U-600275
058-85(10-02)-L
1A.120

ILLINOIS POWER COMPANY

CLINTON POWER STATION, P.O. BOX 678, CLINTON, ILLINOIS 61727

October 2, 1985

Docket No. 50-461

Director of Nuclear Reactor Regulation
Attn: Mr. W. R. Butler, Chief
Licensing Branch No. 2
Division of Licensing
U. S. Nuclear Regulatory Commission
Washington, DC 20555

Subject: Clinton Power Station Unit #1
Technical Specifications

Dear Mr. Butler:

Consistent with your request in your letter dated September 4, 1985, to Mr. F. A. Spangenberg, Illinois Power Company is providing information relating to inconsistencies identified as a result of our review of the "Proof and Review" copy of the Clinton Power Station Technical Specifications (CPS-TS).

The enclosure consists of marked up pages from the "Proof and Review" copy of CPS-TS. These pages identif, such items as typographical errors and corrections to information previously submitted in letters dated September 28, 1984 (U-0739) and May 23, 1985 (U-600079). These corrections have been discussed with your Mr. C. S. Schulten of the Technical Specification Review Group.

On-going programs such as the Technical Specification Commitment Tracking System, Preoperational testing, surveillance procedure writing and the Final Safety Analysis Report (FSAR) certification will provide final confirmation that the information in the CPS-TS is consistent with the Safety Evaluation Report (SER), FSAR, and the As-Built design. We are confident that final certification can take place in accordance with the schedule provided to Illinois Power Company in a letter from A. Schwencer to F. A. Spangenberg dated January 31, 1985. We will keep Mr. C. S. Schulten informed of any changes to the "Proof and Review" copy of CPS-TS as a result of our continued review. We will work with Mr. Schulten as requested in order to resolve concerns of the Technical Branches and the Region as they occur.

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Please contact us if you have any questions regarding this information.

Sincerely yours,

F. A. Spangenberg

F. A. Spangenberg
Manager - Licensing
and Safety

FAS:RFP/kaf

Attachments

cc: B. L. Siegel, Clinton Licensing Project Manager, w/o enclosure
NRC Resident Office, w/o enclosure
Regional Administrator, Region III, USNRC, w/o enclosure
Illinois Department of Nuclear Safety, w/o enclosure
C. S. Schulten, NRC Technical Specification Review Group, w/enclosure
USNRC
Mail Stop 509
Washington, DC 20555

Attachment

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SECONDARY CONTAINMENT INTEGRITY

1.38 SECONDARY CONTAINMENT INTEGRITY shall exist when:

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

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

   2. Closed by at least one manual valve, blind flange, or deactivated automatic valve or damper as applicable secured in its closed position, except as provided in Table 3.6.6.2-1 of Specification 3.6.6.2.

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

c. The standby gas treatment system is in compliance with the requirements of Specification 3.6.6.3.

d. At least one door in each access to the secondary containment is closed, except for normal entry and exit.

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

f. The pressure within the secondary containment is less than or equal to the value required by Specification 4.6.6.1.a.

SELF TEST SYSTEM

1.39 The SELF TEST SYSTEM shall be that automatic system that injects short-duration pulses into the solid state nuclear system protection system (NSPS) circuits and verifies proper response to various input combinations. The SELF TEST SYSTEM is ~~shall be~~ designed to maintain surveillance over all NSPS cabinet circuitry essential to the Reactor Protection System, Emergency Core Cooling Systems, and the Nuclear Steam Supply Shutoff System on a continuous cyclic basis.

The SELF TEST SYSTEM may be used to perform various surveillance testing functions to satisfy technical specifications requirements for those components it is designed to monitor. The STS may be used to augment conventional testing methods to perform CHANNEL CHECKS, CHANNEL FUNCTIONAL TESTS, CHANNEL CALIBRATIONS, RESPONSE TIME TESTS AND LOGIC SYSTEM FUNCTIONAL TESTS.

SHUTDOWN MARGIN

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

SITE BOUNDARY

1.41 The SITE BOUNDARY shall be that line beyond which the land is neither owned, nor leased, nor otherwise controlled by the licensee.

2.1.3 REACTOR COOLANT SYSTEM PRESSURE

The Safety Limit for the reactor coolant system pressure has been selected such that it is at a pressure below which it can be shown that the integrity of the system is not endangered. The reactor pressure vessel is designed to Section III of the ASME Boiler and Pressure Vessel Code 1971 Edition, including Addenda through Summer 1973, which permits a maximum pressure transient of 110%, 1375 psig, of design pressure 1250 psig. The Safety Limit of 1325 psig, as measured by the reactor vessel steam dome pressure indicator, is equivalent to 1375 psig at the lowest elevation of the reactor coolant system. The reactor coolant system is designed to the ASME Boiler and Pressure Vessel Code, 1974 Edition, including Addenda through the Summer of 1974, for the reactor recirculation piping which permits a maximum pressure transient of 120% equaling to 1500 (suction) psig and 1980 (discharge) psig of design pressures of 1250 psig for suction piping and 1650 psig for discharge piping from the recirculation pump discharge to the outlet side of the discharge shutoff valve and 1550 psig from the discharge shutoff valve to the jet pumps. The pressure Safety Limit is selected to be the lowest transient overpressure allowed by the applicable codes.

2.1.4 REACTOR VESSEL WATER LEVEL

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

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SURVEILLANCE REQUIREMENTS (Continued)

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

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

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

   2. Open when the scram signal is reset.

b. Proper level sensor response by performance of a CHANNEL FUNCTIONAL TEST for each scram discharge volume scram and control rod block level instrumentation at least once per 31 days.

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4.1.3.1.4 The scram discharge volume shall be determined OPERABLE by demonstrating the scram discharge volume drain and vent valves OPERABLE, at least once per 18 months, by verifying that the drain and vent valves:

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

   b. Open when the scram signal is reset.

CPS Proposed

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3/4.3.1 REACTOR PROTECTION SYSTEM INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

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

APPLICABILITY: As shown in Table 3.3.1-1.

ACTION:

As shown in Table 3.3.1-1.

under CPS/NRC review. Not iaw. GE recommendations for Solid State design and 2/4 logic.

SURVEILLANCE REQUIREMENTS

4.3.1.1 Each reactor protection system instrumentation channel shall be demonstrated OPERABLE by the performance of the CHANNEL CHECK, CHANNEL FUNCTIONAL TEST and CHANNEL CALIBRATION operations for the OPERATIONAL CONDITIONS and at the frequencies shown in Table 4.3.1.1-1.

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

4.3.1.3 The REACTOR PROTECTION SYSTEM RESPONSE TIME of each reactor trip functional unit shown in Table 3.3.1-2 shall be demonstrated to be within its limit at least once per 18 months. Each test shall include at least two logic trains such that all logic trains are tested at least once per 36 months and one channel per trip function such that all channels are tested at least once every N times 18 months where N is the total number of redundant channels in a specific reactor trip function.

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TABLE 4.3.1.1-1 (Continued)

REACTOR PROTECTION SYSTEM INSTRUMENTATION SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL FUNCTIONAL TEST	CHANNEL CALIBRATION[a]	OPERATIONAL CONDITIONS IN WHICH SURVEILLANCE REQUIRED
9. Scram Discharge Volume Water Level - High				
a. Level Transmitter	S	M	R[g]	1, 2, 5[k]
b. Float Switches	NA	Q	R	1, 2, 5[k]
10. Turbine Stop Valve - Closure	NA	M	R	1
11. Turbine Control Valve Fast Closure Valve Trip System Oil Pressure - Low	NA	M	R	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 decade during each startup after entering OPERATIONAL CONDITION 2 and the IRM and APRM channels shall be determined to overlap for at least 1 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 > 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 the analog trip module ~~unit~~ at least once per 31 days.
(h) Verify measured core (total core flow) flow to be greater than or equal to established core flow at the existing loop flow control (APRM % flow).
(i) This calibration shall consist of verifying the 6±0.6 second simulated thermal power time constant.
(j) This function is not required to be OPERABLE when the reactor pressure vessel head is removed per Specification 3.10.1.
(k) With any control rod withdrawn. Not applicable to control rods removed per Specification 3.9.10.1 or 3.9.10.2.
(l) This function is not required to be OPERABLE when DRYWELL INTEGRITY is not required to be OPERABLE per Special Test Exception 3.10.1.

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TABLE 3.3.2-1

ISOLATION ACTUATION INSTRUMENTATION

TRIP FUNCTION	ISOLATION SIGNAL ††	MINIMUM OPERABLE CHANNELS PER TRIP SYSTEM(a)	APPLICABLE OPERATIONAL CONDITION	ACTION
1. PRIMARY CONTAINMENT ISOLATION				
a. Reactor Vessel Water Level- Low Low, Level 2	B(b)(c)	2	1, 2, 3 and #	20
b. Drywell Pressure - High	L(b)(c)	2	1, 2, 3	20
c. Containment Building Fuel Transfer Pool Ventilation Plenum Radiation - High	Z	2	1, 2, 3 and *	21
d. Containment Building Exhaust Radiation - High	M	2	1, 2, 3 and *	21
e. Containment Building Continuous Containment Purge (CCP) Exhaust Radiation - High	5	2	1, 2, 3 and *	21
f. Manual Initiation	NA	1/system	1, 2, 3 and *#	26

2. MAIN STEAM LINE ISOLATION†	ISOLATION SIGNAL ~~VALVE GROUPS~~	TOTAL NO. OF CHANNELS	CHANNELS TO TRIP	MINIMUM OPERABLE CHANNELS	APPLICABLE OPERATIONAL CONDITIONS	ACTION
a. Reactor Vessel Water Level- Low Low Low, Level 1	U	4	2	3	1, 2, 3	20
b. Main Steam Line Radiation - High(d)	C	4	2	3	1, 2, 3	23
c. Main Steam Line Pressure - Low	H	4	2	3	1, 2, 3	23
d. Main Steam Line Flow - High	D	4/MSL	2~~(g)~~	3/MSL	1	23
e. Condenser Vacuum - Low	J	4	2	3	1, 2,** 3**	23
f. Main Steam Line Tunnel Temp. - High	E	4	2~~(g)~~	3	1, 2, 3	23
g. Main Steam Line Tunnel Δ Temp. - High	F	4	2~~(g)~~	3	1, 2, 3	23
h. Main Steam Line Turbine Bldg. Temp. - High	G	4	2	3	1, 2, 3	23
i. Manual Initiation	NA	2/system	2/system	2/system	1, 2, 3	22

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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 1 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 1 hour.

ACTION 26 - Restore the manual initiation function to OPERABLE status within 8 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

ACTION 27 - Close the affected system isolation valves within 1 hour and declare the affected system inoperable.

ACTION 28 - Lock the affected system isolation valves closed within 1 hour and declare the affected system inoperable.

NOTES

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

** May be bypassed with reactor mode switch not in Run ~~steam pressure ≤ (1043) psig~~ and all turbine stop valves closed.

*** When handling irradiated fuel in the secondary containment.

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

† Main Steam line isolation trip functions have 2 out-of 4 isolation logic.

†† See Specification 3.6.4 Table 3.6.4-1 for valves which are actuated by these isolation signals.

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

(b) Also actuates the standby gas treatment system.

(c) Also actuates the control room emergency filtration system in the isolation mode of operation.

(d) Also trips and isolates the mechanical vacuum pumps.

(e) This note deleted.

(f) Also actuates secondary containment ventilation isolation dampers and valves per Table 3.6.6.2-1.

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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	≥ -45.5 in.*	≥ -47.7 in.
b. Drywell Pressure - High	≤ 1.68 psig	≤ 1.88 psig
c. Containment Bldg. Fuel Pool Transfer Ventilation Plenum Radiation - High	≤ 100 mR/hr	≤ 500 mR/hr
d. Containment Bldg. Exhaust Radiation - High	≤ 100 mR/hr	≤ 500 mR/hr
e. Containment Bldg. Continuous Containment Purge (CCP) Exhaust Radiation - High	≤ 100 mR/hr	≤ 400 mR/hr
f. Manual Initiation	NA	NA
2. MAIN STEAM LINE ISOLATION		
a. Reactor Vessel Water Level - Low Low Low, Level 1	≥ -145.5 in.*	≥ -147.7 in.
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	≤ 170 psid**	≤ 178 psid**
e. Condenser Vacuum - Low	≥ 8.5 in. Hg vacuum	≥ 7.6 in. Hg vacuum
f. Main Steam Line Tunnel Temp. - High	≤ 165°F	≤ 176°F
g. Main Steam Line Tunnel Δ Temp. - High	≤ 54.5°F	≤ 60°F
h. Main Steam Line Turbine Bldg. Temp. - High	≤ 131.2°F	≤ 138°F
i. Manual Initiation	NA	NA

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TABLE 3.3.2-3

ISOLATION SYSTEM INSTRUMENTATION RESPONSE TIME

TRIP FUNCTION	RESPONSE TIME (Seconds)#
1. PRIMARY CONTAINMENT ISOLATION	
a. Reactor Vessel Water Level - Low Low, Level 2	(≤ 10[a])
b. Drywell Pressure - High	(≤ 10[a])
c. Containment Building Continuous Containment Purge (CCP) Exhaust Radiation - High (b)	(≤ 10[a])
d. Manual Initiation	NA
2. MAIN STEAM LINE ISOLATION	
a. Reactor Vessel Water Level - Low Low Low, Level 1	≤ 1.0*(/< 10[a]**)
b. Main Steam Line Radiation - High (b)	(≤ 1.0*(/< 10[a]**))
c. Main Steam Line Pressure - Low	≤ 1.0*(/< 10[a]**)
d. Main Steam Line Flow - High	≤ 0.5*(/< 10[a]**)
e. Condenser Vacuum - Low	NA
f. Main Steam Line Tunnel Temp. - High	NA
g. Main Steam Line Tunnel Δ Temp. - High	NA
h. Main Steam Line Turbine Bldg. Temp. - High	NA
i. Manual Initiation	NA
3. SECONDARY CONTAINMENT ISOLATION	
a. Reactor Vessel Water Level - Low Low, Level 2	(≤ 10[a])
b. Drywell Pressure - High	(≤ 10[a])
c. Containment Bldg. Fuel Transfer Pool Ventilation Plenum Radiation - High[b]	(≤ 10[a])
d. Containment Bldg. Exhaust Radiation - High[b]	(≤ 10[a])
e. Containment Bldg. Continuous Containment Purge (CCP) Exhaust Radiation - High[b]	(≤ 10[a])
f. Fuel Bldg. Ventilation Exhaust Radiation - High[b]	(≤ 10[a])
g. Manual Initiation	NA
4. REACTOR WATER CLEANUP SYSTEM ISOLATION	
a. Δ Flow - High	(≤ 10[a]##)
b. Δ Flow Timer	NA
c. Equipment Area Temp. - High	NA
d. Equipment Area Δ Temp. - High	NA
e. Reactor Vessel Water Level - Low Low, Level 2	(≤ 10[a])
f. Main Steam Line Tunnel Ambient Temp. - High	NA
g. Main Steam Line Tunnel Δ Temp. - High	NA
h. SLCS Initiation	NA
i. Manual Initiation	NA

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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	($\leq$ 10(a)###)
b. RCIC Steam Line Flow High - Timer	NA
c. RCIC Steam Supply Pressure - Low	($\leq$ 10(a))
d. RCIC Turbine Exhaust Diaphragm Pressure - High	NA
e. RCIC Equipment Room Ambient Temp. - High	NA
f. RCIC Equipment Room Δ Temp. - High	NA
g. Main Steam Line Tunnel Ambient Temp. - High	NA
h. Main Steam Line Tunnel Δ Temp. - High	NA
i. Main Steam Line Tunnel Temp. Timer	NA
j. RHR Equipment Room Ambient Temp. - High	NA
k. RHR Equipment Room Δ Temp. - High	NA
l. Drywell Pressure - High	($\leq$ 10(a))
m. Manual Initiation	NA
6. RHR SYSTEM ISOLATION	
a. RHR Equipment Area Ambient Temp. - High	NA
b. RHR Equipment Area Δ Temp. - High	NA
c. RHR/RCIC Steam Line Flow - High	NA
d. Reactor Vessel Water Level - Low, Level 3	($\leq$ 10(a))
e. Reactor Vessel Water Level - Low Low Low, Level 1	($\leq$ 10(a))
f. Reactor Vessel (RHR Cut-in Permissive) Pressure - High	NA
g. Drywell Pressure - High	NA
h. Manual Initiation	NA

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(a) Isolation system instrumentation response time specified includes the diesel generator starting and sequence loading delays.
(b) Radiation detectors are exempt from response time testing. Response time shall be measured from detector output or the input of the first electronic component in the channel.
*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 shall be added to isolation time shown in Tables 3.6.4-1 for valves and 3.6.6.2-1 for dampers to obtain ISOLATION SYSTEM RESPONSE TIME for each valve/damper.
##Time delay of 45 to 47 seconds.
###Time delay of 3 to 13 seconds.

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TABLE 4.3.2.1-1 (Continued)

ISOLATION ACTUATION INSTRUMENTATION SURVEILLANCE REQUIREMENTS

TRIP FUNCTION	CHANNEL CHECK	CHANNEL FUNCTIONAL TEST	CHANNEL CALIBRATION	OPERATIONAL CONDITIONS IN WHICH SURVEILLANCE REQUIRED
6. RHR SYSTEM ISOLATION				
a. RHR Equipment Area Ambient Temp. - High	S	M	R	1, 2, 3
b. RHR Equipment Area Δ Temp. - High	S	M	R	1, 2, 3
c. RHR/RCIC Steam Line Flow - High	S	M	R (b)	1, 2, 3
d. Reactor Vessel Water Level - Low, Level 3	S	M	R (b)	1, 2, 3
e. Reactor Vessel Water Level - Low Low Low, Level 1	S	M	R (b)	1, 2, 3
f. Reactor Vessel (RHR Cut-in Permissive) Pressure - High	S	M	R (b)	1, 2, 3
g. Drywell Pressure - High	S	M	R (b)	1, 2, 3
h. Manual Initiation	NA	R	NA	1, 2, 3

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

**When reactor is in Run ~~steam pressure > (1043) psig~~ and/or any turbine stop valve is open.

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

(a) Each train or logic channel shall be tested at least every other 31 days.

(b) Calibrate the analog trip modules at least once per 31 days.

** Refer to pg 3/4 3-15 : NRC letter 9/4/85 : Under NRC/CPS review.

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TABLE 3.3.3-1 (Continued)

EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION

ACTION

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

a. With one channel inoperable, place the inoperable channel in the tripped condition within 1 hour* or declare the associated system inoperable.
b. With more than one channel inoperable, declare the associated system inoperable.

ACTION 31 - Deleted.

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

ACTION 33 - With the number of OPERABLE channels less than the Minimum OPERABLE Channels per Trip Function requirement, place the inoperable channel(s) in the tripped condition within 1 hour.

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

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

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

a. For one trip system, place that trip system in the tripped condition within 1 hour or declare the HPCS system inoperable.
b. For both trip systems, declare the HPCS system inoperable.

ACTION 37 - With the number of OPERABLE channels less than required by the Minimum OPERABLE Channels per Trip Function requirement, place at least one inoperable channel in the tripped condition within 1 hour* or declare the HPCS system inoperable.

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

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

*The provisions of Specification 3.0.4 are not appliable.

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TABLE 3.3.3-3

EMERGENCY CORE COOLING SYSTEM RESPONSE TIMES

ECCS	RESPONSE TIME (Seconds)
1. LOW PRESSURE CORE SPRAY SYSTEM	$\leq$ 37
2. LOW PRESSURE COOLANT INJECTION MODE OF RHR SYSTEM	
a. Pumps A, ~~and~~ B, and C	$\leq$ 37
~~b. Pump C~~	$\leq$ 37
3. AUTOMATIC DEPRESSURIZATION SYSTEM	NA
4. HIGH PRESSURE CORE SPRAY SYSTEM	$\leq$ 27
5. LOSS OF POWER	NA

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TABLE 3.3.4.1-2

ATWS RECIRCULATION PUMP TRIP SYSTEM INSTRUMENTATION SETPOINTS

TRIP FUNCTION	TRIP SETPOINT	ALLOWABLE VALUE
1. Reactor Vessel, Water Level - Low Low, Level 2	$\geq$ -45.5 in.*	$\geq$ -~~(53)~~ 47.7 in.
2. Reactor Vessel Pressure - High	$\leq$ ~~1127~~ 1065 psig	$\leq$ ~~(1150)~~ 1080 psig

*See Bases Figure B3/4 3-1.

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END-OF-CYCLE RECIRCULATION PUMP TRIP SYSTEM INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

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

APPLICABILITY: OPERATIONAL CONDITION 1, when THERMAL POWER is $\geq$ to 40% of RATED THERMAL POWER.

ACTION:

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

b. An inoperable channel may be left in inoperable status for up to 48 hours prior to placing it in the tripped condition, provided at least three OPERABLE channels in the same trip logic are monitoring that parameter.

c. With the number of OPERABLE channels one less than the Minimum OPERABLE Channels per Trip Function requirement:

   1. For one trip function, place one channel in the tripped condition and restore the inoperable trip function to OPERABLE status within 48 hours or reduce THERMAL POWER to less than 40% of RATED THERMAL POWER within the next 6 hours.

   2. For both trip functions, place one channel in each trip function in the tripped condition and restore at least one trip function to OPERABLE status within one hour or reduce THERMAL POWER to less than 40% of RATED THERMAL POWER within the next 6 hours.

Under CPS/NRC review
Not iaw. GE
recommendations for
Solid State 2/4 logic

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TABLE 3.3.7.1-1 (Continued)

RADIATION MONITORING INSTRUMENTATION

ACTION

ACTION 70 -

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

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

ACTION 71 - With the required monitor inoperable, perform area surveys of the monitored area with portable monitoring instrumentation at least once per 24 hours.

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REMOTE SHUTDOWN MONITORING INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.7.4 The remote shutdown system instrumentation and controls shown in Table 3.3.7.4-1 and 3.3.7.4-2, respectively shall be OPERABLE.

APPLICABILITY: OPERATIONAL CONDITIONS 1 and 2.

ACTION:

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

b. With the number of OPERABLE remote shutdown system controls less than required by Table 3.3.7.4-2, restore the inoperable control(s) to OPERABLE status within 7 days or be in at least HOT SHUTDOWN within the next 12 hours.

c. The provisions of Specification 3.0.4 are not applicable.

SURVEILLANCE REQUIREMENTS

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

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

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TABLE 3.3.7.4-1

REMOTE SHUTDOWN MONITORING INSTRUMENTATION

		DIVISION I		DIVISION II	
INSTRUMENT		EQUIPMENT NUMBER	MINIMUM CHANNELS OPERABLE	EQUIPMENT NUMBER	MINIMUM CHANNELS OPERABLE
1.	SRV 51D Temp., Supp. Pool Temp.	1C61-R506	1	1C61-R512	1
2.	SRV 51C Temp., Supp. Pool Temp.	1C61-R507	1	1C61-R513	1
3.	SRV 51G Temp., Supp. Pool Temp.	1C61-R508	1	1C61-R514	1
4.	Supp. Pool. Lvl	1C61-R504	1	1C61-R511	1
5.	RPV Lvl	1C61-R010	1	1C61-R509	1
6.	RPV Press.	1C61-R011	1	1C61-R510	1
7.	Upper DW Temp.	1C61-R502	1		NA
8.	Lower DW Temp.	1C61-R501	1		NA
9.	SX Strnr. Dsch. Press.	1C61-R503	1		NA
10.	RCIC Cond. Tnk Lvl.	1C61-R505	1		NA
11.	RHR Loop A Flow	1C61-R005	1		NA
12.	RCIC Turb. Speed	1C61-R003	1		NA
13.	RCIC Flow	1C61-R001	1		NA
14.	RCIC Turb. Flow Cntl	1C61-R001	1		NA
~~15.~~	~~Supp. Pool Temp.~~	~~1C61-R506 R508~~	~~1~~		~~NA~~

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TABLE 4.3.7.5-1

ACCIDENT MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS

INSTRUMENT	CHANNEL CHECK	CHANNEL CALIBRATION	APPLICABLE OPERATIONAL CONDITIONS
1. Reactor Vessel Pressure	M	R	1, 2
2. Reactor Vessel Water Level	M	R	1, 2
3. Suppression Pool Water Level	M	R	1, 2, 3
4. Suppression Pool Water Temperature	M	R	1, 2, 3
5. Drywell Pressure	M	R	1, 2
6. Drywell Air Temperature	M	R	1, 2
7. Drywell Hydrogen and Oxygen Concentration Analyzer and Monitor	M*	Q*	1, 2
8. Containment Pressure	M	R	1, 2
9. Containment Temperature	M	R	1, 2
10. Containment Hydrogen and Oxygen Concentration Analyzer and Monitor	M*	Q*	1, 2
11. Safety/Relief Valve Acoustic Monitor	NA	R	1, 2
12. Containment/Drywell High Range Gross Gamma Radiation Monitors	M	R**	1, 2, 3
13. HVAC Stack High Range Radioactivity Monitor#	M	R**	1, 2, 3
14. SGTS Exhaust High Range Radioactivity Monitor#	M	R**	1, 2, 3

*Accomplished automatically using an integral sample gas supply containing (a) 3.2 vol.% hydrogen, 1.0 vol.% helium, 21 vol.% oxygen, 0.9 vol.% argon and 73.9 vol.% nitrogen.

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

#High range noble gas monitors.

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TABLE 3.3.7.9-1

FIRE DETECTION INSTRUMENTATION

INSTRUMENT LOCATION	TOTAL NUMBER OF INSTRUMENTS* HEAT (x/y)	FLAME (x/y)	SMOKE (x/y)
AUXILIARY BUILDING FIRE DETECTION ZONE			
A-1a			7/0
A-1b			11/0
A-1c			
A-1d			
A-1e			
A-2a			3/0
A-2b			3/0
A-2c			3/0
A-2d			
A-2e			
A-2f			
A-2g			
A-2h			
A-2i			
A-2j			
A-2k			10/0
A-2l			
A-2m			1/0
A-2n			33/0
A-2o			5/0
A-3a			3/0
A-3b			2/0
A-3c			
A-3d			10/0
A-3e			1/0
A-3f			63/0
A-3g			5/0
A-4			1/0
A-5			1/0
CONTAINMENT BUILDING FIRE DETECTION ZONE			
C-1		4/0	
C-2			1/0

*(x/y): x is number of Function A (early warning fire detection and notification only) instruments.
y is number of Function B (actuation of fire suppression systems and early warning fire detection and notification) instruments.

#The fire detection instruments located within the containment are not required to be OPERABLE during the performance of Type A Containment Leakage Rate Tests.

TABLE 3.3.7.9-1 (Continued)

FIRE DETECTION INSTRUMENTATION

INSTRUMENT LOCATION	TOTAL NUMBER OF INSTRUMENTS* HEAT (x/y)	FLAME (x/y)	SMOKE (x/y)
FUEL BUILDING FIRE DETECTION ZONE			
F-1a			
F-1b			3/0
F-1c			
F-1d			
F-1e			
F-1f			
F-1g			
F-1h			
F-1i			
F-1j			
F-1k			
F-1m	14/0		
F-1n			
F-1o			
F-1p			131/0
DIESEL GENERATOR BUILDING FIRE DETECTION ZONE			
D-1			
D-2			
D-3			
D-4a	0/5		
D-4b			
D-5a	0/5		
D-5b			
D-6a	0/5		
D-6b			
D-7			
D-8	To be supplied later		
D-9			
D-10			24/0

TABLE 3.3.7.9-1 (Continued)

FIRE DETECTION INSTRUMENTATION

INSTRUMENT LOCATION	TOTAL NUMBER OF INSTRUMENTS* HEAT (x/y)	FLAME (x/y)	SMOKE (x/y)
CONTROL BUILDING FIRE DETECTION ZONE			
CB-1a			
CB-1b			-
CB-1c			
CB-1d			16/0
CB-1e			36/0
CB-1f			39/0
CB-1g			2/0
CB-1h			
CB-1i			94/0
CB-2			5/0
CB-3a			6/0
CB-3b			1/0
CB-3c			1/0
CB-3d			1/0
CB-3e			1/0
CB-3f			1/0
CB-3g			1/0
CB-4			5/0
CB-5a			3/0
CB-5b			
CB-5c			
CB-6a			110/0
CB-6b			6/0
CB-6c			17/0
CB-6d		2/0	50/0
CB-7			6/0
PGC C Panels and Floor Sections		0/225	309/0

TABLE 3.3.7.11-1

RADIOACTIVE LIQUID EFFLUENT MONITORING INSTRUMENTATION

INSTRUMENT	MINIMUM CHANNELS OPERABLE	ACTION
1. GROSS RADIOACTIVITY MONITORS PROVIDING ALARM AND AUTOMATIC TERMINATION OF RELEASE		
a. Liquid Radwaste Discharge Process Radiation Monitor	1	110
2. GROSS BETA OR GAMMA RADIOACTIVITY MONITORS PROVIDING ALARM BUT NOT PROVIDING AUTOMATIC TERMINATION OF RELEASE		
a. Plant Service Water Effluent Process Radiation Monitor	1	111
b. Shutdown Service Water Effluent Process Radiation Monitor	1/Division *	111
c. Fuel Pool Heat Exchanger Service Water Radiation Monitor	1	111
3. FLOW RATE MEASUREMENT DEVICES		
a. Liquid Radwaste Effluent Line	1	112
b. Plant Service Water Effluent Line	1	112
c. Plant Circulating Water Effluent Line	1	112

* Division I and Division II only

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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 Discharge Process Radiation Monitor Effluent Line	D	P	R(3)	Q(1)
2. GROSS BETA OR GAMMMA RADIOACTIVITY MONITORS PROVIDING ALARM BUT NOT PROVIDING AUTOMATIC TERMINATION OF RELEASE				
a. Plant Service Water Effluent Process Radiation Monitor	D	M	R(3)	Q(2)
b. Shutdown Service Water Effluent Process Radiation Monitor	D	M	R(3)	Q(2)
c. Fuel Pool Heat Exchanger Service Water Radiation Monitor	D	M	R(3)	Q(2)
3. FLOW RATE MEASUREMENT DEVICES				
a. Liquid Radwaste Effluent Line	D(4)	NA	R	Q
b. Plant Service Water Effluent Line	D(4)	NA	R	Q
~~c. Plant Circulating Water Effluent Line~~	~~D(4)~~	~~NA~~	~~R~~	~~Q~~

TABLE 4.3.7.12-1

RADIOACTIVE GASEOUS EFFLUENT MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS

INSTRUMENT	CHANNEL CHECK	SOURCE CHECK	CHANNEL CALIBRATION	CHANNEL FUNCTIONAL TEST	MODE IN WHICH SURVEILLANCE REQUIRED
1. POST-TREATMENT AIR EJECTOR OFF-GAS PRM					
a. High Range Noble Gas Activity Monitor Providing Alarm and Automatic Termination of Release	D	D	R(2)	Q(1)	*
b. Effluent System Flow-Rate Monitor	D	NA	R ~~NA~~	Q ~~NA~~	*
c. PRM Flow-Rate Monitor	D	NA	R ~~NA~~	Q ~~NA~~	*
2. STATION HVAC EXHAUST PRM					
a. High-Range Noble Gas Activity Monitor	D	M	R(2)	Q(1)	*
b. Low-Range Noble Gas Activity Monitor	D	M	R(2)	Q(1)	*
c. Iodine Sampler	W	NA	NA	NA	*
d. Particulate Sampler	W	NA	NA	NA	*
e. PRM Flow Rate Monitor	D	NA	R	Q	*
f. Effluent System Flow Rate Monitor	D	NA	R	Q	*
3. STANDBY GAS TREATMENT SYSTEM EXHAUST PRM					
a. High-Range Noble Gas Activity Monitor	D	M	R(2)	Q(1)	*
b. Medium-Range Noble Gas Activity Monitor	D	M	R(2)	Q(1)	*
c. Low-Range Noble Gas Activity Monitor	D	M	R(2)	Q(1)	*
d. High-Range Iodine Sampler	W	NA	NA	NA	*
e. Low-Range Iodine Sampler	W	NA	NA	NA	
f. Particulate Sampler	W	NA	NA	NA	*
g. PRM Flow-Rate Monitor	D	NA	R	Q	*
h. Effluent System Flow-Rate Monitor	D	NA	R	Q	*

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TABLE 4.3.7.12-1 (Continued)

TABLE NOTATION

* At all times.
** During main condenser off-gas system operation.
*** During operation of the main condenser air ejector.

(1) The CHANNEL FUNCTIONAL TEST shall also demonstrate that control room alarm annunciation occurs if any of the following conditions exist;

1. Instrument indicates measured levels above the alarm setpoint.
2. Circuit failure.
3. Instrument indicates a downscale failure.
4. Instrument controls not set in operate mode.

(2) The initial CHANNEL CALIBRATION shall be performed using one or more of the reference standards certified by the National Bureau of Standards or using standards that have been obtained from suppliers that participate in measurement assurance activities with NBS. These standards shall permit calibrating the system over its intended range of energy and measurement range. Subsequent CHANNEL CALIBRATION shall be performed using the initial radioactive standards or other standards of equivalent quality or radioactive sources that have been related to the initial calibration.

(3) The CHANNEL CALIBRATION shall include the use of standard samples containing a nominal:

1. 1.0 vol. % hydrogen, balance nitrogen, and
2. 4.0 ~~2.0~~ vol. % hydrogen, balance nitrogen.

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TABLE 3.3.9-1

PLANT SYSTEMS ACTUATION INSTRUMENTATION

TRIP FUNCTION	MINIMUM OPERABLE CHANNELS	APPLICABLE OPERATIONAL CONDITIONS	ACTION
1. CONTAINMENT SPRAY SYSTEM	Per Containment Spray Loop		
a. Drywell Pressure-High	2	1, 2, 3	
b. Containment Pressure-High	2	1, 2, 3	
c. Reactor Vessel Water Level-Low Low Low, Level 1	2	1, 2, 3	
d. Timers			
(1) Loop A, Loop B (10 Min.)	1	1, 2, 3	
(2) Loop B only (90 sec.)	1	1, 2, 3	
e. Manual Initiation	1	1, 2, 3	
2. FEEDWATER SYSTEM/MAIN TURBINE TRIP SYSTEM	Minimum Operable Channels		
a. Reactor Vessel Water Level-High, Level 8	3	1	
3. SUPPRESSION POOL MAKEUP SYSTEM			
a. Drywell Pressure-High	2	1, 2, 3	50
b. Reactor Vessel Water Level-Low Low Low, Level 1	2	1, 2, 3	50
c. Suppression Pool Water Level-Low Low	2*	1, 2, 3	51
d. Suppression Pool Makeup Time	1	1, 2, 3	51
e. SPMS Manual Initiation	2*	1, 2, 3	51
f. SPMS Mode Switch Permissive	1	1, 2, 3	51

*Two trip systems with two-out-of-two logic.

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TABLE 3.3.9-2

PLANT SYSTEMS ACTUATION INSTRUMENTATION SETPOINTS

TRIP FUNCTION	TRIP SETPOINT	ALLOWABLE VALUE
1. CONTAINMENT SPRAY SYSTEM		
a. Drywell Pressure-High	≤ 1.68 psig	≤ 1.88 psig
b. Containment Pressure-High	≤ 23.0 psia	≤ 23.5 psia
c. Reactor Vessel Water Level-Low Low Low, Level 1	≥-145.5 in.*	≥-147.7 in.
d. Timers		
1. Loop A, Loop B (10 min.)	≤ 10.17 min.	≥ 10.10 ≤ 10.23 min.
2. Loop B only (90 sec.)	≤ 90 sec.	≤ 90.6 sec.
2. FEEDWATER SYSTEM/MAIN TURBINE TRIP SYSTEM		
a. Reactor Vessel Water Level-High, Level 8	≤ 52.0 in.*	≤ 52.6 in.
3. SUPPRESSION POOL MAKEUP SYSTEM		
a. Drywell Pressure-High	≤ 1.68 psig	≤ 1.88 psig
b. Reactor Vessel Water Level-Low Low Low, Level 1	≥ -145.5 inches*	≥ -147.7 inches
c. Suppression Pool Water Level-Low Low	≥ El. 730'-1 9/16"	≥ 729'-0"
d. Suppression Pool Makeup Timer	25 minutes	30 minutes
e. SPMS Manual Initiation	NA	NA
f. SPMS Mode Switch Permissive	NA	NA

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

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TABLE 4.3.9.1-1

PLANT SYSTEMS ACTUATION INSTRUMENTATION SURVEILLANCE REQUIREMENTS

TRIP FUNCTION	CHANNEL CHECK	CHANNEL FUNCTIONAL TEST	OPERATIONAL CHANNEL CALIBRATION	CONDITIONS IN WHICH SURVEILLANCE REQUIRED
1. CONTAINMENT SPRAY SYSTEM				
a. Drywell Pressure-High	S	M	R(a)	1, 2, 3
b. Containment Pressure-High	S	M	R(a)	1, 2, 3
c. Reactor Vessel Water Level-Low Low Low, Level 1	S	M	R(a)	1, 2, 3
d. Timers	NA	M	R	1, 2, 3
e. Manual Initiation	NA	M	NA	1, 2, 3
2. FEEDWATER SYSTEM/MAIN TURBINE TRIP SYSTEM				
a. Reactor Vessel Water Level-High, Level 8	S	M	R	1
3. SUPPRESSION POOL MAKEUP				
a. Drywell Pressure-High	S	M	R(a)	1, 2, 3
b. Reactor Vessel Water Level - Low Low Low, Level 1	S	M	R(a)	1, 2, 3
c. Suppression Pool Water Level-Low Low	S	M	R(~~a~~) b	1, 2, 3
d. Suppression Pool Makeup Timer	NA	M	Q	1, 2, 3
e. SPMS Manual Initiation	NA	R	NA	1, 2, 3
f. SPMS Mode Switch Permissive	NA	R	NA	1, 2, 3

(a)Calibrate the analog trip module at least once every 31 days.

(b) Calibrate the trip unit (ACU) at least once every 31 days

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3/4.4.3 REACTOR COOLANT SYSTEM LEAKAGE

LEAKAGE DETECTION SYSTEMS

LIMITING CONDITION FOR OPERATION

3.4.3.1 The following reactor coolant system leakage detection systems shall be OPERABLE:

a. The drywell atmosphere particulate radioactivity monitoring system,

b. The drywell sump flow monitoring system, and

c. Either the drywell atmosphere gaseous radioactivity monitoring system or the drywell air coolers condensate flow rate monitoring system.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2 and 3.

ACTION:

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

SURVEILLANCE REQUIREMENTS

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

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

b. Drywell sump flow monitoring system-performance of a CHANNEL FUNCTIONAL TEST at least once per 31 days and a CHANNEL CALIBRATION TEST at least once per 18 months.

c. Drywell air cooler condensate flow rate monitoring system performance of a CHANNEL FUNCTIONAL TEST at least once per 31 days and a CHANNEL CALIBRATION at least once per 18 months.

(d. Flow testing the drywell floor drain sump inlet piping for blockage at least once every 18 months during shutdown.)

Not required of River Bend or Grand Gulf

TABLE 4.4.6.1.3-1

REACTOR VESSEL MATERIAL SURVEILLANCE PROGRAM-WITHDRAWAL SCHEDULE

CAPSULE NUMBER	VESSEL LOCATION	LEAD FACTOR at Inside Surface	LEAD FACTOR at 1/4 T	WITHDRAWAL TIME (EFPY)
1. Capsule 1	3°	.67	0.89	~~10~~ 6
2. Capsule 2	177°	.67	0.89	~~20~~ 15
3. Capsule 3	183°	.67	0.89	~~Spare~~ EOL

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3/4.4.9 RESIDUAL HEAT REMOVAL

HOT SHUTDOWN

LIMITING CONDITION FOR OPERATION

3.4.9.1 Two# shutdown cooling mode loops of the residual heat removal (RHR) system shall be OPERABLE and, unless at least one recirculation pump is in operation, at least one shutdown cooling mode loop shall be in operation*,## with each loop consisting of at least:

a. One OPERABLE RHR pump, and

b. One OPERABLE RHR heat exchanger.

APPLICABILITY: OPERATIONAL CONDITION 3, with reactor vessel pressure less than the RHR cut-in permissive setpoint.

ACTION:

a. With less than the above required RHR shutdown cooling mode loops OPERABLE, immediately initiate corrective action to return the required loops to OPERABLE status as soon as possible. Within one hour and at least once per 24 hours thereafter, demonstrate the operability of at least one alternate method capable of decay heat removal for each inoperable RHR shutdown cooling mode loop. Be in at least COLD SHUTDOWN within 24 hours.**

b. With no RHR shutdown cooling mode loop or recirculation pump in operation, immediately initiate corrective action to return at least one RHR shutdown cooling mode loop or recirculation pump to operation as soon as possible. Within one hour establish reactor coolant circulation by an alternate method and monitor reactor coolant temperature and pressure at least once per hour.

SURVEILLANCE REQUIREMENTS

4.4.9.1 At least one shutdown cooling mode loop of the residual heat removal system, one recirculation pump, or alternate method shall be determined to be in operation and circulating reactor coolant at least once per 12 hours.

#One RHR shutdown cooling mode loop may be inoperable for up to 2 hours for surveillance testing provided the other loop is OPERABLE and in operation.

*The shutdown cooling pump may be removed from operation for up to 2 hours per 8 hour period provided the other loop is OPERABLE.

##The RHR shutdown cooling mode loop may be removed from operation during hydrostatic testing.

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

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REACTOR COOLANT SYSTEM

COLD SHUTDOWN

LIMITING CONDITION FOR OPERATION

3.4.9.2 Two# shutdown cooling mode loops of the residual heat removal (RHR) system shall be OPERABLE unless one recirculation pump is in operation, then at least one shutdown cooling mode loop shall be in operation*,## with each loop consisting of at least:

a. One OPERABLE RHR pump, and

b. One OPERABLE RHR heat exchanger.

APPLICABILITY: OPERATIONAL CONDITION 4.

ACTION:

a. With less than the above required RHR shutdown cooling mode loops OPERABLE, within one hour and at least once per 24 hours thereafter demonstrate the operability of at least one alternate method capable of decay heat removal for each inoperable RHR shutdown cooling mode loop.

b. With no RHR shutdown cooling mode loop or recirculation pump in operation, within one hour establish reactor coolant circulation by an alternate method and monitor reactor coolant temperature and pressure at least once per hour.

SURVEILLANCE REQUIREMENTS

4.4.9.2 At least one shutdown cooling mode loop of the residual heat removal system, recirculation pump, or alternate method shall be determined to be in operation and circulating reactor coolant at least once per 12 hours.

#One RHR shutdown cooling mode loop may be inoperable for up to 2 hours for surveillance testing provided the other loop is OPERABLE and in operation.

*The shutdown cooling pump may be removed from operation for up to 2 hours per 8 hour period provided the other loop is OPERABLE.

##The shutdown cooling mode loop may be removed from operation during hydrostatic testing.

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3/4.5 EMERGENCY CORE COOLING SYSTEMS

3/4.5.1 ECCS - OPERATING

LIMITING CONDITION FOR OPERATION

3.5.1 ECCS divisions I, II and III shall be OPERABLE with:

a. ECCS division I consisting of:

1. The OPERABLE low pressure core spray (LPCS) system with a flow path capable of taking suction from the suppression pool and transferring the water through the spray sparger to the reactor vessel.

2. The OPERABLE low pressure coolant injection (LPCI) subsystem "A" of the RHR system with a flow path capable of taking suction from the suppression pool and transferring the water to the reactor vessel.

3. Seven OPERABLE ADS valves.

b. ECCS division II consisting of:

1. The OPERABLE low pressure coolant injection (LPCI) subsystems "B" and "C" of the RHR system, each with a flow path capable of taking suction from the suppression pool and transferring the water to the reactor vessel.

2. Seven OPERABLE ADS valves.

c. ECCS division III consisting of the OPERABLE high pressure core spray (HPCS) system with a flow path capable of taking suction from the suppression pool or RCIC storage tank and transferring the water through the spray sparger to the reactor vessel.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2*,# and 3*,##] RB-TS

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

#See Special Test Exception 3.10.5.

One LPCI subsystem of the RHR system may be aligned in the shutdown cooling mode when reactor vessel pressure is less than the cut-in permissive setpoint.] RB-TS

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SURVEILLANCE REQUIREMENTS

4.5.1 ECCS divisions I, II and III shall be demonstrated OPERABLE by:

a. At least once per 31 days for the LPCS, LPCI and HPCS systems:

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

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

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

1. LPCS pump develops a flow of at least 5010 gpm against a test line pressure greater than or equal to (119) psid.

2. LPCI pump develops a flow of at least 5050 gpm against a test line pressure greater than or equal to (119) psid.

3. HPCS pump develops a flow of at least 5010 gpm against a test line pressure greater than or equal to (490) psid.

c. For the LPCS, LPCI and HPCS systems, at least once per 18 months performing a system functional test which includes simulated automatic actuation of the system throughout its emergency operating sequence and verifying that each automatic valve in the flow path actuates to its correct position. Actual injection of coolant into the reactor vessel may be excluded from this test.

d. For the HPCS system, at least once per 18 months, verifying that the suction is automatically transferred from the RCIC storage tank to the suppression pool on a RCIC storage tank low water level signal and on a suppression pool high water level signal.

e. For the ADS by:

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

1 ~~2~~. At least once per 18 months, performing a system functional test which includes simulated automatic actuation of the system throughout its emergency operating sequence, but excluding actual valve actuation.

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

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SURVEILLANCE REQUIREMENTS (Continued)

2 ~~5~~. Manually opening each ADS valve when the reactor steam dome pressure is greater than or equal to 100 psig* and observing that:

a. The control valve or bypass valve position responds accordingly, or

b. There is a corresponding change in the measured stream flow, and

c. The acoustic tail-pipe monitor alarms.

3 ~~4~~. Performing a CHANNEL CALIBRATION of the accumulator low pressure alarm system and verifying an alarm setpoint of $\geq$ 140 psig on decreasing pressure.

*The provisions of Specification 4.0.4 are not applicable provided the surveillance is performed within 12 hours after reactor steam pressure is adequate to perform the test.

3/4 5.2 ECCS - SHUTDOWN

LIMITING CONDITION FOR OPERATION

3.5.2 At least two of the following shall be OPERABLE:

a. The low pressure core spray (LPCS) system with a flow path capable of taking suction from the suppression pool and transferring the water through the spray sparger to the reactor vessel.

b. Low pressure coolant injection (LPCI) subsystem "A" of the RHR system with a flow path capable of taking suction from the suppression pool and transferring the water to the reactor vessel.

c. Low pressure coolant injection (LPCI) subsystem "B" of the RHR system with a flow path capable of taking suction from the suppression pool and transferring the water to the reactor vessel.

d. Low pressure coolant injection (LPCI) subsystem "C" of the RHR system with a flow path capable of taking suction from the suppression pool and transferring the water to the reactor vessel.

e. The high pressure core spray (HPCS) system with a flow path capable of taking suction from one of the following water sources and transferring the water through the spray sparger to the reactor vessel:

   1. From the suppression pool, or

   2. When the suppression pool level is less than the limit or is drained, from the RCIC storage tank containing at least 125,000 available gallons of water, equivalent to a level of 95%.

APPLICABILITY: OPERATIONAL CONDITIONS 4 and 5*.

ACTION:

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

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

*The ECCS is not required to be OPERABLE provided that the reactor vessel head is removed, the cavity is flooded, the reactor cavity to steam dryer pool gate is removed and water level in these upper containment pools is maintained within the limits of Specification 3.9.8 and 3.9.9.

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3/4.5.3 SUPPRESSION POOL

LIMITING CONDITION FOR OPERATION

3.5.3 The suppression pool shall be OPERABLE:

a. In OPERATIONAL CONDITIONS 1, 2 and 3 with a contained water volume of at least 146,400 ft^3, equivalent to a level of 18'11".

b. In OPERATIONAL CONDITIONS 4 and 5* with a contained water volume of at least 98,700 ft^3, equivalent to a level of 12'8", except that the suppression pool level may be less than the limit or may be drained provided that:

1. No operations are performed that have a potential for draining the reactor vessel,
2. The reactor mode switch is locked in the Shutdown or Refuel position,
3. The RCIC storage tank contains at least 125,000 available gallons of water, equivalent to a level of 95%, and
4. The HPCS system is OPERABLE per Specification 3.5.2 with an OPERABLE flow path capable of taking suction from the RCIC storage tank and transferring the water through the spray sparger to the reactor vessel.

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

ACTION:

a. In OPERATIONAL CONDITION 1, 2 or 3 with the suppression pool water level less than the above limit, restore the water level to within the limit within 1 hour or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

b. In OPERATIONAL CONDITION 4 or 5* with the suppression pool water level less than the above limit or drained and the above required conditions not satisfied, suspend CORE ALTERATIONS and all operations that have a potential for draining the reactor vessel and lock the reactor mode switch in the Shutdown position. Establish SECONDARY CONTAINMENT INTEGRITY within 8 hours.

*The suppression pool is not required to be OPERABLE provided that the reactor vessel head is removed, the cavity is flooded, the reactor cavity to steam dryer pool gate is removed and the water level in these upper containment pools is maintained within the limits of Specifications 3.9.8 and 3.9.9.

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SURVEILLANCE REQUIREMENTS

4.5.3.1 The suppression pool shall be determined OPERABLE by verifying the water level to be greater than or equal to

a. 18'11" at least once per 24 hours, in OPERATIONAL CONDITION 1, 2 or 3.

b. 12'8" at least once per 12 hours, in OPERATIONAL CONDITIONS 4 and 5.

4.5.3.2 With the suppression pool level less than the above limit or drained in OPERATIONAL CONDITION 4 or 5*, at least once per 12 hours:

a. Verify the required conditions of Specification 3.5.3.b to be satisfied, or

b. Verify footnote conditions * to be satisfied.

*The suppression pool is not required to be OPERABLE provided that the reactor vessel head is removed, the cavity is flooded, the reactor cavity to steam dryer pool gate is removed and the water level is maintained within the limits of Specifications 3.9.8 and 3.9.9.

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CONTAINMENT LEAKAGE

LIMITING CONDITION FOR OPERATION

3.6.1.2 Containment leakage rates shall be limited to:

a. An overall integrated leakage rate of less than or equal to:

   1. La, 0.65 percent by weight of the containment air per 24 hours at Pa, 9.0 psig.

b. A combined leakage rate of less than or equal to 0.60 La, for all penetrations and all valves subject to Type B and C tests when pressurized to Pa, 9.0 psig.

c. * Less than or equal to 28 scf per hour for any one main steam line through the isolation valves when tested at Pa, 9.0 psig.

d. A combined leakage rate of less than or equal to 0.08 La, for all penetrations shown in Table 3.6.4-1 of Specification 3.6.4 as secondary containment bypass leakage paths when pressurized to Pa 9.0 psig.

e. A combined leakage rate of less than or equal to 1 gpm times the total number of ECCS and RCIC containment isolation valves in hydrostatically tested lines which penetrate the primary containment, when tested at 1.10 Pa, 9.9 psig.

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

ACTION:

With:

a. The measured overall integrated containment leakage rate exceeding 0.75 La, or

b. The measured combined leakage rate for all penetrations and all valves subject to Type B and C tests exceeding 0.60 La, or

c. The measured leakage rate exceeding 28 scf per hour for all four main steam lines through the isolation valves, or

d. The combined leakage rate for all penetrations shown in Table 3.6.4-1 as secondary containment bypass leakage paths exceeding 0.08 La; or

e. The measured combined leakage rate for all ECCS and RCIC containment isolation valves in hydrostatically tested lines which penetrate the primary containment exceeding 1 gpm times the total number of such valves,

* Exemption to Appendix J of 10CFR50 (SSER-2, pg. 6-6,7)

**See Special Test Exception 3.10.1.

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CONTAINMENT AIR LOCKS

LIMITING CONDITION FOR OPERATION

3.6.1.3 Each containment air lock shall be OPERABLE with:

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

b. An overall air lock leakage rate at Pa, 9.0 psig:

   1. For the personnel air lock, elevation 823'-3", of less than or equal to 0.02 La.

   2. For the personnel air lock, elevation 741'-0", of less than or equal to 0.05 La.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2* and 3.

ACTION:

a. With one containment air lock door inoperable:

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

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

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

   4. The provisions of Specification 3.0.4 are not applicable.

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

c. With one containment air lock door inflatable seal system air flask pressure instrument channel inoperable, restore the inoperable channel to OPERABLE status within 7 days or verify air flask pressures to be $\geq$ 90 psig at least once per 24 hours.

*See Special Test Exception 3.10.1.

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SURVEILLANCE REQUIREMENTS

4.6.1.3 Each containment air lock shall be demonstrated OPERABLE:

a. Within 72 hours# following each closing, except when the air lock is being used for multiple entries, then at least once per 72 hours, by verifying seal leakage rate less than or equal to 5 scf per hour when the gap between the door seals is pressurized to Pa, 9.0 psig.

b. By conducting an overall air lock leakage test at Pa, 9.0 psig, and verifying that the overall air lock leakage rate is within its limit:

   1. At least once per 6 months#,

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

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

#The provisions of Specification 4.0.2 are not applicable.

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DRYWELL STRUCTURAL INTEGRITY

LIMITING CONDITION FOR OPERATION

3.6.2.4 The structural integrity of the drywell shall be maintained at a level consistent with the acceptance criteria in Specification 4.6.2.4.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2 and 3.

ACTION:

With the structural integrity of the drywell not conforming to the above requirements, restore the structural integrity to within the limits within 24 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

SURVEILLANCE REQUIREMENTS

4.6.2.4.1 The structural integrity of the exposed accessible interior and exterior surfaces of the drywell shall be determined during the shutdown for each Type A containment leakage rate test by a visual inspection of those surfaces. This inspection shall be performed prior to the Type A containment leakage rate test to verify no apparent changes in appearance or other abnormal degradation.

4.6.2.4.2 Reports Any abnormal degradation of the drywell structure detected during the above required inspections shall be reported to the Commission pursuant to Specification 6.9.2. This report shall include a description of the condition of the concrete, the inspection procedure, the tolerances on cracking, and the corrective actions taken.

Incomplete
? Time requirement
? Not a surveillance but an action!
? Not part of RBTS

TABLE 3.6.4-1

CONTAINMENT AND DRYWELL ISOLATION VALVES

VALVE NUMBER	PENETRATION NUMBER	ISOLATION SIGNAL†	APPLICABLE OPERATIONAL CONDITIONS	MAXIMUM ISOLATION TIME (Seconds)	SECONDARY CONTAINMENT BYPASS PATH (Yes/No)	TEST PRESSURE (psig)
1. Automatic Isolation Valves						
a. Primary Containment						
1) Main Steam Line C	5		1, 2, 3		No	9.0
1B21-F022C		C, D, E, F, G, H, J, U		3-5		
1B21-F028C		C, D, E, F, G, H, J, U		3-5		
1B21-F067C		C, D, E, F, G, H, J, U		21		
2) Main Steam Line A	6		1, 2, 3		No	9.0
1B21-F022A		C, D, E, F, G, H, J, U		3-5		
1B21-F028A		C, D, E, F, G, H, J, U		3-5		
1B21-F067A		C, D, E, F, G, H, J, U		21		
3) Main Steam Line D	7		1, 2, 3		No	9.0
1B21-F022D		C, D, E, F, G, H, J, U		3-5		
1B21-F028D		C, D, E, F, G, H, J, U		3-5		
1B21-F067D		C, D, E, F, G, H, J, U		21		
4) Main Steam Line B	8		1, 2, 3		No	9.0
1B21-F022B		C, D, E, F, G, H, J, U		3-5		
1B21-F028B		C, D, E, F, G, H, J, U		3-5		
1B21-F067B		C, D, E, F, G, H, J, U		21		
5) Feedwater/RHR Line A	9		1, 2, 3		Yes	9.0
1B21-F032A		B, L		0.5		
1E12-F053A		A, S, T, X		~~44~~ 39		
6) Feedwater/RHR Line B	10		1, 2, 3		Yes	9.0
1B21-F032B		B, L		0.5		
1E12-F053B		A, S, T, X		~~44~~ 39		

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TABLE 3.6.4-1 (Continued)

CONTAINMENT AND DRYWELL ISOLATION VALVES

VALVE NUMBER	PENETRATION NUMBER	ISOLATION SIGNAL†	APPLICABLE OPERATIONAL CONDITIONS	MAXIMUM ISOLATION TIME (Seconds)	SECONDARY CONTAINMENT BYPASS PATH (YES/NO)	TEST PRESSURE (psig)
Automatic Isolation Valves (Continued)						
Primary Containment (Continued)						
30) Instrument Air Supply	57		1; 2, 3		Yes	9.0
1IA005		U		5		
1IA006		U		5		
31) Instrument Air Bottles	58		1, 2, 3		Yes	9.0
1IA012B		L, B		14		
1IA012A		X		14		
32) Service Air Supply	59		1,2,3		Yes	9.0
1SA030		B, L		5		
1SA029		B, L		5		
33) RWCU Suction Line	60		1, 2, 3		No	9.0
1G33-F001		B, F, N, 1, 2, E, X		15		
1G33-F004		B, F, N, 1, 2, E, X		15		
34) RWCU Return to Filter	61		1, 2, 3		No	9.0
1G33-F053		B, F, N, 1, 2, E, X,		15		
1G33-F054		B, F, N, 1, 2, E, X		15		
35) Hydrogen Recombiner Supply	62		1, 2, 3		Yes	9.0
1G[illegible]008		B, L		30		
36) RWCU To RHR/FW	64		1, 2, 3		No	9.0
1G33-F040		B, F, N, 1, 2, E, X		15		
1G33-F039		B, F, N, 1, 2, E, X		15		
37) RWCU Transfer To Radwaste	65		1, 2, 3, & ##		Yes	9.0
1WX019		B, L		2		
1WX020		B, L		2		

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TABLE 3.6.4-1 (Continued)

CONTAINMENT AND DRYWELL ISOLATION VALVES

VALVE NUMBER	PENETRATION NUMBER	ISOLATION SIGNAL†	APPLICABLE OPERATIONAL CONDITIONS	MAXIMUM ISOLATION TIME (Seconds)	SECONDARY CONTAINMENT BYPASS PATH (YES/NO)	TEST PRESSURE (psig)
Automatic Isolation Valves (Continued)						
Primary Containment (Continued)						
b. Drywell						
1) Plant Chilled Water Supply	53		1, 2, 3	NA	No	NA
1W0551A		L, U				
1W0551B		L, U				
2) Plant Chilled Water Return	53		1, 2, 3	NA	No	NA
1W0552A		L, U		6		
1W0552B		L, U		6		
3) Drywell HVAC Supply	101		1, 2, 3	1	No	NA
1VQ001A		L, B, M, Z, 5				
1VQ001B		L, B, M, Z, 5				
4) Drywell HVAC Exhaust	102		1, 2, 3		No	NA
1VQ002		L, B, M, Z, 5		6		
1VQ005		L, B, M, Z, 5		6		
1VQ003		L, B, M, Z, 5		6		
2. **Manual Isolation Valves**						
a. Primary Containment						
1) RHR/LPCI A Injection	15	NA	At All Times[(a)]	NA	No	9.0
1E12-F044A						
2) RHR/LPCI B Injection	16	NA	At All Times[(a)]	NA	No	9.0
1E12-F044B						

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TABLE 3.6.4-1 (Continued)

CONTAINMENT AND DRYWELL ISOLATION VALVES

VALVE NUMBER	PENETRATION NUMBER	ISOLATION SIGNAL†	APPLICABLE OPERATIONAL CONDITIONS	MAXIMUM ISOLATION TIME (Seconds)	SECONDARY CONTAINMENT BYPASS PATH (YES/NO)	TEST PRESSURE (psig)
Test Connections, Vents and Drains (Continued)						
Primary Containment (continued)						
26) Head Spray 1E51-F034 1E51-F035 1E51-F390 1E51-F391 1E12-F061 1E12-F062	42	NA	At All Times(a)	NA	No	9.0
27) RCIC Turb Steam Supply 1E51-F399 1E51-F072 1E51-F401	43	NA	At All Times(a)	NA	No	9.0
28) RCIC Turb Vacuum Breaker 1E51-F080 1E51-F082 1E51-F345 ~~1E51-F376~~ 1E51-F376 1E51-F083	44	NA	At All Times(a)	NA	No	9.0
29) Main Stream Drain Line 1B21-F017	45	NA	At All Times(a)	NA	No	9.0
30) CCW Supply 1CC164 1CC266	46	NA	At All Times(a)	NA	 No Yes	9.0

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3/4.6.7 ATMOSPHERE CONTROL

THIS PAGE OPEN PENDING RECEIPT OF INFORMATION FROM THE APPLICANT

CONTAINMENT HYDROGEN RECOMBINER SYSTEMS

LIMITING CONDITION FOR OPERATION

3.6.7.1 Two independent containment hydrogen recombiner systems shall be OPERABLE.

APPLICABILITY: OPERATIONAL CONDITIONS 1 and 2.

ACTION:

With one containment ~~and/or 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 hydrogen recombiner system shall be demonstrated OPERABLE:

a. At least once per 6 months by verifying during a recombiner system functional test that the heater sheath temperature increases to greater than or equal to 600°F within 60 minutes.

b. At least once per 18 months by:

1. Performing a CHANNEL CALIBRATION of all recombiner operating instrumentation and control circuits.

2. 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.

3. Verifying the integrity of all heater electrical circuits by performing a resistance to ground test following the above required functional test. The resistance to ground for any heater phase phase shall be greater than or equal to 10,000 ohms.

4. Verifying during a recombiner system functional test that the reaction chamber temperature increase to be > (1150)°F within 2 hours and is maintained between (1177)°F and (1223)°F for at least 2 hours.

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CONTAINMENT AND DRYWELL HYDROGEN IGNITION SYSTEM

LIMITING CONDITION FOR OPERATION

3.6.7.3 The containment and drywell hydrogen ignition system consisting of:

a. Two independent containment and drywell hydrogen ignition subsystems each consisting of six circuits as listed in Table 3.6.7.3-1 with no more than two igniter assemblies inoperable per circuit and no more than five igniter assemblies inoperable per subsystem, and

b. At least two igniter assemblies in each enclosed area specified in Table 3.6.7.3-2 shall be OPERABLE.

APPLICABILITY: OPERATIONAL CONDITIONS 1 and 2

ACTION:

a. With one containment and drywell hydrogen ignition subsystem inoperable, restore the inoperable subsystem to OPERABLE status within 30 days or be in at least HOT SHUTDOWN within the next 12 hours.

b. With less than two igniter assemblies OPERABLE in any enclosed area specified in Table 3.6.7.3-1, restore at least two igniter assemblies in each enclosed area to OPERABLE status within 30 days or be in at least HOT SHUTDOWN within the next 12 hours.

SURVEILLANCE REQUIREMENTS

4.6.7.3 The containment and drywell hydrogen ignition system shall be demonstrated OPERABLE:

a. At least once per 92 days by energizing the supply breakers and performing a current measurement of each circuit.

b. At least once per 18 months by energizing the supply breakers and verifying by current measurement sufficient current draw to develop 1700°F temperature for those igniter assemblies in high radiation areas and verifying a surface temperature of at least 1700°F for each of the remaining igniters.

184 in RBTS CSS Evaluate.

Voltage and

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Table 3.6.7.3-1

Hydrogen Igniter Circuits

Division I

Circuit I	Circuit 2	Circuit 3	Circuit 4	Circuit 5	Circuit 6
1HG12EN	1HG03EB	1HG07EB	1HG06ED	1HG07EM	1HG08EA
1HG11EB	1HG03ED	1HG12EA	1HG06EE	1HG09ED	1HG08EC
1HG11ED	1HG03EF	1HG12EC	1HG06EG	1HG09EF	1HG08EE
1HG11EF	1HG05EB	1HG12EE	1HG06EJ	1HG09EH	1HG08EF
1HG11EH	1HG05EC	1HG12EG	1HG06EL	1HG09EN	1HG08EG
1HG11EK	1HG05EF	1HG13EB	1HG07ED	1HG09EM	1HG08EJ
1HG11EM		1HG13ED	1HG07EF	1HG09EQ	1HG10EE
1HG12EJ		1HG13EF	1HG07EH	1HG10EA	1HG10EG
1HG12EL		1HG13EH	1HG07EK	1HG10EC	1HG10EJ
		1HG13EK	1HG09EB		1HG10EK
		1HG13EM	1HG13EP		

Division II

Circuit 1	Circuit 2	Circuit 3	Circuit 4	Circuit 5	Circuit 6
1HG06EA	~~1HG03EA~~	1HG07EN	1HG06EH	1HG06EH	1HG06EB
1HG06EC	1HG03EC	1HG08EB	1HG11EA	1HG11EA	1HG06EK
1HG06EM	1HG03EE	1HG08ED	1HG11EC	1HG11EC	1HG08EH
1HG06EF	1HG05ED	1HG09EA	1HG11EE	1HG11EE	1HG08EK
1HG07EA	1HG05EE	1HG09EC	1HG11EG	1HG11EG	1HG08EM
1HG07EC	1HG05EG	1HG09EE	1HG11EJ	1HG11EJ	1HG08EN
1HG07EE		1HG09EG	1HG11EL	1HG11EL	1HG10EB
1HG07EG		1HG09EJ	1HG11EN	1HG11EN	1HG10ED
1HG07EJ		1HG09EL	1HG12EH	1HG12EH	1HG10EF
1HG07EL		1HG09EP	1HG12EK	1HG12EK	1HG10EH
			1HG12EM	1HG12EM	1HG10EL
					1HG10EM

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SURVEILLANCE REQUIREMENTS (Continued)

4. Verifying that each fire protection pump starts sequentially to maintain the fire protection water system pressure greater than or equal to 65 psig.

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

4.7.6.1.2 Each diesel driven fire protection pump shall be demonstrated OPERABLE:

a. At least once per 31 days by:

1. Verifying that the fuel day tank contains at least ~~250~~ 410 gallons of fuel.

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

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

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

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

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

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

2. The pilot cell specific gravity, corrected to 77°F and full electrolyte level, is greater than or equal to 1.250 , and

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

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

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

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

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

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TABLE 3.7.6.5-1 (Continued)

FIRE HOSE STATIONS

LOCATION AND ELEVATION	HOSE RACK (1) INDENTIFICATION
q. Control Building, Elevation 781'	
1. Stairwell - southwest corner	AA - 125
2. Outside Div. 3 Battery Room	AA - 130
3. Div. 1 Cable Spreading Area	Y - 128
4. Passage outside Div. 1 Inverter Room	Y - 130
5. Outside Div. 4 Inverter Room	V - 124
6. Passage outside Div. 2 Inverter Room	V - 130
7. Div. 2 Cable Spreading Area	T - 128
8. North side of wall	V - 130
9. Northeast quadrant	T - 133
10. East side of wall	Y - 130
11. East from battery charger	AA - 130
12. South side	Y - 133
13. Southeast corner	AA - 135
14. East side new door	V - 202
r. Control Building, Elevation 800'	
1. Northwest quadrant	T - 124
2. Southwest corner	AA - 124
3. Southwest quadrant between doors	AC - 128
4. Outside shift sup. office	AC - 130
5. Outside planning and sched. room	AC - 130
6. Southeast quadrant	AC - 133
7. Southeast corner	AA - 135
s. Control Building, Elevation 825'	
1. West side on wall	AA - 130
2. Near 480 Volt substation K	Y - 125
3. Southwest quadrant near door	AA - 124
4. Southwest quadrant	AA - 133
5. West side of wall	V - 135
6. Southeast corner	AA - 135
t. Control Building, Elevation 847'	
1. South side of wall	AA - 124
2. South side of wall near door	AC-133 ~~AA - 202~~
u. Screen House Elevation 699'	
1. On west side of missile wall	B - 2
2. Between plant service water pumps	B - 6
3. Diesel fire water pump room	B -11

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TABLE 3.7.6.6-1

YARD FIRE HYDRANTS AND ASSOCIATED HYDRANT HOSE HOUSES

HYDRANT NUMBER	HOSE HOUSE NUMBER	LOCATION
OFP 112	29	9 + 23 N / 5 + 38 E
OFP 113	30	8 + 04 N / 8 + 33 E
OFP 128	4	4 + 20 S / 8 + 95 E
OFP 131	5	1 + 24 S / 8 + 93 E
OFP 132	23	0 + 79 N / 4 + 73 E
OFP 133	24	0 + 48.5 N / 2 + 77 E
OFP 134	25	1 + 56 N / 0 + 05 E
OFP 135	10	5 + 05 N / 8 + 94 E
OFP 136	8	2 + 28 N / 8 + 81 E
OFP 168	27	7 + 46 N / 0 + 05 E
OFP 169	26	4 + 66 N / 0 + 05 E
OFP 171	28	9 + 25 N / 1 + 74 E

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LIMITING CONDITION FOR OPERATION (Continued)

ACTION (Continued)

c. With one offsite circuit of the above-required A.C. sources and diesel generator 1A or 1B of the above required A.C. electrical power sources inoperable, demonstrate the OPERABILITY of the remaining A.C. sources by performing Surveillance Requirement 4.8.1.1.1.a within 1 hour and at least once per 8 hours thereafter. If a diesel generator became inoperable due to any cause other than preplanned preventive maintenance or testing, demonstrate the OPERABILITY of the remaining OPERABLE diesel generators, separately, by performing Surveillance Requirements 4.8.1.1.2.a.4 and 4.8.1.1.2.a.5 within 8 hours*. Restore at least one of the inoperable A.C. sources to OPERABLE status within 12 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours. Restore at least two offsite circuits and diesel generators 1A and 1B to OPERABLE status within 72 hours from time of initial loss or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

d. With diesel generator 1C of the above required A.C. electrical power sources inoperable, demonstrate the OPERABILITY of the offsite A.C. sources by performing Surveillance Requirement 4.8.1.1.1.a within 1 hour and at least once per 8 hours thereafter. If the diesel generator became inoperable as a result of any cause other than preplanned preventive maintenance or testing, demonstrate the OPERABILITY of the remaining OPERABLE diesel generators, separately, by performing Surveillance Requirements 4.8.1.1.2.a.4 and 4.8.1.1.2.a.5 within 24 hours*. Restore diesel generator 1C to OPERABLE status within 72 hours or declare the HPCS system inoperable and take the ACTION required by Specifications 3.5.1 and 3.7.1.1.

e. With diesel generator 1A or 1B of the above required A.C. electrical power sources inoperable, in addition to taking ACTION b or c, as applicable, verify within 2 hours that all required systems, subsystems, trains, components and devices that depend on the remaining OPERABLE diesel generator as a source of emergency power are also OPERABLE, and that the appropriate shutdown service water (SX) pump is OPERABLE if diesel generator 1B is inoperable; otherwise, be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours. under CPS/NRC review

f. With both of the above required offsite circuits inoperable, demonstrate the OPERABILITY of three diesel generators, separately, by performing Surveillance Requirements 4.8.1.1.2.a.4 and 4.8.1.1.2.a.5 within 8 hours unless the diesel generators are already operating. Restore at least one of the above-required offsite circuits to OPERABLE status within 24 hours or be in at least HOT SHUTDOWN within the next 12 hours. With only one offsite circuit restored to OPERABLE status,

*This test is required to be completed regardless of when the inoperable diesel generator is restored to OPERABILITY.

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 fuel tank.
   2. Verifying the fuel level in the fuel storage tank.
   3. Verifying the fuel transfer pump starts and transfers fuel from the storage system to the day fuel tank.
   4. Verifying the diesel starts* from ambient condition and accelerates to at least 870 rpm in less than or equal to 10 seconds. The generator 1A and 1B voltage and frequency shall be 4160 + 420, - 0 volts and 60 + 6, - 0 Hz and the generator 1C voltage and frequency shall be 4160 ± 420 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 ECCS actuation test signal by itself.

   5. Verifying the diesel generator is synchronized, loaded to greater than or equal to 3875 ~~3869~~ kW for diesel generator 1A, 3869 ~~3875~~ kw for diesel generator 1B and 2200 kW for diesel generator 1C in less than or equal to 90 seconds,* and operates with this load for at least 60 minutes.
   6. Verifying the diesel generator is aligned to provide standby power to the associated emergency busses.

*All diesel generator starts for the purpose of this surveillance test may be preceded by an engine prelube period. Further, all surveillance tests, with the exception of once per 184 days, may also be preceded by warmup procedures and may also include gradual loading as recommended by the manufacturer so that the mechanical stress and wear on the diesel engine is minimized.

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7. Verifying the pressure in all diesel generator air start receivers to be greater than or equal to 200 psig.

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

c. At least once per 92 days by removing accumulated water from the fuel storage tanks.

d. At least once per 92 days and from new fuel oil prior to addition to the storage tanks, by obtaining a sample in accordance with ASTM-D270-1975, and by verifying that the sample meets the following minimum requirements and is tested within the specified time limits:

1. As soon as sample is taken from new fuel or prior to addition to the storage tank, as applicable, verify in accordance with the tests specified in ASTM-D975-77 that the sample has:

a) A water and sediment content of less than or equal to 0.05 volume percent.

b) A kinematic viscosity @ 40°C of greater than or equal to 1.9 centistokes, but less than or equal to 4.1 centistokes.

(Delete) (c) A specific gravity as specified by the manufacturer @ 60/60°F of greater than or equal to ____ but less than or equal to ____ or an API gravity @ 60°F of greater than or equal to ____ degrees but less than or equal to ____ degrees.)

(2) d) An impurity level of less than 2 mg of insolubles per 100 ml. when tested in accordance with ASTM-D2274-70; analysis shall be completed within 7 days after obtaining the sample but may be sampled and analyzed after the addition of new fuel oil.

(3.) 2. Within two weeks after obtaining the sample, verify that the other properties specified in Table 1 of ASTM-D975-77 and Regulatory Guide 1.137, Position 2.a, are met when tested in accordance with ASTM-D975-77.

Under NRC/CPS review

e. 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.

#For any start of a diesel, the diesel must be operated with a load in accordance with the manufacturer's recommendations.

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SURVEILLANCE REQUIREMENTS (Continued)

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

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

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

   3. The average electrolyte temperature of the pilot cells of connected cells is above 65°F.

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

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

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

   3. The resistance of each cell-to-cell and terminal connection is less than or equal to 150×10^{-6} ohms, and

   4. The battery charger will supply at least 300 amperes for Divisions I and II and 100 amperes for Division III at a minimum of 105 volts for at least 4 hours.

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

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

   2. The battery capacity is adequate to supply a dummy load of the following profile while maintaining the battery terminal voltage greater than or equal to 105 volts.

      a) Division I

         $\geq$ 549 amperes for the first 60 seconds
         $\geq$ 227 amperes for the next 59 minutes
         $\geq$ 147 amperes for the next 180 minutes

      b) Division 2

         $\geq$ 404 amperes for the first 60 seconds
         $\geq$ 274 amperes for the next 59 minutes
         $\geq$ 86 amperes for the next 180 minutes

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TABLE 4.8.2.1-1

BATTERY SURVEILLANCE REQUIREMENTS

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

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

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3/4.8.3 ONSITE POWER DISTRIBUTION SYSTEMS

DISTRIBUTION - OPERATING

LIMITING CONDITION FOR OPERATION

3.8.3.1 The following power distribution system divisions shall be energized:

a. A.C. power distribution:

1. Division I, consisting of:
   a) 4160 volt A~~.~~C~~.~~ Bus 1A1
   b) 480 volt Unit Substations A and 1A
   c) 480 volt AC MCC's
      1) Aux. Bldg. MCC's 1A1, 1A2, 1A3, 1A4
      2) SSW MCC 1A
      3) DG MCC 1A
      4) ~~Containment~~ Control Bldg. MCC's E1, E2, and G
      5) Damper MCC A
   d) 120 volt A.C. distribution panels in 480 volt Auxiliary Building MCC 1A1 and Control Building MCC E2.
   e) 120 volt AC uninterruptible distribution panels energized from 1C71-S001A, which is fed from Control Building MCC E2 and from 480V Auxiliary Building MCC 1A1 through ~~and~~ 125V DC MCC 1DC13E.

2. Division II, consisting of:
   a) 4160 volt A~~.~~C~~.~~ Bus 1B1
   b) 480 volt Unit Substations B and 1B
   c) 480 volt AC MCC's
      1) Aux. Bldg. MCC's 1B1, 1B2, 1B3, 1B4
      2) SSW MCC 1B
      3) DG MCC 1B
      4) ~~Containment~~ Control Bldg. MCC's F1, F2, and H
      5) Damper MCC B
   d) 120 volt A~~.~~C~~.~~ distribution panels in 480 volt Auxiliary Building MCC 1B1 and Control Building MCC F2.
   e) 120 volt AC uninterruptible distribution panels energized from 1C71-S001B, which is fed from Control Building MCC F2 and from 480V Auxiliary Building MCC 1B1 through ~~and~~ 125V DC MCC 1DC14E.

3. Division III, consisting of:
   a) 4160 volt A~~.~~C~~.~~ Bus 1C1
   b) 480 volt A~~.~~C~~.~~ Aux. Bldg. MCC 1C and 1C1 and SSW MCC 1C
   c) 120 volt A~~.~~C~~.~~ distribution panels in 480 volt Aux. Bldg. MCC 1C and 1C1.
   d) 120 volt AC uninterruptible distribution panels energized from 1C71-S001~~A~~ C, which is fed from 480V Auxiliary Building MCC 1C and 125V DC ~~MCC~~ Distribution 1E22-S001~~B~~ C 5

4. Reactor Protection System (RPS) 120V AC Solenoid Buses A and B from their associated inverters.

b. D. C. power distribution

1. Division I, consisting of 125 volt D~~.~~C~~.~~ Battery 1A, 125 volt Battery Charger 1A, 125 volt D~~.~~C~~.~~ MCC 1A and Distribution Panel.

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LIMITING CONDITION FOR OPERATION (Continued)

2. Division II, consisting of 125 volt D.C. Battery 1B, 125 volt Battery Charger 1B, 125 volt D.C. MCC 1B, and Distribution Panel.

3. Division III, consisting of 125 volt D.C. Battery 1C, 125 volt Battery Charger 1C, 125 volt D.C. ~~MCC 1C, and~~ Distribution Panel.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2 and 3.

ACTION:

a. For A.C. power distribution:

1. With either Division I or Division II of the above required A.C. distribution system not energized, re-energize the division within 8 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

2. With Division III of the above required A.C. distribution system not energized, declare the HPCS system inoperable and take the ACTION required by Specification 3.5.1.

3. For inoperable RPS Solenoid Bus inverters:

a. With an RPS Solenoid Bus inverter inoperable transfer the bus to the alternate power source provided the other RPS Solenoid Bus is not being supplied from the alternate source.

b. With both RPS Solenoid Bus inverters inoperable de-energize one RPS Solenoid Bus.

c. With the frequency of the 120V A.C. supply to the RPS Solenoid buses A or B $\leq$ 57 Hz, demonstrate the OPERABILITY of all equipment which could have been subjected to the abnormal frequency for all class 1E loads connected to the associated buses, by performance of a CHANNEL FUNCTIONAL TEST or CHANNEL CALIBRATION, as required, within 24 hours.

b. For D.C. power distribution:

1. With either Division I or Division II of the above required D.C. distribution system not energized, re-energize the division within 2 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

2. With Division III of the above required D.C. distribution system not energized, declare the HPCS system inoperable and take the ACTION required by Specification 3.5.1.

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DISTRIBUTION - SHUTDOWN

LIMITING CONDITION FOR OPERATION

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

a. For A.C. power distribution, Division I or Division II, and when the HPCS system is required to be OPERABLE, Division III, with:

1. Division I consisting of:
   a) 4160 volt A/C Bus 1A1.
   b) 480 volt Unit Substations A and 1A.
   c) 480 volt A/C MCC's
      1) Aux. Bldg. MCC's 1A1, 1A2, 1A3, 1A4.
      2) SSW ~~MMC~~ MCC 1A.
      3) D.G. MCC 1A
      4) ~~Cont.~~ Control Bldg. MCC's E1, E2, and G
      5) Damper MCC A
   d) 120 volt A.C. distribution panels in 480 volt Auxiliary Building MCC 1A1 and Control Building MCC E2.
   e) 120 volt AC uninterruptible distribution panels energized from 1C71-S001A, which is fed from 480V Auxiliary Building MCC 1A1 through Control Building MCC E2 and from ~~and~~ 125V DC MCC 1DC13E.
2. Division II consisting of:
   a) 4160 volt A/C Bus 1B1.
   b) 480 volt Unit Substations B and 1B.
   c) 480 volt A/C MCC's
      1) Aux. Bldg. MCC's 1B1, 1B2, 1B3, 1B4
      2) SSW MCC 1B
      3) D.G. MCC 1B
      4) ~~Cont~~ Control ~~Bldg~~. MCC's F1, F2, and H
      5) Damper MCC B
   d) 120 volt A.C. distribution panels in 480 volt Auxiliary Building and Control Building MCC F2.
   e) 120 volt AC uninterruptible distribution panels energized from 1C71-S001B, which is fed from 480V Auxiliary Building MCC 1B1 through Control Building MCC F2 and from ~~and~~ 125V DC MCC 1DC14E.
3. Division III consisting of:
   a) 4160 volt A/C Bus 1C1.
   b) 480 VAC Transformer
   c ~~b)~~ 480 volt A/C AB MCC 1C and Aux. Bldg. MCC 1C1, and SSW MCC 1C.
   d ~~c)~~ 120 volt A/C distribution panels in 480 volt Aux. Bldg. MCC 1C and Aux. Bldg. MCC 1C1.
   e ~~d)~~ 120 volt AC uninterruptible distribution panels energized from 1C71-S001A, which is fed from 480V Auxiliary Building MCC 1C and 125V DC ~~MCC~~ Distribution Panel 1E22-~~S001B~~ S001C.*

b. For D.C. power distribution, Division I or Division II, and when the HPCS system is required to be OPERABLE, Division III, with:

1. Division I consisting of 125 volt D.C. Batteries 1A, 125 volt Battery Charger 1A, 125 volt D/C MCC-1A, and Distribution Panel.

2. Division II consisting of 125 volt D.C. Batteries 1B, 125 Volt Battery Charger 1B, 125 volt D/C MCC-1B, and Distribution Panel.

LIMITING CONDITION FOR OPERATION (Continued)

3. Division III consisting of 125 volt D.C. Batteries 1C, 125 volt Battery Charger 1C, 125 volt D.C. ~~MCC-1C, and~~ Distribution Panel.

APPLICABILITY: OPERATIONAL CONDITIONS 4, 5 and *.

ACTION:

a. For A.C. power distribution:

1. With both Division I and Division II of the above required A.C. distribution system not energized, suspend CORE ALTERATIONS, handling of irradiated fuel in the secondary containment and operations with a potential for draining the reactor vessel.

2. With Division III of the above required A.C. distribution system not energized, declare the HPCS system inoperable and take the ACTION required by Specifications 3.5.2 and 3.5.3.

b. For D.C. power distribution:

1. With both Division I and Division II 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 III of the above required D.C. distribution system not energized, declare the HPCS system inoperable and take the ACTION required by Specifications 3.5.2 and 3.5.3.

c. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.8.3.2 At least the above required power distribution system divisions shall be determined energized at least once per 7 days by verifying correct breaker alignment and voltage on the busses/MCCs/panels.

*When handling irradiated fuel in the secondary containment.

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TABLE 3.8.4.1-1
(continued)

Auxiliary Building MCC 1A2 (1AP73E)
Location 121, V (R,C); EL 781 FT.

Each Compartment listed below has two (2) identical circuit breakers in series

COMPT	CIR BKR TRIP	PENETRATION CABLE SIZE	EQUIPMENT SERVICE	CABLE NUMBER	PENETRATION NUMBER	SYSTEMS AFFECTED
1B	15	#6	RHR Valve 1E12-F037A	1RH63A	1EE09E	Resid. Ht. Removal
13C	15	#6	1IA012B	1IA02A	1EE09E	Instrument Air

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TABLE 3.8.4.1-1
(continued)

Auxiliary Building MCC 1B2 (1AP76E)
Location 106, V (R,C); EL 781 FT

Each Compartment listed below has two (2) identical circuit breakers in series.

COMPT	CIR BKR TRIP	PENETRATION CABLE SIZE	EQUIPMENT SERVICE	CABLE NUMBER	PENETRATION NUMBER	SYSTEMS AFFECTED
11C	15	#6	Isol. Valve 1C41-F001B	1SC06A	1EE10E	Standby Liq. Cont.
2B	15	#6	Inlet Valve 1CC068	1CC08A	1EE10E	Component Cool Water
1B	15	#6	Inlet Valve 1CC065	1CC08D	1EE10E	Component Cool Water
2C	15	#6	Outlet Valve 1CC070	1CC09A	1EE10E	Component Cool Water
2A	15	#6	Outlet Valve 1CC067	1CC09D	1EE10E	Component Cool Water
10C	15	#6	Sup Pool Vlv 1E12-F073A	1RH42A	1EE11E	Resid. Ht. Removal
11B	15	#6	Isol Valve 1SX095B	1SX57A	1EE11E	Shutdown Serv. Water
10A	15	#6	Suct. Valve 1HG009B	1HG06A	1EE11E	H2 Recomb.
11A	15	#6	Sup. Pool Vlv 1E12-F073B	1RH43A	1EE11E	Resid. Ht. Removal
14R	15	#6	Spray Valve 1E12-F028B	1RH62A	1EE11E	Resid. Ht. Removal
10B	15	#6	Upper Pool Univ. 1E12-F037B	1RH64A	1EE11E	Resid Ht. Removal

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TABLE 3.8.4.1-1
(continued)

Auxiliary Building MCC 1B3 (1AP77E)
Location 106, V (R,C); EL 781 FT

Each Compartment listed below has two (2) identical circuit breakers in series.

COMPT	CIR BKR TRIP	PENETRATION CABLE SIZE	EQUIPMENT SERVICE	CABLE NUMBER	PENETRATION NUMBER	SYSTEMS AFFECTED
2A	15	#6	Isol. Valve 1CC050	1CC12A	1EE10E	Component Cool Water
2B	15	#6	Isol. Valve 1CC053	1CC12D	1EE10E	Component Cool Water
3B	15	#6	Isol. Valve 1CC071	1CC13A	1EE10E	Component Cool Water
3C	15	#6	Isol. Valve 1CC074	1CC13D	1EE10E	Component Cool Water
3A	15	#6	Isol. Valve 1CC060	1CC16D	1EE10E	Component Cool Water
4A	15	#6	Isol. Valve 1CC127	1CC16L	1EE10E	Component Cool Water
4C	15	#6	Isol. Valve 1CY017	1CY06A	1EE10E	Cycled Condensate
5A	15	#6	Isol. Valve 1CY020	1CY06F	1EE10E	Cycled Condensate
5B	15	#6	Isol. Valve 1FC007	1FC05A	1EE10E	Fuel Pool Cooling
5C	15	#6	Isol. Valve 1FC037	1FC20A	1EE10E	Fuel Pool Cooling
10A	15	#6	Isol. Valve 1E51-F063	1RI02A	1EE11E	Reac. Inject.
14A	15	#6	RCIC Valve 1E51-F076	1RI15A	1EE11E	Reac. Inject.
10B	15	#6	Isol. Valve 1G33-F001	1RI15A	1EE11E	Reac. Water Cleanup

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TABLE 3.8.4.1-1
(continued)

Auxiliary Building MCC 1H (1AP95E)
Location 119, Z (R, C); EL 762 Ft

Each Compartment listed below has two (2) identical circuit breakers in series.

COMPT	CIR BKR TRIP	PENETRATION CABLE SIZE	EQUIPMENT SERVICE	CABLE NUMBER	PENETRATION NUMBER	SYSTEMS AFFECTED
7D	80	350 MCM	Welding 1EW02E	1EW01A	1EE03E	Welding
2C	15	#6	Supp. Pool Fill Valve 1SM004	1SM05A	1EE05E	Supp. Pool Make-up
3C	15	#6	RWCU 1WX01PA	1WX06A	1EE05E	Reac. Waste Cleanup
2A	15	#6	RWCU 1G33-F107	1RT33A	1EE05E	Hoists
3A	15	#6	RWCU 1G36-C001A	1RT43A	1EE05E	Reac. Water Cleanup
7B	30	#2	Monorail 1B21-E300	1HC13E	1EE05E	Hoists
7F	15	#6	Hatch Shield Door 1HC68G	1HC65A	1EE07E	Hoists
5A	20	#6	Circuit 7 1F42-E001	1FH06Y	1EE07E	Fuel Handling
6B	15	#6	Refuel Plat 1F15-E003	1FH11E	1EE05E	Fuel Handling
4A	15	#6	Air Hand Fan 1WØ05SF	1WØ25G	1EE07E	Chilled Water
4B	40	#6	Air Hand Fan 1WØ05SH	1WO99A	1EE07E	Chilled Water
4D	15	#6	Air Hand Fan 1WØ05SM	1WØ25U	1EE07E	Chilled Water
4C	15	#6	Air Hand Fan 1WØ05SK	1WØ27A	1EE07E	Chilled Water

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TABLE 3.8.4.1-1
(continued)

Auxiliary Building MCC 1H (1AP95E) (Continued)

COMPT	CIR BKR TRIP	PENETRATION CABLE SIZE	EQUIPMENT SERVICE	CABLE NUMBER	PENETRATION NUMBER	SYSTEMS AFFECTED
3D	40	#2	Air Hand Fan 1WØ05SB	1W025A	1EE05E	Chilled Water
6A	100	350 MCM	Oil Pump 1B33-D003A	1RR19A	1EE36E	Reac. Recirc.
2B	100	350 MCM	Mixing Htr. 1C41-D003	1SC03A	1EE36E	Standby Liq. Control
3B	30	350 MCM	Tnk Htr. 1C41-D002	1SC04A	1EE36E	Standby Liq. Control
7A	15	#6	Fan Mtr. 1B33-D003A	1RR21A	1EE36E	Reac. Recirc.
7C	15	#6	Area Coolers	1W034C	1EE07E	Area Coolers
				1W034D	1EE07E	Area Coolers
				1W034E	1EE07E	Area Coolers
				1W034F	1EE07E	Area Coolers
				1W034P	1EE07E	Area Coolers
				1W034Q	1EE07E	Area Coolers
				1W034R	1EE07E	Area Coolers
				1W034S	1EE07E	Area Coolers
1B	15	#6	1VP090A	1VP37A	1EE05E	Chilled Water
1C	15	#6	1VP091A	1VP38A	1EE05E	Chilled Water
1D	20	#6	1F15-E003EC	1FH13C	1EE07E	Fuel Handling
7D	20	#6	1F15-E003EA	1FH13A	1EE07E	Fuel Handling

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TABLE 3.8.4.1-1

CONTAINMENT PENETRATION CONDUCTOR OVERCURRENT PROTECTIVE DEVICES

DEVICE NUMBER(*) AND LOCATION	SYSTEM(S) AFFECTED
2. Type Switchgear	
Polar Crane - Penetration 1EE03E	2-350MCM per Ø
Unit Substation 1A1 Compt. 7B (R,C); EL 781 FT	
Primary Protection	
BBE Solid State Trip Device Type SS14	
Current Sensor 600A	
L.T. Setting 1.1 X TAP	
ST Setting 10 X TAP	
Secondary Protection	
Westinghouse Type CO-8 Relay	

(*List all primary and backup breakers.)

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TABLE 3.8.4.2-1

MOTOR OPERATED VALVES THERMAL OVERLOAD PROTECTION

Valve No.	Bypass	Direction	System(s) Affected
1B21-F016	Continuous	Close	Nuclear Boiler
1B21-F019	Continuous	Close	Nuclear Boiler
1B21-F065A	Continuous	Open/Close	Nuclear Boiler
1B21-F065B	Continuous	Open/Close	Nuclear Boiler
1B21-F067A	Continuous	Close	Nuclear Boiler
1B21-F067B	Continuous	Close	Nuclear Boiler
1B21-F067C	Continuous	Close	Nuclear Boiler
1B21-F067D	Continuous	Close	Nuclear Boiler
1B21-F068	Continuous	Close	Nuclear Boiler
1B21-F098A	Continuous	Close	Nuclear Boiler
1B21-F098B	Continuous	Close	Nuclear Boiler
1B21-F098C	Continuous	Close	Nuclear Boiler
1B21-F098D	Continuous	Close	Nuclear Boiler
1CC049	Continuous	Close	Component Cool Water
1CC050	Continuous	Close	Component Cool Water
1CC053	Continuous	Close	Component Cool Water
1CC054	Continuous	Close	Component Cool Water
1CC057	Continuous	Close	Component Cool Water
1CC060	Continuous	Close	Component Cool Water
1CC065	Continuous	Close	Component Cool Water
1CC068	Continuous	Close	Component Cool Water
1CC071	Continuous	Open/Close	Component Cool Water
1CC072	Continuous	Open	Component Cool Water
1CC073	Continuous	Open	Component Cool Water
1CC074	Continuous	Open/Close	Component Cool Water
1CC075A	Continuous	Close	Component Cool Water
1cc075B	Continuous	Close	Component Cool Water
1CC076A	Continuous	Close	Component Cool Water
1CC076B	Continuous	Close	Component Cool Water
1CC127	Continuous	Close	Component Cool Water
1CC128	Continuous	Close	Component Cool Water
~~1CC264~~	~~Continuous~~	~~Close~~	~~Component Cool Water~~
~~1CC265~~	~~Continuous~~	~~Close~~	~~Component Cool Water~~
1CY016	Continuous	Close	Cycled Condensate
1CY017	Continuous	Close	Cycled Condensate
1CY020	Continuous	Close	Cycled Condensate
1CY021	Continuous	Close	Cycled Condensate
1C41-F001A	Continuous	Open	Standby Liquid Control
1C41-F001B	Continuous	Open	Standby Liquid Control

1CC067	Continuous	Close	Component Cool Water
1CC070	Continuous	Close	Component Cool Water

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TABLE 3.8.4.2-1(Continued)

MOTOR OPERATED VALVES THERMAL OVERLOAD PROTECTION

Valve No.	Bypass	Direction	System(s) Affected
1E12-F003A	Continuous	Open	Residual Heat Removal
1E12-F003B	Continuous	Open	Residual Heat Removal
1E12-F004A	Continuous	Open/Close	Residual Heat Removal
1E12-F004B	Continuous	Open/Close	Residual Heat Removal
1E12-F006A	Continuous	Close	Residual Heat Removal
1E12-F006B	Continuous	Close	Residual Heat Removal
1E12-F008	Continuous	Open/Close	Residual Heat Removal
1E12-F009	Continuous	Close	Residual Heat Removal
1E12-F011A	Continuous	Close	Residual Heat Removal
1E12-F011B	Continuous	Close	Residual Heat Removal
1E12-F014A	Continuous	Open/Close	Residual Heat Removal
1E12-F014B	Continuous	Open/Close	Residual Heat Removal
1E12-F021	Continuous	Close	Residual Heat Removal
1E12-F023	Continuous	Open/Close	Residual Heat Removal
1E12-F024A	Continuous	Open/Close	Residual Heat Removal
1E12-F024B	Continuous	Open/Close	Residual Heat Removal
1E12-F026A	Continuous	Close	Residual Heat Removal
1E12-F026B	Continuous	Close	Residual Heat Removal
1E12-F027A	Continuous	Open/Close	Residual Heat Removal
1E12-F027B	Continuous	Open/Close	Residual Heat Removal
1E12-F028A	Continuous	Open/Close	Residual Heat Removal
1E12-F028B	Continuous	Open/Close	Residual Heat Removal
1E12-F037A	Continuous	Open/Close	Residual Heat Removal
1E12-F037B	Continuous	Open/Close	Residual Heat Removal
1E12-F040	Continuous	Close	Residual Heat Removal
1E12-F042A	Continuous	Open/Close	Residual Heat Removal
1E12-F042B	Continuous	Open/Close	Residual Heat Removal
1E12-F042C	Continuous	Open/Close	Residual Heat Removal
1E12-F047A	Continuous	Open	Residual Heat Removal
1E12-F047B	Continuous	Open	Residual Heat Removal
1E12-F048A	Continuous	Open/Close	Residual Heat Removal
1E12-F048B	Continuous	Open/Close	Residual Heat Removal
1E12-F049	Continuous	Close	Residual Heat Removal
1E12-F052A	Continuous	Close	Residual Heat Removal
1E12-F052B	Continuous	Close	Residual Heat Removal
1E12-F053A	Continuous	Open/Close	Residual Heat Removal
1E12-F053B	Continuous	Open/Close	Residual Heat Removal
1E12-F064A	Continuous	Open/Close	Residual Heat Removal
1E12-F064B	Continuous	Open/Close	Residual Heat Removal
1E12-F064~~B~~C	Continuous	Open/Close	Residual Heat Removal
1E12-F068A	Continuous	Open	Residual Heat Removal
1E12-F068B	Continuous	Open	Residual Heat Removal
1E12-F073A	Continuous	Open/Close	Residual Heat Removal
1E12-F073B	Continuous	Open/Close	Residual Heat Removal

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TABLE 3.8.4.2-1(Continued)

MOTOR OPERATED VALVES THERMAL OVERLOAD PROTECTION

Valve No.	Bypass	Direction	System(s) Affected
1E51-F059	Continuous	Open/Close	Reac. Core Isol. Cool
1E51-F063	Continuous	Open/Close	Reac. Core Isol. Cool
1E51-F064	Continuous	Open/Close	Reac. Core Isol. Cool
1E51-F068	Continuous	Open/Close	Reac. Core Isol. Cool
1E51-F076	Continuous	Open/Close	Reac. Core Isol. Cool
1E51-F077	Continuous	Open/Close	Reac. Core Isol. Cool
1E51-F078	Continuous	Open/Close	Reac. Core Isol. Cool
> 1E51-F095	Continuous	Open/Close	Reac. Core Isol. Cool
1FC007	Continuous	Close	Fuel Pool Cool & Clean
1FC008	Continuous	Close	Fuel Pool Cool & Clean
1FC011A	Continuous	Open/Close	Fuel Pool Cool & Clean
1FC011B	Continuous	Open/Close	Fuel Pool Cool & Clean
1FC015A	Continuous	Open/Close	Fuel Pool Cool & Clean
1FC015B	Continuous	Open/Close	Fuel Pool Cool & Clean
1FC016A	Continuous	Close	Fuel Pool Cool & Clean
1FC016B	Continuous	Close	Fuel Pool Cool & Clean
1FC024A	Continuous	Close	Fuel Pool Cool & Clean
1FC024B	Continuous	Close	Fuel Pool Cool & Clean
1FC026A	Continuous	Open/Close	Fuel Pool Cool & Clean
1FC026B	Continuous	Open/Close	Fuel Pool Cool & Clean
1FC036	Continuous	Close	Fuel Pool Cool & Clean
1FC037	Continuous	Close	Fuel Pool Cool & Clean
1FP050	Continuous	Close	Fire Protection
1FP051	Continuous	Close	Fire Protection
1FP052	Continuous	Close	Fire Protection
1FP053	Continuous	Close	Fire Protection
1FP054	Continuous	Close	Fire Protection
1FP078	Continuous	Close	Fire Protection
1FP079	Continuous	Close	Fire Protection
1FP092	Continuous	Close	Fire Protection
1G33-F001	Continuous	Close	React. Wtr. Clean Up
1G33-F004	Continuous	Close	React. Wtr. Clean Up
1G33-F028	Continuous	Close	React. Wtr. Clean Up
1G33-F034	Continuous	Close	React. Wtr. Clean Up
1G33-F039	Continuous	Close	React. Wtr. Clean Up
1G33-F040	Continuous	Close	React. Wtr. Clean Up
1G33-F053	Continuous	Close	React. Wtr. Clean Up
1G33-F054	Continuous	Close	React. Wtr. Clean Up
1HG001	Continuous	Open	H2 Recombining
1HG004	Continuous	Open/Close	H2 Recombining
1HG005	Continuous	Open/Close	H2 Recombining
1HG008	Continuous	Open/Close	H2 Recombining

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3/4.8.4.5 REDUNDANT FAULT PROTECTION FOR PGCC FIRE PROTECTION, COMMUNICATION, RPS AND MSIV CIRCUITS

LIMITING CONDITION FOR OPERATION

3.8.4.5 All over-current devices shown in Table 3.8.4.5-1 shall be OPERABLE.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2 and 3.

ACTION:

a. With one or more of the above required conductor overcurrent devices shown in Table 3.8.4.5-1 and/or fuses tested pursuant to Specification 4.8.4.5.a.2 inoperable:

1. Restore the protective device(s) to OPERABLE status or deenergize the circuit(s) by tripping, racking out, or removing inoperable device within 72 hours, and

2. Verify at least once per 7 days thereafter the inoperable device is tripped, racked out, or removed.

b. The provisions of Specification 3.0.4 are not applicable to overcurrent devices which have the inoperable device racked out or removed or, which have the alternate device tripped, racked out, or removed.

SURVEILLANCE REQUIREMENTS

4.8.4.5 Each over-current protective device shown in Table ~~4~~3.8.4.5-1 shall be demonstrated OPERABLE:

a. At least once per 18 months.

1. By selecting and functionally testing a representative sample of at least 10% of each type of circuit breakers. Circuit breakers selected for functional testing shall be selected on a rotating basis. Testing of these circuit breakers shall follow manufacturer's instructions and shall test the long time, and instantaneous elements for pickup and time delay, where applicable. Circuit breakers found inoperable during functional testing shall be restored to OPERABLE status prior to resuming operation. For each circuit breaker found inoperable during these functional tests, an additional representative sample of at least 10% of all the circuit breakers of the inoperable type shall also be functionally tested until no more failures are found or all circuit breakers of that type have been functionally tested.

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REFUELING PLATFORM

LIMITING CONDITION FOR OPERATION

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

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

ACTION:

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

SURVEILLANCE REQUIREMENTS

4.9.6.2 Each refueling platform crane or hoist used for handling of control rods or fuel assemblies within the reactor pressure vessel shall be demonstrated OPERABLE within 7 days prior to the start of such operations with that crane or hoist by:

a. Demonstrating operation of the overload cutoff on the main hoist when the load exceeds 1200 ± 50 pounds.

b. Demonstrating operation of the overload cutoff on the frame mounted and monorail hoists when the load exceeds 500 ± 50 pounds.

c. Demonstrating operation of the uptravel mechanical stop on the frame mounted and monorail hoists when uptravel brings the top of the grapple to ~~(8)~~ 7 feet below the ~~normal water level.~~ platform rails

d. Demonstrating operation of the downtravel mechanical cutoff on the main hoist when grapple hook down travel reaches 2-4 inches below fuel assembly handle.

e. Demonstrating operation of the slack cable cutoff on the main hoist when the load is less than 50 ± 10 pounds.

f. Demonstrating operation of the loaded interlock on the main hoist when the load exceeds 485 ± 50 pounds.

g. Demonstrating operation of the redundant loaded interlock on the main hoist when the load exceeds 550 ± 50 pounds.

h. Demonstrating operation of the main hoist raise power cutoff when the refueling platform area radiation monitor dose rate exceeds 10 mR/hr.

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AUXILIARY PLATFORM

LIMITING CONDITION FOR OPERATION

3.9.6.3 The auxiliary platform shall be OPERABLE.

APPLICABILITY: During handling of control rods with the auxiliary platform.

ACTION:

With the requirements for auxiliary platform OPERABILITY not satisfied, suspend use of the auxiliary platform after placing the load in a safe condition.

SURVEILLANCE REQUIREMENTS

4.9.6.3 The auxiliary platform hoist shall be demonstrated OPERABLE within 7 days prior to the handling of control rods by:

a. Demonstrating operation of the overload cutoff when the load exceeds 500 pounds.

b. Demonstrating operation of the auxiliary platform hoist uptravel stops when the grapple is lower than or equal to ~~6~~ 8 feet below the platform rails.

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MULTIPLE CONTROL ROD REMOVAL

LIMITING CONDITION FOR OPERATION

3.9.10.2 Any number of control rods and/or control rod drive mechanisms may be removed from the core and/or reactor pressure vessel provided that at least the following requirements are satisfied until all control rods and control rod drive mechanisms are reinstalled and all control rods are inserted in the core.

a. The reactor mode switch is OPERABLE and locked in the Shutdown position or in the Refuel position per Specification 3.9.1, except that the Refuel position "one-rod-out" interlock may be bypassed, as required, for those control rods and/or control rod drive mechanisms to be removed, after the fuel assemblies have been removed as specified below.

b. The source range monitors (SRM) are OPERABLE per Specification 3.9.2.

c. The SHUTDOWN MARGIN requirements of Specification 3.1.1 are satisfied.

d. All other control rods are either inserted or have the surrounding four fuel assemblies removed from the core cell.

e. The four fuel assemblies surrounding each control rod or control rod drive mechanism to be removed from the core and/or reactor vessel are removed from the core cell.

> f.

APPLICABILITY: OPERATIONAL CONDITION 5.

ACTION:

With the requirements of the above specification not satisfied, suspend removal of control rods and/or control rod drive mechanisms from the core and/or reactor pressure vessel and initiate action to satisfy the above requirements.

CSS ✓ RBTS item f See also CPS-TS 4.9.10.2.1.f

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TABLE 3.12-1

RADIOLOGICAL ENVIRONMENTAL MONITORING PROGRAM

Exposure Pathway and/or Sample	Number of Representative Samples and Sample Locations[a]	Sampling and Collection Frequency	Type and Frequency of Analysis
1. DIRECT RADIATION[b]	40 routine monitoring stations (DR1-DR40) either with two or more dosimeters or with one instrument for measuring and recording dose rate continuously, placed as follows: (1) an inner ring of stations, one in each meteorological sector in the general area of the SITE BOUNDARY; (2) an outer ring of stations, one in each meteorological sector in the 6 to 8 km range from the site; (3) the balance of the stations to be placed in special interest areas such as population centers, nearby residences, schools, and in 1 or 2 areas to serve as control stations.	Quarterly	Gamma dose quarterly.

TABLE 3.12-1 (Continued)

RADIOLOGICAL ENVIRONMENTAL MONITORING PROGRAM

Exposure Pathway and/or Sample	Number of Representative Samples and Sample Locations[a]	Sampling and Collection Frequency	Type and Frequency of Analysis
2. AIRBORNE			
Radioiodine and Particulates	Samples from 5 locations: a. 3 samples from close to the 3 SITE BOUNDARY locations in different sectors of the highest calculated annual average ground-level D/Q. b. 1 sample from the vicinity of a community having the highes calculated annual average ground-level D/Q. c. 1 sample from a control location, as for example 15-30 km distant and in the least prevalent wind direction.[c]	Continuous sampler operation with sample collection weekly, or more frequently if required by dust loading.	Radioiodine Cannister: I-131 analysis weekly. Particulate Sampler: Gross beta radioactivity analysis following filter change;[d] Gamma isotopic analysis[e] of composite (by location) quarterly.
3. WATERBORNE			
a. Surface[f]	1 sample upstream 1 sample downstream	Composite sample over 1-month period[g]	Gamma isotopic analysis[e] monthly. Composite for tritium analysis quarterly.
b. Ground	Samples from 1 or 2 sources, only if likely to be affected[h].	Quarterly	Gamma isotopic[e] and tritium analysis quarterly.
c. Drinking	1 sample of each of 1 to 3 of the nearest water supplies that could be affected by its discharge. 1 sample from a control location.	Composite sample over 2-week period[g] when I-131 analysis is performed, monthly composite otherwise	I-131 analysis on each composite when the dose calculated for the consumption of the water is greater than 1 mrem per year.[i] Composite for gross beta and gamma isotopic analyses[e] monthly. Composite for tritium analysis quarterly.

REACTOR PROTECTION SYSTEM INSTRUMENTATION (Continued)

The system meets the intent of IEEE 279 for nuclear power plant protection systems. The bases for the trip settings of the RPS are discussed in the bases for Specification 2.2-1.

The measurement of response time at the specified frequencies provides assurance that the protective functions associated with each channel are completed within the time limit assumed in the accident analysis. No credit was taken for those channels with response times indicated as not applicable.

Response time may be demonstrated by any series of sequential, overlapping or total channel test measurement, provided such tests demonstrate the total channel response time as defined. Sensor response time verification may be demonstrated by either (1) inplace, onsite or offsite test measurements, or (2) utilizing replacement sensors with certified response times.

Because the trip logic of the solid state reactor protection system results in a trip of all four divisions and full reactor scram if the logic is satisfied for the coincident logic reactor trip functions or the non-coincident NMS reactor trip function, the REACTOR PROTECTION SYSTEM RESPONSE TIME tests of the various reactor trip functions can only be performed during shutdown. All four divisional logic response times are therefore checked for every response test of two RPS channels of each function. Each function has four logic trains through two out of four coincident logic circuits located one in each division. There are four coincident logic circuits associated with each reactor trip function each of which will cause the trip of one RPS division logic.

3/4.3.2 ISOLATION ACTUATION INSTRUMENTATION

Under NRC/CPS review

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

The 2-out-of-4 logic for the MSIV isolation functions is identical to the logic of the RPS and the instrumentation response time is demonstrated, in an identical manner.

Except for the MSIVs, the safety analysis does not address individual sensor response times or the response times of the logic systems to which the sensors are connected. (For D.C. operated valves, a 3 second delay is assumed before the valve starts to move. For A.C. operated valves, it is assumed that the A.C.

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3/4.6.2.3 DRYWELL AIR LOCKS

The limitations on closure for the drywell air locks are required to meet the restrictions on DRYWELL INTEGRITY and the drywell leakage rate given in Specifications 3.6.2.1 and 3.6.2.2. The specification makes allowances for the fact that there may be long periods of time when the air locks will be in a closed and secured position during reactor operation. Only one closed door in each air lock is required to maintain the integrity of the drywell.

3/4.6.2.4 DRYWELL STRUCTURAL INTEGRITY

This limitation ensures that the structural integrity of the drywell will be maintained comparable to the original design specification for the life of the unit. A visual inspection in conjunction with Type A leakage tests is sufficient to demonstrate this capability.

3/4.6.2.5 DRYWELL INTERNAL PRESSURE

The limitations on drywell-to-containment differential pressure ensure that the drywell peak pressure of 18.9 psig does not exceed the design pressure of 30.0 psig and that the containment peak pressure of 9.0 psig does not exceed the design pressure of 15.0 psig during steam-line break conditions. The maximum external drywell pressure differential is limited to 0.1 psid, well below the (2.3) psid at which suppression pool water will be forced over the wier wall and into the drywell. The limit of 1.0 psid for initial positive drywell to containment pressure will limit the drywell pressure to 18.9 psid which is less than the design pressure and is consistent with the safety analysis to limit drywell internal pressure.

3/4.6.2.6 DRYWELL AVERAGE AIR TEMPERATURE

The limitation on drywell average air temperature ensures that peak drywell temperature does not exceed the design temperature of 330°F during LOCA conditions and is consistent with the safety analysis.

3/4.6.2.7 DRYWELL VENT AND PURGE

The drywell purge system must be normally maintained closed to eliminate a potential challenge to containment structural integrity due to a steam bypass of the suppression pool Intermittent venting of the drywell is allowed for pressure control during OPERATIONAL CONDITIONS 1, 2 and 3, but the cumulative time of venting is limited to 5 hours per fuel cycle. Venting of the drywell is prohibited when the 12-inch continuous containment purge system or the 36-inch containment building ventilation system supply or exhaust valves are open. This eliminates any resultant direct leakage path from the drywell to the environment.

In OPERATIONAL CONDITIONS 1, 2 and 3, the drywell purge 24-inch exhaust valve can be opened only if it is blocked so as not to open more than 50°. This assures that the valve would be able to close against ~~containment~~ pressure buildup resulting from a LOCA.
drywell

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DRYWELL VENT AND PURGE (Continued)

Operation of the drywell vent and purge 24-inch supply and exhaust valves during plant operational conditions 4 and 5 is unrestricted; the 50° blocks may be removed to allow full opening of the valves, and the cumulative time for vent and purge operation is unlimited.

3/4.6.3 DEPRESSURIZATION SYSTEMS

The specifications of this section ensure that the drywell and containment pressure will not exceed the design pressure of 30 psig and 15 psig, respectively, during primary system blowdown from full operating pressure.

The suppression pool water volume must absorb the associated decay and structural sensible heat released during a reactor blowdown from 1040 psia. Using conservative parameter inputs, the maximum calculated containment pressure during and following a design basis accident is below the containment design pressure of 15 psig. Similarly the drywell pressure remains below the design pressure of 30 psig. The maximum and minimum water volumes for the suppression pool are 150,230 cubic feet and 146,400 cubic feet, respectively. These values include the water volume of the containment pool, horizontal vents, and weir annulus. Testing in the Mark III Pressure Suppression Test Facility and analysis have assured that the suppression pool temperature will not rise above 185°F for the full range of break sizes.

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

Experimental data indicates that effective steam condensation without excessive load on the containment pool walls will occur with a quencher device and pool temperature below 200°F during relief valve operation. Specifications have been placed on the envelope of reactor operating conditions to assure the bulk pool temperature does not rise above 185°F in compliance with the containment structural design criteria.

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

The containment spray system consists of two 100% capacity trains, each with Two ~~three~~ spray rings located at different elevations about the inside circumference of the containment. RHR A pump supplies one train and RHR pump B supplies the other. RHR pump C cannot supply the spray system. Dispersion of the flow of water is effected by 251 nozzles in each train, enhancing the condensaton of

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3/4.6.5 DRYWELL POST-LOCA VACUUM RELIEF VALVES

The post-LOCA drywell vacuum relief valve system is provided to relieve the vacuum in the drywell due to steam condensation following blow-down. Containment air is drawn through the vacuum relief valve check valves in the two branches of the separate post-LOCA vacuum relief line and in a branch of each drywell purge compressor discharge line. Vacuum relief initiates at a differential pressure of one psi. This vacuum relief, in conjunction with the rest of the drywell purge system, is necessary to insure that the post-LOCA drywell H_2 concentration does not exceed 4% by volume.

Following vacuum relief, the drywell purge system pressurizes the drywell, forcing noncondensibles through the horizontal vents and into the containment at a rate designed to maintain the H_2 concentration below the flammable limits.

There are two 100% vacuum relief systems so that the plant may continue operation with one system out of service for a limited period of time.

Four vacuum breaker lines, with two valves in series in each line are provided. Any (three) vacuum relief valve lines can provide full vacuum relief capability.

GGNS - Description

3/4.6.6 SECONDARY CONTAINMENT

The secondary containment completely encloses the primary containment, except for the upper personnel hatch. It consists of the fuel building, gas control boundary, and portions of the auxiliary building enclosed by the extension of the gas control boundary and the ECCS cubicles. The standby gas treatment system (SGTS) is designed to achieve and maintain a negative 1/4" W.G. pressure within the secondary containment following a design basis accident. This design provides for the capture within the secondary containment of the radioactive releases from the primary containment, and their filtration before release to the atmosphere.

Establishing and maintaining a vacuum in the secondary containment with the standby gas treatment system once per 18 months, along with the surveillance of the doors, hatches, dampers, and valves, is adequate to ensure that there are no violations of the integrity of the secondary containment.

The OPERABILITY of the standby gas treatment systems ensures that sufficient iodine removal capability will be available in the event of a LOCA. The reduction in containment iodine inventory reduces the resulting site boundary radiation doses associated with containment leakage. The operation of this system and resultant iodine removal capacity are consistent with the assumptions used in the LOCA analyses. Continuous operation of the system with the heaters OPERABLE for 10 hours during each 31 day period is sufficient to reduce the buildup of moisture on the absorbers and HEPA filters.

Drywell vacuum relief valves are provided on the drywell to pass suffient quantities of gas from the containment to the drywell to prevent an excess negative pressure from developing in the drywell.

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6.4 TRAINING

6.4.1 A retraining and replacement training program for the unit staff shall be maintained under the direction of the Director-Nuclear Training, shall meet or exceed the requirements and recommendations of Section 5.5 of ANSI Standard N18.1-1971 and Appendix "A" of 10 CFR Part 55 and the supplemental requirements specified in Sections A and C of Enclosure 1 of the March 28, 1980 NRC letter to all licensees, and shall include familiarization with relevant industry operational experience.

6.5 REVIEW AND AUDIT

6.5.1 FACILITY REVIEW GROUP (FRG)

FUNCTION

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

COMPOSITION

6.5.1.2 The FRG shall be composed of the:

Chairman:	Assistant Power Plant Manager-Operations
Member:	Director ~~Assistant Power Plant Manager~~-Maintenance
Member:	Director- ~~Supervisor-Plant~~ Operations
Member:	Director ~~Supervisor~~-Technical
Member:	Supervisor-C&I
Member:	Director ~~Supervisor~~-Radiation Protection
Member:	Supervisor-Nuclear
Member:	~~Supervisor~~-Quality Assurance Representative

ALTERNATES

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

MEETING FREQUENCY

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

QUORUM

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