in the Shutdown or Refuel position as specified, suspend CORE ALTERATIONS and lock the reactor mode switch in the Shutdown or Refuel position.

b. With the one-rod-out interlock inoperable, lock the reactor mode switch in the Shutdown position.

c. With any of the above required Refuel position equipment interlocks inoperable, suspend CORE ALTERATIONS with equipment associated with the inoperable Refuel position equipment interlock.

---

* See Special Test Exceptions 3.10.1 and 3.10.3.

The reactor shall be maintained in OPERATIONAL CONDITION 5 whenever fuel is in the reactor vessel with the vessel head closure bolts less than fully tensioned or with the head removed.

SURVEILLANCE REQUIREMENTS

4.9.1.1 The reactor mode switch shall be verified to be locked in the Shutdown or Refuel position as specified:

a. Within 2 hours prior to:

1. Beginning CORE ALTERATIONS, and

2. Resuming CORE ALTERATIONS when the reactor mode switch has been unlocked.

b. At least once per 12 hours.

4.9.1.2 Each of the above required reactor mode switch Refuel position interlocks* shall be demonstrated OPERABLE by performance of a CHANNEL FUNCTIONAL TEST within 24 hours prior to the start of and at least once per 7 days during control rod withdrawal or CORE ALTERATIONS, as applicable.

4.9.1.3 Each of the above required reactor mode switch Refuel position interlocks* that is affected shall be demonstrated OPERABLE by performance of a CHANNEL FUNCTIONAL TEST prior to resuming control rod withdrawal or CORE ALTERATIONS, as applicable, following repair, maintenance or replacement of any component that could affect the Refuel position interlock.

*The reactor mode switch may be placed in the Run or Startup/Hot Standby position to test the switch interlock functions provided that all control rods are verified to remain fully inserted by a second licensed operator or other technically qualified member of the unit technical staff.

REFUELING OPERATIONS

3/4.9.2 INSTRUMENTATION

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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. Audible indication 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.~~ Unless adequate shutdown margin has been demonstrated per Specification 3.1.1, and the "one rod out" interlock is OPERABLE per Specification 3.9.1, the shorting links shall be removed from the RPS circuitry prior to, and any time any control rod is withdrawn

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.

*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.

**Except movement of IRM, SRM or special movable detectors.

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

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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 3 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, within 8 hours prior to and at least once per 12 hours during, that the RPS circuitry "shorting links" have been removed during:~~

~~1. The time any control rod is withdrawn, ** or~~

~~2. Shutdown margin demonstrations.~~

Verifying, within 8 hours prior to and at least once per 12 hours during the time any control rod is withdrawn that the shorting links have been removed from the RPS circuitry, unless adequate shutdown margin has been demonstrated per Specification 3.1.1 and the "one rod out" interlock is OPERABLE per Specification 3.9.1.

*For initial loading and startup the count rate may be less than 3 cps if the following conditions are met; (1) the signal to noise ratio is greater than 2.0 and (2) the signal is greater than 0.7 cps. ~~and (3) a counting interval sufficient to accumulate at least 500 counts is employed.~~

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

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3/4.9.3 CONTROL ROD POSITION

LIMITING CONDITION FOR OPERATION

3.9.3 All control rods shall be inserted.*

APPLICABILITY: OPERATIONAL CONDITION 5, during CORE ALTERATIONS.**

ACTION:

With all control rods not inserted, suspend all other CORE ALTERATIONS.

SURVEILLANCE REQUIREMENTS

4.9.3 All control rods shall be verified to be inserted, except as above specified:

a. Within 2 hours prior to:

1. The start of CORE ALTERATIONS.
2. The withdrawal of one control rod under the control of the reactor mode switch Refuel position one-rod-out interlock.

b. At least once per 12 hours.

*Except control rods removed per Specification 3.9.10.1 or 3.9.10.2, or with one control rod withdrawn under control of the reactor mode switch Refuel position one-rod-out interlock.

**See Special Test Exception 3.10.3.

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3/4.9.4 DECAY TIME

LIMITING CONDITION FOR OPERATION

3.9.4 The reactor shall be subcritical for at least 24 hours.

APPLICABILITY: OPERATIONAL CONDITION 5, during movement of irradiated fuel in the reactor pressure vessel.

ACTION:

With the reactor subcritical for less than 24 hours, suspend all operations involving movement of irradiated fuel in the reactor pressure vessel.

SURVEILLANCE REQUIREMENTS

4.9.4 The reactor shall be determined to have been subcritical for at least 24 hours by verification of the date and time of subcriticality prior to movement of irradiated fuel in the reactor pressure vessel.

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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.

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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 Each refueling platform crane or 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 with that crane or hoist by:

a. Demonstrating operation of the overload cutoff on the main hoist when the load exceeds 1200 ± 50 pounds.

b. Demonstrating operation of the overload cutoff on the frame mounted and monorail mounted auxiliary hoists when the load exceeds 1000 ± 50 pounds.

c. Demonstrating operation of the main and auxiliary hoist uptravel stops when the grapple is lower than or equal to 8 feet below the platform tracks.

d. Demonstrating operation of the downtravel mechanical cutoff on the main hoist when grapple hook down travel reaches 4 inches below fuel assembly handle.

e. Demonstrating operation of the slack cable cutoff on the main hoist when the load is less than 50 ± 10 pounds.

f. Demonstrating operation of the loaded interlock on the main hoist when the load exceeds 485 ± 50 pounds.

g. Demonstrating operation of the redundant loaded interlock on the main hoist when the load exceeds 550 ± 50 pounds.

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3/4.9.7 CRANE TRAVEL-SPENT FUEL STORAGE POOL

LIMITING CONDITION FOR OPERATION

3.9.7 Loads in excess of 1150 pounds shall be prohibited from travel over fuel assemblies in the spent fuel storage pool racks.

APPLICABILITY: With fuel assemblies in the spent fuel storage pool racks.

ACTION:

With the requirements of the above specification not satisfied, place the crane load in a safe condition. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.9.7 Crane interlocks ~~and physical stops~~ which prevent crane travel ~~with loads in excess of 1150 pounds~~ over fuel assemblies in the spent fuel storage pool racks shall be demonstrated OPERABLE within 7 days prior to and at least once per 7 days during crane operation.

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3/4.9.8 WATER LEVEL - REACTOR VESSEL

LIMITING CONDITION FOR OPERATION

3.9.8 At least 22'3" of water shall be maintained over the top of the reactor pressure vessel flange.

APPLICABILITY: During handling of fuel assemblies or control rods within the reactor pressure vessel while in OPERATIONAL CONDITION 5 when the fuel assemblies being handled are irradiated or the fuel assemblies seated within the reactor vessel are irradiated.

ACTION:

With the requirements of the above specification not satisfied, suspend all operations involving handling of fuel assemblies or control rods within the reactor pressure vessel after placing all fuel assemblies and control rods in a safe condition.

SURVEILLANCE REQUIREMENTS

4.9.8 The reactor vessel water level shall be determined to be at least its minimum required depth within 2 hours prior to the start of and at least once per 24 hours during handling of fuel assemblies or control rods within the reactor pressure vessel.

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3/4.9.9 WATER LEVEL - SPENT FUEL STORAGE POOL

LIMITING CONDITION FOR OPERATION

3.9.9 At least 22'3" of water shall be maintained over the top of irradiated fuel assemblies seated in the spent fuel storage pool racks.

APPLICABILITY: Whenever irradiated fuel assemblies are in the spent fuel storage pool.

ACTION:

With the requirements of the above specification not satisfied, suspend all movement of fuel assemblies and crane operations with loads in the spent fuel storage pool area after placing the fuel assemblies and crane load in a safe condition. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.9.9 The water level in the spent fuel storage pool shall be determined to be at least at its minimum required depth at least once per 7 days.

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3/4.9.10 CONTROL ROD REMOVAL

SINGLE CONTROL ROD REMOVAL

LIMITING CONDITION FOR OPERATION

3.9.10.1 One control rod and/or the associated control rod drive mechanism may be removed from the core and/or reactor pressure vessel provided that at least the following requirements are satisfied until a control rod and associated control rod drive mechanism are reinstalled and the control rod is fully inserted in the core.

a. The reactor mode switch is OPERABLE and locked in the Shutdown position or in the Refuel position per Table 1.2 and Specification 3.9.1.

b. The source range monitors (SRM) are OPERABLE per Specification 3.9.2.

c. The SHUTDOWN MARGIN requirements of Specification 3.1.1 are satisfied, except that the control rod selected to be removed;

   1. May be assumed to be the highest worth control rod required to be assumed to be fully withdrawn by the SHUTDOWN MARGIN test, and

   2. Need not be assumed to be immovable or untrippable.

d. All other control rods in a five-by-five array centered on the control rod being removed are inserted and electrically or hydraulically disarmed or the four fuel assemblies surrounding the control rod or control rod drive mechanism to be removed from the core and/or reactor vessel are removed from the core cell.

e. All other control rods are inserted.

APPLICABILITY: OPERATIONAL CONDITIONS 4 and 5.

ACTION:

With the requirements of the above specification not satisfied, suspend removal of the control rod and/or associated control rod drive mechanism from the core and/or reactor pressure vessel and initiate action to satisfy the above requirements.

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SURVEILLANCE REQUIREMENTS

4.9.10.1 Within 4 hours prior to the start of removal of a control rod and/or the associated control rod drive mechanism from the core and/or reactor pressure vessel and at least once per 24 hours thereafter until a control rod and associated control rod drive mechanism are reinstalled and the control rod is inserted in the core, verify that:

a. The reactor mode switch is OPERABLE per Surveillance Requirement 4.3.1.1 or 4.9.1.2, as applicable, and locked in the Shutdown position or in the Refuel position with the "one rod out" Refuel position interlock OPERABLE per Specification 3.9.1.

b. The SRM channels are OPERABLE per Specification 3.9.2.

c. The SHUTDOWN MARGIN requirements of Specification 3.1.1 are satisfied per Specification 3.9.10.1.c.

d. All other control rods in a five-by-five array centered on the control rod being removed are inserted and electrically or hydraulically disarmed or the four fuel assemblies surrounding the control rod or control rod drive mechanism to be removed from the core and/or reactor vessel are removed from the core cell.

e. All other control rods are inserted.

MULTIPLE CONTROL ROD REMOVAL

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LIMITING CONDITION FOR OPERATION

3.9.10.2 Any number of control rods and/or control rod drive mechanisms may be removed from the core and/or reactor pressure vessel provided that at least the following requirements are satisfied until all control rods and control rod drive mechanisms are reinstalled and all control rods are inserted in the core.

a. The reactor mode switch is OPERABLE and locked in the Shutdown position or in the Refuel position per Specification 3.9.1, except that the Refuel position "one-rod-out" interlock may be bypassed, as required, for those control rods and/or control rod drive mechanisms to be removed, after the fuel assemblies have been removed as specified below.

b. The source range monitors (SRM) are OPERABLE per Specification 3.9.2.

c. The SHUTDOWN MARGIN requirements of Specification 3.1.1 are satisfied.

d. All other control rods are either inserted or have the surrounding four fuel assemblies removed from the core cell.

e. The four fuel assemblies surrounding each control rod or control rod drive mechanism to be removed from the core and/or reactor vessel are removed from the core cell.

f. All fuel loading operations shall be suspended.

APPLICABILITY: OPERATIONAL CONDITION 5.

ACTION:

With the requirements of the above specification not satisfied, suspend removal of control rods and/or control rod drive mechanisms from the core and/or reactor pressure vessel and initiate action to satisfy the above requirements.

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SURVEILLANCE REQUIREMENTS

4.9.10.2.1 Within 4 hours prior to the start of removal of control rods and/or control rod drive mechanisms from the core and/or reactor pressure vessel and at least once per 24 hours thereafter until all control rods and control rod drive mechanisms are reinstalled and all control rods are inserted in the core, verify that:

a. The reactor mode switch is OPERABLE per Surveillance Requirement 4.3.1.1 or 4.9.1.2, as applicable, and locked in the Shutdown position or in the Refuel position per Specification 3.9.1.

b. The SRM channels are OPERABLE per Specification 3.9.2.

c. The SHUTDOWN MARGIN requirements of Specification 3.1.1 are satisfied.

d. All other control rods are either inserted or have the surrounding four fuel assemblies removed from the core cell.

e. The four fuel assemblies surrounding each control rod and/or control rod drive mechanism to be removed from the core and/or reactor vessel are removed from the core cell.

f. all fuel loading operations are suspended

4.9.10.2.2 Following replacement of all control rods and/or control rod drive mechanisms removed in accordance with this specification, perform a functional test of the "one-rod-out" Refuel position interlock, if this function had been bypassed.

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3/4.9.11 RESIDUAL HEAT REMOVAL AND COOLANT CIRCULATION

HIGH WATER LEVEL

LIMITING CONDITION FOR OPERATION

3.9.11.1 At least one shutdown cooling mode loop of the residual heat removal (RHR) system shall be OPERABLE and in operation* with at least:

a. One OPERABLE RHR pump, and

b. One OPERABLE RHR heat exchanger.

APPLICABILITY: OPERATIONAL CONDITION 5, when irradiated fuel is in the reactor vessel and the water level is greater than or equal to 22'3" above the top of the reactor pressure vessel flange.

ACTION:

a. With no RHR shutdown cooling mode loop OPERABLE, within one hour and at least once per 24 hours thereafter, demonstrate the operability of at least one alternate method of decay heat removal. Otherwise, suspend all operations involving an increase in the reactor decay heat load and establish SECONDARY CONTAINMENT INTEGRITY within 4 hours.

b. With no RHR shutdown cooling mode loop in operation, within one hour establish reactor coolant circulation by an alternate method and monitor reactor coolant temperature at least once per hour.

SURVEILLANCE REQUIREMENTS

4.9.11.1 At least one shutdown cooling mode loop of the residual heat removal system or alternate method shall be verified to be in operation and circulating reactor coolant at least once per 12 hours.

---

*The shutdown cooling pump may be removed from operation for up to 2 hours per 8-hour period.

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LIMITING CONDITION FOR OPERATION

3.9.11.2 Two shutdown cooling mode loops of the residual heat removal (RHR) system shall be OPERABLE and at least one loop shall be in operation,* with each loop consisting of at least:

a. One OPERABLE RHR pump, and

b. One OPERABLE RHR heat exchanger.

APPLICABILITY: OPERATIONAL CONDITION 5, when irradiated fuel is in the reactor vessel and the water level is less than 22'3" above the top of the reactor pressure vessel flange.

ACTION:

a. With less than the above required shutdown cooling mode loops of the RHR system OPERABLE, within one hour and at least once per 24 hours thereafter, demonstrate the operability of at least one alternative method capable of decay heat removal for each inoperable RHR shutdown cooling mode loop.

b. With no RHR shutdown cooling mode loop in operation, within one hour establish reactor coolant circulation by an alternative method and monitor reactor coolant temperature at least once per hour.

SURVEILLANCE REQUIREMENTS

4.9.11.2 At least one shutdown cooling mode loop of the residual heat removal system, or alternate method shall be verified to be in operation and circulating reactor coolant at least once per 12 hours.

*The shutdown cooling pump may be removed from operation for up to 2 hours per 8-hour period.

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3/4.10 SPECIAL TEST EXCEPTIONS

3/4.10.1 PRIMARY CONTAINMENT INTEGRITY

LIMITING CONDITION FOR OPERATION

3.10.1 The provisions of Specifications 3.6.1.1, 3.6.1.3 and 3.9.1 and Table 1.2 may be suspended to permit 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

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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 Specifications 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 on control rod groups by the RSCS are bypassed, verify:

a. Within 8 hours prior to bypassing any sequence constraint and at least once per 12 hours while any sequence constraint is bypassed:

   1. That the rod worth minimizer is OPERABLE per Specification 3.1.4.1,

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

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

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3/4.10.3 SHUTDOWN MARGIN DEMONSTRATIONS

LIMITING CONDITION FOR OPERATION

3.10.3 The provisions of Specification 3.9.1, Specification 3.9.3 and Table 1.2 may be suspended to permit the reactor mode switch to be in the Startup position and to allow more than one control rod to be withdrawn for shutdown margin demonstration, provided that at least the following requirements are satisfied.

a. The source range monitors are OPERABLE with the RPS circuitry "shorting links" removed per Specification 3.9.2.

b. The rod worth minimizer is OPERABLE per Specification 3.1.4.1 and is programmed for the shutdown margin demonstration, or conformance with the shutdown margin demonstration procedure is verified by a second licensed operator or other technically qualified member of the unit technical staff.

c. The continuous rod withdrawal control shall not be used during out-of-sequence movement of the control rods.

d. No other CORE ALTERATIONS are in progress.

APPLICABILITY: OPERATIONAL CONDITION 5, during shutdown margin demonstrations.

ACTION:

With the requirements of the above specification not satisfied, immediately place the reactor mode switch in the Shutdown or Refuel position.

SURVEILLANCE REQUIREMENTS

4.10.3 Within 30 minutes prior to and at least once per 12 hours during the performance of a shutdown margin demonstration, verify that;

a. The source range monitors are OPERABLE per Specification 3.9.2,

b. The rod worth minimizer is OPERABLE with the required program per Specification 3.1.4.1 or a second licensed operator or other technically qualified member of the unit technical staff is present and verifies compliance with the shutdown demonstration procedures, and

c. No other CORE ALTERATIONS are in progress.

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3/4.10.4 RECIRCULATION LOOPS

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LIMITING CONDITION FOR OPERATION

3.10.4 The requirements of Specifications 3.4.1.1 and 3.4.1.3 that recirculation loops be in operation with matched flow may be suspended for up to 24 hours for the performance of:

a. PHYSICS TESTS, provided that THERMAL POWER does not exceed 5% of RATED THERMAL POWER, or

b. The Startup Test Program.

APPLICABILITY: OPERATIONAL CONDITIONS 1 and 2, during PHYSICS TESTS and the Startup Test Program.

ACTION:

a. With the above specified time limit exceeded, insert all control rods.

b. With the above specified THERMAL POWER limit exceeded during PHYSICS TESTS, immediately place the reactor mode switch in the Shutdown position.

SURVEILLANCE REQUIREMENTS

4.10.4.1 The time during which the above specified requirement has been suspended shall be verified to be less than 24 hours at least once per hour during PHYSICS TESTS and the Startup Test Program.

4.10.4.2 THERMAL POWER shall be determined to be less than 5% of RATED THERMAL POWER at least once per hour during PHYSICS TESTS.

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SPECIAL TEST EXCEPTIONS

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3/4.10.6 TRAINING STARTUPS

LIMITING CONDITION FOR OPERATION

3.10.6 The provisions of Specification 3.5.1 may be suspended to permit one RHR subsystem to be aligned in the shutdown cooling mode during training startups provided that the reactor vessel is not pressurized, THERMAL POWER is less than or equal to 1% of RATED THERMAL POWER and reactor coolant temperature is less than 200°F.

APPLICABILITY: OPERATIONAL CONDITION 2, during training startups.

ACTION:

With the requirements of the above specification not satisfied, immediately place the reactor mode switch in the Shutdown position.

SURVEILLANCE REQUIREMENTS

4.10.6 The reactor vessel shall be verified to be unpressurized and the THERMAL POWER and reactor coolant temperature shall be verified to be within the limits at least once per hour during training startups.

The page a duplicate of page 3/4 10-6; This page should contain T.S 3/4.10.5, "Oxygen Concentration"

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3/4.10.6 TRAINING STARTUPS

LIMITING CONDITION FOR OPERATION

3.10.6 The provisions of Specification 3.5.1 may be suspended to permit one RHR subsystem to be aligned in the shutdown cooling mode during training startups provided that the reactor vessel is not pressurized, THERMAL POWER is less than or equal to 1% of RATED THERMAL POWER and reactor coolant temperature is less than 200°F.

APPLICABILITY: OPERATIONAL CONDITION 2, during training startups.

ACTION:

With the requirements of the above specification not satisfied, immediately place the reactor mode switch in the Shutdown position.

SURVEILLANCE REQUIREMENTS

4.10.6 The reactor vessel shall be verified to be unpressurized and the THERMAL POWER and reactor coolant temperature shall be verified to be within the limits at least once per hour during training startups.

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3/4.11.1 LIQUID EFFLUENTS

CONCENTRATION

LIMITING CONDITION FOR OPERATION

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

APPLICABILITY: At all times.

ACTION:

With the concentration of radioactive material released in liquid effluents to UNRESTRICTED AREAS exceeding the above limits, without delay restore the concentration to within the above limits.

SURVEILLANCE REQUIREMENTS

4.11.1.1.1 Radioactive liquid wastes shall be sampled and analyzed according to the sampling and analysis program of Table 4.11-1.

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

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TABLE 4.11-1

RADIOACTIVE LIQUID WASTE SAMPLING AND ANALYSIS PROGRAM

LIQUID RELEASE TYPE	SAMPLING FREQUENCY	MINIMUM ANALYSIS FREQUENCY	TYPE OF ACTIVITY ANALYSIS	LOWER LIMIT OF DETECTION (LLD)[1] (µCi/ml)
1. Batch Waste Release Tanks[2] a. 2LWS-TK5A b. 2LWS-TK5B	P Each Batch	P Each Batch	Principal Gamma Emitters[3]	5×10^{-7}
			I-131	1×10^{-6}
	P One Batch/M	One Batch/M	Dissolved and Entrained Gases (Gamma Emitters)	1×10^{-5}
	P Each Batch	M Composite[4]	H-3	1×10^{-5}
			Gross Alpha	1×10^{-7}
	P Each Batch	Q Composite[4]	Sr-89, Sr-90	5×10^{-8}
			Fe-55	1×10^{-6}
2. Continuous Releases a. Service Water Effluent A b. Service Water Effluent B c. Cooling Tower Blowdown	Grab Sample M[5]	Grab Sample M[5]	Principal Gamma Emitters[3]	5×10^{-7}
			I-131	1×10^{-6}
			Dissolved and Entrained Gases (Gamma Emitters)	1×10^{-5}
			H-3	1×10^{-5}
			Gross Alpha	1×10^{-7}
	Grab Sample Q[5]	Grab Sample Q[5]	Sr-89, Sr-90	5×10^{-8}
			Fe-55	1×10^{-6}

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TABLE NOTATIONS

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

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

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

Where:

LLD = the "a priori" lower limit of detection (microCurie per unit mass or volume),

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

E = the counting efficiency (counts per disintegration),

V = the sample size (units of mass or volume),

2.22×10^6 = the number of disintegrations per minute per microCurie,

Y = the fractional radiochemical yield, when applicable,

λ = the radioactive decay constant for the particular radionuclide (sec^{-1}), and

Δt = the elapsed time between the midpoint of sample collection and the time of counting (sec).

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

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

(2)A batch release is the discharge of liquid wastes of a discrete volume. Prior to sampling for analyses, each batch shall be isolated, and then thoroughly mixed by a method described in the ODCM to assure representative sampling.

TABLE 4.11-1 (Continued)

TABLE NOTATIONS (Continued)

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(3)The principal gamma emmiters for which the LLD specification applies include the following radionuclides: Mn-54, Fe-59, Co-58, Co-60, Zn-65, Mo-99, Cs-134, Cs-137 and Ce-141. Ce-144 shall also be measured, but with an LLD of 5 x 10^{-6}. This list does not mean that only these nuclides are to be considered. Other gamma peaks that are identifiable, together with those of the above nuclides, shall also be analyzed and reported in the Semiannual Radioactive Effluent Release Report pursuant to Specification 6.9.1.8 in the format outlined in Regulatory Guide 1.21, Appendix B, Revision 1, June 1974.

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

(5)If the alarm setpoint of the effluent monitor, as determined by the method presented in the ODCM, is exceeded, the frequency of sampling shall be increased to daily until the condition no longer exists. Frequency of analysis shall be increased to daily for principal gamma emitters and an incident composite for H-3, gross alpha, Sr-89, Sr-90, and Fe-55.

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LIMITING CONDITION FOR OPERATION

3.11.1.2 The dose or dose commitment to a MEMBER OF THE PUBLIC from radioactive materials in liquid effluents released, from each unit, to UNRESTRICTED AREAS (see Figure 5.1.3-1) shall be limited:

a. During any calendar quarter to less than or equal to 1.5 mrems to the whole body and to less than or equal to 5 mrems to any organ, and

b. During any calendar year to less than or equal to 3 mrems to the whole body and to less than or equal to 10 mrems to any organ.

APPLICABILITY: At all times.

ACTION:

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

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

SURVEILLANCE REQUIREMENTS

4.11.1.2 Cumulative dose contributions from liquid effluents for the current calendar quarter and the current calendar year shall be determined in accordance with the methodology and parameters in the ODCM at least once per 31 days.

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LIMITING CONDITION FOR OPERATION

3.11.1.3 The Liquid Radwaste Treatment System shall be OPERABLE and appropriate portions of the system shall be used to reduce releases of radioactivity when the projected doses due to the liquid effluent, from the unit, to UNRESTRICTED AREAS (see Figure 5.1.3-1) would exceed 0.06 mrem to the whole body or 0.2 mrem to any organ in a 31-day period.

APPLICABILITY: At all times.

ACTION:

a. With radioactive liquid waste being discharged without treatment and in excess of the above limits and any portion of the Liquid Radwaste Treatment System not in operation, prepare and submit to the Commission within 30 days, pursuant to Specification 6.9.2, a Special Report that includes the following information:

   1. Explanation of why liquid radwaste was being discharged without treatment, identification of any inoperable equipment or subsystems, and the reason for the inoperability,

   2. Action(s) taken to restore the inoperable equipment to OPERABLE status, and

   3. Summary description of action(s) taken to prevent a recurrence.

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

SURVEILLANCE REQUIREMENTS

4.11.1.3.1 Doses due to liquid releases from each unit to UNRESTRICTED AREAS shall be projected at least once per 31 days in accordance with the methodology and parameters in the ODCM when Liquid Radwaste Treatment Systems are not being fully utilized.

4.11.1.3.2 The installed Liquid Radwaste Treatment System shall be considered OPERABLE by meeting Specifications 3.11.1.1 and 3.11.1.2.

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LIQUID HOLDUP TANKS*

LIMITING CONDITION FOR OPERATION

3.11.1.4 The quantity of radioactive material contained in each unprotected outdoor tank shall be limited to less than or equal to 10 Curies, excluding tritium and dissolved or entrained noble gases:

APPLICABILITY: At all times.

ACTION:

a. With the quantity of radioactive material in any tank exceeding the above limit, immediately suspend all additions of radioactive material to the tank, within 48 hours reduce the tank contents to within the limit, and describe the events leading to this condition in the next Semiannual Radioactive Effluent Release Report, pursuant to Specification 6.9.1.8.

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

SURVEILLANCE REQUIREMENTS

4.11.1.4 The quantity of radioactive material contained in each tank shall be determined to be within the above limit by analyzing a representative sample of the tank's contents at least once per 7 days when radioactive materials are being added to the tank.

*Tanks included in this specification are those outdoor tanks that are not surrounded by liners, dikes, or walls capable of holding the tank contents and that do not have tank overflows and surrounding area drains connected to the Liquid Radwaste Treatment System, such as temporary tanks.

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3/4.11.2 GASEOUS EFFLUENTS

DOSE RATE

LIMITING CONDITION FOR OPERATION

3.11.2.1 The dose rate due to radioactive materials released in gaseous effluents from the site to areas at or beyond the SITE BOUNDARY (see Figure 5.1.1-1) shall be limited to the following:

a. For noble gases: Less than or equal to 500 mrems/yr to the whole body and less than or equal to 3000 mrems/yr to the skin, and

b. For Iodine-131, for Iodine-133, for tritium, and for all radionuclides in particulate form with half-lives greater than 8 days: Less than or equal to 1500 mrems/yr to any organ.

APPLICABILITY: At all times.

ACTION:

With the dose rate(s) exceeding the above limits, immediately restore the release rate to within the above limit(s).

SURVEILLANCE REQUIREMENTS

4.11.2.1.1 The dose rate due to noble gases in gaseous effluents shall be determined to be within the above limits in accordance with the methodology and parameters in the ODCM.

4.11.2.1.2 The dose rate due to Iodine-131, Iodine-133, tritium, and all radionuclides in particulate form with half-lives greater than 8 days in gaseous effluents shall be determined to be within the above limits in accordance with the methodology and parameters in the ODCM by obtaining representative samples and performing analyses in accordance with the sampling and analysis program specified in Table 4.11-2.

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TABLE 4.11-2

RADIOACTIVE GASEOUS WASTE SAMPLING AND ANALYSIS PROGRAM

GASEOUS RELEASE TYPE	SAMPLING FREQUENCY	MINIMUM ANALYSIS FREQUENCY	TYPE OF ACTIVITY ANALYSIS	LOWER LIMIT OF DETECTION (LLD)[1] (μCi/ml)
1. Containment[7]	Each PURGE	P	Principal Gamma Emitters[2]	1×10^{-4}
		Each PURGE	H-3 (oxide), Principal Gamma Emitters[2]	1×10^{-6}, 1×10^{-4}
2. Main Stack Radwaste/Reactor Building Vent	M[3]	M[3]	Principal Gamma Emitters[2]	1×10^{-4}
	Grab Sample M[4]	M[4]	H-3 (oxide)	1×10^{-6}
	Continuous[5]	W[6] Charcoal Sample	I-131	1×10^{-12}
	Continuous[5]	W[6] Particulate Sample	Principal Gamma Emitters[2]	1×10^{-11}
	Continuous[5]	M Composite Particulate Sample	Gross Alpha	1×10^{-11}
	Continuous[5]	Q Composite Particulate Sample	Sr-89, Sr-90	1×10^{-11}

TABLE 4.11-2 (Continued) PROOF & REVIEW COPY

TABLE NOTATIONS

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

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

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

Where:

LLD = the "a priori" lower limit of detection (microCurie per unit mass or volume),

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

E = the counting efficiency (counts per disintegration),

V = the sample size (units of mass or volume),

2.22×10^6 = the number of disintegrations per minute per microCurie,

Y = the fractional radiochemical yield, when applicable,

λ = the radioactive decay constant for the particular radionuclide (sec^{-1}), and

Δt = the elapsed time between the midpoint of sample collection and the time of counting (sec).

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

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

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TABLE 4.11-2 (Continued)

TABLE NOTATIONS (Continued)

(2) The principal gamma emitters for which the LLD specification applies include the following radionuclides: Kr-87, Kr-88, Xe-133, Xe-133m, Xe-135, and Xe-138 in noble gas releases and Mn-54, Fe-59, Co-58, Co-60, Zn-65, Mo-99, I-131, Cs-134, Cs-137, Ce-141 and Ce-144 in Iodine and particulate releases. This list does not mean that only these nuclides are to be considered. Other gamma peaks that are identifiable, together with those of the above nuclides, shall also be analyzed and reported in the Semiannual Radioactive Effluent Release Report pursuant to Specification 6.9.1.8 in the format outlined in Regulatory Guide 1.21, Appendix B, Revision 1, June 1974.

(3) If the Main Stack or Reactor/Radwaste building isotopic monitor is not OPERABLE, sampling and analysis shall also be performed following shutdown, startup, or when there is an alert alarm on the offgas pretreatment monitor.

(4) Tritium grab samples shall be taken weekly from the Reactor/Radwaste ventilation system when fuel is offloaded until stable tritium release levels can be demonstrated.

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

(6) When the release rate of the Main Stack or Reactor/Radwaste building vent exceeds its alert alarm setpoint, the iodine and particulate device shall be removed and analyzed to determine the changes in iodine and particulate release rates. The analysis shall be done daily until the release no longer exceeds the alarm setpoint. When samples collected for 24 hours are analyzed, the corresponding LLD's may be increased by a factor of 10.

(7) Sample and analysis prior to PURGE is used to determine permissable PURGE rates. Sample and analysis during actual PURGE is used for offsite dose calculations.

RADIOACTIVE EFFLUENTS

DOSE - NOBLE GASES

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LIMITING CONDITION FOR OPERATION

3.11.2.2 The air dose due to noble gases released in gaseous effluents, from each unit, to areas at or beyond the SITE BOUNDARY (see Figure 5.1.1-1) shall be limited to the following:

a. During any calendar quarter: Less than or equal to 5 mrads for gamma radiation and less than or equal to 10 mrads for beta radiation, and

b. During any calendar year: Less than or equal to 10 mrads for gamma radiation and less than or equal to 20 mrads for beta radiation.

APPLICABILITY: At all times.

ACTION

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

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

SURVEILLANCE REQUIREMENTS

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

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DOSE - IODINE-131, IODINE-133, TRITIUM, AND RADIONUCLIDES IN PARTICULATE FORM

LIMITING CONDITION FOR OPERATION

3.11.2.3 The dose to a MEMBER OF THE PUBLIC from Iodine-131, Iodine-133, tritium, and all radionuclides in particulate form with half-lives greater than 8 days in gaseous effluents released, from each unit, to areas at or beyond the SITE BOUNDARY (see Figure 5.1.1-1) shall be limited to the following:

a. During any calendar quarter: Less than or equal to 7.5 mrems to any organ and,

b. During any calendar year: Less than or equal to 15 mrems to any organ.

APPLICABILITY: At all times.

ACTION:

a. With the calculated dose from the release of Iodine-131, Iodine-133, tritium, and radionuclides in particulate form with half-lives greater than 8 days, in gaseous effluents exceeding any of the above limits, prepare and submit to the Commission within 30 days, pursuant to Specification 6.9.2, a Special Report that identifies the cause(s) for exceeding the limit(s) and defines the corrective actions that have been taken to reduce the releases and the proposed corrective actions to be taken to assure that subsequent releases will be in compliance with the above limits.

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

SURVEILLANCE REQUIREMENTS

4.11.2.3 Cumulative dose contributions for the current calendar quarter and current calendar year for Iodine-131, Iodine-133, tritium and radionuclides in particulate form with half-lives greater than 8 days shall be determined in accordance with the methodology and parameters in the ODCM at least once per 31 days.

RADIOACTIVE EFFLUENTS

GASEOUS RADWASTE TREATMENT SYSTEM

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LIMITING CONDITION FOR OPERATION

3.11.2.4 The GASEOUS RADWASTE TREATMENT SYSTEM shall be in operation.

APPLICABILITY: Whenever the main condenser air ejector system is in operation.

ACTION:

a. With gaseous radwaste from the main condenser air ejector system being discharged without treatment for more than 7 days, prepare and submit to the Commission within 30 days, pursuant to Specification 6.9.2, a Special Report that includes the following information.

   1. Identification of the inoperable equipment or subsystems and the reason for the inoperability,

   2. Action(s) taken to restore the inoperable equipment to OPERABLE status, and

   3. Summary description of action(s) taken to prevent a recurrence.

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

SURVEILLANCE REQUIREMENTS

4.11.2.4 The readings of the relevant instruments shall be checked every 12 hours when the main condenser air ejector is in use to ensure that the gaseous radwaste treatment system is functioning.

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RADIOACTIVE EFFLUENTS

VENTILATION EXHAUST TREATMENT SYSTEM

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LIMITING CONDITION FOR OPERATION

3.11.2.5 The VENTILATION EXHAUST TREATMENT SYSTEM shall be OPERABLE and appropriate portions of this system shall be used to reduce releases of radioactivity when the projected doses in 31 days due to iodine and particulate releases, from each unit, to areas at or beyond the SITE BOUNDARY (see Figure 5.1.1-1) would exceed 0.3 mrem to any organ of a MEMBER OF THE PUBLIC.

APPLICABILITY: At all times.

ACTION:

a. With radioactive gaseous waste being discharged without treatment and in excess of the above limits, prepare and submit to the Commission within 30 days, pursuant to Specification 6.9.2, a Special Report that includes the following information:

   1. Identification of any inoperable equipment or subsystems, and the reason for the inoperability,

   2. Action(s) taken to restore the inoperable equipment to OPERABLE status, and

   3. Summary description of action(s) taken to prevent a recurrence.

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

SURVEILLANCE REQUIREMENTS

4.11.2.5.1 Doses due to iodine and particulate releases from each unit to areas at or beyond the SITE BOUNDARY shall be projected at least once per 31 days in accordance with the methodology and parameters in the ODCM when the VENTILATION EXHAUST TREATMENT SYSTEM is not being fully utilized.

4.11.2.5.2 The installed VENTILATION EXHAUST TREATMENT SYSTEM shall be considered OPERABLE by meeting Specifications 3.11.2.1 or 3.11.2.3.

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LIMITNG CONDITION FOR OPERATION

3.11.2.6 The concentration of hydrogen in the main condenser offgas treatment system shall be limited to less than or equal to 4% by volume.

APPLICABILITY: At all times.

ACTION:

a. With the concentration of hydrogen in the main condenser offgas treatment system exceeding the limit, restore the concentration to within the limit within 48 hours.

b. With continuous monitors inoperable, utilize grab sampling procedures for a period not to exceed 30 days.

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

SURVEILLANCE REQUIREMENTS

4.11.2.6 The concentration of hydrogen in the main condenser offgas treatment system shall be determined to be within the above limits by continuously monitoring the waste gases in the main condenser offgas treatment system whenever the main condenser evacuation sytem is in operation with the hydrogen monitors required OPERABLE by Table 3.3.7.11-1 of Specification 3.3.7.11.

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RADIOACTIVE EFFLUENTS

MAIN CONDENSER - OFFGAS

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LIMITING CONDITION FOR OPERATION

3.11.2.7 The radioactivity rate of noble gases measured downstream of the recombiner shall be limited to less than or equal to 350,000 microcuries/sec.

APPLICABILITY: At all times.

ACTION:

With the radioactive rate of noble gases downstream of the recombiner exceeding 350,000 microcuries/sec, restore the radioactivity rate to within its limit within 72 hours or be in at least HOT STANDBY within the next 12 hours.

SURVEILLANCE REQUIREMENTS

4.11.2.7.1 The radioactive rate of noble gases downstream of the recombiner shall be continuously monitored in accordance with Specification 3.3.7.11.

4.11.2.7.2 The radioactivity rate of noble gases downstream of the recombiner shall be determined to be within the limits of Specifications 3.11.2.7 at the following frequencies by performing an isotopic analysis of a representative sample of gases taken prior to holdup and discharge downstream of the recombiner:

a. At least once per 31 days.

b. Within 4 hours following an increase, as indicated by the Offgas Noble Gas Activity Monitor, of greater than 50%, after factoring out increases due to changes in THERMAL POWER level, in the nominal steady state fission gas release from the primary coolant.

RADIOACTIVE EFFLUENTS

VENTING OR PURGING

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LIMITING CONDITION FOR OPERATION

3.11.2.8 VENTING* or PURGING* of the drywell and/or suppression chamber shall be through the standby gas treatment system.

APPLICABILITY: ~~Whenever the drywell and/or suppression chamber is vented or purged.#~~ 1, 2 and 3

ACTION:

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

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

SURVEILLANCE REQUIREMENTS

4.11.2.8.1 The containment drywell and/or suppression chamber 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,~~ one standby gas treatment system train shall be in operation.

#Not applicable until initial criticality.

*Not applicable during pressure control when using the 2 inch inlet to standby gas treatment trains

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3/4.11.3 SOLID RADIOACTIVE WASTES

LIMITING CONDITION FOR OPERATION

3.11.3 Radioactive wastes shall be solidified or dewatered in accordance with the PROCESS CONTROL PROGRAM to meet shipping and transportation requirements during transit, and disposal site requirements when received at the disposal site.

APPLICABILITY: At all times.

ACTION:

a. With SOLIDIFICATION or dewatering not meeting disposal site and shipping and transportation requirements, suspend shipment of the inadequately processed wastes and correct the PROCESS CONTROL PROGRAM, the procedures, and/or the Solid Waste System as necessary to prevent recurrence.

b. With SOLIDIFICATION or dewatering not performed in accordance with the PROCESS CONTROL PROGRAM, test the improperly processed waste in each container to ensure that it meets burial ground and shipping requirements and take appropriate administrative action to prevent recurrence.

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

SURVEILLANCE REQUIREMENTS

4.11.3 SOLIDIFICATION of at least one representative test specimen from at least every tenth batch of each type of wet radioactive wastes (e.g., filter sludges, spent resins, evaporator bottoms, and sodium sulfate solutions) shall be verified in accordance with the PROCESS CONTROL PROGRAM:

a. If any test specimen fails to verify SOLIDIFICATION, the SOLIDIFICATION of the batch under test shall be suspended until such time as additional test specimens can be obtained, alternative SOLIDIFICATION parameters can be determined in accordance with the PROCESS CONTROL PROGRAM, and a subsequent test verifies SOLIDIFICATION. SOLIDIFICATION of the batch may then be resumed using the alternative SOLIDIFICATION parameters determined by the PROCESS CONTROL PROGRAM;

b. If the initial test specimen from a batch of waste fails to verify SOLIDIFICATION, the PROCESS CONTROL PROGRAM shall provide for the collection and testing of representative test specimens from each consecutive batch of the same type of wet waste until at least three consecutive initial test specimens demonstrate SOLIDIFICATION. The PROCESS CONTROL PROGRAM shall be modified as required, as provided in Specification 6.13, to assure SOLIDIFICATION of subsequent batches of waste; and

c. With the installed equipment incapable of meeting Specification 3.11.3 or declared inoperable, restore the equipment to OPERABLE status or provide for contract capability to process wastes as necessary to satisfy all applicable transportation and disposal requirements.

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3/4.11.4 TOTAL DOSE

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LIMITING CONDITION FOR OPERATION

3.11.4 The annual (calendar year) dose or dose commitment to any MEMBER OF THE PUBLIC due to releases of radioactivity and to radiation from uranium fuel cycle sources shall be limited to less than or equal to 25 mrems to the whole body or any organ, except the thyroid, which shall be limited to less than or equal to 75 mrems.

APPLICABILITY: At all times.

ACTION:

a. With the calculated doses from the release of radioactive materials in liquid or gaseous effluents exceeding twice the limits of Specification 3.11.1.2a., 3.11.1.2b., 3.11.2.2a., 3.11.2.2b., 3.11.2.3a., or 3.11.2.3b., calculations shall be made including direct radiation contributions from the units (including outside storage tanks, etc.) to determine whether the above limits of Specification 3.11.4 have been exceeded. If such is the case, prepare and submit to the Commission within 30 days, pursuant to Specification 6.9.2, a Special Report that defines the corrective action to be taken to reduce subsequent releases to prevent recurrence of exceeding the above limits and includes the schedule for achieving conformance with the above limits. This Special Report, as defined in 10 CFR 20.405(c), shall include an analysis that estimates the radiation exposure (dose) to a MEMBER OF THE PUBLIC from uranium fuel cycle sources, including all effluent pathways and direct radiation, for the calendar year that includes the release(s) covered by this report. It shall also describe levels of radiation and concentrations of radioactive material involved, and the cause of the exposure levels or concentrations. If the estimated dose(s) exceeds the above limits, and if the release condition resulting in violation of 40 CFR Part 190 has not already been corrected, the Special Report shall include a request for a variance in accordance with the provisions of 40 CFR Part 190. Submittal of the report is considered a timely request, and a variance is granted until staff action on the request is complete.

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

SURVEILLANCE REQUIREMENTS

4.11.4.1 Cumulative dose contributions from liquid and gaseous effluents shall be determined in accordance with Specifications 4.11.1.2, 4.11.2.2, and 4.11.2.3, and in accordance with the methodology and parameters in the ODCM.

4.11.4.2 Cumulative dose contributions from direct radiation from the units (including outside storage tanks, etc.) shall be determined in accordance with the methodology and parameters in the ODCM. This requirement is applicable only under conditions set forth in ACTION a. of Specification 3.11.4.

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3/4.12.1 MONITORING PROGRAM

LIMITING CONDITION FOR OPERATION

3.12.1 The Radiological Environmental Monitoring Program shall be conducted as specified in Table 3.12-1.

APPLICABILITY: At all times.

ACTION:

a. With the Radiological Environmental Monitoring Program not being conducted as specified in Table 3.12-1, prepare and submit to the Commission, in the Annual Radiological Environmental Operating Report required by Specification 6.9.1.7, a description of the reasons for not conducting the program as required and the plans for preventing a recurrence.

b. With the level of radioactivity as the result of plant effluents in an environmental sampling medium at a specified location exceeding the reporting levels of Table 3.12-2 when averaged over any calendar quarter, prepare and submit to the Commission within 30 days, pursuant to Specification 6.9.2, a Special Report that identifies the cause(s) for exceeding the limit(s) and defines the corrective actions to be taken to reduce radioactive effluents so that the potential annual dose* to a MEMBER OF THE PUBLIC is less than the calendar year limits of Specifications 3.11.1.2, 3.11.2.2, or 3.11.2.3. When more than one of the radionuclides in Table 3.12-2 are detected in the sampling medium, this report shall be submitted if:

$$\frac{\text{concentration (1)}}{\text{reporting level (1)}} + \frac{\text{concentration (2)}}{\text{reporting level (2)}} + \ldots \geq 1.0$$

When radionuclides other than those in Table 3.12-2 are detected and are the result of plant effluents, this report shall be submitted if the potential annual dose* to a MEMBER OF THE PUBLIC from all radionuclides is equal to or greater than the calendar year limits of Specification 3.11.1.2, 3.11.2.2, or 3.11.2.3. This report is not required if the measured level of radioactivity was not the result of plant effluents; however, in such an event, the condition shall be reported and described in the Annual Radiological Environmental Operating Report required by Specification 6.9.1.7.

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*The methodology and parameters used to estimate the potential annual dose to a MEMBER OF THE PUBLIC shall be indicated in this report.

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LIMITING CONDITION FOR OPERATION

ACTION (Continued)

c. With milk or fresh leafy vegetable samples unavailable from one or more of the sample locations required by Table 3.12-1, identify specific locations for obtaining replacement samples and add them within 30 days to the Radiological Environmental Monitoring Program. The specific locations from which samples were unavailable may then be deleted from the monitoring program. Pursuant to Specification 6.9.1.8, submit in the next Semiannual Radioactive Effluent Release Report documentation for a change in the ODCM including a revised figure(s) and table for the ODCM reflecting the new location(s) with supporting information identifying the cause of the unavailability of samples and justifying the selection of the new location(s) for obtaining samples.

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

SURVEILLANCE REQUIREMENTS

4.12.1 The radiological environmental monitoring samples shall be collected pursuant to Table 3.12-1 from the specific locations given in the table and figure(s) in the ODCM, and shall be analyzed pursuant to the requirements of Table 3.12-1 and the detection capabilities required by Table 4.12-1.

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TABLE 3.12-1

RADIOLOGICAL ENVIRONMENTAL MONITORING PROGRAM*

EXPOSURE PATHWAY AND/OR SAMPLE	NUMBER OF SAMPLES AND SAMPLE LOCATIONS[1]	SAMPLING AND COLLECTION FREQUENCY	TYPE AND FREQUENCY OF ANALYSIS
1. Direct Radiation[2]	Thirty two routine monitoring stations either with two or more dosimeters or with one instrument for measuring and recording dose rate continuously, placed as follows: An inner ring of stations, one in each meteorological sector in the general area of the SITE BOUNDARY; An outer ring of stations, one in each land base meteorological sector in the 4 to 5 mile* range from the site; and The balance of the stations should be placed in special interest areas such as population centers, nearby residences, schools, and in one or two areas to serve as control stations.[7]	Once per three months.	Gamma dose once per three months.

*At this distance, 8 wind rose sectors are over Lake Ontario.

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TABLE 3.12-1 (Continued)

RADIOLOGICAL ENVIRONMENTAL MONITORING PROGRAM

EXPOSURE PATHWAY AND/OR SAMPLE	NUMBER OF SAMPLES AND SAMPLE LOCATIONS(1)	SAMPLING AND COLLECTION FREQUENCY	TYPE AND FREQUENCY OF ANALYSIS
2. Airborne			
Radioiodine and Particulates	Samples from five locations: Three samples from off-site locations in different sectors of the highest calculated annual site average ground-level D/Q (based on all site licensed reactors); One sample from the vicinity of an established year round community having the highest calculated annual site average ground-level D/Q (based on all site licensed reactors); and One sample from a control location, at least ten miles distant and in a least prevalent wind direction.(7)	Continuous sampler operation with sample collection weekly, or more frequently if required by dust loading.	Radioiodine Cannister: I-131 analysis weekly. Particulate Sampler: Gross beta radioactivity analysis following filter change;(3) and gamma isotopic analysis(4) of composite (by location) quarterly (as a minimum).
3. Waterborne			
a. Surface(5)	One sample upstream.(7) One sample from the site's downstream cooling water intake.	Composite sample over 1-month period.(6)	Gamma isotopic analysis(4) once per month. Composite for tritium analysis once per three months.

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TABLE 3.12-1 (Continued)

RADIOLOGICAL ENVIRONMENTAL MONITORING PROGRAM

EXPOSURE PATHWAY AND/OR SAMPLE	NUMBER OF SAMPLES AND SAMPLE LOCATIONS[1]	SAMPLING AND COLLECTION FREQUENCY	TYPE AND FREQUENCY OF ANALYSIS
3. Waterborne (Continued)			
b. Sediment from Shoreline	One sample from a downstream area with existing or potential recreational value.	Twice per year.	Gamma isotopic analysis[4]
4. Ingestion			
a. Milk	Samples from MILK SAMPLING LOCATIONS in three locations within 3.5 miles distance having the highest calculated site average D/Q (based on all licensed site reactors). If there are none, then one sample from MILK SAMPLING LOCATIONS in each of three areas 3.5-5.0 miles distant having the highest calculated site average D/Q (based on all licensed site reactors). One sample from a MILK SAMPLING LOCATION at a control location (9-20 miles distant and in a least prevelant wind direction.[7]	Twice per month, April-December, (samples will be collected January-March if I-131 is detected in November and December of the preceding year).	Gamma isotopic[4] and I-131 analysis twice per month when animals are on pasture (April-December) once per month at other times (January-March if required.)
b. Fish	Two samples of a commercially or recreationally important species in the vicinity of a plant discharge area.(8) One sample of the same species or of a species with similar feeding habits from an area at least 5 miles distant from the site.[7]	Twice per year.	Gamma isotopic analysis[4] on edible portions twice per year.

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TABLE 3.12-1 (Continued)

RADIOLOGICAL ENVIRONMENTAL MONITORING PROGRAM

EXPOSURE PATHWAY AND/OR SAMPLE	NUMBER OF SAMPLES AND SAMPLE LOCATIONS[1]	SAMPLING AND COLLECTION FREQUENCY	TYPE AND FREQUENCY OF ANALYSIS
4. Ingestion (Continued)			
c. Food Products	Six samples total (utilizing at least two sectors) of fruits and/or vegetables will be collected from available off-site locations of highest calculated site average D/Q (based on all licensed site reactors).	Once per year during the harvest season.	Gamma isotopic[4] analysis of edible portions (isotopic to include I-131) once during the harvest season.
	One sample of each of similar vegetation grown in a least prevalent wind direction.[7]	Once per year during the harvest season.	Gamma isotopic[4] analysis of edible porrtions (isotopic to include I-131) once during the harvest season.

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TABLE 3.12-1 (Continued)

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TABLE NOTATIONS

(1) Specific parameters of distance and direction sector from the centerline of one reactor, and additional description where pertinent, shall be provided for each and every sample location in Table 3.12-1 in a table and figure(s) in the ODCM. Refer to NUREG-0133, "Preparation of Radiological Effluent Technical Specifications for Nuclear Power Plants," October 1978, and to Radiological Assessment Branch Technical Position, Revision 1, November 1979. Deviations are permitted from the required sampling schedule if specimens are unobtainable due to circumstances such as hazardous conditions, seasonal unavailability, theft, uncooperative residents or malfunction of automatic sampling equipment. If specimens are unobtainable due to sampling equipment malfunction, effort shall be made to complete corrective action prior to the end of the next sampling period. All deviations from the sampling schedule shall be documented in the Annual Radiological Environmental Operating Report pursuant to Specification 6.9.1.7. It is recognized that, at times, it may not be possible or practicable to continue to obtain samples of the media of choice at the most desired location or time. In these instances suitable alternative media and locations may be chosen for the particular pathway in question and appropriate substitutions made. Pursuant to Specification 6.9.1.8, submit in next Semiannual Radioactive Effluent Release Report a revised figure(s) and table for the ODCM reflecting the new location(s).

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

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

previous

TABLE 3.12-1 (Continued)

TABLE NOTATIONS (Continued)

(4) Gamma isotopic analysis means the identification and quantification of gamma-emitting radionuclides that may be attributable to the effluents from the facility.

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

(6) In this program composite sample aliquots shall be collected at time intervals that are very short (e.g., hourly) relative to the compositing period (e.g., monthly) in order to assure obtaining a representative sample.

(7) The purpose of these samples is to obtain background information. If it is not practical to establish control locations in accordance with the distance and wind direction criteria, other sites, such as historical control locations which provide valid background data may be substituted.

(8) In the event commercial or recreational important species are not available as a result of three attempts, then other species may be utilized as available.

TABLE 3.12-2

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	30,000*				
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-95, Nb-95	400				
I-131	20	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			300	

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TABLE 4.12-1

DETECTION CAPABILITIES FOR ENVIRONMENTAL SAMPLE ANALYSIS[1]

LOWER LIMIT OF DETECTION (LLD)[2]

ANALYSIS	WATER (pCi/l)	AIRBORNE PARTICULATE OR GASES (pCi/m^3)	FISH (pCi/kg, wet)	MILK (pCi/l)	FOOD PRODUCTS (pCi/kg, wet)	SEDIMENT (pCi/kg, dry)
Gross Beta	4	0.01				
H-3	3000					
Mn-54	15		130			
Fe-59	30		260			
Co-58,60	15		130			
Zn-65	30		260			
Zr-95, Nb-95	15					
I-131	15	0.07		1	60	
Cs-134	15	0.05	130	15	60	150
Cs-137	18	0.06	150	18	80	180
Ba/La-140	15			15		

TABLE 4.12-1 (Continued)

TABLE NOTATIONS

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(1)This list does not mean that only these nuclides are to be considered. Other peaks that are identifiable, together with those of the above nuclides, shall also be analyzed and reported in the Annual Radiological Environmental Operating Report pursuant to Specification 6.9.1.7.

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

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

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

Where:

LLD = the "a priori" lower limit of detection (picoCuries per unit mass or volume),

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

E = the counting efficiency (counts per disintegration),

V = the sample size (units of mass or volume),

2.22 = the number of disintegrations per minute per picoCurie,

Y = the fractional radiochemical yield, when applicable,

λ = the radioactive decay constant for the particular radionuclide (sec^{-1}), and

Δt = the elapsed time between environmental collection, or end of the sample collection period, and time of counting (sec).

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

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TABLE 4.12-1 (Continued)

TABLE NOTATIONS (Continued)

It should be recognized that the LLD is defined as an a priori (before the fact) limit representing the capability of a measurement system and not as an a posteriori (after the fact) limit for a particular measurement. Analyses shall be performed in such a manner that the stated LLDs will be achieved under routine conditions. Occasionally background fluctuations, unavoidable small sample sizes, the presence of interfering nuclides, or other uncontrollable circumstances may render these LLDs unachievable. In such cases, the contributing factors shall be identified and described in the Annual Radiological Environmental Operating Report pursuant to Specification 6.9.1.7.

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3/4.12.2 LAND USE CENSUS

LIMITING CONDITION FOR OPERATION

3.12.2 A Land Use Census shall be conducted and shall identify within a distance of 5 miles the location in each of the 16 meteorological sectors of the nearest milk animal, and the nearest residence. In lieu of a garden census, specifications for vegetation sampling in Table 3.12-1 shall be followed, including analysis of appropriate controls.

APPLICABILITY: At all times.

ACTION:

a. With a Land Use Census identifying a location(s) that yields a D/Q value greater than the values currently being calculated in Specification 4.11.2.3, pursuant to Specification 6.9.1.8, identify the new location(s) in the next Semiannual Radioactive Effluent Release Report.

b. With a Land Use Census identifying a milk animal location(s) that yields a D/Q (via the same exposure pathway) 50% greater than at a location from which samples are currently being obtained in accordance with Specification 3.12.1, add the new location(s) within 30 days to the Radiological Environmental Monitoring Program. The sampling location(s), excluding the control station location, having the lowest D/Q value, via the same exposure pathway, may be deleted from this monitoring program after October 31 of the year in which this Land Use Census was conducted. Pursuant to Specification 6.9.1.8, submit in the next Semiannual Radioactive Effluent Release Report documentation for a change in the ODCM including a revised figure(s) and table(s) for the ODCM reflecting the new location(s).

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

SURVEILLANCE REQUIREMENTS

4.12.2 The Land Use Census shall be conducted during the growing season at least once per 12 months using that information that will provide the best results, such as by a door-to-door survey, aerial survey, or by consulting local agriculture authorities. The results of the Land Use Census shall be included in the Annual Radiological Environmental Operating Report pursuant to Specification 6.9.1.7.

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3/4.12.3 INTERLABORATORY COMPARISON PROGRAM

LIMITING CONDITION FOR OPERATION

3.12.3 Analyses shall be performed on all radioactive materials, supplied as part of an Interlaboratory Comparison Program that has been approved by the Commission, that correspond to samples required by Table 3.12-1. Participation in this program shall include media for which environmental samples are routinely collected and for which inter-comparison samples are available.

APPLICABILITY: At all times.

ACTION:

a. With analyses not being performed as required above, report the corrective actions taken to prevent a recurrence to the Commission in the Annual Radiological Environmental Operating Report pursuant to Specification 6.9.1.7.

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

SURVEILLANCE REQUIREMENTS

4.12.3 The Interlaboratory Comparison Program shall be described in the ODCM. A summary of the results obtained as part of the above required Interlaboratory Comparison Program shall be included in the Annual Radiological Environmental Operating Report pursuant to Specification 6.9.1.7. Participants in the EPA Cross Check Program may provide the EPA program code designation in lieu of providing results.

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BASES FOR

SECTIONS 3.0 AND 4.0

LIMITING CONDITIONS FOR OPERATION

AND

SURVEILLANCE REQUIREMENTS

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NOTE

The BASES contained in succeeding pages summarize the reasons for the Specifications in Section 3.0 and 4.0, but in accordance with 10 CFR 50.36 are not part of these Technical Specifications.

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BASES

The specifications of this section provide the general requirements applicable to each of the Limiting Conditions for Operation and Surveillance Requirements within Section 3/4.

3.0.1 This specification states the applicability of each specification in terms of defined OPERATIONAL CONDITION or other specified applicability condition and is provided to delineate specifically when each specification is applicable.

3.0.2 This specification defines those conditions necessary to constitute compliance with the terms of an individual Limiting Condition for Operation and associated ACTION requirement.

3.0.3 This specification delineates the measures to be taken for those circumstances not directly provided for in the ACTION statements and whose occurrence would violate the intent of the specification. For example, Specification 3.7.2 requires two control room emergency filtration subsystems to be OPERABLE and provides explicit ACTION requirements if one subsystem is inoperable. Under the requirements of Specification 3.0.3, if both of the required subsystems are inoperable, within one hour measures must be initiated to place the unit in at least STARTUP within the next 6 hours, in at least HOT SHUTDOWN within the following 6 hours and in COLD SHUTDOWN within the subsequent 24 hours. As a further example, Specification 3.6.6.1 requires two primary containment hydrogen recombiner systems to be OPERABLE and provides explicit ACTION requirements if one recombiner system is inoperable. Under the requirements of Specification 3.0.3, if both of the required systems are inoperable, within one hour measures must be initiated to place the unit in at least STARTUP within the next 6 hours and in at least HOT SHUTDOWN within the following 6 hours.

3.0.4 This specification provides that entry into an OPERATIONAL CONDITION must be made with (a) the full complement of required systems, equipment or components OPERABLE and (b) all other parameters as specified in the Limiting Conditions for Operation being met without regard for allowable deviations and out of service provisions contained in the ACTION statements.

The intent of this provision is to ensure that unit operation is not initiated with either required equipment or systems inoperable or other limits being exceeded.

Exceptions to this provision have been provided for a limited number of specifications when startup with inoperable equipment would not affect plant safety. These exceptions are stated in the ACTION statements of the appropriate specifications.

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4.0.1 This specification provides that surveillance activities necessary to ensure the Limiting Conditions for Operation are met and will be performed during the OPERATIONAL CONDITIONS or other conditions for which the Limiting Conditions for Operation are applicable. Provisions for additional surveillance activities to be performed without regard to the applicable OPERATIONAL CONDITIONS or other conditions are provided in the individual Surveillance Requirements. Surveillance Requirements for Special Test Exceptions need only be performed when the Special Test Exception is being utilized as an exception to an individual specification.

4.0.2 The provisions of this specification provide allowable tolerances for performing surveillance activities beyond those specified in the nominal surveillance interval. These tolerances are necessary to provide operational flexibility because of scheduling and performance considerations. The phrase "at least" associated with a surveillance frequency does not negate this allowable tolerance; instead, it permits the more frequent performance of surveillance activities.

The tolerance values, taken either individually or consecutively over 3 test intervals, are sufficiently restrictive to ensure that the reliability associated with the surveillance activity is not significantly degraded beyond that obtained from the nominal specified interval.

4.0.3 The provisions of this specification set forth the criteria for determination of compliance with the OPERABILITY requirements of the Limiting Conditions for Operation. Under this criteria, equipment, systems or components are assumed to be OPERABLE if the associated surveillance activities have been satisfactorily performed within the specified time interval. Nothing in this provision is to be construed as defining equipment, systems or components OPERABLE, when such items are found or known to be inoperable although still meeting the Surveillance Requirements.

4.0.4 This specification ensures that surveillance activities associated with a Limiting Conditions for Operation have been performed within the specified time interval prior to entry into an applicable OPERATIONAL CONDITION or other specified applicability condition. The intent of this provision is to ensure that surveillance activities have been satisfactorily demonstrated on a current basis as required to meet the OPERABILITY requirements of the Limiting Condition for Operation.

Under the terms of this specification, for example, during initial plant startup or following extended plant outage, the applicable surveillance activities must be performed within the stated surveillance interval prior to placing or returning the system or equipment into OPERABLE status.

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4.0.5 This specification ensures that inservice inspection of ASME Code Class 1, 2 and 3 components and inservice testing of ASME Code Class 1, 2 and 3 pumps and valves will be performed in accordance with a periodically updated version of Section XI of the ASME Boiler and Pressure Vessel Code and Addenda as required by 10 CFR 50, Section 50.55a. Relief from any of the above requirements has been provided in writing by the Commission and is not a part of these Technical Specifications.

This specification includes a clarification of the frequencies of performing the inservice inspection and testing activities required by Section XI of the ASME Boiler and Pressure Vessel Code and applicable Addenda. This clarification is provided to ensure consistency in surveillance intervals throughout these Technical Specifications and to remove any ambiguities relative to the frequencies for performing the required inservice inspection and testing activities.

Under the terms of this specification, the more restrictive requirements of the Technical Specifications take precedence over the ASME Boiler and Pressure Vessel Code and applicable Addenda. For example, the requirements of Specification 4.0.4 to perform surveillance activities prior to entry into an OPERATIONAL CONDITION or other specified applicability condition takes precedence over the ASME Boiler and Pressure Vessel Code provision which allows pumps to be tested up to one week after return to normal operation. And for example, the Technical Specification definition of OPERABLE does not grant a grace period before a device that is not capable of performing its specified function is declared inoperable and takes precedence over the ASME Boiler and Pressure Vessel provision which allows a valve to be incapable of performing its specified function for up to 24 hours before being declared inoperable.

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3/4.1.1 SHUTDOWN MARGIN

A sufficient SHUTDOWN MARGIN ensures that 1) the reactor can be made subcritical from all operating conditions, 2) the reactivity transients associated with postulated accident conditions are controllable within acceptable limits, and 3) the reactor will be maintained sufficiently subcritical to preclude inadvertent criticality in the shutdown condition.

Since core reactivity values will vary through core life as a function of fuel depletion and poison burnup, the demonstration of SHUTDOWN MARGIN will be performed in the cold, xenon-free condition and shall show the core to be subcritical by at least R + 0.38% delta k/k or R + 0.28% delta k/k, as appropriate. The value of R in units of % delta k/k is the difference between the calculated value of maximum core reactivity during the operating cycle and the calculated beginning-of-life core reactivity. The value of R must be positive or zero and must be determined for each fuel loading cycle.

Two different values are supplied in the Limiting Condition for Operation to provide for the different methods of demonstration of the SHUTDOWN MARGIN. The highest worth rod may be determined analytically or by test. The SHUTDOWN MARGIN is demonstrated by an insequence control rod withdrawal at the beginning of life fuel cycle conditions, and, if necessary, at any future time in the cycle if the first demonstration indicates that the required margin could be reduced as a function of exposure. Observation of subcriticality in this condition assures subcriticality with the most reactive control rod fully withdrawn.

This reactivity characteristic has been a basic assumption in the analysis of plant performance and can be best demonstrated at the time of fuel loading, but the margin must also be determined anytime a control rod is incapable of insertion.

3/4.1.2 REACTIVITY ANOMALIES

Since the SHUTDOWN MARGIN requirement for the reactor is small, a careful check on actual conditions to the predicted conditions is necessary, and the changes in reactivity can be inferred from these comparisons of rod patterns. Since the comparisons are easily done, frequent checks are not an imposition on normal operations. A 1% delta k/k change is larger than is expected for normal operation so a change of this magnitude should be thoroughly evaluated. A change as large as 1% delta k/k would not exceed the design conditions of the reactor and is on the safe side of the postulated transients.

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3/4.1.3 CONTROL RODS

The specification of this section ensure that (1) the minimum SHUTDOWN MARGIN is maintained, (2) the control rod insertion times are consistent with those used in the safety analyses, and (3) limit the potential effects of the rod drop accident. The ACTION statements permit variations from the basic requirements but at the same time impose more restrictive criteria for continued operation. A limitation on inoperable rods is set such that the resultant effect on total rod worth and scram shape will be kept to a minimum. The requirements for the various scram time measurements ensure that any indication of systematic problems with rod drives will be investigated on a timely basis.

Damage within the control rod drive mechanism could be a generic problem; therefore with a control rod immovable because of excessive friction or mechanical interference, operation of the reactor is limited to a time period which is reasonable to determine the cause of the inoperability and at the same time prevent operation with a large number of inoperable control rods.

Control rods that are inoperable for other reasons are permitted to be taken out of service provided that those in the nonfully-inserted position are consistent with the SHUTDOWN MARGIN requirements.

The number of control rods permitted to be inoperable could be more than the eight allowed by the specification, but the occurrence of eight inoperable rods could be indicative of a generic problem and the reactor must be shutdown for investigation and resolution of the problem.

The control rod system is designed to bring the reactor subcritical at a rate fast enough to prevent the MCPR from becoming less than 1.06 during the limiting power transient analyzed in Section 15.4 of the FSAR. This analysis shows that the negative reactivity rates resulting from the scram with the average response of all the drives as given in the specifications, provide the required protection and MCPR remains greater than 1.06. The occurrence of scram times longer then those specified should be viewed as an indication of a systemic problem with the rod drives and therefore the surveillance interval is reduced in order to prevent operation of the reactor for long periods of time with a potentially serious problem.

The scram discharge volume is required to be OPERABLE so that it will be available when needed to accept discharge water from the control rods during a reactor scram and will isolate the reactor coolant system from the containment when required.

Control rods with inoperable accumulators are declared inoperable and Specification 3.1.3.1 then applies. This prevents a pattern of inoperable accumulators that would result in less reactivity insertion on a scram than has been analyzed even though control rods with inoperable accumulators may still be inserted with normal drive water pressure. Operability of the accumulator ensures that there is a means available to insert the control rods even under the most unfavorable depressurization of the reactor.

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CONTROL RODS (Continued)

Control rod coupling integrity is required to ensure compliance with the analysis of the rod drop accident in the FSAR. The overtravel position feature provides the only positive means of determining that a rod is properly coupled and therefore this check must be performed prior to achieving criticality after completing CORE ALTERATIONS that could have affected the control rod coupling integrity. The subsequent check is performed as a backup to the initial demonstration.

In order to ensure that the control rod patterns can be followed and therefore that other parameters are within their limits, the control rod position indication system must be OPERABLE.

The control rod housing support restricts the outward movement of a control rod to less than 6 inches in the event of a housing failure. The amount of rod reactivity which could be added by this small amount of rod withdrawal is less than a normal withdrawal increment and will not contribute to any damage to the primary coolant system. The support is not required when there is no pressure to act as a driving force to rapidly eject a drive housing.

The required surveillance intervals are adequate to determine that the rods are OPERABLE and not so frequent as to cause excessive wear on the system components.

3/4.1.4 CONTROL ROD PROGRAM CONTROLS

Control rod withdrawal and insertion sequences are established to assure that the maximum insequence individual control rod or control rod segments which are withdrawn at any time during the fuel cycle could not be worth enough to result in a peak fuel enthalpy greater than 280 cal/gm in the event of a control rod drop accident. The specified sequences are characterized by homogeneous, scattered patterns of control rod withdrawal. When THERMAL POWER is greater than 20% of RATED THERMAL POWER, there is no possible rod worth which, if dropped at the design rate of the velocity limiter, could result in a peak enthalpy of 280 cal/gm. Thus requiring the RSCS and RWM to be OPERABLE when THERMAL POWER is less than or equal to 20% of RATED THERMAL POWER provides adequate control.

The RSCS and RWM provide automatic supervision to assure that out-of-sequence rods will not be withdrawn or inserted.

The analysis of the rod drop accident is presented in Section 15.4 of the FSAR and the techniques of the analysis are presented in a topical report, Reference 1, and two supplements, References 2 and 3.

The RBM is designed to automatically prevent fuel damage in the event of erroneous rod withdrawal from locations of high power density during high power operation. Two channels are provided. Tripping one of the channels will block erroneous rod withdrawal soon enough to prevent fuel damage. This system backs up the written sequence used by the operator for withdrawal of control rods.

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3/4.1.5 STANDBY LIQUID CONTROL SYSTEM

The standby liquid control system provides a backup capability for bringing the reactor from full power to a cold, Xenon-free shutdown, assuming that the withdrawn control rods remain fixed in the rated power pattern. To meet this objective it is necessary to inject a quantity of boron which produces a concentration of 660 ppm in the reactor core and other piping systems connected to the reactor vessel. To allow for potential leakage and imperfect mixing, this concentration is increased by 20%. The required concentration is achieved by having a minimum available quantity of 4625 gallons of sodium-pentaborate solution containing a minimum of 5493 lbs of sodium-pentaborate. This quantity of solution is a net amount which is above the pump suction, thus allowing for the portion which cannot be injected. The minimum pumping rate of 41.2 gpm per pump provides a negative reactivity insertion rate over the permissible penetaborate solution volume range, which adequately compensates for the positive reactivity effects due to temperature and Xenon during shutdown. The temperature requirement~~s~~ is necessary to ensure that the sodium pentaborate remains in solution.

With redundant pumps and explosive injection valves and with a highly reliable control rod scram system, operation of the reactor is permitted to continue for short periods of time with the system inoperable or for longer periods of time with one of the redundant components inoperable.

Surveillance requirements are established on a frequency that assures a high reliability of the system. Once the solution is established, boron concentration will not vary unless more boron or water is added, thus a check on the temperature and volume once each 24 hours assures that the solution is available for use.

Replacement of the explosive charges in the valves at regular intervals will assure that these valves will not fail because of deterioration of the charges.

1. C. J. Paone, R. C. Stirn and J. A. Woolley, "Rod Drop Accident Analysis for Large BWR's," G. E. Topical Report NEDO-10527, March 1972
2. C. J. Paone, R. C. Stirn and R. M. Young, Supplement 1 to NEDO-10527, July 1972
3. J. M. Haun, C. J. Paone and R. C. Stirn, Addendum 2, "Exposed Cores," Supplement 2 to NEDO-10527, January 1973

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BASES

The specifications of this section assure that the peak cladding temperature following the postulated design basis loss-of-coolant accident will not exceed the 2200°F limit specified in 10 CFR 50.46.

3/4.2.1 AVERAGE PLANAR LINEAR HEAT GENERATION RATE

The peak cladding temperature (PCT) following a postulated loss-of-coolant accident is primarily a function of the average heat generation rate of all the rods of a fuel assembly at any axial location and is dependent only secondarily on the rod to rod power distribution within an assembly. The peak clad temperature is calculated assuming a LHGR for the highest powered rod which is equal to or less than the design LHGR corrected for densification. This LHGR times ~~(1.02)~~ is used in the heatup code along with the exposure dependent steady state gap conductance and rod-to-rod local peaking factor. The Technical Specification AVERAGE PLANAR LINEAR HEAT GENERATION RATE (APLHGR) is the LHGR of the highest powered rod divided by its local peaking factor. The limiting value for APLHGR is ~~is~~ shown in Figures 3.2.1-1, 3.2.1-2 and 3.2.1-3, for two recirculation loop operation.

The calculational procedure used to establish the APLHGR shown on Figures ~~3.2.1-1,~~ 3.2.1-2 and 3.2.1-3 is based on a loss-of-coolant accident analysis. The analysis was performed using General Electric (GE) calculational models which are consistent with the requirements of Appendix K to 10 CFR 50. A complete discussion of each code employed in the analysis is presented in Reference 1. Differences in this analysis compared to previous analyses can be broken down as follows.

a. Input Changes

1. Corrected Vaporization Calculation - Coefficients in the vaporization correlation used in the REFLOOD code were corrected.

2. Incorporated more accurate bypass areas - The bypass areas in the top guide were recalculated using a more accurate technique.

3. Corrected guide tube thermal resistance.

4. Correct heat capacity of reactor internals heat nodes.

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BASES

AVERAGE PLANAR LINEAR HEAT GENERATION RATE (Continued)

b. Model Change

1. Core CCFL pressure differential - 1 psi - Incorporate the assumption that flow from the bypass to lower plenum must overcome a 1 psi pressure drop in core.

2. Incoporate NRC pressure transfer assumption - The assumption used in the SAFE-REFLOOD pressure transfer when the pressure is increasing was changed.

A few of the changes affect the accident calculation irrespective of CCFL. These changes are listed below.

a. Input Change

1. Break Areas - The DBA break area was calculated more accurately.

b. Model Change

1. Improved Radiation and Conduction Calculation - Incorporation of CHASTE 05 for heatup calculation.

A list of the significant plant input parameters to the loss-of-coolant accident analysis is presented in Bases Table B 3.2.1-1.

3/4.2.2 APRM SETPOINTS

The fuel cladding integrity Safety Limits of Specification 2.1 were based on a power distribution which would yield the design LHGR at RATED THERMAL POWER. The flow biased simulated thermal power-upscale scram setting and flow biased neutron flux upscale control rod block functions of the APRM instruments must be adjusted to ensure that the MCPR does not become less than 1.06 or that $\geq$ 1% plastic strain does not occur in the degraded situation. The scram set point and rod block settings are adjusted in accordance with the formula in this specification when the combination of THERMAL POWER and CMFLPD indicates a higher peaked power distribution to ensure that an LHGR transient would not be increased in the degraded condition.

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Bases Table B 3.2.1-1

SIGNIFICANT INPUT PARAMETERS TO THE LOSS-OF-COOLANT ACCIDENT ANALYSIS

Plant Parameters;

Core THERMAL POWER	3461 MWt* which corresponds to 105% of rated steam flow
Vessel Steam Output	15.0 x 10^6 lbm/hr which corresponds to 105% of rated steam flow
Vessel Steam Dome Pressure..............	1055 psia

Design Basis Recirculation Line Break Area for:

a. Large Breaks 3.1 ft^2

b. Small Breaks 0.09 ft^2

Fuel Parameters:

FUEL TYPE	FUEL BUNDLE GEOMETRY	PEAK TECHNICAL SPECIFICATION LINEAR HEAT GENERATION RATE (kw/ft)	DESIGN AXIAL PEAKING FACTOR	INITIAL MINIMUM CRITICAL POWER RATIO
Initial Core	8 x 8	13.4	1.4	1.20

A more detailed listing of input of each model and its source is presented in Section II of Reference 1 and subsection 6.3.3 of the FSAR.

*This power level meets the Appendix K requirement of 102%. The core heatup calculation assumes a bundle power consistent with operation of the highest powered rod at 102% of its Technical Specification LINEAR HEAT GENERATION RATE limit.

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3/4.2.3 MINIMUM CRITICAL POWER RATIO

The required operating limit MCPRs at steady state operating conditions as specified in Specification 3.2.3 are derived from the established fuel cladding integrity Safety Limit MCPR of 1.06, and an analysis of abnormal operational transients. For any abnormal operating transient analysis evaluation with the initial condition of the reactor being at the steady state operating limit, it is required that the resulting MCPR does not decrease below the Safety Limit MCPR at any time during the transient assuming instrument trip setting given in Specification 2.2.

To assure that the fuel cladding integrity Safety Limit is not exceeded during any anticipated abnormal operational transient, the most limiting transients have been analyzed to determine which result in the largest reduction in CRITICAL POWER RATIO (CPR). The type of transients evaluated were loss of flow, increase in pressure and power, positive reactivity insertion, and coolant temperature decrease. The limiting transient yields the largest delta MCPR. When added to the Safety Limit MCPR of 1.06, the required minimum operating limit MCPR of Specification 3.2.3 is obtained and presented in Figure 3.2.3-1.

The evaluation of a given transient begins with the system initial parameters shown in FSAR Table 15.0.3 that are input to a GE-core dynamic behavior transient computer program. The code used to evaluate pressurization events is described in NEDO-24154[3] and the program used in non-pressurization events is described in NEDO-10802[2]. The outputs of this program along with the initial MCPR form the input for further analyses of the thermally limiting bundle with the single channel transient thermal hydraulic TASC code described in NEDE-25149[4]. The principal result of this evaluation is the reduction in MCPR caused by the transient.

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The purpose of the K_f factor of Figure 3.2.3-1 is to define operating limits at other than rated core flow conditions. At less than 100% of rated flow the required MCPR is the product of the MCPR and the K_f factor. The K_f factors assure that the Safety Limit MCPR will not be violated. The K_f factors were derived using THERMAL POWER and core flow corresponding to 105% of rated steam flow.

The K_f factors were calculated such that for the maximum core flow rate and the corresponding THERMAL POWER along the 105% of rated steam flow control line, the limiting bundle's relative power was adjusted until the MCPR was slightly above the Safety Limit. Using this relative bundle power, the MCPRs were calculated at different points along the 105% of rated steam flow control line corresponding to different core flows. The ratio of the MCPR calculated at a given point of core flow, divided by the operating limit MCPR, determines the K_f.

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MINIMUM CRITICAL POWER RATIO (Continued)

~~The K_f factors shown in Figure 3.2.3-1 are conservative for the General Electric plant operation because the operating limit MCPRs of Specification 3.2.3 are greater than the original 1.20 operating limit MCPR used for the generic derivation of K_f.~~

At THERMAL POWER levels less than or equal to 25% of RATED THERMAL POWER, the reactor will be operating at minimum recirculation pump speed and the moderator void content will be very small. For all designated control rod patterns which may be employed at this point, operating plant experience indicates that the resulting MCPR value is in excess of requirements by a considerable margin. During initial start-up testing of the plant, a MCPR evaluation will be made at 25% of RATED THERMAL POWER level with minimum recirculation pump speed. The MCPR margin will thus be demonstrated such that future MCPR evaluation below this power level will be shown to be unnecessary. The daily requirement for calculating MCPR when THERMAL POWER is greater than or equal to 25% of RATED THERMAL POWER is sufficient since power distribution shifts are very slow when there have not been significant power or control rod changes. The requirement for calculating MCPR within 12 hours after the completion of a THERMAL POWER increase of at least 15% of RATED THERMAL POWER ensures thermal limits are met after power distribution shifts while still allotting time for the power distribution to stabilize. The requirement for calculating MCPR after initially determining a LIMITING CONTROL ROD PATTERN exists ensures MCPR will be known following a change in THERMAL POWER or power shape, that could place operation exceeding a thermal unit.

3/4.2.4 LINEAR HEAT GENERATION RATE

This specification assures that the Linear Heat Generation Rate (LHGR) in any rod is less than the design linear heat generation even if fuel pellet densification is postulated. The daily requirement for calculating LHGR when THERMAL POWER is greater than or equal to 25% of RATED THERMAL POWER is sufficient since power distribution shifts are very slow when there have not been significant power or control rod changes. The requirement to calculate LHGR within 12 hours after the completion of a THERMAL POWER increase of at least 15% of RATED THERMAL POWER ensures thermal limits are met after power distribution shifts while still allotting time for the power distribution to stabilize. The requirement for calculating LHGR after initially determining a LIMITING CONTROL ROD PATTERN exists ensures that LHGR will be known following a change in THERMAL POWER or power shape that could place operation exceeding a thermal limit.

References:

1. General Electric Company Analytical Model for Loss-of-Coolant Analysis in Accordance with 10 CFR 50, Appendix K, NEDE-20566, November, 1975.

2. R. B. Linford, Analytical Methods of Plant Transient Evaluations for the GE BWR, NEDO-10802, February 1973.

3. Qualification of the One Dimensional Core Transient Model For Boiling Water Reactors, NEDO-24154, October 1978.

4. TASC 01-A Computer Program For The Transient Analysis of a Single Channel, Technical Description, NEDE-25149, January 1980.

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3/4.3.1 REACTOR PROTECTION SYSTEM INSTRUMENTATION

The reactor protection system automatically initiates a reactor scram to:

a. Preserve the integrity of the fuel cladding.

b. Preserve the integrity of the reactor coolant system.

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

d. Prevent inadvertent criticality.

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

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

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

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3/4.3.2 ISOLATION ACTUATION INSTRUMENTATION

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

Except for the MSIVs, the safety analysis does not address individual sensor response times or the response times of the logic systems to which the sensors are connected. For A.C. operated valves, it is assumed that the A.C. power supply is lost and is restored by startup of the emergency diesel generators. In this event, a time of 13 seconds is assumed before the valve starts to move. In addition to the pipe break, the failure of the D.C. operated valve is assumed; thus the signal delay (sensor response) is concurrent with the 13 second diesel startup. The safety analysis considers an allowable inventory loss in each case which in turn determines the valve speed in conjunction with the 13 second delay. It follows that checking the valve speeds and the 13 second time for emergency power establishment will establish the response time for the isolation functions. However, to enhance overall system reliability and to monitor instrument channel response time trends, the isolation actuation instrumentation response time shall be measured and recorded as part of the ISOLATION SYSTEM RESPONSE TIME.

Operation with a trip set less conservative than its Trip Setpoint but within its specified Allowable Value is acceptable on the basis that the difference between each Trip Setpoint and the Allowable Value is an allowance for instrument drift specifically allocated for each trip in the safety analysis. The Trip Setpoint and Allowable Value also contain additional margin for instrument accuracy and calibration capability.

3/4.3.3 EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION

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

Operation with a trip set less conservative than its Trip Setpoint but within its specified Allowable Value is acceptable on the basis that the difference between each Trip Setpoint and the Allowable Value is an allowance for instrument drift specifically allocated for each trip in the safety analysis. The Trip Setpoint and Allowable Value also contain additional margin for instrument accuracy and calibration capability.

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3/4.3.4 RECIRCULATION PUMP TRIP ACTUATION INSTRUMENTATION

The anticipated transient without scram (ATWS) recirculation pump trip system provides a means of limiting the consequences of the unlikely occurrence of a failure to scram during an anticipated transient. The response of the plant to this postulated event falls within the envelope of study events in General Electric Company Topical Report NEDO-10349, dated March 1971, NEDO-24222, dated December 1979, and Section 15.8 of the FSAR.

The end-of-cycle recirculation pump trip (EOC-RPT) system is a part of the Reactor Protection System and is an essential safety supplement to the reactor trip. The purpose of the EOC-RPT is to recover the loss of thermal margin which occurs at the end-of-cycle. The physical phenomenon involved is that the void reactivity feedback due to a pressurization transient can add positive reactivity to the reactor system at a faster rate than the control rods add negative scram reactivity. Each EOC-RPT system trips both recirculation pumps, reducing coolant flow in order to reduce the void collapse in the core during two of the most limiting pressurization events. The two events for which the EOC-RPT protective feature will function are closure of the turbine stop valves and fast closure of the turbine control valves.

A fast closure sensor from each of two turbine control valves provides input to the EOC-RPT system; a fast closure sensor from each of the other two turbine control valves provides input to the second EOC-RPT system. Similarly, a position switch for each of two turbine stop valves provides input to one EOC-RPT system; a position switch from each of the other two stop valves provides input to the other EOC-RPT system. For each EOC-RPT system, the sensor relay contacts are arranged to form a 2-out-of-2 logic for the fast closure of turbine control valves and a 2-out-of-2 logic for the turbine stop valves. The operation of either logic will actuate the EOC-RPT system and trip both recirculation pumps.

Each EOC-RPT system may be manually bypassed by use of a keyswitch which is administratively controlled. The manual bypasses and the automatic Operating Bypass at less than 30% of RATED THERMAL POWER are annunciated in the control room.

The EOC-RPT system response time is the time assumed in the analysis between initiation of valve motion and complete suppression of the electric arc, i.e., 190ms. Included in this time are: the time from initial valve movement to reaching the trip setpoint, the response time of the sensor, the response time of the system logic and the time alloted for breaker arc supression.

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

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3/4.3.5 REACTOR CORE ISOLATION COOLING SYSTEM ACTUATION INSTRUMENTATION

The reactor core isolation cooling system actuation instrumentation is provided to initiate actions 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.

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

3/4.3.6 CONTROL ROD BLOCK INSTRUMENTATION

The control rod block functions are provided consistent with the requirements of the specifications in Section 3/4.1.4, Control Rod Program Controls and Section 3/4.2 Power Distribution Limits. The trip logic is arranged so that a trip in any one of the inputs will result in a control rod block.

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

3/4.3.7 MONITORING INSTRUMENTATION

3/4.3.7.1 RADIATION MONITORING INSTRUMENTATION

The OPERABILITY of the radiation monitoring instrumentation ensures that; (1) the radiation levels are continually measured in the areas served by the individual channels; (2) the alarm or automatic action is initiated when the radiation level trip setpoint is exceeded; and (3) sufficient information is available on selected plant parameters to monitor and assess these variables following an accident. This capability is consistent with 10 CFR Part 50, Appendix A, General Design Criteria 19, 41, 60, 61, 63 and 64.

3.4.3.7.2 SEISMIC MONITORING INSTRUMENTATION

The OPERABILITY of the seismic monitoring instrumentation ensures that sufficient capability is available to promptly determine the magnitude of a seismic event and evaluate the response of those features important to safety. This capability is required to permit comparison of the measured response to that used in the design basis for the unit. This instrumentation is consistent with the recommendations of Regulatory Guide 1.12, "Instrumentation for Earthquakes," April 1974.

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MONITORING INSTRUMENTATION (Continued)

3/4.3.7.3 METEOROLOGICAL MONITORING INSTRUMENTATION

The OPERABILITY of the meteorological monitoring instrumentation ensures that sufficient meteorological data is available for estimating potential radiation doses to the public as a result of routine or accidental release of radioactive materials to the atmosphere. This capability is required to evaluate the need for initiating protective measures to protect the health and safety of the public. This instrumentation is consistent with the recommendations of Regulatory Guide 1.23 "Onsite Meteorological Programs," February 1972.

3/4.3.7.4 REMOTE SHUTDOWN MONITORING INSTRUMENTATION

The OPERABILITY of the remote shutdown monitoring instrumentation ensures that sufficient capability is available to permit shutdown and maintenance of HOT SHUTDOWN of the unit from locations outside of the control room. This capability is required in the event control room habitability is lost and is consistent with General Design Criteria 19 of 10 CFR 50.

The OPERABILITY of the remote shutdown system controls ensures that a fire will not preclude achieving safe shutdown. The remote shutdown system instrumentation, controls and power circuits and transfer switches necessary to eliminate effects of a fire and allow operation of instrumentation, control and power circuits required to achieve and maintain a safe shutdown condition are independent of areas where a fire could damage systems normally used to shutdown the reactor. This capability is consistent with General Design Criterion 3 of Appendix R to 10 CFR Part 50.

3/4.3.7.5 ACCIDENT MONITORING INSTRUMENTATION

The OPERABILITY of the accident monitoring instrumentation ensures that sufficient information is available on selected plant parameters to monitor and assess important variables following an accident. This capability is consistent with the recommendations of Regulatory Guide 1.97, "Instrumentation for Light Water Cooled Nuclear Power Plants to Assess Plant Conditions During and Following an Accident," December 1980 and NUREG-0737, "Clarification of TMI Action Plan Requirements," November 1980.

3/4.3.7.6 SOURCE RANGE MONITORS

The source range monitors provide the operator with information of the status of the neutron level in the core at very low power levels during startup and shutdown. At these power levels, reactivity additions shall not be made without this flux level information available to the operator. When the intermediate range monitors are on scale, adequate information is available without the SRMs and they can be retracted.

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MONITORING INSTRUMENTATION (Continued)

3/4.3.7.7 TRAVERSING IN-CORE PROBE SYSTEM

The OPERABILITY of the traversing in-core probe system with the specified minimum complement of equipment ensures that the measurements obtained from use of this equipment accurately represent the spatial neutron flux distribution of the reactor core.

The TIP system OPERABILITY is demonstrated by normalizing all probes (i.e., detectors) prior to performing an LPRM function calibration. Monitoring core thermal limits may involve utilizing individual detectors to monitor selected areas of the reactor core thus all detectors may not be required to be OPERABLE. The operability of individual detectors to be used for monitoring is demonstrated by comparing the detector(s) output with data obtained during the previous LPRM calibrations.

3/4.3.7.8 FIRE DETECTION INSTRUMENTATION

OPERABILITY of the detection instrumentation ensures that both adequate warning capability is available for prompt detection of fires and that fire suppression systems, that are actuated by fire detectors, will discharge extinguishing agent in a timely manner. Prompt detection and suppression of fires will reduce the potential for damage to safety-related equipment and is an integral element in the overall facility fire protection program.

Fire detectors that are used to actuate fire suppression systems represent a more critically important component of a plant's fire protection program than detectors that are installed solely for early fire warning and notification. Consequently, the minimum number of OPERABLE fire detectors must be greater.

The loss of detection capability for fire suppression systems, actuated by fire detectors, represents a significant degradation of fire protection for any area. As a result, the establishment of a fire watch patrol must be initiated at an earlier stage than would be warranted for the loss of detectors that provide only early fire warning. The establishment of frequent fire patrols in the affected areas is required to provide detection capability until the inoperable instrumentation is restored to OPERABILITY.

3/4.3.7.9 LOOSE-PART DETECTION SYSTEM

The OPERABILITY of the loose-part detection system ensures that sufficient capability is available to detect loose metallic parts in the primary system and avoid or mitigate damage to primary system components. The allowable out-of-service times and surveillance requirements are consistent with the recommendations of Regulatory Guide 1.133, "Loose-Part Detection Program for the Primary System of Light-Water-Cooled Reactors," May 1981.

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MONITORING INSTRUMENTATION (Continued)

3/4.3.7.10 RADIOACTIVE LIQUID EFFLUENT MONITORING INSTRUMENTATION

The radioactive liquid effluent instrumentation is provided to monitor and control, as applicable, the releases of radioactive materials in liquid effluents during actual or potential releases of liquid effluents. The alarm/trip setpoints for these instruments shall be calculated and adjusted in accordance with the methodology and parameters in the ODCM to ensure that the alarm/trip will occur prior to exceeding the limits of 10 CFR Part 20. The OPERABILITY and use of this instrumentation is consistent with the requirements of General Design Criteria 60, 63 and 64 of Appendix A to 10 CFR Part 50. The purpose of tank level indicating devices is to assure the detection and control of leaks that if not controlled could potentially result in the transport of radioactive materials to UNRESTRICTED AREAS.

3/4.3.7.11 RADIOACTIVE GASEOUS EFFLUENT MONITORING INSTRUMENTATION

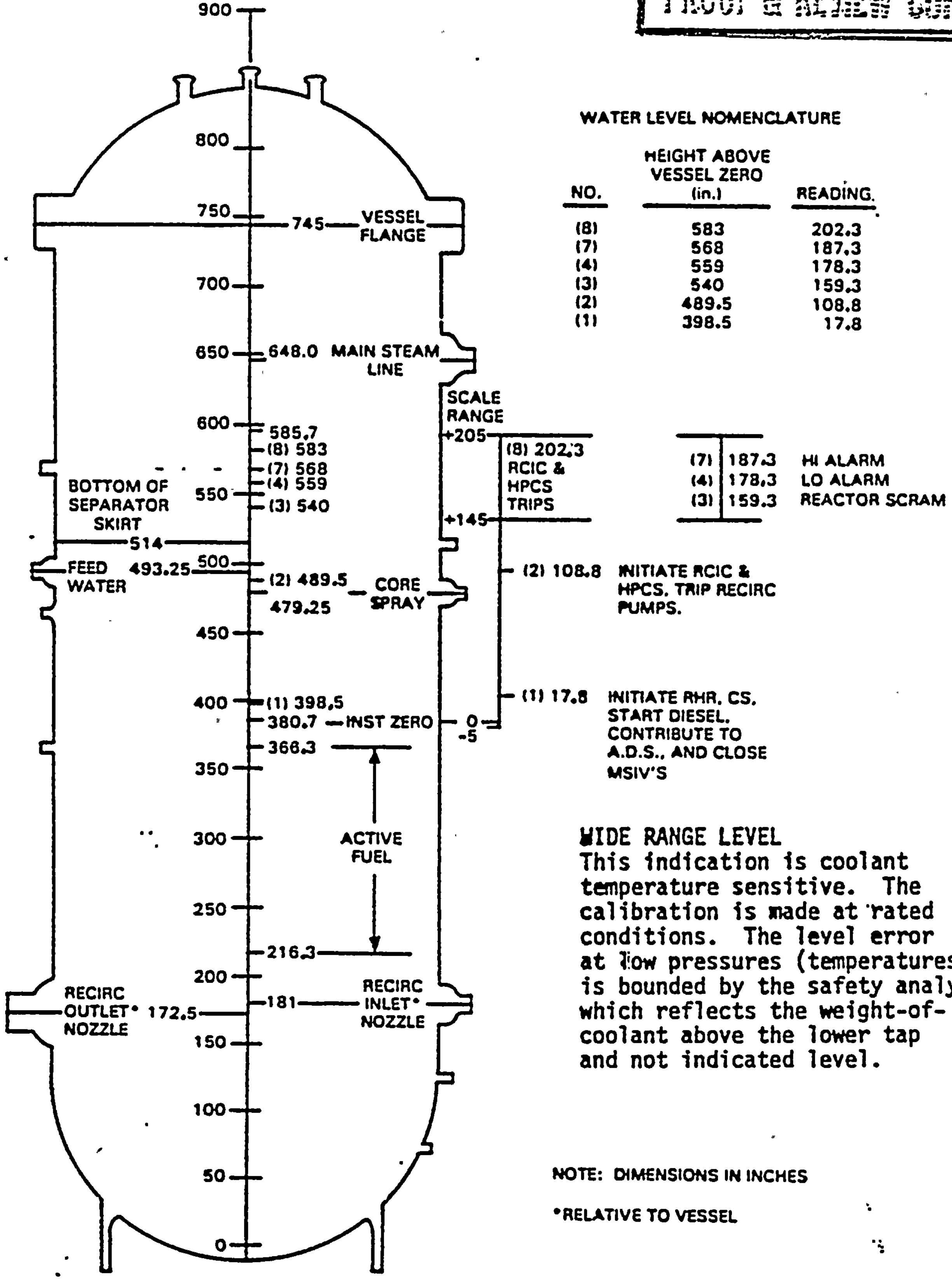
The radioactive gaseous effluent instrumentation is provided to monitor and control, as applicable, the releases of radioactive materials in gaseous effluents during actual or potential releases of gaseous effluents. The alarm/trip setpoints for these instruments shall be calculated and adjusted in accordance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

3/4.3.8 TURBINE OVERSPEED PROTECTION SYSTEM

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

3/4.3.9 PLANT SYSTEMS ACTUATION INSTRUMENTATION

The plant systems actuation instrumentation is provided: 1) to initiate action of the feedwater system/main turbine trip system in the event of feedwater controller failure, and 2) to ensure the proper operation of the service water system during normal and accident conditions.



WATER LEVEL NOMENCLATURE

NO.	HEIGHT ABOVE VESSEL ZERO (in.)	READING.
(8)	583	202.3
(7)	568	187.3
(4)	559	178.3
(3)	540	159.3
(2)	489.5	108.8
(1)	398.5	17.8

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

NOTE: DIMENSIONS IN INCHES

*RELATIVE TO VESSEL

Bases Figure B3/4.3-1. Reactor Vessel Water Level

3/4.4.1 RECIRCULATION SYSTEM

Operation with one reactor core coolant recirculation loop inoperable is prohibited until an evaluation of the performance of the ECCS during one loop operation has been performed, evaluated and determined to be acceptable.

The objective of GE BWR plant and fuel design is to provide stable operation with margin over the normal operating domain. However, at the high power/low flow corner of the operating domain, a small probability of limit cycle neutron flux oscillations exists depending on combinations of operating conditions (e.g., rod pattern, power shape). To provide assurance that neutron flux limit cycle oscillations are detected and suppressed, APRM and LPRM neutron flux noise levels should be monitored while operating in this region.

Stability tests at operating BWRs were reviewed to determine a generic region of the power/flow map in which surveillance of neutron flux noise levels should be performed. A conservative decay ratio of 0.6 was chosen as the bases for determining the generic region for surveillance to account for the plant to plant variability of decay ratio with core and fuel designs. This generic region has been determined to correspond to a core flow of less than or equal to 45% of rated core flow and a THERMAL POWER greater than that specified in Figure 3.4.1.1-1.

Plant specific calculations can be performed to determine an applicable region for monitoring neutron flux noise levels. In this case the degree of conservatism can be reduce since plant to plant variability would be eliminated. In this case, adequate margin will be assured by monitoring the region which has a decay ratio greater than or equal to 0.8.

Neutron flux noise limits are also established to ensure early detection of limit cycle neutron flux oscillations. BWR cores typically operate with neutron flux noise caused by random boiling and flow noise. Typical neutron flux noise levels of 1-12% of rated power (peak-to-peak) have been reported for the range of low to high recirculation loop flow during both single and dual recirculation loop operation. Neutron flux noise levels which significantly bound these values are considered in the thermal/mechanical design of GE BWR fuel and are found to be of negligible consequence. In addition, stability tests at operating BWRs have demonstrated that when stability related neutron flux limit cycle oscillations occur they result in peak-to-peak neutron flux limit cycles of 5-10 times the typical values. Therefore, actions taken to reduce neutron flux noise levels exceeding three (3) times the typical value are sufficient to ensure early detection of limit cycle neutron flux oscillations.

Typically, neutron flux noise levels show a gradual increase in absolute magnitude as core flow is increased (constant control rod pattern) with two reactor recirculation loops in operation. Therefore, the baseline neutron

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3/4.4 REACTOR COOLANT SYSTEM

BASES

3/4.4.1 RECIRCULATION SYSTEM (Continued)

flux noise level obtained at a specified core flow can be applied over a range of core flows. To maintain a reasonable variation between the low flow and high flow end of the flow range, the range over which a specific baseline is applied should not exceed 20% of rated core flow with two recirculation loops in operation. Data from tests and operating plants indicate that a range of 20% of rated core flow will result in approximately a 50% increase in neutron flux noise level during operation with two recirculation loops. Baseline data should be taken near the maximum rod line at which the majority of operation will occur. However, baseline data taken at lower rod lines (i.e., lower power will result in a conservative value since the neutron flux noise level is proportional to the power level at a given core flow.

An inoperable jet pump is not, in itself, a sufficient reason to declare a recirculation loop inoperable, but it does, in case of a design-basis-accident, increase the blowdown area and reduce the capability of reflooding the core; thus, the requirement for shutdown of the facility with a jet pump inoperable. Jet pump failure can be detected by monitoring jet pump performance on a prescribed schedule for significant degradation.

Recirculation loop flow mismatch limits are in compliance with the ECCS LOCA analysis design criteria. The limits will ensure an adequate core flow coastdown from either recirculation loop following a LOCA.

In order to prevent undue stress on the vessel nozzles and bottom head region, the recirculation loop temperatures shall be within 50°F of each other prior to startup of an idle loop. The loop temperature must also be within 50°F of the reactor pressure vessel coolant temperature to prevent thermal shock to the recirculation pump and recirculation nozzles. Since the coolant in the bottom of the vessel is at a lower temperature than the coolant in the upper regions of the core, undue stress on the vessel would result if the temperature difference was greater than 145° F.

3/4.4.2 SAFETY/RELIEF VALVES

The safety/relief valves operate during a postulated ATWS event to prevent the reactor coolant system being pressurized above a design allowable value of 1375 psig in accordance with the ASME Code. A total of 17 OPERABLE safety/relief valves is required to limit local pressure at active components to within ASME III allowable design values (Service Level A). All other appropriate ASME III limits are also bounded by this requirement.

Demonstration of the safety-relief valve lift settings will occur only during shutdown and will be performed in accordance with the provisions of Specification 4.0.5.

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3/4.4 REACTOR COOLANT SYSTEM

BASES

3/4.4.3.1 LEAKAGE DETECTION SYSTEMS

The RCS leakage detection systems required by this specification are provided to monitor and detect leakage from the reactor coolant pressure boundary. These detection systems are consistent with the recommendations of Regulatory Guide 1.45, "Reactor Coolant Pressure Boundary Leakage Detection Systems", May 1973.

3/4.4.3.2 OPERATIONAL LEAKAGE

The allowable leakage rates from the reactor coolant system have been based on the predicted and experimentally observed behavior of cracks in pipes. The normally expected background leakage due to equipment design and the detection capability of the instrumentation for determining system leakage was also considered. The evidence obtained from experiments suggests that for leakage somewhat greater than that specified for UNIDENTIFIED LEAKAGE the probability is small that the imperfection or crack associated with such leakage would grow rapidly. However, in all cases, if the leakage rates exceed the values specified or the leakage is located and known to be PRESSURE BOUNDARY LEAKAGE, the reactor will be shutdown to allow further investigation and corrective action.

The Surveillance Requirements for RCS pressure isolation valves provide added assurance of valve integrity thereby reducing the probability of gross valve failure and consequent intersystem LOCA.

3/4.4.4 CHEMISTRY

The water chemistry limits of the reactor coolant system are established to prevent damage to the reactor materials in contact with the coolant. Chloride limits are specified to prevent stress corrosion cracking of the stainless steel. The effect of chloride is not as great when the oxygen concentration in the coolant is low, thus the 0.2 ppm limit on chlorides is permitted during POWER OPERATION. During shutdown and refueling operations, the temperature necessary for stress corrosion to occur is not present so a 0.5 ppm concentration of chlorides is not considered harmful during these periods.

Conductivity measurements are required on a continuous basis since changes in this parameter are an indication of abnormal conditions. When the conductivity is within limits, the pH, chlorides and other impurities affecting conductivity must also be within their acceptable limits. With the conductivity meter inoperable, additional samples must be analyzed to ensure that the chlorides are not exceeding the limits.

The surveillance requirements provide adequate assurance that concentrations in excess of the limits will be detected in sufficient time to take corrective action.

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3/4.4 REACTOR COOLANT SYSTEM

BASES

3/4.4.5 SPECIFIC ACTIVITY

The limitations on the specific activity of the primary coolant ensure that the 2 hour thyroid and whole body doses resulting from a main steam line failure outside the containment during steady state operation will not exceed small fractions of the dose guidelines of 10 CFR 100. The values for the limits on specific activity represent interim limits based upon a parametric evaluation by the NRC of typical site locations. These values are conservative in that specific site parameters, such as site boundary location and meteorological conditions, were not considered in this evaluation.

The ACTION statement permitting POWER OPERATION to continue for limited time periods with the primary coolant's specific activity greater than 0.2 microcuries per gram DOSE EQUIVALENT I-131, but less than or equal to 4.0 microcuries per gram DOSE EQUIVALENT I-131, accommodates possible iodine spiking phenomenon which may occur following changes in THERMAL POWER. ~~Operation with specific activity levels exceeding 0.2 microcuries per gram DOSE EQUIVALENT I-131 but less than or equal to 4.0 microcuries per gram DOSE EQUIVALENT I-131 must be restricted to no more than 800 hours per year, approximately 10 percent of the unit's yearly operating time, since these activity levels increase the 2 hour thyroid dose at the site boundary by a factor of up to 20 following a postulated steam line rupture. The reporting of cumulative operating time over 500 hours in any 6 month consecutive period with greater than 0.2 microcuries per gram DOSE EQUIVALENT I-131 will allow sufficient time for Commission evaluation of the circumstances prior to reaching the 800 hour limit.~~

Information obtained on iodine spiking will be used to assess the parameters associated with spiking phenomena. A reduction in frequency of isotopic analysis following power changes may be permissible if justified by the data obtained.

Closing the main steam line isolation valves limits the release of activity to the environs should a steam line rupture occur outside containment. The surveillance requirements provide adequate assurance that excessive specific activity levels in the reactor coolant will be detected in sufficient time to take corrective action.

3/4.4.6 PRESSURE/TEMPERATURE LIMITS

All components in the reactor coolant system are designed to withstand the effects of cyclic loads due to system temperature and pressure changes. These cyclic loads are introduced by normal load transients, reactor trips, and startup and shutdown operations. The various categories of load cycles used for design purposes are provided in Section 3.9 of the FSAR. During startup and shutdown, the rates of temperature and pressure changes are limited so that the maximum specified heatup and cooldown rates are consistent with the design assumptions and satisfy the stress limits for cyclic operation.

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3/4.4 REACTOR COOLANT SYSTEM

BASES

PRESSURE/TEMPERATURE LIMITS (Continued)

The operating limit curves of Figures 3.4.6.1-1, 3.4.6.1-2 and 3.4.6.1-3 are derived from the fracture toughness requirements of 10 CFR 50 Appendix G and ASME Code Section III, Appendix G. The curves are based on the RT_{NDT} and stress intensity factor information for the reactor vessel components. Fracture toughness limits and the basis for compliance are more fully discussed in FSAR Chapter 5, Paragraph 5.3.1.5, "Fracture Toughness."

The reactor vessel materials have been tested to determine their initial RT_{NDT}. The results of these tests are shown in Table ~~Figure~~ B 3/4.4.6-1. Reactor operation and resultant fast neutron, E greater than 1 MeV, irradiation will cause an increase in the RT_{NDT}. Therefore, an adjusted reference temperature, based upon the fluence, phosphorus content and copper content of the material in question, can be predicted using Bases Figure B 3/4.4.6-1 and the recommendations of Regulatory Guide 1.99, Revision 1, "Effects of Residual Elements on Predicted Radiation Damage to Reactor Vessel Materials."

The actual shift in RT_{NDT} of the vessel material will be established periodically during operation by removing and evaluating, irradiated specimens ~~flux wires~~ installed near the inside wall of the reactor vessel in the core area since the neutron spectra at the specimens ~~flux wires~~ and vessel inside radius are essentially identical. The irradiated specimens ~~flux wires~~ can be used with confidence in predicting reactor vessel material transition temperature shift. The operating limit curves of Figure 3.4.6.1-1, 3.4.6.1-2 and 3.4.6.1-3 shall be adjusted, as required, on the basis of the specimen data and recommendations of Regulatory Guide 1.99, Revision 1. Data determined from flux wires removed at the end of the first cycle will be used to adjust the fluence of Figure B3/4.4.6-1.

The pressure-temperature limit lines shown in Figures 3.4.6.1-3 and 3.4.6.1-1, curves C and A for reactor criticality and for inservice leak and hydrostatic testing have been provided to assure compliance with the minimum temperature requirements of Appendix G to 10 CFR Part 50 for reactor criticality and for inservice leak and hydrostatic testing.

The number of rector vessel irradiation surveillance capsules and the frequencies for removing and testing the specimens in these capsules are provided in Table 4.4.6.1.3-1 to assure compliance with the requirements of Appendix H to 10 CFR Part 50.

3/4.4.7 MAIN STEAM LINE ISOLATION VALVES

Double isolation valves are provided on each of the main steam lines to minimize the potential leakage paths from the containment in case of a line break. Only one valve in each line is required to maintain the integrity of the containment, however, single failure considerations require that two valves be OPERABLE. The surveillance requirements are based on the operating history of this type valve. The maximum closure time has been selected to

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3/4.4.7 MAIN STEAM LINE ISOLATION VALVES (Continued)

contain fission products and to ensure the core is not uncovered following line breaks. The minimum closure time is consistent with the assumptions in the safety analyses to prevent pressure surges.

3/4.4.8 STRUCTURAL INTEGRITY

The inspection programs for ASME Code Class 1, 2 and 3 components ensure that the structural integrity of these components will be maintained at an acceptable level throughout the life of the plant.

Components of the reactor coolant system were designed to provide access to permit inservice inspections in accordance with Section XI of the ASME Boiler and Pressure Vessel Code 1980 Edition and Addenda through W80.

The inservice inspection program for ASME Code Class 1, 2 and 3 components will be performed in accordance with Section XI of the ASME Boiler and Pressure Vessel Code and applicable addenda as required by 10 CFR Part 50.55a(g) except where specific written relief has been granted by the NRC pursuant to 10 CFR Part 50.55a(g)(6)(i).

3/4.4.9 RESIDUAL HEAT REMOVAL

A single shutdown cooling mode loop provides sufficient heat removal capability for removing core decay heat and mixing to assure accurate temperature indication, however, single failure considerations require that two loops be OPERABLE or that alternate methods capable of decay heat removal be demonstrated and that an alternate method of coolant mixing be in operation.

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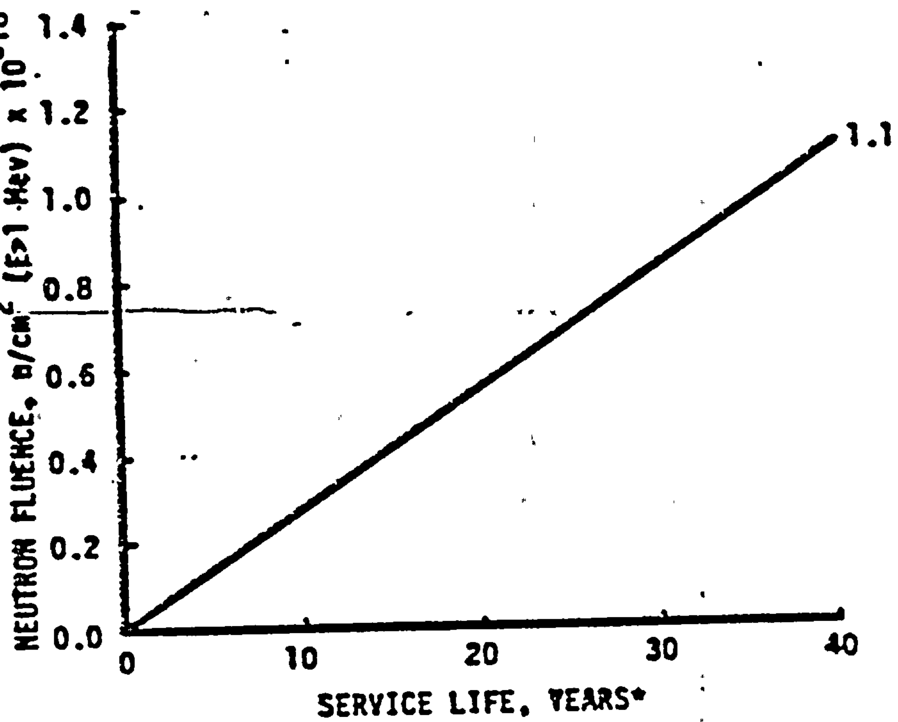

FIGURE B 3/4 4.6-1 FAST NEUTRON FLUENCE (E>1 Mev) AT 1/4 T AS A FUNCTION OF SERVICE LIFE*

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

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3/4.5.1 and 3/4.5.2 ECCS - OPERATING and SHUTDOWN

ECCS Division I consists of the low pressure core spray system and low pressure coolant injection subsystem "A" of the RHR system and the automatic depressurization system (ADS) as actuated by ADS trip system "A". ECCS division 2 consists of low pressure coolant injection subsystems "B" and "C" of the RHR system and the automatic depressurization system as actuated by ADS trip system "B".

The low pressure core spray (LPCS) system is provided to assure that the core is adequately cooled following a loss-of-coolant accident and provides adequate core cooling capacity for all break sizes up to and including the double-ended reactor recirculation line break, and for smaller breaks following depressurization by the ADS.

The LPCS is a primary source of emergency core cooling after the reactor vessel is depressurized and a source for flooding of the core in case of accidental draining.

The surveillance requirements provide adequate assurance that the LPCS system will be OPERABLE when required. Although all active components are testable and full flow can be demonstrated by recirculation through a test loop during reactor operation, a complete functional test requires reactor shutdown. The pump discharge piping is maintained full to prevent water hammer damage to piping.

The low pressure coolant injection (LPCI) mode of the RHR system is provided to assure that the core is adequately cooled following a loss-of-coolant accident. Three subsystems, each with one pump, provide adequate core flooding for all break sizes up to and including the double-ended reactor recirculation line break, and for small breaks following depressurization by the ADS.

The surveillance requirements provide adequate assurance that the LPCI system will be OPERABLE when required. Although all active components are testable and full flow can be demonstrated by recirculation through a test loop during reactor operation, a complete functional test requires reactor shutdown. The pump discharge piping is maintained full to prevent water hammer damage to piping.

ECCS Division III consists of the high pressure core spray system. The high pressure core spray (HPCS) system is provided to assure that the reactor core is adequately cooled to limit fuel clad temperature in the event of a small break in the reactor coolant system and loss of coolant which does not result in rapid depressurization of the reactor vessel. The HPCS system permits the reactor to be shut down while maintaining sufficient reactor vessel water level inventory until the vessel is depressurized. The HPCS system operates over a range of 1160 psid, differential pressure between reactor vessel and HPCS suction source, to 0 psid.

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ECCS-OPERATING and SHUTDOWN (Continued)

The capacity of the system is selected to provide the required core cooling. The HPCS pump is designed to deliver greater than or equal to 516/1550/6350 gpm at differential pressures of 1160/1130/200 psi. Initially, water from the condensate storage tank is used instead of injecting water from the suppression pool into the reactor, but no credit is taken in the safety analyses for the condensate storage tank water.

With the HPCS system inoperable, adequate core cooling is assured by the OPERABILITY of the redundant and diversified automatic depressurization system and both the LPCS and LPCI systems. In addition, the reactor core isolation cooling (RCIC) system, a system for which no credit is taken in the safety analysis, will automatically provide makeup at reactor operating pressures on a reactor low water level condition. The HPCS out-of-service period of 14 days is based on the demonstrated OPERABILITY of redundant and diversified low pressure core cooling systems.

The surveillance requirements provide adequate assurance that the HPCS system will be OPERABLE when required. Although all active components are testable and full flow can be demonstrated by recirculation through a test loop during reactor operation, a complete functional test with reactor vessel injection requires reactor shutdown. The pump discharge piping is maintained full to prevent water hammer damage.

Upon failure of the HPCS system to function properly after a small break loss-of-coolant accident, the automatic depressurization system (ADS) automatically causes selected safety-relief valves to open, depressurizing the reactor so that flow from the low pressure core cooling systems can enter the core in time to limit fuel cladding temperature to less than 2200°F. ADS is conservatively required to be OPERABLE whenever reactor vessel pressure exceeds 100 psig. This pressure is substantially below that for which the low pressure core cooling systems can provide adequate core cooling for events requiring ADS.

ADS automatically controls seven selected safety-relief valves although the safety analysis only takes credit for six valves. It is therefore appropriate to permit one valve to be out-of-service for up to 14 days without materially reducing system reliability.

3/4.5.3 SUPPRESSION POOL

The suppression pool is required to be OPERABLE as part of the ECCS to ensure that a sufficient supply of water is available to the HPCS, LPCS and LPCI systems in the event of a LOCA. This limit on suppression pool minimum water volume ensures that sufficient water is available to permit recirculation cooling flow to the core. The OPERABILITY of the suppression pool in OPERATIONAL CONDITIONS 1, 2 or 3 is required by Specification 3.6.2.1.

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SUPPRESSION POOL (Continued)

Repair work might require making the suppression pool inoperable. This specification will permit those repairs to be made and at the same time give assurance that the irradiated fuel has an adequate cooling water supply when the suppression pool must be made inoperable, including draining, in OPERATIONAL CONDITION 4 or 5.

In OPERATIONAL CONDITION 4 and 5 the suppression pool minimum required water volume is equal to that required for OPERATIONAL CONDITIONS 1, 2 and 3 because in all cases the minimum water volume is based on NPSH, recirculation volume and vortex prevention in accordance with NUREG 0869 (April 1983, issued For Comment).

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3/4.6.1 PRIMARY CONTAINMENT

3/4.6.1.1 PRIMARY CONTAINMENT INTEGRITY

PRIMARY CONTAINMENT INTEGRITY ensures that the release of radioactive materials from the containment atmosphere will be restricted to those leakage paths and associated leak rates assumed in the accident analyses. This restriction, in conjunction with the leakage rate limitation, will limit the site boundary radiation doses to within the limits of General Design Criteria 19 and 10 CFR Part 100 during accident conditions.

3/4.6.1.2 PRIMARY CONTAINMENT LEAKAGE

The limitations on primary containment leakage rates ensure that the total containment leakage volume will not exceed the value assumed in the accident analyses at the peak accident pressure of 39.75 psig, Pa. As an added conservatism, the measured overall integrated leakage rate is further limited to less than or equal to 0.75 La during performance of the periodic tests to account for possible degradation of the containment leakage barriers between leakage tests.

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

The surveillance testing for measuring leakage rates is consistent with the requirements of Appendix "J" of 10 CFR Part 50 with the exception of exemptions granted for main steam isolation valve leak testing and testing the airlocks after each opening.

The leakage rates specified for the main steam line isolation valves, the main steam drain line isolation valves, and the post-accident sampling system gas sample and return line block valves are used to quantify the maximum amount of primary containment atmosphere that could bypass secondary containment and leak directly to the environment after a design basis loss-of-coolant accident. This data is used to determine the radiological consequences of this accident and ensure that the resultant doses are within the limits of the General Design Criteria 19 and 10 CFR 100.

3/4.6.1.3 PRIMARY CONTAINMENT AIR LOCKS

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

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3/4.6.1.5 PRIMARY CONTAINMENT STRUCTURAL INTEGRITY

This limitation ensures that the structural integrity of the containment will be maintained comparable to the original design standards for the life of the unit. Structural integrity is required to ensure that the containment will withstand the design pressure of 45 psig in the event of a LOCA. A visual inspection in conjunction with Type A leakage tests is sufficient to demonstrate this capability.

3/4.6.1.6 DRYWELL AND SUPPRESSION CHAMBER INTERNAL PRESSURE

The limitations on drywell and suppression chamber internal pressure ensure that the containment peak pressure of 39.75 psig does not exceed the design pressure of 45.0 psig during LOCA conditions or that the external pressure differential does not exceed the design maximum external pressure differential of 4.7 psi. The limit of 14.2 to 15.4 psia for initial positive containment pressure will limit the total pressure to 39.75 psig which is less than the design pressure and is consistent with the safety analysis.

3/4.6.1.7 DRYWELL AVERAGE AIR TEMPERATURE

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

In addition, the maximum drywell average air temperature is also the limiting initial condition used to determine the maximum negative differential pressure acting on the drywell and suppression chamber following inadvertent actuation of the containment sprays.

3/4.6.1.8 PRIMARY CONTAINMENT PURGE SYSTEM

INSERT "A"

The 14 inch and 12 inch drywell and suppression chamber purge supply and exhaust isolation valves 2CPS*AOV-105, 2CPS*AOV-107, 2CPS*AOV-110 and 2CPS*AOV-111 are required to be sealed closed during plant operation since these valves have not been demonstrated capable of closing during a LOCA. Maintaining these valves sealed closed during plant operations ensures that excessive quantities of radioactive materials will not be released via the purge system. To provide assurance that these valves cannot be inadvertently opened, they are sealed closed in accordance with Standard Review Plan 6.2.4, which includes mechanical devices to seal or lock the valve closed or prevent power from being supplied to the valve operator.

The use of the drywell and suppression chamber purge lines is restricted to the 14 and 12 inch purge supply and exhaust isolation valves 2CPS*AOV-106, 2CPS*AOV-108, 2CPS*AOV-109 and 2CPS*AOV-104 since, unlike the other valves, these valves will close during a LOCA or steam line break accident and therefore the site boundary dose guidelines of 10 CFR Part 100 would not be exceeded in the event of an accident during purging operations. The design of the purge supply and exhaust isolation valves meets the requirements of Branch Technical Position CSB 6-4, "Containment Purging During Normal Plant Operations."

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INSERT "A" (place on B 3/4 6-2)

The 14 inch drywell and 12 inch suppression chamber supply and exhaust valves open limit of 90 hours per 365 days during purge or vent operation in conditions 1, 2 and 3 meet the requirement of Branch Technical Position CSB 6-4 for valves greater than 8 inches in diameter. The requirement to limit the opening of 2CPS*AOV105 and 2CPS*AOV110 to 70 degrees, and 2CPS*AOV111 to 60 degrees ensure these valves will close during a LOCA or steam line break accident, and therefore, the site boundary dose guidelines of 10CFR100 would not be exceeded in the event of an accident during purging or venting operations.

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PRIMARY CONTAINMENT PURGE SYSTEM (Continued)

Leakage integrity tests with a maximum allowable leakage rate for purge supply and exhaust isolation valves will provide early indication of resilient material seal degradation and will allow the opportunity for repair before gross leakage failure develops. The leakage limit shall not be exceeded when the leakage rates are determined to be $\leq$ 4.38 scf/h per 14 inch valve and 3.75 scf/h per 12 inch valve where pressurized to 40.0 psig.

3/4.6.2. DEPRESSURIZATION SYSTEMS

The specifications of this section ensure that the primary containment pressure will not exceed the design pressure of 45 psig during primary system blowdown from full operating pressure.

The suppression pool water provides the heat sink for the reactor coolant system energy release following a postulated rupture of the system. The suppression pool water volume must absorb the associated decay and structural sensible heat released during reactor coolant system blowdown from 1040 psig. Since all of the gases in the drywell are purged into the suppression pool air space during a loss of coolant accident, the pressure of the liquid must not exceed 45 psig, the suppression chamber maximum pressure. The design volume of the suppression chamber, water and air, was obtained by considering that the total volume of reactor coolant is discharged to the suppression chamber and that the drywell volume is purged to the suppression chamber.

Using the minimum or maximum water volumes given in this specification, containment pressure during the design basis accident is approximately 40 psig which is below the design pressure of 45 psig. Maximum water volume of 154,794 ft^3 results in a downcomer submergence of 11'-0" and the minimum volume of 145,495 ft^3 results in a submergence approximately 18 inches less. The majority of the Bodega tests were run with a submerged length of four feet and with complete condensation. Thus, with respect to the downcomer submergence, this specification is adequate. The maximum temperature at the end of the blowdown tested during the Humboldt Bay and Bodega Bay tests was 170°F and this is conservatively taken to be the limit for complete condensation of the reactor coolant, although condensation would occur for temperatures above 170°F.

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

Under full power operating conditions, blowdown to the suppression pool at the initial water temperature of 90°F results in a water temperature of approximately 140 °F immediately following blowdown which is below the 200°F used for complete condensation via T-quencher devices. At this temperature and atmospheric pressure, the available NPSH exceeds that required by both the RHR and core spray pumps, thus there is no dependency on containment overpressure during the accident injection phase. If both RHR loops are used for containment cooling, there is no dependency on containment overpressure for post-LOCA operations.

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DEPRESSURIZATION SYSTEMS (Continued)

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

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

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

3/4.6.3 PRIMARY CONTAINMENT ISOLATION VALVES

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

3/4.6.4 SUPPRESSION CHAMBER-DRYWELL VACUUM BREAKERS

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

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

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3/4.6.5 SECONDARY CONTAINMENT

Secondary containment is designed to minimize any ground level release of radioactive material which may result from an accident. The Reactor Building and associated structures provide secondary containment during normal operation when the drywell is sealed and in service. At other times the drywell may be open and, when required, secondary containment integrity is specified.

Establishing and maintaining a sub-atmospheric condition in the reactor building with the standby gas treatment system once per 18 months, along with the surveillance of the doors, hatches, dampers and valves, is adequate to ensure that there are no violations of the integrity of the secondary containment.

The OPERABILITY of the standby gas treatment systems ensures that sufficient iodine removal capability will be available in the event of a LOCA. The reduction in containment iodine inventory reduces the resulting site boundary radiation doses associated with containment leakage. The operation of this system and resultant iodine removal capacity are consistent with the assumptions used in the LOCA analyses. Continuous operation of the system with the heaters operating for 10 hours during each 31 day period is sufficient to reduce the buildup of moisture on the adsorbers and HEPA filters.

3/4.6.6 PRIMARY CONTAINMENT ATMOSPHERE CONTROL

The OPERABILITY of the systems required for the detection and control of hydrogen gas ensures that these systems will be available to maintain the hydrogen concentration within the primary containment below its flammable limit during post-LOCA conditions. The drywell and suppression chamber hydrogen recombiner system is capable of controlling the expected hydrogen and oxygen generation associated with (1) zirconium-water reactions, (2) radiolytic decomposition of water and (3) corrosion of metals within containment. The hydrogen control system is consistent with the recommendations of Regulatory Guide 1.7, "Control of Combustible Gas Concentrations in Containment Following a LOCA," March 1971.

3/4.7.1 PLANT 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.

The Intake Deicing heater specification is to ensure adequate water is available to the service water system. In order to prove that the system is supplying adequate heat to the bar racks, a portable ammeter shall be used to check the full load current of the heaters. The current should be checked on a weekly basis. Current shall be measured for each phase at each of the four motor control center locations. If a major deviation from rated current is detected, further investigation is required to determine if an open circuit exists in the individual heater circuits.

The 10 month check of circuit meggar readings will check against long term degradation of circuit insulations.

3/4.7.2 REVETMENT DITCH STRUCTURE PROTECTION

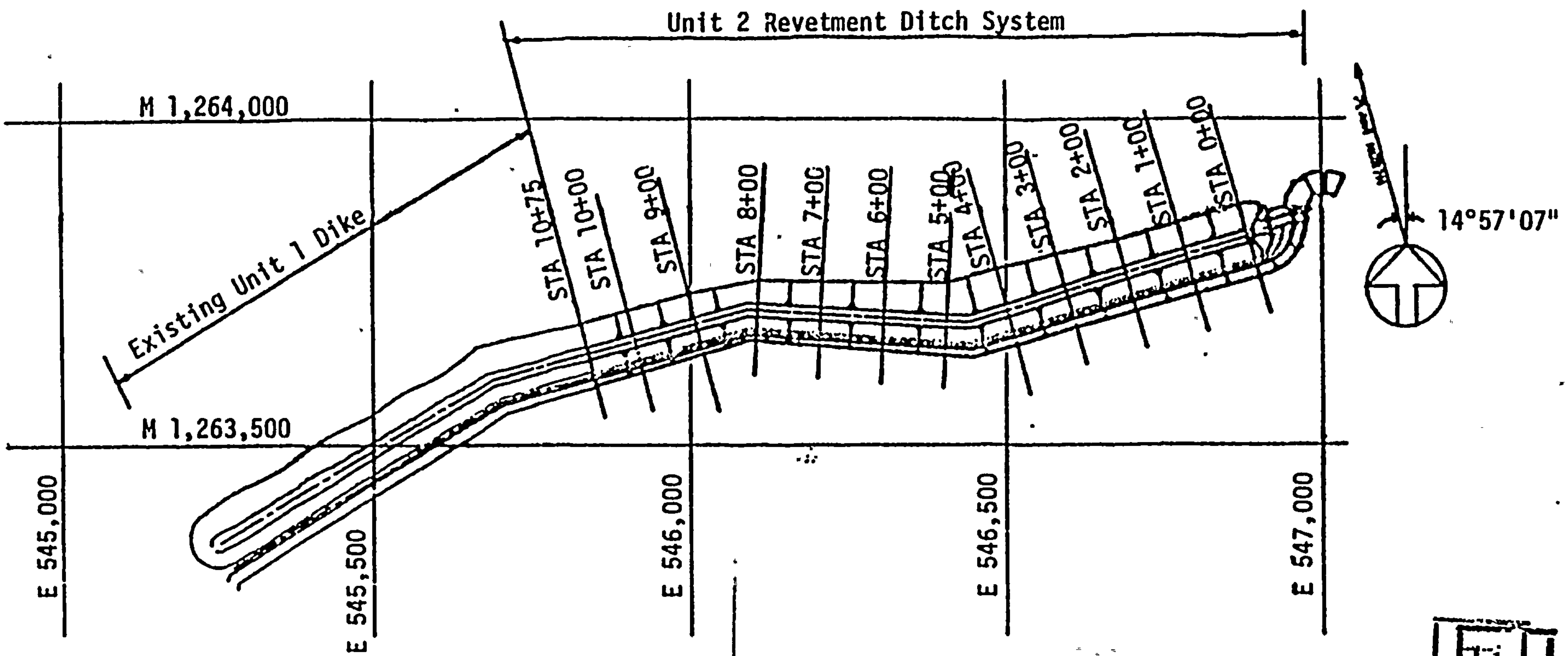
The purpose of the revetment ditch structure is to protect the plant fill and foundation from wave erosion, expected during the probable maximum windstorm for a maximum still water elevation of 254 feet.

Category 1 structures are the designed to withstand the impact of waves. So long as the fill is in place, waves cannot impact Category 1 structures because of the lack of sufficient depth of water to sustain such waves.

The revetment ditch structure can sustain a high degree of damage and still perform its function, protecting the site fill from erosion. Thus the operability condition for operation of the revetment ditch structure has been written to ensure that severe damage to the structure will not go undetected for a substantial period of time and to provide for prompt corrective action and NRC notification.

3/4.7.~~6~~.3 CONTROL ROOM EMERGENCY OUTDOOR AIR SPECIAL FILTER TRAIN SYSTEM

The OPERABILITY of the control room emergency outdoor air special filter train system ensures that 1) the ambient air temperature does not exceed the allowable temperature for continuous duty rating for the equipment and instrumentation cooled by this system and 2) the control room will remain habitable for operations personnel during and following all design basis accident conditions. Continuous operation of the system with the heaters OPERABLE for 10 hours during each 31-day period is sufficient to reduce the buildup of moisture on the adsorbers and HEPA filters. 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.



(Not to scale)

NOTE: Survey measurements shall be taken at 100 ft stations as shown. All station locations are approximate and will be determined upon installation of survey mounts.

FIGURE B 3/4 7.2-1 PLAN VIEW - REVETMENT DITCH STRUCTURE, INSERVICE INSPECTION STATION LOCATIONS

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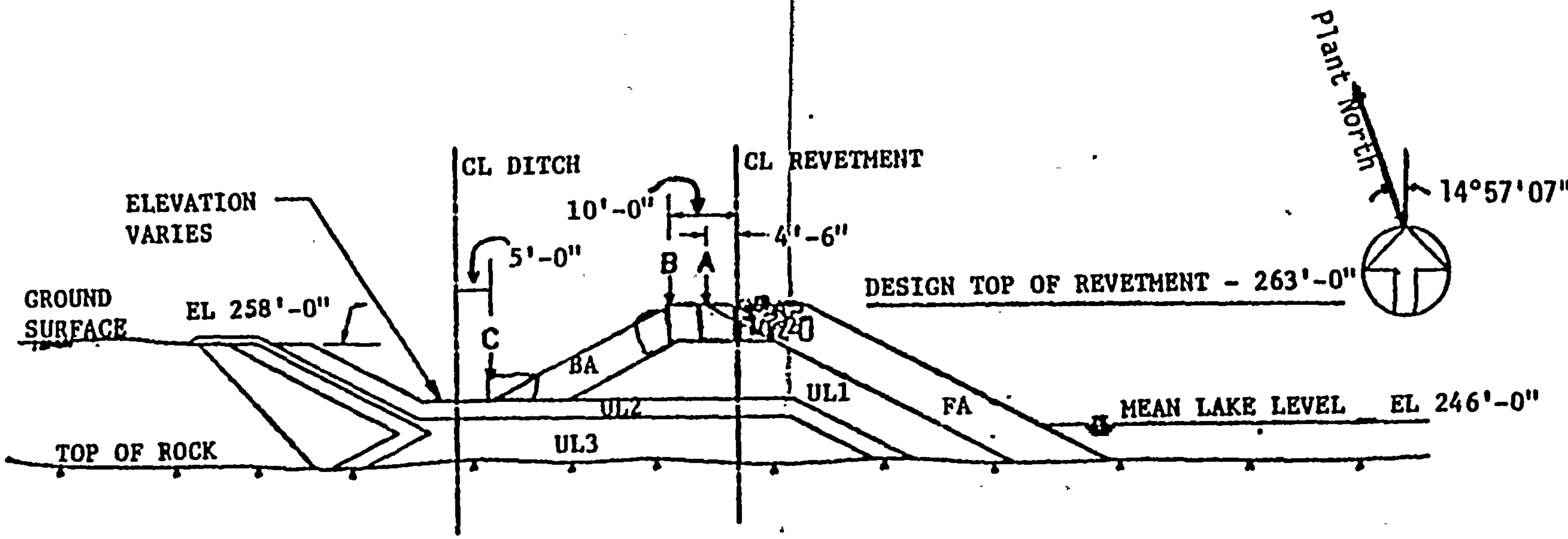

LEGEND

FA	Front Armor, Double Layer of 4900 lb Dolids Units
UL1	First Underlayer, 2000 to5000 lb Stone Units
UL2	Second Underlayer, 75 to 250 lb Stone Units
UL3	Third Underlayer, 2.3 to 15 lb Stone Units
BA	Back Armor, Single Layer of 10,000 to 16,000 lb Stone Armor Units
A,B,C	Survey Points

FIGURE B 3/4 7.2-2 TYPICAL SECTION - REVETMENT DITCH STRUCTURE, INSERVICE INSPECTION STATION LOCATIONS

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~~REACTOR CORE ISOLATION COOLING SYSTEM (Continued)~~

3/4.7.4 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 HPCS 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.

3/4.7.5 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 interval varies inversely with the observed snubber failures 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

SNUBBERS (Continued)

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 adversly 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.

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, i.e., 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.

3/4.7.6 SEALED SOURCE CONTAMINATION

The limitations on removable contamination for sources requiring 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 devices, are considered to be stored and need not be tested unless they are removed from the shielded mechanism.

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FIRE SUPPRESSION SYSTEMS (Continued)

3/4 7.7 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 sprinkler systems, 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.

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 or level and pressure of the tanks. Level measurements are made by either a U.L. or F.M. approved method.

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.

3/4.7.8 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 dampers, and fire doors are periodically inspected to verify their OPERABILITY.

3/4.7.9 MAIN TURBINE BYPASS SYSTEM

The main turbine bypass system is required to be OPERABLE consistent with the assumptions of the feedwater controller failure analysis of FSAR Chapter 15.

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3/4.8 ELECTRICAL POWER SYSTEMS

BASES

3/4.8.1, 3/4.8.2 and 3/4.8.3 A.C. SOURCES, D.C. SOURCES and ONSITE POWER DISTRIBUTION SYSTEMS

The OPERABILITY of the A.C. and D.C. power sources and associated distribution systems during operation ensures that sufficient power will be available to supply the safety related equipment required for (1) the safe shutdown of the facility and (2) the mitigation and control of accident conditions within the facility. The minimum specified independent and redundant A.C. and D.C. power sources and distribution systems satisfy the requirements of General Design Criteria 17 of Appendix "A" to 10 CFR 50.

The ACTION requirements specified for the levels of degradation of the power sources provide restriction upon continued facility operation commensurate with the level of degradation. The OPERABILITY of the power sources consistent with the initial condition assumptions of the safety analyses and are based upon maintaining at least Division I or II of the onsite A.C. and D.C. power sources and associated distribution systems OPERABLE during accident conditions coincident with an assumed loss of offsite power and single failure of the other onsite A.C. or D.C. source. Division III supplies the high pressure core spray (HPCS) system only.

The A.C. and D.C. source allowable out-of-service times are based on Regulatory Guide 1.93, "Availability of Electrical Power Sources", December 1974. When diesel generator EDG-1 (DIV I) or EDG-3 (DIV II) is inoperable, there is an additional ACTION requirement to verify that all required systems, subsystems, trains, components and devices, that depend on the remaining OPERABLE diesel generator EDG-1 (DIV I) or EDG-3 (DIV II) as a source of emergency power, are also OPERABLE. This requirement is intended to provide assurance that a loss of offsite power event will not result in a complete loss of safety function of critical systems during the period diesel generator EDG-1 (DIV I) or EDG-3 (DIV II) is inoperable. The term verify as used in this context means to administratively check by examining logs or other information to determine if certain components are out-of-service for maintenance or other reasons. It does not mean to perform the surveillance requirements needed to demonstrate the OPERABILITY of the component.

The OPERABILITY of the minimum specified A.C. and D.C. power sources and associated distribution systems during shutdown and refueling ensures that (1) the facility can be maintained in the shutdown or refueling condition for extended time periods and (2) sufficient instrumentation and control capability is available for monitoring and maintaining the unit status.

The surveillance requirements for demonstrating the OPERABILITY of the diesel generators are in accordance with the recommendations of Regulatory Guide 1.9, "Selection of Diesel Generator Set Capacity for Standby Power Supplies", December 1979, Regulatory Guide 1.108, "Periodic Testing of Diesel Generator Units Used as Onsite Electric Power Systems at Nuclear Power Plants", Revision 1, August 1977 and Regulatory Guide 1.137" Fuel-Oil Systems for Standby Diesel Generators", Revision 1, October 1979.

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A.C. SOURCES, D.C. SOURCES and ONSITE POWER DISTRIBUTION SYSTEMS (Continued)

The surveillance requirements for demonstrating the OPERABILITY of the unit batteries are in accordance with the recommendations of Regulatory Guide 1.129, "Maintenance Testing and Replacement of Large Lead Storage Batteries for Nuclear Power Plants," February 1978, and IEEE Std 450-1980, "IEEE Recommended Practice for Maintenance, Testing, and Replacement of Large Lead Storage Batteries for Generating Stations and Substations."

Verifying average electrolyte temperature above the minimum for which the battery was sized, total battery terminal voltage on float charge, connection resistance values and the performance of battery service and discharge tests ensures the effectiveness of the charging system, the ability to handle high discharge rates and compares the battery capacity at that time with the rated capacity.

Table 4.8.2.1-1 specifies the normal limits for each designated pilot cell and each connected cell for electrolyte level, float voltage and specific gravity. The limits for the designated pilot cells float voltage and specific gravity, greater than 2.13 volts and .015 below the manufacturer's full charge specific gravity or a battery charger current that had stabilized at a low value, is characteristic of a charged cell with adequate capacity. The normal limits for each connected cell for float voltage and specific gravity, greater than 2.13 volts and not more than .020 below the manufacturer's full charge specific gravity with an average specific gravity of all the connected cells not more than .010 below the manufacturer's full charge specific gravity, ensures the OPERABILITY and capability of the battery.

Operation with a battery cell's parameter outside the normal limit but within the allowable value specified in Table 4.8.2.1-1 is permitted for up to 7 days. During this 7 day period: (1) the allowable values for electrolyte level ensures no physical damage to the plates with an adequate electron transfer capability; (2) the allowable value for the average specific gravity of all the cells, not more than .020 below the manufacturer's recommended full charge specific gravity ensures that the decrease in rating will be less than the safety margin provided in sizing; (3) the allowable value for an individual cell's specific gravity, ensures that an individual cell's specific gravity will not be more than .040 below the manufacturer's full charge specific gravity and that the overall capability of the battery will be maintained within an acceptable limit; and (4) the allowable value for an individual cell's float voltage, greater than 2.07 volts, ensures the battery's capability to perform its design function.

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3/4.8.4 ELECTRICAL EQUIPMENT PROTECTIVE DEVICES

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

The surveillance requirements applicable to lower voltage circuit breakers and fuses provides assurance of breaker and fuse reliability by testing at least one representative sample of each manufacturers brand of circuit breaker and/or fuse. Each manufacturer's molded case and metal case circuit breakers and/or fuses are grouped into representative samples which are than tested on a rotating basis to ensure that all breakers and/or fuses are tested. If a wide variety exists within any manufacturer's brand of circuit breakers and/or fuses, it is necessary to divide that manufacturer's breakers and/or fuses into groups and treat each group as a separate type of breaker or fuses for surveillance purposes.

The emergency lighting system overcurrent protective devices ensure that a failure of the non-Class 1E portion of the circuit will not effect the operation of the remaining portions of the Class 1E circuits that are necessary for safe shutdown.

The EPAs provide Class 1E isolation capabilities for the RPS power supplies and the Scram power supplies. This is required because the power supplies are not Class 1E power supplies.

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3/4.9 REFUELING OPERATIONS

BASES

3/4.9.1 REACTOR MODE SWITCH

Locking the OPERABLE reactor mode switch in the Shutdown or Refuel position, as specified, ensures that the restrictions on control rod withdrawal and refueling platform movement during the refueling operations are properly activated. These conditions reinforce the refueling procedures and reduce the probability of inadvertent criticality, damage to reactor internals or fuel assemblies, and exposure of personnel to excessive radioactivity.

3/4.9.2 INSTRUMENTATION

The OPERABILITY of at least two source range monitors ensures that redundant monitoring capability is available to detect changes in the reactivity condition of the core.

3/4.9.3 CONTROL ROD POSITION

The requirement that all control rods be inserted during other CORE ALTERATIONS ensures that fuel will not be loaded into a cell without a control rod.

3/4.9.4 DECAY TIME

The minimum requirement for reactor subcriticality prior to fuel movement ensures that sufficient time has elapsed to allow the radioactive decay of the short lived fission products. This decay time is consistent with the assumptions used in the accident analyses.

3/4.9.5 COMMUNICATIONS

The requirement for communications capability ensures that refueling station personnel can be promptly informed of significant changes in the facility status or core reactivity condition during movement of fuel within the reactor pressure vessel.

3/4.9.6 REFUELING PLATFORM

The OPERABILITY requirements ensure that (1) the refueling platform will be used for handling control rods and fuel assemblies within the reactor pressure vessel, (2) each crane and hoist has sufficient load capacity for handling fuel assemblies and control rods, and (3) the core internals and pressure vessel are protected from excessive lifting force in the event they are inadvertently engaged during lifting operations.

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3/4.9.7 CRANE TRAVEL - SPENT FUEL STORAGE POOL

The restriction on movement of loads in excess of the nominal weight of a fuel assembly over other fuel assemblies in the storage pool ensures that in the event this load is dropped 1) the activity release will be limited to that contained in a single fuel assembly, and 2) any possible distortion of fuel in the storage racks will not result in a critical array. This assumption is consistent with the activity release assumed in the safety analyses.

3/4.9.8 and 3/4.9.9 WATER LEVEL - REACTOR VESSEL and WATER LEVEL -SPENT FUEL STORAGE POOL

The restrictions on minimum water level ensure that sufficient water depth is available to remove 99% of the assumed 10% iodine gap activity released from the rupture of an irradiated fuel assembly. This minimum water depth is consistent with the assumptions of the accident analysis.

3/4.9.10 CONTROL ROD REMOVAL

These specifications ensure that maintenance or repair of control rods or control rod drives will be performed under conditions that limit the probability of inadvertent criticality. The requirements for simultaneous removal of more than one control rod are more stringent since the SHUTDOWN MARGIN specification provides for the core to remain subcritical with only one control rod fully withdrawn.

3/4.9.11 RESIDUAL HEAT REMOVAL AND COOLANT CIRCULATION

The requirement that at least one residual heat removal loop be OPERABLE or that an alternate method capable of decay heat removal be demonstrated and that an alternate method of coolant mixing be in operation ensures that (1) sufficient cooling capacity is available to remove decay heat and maintain the water in the reactor pressure vessel below 140°F as required during REFUELING, and (2) sufficient coolant circulation would be available through the reactor core to assure accurate temperature indication and to distribute and prevent stratification of the poison in the event it becomes necessary to actuate the standby liquid control system.

The requirement to have two shutdown cooling mode loops OPERABLE when there is less than (22'-3") of water above the reactor vessel flange ensures that a single failure of the operating loop will not result in a complete loss of residual heat removal capability. With the reactor vessel head removed and (22'-3") of water above the reactor vessel flange, a large heat sink is available for core cooling. Thus, in the event a failure of the operating RHR loop, adequate time is provided to initiate alternate methods capable of decay heat removal or emergency procedures to cool the core.

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BASES

3/4.10.1 PRIMARY CONTAINMENT INTEGRITY

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

3/4.10.2 ROD SEQUENCE CONTROL SYSTEM

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

3/4.10.3 SHUTDOWN MARGIN DEMONSTRATIONS

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

3/4.10.4 RECIRCULATION LOOPS

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

3/4.10.5 OXYGEN CONCENTRATION

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

3/4.10.6 TRAINING STARTUPS

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

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3/4.11.1 LIQUID EFFLUENTS

3/4.11.1.1 CONCENTRATION

This specification is provided to ensure that the concentration of radioactive materials released in liquid waste effluents to UNRESTRICTED AREAS will be less than the concentration levels specified in 10 CFR Part 20, Appendix B, Table II, Column 2. This limitation provides additional assurance that the levels of radioactive materials in bodies of water in UNRESTRICTED AREAS will result in exposures within: (1) the Section II.A design objectives of Appendix I, 10 CFR Part 50, to a MEMBER OF THE PUBLIC, and (2) the limits of 10 CFR Part 20.106(e) to the population. The concentration limit for dissolved or entrained noble gases is based upon the assumption that Xe-135 is the controlling radioisotope and its MPC in air (submersion) was converted to an equivalent concentration in water using the methods described in International Commission on Radiological Protection (ICRP) Publication 2.

The required detection capabilities for radioactive materials in liquid waste samples are tabulated in terms of the lower limits of detection (LLDs). Detailed discussion of the LLD, and other detection limits can be found in Currie, L.A., "Lower Limit of Detection: Definition and Elaboration of a Proposed Position for Radiological Effluent and Environmental Measurements," NUREG/CR-4007 (September 1984), and in the HASL Procedures Manual, HASL-300 (revised annually).

3/4.11.1.2 DOSE

This specification is provided to implement the requirements of Sections II.A, III.A and IV.A of Appendix I, 10 CFR Part 50. The Limiting Condition for Operation implements the guides set forth in Section II.A of Appendix I. The ACTION statements provide the required operating flexibility and at the same time implement the guides set forth in Section IV.A of Appendix I to assure that the releases of radioactive material in liquid effluents to UNRESTRICTED AREAS will be kept "as low as is reasonably achievable." The dose calculation methodology and parameters in the ODCM implement the requirements in Section III.A of Appendix I that conformance with the guides of Appendix I be shown by calculational procedures based on models and data, such that the actual exposure of a MEMBER OF THE PUBLIC through appropriate pathways is unlikely to be substantially underestimated. The equations specified in the ODCM for calculating the doses due to the actual release rates of radioactive materials in liquid effluents are consistent with the methodology provided in Regulatory Guide 1.109, "Calculation of Annual Doses to Man from Routine Releases of Reactor Effluents for the Purpose of Evaluating Compliance with 10 CFR Part 50, Appendix I" Revision 1, October 1977 and Regulatory Guide 1.113, "Estimating Aquatic Dispersion of Effluents from Accidental and Routine Reactor Releases for the Purpose of Implementing Appendix I," April 1977.

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3/4.11.1.3 LIQUID RADWASTE TREATMENT SYSTEM

The OPERABILITY of the Liquid Radwaste Treatment System ensures that this system will be available for use whenever liquid effluents require treatment prior to release to the environment. The requirement that the appropriate portions of this system be used when specified provides assurance that the releases of radioactive materials in liquid effluents will be kept "as low as is reasonably achievable". This specification implements the requirements of 10 CFR 50.36a, General Design Criterion 60 of Appendix A to 10 CFR Part 50 and the design objective given in Section II.D of Appendix I to 10 CFR Part 50. The specified limits governing the use of appropriate portions of the Liquid Radwaste Treatment System were specified as a suitable fraction of the dose design objectives set forth in Section II.A of Appendix I, 10 CFR Part 50, for liquid effluents.

3/4.11.1.4 LIQUID HOLDUP TANKS

The tanks listed in this specification include all those outdoor radwaste tanks that are not surrounded by liners, dikes, or walls capable of holding the tank contents and that do not have tank overflows and surrounding area drains connected to the Liquid Radwaste Treatment System.

Restricting the quantity of radioactive material contained in the specified tanks provides assurance that in the event of an uncontrolled release of the tanks' contents, the resulting concentrations would be less than the limits of 10 CFR Part 20, Appendix B, Table II, Column 2, at the nearest potable water supply and the nearest surface water supply in an UNRESTRICTED AREA.

3/4.11.2 GASEOUS EFFLUENTS

3/4.11.2.1 DOSE RATE

This specification is provided to ensure that the dose at any time at and beyond the SITE BOUNDARY from gaseous effluents from all units on the site will be within the annual dose limits of 10 CFR Part 20 to UNRESTRICTED AREAS. The annual dose limits are the doses associated with the concentrations of 10 CFR Part 20, Appendix B, Table II, Column 1. These limits provide reasonable assurance that radioactive material discharged in gaseous effluents will not result in the exposure of a MEMBER OF THE PUBLIC in an UNRESTRICTED AREA, either within or outside the SITE BOUNDARY, to annual average concentrations exceeding the limits specified in Appendix B, Table II of 10 CFR Part 20 (10 CFR 20.106(b)). For MEMBERS OF THE PUBLIC who may at times be within the SITE BOUNDARY, the occupancy of that MEMBER OF THE PUBLIC will usually be sufficiently low to compensate for any increase in the atmospheric diffusion factor above that for the SITE BOUNDARY. The specified release rate limits restrict, at all times, the corresponding gamma and beta dose rates above background to a MEMBER OF THE PUBLIC at or beyond the SITE BOUNDARY to less than or equal to 500 mrems/year to the whole body or to less than or equal to 3000 mrems/year to the skin. These release rate limits also restrict, at all

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DOSE RATE (Continued)

times the corresponding thyroid dose rate above background via the cow-milk-child pathway to less than or equal to 1500 mrems/year.

The required detection capabilities for radioactive materials in gaseous waste samples are tabulated in terms of the lower limits of detection (LLDs). Detailed discussion of the LLD, and other detection limits can be found in Currie, L.A., "Lower Limit of Detection: Definition and Elaboration of a Proposed Position for Radiological Effluent and Environments Measurements," NUREG/CR-4007 (September 1984), and in the HASL Procedures Manual, HASL-300 (revised annually).

3/4.11.2.2 DOSE - NOBLE GASES

This specification is provided to implement the requirements of Sections II.B, III.A and IV.A of Appendix I, 10 CFR Part 50. The Limiting Condition for Operation implements the guides set forth in Section II.B of Appendix I. The ACTION statements provide the required operating flexibility and at the same time implement the guides set forth in Section IV.A of Appendix I to assure that the releases of radioactive material in gaseous effluents to UNRESTRICTED AREAS will be kept "as low as is reasonably achievable." The Surveillance Requirements implement the requirements in Section III.A of Appendix I that conformance with the guides of Appendix I be shown by calculational procedures based on models and data such that the actual exposure of a MEMBER OF THE PUBLIC through appropriate pathways is unlikely to be substantially underestimated. The dose calculation methodology and parameters established in the ODCM for calculating the doses due to the actual release rates of radioactive materials in liquid effluents are consistent with the methodology provided in Regulatory Guide 1.109, "Calculation of Annual Doses to Man from Routine Releases of Reactor Effluents for the Purpose of Evaluating Compliance with 10 CFR Part 50, Appendix I" Revision 1, October 1977 and Regulatory Guide 1.111, "Methods for Estimating Atmospheric Transport and Dispersion of Gaseous Effluents in Routine Releases from Light-Water Cooled Reactors," Revision 1," July 1977. The ODCM equations provided for determining the air doses at ~~and~~ beyond the SITE BOUNDARY are based upon real-time meteorological conditions or the historical average atmospheric conditions.

3/4.11.2.3 DOSE - IODINE-131 AND 133, TRITIUM, AND RADIONUCLIDES IN PARTICULATE FORM

This specification is provided to implement the requirements of Sections II.C, III.A and IV.A of Appendix I, 10 CFR Part 50. The Limiting Conditions for Operation are the guides set forth in Section II.C of Appendix I. The ACTION statements provide the required operating flexibility and at the same time implement the guides set forth in Section IV.A of Appendix I to assure that the releases of radioactive materials in gaseous effluents to UNRESTRICTED AREAS will be kept "as low as is reasonably achievable." The ODCM calculational

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DOSE - IODINE-131 AND 133, TRITIUM, AND RADIONUCLIDES IN PARTICULATE FORM (Continued)

methods specified in the Surveillance Requirements implement the requirements in Section III.A of Appendix I that conformance with the guides of Appendix I be shown by calculational procedures based on models and data, such that the actual exposure of a MEMBER OF THE PUBLIC through appropriate pathways is unlikely to be substantially underestimated. The ODCM calculational methodology and parameters for calculating the doses due to the actual release rates of the subject materials are consistent with the methodology provided in Regulatory Guide 1.109, "Calculation of Annual Doses to Man from Routine Releases of Reactor Effluents for the Purpose of Evaluating Compliance with 10 CFR Part 50, Appendix I," Revision 1, October 1977 and Regulatory Guide 1.111, "Methods for Estimating Atmospheric Transport and Dispersion of Gaseous Effluents in Routine Releases from Light-Water-Cooled Reactors," Revision 1, July 1977. These equations also provide for determining the actual doses based upon the historical average atmospheric conditions. The release rate specifications for Iodine-131, Iodine-133, tritium, and radionuclides in particulate form with half-lives greater than 8 days are dependent upon the existing radionuclide pathways to man, in the areas at ~~and~~ or beyond the SITE BOUNDARY. The pathways that were examined in the development of these calculations were: (1) individual inhalation of airborne radionuclides, (2) deposition of radionuclides onto green leafy vegetation with subsequent consumption by man, (3) deposition onto grassy areas where milk animals and meat producing animals graze with consumption of the milk and meat by man, and (4) deposition on the ground with subsequent exposure to man.

3/4.11.2.4 AND 3/4.11.2.5 GASEOUS RADWASTE TREATMENT SYSTEM AND VENTILATION EXHAUST TREATMENT SYSTEM

The OPERABILITY of the GASEOUS RADWASTE TREATMENT SYSTEM and the VENTILATION EXHAUST TREATMENT SYSTEM ensures that the systems will be available for use whenever gaseous effluents require treatment prior to release to the environment. The requirement that the appropriate portions of these systems be used, when specified provides reasonable assurance that the releases of radioactive materials in gaseous effluents will be kept "as low as is reasonably achievable". This specification implements the requirements of 10 CFR 50.36a, General Design Criterion 60 of Appendix A to 10 CFR Part 50 and the design objectives given in Section II.D of Appendix I to 10 CFR Part 50. The specified limits governing the use of appropriate portions of the system were specified as a suitable fraction of the dose design objectives set forth in Section II.B and II.C of Appendix I, 10 CFR Part 50, for gaseous effluents.

3/4.11.2.6 EXPLOSIVE GAS MIXTURE

This specification is provided to ensure that the concentration of potentially explosive gas mixtures contained in the GASEOUS RADWASTE TREATMENT SYSTEM is maintained below the flammability limits of hydrogen. Automatic control features are included in the system to prevent the hydrogen concentrations from reaching these flammability limits. These automatic control

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3/4.11.2.6 EXPLOSIVE GAS MIXTURE (continued)

features include injection of dilutants to reduce concentrations below flammability limits. Maintaining the concentration of hydrogen below their flammability limits provides assurance that the releases of radioactive materials will be controlled in conformance with the requirements of General Design Criterion 60 of Appendix A to 10 CFR Part 50.

3/4.11.2.7 MAIN CONDENSER - OFFGAS

Restricting the gross radioactivity rate of noble gases from the main condenser offgas provides reasonable assurance that the total body exposure to an individual at the exclusion area boundary will not exceed a small fraction of the limits of 10 CFR Part 100 in the event this effluent is inadvertently discharged directly to the environment without treatment. This specification implements the requirements of General Design Criteria 60 and 64 of Appendix A to 10 CFR Part 50.

3/4.11.2.8 VENTING OR PURGING

This specification provides reasonable assurance that releases from drywell and/or suppression chamber purging operations will not exceed the annual dose limits of 10 CFR Part 20 for unrestricted areas.

3/4.11.3 SOLID RADIOACTIVE WASTES

This specification implements the requirements of 10 CFR 50.36a and General Design Criterion 60 of Appendix A to 10 CFR Part 50. The process parameters included in establishing the PROCESS CONTROL PROGRAM may include, but are not limited to, waste type, waste pH, waste/liquid/SOLIDIFICATION agent/catalyst ratios, waste oil content, waste principal chemical constituents, and mixing and curing times.

3/4.11.4 TOTAL DOSE

This specification is provided to meet the dose limitations of 40 CFR Part 190 that have been incorporated into 10 CFR Part 20 by 46 FR 18525. The specification requires the preparation and submittal of a Special Report whenever the calculated doses due to releases of radioactivity and to radiation from uranium fuel cycle sources exceed 25 mrems to the whole body or any organ, except the thyroid, which shall be limited to less than or equal to 75 mrems. For sites containing up to four reactors, it is highly unlikely that the resultant dose to a MEMBER OF THE PUBLIC will exceed the dose limits of 40 CFR Part 190 if the individual reactors remain within twice the dose design objectives of Appendix I, and if direct radiation doses from the units including outside storage tanks, etc., are kept small. The Special Report will describe a course of action that should result in the limitation of the annual dose to a MEMBER OF THE PUBLIC to within the 40 CFR Part 190 limits. For the purposes of the

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TOTAL DOSE (Continued)

Special Report, it may be assumed that the dose commitment to the MEMBER of the PUBLIC from other uranium fuel cycle sources is negligible, with the exception that dose contributions from other nuclear fuel cycle facilities at the same site or within a radius of 5 miles must be considered. If the dose to any MEMBER OF THE PUBLIC is estimated to exceed the requirements of 40 CFR Part 190, the Special Report with a request for a variance (provided the release conditions resulting in violation of 40 CFR Part 190 have not already been corrected), in accordance with the provisions of 40 CFR 190.11 and 10 CFR 20.405c, is considered to be a timely request and fulfills the requirements of 40 CFR Part 190 until NRC staff action is completed. The variance only relates to the limits of 40 CFR Part 190, and does not apply in any way to the other requirements for dose limitation of 10 CFR Part 20, as addressed in Specifications 3.11.1.1 and 3.11.2.1. An individual is not considered a MEMBER OF THE PUBLIC during any period in which he/she is engaged in carrying out any operation that is part of the nuclear fuel cycle.

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3/4.12 RADIOLOGICAL ENVIRONMENTAL MONITORING

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BASES

3/4.12.1 MONITORING PROGRAM

The Radiological Environmental Monitoring Program required by this specification provides representative measurements of radiation and of radioactive materials in those exposure pathways and for those radionuclides that lead to the highest potential radiation exposure of MEMBERS OF THE PUBLIC resulting from the plant operation. This monitoring program implements Section IV.B.2 of Appendix I to 10 CFR Part 50 and thereby supplements the Radiological Effluent Monitoring Program by verifying that the measurable concentrations of radioactive materials and levels of radiation are not higher than expected on the basis of the effluent measurements and the modeling of the environmental exposure pathways. Guidance for this monitoring program is provided by the Radiological Assessment Branch Technical Position on Environmental Monitoring, Revision 1, November 1979. The initially specified monitoring program will be effective for at least the first 3 years of commercial operation. Following this period, program changes may be initiated based on operational experience.

The required detection capabilities for environmental sample analyses are tabulated in terms of the lower limits of detection (LLDs). The LLDs required by Table 4.12-1 are considered optimum for routine environmental measurements in industrial laboratories. It should be recognized that the LLD is defined as an a priori (before the fact) limit representing the capability of a measurement system and not as an a posteriori (after the fact) limit for a particular measurement.

Detailed discussion of the LLD, and other detection limits, can be found in Currie, L.A., "Lower Limit of Detection: Definition and Elaboration of a Proposed Position for Radiological Effluent and Environmental Measurements," NUREG/CR-4007 (September 1984), and in the HASL Procedures Manual, HASL-300 (revised annually).

3/4.12.2 LAND USE CENSUS

This specification is provided to ensure that changes in the use of areas at and beyond the SITE BOUNDARY are identified and that modifications to the Radiological Environmental Monitoring Program are made if required by the results of this census. The best information, such as from a door-to-door survey, from an aerial survey, or from consulting with local agricultural authorities shall be used. This census satisfies the requirements of Section IV.B.3 of Appendix I to 10 CFR Part 50. In lieu of a graden census, the significance of the exposure via the garden pathway can be evaluated by the sampling of vegetation as specified in Table 3.12-1.

A MILK SAMPLING LOCATION, as defined in Section 1, requires that at least 10 milking cows are present at a designated milk sample location. It has been found from past experience, and as a result of conferring with local farmers, that a minimum of 10 milking cows is necessary to guarantee an adequate supply of milk twice per month for analytical purposes. Locations with less than 10 milking cows are usually utilized for breeding purposes which eliminates a stable supply of milk for samples as a result of suckling calves and periods when the adult animals are dry.

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3/4.12.3 INTERLABORATORY COMPARISON PROGRAM

The requirement for participation in an approved Interlaboratory Comparison Program is provided to ensure that independent checks on the precision and accuracy of the measurements of radioactive materials in environmental sample matrices are performed as part of the quality assurance program for environmental monitoring in order to demonstrate that the results are valid for the purposes of Section IV.B.2 of Appendix I to 10 CFR Part 50.

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SECTION 5.0

DESIGN FEATURES

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5.0 DESIGN FEATURES

5.1 SITE

The Nine Mile Point Nuclear Station and James A. FitzPatrick Nuclear Power Plant site comprising approximately 1500 acres, is located on the shores of Lake Ontario, about seven miles northeast of Oswego, New York. An exclusion distance of nearly 4000 feet is provided between the station and the nearest SITE BOUNDARY to the west, a mile to the boundary on the east, and a mile and a half to the southern SITE BOUNDARY.

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 AND SITE BOUNDARY FOR RADIOACTIVE GASEOUS AND LIQUID EFFULENTS

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 Figure 5.1.3-1.

5.2 CONTAINMENT

5.2.1 The primary containment is a steel lined concrete structure consisting of a drywell and suppression chamber. The drywell is a steel-lined prestressed 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 (303,418) cubic feet. The suppression chamber has a minimum air region of 192,028 cubic feet and a minimum water region of 145,495 cubic feet.

DESIGN TEMPERATURE AND PRESSURE

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

a. Maximum internal pressure 45 psig.

b. Maximum internal temperature: drywell 340°F.
suppression pool 212°F
suppression chamber 270°F.

c. Maximum external pressure 4.7 psig.

d. Maximum floor differential pressure: 25 psid, downward.
10 psid, upward.

ITEM NO.	FSAR LOCATION	TECH. SPEC. LOCATION	SUBJECT
28)	6.3-14a 1886	Table 3.3.3-2	LPCS Injection Valve Differential Pressure Perimissive Setpoint
29)	F210.62 1908	L.C.O. 3.4.3.2.d and Tables 3.4.3.2-1, 3.4.3.2-2 and 3.4.3.2-3	Leak Rate Testing Of Valves Separating Reactor Coolant System From Low Pressure Systems
1889 30)	Table 12.3-1 Page 2 of 4	Table 3.3.7.1-1	Main Control Room Ventilation Radiation Monitors
1818 31)	Tables 8.3-8 and 8.3-9	4.8.2.1.d.2.a) and b)	Divisions I and II Battery Load Profiles

ABBREVIATION LIST

HPCS - High Pressure Core Spray
ADS - Automatic Depressurization System
LPCI - Low Pressure Coolant Injection
TIP - Traversing Incore Probe
RCIC - Reactor Core Isolation Cooling
RHR - Residual Heat Removal
RWCU - Reactor Water Cleanup
LPCS - Low Pressure Core Spray

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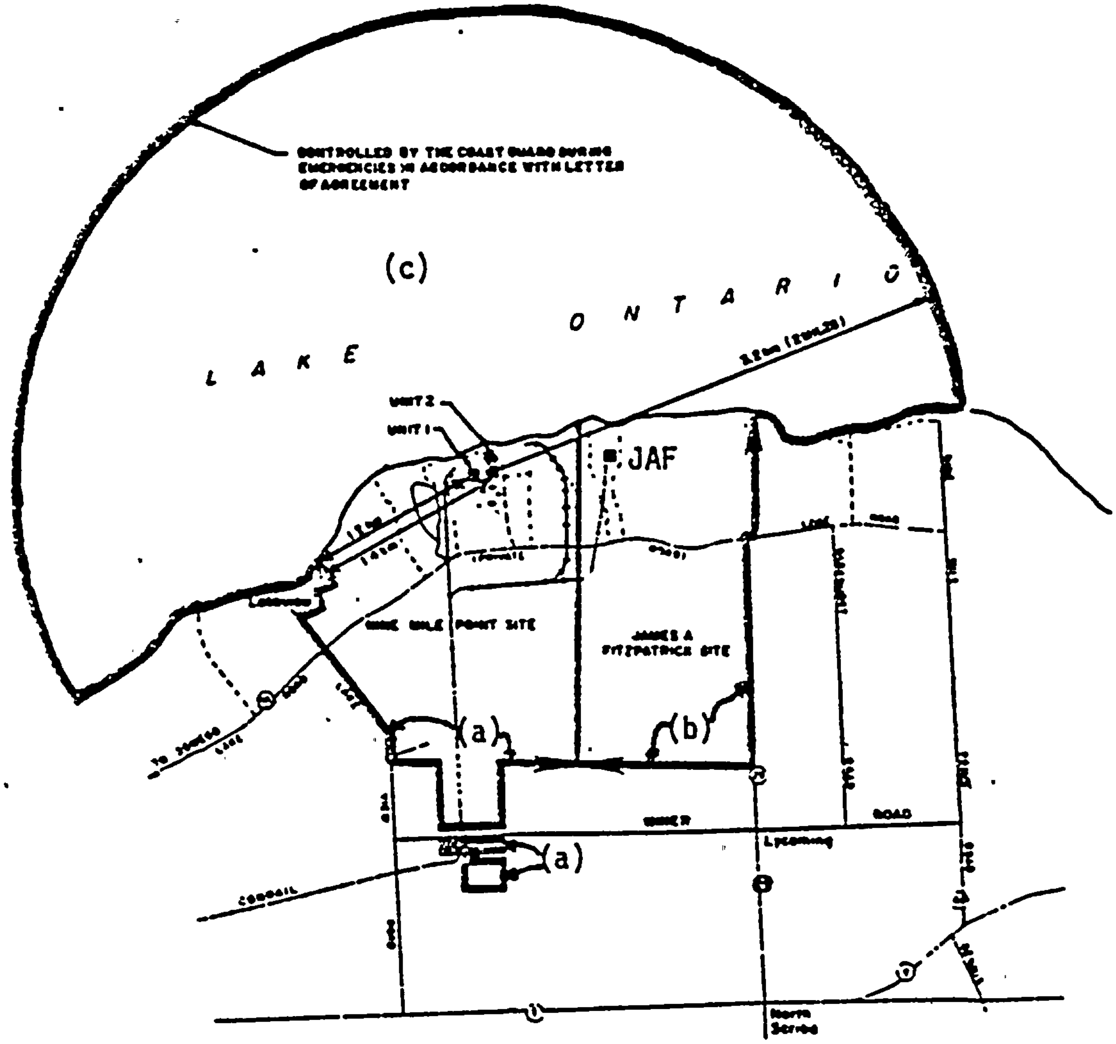

EXCLUSION AREA BOUNDARY

(a) Niagara Mohawk Power Corp. Property Line
(b) New York Power Authority Property Line
(c) Region Controlled By Coast Guard During Emergencies.

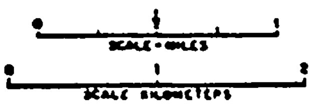

FIGURE 5.1.1-1 EXCLUSION AREA BOUNDARY

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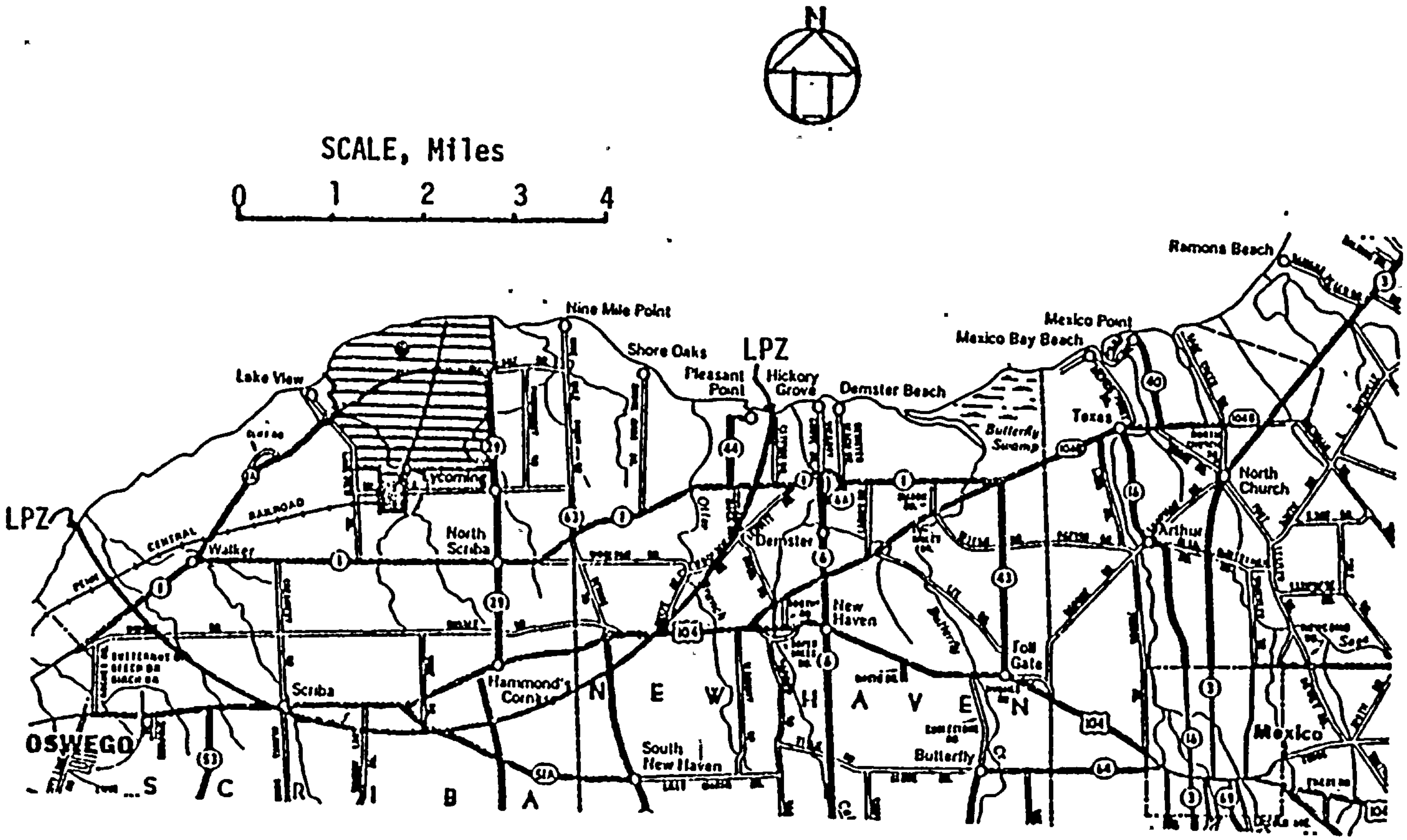
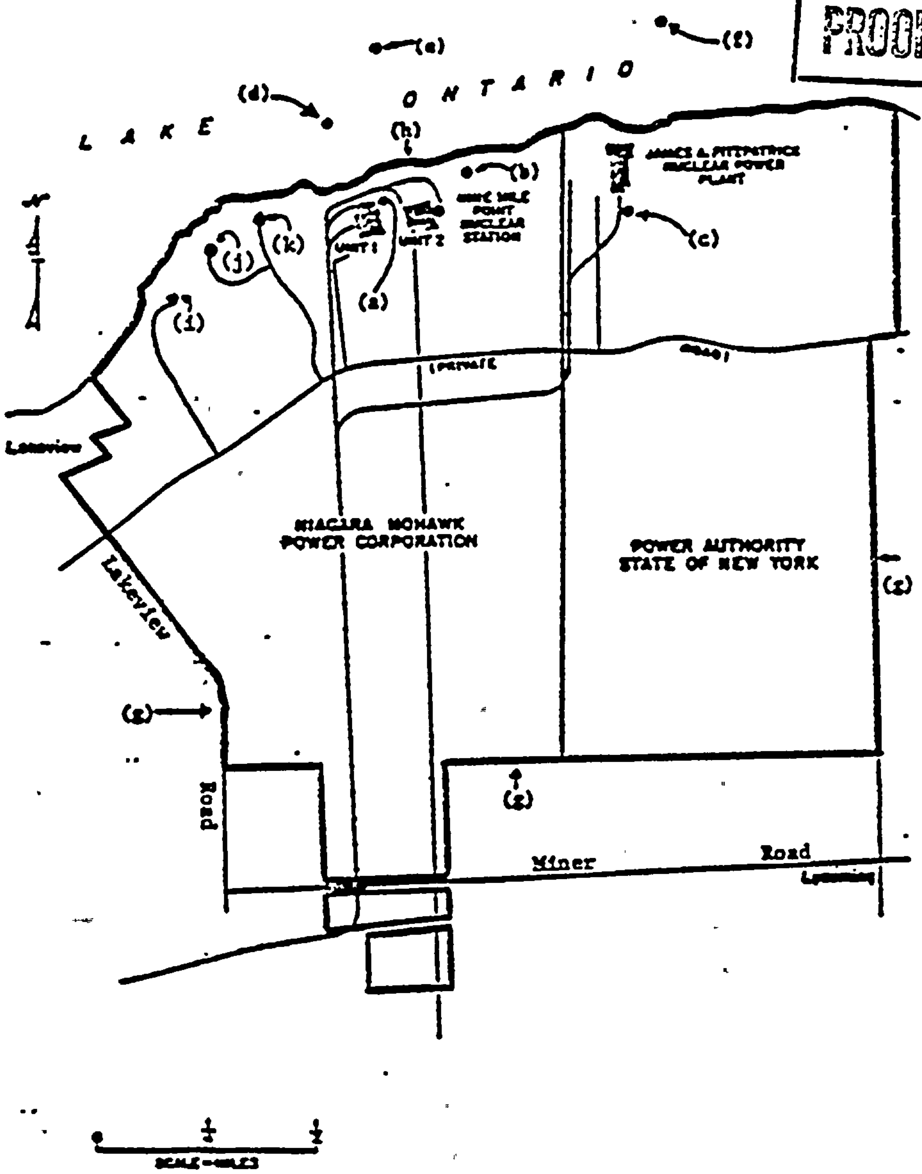


FIGURE 5.1.2-1 LOW POPULATION ZONE, LPZ



SITE BOUNDARIES
FIGURE 5.1.3-1

NOTES TO FIGURE 5.1.3-1

(a) NMP1 Stack (height is 350')
(b) NMP2 Stack (height is 430')
(c) JAFNPP Stack (height is 385')
(d) NMP1 Radioactive Liquid Discharge (Lake Ontario, bottom)
(e) NMP2 Radioactive Liquid Discharge (Lake Ontario, bottom)
(f) JAFNPP Radioactive Liquid Discharge (Lake Ontario, bottom)
(g) Site Boundary
(h) Lake Ontario Shoreline
(i) Meteorological Tower
(j) Training Center
(k) Energy Information Center

Additional Information:

- NMP2 Reactor Building Vent is located 187 feet above ground level
- JAFNPP Reactor and Turbine Building Vents are located 173 feet above ground level
- JAFNPP Radwaste Building Vent is 112 feet above ground level
- The Energy Information Center and adjoining picnic area are UNRESTRICTED AREAS within the SITE BOUNDARY that are accessible to MEMBERS OF THE PUBLIC
- Lake Road, a private road, is an UNRESTRICTED AREA within the SITE BOUNDARY accessible to MEMBERS OF THE PUBLIC

SECONDARY CONTAINMENT

5.2.3 The secondary containment consists of the (Reactor Building, and the North and South Auxiliary Bays and has a minimum free volume of 3,876,630 cubic feet.

5.3 REACTOR CORE

FUEL ASSEMBLIES

5.3.1 The reactor core shall contain 764 fuel assemblies with each fuel assembly containing 62 fuel rods and two water rods clad with Zircaloy -2. Each fuel rod shall have a nominal active fuel length of 150 inches. The initial core loading shall have a maximum average enrichment of 1.88 weight percent U-235.

CONTROL ROD ASSEMBLIES

5.3.2 The reactor core shall contain 185 control rod assemblies, each consisting.of a cruciform array of stainless steel tubes containing 143 inches of boron carbide, B_4C, powder surrounded by a cruciform shaped stainless steel sheath.

5.4 REACTOR COOLANT SYSTEM

DESIGN PRESSURE AND TEMPERATURE

5.4.1 The reactor coolant system is designed and shall be maintained:

a. In accordance with the code requirements specified in Section 5.2 of the FSAR, with allowance for normal degradation pursuant to the applicable Surveillance Requirements,

b. For a pressure of:

1. 1250 psig on the suction side of the recirculation pump.
2. 1650 psig from the recirculation pump discharge to the outlet side of the discharge shutoff valve.
3. 1550 psig from the discharge shutoff valve to the jet pumps.

c. For a temperature of 575°F.

VOLUME

5.4.2 The total water and steam volume of the reactor vessel and recirculation system is approximately 22,000 cubic feet at a nominal steam dome saturation (average) temperature of 533°F.

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5.5 METEOROLOGICAL TOWER LOCATION

5.5.1 The meteorological tower shall be located as shown on Figure 5.1.~~1~~ 3-1.

5.6 FUEL STORAGE

CRITICALITY

5.6.1 The spent fuel storage racks are designed and shall be maintained with:

a. A k_{eff} equivalent to less than or equal to 0.95 when flooded with unborated water, including all calculational uncertainties and biases as described in Section 9-1 of the FSAR.

b. A nominal 6.18 inch center-to-center distance between fuel assemblies placed in the storage racks.

5.6.1.2 The k_{eff} for new fuel stored in the new fuel storage racks shall not exceed 0.95 in the normal dry condition or in the abnormal completely water flooded condition, ~~with the non-combustible storage vault covers in place~~. The K_{eff} shall not exceed 0.98 ~~when optimum moderation (foam, spray, fogging, or small droplets) is assumed.~~ with all but one of the non-combustible storage vault covers in place when optimum moderation (foam, spray, fogging, or small droplets) is assumed.

DRAINAGE

5.6.2 The spent fuel storage pool is designed and shall be maintained to prevent inadvertent draining of the pool below elevation 329'-7".

CAPACITY

5.6.3 The spent fuel storage pool is designed and shall be maintained with a storage capacity limited to no more than 4050 fuel assemblies.

5.7 COMPONENT CYCLIC OR TRANSIENT LIMIT

5.7.1 The components identified in Table 5.7.1-1 are designed and shall be maintained within the cyclic or transient limits of Table 5.7.1-1.

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TABLE 5.7.1-1

COMPONENT CYCLIC OR TRANSIENT LIMITS

COMPONENT	CYCLIC OR TRANSIENT LIMIT	DESIGN CYCLE OR TRANSIENT
Reactor	120 heatup and cooldown cycles	70°F to 565°F to 70°F
	80 step change cycles	Loss of feedwater heaters
	198 reactor trip cycles	100% to 0% of RATED THERMAL POWER
	130 hydrostatic pressure and leak tests	Pressurized to $\geq$ 930 psig and $\leq$ 1250 psig

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5.5 METEOROLOGICAL TOWER LOCATION

5.5.1 The meteorological tower shall be located as shown on Figure 5.1.1-1.

5.6 FUEL STORAGE

CRITICALITY

5.6.1 The spent fuel storage racks are designed and shall be maintained with:

a. A k_{eff} equivalent to less than or equal to 0.95 when flooded with unborated water, including all calculational uncertainties and biases as described in Section 4.3 of the FSAR.

b. A nominal 6.18 inch center-to-center distance between fuel assemblies placed in the storage racks.

5.6.1.2 The k_{eff} for new fuel stored in the new fuel storage racks shall not exceed 0.95 in the normal dry condition or in the abnormal completely water flooded condition with the non-combustible storage vault covers in place.

DRAINAGE

5.6.2 The spent fuel storage pool is designed and shall be maintained to prevent inadvertent draining of the pool below elevation 329'-7".

CAPACITY

5.6.3 The spent fuel storage pool is designed and shall be maintained with a storage capacity limited to no more than 4050 fuel assemblies.

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	198 reactor trip cycles	100% to 0% of RATED THERMAL POWER
	130 hydrostatic pressure and leak tests	Pressurized to $\geq$ 930 psig and $\leq$ 1250 psig

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SECTION 6.0

ADMINISTRATIVE CONTROLS

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6.1 RESPONSIBILITY

6.1.1 The General Superintendent - Nuclear Generation shall be responsible for overall unit operation and shall delegate in writing the succession to this responsibility during his absence.

6.1.2 The Station Shift Supervisor - Nuclear (or during his absence from the control room, a designated individual) shall be responsible for the control room command function. A management directive to this effect, signed by the Vice President - Nuclear Generation shall be reissued to all station personnel on an annual basis.

6.2 ORGANIZATION

OFFSITE

6.2.1 The offsite organization for unit management and technical support shall be as shown on Figure 6.2.1-1.

UNIT STAFF

6.2.2 The unit organization shall be as shown on Figure 6.2.2-1 and:

a. Each on duty shift shall be composed of at least the minimum shift crew composition shown in Table 6.2.2-1;

b. At least one licensed Operator shall be in the control room when fuel is in the reactor. During reactor operation, this licensed operator shall be present at the controls of the facility.

c. An individual qualified in radiation protection* procedures shall be on site when fuel is in the reactor;

d. At least two licensed operators shall be present in the control room during reactor startup, scheduled reactor shutdown and during recovery from reactor trips.

e. A licensed Senior Reactor Operator shall be required in the Control Room during Operational Conditions 1, 2 and 3 and when the emergency plan is activated. This may be the Station Shift Supervisor - Nuclear or the Assistant Station Shift Supervisor - Nuclear during power operations. When the emergency plan is activated, the Assistant Station Shift Supervisor - Nuclear becomes the Shift Technical Advisor and the Station Shift Supervisor - Nuclear is restricted in the control room until an additional licensed Senior Reactor Operator arrives.

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*The Radiation Protection qualified individual and fire brigade composition may be less than the minimum requirements for a period of time not to exceed 2 hours, in order to accommodate unexpected absence, provided immediate action is taken to fill the required positions.

UNIT STAFF (continued)

f. A licensed Senior Reactor Operator shall be responsible for all movement of new and irradiated fuel within the site boundary. All core alterations shall be directly supervised by a licensed senior reactor operator who has no other concurrent responsibilities during this operation. A Licensed Operator will be required to manipulate the controls of all fuel handling equipment except movement of new fuel from receipt through dry storage. All fuel moves within the core shall be directly monitored by a member of the reactor analyst group.

g. A Fire Brigade* of five (5) members shall be maintained on site at all times.

h. Administrative procedures shall be developed and implemented to limit the working hours of facility staff who perform safety-related functions; e.g., licensed Senior Operators, licensed Operators, health physicists, auxillary operators and key maintenance personnel.

i. Adequate shift coverage shall be maintained without routine heavy use of overtime. The objective shall be to have operating personnel work a normal 8-hour day, 40-hour week while the unit is operating. However, in the event that unforeseen problems require substantial amounts of overtime to be used, or during extended periods of shutdown for refueling, major maintenance, or major unit modifications, on a temporary basis the following guidelines shall be followed:

1. An individual should not be permitted to work more than 16 hours straight, excluding shift turnover time.

2. An individual should not be permitted to work more than 16 hours in any 24-hour period, nor more than 24 hours in any 48-hour period, nor more than 72 hours in any seven day period, all excluding shift turnover time.

3. A break of at least eight hours should be allowed between work periods, including shift turnover time.

4. Except during extended shutdown periods, the use of overtime should be considered on an individual basis and not for the entire staff on a shift.

Any deviation from the above guidelines shall be authorized by the General Superintendent - Nuclear Generation or his deputy, or higher levels of management, in accordance with established procedures and with documentation of the basis for granting the deviation. Controls shall be included in the procedures such that individual overtime shall be reviewed monthly by the General Superintendent - Nuclear Generation or his designee to assure that excessive hours have not been assigned. Routine deviation from the above guidelines is not authorized.

repeat footnote from 6-1

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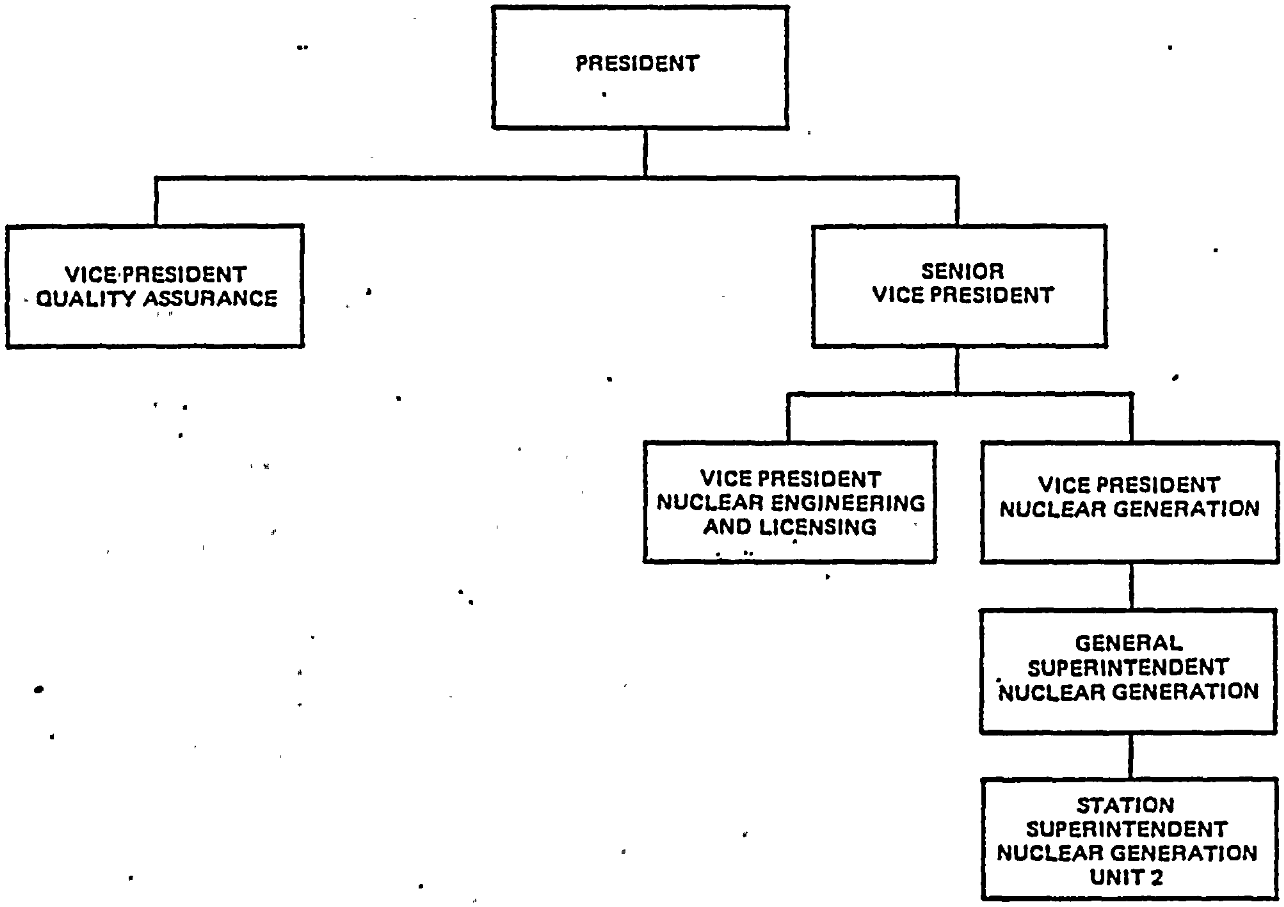
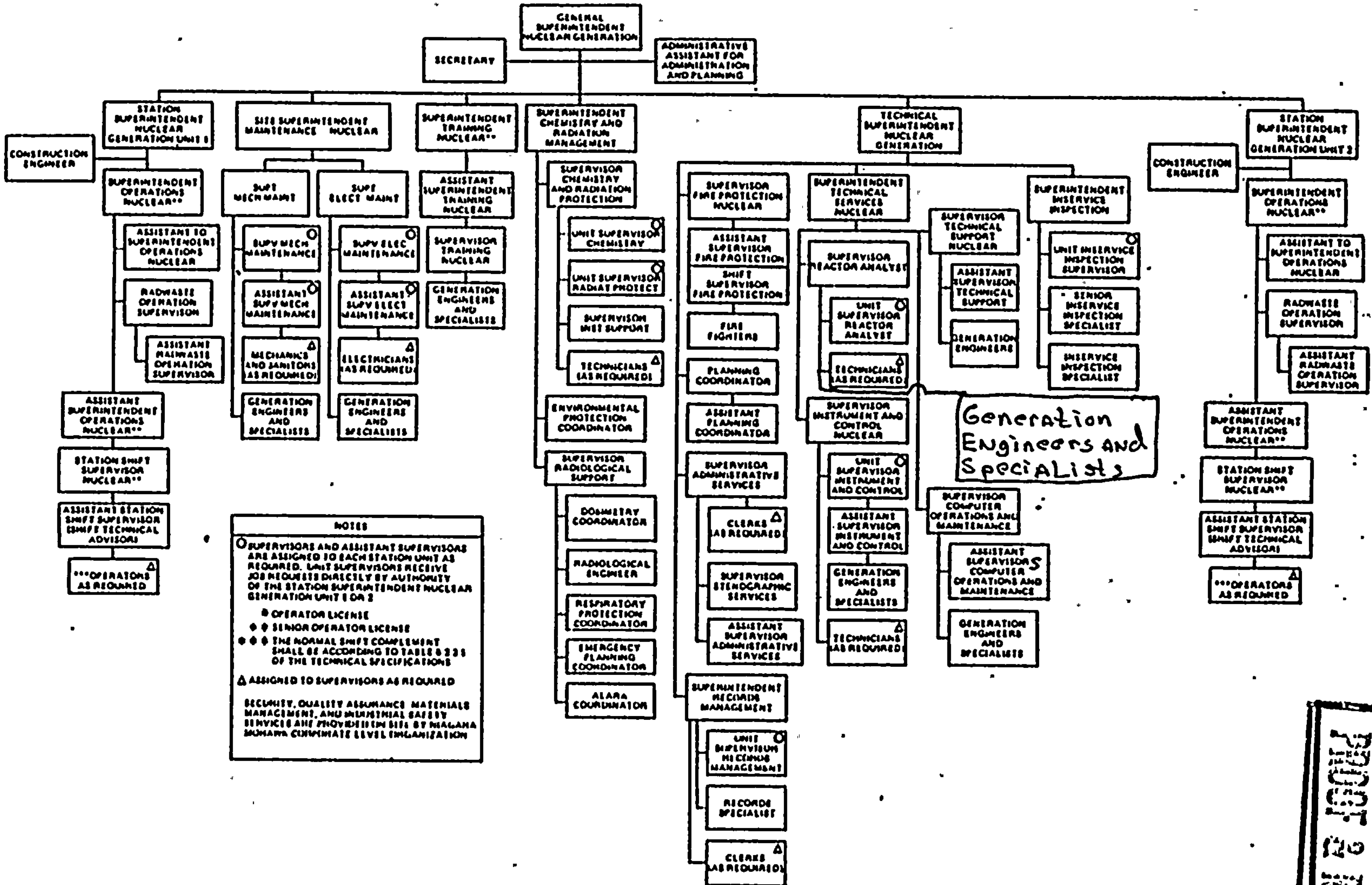


Figure 6.2.1-1
Nine Mile Point Nuclear Station
Management Organization Chart

FIGURE 6.2-2
NINE MILE POINT NUCLEAR SITE OPERATIONS ORGANIZATION



NOTES

○ SUPERVISORS AND ASSISTANT SUPERVISORS ARE ASSIGNED TO EACH STATION UNIT AS REQUIRED. UNIT SUPERVISORS RECEIVE JOB REQUESTS DIRECTLY BY AUTHORITY OF THE STATION SUPERINTENDENT NUCLEAR GENERATION UNIT 1 OR 2

* OPERATOR LICENSE

** SENIOR OPERATOR LICENSE

*** THE NORMAL SHIFT COMPLEMENT SHALL BE ACCORDING TO TABLE 6.2.2-1 OF THE TECHNICAL SPECIFICATIONS

△ ASSIGNED TO SUPERVISORS AS REQUIRED

SECURITY, QUALITY ASSURANCE, MATERIALS MANAGEMENT, AND INDUSTRIAL SAFETY SERVICES ARE PROVIDED ON SITE BY NIAGARA MOHAWK CORPORATE LEVEL ORGANIZATION

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TABLE 6.2.2-1

MINIMUM SHIFT CREW COMPOSITION (1) (6)

License	Normal Operation	Shutdown Condition	Operation (1) W/O Process Computer	Reactor Startups
Senior Operator	1(8)	1(5)	1	1
Operator	2	1	2	3
Unlicensed(2)	2	1	3	2
Asst. Station Shift Supervisor (Shift Technical Advisor Function) (Senior Operator License)(7)	1	1(4)	1	1

TABLE NOTATION

(1) At any one time, more licensed or unlicensed operating people could be present for maintenance, repairs, refuel outages, etc.

(2) Those operating personnel not holding an "Operator" or "Senior Operator" License.

(3) For operation longer than eight hours without process computer.

(4) Hot shutdown condition only.

(5) An additional senior reactor operator who has no other concurrent responsibilities shall supervise all core alterations.

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

(7) The Assistant Station Shift Supervisor performs the Shift Technical Advisor function and shall hold a senior reactor operator license.

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

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

from the control room while the unit is in OPERATIONAL CONDITION 4 or 5, an individual with a valid Senior Operator license or Operator license shall be designated to assume the control room command function.

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6.2.3 INDEPENDENT SAFETY ENGINEERING GROUP (ISEG)

FUNCTION

6.2.3.1 The ISEG shall function to examine unit operating characteristics, NRC issuances, industry advisories, Licensee Event Reports, and other sources of unit design and operating experience information, including units of similar design, which may indicate areas for improving unit safety. The ISEG shall make detailed recommendations for revised procedures, equipment modifications, maintenance activities, operations activities, or other means of improving unit safety to the Supervisor Technical Support Nuclear.

COMPOSITION

6.2.3.2 The ISEG shall be composed of at least five, dedicated, full-time engineers located onsite. Each shall have a bachelor's degree in engineering or related science and at least 2 years professional level experience in his field, at least 1 year of which experience shall be in the nuclear field.

RESPONSIBILITIES

6.2.3.3 ~~The principal function of the ISEG is to examine plant operating characteristics and the various NRC and industry licensing and service advisories, and to recommend areas for improving plant operations or safety. The ISEG will perform independent review of plant activities, including maintenance, modifications, operational concerns and analysis and make recommendations to the Supervisor Technical Support-Nuclear.~~ ISEG is responsible to the Technical Superintendent Nuclear Generation and Superintendent Technical Services Nuclear to insure items identified as deficient get resolved in accordance with approved methods and procedures.

RECORDS

6.2.3.4 Records of activities performed by the ISEG shall be prepared, maintained, and forwarded each calendar month to the ~~Manager - Nuclear Technology.~~ Technical Superintendent Nuclear Generation.

6.2.4 ASSISTANT STATION SHIFT SUPERVISOR (ASSS)

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

6.3 FACILITY STAFF QUALIFICATIONS

ANSI/ANS-3.1-1978

6.3.1 Each member of the unit staff shall meet or exceed the minimum qualifications of ~~ANSI N18.1-1971~~ for comparable positions, ~~except for~~ in addition the ASSS who shall meet or exceed the qualifications of Regulatory Guide 1.8, September 1975. The licensed Operators and Senior Operators shall also meet or exceed the minimum qualifications of the supplemental requirements specified in Sections A and C of Enclosure 1 of the March 28, 1980 NRC letter to all licensees.

~~*Not responsible for sign-off function.~~

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6.4 TRAINING

ANSI/ANS -3.1-1978

6.4.1 A retraining and replacement training program for the unit staff shall be maintained under the direction of the Superintendent-Training Nuclear, shall meet or exceed the requirements and recommendations of Section 5.5 of ~~ANSI N18.1-1971~~ and Appendix A of 10 CFR Part 55 and the supplemental requirements specified in Sections A and C of Enclosure 1 of the March 28, 1980 NRC letter to all licensees, and shall include familiarization with relevant industry operational experience. A training program for the Fire Brigade shall be maintained under the direction of the Superintendent - Training Nuclear and Supervisor - Fire Protection Nuclear and shall meet or exceed the requirements of Appendix R to 10 CFR Part 50.

6.5 REVIEW AND AUDIT

6.5.1 SITE OPERATIONS REVIEW COMMITTEE (SORC)

FUNCTION

6.5.1.1 The SORC shall function to advise the General Superintendent-Nuclear Generation on all matters related to nuclear safety.

COMPOSITION

6.5.1.2 The SORC shall be composed of the:

Chairman:	General Superintendent-Nuclear Generation
Member:	Station Superintendent-Nuclear Generation
Member:	Technical Superintendent-Nuclear Generation
Member:	Superintendent Technical Services-Nuclear
Member:	Site Superintendent Maintenance-Nuclear
Member:	Supervisor Instrument and Control-Nuclear
Member:	Superintendent Chemistry and Radiation Management
Member:	Supervisor Reactor Analysis
Member:	Supervisor Technical Support
Member:	(Engineer)
Member:	Supervisor Computer Operations and Maintenance

ALTERNATES

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

MEETING FREQUENCY

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

QUORUM

6.5.1.5 The quorum of the SORC necessary for the performance of the SORC responsibility and authority provisions of these Technical Specifications shall consist of the Chairman or his designated alternate and ~~four~~ 5 members including alternates.

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RESPONSIBILITIES

6.5.1.6 The SORC shall be responsible for:

a. Investigation of all violations of the Technical Specifications, including the preparation and forwarding of reports covering evaluation and recommendations to prevent recurrence, to the Vice President-Nuclear Generation and to the Safety Review and Audit Board;

b. Review all REPORTABLE EVENTS;

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

d. Performance of special reviews, investigations, or analyses and reports thereon as requested by the General Superintendent-Nuclear Generation or the Safety Review and Audit Board;

6.5.1.7 The SORC shall:

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

b. Provide written notification within 24 hours to the Vice President-Nuclear Generation and the Safety Review and Audit Board of disagreement between the SORC and the General Superintendent-Nuclear Generation; however, the General Superintendent-Nuclear Generation shall have responsibility for resolution of such disagreements pursuant to Specification 6.1.1.

RECORDS

6.5.1.8 The SORC shall maintain written minutes of each SORC meeting. Copies shall be provided to the Vice President - Nuclear Generation and the Safety Review and Audit Board.

6.5.2 TECHNICAL REVIEW AND CONTROL

ACTIVITIES

6.5.2.1 Each procedure and program required by Specification 6.8 and other procedures which affect nuclear safety, and changes thereto, shall be prepared by a qualified individual/organization. Each such procedure, and changes thereto, shall be reviewed by an individual/group other than the individual/group which prepared the procedure, or changes thereto, but who may be from the same organization as the individual/group which prepared the procedure, or changes thereto. Approval of procedures and programs and changes thereto and their safety evaluations, shall be controlled by administrative procedures.

6.5.2.2 Proposed changes to the Technical Specifications shall be prepared by a qualified individual/organization. The preparation of each proposed Technical Specifications change shall be reviewed by an individual/group other than the individual/group which prepared the proposed change, but who may be from the same organization as the individual/group which prepared the proposed change. Proposed changes to the Technical Specifications shall be approved by the General Superintendent-Nuclear Generation.

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ACTIVITIES (Continued)

6.5.2.3 Proposed modifications to unit structures, systems and components that affect nuclear safety shall be designed by a qualified individual/organization. Each such modification shall be reviewed by an individual/group other than the individual/group which designed the modification, but who may be from the same organization as the individual/group which designed the modification. Proposed modifications to structures, systems and components and the safety evaluations shall be approved prior to implementation by the General Superintendent-Nuclear Generation; or the Station Superintendent-Nuclear Generation; or the Technical Superintendent-Nuclear Generation as previously ~~designed~~ designated by the General Superintendent-Nuclear Generation.

6.5.2.4 Individuals responsible for reviews performed in accordance with Specifications 6.5.2.1, 6.5.2.2 and 6.5.2.3 shall be members of the station supervisory staff, previously designated by the General Superintendent-Nuclear Generation to perform such reviews. Each such review shall include a determination of whether or not additional, cross-disciplinary, review is necessary. If deemed necessary such review shall be performed by the appropriate designated station review personnel.

6.5.2.5 Proposed tests and experiments which affect station nuclear safety and are not addressed in the FSAR or Technical Specifications and their safety evaluations shall be reviewed by the General Superintendent-Nuclear Generation; or or by the Station Superintendent-Nuclear Generation, or the Technical Superintendent-Nuclear-Generation-as-previously-designated by the General Superintendent-Nuclear Generation.

6.5.2.6 The General Superintendent-Nuclear Generation shall assure the performance of special reviews and investigations, and the preparation and submittal of reports thereon, as requested by the Vice President-Nuclear Generation.

6.5.2.7 The facility security program, and implementing procedures, shall be reviewed at least every 12 months. Recommended changes shall be approved by the General Superintendent-Nuclear Generation and transmitted to the Vice President-Nuclear Generation, and to the Chairman of the Safety Review and Audit Board.

6.5.2.8 The facility emergency plan, and implementing procedures shall be reviewed at least every 12 months. Recommended changes shall be approved by the General Superintendent-Nuclear Generation and transmitted to the Vice President-Nuclear Generation and to the Chairman of the Safety Review and Audit Board.

6.5.2.9 The General Superindendent-Nuclear Generation shall assure the performance of a review by a qualified individual/organization of changes to the Radiological Waste Treatment systems.

6.5.2.10 Review of any accidental, unplanned, or uncontrolled radioactive release including the preparation of reports covering evaluation, recommendations and disposition of the corrective action to prevent recurrence and the forwarding of these reports to the Vice President - Nuclear Generation and to the Safety Review and Audit Board.

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ACTIVITIES (Continued) capitalize

6.5.2.11 Review of changes to the Process Control Program and the Offsite Dose Calculation Manual. Approval of any changes shall be made by the General Superintendent - Nuclear Generation or his designee before implementation of such changes.

6.5.2.12 Reports documenting each of the activities performed under Specifications 6.5.2.1 through 6.5.2.9 shall be maintained. Copies shall be provided to the Vice President-Nuclear Generation and the Safety Review and Audit Board.

6.5.3 SAFETY REVIEW AND AUDIT BOARD (SRAB)

FUNCTION

6.5.3.1 The SRAB shall function to provide independent review and audit of designated activities in the areas of:

a. Nuclear power plant operations,
b. Nuclear engineering,
c. Chemistry and radiochemistry,
d. Metallurgy,
e. Instrumentation and control,
f. Radiological safety,
g. Mechanical and electrical engineering,
h. Quality assurance practices, and
i. (Other appropriate fields associated with the unique characteristics of the nuclear power plant).

The SRAB shall report to and advise the Vice President - Nuclear Generation on those areas of responsibility in Specifications 6.5.2.7 and 6.5.2.8.

COMPOSITION

6.5.3.2 The SRAB shall be composed of the:

Chairman:	Vice President-Nuclear Generation or staff engineer or manager or vice-president
Member:	General Superintendent-Nuclear Operation
Member:	Staff Engineer-Nuclear
Member:	Staff Engineer-Mechanical or Nuclear
Member:	Staff Engineer-Environmental
Member:	Consultant (Specification 6.5.3.4)

ALTERNATES

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

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CONSULTANTS

6.5.3.4 Consultants shall be utilized as determined by the SRAB Director to provide expert advice to the SRAB.

MEETING FREQUENCY

6.5.3.5 The SRAB shall meet at least once per calendar quarter during the initial year of unit operation following fuel loading and at least once per 6 months thereafter.

QUORUM

6.5.3.6 The quorum of the SRAB necessary for the performance of the SRAB review and audit functions of these Technical Specifications shall consist of the Chairman or his designated alternate and at least three SRAB members including alternates. No more than a minority of the quorum shall have line responsibility for operation of the unit.

REVIEW

6.5.3.7 The SRAB shall be responsible for the review of:

a. The safety evaluations for (1) changes to procedures, equipment, or systems; and (2) tests or experiments completed under the provision of 10 CFR 50.59 to verify that such actions did not constitute an unreviewed safety question;

b. Proposed changes to procedures, equipment, or systems which involve an unreviewed safety question as defined in 10 CFR 50.59;

c. Proposed tests or experiments which involve an unreviewed safety question as defined in 10 CFR 50.59;

d. Proposed changes to Technical Specifications or this Operating License;

e. Violations of codes, regulations, orders, Technical Specifications, license requirements, or of internal procedures or instructions having nuclear safety significance;

f. Significant operating abnormalities or deviations from normal and expected performance of unit equipment that affect nuclear safety;

g. All REPORTABLE EVENTS;

h. All recognized indications of an unanticipated deficiency in some aspect of design or operation of structures, systems, or components that could affect nuclear safety; and

i. Reports and meeting minutes of the SORC.

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AUDITS

6.5.3.8 Audits of unit activities shall be performed under the cognizance of the SRAB. These audits shall encompass:

a. The conformance of unit operation to provisions contained within the Technical Specifications and applicable license conditions at least once per 12 months;

b. The performance, training and qualifications of the entire unit staff at least once per 12 months;

c. The results of actions taken to correct deficiencies occurring in unit equipment, structures, systems, or method of operation that affect nuclear safety, at least once per 6 months;

d. The performance of activities required by the Operational Quality Assurance Program to meet the criteria of Appendix B, 10 CFR Part 50, at least once per 24 months;

e. The Unit Emergency Plan and implementing procedures at least once every 12 months.

f. The Unit Security Plan and implementing procedures at least once every 12 months.

g. The Radiological Environmental Monitoring Program and the results thereof at least once per 12 months;

h. The OFFSITE DOSE CALCULATION MANUAL and implementing procedures at least once per 24 months;

i. The PROCESS CONTROL PROGRAM and implementing procedures for processing and packaging of radioactive wastes at least once ~~pre~~ per 24 months;

j. The performance of activities required by the Quality Assurance Program to meet the Criteria of Appendix B 10 CFR 50 at least once per year.

k. Any other area of unit operation considered appropriate by the SRAB or the Vice President - Nuclear Generation or the Vice President - Nuclear Engineering and Licensing.

RECORDS

6.5.3.~~9~~10 Records of SRAB activities shall be prepared, approved, and distributed as indicated below:

a. Minutes of each SRAB meeting shall be prepared, approved, and forwarded to the Vice President - Nuclear Generation and Vice President - Nuclear Engineering and Licensing within ~~14~~ 30 days following each meeting.

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RECORDS (Continued)

b. Reports of reviews encompassed by Specification 6.5.3.7 e, ~~b~~ f, g, h shall be prepared, approved, and forwarded to the Vice President - Nuclear Generation and Vice President - Nuclear Engineering and Licensing within 14 days following completion of the review.

c. Audit reports encompassed by Specification 6.5.2.8 shall be forwarded to the Vice President - Nuclear Generation and Vice President - Nuclear Engineering and Licensing and to the management positions responsible for the areas audited within 90 days after completion of the audit by the auditing organization.

AUTHORITY

6.5.3.~~10~~ 9 The SRAB shall report to and advise the Vice President - Nuclear Generation and Vice President - Nuclear Engineering and Licensing on those areas of responsibility specified in Section 6.5.3.7 and 6.5.3.8.

6.6 REPORTABLE EVENT ACTION

6.6.1 The following actions shall be taken for REPORTABLE EVENTS:

a. The Commission shall be notified and a report submitted pursuant to the requirements of Sections 50.72 and 50.73 to 10 CFR Part 50, and

b. Each REPORTABLE EVENT ~~requiring 24-hour notification~~ to the Commission shall be reviewed by the SORC, and the results of this review shall be submitted to the SRAB and the Vice President - Nuclear Generation.

6.7 SAFETY LIMIT VIOLATION

6.7.1 The following actions shall be taken in the event a Safety Limit is violated:

a. The NRC Operations Center shall be notified by telephone as soon as possible and in all cases within 1 hour. ~~The Vice President - Nuclear Generation and the SRAB shall be notified within 24 hours.~~

b. A Safety Limit Violation Report shall be prepared. The report shall be reviewed by the SORC. This report shall describe (1) applicable circumstances preceding the violation, (2) effects of the violation upon unit components, systems, or structures, and (3) corrective action taken to prevent recurrence.

c. The Safety Limit Violation Report shall be submitted to the Commission within 30 days of the violation and to the SRAB, and the Vice President - Nuclear Generation immediately.

~~d. Critical operation of the unit shall not be resumed until authorized by the Commission.~~

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6.8 PROCEDURES AND PROGRAMS

6.8.1 Written procedures shall be established, implemented, and maintained covering the activities referenced below:

a. The applicable procedures recommended in Appendix A of Regulatory Guide 1.33, Revision 2, February 1978.
b. The applicable procedures required to implement the requirements of NUREG-0737.
c. Refueling operations.
d. Surveillance and test activities of safety-related equipment.
e. Security Plan implementation.
f. Emergency Plan implementation.
g. Fire Protection Program implementation.
h. PROCESS CONTROL PROGRAM implementation.
i. OFFSITE DOSE CALCULATION MANUAL implementation; and
j. Quality Assurance for effluent and environmental monitoring.

6.8.2 Each procedure of Specification 6.8.1, and changes thereto, shall be reviewed ~~by the SORC and shall be~~ approved by the General Superintendent - Nuclear Generation prior to implementation and reviewed periodically as set forth in administrative procedures.

6.8.3 Temporary changes to procedures of Specification 6.8.1 may be made provided:

a. The intent of the original procedure is not altered;

b. The change is approved by two members of the unit management staff, at least one of whom holds a Senior Operator license on the unit affected; and

c. The change is documented, reviewed ~~by the SORC~~, and approved by the General Superintendent - Nuclear Generation within 14 days of implementation.

6.8.4 The following programs shall be established, implemented, and maintained:

a. Primary Coolant Sources Outside Containment

A program to reduce leakage from those portions of systems outside containment that could contain highly radioactive fluids during a serious transient or accident to as low as practical levels. The systems include the (HPCS, RHR, RCIC, hydrogen recombiner, process sampling, containment and standby gas treatment) systems. The program shall include the following:

1. Preventive maintenance and periodic visual inspection requirements, and

2. Integrated leak test requirements for each system at refueling cycle intervals or less.

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PROCEDURES AND PROGRAMS (Continued)

b. In-Plant Radiation Monitoring

A program which will ensure the capability to accurately determine the airborne iodine concentration in vital areas under accident conditions. This program shall include the following:

1. Training of personnel,
2. Procedures for monitoring, and
3. Provisions for maintenance of sampling and analysis equipment.

c. Post-accident Sampling

A program which will ensure the capability to obtain and analyze reactor coolant, radioactive iodines and particulates in plant gaseous effluents, and containment atmosphere samples under accident conditions. The program shall include the following:

1. Training of personnel,
2. Procedures for sampling and analysis, and
3. Provisions for maintenance of sampling and analysis equipment.

6.9 REPORTING REQUIREMENTS

ROUTINE REPORTS

6.9.1 In addition to the applicable reporting requirements of Title 10, Code of Federal Regulations, the following reports shall be submitted to the Regional Administrator of the Regional Office of the NRC unless otherwise noted.

STARTUP REPORT

6.9.1.1 A summary report of plant startup and power escalation testing shall be submitted following (1) receipt of an Operating License, (2) amendment to the license involving a planned increase in power level, (3) installation of fuel that has a different design or has been manufactured by a different fuel supplier, and (4) modifications that may have significantly altered the nuclear, thermal, or hydraulic performance of the unit.

6.9.1.2 The startup report shall address each of the tests identified in the Final Safety Analysis Report and shall include a description of the measured values of the operating conditions or characteristics obtained during the test program and a comparison of these values with design predictions and specifications. Any corrective actions that were required to obtain satisfactory operation shall also be described. Any additional specific details required in license conditions based on other commitments shall be included in this report.

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STARTUP REPORT (Continued)

6.9.1.3 Startup reports shall be submitted within (1) 90 days following completion of the startup test program, (2) 90 days following resumption or commencement of commercial power operation, or (3) 9 months following initial criticality, whichever is earliest. If the startup report does not cover all three events (i.e., initial criticality, completion of startup test program, and resumption or commencement of commercial operation) supplementary reports shall be submitted at least every 3 months until all three events have been completed.

ANNUAL REPORTS*

6.9.1.4 Annual reports covering the activities of the unit as described below for the previous calendar year shall be submitted prior to March 1 of each year. The initial report shall be submitted prior to March 1 of the year following initial criticality.

6.9.1.5 Reports required on an annual basis shall include:

a. A tabulation on an annual basis of the number of station, utility, and other personnel (including contractors) receiving exposures greater than 100 mrem/yr and their associated man-rem exposure according to work and job functions* (e.g., reactor operations and surveillance, inservice inspection, routine maintenance, special maintenance [describe maintenance], waste processing, and refueling). The dose assignments to various duty functions may be estimated based on pocket dosimeter, thermoluminescent dosimeter (TLD), or film badge measurements. Small exposures totalling less than 20% of the individual total dose need not be accounted for. In the aggregate, at least 80% of the total whole-body dose received from external sources should be assigned to specific major work functions;

b. The results of specific activity analysis in which the primary coolant exceeded the limits of Specification 3.4.5. The following information shall be included: (1) Reactor power history starting 48 hours prior to the first sample in which the limit was exceeded; (2) Results of the last isotopic analysis for radioiodine performed prior to exceeding the limit, results of analysis while limit was exceeded and results of one analysis after the radioiodine activity was reduced to less than limit. Each result should include date and time of sampling and the radioiodine concentrations; (3) Clean-up system flow history starting 48 hours prior to the first sample in which the limit was exceeded; (4) Graph of the I-131 concentration and one other radioiodine isotope concentration in microcuries per gram as a function of time for the duration of the specific activity above the steady-state level; and (5) The time duration when the specific activity of the primary coolant exceeded the radioiodine limit.

*This tabulation supplements the requirements of §20.407 of 10 CFR Part 20.

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ANNUAL REPORTS (Continued)

c. Documentation of all challenges to safety/relief valves; and

d. Any other unit unique reports required ~~on an annual basis.~~ by Technical Specifications.

MONTHLY OPERATING REPORTS

6.9.1.6 Routine reports of operating statistics and shutdown experience, including documentation of all challenges to the main steam system safety/relief valves, shall be submitted on a monthly basis to the Director, Office of Resource Management, U.S. Nuclear Regulatory Commission, Washington, D.C. 20555, with a copy to the Regional Administrator of the Regional Office of the NRC no later than the 15th of each month following the calendar month covered by the report.

ANNUAL RADIOLOGICAL ENVIRONMENTAL OPERATING REPORT*

6.9.1.7 Routine Annual Radiological Environmental Operating Reports covering the operation of the unit during the previous calendar year shall be submitted prior to May 1 of each year. The initial report shall be submitted prior to May 1 of the year following initial criticality. for the last 5 years.

The Annual Radiological Environmental Operating Reports shall include summaries, interpretations, and an analysis of trends of the results of the radiological environmental surveillance activities for the report period, including a comparison as appropriate with preoperational studies, operational controls, previous environmental surveillance reports, and an assessment of the observed impacts of the plant operation on the environment. The reports shall also include the results of the Land Use Census required by Specification 3.12.2.

The Annual Radiological Environmental Operating Reports shall include the results of analysis of all radiological environmental samples and of all environmental radiation measurements taken during the period pursuant to the locations specified in the table and figures in the Offsite Dose Calculation Manual, as well as summarized and tabulated results of these analyses and measurements in the format of the table in the Radiological Assessment Branch Technical Position, Revision 1, November 1979. In the event that some individual results are not available for inclusion with the report, the report shall be submitted noting and explaining the reasons for the missing results. The missing data shall be submitted as soon as possible in a supplement report.

The reports shall also include the following: a summary description of the Radiological Environmemtal Monitoring Program; at least two legible maps** covering all sampling locations keyed to a table giving distances and directions from the centerline of one reactor; the results of licensee participation in the Interlaboratory Comparison Program, required by Specification 3.12.3; discussion of all deviations from the Sampling Schedule of Table 3.12-1; and discussion of all analyses in which the LLD required by Table 4.12-1 was not achievable.

*A single submittal may be made for a multiple unit site ~~station~~. The submittal should combine those sections that are common to all units at the station.

**One map shall cover stations near the SITE BOUNDARY; a second shall include the more distant stations.

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SEMIANNUAL RADIOACTIVE EFFLUENT RELEASE REPORT*

6.9.1.8 Routine Semiannual Radioactive Effluent Release Reports covering the operation of the unit during the previous 6 months of operation shall be submitted within 60 days after January 1 and July 1 of each year. The period of the first report shall begin with the date of initial criticality.

The Semiannual Radioactive Effluent Release Reports shall include a summary of the quantities of radioactive liquid and gaseous effluents and solid waste released from the unit as outlined in Regulatory Guide 1.21, "Measuring, Evaluating, and Reporting Radioactivity in Solid Wastes and Releases of Radioactive Materials in Liquid and Gaseous Effluents from Light-Water-Cooled Nuclear Power Plants," Revision 1, June 1974, with data summarized on a quarterly basis following the format of Appendix B thereof. For solid wastes, the format for Table 3 in Appendix B shall be supplemented with three additional categories: class of solid wastes (as defined by 10 CFR Part 61), type of container (e.g., LSA, Type A, Type B, Large Quantity) and SOLIDIFICATION agent or absorbent (e.g., cement, urea formaldehyde).

The Semiannual Radioactive Effluent Release Report to be submitted within 60 days after January 1 of each year shall include an annual summary of hourly meteorological data collected over the previous year. This annual summary may be either in the form of an hour-by-hour listing on magnetic tape of wind speed, wind direction, atmospheric stability, and precipitation (if measured), or in the form of joint frequenc distribution of wind speed, wind direction, and atmospheric stability.** This same report shall include an assessment of the radiation doses due to the radioactive liquid and gaseous effluents released from the unit or station during the previous calendar year. This same report shall also include an assessment of the radiation doses from radioactive liquid and gaseous effluents to MEMBERS OF THE PUBLIC due to their activities inside the SITE BOUNDARY (Figure 5.1.3) during the report period. All assumptions used in making these assessments, i.e., specific activity, exposure time, and location, shall be included in these reports. The meteorological conditions concurrent with the time of release of radioactive materials in gaseous effluents, as determined by sampling frequency and measurement, shall be used for determining the gaseous pathway doses. The assessment of radiation doses shall be performed in accordance with the methodology and parameters in the OFFSITE DOSE CALCULATION MANUAL (ODCM).

The Semiannual Radioactive Effluent Release Report to be submitted within 60 days after January 1 of each year shall also include an assessment of radiation doses to the likely most exposed MEMBER OF THE PUBLIC from reactor releases and other nearby uranium fuel cycle sources, including doses from

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*A single submittal may be made for a multiple unit station. The submittal should combine those sections that are common to all units at the station; however, for units with separate radwaste systems, the submittal shall specify the releases of radioactive material from each unit.

**In lieu of submission with the Semiannual Radoactive Effluent Release Report, the licensee has the option of retaining this summary of required meteorological data on site in a file that shall be provided to the NRC upon request.

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SEMIANNUAL RADIOACTIVE EFFLUENT RELEASE REPORT (Continued)

primary effluent pathways and direct radiation, for the previous calendar year to show conformance with 40 CFR Part 190, "Environmental Radiation Protection Standards for Nuclear Power Operation." Acceptable methods for calculating the dose contribution from liquid and gaseous effluents are given in the ODCM.

The Semiannual Radioactive Effluent Release Reports shall include a list and description of unplanned releases from the site to UNRESTRICTED AREAS of radioactive materials in gaseous and liquid effluents made during the reporting period.

The Semiannual Radioactive Effluent Release Reports shall include any changes made during the reporting period to the PROCESS CONTROL PROGRAM (PCP) and to the OFFSITE DOSE CALCULATION MANUAL (ODCM), pursuant to Specifications 6.13 and 6.14, respectively, as well as any major change to Liquid, Gaseous, or Solid Radwaste Treatment Systems pursuant to Specification 6.15. It shall also include a listing of new locations for dose calculations and/or environ mental monitoring identified by the Land Use Census pursuant to Specification 3.12.2.

The Semiannual Radioactive Effluent Release Reports shall also include the following: an explanation as to why the inoperability of liquid or gaseous effluent monitoring instrumentation was not corrected within the time specified in Specification 3.3.3.10 or 3.3.3.11, respectively; and description of the events leading to liquid holdup tanks or gas storage tanks exceeding the limits of Specification 3.11.1.4 or 3.11.2.6, respectively.

SPECIAL REPORTS

6.9.2 Special reports shall be submitted to the Regional Administrator of the Regional Office of the NRC within the time period specified for each report.

6.10 RECORD RETENTION

6.10.1 In addition to the applicable record retention requirements of Title 10, Code of Federal Regulations, the following records shall be retained for at least the minimum period indicated.

6.10.1.1 The following records shall be retained for at least 5 years:

a. Records and logs of unit operation covering time interval at each power level.

b. Records and logs of principal maintenance activities, inspections, repair, and replacement of principal items of equipment related to nuclear safety.

c. All REPORTABLE EVENTS submitted to the Commission.

d. Records of surveillance activities, inspections, and calibrations required by these Technical Specifications.

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RECORD RETENTION (Continued)

e. Records of changes made to the procedures required by Specification 6.8.1.

f. Records of radioactive shipments.

g. Records of sealed source and fission detector leak tests and results.

h. Records of annual physical inventory of all sealed source material of record.

i. Records of reactor tests and experiments.

6.10.1.2 The following records shall be retained for the duration of the unit Operating License:

a. Records and drawing changes reflecting unit design modifications made to systems and equipment described in the Final Safety Analysis Report.

b. Records of new and irradiated fuel inventory, fuel transfers, and assembly burnup histories.

c. Records of radiation exposure for all individuals entering radiation control areas.

d. Records of gaseous and liquid radioactive material released to the environs.

e. Records of transient or operational cycles for those unit components identified in Table 5.7.1-1.

f. Records of reactor tests and experiments.

g. Records of training and qualification for current members of the unit staff.

h. Records of inservice inspections performed pursuant to these Technical Specifications.

i. Records of quality assurance activities required by the Operational Quality Assurance Manual, and not listed in Specification 6.10.1.1.

j. Records of reviews performed for changes made to procedures or equipment or reviews of tests and experiments pursuant to 10 CFR 50.59.

k. Records of meetings of the SORC and the SRAB.

l. Records of the service lives of all snubbers including the date at which the service life commences and associated installation and maintenance records.

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RECORD RETENTION (Continued)

m. Records of analyses required by the Radiological Environmental Monitoring Program that would permit evaluation of the accuracy of the analysis at a later date. This should include procedures effective at specified times and QA records showing that these procedures were followed.

n. Records of unit radiation and contamination surveys.

6.11 RADIATION PROTECTION PROGRAM

6.11.1 Procedures for personnel radiation protection shall be prepared consistent with the requirements of 10 CFR Part 20 and shall be approved, maintained, and adhered to for all operations involving personnel radiation exposure.

6.12 HIGH RADIATION AREA

6.12.1 In lieu of the "control device" or "alarm signal" required by paragraph 20.203(c)(2) of 10 CFR Part 20, each high radiation area in which the intensity of radiation is greater than 100 mrem/hr** but less than 1000 mrem/hr** shall be barricaded and conspicuously posted as a high radiation area and entrance thereto shall be controlled by requiring issuance of a Radiation Work Permit (RWP)*. Any individual or group of individuals permitted to enter such areas shall be provided with or accompanied by one or more of the following:

a. A radiation monitoring device which continuously indicates the radiation dose rate in the area.

b. A radiation monitoring device which continuously integrates the radiation dose rate in the area and alarms when a preset integrated dose is received. Entry into such areas with this monitoring device may be made after the dose rate levels in the area have been established and personnel have been made knowledgeable of them.

c. An individual qualified in radiation protection (i.e., qualified in radiation protection procedures) with a radiation dose rate monitoring device who is responsible for providing positive control over the activities within the area and shall perform periodic radiation surveillance at the frequency specified by the Radiation Protection Supervisor or his designee in the RWP.

*Health physics personnel or personnel escorted by health physics personnel shall be exempt from the RWP issuance requirement during the performance of their assigned radiation protection duties, provided they are otherwise following plant radiation protection procedures for entry into high radiation areas.

** measurement made at 18 inches from source of activity

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HIGH RADIATION AREA (Continued)

6.12.2 In addition to the requirements of Specification 6.12.1, areas accessible to personnel with radiation levels such that a major portion of the body could receive in 1 hour a dose greater than 1000 mrem** shall be provided with locked doors to prevent unauthorized entry, and the keyed access shall be maintained under the administrative control of the Station Shift Supervisor or his designee on duty and/or the Radiation Protection Supervisor or his designee. Doors shall remain locked except during periods of access by personnel under an approved RWP which shall specify the dose rate levels in the immediate work area and the maximum allowable stay time for individuals in that area. For individual areas accessible to personnel with radiation levels such that a major portion of the body could receive in 1 hour a dose in excess of 1000 mrem** that are located within large areas, such as the drywell, where no enclosure exists for purposes of locking, and no enclosure can be reasonably constructed around the individual areas, then that area shall be roped off, conspicuously posted, and a flashing light shall be activated as a warning device. In lieu of the stay time specification of the RWP, continuous surveillance direct or remote (such as use of closed circuit TV cameras), may be made by personnel qualified in radiation protection procedures to provide positive exposure control over the activities within the area.

6.13 PROCESS CONTROL PROGRAM (PCP)

6.13.1 The PCP shall be approved by the Commission prior to implementation.

6.13.2 Licensee-initiated changes to the PCP:

a. Shall be submitted to the Commission in the Semiannual Radioactive Effluent Release Report for the period in which the change(s) was made. This submittal shall contain:

   1) Sufficiently detailed information to totally support the rationale for the change without benefit of additional or supplemental information;

   2) A determination that the change did not reduce the overall conformance of the solidified waste product to existing criteria for solid wastes; and

   3) Documentation of the fact that the change has been reviewed and found acceptable by the SORC.

b. Shall become effective upon review and acceptance by the SORC.

6.14 OFFSITE DOSE CALCULATION MANUAL (ODCM)

6.14.1 The ODCM shall be approved by the Commission prior to implementation.

** Measurement made at 18 inches from source of activity

OFFSITE DOSE CALCULATION MANUAL (ODCM) (Continued)

6.14.2 Licensee-initiated changes to the ODCM:

a. Shall be submitted to the Commission in the Semiannual Radioactive Effluent Release Report for the period in which the change(s) was made effective. This submittal shall contain:

1) Sufficiently detailed information to totally support the rationale for the change without benefit of additional or supplemental information. Information submitted should consist of a package of those pages of the ODCM to be changed with each page numbered, dated and containing the revision number, together with appropriate analyses or evaluations justifying the change(s);

2) A determination that the change will not reduce the accuracy or reliability of dose calculations or Setpoint determinations; and

3) Documentation of the fact that the change has been reviewed and found acceptable by the SORC.

b. Shall become effective upon review and acceptance by the SORC.

6.15 MAJOR CHANGES TO LIQUID, GASEOUS, AND SOLID RADWASTE TREATMENT SYSTEMS*

6.15.1 Licensee-initiated major changes to the Radwaste Treatment Systems (liquid, gaseous, and solid):

a. Shall be reported to the Commission in the Semiannual Radioactive Effluent Release Report for the period in which the evaluation was reviewed by the SORC. The discussion of each change shall contain:

1) A summary of the evaluation that led to the determination that the change could be made in accordance with 10 CFR 50.59;

2) Sufficient detailed information to totally support the reason for the change without benefit of additional or supplemental information;

3) A detailed description of the equipment, components, and processes involved and the interfaces with other plant systems;

4) An evaluation of the change, which shows the predicted releases of radioactive materials in liquid and gaseous effluents and/or quantity of solid waste that differ from those previously predicted in the License application and amendments thereto;

*Licensees may choose to submit the information called for in this Specification as part of the annual FSAR update.

MAJOR CHANGES TO LIQUID, GASEOUS, AND SOLID RADWASTE TREATMENT SYSTEMS (Cont)

5) An evaluation of the change, which shows the expected maximum exposures to a MEMBER OF THE PUBLIC in the UNRESTRICTED AREA and to the general population that differ from those previously estimated in the License application and amendments thereto;

6) A comparison of the predicted releases of radioactive materials, in liquid and gaseous effluents and in solid waste, to the actual releases for the period prior to when the change is to be made;

7) An estimate of the exposure to plant operating personnel as a result of the change; and

8) Documentation of the fact that the change was reviewed and found acceptable by the SORC.

b. Shall become effective upon review and acceptance by the SORC.

ATTACHMENT B

1) COMMENTS

2) JUSTIFICATION FOR PROPOSED TECHNICAL SPECIFICATION CHANGES

3) NEW PAGES

COMMENTS

1. 6-14, 6.6.1.b; Clarify the meaning of this statement. Our review of 10CFR50.72 and 10CFR50.73 reveals no 24 hour notification requirements. Does 6.6.1.b require only REPORTABLE EVENTS requiring 24-hour notification be SORC, SRAB and VP reviewed?

2. 3/4 7-5, 4.7.2.c; It is impractical to ask NMP2 to perform this surveillance since: 1) wave runup (splashing) can occur frequently; 2) during winter, due to white-outs, the shore barrier cannot be seen; 3) impractical and dangerous to dig through several feet of ice to find markers during a storm; and 4) storms run together and are sometimes longer than seven days. NMPC is requesting relief from this surveillance.

3. Bases page B 3/4 4-6 is provided under Attachment B for inclusion in Tech. Specs.

4. An updated version of Figure 6.2.2-1, 6-4, is provided under Attachment "B" for inclusion in Tech. Specs. The new mylar will be mailed directly to Mr. Schulten.

5. NMPC is requesting that page 5-4 of the Tech. Specs. be split into two pages (Site Boundaries and Notes). This request is made because the present version of these two items on 5-4 is illegible.

6. NMPC is requesting an interpretation of the phrase "unexpected, potentially damaging transient" in 4.7.5.d on 3/4 7-14.

7. Page 3/4 10-5, LCO 3.10.5, is provided in Attachment "B" since this LCO was omitted in the Proof and Review version of Tech. Specs.

8. Page 3/4 7-11, 4.7.4.a.1; NMPC is requesting that a footnote be added to this surveillance that allows violation of primary containment to perform item 4.7.4.a.1. A similar change must be made to High Pressure Core Spray, Low Pressure Core Spray and Residual Heat Removal Systems.

9. A comparison of LCO's 3.6.5.3, 3/4 6-38, and 3.11.2.8, 3/4 11-18 indicates that work on one standby gas treatment subsystem can only be performed in mode switch positions 4 and 5 with primary containment in effect. NMPC views this as an incorrect interpretation of the SER statement (page 6-23) requiring both SGTS trains to be operable during purging. The SER concern is based solely around the inability of the SGTS to resist the postulated impulse loading post-LOCA event. The actual pressure rise is essentially zero in mode switch condition 4 and 5 for a LOCA. It is our position that LCO 3.11.2.8 should apply only in OPERATIONAL CONDITIONS 1, 2 and 3.

10. NMPC is requesting SER changes on page 6-23 to eliminate the requirement of both SGTS trains being OPERABLE and to eliminate the limiting of 90 hours per year of operation of the 12 and 14 inch lines. This request is based upon the ability of the SGTS to survive a post-LOCA impulse loading due to the restricting orifice effect of the 2 inch piping between the SGTS trains and the 12 and 14 lines. These SER changes would also result in changes to proof and review versions of Tech. Specs.

11. We are requesting an SER change on page 3-49 to support LCO 3.4.3.2.d on page 3/4 4-9.

12. We are requesting the changes on pages 3/4 6-11 and B 3/4 6-2 be granted based upon a letter sent to Dr. Butler, dated November 19, 1985, from C. V. Mangan. This letter addresses an SER concern raised on page 6-23. A copy of this letter is provided under Attachment B.

13. We are requesting a change be granted to note (g) on page 3/4 3-8. The change and justification are in Attachment B.

14. We are requesting a deletion of item 5.b., "Scram Trip Bypass" on pages 3/4 3-56, 3/4 3-58 and 3/4 3-60. The justification for this change is provided in Attachment B.

15. Changes in Section 6.0, Administrative Controls, are requested in order to make Nine Mile Point Units 1 and 2 identical in this section of Technical Specifications.

16. We are requesting deletion of 4.8.1.1.2.b and c based on SER pages 9-7, 9-4 and 9-5 in supplement 2.

17. We are requesting deletion of the phrase, "be in at least HOT SHUTDOWN" in action "F" on page 3/4 8-3 and replacing it with "reduce power to $\leq$ 15%." The justification for this change is in Attachment B.

NIAGARA MOHAWK

INFORMATION ONLY

NIAGARA MOHAWK POWER CORPORATION/300 ERIE BOULEVARD WEST, SYRACUSE, N.Y. 13202/TELEPHONE (315) 474-1511

November 19, 1985
(NMP2L 0539)

Dr. Walter Butler, Chief
Licensing Branch No. 2
U.S. Nuclear Regulatory Commission
Washington, DC 20555

Dear Dr. Butler:

Re: Nine Mile Point Unit 2
Docket No. 50-410

Your letter of September 10, 1985 to Mr. B. G. Hooten concerning the operability of containment purge and vent valves for Nine Mile Point 2 requested a submittal of additional information by November 15, 1985. The information below is submitted in response to that letter.

1. Valves AOV-106, AOV-108, and AOV-109

   The NRC concluded that operability of these valves has been satisfactorily demonstrated.

2. Valve AOV-104

   This valve will be oriented in the preferred direction in accordance with Posi Seal International recommendation. Operability for this valve will thus be demonstrated consistent with the NRC letter.

   NOTE: Preferred direction is defined relative to the direction of flow following a loss of coolant accident: i.e., from inside to outside containment.

3. Valves AOV-105, AOV-107, AOV-110, and AOV-111

   The NRC concluded that operability for these valves was not demonstrated. The following actions have been taken or are in process:

   a. Valves AOV-105 and AOV-110

      Both of these valves will be reoriented in the preferred direction. Posi Seal International has reanalyzed these valves and concluded that, using an allowable shear stress of 21,120

psi for the disc pin, the angle of opening of Valves AOV-105 and AOV-110 should be restricted to 70 degrees. This modification will be implemented before fuel load.

b. Valve AOV-107

This valve will be oriented in the preferred direction. Posi Seal International indicates that with the valve so oriented, the torque will be reduced from 3,998 to 3,237 in.-lb. This will result in a disc pin stress less than the 21,120 psi allowable. No further modifications are required to demonstrate operability for Valve AOV-107.

c. Valve AOV-111

This valve will be reoriented in the preferred direction. Posi Seal International has reanalyzed this valve and concluded that, using an allowable shear stress of 21,120 psi for the disc pin, the angle of opening should be restricted to 60 degrees. This modification will be implemented before fuel load.

Posi Seal International will supplement their Loss of Coolant Accident and Seismic Analysis Report to incorporate the results and recommendations discussed above. Limit stops to limit the opening angle for Valves AOV-105, AOV-110, and AOV-111 have been ordered and will be installed prior to fuel load.

We believe that completion of the items discussed above adequately addresses the identified concerns.

Very truly yours,

CVMangan

C. V. Mangan
Senior Vice President

[illegible]:rla
1098G

xc: R. A. Gramm, NRC Resident Inspector
Project File (2)

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

In the Matter of Niagara Mohawk Power Corporation (Nine Mile Point Unit 2)	)))))	Docket No. 50-410

AFFIDAVIT

C. V. Mangan, being duly sworn, states that he is Vice President of Niagara Mohawk Power Corporation; that he is authorized on the part of said Corporation to sign and file with the Nuclear Regulatory Commission the documents attached hereto; and that all such documents are true and correct to the best of his knowledge, information and belief.

CV Mangan

Subscribed and sworn to before me, a Notary Public in and for the State of New York and County of Onondaga, this 19th day of November, 1985.

Janis M. Macro
Notary Public in and for
Onondaga County, New York

My Commission expires:
JANIS M. MACRO
Notary Public in the State of New York
Qualified in Onondaga County No. 4705555
My Commission Expires March 30, 1987

Subject: Deletion of item 5.b., "Scram Trip Bypass" on pages 3/4 3-56, 3/4 3-58 and 3/4 3-60

Justification for deletion of Item 5b, all tables of Control Rod Block Instrumentation.

A scram discharge volume water level-high signal currently provides a scram signal to the Reactor Protection System. A manually initiated scram discharge volume water level-high bypass exists (in Operational Conditions (OC) 3, 4 and 5 only) for arming the Reactor Protection System immediately following a scram (when the scram discharge volume is expected to be high).

The bypass is only functional when in OC 3, 4 and 5 and the switch is in the bypass position. The rod block for these conditions then exists. Alternate rod blocks, due to the reactor mode switch, exist which prevent rod movement in OC 3 and 4 (designed to single failure criteria). Therefore, the rod block from the SDV trip bypass is redundant.

Surveillance testing of this redundant SDV trip bypass rod block function is very difficult in the presence of the Reactor Mode Switch Rod Block and would probably require circuit disconnections. Due to the very minor significance (redundancy) of the SDV trip bypass rod block, it is considered counter-productive to safety to prescribe surveillance testing. This position was established for Grand Gulf and is recommended for all plants, hence the deletion of Item 5b from all tables.

Subject: Change to note (g) on page 3/4 3-8

The original note (g) was placed here by the NRC, as a means of determining crudding of the flow control valve. As it was written, it was nonconservative for the instrument; therefore, Grand Gulf, in conjunction with the NRC, modified it to the note they now have.

Original STS note (h) - 1983:
Verify measured core flow to be greater than or equal to established core flow at the existing flow control valve position.

Current Grand Gulf note (h):
Verify measured drive flow to be less than or equal to established drive flow at the existing flow control valve position.

Current Standard Technical Specification note (g):
Verify measured core flow (total core flow) to be greater than or equal to established core flow at the existing loop (APRM%).

Note (g), as shown in Table 4.3.1.1-1, provides a surveillance check which is outside the normal scope of a CHANNEL CHECK. A CHANNEL CHECK as defined normally only requires a qualitative determination that the parameter of interest is being indicated in the expected range. Note (g), however, is a "go/no go" situation; i.e., indication must be to one side of an established value. If it does not meet this criterion, there is no clearly defined ACTION.

There would seem to be two possible courses of action: First, remove the note; which, as explained previously, is there by default. Second, rewrite the note as follows:

"Verify measured core flow (total core flow) to be in the range of established core flow for the existing loop flow (APRM%).

Subject: Deletion of phrase "be in at least HOT SHUTDOWN" in ACTION "F" on page 3/4 8-3 and replacement with phrase "reduce power to 15%."

Niagara Mohawk Power Corporation is requesting a relief from the requirement in action statement "F" of L.C.O. 3.8.1.1 which requires the plant to go to hot shutdown within 36 hours of the loss of both of the required offsite circuits for its Nine Mile Point Unit 2 Nuclear Station. NMPC's position is that this requirement will reduce the level of plant safety rather than enhance it.

During a normal shutdown, load is transferred to the offsite sources at 10 to 12 percent reactor power to preclude a reverse power trip of the turbine generator. This 10 to 12 percent corresponds to the load required for our house loads. This transfer allows us to maintain all of our turbine auxiliaries such as circulating water for our reactor heat sink, gland exhausters, lube oil pumps, closed loop cooling pumps, as well as reactor feed pumps (three available, two running), thereby permitting a controlled reactor shutdown and cool down. Shutdown without at least one of these sources of normal A.C. power would result in a complete loss of normal A.C. power when the turbine was removed from the grid. This would cause a loss of the two operating feed pumps, as well as the one in standby, a loss of the condenser within 15 seconds of the loss of power due to the loss of circulating water pumps, isolation of the reactor from the heat sink (MSIV closure on low vacuum) and subsequent scram, a challenge to the relief valves with the accompanying heat addition to the suppression pool, an ECCS initiation (HPCS) to restore level following the loss of feedwater and shrink due to MSIV closure.

Since it is both the industry's as well as the NRC's goal to reduce the number of scrams and reduce the challenges to the relief valves and ECCS systems, we feel that a reduction to 15 percent power is a safer alternative than a reactor shutdown under these conditions. We also feel this would be in harmony with NU Reg 0737, TMI action item II.K.3.16, reducing challenges to the relief valves, and in the spirit of NU Reg 1024, "Technical Specifications - Enhancing the Safety Impact," Section 3.6, "Mode Changes."

NINE MILE POINT 2
BASES TABLE B 3/4.4.6-1

LIMITING REACTOR VESSEL TOUGHNESS

BELTLINE COMPONENT	WELD SEAM I.D. OR MAT'L TYPE	HEAT/SLAB OR HEAT/LOT	CU(%)	P(%)	STARTING RT_{NDT} (°F)	MAX.* ΔRT_{NDT} (°F)	UNIRRADIATED UPPER SHELF (FT-LBS)	MAX. RT_{NDT} (°F)
Plate	SA-533 GR B CL.1	C3147-2	0.11	0.012	0	30	88	+30
Weld	Seams BA, BB, & BC	5P6214B/0331	0.014	0.011	-40	18	97	-22

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

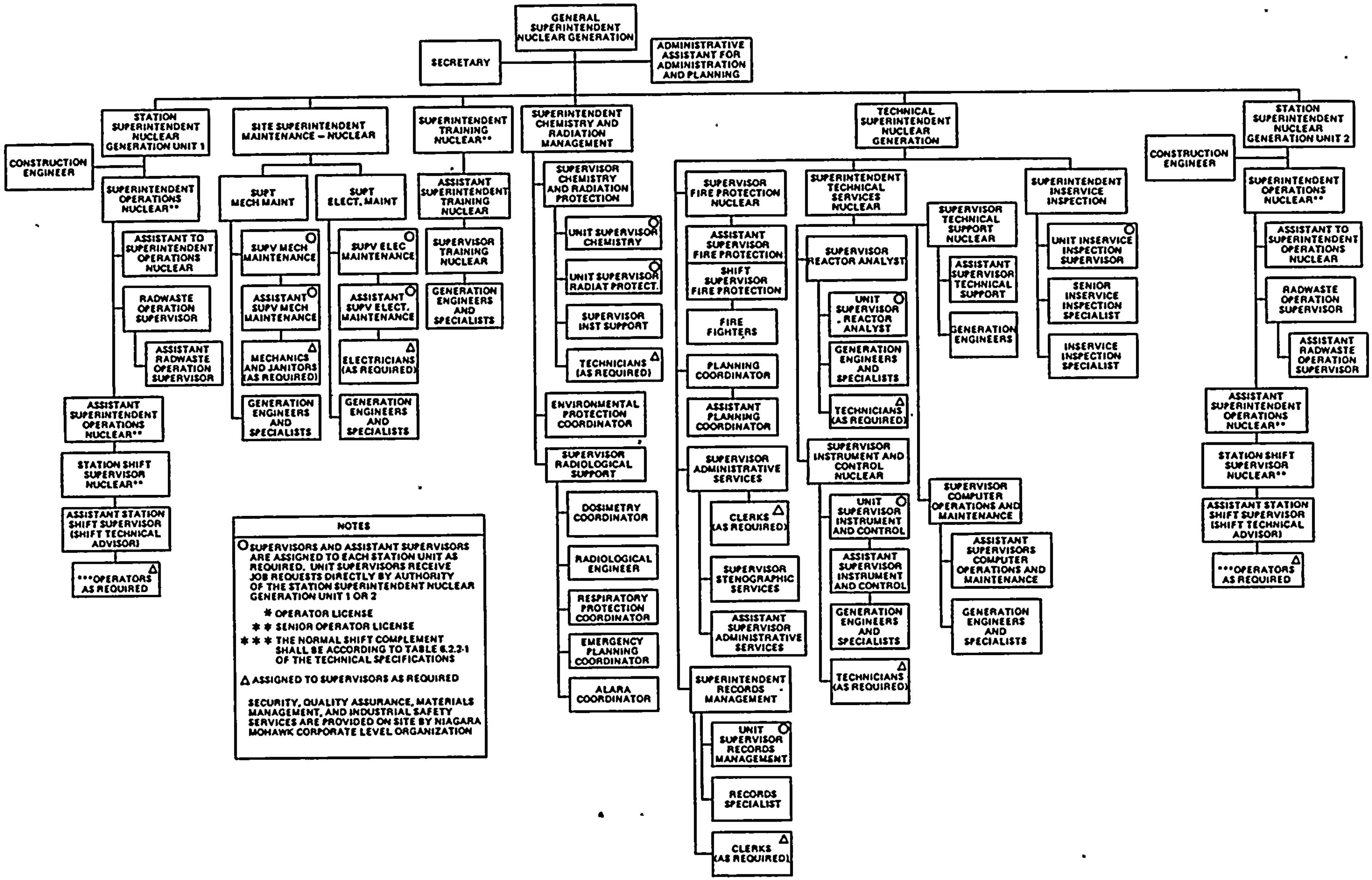
NON-BELTLINE COMPONENT	MT'L TYPE OR WELD STEAM I.D.	HEAT/SLAB OR HEAT/LOT	HIGHEST REFERENCE TEMP. RT_{NDT} (°F)
Shell Ring	SA-533, Gr. B, CL. 1	All Plates	+10
Bottom Head Dome	" "	C3073/2	+10
Bottom Head Torus	" "	" "	+10
Top Head Dome	" "	A0678/1	-20
Top Head Torus	" "	C2325/2	-1
Top Head Flange	SA-508, CL. 2	49D161, 49B168	-30
Vessel Flange	" "	48D1072, 48B1121	-20
**LPCI Nozzle	" "	Q2QL3W	-20
Feedwater Nozzle	" "	Q2QL2W	-20
Weld	INMM/LINDE 124	All Heats	-20
Closure Studs	SA-540, Gr. B24	All Heats	Meet 45 ft-lb & 25 mils lateral expansion requirement @ +10°F

**NOTE: The design location of the Low Pressure Core Injection (LPCI) nozzles results in these components and their related vessel welds to experience an End-of-Life (EOL) fluence of 1.7×10^{17} n/cm² (E>1MeV). As a result, the nozzles are predicted to have an EOL RT_{NDT} of -13°F and the limiting weld material will have an EOL RT_{NDT} of -12°F.

NSS:cal:rm/K051511*
5/20/85

OPEN ITEM 92

FIGURE 6.2.2-1
NINE MILE POINT NUCLEAR SITE OPERATIONS ORGANIZATION



DRAFT

SPECIAL TEST EXCEPTIONS

3/4.10.5 OXYGEN CONCENTRATION

LIMITING CONDITION FOR OPERATION

3.10.5 The provisions of Specification 3.6.6.~~4~~ 2 may be suspended during the performance of the Startup Test Program ~~until 6 months after initial criticality~~.

APPLICABILITY: OPERATIONAL CONDITION 1.

ACTION:

With the requirements of the above specification not satisfied, be in at least STARTUP within 6 hours.

SURVEILLANCE REQUIREMENTS

4.10.5 The number of months since initial criticality shall be verified to be less than or equal to 6 months at least once per 31 days during the Startup Test Program.

ATTACHMENT C

CHANGES IN AMENDMENT 23 OF THE FINAL SAFETY ANALYSIS REPORT WHICH AFFECT TECHNICAL SPECIFICATIONS

ITEM NO.	FSAR LOCATION	TECH. SPEC. LOCATION	SUBJECT
1) a	Table 7.3-1	Table 3.3.3-2	HPCS Setpoints
1) b	Table 7.3-2	Table 3.3.3-2	ADS Setpoints
1) c	Tables 7.3-1,2,3 4,5,6 and 7. Table 7.4-1	Figure B3/4.3-1	Instrument Zero
2)	Table 5.2-6	Table 3.4.4-1	BWR Water Chemistry
3)	Page 6.2-86	Table 3.6.3-1 3/4 6-24	Scram Discharge Vent And Drain Lines
4)	Page 9.2-6	4.7.1.1.d.2	Service Water Pump Starting On Loss Of Offsite Power
5)	Page 5.4-37	Table 3.3.3.2	LPCI Injection Valve Pressure Interlock Setpoints
6)	Page 7.6-7	Table 3.3.4.2-1	End Of Cycle Recirc. Pump Trip
7)	Page 7.7-5	L.C.O. 3.2.2 3/4 2-5	APRM and Rod Block Setpoints
8)	Table 8.3-10 1 of 1	4.8.2.1.d.2.c) 3/4 8-13	Div. III Battery Load Profile
9)	F430.74	4.8.1.1.2.b	Room Temp., Div. III Diesel Generator
10)	Table 6.2-56 7 of 24 Penetration Z-32	Table 3.6.3-1 3/4 6-23	Nitrogen Purge To TIP Indexing Mechanism Outside Isolation Valves
11)	Table 6.2-56 Note 19, Page 20 of 24	Table 3.6.3-1 3/4 6-23	Type "C" Testing Of TIP Ball Valves
12)	11.5-2	Table 3.3.7.10-1	Service Water Discharge Liquid Effluent Radiation Monitoring
13)	11.5-2	Table 3.3.7.11-1	Standby Gas Treatment Radiation Monitoring
14)	11.5-8 and 11.5-9	Table 3.3.7.10-1	Cooling Tower Blowdown, Liquid Radwaste And Service Water Effluent Radiation Monitors

ITEM NO.	FSAR LOCATION	TECH. SPEC. LOCATION	SUBJECT
15)	11.5-11	Tables 3.3.7.1-1, 3.3.7.10-1 and 3.3.7.11-1	Liquid And Gaseous Radiation Monitoring Instrumentation
16)	Table 11.5-1 Pages 1 and 2	Tables 3.3.7.1-1, 3.3.7.10-1 and 3.3.7.11-1; and RETS Portion of T.S.	Process And Effluent Radiation Monitoring Instrumentation Trip/High Set Points
17)	9.5-23	L.C.O.3.8.1.1.b	Fuel Oil Storage Requirements For Divisions I, II and III Diesel Generators
18)	Tables 9B.6-1, 9B.8-1, and 9B.8-2	Table 3.3.7.8-1	Fire Detection Instrumentation
19)	F440.16	Table 3.3.2-2 Items 2.e.2 and 2.f.2	RCIC Delta Temperature Isolation Signals
20)	Table 6.2-3 Page 1 of 2	5.2.2.b Page 5-1	Maximum Design Suppression Chamber Temperature
21)	Pages 5.2-31, 32 and 37	Table 3.3.2-2	Delta Temperature Leak Detection For Main Steam Line Tunnel, RHR, RCIC and RWCU
22)	Table 6.2-56	Tables 3.6.3-1 3.3.2-4 and 3.3.2-5	Containment Isolation Valves
23)	7.3-16, 17 and 7.6-9 and 7.3-25	Table 3.3.2-2	Delta Temp. Leak Detection For RWCU, RCIC and RHR
24)	7.4-11	Table 3.3.7.4-1	RHR Loops "A" and "B" Flow On Remote Shutdown Panel
25)	Table 12.3-2	None	Definition Of High Setpoint Bases
26)	7.3-5	Table 3.3.3-2	ADS Logic Operation
27)	Tables 9A.3-1 9A.3-2, 9A.3-4 9A.3-5, 9A.3-7 and 9A.3-12	Table 3.3.7.8-1	Fire Detection Instrumentation

ITEM NO.	FSAR LOCATION	TECH. SPEC. LOCATION	SUBJECT
28)	6.3-14a	Table 3.3.3-2	LPCS Injection Valve Differential Pressure Perimissive Setpoint
29)	F210.62	L.C.O. 3.4.3.2.d and Tables 3.4.3.2-1, 3.4.3.2-2 and 3.4.3.2-3	Leak Rate Testing Of Valves Separating Reactor Coolant System From Low Pressure Systems
30)	Table 12.3-1 Page 2 of 4	Table 3.3.7.1-1	Main Control Room Ventilation Radiation Monitors
31)	Tables 8.3-8 and 8.3-9	4.8.2.1.d.2.a) and b)	Divisions I and II Battery Load Profiles

ABBREVIATION LIST

HPCS - High Pressure Core Spray
ADS - Automatic Depressurization System
LPCI - Low Pressure Coolant Injection
TIP - Traversing Incore Probe
RCIC - Reactor Core Isolation Cooling
RHR - Residual Heat Removal
RWCU - Reactor Water Cleanup
LPCS - Low Pressure Core Spray

ATTACHMENT D

SINGLE LOOP OPERATION
PROPOSED TECHNICAL SPECIFICATION CHANGES

PROOF & REVIEW COPY

2.0 SAFETY LIMITS AND LIMITING SAFETY SYSTEM SETTINGS

2.1 SAFETY LIMITS

THERMAL POWER, Low Pressure or Low Flow

2.1.1 THERMAL POWER shall not exceed 25% of RATED THERMAL POWER with the reactor vessel steam dome pressure less than 785 psig or core flow less than 10% of rated flow.

APPLICABILITY: OPERATIONAL CONDITIONS 1 and 2.

ACTION:

With THERMAL POWER exceeding 25% of RATED THERMAL POWER and the reactor vessel steam dome pressure less than 785 psig or core flow less than 10% of rated flow, be in at least HOT SHUTDOWN within 2 hours and comply with the requirements of Specification 6.7.1.

two recirculation loop operation and shall not be less than 1.07 with single recirculation loop operation with

THERMAL POWER, High Pressure and High Flow

2.1.2 The MINIMUM CRITICAL POWER RATIO (MCPR) shall not be less than 1.06 with the reactor vessel steam dome pressure greater than 785 psig and core flow greater than 10% of rated flow.

APPLICABILITY: OPERATIONAL CONDITIONS 1 and 2.

with two recirculation loop operation or less than 1.07 with single loop operation

ACTION:

With MCPR less than 1.06 and the reactor vessel steam dome pressure greater than 785 psig and core flow greater than 10% of rated flow, be in at least HOT SHUTDOWN within 2 hours and comply with the requirements of Specification 6.7.1.

REACTOR COOLANT SYSTEM PRESSURE

2.1.3 The reactor coolant system pressure, as measured in the reactor vessel steam dome, shall not exceed 1325 psig.

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

ACTION:

With the reactor coolant system pressure, as measured in the reactor vessel steam dome, above 1325 psig, be in at least HOT SHUTDOWN with reactor coolant system pressure less than or equal to 1325 psig within 2 hours and comply with the requirements of Specification 6.7.1.

NOV 2 0 1985

TABLE 2.2.1-1

REACTOR PROTECTION SYSTEM INSTRUMENTATION SETPOINTS

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUES
1. Intermediate Range Monitor, Neutron Flux-High	$\leq$ 120/125 divisions of full scale	$\leq$ 122/125 divisions of full scale
2. Average Power Range Monitor:		
a. Neutron Flux-Upscale, Setdown	$\leq$ 15% of RATED THERMAL POWER	$\leq$ 20% of RATED THERMAL POWER
b. Flow Biased Simulated Thermal Power-Upscale		
1) Flow Biased	0.66(W-ΔW)+51%# $\leq$ ~~0.66 W+51%~~, with a maximum of	0.66(W-ΔW)+54%# $\leq$ ~~0.66 W+54%~~, with a maximum of
2) High Flow Clamped	$\leq$ 113.5% of RATED THERMAL POWER	$\leq$ 115.5% of RATED THERMAL POWER
c. Fixed Neutron Flux-Upscale	$\leq$ 118% of RATED THERMAL POWER	$\leq$ 120% of RATED THERMAL POWER
d. Inoperative	NA	NA
3. Reactor Vessel Steam Dome Pressure - High	$\leq$ 1037 psig	$\leq$ 1057 psig
4. Reactor Vessel Water Level - Low, Level 3	$\geq$ 159.3 inches above instrument zero*	$\geq$ 157.8 inches above instrument zero
5. Main Steam Line Isolation Valve - Closure	$\leq$ 6% closed	$\leq$ 7% closed
6. Main Steam Line Radiation - High	$\leq$ 3.0 x full power background	$\leq$ 3.6 x full power background
7. Drywell Pressure - High	$\leq$ 1.68 psig	$\leq$ 1.88 psig
8. Scram Discharge Volume Water Level - High		
a. Level Transmitter/Trip Units	$\leq$ 46.5 inches	$\leq$ 79.5 inches
b. Float Switch	$\leq$ 46.5 inches	$\leq$ 79.5 inches
9. Turbine Stop Valve - Closure	$\leq$ 5% closed	$\leq$ 7% closed
10. Turbine Control Valve Fast Closure, Trip Oil Pressure - Low	$\geq$ 530 psig	$\geq$ 465 psig
11. Reactor Mode Switch Shutdown Position	NA	NA
12. Manual Scram	NA	NA

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

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Notes

(a) The Average Power Range Monitor Scram Function varies as a function of recirculation loop drive flow (W). ΔW is defined as the difference in indicated drive flow (in percent of drive flow which produces rated core flow) between two loop and single loop operation at the same core flow.

$\Delta W = 0$ for two loop operation

$\Delta W = 5\%$ for single loop operation

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2.1 SAFETY LIMITS

BASES

2.0 INTRODUCTION

for two recirculation loop operation and 1.07 for single recirculation loop operation

The fuel cladding, reactor pressure vessel and primary system piping are the principal barriers to the release of radioactive materials to the environs. Safety Limits are established to protect the integrity of these barriers during normal plant operations and anticipated transients. The fuel cladding integrity Safety Limit is set such that no fuel damage is calculated to occur if the limit is not violated. Because fuel damage is not directly observable, a step-back approach is used to establish a Safety Limit such that the MCPR is not less than 1.06. MCPR greater than 1.06 represents a conservative margin relative to the conditions required to maintain fuel cladding integrity. The fuel cladding is one of the physical barriers which separate the radioactive materials from the environs. The integrity of this cladding barrier is related to its relative freedom from perforations or cracking. Although some corrosion or use-related cracking may occur during the life of the cladding, fission product migration from this source is incrementally cumulative and continuously measurable. Fuel cladding perforations, however, can result from thermal stresses which occur from reactor operation significantly above design conditions and the Limiting Safety System Settings. While fission product migration from cladding perforation is just as measurable as that from use-related cracking, the thermally caused cladding perforations signal a threshold beyond which still greater thermal stresses may cause gross rather than incremental cladding deterioration. Therefore~~, the fuel cladding Safety Limit is defined~~ with a margin to the conditions which would produce onset of transition boiling, MCPR of 1.0. These conditions represent a significant departure from the condition intended by design for planned operation.

2.1.1 THERMAL POWER, Low Pressure or Low Flow

The use of the GEXL correlation is not valid for all critical power calculations at pressures below 785 psig or core flows less than 10% of rated flow. Therefore, the fuel cladding integrity Safety Limit is established by other means. This is done by establishing a limiting condition on core THERMAL POWER with the following basis. Since the pressure drop in the bypass region is essentially all elevation head, the core pressure drop at low power and flows will always be greater than 4.5 psi. Analyses show that with a bundle flow of 28×10^3 lbs/hr, bundle pressure drop is nearly independent of bundle power and has a value of 3.5 psi. Thus, the bundle flow with a 4.5 psi driving head will be greater than 28×10^3 lbs/hr. Full scale ATLAS test data taken at pressures from 14.7 psia to 800 psia indicate that the fuel assembly critical power at this flow is approximately 3.35 MWt. With the design peaking factors, this corresponds to a THERMAL POWER of more than 50% of RATED THERMAL POWER. Thus, a THERMAL POWER limit of 25% of RATED THERMAL POWER for reactor pressure below 785 psig is conservative.

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Bases Table B2.1.2-1

UNCERTAINTIES USED IN THE DETERMINATION

OF THE FUEL CLADDING SAFETY LIMIT*

Quantity	Standard Deviation (% of Point)
Feedwater Flow	1.76
Feedwater Temperature	0.76
Reactor Pressure	0.5
Core Inlet Temperature	0.2
Core Total Flow	~~2.5~~
Two Recirculation Loop Operation	2.5
Single Recirculation Loop Operation	6.0
Channel Flow Area	3.0
Friction Factor Multiplier	10.0
Channel Friction Factor Multiplier	5.0
TIP Readings	~~6.3~~
Two Recirculation Loop Operation	6.3
Single Recirculation Loop Operation	6.8
R Factor	1.5
Critical Power	3.6

* The uncertainty analysis used to establish the core wide Safety Limit MCPR is based on the assumption of quadrant power symmetry for the reactor core. The values herein apply to both two recirculation loop operation and single recirculation loop operation, except as noted.

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3/4.2 POWER DISTRIBUTION LIMITS

3/4.2.1 AVERAGE PLANAR LINEAR HEAT GENERATION RATE

LIMITING CONDITION FOR OPERATION

3.2.1 All AVERAGE PLANAR LINEAR HEAT GENERATION RATES (APLHGRs) for each type of fuel as a function of AVERAGE PLANAR EXPOSURE shall not exceed the limits shown in Figures 3.2.1-1, 3.2.1-2, and 3.2.1-3.

APPLICABILITY: OPERATIONAL CONDITION 1, when THERMAL POWER is greater than or equal to 25% of RATED THERMAL POWER.

ACTION:

With an APLHGR exceeding the limits of Figure 3.2.1-1, 3.2.1-2, or 3.2.1-3, initiate corrective action within 15 minutes and restore APLHGR to within the required limits within 2 hours or reduce THERMAL POWER to less than 25% of RATED THERMAL POWER within the next 4 hours.

The Limits of Figures 3.2.1-1, 3.2.1-2 and 3.2.1-3 shall be reduced to a value of 0.81 times the two recirculation loop operation limit when in single recirculation loop operation.

SURVEILLANCE REQUIREMENTS

4.2.1 All APLHGRs shall be verified to be equal to or less than the limits determined from Figures 3.2.1-1, 3.2.1-2, and 3.2.1-3:

a. At least once per 24 hours,

b. Within 12 hours after completion of a THERMAL POWER increase of at least 15% of RATED THERMAL POWER, and

c. Initially and at least once per 12 hours when the reactor is operating with a LIMITING CONTROL ROD PATTERN for APLHGR.

d. The provisions of Specification 4.0.4 are not applicable.

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3/4.2.2 APRM SETPOINTS

LIMITING CONDITION FOR OPERATION

3.2.2 The APRM flow biased simulated thermal power-upscale scram trip setpoint (S) and flow biased neutron flux-upscale control rod block trip setpoint (S_{RB}) shall be established according to the following relationships:

	TRIP SETPOINT	ALLOWABLE VALUE	
(W−ΔW)**	$S \leq (0.66W + 51\%)T$	$S \leq (0.66W + 54\%)T$	(W−ΔW)**
	$S_{RB} \leq (0.66W + 42\%)T$	$S_{RB} \leq (0.66W + 45\%)T$	

where: S and S_{RB} are in percent of RATED THERMAL POWER,

W = Loop recirculation flow as a percentage of the loop recirculation flow which produces a rated core flow of 108.5 million lbs/hr.

T = The ratio FRACTION OF RATED THERMAL POWER divided by the CORE MAXIMUM FRACTION OF LIMITING POWER DENSITY. T is applied only if less than or equal to 1.0.

APPLICABILITY: OPERATIONAL CONDITION 1, when THERMAL POWER is greater than or equal to 25% of RATED THERMAL POWER.

ACTION:

With the APRM flow biased simulated thermal power-upscale scram trip setpoint and/or the flow biased neutron flux-upscale control rod block trip setpoint less conservative than the value shown in the Allowable Value column for S or S_{RB}, as above determined, initiate corrective action within 15 minutes and adjust S and/or S_{RB} to be consistent with the Trip Setpoint value* within 6 hours or reduce THERMAL POWER to less than 25% of RATED THERMAL POWER within the next 4 hours.

SURVEILLANCE REQUIREMENTS

4.2.2 The FRTP and the CMFLPD shall be determined, the value of T calculated, and the most recent actual APRM flow biased simulated thermal power-upscale scram and flow biased neutron flux-upscale control rod block trip setpoints verified to be within the above limits or adjusted, as required:

a. At least once per 24 hours,

b. Within 12 hours after completion of a THERMAL POWER increase of at least 15% of RATED THERMAL POWER, and

c. Initially and at least once per 12 hours when the reactor is operating with CMFLPD greater than or equal to FRTP.

d. The provisions of Specification 4.0.4 are not applicable.

*With CMFLPD greater than the FRTP ~~during power ascension up to 90% of RATED THERMAL POWER~~, rather than adjusting the APRM setpoints, the APRM gain may be adjusted such that APRM readings are greater than or equal to 100% times CMFLPD provided that the adjusted APRM reading does not exceed 100% of RATED THERMAL POWER and a notice of adjustment is posted on the reactor control panel.

** See note (a) to Table 2.2.1-1

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TABLE 3.3.6-2

CONTROL ROD BLOCK INSTRUMENTATION SETPOINTS

TRIP FUNCTION	TRIP SETPOINT	ALLOWABLE VALUE
1. ROD BLOCK MONITOR		
a. Upscale	≤ 0.66 W + 40%	≤ 0.66 W + 43%
b. Inoperative	NA	NA
c. Downscale	≥ 5% of RATED THERMAL POWER	≥ 3% of RATED THERMAL POWER
2. APRM		
a. Flow Biased Neutron Flux Upscale	≤ 0.66 ~~W~~ (W-ΔW) + 42%*	≤ 0.66 ~~W~~ (W-ΔW) + 45%*
b. Inoperative	NA	NA
c. Downscale	≥ 4% of RATED THERMAL POWER	≥ 3% of RATED THERMAL POWER
d. Neutron Flux - Upscale, Startup	≤ 12% of RATED THERMAL POWER	≤ 14% of RATED THERMAL POWER
3. SOURCE RANGE MONITORS		
a. Detector not full in	NA	NA
b. Upscale	≤ 1 x 10^5 cps	≤ 1.6 x 10^5 cps
c. Inoperative	NA	NA
d. Downscale	≥ 3 cps**	≥ 1.8 cps**
4. INTERMEDIATE RANGE MONITORS		
a. Detector not full in	NA	NA
b. Upscale	≤ 108/125 divisions of full scale	≤ 110/125 divisions of full scale
c. Inoperative	NA	NA
d. Downscale	≥ 5/125 divisions of full scale	≥ 3/125 divisions of full scale
5. SCRAM DISCHARGE VOLUME		
a. Water Level-High	≤ 16.5 in.	≤ 39.75 in.
~~b. Scram Trip Bypass~~	~~NA~~	~~NA~~
6. REACTOR COOLANT SYSTEM RECIRCULATION FLOW		
a. Upscale	≤ 108% rated flow	≤ 111% rated flow
b. Inoperative	NA	NA
c. Comparator	≤ 10% flow deviation	≤ 11% flow deviation

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*The Average Power Range Monitor rod block function is varied as a function of recirculation loop flow (W). The trip setting of this function must be maintained in accordance with Specification 3.2.2.

**For initial loading and startup the count rate may be less than 3 cps if the following conditions are met; (1) the signal to noise ratio is greater than 2.0, and (2) the signal is greater than 0.7 cps~~; and (3) and counting interval sufficient to accumulate at least 500 counts is employed.~~ and note (a) of Table 2.2.1-1

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3/4.4 REACTOR COOLANT SYSTEM

3/4.4.1 RECIRCULATION SYSTEM

RECIRCULATION LOOPS

LIMITING CONDITION FOR OPERATION

3.4.1.1 Two reactor coolant system recirculation loops shall be in operation with:

a. Total core flow greater than or equal to 45% of rated core flow, or

b. THERMAL POWER within the unrestricted zone of Figure 3.4.1.1-1.

APPLICABILITY: OPERATIONAL CONDITIONS 1* and 2*.

ACTION:

a. With one reactor coolant system recirculation loop not in operation:

1. Within four hours:

a) Place the recirculation flow control system in the Local Manual (Position Control) mode, and

b) Reduce THERMAL POWER to ≤ 70% of RATED THERMAL POWER, and,

c) Increase the MINIMUM CRITICAL POWER RATIO (MCPR) Safety Limit by 0.01 to 1.07 per Specification 2.1.2, and,

d) Reduce the Maximum Average Planar Linear Heat Generation Rate (MAPLHGR) limit to a value of 0.81 times the two recirculation loop operation limit per Specification 3.2.1, and,

e) Reduce the Average Power Range Monitor (APRM) Scram and Rod Block and Rod Block Monitor Trip Setpoints and Allowable Values to those applicable for single recirculation loop operation per Specifications 2.2.1, 3.2.2 and 3.3.6.

f) Reduce the volumetric flow rate of the operating recirculation loop to ≤ 41,000** gpm.

* See Special Test Exception 3.10.4.

** This value represents the design volumetric recirculation loop flow which produces 100% core flow at 100% THERMAL POWER. The actual value will be established during the Startup Test Program.

LIMITING CONDITION FOR OPERATION (Continued)

g) Perform Surveillance Requirement 4.4.1.1.2 if THERMAL POWER is $\leq$ 30%*** of RATED THERMAL POWER or the recirculation loop flow in the operating loop is $\leq$ 50%*** of rated loop flow.

h) Determine that the reactor THERMAL POWER level is not within the restricted zone of Figure 3.4.1.1-1; otherwise, reduce the THERMAL POWER level or increase core flow.

2. The provisions of Specification 3.0.4 are not applicable.

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

b. With no reactor coolant system recirculation loops in operation, immediately initiate action to reduce THERMAL POWER such that it is not within the restricted zone of Figure 3.4.1.1-1 within two hours, and initiate measures to place the unit in at least STARTUP within six hours and in HOT SHUTDOWN within the next six hours.

c. With two reactor coolant system recirculation loops in operation and total core flow less than 45% of rated core flow and THERMAL POWER greater than the limit specified in Figure 3.4.1.1-1:

1. Determine the APRM and LPRM** noise levels (Surveillance 4.4.1.1.4):

a) At least once per eight hours, and

b) Within 30 minutes after the completion of a THERMAL POWER increase of at least 5% of RATED THERMAL POWER.

2. With the APRM or LPRM** neutron flux noise levels greater than three times their established baseline noise levels, immediately initiate corrective action to restore the noise levels within the required limits within two hours by increasing core flow to greater than 45% of rated core flow or by reducing THERMAL POWER so that it is not within the restricted zone of Figure 3.4.1.1-1.

** Detector levels A and C of one LPRM string per core octant plus detectors A and C of one LPRM strong in the center of the core should be monitored.

*** Initial values. Final values to be determined during Startup Testing based upon the threshold THERMAL POWER and recirculation loop flow which will sweep the cold water from the vessel bottom heat preventing stratification.

SURVEILLANCE REQUIREMENTS

4.4.1.1.1 With one reactor coolant system recirculation loop not in operation, at least once per 12 hours verify that:

a. Reactor THERMAL POWER is ≤ 70% of RATED THERMAL POWER,

b. The recirculation flow control system is in the Local Manual (Position Control) mode, and

c. The volumetric flow rate of the operating loop is ≤ 41,000 gpm.*

4.4.1.1.2 With one reactor coolant system recirculation loop not in operation, within no more than 15 minutes prior to either THERMAL POWER increase or recirculation loop flow increase, verify that the following differential temperature requirements are met if THERMAL POWER is ≤ 30%** of RATED THERMAL POWER or the recirculation loop flow in the operating recirculation loop is ≤ 50%*** of rated loop flow:

a. ≤ 145°F between reactor vessel steam space coolant and bottom head drain line coolant,

b. ≤ 50°F between the reactor coolant within the loop not in operation and the coolant in the reactor pressure vessel, and

c. ≤ 50°F between the reactor coolant within the loop not in operation and the operating loop.

The differential temperature requirements of Specification 4.4.1.1.2b. and c. do not apply when the loop not in operation is isolated from the reactor pressure vessel.

4.4.1.1.3 Each reactor coolant system recirculation loop flow control valve shall be demonstrated OPERABLE at least once per 18 months by:

a. Verifying that the control valve fails "as is" on loss of hydraulic pressure at the hydraulic control unit, and

b. Verifying that the average rate of control valve movement is:

   1. Less than or equal to 11% of stroke per second opening, and

   2. Less than or equal to 11% of stroke per second closing.

---

* This value represents the design volumetric recirculation loop flow which produces 100% core flow at 100% THERMAL POWER. The actual value will be established during the Startup Test Program.

** Initial values. Final values to be determined during Startup Testing based upon the threshold THERMAL POWER and recirculation loop flow which will sweep the cold water from the vessel bottom head preventing stratification.

SURVEILLANCE REQUIREMENTS (Continued)

4.4.1.1.4 Establish a baseline APRM and LPRM* neutron flux noise value within the regions for which monitoring is required (Specification 3.4.1.1, ACTION c) within two hours of entering the region for which monitoring is required unless baselining has previously been performed in the region since the last refueling outage.

* Detector levels A and C of one LPRM string per core octant plus detectors A and C of one LPRM string in the center of the core should be monitored.

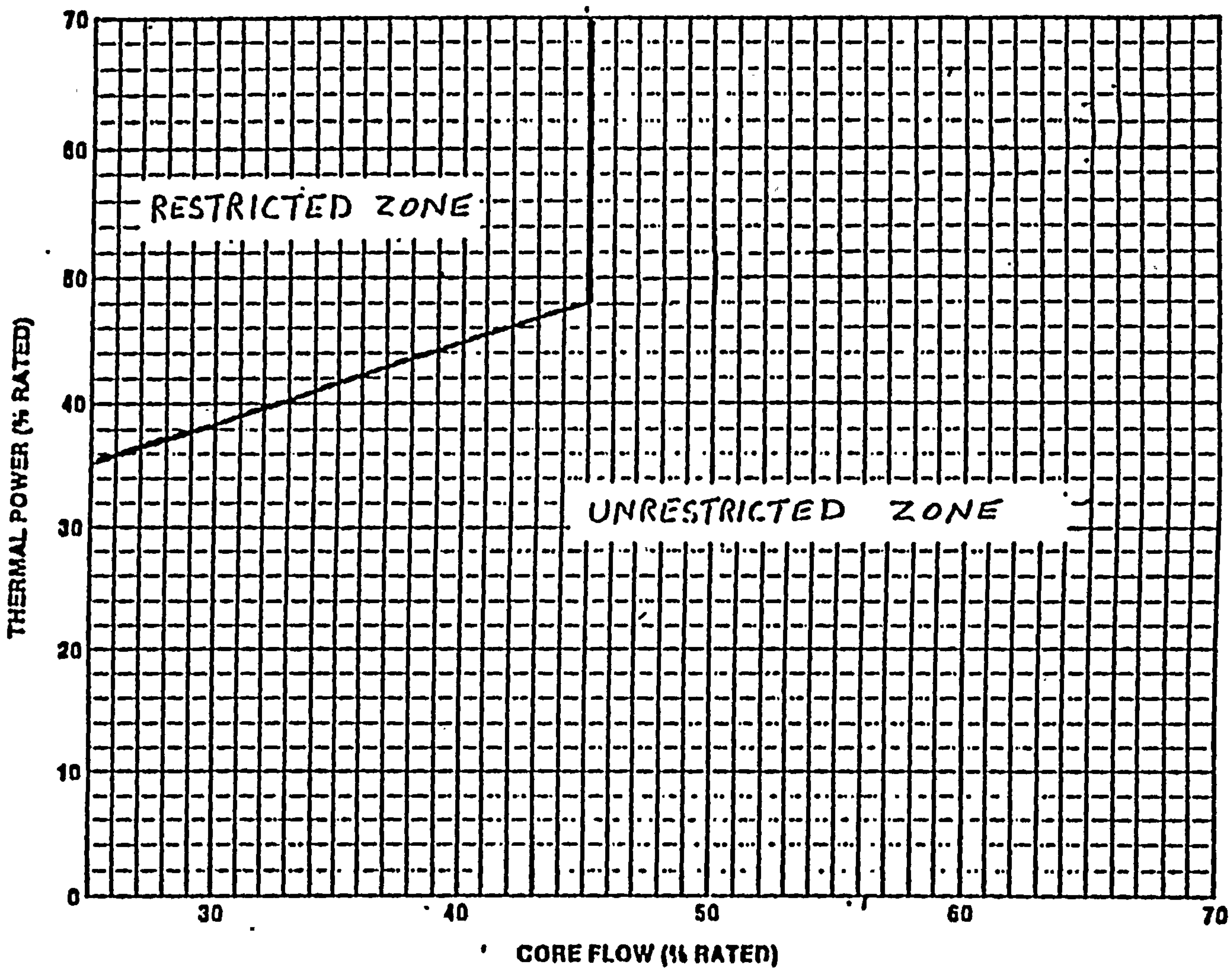

FIGURE 3.4.1.1-1
THERMAL POWER VERSUS CORE FLOW

LIMITING CONDITION FOR OPERATION

3.4.1.2 All jet pumps shall be OPERABLE.

APPLICABILITY: OPERATIONAL CONDITIONS 1 and 2.

ACTION:

With one or more jet pumps inoperable, be in at least HOT SHUTDOWN within 12 hours.

SURVEILLANCE REQUIREMENTS

4.4.1.2 All jet pumps shall be demonstrated OPERABLE as follows:

a. Each of the above required jet pumps shall be demonstrated OPERABLE prior to THERMAL POWER exceeding 25% of RATED THERMAL POWER, and at least once per 24 hours while greater than 25% of RATED THERMAL POWER, by determining recirculation loop flow, total core flow and diffuser-to-lower plenum differential pressure for each jet pump and verifying that no two of the following conditions occur when both recirculation loop indicated flows are in compliance with Specification 3.4.1.3.

   1. The indicated recirculation loop flow differs by more than 10% from the established* flow control valve position-loop flow characteristics.

   2. The indicated total core flow differs by more than 10% from the established* total core flow value derived from recirculation loop flow measurements.

   3. The indicated diffuser-to-lower plenum differential pressure of any individual jet pump differs from established* patterns by more than 10%.

b. During single recirculation loop operation, each of the above required jet pumps shall be demonstrated OPERABLE at least once per 24 hours by verifying that no two of the following conditions occur:

   1. The indicated recirculation loop flow in the operating loop differs by more than 10% from the established single recirculation flow control valve position-loop flow characteristics.

---

*To be determined during the startup test program.

SURVEILLANCE REQUIREMENTS (Continued)

2. The indicated total core flow differs by more than 10% from the established total core flow value derived from single recirculation loop flow measurements.

3. The indicated difference-to-lower plenum differential pressure of any individual jet pump differs from established single recirculation loop patterns by more than 10%.

c. The provisions of Specification 4.0.4 are not applicable provided that this surveillance is performed within 24 hours after exceeding 25% of RATED THERMAL POWER.

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RECIRCULATION LOOP FLOW

LIMITING CONDITION FOR OPERATION

3.4.1.3 Recirculation loop flow mismatch shall be maintained within:

a. 5% of rated core ~~recirculation~~ flow with effective core flow* greater than or equal to 70% of rated core flow.

b. 10% of rated core ~~recirculation~~ flow with effective core flow less than 70% of rated core flow.

APPLICABILITY: OPERATIONAL CONDITIONS 1** and 2** during two recirculation loop operation.

ACTION:

With the recirculation loop flows different by more than the specified limits, either:

a. Restore the recirculation loop flows to within the specified limit within 2 hours, or

b. ~~Declare the recirculation loop with the lower flow not in operation and take the ACTION required by Specification 3.4.1.1.~~ Shutdown one of the recirculation loops and take the ACTION required by Specification 3.4.1.1

c. The provisions of Specification 3.0.4 are not applicable.

SURVEILLANCE REQUIREMENTS

4.4.1.3 Recirculation loop flow mismatch shall be verified to be within the limits at least once per 24 hours.

**See Special Test Exception 3.10.4.

*Effective core flow shall be the core flow that would result if both recirculation loop flows were assumed to be at the smaller value of the two loop flows.

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3/4.1.3 CONTROL RODS

The specification of this section ensure that (1) the minimum SHUTDOWN MARGIN is maintained, (2) the control rod insertion times are consistent with those used in the safety analyses, and (3) limit the potential effects of the rod drop accident. The ACTION statements permit variations from the basic requirements but at the same time impose more restrictive criteria for continued operation. A limitation on inoperable rods is set such that the resultant effect on total rod worth and scram shape will be kept to a minimum. The requirements for the various scram time measurements ensure that any indication of systematic problems with rod drives will be investigated on a timely basis.

Damage within the control rod drive mechanism could be a generic problem, therefore with a control rod immovable because of excessive friction or mechanical interference, operation of the reactor is limited to a time period which is reasonable to determine the cause of the inoperability and at the same time prevent operation with a large number of inoperable control rods.

Control rods that are inoperable for other reasons are permitted to be taken out of service provided that those in the nonfully-inserted position are consistent with the SHUTDOWN MARGIN requirements.

The number of control rods permitted to be inoperable could be more than the eight allowed by the specification, but the occurrence of eight inoperable rods could be indicative of a generic problem and the reactor must be shutdown for investigation and resolution of the problem. the fuel cladding safety limit

The control rod system is designed to bring the reactor subcritical at a rate fast enough to prevent the MCPR from becoming less than ~~1.06~~ during the limiting power transient analyzed in Section 15.4 of the FSAR. This analysis shows that the negative reactivity rates resulting from the scram with the average response of all the drives as given in the specifications, provide the required protection and MCPR remains greater than ~~1.06.~~ The occurrence of scram times longer then those specified should be viewed as an indication of a systemic problem with the rod drives and therefore the surveillance interval is reduced in order to prevent operation of the reactor for long periods of time with a potentially serious problem.

The scram discharge volume is required to be OPERABLE so that it will be available when needed to accept discharge water from the control rods during a reactor scram and will isolate the reactor coolant system from the containment when required.

Control rods with inoperable accumulators are declared inoperable and Specification 3.1.3.1 then applies. This prevents a pattern of inoperable accumulators that would result in less reactivity insertion on a scram than has been analyzed even though control rods with inoperable accumulators may still be inserted with normal drive water pressure. Operability of the accumulator ensures that there is a means available to insert the control rods even under the most unfavorable depressurization of the reactor.

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AVERAGE PLANAR LINEAR HEAT GENERATION RATE (Continued)

b. Model Change

1. Core CCFL pressure differential - 1 psi - Incorporate the assumption that flow from the bypass to lower plenum must overcome a 1 psi pressure drop in core.

2. Incoporate NRC pressure transfer assumption - The assumption used in the SAFE-REFLOOD pressure transfer when the pressure is increasing was changed.

A few of the changes affect the accident calculation irrespective of CCFL. These changes are listed below.

a. Input Change

1. Break Areas - The DBA break area was calculated more accurately.

b. Model Change

1. Improved Radiation and Conduction Calculation - Incorporation of CHASTE 05 for heatup calculation.

A list of the significant plant input parameters to the loss-of-coolant accident analysis is presented in Bases Table B 3.2.1-1.

3/4.2.2 APRM SETPOINTS

The fuel cladding integrity Safety Limits of Specification 2.1 were based on a power distribution which would yield the design LHGR at RATED THERMAL POWER. The flow biased simulated thermal power-upscale scram setting and flow biased neutron flux upscale control rod block functions of the APRM instruments must be adjusted to ensure that the MCPR does not become less than 1.06 or that ≥ 1% plastic strain does not occur in the degraded situation. The scram set point and rod block settings are adjusted in accordance with the formula in this specification when the combination of THERMAL POWER and CMFLPD indicates a higher peaked power distribution to ensure that an LHGR transient would not be increased in the degraded condition.

For plant operation with single recirculation loop, the MAPLHGR limits of Figures 3.2.1-1, 3.2.1-2 and 3.2.1-3 are multiplied by 0.81. The constant factor 0.81, is derived from LOCA analysis initiated from single loop operation to account for earlier boiling transition at the limiting fuel node compared to the standard LOCA evaluations.

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Bases Table B 3.2.1-1

SIGNIFICANT INPUT PARAMETERS TO THE

LOSS-OF-COOLANT ACCIDENT ANALYSIS

Plant Parameters;

Core THERMAL POWER .... 3461 MWt* which corresponds to 105% of rated steam flow

Vessel Steam Output .... 15.0×10^6 lbm/hr which corresponds to 105% of rated steam flow

Vessel Steam Dome Pressure.............. 1055 psia

Design Basis Recirculation Line Break Area for:

a. Large Breaks $3.1\ ft^2$

b. Small Breaks $0.09\ ft^2$

Fuel Parameters:

FUEL TYPE	FUEL BUNDLE GEOMETRY	PEAK TECHNICAL SPECIFICATION LINEAR HEAT GENERATION RATE (kw/ft)	DESIGN AXIAL PEAKING FACTOR	INITIAL MINIMUM CRITICAL POWER RATIO
Initial Core	8 x 8	13.4	1.4	1.20 **

A more detailed listing of input of each model and its source is presented in Section II of Reference 1 and subsection 6.3.3 of the FSAR.

*This power level meets the Appendix K requirement of 102%. The core heatup calculation assumes a bundle power consistent with operation of the highest powered rod at 102% of its Technical Specification LINEAR HEAT GENERATION RATE limit.

** For single recirculation loop operation, loss of nucleate boiling is assumed at 0.1 second after LOCA regardless of initial MCPR.

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3/4.2.3 MINIMUM CRITICAL POWER RATIO

The required operating limit MCPRs at steady state operating conditions as specified in Specification 3.2.3 are derived from the established fuel cladding integrity Safety Limit MCPR ~~of 1.06~~, and an analysis of abnormal operational transients. For any abnormal operating transient analysis evaluation with the initial condition of the reactor being at the steady state operating limit, it is required that the resulting MCPR does not decrease below the Safety Limit MCPR at any time during the transient assuming instrument trip setting given in Specification 2.2.

To assure that the fuel cladding integrity Safety Limit is not exceeded during any anticipated abnormal operational transient, the most limiting transients have been analyzed to determine which result in the largest reduction in CRITICAL POWER RATIO (CPR). The type of transients evaluated were loss of flow, increase in pressure and power, positive reactivity insertion, and coolant temperature decrease. ~~The limiting transient yields the largest delta MCPR. When added to the Safety Limit MCPR of 1.06, the required minimum operating limit MCPR of Specification 3.2.3 is obtained and presented in Figure 3.2.3-1.~~

The evaluation of a given transient begins with the system initial parameters shown in FSAR Table 15.0.3 that are input to a GE-core dynamic behavior transient computer program. The code used to evaluate pressurization events is described in NEDO-24154[3] and the program used in non-pressurization events is described in NEDO-10802[2]. The outputs of this program along with the initial MCPR form the input for further analyses of the thermally limiting bundle with the single channel transient thermal hydraulic TASC code described in NEDE-25149[4]. The principal result of this evaluation is the reduction in MCPR caused by the transient.

The purpose of the K_f factor of Figure 3.2.3-1 is to define operating limits at other than rated core flow conditions. At less than 100% of rated flow the required MCPR is the product of the MCPR and the K_f factor. The K_f factors assure that the Safety Limit MCPR will not be violated. The K_f factors were derived using THERMAL POWER and core flow corresponding to 105% of rated steam flow.

The K_f factors were calculated such that for the maximum core flow rate and the corresponding THERMAL POWER along the 105% of rated steam flow control line, the limiting bundle's relative power was adjusted until the MCPR was slightly above the Safety Limit. Using this relative bundle power, the MCPRs were calculated at different points along the 105% of rated steam flow control line corresponding to different core flows. The ratio of the MCPR calculated at a given point of core flow, divided by the operating limit MCPR, determines the K_f.

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3/4.4.1 RECIRCULATION SYSTEM Replace with Insert "E"

~~Operation with one reactor core coolant recirculation loop inoperable is prohibited until an evaluation of the performance of the ECCS during one loop operation has been performed, evaluated and determined to be acceptable.~~

The objective of GE BWR plant and fuel design is to provide stable operation with margin over the normal operating domain. However, at the high power/low flow corner of the operating domain, a small probability of limit cycle neutron flux oscillations exists depending on combinations of operating conditions (e.g., rod pattern, power shape). To provide assurance that neutron flux limit cycle oscillations are detected and suppressed, APRM and LPRM neutron flux noise levels should be monitored while operating in this region.

Stability tests at operating BWRs were reviewed to determine a generic region of the power/flow map in which surveillance of neutron flux noise levels should be performed. A conservative decay ratio of 0.6 was chosen as the bases for determining the generic region for surveillance to account for the plant to plant variability of decay ratio with core and fuel designs. This generic region has been determined to correspond to a core flow of less than or equal to 45% of rated core flow and a THERMAL POWER greater than that specified in Figure 3.4.1.1-1.

Plant specific calculations can be performed to determine an applicable region for monitoring neutron flux noise levels. In this case the degree of conservatism can be reduce since plant to plant variability would be eliminated. In this case, adequate margin will be assured by monitoring the region which has a decay ratio greater than or equal to 0.8.

Neutron flux noise limits are also established to ensure early detection of limit cycle neutron flux oscillations. BWR cores typically operate with neutron flux noise caused by random boiling and flow noise. Typical neutron flux noise levels of 1-12% of rated power (peak-to-peak) have been reported for the range of low to high recirculation loop flow during both single and dual recirculation loop operation. Neutron flux noise levels which significantly bound these values are considered in the thermal/mechanical design of GE BWR fuel and are found to be of negligible consequence. In addition, stability tests at operating BWRs have demonstrated that when stability related neutron flux limit cycle oscillations occur they result in peak-to-peak neutron flux limit cycles of 5-10 times the typical values. Therefore, actions taken to reduce neutron flux noise levels exceeding three (3) times the typical value are sufficient to ensure early detection of limit cycle neutron flux oscillations.

Typically, neutron flux noise levels show a gradual increase in absolute magnitude as core flow is increased (constant control rod pattern) with two reactor recirculation loops in operation. Therefore, the baseline neutron

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3/4.4 REACTOR COOLANT SYSTEM

BASES

3/4.4.1 RECIRCULATION SYSTEM (Continued)

flux noise level obtained at a specified core flow can be applied over a range of core flows. To maintain a reasonable variation between the low flow and high flow end of the flow range, the range over which a specific baseline is applied should not exceed 20% of rated core flow with two recirculation loops in operation. Data from tests and operating plants indicate that a range of 20% of rated core flow will result in approximately a 50% increase in neutron flux noise level during operation with two recirculation loops. Baseline data should be taken near the maximum rod line at which the majority of operation will occur. However, baseline data taken at lower rod lines (i.e., lower power will result in a conservative value since the neutron flux noise level is proportional to the power level at a given core flow.

An inoperable jet pump is not, in itself, a sufficient reason to declare a recirculation loop inoperable, but it does, in case of a design-basis-accident, increase the blowdown area and reduce the capability of reflooding the core; thus, the requirement for shutdown of the facility with a jet pump inoperable. Jet pump failure can be detected by monitoring jet pump performance on a prescribed schedule for significant degradation.

for two recirculation loop operation

Recirculation loop flow mismatch limits are in compliance with the ECCS LOCA analysis design criteria. The limits will ensure an adequate core flow coastdown from either recirculation loop following a LOCA.

Replace with Insert "F"

In order to prevent undue stress on the vessel nozzles and bottom head region, the recirculation loop temperatures shall be within 50°F of each other prior to startup of an idle loop. The loop temperature must also be within 50°F of the reactor pressure vessel coolant temperature to prevent thermal shock to the recirculation pump and recirculation nozzles. ~~Since the coolant in the bottom of the vessel is at a lower temperature than the coolant in the upper regions of the core, undue stress on the vessel would result if the temperature difference was greater than 145° F.~~

Replace with Insert "G"

3/4.4.2 SAFETY/RELIEF VALVES

The safety/relief valves operate during a postulated ATWS event to prevent the reactor coolant system being pressurized above a design allowable value of 1375 psig in accordance with the ASME Code. A total of 17 OPERABLE safety/relief valves is required to limit local pressure at active components to within ASME III allowable design values (Service Level A). All other appropriate ASME III limits are also bounded by this requirement.

Demonstration of the safety-relief valve lift settings will occur only during shutdown and will be performed in accordance with the provisions of Specification 4.0.5.

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INSERT "E"

The impact of single recirculation loop operation upon plant safety is assessed and shows that single-loop operation is permitted if the MCPR fuel cladding safety limit is increased as noted by Specification 2.1.2, APRM scram and control rod block setpoints are adjusted as noted in Tables 2.2.1-1 and 3.3.6.2, respectively, MAPLHGR limits are decreased by the factor given in Specification 3.2.1, and MCPR operating limits are adjusted per Section 3/4.2.3.

Additionally, surveillance on the volumetric flow rate of the operating recirculation loop is imposed to exclude the possibility of excessive core internals vibration. The surveillance on differential temperatures below 30%* THERMAL POWER or 50%* rated recirculation loop flow is to mitigate the undue thermal stress on vessel nozzles, recirculation pump and vessel bottom head during the extended operation of the single recirculation loop mode.

INSERT "F"

In the case where the mismatch limits cannot be maintained during two loop operation, continued operation is permitted in a single recirculation loop mode.

INSERT "G"

Sudden equalization of a temperature difference 145°F between the reactor vessel bottom head coolant and the coolant in the upper region of the reactor vessel by increasing core flow rate would cause undue stress in the reactor vessel bottom head.

---

* Initial values. The final values are determined during startup testing based upon the threshold THERMAL POWER and recirculation loop flow which will sweep the cold water from the vessel bottom head, preventing saturation.

ATTACHMENT E

END OF CYCLE - RECIRCULATION PUMP TRIP
INOPERABLE AND TURBINE BYPASS INOPERABLE
PROPOSED TECHNICAL SPECIFICATION CHANGES

3/4.2.3 MINIMUM CRITICAL POWER RATIO

LIMITING CONDITION FOR OPERATION

3.2.3 The MINIMUM CRITICAL POWER RATIO (MCPR) shall be equal to or greater than the MCPR limit shown in Figure 3.2.3-1 times the K_f shown in Figure 3.2.3-2 with:

$$\tau = \frac{(\tau_{ave} - \tau_B)}{\tau_A - \tau_B}$$

where:

τ_A = 0.86 seconds, control rod average scram insertion time limit to notch 39 per Specification 3.1.3.3,

$$\tau_B = 0.688 + 1.65\left[\frac{N_1}{\sum_{i=1}^{n} N_i}\right]^{1/2}[0.052],$$

$$\tau_{ave} = \frac{\sum_{i=1}^{n} N_i \tau_i}{\sum_{i=1}^{n} N_i},$$

n = number of surveillance tests performed to date in cycle,

N_i = number of active control rods measured in the i^{th} surveillance test,

τ_i = average scram time to notch 39 of all rods measured in the i^{th} surveillance test, and

N_1 = total number of active rods measured in Specification 4.1.3.2.a.

APPLICABILITY:

OPERATION CONDITION 1, when THERMAL POWER is greater than or equal to 25% of RATED THERMAL POWER.

LIMITING CONDITION FOR OPERATION (Continued)

ACTION

a. With the end-of-cycle recirculation pump trip system inoperable per Specification 3.3.4.2, operation may continue and the provisions of Specification 3.0.4 are not applicable provided that, within one hour, MCPR is determined to be equal to or greater than the MCPR limit shown in Figure 3.2.3-1 EOC-RPT inoperable curve, times the K_f shown in Figure 3.2.3-2.

b. With the main turbine bypass system inoperable per Specification 3.7.8, operation may continue and the provisions of Specification 3.0.4 are not applicable provided that, within one hour, MCPR is determined to be equal to or greater than the MCPR limit shown in Figure 3.2.3-1, main turbine bypass inoperable curve times the K_f shown in Figure 3.2.3-2.

c. With MCPR less than the applicable MCPR limit determined from Figures 3.2.3-1 and 3.2.3-2, as applicable, initiate corrective action within 15 minutes to restore MCPR within the required limit. Restore MCPR to within the required limit within 4 hours, if necessary, by reducing THERMAL POWER to the level required.

SURVEILLANCE REQUIREMENTS

4.2.3 MCPR, with:

a. τ = 1.0 prior to performance of the initial scram time measurements for the cycle in accordance with Specification 4.1.3.2, or

b. τ as defined in Specification 3.2.3 used to determine the limit within 72 hours of the conclusion of each scram time surveillance test required by Specification 4.1.3.2,

c. The provisions of Specification 4.0.4 are not applicable

shall be determined to be equal to or greater than the applicable MCPR limit determined from Figures 3.2.3-1 and 3.2.3-2:

a. At least once per 24 hours,

b. Within 12 hours after completion of a THERMAL POWER increase of at least 15% of RATED THERMAL POWER, and

c. Initially and at least once per 12 hours when the reactor is operating with a LIMITING CONTROL ROD PATTERN for MCPR.

d. The provisions of Specification 4.0.4 are not applicable.

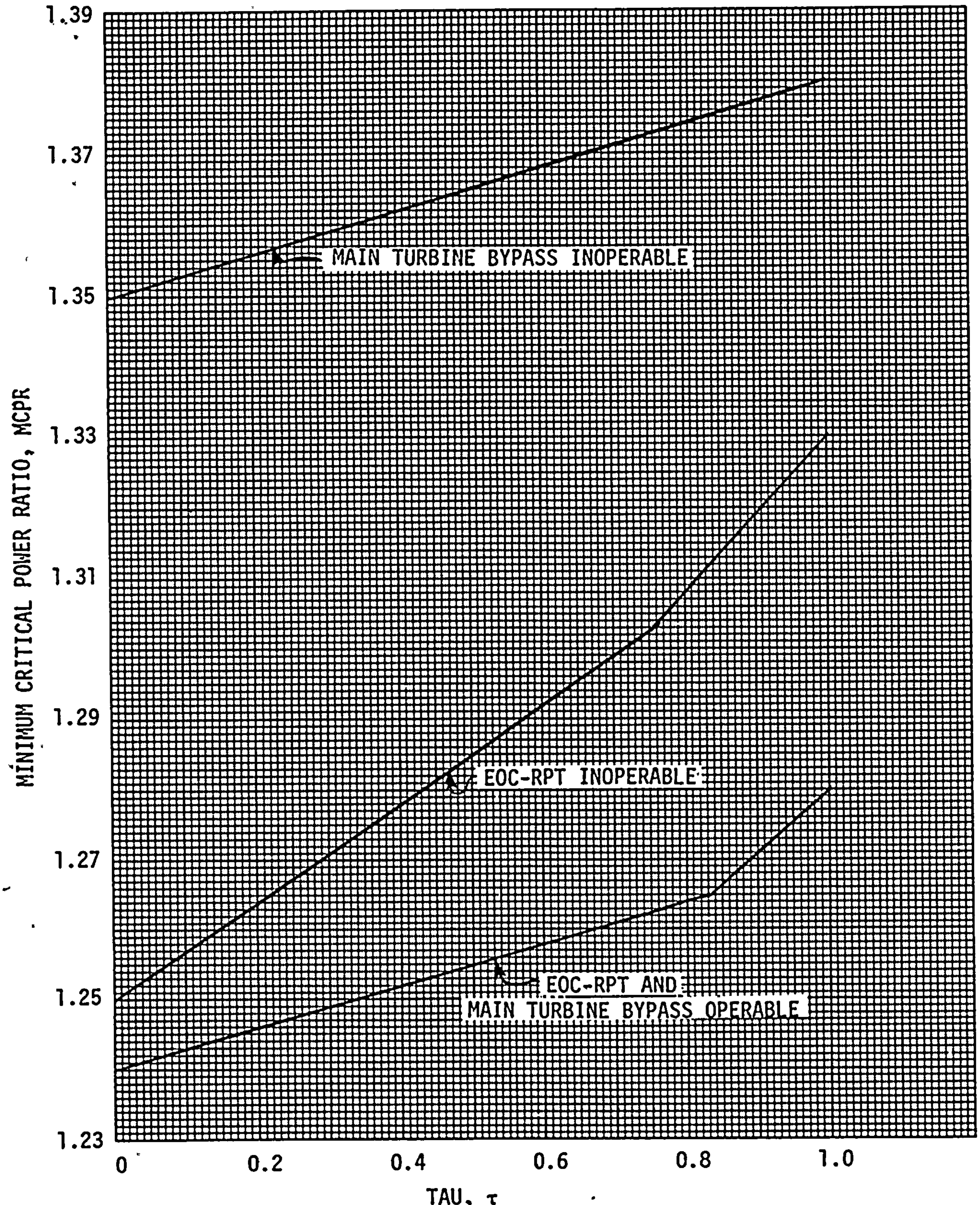

FIGURE 3.2.3-1 MINIMUM CRITICAL POWER RATIO, MCPR, vs TAU AT RATED FLOW

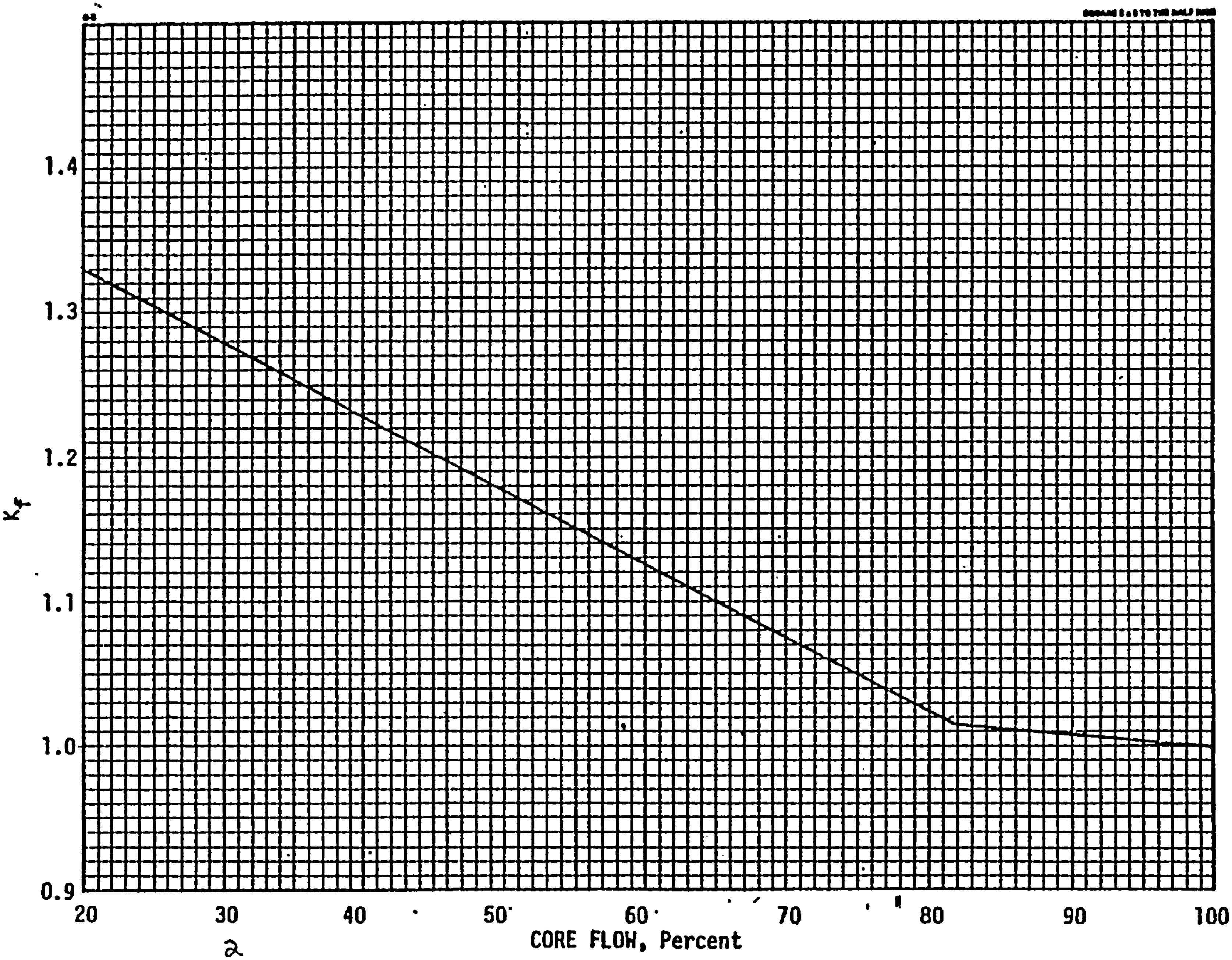

FIGURE 3.2.3-~~1~~2 K_f AS A FUNCTION OF PERCENT CORE FLOW

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END-OF-CYCLE RECIRCULATION PUMP TRIP SYSTEM INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.4.2 The end-of-cycle recirculation pump trip (EOC-RPT) system instrumentation channels shown in Table 3.3.4.2-1 shall be OPERABLE with their trip setpoints set consistent with the values shown in the Trip Setpoint column of Table 3.3.4.2-2 and with the END-OF-CYCLE RECIRCULATION PUMP TRIP SYSTEM RESPONSE TIME as shown in Table 3.3.4.2-3.

APPLICABILITY: OPERATIONAL CONDITION 1, when THERMAL POWER is greater than or equal to 30% of RATED THERMAL POWER.

ACTION:

a. With an end-of-cycle recirculation pump trip system instrumentation channel trip setpoint less conservative than the value shown in the Allowable Values column of Table 3.3.4.2-2, declare the channel inoperable until the channel is restored to OPERABLE status with the channel setpoint adjusted consistent with the Trip Setpoint value.

b. With the number of OPERABLE channels one less than required by the Minimum OPERABLE Channels per Trip System requirement for one or both trip systems, place the inoperable channel(s) in the tripped condition within one hour.

c. With the number of OPERABLE channels two or more less than required by the Minimum OPERABLE Channels per Trip System requirement for one trip system and:

   1. If the inoperable channels consist of one turbine control valve channel and one turbine stop valve channel, place both inoperable channels in the tripped condition within one hour.

   2. If the inoperable channels include two turbine control valve channels or two turbine stop valve channels, declare the trip system inoperable.

d. With one trip system inoperable, restore the inoperable trip system to OPERABLE status within 72 hours or ~~reduce THERMAL POWER to less than 30% of RATED THERMAL POWER within the next 6 hours.~~ take the ACTION required by Specification 3.2.3.

e. With both trip systems inoperable, restore at least one trip system to OPERABLE status within one hour or ~~reduce THERMAL POWER to less than 30% of RATED THERMAL POWER within the next 6 hours.~~ take the ACTION required by Specification 3.2.3.

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3/4.7.9 MAIN TURBINE BYPASS SYSTEM

LIMITING CONDITION FOR OPERATION

3.7.9 The main turbine bypass system shall be OPERABLE.

APPLICABILITY: OPERATIONAL CONDITION 1 when THERMAL POWER is greater than or equal to 25% of RATED THERMAL POWER.

ACTION: With the main turbine bypass system inoperable, restore the system to OPERABLE status within 1 hour or ~~reduce THERMAL POWER to less than 25% of RATED THERMAL POWER within the next 4 hours.~~ take the ACTION required by Specification 3.2.3.

SURVEILLANCE REQUIREMENTS

4.7.9 The main turbine bypass system shall be demonstrated OPERABLE:

a. At least once per 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 meets the following requirements when measured from initial movement of the main turbine stop or control valve:

    a. 80% of the turbine bypass system capacity shall be established within 0.3 seconds, and

    b. Bypass valve opening shall start in less than or equal to 0.1 seconds.

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3/4.2.3 MINIMUM CRITICAL POWER RATIO

The required operating limit MCPRs at steady state operating conditions as specified in Specification 3.2.3 are derived from the established fuel cladding integrity Safety Limit MCPR of 1.06, and an analysis of abnormal operational transients. For any abnormal operating transient analysis evaluation with the initial condition of the reactor being at the steady state operating limit, it is required that the resulting MCPR does not decrease below the Safety Limit MCPR at any time during the transient assuming instrument trip setting given in Specification 2.2.

To assure that the fuel cladding integrity Safety Limit is not exceeded during any anticipated abnormal operational transient, the most limiting transients have been analyzed to determine which result in the largest reduction in CRITICAL POWER RATIO (CPR). The type of transients evaluated were loss of flow, increase in pressure and power, positive reactivity insertion, and coolant temperature decrease. The limiting transient yields the largest delta MCPR. When added to the Safety Limit MCPR of 1.06, the required minimum operating limit MCPR of Specification 3.2.3 is obtained and presented in Figure 3.2.3-1.

The evaluation of a given transient begins with the system initial parameters shown in FSAR Table 15.0.3 that are input to a GE-core dynamic behavior transient computer program. The code used to evaluate pressurization events is described in NEDO-24154[3] and the program used in non-pressurization events is described in NEDO-10802[2]. The outputs of this program along with the initial MCPR form the input for further analyses of the thermally limiting bundle with the single channel transient thermal hydraulic TASC code described in NEDE-25149[4]. The principal result of this evaluation is the reduction in MCPR caused by the transient.

The purpose of the K_f factor of Figure 3.2.3-~~1~~ 2 is to define operating limits at other than rated core flow conditions. At less than 100% of rated flow the required MCPR is the product of the MCPR and the K_f factor. The K_f factors assure that the Safety Limit MCPR will not be violated. The K_f factors were derived using THERMAL POWER and core flow corresponding to 105% of rated steam flow.

The K_f factors were calculated such that for the maximum core flow rate and the corresponding THERMAL POWER along the 105% of rated steam flow control line, the limiting bundle's relative power was adjusted until the MCPR was slightly above the Safety Limit. Using this relative bundle power, the MCPRs were calculated at different points along the 105% of rated steam flow control line corresponding to different core flows. The ratio of the MCPR calculated at a given point of core flow, divided by the operating limit MCPR, determines the K_f.

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ATTACHMENT F

SINGLE LOOP OPERATION ANALYSIS

APPENDIX 15.B

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15.B RECIRCULATION SYSTEMS SINGLE-LOOP OPERATION

15.B.1 INTRODUCTION AND SUMMARY

Single-loop operation (SLO) at reduced power is highly desirable in the event recirculation pump or other component maintenance renders one loop inoperative. To justify single-loop operation, accidents and abnormal operational transients associated with power operations, as presented in Sections 6.2 and 6.3 and the main text of Chapter 15.0, were reviewed for the single-loop case with only one pump in operation. This appendix presents the results of this safety evaluation for the operation of the Nine Mile Point Unit 2 (NMP2) with single recirculation loop inoperable. This evaluation is performed for GE-6 fueled NMP2 on an initial cycle basis and is applicable to GE-6 fueled normal initial cycle operation. The conditions are those of continued operation in the operating domain currently defined in Figure 4.4.5 of Chapter 4 up to maximum power of approximately 70% of rated.

Increased uncertainties in the core total flow and Traversing In-Core Probe (TIP) readings resulted in a 0.01 incremental increase in the Minimum Critical Power Ratio (MCPR) fuel cladding integrity safety limit during single-loop operation. No increase in rated MCPR operating limit and no change in the flow dependent MCPR limit ($MCPR_f$) is required because all abnormal operational transients analyzed for single-loop operation indicated that there is more than enough MCPR margin to compensate for this increase in MCPR safety limit. The recirculation flow rate dependent rod block and scram setpoint equation given in Chapter 16 (Technical Specifications) are adjusted for one-pump operation.

Thermal-hydraulic stability was evaluated for its adequacy with respect to General Design Criteria 12 (10CFR50, Appendix A). It is shown that SLO satisfies this stability criterion. It is further shown that the increase in neutron noise observed during SLO is independent of system stability margin.

To prevent potential control oscillations from occurring in the recirculation flow control system, the flow controller should be in master manual for single-loop operation.

The limiting Maximum Average Planar Linear Heat Generation Rate (MAPLHGR) reduction factor for single-loop operation is calculated to be 0.81.

The containment response for a Design Basis Accident (DBA) recirculation line break with single-loop operation is bounded by the rated power two-loop operation analysis presented in Section 6.2. This conclusion covers all single-loop operation power/flow conditions.

The impact of single loop operation on the Anticipated Transient Without Scram (ATWS) analysis was evaluated. It is found that all ATWS acceptance criteria are met during SLO.

The fuel thermal and mechanical duty for transient events occurring during SLO is found to be bounded by the fuel design bases. The Average Power Range Monitor (APRM) fluctuation should not exceed a flux amplitude of ±15% of rated and the core plate differential pressure fluctuation should not exceed 3.2 psi peak to peak to be consistent with the fuel rod and assembly design bases.

A recirculation pump drive flow limit is imposed for SLO. The highest drive flow that meets acceptable vessel internal vibration criteria is the drive flow limit for SLO. The expected allowable drive flow in SLO is approximately 41,000 gpm. Actual drive flow flimit in SLO will be determined during the startup test program at NMP2.

15.B.2 MCPR FUEL CLADDING INTEGRITY SAFETY LIMIT

Except for core total flow and TIP reading, the uncertainties used in the statistical analysis to determine the MCPR fuel cladding integrity safety limit are not dependent on whether coolant flow is provided by one or two recirculation pumps. Uncertainties used in the two-loop operation analysis are documented in the FSAR. A 6% core flow measurement uncertainty has been established for single-loop operation (compared to 2.5% for two-loop operation). As shown below, this value conservatively reflects the one standard deviation (one sigma) accuracy of the core flow measurement system documented in Reference 15.B.8-1. The random noise component of the TIP reading uncertainty was revised for single recirculation loop operation to reflect the operating plant test results given in Subsection 15.B.2.2. This revision resulted in a single-loop operation process computer effective TIP uncertainty of 6.8% of initial cores and 9.1% for reload cores. Comparable two-loop process computer uncertainty values are 6.3% for initial cores and 8.7% for reload cores. The net effect of these two revised uncertainties is a 0.01 increase in the required MCPR fuel cladding integrity safety limit.

15.B.2.1 Core Flow Uncertainty

15.B.2.1.1 Core Flow Measurement During Single-Loop Operation

The jet pump core flow measurement system is calibrated to measure core flow when both sets of jet pumps are in forward flow; total core flow is the sum of the indicated loop flows. For single-loop operation, however, some inactive jet pumps will be backflowing (at active pump flow above approximately 38%). Therefore, the measured flow in the backflowing jet pumps must be subtracted from the measured flow in the active loop to obtain the total core flow. In addition, the jet pump coefficient is different for reverse flow than for forward flow, and the measurement of reverse flow must be modified to account for this difference.

In single-loop operation, the total core flow is derived by the following formula:

$$\text{Total Core Flow} = \left(\begin{array}{c}\text{Active Loop}\\ \text{Indicated Flow}\end{array}\right) - C\left(\begin{array}{c}\text{Inactive Loop}\\ \text{Indicated Flow}\end{array}\right).$$

Where C (= 0.95) is defined as the ratio of "Inactive Loop True Flow" to "Inactive Loop Indicated Flow". "Loop Indicated Flow" is the flow measured by the jet pump "single-tap" loop flow summers and indicators, which are set to read forward flow correctly.

The 0.95 factor was the result of a conservative analysis to appropriately modify the single-tap flow coefficient for reverse flow.* If a more exact, less conservative core flow is required, special in-reactor calibration tests would have to be made. Such calibration tests would involve: calibrating core support plate ΔP versus core flow during one-pump and two-pump operation along with 100% flow control line and calculating the correct value of C based on the core support plate ΔP and the loop flow indicator readings.

15.B.2.1.2 Core Flow Uncertainty Analysis

The uncertainty analysis procedure used to establish the core flow uncertainty for one-pump operation is essentially the same as for two-pump operation, with some exceptions. The core flow uncertainty analysis is described in Reference 15.B.8-1. The analysis of one-pump core flow uncertainty is summarized below.

For single-loop operation, the total core flow can be expressed as follows (refer to Figure 15.B.2-1):

---

*The analytical expected value of the "C" coefficient for NMP2 is 0.88.

$$\dot{W}_C = \dot{W}_A - \dot{W}_I$$

where:

$\dot{W}_C$ = total core flow,

W_A = active loop flow, and

W_I = inactive loop (true) flow.

By applying the "propagation of errors" method to the above equation, the variance of the total flow uncertainty can be approximated by:

$$\sigma^2_{W_C} = \sigma^2_{W_{sys}} + \left(\frac{1}{1-a}\right)^2 \sigma^2_{W_{A_{rand}}} + \left(\frac{a}{1-a}\right)^2 \left(\sigma^2_{W_{I_{rand}}} + \sigma^2_{C}\right)$$

where:

σ_{W_C} = uncertainty of total core flow;

$\sigma_{W_{sys}}$ = uncertainty systematic to both loops;

$\sigma_{W_{A_{rand}}}$ = random uncertainty of active loop only;

$\sigma_{W_{I_{rand}}}$ = random uncertainty of inactive loop only;

σ_C = uncertainty of "C" coefficient; and

a = ratio of inactive loop flow (W_I) to active loop flow (W_A).

From an uncertainty analysis, the conservative, bounding values of $\sigma_{W_{sys}}$, $\sigma_{W_{A_{rand}}}$, $\sigma_{W_{I_{rand}}}$ and σ_C are 1.6%, 2.6%, 3.5%, and 2.8%, respectively. Based on the above uncertainties and a bounding value of 0.36* for "a", the variance of the total flow uncertainty is approximately:

$$\sigma^2_{W_C} = (1.6)^2 + \left(\frac{1}{1-0.36}\right)^2 (2.6)^2 + \left(\frac{0.36}{1-0.36}\right)^2 \left((3.5)^2 + (2.8)^2\right)$$
$$= (5.0\%)^2$$

When the effect of 4.1% core bypass flow split uncertainty at 12% (bounding case) bypass flow fraction is added to the total core flow uncertainty, the active coolant flow uncertainty is:

$$\sigma^2_{\substack{\text{active}\\\text{coolant}}} = (5.0\%)^2 + \left(\frac{0.12}{1-0.12}\right)^2 (4.1\%)^2 = (5.1\%)^2$$

which is less than the 6% flow uncertainty assumed in the statistical analysis.

In summary, core flow during one-pump operation is measured in a conservative way and its uncertainty has been conservatively evaluated.

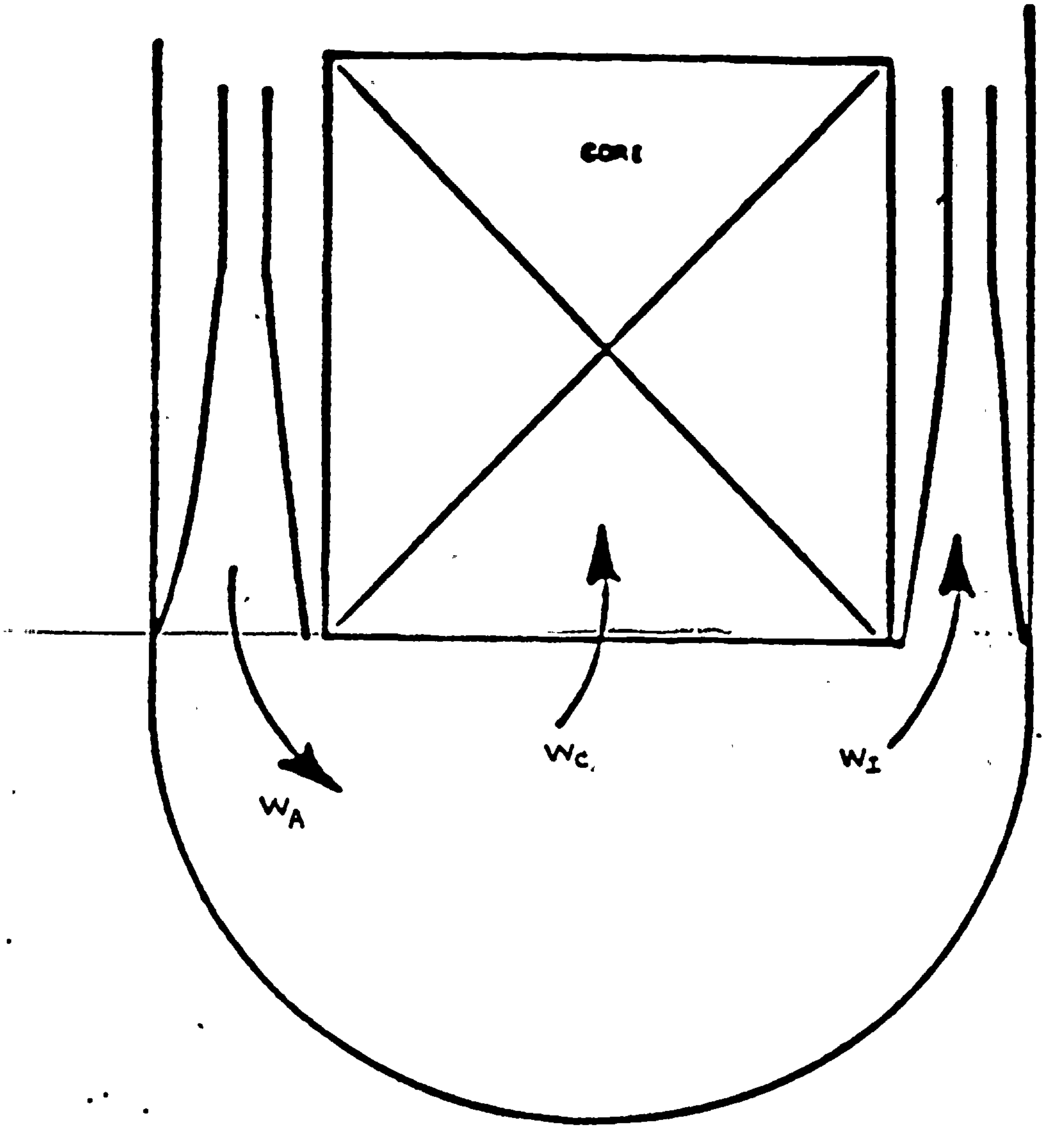
15.B.2.2 TIP READING UNCERTAINTY

To ascertain the TIP noise uncertainty for single recirculation loop operation, a test was performed at an operating BWR. The test was performed at a power level 59.3% of rated with a single recirculation pump in operation (core flow 46.3% of rated). A rotationally symmetric control rod pattern existed during the test.

---

*This flow split ratio varies from about 0.13 to 0.36. The 0.36 value is a conservative bounding value. The analytical expected value of the flow split ratio for NMP2 is ∿ 0.23.

Five consecutive traverses were made with each of five TIP machines, giving a total of 25 traverses. Analysis of this data resulted in a nodal TIP noise of 2.85%. Use of this TIP noise value as a component of the process computer total uncertainty results in a one-sigma process computer total effective TIP uncertainty value for single-loop operation of 6.8% for initial cores and 9.1% for reload cores.



W_C = Total Core Flow
W_A = Active Loop Flow
W_I = Inactive Loop Flow

Niagara Mohawk Power Corp.	Illustration of Single Recirculation Loop Operation Flows	Figure 15.B.2-1

15.B.3 MCPR OPERATING LIMIT

15.B.3.1 ABNORMAL OPERATING TRANSIENTS

Operating with one recirculation loop results in a maximum power output which is about 30% below that which is attainable for two-pump operation. Therefore, the consequences of abnormal operation transients from one-loop operation will be considerably less severe than those analyzed from a two-loop operational mode. For pressurization, flow increase, flow decrease, and cold water injection transients, the results presented in Chapter 15 bound both the thermal and overpressure consequences of one-loop operation.

Figure 15.B.3-1 shows the consequences of a typical pressurization transient (generator load rejection) as a function of power level. As can be seen, the consequences of one-loop operation are considerably less because of the associated reduction in operating power level.

The consequences of flow decrease transients are also bounded by the full power analysis. A single pump trip from one-loop operation is less severe than a two-pump trip from full power because of the reduced initial power level.

The worst flow increase transient results from recirculation flow controller failure, and the worst cold water injection transient results from the loss of feedwater heater. For the former, the $MCPR_f$ (K_f) curve is derived assuming both recirculation loop controllers fail. This condition produces the maximum possible power increase and hence maximum ΔCPR for transients initiated from less than rated power and flow. When operating with only one recirculation loop, the flow and power increase associated with this failure with only one loop will be less than that associated with both loops; therefore, the K_f curve derived with the two-pump assumption is conservative for single-loop operation. The latter event, loss of feedwater heating, is generally the most severe cold water increase event with respect to increase in core power. This event is caused by positive reactivity insertion from core inlet

subcooling and it is relatively insensitive to initial power level. A generic statistical loss of feedwater heater analysis using different initial power levels and other core design parameters concluded one-pump operation with lower initial power level is conservatively bounded by the full power two-pump analysis. Inadvertent restart of the idle recirculation pump has been analyzed in the FSAR (Chapter 15.4.4) and is still applicable for single-loop operation.

From the above discussions, it is concluded that the transient consequence from one-loop operation is bounded by previously submitted full power analyses. The maximum power level that can be attained with one-loop operation is only restricted by the MCPR and overpressure limits established from a full-power analysis.

In the following sections, the results of two of the most limiting transients analyzed for single-loop operation are presented. They are, respectively:

a. feedwater flow controller failure (maximum demand), (FWCF)

b. generator load rejection with bypass failure, (LRBPF).

The plant initial conditions are given in Table 15.B.3-1.

15.B.3.1.1 <u>Feedwater Controller Failure - Maximum Demand</u>

This event is postulated on the basis of a single failure of a control device, specifically one which can directly cause an increase in coolant inventory by increasing the feedwater flow. The most severe applicable event is a feedwater controller failure to maximum flow demand. The feedwater controller is forced to its upper limit at the beginning of the event.

With excess feedwater flow, the water level rises to the high-level reference point at which time the feedwater pumps and the main turbine are tripped and a scram is initiated. Table 15.B.3-2 lists the sequence

of events. Figure 15.B.3-2 shows the changes in important variables during this transient.

The computer model described in Reference 15.B.8-2 was used to simulate this event.

The analysis has been performed with the plant conditions tabulated in Table 15.B.3-1, except the initial vessel water level at level setpoint L4 for conservatism. By lowering the initial water level, more cold feedwater will be injected before Level 8 is reached resulting in higher heat fluxes.

The same void reactivity coefficient used for the pressurization transient is applied since a more negative value conservatively increases the severity of the power increase. End of cycle (all rods out) scram characteristics are assumed. The safety/relief valve action is conservatively assumed to occur with higher than nominal setpoints. The transient is simulated by programming an upper limit failure in the feedwater system such that 145% of rated feedwater flow occurs at the design pressure of 1060 psig. Since the reactor is initially operating at a lower power level, the feedwater sparger experiences a pressure which is much lower than the design pressure, hence the feedwater runout capacity reaches 167% of initial flow.

Results

The simulated feedwater controller transient is shown in Figure 15.B.3-2 for the case of 75% power and 60% core flow. The high-water level turbine trip and feedwater pump trip are initiated at approximately 6.4 seconds. Scram occurs simultaneously from stop valve closure, and limits the neutron flux peak and fuel thermal transient so that no fuel damage occurs. Table 15.B.3-4 gives a summary of the transient analysis results. The calculated MCPR is 1.20, which is well above the safety limit MCPR of 1.07 so no fuel failure due to boiling transition is predicted. The peak vessel pressure predicted is 1134 psig and is well below the ASME limit of 1375 psig.

15.B.3.1.2 Generator Load Rejection With Bypass Failure

Fast closure of the turbine control valves (TCV) is initiated whenever electrical grid disturbances occur which result in significant loss of electrical load on the generator. The turbine control valves are required to close as rapidly as possible to prevent overspeed of the turbine-generator rotor. Closure of the main turbine control valves will increase system pressure. Mitigation of pressure increase during this transient is accomplished by the scram and RPT.

A loss of generator electrical load at 75% power and 60% flow under single recirculation loop operation produces the sequence of events listed in Table 15.B.3-3. Figure 15.B.3-3 shows the changes in important variables during this transient.

The computer model described in Reference 15.B.8-2 was used to simulate this event.

The analysis has been performed with the plant conditions tabulated in Table 15.B.3-1, except that the turbine bypass function is assumed to fail.

The simulated generator load rejection with bypass failure is shown in Figure 15.B.3-3.

Table 15.B.3-4 summarizes the transient analysis results. The peak neutron flux reaches about 166% of rated and average surface heat flux peaks at 106.5% of its initial value. The peak vessel pressure predicted is 1175 psig and is well below the ASME limit of 1375 psig. The calculated MCPR is 1.27 which is considerably above the safety limit MCPR of 1.07.

15.B.3.1.3 Summary and Conclusions

The transient peak value results and the Critical Power Ratio results are summarized in Table 15.B.3-4. This table indicates that for the transient events analyzed here, the MCPRs for all transients are above the single-loop operation safety limit value of 1.07. It is concluded the operating limit MCPRs established for two-pump operation are also applicable to single-loop operation conditions.

For pressurization, Table 15.B.3-4 indicates the peak pressures are below the ASME code value of 1375 psig. Hence, it is concluded the pressure barrier integrity is maintained under single-loop operation conditions.

15.B.3.2 ROD WITHDRAWAL ERROR

The rod withdrawal error at rated power is given in the FSAR. These analyses are performed to demonstrate, even if the operator ignores all instrument indications and the alarm which could occur during the course of the transient, the rod block system will stop rod withdrawal at a minimum critical power ratio (MCPR) which is higher than the fuel cladding integrity safety limit. Modification of the rod block equation (below) assures the MCPR safety limit is not violated.

The Average Power Range Monitor (APRM) rod block system provides additional alarms and rod blocks when power levels are grossly exceeded. Modification of the APRM rod block equation (below) is required to maintain the two loop rod block versus power relationship when in one loop operation.

One-pump operation results in backflow through 10 of the 20 jet pumps while the flow is being supplied into the lower plenum from the 10 active jet pumps. Because of the backflow through the inactive jet pumps, the present rod block equation was conservatively modified for use during one-pump operation because the direct active-loop flow measurement may not indicate actual flow above about 38% core flow without correction.

A procedure has been established for correcting the APRM rod block equation to account for the discrepancy between actual flow and indicated flow in the active loop. This preserves the original relationship between APRM rod block and actual effective drive flow when operating with a single loop.

The two-pump rod block equation is:

$$RB = mW + RB_{100} - m(100)$$

The one-pump equation becomes:

$$RB = mW + RB_{100} - m(100) - m\Delta W$$

where

ΔW = difference between two-loop and single-loop effective drive flow at the same core flow. This value is expected to be 5% of rated (to be determined by the Niagara Mohawk Power Corporation)

RB = power at rod block in %

m = flow reference slope

W = drive flow in % of rated.

RB_{100} = top level rod block at 100% flow.

If the rod block setpoint (RB_{100}) is changed, the equation must be recalculated using the new value.

The APRM scram trip settings are flow biased in the same manner as the APRM rod block setting. Therefore, the APRM scram trip settings are subject to the same procedural changes as the rod block settings discussed above.

15.B.3.3 OPERATING MCPR LIMIT

For single-loop operation, the operating MCPR limit remains unchanged from the normal two-loop operation limit. Although the increased uncertainties in core total flow and TIP readings resulted in a 0.01 increase in MCPR fuel cladding integrity safety limit during single-loop operation (Section 15.B.2), the limiting transients have been analyzed to indicate that there is more than enough MCPR margin during single-loop operation to compensate for this increase in safety limit. For single loop operation at off-rated conditions, the steady-state operating MCPR limit is established by the K_f curve. This ensures the 99.9% statistical limit requirement is always satisfied for any postulated abnormal operational occurrence. Since the maximum core flow runout during single loop operation is only about 60% of rated, the current flow dependent K_f curve which is generated based on the flow runout up to rated core flow are also adequate to protect the flow runout events during single loop operation.

TABLE 15.B.3-1

INPUT PARAMETERS AND INITIAL CONDITIONS

1.	Thermal Power Level, MWt Analysis Value	2492
2.	Steam Flow, lb per hr Analysis Value	10.28×10^6
3.	Core Flow, lb per hr	65.10×10^6
4.	Feedwater Flow Rate, lb per hr Analysis Value	10.28×10^6
5.	Feedwater Temperature, °F	394
6.	Vessel Dome Pressure, psig	981
7.	Core Pressure, psig	987
8.	Turbine Bypass Capacity, % NBR	25.
9.	Core Coolant Inlet Enthalpy, Btu per lb	515.1
10.	Turbine Inlet Pressure, psig	952
11.	Fuel Lattice	P8x8R
12.	Core Average Gap Conductance, Btu/sec-ft²-°F	0.1744
13.	Core Bypass Flow, %	11.84
14.	Required MCPR Operating Limit Option A Option B	 1.44 1.40
15.	MCPR Safety Limit	1.07
16.	Doppler Coefficient ¢/°F	*
17.	Void Coefficient ¢/% Rated Voids	*
18.	Core Average Rated Void Fraction, %	43.5
19.	Scram Reactivity, $ΔK	*

*This value is calculated within the Computer code (Reference 15.B.8-2) for end of Cycle 1 condition based on the input from CRUNCH tape.

TABLE 15.B.3-1 (Continued)

INPUT PARAMETERS AND INITIAL CONDITIONS

20.	Control Rod Drive Speed Position Versus Time	Figure 15.0-3
21.	Jet Pump Ratio, M	3.16
22.	Safety/Relief Valve Capacity, % NBR @ 103% of 1177 psig Manufacturer Quantity Installed	 $\geq$ 113.8 DIKKERS 18
23.	Relief Function Delay, seconds	0.4
24.	Relief Function Response Time Constant, sec.	0.1
25.	Set Points for Safety/Relief Valves Safety Function, psig Relief Function, psig	 1177, 1187, 1197, 1207, 1217 1106, 1116, 1126, 1136, 1146
26.	Number of Valve Groupings Simulated Safety Function, No. Relief Function, No.	 5 5
27.	High Flux Trip, % NBR Analysis Set Point (121 x 1.043)	 126.2
28.	High Pressure Scram Set Point, psig	1071
29.	Vessel Level Trips, Feet Above Separator Skirt Bottom Level 8 - (L8), Feet Level 4 - (L4), Feet Level 3 - (L3), Feet Level 2 - (L2), Feet	 6.175 3.75 1.75 -4.708

TABLE 15.B.3-1 (Continued)

INPUT PARAMETERS AND INITIAL CONDITIONS

30.	APRM Thermal Trip Set Point, % NBR @ 100% Core Flow (117 x 1.043)	122
31.	RPT Delay, seconds	0.19
32.	Time Constant of Recirculation Pump - Motor, seconds** Analysis Value	6.0
33.	Set Pressure of ATWS Recirculation Pump Trip, psig	1080
34.	Total Steam Line Volume, ft^3	4012

**The inertia time constant is defined by the expression:

$$t = \frac{2\pi J_o n}{g T_o}$$

where:

t = inertia time constant (sec)
J_o = pump motor inertia (lb-ft)
n = rated pump speed (rps)
g = gravitational constant (ft/sec^2)
T_o = pump shaft torque (ft-lb)

TABLE 15.B.3-2

SEQUENCE OF EVENTS FOR FEEDWATER CONTROLLER FAILURE, MAXIMUM DEMAND (Figure 15.B.3-2)

Time-sec	Event
0	Initiate simulated failure to the upper limit on feedwater flow.
6.4	L8 vessel level set point trips main turbine and feedwater pumps.
6.4	Reactor scram trip actuated from main turbine stop valve position switches.
6.4	Recirculation pump trip (RPT) actuated by stop valve position switches.
6.5	Main turbine stop valves closed and turbine bypass valves start to open.
6.6	Recirculation pump motor circuit breakers open causing decrease in core flow to natural circulation.
9.5	Group 1 relief valves actuated.
10.0	Group 2 relief valves actuated.
15.2	All relief valves are closed.

TABLE 15.B.3-3

SEQUENCE OF EVENTS FOR GENERATOR LOAD REJECTION WITH BYPASS FAILURE (Figure 15.B.3-3)

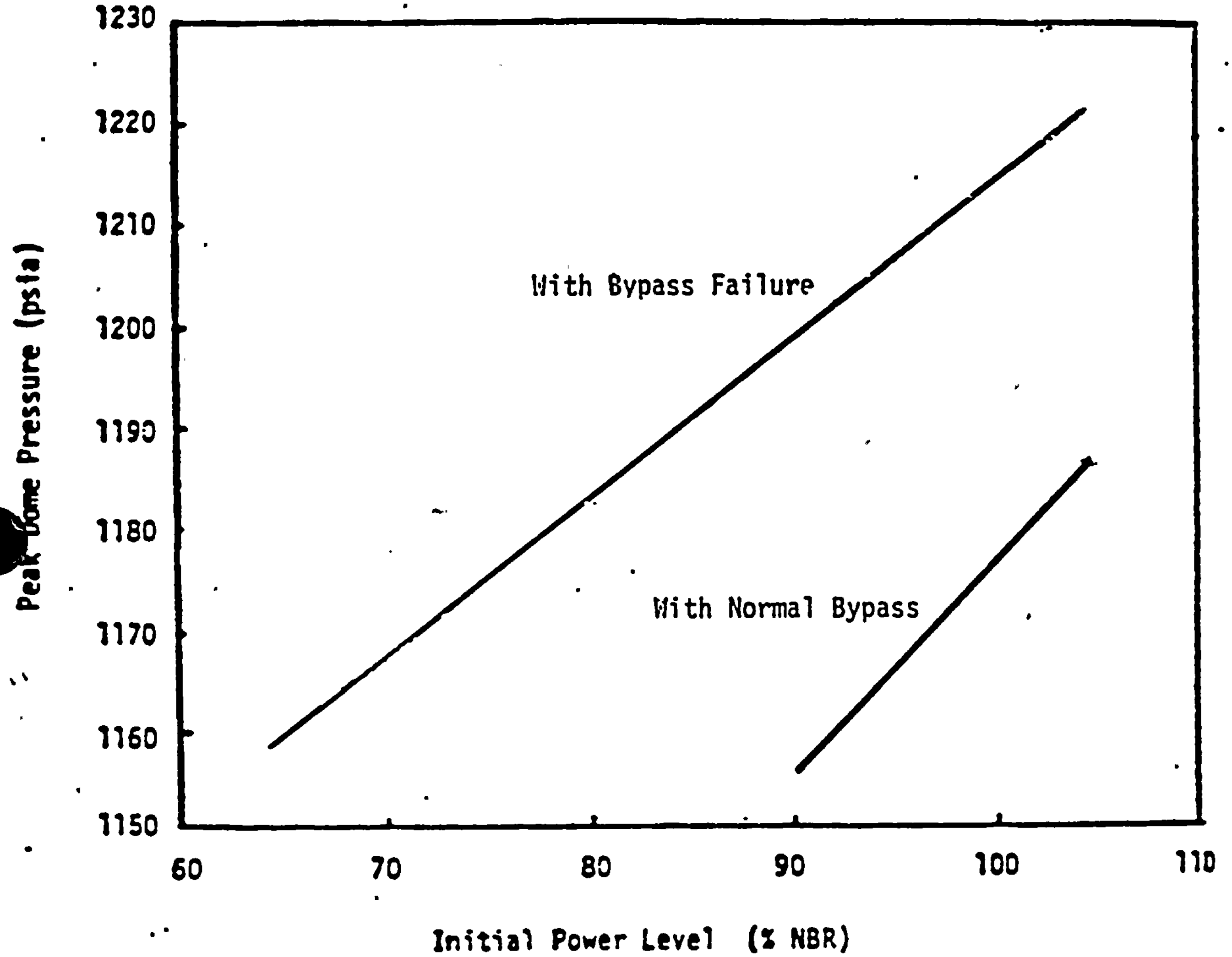
Time-sec	Event
(-)0.015 (approx.)	Turbine-generator detects loss of electrical load.
0	Turbine-generator load rejection sensing devices trip to initiate turbine control valve fast closure.
0	Turbine bypass valves fail to operate.
0	Fast control valve closure (FCV) initiates scram trip and recirculation pump trip (RPT).
0.07	Turbine control valves closed.
0.10	Turbine bypass valves should start to open - assumed to fail.
0.19	Recirculation pump motor circuit breakers open causing decrease in core flow to natural circulation.
2.1	Group 1 relief valves actuated.
2.2	Group 2 relief valves actuated.
2.4	Group 3 relief valves actuated.
2.6	Group 4 relief valves actuated.
2.8	Group 5 relief valves actuated.
5.4	Feedwater pump motors tripped on L8 high water level.
5.5	Group 5 relief valves start to close.
8.2	All relief valves are closed.

TABLE 15.B.3-4

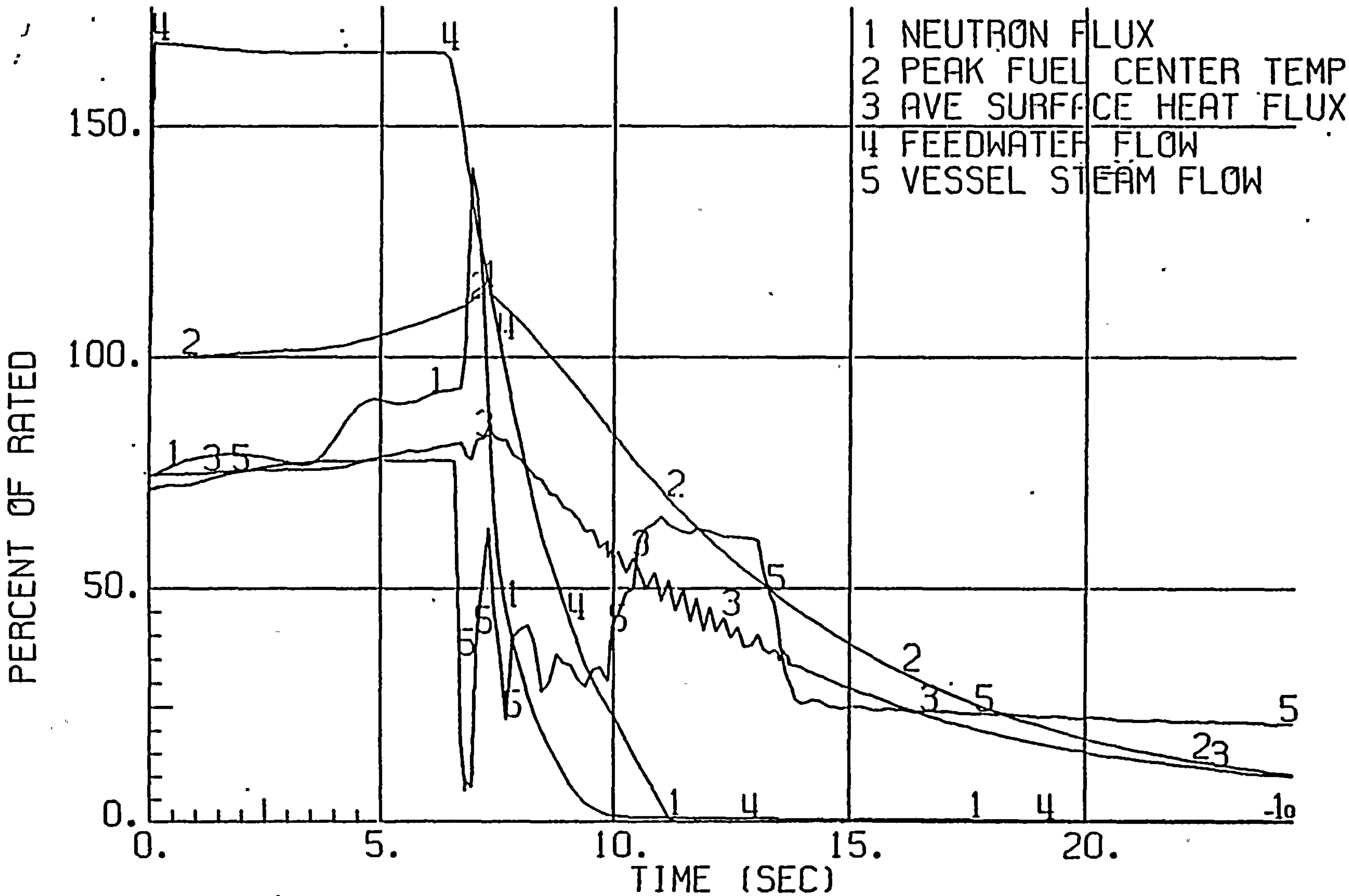
SUMMARY OF TRANSIENT PEAK VALUE AND CPR RESULTS

	LRBPF	FWCF
Initial Power/Flow (% Rated)	75/60	75/60
Peak Neutron Flux (% NBR)	165.7	157.3
Peak Heat Flux (% Initial)	106.5	113.8
Peak Dome Pressure (psig)	1160	1120
Peak Vessel Bottom Pressure (psig)	1175	1134
Required Initial MCPR Operating Limit at SLO Condition	1.44	1.44
ΔCPR	0.17*	0.24*
Transient MCPR	1.27	1.20
SLMCPR at SLO	1.07	1.07
Margin to SLMCPR	0.20	0.13

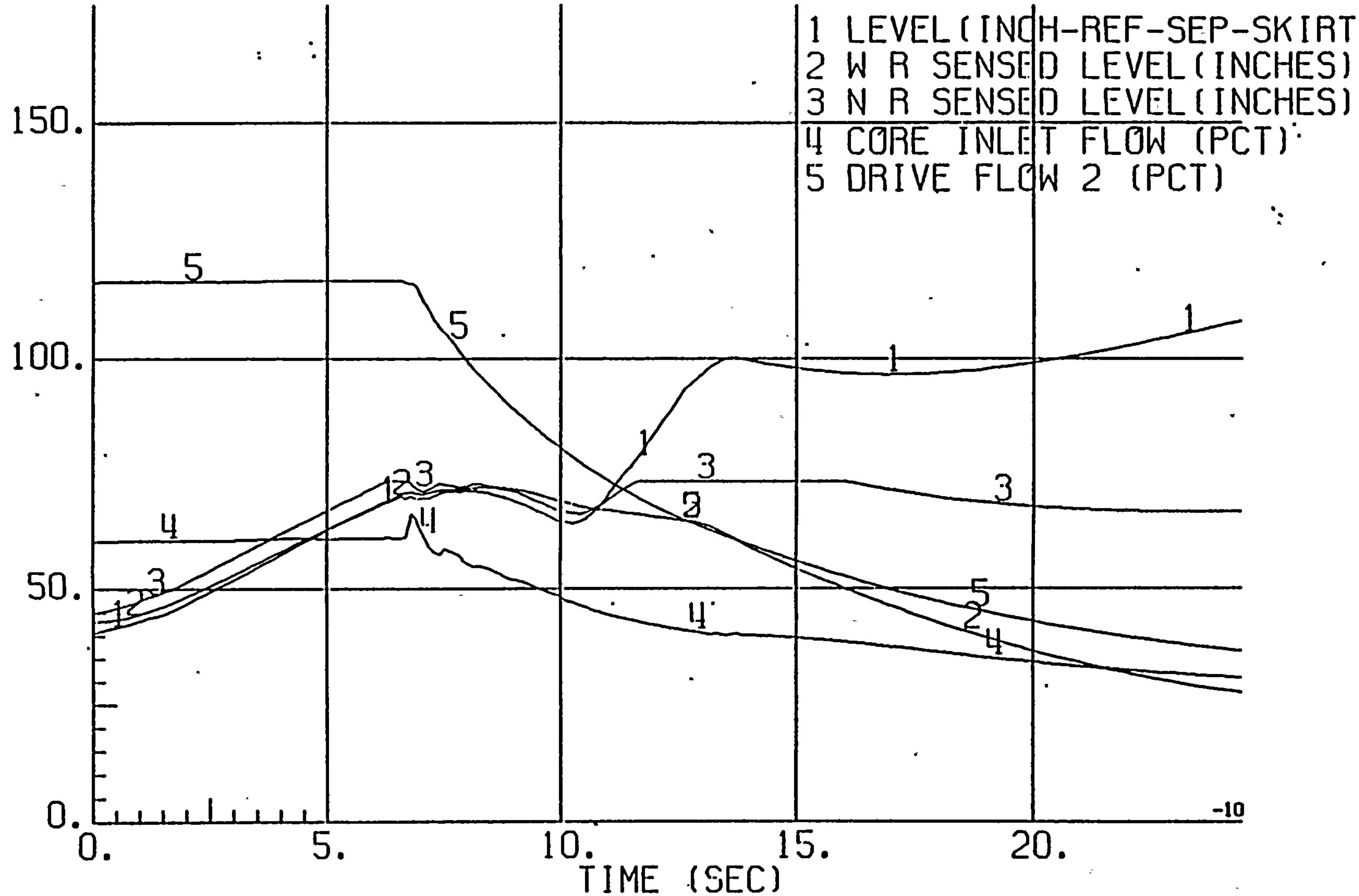
*Value includes option A adder



Niagara Mohawk Power Corporation	Peak Dome Pressure vs. Initial Power Level, LRBPF at EOC	Figure 15.B.3-1

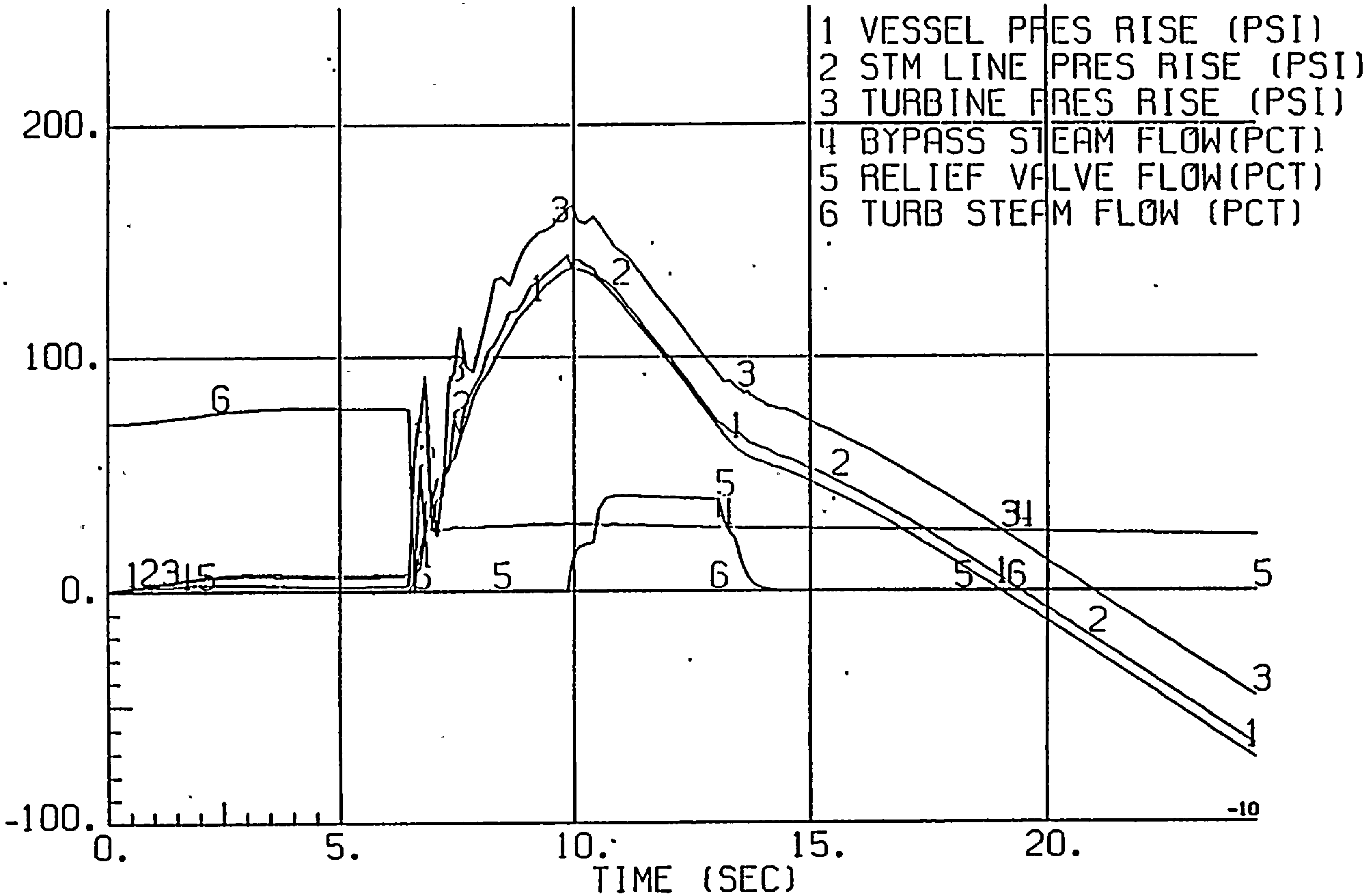


NIAGARA MOHAWK POWER CORPORATION	Feedwater Controller Failure - Maximum Demand 75% Power, 60% Flow	Figure 15.B.3-2

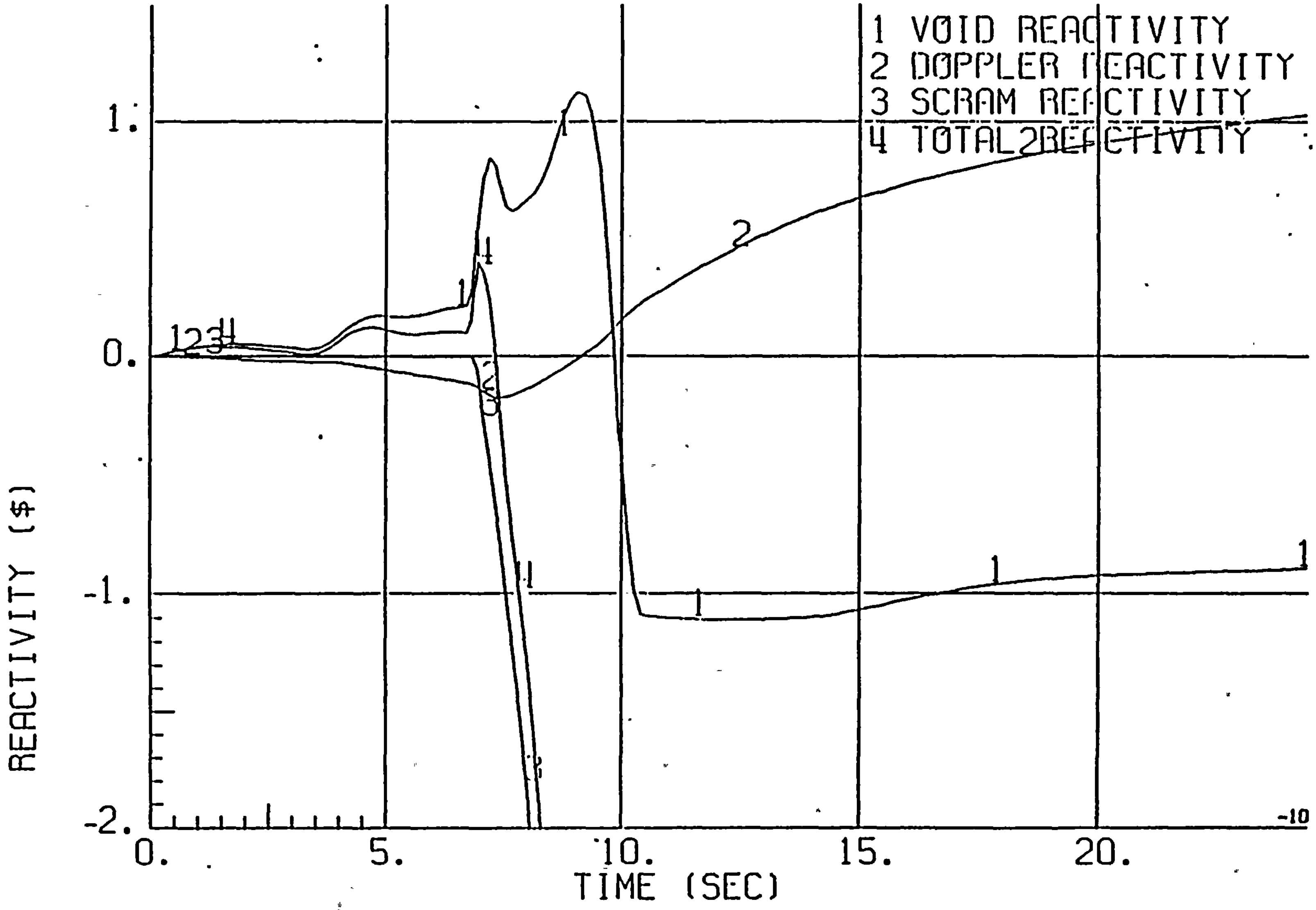


NIAGARA MOHAWK POWER CORPORATION	Feedwater Controller Failure - Maximum Demand 75% Power, 60% Flow	Figure 15.B.3-2 Cont'd.

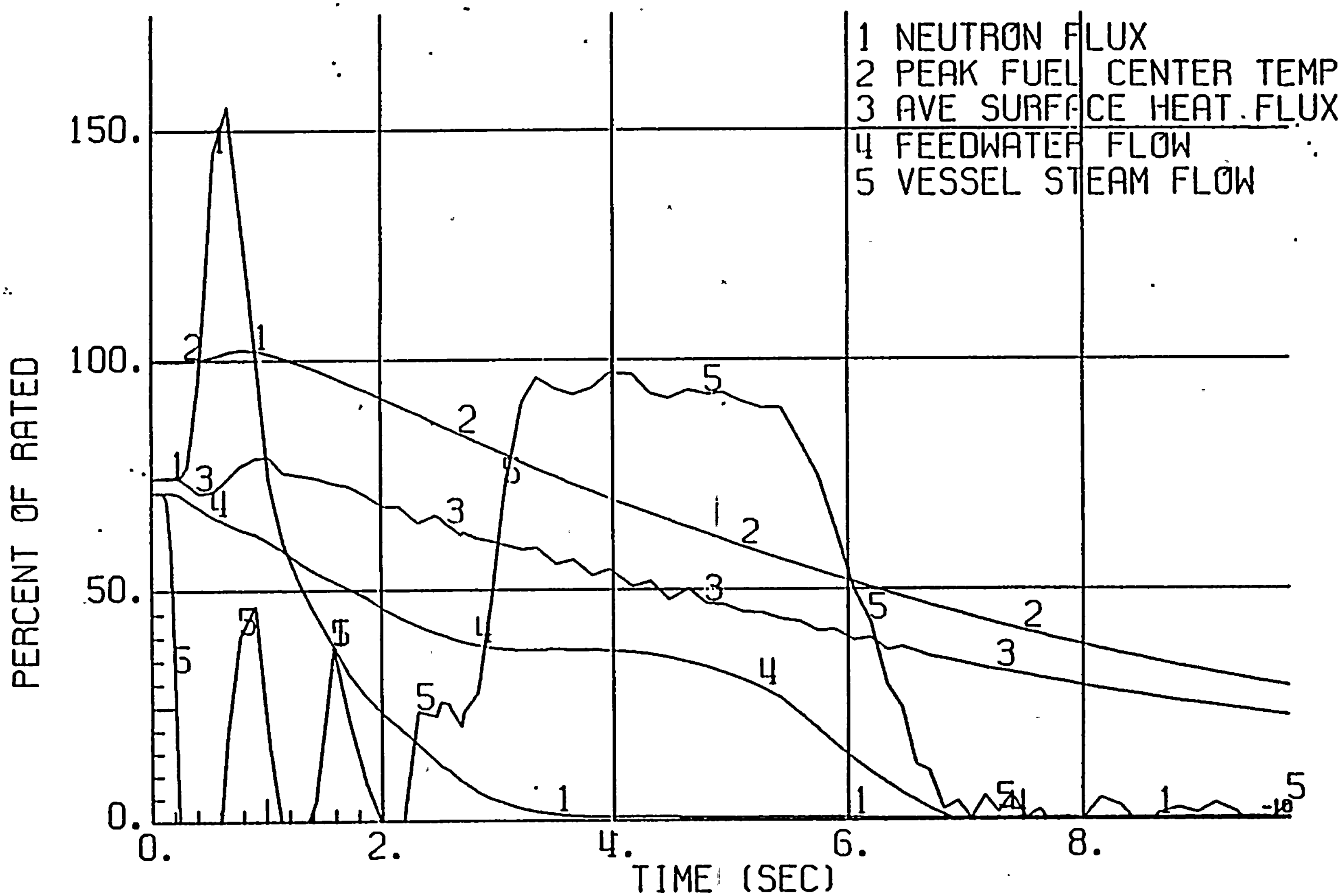
15 B 3-16



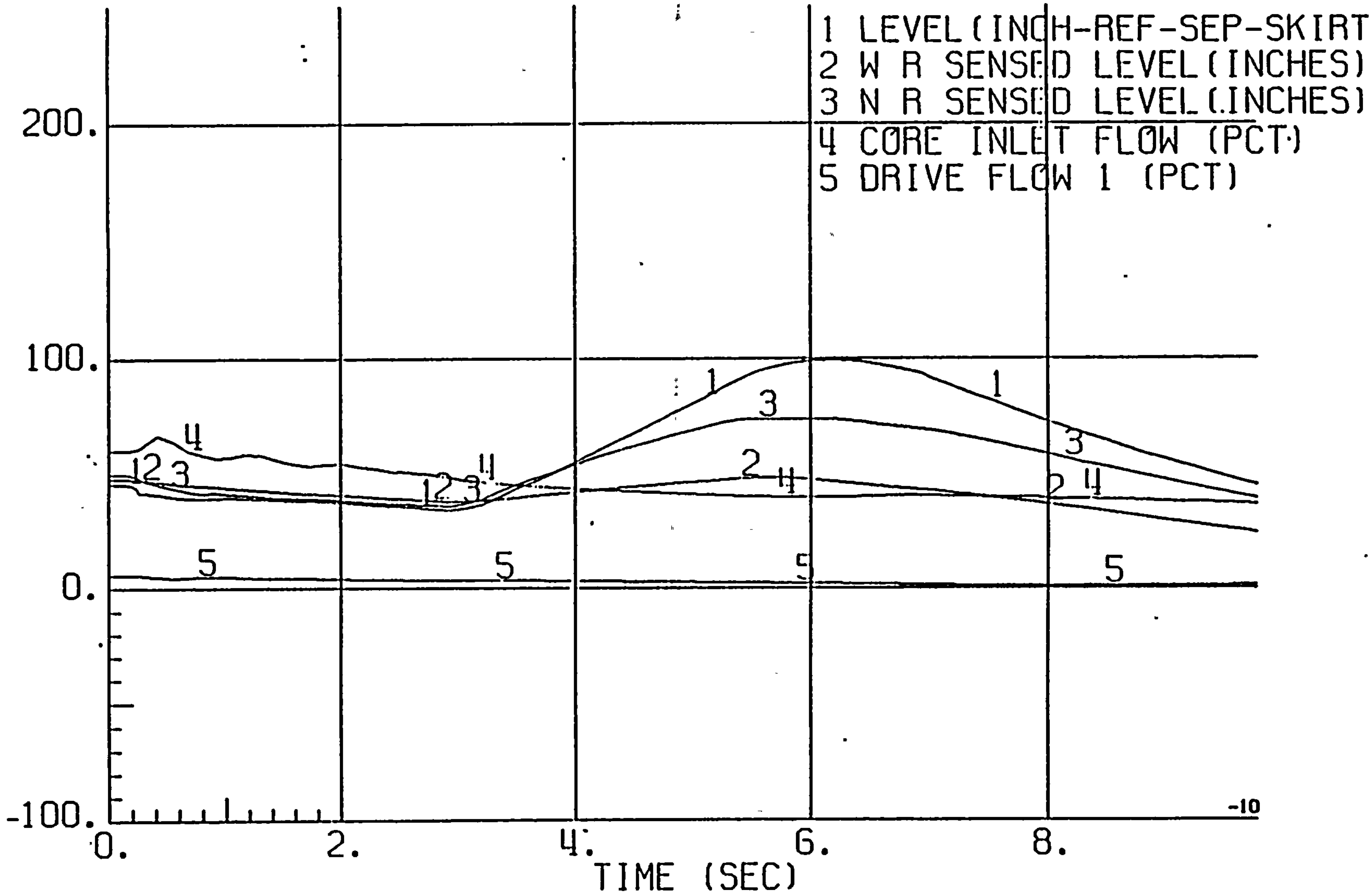
NIAGARA MOHAWK POWER CORPORATION	Feedwater Controller Failure - Maximum Demand 75% Power, 60% Flow	Figure 15.B.3-2 Cont'd.



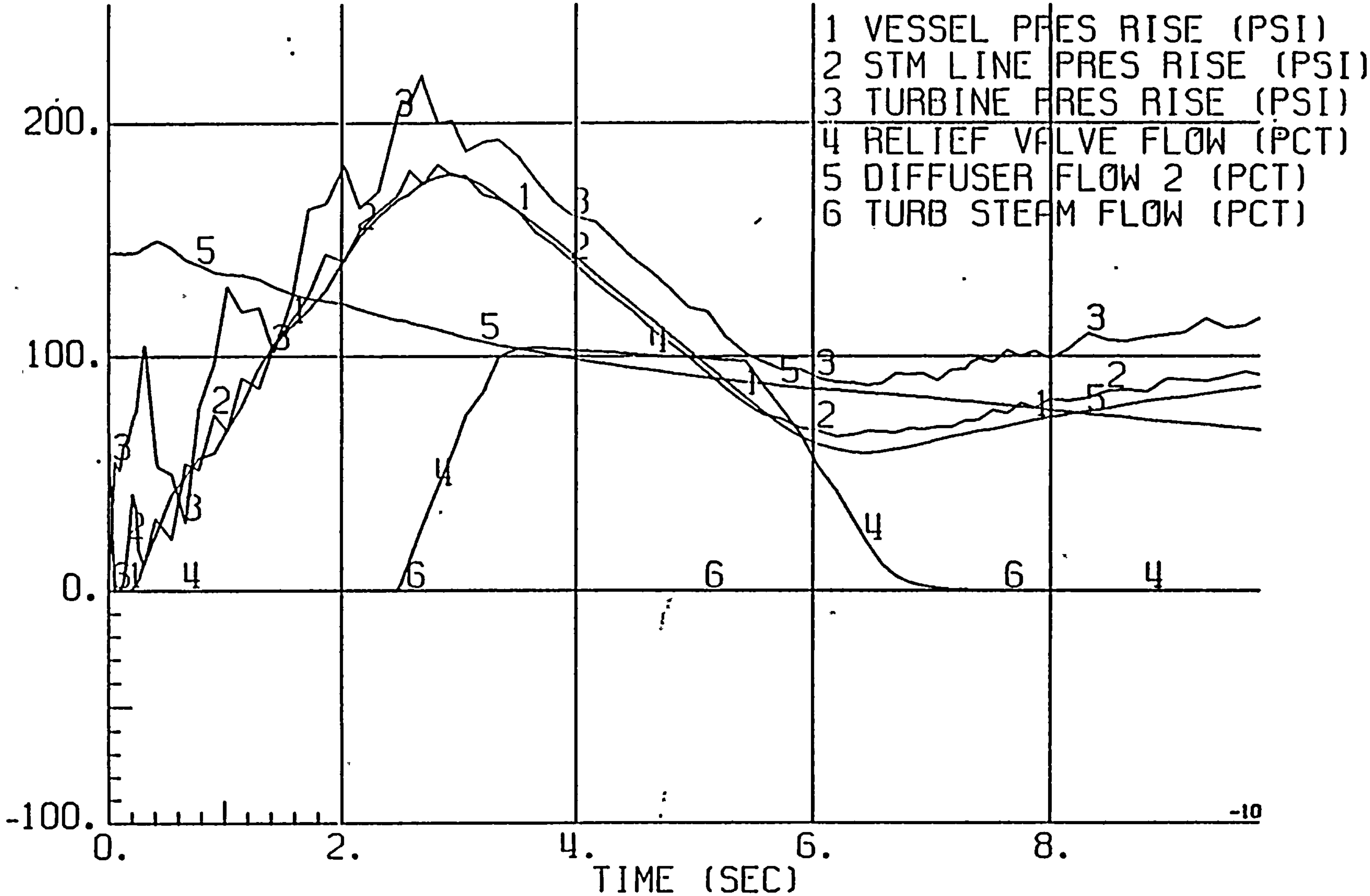
NIAGARA MOHAWK POWER CORPORATION	Feedwater Controller Failure - Maximum Demand 75% Power, 60% Flow	Figure 15.B.3-2 Cont'd.



NIAGARA MOHAWK POWER CORPORATION	Load Rejection With Bypass Failure 75% Power, 60% Flow	Figure 15.B.3-3



NIAGARA MOHAWK POWER CORPORATION	Load Rejection With Bypass Failure 75% Power, 60% Flow	Figure 15.B.3-3 Cont'd.



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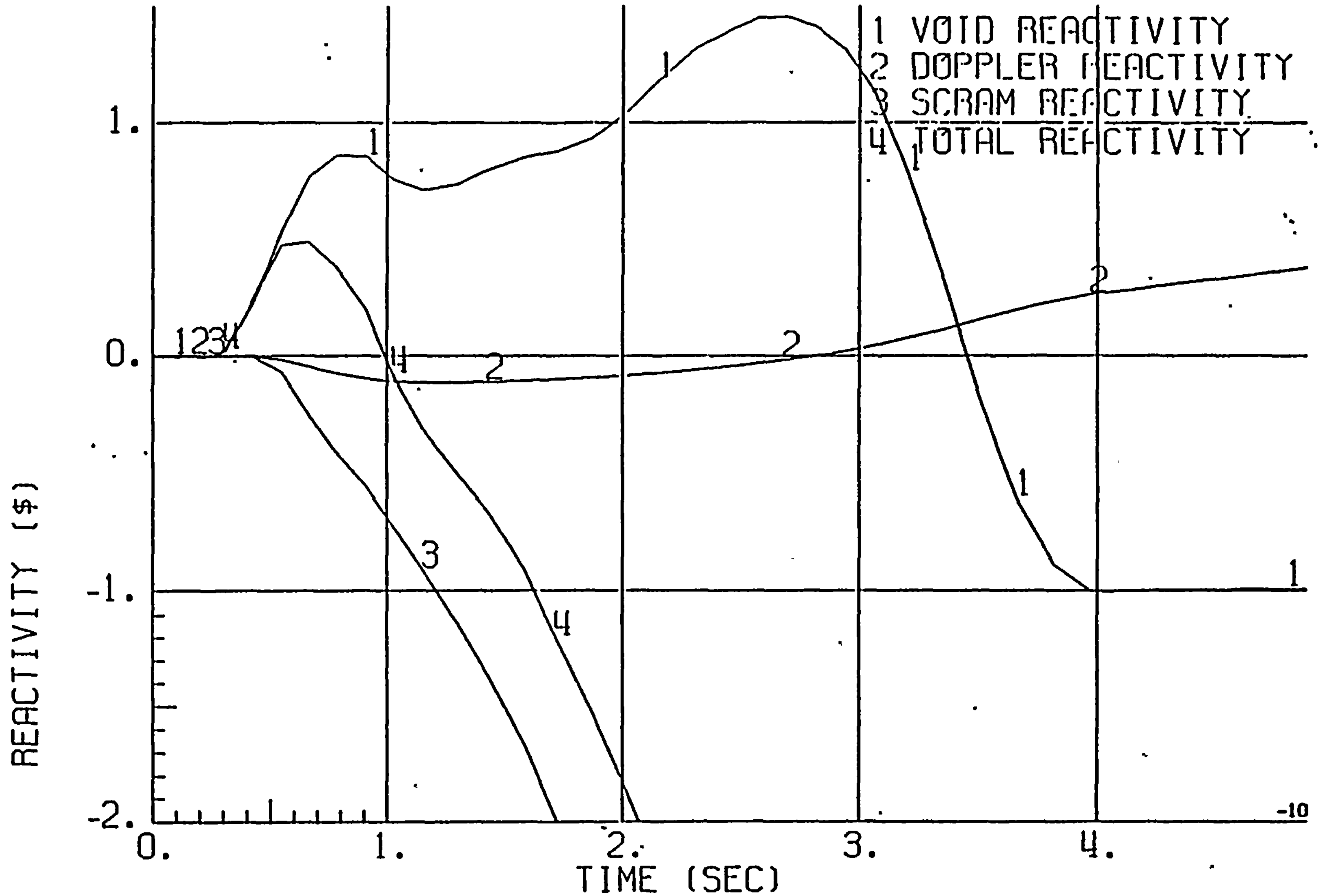
Load Rejection with Bypass Failure 75% Power, 60% Flow

Figure
15.B.3-3
Cont'd.



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Load Rejection with Bypass Failure 75% Power, 60% Flow

Figure 15.B.3-3 Cont'd.

15.B.4 STABILITY ANALYSIS

15.B.4.1 Phenomena

The primary contributing factors to the stability performance with one recirculation loop not in service are the power/flow ratio and the recirculation loop characteristics. At forced circulation with only one recirculation loop in operation, the reactor core stability is influenced by the inactive recirculation loop. As core flow increases in SLO, the inactive jet pump forward flow decreases because the driving head across the inactive jet pumps decreases with increasing core flow. The reduced flow in the inactive loop reduces the resistance that the recirculation loops impose on reactor core flow perturbations thereby adding a destabilizing effect. At the same time the increased core flow results in a lower power/flow ratio which is a stabilizing effect. These two countering effects result in slightly decreased stability margin (higher decay ratio) initially as core flow is increased (from minimum) in SLO and then an increase in stability margin (lower decay ratio) as core flow is increased further and reverse flow in the inactive loop is established.

As core flow is increased further during SLO and substantial reverse flow is established in the inactive loop an increase in jet pump flow, core flow and neutron noise is observed. A cross flow is established in the annular downcomer region near the jet pump suction entrance caused by the reverse flow of the inactive recirculation loop. This cross flow interacts with the jet pump suction flow of the active recirculation loop and increases the jet pump flow noise. This effect increases the total core flow noise which tends to drive the neutron flux noise.

To determine if the increased noise is being caused by reduced stability margin as SLO core flow was increased, an evaluation was performed which phenomenologically accounts for single loop operation effects on stability, as summarized in Reference 15.B.8-4. The model predictions were initially compared with test data and showed very good agreement for both two loop and single loop test conditions. An evaluation was performed to determine the effect of reverse flow on stability during SLO. With increasing reverse flow, SLO exhibited slightly lower decay ratios than two loop operation. However, at core flow conditions with no reverse flow, SLO was slightly less stable. This is consistent with observed behavior in stability tests at operating BWRs (Reference 15.B.8-5).

In addition to the above analyses, the cross flow established during reverse flow conditions was simulated analytically and shown to cause an increase in the individual and total jet pump flow noise, which is consistent with test data (Reference 15.B.8-4). The results of these analyses and tests indicate that the stability characteristics are not significantly different from two loop operation. At low core flow, SLO may be slightly less stable than two loop operation but as core flow is increased and reverse flow is established the stability performance is similar. At even higher core flow with substantial reverse flow in the inactive recirculation loop, the effect of cross flow on the flow noise results in an increase in system noise (jet pump, core flow and neutron flux noise).

15.B.4.2 Compliance to Stability Criteria

Consistent with the philosophy applied to two loop operation, the stability compliance during single loop operation is demonstrated on a generic basis. Stability acceptance criteria have been established to demonstrate compliance with the requirements set forth in 10CFR50, Appendix A, General Design Criterion (GDC) 12 (Reference 15.B.8-6). Generic analyses which cover those fuels contained in the General Electric Standard Application for Reload Fuel (Reference 15.B.8-7 through Amendment 10) have been performed. The analyses demonstrate that in the event limit

cycle neutron flux oscillations occur within the bounds of safety system intervention, specified acceptable fuel design limits are not exceeded. Since the reactor core is assumed to be in an oscillatory mode, the question of stability margin during SLO is not relevant from a safety standpoint (i.e., the analysis already assumes no stability margin).

The fuel performance during limit cycle oscillations is characteristically dependent on fuel design and certain fixed system features (high neutron flux scram setpoint, channel inlet orifice diameter, etc.). Therefore the acceptability of GE fuel designs independent of plant and cycle parameters has been established. Only those parameters unique to SLO which affect fuel performance need to be evaluated. The major consideration of SLO is the increased Minimum Critical Power Ratio (MCPR) safety limit caused by increased uncertainties in system parameters during SLO. However, the increase in MCPR safety limit (0.01) is well within the margin of the limit cycle analyses (Reference 15.B.8-6) and therefore it is demonstrated that stability compliance criteria are satisfied during single loop operation. Operationally, the effects of higher flow noise and neutron flux noise observed at high SLO core flow are evaluated to determine if acceptable vessel internal vibration levels are met and to determine the effects on fuel and channel fatigue, and are not considered in the compliance to stability criteria.

Service Information Letter-380, Revision 1 (Reference 15.B.8-8) has been developed to inform plant operators how to recognize and suppress unanticipated oscillations when encountered during plant operation.

As a result of the above analysis and operator recommendations, the NRC staff has approved the generic stability analysis for application to single loop operation (Reference 15.B.8-9) provided that the recommendations of SIL-380 have been incorporated into the Plant Technical Specifications.

15.B.5 LOSS-OF-COOLANT ACCIDENT ANALYSIS

If two recirculation loops are operating and a pipe break occurs in one of the two recirlation loops, the pump in the unbroken loop is assumed to immediately trip and begin to coast down. The decaying core flow due to the pump coastdown results in very effective heat transfer (nucleate boiling) during the initial phase of the blowdown. Typically, nucleate boiling will be sustained during the first 5 to 9 seconds after the accident, for the design basis accident (DBA).

If only one recirculation loop is operating, and the break occurs in the operating loop, continued core flow is provided only by natural circulation because the vessel is blowing down to the reactor containment through both sections of the broken loop. The core flow decreases more rapidly than in the two-loop operating case, and the departure from nucleate boiling for the high power node might occur 1 or 2 seconds after the postulated accident, resulting in more severe cladding heatup for the one-loop operating case.

In addition to changing the blowndown heat transfer characteristics, losing recirculation pump coastdown flow can also affect the system inventory and reflooding phenomena. Of particular interest are the changes in the high-power node uncovery and reflooding times, the system pressure and the time of rated core spray for different break sizes. One-loop operation results in small changes in the high-power node uncovery times and times of rated spray. The effect of the reflooding times for various break sizes is also generally small.

An analysis of single recirculation loop operation using the models and assumptions documented in Reference 15.B.8-10 was performed for NMP2. Using this method, SAFE/REFLOOD computer code runs were made for a full spectrum of large break sizes for only the recirculation suction line breaks (most limiting for NMP2). Because the reflood minus uncovery time for the single-loop analysis is similar to the two-loop analysis, the maximum planar linear heat generation rate (MAPLHGR) curves were modified

[illegible]
[illegible]
[illegible]

by derived reduction factors for use during one recirculation pump operation.

15.B.5.1 BREAK SPECTRUM ANALYSIS

SAFE/REFLOOD calculations were performed using assumptions given in Section II.A.7.3.1 of Reference 15.B.8-10. Hot node uncovered time (time between uncovery and reflood) for single-loop operation is compared to that for two-loop operation in Figure 15.B.5-1.

The total uncovered time for two-loop operation is 127 seconds for the 100% DBA suction break. This is the most limiting break for two-loop operation. For single-loop operation, the total uncovered time is 127 seconds and for the 100% DBA suction break. This is the most limiting break for single-loop operation.

15.B.5.2 SINGLE-LOOP MAPLHGR DETERMINATION

The small differences in uncovered time and reflood time for the limiting break size would result in a small change in the calculated peak cladding temperature. Therefore, as noted as Reference 15.B.8-10, the one and two-loop SAFE/REFLOOD results can be considered similar and the generic alternate procedure described in Section II.A.7.4. of this reference was used to calculate the MAPLHGR reduction factors for single-loop operation. The most limiting single-loop operation MAPLHGR reduction factor (i.e., yielding the lowest MAPLHGR) for GE6 8x8 retrofit-fuel is 0.81. One-loop operation MAPLHGR values are derived by multiplying the current two-loop MAPLHGR values by the reduction factor (0.81). As discussed in Reference 15.B.8-10, single recirculation loop MAPLHGR values are conservative when calculated in this manner.

15.B.5.3 SMALL BREAK PEAK CLADDING TEMPERATURE

Section II.A.7.4.4.2 of Reference 15.B.8-10 discusses the low sensitivity of the calculated peak cladding temperature (PCT) to the assumptions used in the one-pump operation analysis and the duration of nucleate boiling. As this slight increase (~ 50°F) in PCT is overwhelmingly offset by the decreased MAPLHGR (equivalent to 300°F to 500°F PCT) for one-pump operation, the calculated PCT values for small breaks will be well below the 1522°F small break PCT value previously reported for NMP2, and significantly below the 2200°F 10CFR50.46 cladding temperature limit.

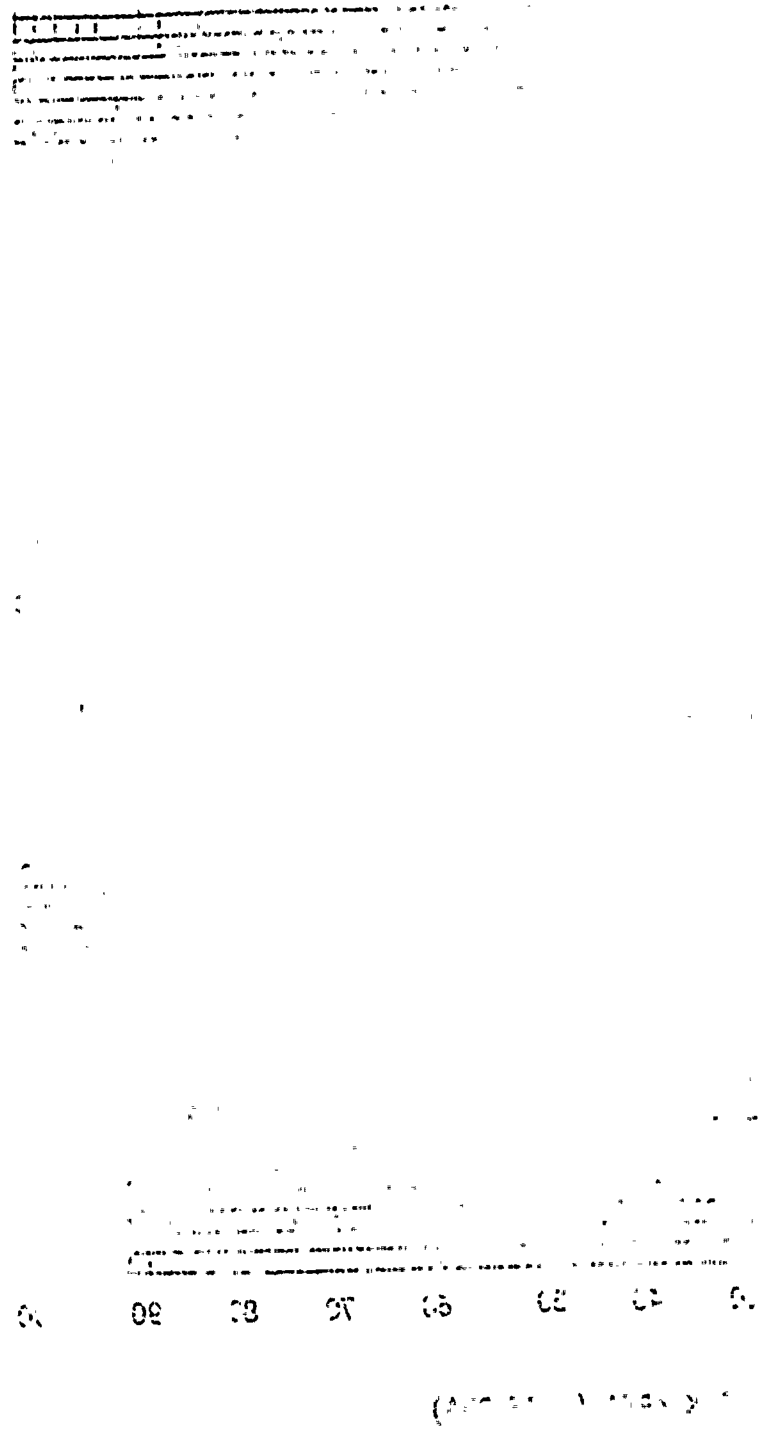
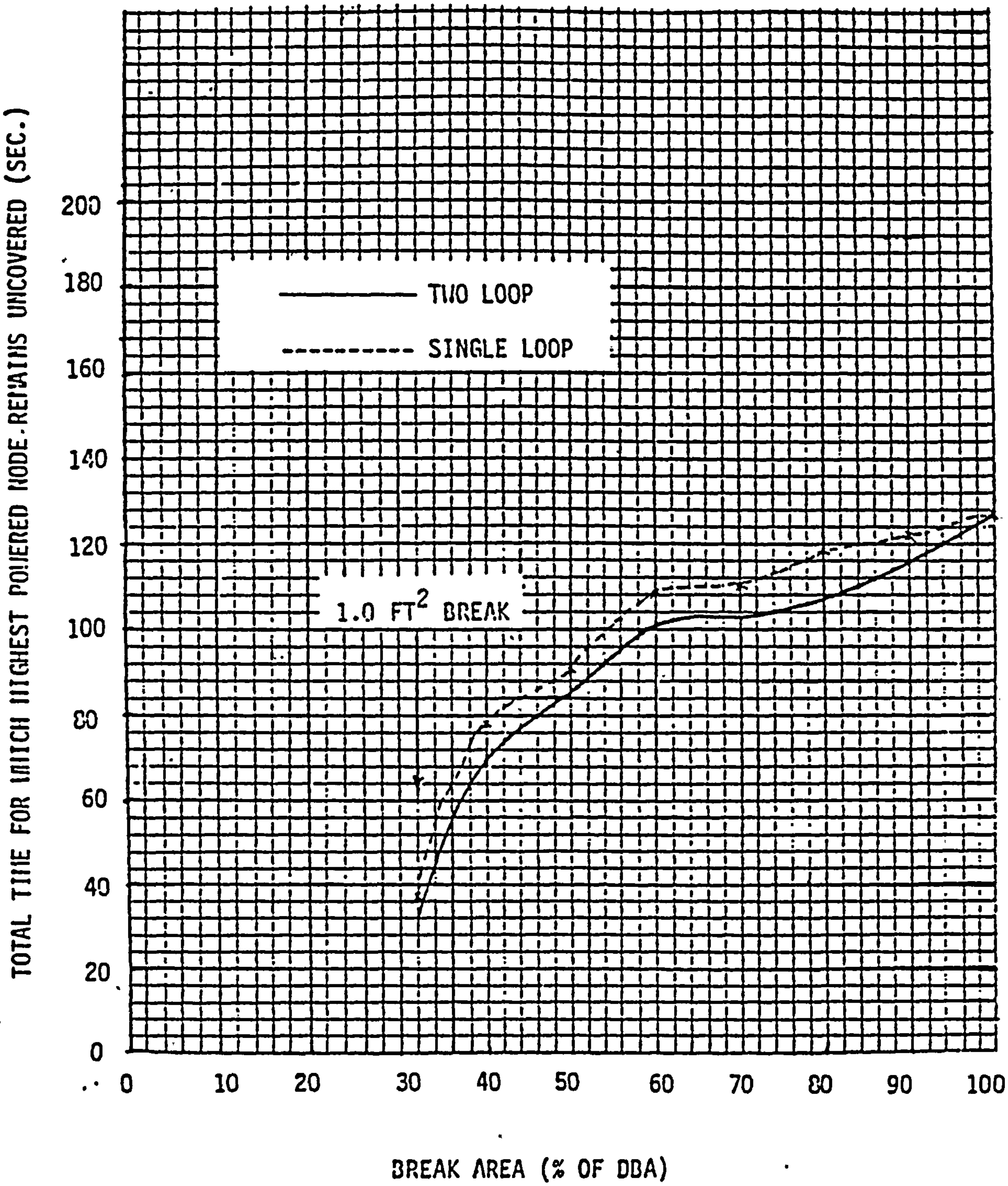


Figure 15.8.5-1



Niagara Mohawk Power Corp.	Uncovered Time vs. Break Area-Suction Break, LPCS Diesel Generator Failure	Figure 15.B.5-1

[illegible] the drywell temperature response is a main

[illegible] vessel subcooling was no

[illegible], the lower vessel [illegible]

[illegible] that

[illegible] the FSAR.

15.B.6 CONTAINMENT ANALYSIS

A single-loop operation containment analysis was performed for NMP2. The peak wetwell pressure, peak drywell pressure, chugging loads, condensation oscillation and pool swell containment response were evaluated over the entire single-loop operation power/flow region.

The analysis shows that the peak drywell and wetwell pressure during single loop operation is 33.1 psig and 27.2 psig respectively and occur under recirculation line break at the maximum vessel subcooling condition in the power/flow map. The corresponding differential peak drywell-to-wetwell pressure is 17.2 psid. A base case, corresponding to the FSAR condition of 102% power/100% core flow, was also analyzed for comparison. The results are presented in Table 15.B.6-1. As noted from the table, the peak drywell and wetwell pressure and the peak drywell-to-wetwell pressure for the SLO are all bounded by those of the base case and are substantially below the design limits. The pressure and temperature responses for the SLO are shown in Figure 15.B.6-1 and 15.B.6-2.

The containment dynamic loads evaluation was performed at the worst condition for the SLO and compared with those for the base case. Pool swell, condensation oscillation, and chugging loads were assessed for the initial phase of a postulated recirculation line break. Additionally, Safety Relief Valve actuation loads were considered. It is concluded from the evaluation results that the current FSAR containment loadings bound the worst SLO loadings.

The bounding event for the drywell temperature response is a main steamline break. Under SLO, the increased vessel subcooling has no impact on the steam break flow. However, the lower vessel pressure resulting from SLO reduces the steam break flow. It is concluded that the peak drywell temperature for SLO is bounded by that of the FSAR.

[illegible]ssion pool and wetwell airspace temperatures are
[illegible]rm release of decay heat and energy removal by the
[illegible] are bounded by
[illegible] is [illegible] that the peak suppression
bounded by [illegible] peak suppression pool temperature

Finally, the peak suppression pool and wetwell airspace temperatures are governed by the long-term release of decay heat and energy removal by the RHR service water. Since the power levels for the SLO are bounded by that of the FSAR, it is therefore concluded that the peak suppression pool temperature is bounded by the peak suppression pool temperature given in the FSAR.

Table [illegible]

[illegible]ison of Containment Peak Pressures

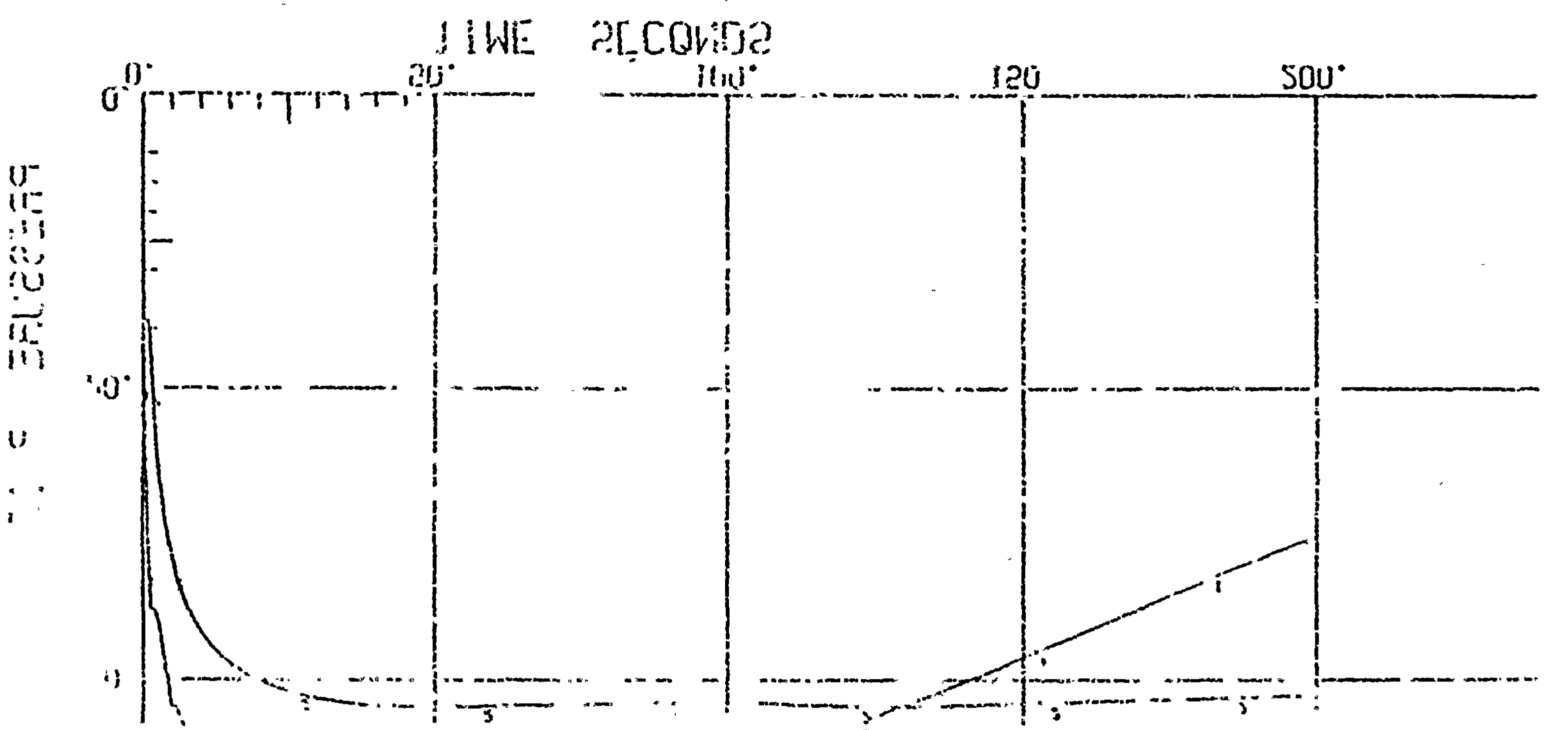
	Base Case (102% Power/ 100% Core Flow)	C.? (64% Power/ 38% Core Flow)	Design Limits
	34.52	[illegible].07	45
	17.81	17.1[illegible]	25
	28.63	27.18	45

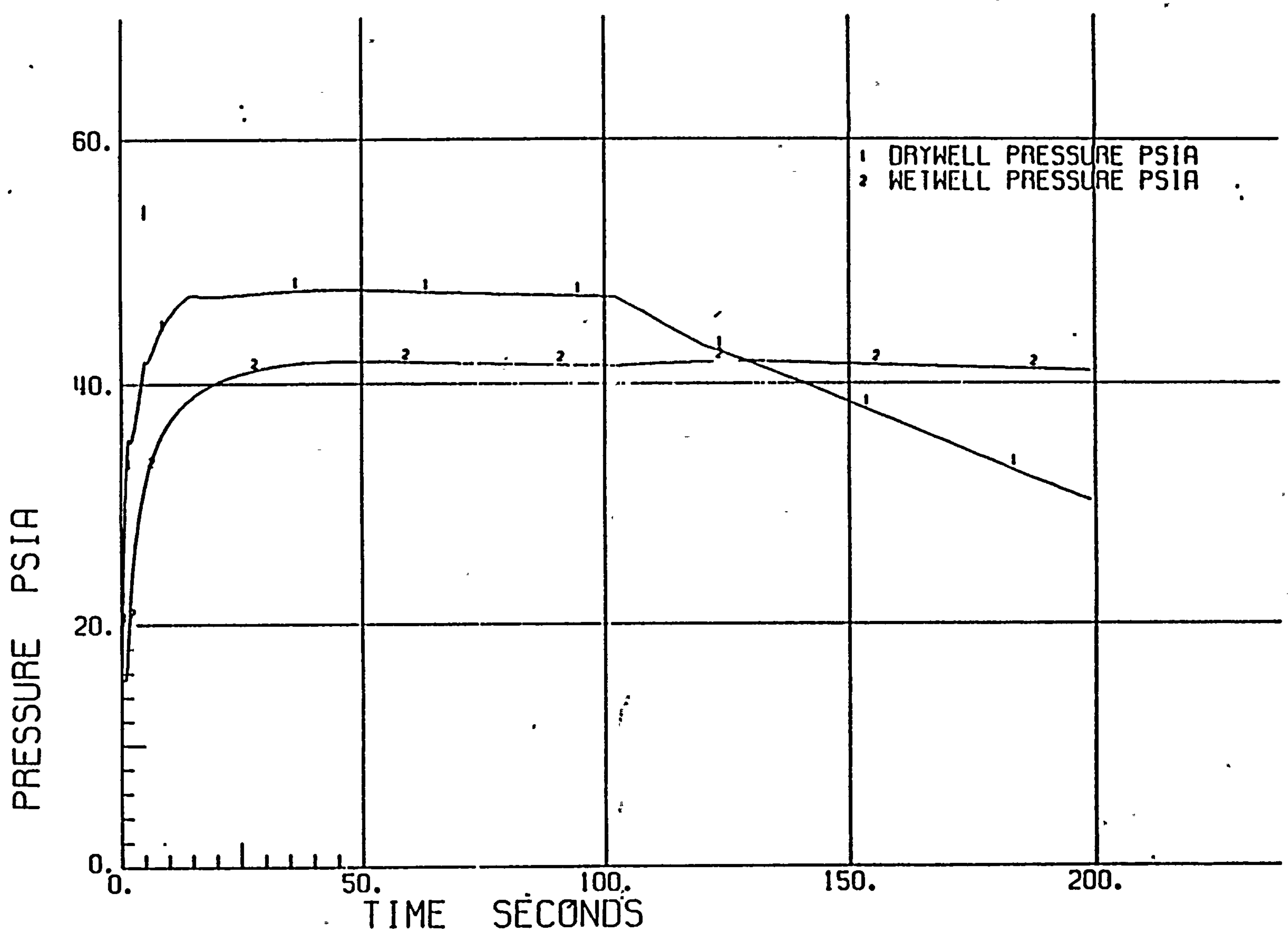
Table 15.B.6-1

Comparison of Containment Peak Pressures

	Base Case (102% Power/ 100% Core Flow)	SLO (54% Power/ 35% Core Flow)	Design Limits
Peak Drywell Pressure, PSIG	34.62	33.07	45
Peak Drywell-To-Wetwell Delta P PSID	17.81	17.17	25
Peak Wetwell Pressure, PSIG	28.63	27.18	45

NIAGARA MOHAWK POWER CORPORATION	DRYWELL AND WETWELL PRESSURE RESPONSES - RECIRCULATION LINE BREAK, 55% POWER, 35% CORE FLOW	FIGURE 15.8.6-1



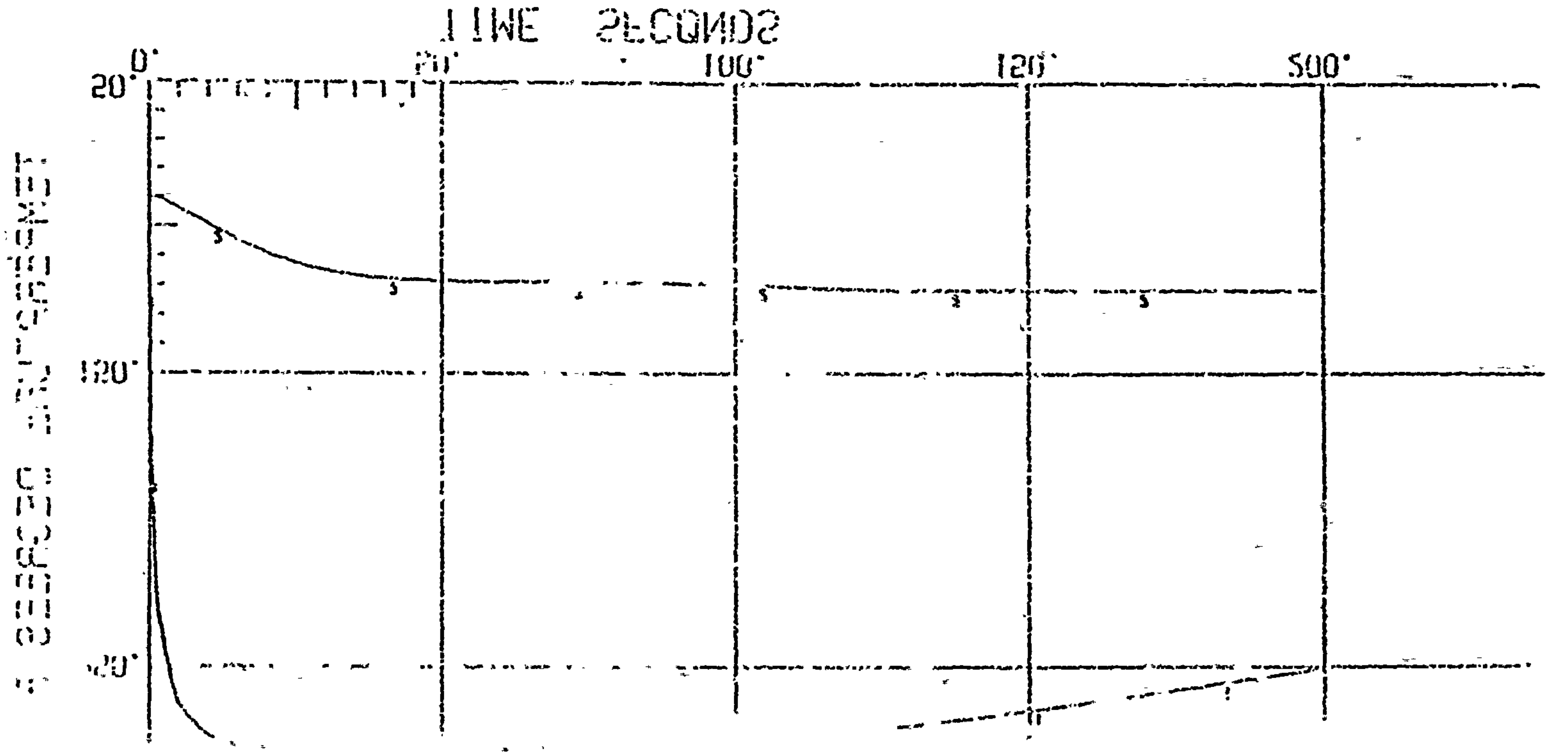


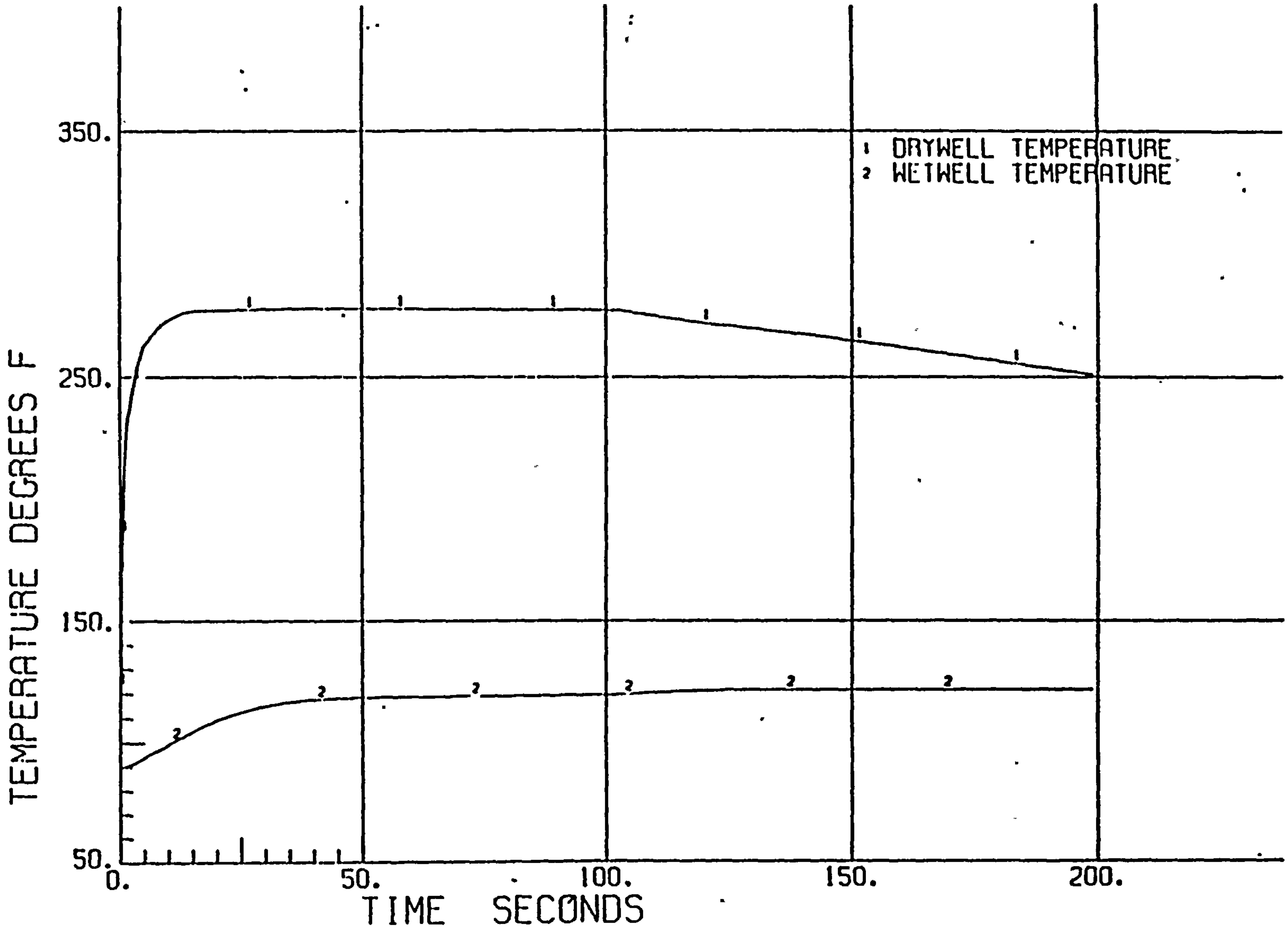
NIAGARA MOHAWK POWER CORPORATION	DRYWELL AND WETWELL PRESSURE RESPONSES - RECIRCULATION LINE BREAK, 55% POWER, 35% CORE FLOW	FIGURE 15.B.6-1

NIAGARA MOHAWK POWER CORPORATION

DRYWELL AND WETWELL TEMPERATURE RESPONSES - RECIRCULATION LINE BREAK, 55% POWER, 35% CORE FLOW

FIGURE 15.8.6-2





NIAGARA MOHAWK POWER CORPORATION	DRYWELL AND WETWELL TEMPERATURE RESPONSES - RECIRCULATION LINE BREAK, 55% POWER, 35% CORE FLOW	FIGURE 15.B.6-2

OUS IMPACT EVALUATION

ated Transient Without Scram (ATWS) Evaluation

fference between single loop operation (SLO) and normal ion (TLO) affecting Anticipated Transient Without Scram e is that of initial reactor conditions. Since the SLO low condition is less than the rated condition used for , the transient response is less severe and therefore O analyses.

hat if an ATWS event were initiated at NMP2 from the SLO results would be less severe than if it were initiated tions.

chanical Performance

echanical duty for the transients analyzed have been d to be bounded by the fuel design bases.

that due to the substantial reverse flow established the Average Power Range Monitor (APRM) noise and core al pressure noise are slightly increased. An analysis out to determine that the APRM fluctuation should not litude of ±15% of rated and the core plate differential ion should not exceed 3.2 psi peak to peak to be consis- l rod and assembly design bases.

Internal Vibration

drive flow limit is imposed for SLO. The highest is acceptable vessel internal vibration criteria is for SLO.

15.B.7 MISCELLANEOUS IMPACT EVALUATION

15.B.7.1 Anticipated Transient Without Scram (ATWS) Impact Evaluation

The principal difference between single loop operation (SLO) and normal two loop operation (TLO) affecting Anticipated Transient Without Scram (ATWS) performance is that of initial reactor conditions. Since the SLO initial power flow condition is less than the rated condition used for TLO ATWS analysis, the transient response is less severe and therefore bounded by the TLO analyses.

It is concluded that if an ATWS event were initiated at NMP2 from the SLO conditions, the results would be less severe than if it were initiated from rated conditions.

15.B.7.2 Fuel Mechanical Performance

The thermal and mechanical duty for the transients analyzed have been evaluated and found to be bounded by the fuel design bases.

It is observed that due to the substantial reverse flow established during SLO both the Average Power Range Monitor (APRM) noise and core plate differential pressure noise are slightly increased. An analysis has been carried out to determine that the APRM fluctuation should not exceed a flux amplitude of ±15% of rated and the core plate differential pressure fluctuation should not exceed 3.2 psi peak to peak to be consistent with the fuel rod and assembly design bases.

15.B.7.3 Vessel Internal Vibration

A recirculation pump drive flow limit is imposed for SLO. The highest drive flow that meets acceptable vessel internal vibration criteria is the drive flow limit for SLO.

been made for the expected reactor vibration level.

the results of the assessment, it is prudent to define
a flow" during balanced 2-loop operation and single loop
mum flow for two-pump balanced operation is equal to
t core flow at normal reactor operating conditions.
single-pump operation is that flow obtained with the
mp drive flow equal to that required for maximum flow
balanced operation. For rated reactor water temperature
e maximum allowable recirculation pump drive flow for
00 gpm.

the Tokai 2 plant showed all components, including the
e during single-loop operation, to have vibration levels
limits. The Tokai 2 is the BWR 5/251 prototype plant.
a prototype plant, there is no reactor internal vibra-
program. Instead, the data from the Tokai 2 plant is
assessment. Based on the Tokai 2 plant data, it can be
vibration levels of the reactor internal components for
cted to be within acceptance limits during single-loop
imum flow as defined above.

s, the NMP2 startup testing will yield the required
P2 jet pumps are instrumented.

An assessment has been made for the expected reactor vibration level during SLO for NMP2.

Before providing the results of the assessment, it is prudent to define the term "maximum flow" during balanced 2-loop operation and single loop operation. Maximum flow for two-pump balanced operation is equal to rated volumetric core flow at normal reactor operating conditions. Maximum flow for single-pump operation is that flow obtained with the recirculation pump drive flow equal to that required for maximum flow during two-pump balanced operation. For rated reactor water temperature and pressure, the maximum allowable recirculation pump drive flow for NMP2 is about 41,000 gpm.

Startup tests at the Tokai 2 plant showed all components, including the in-core guide tube during single-loop operation, to have vibration levels within acceptance limits. The Tokai 2 is the BWR 5/251 prototype plant. Since NMP2 ~~is not a prototype plant, there~~ is no reactor internal vibration monitoring program. Instead, the data from the Tokai 2 plant is used for NMP2 SLO assessment. Based on the Tokai 2 plant data, it can be inferred that the vibration levels of the reactor internal components for NMP2 would be expected to be within acceptance limits during single-loop operation with maximum flow as defined above.

For the jet pumps, the NMP2 startup testing will yield the required confirmation as NMP2 jet pumps are instrumented.

<u>...NCES</u>

...l Electric BWR Thermal Analysis Basis (GETAB): Data, ...lation and "Design Application", NEDO-10958-A, ...y 1977.

...ification of the One-Dimensional Core Transient Model for ...g Water Reactors", NEDO-24154, October 1978.

Linford, "Analytical Methods of Plant Transient Evaluation for the General Electric Boiling Water Reactor", NEDO-10802, ...1973.

...H. C. Pfefferlen (GE) to C. O. Thomas (NRC), "Submittal ...onse to Stability Action Item from NRC Concerning ...oop Operation," September 1983.

...n and R. O. Niemi, "Vermont Yankee Cycle 8 Stability ...rculation Pump Trip Test Report", General Electric ...ust 1982 (NEDE-25445, Proprietary Information).

Watford, "Compliance of the General Electric Boiling Reactor Fuel Designs to Stability Licensing Criteria", Electric Company, October 1984 (NEDE-22277-P-1, Proprietary Information).

"General Electric Standard Application for Reload Fuel", Electric Company, April 1983 (NEDE-24011-P-A-6).

Core Thermal Hydraulic Stability", General Electric February 10, 1984 (Service Information Letter-380, ...).

15.B.8 REFERENCES

15.B.8-1 "General Electric BWR Thermal Analysis Basis (GETAB); Data, Correlation, and Design Application", NEDO-10958-A, January 1977.

15.B.8-2 "Qualification of the One-Dimensional Core Transient Model for Boiling Water Reactors", NEDO-24154, October 1978.

15.B.8-3 R. B. Linford, "Analytical Methods of Plant Transients Evaluation for the General Electric Boiling Water Reactor", NEDO-10802, April 1973.

15.B.8-4 Letter, H. C. Pfefferlen (GE) to C. O. Thomas (NRC), "Submittal of Response to Stability Action Item from NRC Concerning Single-Loop Operation," September 1983.

15.B.8-5 S. F. Chen and R. O. Niemi, "Vermont Yankee Cycle 8 Stability and Recirculation Pump Trip Test Report", General Electric Company, August 1982 (NEDE-25445, Proprietary Information).

15.B.8-6 G. A. Watford, "Compliance of the General Electric Boiling Water Reactor Fuel Designs to Stability Licensing Criteria", General Electric Company, October 1984 (NEDE-22277-P-1, Proprietary Information).

15.B.8-7 "General Electric Standard Application for Reload Fuel", General Electric Company, April 1983 (NEDE-24011-P-A-6).

15.B.8-8 "BWR Core Thermal Hydraulic Stability", General Electric Company, February 10, 1984 (Service Information Letter-380, Revision 1).

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., C. O. Thomas (NRC) to H. C. Pfefferlen (GE), "Accep-
for Referencing of Licensing Topical Report NEDE-24011,
6, Amendment 8, Thermal Hydraulic Stability Amendment to
2 II," April 24, 1985.

ral Electric Company Analytical Model for Loss-of-Coolant
is in Accordance with 10CFR50 Appendix K Amendment No. 2
Recirculation Loop Out-of-Service", NEDO-20566-2 Revision 1,
1978.

15.B.8 REFERENCES (Cont'd)

15.B.8-9 Letter, C. O. Thomas (NRC) to H. C. Pfefferlen (GE), "Acceptance for Referencing of Licensing Topical Report NEDE-24011, Rev. 6, Amendment 8, Thermal Hydraulic Stability Amendment to GESTAR II," April 24, 1985.

15.B.8-10 "General Electric Company Analytical Model for Loss-of-Coolant Analysis in Accordance with 10CFR50 Appendix K Amendment No. 2 - One Recirculation Loop Out-of-Service", NEDO-20566-2 Revision 1, July 1978.

[illegible]

END OF CYCLE – RECIRCULATION PUMP (RCP) INOPERABLE
TURBINE BYPASS INOPERABLE [illegible]

ATTACHMENT G

END OF CYCLE - RECIRCULATION PUMP TRIP INOPERABLE AND TURBINE BYPASS INOPERABLE ANALYSIS

ication for EOC-RPT Inoperable and Turbine Bypass Inoperable
. Specification Changes

rove operating flexibility and plant availability, two
rios have been analyzed to support Tech. Spec. changes for
level reduction.

perable

Limiting Condition for Operation requires that the thermal
duced to less than 30% in case the end-of-cycle recirculation
becomes inoperable. In the supporting analysis to justify less
on, two limiting cases were examined with the transient code
ine the bounding operating limit critical power ratio (OLCPR).

r controller failure with EOC-RPT inoperable

or load rejection without bypass when EOC-RPT is inoperable

s Inoperable ATTAC[illegible] G

Limiting Condition for Operation requires that the thermal
ced to less than 25% in case the turbine bypass becomes
n the supporting analysis to justify less power reduction,
cases were examined with ODYN to define the bounding OLCPR.

r controller failure [illegible] turbine bypass inoperable

feedwater heater with turbine bypass inoperable

obtained from EOC-7 nuclear characteristics (see FSAR Table
ucting OLCPR vs. scram speed is generated for each transient
OLCPR plot and related Tech. Spec. text revision are included
nt.

these postulated [illegible] transients are events beyond the
documented in the FSAR, [illegible] FSAR revision is not required.

O 3.2.3 and two associated figures replaced in its entirety.
eview revision of LCO 3.2.3 and its associated figure on pages

provided for LCO's 3.3.4.2 and 3.7.9 for proof and review
al Specifications.

ided for Bases pages B3/4-2-4.

Subject: Justification for EOC-RPT Inoperable and Turbine Bypass Inoperable Technical Specification Changes

In order to improve operating flexibility and plant availability, two transient scenarios have been analyzed to support Tech. Spec. changes for minimizing power level reduction.

1. EOC-RPT Inoperable

   The current Limiting Condition for Operation requires that the thermal power be reduced to less than 30% in case the end-of-cycle recirculation pump trip becomes inoperable. In the supporting analysis to jusitfy less power reduction, two limiting cases were examined with the transient code ODYN to define the bounding operating limit critical power ratio (OLCPR).

   a. Feedwater controller failure with EOC-RPT inoperable

   b. Generator load rejection without bypass when EOC-RPT is inoperable

2. Turbine Bypass Inoperable

   The current Limiting Condition for Operation requires that the thermal power be reduced to less than 25% in case the turbine bypass becomes inoperable. In the supporting analysis to justify less power reduction, two limiting cases were examined with ODYN to define the bounding OLCPR.

   a. Feedwater controller failure with turbine bypass inoperable

   b. Loss of feedwater heater with turbine bypass inoperable

Using input determined from EOC-1 nuclear characteristics (see FSAR Table 15.0-3), the bounding OLCPR vs. scram speed is generated for each transient scenario. This OLCPR plot and related Tech. Spec. text revision are included in the attachment.

Please note that these postulated scenarios are transient events beyond the design basis documented in the FSAR. Therefore, FSAR revision is not required.

The attached LCO 3.2.3 and two associated figures replace, in its entirety, the proof and review revision of LCO 3.2.3 and its associated figure on pages 3/4 2-6 and 2-7.

Changes are also provided for LCO's 3.3.4.2 and 3.7.9 for proof and review version of Technical Specifications.

A change is provided for Bases pages B3/4 2-4.