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Docket No. 50-416

Mr. J.P. McGaughy, Jr.
Assistant Vice President - Nuclear
Production
Mississippi Power & Light Company
P.O. Box 1640
Jackson, Mississippi 39205

Dear Mr. McGaughy:

Subject: Amendment No. 7 to Facility Operating License No. NPF-13 - Grand Gulf Nuclear Station, Unit 1

The Nuclear Regulatory Commission has issued the enclosed Amendment No. 7 to Facility Operating License No. NPF-13 for the Grand Gulf Nuclear Station, Unit 1. This Amendment is in response to MP&L letters dated March 24, 1983, April 7, 1983, and April 25, 1983, which you submitted in partial response to the NRC Confirmation of Action (COA) letter of October 20, 1982. That COA letter called for MP&L to prepare and submit license amendment requests, where necessary, to correct administrative and technical deficiencies in your Technical Specifications during MP&L's review of the Grand Gulf Unit 1 surveillance procedures.

The bulk of the changes approved in Amendment No. 7 are administrative in nature and are necessary to correct editorial and nomenclature errors and to achieve consistency with the as-built condition of the plant. None of the changes involve a significant relaxation of the criteria used to establish safety limits or the bases for limiting safety system settings or limiting conditions for operation.

A copy of the related staff evaluation supporting Amendment No. 7 to Facility Operating License NPF-13 is enclosed. Also enclosed is a copy of a related notice which has been forwarded to the Office of the Federal Register for publication.

Sincerely,

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

8307150044 830701
PDR ADOCK 05000416
P PDR

Enclosures:
1. Amendment No. 7 to NPF-13
2. Staff Evaluation
3. ~~Federal Register Notice~~

cc w/ enclosures:
See next page

OFFICE			DL:LB#2/PM	OELD	DL:LB#2/BC	
SURNAME			DHouston:pt	MWagner	ASchwencer	
DATE			6/21/83	6/21/83	6/24/83	

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Grand Gulf

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Claiborne County Board of Supervisors
Port Gibson, Mississippi 39150

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State of Mississippi
Jackson, Mississippi 39201

U. S. Environmental Protection Agency
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Atlanta, Georgia 30309

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P. O. Box 1700
Jackson, Mississippi 39205

MISSISSIPPI POWER AND LIGHT COMPANY
MIDDLE SOUTH ENERGY, INC.
SOUTH MISSISSIPPI ELECTRIC POWER ASSOCIATION
DOCKET NO. 50-416
GRAND GULF NUCLEAR STATION, UNIT 1
AMENDMENT TO FACILITY OPERATING LICENSE

License No. NPF-13
Amendment No. 7

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

   A. The applications for the amendment filed by the Mississippi Power and Light Company dated March 24, 1983, April 7, 1983, and April 25, 1983, comply with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act), and the Commission's regulations set forth in 10 CFR Chapter I;

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

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

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

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

2. Accordingly, the license is amended as follows:

   A. Page changes to the Technical Specifications as indicated in the attachment to this license amendment and paragraph 2.C.(2) to read as follows:

      (2) The Technical Specifications contained in Appendix A, as revised through Amendment No. 7, and the Environmental Protection Plan contained in Appendix B, are hereby incorporated in the license. The licensees shall operate the facility in accordance with the Technical Specifications and the Environmental Protection Plan.

OFFICE							
SURNAME							
DATE							

3. This amendment is effective as of the date of issuance.

FOR THE NUCLEAR REGULATORY COMMISSION

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

Date of Issuance: July 01, 1983

*SEE ATTACHED PAGE FOR PREVIOUS CONCURRENCES

OFFICE	DL:LB#2/PM*	OELD*	DL:LB#2/BC*	DL:AD/L*	DL:DIR*		
SURNAME	DHouston:pt	MWagner	ASchwencer	TNovak	DGEisenhut		
DATE	6/21/83	6/21/83	6/21/83	6/24/83	7/01/83		

3. This amendment is effective as of the date of issuance.

FOR THE NUCLEAR REGULATORY COMMISSION

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

Date of Issuance:

concur w. noted changes

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SURNAME	DHouston:pt	MWolfner	ASchwencer	TNovak	DGEisenhut		
DATE	6/21/83	6/21/83	6/21/83	6/28/83	7/01/83		

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STAFF EVALUATION
AMENDMENT NO. 7 TO NPF-13
GRAND GULF NUCLEAR STATION, UNIT 1
DOCKET NO. 50-416

Introduction

Mississippi Power & Light Company, Middle South Energy Inc., and South Mississippi Electric Power Association (the licensees) are the holders of Facility Operating License No. NPF-13, which authorizes the operation of the Grand Gulf Nuclear Station, Unit 1, (the facility) at steady-state reactor power levels not in excess of 191 megawatts thermal. The facility consists of a boiling water reactor (BWR) located in Claiborne County, Mississippi.

It has been discovered that there were editorial and nomenclature errors in the Technical Specifications for the subject facility. The Technical Specifications did not in all cases agree with the actual as-built condition of the facility as actually described, analyzed in the Final Safety Analysis Report and approved in the NRC staff's Safety Evaluation Reports as supplemented. In addition, typographical errors were contained in the Technical Specifications. These matters were in part addressed in a confirmatory letter of October 20, 1982 from the NRC staff to the licensees.

Mississippi Power & Light Company responded by letters dated March 24, 1983, April 7, 1983, and April 25, 1983. In these submittals, MP&L has identified and committed to implement changes to the Technical Specifications. The need for these changes resulted from MP&L's review of the facility's surveillance test procedures.

Evaluation

The bulk of the changes to the Technical Specifications are administrative in nature and are necessary to correct editorial and nomenclature errors and to achieve consistency throughout the Technical Specifications and with the as-built condition of the plant. None of the changes involve a significant relaxation of the criteria used to establish safety limits or the bases for limiting safety system settings or limiting conditions for operation.

In the following tables, the changes are grouped together in common categories with cross-reference to the MP&L letters.

Table 1
Editorial or Nomenclature
Corrections to Technical Specifications

Letter Reference	Item	Technical Specification Section
3/24/83	1	Table 3.6.4-1
3/24/83	2	Table 3.6.4-1
3/24/83	5	Table 3.3.3-2
3/24/83	9	Table 3.6.4-1
3/24/83	10	3.1.3.2.b
3/24/83	11	Table 4.3.7.11-1
3/24/83	17	Table 1.1
3/24/83	18	Table 3.6.6.2-1
3/24/83	21	Table 3.3.7.1-1
3/24/83	24	Table 3.3.7.5-1
3/24/83	27	Tables 3.3.2-1, 3.3.2-2, 3.3.2-3 and 4.3.2.1-1
3/24/83	32	Tables 3.3.7.2-1 and 4.3.7.2-1
3/24/83	34	3.11.1.3

Table 1 (continued)

Letter Reference	Item	Technical Specification Section
4/7/83	1	6.9.1.12.k
4/7/83	2	Table 4.3.1.1-1
4/7/83	7	Table 3.3.3-2
4/7/83	10	Table 3.3.2-3
4/7/83	17	Table 4.3.7.11-1
4/7/83	20	3.5.1
4/7/83	21	4.7.4
4/25/83	2	4.7.5.3

Table 2
Changes to Maintain Consistency
Within Technical Specifications

Letter Reference	Item	Technical Specification Section
3/24/83	13	Table 3.3.6.2 and Section 4.1.4.2
3/24/83	20	Table 3.3.2-2
3/24/83	31	Table 4.3.6-1
4/7/83	8	Table 3.3.4.2-1
4/7/83	16	Table 4.3.7.12-1

The changes listed in Tables 1 and 2 above are purely administrative changes.

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DATE ▸							

The remaining changes to the Technical Specifications are necessary to properly account for as-built plant conditions. The as-built conditions conform to the system described and analyzed in the Final Safety Analysis Report (FSAR). The staff reviewed and approved these as-built conditions in their Operating License review.

Table 3
Technical Specification Changes
to Conform to As-built Plant

Letter Reference	Item	Technical Specification Section/Discussion of Change Bases
3/24/83	7	4.6.4.4/Explosive valves not included in TIP system, none required for Mark III containment
3/24/83	12	4.8.3.1.1 and 4.8.3.2.1/Voltage instrumentation not present on MCCs/panels, sufficient voltage instrumentation present on Busses and LCs
3/24/83	16	Table 3.3.2-3/MSIV isolation not a function of this instrumentation
3/24/83	19	Table 3.3.7.12-1 and Table 4.3.7.12-1/Automatic isolation not a function of noble gas monitor, Isolation provided by ventiliation exhaust monitor
3/24/83	22	4.8.1.1.2.1.16/Lockout features reversed in listing
3/24/83	25	4.9.12/Not appropriate for Horizontal Tube Transfer System
3/24/83	26	3.9.1/Interlocks not provided for fuel grapple or SRM countrate, not required in staff review
3/24/83	29	Table 3.3.2-1/Addition of valves to listing
3/24/83	30	Table 3.3.7.3-1 and Table 4.3.7.3-1/Direct Temperature at 162' level not monitored, Differential Temperature with lower elevation is provided as required parameter
4/7/83	4	Table 3.7.8-1/Lower temperature limits agree with actual qualification temperatures as required by staff evaluation.

Table 3 (continued)

Letter Reference	Item	Technical Specification Section/Discussion of Change Bases
4/7/83	5	4.7.2/Single path system has no bypass valves, Not a requirement and not considered
4/7/83	6	3.9.1/No lever arm on vacuum breaker, testing to be conducted by another suitable method
4/7/83	9	4.8.1.1.2/Diesel generator start time faster than specified, agrees with previous staff evaluation
4/7/83	11	Table 3.3.7.1-1 and Table 4.3.7.1-1/Provides surveillance for additional radiation monitor, installed over approved fuel storage area
4/7/83	12	4.6.7.1/Specified system has no piping penetrations through containment
4/25/83	6	Table 3.7.6.5-1/Provides proper notation for hose station locations

In addition to the above, the licensees have requested some changes to the BASES sections.

Table 4
Changes to BASES Sections

Letter Reference	Item	BASES Section
3/24/83	3	B 3.0.3
3/24/83	4	B Figure 3/4 3-1
3/24/83	8	B 7.2

OFFICE ▶							
SURNAME ▶							
DATE ▶							

Table 4 (continued)

Letter Reference	Item	BASES Section
4/7/83	18	B 6.1.5, B 6.1.6
4/25/83	9	B 2.2.1, B 3.2, B 3.3, B.3.4, B.3.5, and B 3.6

These changes to the Technical Specifications are administrative in nature and are being made as editorial or nomenclature corrections of errors, to assure consistency within the Technical Specifications themselves, and to make the Technical Specifications the as-built condition of the plant which described and analyzed in the FSAR and approved by the staff in its operating license review. These changes are necessary to correct inadvertent errors in the Technical Specifications when the license was issued rather than to change any physical features of the plant.

In view of the foregoing, the NRC staff concludes that these changes to the Technical Specifications and BASES are both appropriate and necessary and should be incorporated into the Technical Specifications at this time.

Environmental Consideration

The Commission has determined that the issuance of this amendment will not result in any environmental impacts other than those evaluated in the Final Environmental Statement since the activity authorized by the amendment is encompassed by the overall action evaluated in the Final Environmental Statement dated September 1981.

Conclusion

We have concluded, based on the considerations discussed above, that: (1) this amendment results as part of the review for the full power operating license (43 FR 32903), (2) there is reasonable assurance that the health and safety of the public will not be endangered by operation in the proposed manner, and (3) such activities will be conducted in compliance with the Commission's regulations and the issuance of this amendment will not be inimical to the common defense and security or to the health and safety of the public.

Dated: July 1, 1983

*SEE ATTACHED PAGE FOR PREVIOUS CONCURRENCES

OFFICE	DL:LB#2/PM*	DL:SSPB	OELD*				
SURNAME	DHouston:pt	DHoffman	MWagner				
DATE	6/21/83	/ /83	6/21/83				

Table 4 (continued)

Letter Reference	Item	BASES Section
4/7/83	18	B 6.1.5, B 6.1.6
4/25/83	9	B 2.2.1, B 3.2, B 3.3, B.3.4, B.3.5, and B 3.6

In view of the foregoing, the NRC staff concludes that these changes to the Technical Specifications and BASES are both appropriate and necessary and should be incorporated into the Technical Specifications at this time.

Environmental Consideration

The Commission has determined that the issuance of this amendment will not result in any environmental impacts other than those evaluated in the Final Environmental Statement since the activity authorized by the license is encompassed by the overall action evaluated in the Final Environmental Statement dated September 1981.

Conclusion

We have concluded, based on the considerations discussed above, that: (1) this amendment results as the normal chain of events leading to a full power license (43 FR 32903), (2) there is reasonable assurance that the health and safety of the public will not be endangered by operation in the proposed manner, and (3) such activities will be conducted in compliance with the Commission's regulations and the issuance of this amendment will not be inimical to the common defense and security or to the health and safety of the public.

Dated:

comments noted changes as changed noted 6/30/83

OFFICE	DL:LB#2/PM	DL:SSPB	OELD				
SURNAME	DHouston:pt	DHoffman	[illegible]				
DATE	6/21/83	/ /83	6/21/83				

SURVEILLANCE REQUIREMENTS

4.1.4.2 The RPCS shall be demonstrated OPERABLE by verifying the OPERABILITY of the:

a. Rod pattern controller when THERMAL POWER is less than the low power setpoint by selecting and attempting to move an inhibited control rod:

   1. After withdrawal of the first insequence control rod for each reactor startup.

   2. As soon as the rod inhibit mode is automatically initiated at the RPCS low power setpoint, 20 +15, -0% of RATED THERMAL POWER, during power reduction.

   3. The first time only that a banked position, N1, N2, or N3, is reached during startup or during power reduction below the RPCS low power setpoint.

b. Rod withdrawal limiter when THERMAL POWER is greater than or equal to the low power setpoint by selecting and attempting to move a restricted control rod in excess of the allowable distance:

   1. As each power range above the RPCS low power setpoint is entered during a power increase or decrease.

   2. At least once per 31 days while operation continues within a given power range above the RPCS low power setpoint.

LIMITING CONDITION FOR OPERATION (Continued)

ACTION: (Continued)

b. With a "slow" control rod(s) not satisfying ACTION a.1, above:

   1. Declare the "slow" control rod(s) 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 "slow" control rods declared inoperable.

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

c. With the maximum scram insertion time of one or more control rods exceeding the maximum scram insertion time limits of Specification 3.1.3.2 as determined by Specification 4.1.3.2.c, operation may continue provided that:

   1. "Slow" control rods, i.e., those which exceed the limits of Specification 3.1.3.2, do not make up more than 20% of the 10% sample of control rods tested.

   2. Each of these "slow" control rods satisfies the limits of ACTION a.1.

   3. The eight adjacent control rods surrounding each "slow" control rod are:

      a) Demonstrated through measurement within 12 hours to satisfy the maximum scram insertion time limits of Specification 3.1.3.2, and

      b) OPERABLE.

   4. The total number of "slow" control rods, as determined by Specification 3.1.3.2.c, when added to the sum of ACTION a.3, as determined by Specification 4.1.3.2.a and b, does not exceed 7.

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

SURVEILLANCE REQUIREMENTS

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

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

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

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

*Except movement of SRM, IRM, or special removable detectors or normal control rod movement.

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.
N.A.	Not applicable.
P	Completed prior to each release.

2.2.1 REACTOR PROTECTION SYSTEM INSTRUMENTATION SETPOINTS

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

1. Intermediate Range Monitor, Neutron Flux - High

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

The most significant source of reactivity changes during the power increase is due to control rod withdrawal. In order to ensure that the IRM provides the required protection, a range of rod withdrawal accidents have been analyzed. The results of these analyses are in Section 15.4 of the FSAR. The most severe case involves an initial condition in which THERMAL POWER is at approximately 1% of RATED THERMAL POWER. Additional conservatism was taken in this analysis by assuming the IRM channel closest to the control rod being withdrawn is bypassed. The results of this analysis show that the reactor is shutdown and peak power is limited to 21% of RATED THERMAL POWER with the peak fuel enthalpy well below the fuel failure threshold criterion 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 RPCS. Of all the possible sources of reactivity input, uniform control 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

TABLE 4.3.1.1-1 (Continued)

REACTOR PROTECTION SYSTEM INSTRUMENTATION SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL FUNCTIONAL TEST	CHANNEL CALIBRATION	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED
9. Scram Discharge Volume Water Level - High	S	M	R(g)	1, 2, 5
10. Turbine Stop Valve - Closure	S	M	R(g)	1
11. Turbine Control Valve Fast Closure Valve Trip System Oil Pressure - Low	S	M	R(g)	1
12. Reactor Mode Switch Shutdown Position	NA	R	NA	1, 2, 3, 4, 5
13. 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) Calibrate trip unit at least once per 31 days.
(h) Verify measured core flow to be less than or equal to established core flow at the existing flow control valve position.
(i) This calibration shall consist of verifying the 6 ± 1 second simulated thermal power time constant.

TABLE 3.3.2-1

ISOLATION ACTUATION INSTRUMENTATION

TRIP FUNCTION	VALVE GROUPS OPERATED BY SIGNAL (a)	MINIMUM OPERABLE CHANNELS PER TRIP SYSTEM (b)	APPLICABLE OPERATIONAL CONDITION	ACTION
1. PRIMARY CONTAINMENT ISOLATION				
a. Reactor Vessel Water Level-Low Low, Level 2	6, 7, 8, 10[c][d]	2	1, 2, 3 and #	20
b. Drywell Pressure - High	5, 6, 7, 9[c][d]	2	1, 2, 3	20
c. Containment and Drywell Ventilation Exhaust Radiation - High High	7	2[e]	1, 2, 3 and *	21
d. Manual Initiation	5, 6, 7, 8, 9, 10	2/group	1, 2, 3 and *#	22
2. MAIN STEAM LINE ISOLATION				
a. Reactor Vessel Water Level-Low Low Low, Level 1	1, 5	2	1, 2, 3	20
b. Main Steam Line Radiation - High	1, 10(f)	1/line	1, 2, 3	23
c. Main Steam Line Pressure - Low	1	1/line	1	24
d. Main Steam Line Flow - High	1	2/line[g]	1, 2, 3	23
e. Condenser Vacuum - Low	1	2	1, 2, 3	23
f. Main Steam Line Tunnel Temperature - High	1	2	1, 2, 3	23
g. Main Steam Line Tunnel Δ Temp.- High	1	2	1, 2, 3	23
h. Manual Initiation	1, 5, 10	2/group	1, 2, 3	22

TABLE 3.3.2-1 (Continued)
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 - Close the affected system isolation valve(s) within one hour or:

a. 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.
b. In Operational Condition *, suspend CORE ALTERATIONS, handling of irradiated fuel in the containment and operations with a potential for draining the reactor vessel.

ACTION 22 - Restore the manual initiation 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 23 - 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 24 - Be in at least STARTUP within 6 hours.

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

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

ACTION 27 - Close the affected system isolation valves within one hour and declare the affected system inoperable.

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

NOTES

* When handling irradiated fuel in the containment and during CORE ALTERATIONS and operations with a potential for draining the reactor vessel.
# During CORE ALTERATIONS and operations with a potential for draining the reactor vessel.
(a) See Specification 3.6.4, Table 3.6.4-1 for valves in each valve group.
(b) 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.
(c) Also actuates the standby gas treatment system.
(d) Also actuates the control room emergency filtration system in the isolation mode of operation.
(e) One upscale and/or two downscale actuate the trip system.
(f) Also trips and isolates the mechanical vacuum pumps.
(g) A channel is OPERABLE if 2 of 4 instruments in that channel are OPERABLE.
(h) Also actuates secondary containment ventilation isolation dampers and valves per Table 3.6.6.2-1.
(i) Closes only RWCU system isolation valves G33-F001, G33-F004, and G33-F251.

TABLE 3.3.2-2

ISOLATION ACTUATION INSTRUMENTATION SETPOINTS

TRIP FUNCTION	TRIP SETPOINT	ALLOWABLE VALUE
1. PRIMARY CONTAINMENT ISOLATION		
a. Reactor Vessel Water Level - Low Low, Level 2	≥ -41.6 inches *	≥ -43.8 inches
b. Drywell Pressure - High	≤ 1.73 psig	≤ 1.93 psig
c. Containment and Drywell Ventilation Exhaust Radiation - High High	≤ 2.0 mr/hr**	≤ 4.0 mr/hr**
d. Manual Initiation	NA	NA
2. MAIN STEAM LINE ISOLATION		
a. Reactor Vessel Water Level - Low Low Low, Level 1	≥ -150.3 inches*	≥ -152.5 inches
b. Main Steam Line Radiation - High	≤ 3.0 x full power background	≤ 3.6 x full power background
c. Main Steam Line Pressure - Low	≥ 849 psig	≥ 837 psig
d. Main Steam Line Flow - High	≤ 169 psid	≤ 176.5 psid
e. Condenser Vacuum - Low	≥ 9 inches Hg. Vacuum	≥ 8.7 inches Hg. Vacuum
f. Main Steam Line Tunnel Temperature - High	≤ 180°F**	≤ 186°F**
g. Main Steam Line Tunnel Δ Temp. - High	≤ 80°F**	≤ 83°F**
h. Manual Initiation	NA	NA
3. SECONDARY CONTAINMENT ISOLATION		
a. Reactor Vessel Water Level - Low Low, Level 2	≥ -41.6 inches*	≥ -43.8 inches
b. Drywell Pressure - High	≤ 1.73 psig	≤ 1.93 psig
c. Fuel Handling Area Ventilation Exhaust Radition - High High	≤ 2.0 mR/hr**	≤ 4.0 mR/hr**
d. Fuel Handling Area Pool Sweep Exhaust Radiation - High High	≤ 18 mR/hr**	≤ 35 mR/hr**
e. Manual Initiation	NA	NA

TABLE 3.3.2-3

ISOLATION SYSTEM INSTRUMENTATION RESPONSE TIME

TRIP FUNCTION	RESPONSE TIME (Seconds)#
1. PRIMARY CONTAINMENT ISOLATION	
a. Reactor Vessel Water Level - Low Low, Level 2	$\leq 13^{(a)}$
b. Drywell Pressure - High	$\leq 13^{(a)}$
c. Containment and Drywell Ventilation Exhaust Radiation - High High$^{(b)}$	$\leq 13^{(a)}$**
d. Manual Initiation	NA
2. MAIN STEAM LINE ISOLATION	
a. Reactor Vessel Water Level - Low Low Low, Level 1	$\leq$ 1.0*/$\leq 13^{(a)}$**
b. Main Steam Line Radiation - High$^{(b)}$	$\leq$ 1.0*/$\leq 13^{(a)}$**
c. Main Steam Line Pressure - Low	$\leq$ 1.0*/$\leq 13^{(a)}$**
d. Main Steam Line Flow - High	$\leq$ 0.5*/$\leq 13^{(a)}$**
e. Condenser Vacuum - Low	NA
f. Main Steam Line Tunnel Temperature - High	NA
g. Main Steam Line Tunnel Δ Temp. - High	NA
h. Manual Initiation	NA
3. SECONDARY CONTAINMENT ISOLATION	
a. Reactor Vessel Water Level - Low Low, Level 2	$\leq 13^{(a)}$
b. Drywell Pressure - High	$\leq 13^{(a)}$
c. Fuel Handling Area Ventilation Exhaust Radiation - High High(b)	$\leq 13^{(a)}$
d. Fuel Handling Area Pool Sweep Exhaust Radiation - High High(b)	$\leq 13^{(a)}$
e. Manual Initiation	NA
4. REACTOR WATER CLEANUP SYSTEM ISOLATION	
a. Δ Flow - High	NA
b. Δ Flow Timer	NA
c. Equipment Area Temperature - High	NA
d. Equipment Area Δ Temp. - High	NA
e. Reactor Vessel Water Level - Low Low, Level 2	$\leq 13^{(a)}$
f. Main Steam Line Tunnel Ambient Temperature - High	NA
g. Main Steam Line Tunnel Δ Temp. - High	NA
h. SLCS Initiation	NA
i. Manual Initiation	NA

TABLE 3.3.2-3 (Continued)

ISOLATION SYSTEM INSTRUMENTATION RESPONSE TIME

TRIP FUNCTION	RESPONSE TIME (Seconds)#
5. REACTOR CORE ISOLATION COOLING SYSTEM ISOLATION	
a. RCIC Steam Line Flow - High	$\leq 13^{(a)\#\#\#}$
b. RCIC Steam Supply Pressure - Low	$\leq 13^{(a)}$
c. RCIC Turbine Exhaust Diaphragm Pressure - High	NA
d. RCIC Equipment Room Ambient Temperature - High	NA
e. RCIC Equipment Room Δ Temp. - High	NA
f. Main Steam Line Tunnel Ambient Temp. - High	NA
g. Main Steam Line Tunnel Δ Temp. - High	NA
h. Main Steam Line Tunnel Temperature Timer	NA
i. RHR Equipment Room Ambient Temperature - High	NA
j. RHR Equipment Room Δ Temp. - High	NA
k. RHR/RCIC Steam Line Flow - High	NA
l. Manual Initiation	NA
6. RHR SYSTEM ISOLATION	
a. RHR Equipment Room Ambient Temperature - High	NA
b. RHR Equipment Room Δ Temp. - High	NA
c. Reactor Vessel Water Level - Low, Level 3	$\leq 13^{(a)}$
d. Reactor Vessel (RHR Cut-in Permissive) Pressure - High	NA
e. Drywell Pressure - High	NA
f. Manual Initiation	NA

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

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

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

**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 Tables 3.6.4-1 and 3.6.5.2-1 for valves in each valve group to obtain ISOLATION SYSTEM RESPONSE TIME for each valve.

###Without 13 second time delay.

TABLE 4.3.2.1-1

ISOLATION ACTUATION INSTRUMENTATION SURVEILLANCE REQUIREMENTS

TRIP FUNCTION	CHANNEL CHECK	CHANNEL FUNCTIONAL TEST	CHANNEL CALIBRATION	OPERATIONAL CONDITIONS IN WHICH SURVEILLANCE REQUIRED
1. PRIMARY CONTAINMENT ISOLATION				
a. Reactor Vessel Water Level - Low Low, Level 2	S	M	R	1, 2, 3 and #
b. Drywell Pressure - High	S	M	R	1, 2, 3
c. Containment and Drywell Ventilation Exhaust Radiation - High High	S	M	R	1, 2, 3 and *
d. Manual Initiation	NA	M(a)	NA	1, 2, 3 and *#
2. MAIN STEAM LINE ISOLATION				
a. Reactor Vessel Water Level - Low Low Low, Level 1	S	M	R	1, 2, 3
b. Main Steam Line Radiation - High	S	M	R	1, 2, 3
c. Main Steam Line Pressure - Low	S	M	R	1
d. Main Steam Line Flow - High	S	M	R	1, 2, 3
e. Condenser Vacuum - Low	S	M	R	1, 2**, 3**
f. Main Steam Line Tunnel Temperature - High	S	M	R	1, 2, 3
g. Main Steam Line Tunnel Δ Temp. - High	S	M	R	1, 2, 3
h. Manual Initiation	NA	M(a)	NA	1, 2, 3

TABLE 3.3.3-2

EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION SETPOINTS

TRIP FUNCTION	TRIP SETPOINT	ALLOWABLE VALUE
A. DIVISION 1 TRIP SYSTEM		
1. RHR-A (LPCI MODE) AND LPCS SYSTEM		
a. Reactor Vessel Water Level - Low Low Low, Level 1	≥ -150.3 inches*	≥ -152.5 inches
b. Drywell Pressure - High	≤ 1.89 psig	≤ 1.94 psig
c. LPCI Pump A Start Time Delay Relay	≤ 5 seconds	≤ 5 seconds
d. Manual Initiation	NA	NA
2. AUTOMATIC DEPRESSURIZATION SYSTEM TRIP SYSTEM "A"		
a. Reactor Vessel Water Level - Low Low Low, Level 1	≥ -150.3 inches*	≥ -152.5 inches
b. Drywell Pressure - High	≤ 1.89 psig	≤ 1.94 psig
c. ADS Timer	≤ 115 seconds	≤ 117 seconds
d. Reactor Vessel Water Level-Low, Level 3	≥ 11.4 inches*	≥ 10.8 inches
e. LPCS Pump Discharge Pressure-High	≥ 145 psig, increasing	≥ 140 psig, increasing
f. LPCI Pump A Discharge Pressure-High	≥ 125 psig, increasing	≥ 122 psig, increasing
g. Manual Initiation	NA	NA
B. DIVISION 2 TRIP SYSTEM		
1. RHR B AND C (LPCI MODE)		
a. Reactor Vessel Water Level - Low Low Low, Level 1	≥ -150.3 inches*	≥ -152.5 inches
b. Drywell Pressure - High	≤ 1.89 psig	≤ 1.94 psig
c. LPCI Pump B Start Time Delay Relay	≤ 5 seconds	≤ 5 seconds
d. Manual Initiation	NA	NA
2. AUTOMATIC DEPRESSURIZATION SYSTEM TRIP SYSTEM "B"		
a. Reactor Vessel Water Level - Low Low Low, Level 1	≥ -150.3 inches*	≥ -152.5 inches
b. Drywell Pressure - High	≤ 1.89 psig	≤ 1.94 psig
c. ADS Timer	≤ 115 seconds	≤ 117 seconds
d. Reactor Vessel Water Level-Low, Level 3	≥ 11.4 inches*	≥ 10.8 inches
e. LPCI Pump B and C Discharge Pressure-High	≥ 125 psig, increasing	≥ 122 psig, increasing
f. Manual Initiation	NA	NA
C. DIVISION 3 TRIP SYSTEM		
1. HPCS SYSTEM		
a. Reactor Vessel Water Level - Low Low, Level 2	≥-41.6 inches*	≥-43.8 inches
b. Drywell Pressure - High	≤ 1.89 psig	≤ 1.94 psig
c. Reactor Vessel Water Level - High, Level 8	≤ 53.5 inches*	≤ 55.7 inches
d. Condensate Storage Tank Level - Low	≥ 0 inches	≥ -3 inches
e. Suppression Pool Water Level - High	≤ 5.9 inches	≤ 6.5 inches
f. Manual Initiation	NA	NA

INSTRUMENTATION

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 30%* of the value of turbine first stage pressure, in psia, at valves wide open (VWO) steam flow, equivalent to THERMAL POWER less than 40% of RATED THERMAL POWER.

*Initial setpoint, final setpoint to be determined during startup test program. Any required change to this setpoint shall be submitted to the Commission within 90 days of test completion.

TABLE 3.3.6-2

CONTROL ROD BLOCK INSTRUMENTATION SETPOINTS

TRIP FUNCTION	TRIP SETPOINT	ALLOWABLE VALUE
1. ROD PATTERN CONTROL SYSTEM		
a. Low Power Setpoint	20 + 15, -0% of RATED THERMAL POWER	20 + 15, -0% of RATED THERMAL POWER
b. Intermediate Rod Withdrawal Limiter Setpoint	≤ 70% of RATED THERMAL POWER	≤ 70% of RATED THERMAL POWER
2. APRM		
a. Flow Biased Neutron Flux-Upscale	≤ 0.66 W + 42%*	≤ 0.66 W + 45%*
b. Inoperative	NA	NA
c. Downscale	≥ 5% 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	≤ 1×10^5 cps	≤ 1.5×10^5 cps
c. Inoperative	NA	NA
d. Downscale	≥ 3 cps	≥ 2 cps
4. INTERMEDIATE RANGE MONITORS		
a. Detector not full in	NA	NA
b. Upscale	≤ 108/125 of full scale	≤ 110/125 of full scale
c. Inoperative	NA	NA
d. Downscale	≥ 5/125 of full scale	≥ 3/125 of full scale
5. SCRAM DISCHARGE VOLUME		
a. Water Level-High	≤ 32 inches	≤ 33.5 inches
6. REACTOR COOLANT SYSTEM RECIRCULATION FLOW		
a. Upscale	≤ 108% of rated flow	≤ 111% of rated flow

*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.

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 PATTERN CONTROL SYSTEM				
a. Low Power Setpoint	NA	S/U(b)(e), D(c)(e), M(d)(e)	Q	1, 2
b. Intermediate Rod Withdrawal Limiter Setpoint	NA	S/U(b)(e), D(c)(e), M(d)(e)	Q	1, 2
2. APRM				
a. Flow Biased Neutron Flux-Upscale	NA	S/U(b),W	W(f)(g), SA	1
b. Inoperative	NA	S/U(b),W	NA	1, 2, 5
c. Downscale	NA	S/U(b),W	W(h), SA	1
d. Neutron Flux - Upscale, Startup	NA	S/U(b),M	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	M	R	1, 2, 5*
6. REACTOR COOLANT SYSTEM RECIRCULATION FLOW				
a. Upscale	NA	S/U(b),M	Q	1

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. Within one hour prior to control rod movement, unless performed within the previous 24 hours, and as each power range above the RPCS low power setpoint is entered for the first time during any 24 hour period during power increase or decrease.

d. At least once per 31 days while operation continues within a given power range above the RPCS low power setpoint.

e. Includes reactor manual control multiplexing system input.

f. 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 is greater than or equal to 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.

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

h. This calibration shall consist of verifying the trip setpoint only.

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

TABLE 3.3.7.1-1

RADIATION MONITORING INSTRUMENTATION

INSTRUMENTATION	MINIMUM CHANNELS OPERABLE	APPLICABLE CONDITIONS	ALARM/TRIP SETPOINT	MEASUREMENT RANGE	ACTION
1. Component Cooling Water Radiation Monitor	1	At all times	$\leq 1 \times 10^5$ cpm/NA	10 to 10^6 cpm	70
2. Standby Service Water System Radiation Monitor	1/heat exchanger train	1, 2, 3, and*	$\leq 1 \times 10^5$ cpm/NA	10 to 10^6 cpm	70
3. Offgas Pre-treatment Radiation Monitor	1	1, 2	$\leq 5 \times 10^3$ mR/hr/NA	1 to 10^6 mR/hr	70
4. Offgas Post-treatment Radiation Monitor	2(a)	1, 2	$\leq 1 \times 10^5$ cpm (Hi), $\leq 1.0 \times 10^6$ cpm (Hi Hi)	10 to 10^6 cpm	71
5. Carbon Bed Vault Radiation Monitor	1	1, 2	$\leq$ 2 x full power background/NA	1 to 10^6 mR/hr	72
6. Control Room Ventilation Radiation Monitor	2	1,2,3,5 and**	≤ 4 mR/hr/ ≤ 5 mR/hr#	10^{-2} to 10^2 mR/hr	73
7. Containment and Drywell Ventilation Exhaust Radiation Monitor	3(a)	At all times	≤ 2.0 mR/hr/ ≤ 4 mR/hr(b)#	10^{-2} to 10^2 mR/hr	74
8. Fuel Handling Area Ventilation Exhaust Radiation Monitor	3(a)	1,2,3,5 and**	$\leq$ 2mR/hr/ ≤ 4 mR/hr(d)#	10^{-2} to 10^2 mR/hr	75
9. Fuel Handling Area Pool Sweep Exhaust Radiation Monitor	3(a)	(c)	$\leq$ 18 mR/hr/ ≤ 35 mR/hr(d)#	10^{-2} to 10^2 mR/hr	75

TABLE 3.3.7.1-1 (Continued)

RADIATION MONITORING INSTRUMENTATION

INSTRUMENTATION	MINIMUM CHANNELS OPERABLE	APPLICABLE CONDITIONS	ALARM/TRIP SETPOINT	MEASUREMENT RANGE	ACTION
10. Area Monitors					
a. Fuel Handling Area Monitors					
1) New Fuel Storage Vault	1	(e)	$\leq$2.5 mR/hr/NA	10^{-2} to 10^{3} mR/hr	72
2) Spent Fuel Storage Pool	1	(f)	$\leq$2.5 mR/hr/NA	10^{-2} to 10^{3} mR/hr	72
3) Dryer Storage Area		(g)	$\leq$2.5 mR/hr/NA	10^{-2} to 10^{3} mR/hr	72
b. Control Room Radiation Monitor	1	At all times	$\leq$0.5 mR/hr/NA	10^{-2} to 10^{3} mR/hr	72

* With RHR heat exchangers in operation.
** When irradiated fuel is being handled in the secondary containment.
\# Initial setpoint. Final Setpoint to be determined during startup test program. Any required change to this setpoint shall be submitted to Commission within 90 days after test completion.
(a) Trips system with 2 channels upscale-high high, or one channel upscale and one channel inoperative, or 2 channels inoperative.
(b) Isolates containment/drywell purge penetrations.
(c) With irradiated fuel in spent fuel storage pool.
(d) Also isolates the secondary containment penetrations.
(e) With fuel in the new fuel storage vault.
(f) With fuel in the spent fuel storage pool.
(g) With fuel in the dryer storage area.

TABLE 4.3.7.1-1

RADIATION MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS

INSTRUMENTATION	CHANNEL CHECK	CHANNEL FUNCTIONAL TEST	CHANNEL CALIBRATION	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED
1. Component Cooling Water Radiation Monitor	S	M	R	At all times
2. Standby Service Water System Radiation Monitor	S	M	R	1, 2, 3, and*
3. Offgas Pre-treatment Radiation Monitor	S	M	R	1, 2
4. Offgas Post-treatment Radiation Monitor	S	M	R	1, 2
5. Carbon Bed Vault Radiation Monitor	S	M	R	1, 2
6. Control Room Ventilation Radiation Monitor	S	M(a)	R	1, 2, 3, 5 and**
7. Containment and Drywell Ventilation Exhaust Radiation Monitor	S	M	R	At all times
8. Fuel Handling Area Ventilation Radiation Monitor	S	M	R	1, 2, 3, 5 and**
9. Fuel Handling Area Pool Sweep Exhaust Radiation Monitor	S	M	R	(b)
10. Area Monitors				
a. Fuel Handling Area Monitors				
1) New Fuel Storage Vault	S	M	R	(c)
2) Spent Fuel Storage Pool	S	M	R	(d)
3) Dryer Storage Area	S	M	R	(e)
b. Control Room Radiation Monitor	S	M	R	At all times

* With RHR heat exchangers in operation.

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

(a) The CHANNEL FUNCTIONAL TEST shall demonstrate that control room annunciation occurs if any of the following conditions exist.
1. Instrument indicates measured levels above the alarm/trip setpoint.
2. Circuit failure.
3. Instrument indicates a downscale failure.
4. Instrument controls not in Operate mode.

(b) With irradiated fuel in the spent fuel storage pool.

(c) With fuel in the new fuel storage vault.

(d) With fuel in the spent fuel storage pool.

(e) With fuel in the dryer storage area.

TABLE 3.3.7.2-1

SEISMIC MONITORING INSTRUMENTATION

INSTRUMENTS AND SENSOR LOCATIONS	MEASUREMENT RANGE	MINIMUM INSTRUMENTS OPERABLE
1. Triaxial Strong Motion Accelerometer		
a. Containment foundation	0.001 to 1.0g	1
b. Drywell	0.001 to 1.0g	1
c. SGTS Filter Train	0.001 to 1.0g	1
d. SSW Pump House A	0.001 to 1.0g	1
e. Free Field	0.001 to 1.0g	1
2. Triaxial Peak Recording Accelerograph		
a. Containment Dome	0.01 to 2g	1
b. Auxiliary Building Foundation	0.01 to 2g	1
c. Diesel Generator 11	0.01 to 2g	1
d. Control Building Foundation	0.01 to 2g	1
e. Control Room	0.01 to 2g	1
f. Reactor Vessel Support	0.01 to 2g	1
g. Reactor Recirc. Piping	0.01 to 2g	1
h. Main Steam Piping	0.01 to 2g	1
i. LPCS Spray Line	0.01 to 2g	1
j. HPCS Spray Line	0.01 to 2g	1
k. SSW Pump House B	0.01 to 2g	1
3. Triaxial Seismic Switches		
a. Containment Foundation (SSE)	0.025 to 0.25g	1*
b. Containment Foundation (OBE)	0.025 to 0.25g	1*
c. Drywell (SSE)	0.025 to 0.25g	1*
d. Drywell (OBE)	0.025 to 0.25g	1*
4. Vertical Seismic Trigger		
a. Containment Foundation	0.005 to 0.05g	1*
5. Horizontal Seismic Trigger		
a. Drywell	0.005 to 0.05g	1*

*With control room annunciation.

TABLE 4.3.7.2-1

SEISMIC MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS

INSTRUMENTS AND SENSOR LOCATIONS	CHANNEL CHECK	CHANNEL FUNCTIONAL TEST	CHANNEL CALIBRATION
1. Triaxial Strong Motion Accelerometer			
a. Containment Foundation	M	SA	R
b. Drywell	M	SA	R
c. SGTS Filter Train	M	SA	R
d. SSW Pump House A	M	SA	R
e. Free Field	M	SA	R
2. Triaxial Peak Recording Accelerograph			
a. Containment Dome	NA	NA	R
b. Auxiliary Building Foundation	NA	NA	R
c. Diesel Generator 11	NA	NA	R
d. Control Building Foundation	NA	NA	R
e. Control Room	NA	NA	R
f. Reactor Vessel Support	NA	NA	R
g. Reactor Recirc. Piping	NA	NA	R
h. Main Steam Piping	NA	NA	R
i. LPCS Spray Line	NA	NA	R
j. HPCS Spray Line	NA	NA	R
k. SSW Pump House B	NA	NA	R
3. Triaxial Seismic Switches			
a. Containment Foundation (SSE)	M	SA	R
b. Containment Foundation (OBE)	M	SA	R
c. Drywell (SSE)	M	SA	R
d. Drywell (OBE)	M	SA	R
4. Vertical Seismic Trigger			
a. Containment Foundation	M	SA	R
5. Horizontal Seismic Trigger			
a. Drywell	M	SA	R

TABLE 3.3.7.3-1

METEOROLOGICAL MONITORING INSTRUMENTATION

INSTRUMENT	MINIMUM INSTRUMENTS OPERABLE
a. Wind Speed	
1. Elev. 33 ft and 162 ft	1 each
b. Wind Direction	
1. Elev. 33 ft and 162 ft	1 each
c. Air Temperature	
1. Elev. 33 ft	1
d. Air Temperature Difference	
1. Elev. 33/162 ft	1

TABLE 4.3.7.3-1

METEOROLOGICAL MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS

INSTRUMENT	CHANNEL CHECK	CHANNEL CALIBRATION
a. Wind Speed		
1. Elev. 33 ft and 162 ft	D	SA
b. Wind Direction		
1. Elev. 33 ft and 162 ft	D	SA
c. Air Temperature		
1. Elev. 33 ft	D	SA
d. Air Temperature Difference		
1. Elev. 33/162 ft	D	SA

TABLE 3.3.7.5-1 (Continued)
ACCIDENT MONITORING INSTRUMENTATION

ACTION STATEMENTS

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. 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.

TABLE 4.3.7.11-1

RADIOACTIVE LIQUID EFFLUENT MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS

INSTRUMENT	CHANNEL CHECK	SOURCE CHECK	CHANNEL CALIBRATION	CHANNEL FUNCTIONAL TEST
1. GROSS RADIOACTIVITY MONITORS PROVIDING ALARM AND AUTOMATIC TERMINATION OF RELEASE				
a. Liquid Radwaste Effluent Line	D	P	R(2)	Q(1)
2. FLOW RATE MEASUREMENT DEVICES				
a. Liquid Radwaste Effluent Line	D(3)	N.A.	R	Q
b. Discharge Canal	D(3)	N.A.	R	Q

TABLE 3.3.7.12-1

RADIOACTIVE GASEOUS EFFLUENT MONITORING INSTRUMENTATION

INSTRUMENT	MINIMUM CHANNELS OPERABLE	APPLICABILITY	ACTION
1. RADWASTE BUILDING VENTILATION MONITORING SYSTEM			
a. Noble Gas Activity Monitor - Providing Alarm	1	*	121
b. Iodine Sampler	1	*	122
c. Particulate Sampler	1	*	122
d. Effluent System Flow Rate Measuring Device	1	*	123
e. Sampler Flow Rate Measuring Device	1	*	123
2. MAIN CONDENSER OFFGAS TREATMENT SYSTEM EXPLOSIVE GAS MONITORING SYSTEM			
a. Hydrogen Monitor	1	**	124
3. CONTAINMENT VENTILATION MONITORING SYSTEM			
a. Noble Gas Activity Monitor Providing Alarm	1	*	121
b. Iodine Sampler	1	*	122
c. Particulate Sampler	1	*	122
d. Effluent System Flow Rate Monitor	1	*	123
e. Sampler Flow Rate Monitor	1	*	123

TABLE 3.3.7.12-1 (Continued)

RADIOACTIVE GASEOUS EFFLUENT MONITORING INSTRUMENTATION

TABLE NOTATION

* At all times.

** During main condenser offgas treatment system operation.

*** During operation of the main condenser air ejector.

ACTION 121 - With the number of channels OPERABLE less than required by the Minmum Channels OPERABLE requirement, effluent releases via this pathway may continue for up to 30 days provided grab samples are taken at least once per 8 hours and these samples are analyzed for gross activity within 24 hours.

ACTION 122 - With the number of channels OPERABLE less than required by the Minimum Channels OPERABLE requirement, effluent releases via this pathway may continue for up to 30 days provided samples are continuously collected with auxiliary sampling equipment as required by Table 4.11.2.1.2-1.

ACTION 123 - With the number of channels OPERABLE less than required by the Minimum Channels OPERABLE requirement, effluent release via this pathway may continue for up to 30 days provided the flow rate is estimated at least once per 8 hours.

ACTION 124 - With the number of channels OPERABLE less than required by the Minimum Channels OPERABLE requirement, operation of main condenser offgas treatment system may continue for up to 30 days provided grab samples are collected at least once per 4 hours and analyzed within the following 4 hours.

ACTION 125 - [DELETED]

ACTION 126 - With the number of channels OPERABLE less than required by the Minimum Channels OPERABLE requirement, the SJAE effluent may be released to the environment for up to 72 hours provided:

a. The offgas system is not bypassed, except for filtration system bypass during plant startups, and

b. The offgas delay system noble gas activity effluent downstream monitor is OPERABLE;

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

TABLE 4.3.7.12-1

RADIOACTIVE GASEOUS EFFLUENT MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS

INSTRUMENT	CHANNEL CHECK	SOURCE CHECK	CHANNEL CALIBRATION	CHANNEL FUNCTIONAL TEST	MODES IN WHICH SURVEILLANCE REQUIRED
1. RADWASTE BUILDING VENTILATION MONITORING SYSTEM					
a. Noble Gas Activity Monitor - Providing Alarm	D	M	R(3)	Q(2)	*
b. Iodine Sampler	W	N.A.	N.A.	N.A.	*
c. Particulate Sampler	W	N.A.	N.A.	N.A.	*
d. Flow Rate Monitor	D	N.A.	R	Q	*
e. Sampler Flow Rate Monitor	D	N.A.	R	N.A.	*
2. MAIN CONDENSER OFFGAS TREATMENT SYSTEM EXPLOSIVE GAS MONITORING SYSTEM					
a. Hydrogen Monitor	D	N.A.	Q(4)	M	**
3. CONTAINMENT VENTILATION MONITORING SYSTEM					
a. Noble Gas Activity Monitor Providing Alarm	D	M	R(3)	Q(2)	*
b. Iodine Sampler	W	N.A.	N.A.	N.A.	*
c. Particulate Sampler	W	N.A.	N.A.	N.A.	*
d. Effluent System Flow Rate Monitor	D	N.A.	R	Q	*
e. Sampler Flow Rate Monitor	D	N.A.	R	N.A.	*

TABLE 4.3.7.12-1 (Continued)

RADIOACTIVE GASEOUS EFFLUENT MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS

INSTRUMENT	CHANNEL CHECK	SOURCE CHECK	CHANNEL CALIBRATION	CHANNEL FUNCTIONAL TEST	MODES IN WHICH SURVEILLANCE REQUIRED
6. OFFGAS PRE-TREATMENT MONITOR					
a. Noble Gas Activity Monitor	D	M#	R(3)##	Q(2)	***
7. OFFGAS POST-TREATMENT MONITOR					
a. Noble Gas Activity Monitor Providing Alarm and Automatic Termination of Release	D	M	R(3)##	Q(1)	**

3/4.5 EMERGENCY CORE COOLING SYSTEMS

3/4.5.1 ECCS - OPERATING

LIMITING CONDITION FOR OPERATION

3.5.1 ECCS divisions 1, 2 and 3 shall be OPERABLE with:

a. ECCS division 1 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. At least 7 OPERABLE ADS valves.

b. ECCS division 2 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. At least 7 OPERABLE ADS valves.

c. ECCS division 3 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*.

ACTION:

a. For ECCS division 1, provided that ECCS divisions 2 and 3 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.

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*The ADS is not required to be OPERABLE when reactor steam dome pressure is less than or equal to 135 psig.

#See Special Test Exception 3.10.5.

SURVEILLANCE REQUIREMENTS

4.6.4.1 Each isolation valve shown in Table 3.6.4-1 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.

4.6.4.2 Each automatic isolation valve shown in Table 3.6.4-1 shall be demonstrated OPERABLE during COLD SHUTDOWN or REFUELING at least once per 18 months by verifying that on an isolation test signal each automatic isolation valve actuates to its isolation position.

4.6.4.3 The isolation time of each power operated or automatic valve shown in Table 3.6.4-1 shall be determined to be within its limit when tested pursuant to Specification 4.0.5.

4.6.4.4 [DELETED]

TABLE 3.6.4-1

CONTAINMENT AND DRYWELL ISOLATION VALVES

SYSTEM AND VALVE NUMBER		PENETRATION NUMBER	VALVE GROUP[(a)]	MAXIMUM ISOLATION TIME (Seconds)
1. Automatic Isolation Valves				
a. Containment				
Main Steam Lines	B21-F028A	5(O)	1	5
Main Steam Lines	B21-F022A	5(I)	1	5
Main Steam Lines	B21-F067A-A	5(O)	1	6
Main Steam Lines	B21-F028B	6(O)	1	5
Main Steam Lines	B21-F022B	6(I)	1	5
Main Steam Lines	B21-F067B-A	6(O)	1	6
Main Steam Lines	B21-F028C	7(O)	1	5
Main Steam Lines	B21-F022C	7(I)	1	5
Main Steam Lines	B21-F067C-A	7(O)	1	6
Main Steam Lines	B21-F028D	8(O)	1	5
Main Steam Lines	B21-F022D	8(I)	1	5
Main Steam Lines	B21-F067D-A	8(O)	1	6
RHR Reactor Shutdown Cooling Suction	E12-F008-A	14(O)[(c)]	3	40
RHR Reactor Shutdown Cooling Suction	E12-F009-B	14(I)[(c)]	3	40
Steam Supply to RHR and RCIC Turbine	E51-F063-B	17(I)	4	20
Steam Supply to RHR and RCIC Turbine	E51-F064-A	17(O)	4	20
Steam Supply to RHR and RCIC Turbine	E51-F076-B	17(I)	4	20
RHR to Head Spray	E12-F023-B	18(O)[(c)]	3	90
Main Steam Line Drains	B21-F019-A	19(O)	1	15
Main Steam Line Drains	B21-F016-B	19(I)	1	15
RHR Heat Exchanger "A" to LPCI	E12-F042A-A	20(I)[(c)]	5	22

(a) See Specification 3.3.2, Table 3.3.2-1, for isolation signal(s) that operates each valve group.
(b) Hydrostatically tested to ASME Section XI criteria.
(c) Hydrostatically tested with water at P_a, 11.5 psig.
(d) Hydrostatically tested by pressurizing system to 1.10 P_a, 12.65 psig.
(e) Hydrostatically tested during system functional tests.
(f) Hydrostatically sealed by feedwater leakage control system. Type C test not required.

TABLE 3.6.4-1 (Continued)

CONTAINMENT AND DRYWELL ISOLATION VALVES

SYSTEM AND VALVE NUMBER		PENETRATION NUMBER	VALVE GROUP[a]	MAXIMUM ISOLATION TIME (Seconds)
Containment (Continued)				
RHR Heat Exchanger "A" to LPCI	E12-F028A-A	20(I)[c]	5	78
RHR Heat Exchanger "A" to LPCI	E12-F037A-A	20(I)[c]	3	63
RHR Heat Exchanger "B" to LPCI	E12-F042B-B	21(I)[c]	5	22
RHR Heat Exchanger "B" to LPCI	E12-F028B-B	21(I)[c]	5	78
RHR Heat Exchanger "B" to LPCI	E12-F037B-B	21(I)[c]	3	63
RHR "A" Test Line to Supp. Pool	E12-F024A-A	23(0)[d]	5	93
RHR "A" Test Line to Supp. Pool	E12-F011A-A	23(0)[d]	5	27
RHR "A" Test Line to Supp. Pool	E12-F290A-A	23(0)[d]	6	8
RHR "C" Test Line to Supp. Pool	E12-F021-B	24(0)[d]	5	101
HPCS Test Line	E22-F023-C	27(0)	6	60
RCIC Pump Suction	E51-F031-A	28(0)	4	38
RCIC Turbine Exhaust	E51-F077-A	29(0)[c]	9	18
LPCS Test Line	E21-F012-A	32(0)	5	101
Cont. Purge and Vent Air Supply	M41-F011	34(0)	7	4
Cont. Purge and Vent Air Supply	M41-F012	34(I)	7	4
Cont. Purge and and Vent Air Exh.	M41-F034	35(I)	7	4
Cont. Purge and and Vent Air Exh.	M41-F035	35(0)	7	4
Plant Service Water Return	P44-F070-B	36(I)	6	24
Plant Service Water Return	P44-F069-A	36(0)	6	24
Plant Service Water Supply	P44-F053-A	37(0)	6	24
Chilled Water Supply	P71-F150	38(0)	6	30
Chilled Water Return	P71-F148	39(0)	6	30

TABLE 3.6.4-1 (Continued)

CONTAINMENT AND DRYWELL ISOLATION VALVES

SYSTEM AND VALVE NUMBER		PENETRATION NUMBER
b. Drywell		
Cont. Cooling Water Inlet	P42-F114-B	329(0)
Cont. Cooling Water Outlet	P42-F116-A	330(I)
Cont. Cooling Water Outlet	P42-F117-B	330(0)
Plant Serv. Water Return	P44-F076-A	331(I)
Plant Serv. Water Return	P44-F077-B	331(0)
Plant Serv. Water Supply	P44-F074-B	332(0)
Condensate Flush Connection	B33-F204	333(I)
Condensate Flush Connection	B33-F205	333(0)
3. Other Isolation Valves		
a. Containment		
Fuel Transfer Tube	F11-E015	4(I)
Cont. Leak Rate Sys.	NA	40(I)(0)
Feedwater Inlet	B21-F010A	9(I)(f)
Feedwater Inlet	B21-F032A	9(0)(f)
Feedwater Inlet	B21-F010B	10(I)(f)
Feedwater Inlet	B21-F032B	10(0)(f)
RHR "A" Suction	E12-F017A	11(0)(d)
RHR "B" Suction	E12-F017B	12(0)(d)
RHR "C" Suction	E12-F017C	13(0)(d)
RHR Shutdown Cooling Suction	E12-F308	14(I)(c)
RHR Head Spray	E51-F066	18(I)(c)
RHR Head Spray	E12-F344	18(I)(c)
RHR Heat Ex. "A" to LPCI	E12-F044A	20(I)(c)
RHR Heat Ex. "A" to LPCI	E12-F025A	20(I)(c)
RHR Heat Ex. "A" to LPCI	E12-F107A	20(I)(c)
RHR Heat Ex. "B" to LPCI	E12-F025B	21(I)(c)
RHR Heat Ex. "B" to LPCI	E12-F044B	21(I)(c)
RHR Heat Ex. "B" to LPCI	E12-F107B	21(I)(c)

TABLE 3.6.4-1 (Continued)

CONTAINMENT AND DRYWELL ISOLATION VALVES

SYSTEM AND VALVE NUMBER		PENETRATION NUMBER
4. Test Connections		
a. Containment		
Main Steam T/C	B21-F025A	5(0)
Main Steam T/C	B21-F025B	6(0)
Main Steam T/C	B21-F025C	7(0)
Main Steam T/C	B21-F025D	8(0)
Feedwater T/C	B21-F030A	9(0)[f]
Feedwater T/C	B21-F063A	9(0)[f]
Feedwater T/C	B21-F063B	10(0)[f]
Feedwater T/C	B21-F030B	10(0)[f]
RHR Shutdown Cool. Suction T/C	E12-F002	14(0)[c]
RCIC Steam Line T/C	E51-F072	17(0)
RHR to Head Spray T/C	E12-F342	18(0)[c]
RHR to Head Spray T/C	E12-F061	18(0)[c]
LPCI "C" T/C	E12-F056C	22(0)[c]
RHR "A" Pump Test Line T/C	E12-F322	23(0)[c]
RHR "A" Pump Test Line T/C	E12-F336	23(0)[c]
RHR "A" Pump Test Line T/C	E12-F349	23(0)[c]
RHR "A" Pump Test Line T/C	E12-F303	23(0)[c]
RHR "A" Pump Test Line T/C	E12-F310	23(0)[c]
RHR "A" Pump Test Line T/C	E12-F348	23(0)[c]
RHR"C" Pump Test Line T/C	E12-F311	24(0)[c]
RHR"C" Pump Test Line T/C	E12-F304	24(0)[c]
HPCS Discharge T/C	E22-F021	26(0)[c]
HPCS Test Line T/C	E22-F303	27(0)[c]
HPCS Test Line T/C	E22-F304	27(0)[c]
RCIC Turbine Exhaust T/C	E51-F258	24(0)[c]
RCIC Turbine Exhaust T/C	E51-F257	27(0)[c]
LPCS T/C	E21-F013	31(0)[c]
LPCS Test Line T/C	E21-F222	32(0)[c]
LPCS Test Line T/C	E21-F221	32(0)[c]

TABLE 3.6.4-1 (Continued)

CONTAINMENT AND DRYWELL ISOLATION VALVES

SYSTEM AND VALVE NUMBER		PENETRATION NUMBER
Containment (Continued)		
RHR "B" Test Line T/C	E12-F350	67(0)(c)
RHR "B" Test Line T/C	E12-F312	67(0)(c)
RHR "B" Test Line T/C	E12-F305	67(0)(c)
Refueling Water Transf. Pump Suction T/C	P11-F425	69(0)(c)
Refueling Water Transf. Pump Suction T/C	P11-F132	69(0)(c)
Inst. Air to ADS T/C	P53-F043	70(0)
Cont. Leak Rate T/C	M61-F010	82(I)
RWCU To Feedwater T/C	G33-F055	83(0)
Suppr. Pool Cleanup T/C	P60-F011	85(0)
Suppr. Pool Cleanup T/C	P60-F034	85(0)
RWCU Pump Suction T/C	G33-F002	87(0)
RWCU Pump Discharge T/C	G33-F061	88(0)
SSW T/C	P41-F163A	89(0)(c)
SSW T/C	P41-F163B	92(0)(c)
b. Drywell		
LPCI "A" T/C	E12-F056A	313(0)
LPCI "B" T/C	E12-F056B	314(0)
Intrument Air T/C	P53-F493	327(0)
SLCS T/C	C41-F026	328(0)
Service Air T/C	P52-F476	363(0)
Reactor Sample T/C	B33-F021	465(0)

SURVEILLANCE REQUIREMENTS (Continued)

3. By verifying the OPERABILITY of the vacuum breaker isolation valve differential pressure actuation instrumentation with the opening setpoint 1.0 psid by performance of a:

   a) CHANNEL CHECK at least once per 24 hours,

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

   c) CHANNEL CALIBRATION at least once per 18 months.

Note 1: Until restart after the first refueling outage, the following requirements shall apply:

3.6.5

c. With the position indicator of an OPERABLE drywell post-LOCA isolation valve for a vacuum breaker inoperable, verify the isolation valve to be closed at least once per 24 hours by local indication. Otherwise declare the isolation valve inoperable.

4.6.5.b.1

b. Verifying the position indicator for the vacuum breaker isolation valve OPERABLE by observing expected valve movement during the cycling test.

4.6.5.b.2

At least once per 18 months by:

a) Verifying the pressure differential required to open the vacuum breaker, from the closed position, to be less than or equal to 1.0 psid, and

b) Verifying the position indicator for the vacuum breaker isolation valve OPERABLE by performance of a CHANNEL CALIBRATION.

TABLE 3.6.6.2-1

SECONDARY CONTAINMENT VENTILATION SYSTEM AUTOMATIC ISOLATION DAMPERS/VALVES

DAMPER/VALVE FUNCTION (Number)	MAXIMUM ISOLATION TIME (Seconds)
a. Dampers	
Auxiliary Building Ventilation Supply Damper (Q1T41F006)	5
Auxiliary Building Ventilation Supply Damper (Q1T41F007)	5
Fuel Handling Area Ventilation Exhaust Damper (Q1T42F003)	5
Fuel Handling Area Ventilation Exhaust Damper (Q1T42F004)	5
Fuel Handling Area Ventilation Supply Damper (Q1T42F011)	5
Fuel Handling Area Ventilation Supply Damper (Q1T42F012)	5
Fuel Pool Sweep Ventilation Supply Damper (Q1T42F019)	5
Fuel Pool Sweep Ventilation Supply Damper (Q1T42F020)	5

CONTAINMENT SYSTEMS

3/4.6.7 ATMOSPHERE CONTROL

CONTAINMENT AND DRYWELL HYDROGEN RECOMBINER SYSTEMS

LIMITING CONDITION FOR OPERATION

3.6.7.1 Two independent containment and drywell hydrogen recombiner systems shall be OPERABLE.

APPLICABILITY: OPERATIONAL CONDITIONS 1 and 2.

ACTION:

With one containment and drywell 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

4.6.7.1 Each containment and drywell 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 heater sheath temperature increases to greater than or equal to 700°F within 90 minutes. Maintain $\geq$700°F for at least 2 hours.

b. At least once per 18 months by:

1. Performing a CHANNEL CALIBRATION of all control room 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 10,000 ohms.

3. Verifying during a recombiner system functional test that the heater sheath temperature increases to greater than or equal to 1200°F within 5 hours and is maintained between 1150°F and 1300°F for at least 4 hours.

4. 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. [DELETED]

CONTAINMENT SYSTEMS

CONTAINMENT AND DRYWELL HYDROGEN IGNITION SYSTEM

LIMITING CONDITION FOR OPERATION

3.6.7.2 Two independent containment and drywell hydrogen ignition system subsystems shall be OPERABLE.

APPLICABILITY: OPERATIONAL CONDITIONS 1 and 2.

ACTION:

With one containment and drywell hydrogen ignition subsystem inoperable, restore the inoperable subsystem to OPERABLE status within 7 days or be in at least HOT SHUTDOWN within the next 12 hours.

SURVEILLANCE REQUIREMENTS

4.6.7.2 Each containment and drywell hydrogen ignition subsystem shall be demonstrated OPERABLE:

a. At least once per 92 days by energizing the supply breakers and verifying that at least 41 glow plugs are energized.

b. At least once per 18 months by:

   1. Verifying the cleanliness of each glow plug by a visual inspection.

   2. Energizing each glow plug and verifying a surface temperature of at least 1700°F.

DRYWELL PURGE SYSTEM

LIMITING CONDITION FOR OPERATION

3.6.7.3 Two independent drywell purge system subsystems shall be OPERABLE.

APPLICABILITY: OPERATIONAL CONDITIONS 1 and 2.

ACTION:

With one drywell purge system subsystem inoperable, restore the inoperable subsystem to OPERABLE status within 30 days or be in at least HOT SHUTDOWN within the next 12 hours.

SURVEILLANCE REQUIREMENTS Continued

4.6.7.3 Each drywell purge system subsystem shall be demonstrated OPERABLE:

a. At least once per 92 days by:

1. Starting the subsystem from the control room, and

2. Verifying that the system operates for at least 15 minutes.

b. At least once per 18 months by:

1. Verifying a subsystem flow rate of at least 500 cfm during subsystem operation for at least 15 minutes.

2. Verifying the pressure differential required to open the vacuum breakers on the drywell purge compressor discharge lines, from the closed position, to be less than or equal to 1.0 psid.

c. Verifying the OPERABILITY of the drywell purge compressor discharge line vacuum breaker isolation valve differential pressure actuation instrumentation with an opening setpoint of 1.0 psid 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.

PLANT SYSTEMS

3/4.7.2 CONTROL ROOM EMERGENCY FILTRATION SYSTEM

LIMITING CONDITION FOR OPERATION

3.7.2 Two independent control room emergency filtration system subsystems shall be OPERABLE.

APPLICABILITY: All OPERATIONAL CONDITIONS and *.

ACTION:

a. In OPERATIONAL CONDITION 1, 2 or 3 with one control room emergency filtration subsystem inoperable, restore the inoperable subsystem to OPERABLE status within 7 days or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

b. In OPERATIONAL CONDITION 4, 5 or *:

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

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

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

SURVEILLANCE REQUIREMENTS

4.7.2 Each control room emergency filtration subsystem shall be demonstrated OPERABLE:

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

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

   1. [DELETED]

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

b. Visual Inspection Acceptance Criteria

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

c. Functional Tests

During the first refueling shutdown and at least once per 18 months thereafter during shutdown, a representative sample of at least:

1. 10% of the total of the hydraulic snubbers listed in Table 3.7.4-1 shall be functionally tested either in place or in a bench test. For each snubber that does not meet the functional test acceptance criteria of Surveillance Requirement 4.7.4.d, an additional 10% of the hydraulic snubbers shall be functionally tested.

2. That number of mechanical snubbers which follows the expression $35\ (1 + \frac{c}{2})$, where c = 2, the allowable number of snubbers not meeting the acceptance criteria, shall be functionally tested either in-place or in a bench test. For each number of snubbers above c which does not meet the functional test acceptance criteria of Specifications 4.7.4.e, an additional sample selected according to the expression $35\ (1 + \frac{c}{2})\ (\frac{2}{c + 1})^2\ (a - c)$ shall be functionally tested, where a is the total number of snubbers found inoperable during the functional testing of the representative sample.

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

SURVEILLANCE REQUIREMENTS (Continued)

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

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

4.7.5.3 Reports - A report shall be prepared and submitted to the Commission within 30 days if sealed source or fission detector leakage tests reveal the presence of greater than or equal to 0.005 microcuries of removable contamination.

TABLE 3.7.6.5-1

FIRE HOSE STATIONS

LOCATION	ELEVATION	HOSE RACK INDENTIFICATION
AUXILIARY BUILDING		
Q.1-6.0	103'-0"	13A
Q-5.7	119'-0"	13B
Q.1-6.1	139'-0"	13C
Q-6.0	166'-0"	13D
Q-5.9	185'-0"	13E
Q-6.0	208'-0"	13F
Q-11.3	93'-0"	14A
P.4-9.0	119'-0"	14B
P.4-9.0	139'-0"	14C
P.4-8.6	166'-0"	14D
P.4-9.5	185'-0"	14E
P-10	208'-10"	14F
P.4-12.5	139'-0"	15A
P.4-12.5	166'-0"	15B
P.4-13.1	185'-0"	15C
R-13.7	208'-10"	15D
M.2-15.1	103'-0"	16A
M.7-15.1	119'-0"	16B
L.7-15.1	139'-0"	16C
L.7-15.1	166'-0"	16D
L.7-15.1	185'-0"	16E
M.7-15.1	208'-10"	16F
H.3-13.8	103'-0"	17A
J.4-13.8	119'-0"	17B
H-13.8	139'-0"	17C
J-13.8	166'-0"	17D
G.4-11	103'-0"	18A
G.4-11.7	119'-0"	18B
G.4-12.2	139'-0"	18C
G.4-11.3	166'-0"	18D
G.4-7.5	103'-0"	19A
G.4-8.3	119'-0"	19B
G.4-7.5	139'-0"	19C
G.4-8.4	166'-0"	19D
G.6-6.4	103'-0"	20A
G.6-6.4	119'-0"	20B
H-6.2	139"-0"	20C
H-6.2	166'-0"	20D
L-6.2	103'-0"	21A
L-6.2	119'-0"	21B
L-6.2	139"-0"	21C
L-6.2	166'-0"	21D

TABLE 3.7.6.5-1 (Continued)

FIRE HOSE STATIONS

LOCATION	ELEVATION	HOSE RACK INDENTIFICATION
CONTAINMENT		
M.7-7.8	120'-10"	22A
H.8-8.1	135'-4"	23A
J.1-8.1	161'-10"	23B
J.8-7.2	184'-6"	23C
J.4-7.5	208'-10"	23D
M.2-7.2	135'-4"	24A
M.8-7.9	161'-10"	24B
M.2-7.2	184'-6"	24C
N-8.2	208'-10"	24D
M.6-12.4	135'-4"	25A
N.2-11.5	161'-10"	25B
N.3-11.3	208'-10"	25C
J.1-12.0	135'-4"	26A
J-11.6	161'-10"	26B
K.2-13.1	184'-6"	26C
J-11.8	208'-10"	26D
CONTROL BUILDING		
J.9-18.8	133'-0"	53A
K.2-18.8	111'-0"	53B
G.1-18.4	111'-0"	54B
G.2-18.4	133'-0"	54C
G.1-18.7	148'-0"	54D
G.2-18.8	166'-0"	54E
G.1-18.7	189'-0"	54F
K.2-18.8	148'-0"	55A
K.2-18.8	166'-0"	55B
K.2-18.8	189'-0"	55D
DIESEL GENERATOR BUILDING		
R-10.6	133'-0"	66A
R-8.4	133'-0"	66B

TABLE 3.7.8-1

AREA TEMPERATURE MONITORING

AREA		TEMPERATURE LIMIT (°F) EQUIPMENT NOT OPERATING	TEMPERATURE LIMIT (°F) EQUIPMENT OPERATING
a.	Containment		
	Inside Drywell	135	150
	CRD Cavity	135	185
	Outside Drywell	80	105
	Steam Tunnel	125	125
b.	Auxiliary Building		
	General	104	104
	ECCS Rooms	105	150
	ESF Electrical Rooms	104	104
c.	Control Building		
	ESF Switchgear and Battery Rooms	104	104
	Control Room	77	77
d.	Diesel Generator Rooms	125	125
e.	SSW Pumphouse	104*	104*

*For this area, the limit shall be the greater of 104°F or outside ambient temperature plus 20°F, not to exceed 122°F for greater than one hour.

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

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

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

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

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

1. Verifying the fuel level in the day tank.

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

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

4. Verifying the diesel starts from ambient condition and accelerates to at least 441 rpm for diesel generators 11 and 12 and 882 rpm for diesel generator 13 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 greater than or equal to 3500 kW for diesel generators 11 and 12 and 1650 kW for diesel generator 13 in less than or equal to 60 seconds, 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 all diesel generator air start receivers to be greater than or equal to:

   a) 160 psig for diesel generator 11 and 12, and

   b) 175 psig for diesel generator 13.

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

c. At least once per 92 days and from new oil prior to addition to the storage tanks by verifying that a sample obtained in accordance with ASTM-D270-1975 has a water and sediment content of less than or equal to .05 volume percent and a kinematic viscosity @ 40°C of greater than or equal to 1.9 but less than or equal to 4.1 when tested in accordance with ASTM-D975-77, and an impurity level of less than 2 mg. of insolubles per 100 ml. when tested in accordance with ASTM-D2274-70, except that the test of new fuel for impurity level shall be performed within 7 days after addition of the new fuel to the storage tank.

d. 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 1735 kW for diesel generator 11, greater than or equal to 890 kW for diesel generator 12, and greater than or equal to 2780 kW for diesel generator 13 while maintaining less than or equal to 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 7000 kW for diesel generators 11 and 12 and 3300 kW for diesel generator 13 without tripping. The generator voltage shall not exceed 5000 volts during and following the load rejection.

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

a) For Divisions 1 and 2:

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 10 seconds, energizes the auto-connected shutdown loads through the load sequencer 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 3:

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 loads within 10 seconds and operates for greater than or equal to 5 minutes while its generator is loaded with the shutdown loads. After energization, the steady state voltage and frequency of the emergency bus shall be maintained at 4160 ± 416 volts and 60 ± 1.2 Hz during this test.

SURVEILLANCE REQUIREMENTS (Continued)

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 1 and 2:

      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 10 seconds, energizes the auto-connected shutdown loads through the load sequencer 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 3:

      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 10 seconds and the autoconnected emergency loads within 20 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.

8. Verifying that all automatic diesel generator trips are automatically bypassed upon an ECCS actuation signal except:

   a) For Divisions 1 and 2, engine overspeed, generator differential current, low lube oil pressure, and generator ground overcurrent.

   b) For Division 3, engine overspeed and generator differential current.

SURVEILLANCE REQUIREMENTS (Continued)

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 greater than or equal to 7700 kW for diesel generators 11 and 12 and 3630 kW for diesel generator 13 and during the remaining 22 hours of this test, the diesel generator shall be loaded to 7000 kW for diesel generators 11 and 12 and 3300 kW for diesel generator 13. 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.d.4.a).2) and b).2)*.

10. Verifying that the auto-connected loads to each diesel generator do not exceed the continuous rating of 7000 kW for diesel generators 11 and 12 and 3300 kW for diesel generator 13.

11. Verifying the diesel generator's capability to:

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

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

    c) Be restored to its standby status.

12. Verifying that with the diesel generator operating in a test mode and connected to its bus that a simulated ECCS actuation signal:

    a) For Divisions 1 and 2, overrides the test mode by returning the diesel generator to standby operation.

    b) For Division 3, overrides the test mode by bypassing the diesel generator automatic trips per Surveillance Requirement 4.8.1.1.2.d.8.b).

13. Verifying that with all diesel generator air start receivers pressurized to less than or equal to 256 psig and the compressors secured, the diesel generator starts at least 5 times from ambient conditions and accelerates to at least 441 rpm for diesel generators 11 and 12 and 882 rpm for diesel generator 13 in less than or equal to 10 seconds.

*If Surveillance Requirement 4.8.1.1.2.d.4.a)2) 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 rated load for one hour or until operating temperatures have stabilized.

14. Verifying that the fuel transfer pump transfers fuel from each fuel storage tank to the day tank of each diesel via the installed lines.

15. Verifying that the automatic load sequence timer is OPERABLE with the interval between each load block within ± 10% of its design interval for diesel generators 11 and 12.

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

    a) Generator loss of excitation.
    b) Generator reverse power.
    c) High jacket water temperature.
    d) Generator overcurrent with voltage restraint.
    e) Bus underfrequency (11 and 12 only).
    f) Engine bearing temperature high (11 and 12 only).
    g) Low turbo charger oil pressure (11 and 12 only).
    h) High vibration (11 and 12 only).
    i) High lube oil temperature (11 and 12 only).
    j) Low lube oil pressure (13 only).
    k) High crankcase pressure.

e. 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 the three diesel generators accelerate to at least 441 rpm for diesel generators 11 and 12 and 882 rpm for diesel generator 13 in less than or equal to 10 seconds.

f. At least once per 10 years by:

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

2. Performing a pressure test of those portions of the diesel fuel oil system designed to Section III, subsection ND of the ASME Code in accordance with ASME Code Section 11, 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.

LIMITING CONDITIONS FOR OPERATION (Continued)

ACTION:

a. For A.C. power distribution:

1. With either Division 1 or Division 2 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 3 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.

3. With one of the above required load shedding and sequencing panels inoperable, restore the inoperable panel 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.

b. For D.C. power distribution:

1. With either Division 1 or Division 2 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 3 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 breaker alignment on the busses/LCs/MCCs/panels and voltage on the busses/LCs.

4.8.3.1.2 Each of the above required load shedding and sequencing panels shall be demonstrated OPERABLE:

a. At least once per 12 hours by determining that the auto-test system is operating and is not indicating a faulted condition.

b. At least once per 31 days by performance of a manual test and verifying response within the design criteria to the following test inputs:

a) LOCA.
b) Bus undervoltage.
c) Bus undervoltage followed by LOCA.
d) LOCA followed by bus undervoltage.

LIMITING CONDITION FOR OPERATION (Continued)

ACTION:

a. For A.C. power distribution:

   1. With both Division 1 and Division 2 of the above required A.C. distribution system not energized and/or with the load shedding and sequencing panel associated with the division(s) required to be energized inoperable, suspend CORE ALTERATIONS, handling of irradiated fuel in the Auxiliary Building and Enclosure Building and operations with a potential for draining the reactor vessel.

   2. With Division 3 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 both Division 1 and Division 2 of the above required D.C. distribution system not energized, suspend CORE ALTERATIONS, handling of irradiated fuel in the Auxiliary Building and Enclosure Building and operations with a potential for draining the reactor vessel.

   2. With Division 3 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 breaker alignment on the busses/LCs/MCCs/panels and voltage on the busses/LCs.

4.8.3.2.2 The above required load shedding and sequencing panel(s) shall be demonstrated OPERABLE:

a. At least once per 12 hours by determining that the auto-test system is operating and is not indicating a faulted condition.

b. At least once per 31 days by performance of a manual test and verifying response within the design criteria to the following test inputs:

   a) LOCA.
   b) Bus undervoltage.
   c) Bus undervoltage followed by LOCA.
   d) LOCA followed by bus undervoltage.

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 main 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.

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* 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.

##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.

3/4.9.12 HORIZONTAL FUEL TRANSFER SYSTEM

LIMITING CONDITION FOR OPERATION

3.9.12 The horizontal fuel transfer system (HFTS) may be in operation provided that:

a. The room through which the transfer system penetrates is sealed.

b. All interlocks with the refueling and fuel handling platforms are OPERABLE.

c. All HFTS primary carriage position indicators are OPERABLE.

APPLICABILITY: OPERATIONAL CONDITION 4* and 5*.

ACTION:

With the requirements of the above specification not satisfied, suspend HFTS operation with the HFTS at either the Spent Fuel Building pool or the Reactor Containment Building pool terminal point.

SURVEILLANCE REQUIREMENTS

4.9.12 Within 24 hours prior to the operation of HFTS and at least once per 7 days thereafter, verify that:

a. All interlocks with the refueling and fuel handling platforms are OPERABLE.

b. All HFTS primary carriage position indicators are OPERABLE.

*When the reactor mode switch is in the Refuel position.

RADIOACTIVE EFFLUENTS

LIQUID WASTE TREATMENT

LIMITING CONDITION FOR OPERATION

3.11.1.3 The liquid radwaste system components as specified in the ODCM shall be OPERABLE. The appropriate portions of the system shall be used to reduce the radioactive materials in liquid wastes prior to their discharge when the cumulative projected dose due to the liquid effluent from the site (see Figure 5.1.3-1) in a 31 day period would exceed 0.06 mrem to the total body or 0.2 mrem to any organ.

APPLICABILITY: At all times.

ACTION:

a. With the liquid radwaste treatment system inoperable for more than 31 days or with radioactive liquid waste being discharged without treatment and in excess of the above limits, in lieu of any other report required by Specification 6.9.1, prepare and submit to the Commission within 30 days pursuant to Specification 6.9.2 a Special Report which includes the following information:

    1. Identification of the inoperable equipment or subsystems and the reason for inoperability,

    2. Action(s) taken to restore the inoperable equipment to OPERABLE status, and

    3. Summary description of action(s) taken to prevent a recurrence.

b. The provisions of Specifications 3.0.3, 3.0.4 and 6.9.1.11 are not applicable.

SURVEILLANCE REQUIREMENTS

4.11.1.3.1 Doses due to liquid releases to unrestricted areas shall be projected at least once per 31 days, in accordance with the ODCM.

4.11.1.3.2 The liquid radwaste system components specified in the ODCM shall be demonstrated OPERABLE by operating the liquid radwaste treatment system equipment for at least 30 minutes at least once per 92 days unless the liquid radwaste system has been utilized to process radioactive liquids during the previous 92 days.

PROMPT NOTIFICATION WITH WRITTEN FOLLOWUP (Continued)

d. Reactivity anomalies involving disagreement with the predicted value of reactivity balance under steady state conditions during power operation greater than or equal to 1% delta k/k; a calculated reactivity balance indicating a SHUTDOWN MARGIN less conservative than specified in the technical specifications; short-term reactivity increases that correspond to a reactor period of less than 5 seconds or, if subcritical, an unplanned reactivity insertion of more than 0.5% delta k/k; or occurrence of any unplanned criticality.

e. Failure or malfunction of one or more components which prevents or could prevent, by itself, the fulfillment of the functional requirements of system(s) used to cope with accidents analyzed in the SAR.

f. Personnel error or procedural inadequacy which prevents or could prevent, by itself, the fulfillment of the functional requirements of systems required to cope with accidents analyzed in the SAR.

g. Conditions arising from natural or man-made events that, as a direct result of the event, require unit shutdown, operation of safety systems, or other protective measures required by technical specifications.

h. Errors discovered in the transient or accident analyses or in the methods used for such analyses as described in the safety analysis report or in the bases for the technical specifications that have or could have permitted reactor operation in a manner less conservative than assumed in the analyses.

i. Performance of structures, systems, or components that requires remedial action or corrective measures to prevent operation in a manner less conservative than assumed in the accident analyses in the safety analysis report or technical specifications bases; or discovery during unit life of conditions not specifically considered in the safety analysis report or technical specifications that require remedial action or corrective measures to prevent the existence or development of an unsafe condition.

j. Offsite releases of radioactive materials in liquid and gaseous effluents which exceed the limits of Specification 3.11.1.1 or 3.11.2.1.

k. Exceeding the limits in Specification 3.11.1.4 for the storage of radioactive materials in the listed tanks. The written follow-up report shall include a schedule and a description of activities planned and/or taken to reduce the contents to within the specified limits.

3/4.0 APPLICABILITY

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 at least COLD SHUTDOWN within the subsequent 24 hours. As a further example, Specification 3.6.7.1 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.

ISOLATION ACTUATION INSTRUMENTATION (continued)

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 a 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 equal to or greater than the drift allowance assumed for each trip in the safety analyses.

3/4.3.3 EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION

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

Operation with a trip set less conservative than its Trip Setpoint but within its specified Allowable Value is acceptable on the basis that the difference between each Trip Setpoint and the Allowable Value is equal to or greater than the drift allowance assumed for each trip in the safety analyses.

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 and NEDO-24222, dated December 1979, and Section 15.8 Appendix 15A 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

RECIRCULATION PUMP TRIP ACTUATION INSTRUMENTATION (Continued)

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 closure sensor for each of two turbine stop valves provides input to one EOC-RPT system; a closure sensor 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 40% 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., 190 ms, less the time allotted from start of motion of the stop valve or turbine control valve until the sensor relay contact supplying the input to the reactor protection system opens, i.e., 70 ms, and less the time allotted for breaker arc suppression determined by test, as correlated to manufacturer's test results, i.e., 50 ms, and plant pre-operational test results.

Operation with a trip set less conservative than its Trip Setpoint but within its specified Allowable Value is acceptable on the basis that the difference between each Trip Setpoint and the Allowable Value is equal to or greater than the drift allowance assumed for each trip in the safety analyses.

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 without providing actuation of any of the emergency core cooling equipment.

Operation with a trip set less conservative than its Trip Setpoint but within its specified Allowable Value is acceptable on the basis that the difference between each Trip Setpoint and the Allowable Value is equal to or greater than the drift allowance assumed for each trip in the safety analyses.

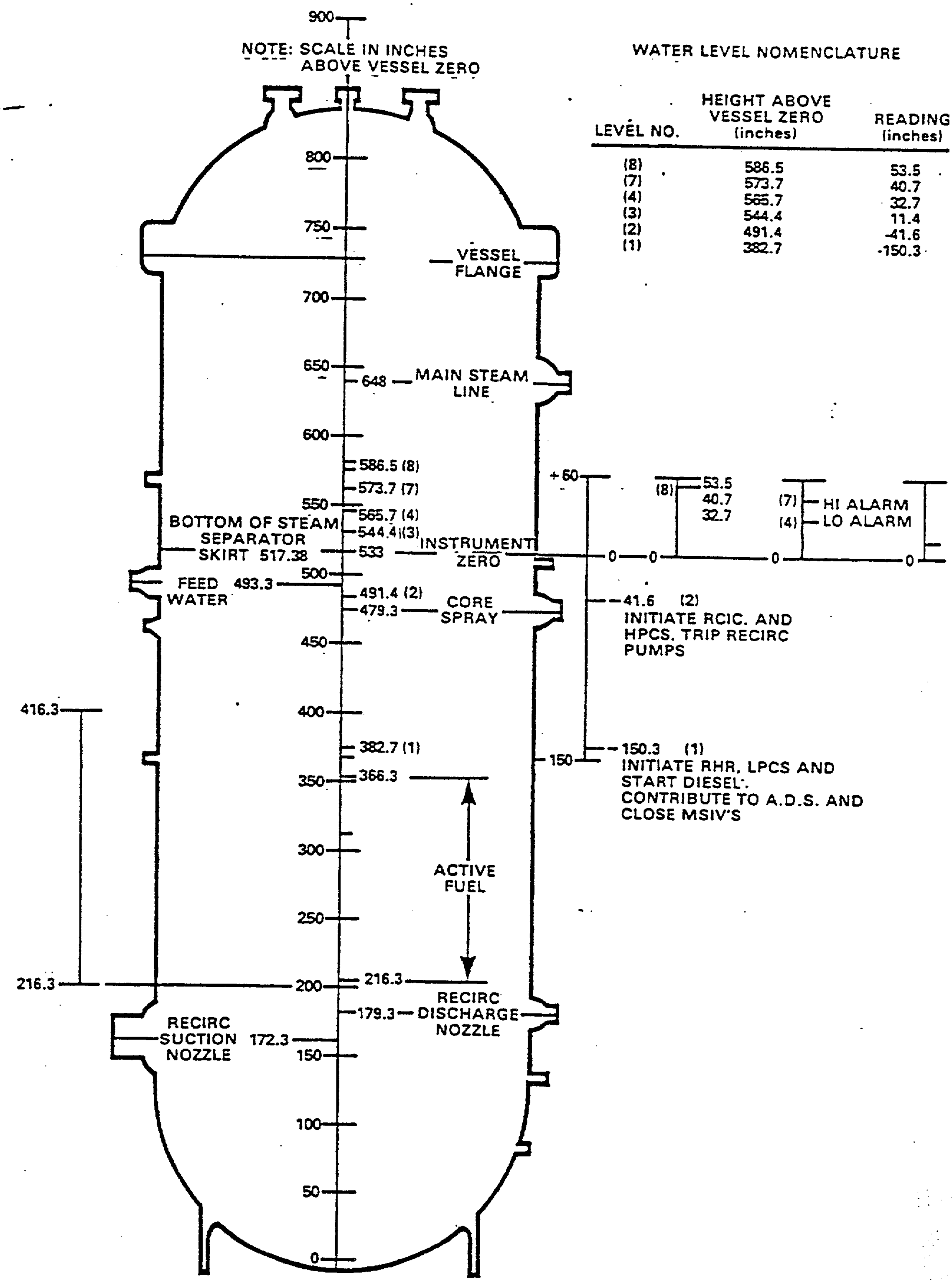
3/4.3.6 CONTROL ROD BLOCK INSTRUMENTATION

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 equal to or greater than the drift allowance assumed for each trip in the safety analyses.

WATER LEVEL NOMENCLATURE

LEVEL NO.	HEIGHT ABOVE VESSEL ZERO (inches)	READING (inches)
(8)	586.5	53.5
(7)	573.7	40.7
(4)	565.7	32.7
(3)	544.4	11.4
(2)	491.4	-41.6
(1)	382.7	-150.3



Bases Figure B 3/4 3-1

REACTOR VESSEL WATER LEVEL

3/4.6.1.5 FEEDWATER LEAKAGE CONTROL SYSTEM

The feedwater leakage control system consists of two independent subsystems designed to eliminate through-line leakage in the feedwater piping by pressurizing the feedwater lines to a higher pressure than the containment and drywell pressure. This ensures that no release of radioactivity through the feedwater line isolation valves will occur following a loss of all offsite power coincident with the postulated design basis loss-of-coolant accident.

3/4.6.1.6 CONTAINMENT STRUCTURAL INTEGRITY

This limitation ensures that the structural integrity of the containment will be maintained comparable to the original design standards for the life of the unit. Structural integrity is required to ensure that the containment will withstand the maximum pressure of 11.5 psig in the event of a LOCA. A visual inspection in conjunction with Type A leakage tests is sufficient to demonstrate this capability.

3/4.6.1.7 CONTAINMENT INTERNAL PRESSURE

The limitations on containment-to-Auxiliary Building and Enclosure Building differential pressure ensure that the containment peak pressure of 11.5 psig does not exceed the design pressure of 15.0 psig during LOCA conditions or that the external pressure differential does not exceed the design maximum external pressure differential of 3.0 psid. The limit of -2.0 to 0.0 psid for initial containment-to-Auxiliary Building and Enclosure Building differential pressure will limit the containment pressure to 11.5 psid which is less than the design pressure and is consistent with the safety analysis.

3/4.6.1.8 CONTAINMENT AVERAGE AIR TEMPERATURE

The limitation on containment average air temperature ensures that the containment peak air temperature does not exceed the design temperature of 185°F during LOCA conditions and is consistent with the safety analysis.

3/4.6.1.9 CONTAINMENT PURGE SYSTEM

The continuous use of the containment purge lines during all operational conditions is restricted to the 6-inch purge supply and exhaust isolation valves; whereas, continuous containment purge using the 20-inch purge system is limited to only OPERATIONAL CONDITIONS 4 and 5. Intermittent use of the 20-inch purge system during OPERATIONAL CONDITIONS 1, 2 and 3 is allowed only to reduce airborne activity levels and shall not exceed 1000 hours of use per 365 days.

The design of the 6-inch purge supply and exhaust isolation valves meets the requirements of Branch Technical Position CSB 6-4, "Containment Purging During Normal Plant Operations."

3/4.7.1 SERVICE WATER SYSTEMS

The OPERABILITY of the service water systems ensures that sufficient cooling capacity is available for continued operation of safety-related equipment during normal and accident conditions. The redundant cooling capacity of these systems, assuming a single failure, is consistent with the assumptions used in the accident conditions within acceptable limits.

3/4.7.2 CONTROL ROOM EMERGENCY FILTRATION SYSTEM

The OPERABILITY of the control room emergency filtration system ensures that the control room will remain habitable for operations personnel during and following all design basis accident conditions. Cumulative operation of the system for 10 hours with the heaters OPERABLE over a 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.

3/4.7.3 REACTOR CORE ISOLATION COOLING SYSTEM

The reactor core isolation cooling (RCIC) system is provided to assure adequate core cooling in the event of reactor isolation from its primary heat sink and the loss of feedwater flow to the reactor vessel without requiring actuation of any of the Emergency Core Cooling System equipment. The RCIC system is conservatively required to be OPERABLE whenever reactor pressure exceeds 135 psig even though the LPCI mode of the residual heat removal (RHR) system provides adequate core cooling up to 225 psig.

The RCIC system specifications are applicable during OPERATIONAL CONDITIONS 1, 2 and 3 when reactor vessel pressure exceeds 135 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 RCICS will be OPERABLE when required. Although all active components are testable and full flow can be demonstrated by recirculation during reactor operation, a complete functional test requires reactor shutdown. The pump discharge piping is maintained full to prevent water hammer damage and to start cooling at the earliest possible moment.

ATTACHMENT TO LICENSE AMENDMENT NO. 7
FACILITY OPERATING LICENSE NO. NPF-13
DOCKET NO. 50-416

Replace the following page of the Appendix "A" Technical Specifications with the enclosed page. This revised page is identified by Amendment number and contains a vertical line indicating the area of change.

REMOVE	INSERT
1-9	1-9
3/4 1-7	3/4 1-7
3/4 1-17	3/4 1-17
B 2-6	B 2-6
3/4 3-8	3/4 3-8
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3/4 6-44	3/4 6-44
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3/4 8-18	3/4 8-18
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3/4 9-18	3/4 9-18
3/4 11-6	3/4 11-6
6-20	6-20
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B 3/4 3-2	B 3/4 3-2
B 3/4 3-3	B 3/4 3-3
B 3/4 3-7	B 3/4 3-7
B 3/4 6-2	B 3/4 6-2
B 3/4 7-1	B 3/4 7-1

UNITED STATES NUCLEAR REGULATORY COMMISSION

DOCKET NO. 50-416

MISSISSIPPI POWER AND LIGHT COMPANY

MIDDLE SOUTH ENERGY, INC.

SOUTH MISSISSIPPI ELECTRIC POWER ASSOCIATION

NOTICE OF ISSUANCE OF AMENDMENT TO FACILITY

OPERATING LICENSE

The U.S. Nuclear Regulatory Commission (the Commission) has issued Amendment No. 7 to Facility Operating License No. NPF-13, issued to Mississippi Power and Light Company, Middle South Energy, Inc., and South Mississippi Electric Power Association (the licensees), for Grand Gulf Nuclear Station, Unit No. 1 (the facility) located in Claiborne County, Mississippi. This amendment grants changes to the Technical Specifications which are administrative in nature and are necessary to correct editorial and nomenclature errors and to achieve consistency with the as-built condition of the plant. None of the changes involve a significant relaxation of the criteria used to establish safety limits or the bases for limiting safety system settings or limiting conditions for operation.

The applications for the amendment comply with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act), and the Commission's regulations. The Commission has made appropriate findings as required by the Act and the Commission's regulations in 10 CFR Chapter I, which are set forth in the license amendment. The changes to the Technical Specifications approved in this amendment are to correct deficiencies and inadvertent errors in the Technical Specifications which were identified during the low power testing period at Grand

Gulf Unit 1. These corrective measures result as part of the review for the full power operating license and are encompassed by the prior public notice of the overall action involving the proposed issuance of an operating license published in the FEDERAL REGISTER on July 28, 1978 (43 FR 32903).

The Commission has determined that the issuance of this amendment will not result in any significant environmental impact other than those evaluated in the Final Environmental Statement since the activity authorized by this amendment is encompassed by the overall action evaluated in the Final Environmental Statement dated September 1981.

For further details with respect to this action, see (1) the applications for the amendment dated March 24, 1983, April 7, 1983, and April 25, 1983; (2) Amendment No. 7 to License NPF-13 dated July 1, 1983; (3) the Commission's evaluation dated July 1, 1983; (4) Final Safety Analysis Report (FSAR) and amendments thereto; (5) Final Environmental Statement dated September 1981; and (6) the Commission's Safety Evaluation Report dated September 1981 (NUREG-0831) and supplements thereto; and (7) the Commission's Confirmation of Action letter dated October 20, 1982. All of these items are available for public inspection at the Commission's Public Document Room, 1717 H Street, N.W., Washington, D.C. 20555, and at the Hinds Jr. College, George M. McLendon Library, Raymond, Mississippi 39154. A copy of items (1), (2), (3) and (7) may be obtained upon request addressed to the U. S. Nuclear Regulatory Commission, Washington, D. C. 20555, Attention: Director, Division of Licensing. Copies of items (5) and (6) may be purchased at current rates from the National Technical Information Service, Department of Commerce, 5285 Port Royal Road, Springfield, Virginia 22161, and through the NRC

GPO sales program by writing to the U. S. Nuclear Regulatory Commission, Attention: Sales Manager, Washington, D. C. 20555. GPO deposit account holders may call 301-492-9530.

Dated at Bethesda, Maryland, this 1st day of July 1983.

FOR THE NUCLEAR REGULATORY COMMISSION

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

*SEE ATTACHED PAGE FOR PREVIOUS CONCURRENCES

OFFICE	DL:LB#2/PM*	DL:LB#2/LA*	OELD*	DL:LB#2/BC*			
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DATE	6/21/83	6/21/83	6/21/83	6/21/83			

GPO sales program by writing to the U. S. Nuclear Regulatory Commission, Attention: Sales Manager, Washington, D. C. 20555. GPO deposit account holders may call 301-492-9530.

Dated at Bethesda, Maryland, this day of Ju

FOR THE NUCLEAR REGULATORY COMMISSION

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

concur w/ noted changes

OFFICE	DL:LB#2/PM	DL:LB#2/LA	OELD	DL:LB#2/BC			
SURNAME	DHouston:pt	EHylton		ASchwencer			
DATE	6/21/83	6/21/83	6/21/83	6/21/83			

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